Request IR-1:

Please provide the current status of projects listed in Schedule "A" of the 2016 ACE Plan Decision, and the current status and a cost update for each of the projects listed in Schedules "B", "C", and "D" of the Decision.

Response IR-1:

Please refer to the following:

- Schedule A – Attachment 1
- Schedule B – Attachment 2
- Schedule C – Attachment 3
- Schedule D – Attachment 4

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Schedule A - 2016 ACE Plan

CI#	Project	2015 Budget	Project Total	Status Update
	Generation			
41142	HYD - St. Margaret's Fish Passage	2,900,021	3,433,314	Approved
44978	HYD-Wreck Cove Automation	874,891	2,379,999	Approved
40283	HYD - Wrights Lake Dam Refurbishment	1,967,723	2,242,751	Approved
41130	HYD - Avon #2 Generator Stator Rewind	620,353	694,096	Approved
45171	HYD-Avon 1 Pipeline Replacement	467,755	547,780	Approved
46232	HYD - WHR Pipeline Replacement	458,493	538,454	Approved
33142	CT- Burnside #4 Unit Restoration	3,094,420	3,469,160	Approved
44775	CT - TUC#4 LM6000 Generator Rotor Re-wedge	691,046	803,594	Approved
46506	LM6000 - Noise Mitigation	707,491	707,491	Now less than $250k
46483	CT - Tusket Control System Upgrade	441,816	441,816	Approved
44752	BGT1 - Generator Rotor Retaining Ring Replacement	357,869	357,869	Deferred to 2018
29065	CT - BGT Replace Halon Fire Protection System	234,780	356,682	Now less than $250k
46507	LM6000 - Fuel Nozzle Rotable Kit	295,772	295,772	Approved
45117	BGT1 - PLC and Field Device Control Upgrade	253,768	253,768	Deferred to 2018
46068	UN CW Debris Removal System	1,575,866	1,575,866	Approved
46300	TRE6 - Air Heater Refurbishment	752,215	752,215	Approved
44536	LIN3 HP Rows 1&2 Replacement	706,791	706,791	Cancelled
46466	TUC2 - Rotary Airheater Refurbishment	439,946	439,946	Cancelled
46655	ICP Mile 10.1 Bridge Repairs	377,279	377,279	Deferred to 2018
	Transmission			
46591	88S Lingan Replace 230kV GIS	3,274,637	23,510,262	Approved
43324	L6513 Rebuild/upgrade line terminals	12,735,850	23,429,902	Not approved at this time
43678	Separate L8004/L7005 on Canso Crossing Double Circuit Tower(DCT)	1,367,669	10,797,354	ACE 2017 Subsequent Submittal
41519	Harbour East 138 kV Transmission Line	497,838	8,793,272	Deferred to 2018
44987	L7003 Lidar Upgrades	2,871,847	6,885,817	Approved
45053	69KV Structure Replacements West	290,836	4,495,729	ACE 2017 Subsequent Submittal
45306	George Street Substation Addition	2,431,743	4,300,627	Approved
45066	Upgrade L6511 and L7019 Thermal Rating	3,219,774	3,693,033	Not approved at this time
46587	Metro Voltage Support Add Capacitor	1,499,915	2,522,277	Approved
46586	2015 PCB Removal - Substation	1,262,087	1,262,087	Approved
46333	L6538 Replacements	500,375	1,019,443	Approved
45795	L6503 Upgrade	780,641	780,641	Approved
46332	L6539 Replacements	736,393	736,393	Approved
41438	85S Cable Termination Replacement Wreck Cove	616,959	616,959	Approved
	Distribution			
40320	LED Street Light Conversion	7,280,062	40,609,354	Approved
44749	Tiverton Tower Refurbishment	935,802	1,281,771	ACE 2017 Subsequent Submittal
44836	Halifax 4kV Conversion Part 2	581,405	842,670	Approved
46651	23H-303G Rockingham Conversion Part 1	266,008	572,750	Approved
46398	20H Spryfield Voltage Conversion	329,169	444,970	Approved
43218	88W-323HA Tusket Islands Phase 3	286,911	286,911	Deferred to 2018
	General Plant			
46552	Backbone Communications System Upgrade	1,189,999	12,525,792	Approved
46075	IT - Maximo Upgrade	1,198,973	1,198,973	ACE 2017 Subsequent Submittal
46739	IT - Outage Map Technology Upgrades	982,880	1,023,269	Approved
41425	IT - Cognos Upgrade	323,498	526,740	Approved
46411	AMO Hydro Asset Management PE	205,643	376,637	Approved
46073	IT - Lotus Notes Applications Replacement	308,782	308,782	Approved
46671	CIP v5 Cyber System Systems	730,200	730,200	Approved

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Schedule "B" - 2016 ACE Plan Approved Projects

			ACE 2016		Updated		
Tab #	CI	Project	2016 Budget ($)	Project Total ($)	2016 Budget ($)	Project Total ($)	Status
Generation							
G01	46298	HYD Five Mile Lake Dam Refurbishment	1,793,260	2,209,018	2,287,445	2,419,410	in service
G02	47397	HYD Gisborne Dam D4 and Spillway S4 Refurbishment	1,669,320	2,050,519	1,659,292	1,767,528	on-going
G03	47396	HYD Nictaux Powerhouse Dam Refurbishment	1,437,731	1,792,968	1,115,354	1,220,832	in service
G04	47172	HYD Tidewater 1 Overhaul	962,136	1,418,532	1,896,306	2,017,916	on-going
G05	47332	HYD Methals Overhaul	1,216,083	1,392,927	2,097,037	2,380,900	on-going
G06	47432	HYD Ridge Overhaul	869,304	869,304	732,480	732,480	on-going
G07	47552	TRE5 Boiler Refurbishment 2016	1,204,387	1,204,387	1,345,883	1,345,883	in service
G08	47664	LIN4 Division Wall Replacement	619,243	619,243	664,077	664,077	in service
G09	47666	LIN4 Boiler Refurbishment 2016	571,859	571,859	644,744	644,744	in service
G10	47663	LIN4 - SH5 Boiler Tube Replacement	538,776	538,776	609,036	609,036	in service
G11	46352	TRE5 Air Heater Refurbishments	530,139	530,139	559,217	559,217	in service
G12	47689	LIN4 - Air Heater Refurbishment	521,951	521,951	536,202	536,202	in service
G13	47761	LIN1 Boiler Refurbishment	506,845	506,845	-	398,673	deferred
G14	47690	LIN4 Burner Front Refurbishment	480,349	480,349	559,284	559,284	in service
G15	47658	LIN4 L-0 Blade Replacement	3,550,915	4,597,152	4,395,036	4,481,215	in service
G16	47755	LIN4 Turbine High Temperature Fasteners Replacement	1,073,877	1,073,877	1,072,820	1,072,820	in service
G17	47911	TUC1 High Temperature Fastener Replacement	828,968	828,968	739,560	740,096	in service
G18	46465	TUC2 Turbine Valve Refurbishment	651,362	651,362	111,486	111,914	on-going
G19	48018	TUC1 IP Blading Refurbishments	1,137,208	1,137,208	892,864	892,864	in service
G20	47673	LIN4 Generator Rotor Rewind	2,602,159	2,602,159	2,443,989	2,445,291	in service
G21	43170	LIN4 AVR Replacement	418,432	842,207	754,336	765,914	in service
G22	47657	LIN4 High Voltage Bushing Refurbishment	724,395	822,570	863,318	868,354	in service
G23	47762	LIN4 Analytical Panel Replacement	401,658	401,658	500,677	501,606	in service
G24	47961	LIN1 Condenser Tube Coating	333,944	333,944	-	329,691	deferred
G25	47704	POT - Replace Polisher Chemical Skid	321,950	321,950	236,051	236,051	on-going
G26	47945	TUC Electrode-ionization (EDI) Unit Replacement	275,154	275,154	264,846	336,114	in service
G27	47611	POT - Demolish Unit 1 Stack	1,732,346	1,732,346	33,286	1,128,831	on-going
G28	47505	LIN Coal Mill Refurbishment 2016	749,183	749,183	561,294	561,294	in service
G29	47661	POT - Asbestos Management 2016	721,551	721,551	347,326	347,326	in service
G30	47869	LIN4 Bottom Ash	616,599	616,599	626,842	626,842	in service
G31	47554	TRE5 5-1 FD Fan Refurbishment	494,802	494,802	463,753	463,753	in service
G32	41505	TRE5 - 5F Conveyor Structural Refurbishment	484,801	484,801	356,616	356,616	in service
G33	47872	LIN E Gallery Structural Steel Protective Coating	481,492	481,492	463,145	539,874	in service
G34	47555	TRE5 Coal System Upgrades	414,085	469,942	321,750	556,245	in service
G35	47510	LIN Coal Plant Structural Refurbishment Phase 2	359,425	359,425	207,467	426,693	in service
G36	47662	POT Coal Mill Overhauls 2016	324,874	324,874	223,050	223,050	in service
G37	47617	TRE6 Elevator Controls Upgrade	320,704	320,704	231,143	288,521	on-going
G38	47668	POT - Plant Siding 2016	287,926	287,926	322,629	322,629	on-going
G39	47596	TRE6 ID Fan Damper Upgrades	272,239	272,239	234,990	234,990	in service
G40	47507	LIN CW Pump Rebuild 2016	441,560	441,560	636,584	636,584	in service
G41	47506	LIN CW Screen Refurbishment 2016	349,743	349,743	338,317	338,317	in service

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Schedule "B" - 2016 ACE Plan Approved Projects

			ACE 2016		Updated		
Tab #	**CI**	**Project**	**2016 Budget ($)**	**Project Total ($)**	**2016 Budget ($)**	**Project Total ($)**	**Status**
Transmission							
T01	46591	88S Lingan Replace 230kV GIS	1,351,406	14,249,882	717,636	12,754,231	on-going
T02	48066	2016/2017 Substation Polychlorinated Biphenyl (PCB) Equipment Removal Program	2,160,890	3,500,427	3,232,600	3,657,096	in service
T03	46587	Metro Voltage Support Add Capacitor	2,960,916	3,373,511	1,924,253	3,266,935	on-going
T04	46757	88S Lingan 230kV BPS Upgrades	265,641	3,218,221	243,372	3,046,334	on-going
T05	47950	L5017 Replacements & Upgrades	1,175,785	2,182,142	665,030	1,538,043	on-going
T06	44981	2C Port Hastings Add 138-25kV Transformer	548,727	2,053,799	301,160	1,991,101	on-going
T07	47952	L-7001 Replacements (Phase 3 & 4)	1,617,933	1,725,284	1,009,751	1,513,213	in service
T08	48114	2016 Steel Tower Life Extension - HRM	503,696	1,477,739	886,076	1,477,191	in service
T09	47914	L-6537 Replacements and Upgrades	744,025	1,382,705	531,097	1,084,618	on-going
T10	47935	L5040 Replacements	668,692	1,241,298	1,081,802	1,231,134	on-going
T11	47949	L-5028 Replacements and Upgrades	598,866	1,144,355	977,777	977,777	in service
T12	47912	L-6552 Replacements and Upgrades	1,054,326	1,054,326	1,074,052	1,074,052	in service
T13	48113	2016 Steel Tower Refurbishment	960,453	1,032,578	1,411,068	1,699,991	in service
T14	48059	2016/2017 Transmission Switch & Breaker Replacements	470,933	980,999	1,164,054	1,169,093	in service
T15	48116	2016 Sacrificial Anode Installation Program	452,034	970,909	1,173,256	1,199,157	in service
T16	48067	2016 Oil Containment Program	245,199	468,963	15,451	323,424	on-going
T17	48063	2016/2017 Capacitor Bank Breaker Replacements	199,159	385,850	97,772	303,003	on-going
T18	48062	2016/2017 Reactor Breaker Replacements	201,038	384,974	324,428	514,801	in service
Distribution							
D01	47721	2016 PCB Phase-out for Pole Top Transformers	2,562,582	4,409,579	3,406,192	3,951,338	in service
D02	48093	2016 Padmount Replacement Program	1,761,336	1,911,470	1,400,050	1,840,837	in service
D03	47752	4S-333 Bentinck St. Rebuild	575,357	575,357	769,034	769,034	in service
D04	48092	2016 Substation Recloser Replacements	529,270	529,270	511,607	511,607	in service
D05	47765	58C-405 Belle Cote Phase 2	477,154	477,154	251,270	504,298	in service
D06	47766	70V-302 Centerlea Rebuild	456,314	456,314	375,090	375,090	in service
D07	47734	1C-411 Highway 4 Reconductor	437,410	437,410	5,585	433,477	on-going
D08	47732	131H-424/137H-412 Hammonds Plains Feeder Tie	337,133	337,133	290,108	290,108	on-going
D09	47754	63V-313 Ward Rd Reconductor	308,994	308,994	204,822	204,822	in service
General Plant							
GP01	48072	2016 ADMS Switch Order Management	305,469	305,469	159,438	293,109	on-going
Total New Capital Spending			**$57,223,473**	**$87,278,325**	**$56,553,362**	**$83,684,589**	

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Schedule C - ACE 2016

		ACE 2016		Updated		
CI#	Project Title	2016 Budget ($)	Project Total ($)	2016 Budget ($)	Project Total ($)	Status
Generation						
29807	HYD - Tusket Falls Main Dam	257,292	6,534,233	125,668	9,945,740	ACE 2017 Subsequent Submittal
44595	HYD - Hollow Bridge Canal and Intake Refurbishment	2,907,602	3,137,002	4,231,319	4,494,897	Approved
46254	HYD - Mill Lake Surge Tank Refurbishment	1,380,899	1,421,366	74,149	2,578,958	Deferred to 2018
47167	HYD - Sandy Lake Surge Tank Refurbishment	1,316,587	1,358,796	3,052,055	3,068,557	Approved
47551	HYD - SHH Controls Upgrade	524,406	1,092,851	171,528	1,097,571	Approved
48020	HYD - RUT3 Generator Refurbishment	774,422	1,030,940	1,106,635	1,120,242	Approved
47163	HYD - Tusket Controls Upgrade	472,153	880,570	83,401	665,329	Approved
44775	TUC#4 LM6000 Generator Stator Re-wedge	1,586,056	1,722,180	1,131,759	1,252,648	Approved
46191	Tusket Fuel System Upgrade	606,082	892,178	431,718	1,616,916	Approved
44788	BGT1 Vibration Monitoring & Protection System Upgrade	252,674	252,674	-	253,174	Deferred to 2018
48157	TUC Auxiliary Boiler Purchase	2,822,565	2,822,565	3,587,099	3,660,479	Approved
47870	LIN Cofferdam Outer Cell Refurbishment	850,609	850,609	-	44,692	Now less than $250k
47871	LIN Stack Re-Coating	707,696	707,696	-	389,795	Deferred to 2018
47953	LIN Rail Car Positioner Upgrade	507,812	507,812	-	566,619	ACE 2017 Seek Approval
47687	POT Boiler Chemical Recondition	855,348	855,348	178,359	974,808	ACE 2017 Seek Approval
47893	TUC3 Generator Hydrogen Panel Upgrade	301,806	301,806	2,616	423,798	ACE 2017 Seek Approval
Transmission						
48025	L7018 Upgrade to 345kV & Capacitor Bank Addition	1,982,135	21,495,059	122,589	126,170	Cancelled
41519	Harbour East 138 kV Transmission Line	2,120,250	11,672,021	526,976	15,399,899	Deferred to 2018
43678	Separate L8004/L7005 on Canso Crossing Double Circuit Tower(DCT)	270,900	10,767,280	1,027,519	16,198,977	ACE 2017 Subsequent Submittal
48022	Spider Lake Substation Addition	1,093,651	6,348,981	289,038	6,154,988	Submitted, Awaiting UARB Review & Approval
48154	L5527 Reconductor	297,828	497,606	-	-	Cancelled
48024	90H - Sackville: Capacitor Bank Addition & L-6010/L6005 Breaker Upgrades	794,131	3,852,989	-	-	Cancelled
48023	103H - Lakeside: Capacitor Bank Additions & L-6003 Breaker Upgrades	794,131	3,231,190	169,462	174,460	Cancelled
43268	9W-B53 Tusket Replace Supporting Structure	354,151	354,151	-	335,153	Deferred to 2018
Distribution						
47124	Automated Metering Infrastructure	6,997,996	100,000,000	2,151,979	128,621,050	Approved
47760	85S-402 Re-Insulate	387,024	1,855,988	294,484	1,259,666	Approved
47776	111S Prime Brook Feeder Exits & Feeders	1,474,738	1,560,144	918,763	1,537,242	Approved
47787	2H Armdale New Feeder	451,838	1,272,415	32,233	1,285,527	ACE 2017 Subsequent Submittal
44749	Tiverton Tower Refurbishment	880,250	1,157,069	224,844	1,109,714	ACE 2017 Subsequent Submittal
47753	24C-442GB Highway 16 Reconductor Phase 2	669,565	1,154,302	1,172,720	1,452,356	Approved
47784	103H-Lakeside Feeder Reconfiguration	579,868	579,868	130,728	130,728	Now less than $250k
47792	Distribution Automation Remote Communications	378,666	415,762	-	398,070	Deferred to 2018
48152	20H-Spryfield Voltage Conversion Phase II	375,848	375,848	407,969	407,969	Approved
47403	Load Research Sample Update	286,872	322,387	227,292	478,902	Submitted, Awaiting UARB Review & Approval
47786	129H Kearney Lake New Feeder	311,817	311,817	210,546	210,546	Now less than $250k

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		ACE 2016		Updated		
CI#	**Project Title**	**2016 Budget ($)**	**Project Total ($)**	**2016 Budget ($)**	**Project Total ($)**	**Status**
48195	Halifax 4kV Conversion Ph 3	250,336	250,336	244,128	429,195	Submitted, Awaiting UARB Review & Approval
General Plant						
44671	IT-Oracle Financials Upgrade	3,768,231	9,891,170	29,130,096	65,657,285	Approved
46075	IT - Maximo Upgrade & GIS Integration	3,042,932	7,937,644	1,297,105	29,365,805	ACE 2017 Subsequent Submittal
48232	T&D Scheduling & Dispatch	2,012,050	5,306,971	-	-	To be completed under CI 46075 IT – Work and Asset Management.
48251	T&D Field Design	2,012,050	4,022,082	-	-	
47477	IT - Security Enhancements	2,280,000	2,536,182	2,418,935	3,084,526	Approved
48236	Customer Experience Self Serve Development Phase 1	1,802,719	1,802,719	324,748	815,420	Submitted, Awaiting UARB Review & Approval
46671	NERC CIP Version 5 Implementation	552,227	1,528,492	2,155,668	2,481,287	Approved
48254	IT - Outage Communication Technology Capacity Improvement	1,500,000	1,500,000	989,357	1,873,470	Approved
41425	IT - Cognos Upgrade	190,000	1,431,257	534,829	1,589,573	Approved
46073	IT - Lotus Notes Applications Replacement	415,008	744,698	501,137	530,982	Approved
47751	Dynamic Transmission Limits	414,748	552,560	882	525,049	ACE 2017 Subsequent Submittal
48234	Customer Support System Enhancements	515,063	515,063	234,029	234,029	Now less than $250k
48238	Customer Billing Experience Improvements	515,063	515,063	319,625	443,356	ACE 2017 Subsequent Submittal
48155	2016 SCADA Application Upgrade	426,355	426,355	30,748	404,605	ACE 2017 Subsequent Submittal
	Total Capital Items for Subsequent Approval	**$56,322,449**	**$230,554,091**	**$60,264,734**	**$314,870,222**	

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		ACE 2016		Updated		
CI#	**Project Title**	**2016 Budget ($)**	**Project Total ($)**	**2016 Budget ($)**	**Project Total ($)**	**Status**
Generation						
47613	PHB - Boiler Refurbishment 2016	604,193	604,193	572,360	572,360	Submitted, Awaiting UARB Review & Approval
47614	PHB - Fuel System Refurbishment 2016	296,556	296,556	290,634	290,634	Submitted, Awaiting UARB Review & Approval
	Total Capital Items for Subsequent Approval	**$900,749**	**$900,749**	**$862,994**	**$862,994**	

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CI#	Project Title	ACE 2017 Project Total	ACE 2016 Project Total	ACE 2015 Project Total	Reason not Activated
46075	IT - Work & Asset Management	28,027,680	7,937,644	-	Continued business planning and project scoping is required before this project can be filed. Will be filed in 2017.
43678	Separate L8004/L7005 on Canso Crossing	16,183,691	10,767,280	10,797,354	This project will be executed in 2017. Engineering efforts continued throughout 2016 with construction now scheduled for 2017 to align with the completion of the Maritime Link.
29807	HYD - Tusket Falls Main Dam	9,940,664	6,534,233	-	Consultation with First Nations was required in 2016 in order to proceed with this project, pushing the start of this project into 2017.
47124	Advanced Metering Infrastructure - Pilot Pr	8,274,738	100,000,000	-	Project was not deferred and submitted in 2016. Listed on the Subsequent Submittal list as it was filed after ACE 2017 filing.
45053	69Kv Structure Replacements West	4,818,017	-	4,495,729	At the time of ACE 2015, this was planned for construction in 2016. Further evaluation showed this project could be safely deferred to 2017. Engineering / Assessment will be completed in 2016 with the project being executed in 2017.
47776	111S Prime Brook Feeder Exits & Feeders	1,503,986	1,560,144	-	Project was not deferred and submitted in 2016. Listed on the Subsequent Submittal list as it was filed after ACE 2017 filing.
47787	2H Armdale New Feeder	1,285,679	1,272,415	-	This project is related to the new transformer for 2H (CI 46811) which is now being completed in 2017.
47760	85S-402 Re-Insulate	1,259,666	1,855,988	-	Further engineering required has pushed the filing of this project from late 2016 to early 2017.
44749	Tiverton Tower Refurbishment	1,058,200	1,157,069	1,281,771	Further engineering required has pushed the filing of this project from late 2016 to early 2017.
47687	POT Boiler Chemical Recondition	974,604	855,348	-	During 2016, additional assessments of boiler tube deposits were performed during the planned outage in order to determine the appropriate method to complete this work. Further testing performed on tube samples to simulate results was also completed in order to determine the approach for completing this work in 2017.
47953	LIN Railcar Positioner Upgrade	566,619	507,812	-	Further assessment of this project indicated it could safely be deferred to 2017.
47166	HYD - McAskill Brook Decommissioning	562,684	110,990	-	First Nations, archeological and stakeholder engagement is required throughout 2016 and into 2017 to determine the best approach to completing this work.
47751	Dynamic Transmission Limits	537,466	552,560	-	Further efforts to determine final project scope has pushed this project into 2017.
48238	Customer Billing Experience Improvements	490,878	515,063	-	Project was not deferred and submitted in 2016. Listed on the Subsequent Submittal list as it was filed after ACE 2017 filing.
47893	TUC3 PE Generator Hydrogen Panel Repla	423,798	301,806	-	This project was deferred due to the Major TUC3 Shutdown being moved out to 2017.
48044	Bentley Nevada Upgrade and Integration to	401,459	228,862	-	Continued work with suppliers to develop, test and assess a fleet-wide solution was required in 2016 in order to properly scope this project.
48155	2016 SCADA Application Upgrade	400,688	426,355	-	Project was not deferred and submitted in 2016. Listed on the Subsequent Submittal list as it was filed after ACE 2017 filing.

Request IR-2:

Please identify all 2017 ACE Plan capital items submitted for approval or forecast for subsequent approval, which were in a previous ACE Plan, but have not been activated. Please indicate all ACE Plan years they were part of, their budgeted costs, and reasons why they were deferred and not initiated.

Response IR-2:

Please refer to Attachment 1.

Request IR-3:

In its 2016 ACE Plan submission, NSPI included 111 projects with an estimated cost of less than $250,000 each, with a total spending of $15.5 million (Point Aconi excluded). Has the cost for any of the above projects exceeded, or is it expected to exceed, the $250,000 limit? If so, please identify these projects and their revised cost estimates.

Response IR-3:

The following table lists the projects included in the 2016 ACE Plan as less than $250,000 that have exceeded or are expected to exceed the $250,000 limit.

CI#	Project Title	ACE 2016 ($)	Revised Estimate ($)	Status / Expected Filing Date
47600	TRE Asbestos Abatement (2016)	154,303	2,052,739[1]	To be filed in January 2017
47166	HYD - McAskill Brook Decommissioning	110,990	530,953[2]	Included in ACE 2017 Subsequent Submittal
48044	Bentley Nevada Upgrade and Integration to Fleet Monitoring	228,862	407,145	ACE 2017 Subsequent Submittal
47947	TUC6 Condenser Waterbox Coating	225,210	342,116	To be filed in January 2017
47874	LIN Ash Scale Replacement	237,241	285,803	To be filed in January 2017
47933	LIN4 Turbine Vibration Monitoring Upgrade	238,216	277,772	To be filed in January 2017

- During the planned outage on Trenton Unit #5 in November 2016, a significant amount of asbestos was found to require abatement in order to safely complete the work planned during the outage.

- As more scoping activities were undertaken throughout 2016, the level of effort required to complete this work was found to be much greater.

Request IR-4:

With reference to the 2014 ACE Plan, in its decision the Board noted that "… the ACE Plans include a growing number of projects, especially some having large expenditures, which are to be submitted for subsequent approval." On page 13 of its 2015 ACE Plan application, NSPI stated:

> **In order to reduce the number of capital items found on the Subsequent Submittal list, NS Power proposed that more capital items be submitted in the ACE Plan for review and approval, with the caveat that a number of these capital items may not be fully scoped or have detailed supporting documentation.**

Please provide the following:

(a) A table, related to the 2015, 2016, and 2017 ACE Plan submissions, which includes the number and total cost of individual projects submitted for Board approval in each of these years, and the number and total cost of capital items forecast for subsequent approval.

(b) Please comment on any significant variances in the above indices.

Response IR-4:

(a) The table below shows the quantity and total cost of projects that have been submitted for approval or listed for subsequent approval as part of the 2015, 2016, and 2017 ACE Plans.

	Request Approval		Subsequent Submittal	
	# of Projects	**Total Cost ($)**	**# of Projects**	**Total Cost ($)**
2015	84	83,627,912	46	173,947,254
2016	73	92,452,908	50	230,554,091
2017	71	72,601,321	83	356,038,931

(b) The increase in quantity and total cost of subsequent submittal items in the 2017 ACE Plan is largely driven by an increase in IT and Hydro related projects.

Pursuant to section 1.2.3 of the 2017 ACE Plan, the large increase in IT projects is due to rapid technological advancements, increased use of technology across the business, end of useful life of current systems, and changing customer expectations. This has necessitated NS Power update its approach to managing technology. Accordingly, the level of IT investment will increase, and in this case, much of that investment is not scoped to a level where submission of a capital work order to the UARB for review and approval is appropriate.

Similarly, for the Hydro projects on the subsequent submittal list in the 2017 ACE Plan, the level of scoping and cost estimates is not refined to the point where an approval request is appropriate.

This increase in quantity and total cost does not represent a change in NS Power's approach to reducing the number of capital items found on the Subsequent Submittal list

Request IR-5:

On page 6 of the Application, NSPI states:

> **In addition to sustaining capital projects, there are a number of strategic capital projects. Those projects include the re-implementation of our Enterprise Resource Planning systems, the installation of Advanced Metering Infrastructure, Maritime Link transmission system upgrades, and transmission upgrades to support the economic dispatch of the Tuft's Cove generating station. These strategic capital projects are subject to separate capital work order submissions outside of the 2017 ACE Plan.**

The cost estimates related to the Enterprise Resource Planning ("ERP") project for years 2017 and 2018 are identified separately in a table provided on page 10 of the 2017 ACE Plan. Considering initiation date of the ERP project, and timing of capital funds expended, please explain:

(a) Why this project was not identified in a similar table provided on page 8 of the 2016 ACE Plan.

(b) Does NSPI's discussion related to the Sustaining Capital portion of annual forecasted costs, provided in response to 2016 ACE Plan UARB IR-10, include any indication of spending related to the ERP project? If so, please elaborate.

(c) The ERP project is the subject of a separate filing before the Board (Matter M07746). The Board allowed NSPI to proceed with work on this project at shareholders' risk, pending approval. However, on page 64 of the Application, the project (CI 44671) is listed on a summary of general plant carryover capital spending. At page 33, NSPI identifies carryover projects as multi-year projects that were previously approved by the UARB. Please explain why this capital item is included among the previously approved projects?

Response IR-5:

(a) The ERP project was not noted as a strategic project in the table on Page 8 of the 2016 ACE Plan because at the time of the 2016 ACE Plan filing, the scope of the ERP related reimplementation had not been determined. Pursuant to section 4 of NS Power's ERP Capital Work Order Application filed November 10, 2016,[1] the project framework to establish the scope of the ERP project, the Evaluation Phase, began in November 2015 and continued well into 2016. The $10 million included in the 2016 ACE Plan Subsequent Submittal table was a placeholder estimate, meant to indicate that some level of investment was expected to be required by NS Power related to the reimplementation of its ERP systems.

(b) The response to 2016 ACE Plan UARB IR-10 does not include a specific reference to spending related to the ERP project. However, the response to UARB IR-10 references "$7.4 million investment in IT application upgrades", which included $3.8 million in ERP related costs for 2016. Similarly, UARB IR-10 references "an effort to update aging IT applications" with respect to the forecasted increase in expenditures in 2017, which included $6.1 million in ERP related costs for 2017.

(c) Projects appearing on the carryover spending list have either been approved by the Board or submitted to the Board and awaiting review and approval. The ERP project was submitted to the UARB on November 10, 2016, and therefore appears as a carryover project in the 2017 ACE Plan.

[1] M07746, Exhibit N-1 and N-2, NS Power ERP Application, November 10, 2016.

Request IR-6:

On pages 6 and 7 of the Application, NSPI noted:

> **While NS Power carries out these capital investments, the Company must also consider and adapt to evolving regulatory requirements, such as the adoption of renewable energy and recently introduced performance standards.**

(a) Please discuss the impact of the two above noted factors on the development of NSPI's 2017 ACE Plan.

(b) Please explain how NSPI's compliance "with one of the most ambitious renewable energy requirements and emissions reductions in Canada", as stated on page 7, impacts on capital expenditures in the 2017 ACE Plan.

(c) With reference to the comments made on page 8, please explain how the performance standards ordered by the Board in Matter M07387 may impact any of the transmission and distribution capital investments described in the 2017 ACE Plan submitted for either current or subsequent approval.

Response IR-6:

(a) Please refer to part (b) for the impact of renewable energy requirements on the NS Power system.

The Board's Performance Standards Decision, dated November 28, 2016, does not impact the 2017 ACE Plan capital expenditures as filed.

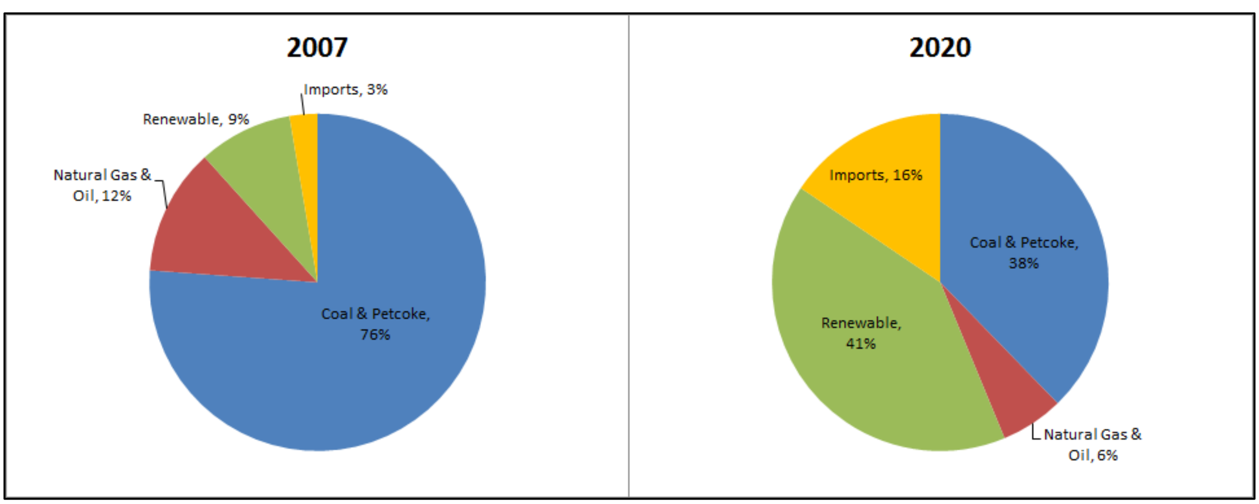
However, in the event that investments related to the Performance Standards approved by the Board are required to be advanced into 2017, the Company will identify them in the corresponding capital work orders.

Please also refer to NSUARB IR-11 with respect to the impact on IT investments.

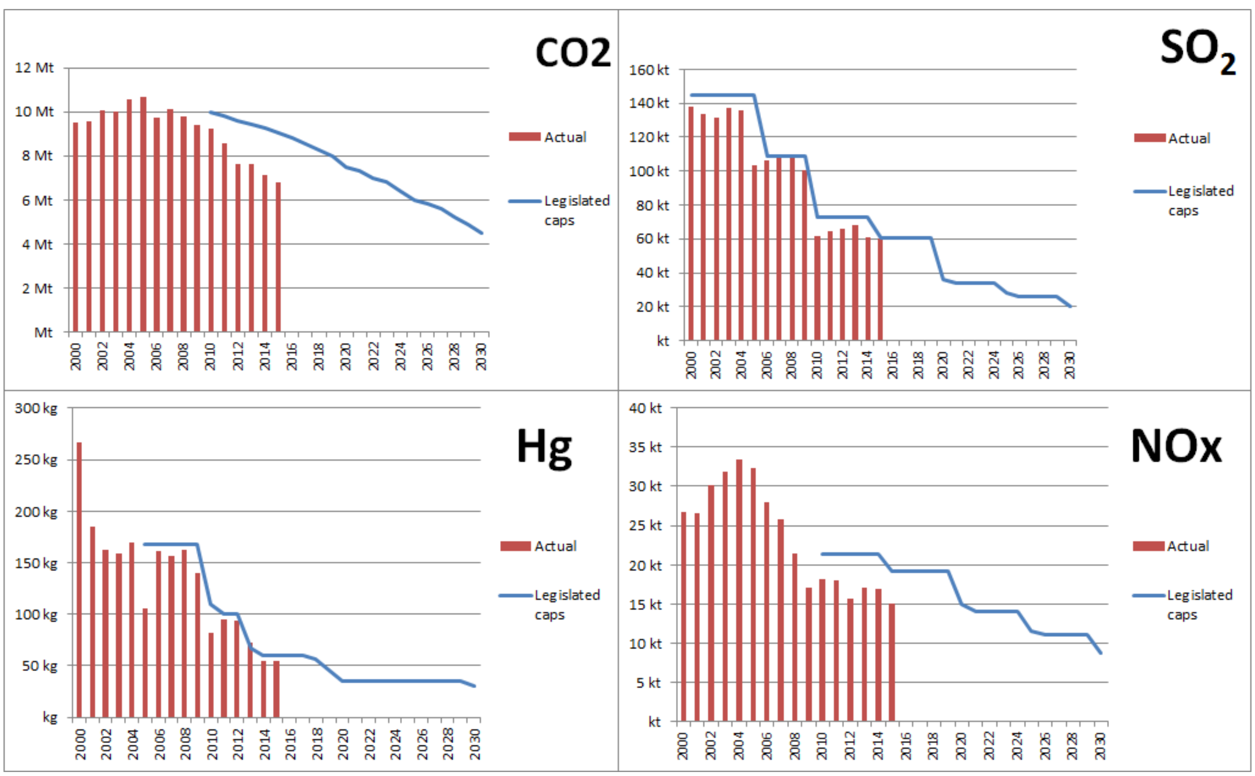
(b) NS Power has conducted Integrated Resource Plans (IRP) to determine the most cost-effective way for the Company to comply with regulations on behalf of customers.

The Renewable Electricity Regulations of the Province of Nova Scotia establish the requirements for the provision of renewable energy for load serving entities in Nova Scotia (https://www.novascotia.ca/just/regulations/regs/elecrenew.htm).

In 2007, over 90 percent of energy sales in Nova Scotia were served by fossil-fired generation. By 2020, a minimum of 40 percent of electricity sales must be supplied from approved sources of renewable electricity generation, as set out in the Regulations. The Pie Charts below show the pace of renewables integration in Nova Scotia.



Further to the requirements under the Renewable Electricity Regulations, NS Power is obliged to meet the air emission limits provided by both the Nova Scotia Air Quality Regulations (for SO_2, NO_x and Hg) and the Nova Scotia Greenhouse Gas Emissions Regulations, which sets air emission limits as prescribed by the Regulations. The air emission limits as prescribed by these regulations are provided in the Graphs below. In addition to these provincial requirements, Federal Regulations under Canadian Environmental Protection Act (CEPA) (Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations, 2012) deal specifically with coal fired units. Nova Scotia meets this obligation via a 2015 Equivalency Agreement, prescribing that compliance with NS provincial requirements for CO_2 emissions also addresses the federal requirements. With the recent Pan-Canadian Framework regarding GHGs, and the related agreement in principle between the federal and provincial governments, it is expected that some amendments to the existing Equivalency Agreement will be required.



These are fleet caps and, as evident in the graphs above, the limits decline over time imposing increasing challenges to the operation of the fossil-fired fleet. This necessitates optimization efforts in the dispatch of existing fossil-fired assets and has required the development of new forms of generation to assist with CO_2 emission compliance and to meet the requirements of the Renewable Electricity Regulations.

The 2017 ACE Plan reflects the need to support the evolving generating fleet utilization. The fossil-fired generating fleet was designed for baseload operation. These units have proven to be reliable and economic and have served customers well when system energy sales were higher and environmental regulations did not limit their operation. More recently this fleet has been required to provide greater operational flexibility with the integration of over 600MW of variable generation in the form of wind, and the effects of industrial load loss and efficiency programming.

As system operators maintain the balance of generation with customer demand on the power system, they require generating units that can be dispatched to provide Load Following and Regulation services. The NS Power steam fleet has proven its flexibility in making these services available.

Evaluations of unit capability have demonstrated that these modified operations are possible for our steam fleet. However, modification of operations places different unit maintenance demands on the fleet. Previously well-established maintenance practices require revisions to respond to new failure mechanisms or permit adjustments to the scope or cycle of maintenance activities as the rate of equipment deterioration is accelerated or slowed by current day operating demands. The 2017 ACE Plan is developed to support these changes through the ongoing work of NS Power's Generation Asset Management Program.

The Asset Management program has been designed to identify and mitigate risk arising from operating activities. Risk mitigation can and does include capital refurbishment or replacement, but other actions are also employed like enhanced monitoring and diagnostics, modification of operating limits, and modification of inspection and maintenance practices. Where capital refurbishment or replacement is deemed to be the necessary course of action, these projects are advanced into the ACE Plan for the coming year.

As some units operate at lower annual capacity factors, all are providing greater dispatch flexibility than they ever have. Some examples from the 2017 ACE Plan that reflect generating fleet investment changes due to renewable electricity requirements and air emission hard caps are:

- <u>Boiler Refurbishment Projects</u> - Scope of selective tube replacements would be higher with greater utilization.

- <u>Ash Site Capping Projects</u> - Deferred projects as less ash is produced through lower utilization.

- <u>Lingan Vacuum Pump Project</u> - CI 49437 – Project scope modified to reflect the near-term retirement plans for Lingan 2.

- <u>Hydro Investments</u> - Ongoing refurbishment activity to sustain a flexible and renewable form of generation.

Beyond the generation fleet, other projects proposed in the 2017 ACE Plan are reflections of the transformation in the Company’s power system brought on by environmental policy and regulations. The AMI pilot project is an example of NS Power responding to trends in the industry driven by the shift towards lower emitting forms of generation. As the generation side of the business is increasingly challenged it becomes necessary to make steps to establish greater visibility and control on the customer demand side of the business. The company is exploring projects to establish greater demand response capability which could reduce some of the burden for flexible operations presently carried by generation.

(c) Please refer to part (a).

Request IR-7:

With reference to page 8 of the Application, please comment on the impact of the Fuel Stability Plan approved by the Board on capital expenditures in the 2017 ACE Plan.

Response IR-7:

The Fuel Stability Plan has not impacted the selection of projects and capital expenditures in the 2017 ACE Plan. Capital investments in NS Power's generation fleet enable the reliable operation of NS Power's generation resources, which allows for the economic dispatch of those generation resources in support of fuel savings and stability.

Request IR-8:

With reference to the table on page 10 of the Application:

(a) Please explain increases in the forecasted spending on Sustaining Capital for years 2017 and 2018, in comparison with the related 2016 ACE Plan budget estimates.

(b) Explain a forecasted increase in 2017 from $23.0 million to $38.7 million on Regulatory / Compliance projects, when compared with the related 2016 ACE Plan budget estimates.

(c) Please provide a detailed explanation and reconciliation for the difference in the forecasted costs on the Metro Transmission Upgrades in 2017 of $5.8 million, and the 2016 forecast of $28.9 million.

Response IR-8:

(a) 2017 (increase of $25.5 million): This increase is largely driven by an increase in IT investment. The two largest IT investments are related to T&D Work & Asset Management ($8 million), and cyber security ($6 million). The level of investment required for these initiatives was not fully scoped during the development of the 2016 ACE Plan. The capital investment in Hydro assets has increased as well, driven by larger investments in controls ($3 million) and powerhouses ($2 million). The remaining variance is largely related to the Burnside #4 Unit Restoration (CI 33142) deferral to 2017.

2018 (increase of $23.9 million): this increase is largely driven by the continued investment in T&D Work & Asset Management ($18.5 million) and cyber security ($3 million). Costs for these initiatives were not forecasted in 2018 at the time of the 2016 ACE Plan submission.

(b) The forecast increase of $15.7 million in 2017 is primarily driven by investments in dam safety ($15 million in 2017), ash site investment ($6 million in 2017), and PCB removals ($5 million). A combination of deferrals from 2016 to 2017 and a general increase in projects completed for compliance purposes led to this increase.

(c) The 2017 capital investment for Metro Transmission Upgrades included in the 2016 ACE Plan was comprised of four projects. Throughout 2016, NS Power continued to evaluate these projects. It was determined that only one of the projects remained economically beneficial. Therefore, three of the four projects were cancelled. CI 48022 was submitted to the UARB on July 15, 2016. The table below shows the breakdown of each project, with the 2017 investment forecasted as per the 2016 and 2017 ACE Plans.

CI#	Project Title	2016 ACE ($M)	2017 ACE ($M)
48025	L7018 Upgrade to 345kV & Capacitor Bank Addition	19.2	Cancelled
48022	Spider Lake Substation Addition	4.9	5.8
48024	90H - Sackville: Capacitor Bank Addition & L-6010 / L6005 Breaker Upgrades	2.7	Cancelled
48023	103H - Lakeside: Capacitor Bank Additions & L-6003 Breaker Upgrades	2.1	Cancelled
	Total 2017 Investment	**28.9**	**5.8**

Request IR-9:

With reference to page 10, does the 2017 ACE Plan submission comply with criteria contained in NSPI's Capital Expenditure Justification Criteria ("CEJC") document, as approved by the Board on October 18, 2016? If not, please elaborate.

Response IR-9:

Yes.

Request IR-10:

With reference to page 14, footnote 2, a specific example cited as a driver influencing the pace of change related to technology is a requirement to comply with NERC reliability standards that fall under the Critical Infrastructure Protection ("CIP") program. Please confirm there are no information technology capital expenditure projects in the 2017 ACE Plan which are related to NERC requirements.

Response IR-10:

Confirmed.

Request IR-11:

With reference to pages 14 and 15:

(a) Will the proposed information technology capital projects outlined in Section 1.2.3 of the Application play any role in assisting NSPI to meet the performance standards ordered by the Board in Matter M07387?

(b) What is the projected IT spending for the next five years after these large investments?

Response IR-11:

(a) IT investments related to transmission & distribution and customer service will help support performance standards, but there are no specific investments in the 2017 ACE Plan designed to respond to performance standards.

(b) The projected IT spend for the next five years after the noted investments is forecasted as:

- 2017 - $30 million
- 2018 - $38 million
- 2019 - $20 million
- 2020 - $19 million
- 2021 - $23 million

This spend forecast is related to investments in technology outside the projects in Section 1.2.3. These are sustaining investments to maintain support, and increase use of technology across the business.

Request IR-12:

In reference to the table on top of page 22, please provide the following:

(a) The table shows there was no spending on New Renewables in 2015. Please reconcile this information with the "2015 Q3 F" and "2015 ACE Budget" amounts, provided on page 16 of the 2016 ACE Plan submission.

(b) With respect to Distribution, please reconcile the differences in the forecasted annual expenditures for years 2017 to 2020, with the related forecast amounts provided on page 16 of the 2016 ACE Plan submission.

(c) Please reconcile the difference in spending on General Plant projects, between the "2016 Q3 F" and "2016 ACE Budget" forecasted amounts.

(d) According to the table, the total forecasted spending on General Plant projects during the 2016-2018 period amounts to $253.3 million. Please reconcile this figure with the amount of $130.5 million, provided on page 16 of the 2016 ACE Plan submission, which represents the total forecasted spending during the same period.

Response IR-12:

(a) The table on page 22 of the 2017 ACE Plan incorrectly included the investment in South Canoe and Sable Wind Farm under Generation. The correct totals should have shown Generation at $110.4 million and New Renewables at $17.1 million. Please refer to Attachment 1 for an updated table.

(b) The table below shows the Distribution spending forecast for 2017-2020 from the 2016 and 2017 ACE Plans:

Distribution	2017 ($ M)	2018 ($ M)	2019 ($ M)	2020 ($ M)
2016 ACE Plan	105.0	98.3	89.5	62.7
2017 ACE Plan	83.9	118.0	118.1	70.3
Variance	**(21.1)**	**19.7**	**28.6**	**7.6**

The main driver for the changes in distribution investment is the profiling of the Advanced Metering Infrastructure (AMI) project. As the project continues to be fully scoped, the level of investment in AMI changed as follows:

AMI	2017 ($ million)	2018 ($ million)	2019 ($ million)	2020 ($ million)
Change	$(20.9)	$18.3	$20.9	$6.1

The remaining variance is due to the re-profiling of the LED Streetlight project. Please refer to NSUARB IR-27 for an update on the LED Streetlight project.

(c) The increase of $33.3 million from the 2016 ACE Budget to the 2016 Q3 Forecast is primarily due to the development of the ERP project which had a forecast of $3.8 million in the 2016 ACE Plan and a Q3 Forecast of $34.2 million. The remaining increase is due to the larger IT cyber security investment.

(d) The increase of $123 million from the 2016 ACE Plan to the 2017 ACE Plan for 2016 – 2018 time period is largely due to the ERP investment which increased by $85 million, an increase in the T&D Work and Asset Management project (CI 46075) of $20 million, and an increase in IT cyber security investment of $9 million that was not fully scoped at the time of ACE 2016 submission. The remaining increase is due to general aging application IT investment and some large scale roofing replacements.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	Actuals							ACE Plan	Forecast			
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2016**		**2017**	**2018**	**2019**	**2020**	**2021**
					Q3 F	**ACE Budget**						
Generation	$88.7	$68.4	$66.0	110.4	$114.8	$105.0		$106.0	$112.5	$136.8	$161.3	$127.6
Renewables	53.2	15.2	82.8	17.1	0.0	0.0		-	-	-	-	-
Transmission	45.4	31.0	51.0	54.4	55.4	56.1		$91.2	68.3	52.3	53.4	54.4
Distribution	68.7	62.9	52.8	62.5	69.7	74.8		$83.9	118.0	118.1	70.3	64.0
General Plant	28.5	29.9	21.7	27.1	77.3	44.0		$116.9	59.1	37.2	36.6	40.2
Total	**$284.5**	**$207.4**	**$274.3**	**$271.5**	**$317.3**	**$279.9**		**$398.0**	**$357.8**	**$344.4**	**$321.6**	**$286.2**

Request IR-13:

With reference to page 22:

(a) Please provide a list of 2016 ACE Plan capital items for subsequent approval which NSPI plans to submit prior to the end of 2016.

(b) Please note if there are any 2016 ACE Plan items that are not listed either on the above list, among the 2016 deferred or cancelled items, or for which NSPI did not request Board approval.

Response IR-13:

(a) The table below lists the projects that were planned to be filed in 2016 at the time of the 2017 ACE Plan submission. Three projects (CI 46075, CI 47760 and CI 44749) were planned to be filed in 2016, but now require additional scoping/engineering in order to file an application to the Board.

CI#	Project Long Title	2016 ACE ($)	Project Total ($)	Status
46075	IT - Maximo Upgrade & GIS Integration	3,042,932	7,937,644	
47760	85S-402 Re-Insulate	387,024	1,855,988	
44749	Tiverton Tower Refurbishment	880,250	1,157,069	
48238	Customer Billing Experience Improvements	515,063	515,063	Filed on December 16, 2016
48155	2016 SCADA Application Upgrade	426,355	426,355	Filed on December 16, 2016
48236	Customer Experience Self Serve Development Phase 1	1,802,719	1,802,719	Filed on November 18, 2016

(b) All projects on the 2016 ACE Plan Subsequent Submittal list are filed, approved, included in the deferred/cancelled list in the 2017 ACE Plan, or listed in the table above.

Request IR-14:

With reference to pages 29 and 30, NSPI cancelled three capital items (48025, 48024, and 48023), and provided the identical justification:

> **Further transmission study showed that this work is currently not an economic alternative. The project will continue to be evaluated based on market conditions and may be brought forward in the future.**

Please explain why these projects are not currently economically justified, and what market conditions would need to be, for these projects to become economically viable.

Response IR-14:

Figure A of the Transmission Planning Study submitted with CI 48022 – Spider Lake (and provided as Partially Confidential Attachment 2, identified that incremental improvements in reducing the requirement to dispatch Tufts Cove Generation out of merit could be obtained through sequential network upgrades. The first of these network upgrade projects was the addition of the Spider Lake Substation. In the Avoided Cost Study submitted with CI 48022 that was completed subsequent to the Transmission Planning Study, provided as Attachment 1, it was identified that the majority of the total duration of when Tufts Cove is required to run out of merit, and hence the majority of the value opportunity, was obtained with the Spider Lake Substation addition. The remaining three network upgrade projects (CI 48023, 48024, and 48025), would also provide some smaller improvements but would not provide a positive return on investment based on the fuel cost assumptions used for the time period studied.

The market condition that would most affect the future economic justification of these projects is a significant increase in natural gas prices.

Nova Scotia Power Inc.

Spider Lake Substation Avoided Cost Study

2016-07-14

Executive Summary

Significant avoided cost of fuel and purchased power is possible if minimum generation requirement at Tufts Cove generating station were to be significantly reduced. Construction of the new transmission substation in the Spider Lake area will alleviate transmission system constraints which are responsible for Tufts Cove generating station minimum required generation regardless of economic dispatch. Installation of Spider Lake substation project, and subsequent easing of transmission system constraints, shows an avoided cost of fuel and purchased power of $9.5 million in three years, 2018 to 2020.

Background

Due to variable and unpredictable nature of daily Natural Gas price swings, minimum generation at Tufts Cove generating station requirement has been observed to be a significant contributor to fuel and purchased power costs. The Tufts Cove minimum generation has not been identified as an issue in the past since Tufts Cove was required to generate regardless of the minimum generation requirements due to relatively high system demand. With the decrease in system load, addition of significant quantity of new renewable generation, and energy efficiency efforts, among other factors, Tufts Cove minimum generation requirement emerged as a binding constraint on the system.

Study Scope and Layout

The potential avoided cost study is based on hourly chronological dispatch optimization simulation conducted in Plexos software.

Preliminary simulations, based on the Base Cost of Fuel reset study, indicated that the avoided cost of fuel and purchased power could provide payback period for this project of less than three years. It was also noted that the avoided cost of reducing minimum Tufts Cove generation is sensitive to fuel prices.

Based on this preliminary finding, the time frame for the study was set to 3 years, 2018-2020 and the study was constructed to utilize fuel price sampling and statistical significance tests of the resulting outcomes in order to test fuel price sensitivity of the avoided cost.

Fuel and purchased power prices are modeled using stochastic variables with standard deviation error and correlation coefficients. Stochastic representation of variables is meant to simulate uncertainties associated with fuel and purchased power prices which would not be captured by the classic sensitivity analysis (High, Base and Low case scenarios).

Study Assumptions and Approach

Tufts Cove minimum generation parameters as specified by NSP System Operator:

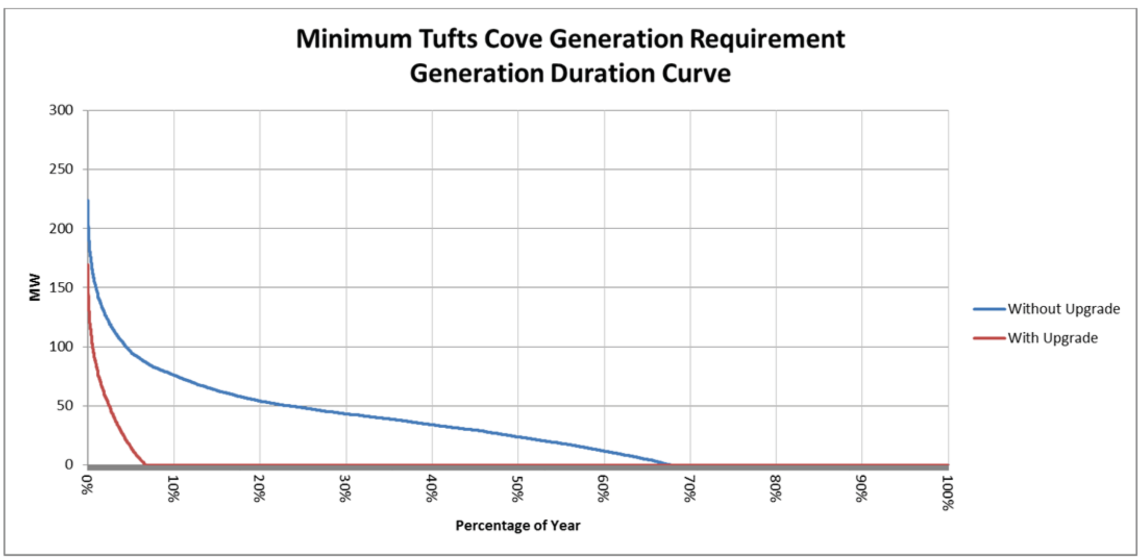
Summer ratings April 1 to Oct 31 - Winter ratings Nov 1 March 31
Maximum Onslow South flow: Summer 880 MW, Winter 985 MW
BSL = Base System Load

Before Spider Lake Upgrades:
Minimum Tufts Cove Generation
Summer:
TUCgen Minimum = 0.241 * (BSL) – 221 MW
Winter:
TUCgen Minimum = 0.286 * (BSL) – 380 MW

After Spider Lake Upgrades:
Minimum Tufts Cove Generation
Summer:
TUCgen Minimum = 0.293 * (BSL) – 368 MW
Winter:
TUCgen Minimum = 0.325 (BSL) – 517 MW

Based on the system security formulae stated above, Tufts Cove minimum generation would be at least 270 GWh without Spider Lake substation system upgrade and 26 GWh with the system upgrade. The figures are based on average 2017-2020 system hourly load forecast. Due to minimum up and down times characteristics of Tuft Cove steam generating units, and the timing of minimum generation requirement, the minimum Tufts Cove minimum steam generation output may be higher than 270 GWh.

Below is a graphical representation of Tufts Cove minimum generation requirement:



It should be noted that when natural gas price is low relative to solid fuel, minimum Tufts Cove generation requirement is inconsequential; however, when natural gas prices are high, Tufts Cove minimum generation requirement can have a significant impact on the system dispatch cost.

Daily Natural Gas and Purchased Power Price Random Sampling

Plexos simulation assumptions set is based on the most recent 2017-2019 Base Cost of Fuel refresh regulatory filing assumptions set and system model file. Delivery of power from the Muskrat Falls Hydro Electric Project in Labrador to Nova Scotia through the Maritime Link is simulated to start in January 2020.

Fuel and purchased power price samples are drawn around the expected values (mean), with error term chosen to be lognormally distributed with standard deviations and correlated in time using Plexos autocorrelation model. Correlation coefficients are also considered for stochastic variables within the same group. Error distribution type and values for standard deviations and correlation coefficients are in the table below:

Distribution Type	Lognormal
Error Autocorrelation	100%
Correlation coefficients	80 – 95%
Error standard deviations Solid Fuel: Diesel, HFO and NG: Imports and Purchased Power:	 5.31 - 7.22 5.83 - 9.48 1.57 - 4.86

Sample size is set to 100 samples and solution is created using 100 sets of fuel and purchased power stochastic variable. Unit commitment and dispatch based on cost minimization objective function are optimized using Plexos system dispatch optimization simulation software for all considered samples. Two models for NSPI system are created:

(1) Base Case (No spider lake substation); and
(2) Spider Lake substation effect (changes in minimum Tufts Cove Generation constraint).

Comparisons of total cost of dispatch for each sample pair, where stochastic variables are generated with the same Plexos random number seed, were carried out. Simulation results and comparisons between the two cases are expressed in terms of avoided cost and P10/P50/P90 likelihood of realized avoided cost framework estimates for years 2018, 2019 and 2020.

Study Results

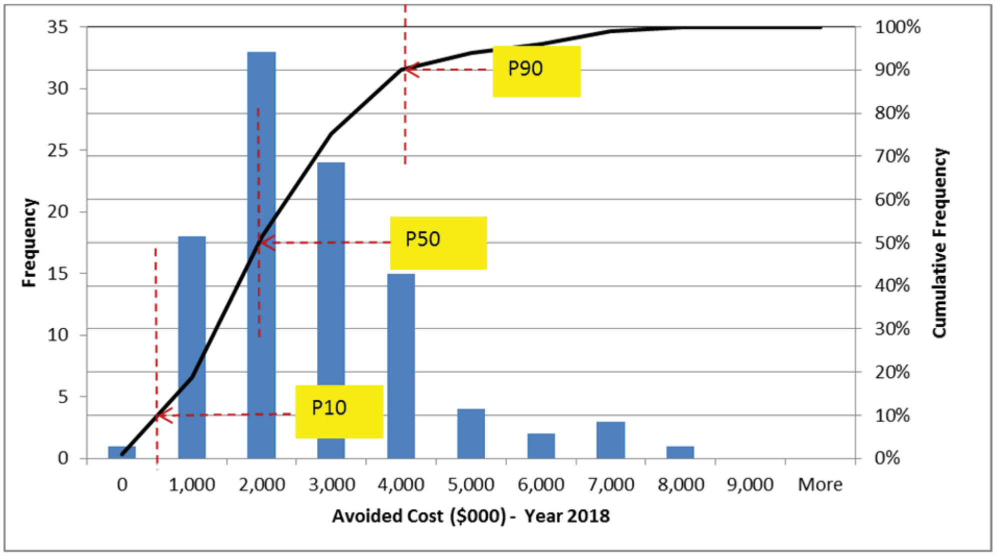
The results summarized below are based on 100 chronological hourly system dispatch optimization simulations, for each year in the study, using randomly sampled daily fuel and purchased power costs.

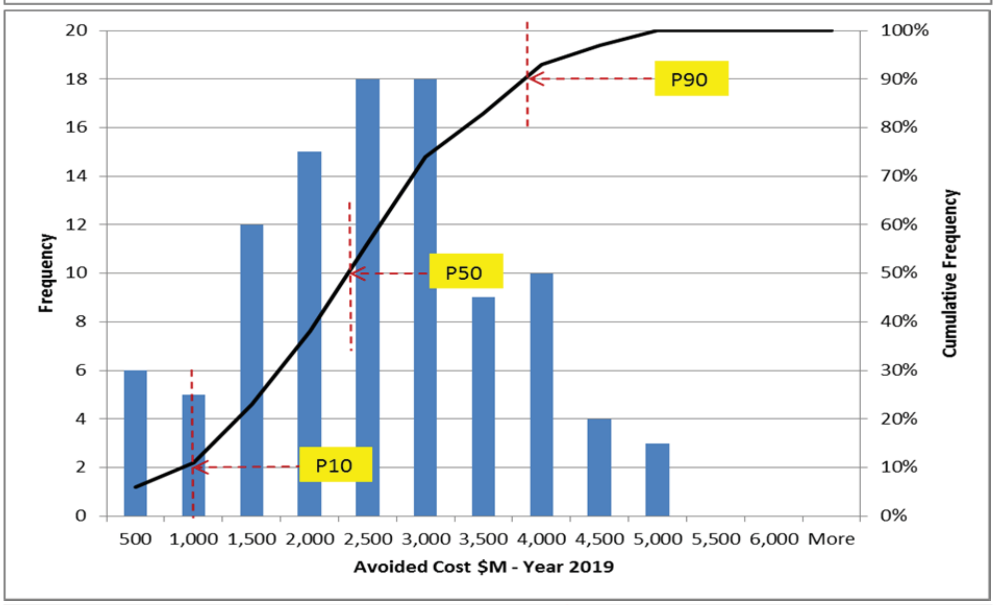
	2018	2019	2020
P10 Avoided Cost Estimate	0.570	1,000	2,389
P50 Avoided Cost Estimate (highest probability)	1,918	2,005	5,684
P90 Avoided Cost Estimate	4,047	4,000	9,833

Table: P10/P50/P90 Estimates ($M)

The most likely avoided cost of removing Tufts Cove minimum generation requirement has been calculated to be $9.5 million in the three year study period. The P10 and P90 probabilities represent the avoided cost in extremely favourable and extremely unfavourable fuel cost cases.

Histograms presented on the next page are a visual representation of avoided costs across 100 simulated daily fuel and purchased power price samples.


Frequency
Cumulative Frequency
P90
P50
P10
0
5
10
15
20
25
30
35
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
0 1,000 2,000 3,000 4,000 5,000 6,000 7,000 8,000 9,000 More
Avoided Cost ($000) - Year 2018


Frequency
Cumulative Frequency
P90
P50
P10
0
2
4
6
8
10
12
14
16
18
20
0%
10%
20%
30%
40%
50%
60%
70%
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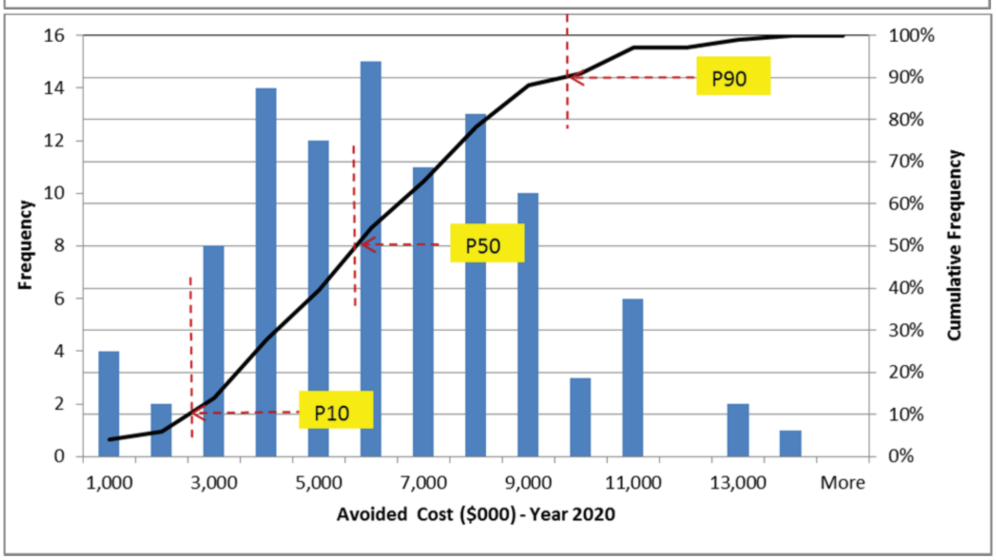
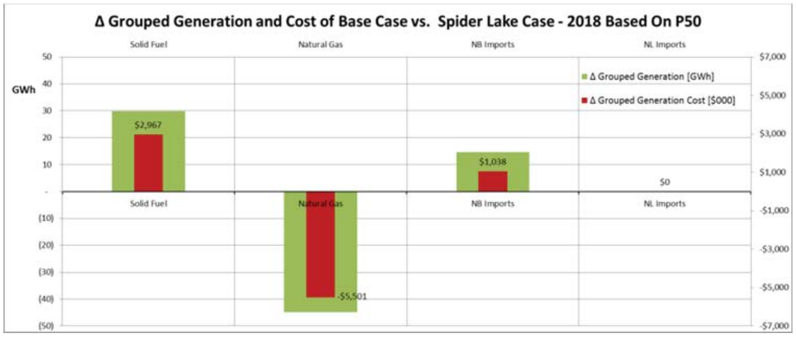
Avoided Cost $M - Year 2019


Frequency
Cumulative Frequency
P90
P50
P10
0
2
4
6
8
10
12
14
16
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
1,000 3,000 5,000 7,000 9,000 11,000 13,000 More
Avoided Cost ($000) - Year 2020

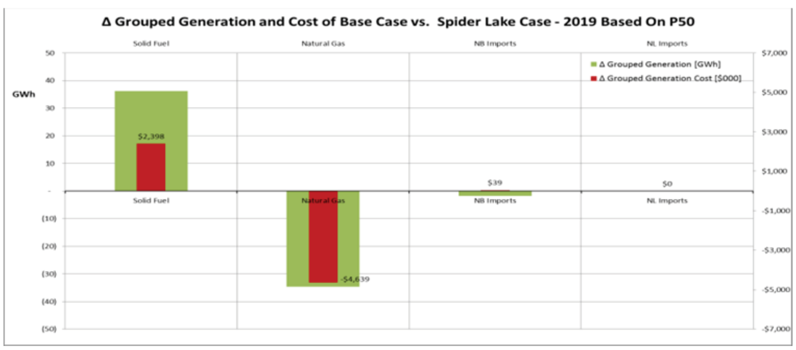
Results Discussion and Interpretation

Generation Profile Changes:

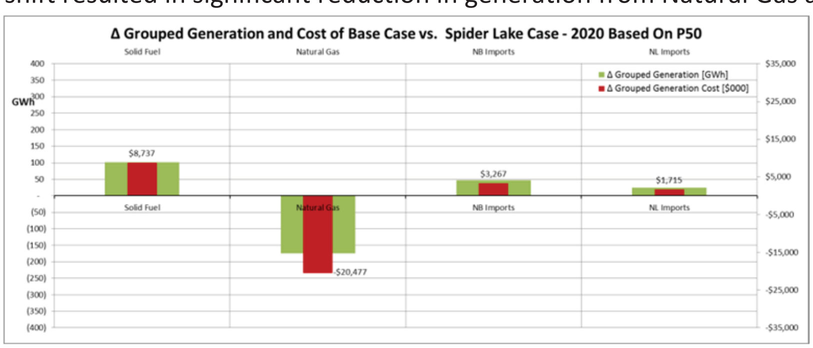
2018 avoided costs are derived from the system being able to utilize more coal generation and imports while reducing natural gas generation and associated cost. Maritime Link was simulated as unavailable in 2018.



2019 avoided costs are derived from the system being able to utilize more coal generation while reducing natural gas generation and associated cost. Maritime Link was simulated as unavailable in 2019.



2020 avoided costs show that in addition to being able to access more coal generation and imports from New Brunswick, the system was able to better utilize Maritime Link surplus energy. The system dispatch shift resulted in significant reduction in generation from Natural Gas and the associated cost.



NOTE: The generation profile delta analysis was conducted on a single sample simulation results whose avoided cost outcome most closely matched the P50 avoided cost result.

Transmission Planning Report
Report 053-2015-TSMG R1

Metro Transmission Upgrades

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2016-03-07

T/D Planning and Optimization
Nova Scotia Power Incorporated

Contents

Metro Transmission Upgrades

1. Introduction

Recent operational experience has indicated that fuel costs for thermal generation in Metro (Tufts Cove) can be particularly volatile due to the price and availability of natural gas or heavy fuel oil. In addition to must-run renewable generation and potentially more economic thermal generation in eastern Nova Scotia, the availability of imported power from either the Maritime Link or external markets via New Brunswick can provide incentives to reduce the need to operate Tufts Cove generation.

The Maritime Link (ML) is a bi-directional bipolar Voltage-Source Converter High Voltage Direct Current interconnection between Nova Scotia (NS) and the island of Newfoundland. The nominal rating of the converters is 500 MW, but with cable and inverter losses, the delivered power at the 101S-Woodbine terminal is expected to be approximately 475 MW. The ML is configured as two poles of 250 MW (net 237.5 MW) each.

This study examines the transmission system upgrades needed to provide maximum flexibility in the scheduling and dispatch/commitment of units at Tufts Cove.

2. Scope

Determine the system upgrades necessary to meet NERC/NPCC/NSPI design criteria under various flexible operating scenarios without the use of generation at Tufts Cove or Burnside (except in the case of operating reserve). Perform steady-state and stability analysis for the following load levels:

1. Summer peak load (highest system load under summer thermal ratings).
2. High ambient temperature line ratings (above 25°C)
3. Winter peak load (highest annual demand)
4. Winter off-peak (highest demand which does not require Tufts Cove generation)

3. Design Criteria

NPCC Directory 1[1] requires the stability of the bulk power system to be maintained during and following a prescribed set of contingencies, including "simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault". In addition to stability, prescribed contingencies cannot result in system voltage or transmission lines or equipment falling outside applicable emergency limits. Other contingencies which determine transmission operating limits include:

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with normal fault clearing.
b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal fault clearing.

[1] NPCC Directory 1 Design and Operation of the Bulk Power System (Sections 5.4.1 and 5.4.2) [https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf]

c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with delayed fault clearing.
d. Loss of any element without a fault.
e. A permanent phase to ground fault on a circuit breaker with normal fault clearing.
f. The failure of a circuit breaker to operate when initiated by a SPS (with limitations).

Avoidance of post-contingency voltage criteria violations generally requires each Transmission Planner to design its system in accordance with its own voltage control procedures and criteria, and coordinate these with adjacent Transmission Planner Areas. “Adequate reactive power resources and appropriate controls shall be installed in each Transmission Planner Area to maintain voltages within normal limits for pre-disturbance conditions, and within applicable emergency limits for the system conditions that exist following the contingencies specified [above]”. The NB Power System Operator has indicated that it is unacceptable for contingencies in NS to cause load shedding in NB or PEI due to UVLS. This will be confirmed during joint operating studies between NB Power, NS Power and Nalcor.

In addition to the above “single contingency criteria” (which in the case of b, c, e and f can result in the loss of more than one system element), NPCC requires that certain combinations of multiple contingencies be accommodated (often referred to as “N-1-1”), assuming that the system is re-dispatched to accommodate the second contingency within a reasonable period of time. After any critical generator, transmission circuit, transformer, shunt compensating device, or single HVdc pole is lost, the criteria must be met for any of the contingencies listed above.

NSPI is also subject to NERC criteria as approved by the Nova Scotia Utility and Review Board. NERC criteria are in some ways less stringent than NPCC; for example loss of only a single pole of a bi-polar HVdc terminal is considered a “design” or “normal” contingency. However, NERC has developed requirements related to the loss of “non-consequential load” for certain contingencies. Footnote 12 to the TPL-001-4 standard[2] permits loss of non-consequential firm load under limited conditions, which applies to imports from New Brunswick. Footnote 9 to this table allows for curtailment of firm transmission service as long as the receiving party carries sufficient Operating Reserve such that firm load is not lost due to this curtailment. This condition applies to Nova Scotia export to New Brunswick.

Although the double circuit lines L-6003/L-6007, L-6003/L7009 and L-6533/L6535 are not considered BES/BPS elements, these contingencies have the potential to impact a significant portion of the load centre.

4. Assumptions

1) All transmission upgrades associated with the Transmission Service Request study TSR-400[3] have been implemented:
    a. 101S-Woodbine substation expanded to incorporate two HVdc inverter terminals in a 345 kV ring-bus arrangement.

[2] Standard TPL-001-4 — Transmission System Planning Performance Requirements; Reliability Standards for the Bulk Electric Systems of North America, April 3, 2015
[3] Transmission Service Request 400 System Impact Re-Study Report TSR400-SIS2-R1, Nova Scotia Power System Operator, March 2013 (filed with NSUARB as *20150331 NSPI to SBA CI 43324 IR Responses P CONFIDENTIAL*)

   b. 230 kV breaker and a half bus development at 101S-Woodbine and L-7011 and L-7012 turned into this new bus.
   c. Second 345 kV-230 kV transformer installed at 101S-Woodbine.
   d. Separation of L-8004 and L-7005 from the common towers at Canso Strait Crossing, each with its own tower.
   e. Line L-6513 is rebuilt (and renumbered to L-6613) to 330 MVA conductor capacity, plus protection and metering upgrade.
   f. Line L-7019 uprated from an operating temperature of 60°C to 70°C.
   g. Line L-6511 uprated from an operating temperature of 50°C to 60°C.
   h. New 345 kV circuit breaker and node swap at 67N-Onslow to separate L-8002 and L-8003.
2) The following assumptions were used by TSR-400 as well:
   a. Brushy Hill Static Var Compensator (SVC) has been refurbished and is in-service.
   b. All four units at Burnside are available for service as 10-minute reserve and operation as synchronous condensers.
   c. Tufts Cove 4 and 5 have 10-minute reserve capability if they are not on-line.
   d. The Mersey Hydro system is assumed to retain its current capacity of 40 MW, and is dispatched at full load in winter.
   e. The Brooklyn Energy biomass plant operates seasonally, on-line at approximately 21 MW in winter, but off-line in summer.
3) Other assumptions include:
   a. Line L-7003 has been uprated to 70°C.
   b. All switchgear associated with L-6613 is rated at 2000 A.
   c. Maritime Link import is assumed to displace Tufts Cove generation instead of being exported out of NS. However, operation of Tufts Cove generation will be considered for limited periods of high flow as an alternative to transmission reinforcement based on financial analysis.
   d. The NS portion of the Joint Operating Reserve Sharing agreement with NB Power will be capped at 220 MW (40 % of the Maritimes Area shared reserve commitment of 550 MW, which is 10% of coincident peak Maritimes Area demand).
   e. NS will not operate Tufts Cove generation out of merit in order to withhold NS transmission capacity to deliver reserve to NB Power. If internal NS transmission limits do not permit delivery of reserve from eastern NS to NB, then NB Power will be contracted to carry the excess Operating Reserve.
   f. It is assumed that there will not be transmission reinforcements in the Moncton area of NB, and therefore simultaneous import restrictions will be imposed (ML import versus NB-NS import).
   g. Double-circuit tower contingencies on the non-Bulk Electric System in the Metro Area will be respected.

4) Although original energy schedules indicated that only 300 MW would be available from Nalcor during the winter months, which includes 150 MW of the “Emera Block” and only 150 MW available for export

to NB, there could be conditions under which the full capacity of the ML (475 MW) could be delivered to NS.

5) Projected fuel prices for thermal generation at Tufts Cove (natural gas or heavy fuel oil) are forecasted to rise over time, particularly in the winter months, therefore it is potentially economic to operate without generation at Tufts Cove. Fuel supply may also impact dispatch patterns for other plants.
6) The current import level from New Brunswick is a function of NB system load, capped at 200 MW in winter.
7) Wind generation in NS remains near presently committed levels, with no large transmission-connected wind generation beyond the plants commissioned in 2015 (Sable and South Canoe). Community Feed-In Tariff (COMFIT) wind generation has not been explicitly handled in system models at this point. Wind generation is varied according to the scenario under investigation, but this study is not meant to be an extensive investigation of the impact of high wind generation penetration on the grid at light load.

5. Summer Operation without Tufts Cove Generation

Tufts Cove is a dual-fuel thermal plant (natural gas or heavy fuel oil) rated at approximately 483 MW. Under conditions of high fuel price or limited fuel availability, operation with no generation at Tufts Cove has been desirable. Displacement of Tufts Cove generation by sources in eastern NS or import from NB is limited by transmission limits on the Onslow South (ONS) corridor. The ONS limit is governed by either voltage stability (voltage collapse) or thermal loading of equipment.

5.1. Metro Dynamic Reactive Power Reserves

Prevention of voltage collapse generally requires sufficient reactive power to support transmission and load before and after a disturbance. A lightly loaded transmission line behaves as a net generator of reactive power, sometimes resulting in excessively high system voltage. Heavily loaded transmission lines (loaded above the so-called Surge Impedance Load - SIL) consume reactive power in a non-linear proportion. The SIL of a transmission line is proportional to the square of the operating voltage of the line (thus a 345 kV line has a SIL of about 300 MW, whereas a 230 kV line has a SIL of about 132 MW. In the present configuration of the transmission lines comprising ONS, there is one 345 kV line and three 230 kV lines. When the 345 kV line L-8002 is lost, flow instantly increases on the parallel 230 kV lines, and the ONS corridor switches from a net producer to a significant consumer of reactive power. To maintain system voltage within acceptable limits following such a contingency, there must be reactive power held in reserve to dynamically respond to the event. The “Dynamic Reactive Reserve” (DRR) is provided by the following sources:

1. Static Var Compensator (SVC) at 120H-Brushy Hill
2. Any thermal generators on-line at Tufts Cove
3. Any gas turbine on-line at 14H-Burnside in either generate mode or synchronous condenser mode
4. Remote hydro or wind generators west of Metro provide little support for the ONS corridor, but help to divert reactive power that might otherwise flow west.

The DRR capability has been enhanced in the past two years to extend the limits on ONS:

1. Undervoltage load shedding of firm load at Spryfield, Kearney Lake Road, Cobequid Road and Dartmouth East eliminates the need for a reserve buffer.
2. Synchronous machines (Burnside and Tufts Cove) have great reactive power capability when operated at less than rated load, which is now counted as DRR.
3. More detailed studies have been conducted, confirming the value of DRR based on the location of its source (reactive power at the 120H-Brushy Hill SVC is more effective than either 14H-Burnside or 91H-Tufts Cove).
4. Shunt reactors are equipped with undervoltage relays with relatively high trip settings, allowing them to be operated in parallel with nearby capacitor banks yielding quasi-dynamic reactive power. This feature is not available at high system load and transfers where static reactive power requirements dictate that reactors must be off-line to support steady-state voltage.
5. The most significant contingency limiting ONS was eliminated in 2015 when L-8002 and L-8003 were separated from a common circuit breaker.
6. Other initiatives expected to improve DRR in the near future include:
    a. Automatic Voltage Regulators on certain wind farms will be activated
    b. New capacitors will be added to the Metro area at 90H-Sackville and 103H-Lakeside

The above enhancements to DRR have extended the ONS capability beyond 900 MW, assuming that the Brushy Hill SVC and Burnside Synchronous Condensers are available and all lines are in service. Figure 1 shows the current MDRR characteristic. Given the dynamic reactive reserve of 150 Mvar (i.e. Brushy Hill SVC and one Burnside synchronous condenser), the ONS limit varies from 775 MW to 870 MW, depending on the number of switchable reactors available at 103-Lakeside and 67N-Onslow. The availability of switchable reactors is related to system load level, where higher load levels prevent the use of these reactors due to local reactive power load.

5.2. Metro Load Characteristics

Figure 2 shows the characteristic system load behavior as a function of ambient temperature[4] for the past 12 months. Figure 2A shows the behavior of system load as temperature varies from 20°C to 32°C. Comparing this trend to past years (Figure 3A) suggests that air conditioning load is becoming a more prevalent influence on summer load. The summer thermal rating of transmission lines is based on an ambient temperature of 25°C and therefore they are de-rated for higher temperatures indicated as Figure 2B. In the past five years, the number of hours per year in which the ambient temperature in the metro area has exceeded 25°C has ranged from 222 to 333 (average 290) hours. Basic System Load[5] peaked at about 1230 MW during this period.

Figure 4 shows a typical annual load cycle, where summer line ratings are applied, in this case from the middle of May until the end of September. Basic load peaked at 1250 – 1300 MW during the period of summer ratings. Typically, Load Retention Rate load operates at about 105 MW on daily peak during the summer period, for a total system load of about 1400 MW.

[4] Ambient temperature is recorded at 120H-Brushy Hill substation

[5] Basic System Load is defined as net in-province load excluding Load Retention Customer load.

Tufts Cove generation dispatch has an impact on the flow in the Halifax-Dartmouth area. For analysis, we define Metro Load Pocket (MLP) as the part of the system shown in Figure 5. The MLP includes all load at 1H-Water Street, 2H-Armdale, 104H-Kempt Rd, 91H-Tufts Cove, 139H-Dartmouth Crossing, 113H-Dartmouth East, 126H-Porters Lake, 87H-Musquodoboit Harbour and the Dartmouth 69 kV Loop (99H-Farrell St., 62H-Albro Lake, 124H-Akerley, 40H-Woodlawn, 58H-Imperial Oil, 48H-Penhorn, and 54H-Maple St.). The peak demand of the MLP in January of 2015 was 459 MW. MLP represents approximately 24.3% of System Basic Load on an annual basis, however during summer load periods the MLP is a higher percentage of System Basic Load as shown in Figure 6. This percentage has been tracking higher in the past five years, as can be seen by comparing charts A-D of Figure 6. This trend can be traced to such factors as "urban migration" of system load, the increased penetration of heat pumps and subsequent use as air conditioning (see discussion of Figure 2 above). In addition, substations at the borders of the MLP are experiencing the transfer of load into the MLP; for example load has moved from 108H-Burnside to 139H-Dartmouth Crossing and from 20H-Spryfield to 2H-Armdale.

5.3. Transmission Line Rating

In the past, load in the MLP has been offset by dispatching generation within the MLP at Tufts Cove (note that 14H-Burnside generation is outside the MLP), and therefore transmission into the MLP has been adequate. Operation without Tufts Cove generation results in all MLP load carried on the interconnecting lines L-6003, L-6007, L6033 and L-5003. Lines L-6003 and L-6007 are located on a common double circuit steel tower between 108H-Burnside and 91H-Tufts Cove.[6]

The ratings of the interconnecting transmission lines are summarized in Table 1. It should be noted that the rating of L-5003 is more sensitive to ambient temperature because it designed to operate closer to ambient temperatures.

Table 1

MLP Line Rating Variation with Ambient Temperature (MVA)

	L-6033	L-6035	L-6003	L-6007	L-5003
Conductor (Design Temp)	Drake(100°C)	Drake(100°C)	Dove(70°C)	Dove(70°C)	Dove(50°C)
Switchgear	287	287	287	287	72
CT Ratio	230	230	287	382	230
Metering	231	231	231	231	138
Summer rating vs Ambient Temperature:					
Conductor at 25°C Ambient	268	268	163	163	55
Conductor at 30°C Ambient	255	255	151	151	45
Conductor at 35°C Ambient	246	246	140	140	35
Winter rating vs Ambient Temperature:					
Conductor at 5°C Ambient	304	304	201	201	82
Conductor at 10°C Ambient	299	299	192	192	78
Conductor at 15°C Ambient	290	290	183	183	70

[6] Similarly, a double-circuit tower connects 90H-Sackville with 108H-Burnside, designated L-6003 and L-6009. Consequences of that double-circuit contingency may be similar, but not as severe as loss of L-6003 and L-6007.

5.4. Summer Peak Load Analysis (1300 MW)

Figure 7 show the flow conditions for a summer load condition of 1310 MW, and only those system upgrades listed in Section 4. This represents the conditions were ambient temperature is likely to be found in the range of 25°C to 32°C. System conditions are summarized in Table 2.

Table 2 S1200-10 Base Case

Conditions			S1200-10
ML Import	475	Lingan 1	0
CBX	725	Lingan 3	0
ONI	814	Lingan 4	147
ONS	751	Wreck Cove	0
NB-NS	0	Pt Aconi	185
Quebec-NB total	754	Pt Tupper	160
NB-New England	979	Trenton 5	0
NS Transmission Losses	67	Trenton 6	100
NB Transmission Losses	106	Non Comfit Wind	215
Base Case	Figure 7	Small Hydro	38
NB Load	1887	NS Load	1310
Inc PEI	180	Inc PHP	112

The results of steady-state analysis are listed in Table 3.

Table 3 S1200-10 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	N/A
4	Loss of L-8001/L-3025	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 no SPS armed	Pass
8	Loss of L-8004 no SPS armed	Pass
9	Loss of L-8002	Pass
10	Breaker Failure SA3-2 L-3006+L-3017	Pass
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	Pass
14	Breaker Failure 67N-811 L-8003+67N-T82	Pass
15	Loss of 79N-T81, L-8004, L-8003 no SPS	Pass
16	DCT L-6003 + L-6007	L6033, L5003 O/L
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	L6007 at limit

Figure 8 shows the details of contingency 17. The results of contingency 17 fail criteria with the present rating of L-6033 and L-5003. From Table 1, the summer rating of L-6033 is currently based on the CT (current transformer) ratio at 1H and full scale metering at 103H. Each of these limits is easily remedied, so the next most limiting element is the conductor, with a summer rating of 268 MVA. Since post-contingency flow on L-6033 is 268 MVA (contingency 17), L-6033 would be at 100% of its continuous summer rating for an ambient temperature of 25°C, but would be overloaded by 4.8% at an ambient temperature of 30°C and overloaded by 8.8% at an ambient temperature of 35°C. As load grows within the MLP, these loading conditions would be worse than simulated.

Figure 8 also shows that contingency 17 loads L-5003 to 117% of its summer rating of 55 MVA, in the section between 90H-Sackville and 124H-Akerley Blvd. Since this rating is based on the conductor and not “soft limits” such as the CT ratio or the line metering scale, it is more problematic. With ambient temperature of 30°C, L-5003 would be overloaded by 48%, and at an ambient temperature of 35°C, it would be overloaded by 89%. L-5003 is equipped with an overload protection scheme which would open L-5003 at 90H for this contingency. Figure 9 shows the results of this protection action assuming that L-6033 is limited only by its summer conductor rating of 268 MVA. In this case, L-6033 is loaded to 339 MVA, which means it is overloaded by 28% in the section between 103H and 2H, and overloaded by 116% along the section between 2H and 1H. Even if the conductor was not the limiting factor, L-6033 would still be limited to 287 MVA by the switchgear at 103H and 2H and 339 MVA would represent an overload of 18%. It should also be noted that this contingency results in relatively low voltage in the MLP.

Contingency 18 brings L-6007 to 99.9% of its continuous summer rating of 163 MVA, which is not an issue at an ambient temperature of 25°C, but would represent an overload of 8% at an ambient temperature of 30°C and overload of 16.4% at 35°C. Figure 10 shows these results.

5.5. Highest Summer Onslow South Flow

Contingency 13 represents the limiting contingency for the establishment of Onslow South (ONS) based on sufficient MDRR, and in the previous case S1200-10 did not produce thermal overloads. Figure 11 shows the potential ONS flow if no generation had been operating at either Tufts Cove or Burnside for the past 12 months. The highest ONS flow during the period of summer line ratings would have been 775 MW. In order to induce the highest ONS flow in the simulated model, it was assumed that no generation west of Metro was on-line (except for synchronous condenser mode of operation). The conditions for this case are summarized in Table 4, and the flow conditions are shown in Figure 12.

Contingency Results are summarized in Table 5.

Table 4 S1200-11a Base Case

Conditions			S1200-11a
ML Import	475	Lingan 1	0
CBX	618	Lingan 3	120
ONI	929	Lingan 4	97
ONS	818	Wreck Cove	0
NB-NS	0	Pt Aconi	0
Quebec-NB total	754	Pt Tupper	160
NB-New England	979	Trenton 5	160
NS Transmission Losses	57	Trenton 6	170
NB Transmission Losses	106	Non Comfit Wind	135
Base Case	Figure 12	Small Hydro	6
NB Load	1887	NS Load	1310
Inc PEI	180	Inc PHP	112

Table 5 S1200-11 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 no SPS armed	Pass
8	Loss of L-8004 Group 5 SPS armed	Pass
9	Loss of L-8002	Pass, L6001 at 99%
10	Breaker Failure SA3-2 L-3006+L-3017	Pass
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	Pass, L6001 at 103%
14	Breaker Failure 67N-811 L-8003+67N-T82	Pass
15	Loss of 79N-T81, L-8004, L-8003 Group 5 SPS	Pass
16	DCT L-6003 + L-6007	L6033, L5003 O/L
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	L6007 O/L

In case S1200-11, contingency 18 brings L-6007 to slightly higher than in case S1200-10, overloaded by 2%.

Figure 13 shows that Contingency 13 resulted in L-6001 loading reached 131 MVA, which is 94 % of its summer rating of 140 MVA. The rating of L-6001 is based on the conductor operating at 60°C with the ambient temperature of 25°C. For higher ambient temperatures, L-6001 would be de-rated to 128 MVA at

30°C and 112 MVA at 35°C. Under such ambient temperature conditions, L-6001 would be overloaded by 2% and 17% respectively. This suggests that small increases in ONS flow will require transmission upgrades.

As a sensitivity case to examine this potential, Case 1200-11b expanded Metro Area Load by 50 MW (10%) in summer. Table 6 shows the base case parameters and Table 7 summarizes the contingency results. Figure 14 shows base case flows.

Table 6 S1200-11b Base Case

Conditions			S1200-11b
ML Import	475	Lingan 1	0
CBX	668	Lingan 3	120
ONI	975	Lingan 4	149
ONS	870	Wreck Cove	0
NB-NS	0	Pt Aconi	0
Quebec-NB total	754	Pt Tupper	160
NB-New England	979	Trenton 5	160
NS Transmission Losses	64	Trenton 6	170
NB Transmission Losses	106	Non Comfit Wind	135
Base Case	Figure 14	Small Hydro	6
NB Load	1887	NS Load	1360
Inc PEI	180	Inc PHP	112

Table 7 S1200-11b Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 no SPS armed	Pass
8	Loss of L-8004 Group 5 SPS armed	Pass
9	Loss of L-8002	Pass
10	Breaker Failure SA3-2 L-3006+L-3017	Pass
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	Pass, L6001 at 94%
14	Breaker Failure 67N-811 L-8003+67N-T82	Pass
15	Loss of 79N-T81, L-8004, L-8003 Group 5 SPS	Pass
16	DCT L-6003 + L-6007	L6033, L5003 O/L
17	DCT L-6003 + L-6009	L5003 O/L
18	Bus 103H-B61, Open L8002, L5039, L6033	L6007 O/L

Contingency 13 results in L-6001 reaching 142 MVA, which is slightly above its summer rating based on ambient temperature of 25°C. At higher ambient temperatures of 30°C or 35°C, L-6001 would be overloaded by 11% or 27% respectively. At this increased load level in Metro, contingency 18 results in a 15% overload of L-6007 and L-6001 reaching 100% of its summer limit, as shown in Figure 15. Figure 16 shows that Contingency 16 results in a significant 33% overload of L-5003 and low voltages throughout the MLP. Opening L-5003 results in a voltage collapse coupled with overloads of L-6033 and L-6035 of up to 45% of normal summer rating. Undervoltage loadshedding installed at 113H-Dartmouth East does not provide sufficient relief to the problem.

5.6. Reserve Delivery to NB

The Interconnection Agreement between Nova Scotia Power and NB Power requires sharing of Operating Reserves based on the largest contingency in the Maritimes Area up to a maximum of 10% of coincident peak demand. Presently the coincident peak demand of the Maritimes Area is approximately 5500 MW; therefore 10-minute reserve of 550 MW is to be shared between NS and NB on the basis of Load Ratio Share. This translates to a responsibility for Nova Scotia Power to deliver up to 40% of 550 MW (220 MW), capped at the largest unit on-line in NS. Before the installation of ML, the largest on-line in NS was Point Aconi at a net 171 MW. The rating of a single ML pole is estimated to be net 237.5 MW, which is greater than the 220 MW agreed share, therefore delivery of reserve will increase from 171 MW to 220 MW. Load Ratio Share and coincident peak demand are reviewed annually.

Although it is assumed that four units at Burnside and Tufts Cove units 4 and 5 will have 10-minute quick-start capability by 2018 (see Section 4, 2b and 2c above), 220 MW of reserve capacity will be available in eastern NS. Case S1200-12 was used to test the deliverability of this reserve. Table 6 summarizes system conditions and Table 7 summarizes contingency results. Figure 17 shows the base case flows.

Table 8 S1200-12 Base Case

Conditions			S1200-12
ML Import	475	Lingan 1	0
CBX	1010	Lingan 3	0
ONI	1151	Lingan 4	166
ONS	818	Wreck Cove	210
NB-NS	220	Pt Aconi	195
Quebec-NB total	754	Pt Tupper	160
NB-New England	979	Trenton 5	0
NS Transmission Losses	94	Trenton 6	170
NB Transmission Losses	106	Non Comfit Wind	135
Base Case	Figure 17	VJ CT	48
NB Load	1887	NS Load	1310
Inc PEI	180	Inc PHP	112

Table 9 S1200-12 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	N/A
4	Loss of L-8001/L-3025, Group 5 SPS	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 Group5 SPS armed	Pass
8	Loss of L-8004 Group 6 SPS armed	Pass
9	Loss of L-8002	Pass
10	Breaker Failure SA3-2 L-3006+L-3017	Pass
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	Pass
14	Breaker Failure 67N-811 L-8003+67N-T82 Gp5 SPS	Pass
15	Loss of 79N-T81, L-8004, L-8003 Group 6 SPS	Pass
16	DCT L-6003 + L-6007	L6033, L5003 O/L
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	L6007 O/L

These results indicate that delivery of reserve to NB is possible without using generation in Halifax, as long as the appropriate SPS's are armed and interface limits CBX and ONI are honoured.

5.7. High NB Import in Summer

High simultaneous import from NB and ML is possible in summer, with restrictions. Case S1200-13 examines the conditions of 300 MW import from NB, 440 MW import from ML and with highest summer ONS flow. Base Case conditions are summarized in Table 8 and contingency results are shown in Table 9.

Table 10 S1200-13 Base Case

Conditions			S1200-13
ML Import	440	Lingan 1	0
CBX	566	Lingan 3	0
ONI	638	Lingan 4	151
ONS	818	Wreck Cove	0
NB-NS	220	Pt Aconi	0
Quebec-NB total	754	Pt Tupper	160
NB-New England	876	Trenton 5	0
NS Transmission Losses	43	Trenton 6	170
NB Transmission Losses	118	Non Comfit Wind	135
Base Case	Figure 18	VJ CT	48
NB Load Inc PEI	1887 180	NS Load Inc PHP	1310 112

Table 11 S1200-13 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Marginal PEI voltage
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	N/A
4	Loss of L-8001/L-3025, Import SPS	Pass, NS separates
5	Loss of L-3006 (Salisbury-Memramcook) Import SPS	Pass, NS separates
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 No SPS armed	Pass
8	Loss of L-8004 No SPS armed	Pass
9	Loss of L-8002	Pass
10	Breaker Failure SA3-2 L-3006+L-3017 Import SPS	Pass, NS separates
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001 Import SPS	Pass, NS separates
13	Breaker Failure 67N-813 L-8002+67N-T81	67N-T82 overload
14	Breaker Failure 67N-811 L-8003+67N-T82 No SPS	Pass
15	Loss of 79N-T81, L-8004, L-8003 No SPS	Pass
16	DCT L-6003 + L-6007	L6033, L5003 O/L
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	L6007 O/L

Base Case flow conditions are shown in Figure 18. Contingency 13 results in transformer 67N-T82 being overloaded by about 5% under these flow conditions, as shown in Figure 19. Operator action would be required to reduce this overload by increasing generation west of 67N-Onslow within 10 minutes. Future load growth resulting in ONS flow higher than 820 MW will result in unacceptable contingency loading on 67N-T82.

6. Winter Operation without Tufts Cove Generation

6.1. Winter Load Characteristics

The analysis of winter operation covers load conditions for which winter line ratings are in effect, generally from the first of November to the end of April. Figure 20 shows the linear relationship between ONS flow and basic system load in the absence of generation at Tufts Cove or Burnside. This characteristic suggests that load south/west of Onslow scales closely with system basic load, and variations around the trend line are likely due to hydro dispatch patterns. System basic load above 1600 MW has very little variation in ONS flow (less than 100 MW). Figure 21 shows the pattern of ONS flow versus ambient temperature, which confirms that ONS greater than 900 MW occurs during the period of winter line ratings (5°C and below). System basic daily peak load in this period, referring back to Figure 4, ranged from 1300 MW to 1950 MW.

6.2. Winter Load above 5°C Ambient Temperature

Figure 22 shows the distribution of system basic load vs. ambient temperature during the period of winter ratings for the past year. The box highlights the 715 hours where ambient temperature exceeded 5°C. It can be seen that most of the hours with ambient temperature above 5°C were experienced with system load level below 1300 MW, which would have been covered in the analysis of summer ratings. The highest system loads coincident with ambient temperature in the 5°C - 10°C range appears to be 1490 MW. With industrial load added, this represents a system load level of about 1600 MW.

Case W1600-10 flows are shown in Figure 23, with the base case parameters summarized in Table 10. Contingency results are shown in Table 11. It is assumed in this case that the CT Ratio and full load metering limit on L-6033 and L-6035 have been remedied, but the switchgear at 103H and 104H have not been uprated beyond their present 1200 A (287 MVA) limit.

Table 12 W1600-10 Base Case

Conditions			W1600-10
ML Import	475	Lingan 1	0
CBX	858	Lingan 3	162
ONI	985	Lingan 4	116
ONS	891	Wreck Cove	0
NB-NS	0	Pt Aconi	195
Quebec-NB total	602	Pt Tupper	165
NB-New England	-45	Trenton 5	0
NS Transmission Losses	94	Trenton 6	170
NB Transmission Losses	106	Non Comfit Wind	135
Base Case	Figure 23	Small Hydro	140
NB Load	2660	NS Load	1620
Inc PEI	164	Inc PHP	110

Table 13 W1600-10 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	N/A
4	Loss of L-8001/L-3025, No SPS	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 No SPS armed	Pass
8	Loss of L-8004 No SPS armed	Pass
9	Loss of L-8002	Pass
10	Breaker Failure SA3-2 L-3006+L-3017	Pass
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	Pass
14	Breaker Failure 67N-811 L-8003+67N-T82 No SPS	Pass
15	Loss of 79N-T81, L-8004, L-8003 No SPS	Pass
16	DCT L-6003 + L-6007	Pass Note 1
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	Pass

Note 1: L-6033 is limited to 287 MVA in winter by switchgear at 103H-Lakeside

6.3. Onslow South 1000 MW / Winter Load 1800 MW

Referring back to Figure 20 shows that Onslow South flow of 1000 MW without Tufts Cove generation is coincident with a system basic load level for approximately 1700 MW plus load retention load of 100 MW. At this load level, static reactive power is required in Metro to supply higher local load and still maintain DRR, therefore case W1800-11 includes new switched capacitor banks at 103H-Lakeside (50 Mvar) and 90H-Sackville (50 Mvar). It is also assumed that all four Burnside synchronous condensers are available, for a total DRR of 220 Mvar including the Brushy Hill SVC. Referring back to Figure 1 suggests that maximum ONS with that level of DRR would be 975 MW.

The base case parameters for W1800-11 are presented in Table 12 and the flows are shown in Figure 24. Contingency results are summarized in Table 13.

Contingency 13 resulted in a 5% overload of 67N-T81, requiring operator action by starting reserve generation at Burnside.

Contingency 16 resulted in a 6% overload of L-6033 based on the rating of the circuit breaker 103H-632 and the switches at 2H as shown in Figure 25. These conditions represent the limit for acceptable operation under winter line ratings. Options are examined in Section 7.

Table 14 W1800-11 Base Case

Conditions			W1800-11
ML Import	475	Lingan 1	0
CBX	874	Lingan 3	162
ONI	1140	Lingan 4	160
ONS	1002	Wreck Cove	0
NB-NS	0	Pt Aconi	195
Quebec-NB total	602	Pt Tupper	165
NB-New England	-47	Trenton 5	160
NS Transmission Losses	87	Trenton 6	170
NB Transmission Losses	110	Non Comfit Wind	135
Base Case	Figure 24	Small Hydro	140
NB Load	2660	NS Load	1800
Inc PEI	164	Inc PHP	110

Table 15 W1800-11 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025, No SPS	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 Gr5 SPS armed	Pass
8	Loss of L-8004 No SPS armed	Pass
9	Loss of L-8002	Pass
10	Breaker Failure SA3-2 L-3006+L-3017	Pass
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	67N-T82 O/L
14	Breaker Failure 67N-811 L-8003+67N-T82 Gr5 SPS	Pass
15	Loss of 79N-T81, L-8004, L-8003 Gr5 SPS	Pass
16	DCT L-6003 + L-6007	L6033 O/L
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	Pass
19	BBU 90H-611, Open L6008, L6009	Pass
20	BBU 90H-608, Open L6005, L6010	Pass
21	BBU 90H-605, Open L6003, L6004	Pass
22	BBU 120H-625, Open L6011, L6010	Pass
23	BBU 120H-622, Open L6005, L6016	Pass

7. Metro Load Pocket Limit Options

Sections 5.4 through 5.7 and Section 6.3 demonstrated the limitations of operation with no generation at Tufts Cove in both summer and winter load conditions. The most significant contingency is the simultaneous loss of L-6003 and L-6007 which share a common tower. It should also be noted that L-6003 is a designated critical facility because it forms part of the blackstart cranking path between Burnside and Tufts Cove.

The following options have been examined:

1. Build a new 138 kV circuit from 129H-Kearney Lake Rd to 91H-Tufts Cove, with a new bus at 129H-Kearney Lake Road. This would occupy the spare side of the existing double circuit along the Bicentennial Highway, through Bayers Lake, into Bayers Road, through the Ceres terminal and Seaview Park. The structures of L-6014 across Halifax Harbour at Seaview Park and Shannon Park would be converted to a double circuit tower. Presently, L-5039 occupies a 2.3 km portion of the double circuit tower and would need to be moved.
2. Build a new 138 kV substation at Spider Lake (junction of Highways 118 and 107) and join L-6001 with L-6040 or L-6042. This would provide an additional circuit from Burnside to Tufts Cove. This option provides less relief to the double circuit contingency L-6009+L-6003 than L-6007+L-6003, but as long as the recommended upgrades to L-6033 are conducted, this option will be adequate.
3. Uprate L-5003 from 50°C to at least 75°C and re-conductor sections of L-6033 with a higher capacity, possibly a composite conductor. Switches at 2H-Armdale and switchgear at the 103H-Lakeside termination of L-6033 would also need to be uprated. Dynamic reactive power would need to be installed somewhere in the MLP, such as a DVAR or switched capacitor bank.
4. Operate with a minimum of 100-150 MW of generation at Tufts Cove during periods of risk. This could be assumed to be Tufts Cove 4 and 5 with Unit 6 on heat recovery, possibly with duct-firing.

7.1. Option 1: New 138 kV line from 129H-Kearney Lake to 91H-Tufts Cove

Figure 26 shows the configuration of a new 138 kV line from 129H to 91H under conditions of high summer metro load (S1200-11a) and the loss of the double circuit tower L-6003 and L-6007. There are no violations of criteria, assuming the protection on L-6038 is no longer the limiting element. Figure 27 shows that the double-circuit contingency loss of L-6003 plus L-6009 (contingency 17) is not an issue at this load level.

Figure 28 and Figure 29 show the results for the same contingencies for the winter case W1800-11, with acceptable results.

This option requires the following facilities

1. Establish a split bus at 129H-Kearney Lake
2. Add two 138 kV circuit breakers and control equipment
3. Build up to 3 km of 69 kV transmission circuit to move L-5039 off the existing double circuit tower along Highway 102.
4. Add second conductor to L-6038 double circuit towers between 129H and Suzie Lake Drive (4.3km), Drake at 70°C.

5. Add second conductor to L-6035 and L-6014 double circuit tower circuits between junction of Bayers Road and Highway 102 and Seaview Park harbour crossing (3 km Drake @ 100°C). New structures are needed where double circuit structures are already used.
6. Convert harbour crossing structures L-6014 to double-circuit.
7. New structures may be needed between Shannon Park and Tufts Cove.

7.2. Option 2: New substation at Spider Lake

L-6001 passes close to the double circuit L-6040/L-6042 at the NSPI-owned land at Spider Lake, near the junction of Highway 118 and Highway 107. L-6001 between Spider Lake (structure 407) and 108H-Burnside is a double circuit tower with conductor on only one side, which could be used for a new circuit.

Figure 30 shows the flow conditions for case S1200-11b and contingency 16. Figure 31 shows acceptable results for contingency 17. Figures 32 and 33 show the results for the same contingencies in winter conditions.

1. Establish new substation at Spider Lake, laid out for ultimate breaker-and-half bus arrangement complete with communication and control.
2. Add four circuit breakers, turn L-6001 and L-6040 into Spider Lake.

7.3. Option 3: Uprate lines and add dynamic var control

Referring back to Figure 16 we can see the amount of line capacity that would be needed to accommodate contingency 16 in summer. L-5003 would need a summer rating of 75 MVA at an ambient temperature of 25°C, meaning a conductor temperature of at least 75°C. L-6033 is already rated at a conductor temperature of 100°C so a larger conductor than the 795 MCM Arbutus or Drake conductor would be needed to raise the summer rating to at least 300 MVA at an ambient temperature of 25°C. Referring back to Figure 25 shows the amount of load that would be carried by L-5003 and L-6033 for contingency 16 in winter. Although thermal uprating of these circuits would alleviate the overloads, transformer 90H-T1 shows evidence of overload, and therefore this option may not be practical.

Because of low voltage in MPL, some form of reactive power support would be required, such as a 36 Mvar capacitor bank would be needed within the MLP.

1. Uprate L-5003 to 75°C conductor operating temperature.
2. Replace switchgear 99H-506 with equipment rated at 143 MVA.
3. Re-conductor 6 km of L-6033 between 2H and 103H (conductor tbd).
4. Replace switchgear 103H-632 with 2000 A breaker/switches.
5. Replace in-line switches 2H-603 and 2H-604 with switches rated 2000 A.
6. Add 36 Mvar capacitor bank to 113H-Dartmouth East.

7.4. Option 4: Operate with Tufts Cove out of merit generation

Figure 34 shows Tufts Cove operating at a minimum of 80 MW to alleviate the overloads and low voltage issues in summer following loss of L-6003 and L-6007 double circuit tower.

8. Winter Peak Operation

8.1. System Load 1900 MW

Operation without Tufts Cove generation at 1900 MW results in ONI of 1250 MW and ONS of 1091, and steady-state voltage control requires the 138 kV capacitor banks at 90H and 103H to be increased from 50 Mvar to 100 Mvar. It is assumed that upgrade Option 2 discussed in Section 7 has been implemented. Case W1900-10 parameters are summarized in Table 16 and the contingency results are shown in Table 17. Flow conditions are shown in Figure 35.

Table 16 W1900-10 Base Case

Conditions			W1900-10
ML Import	475	Lingan 1	0
CBX	993	Lingan 3	162
ONI	1243	Lingan 4	151
ONS	1091	Wreck Cove	150
NB-NS	0	Pt Aconi	195
Quebec-NB total	602	Pt Tupper	165
NB-New England	-47	Trenton 5	160
NS Transmission Losses	107	Trenton 6	170
NB Transmission Losses	116	Non Comfit Wind	135
Base Case	Figure 35	Small Hydro	140
NB Load	3000	NS Load	1900
Inc PEI	182	Inc PHP	110

Table 17 W1900-10 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025, No SPS	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 Gr6 SPS armed	Pass
8	Loss of L-8004 Gr5 SPS armed	Pass
9	Loss of L-8002	L6001 O/L
10	Breaker Failure SA3-2 L-3006+L-3017	Pass
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	L6001, 67N-T82 O/L
14	Breaker Failure 67N-811 L-8003+67N-T82 Gr6 SPS	Pass
15	Loss of 79N-T81, L-8004, L-8003 Gr5 SPS	Pass
16	DCT L-6003 + L-6007	Pass

Contingency	Description	Pass/Fail
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	L6001 at limit
19	BBU 90H-611, Open L6008, L6009	Pass
20	BBU 90H-608, Open L6005, L6010	Pass
21	BBU 90H-605, Open L6003, L6004	Pass
22	BBU 120H-625, Open L6011, L6010	Pass
23	BBU 120H-622, Open L6005, L6016	Pass

Loss of L-8002 (contingencies 9 and 13) results in L-6001 exceeding its normal winter rating. As shown in Figure 36, contingency 13 also overloads 68N-T81 which is limited by the transformer bushing and therefore has low tolerance for overload.

8.2. System Load 1950 MW

System load of 1950 MW with 110 MW of load retention load results in ONS flow of 1130 MW and ONI flow of 1285 MW. Base case W1950-10 flow conditions are shown in Figure 37 and summarized in Table 18. The only upgrades included in this configuration include:

1. 2 x 50 Mvar capacitor banks at 103H-Lakeside
2. 2 x 50 Mvar capacitor banks at 90H-Sackville
3. Spider Lake development
4. CT ratios on L-7018 not limiting factor

Table 19 summarizes the contingency results.

Table 18 W1950-10 Base Case

Conditions			W1950-10
ML Import	475	Lingan 1	130
CBX	1043	Lingan 3	162
ONI	1285	Lingan 4	160
ONS	1130	Wreck Cove	75
NB-NS	0	Pt Aconi	195
Quebec-NB total	602	Pt Tupper	165
NB-New England	-98	Trenton 5	160
NS Transmission Losses	114	Trenton 6	170
NB Transmission Losses	126	Non Comfit Wind	187
Base Case	Figure 37	Small Hydro	140
NB Load	3120	NS Load	1950
Inc PEI	188	Inc PHP	110

Table 19 W1950-Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025, No SPS	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 Gr6 SPS armed	Fail
8	Loss of L-8004 Gr5 SPS armed	Pass
9	Loss of L-8002	L6001 O/L
10	Breaker Failure SA3-2 L-3006+L-3017	PEI UVLS
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	L6001, 67N-T82 O/L
14	Breaker Failure 67N-811 L-8003+67N-T82 Gr6 SPS	Fail
15	Loss of 79N-T81, L-8004, L-8003 Gr6 SPS	Fail
16	DCT L-6003 + L-6007	Pass
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	L6001 O/L
19	BBU 90H-611, Open L6008, L6009	Pass
20	BBU 90H-608, Open L6005, L6010	Pass
21	BBU 90H-605, Open L6003, L6004	Pass
22	BBU 120H-625, Open L6011, L6010	Pass
23	BBU 120H-622, Open L6005, L6016	Pass

Contingencies involving loss of L-8002 (9, 13, and 18) show L-7018 overloading, however the present rating is based on CT ratios at 67N-Onslow and 120H-Brushy Hill which can easily be remedied. The winter rating would then increase to 675 MVA based on the conductor rating.

Contingencies involving loss of L-8003 (7, 14 and 15) fail due to lack of voltage support in the Onslow area. Additionally, 67N-T82 is overloaded of by 23% and L-6001 is overloaded by 6%. Adding a 50 Mvar capacitor bank at 1N allows contingencies 7, 14 and 15 to meet criteria with SPS action, however contingencies 7 and 14 result in an overload of L-6503 due to the low switchgear rating of that line. In addition, the addition of the 1N capacitor bank does not solve the overloads associated with loss of L-8002 (contingencies 9, 13, and 18).

Line L-7018 is designed for operation at 345 kV. Uprating this line would involve moving the 67N-Onslow end to a new node on the 345 kV bus and terminating it at 120H-Brushy Hill with a line-end breaker and 345 kV-138 kV transformer rated at 450 MVA.

Case 1950-12 examined the benefit of uprating L-7018 instead of the capacitor at 1N. This option passed criteria if the switchgear of L-6503 is uprated.

8.3. System Load 2000 MW

At a system load level of 2000 MW, including 110 MW of load retention load, ONS would approach 1170 MW without generation at Tufts Cove. Figure 38 shows that, based on present load topology, this value of ONS would represent 99.95% of the time if no generation was operated at Tufts Cove or Burnside (ONS would be above 1170 MW only 5 hours per year). Table 20 summarizes the base case conditions of W2000-30 with high wind generation in the central part of the province. Base case flow conditions are shown in Figure 39 and contingency results are summarized in Table 21. This case does not include the upgrades examined in Section 8.2 as a way of identification the extent of the issues identified.

Table 20 W2000-30 Base Case

Conditions			W2000-30
ML Import	475	Lingan 1	110
CBX	1033	Lingan 3	162
ONI	1272	Lingan 4	162
ONS	1168	Wreck Cove	90
NB-NS	0	Pt Aconi	195
Quebec-NB total	602	Pt Tupper	165
NB-New England	-47	Trenton 5	160
NS Transmission Losses	126	Trenton 6	170
NB Transmission Losses	125	Non Comfit Wind	247
Base Case	Figure 39	Small Hydro	140
NB Load	3150	NS Load	2015
Inc PEI	190	Inc PHP	110

Table 21 W2000-30 Contingency results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025, No SPS	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 Gr6 SPS armed	L6503 at limit
8	Loss of L-8004 Gr5 SPS armed	Pass
9	Loss of L-8002	L6001, L7018 O/L
10	Breaker Failure SA3-2 L-3006+L-3017	Fail, PEI UVLS
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	L6001, L7018, 67N-T82 O/L
14	Breaker Failure 67N-811 L-8003+67N-T82 Gr6 SPS	L6503 at limit
15	Loss of 79N-T81, L-8004, L-8003 Gr6 SPS	Pass
16	DCT L-6003 + L-6007	Pass
17	DCT L-6003 + L-6009	Pass

Contingency	Description	Pass/Fail
18	Bus 103H-B61, Open L8002, L5039, L6033	L6001, L7018 O/L
19	BBU 90H-611, Open L6008, L6009	Pass
20	BBU 90H-608, Open L6005, L6010	Pass
21	BBU 90H-605, Open L6003, L6004	Pass
22	BBU 120H-625, Open L6011, L6010	Pass
23	BBU 120H-622, Open L6005, L6016	Pass

Contingencies involving loss of L-8002 (9, 13, 18) show L-7018 overloading, however the present rating is based on a CT ratios at 67N-Onslow and 120H-Brushy Hill which can easily be remedied. The winter rating would then increase to 675 MVA based on the conductor rating. Figure 40 shows the conditions for contingency 13, where unacceptable loading of 67N-T82 and L-6001 is demonstrated.

Case W2000-31 shows the same basic load conditions as W2000-30 except with low wind generation, resulting in higher ONI flow for the same value of ONS. The wind generation was assumed to be 10% of nameplate, and the thermal and hydro generation east of metro was increased to maximum capacity. Load at Port Hawkesbury Paper was reduced to 35 MW because of low wind generation. The capacitor bank at 1N-Onslow was increased from 50 Mvar to 100 Mvar to support the higher ONI. Base case flows are shown in Figure 41, with case parameters shown in Table 22 and contingency results summarized in Table 23.

Table 22 W2000-31 Base Case

Conditions			W2000-31
ML Import	475	Lingan 1	165
CBX	1204	Lingan 3	162
ONI	1342	Lingan 4	129
ONS	1168	Wreck Cove	190
NB-NS	0	Pt Aconi	195
Quebec-NB total	602	Pt Tupper	165
NB-New England	-47	Trenton 5	160
NS Transmission Losses	131	Trenton 6	170
NB Transmission Losses	125	Non Comfit Wind	63
Base Case	Figure 41	Small Hydro	140
NB Load	3150	NS Load	1939
Inc PEI	190	Inc PHP	34

Table 23 W2000-31 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025, No SPS	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 Gr6 SPS armed	L6503 O/L
8	Loss of L-8004 Gr6 SPS armed	Pass
9	Loss of L-8002	L6001, L7018 O/L
10	Breaker Failure SA3-2 L-3006+L-3017	PEI UVLS
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	L6001, L7018, 67N-T82 O/L
14	Breaker Failure 67N-811 L-8003+67N-T82 Gr6 SPS	L6503 O/L
15	Loss of 79N-T81, L-8004, L-8003 Gr6 SPS	Fail
16	DCT L-6003 + L-6007	Pass
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	L6001, L7018 O/L
19	BBU 90H-611, Open L6008, L6009	Pass
20	BBU 90H-608, Open L6005, L6010	Pass
21	BBU 90H-605, Open L6003, L6004	Pass
22	BBU 120H-625, Open L6011, L6010	Pass
23	BBU 120H-622, Open L6005, L6016	Pass

Contingency 10 failure is a function of load in the Moncton area of NB and not directly related to NS dispatch.

Line L-7018 is designed for operation at 345 kV; uprating this line would involve moving the 67N-Onslow end to a new node on the 345 kV bus and terminating it at 120H-Brushy Hill with a line-end breaker and 345 kV-138 kV transformer rated at 450 MVA. Base Case W2000-33 demonstrates the effect of this upgrade with the low-wind base case. L-6503 is currently limited by switchgear and not conductor in winter. Table 24 summarizes contingency results and Figure 42 shows the base case flows with the following upgrades:

- Operate L-7018 as 345 kV line designated L-8006 between 68N-Onslow and 120H-Brushy Hill
- New 345 kV – 138 kV transformer rated 450 MVA at 120H-Brushy Hill
- Install 100 Mvar capacitor bank on the 230 kV bus at 67N-Onslow
- Replace breaker 50N-607 with switchgear rated 2000 A, uprate switches at 1N-623 to match breaker rating
- Spider Lake 138 kV development
- 103H-632 switchgear uprated to 2000 A
- Three 50 Mvar capacitors in Metro (one at 90H-Sackville and two at 103H-Lakeside)

Table 24 W2000-32 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025, No SPS	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 Gr6 SPS armed	Pass
8	Loss of L-8004 Gr6 SPS armed	Pass
9	Loss of L-8002	Pass
10	Breaker Failure SA3-2 L-3006+L-3017	PEI UVLS
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass
13	Breaker Failure 67N-813 L-8002+67N-T81	Pass
14	Breaker Failure 67N-811 L-8003+67N-T82 Gr6 SPS	Pass
15	Loss of 79N-T81, L-8004, L-8003 Gr6 SPS	Pass
16	DCT L-6003 + L-6007	Pass
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	Pass
19	BBU 90H-611, Open L6008, L6009	Pass
20	BBU 90H-608, Open L6005, L6010	Pass
21	BBU 90H-605, Open L6003, L6004	Pass
22	BBU 120H-625, Open L6011, L6010	Pass
23	BBU 120H-622, Open L6005, L6016	Pass

All contingencies were satisfied with these upgrades.

8.4. Winter reserve delivery to NB

With NS generation at maximum output with low wind generation and no Tufts Cove generation on-line, it would be necessary to utilize any available generation west of Onslow to deliver the expected reserve share of 220 MW to NB Power should they call for it. Referring back to Figures 2 and 3, winter load conditions above 1900 MW correlate with ambient temperature conditions that are generally below -10°C. At that temperature each gas turbine at Burnside is capable of 33 MW. The Tusket gas turbine is expected to have a winter capability of 30 MW. Tufts Cove 4 and 5 LM6000 combustion turbines are expected to have a 10-minute quick-start capability of at least 25 MW each, for a total 10-minute reserve capability of 212 MW. Starting these units reduces NS system losses by 13 MW, yielding a net reserve delivery of 225 MW, as demonstrated by case W2000-34. Flow conditions are shown in Figure 43. The contingency analysis is summarized in Table 25. With flow towards NB, contingency 10 is seen to pass criteria. With an export level of 225 MW, any contingency involving the loss of L-8001 will result in SPS run-back of ML to maintain other transmission lines within acceptable limits.

Table 25 W2000-34 Reserve Delivery Contingency Results.

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Pass
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025, Export SPS	Pass with Export SPS
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Pass
7	Loss of L-8003 Gr6 SPS armed	Pass
8	Loss of L-8004 Gr6 SPS armed	Pass
9	Loss of L-8002	Pass
10	Breaker Failure SA3-2 L-3006+L-3017	Pass
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Pass with Export SPS
13	Breaker Failure 67N-813 L-8002+67N-T81	Pass
14	Breaker Failure 67N-811 L-8003+67N-T82 Gr6 SPS	Pass
15	Loss of 79N-T81, L-8004, L-8003 Gr6 SPS	Pass
16	DCT L-6003 + L-6007	Pass
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	Pass
19	BBU 90H-611, Open L6008, L6009	Pass
20	BBU 90H-608, Open L6005, L6010	Pass
21	BBU 90H-605, Open L6003, L6004	Pass
22	BBU 120H-625, Open L6011, L6010	Pass
23	BBU 120H-622, Open L6005, L6016	Pass

8.5. Load levels higher than 2000 MW

At load levels with Basic System Load above 2000 MW, representing the few days per year shown in Figure 44, the ability to operate with no generation at Tufts Cove may be difficult. If ML is operating at full load, then import from NB will be significantly restricted by load in NB and PEI. This means the NS demand would be met by in-province generation plus ML import; without generation at Tufts Cove, we would be heavily reliant on wind generation to meet daily peak demand. Case W2070-20 represents forecasted peak demand of 2070 MW in the year 2019-2020. Winter peak load for the NB system is 3326 MW including 200 MW flow to PEI. Flows for this base case are shown in Figure 45 and system conditions are summarized in Table 26.

Table 27 summarizes the contingency results. It can be seen that contingencies in NB (6, 10, and 12) as well as loss of both poles of the ML (2) result in voltage collapse in the Moncton/PEI area. Contingencies on the L-8003 or L-8004 involving SPS runback operation (7, 8, 14, 15) result in instability, and contingencies in Metro (17, 22, 23) result in local transmission overloading. These results compare unfavourably with those of case W2000-34 shown above in Table 25 where system load levels are only 5% lower, but ONI is 67MW higher. This demonstrates the adverse effect of NB system load on NS internal transfer levels.

Table 26 W2070-20 Base Case

Conditions			W2070-20
ML Import	475	Lingan 1	144
CBX	1046	Lingan 3	162
ONI	1275	Lingan 4	162
ONS	1144	Wreck Cove	40
NB-NS	0	Pt Aconi	195
Quebec-NB total	602	Pt Tupper	165
NB-New England	-49	Trenton 5	160
NS Transmission Losses	116	Trenton 6	170
NB Transmission Losses	114	Non Comfit Wind	268
Base Case	Figure 45	Small Hydro	152
NB Load	3326	NS Load	2070
Inc PEI	200	Inc PHP	77

Table 27 W2071-10 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Fail, UVLS in PEI and NB
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025, No SPS	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Fail, UVLS in PEI and NB
7	Loss of L-8003 Gr6 SPS armed	Fail
8	Loss of L-8004 Gr6 SPS armed	Fail
9	Loss of L-8002	Pass
10	Breaker Failure SA3-2 L-3006+L-3017	Fail
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Fail
13	Breaker Failure 67N-813 L-8002+67N-T81	Pass
14	Breaker Failure 67N-811 L-8003+67N-T82 Gr6 SPS	Fail
15	Loss of 79N-T81, L-8004, L-8003 Gr6 SPS	Fail
16	DCT L-6003 + L-6007	Pass
17	DCT L-6003 + L-6009	L5003, 90H-T61 O/L
18	Bus 103H-B61, Open L8002, L5039, L6033	Pass
21	BBU 90H-605, Open L6003, L6004	Pass
22	BBU 120H-625, Open L6011, L6010	L6005A O/L
23	BBU 120H-622, Open L6005, L6016	L6010 O/L with uprate

Case W2070-21 demonstrates the effect of running one unit steam unit at Tufts Cove for the peak load conditions which failed criteria without Tufts Cove generation as shown above. Figure 46 shows base case flow conditions, which are summarized in Table 28.

Table 28 Base Case W2070-21

Conditions			W2070-21
ML Import	475	Lingan 1	100
CBX	973	Lingan 3	162
ONI	1208	Lingan 4	167
ONS	1076	Wreck Cove	0
NB-NS	0	Pt Aconi	195
Quebec-NB total	602	Pt Tupper	165
NB-New England	-49	Trenton 5+6	330
NS Transmission Losses	103	Tufts Cove	70
NB Transmission Losses	116	Non Comfit Wind	268
Base Case	Figure 46	Small Hydro	152
NB Load	3326	NS Load	2070
Inc PEI	200	Inc PHP	77

Table 29 W2070-21 Contingency Results

Contingency	Description	Pass/Fail
1	Loss of one pole of ML	Pass
2	Loss of both poles of ML, including reactive supply	Fail, UVLS in PEI
3	Loss of 2 units at Lingan (Breaker Failure 88S-721)	Pass
4	Loss of L-8001/L-3025, No SPS	Pass
5	Loss of L-3006 (Salisbury-Memramcook)	Pass
6	Loss of Memramcook transformer	Fail, UVLS in PEI
7	Loss of L-8003 Gr5 SPS armed	Pass
8	Loss of L-8004 Gr5 SPS armed	Pass
9	Loss of L-8002	Pass
10	Breaker Failure SA3-2 L-3006+L-3017	Fail UVLS in PEI and NB
11	Breaker Failure SA3-4 L-3013+T2	Pass
12	Breaker Failure ME3-2 L-3006+L-3025/L-8001	Fail UVLS in PEI and NB
13	Breaker Failure 67N-813 L-8002+67N-T81	Pass
14	Breaker Failure 67N-811 L-8003+67N-T82 Gr6 SPS	Pass
15	Loss of 79N-T81, L-8004, L-8003 Gr5 SPS	Pass
16	DCT L-6003 + L-6007	Pass
17	DCT L-6003 + L-6009	Pass
18	Bus 103H-B61, Open L8002, L5039, L6033	Pass
19	BBU 90H-611, Open L6008, L6009	Pass
20	BBU 90H-608, Open L6005, L6010	Pass
21	BBU 90H-605, Open L6003, L6004	Pass
22	BBU 120H-625, Open L6011, L6010	Pass
23	BBU 120H-622, Open L6005, L6016	Pass with L6010 uprate

8.6. Stability Analysis

Dynamics analysis was conducted for various flow conditions to ensure that the recommended system upgrades were sufficient to ensure that required stability criteria are met.

Contingencies results are provided in Appendix A.

At high values of Onslow Import, the most critical involve the loss of L-8003, listed in Table 30:

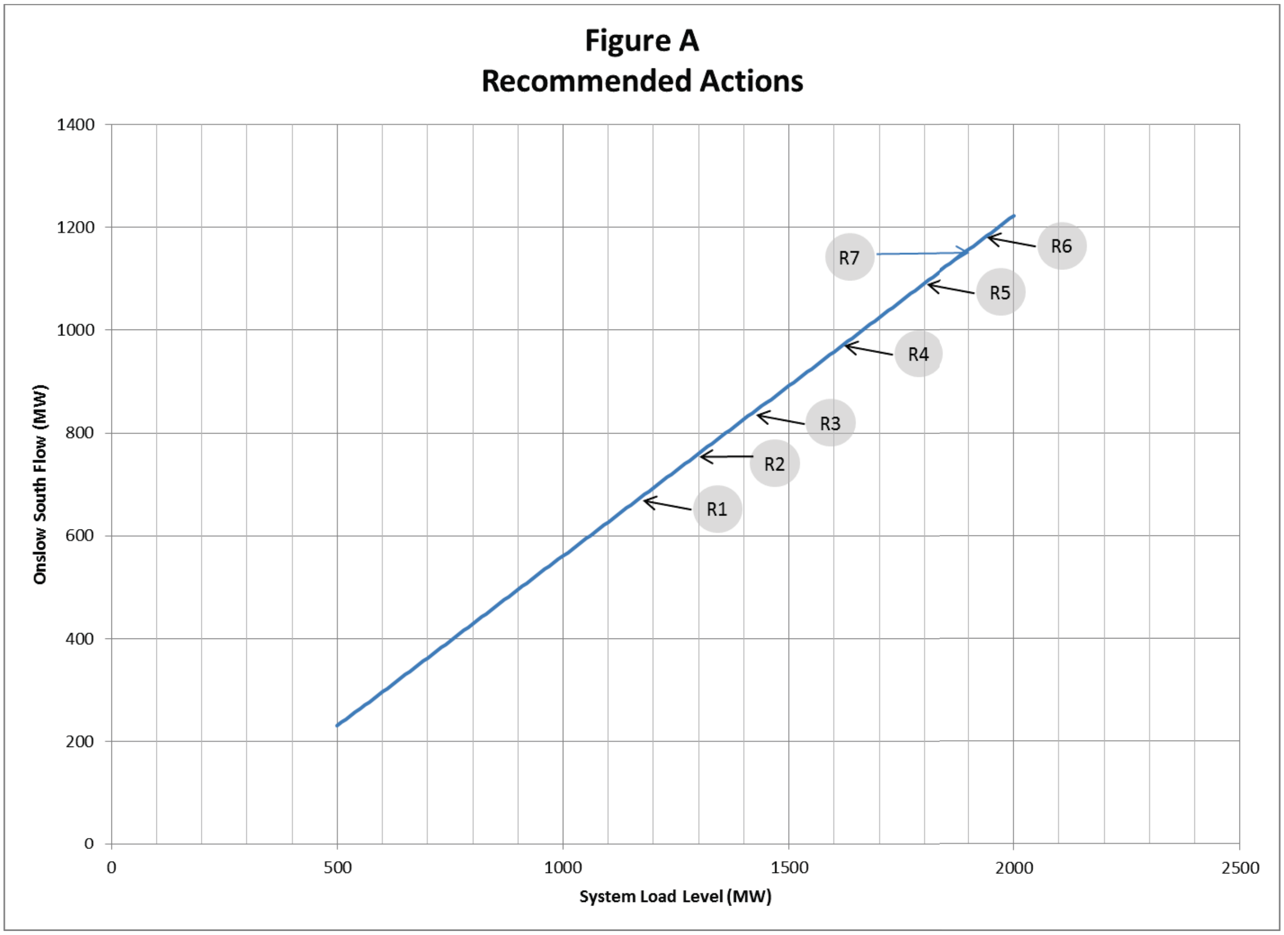
Table 30 Critical Stability Contingencies

Contingency Label	Fault Description
C_3PH_L8003_67N_g6rb	Three phase fault on L-8003 at Onslow with 330 MW runback
C_3PH_L8003_79N_g6rb	Three phase fault on L-8003 at Hopewell with 330 MW runback
C_BBU_L8003_67N811_g6rb	Single phase fault on L-8003, breaker failure trips T82. With 330 MW runback
C_BBU_L8003_79N803_g6rb	Single phase fault on L-8003, breaker failure trips L8004 and 79NT81. With 330 MW runback
C_BBU_L8004_79N810_g6rb	Single phase fault on L-8004, breaker failure trips L8003 and 79NT81. With 330 MW runback
C_3PH_79NT81_g6rb	Three phase fault on 79N-Hopewell Transformer, 330 MW Runback

It was found that a detailed representation of fault clearing time was required for L-8003. Normally, conservative fault duration of 5.0 cycles is assumed for 345 kV lines, which resulted in unstable results in the cases involving three-phase faults on L-8003. Therefore these faults were studied with 4.0 cycles and 4.5 cycles clearing, with a sensitivity case involving fault clearing at the 67N end in four cycles plus a line-end fault on 79N for one cycle. The latter case assumes one cycle for relay initiation, one cycle for transfer-trip communication, and three cycles for breaker operation, with the result that the fault impedance as seen by the 79N end of the line is increased by the line impedance for the one cycle delay between breaker opening at each end. Actual experience with breaker operation time on this line has been faster than the four cycles studied.

9. Summary and Conclusions

System upgrades were found to support increased transmission flow associated with displacement of Tufts Cove generation across a wide range of system conditions. The conditions under which the recommended actions are necessary are summarized on Figure A below. Figure A shows the load level/Onslow South Flow Level for each recommendation.



R1. Under summer operating conditions, loss of double circuit towers (L-6003 plus L-6007) with no Tufts Cove generation resulted in line overloads at load levels in the 1200 – 1300 MW range. Since transmission lines are de-rated at ambient temperatures above the nominal 25°C used for summer ratings, Figure 2 (note B) shows an increasing number of hours when these overload conditions are likely to occur. The recommended action is the development of a new substation at Spider Lake to provide a third 138 kV circuit between Burnside and Tufts Cove. Further details are provided in Section 9.1. With higher ambient temperature, Figure 2 shows a trend towards higher system loads in the metro area, a sign of increased installation of residential air conditioning. The combination of higher system load and de-rated transmission lines may require L-6001 to be uprated (if R5 below is not implemented).

R2. If the amount of imported power from Maritime Link that is kept in Nova Scotia is limited to the "Emera Block" (less than 172 MW), then the Nova Scotia responsibility to the reserve sharing agreement with NB Power will not change. However, if the amount of Maritime Link power that stays in Nova Scotia exceeds 172 MW, reserve sharing commitment will increase up to 220 MW. In summer conditions with system load levels up to 1300 MW, this reserve can be delivered from generation in eastern NS. However, for higher load levels experienced during the period when winter line ratings are in effect, 10-minute operating reserve must be held in the units south of Onslow, which will be possible if four combustion turbines are available at Burnside, and Tufts Cove units 4 and 5 regain quick-start capability.

R3. Import from New Brunswick in summer will be limited to 300 MW and Onslow South would be limited to 820 MW due to the rating of the Onslow 345 kV transformers, unless L-7018 is uprated to 345 kV.

R4. At Onslow South flow of 1000 MW, reactive power deficiencies were identified in metro, as well as overload of the Onslow transformer 67N-T81. Although additional capacitor banks at Sackville and Lakeside would provide the requirements to reach 1000 MW of Onslow South, other issues were found at higher flows which altered the recommendation as discussed below in R5.

R5. At Onslow South Level of 1100 MW, significant overload of Onslow transformers and L-6001 was found along with increased requirement for reactive power in Onslow. Line L-7018 is recommended to be uprated to 345 kV to relieve the overloads associated with loss of L-8002. The details of this recommendation are discussed in Section 9.2. The recommendations for increased reactive power are detailed in Section 9.3. In addition to increasing Onslow South, this recommendation permits higher Onslow Import.

R6. Onslow Import can approach 1300 MW at system peak load levels of 1950 MW – 2000 MW. At that level, L-6503 becomes limited by the switchgear that is rated at 1200 A. As detailed in Section 9.4, this line will be uprated.

R7. Although Spider Lake development eliminates overloaded lines for loss of L-6003 and L-6007, at load levels above 1900 MW the loss of the double circuit towers associated with L-6003 and L-6009 can results in L-6033 exceeding its winter rating based on 1200 A switchgear at 2H-Armdale and 103H-Lakeside. If this switchgear is uprated to 2000 A, as detailed in Section 9.5, the line will reach a rating of 304 MVA based on conductor sag. Circuit breaker failure contingencies can result in the overload of L-6010 which is limited by the rating of switchgear at the 90H-Sackville end. Therefore breakers 90H-608 and 90H-609 shoud be uprated from 1200 A to 2000 A.

9.1. Spider Lake Substation Development

Overloaded lines and low voltage conditions were found in the Metro Load Pocket under both summer and winter loading conditions. Of the options investigated, development of a new substation at Spider Lake to provide an additional in-feed to the MLP via L-6001 and L-6040 is the most practical and estimated least cost option. NSPI owns land in the Spider Lake area of Dartmouth (junction of Highway 118 and Highway 107). L-6001 and the double-circuit towers L-6040/L-6042 converge on this site. Development of a 138 kV bus configured as a partial breaker-and-half arrangement will provide for future transmission expansion from Onslow, Hopewell, or Cape Breton. Initially, a four-breaker ring will interconnect L-6001 and L-6040 as shown in Figure 47.

This substation is to be designated as 132H-Spider Lake and will not initially be classified as Bulk Power System (BPS); however provision should be made for future development as BPS. The connection of this substation to the Metro grid is shown in Figure 48.

The option for re-conductoring L-6033 were not considered further because of the logistics of installing a larger conductor because of the high risk to customer reliability by having all load at 2H-Armdale, 1H-Water Street and 104H-Kempt Road fed from a single circuit (L-6014) for an extended period of time and the disruption of working in the region of Highway 102, Bayers Road, and the Armdale Rotary. Re-conductoring L-5003 would require structure replacements in congested residential areas.

9.2. L-7018 Uprated to 345 kV

L-7018 is designed for operation at 345 kV between 67N-Onslow and 120H-Brushy Hill. Uprating this line will relieve overloads on L-6001 and 67N-T82 as well as meet stability criteria for loss of L-8003 plus 67N-T82. Operating at 345 kV, the line will be designated L-8006. A new transformer will connect L-8006 to the 138 kV bus at 120H-Brushy Hill.

The configuration of the 67N-Onslow end is shown in Figure 49. A new circuit breaker 67N-820 will be required to avoid L-8003 sharing a common breaker failure with either L-8002 or L-8006. Ultimately, the breaker node between 67N-816 and 67N-820 can be used for a future line to New Brunswick.

At 120H-Brushy Hill, the proposed configuration is shown in Figure 50. L8006 will step down from 345 kV to 138 kV, relieving load on the 230 kV-138 kV transformers. It is important to avoid a breaker failure condition which will result in the simultaneous loss of 103H-T81 and either 120H-SVC or 120H-T72. The new transformer 120H-T81 will have a top (OFAF) rating of 450 MVA, similar to 103H-T81, however it should have a short term overload rating of at least 540 MVA (120% of top rating). All switchgear associated with T81 must be rated at least 2500 A, which is the case for circuit breakers and switches 120H-628 and 120H-629. Circuit breaker 120H-627 is rated at 2000 A and therefore must be uprated to 2500 A. The new circuit breakers 120H-610 and 120H-620 will also be rated 2500 A.

With L-8006 brought into 120H-Brushy Hill, breaker failure of 120H-622 will result in loss of L-6005 and L-6016, which will result in L-6010 exceeding its winter rating of 287 MVA, which is based on the rating of switchgear at the 90H-Sackville end. Therefore circuit breakers and associated switches 90H-608 and 90H-609 should be uprated from 1200 A to 2000 A to match the rating of the switchgear at the 120H-Brushy Hill end of L-6010 and ensure a line rating based on conductor temperature (304 MVA at ambient temperature of 5°C).

The short circuit level of 67N-Onslow, 120H-Brushy Hill, and 90H-Sackville will be impacted by the conversion of L-7018 from 230 kV to 345 kV, as summarized in Table 31. All circuit breakers are within limits.

Table 31 Fault Level Impact

Station	Min. Breaker Rating (MVA)	Existing Fault Level (MVA)		New Fault Level (MVA)	
		Three-Phase	Phase-Ground	Three-Phase	Phase-Ground
120H-Brushy Hill 138 kV	5,000	3440	4047	3629	4363
120H-Brushy Hill 230 kV	10,000	3529	3818	3318	3715
90H-Sackville 138 kV	5,000	3585	3389	3672	3450
67N-Onslow 345 kV	15,000	4249	4504	4407	4776
67N-Onslow 230 kV	10,000	4190	4641	4070	4600

9.3. Additional reactive power devices

To support ONS flow above 1000 MW, additional reactive power is required in addition to the two 50 Mvar switched capacitor banks currently planned for 90H-Sackville and 103H-Lakeside. Various options were examined through the progression of this study, with the conclusion that the following switched capacitor bank options would be optimal:

1. A second 50 Mvar capacitor bank added to 103H-Lakeside 138 kV. This will be configured with a single circuit breaker and two circuit switchers each controlling 50 Mvar capacitor banks
2. A single 100 Mvar capacitor bank will be added to the 230 kV bus at 67N-Onslow, in the node vacated by L-7018 when it is upgraded to 345 kV. Switching a 100 Mvar capacitor bank on this 230 kV bus will impact bus voltage by less than 2% at minimum fault level with all lines in-service.

Operation of L-7018 as 345 kV will increase its line-charging from 18.1 Mvar to 40.9 Mvar, which will exacerbate high system voltage issues under light load or low-flow conditions, therefore a switched reactor rated 30 Mvar should be installed on the tertiary of the new transformer 120H-T81.

9.4. L-6503

The winter rating of L-6503 is limited by switchgear (circuit breakers and switches) at 50N-Trenton, 51N-Michelin Tap and 1N-Onslow. Overloading of L-6503 was found for high ONI flow following loss of L-8003 and high generation at Trenton and Glen Dhu; therefore the switchgear on each end of this line and the switches/circuit switcher at 51N-Michelin Tap should be uprated from 287 MVA to 478 MVA. The winter rating of the conductor for L-6503 is 363 MVA between 50N-Trenton and 51N-Michelin Tap and 335 MVA between 51N-Michelin Tap and 1N-Onslow.

9.5. L-6033 and L-6035

These lines are currently limited to 230 MVA by CT ratio at 1H-Water St, which can easily be changed in the field to a higher ratio. The winter rating of L-6033 is limited to 287 MVA by circuit breaker 103H-632. The winter rating of L-6035 is limited to 287 MVA by circuit breaker 104H-635. It is recommended that switchgear at the 103H Lakeside end of L-6033 (i.e. 103H-632) be uprated from 1200 A to 2000 A. L-6033 is also limited by the 1200 A switches at 2H-Armdale, which must be uprated to 2000 A as well. L-6033 will then be limited by its conductor rating of 304 MVA at ambient temperature of 5°C in winter. It is not necessary at this time to uprate the circuit breakers at 104H end of L-6035, however if these circuit breakers become eligible for replacement due to age or condition in the future, they should be rated at 2000 A.

Figures

Figure 1

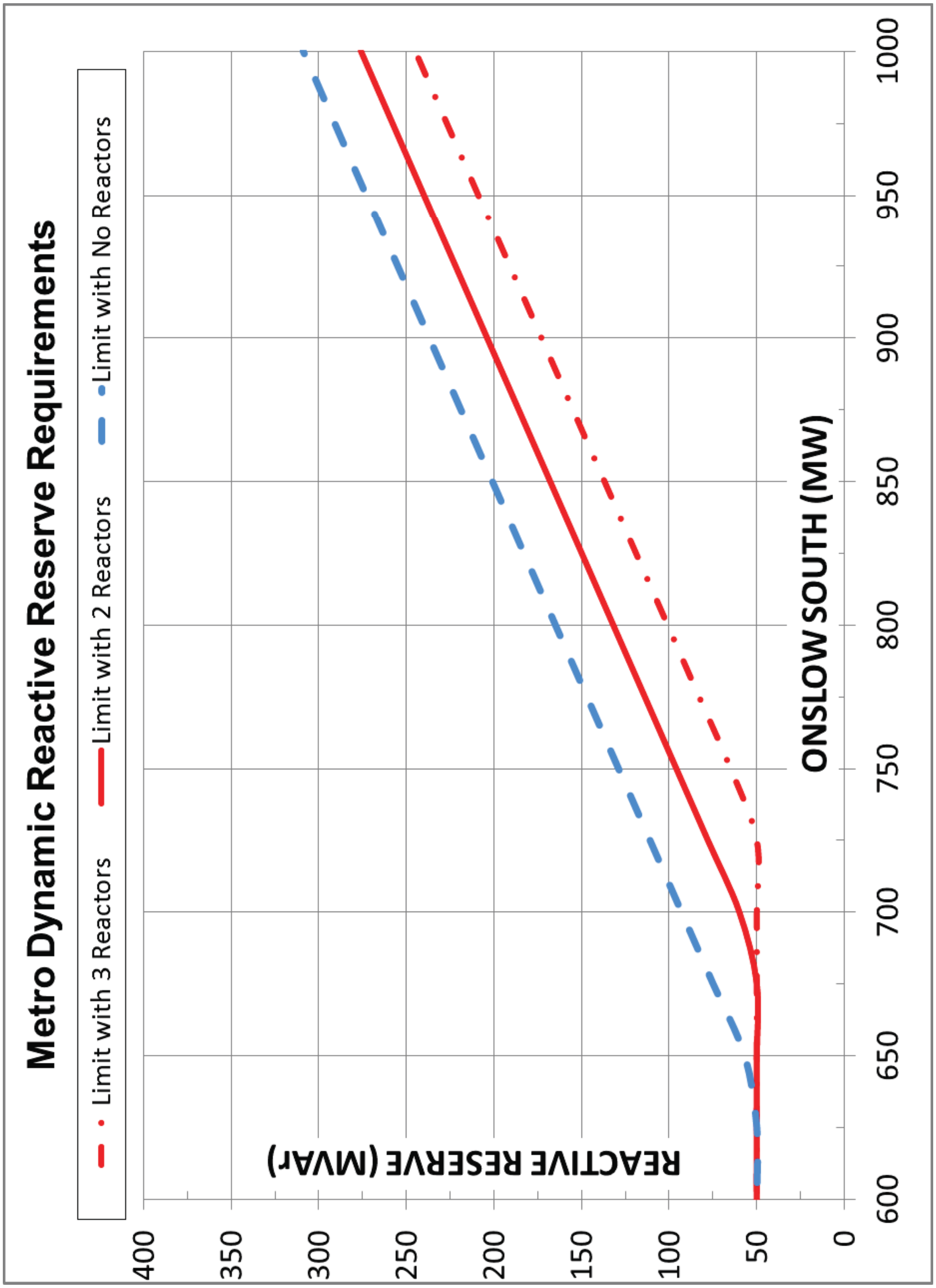

Metro Dynamic Reactive Reserve Requirements
Limit with 3 Reactors
Limit with 2 Reactors
Limit with No Reactors
REACTIVE RESERVE (MVAr)
ONSLOW SOUTH (MW)
0
50
100
150
200
250
300
350
400
600
650
700
750
800
850
900
950
1000

Figure 2

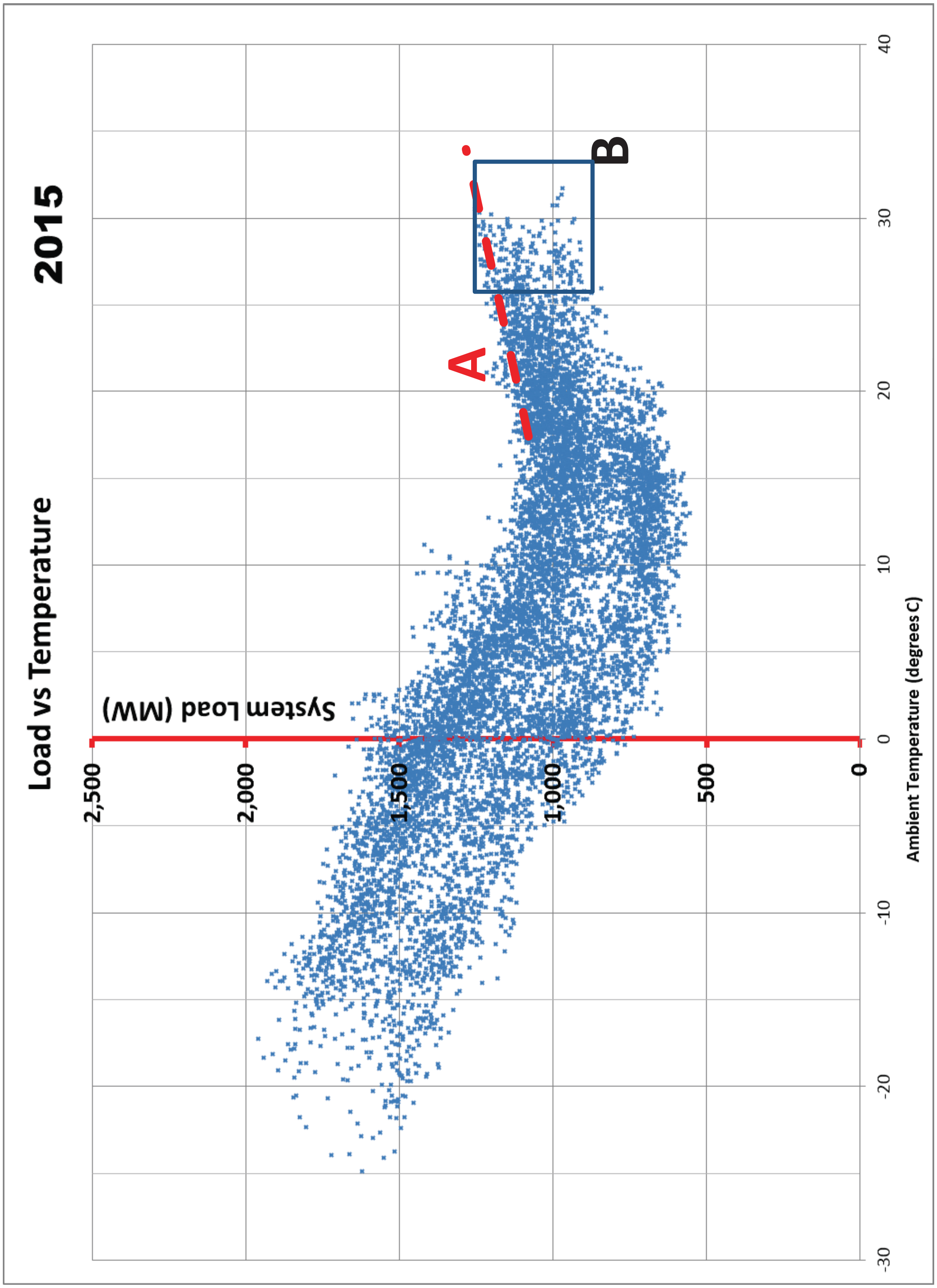

Load vs Temperature
2015
System Load (MW)
2,500
2,000
1,500
1,000
500
0
A
B
-30
-20
-10
0
10
20
30
40
Ambient Temperature (degrees C)

Figure 3

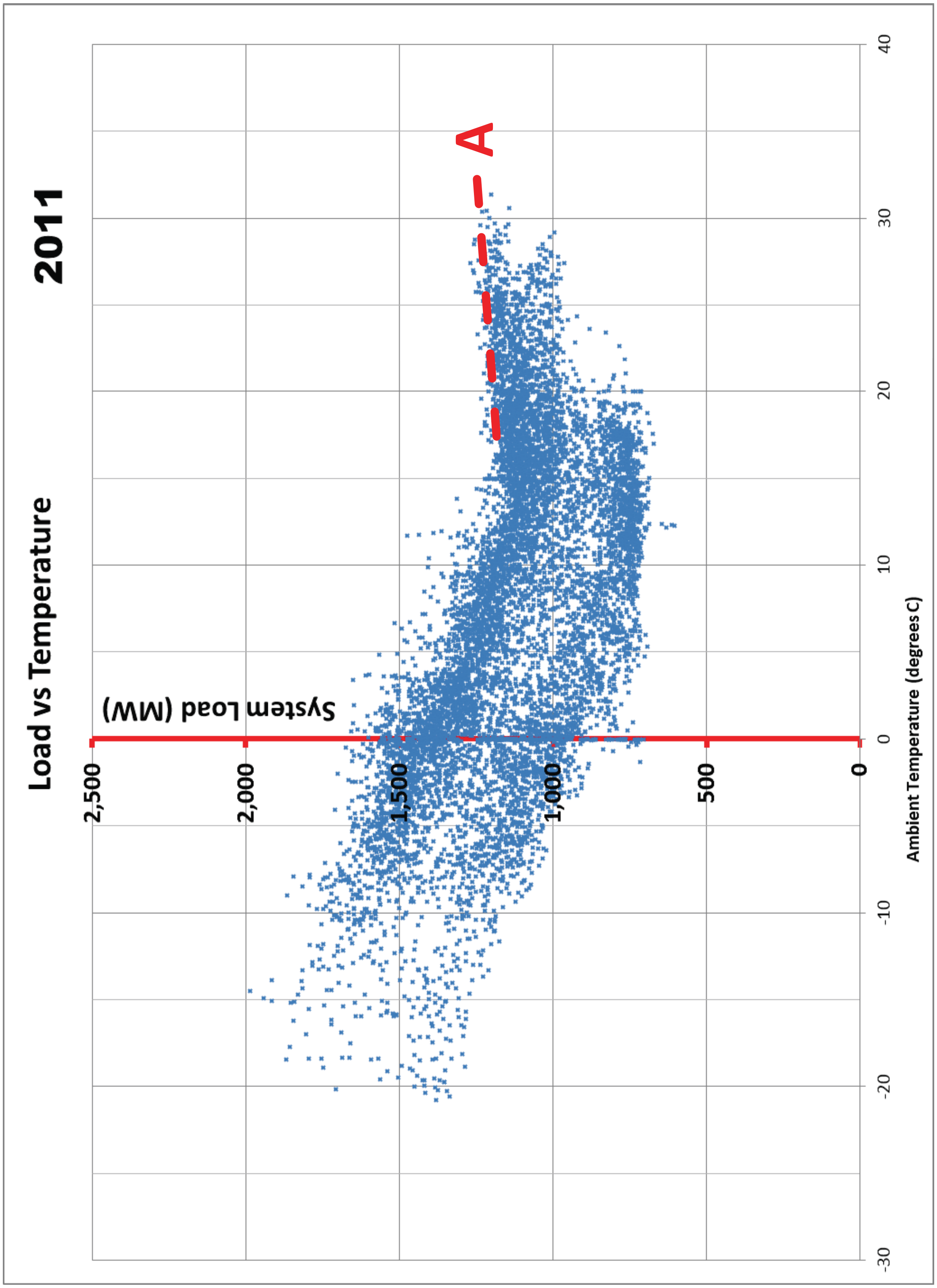

Load vs Temperature
2011
System Load (MW)
2,500
2,000
1,500
1,000
500
0
Ambient Temperature (degrees C)
-30
-20
-10
0
10
20
30
40
A

Figure 4

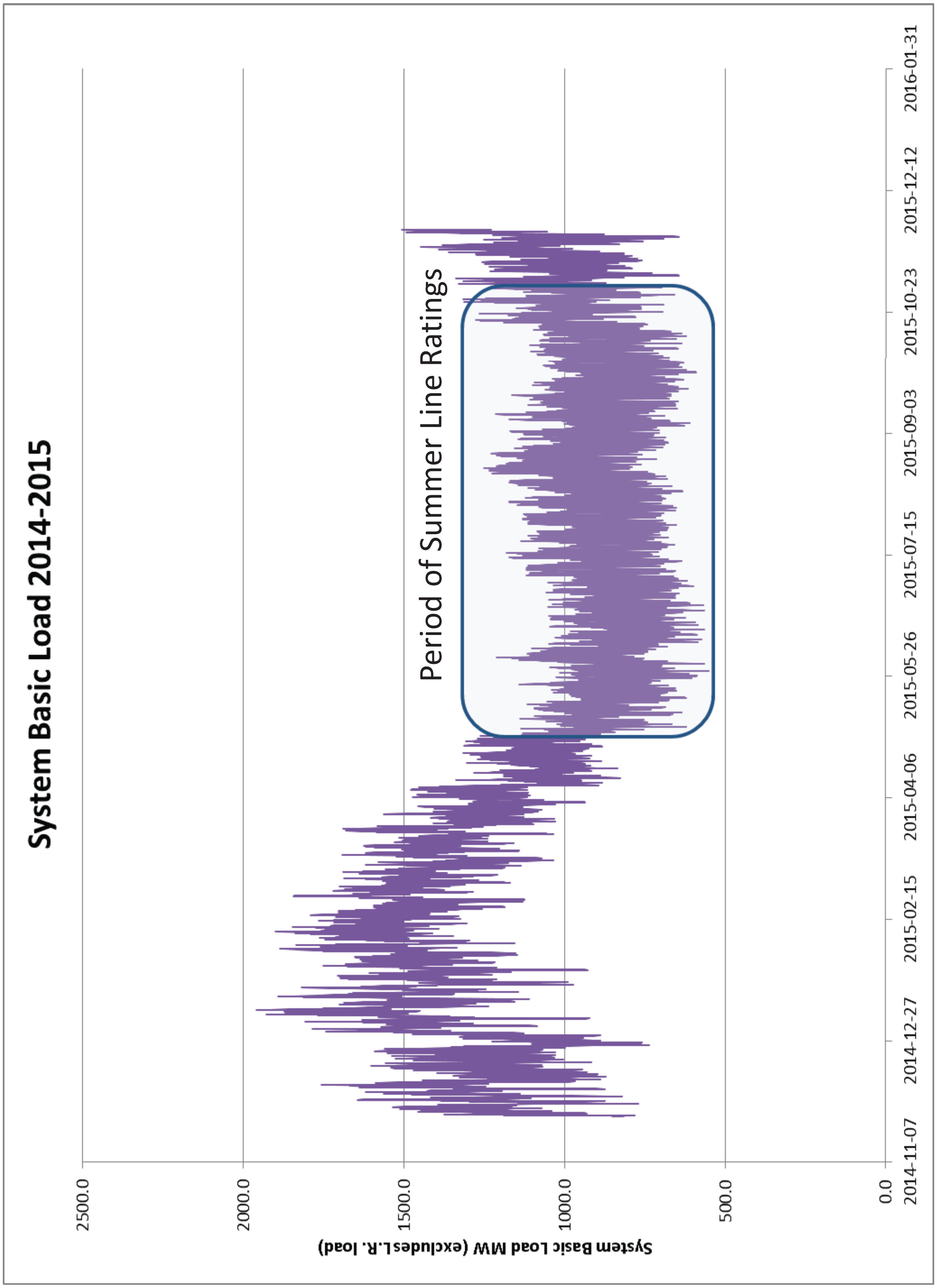
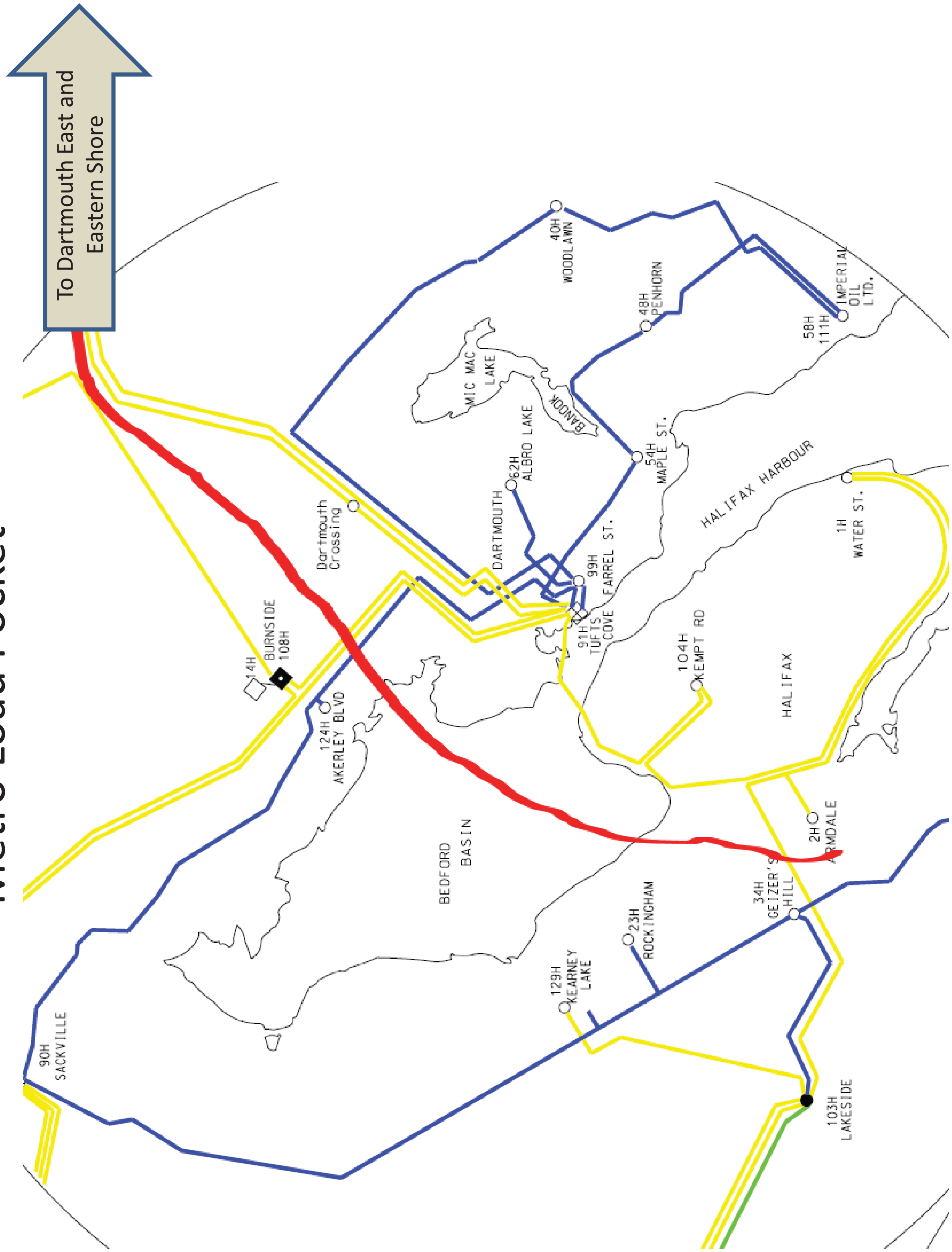
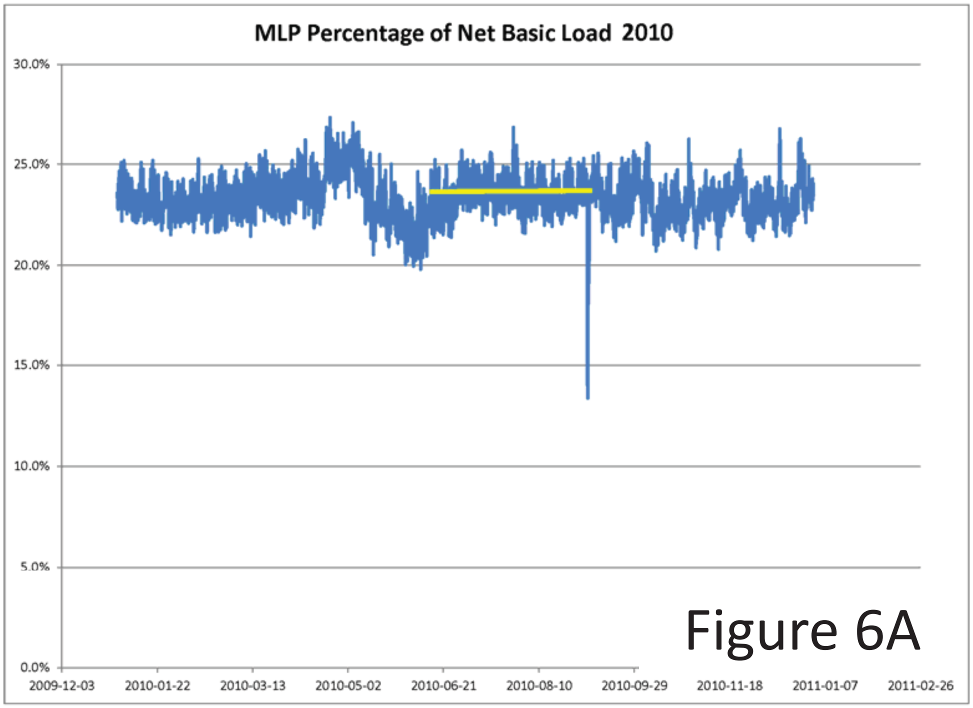
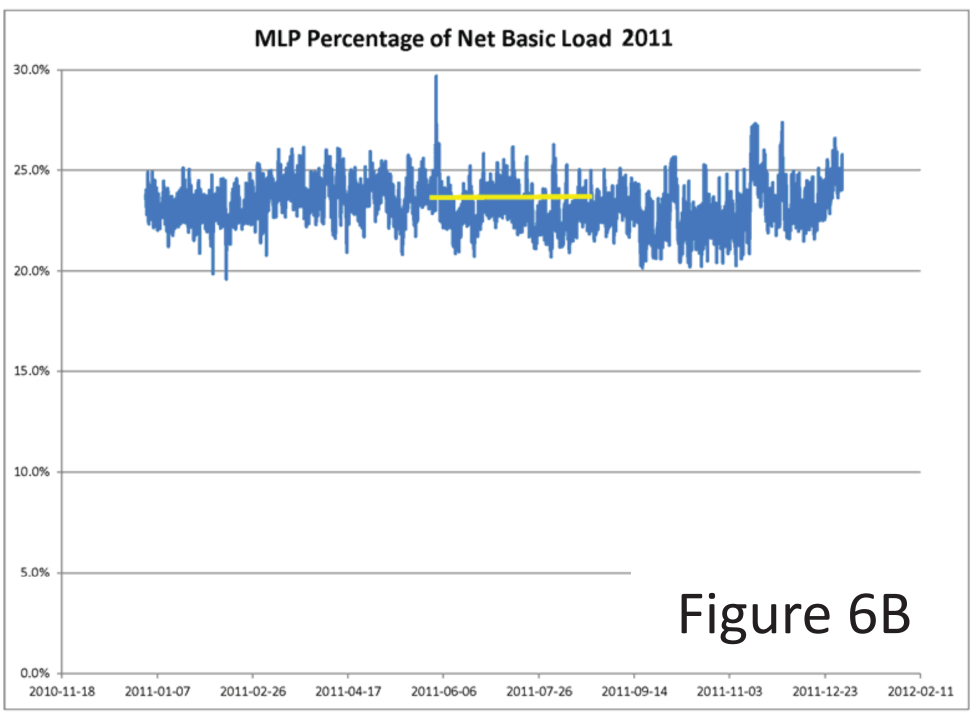

System Basic Load 2014-2015
Period of Summer Line Ratings
System Basic Load MW (excludes L.R. load)
2500.0
2000.0
1500.0
1000.0
500.0
0.0
2014-11-07
2014-12-27
2015-02-15
2015-04-06
2015-05-26
2015-07-15
2015-09-03
2015-10-23
2015-12-12
2016-01-31

Figure 5
Metro Load Pocket




MLP Percentage of Net Basic Load 2010
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
2009-12-03
2010-01-22
2010-03-13
2010-05-02
2010-06-21
2010-08-10
2010-09-29
2010-11-18
2011-01-07
2011-02-26
Figure 6A


MLP Percentage of Net Basic Load 2011
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
2010-11-18
2011-01-07
2011-02-26
2011-04-17
2011-06-06
2011-07-26
2011-09-14
2011-11-03
2011-12-23
2012-02-11
Figure 6B

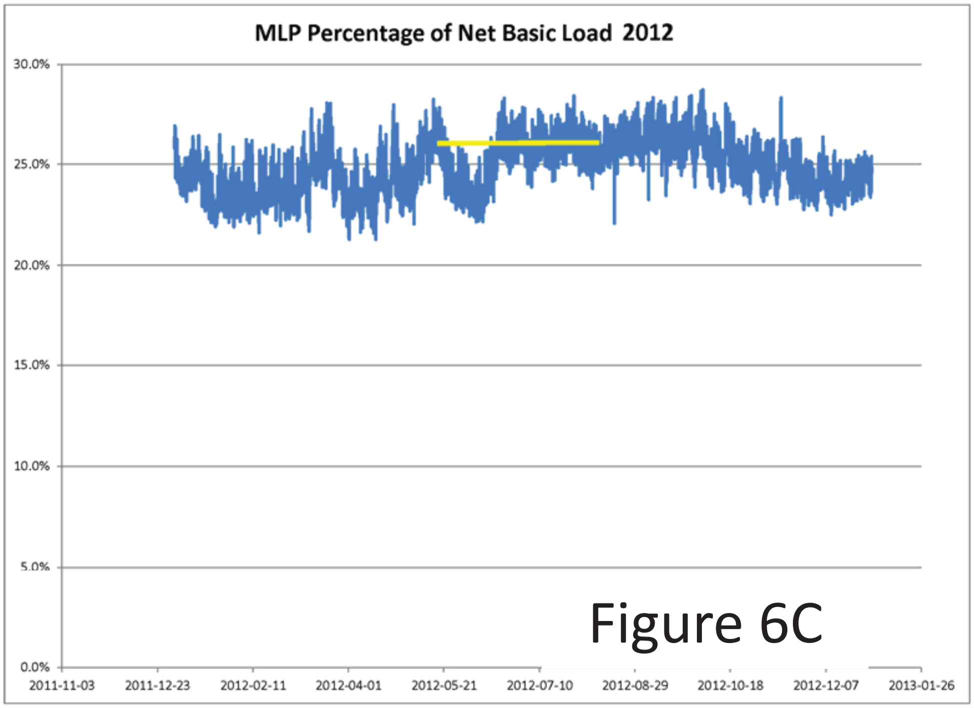


Figure 6C

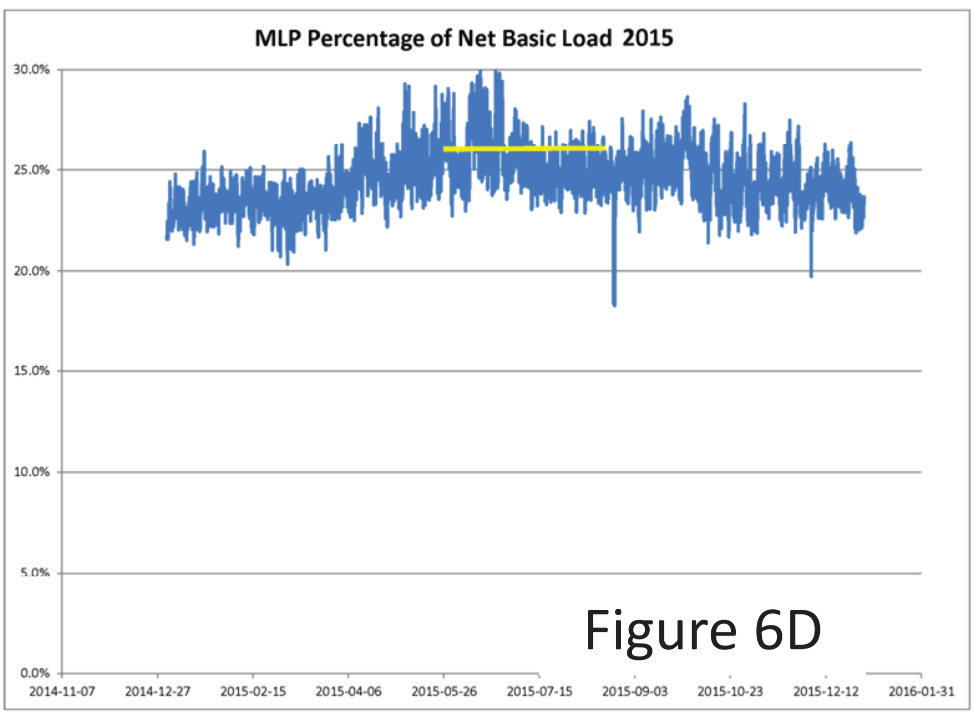
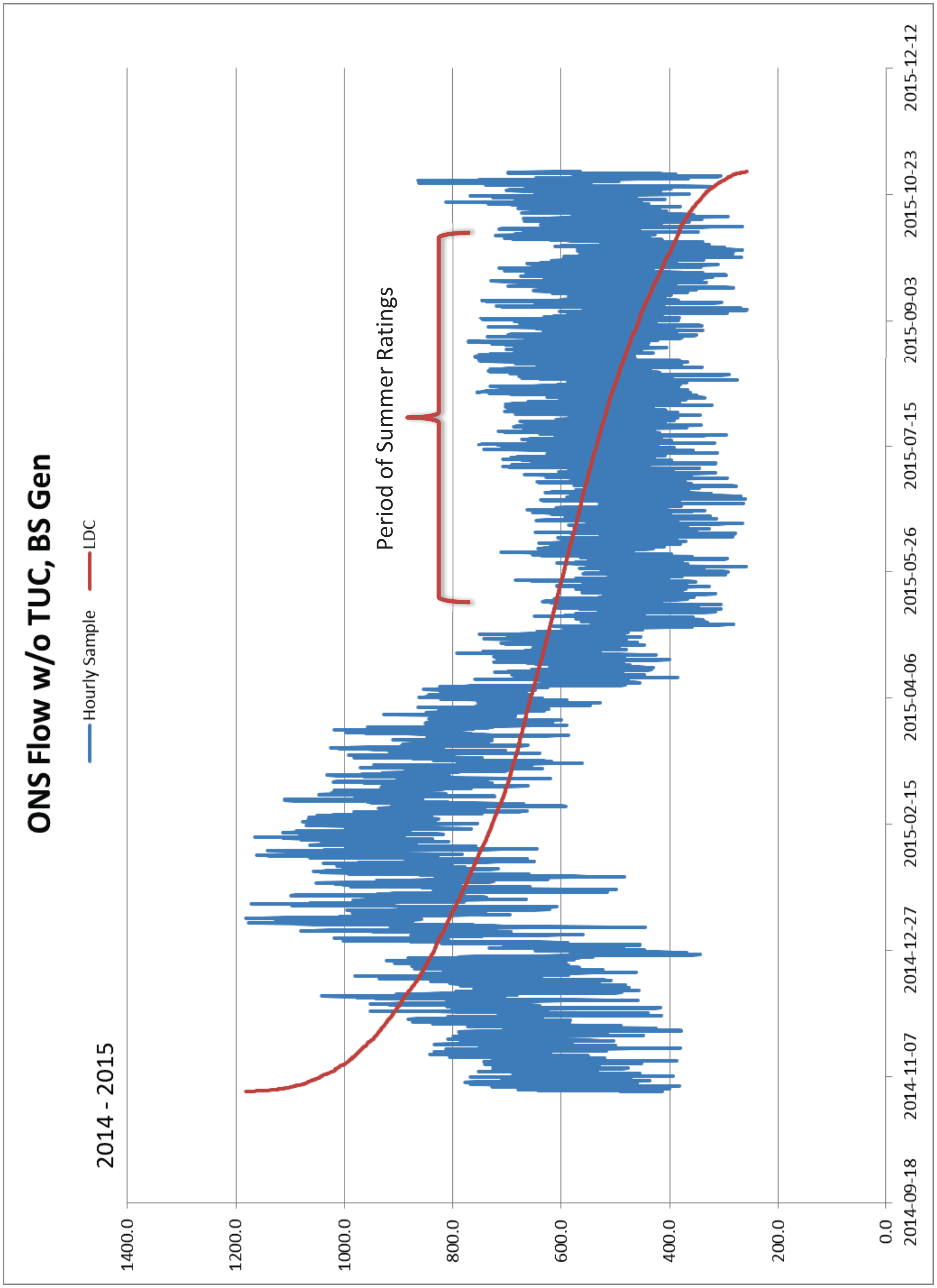


Figure 6D

Pages 45-49 have been removed due to confidentiality.

Figure 11


ONS Flow w/o TUC, BS Gen
Hourly Sample
LDC
2014 - 2015
Period of Summer Ratings
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
2014-09-18
2014-11-07
2014-12-27
2015-02-15
2015-04-06
2015-05-26
2015-07-15
2015-09-03
2015-10-23
2015-12-12

Pages 51-64 have been removed due to confidentiality.

Figure 20

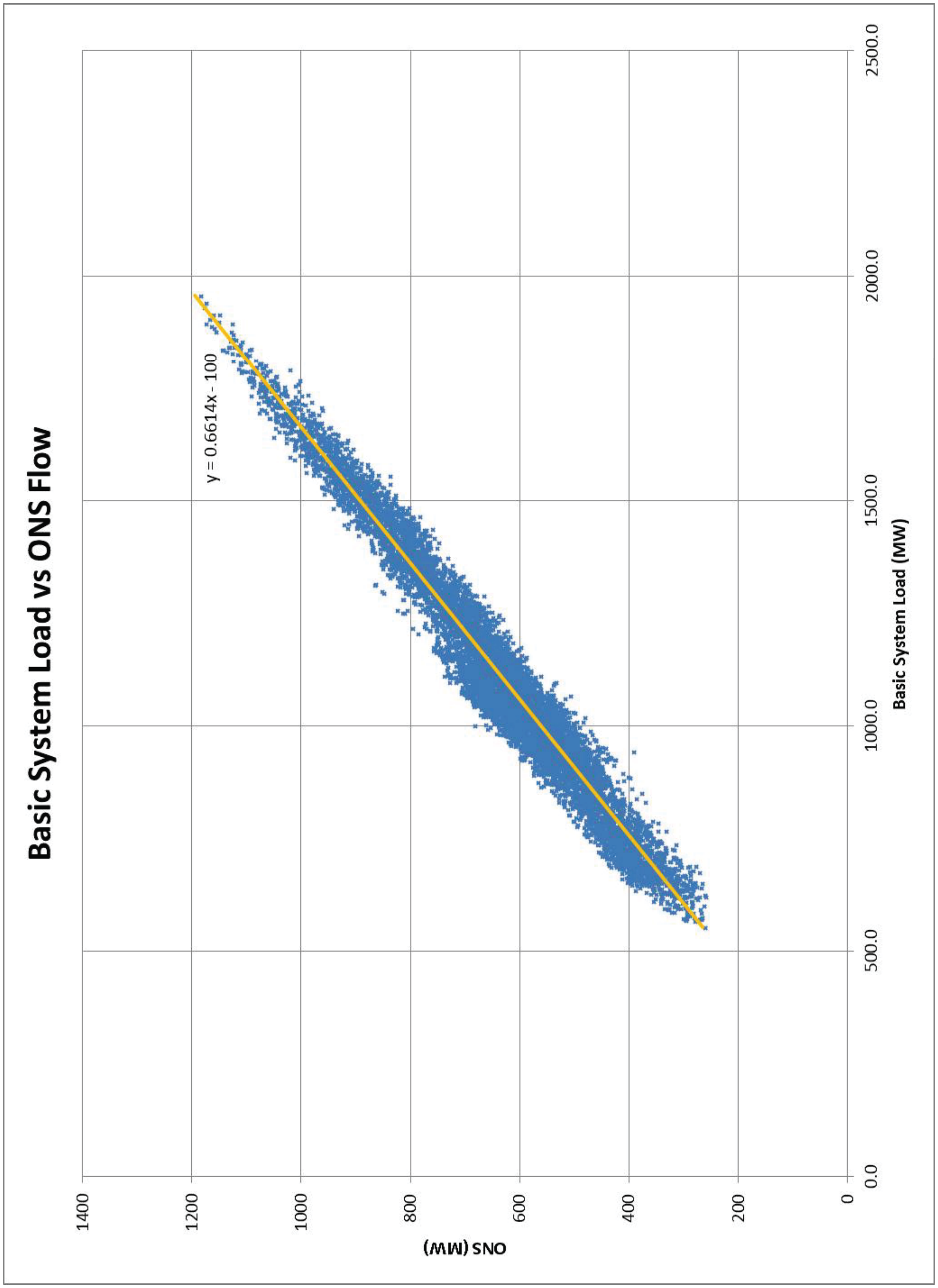
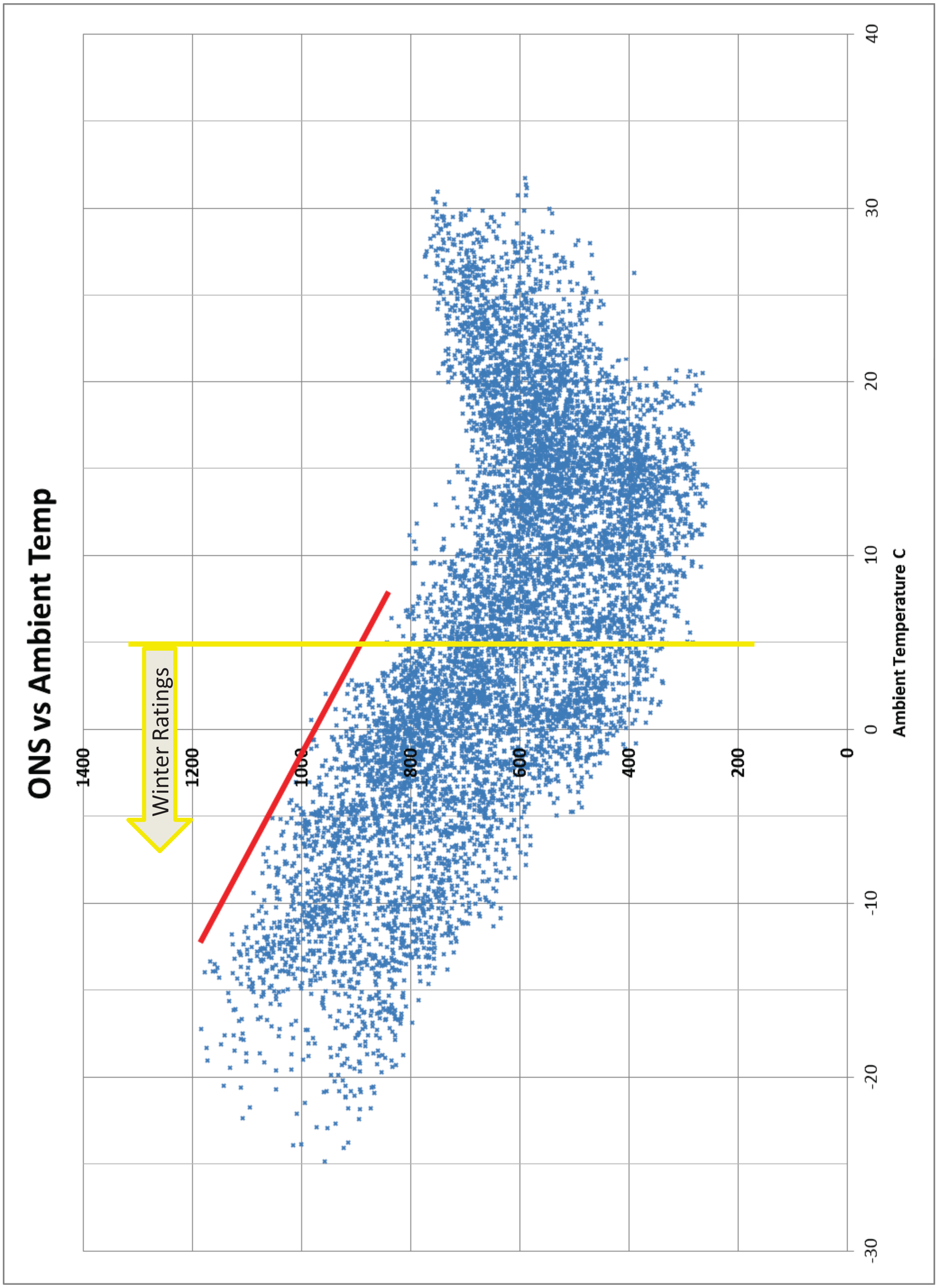

Basic System Load vs ONS Flow
y = 0.6614x - 100
ONS (MW)
Basic System Load (MW)
0
200
400
600
800
1000
1200
1400
0.0
500.0
1000.0
1500.0
2000.0
2500.0

Figure 21


ONS vs Ambient Temp
Winter Ratings
1400
1200
1000
800
600
400
200
0
-30
-20
-10
0
10
20
30
40
Ambient Temperature C

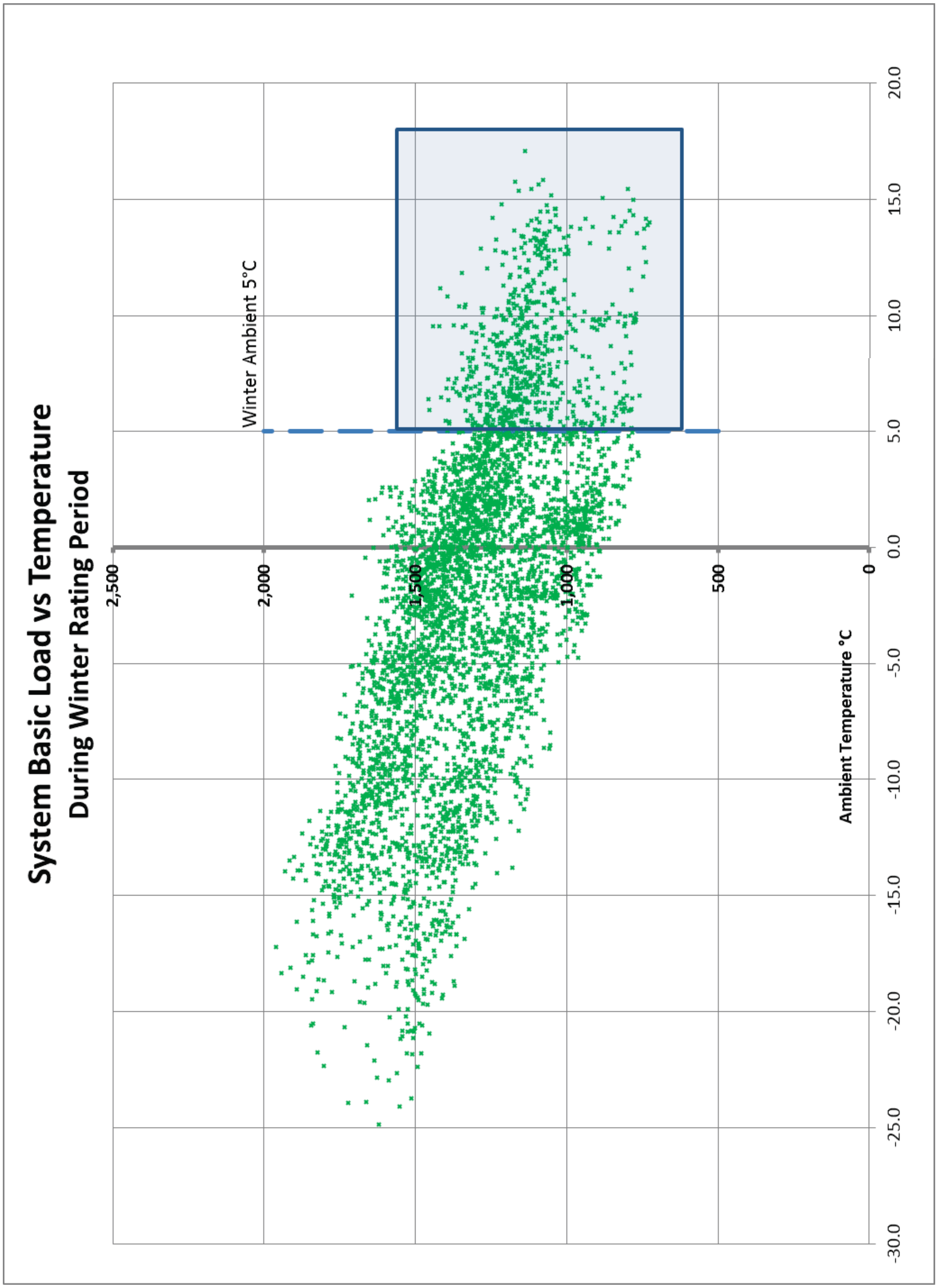
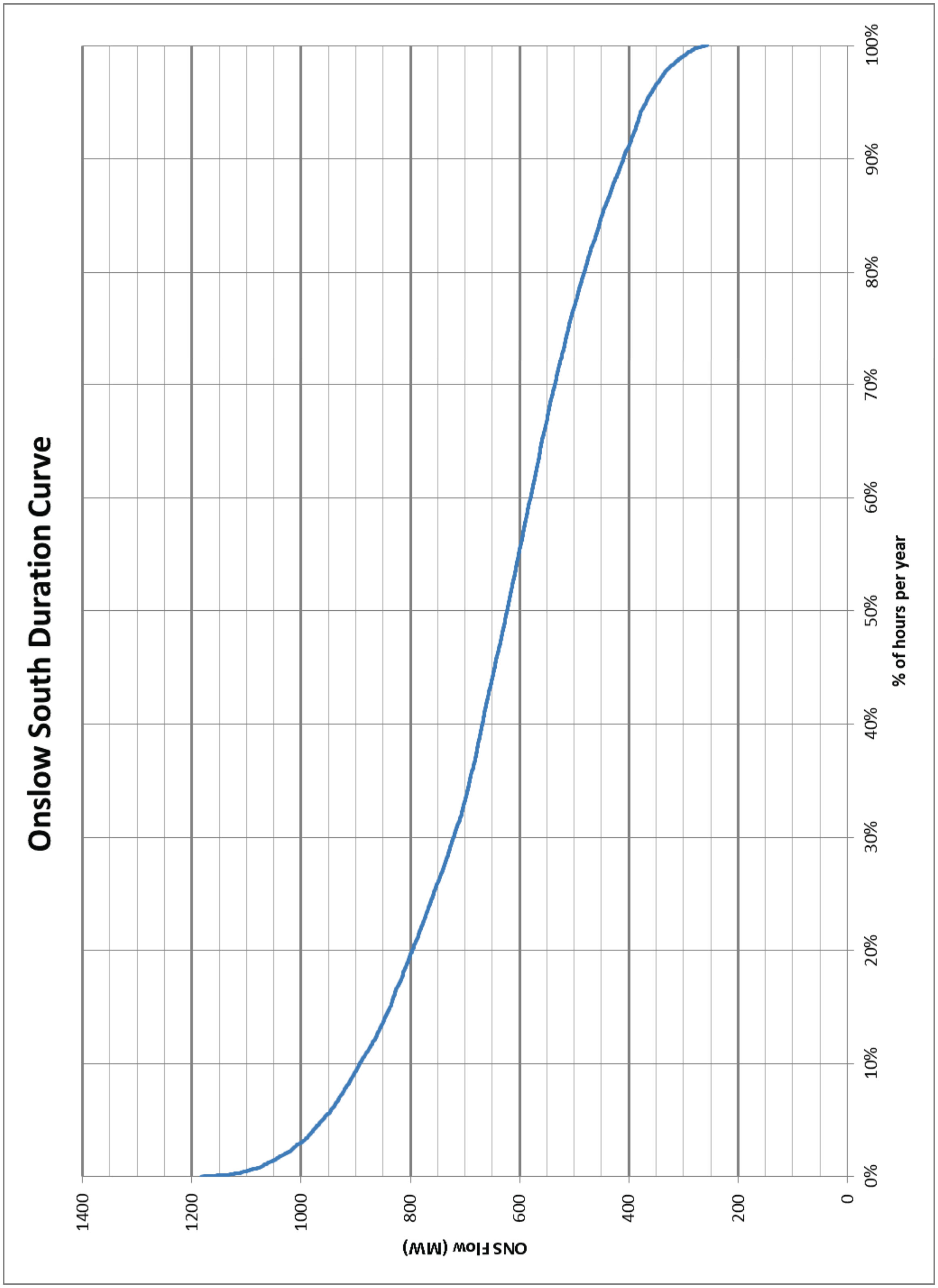


Figure 22
System Basic Load vs Temperature
During Winter Rating Period
Winter Ambient 5°C
2,500
2,000
1,500
1,000
500
0
20.0
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
-30.0
Ambient Temperature °C

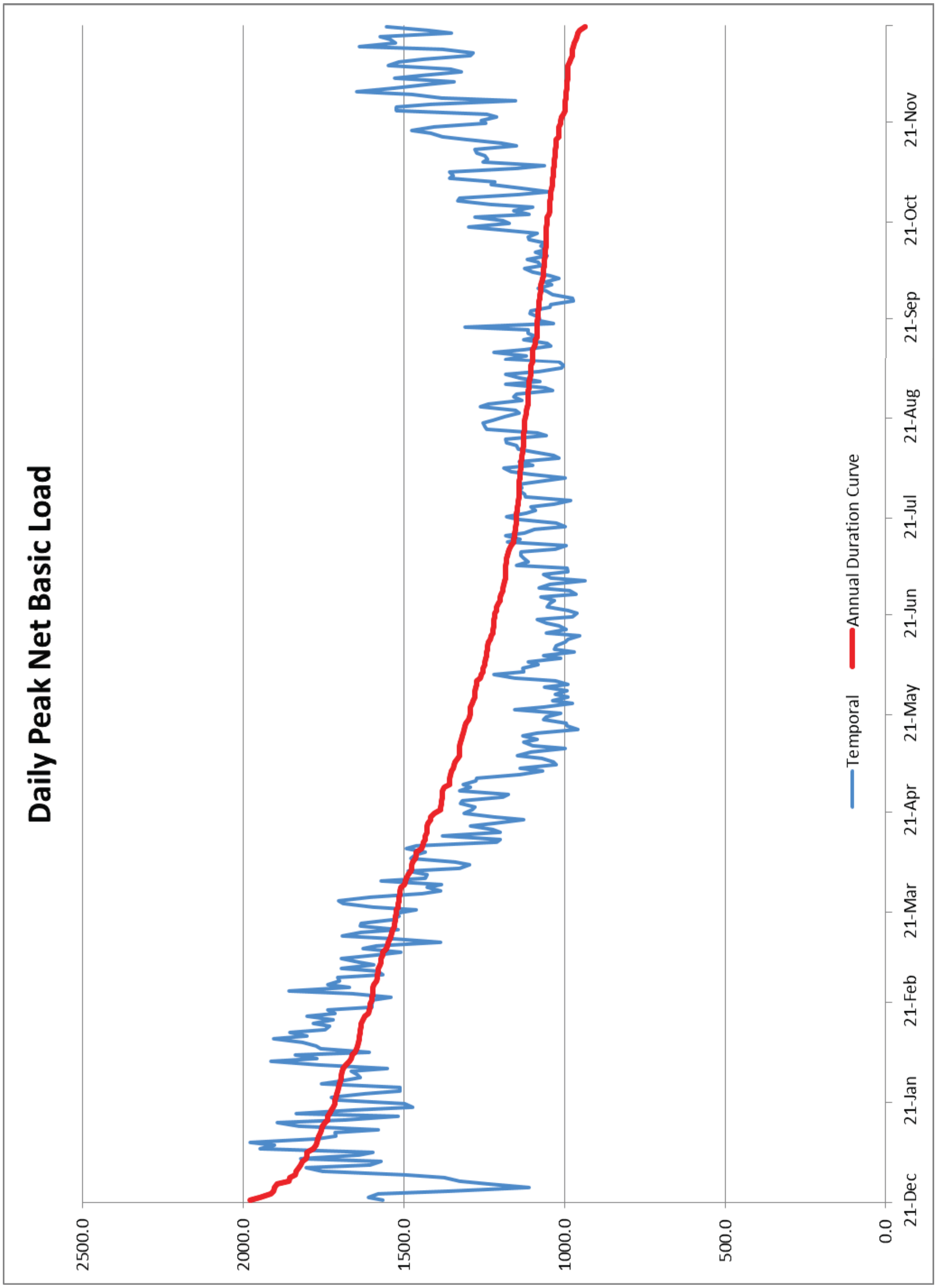
Pages 68-89 have been removed due to confidentiality.

Figure 38


Onslow South Duration Curve
ONS Flow (MW)
0
200
400
600
800
1000
1200
1400
% of hours per year
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%

Pages 91-100 have been removed due to confidentiality.

Figure 44


Daily Peak Net Basic Load
2500.0
2000.0
1500.0
1000.0
500.0
0.0
21-Dec
21-Jan
21-Feb
21-Mar
21-Apr
21-May
21-Jun
21-Jul
21-Aug
21-Sep
21-Oct
21-Nov
Temporal
Annual Duration Curve

Pages 102-109 have been removed due to confidentiality.

Appendices

Appendix A

Stability Results Summary

Table A- 1 Description of Stability Contingencies

Contingency Label	Fault Description
C_3PH_79NT81_g6	Three phase fault on 79N-Hopewell Transformer, 330 MW Runback
C_3PH_L3004_CC	Three phase fault on L3004 (Coleson Cove – Norton) at Coleson Cove
C_3PH_L3006_410N	Three phase fault on L3006 (Salisbury – Memramcook) at Memramcook
C_3PH_L3013_SA	Three phase fault on L3013 (Norton – Salisbury) at Salisbury
C_3PH_L3017_SA	Three phase fault on L3017 (Salisbury – Newcastle) at Salisbury
C_3PH_L6613_74N	Three phase fault on new line L6613 at Springhill
C_3PH_L6514_30N	Three phase fault on L6514 at Maccan
C_3PH_L6535_92N	Three phase fault on L6535 at Amherst Wind
C_3PH_L6536_74N	Three phase fault on L-6536 at Springhill
C_3PH_L8001_67N_g0	Three phase fault on L-8001 at Onslow with no SPS
C_3PH_L8001_67N_g6rb	Three phase fault on L-8001 at Onslow with 330 MW runback (export only)
C_3PH_L8002_103H	Three phase fault on L-8002 at Lakeside
C_3PH_L8002_67N	Three phase fault on L-8002 at Onslow
C_3PH_L8003_67N_g0	Three phase fault on L-8003 at Onslow with no SPS
C_3PH_L8003_67N_g5rb	Three phase fault on L-8003 at Onslow with 165 MW runback
C_3PH_L8003_67N_g6rb	Three phase fault on L-8003 at Onslow with 330 MW runback
C_3PH_L8003_79N_g5rb	Three phase fault on L-8003 at Hopewell with 165 MW runback
C_3PH_L8003_79N_g6rb	Three phase fault on L-8003 at Hopewell with 330 MW runback
C_3PH_L8004_101S_g0	Three phase fault on L-8004 at Woodbine with no SPS
C_3PH_L8004_101S_g5rb	Three phase fault on L-8004 at Woodbine with 165 MW runback
C_3PH_L8004_101S_g6rb	Three phase fault on L-8004 at Woodbine with 330 MW runback
C_3PH_L8004_79N_g0	Three phase fault on L-8004 at Hopewell with no SPS
C_3PH_L8004_79N_g5rb	Three phase fault on L-8004 at Hopewell with 165 MW runback
C_3PH_L8004_79N_g6rb	Three phase fault on L-8004 at Hopewell with 330 MW runback
C_3PH_L8006_67N	Three phase fault on new line L-8006 at Onslow
C_3PH_L8006_120H	Three phase fault on new line L-8006 at Brushy Hill
C_3PH_SVC_120H	Three phase fault on Brushy Hill SVC bus node
C_BBU_L7002_67N701	Single phase fault on L7002 near 67N, breaker failure trips 67N=T71
C_BBU_L7003_67N702	Single phase fault on L7003 near 67N, breaker failure trips L7002
C_BBU_L7005_67N711	Single phase fault on L7005 near 67N, breaker failure trips 67N-T82
C_BBU_L7005_67N712	Single phase fault on L7005 near 67N, breaker failure trips new capacitor bank
C_BBU_L7018_120H710	Single phase fault on L7018 near 120H, breaker failure trips 120HT71
C_BBU_L7018_67N713	Single phase fault on L7018 near 67N, breaker failure trips 67N-T81
C_BBU_L7019_67N705	Single phase fault on L7019 near 67N, breaker failure trips L7001
C_BBU_L8001_67N814_g0	Single phase fault on L-8001, breaker failure trips T81, no SPS
C_BBU_L8001_67N814_g5rb	Single phase fault on L-8001, breaker failure trips T81. With 165 MW runback
C_BBU_L8001_67N814_g6rb	Single phase fault on L-8001, breaker failure trips T81. With 330 MW runback
C_BBU_L8001_67N814_impSPS	Single phase fault on L-8001, breaker failure trips T81, NS separates when importing
C_BBU_L8002_67N813	Single phase fault on L-8003, breaker failure trips T81
C_BBU_L8003_67N811_g0	Single phase fault on L-8003, breaker failure trips T82, no SPS
C_BBU_L8003_67N811_g5rb	Single phase fault on L-8003, breaker failure trips T82. With 165 MW runback
C_BBU_L8003_67N811_g6rb	Single phase fault on L-8003, breaker failure trips T82. With 330 MW runback
C_BBU_L8003_79N803_g0	Single phase fault on L-8003, breaker failure trips L8004 and 79NT81. With 330 MW runback
C_BBU_L8003_79N803_g5rb	Single phase fault on L-8003, breaker failure trips L8004 and 79NT81. With 165 MW runback
C_BBU_L8003_79N803_g6rb	Single phase fault on L-8003, breaker failure trips L8004 and 79NT81. With 330 MW runback
C_BBU_L8004_79N810_g0	Single phase fault on L-8004, breaker failure trips L8003 and 79NT81, no SPS
C_BBU_L8004_79N810_g5rb	Single phase fault on L-8004, breaker failure trips L8003 and 79NT81. With 165 MW runback
C_BBU_L8004_79N810_g6rb	Single phase fault on L-8004, breaker failure trips L8003 and 79NT81. With 330 MW runback
C_Loss_of_ML	Loss of both poles of Maritime link without a fault (475 MW)
C_BBU_L3006_ME3-2_g0	Single phase fault on L3006 breaker failure trips xxx. No SPS
C_BBU_L3006_ME3-2_g5rb	Single phase fault on L3006 breaker failure trips xxx. With 265 MW runback
C_BBU_L3006_ME3-2_g6rb	Single phase fault on L3006 breaker failure trips xxx. With 330 MW runback
C_BBU_L3017_SA3-2_NOSPS	Single phase fault on L3017 breaker failure trips L3006. No SPS
C_BBU_T81_103H681	Fault on Lakeside 345 kV transformer, breaker failure trips B61, L5039, L6033
C_BKR_103H_600_1p	Fault on 138 kV bus tie breaker trips all of 103H-Lakeside
C_BBU_120HT81_120H629	Single phase fault on LV terminals of 120HT81, breaker failure also trips SVC

Table A- 2 Winter Stability Results

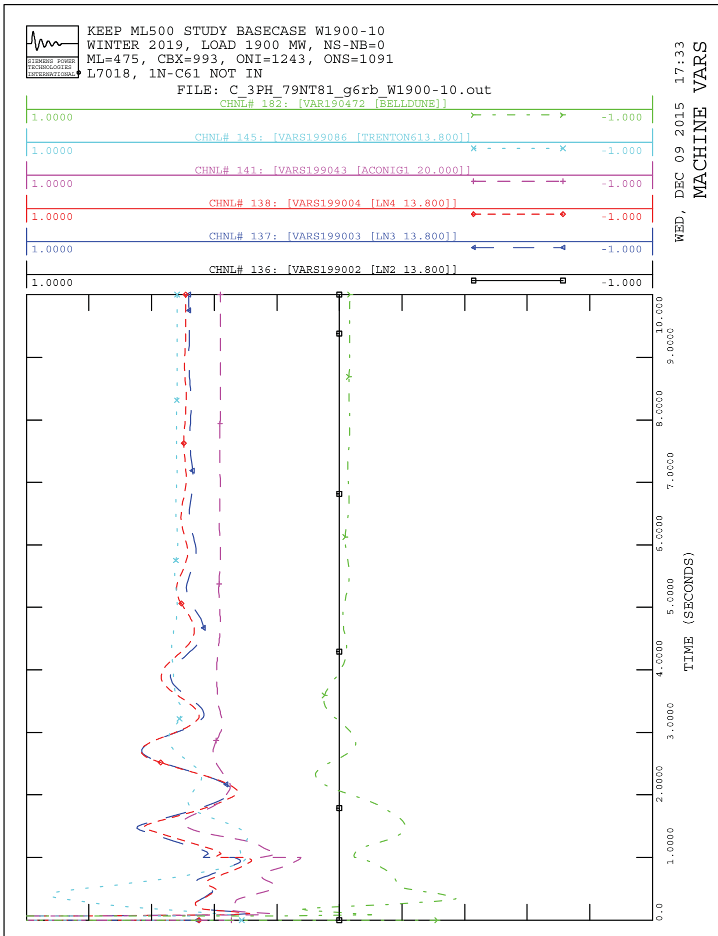
Contingency	W1900-10	W1950-2	W2000-1	W2000-32	W2000-33	W2000-34	W2039-10
NS Load	1900	1950	2100	2000	2000	2000	2039
CBX/ONI/ONS	1243/1091	986/ 1233 /1115	1040/1275 /1143	1205/1343 /1164	1205/1343 /1164	1205/1243/940	1220/1350/1200
Conditions	L7018	L8006	L8006, 1N-C62	L8005, 1N-C62	L8006, 1N-C71, 132H	Deliver reserve	L8006, 67N-C71,132H
C_3PH_79NT81_g6rb	√	√	√	√		√	√
C_3PH_L3004_CC		√	√				
C_3PH_L3006_410N		√	√				
C_3PH_L3013_SA		√	√				
C_3PH_L3017_SA		√	√				
C_3PH_L6613_74N		√	√				
C_3PH_L6514_30N		√	√				
C_3PH_L6535_92N		√	√				
C_3PH_L6536_74N		√	√				
C_3PH_L8001_67N_g0		√	√				
C_3PH_L8002_103H	√	√	√	√		√	√
C_3PH_L8002_67N	√	√	√	√		√	√
C_3PH_L8003_67N_g6rb	√	√	√	X	√	√	√
C_3PH_L8003_67N_g6rb4.5cy				√	√	√	√
C_3PH_L8003_67N_g6rb4cy				√	√	√	X
C_3PH_L8003_79N_g6rb	√	√	√	√		√	√
C_3PH_L8004_101S_g6rb	√	√	√	√		√	√
C_3PH_L8004_79N_g6rb	√	√	√	√		√	√
C_3PH_L8006_67N					√	√	√
C_3PH_L8006_120H					√	√	√
C_3PH_SVC_120H						√	√
C_BBU_L7002_67N701					√	√	√
C_BBU_L7003_67N702					√	√	√
C_BBU_L7005_67N711					√	√	√
C_BBU_L7018_120H710					√	√	√
C_BBU_L7018_67N713					√	√	√
C_BBU_L7019_67N705					√	√	√
C_BBU_L8001_67N814_g6rb	N	N	N	N			√
C_BBU_L8002_67N813		√	√	√		√	
C_BBU_L8003_67N811_g6rb	√	√	√	√		√	X
C_BBU_L8003_79N803_g6rb	√	√	√	√		√	√
C_BBU_L8004_79N810_g6rb	√	√	√	√		√	√
C_Loss_of_ML	√	√	√	√			
C_BBU_L3006_ME3-2_g6rb							
C_BBU_L3017_SA3-2_NOSPS		√	√				√
C_BBU_T81_103H681			√		√	√	√
C_BKR_103H_600_1p			√			√	√
C_BBU_120HT81_120H629					√		√

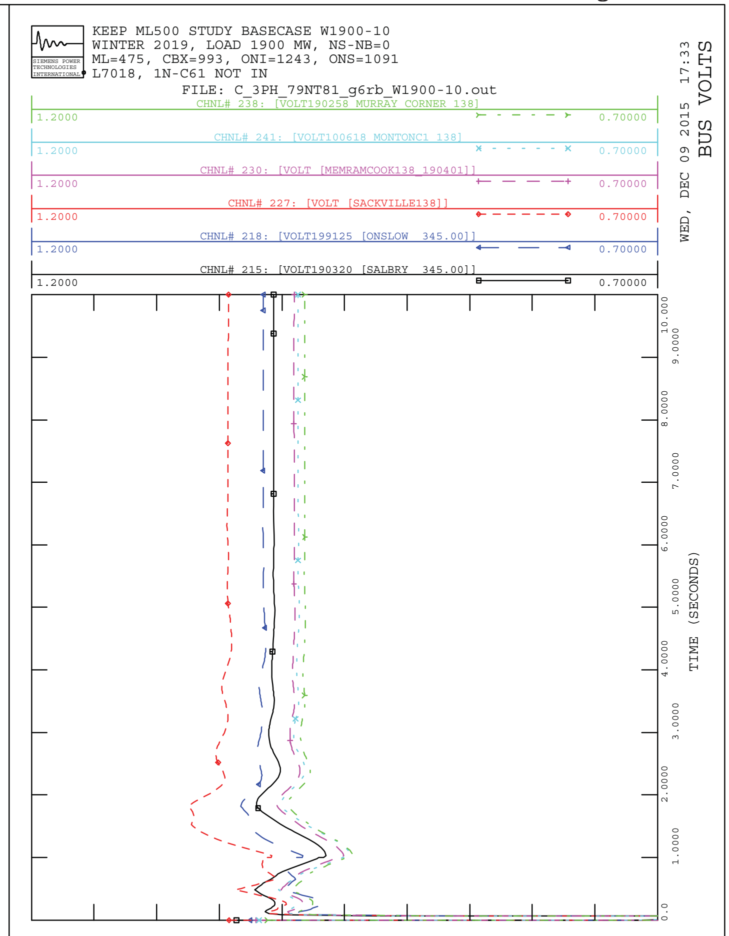
<u>Notes</u>:
√ - Denotes contingency meets criteria
X – Denotes contingency fails criteria
N – Denotes conditions is not applicable
Blank denotes contingency was not studied

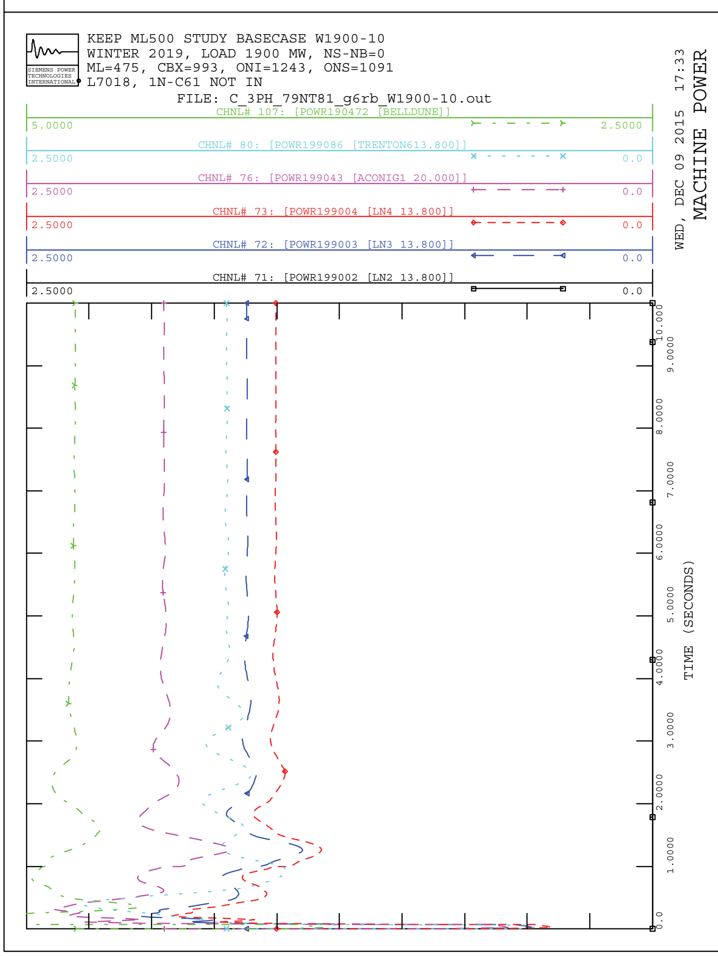
Appendix B

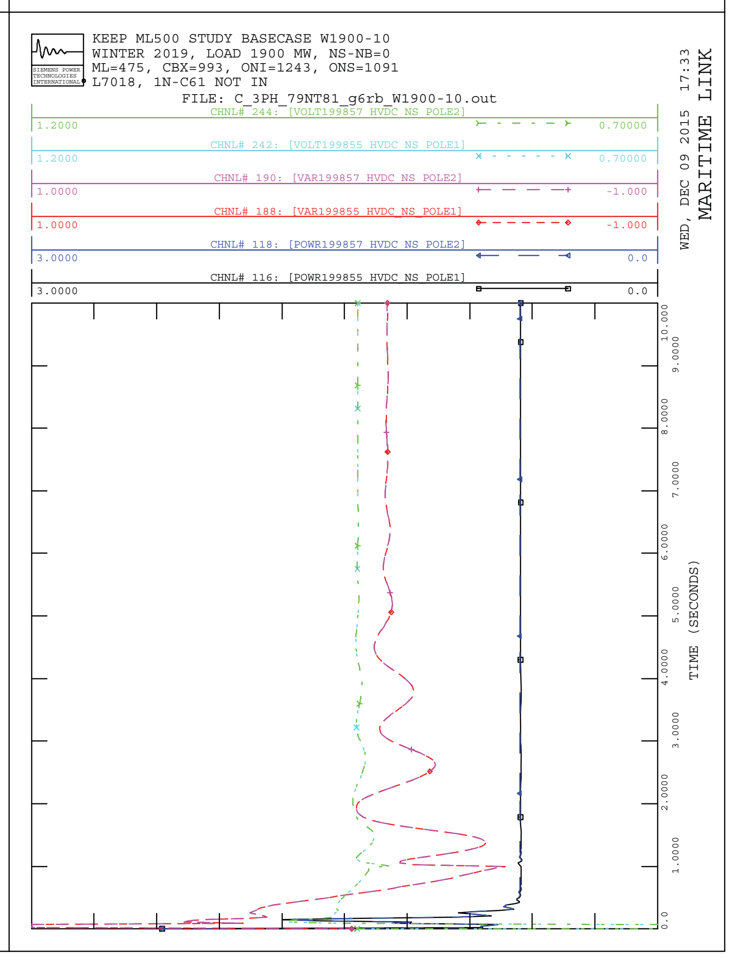
Stability Results Detail

REDACTED (CONFIDENTIAL INFORMATION REMOVED)









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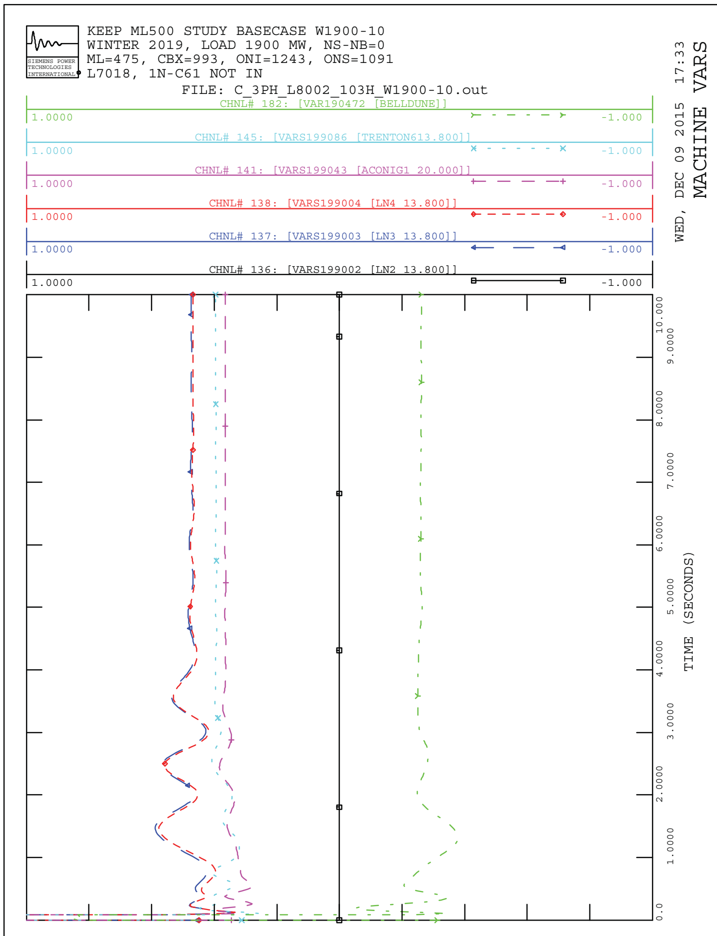
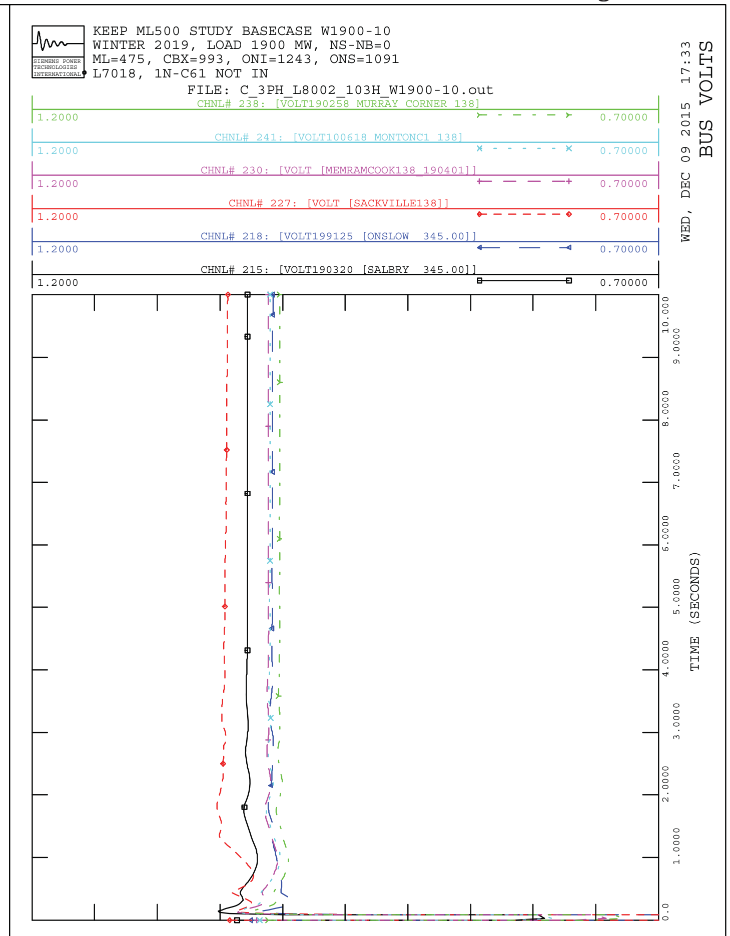
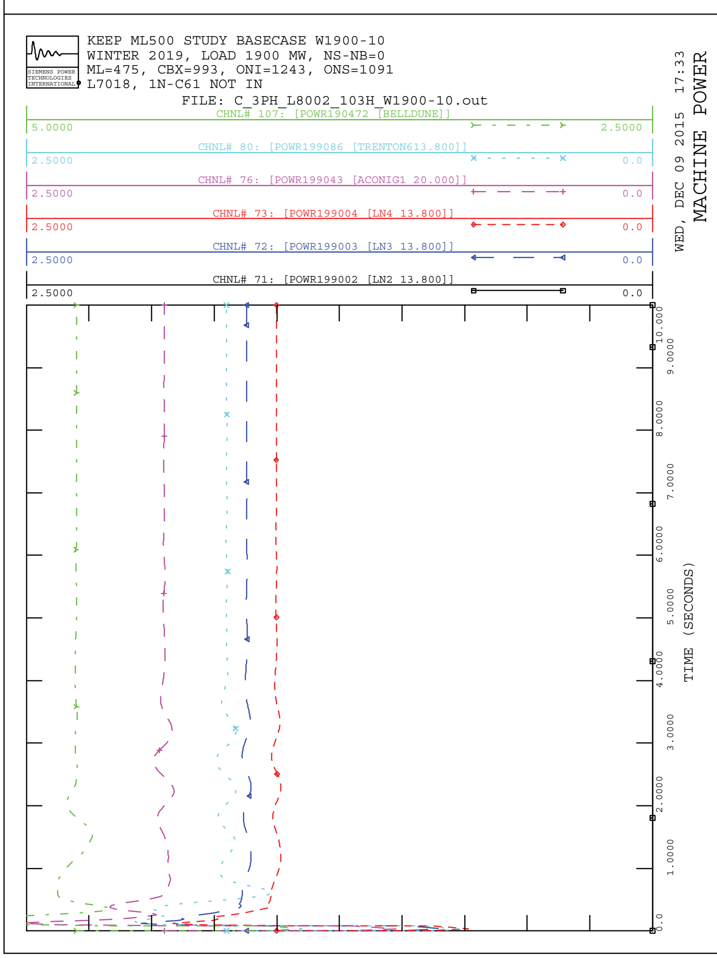
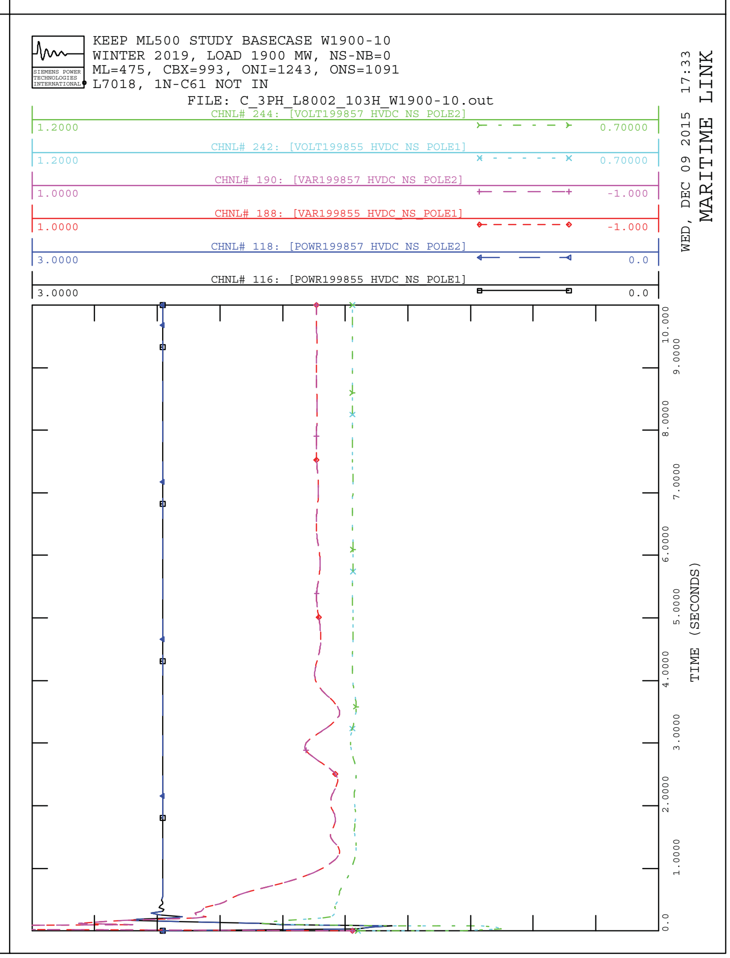
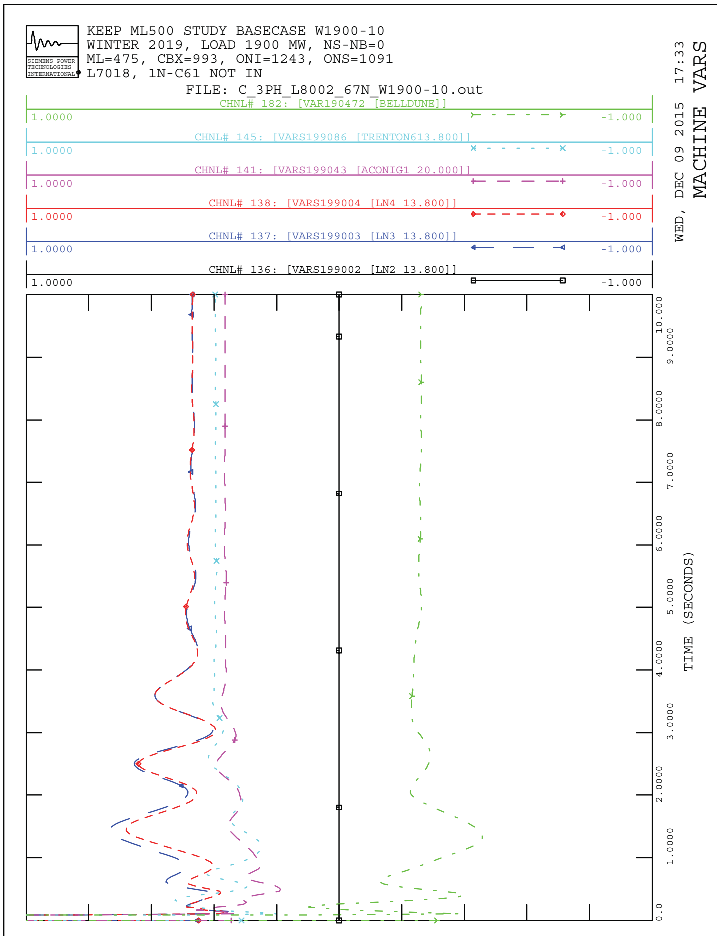


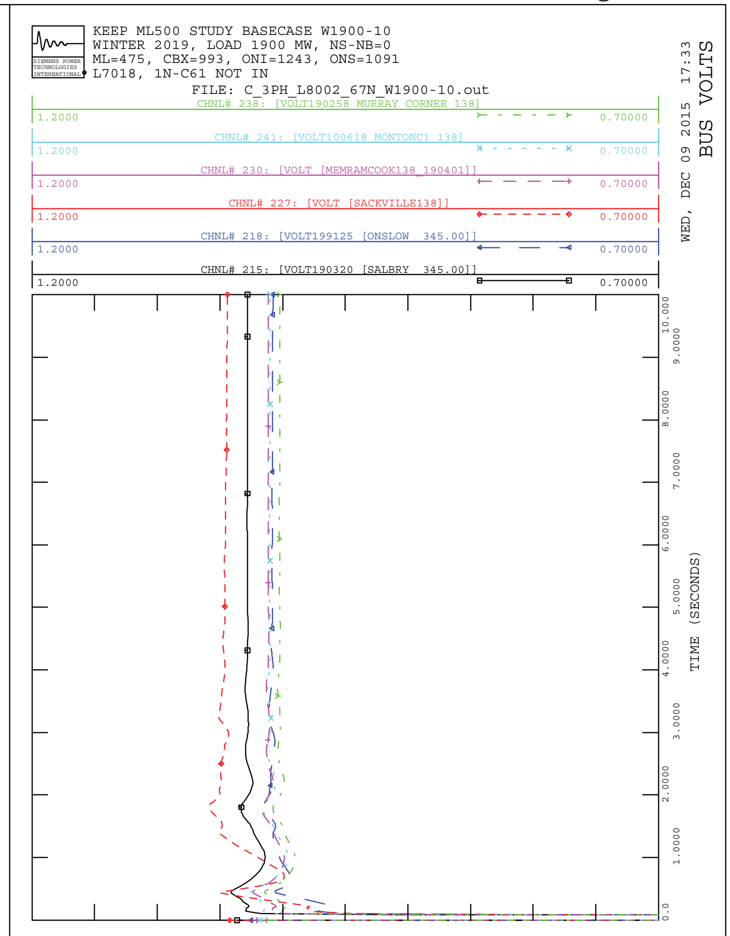




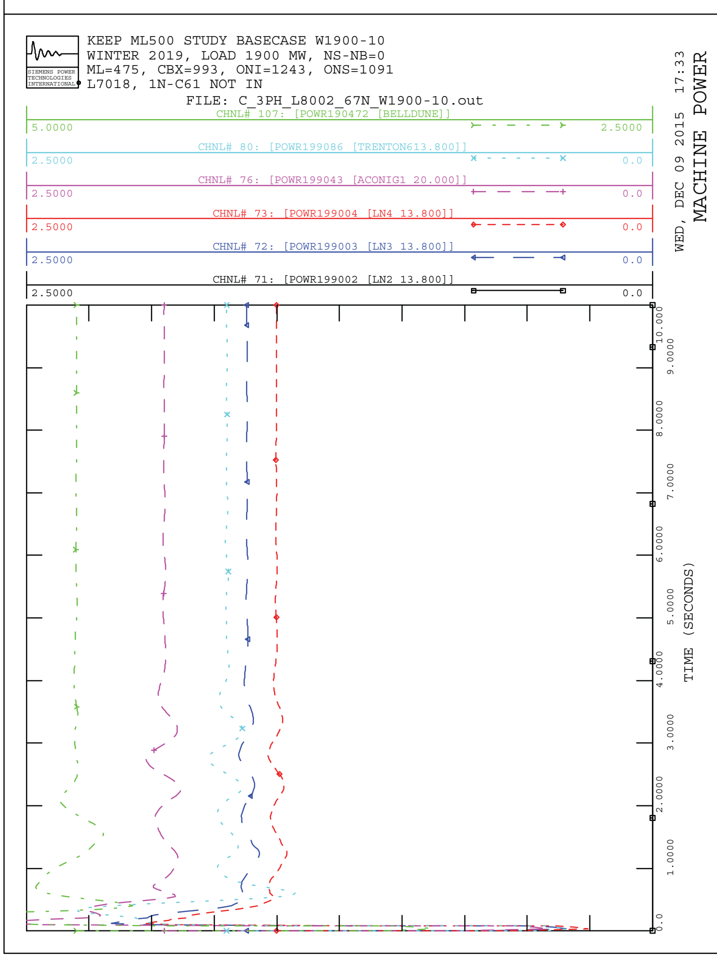




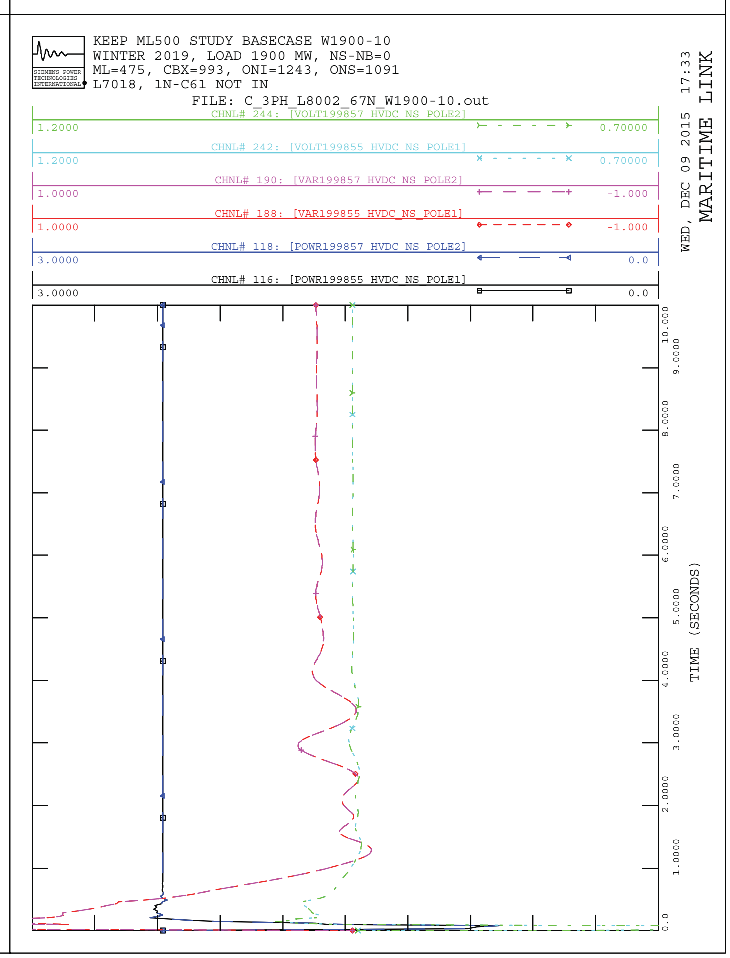
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8002_67N_W1900-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
WED, DEC 09 2015 17:33
MACHINE VARS
TIME (SECONDS)



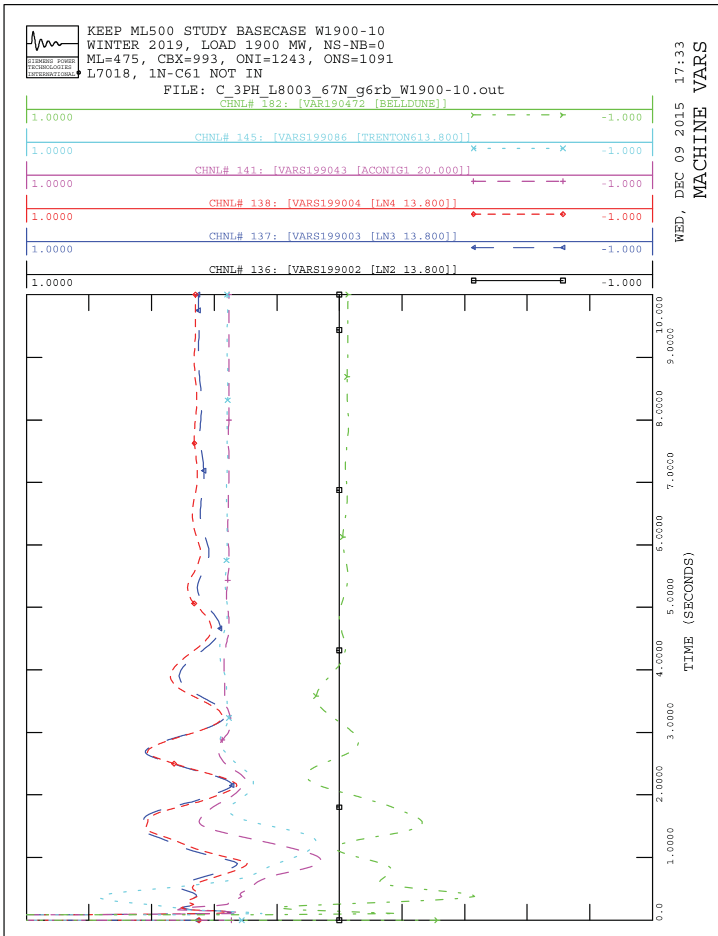
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8002_67N_W1900-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
WED, DEC 09 2015 17:33
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8002_67N_W1900-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
0.0
WED, DEC 09 2015 17:33
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8002_67N_W1900-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
WED, DEC 09 2015 17:33
MARITIME LINK
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8003_67N_g6rb_W1900-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
WED, DEC 09 2015 17:33
MACHINE VARS
TIME (SECONDS)
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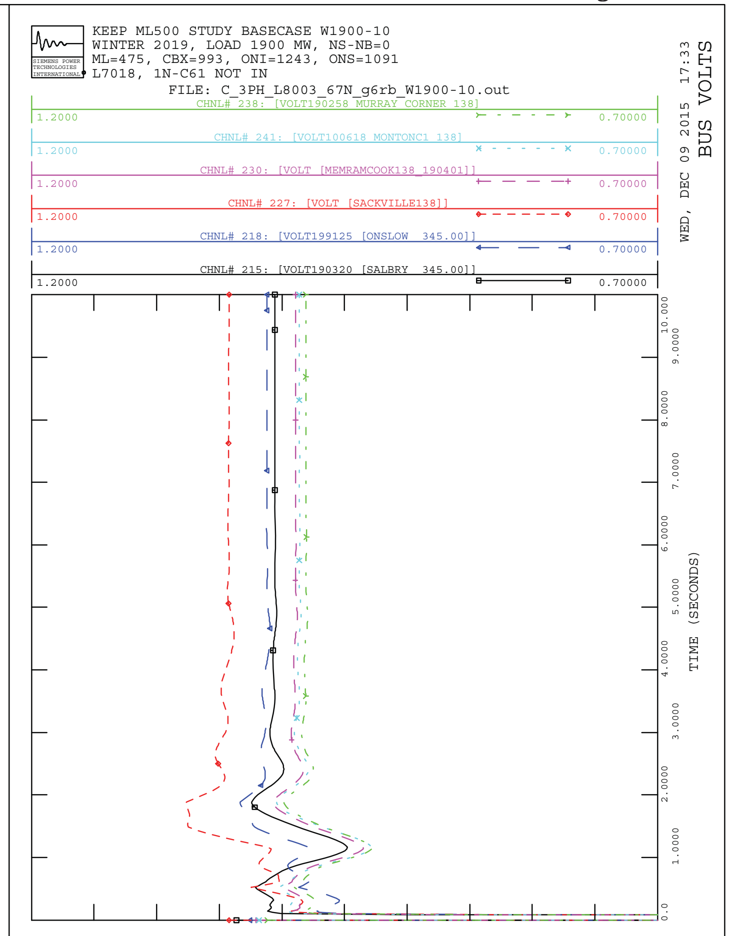
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000



KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8003_67N_g6rb_W1900-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
WED, DEC 09 2015 17:33
BUS VOLTS
TIME (SECONDS)
0.0
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2.0000
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5.0000
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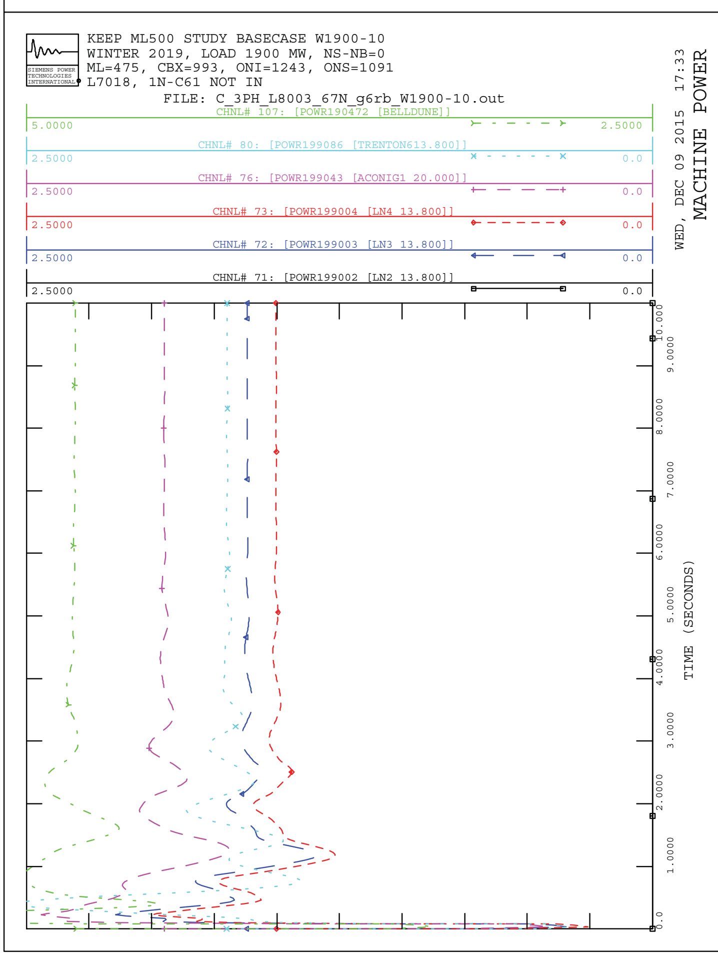
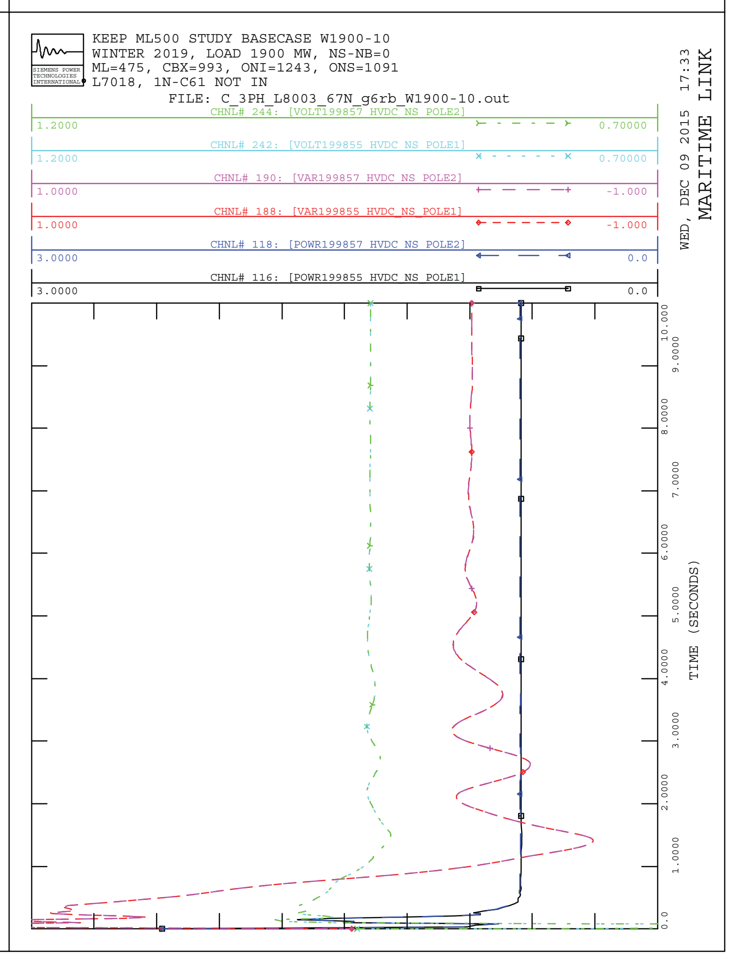
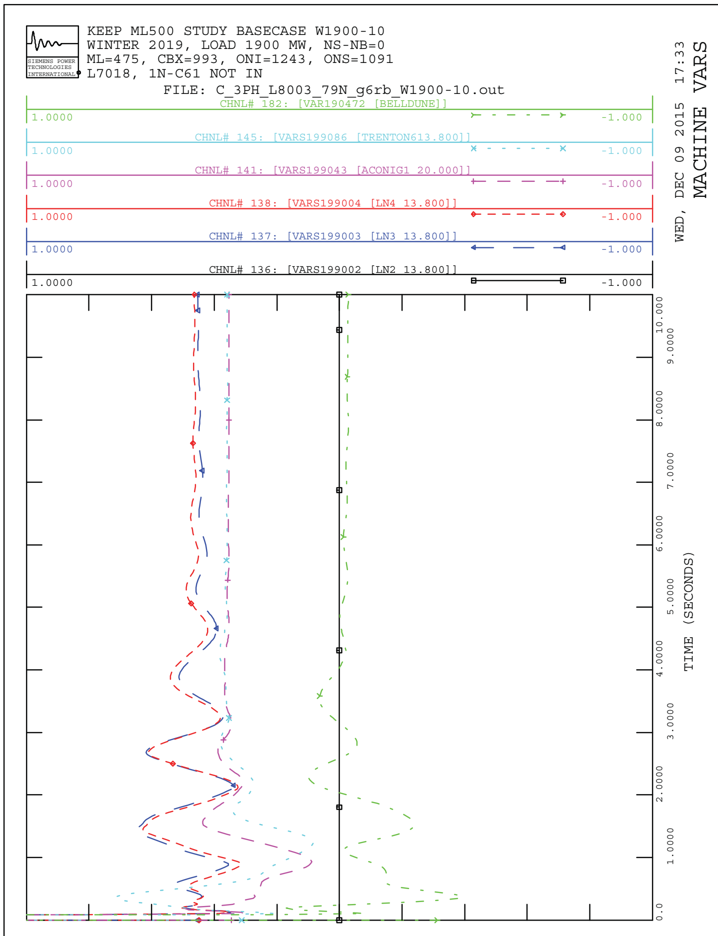
8.0000
9.0000
10.000



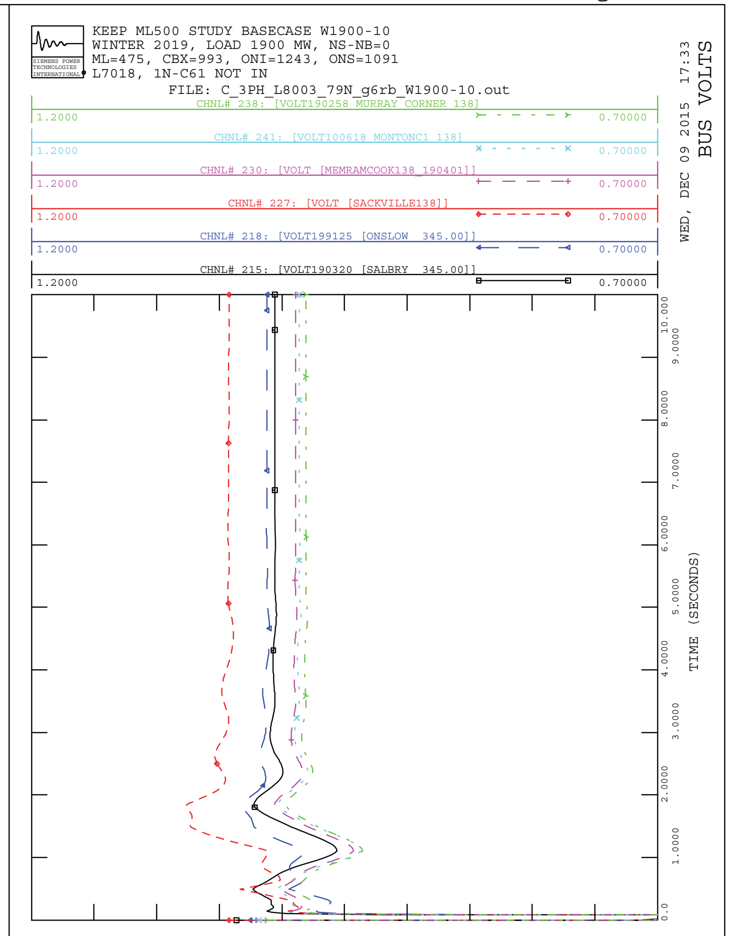
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8003_67N_g6rb_W1900-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
WED, DEC 09 2015 17:33
MACHINE POWER
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000



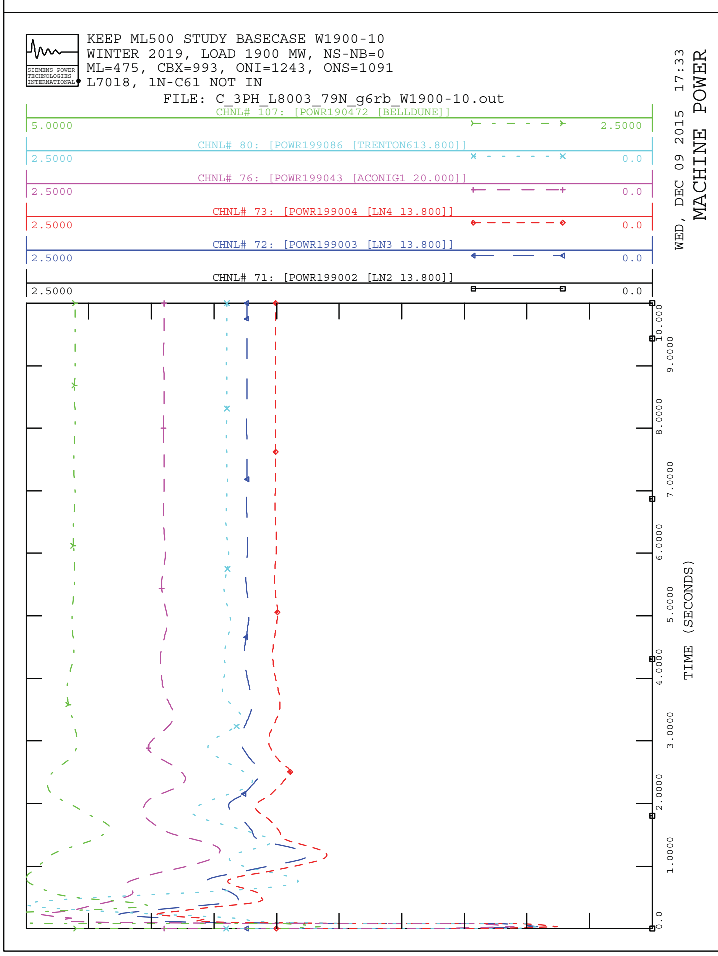
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8003_67N_g6rb_W1900-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
WED, DEC 09 2015 17:33
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000



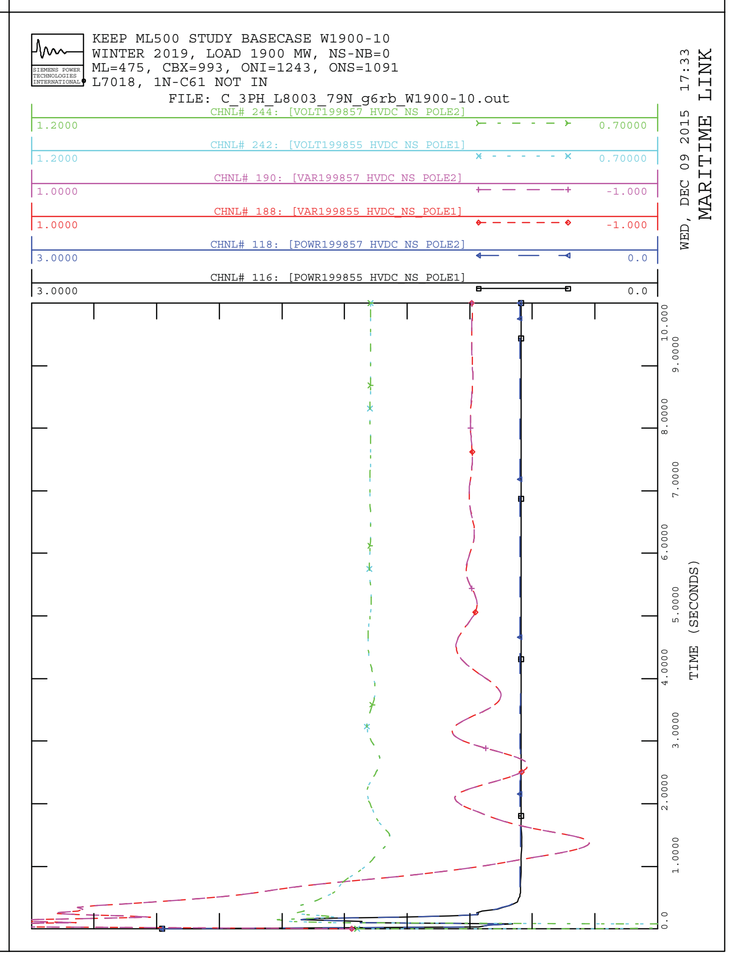
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8003_79N_g6rb_W1900-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
TIME (SECONDS)
WED, DEC 09 2015 17:33
MACHINE VARS



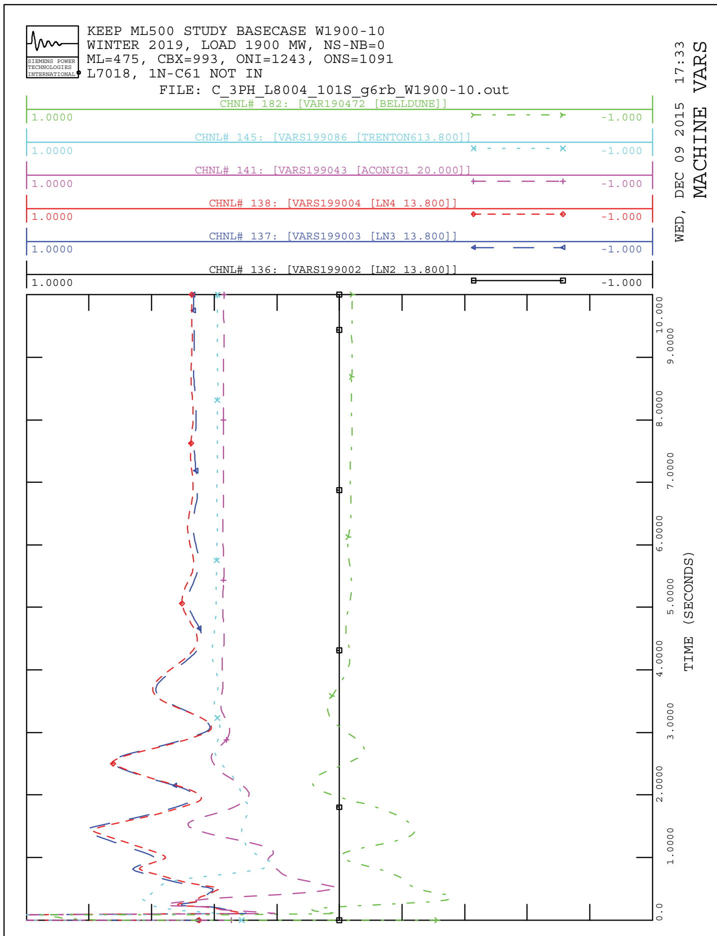
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8003_79N_g6rb_W1900-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
TIME (SECONDS)
WED, DEC 09 2015 17:33
BUS VOLTS



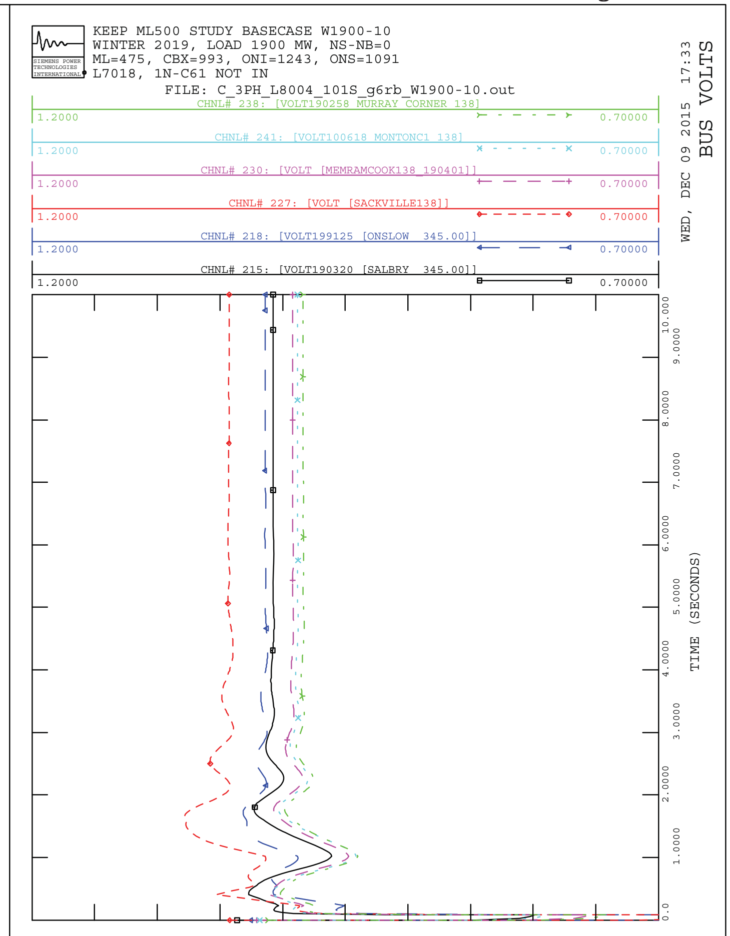
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8003_79N_g6rb_W1900-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
TIME (SECONDS)
WED, DEC 09 2015 17:33
MACHINE POWER



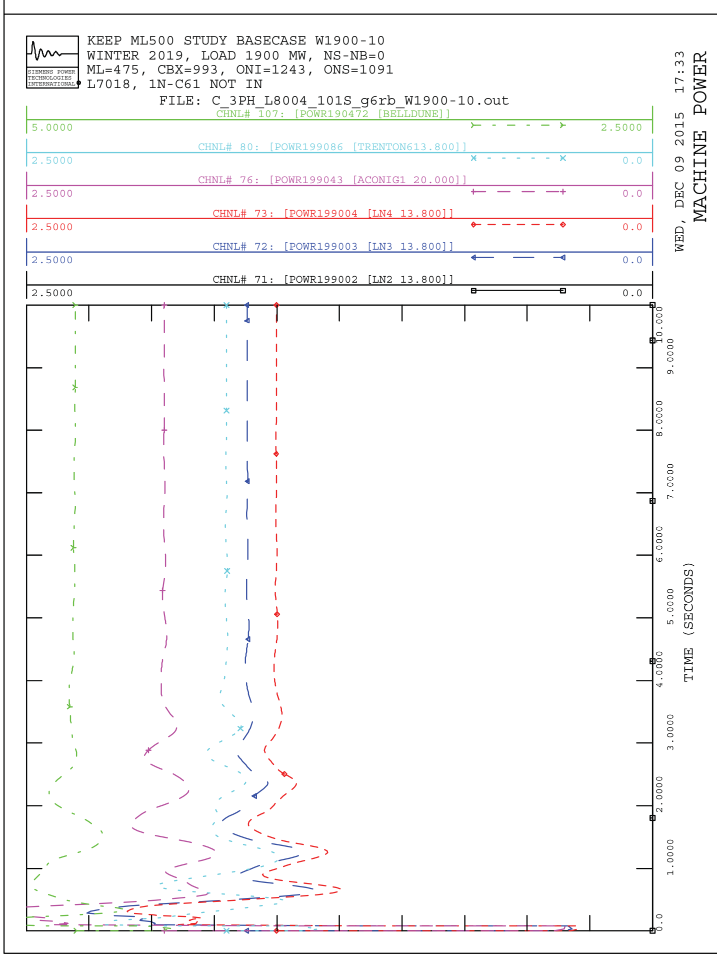
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8003_79N_g6rb_W1900-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
TIME (SECONDS)
WED, DEC 09 2015 17:33
MARITIME LINK



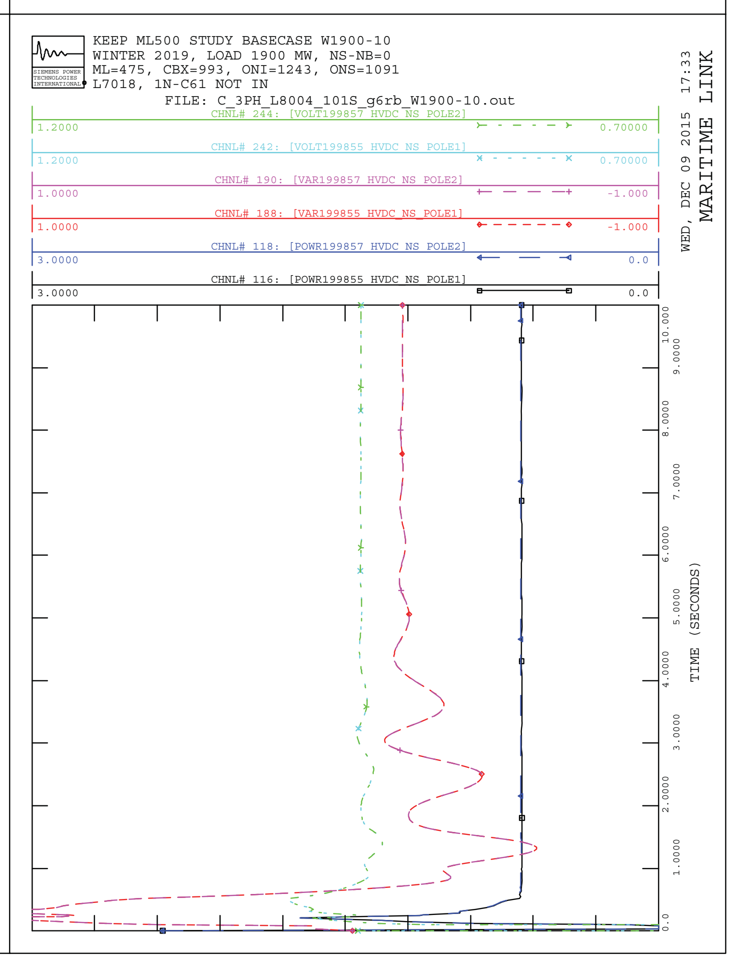
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8004_101S_g6rb_W1900-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
WED, DEC 09 2015 17:33
MACHINE VARS
TIME (SECONDS)



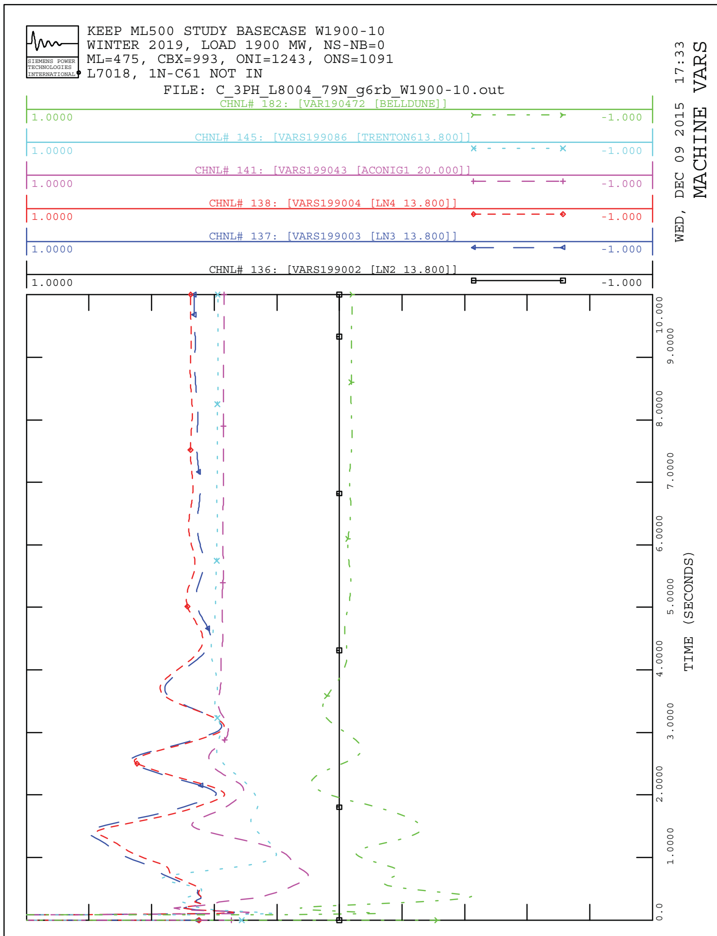
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8004_101S_g6rb_W1900-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
WED, DEC 09 2015 17:33
BUS VOLTS
TIME (SECONDS)

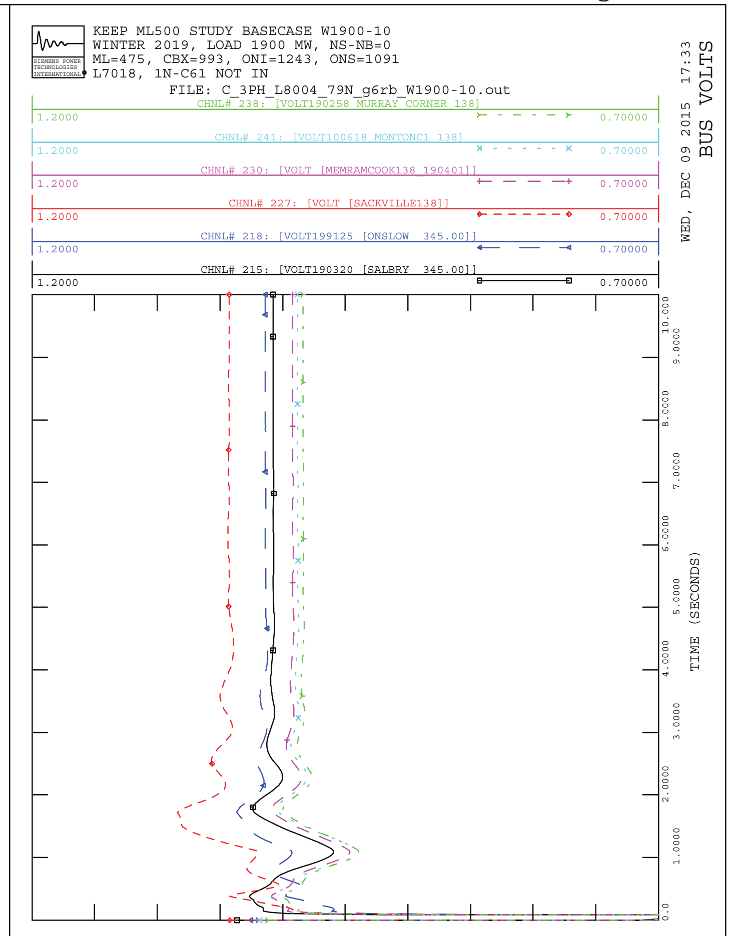


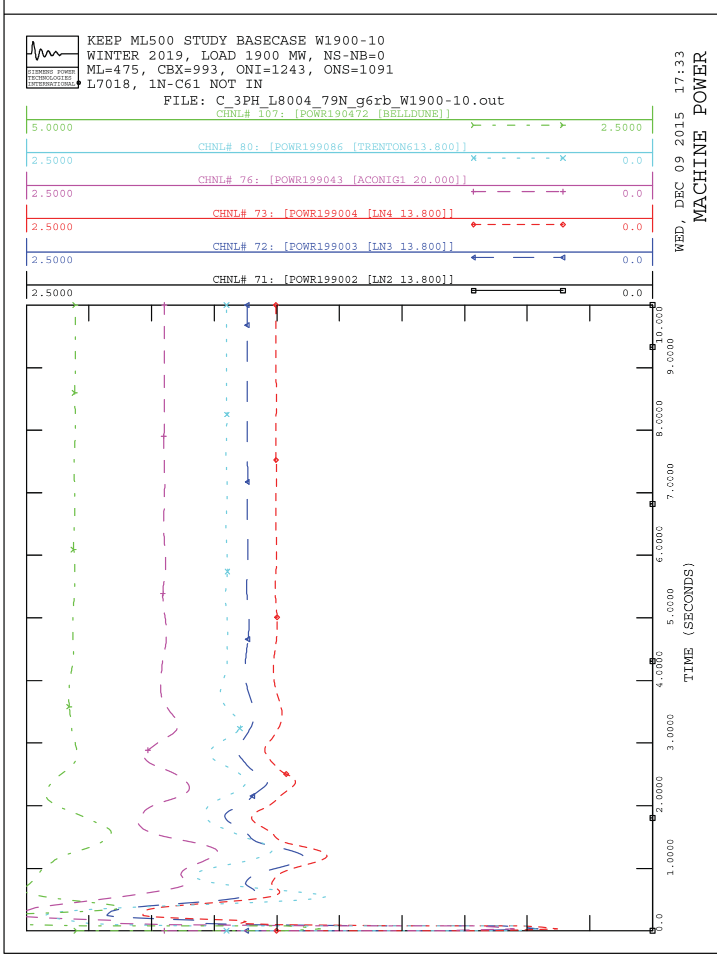
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8004_101S_g6rb_W1900-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
WED, DEC 09 2015 17:33
MACHINE POWER
TIME (SECONDS)

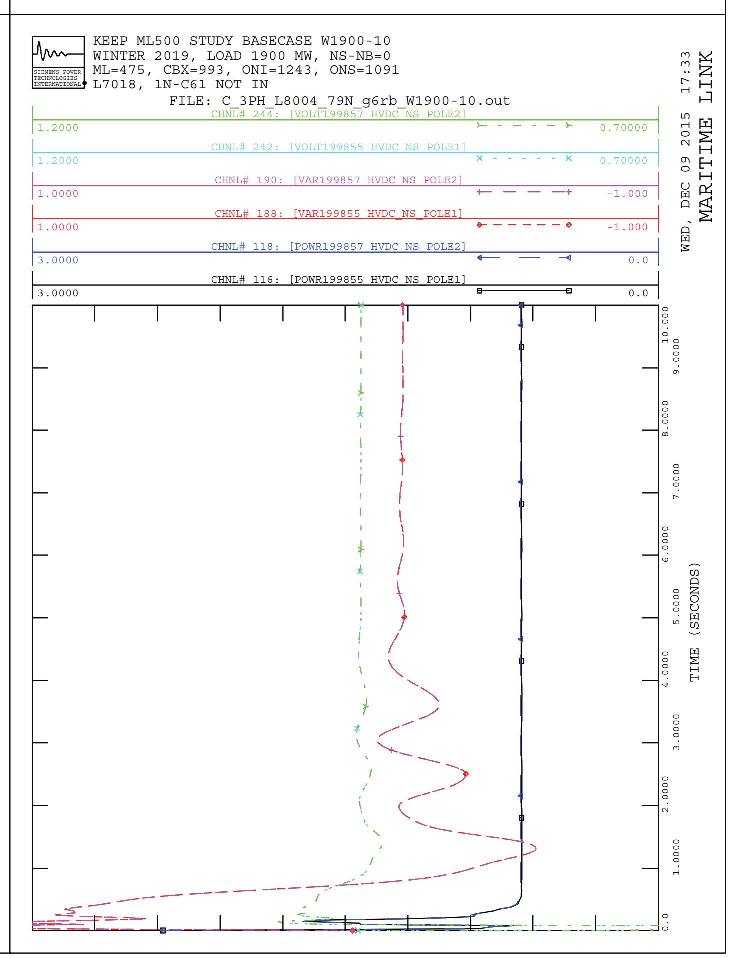


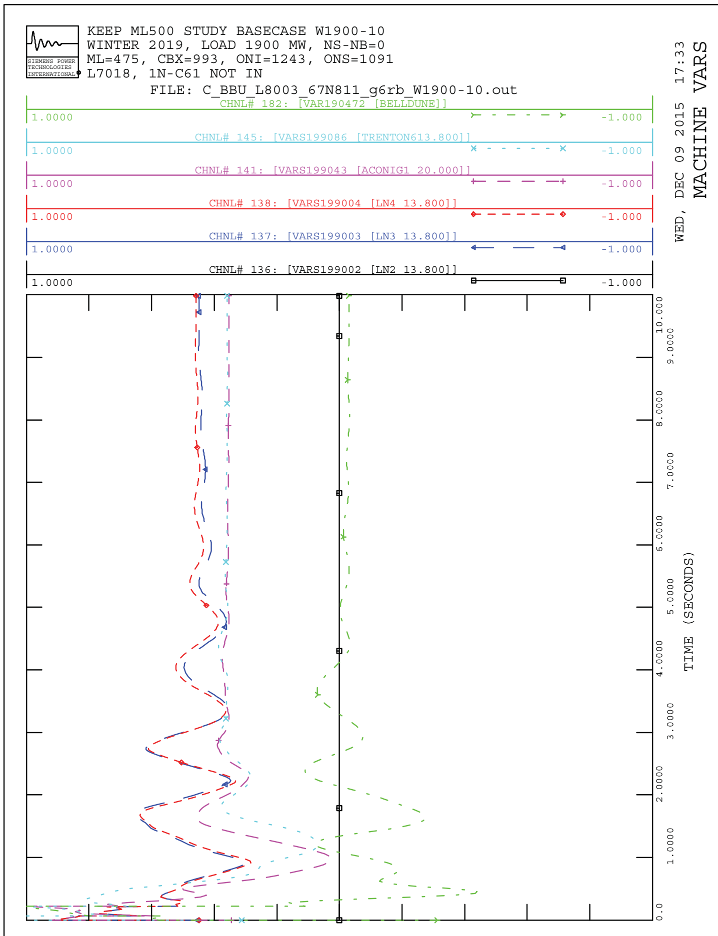
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8004_101S_g6rb_W1900-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
WED, DEC 09 2015 17:33
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8004_79N_g6rb_W1900-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
TIME (SECONDS)
WED, DEC 09 2015 17:33
MACHINE VARS

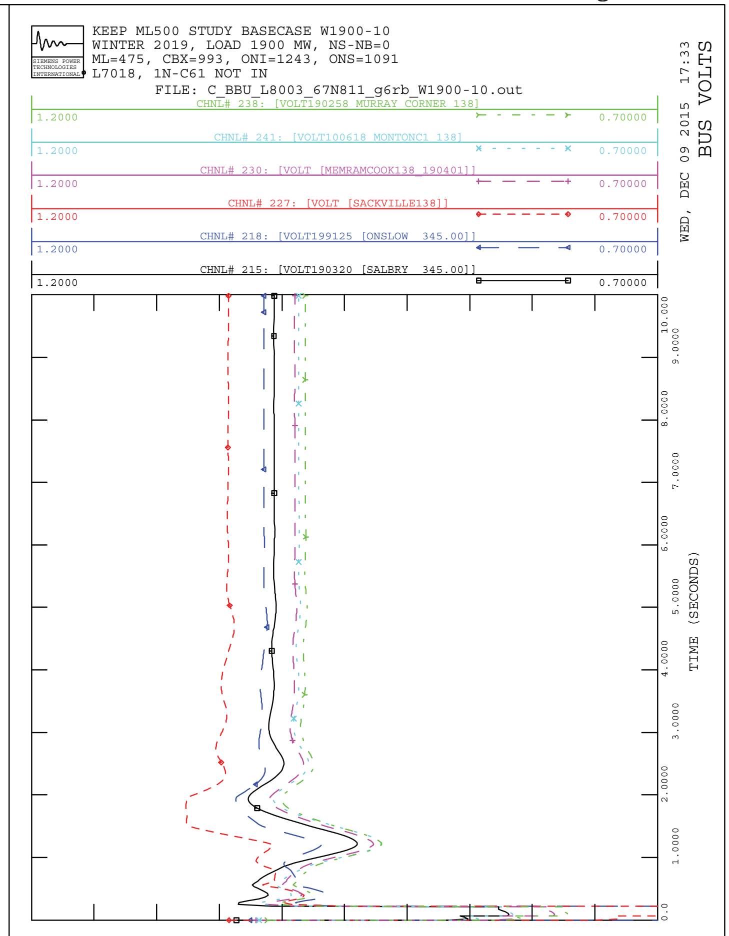

KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8004_79N_g6rb_W1900-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138_190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
TIME (SECONDS)
WED, DEC 09 2015 17:33
BUS VOLTS


KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8004_79N_g6rb_W1900-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
TIME (SECONDS)
WED, DEC 09 2015 17:33
MACHINE POWER

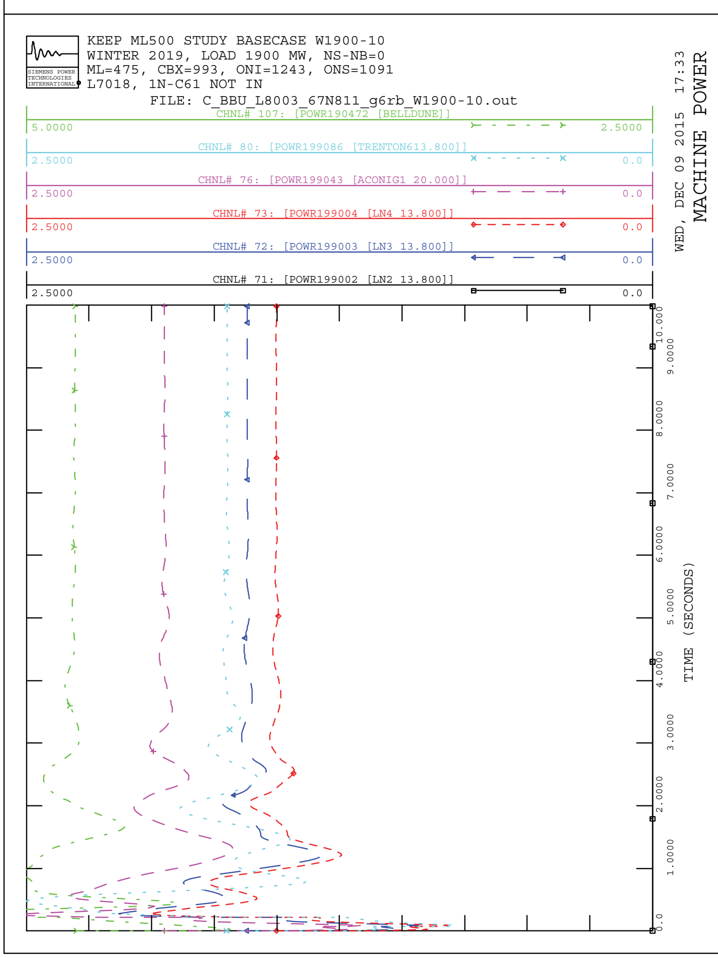

KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_3PH_L8004_79N_g6rb_W1900-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
TIME (SECONDS)
WED, DEC 09 2015 17:33
MARITIME LINK



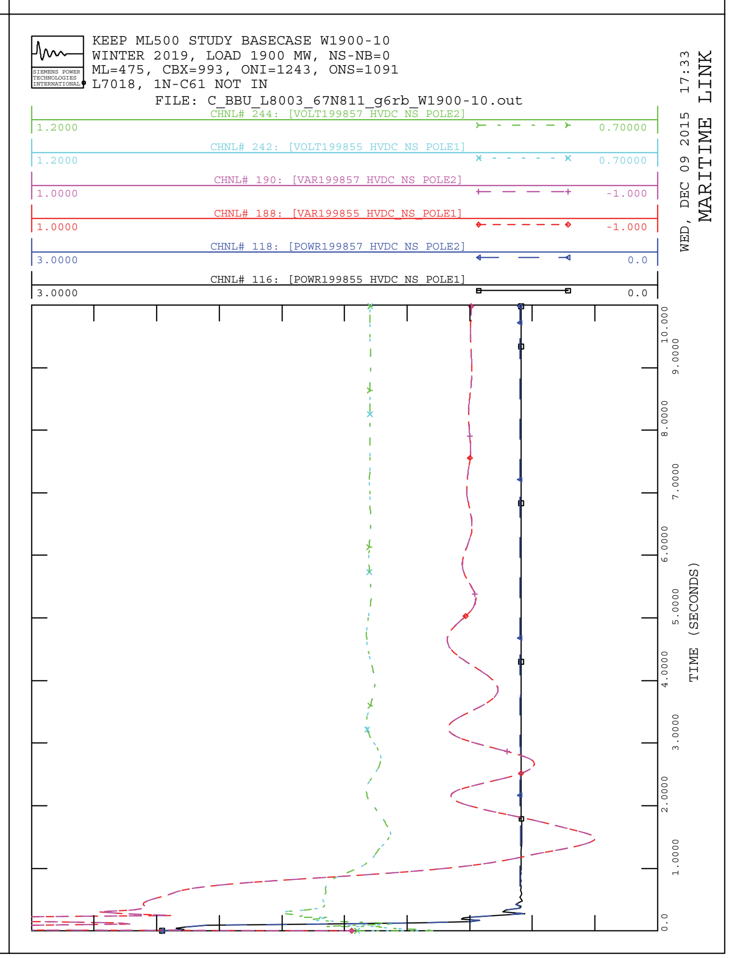
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_BBU_L8003_67N811_g6rb_W1900-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
TIME (SECONDS)
WED, DEC 09 2015 17:33
MACHINE VARS



KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_BBU_L8003_67N811_g6rb_W1900-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
TIME (SECONDS)
WED, DEC 09 2015 17:33
BUS VOLTS

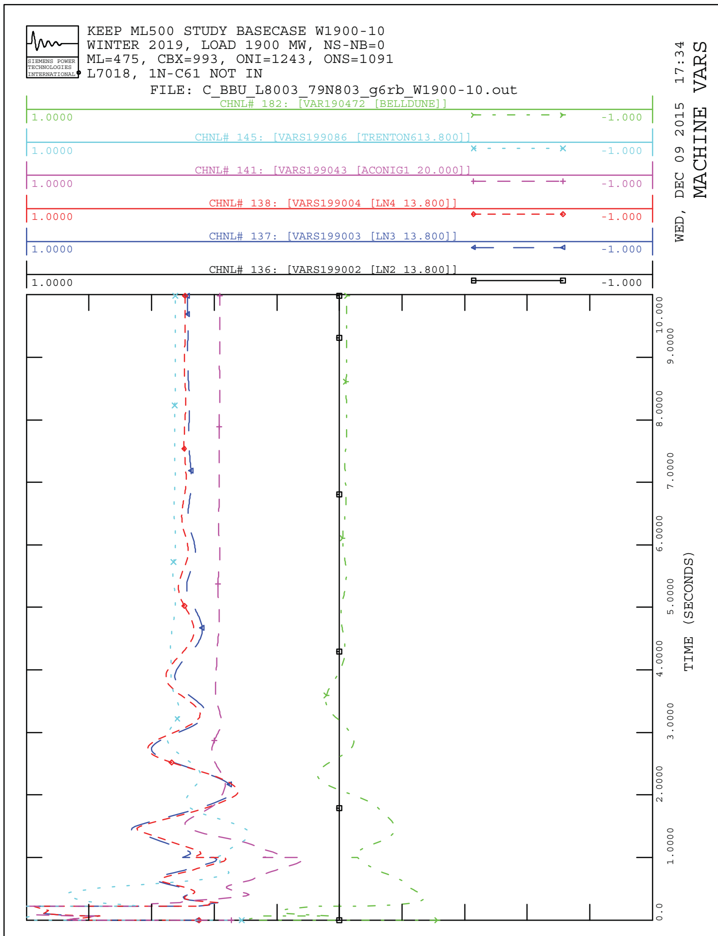


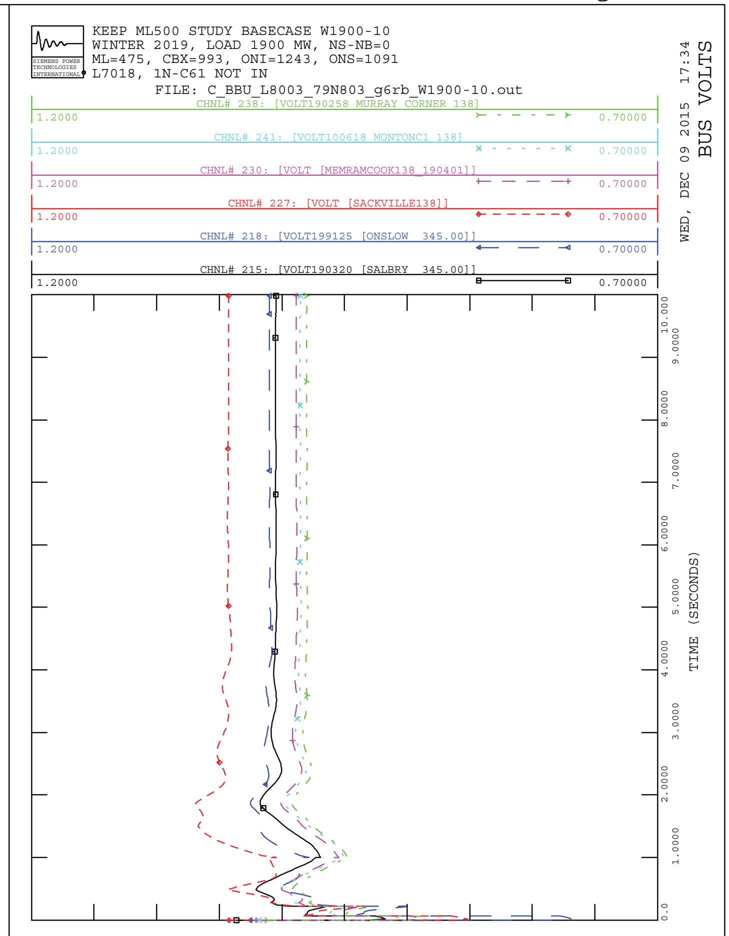
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_BBU_L8003_67N811_g6rb_W1900-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
5.0000
2.5000
2.5000
0.0
TIME (SECONDS)
WED, DEC 09 2015 17:33
MACHINE POWER

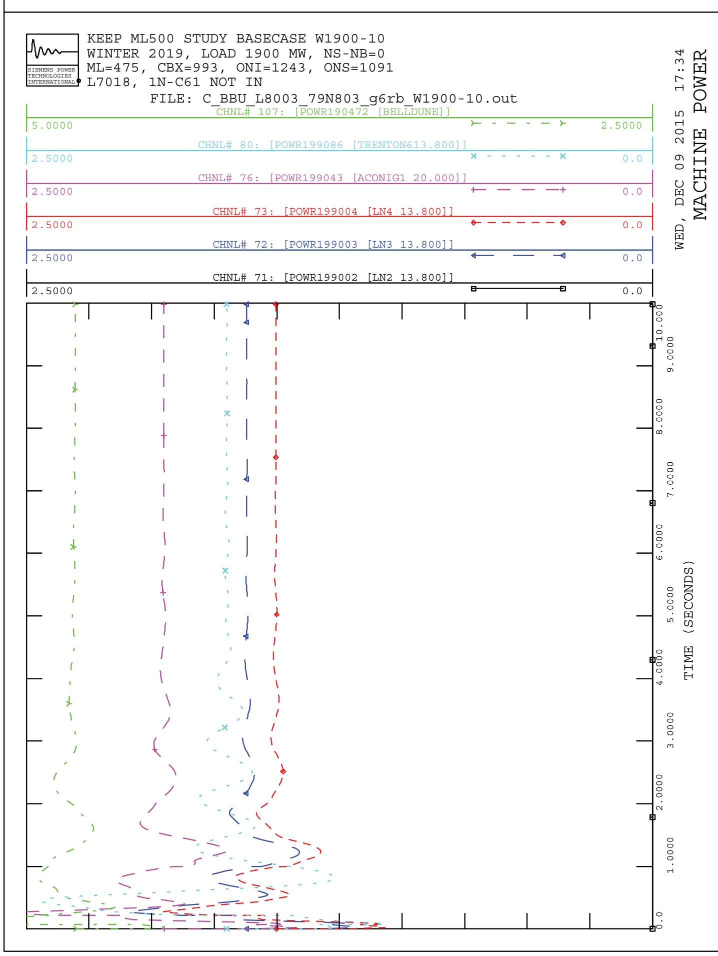


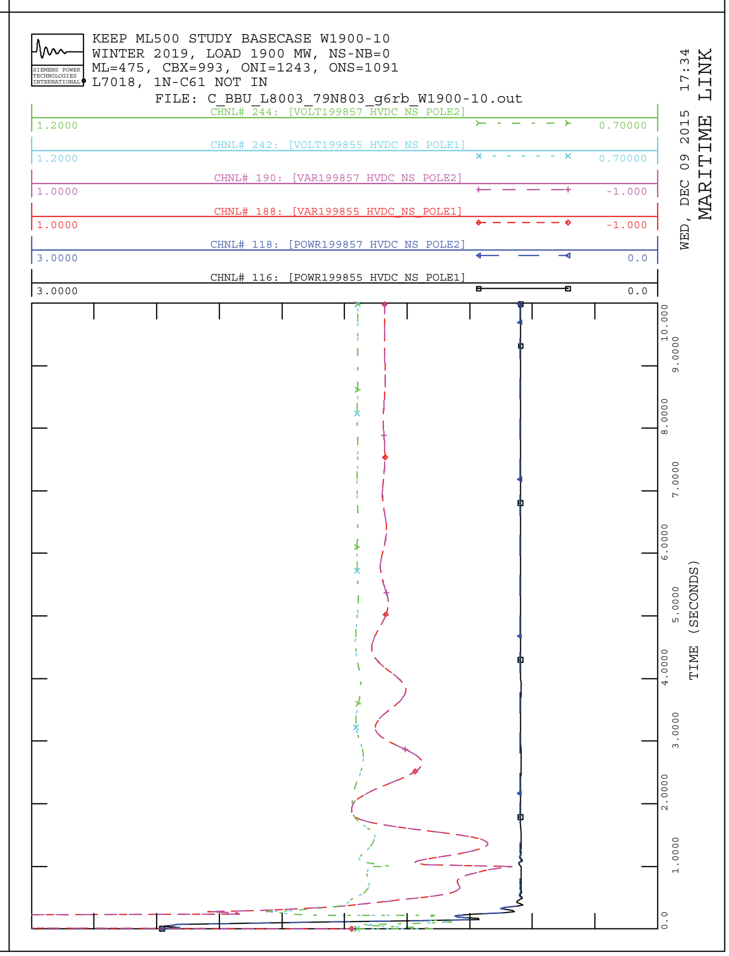
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_BBU_L8003_67N811_g6rb_W1900-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
1.0000
-1.000
3.0000
0.0
TIME (SECONDS)
WED, DEC 09 2015 17:33
MARITIME LINK

REDACTED (CONFIDENTIAL INFORMATION REMOVED)



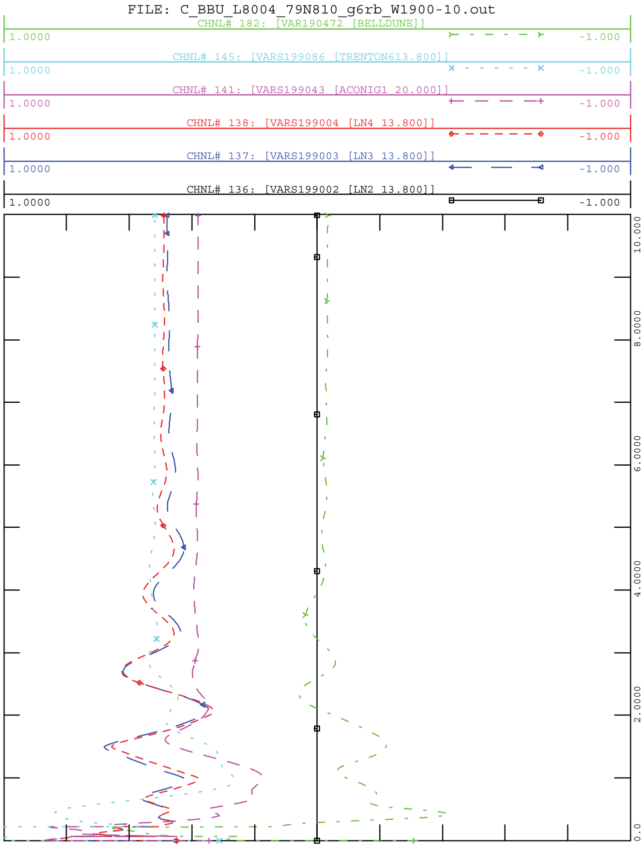






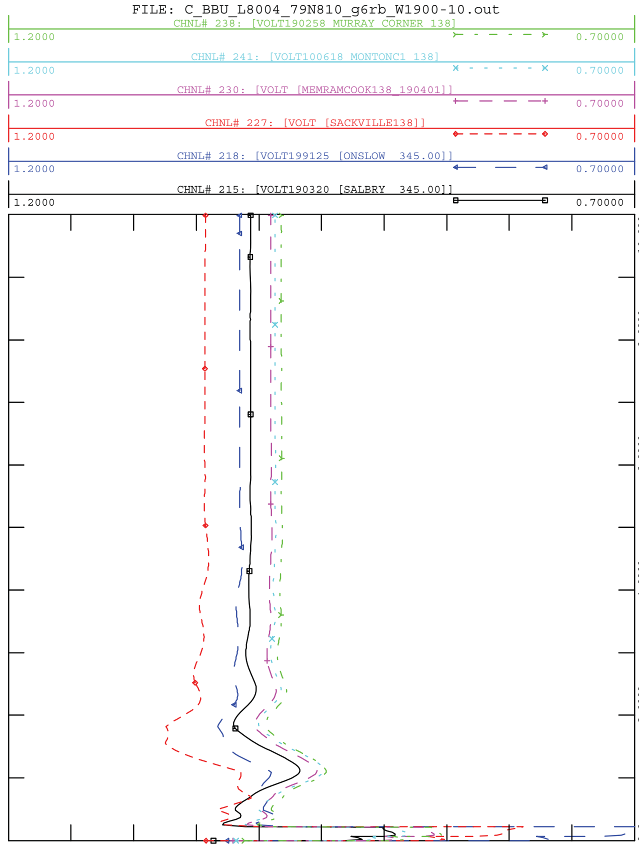
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_BBU_L8004_79N810_g6rb_W1900-10.out

WED, DEC 09 2015 17:34
MACHINE VARS



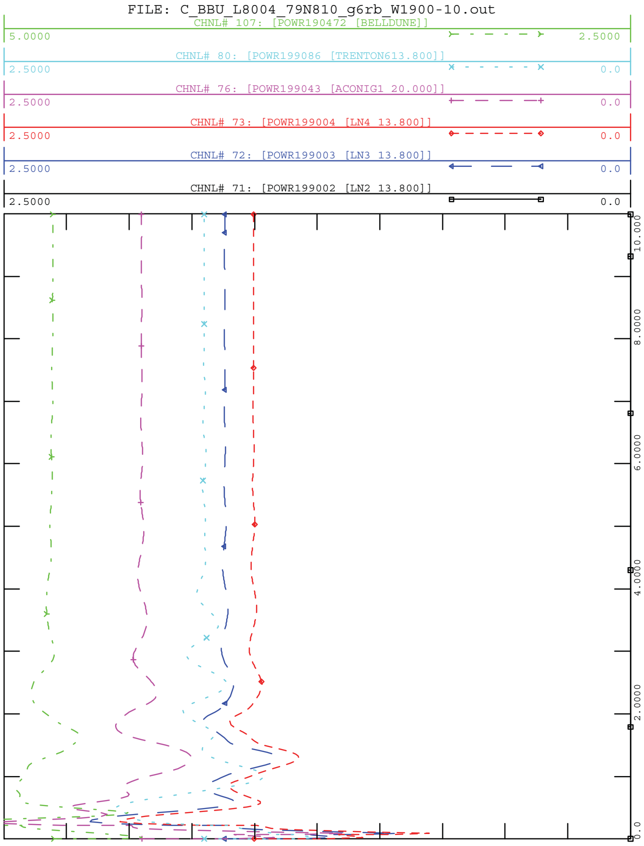
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_BBU_L8004_79N810_g6rb_W1900-10.out

WED, DEC 09 2015 17:34
BUS VOLTS



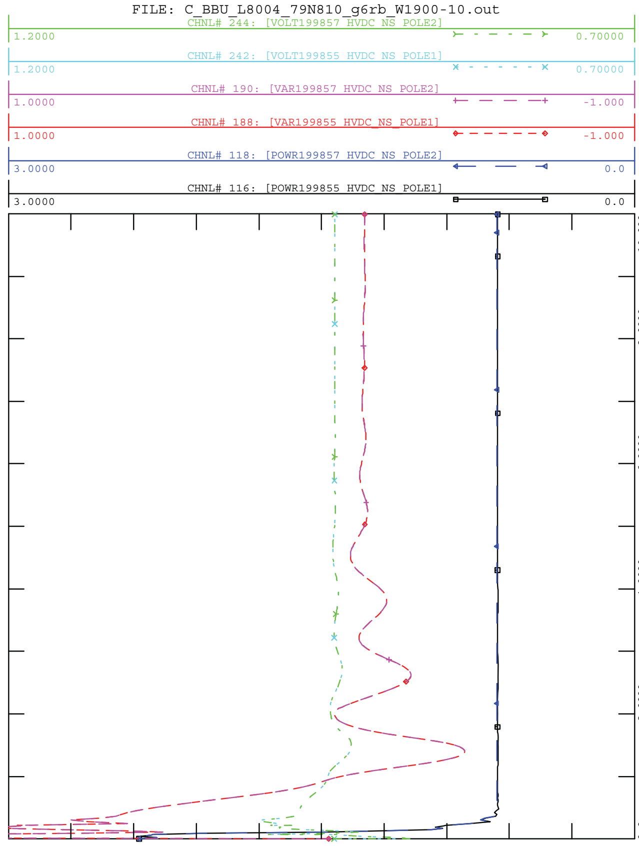
KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_BBU_L8004_79N810_g6rb_W1900-10.out

WED, DEC 09 2015 17:34
MACHINE POWER



KEEP ML500 STUDY BASECASE W1900-10
WINTER 2019, LOAD 1900 MW, NS-NB=0
ML=475, CBX=993, ONI=1243, ONS=1091
L7018, 1N-C61 NOT IN
FILE: C_BBU_L8004_79N810_g6rb_W1900-10.out

WED, DEC 09 2015 17:34
MARITIME LINK



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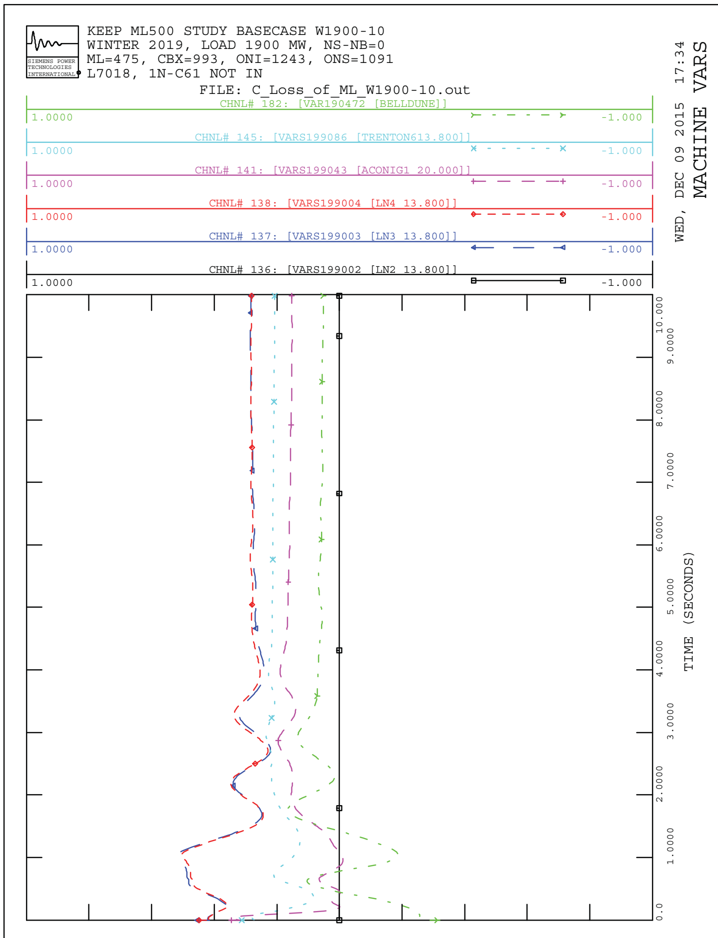
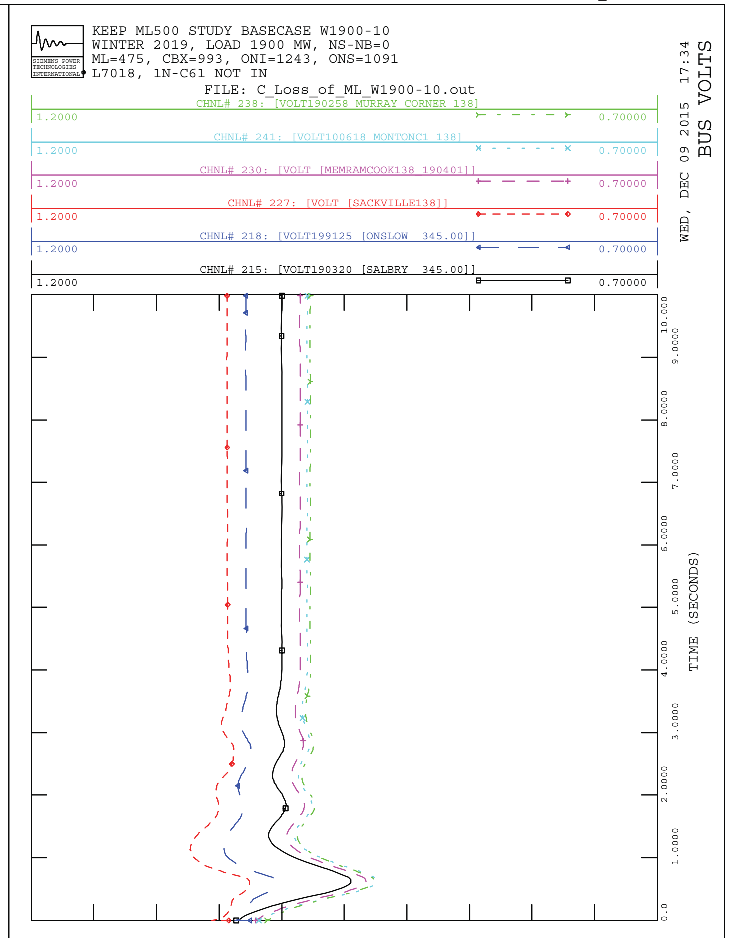
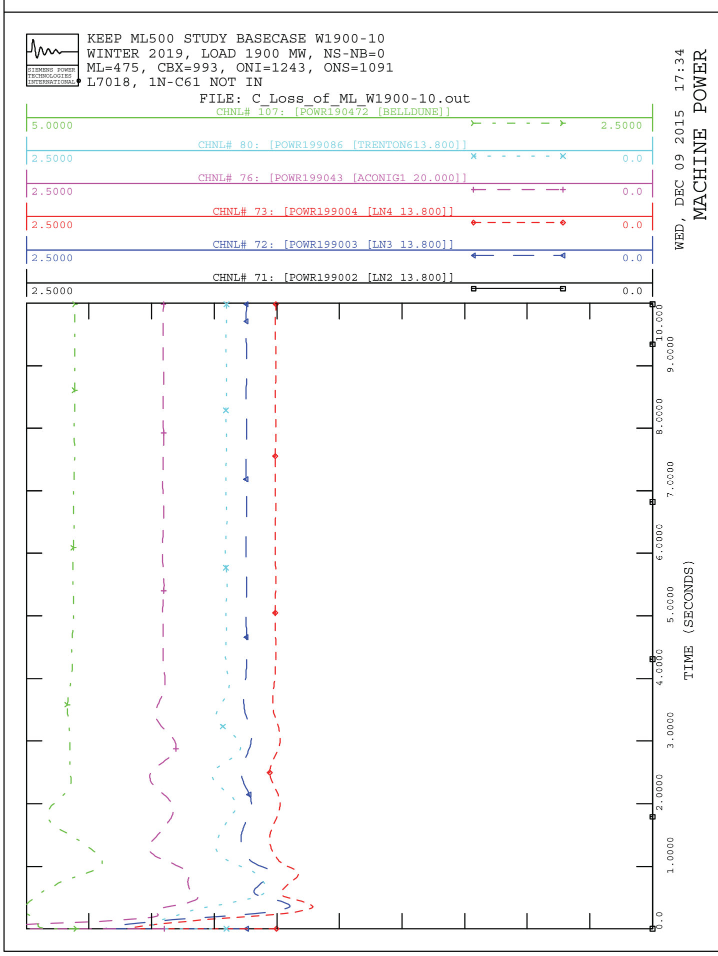
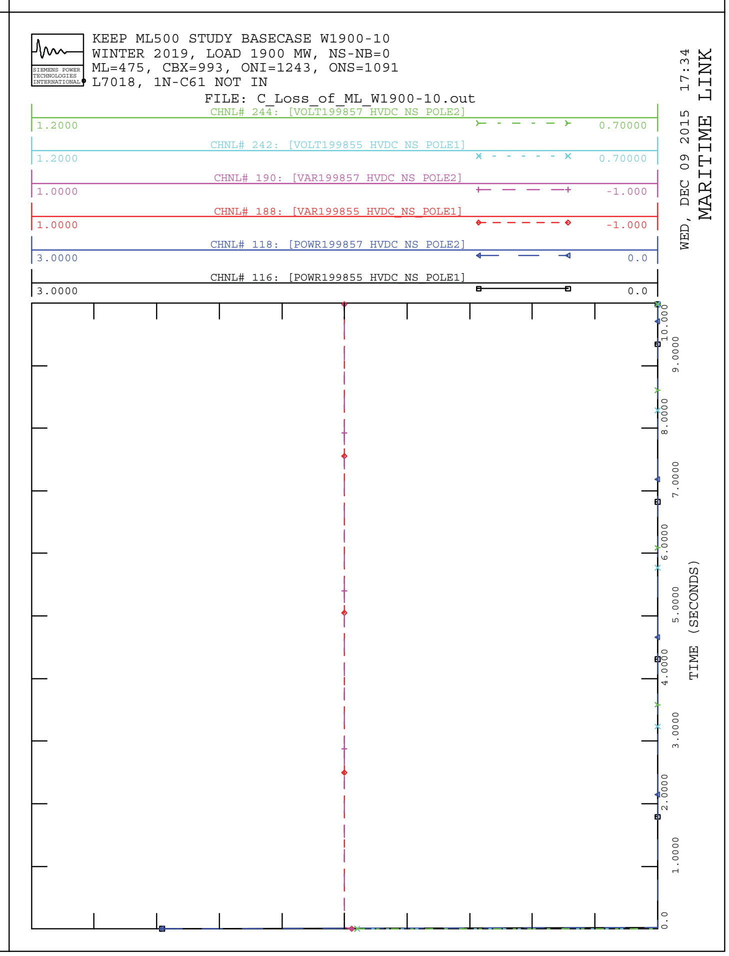
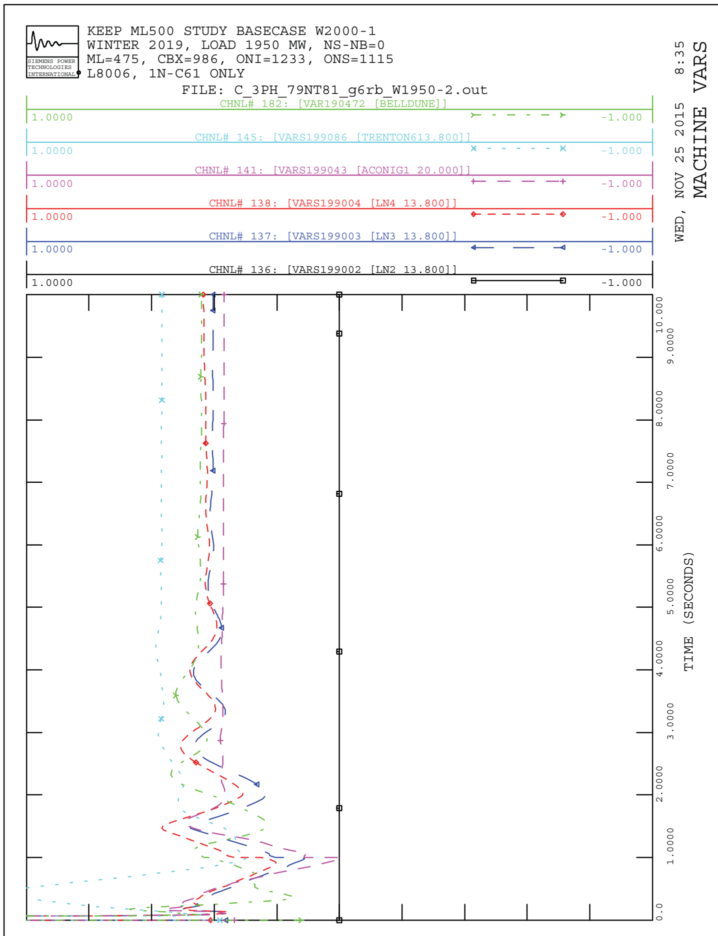


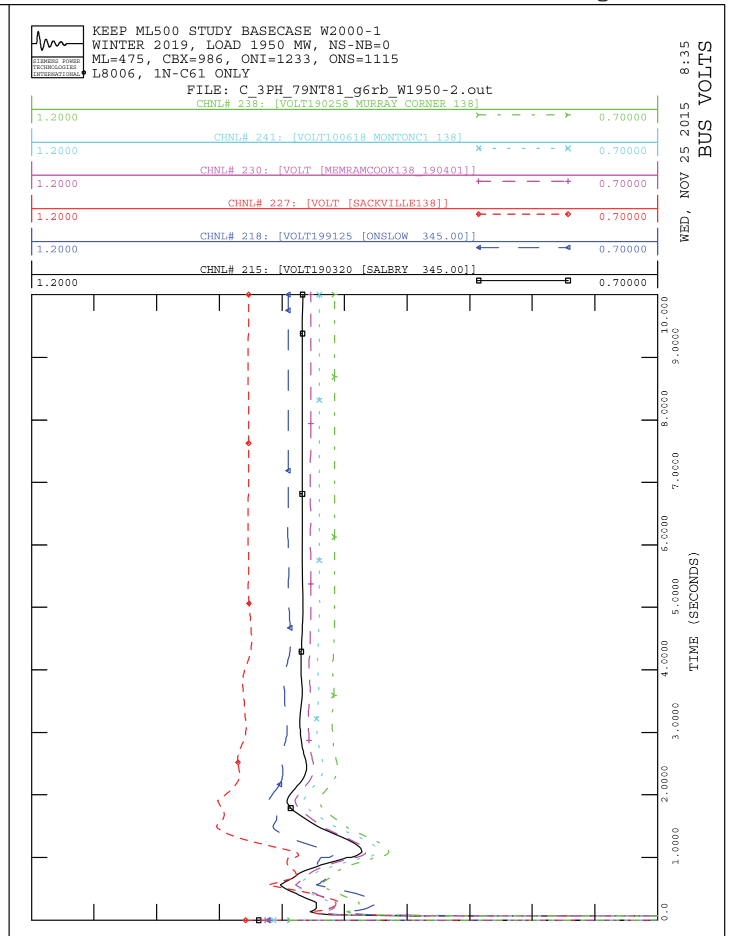


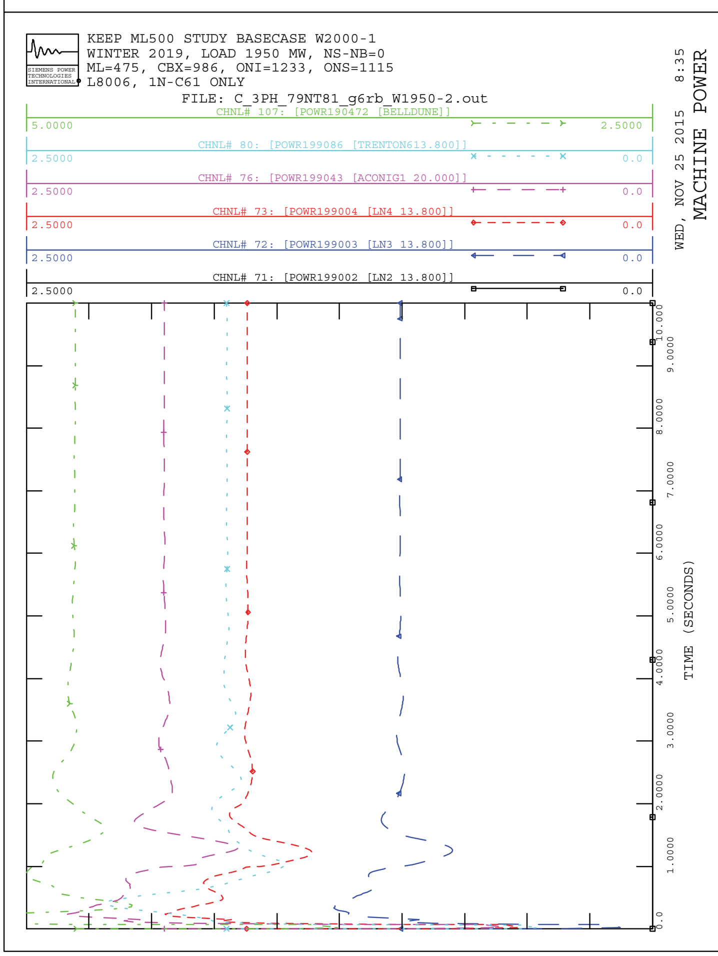


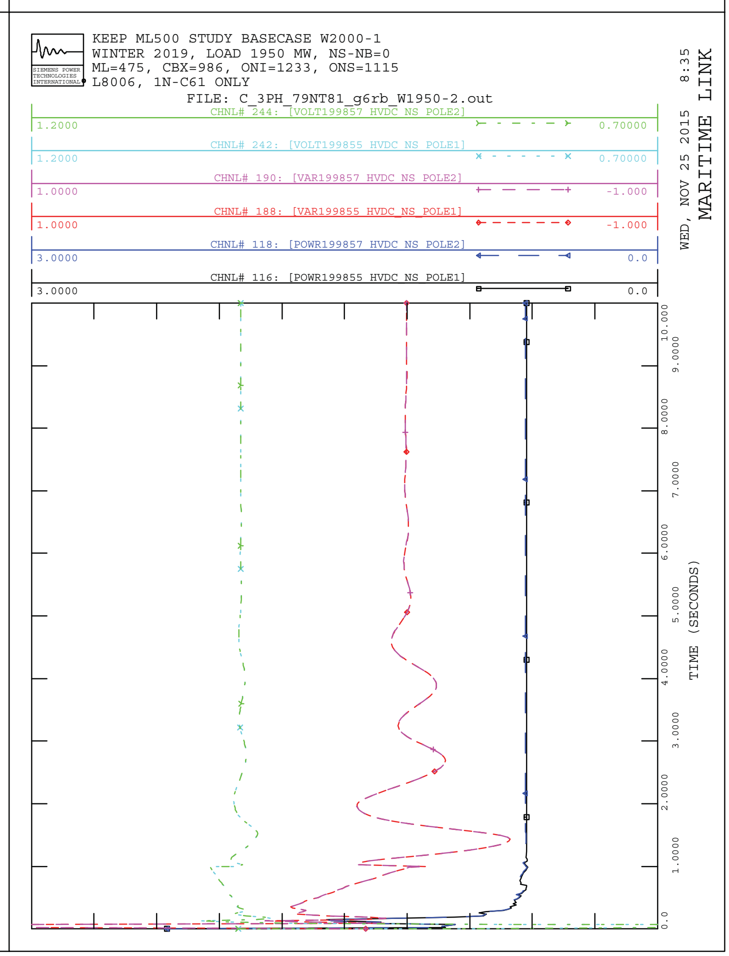


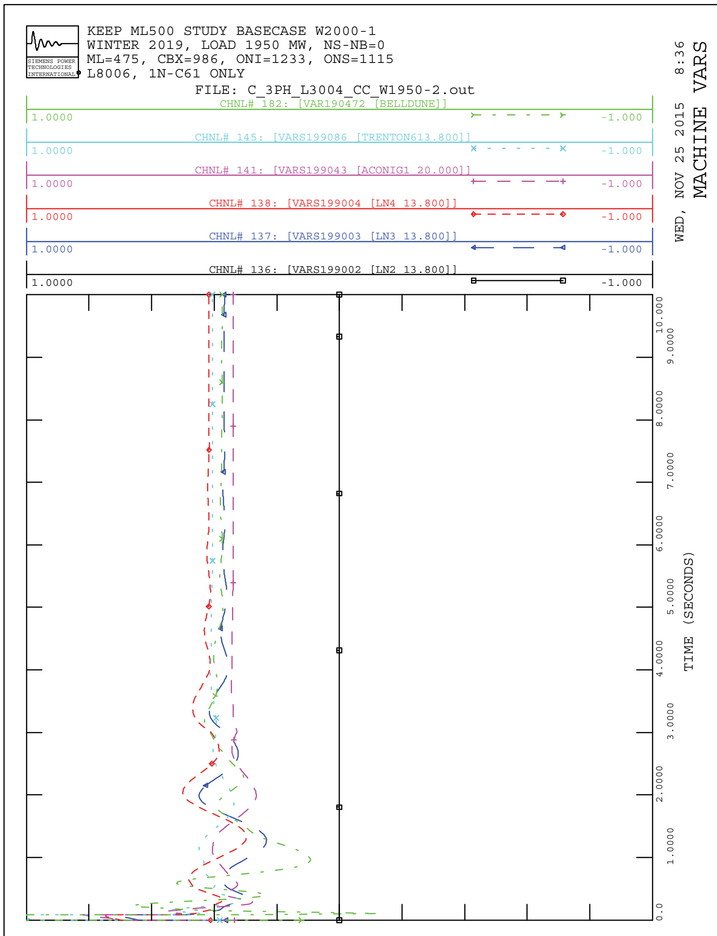
REDACTED (CONFIDENTIAL INFORMATION REMOVED)

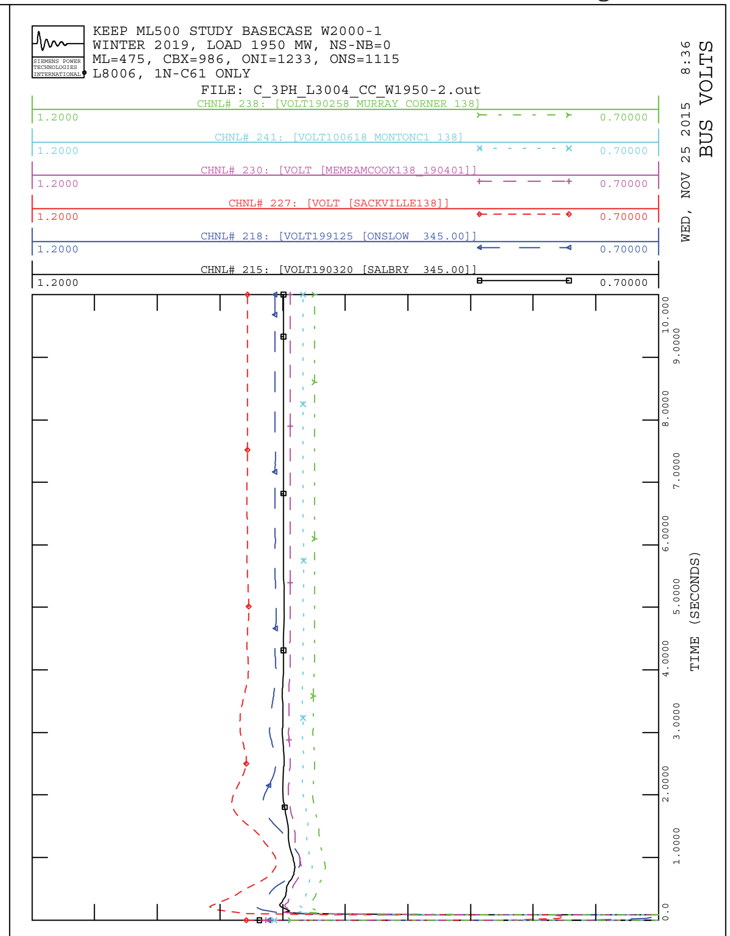


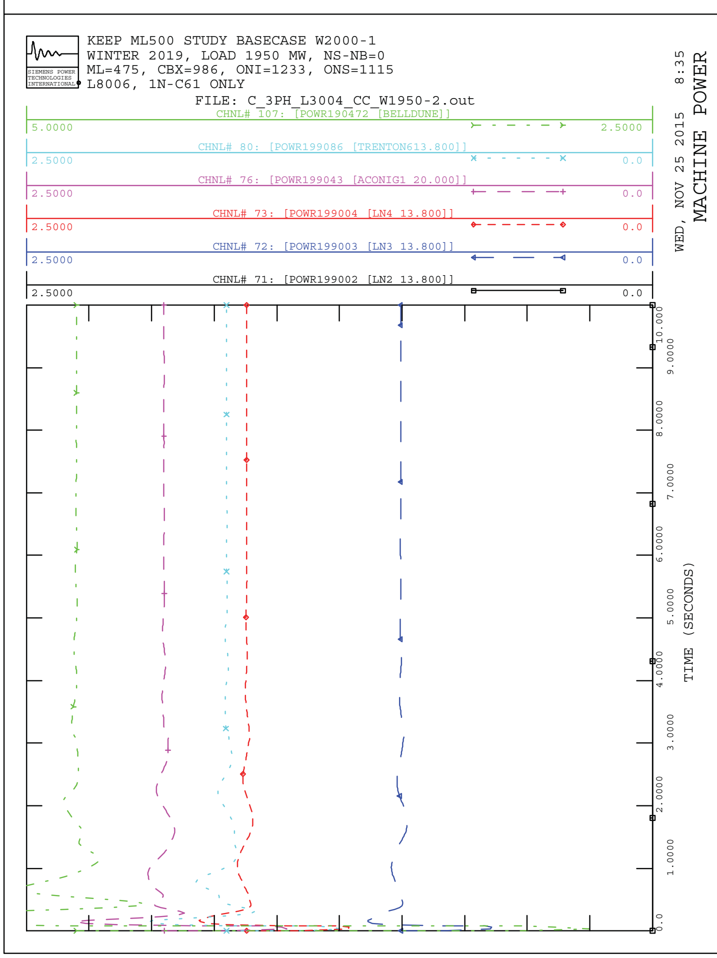







KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3004_CC_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3004_CC_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3004_CC_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
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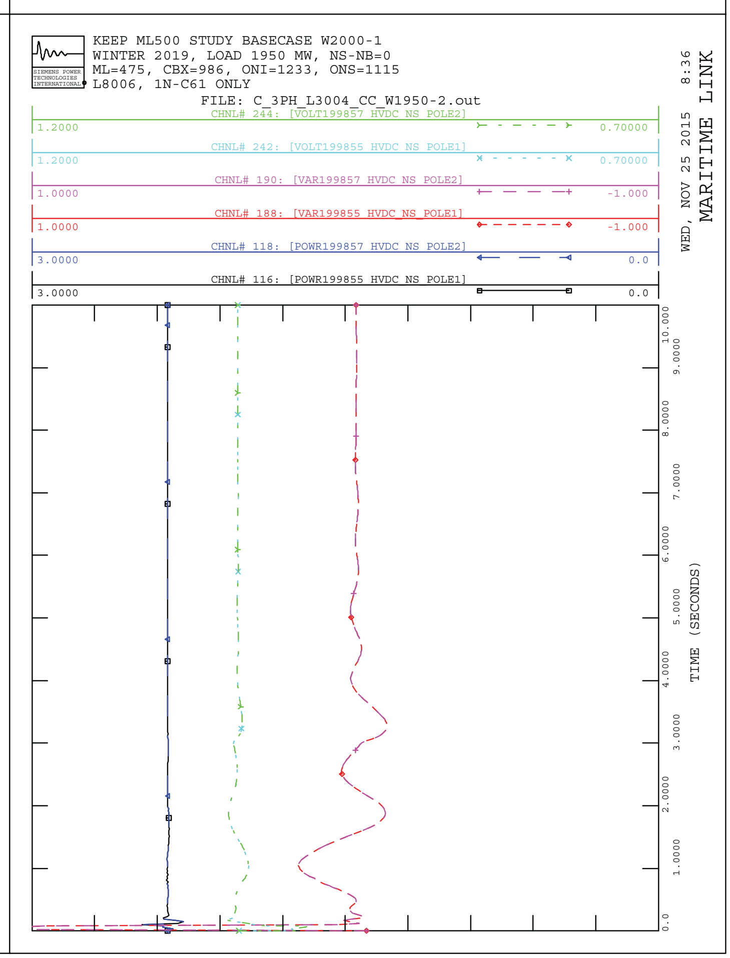
2.5000
0.0
WED, NOV 25 2015 8:35
MACHINE POWER
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3004_CC_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
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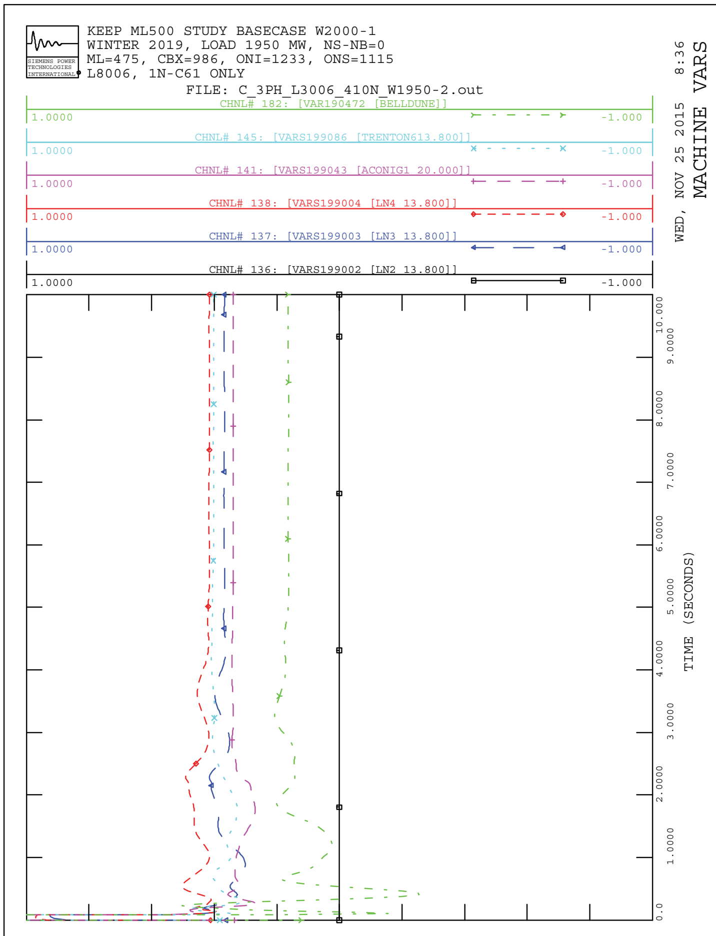
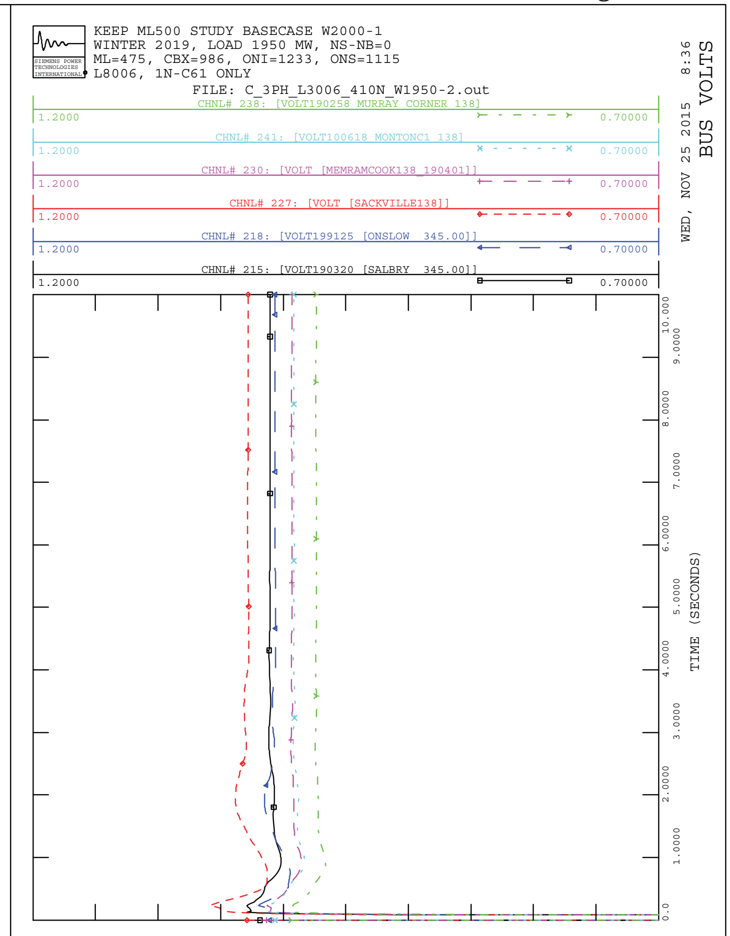
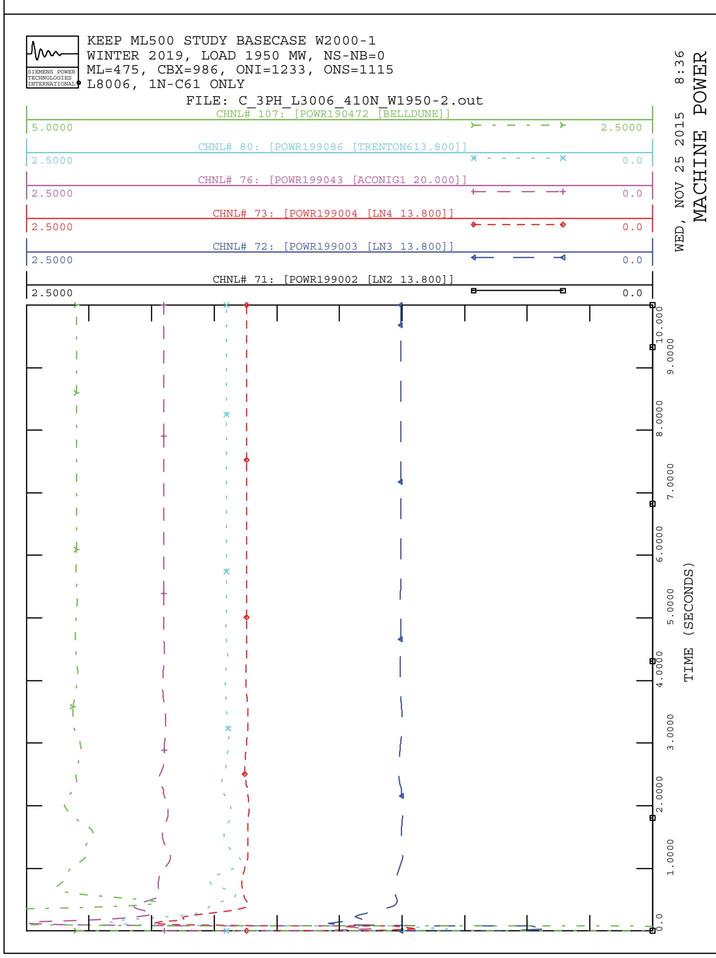
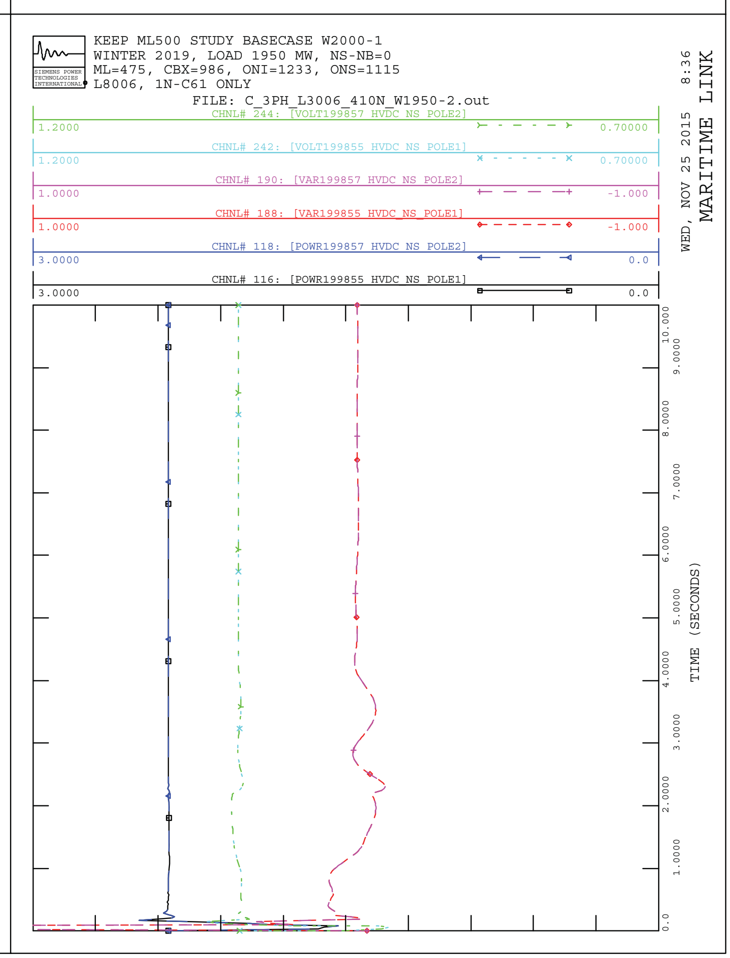
3.0000
0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)

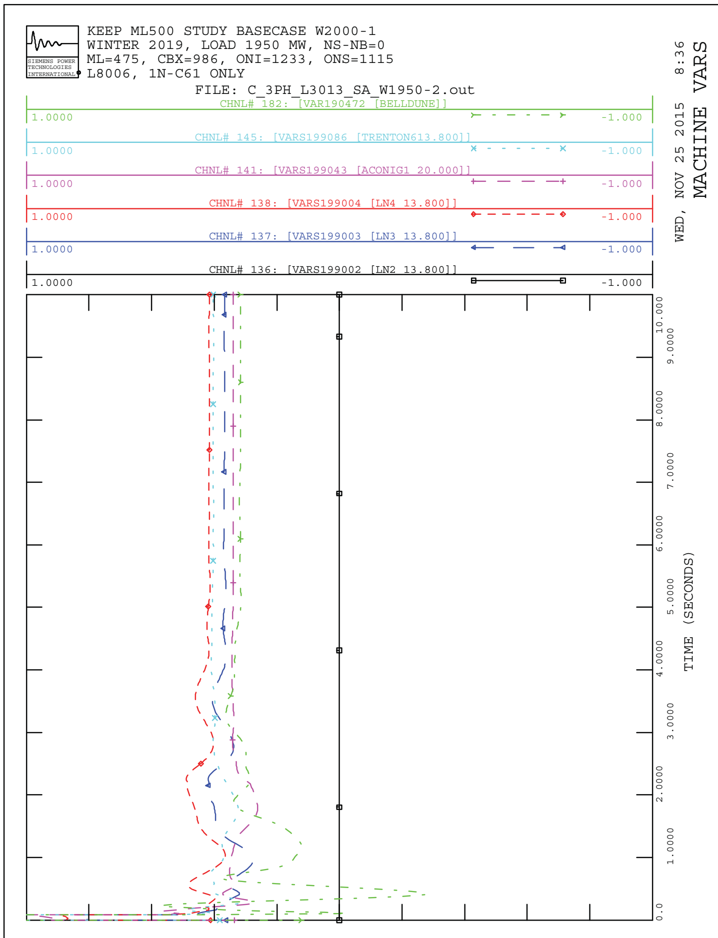
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



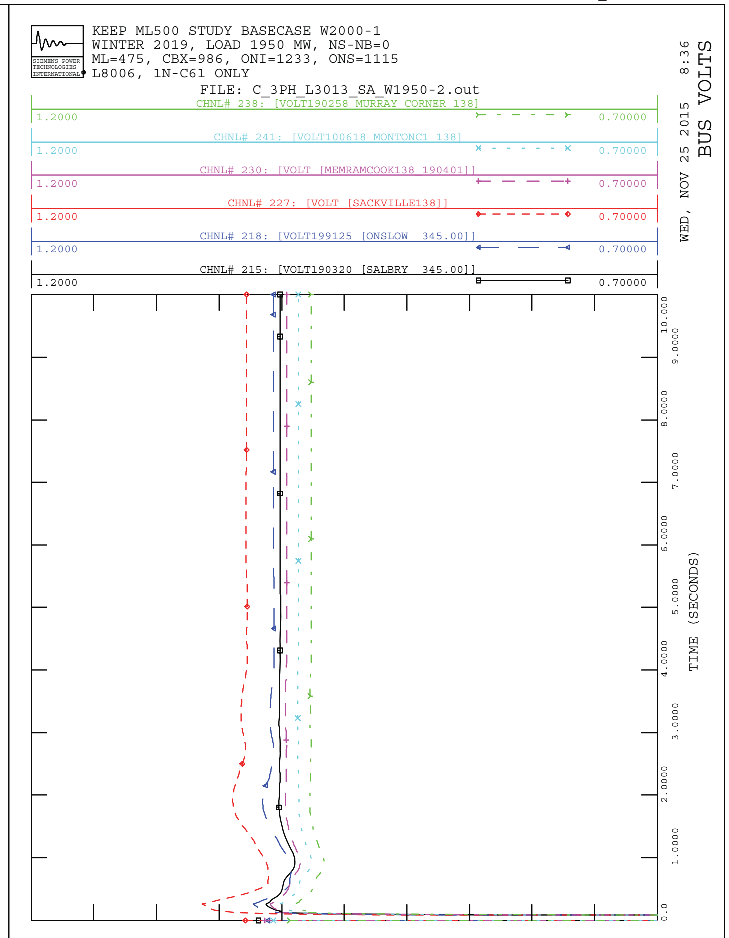




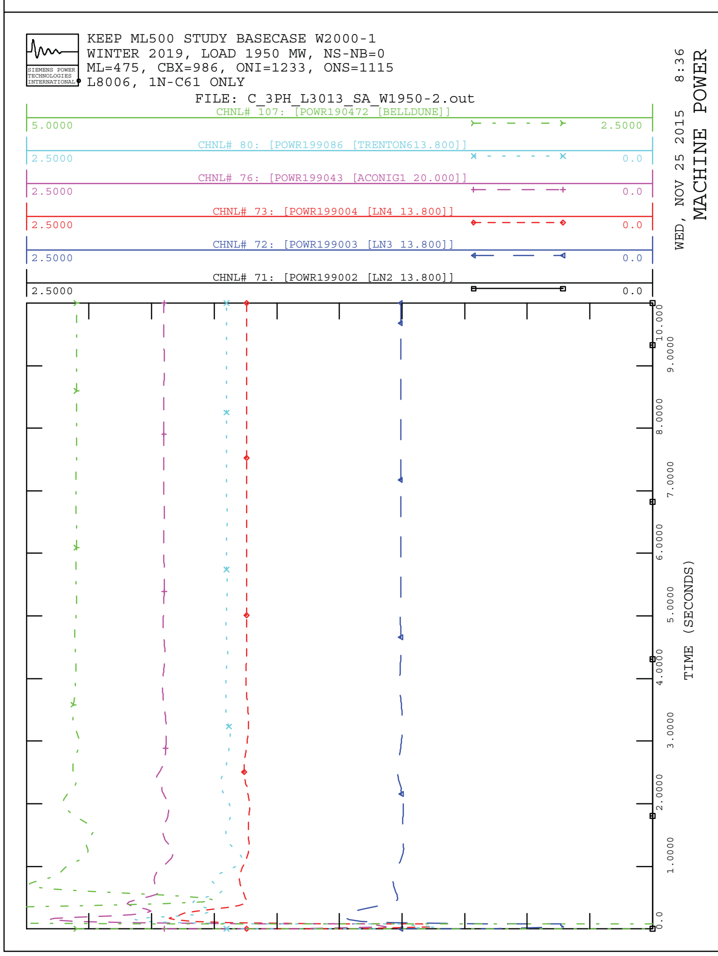




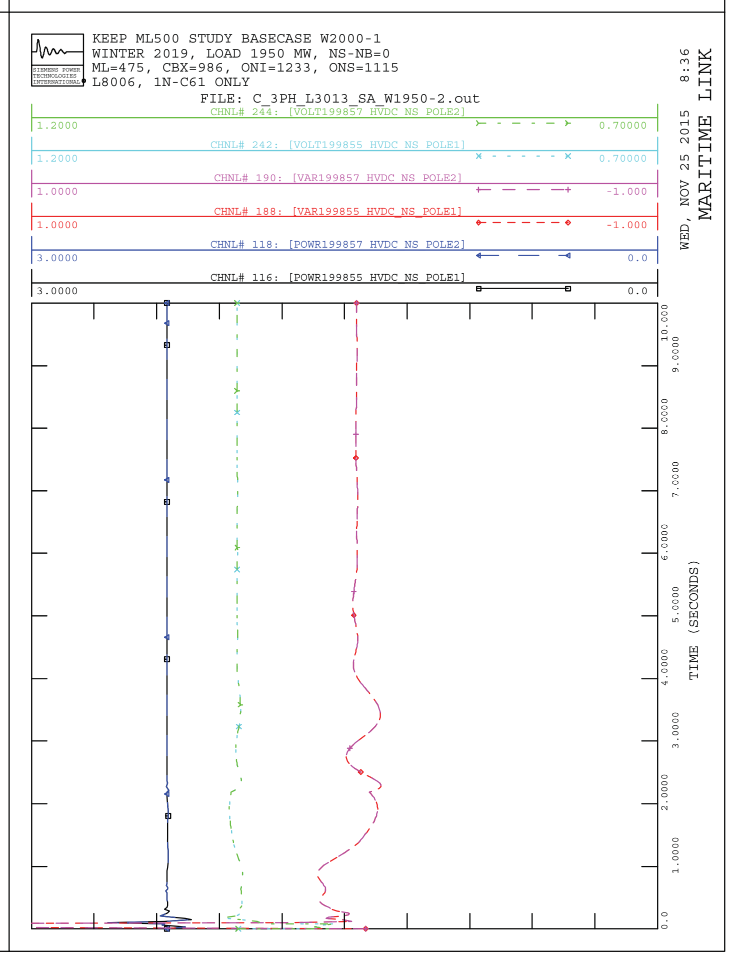
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3013_SA_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
TIME (SECONDS)
WED, NOV 25 2015 8:36
MACHINE VARS



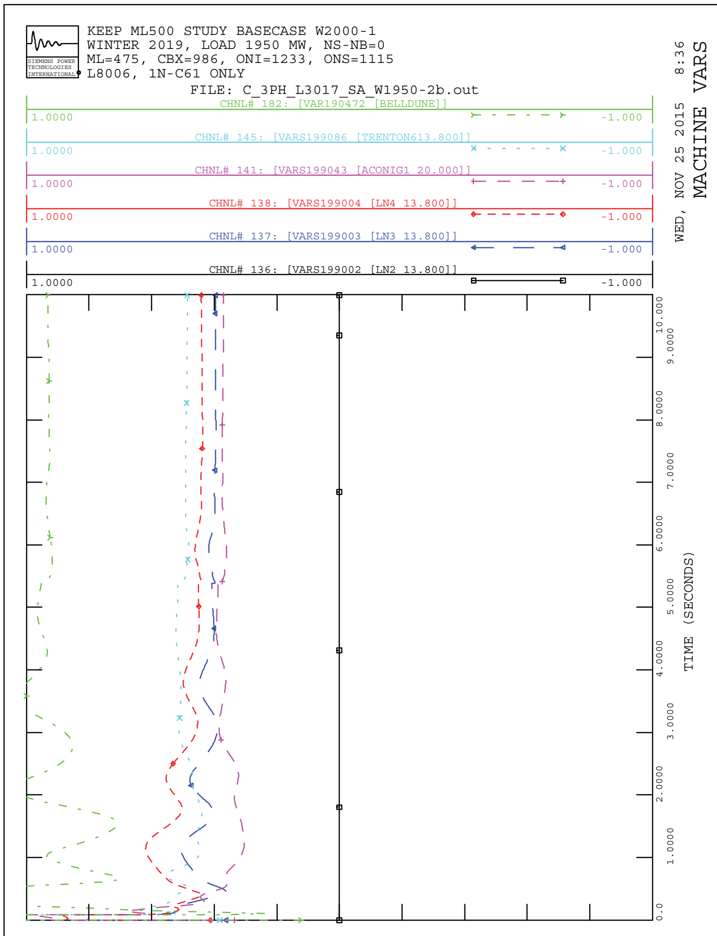
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3013_SA_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
TIME (SECONDS)
WED, NOV 25 2015 8:36
BUS VOLTS



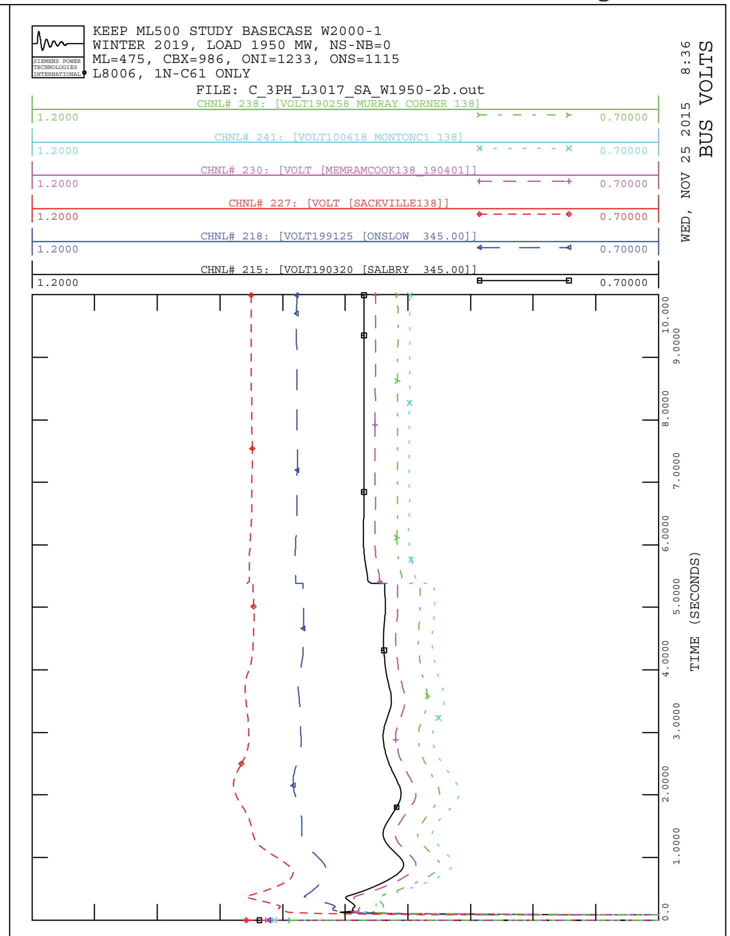
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3013_SA_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
TIME (SECONDS)
WED, NOV 25 2015 8:36
MACHINE POWER



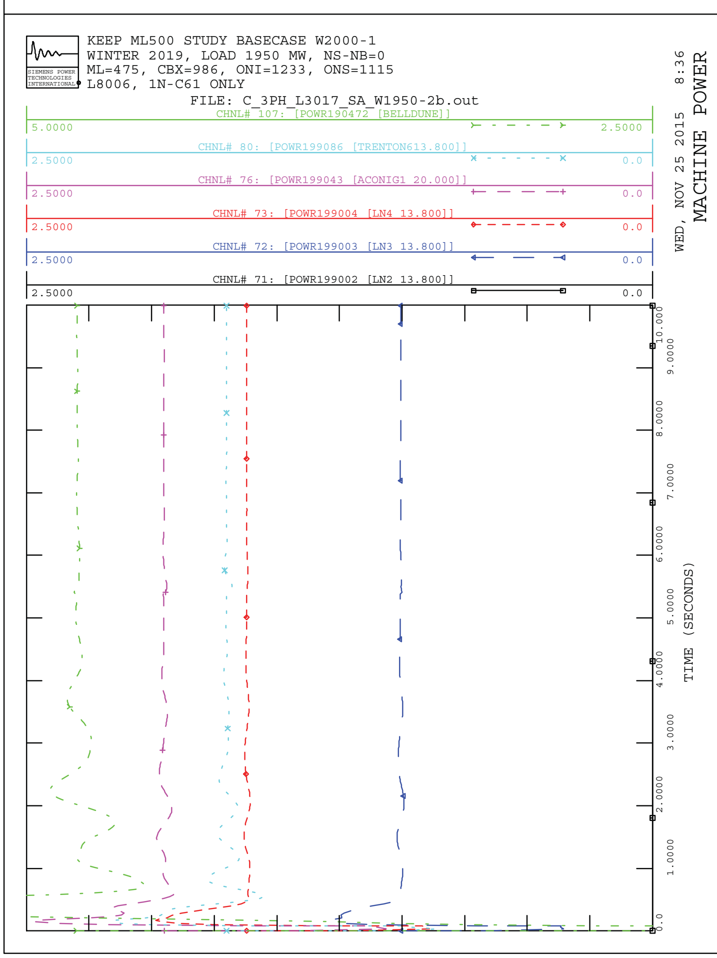
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3013_SA_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
TIME (SECONDS)
WED, NOV 25 2015 8:36
MARITIME LINK



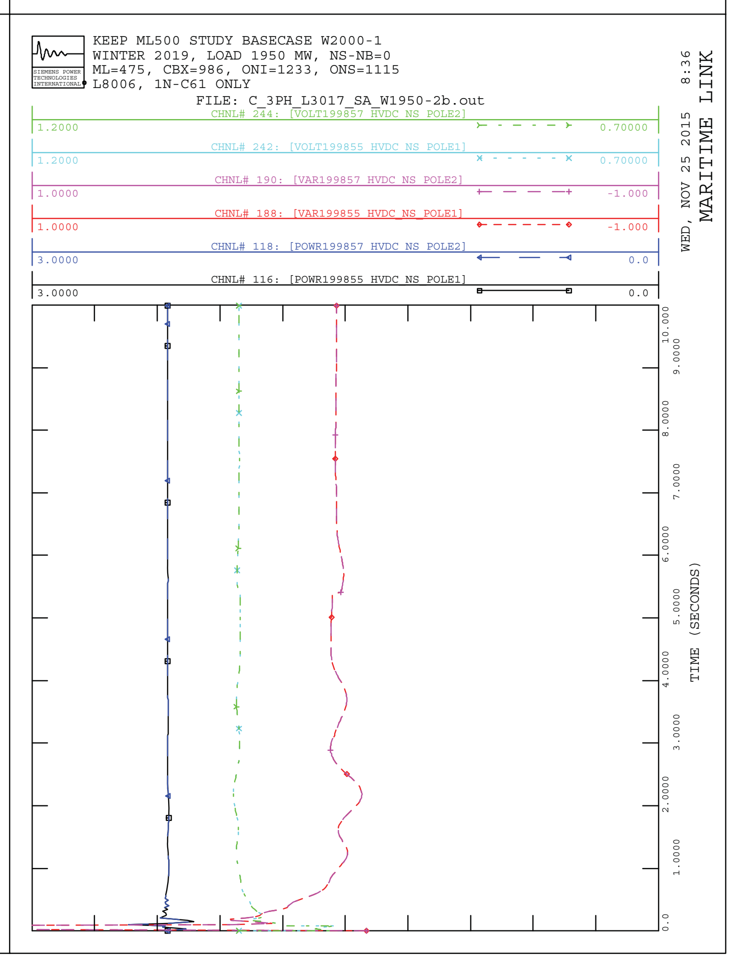
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3017_SA_W1950-2b.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)



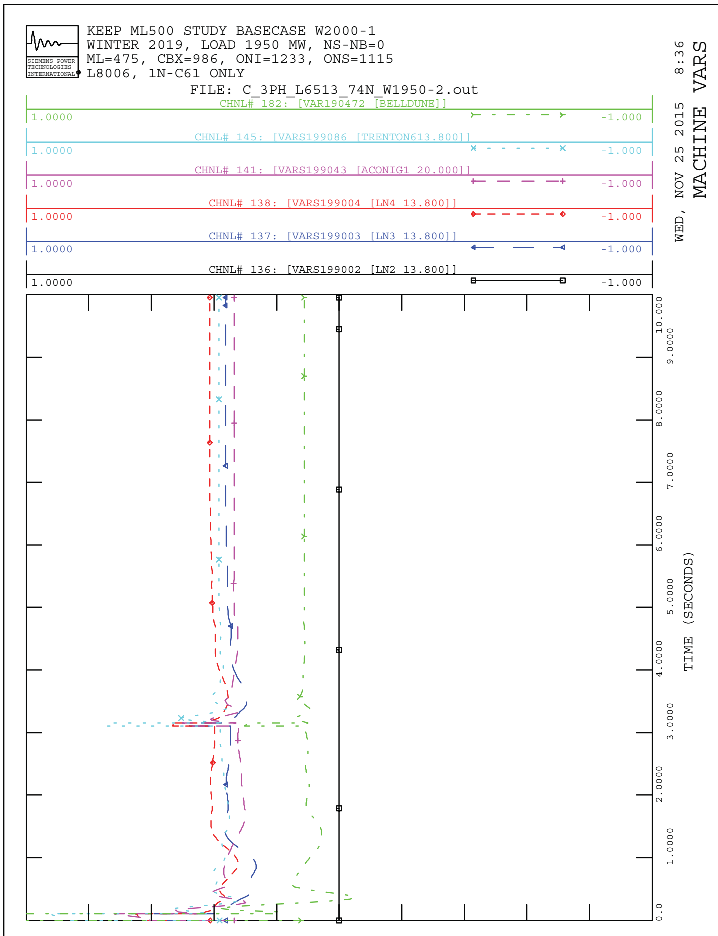
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3017_SA_W1950-2b.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3017_SA_W1950-2b.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L3017_SA_W1950-2b.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6513_74N_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
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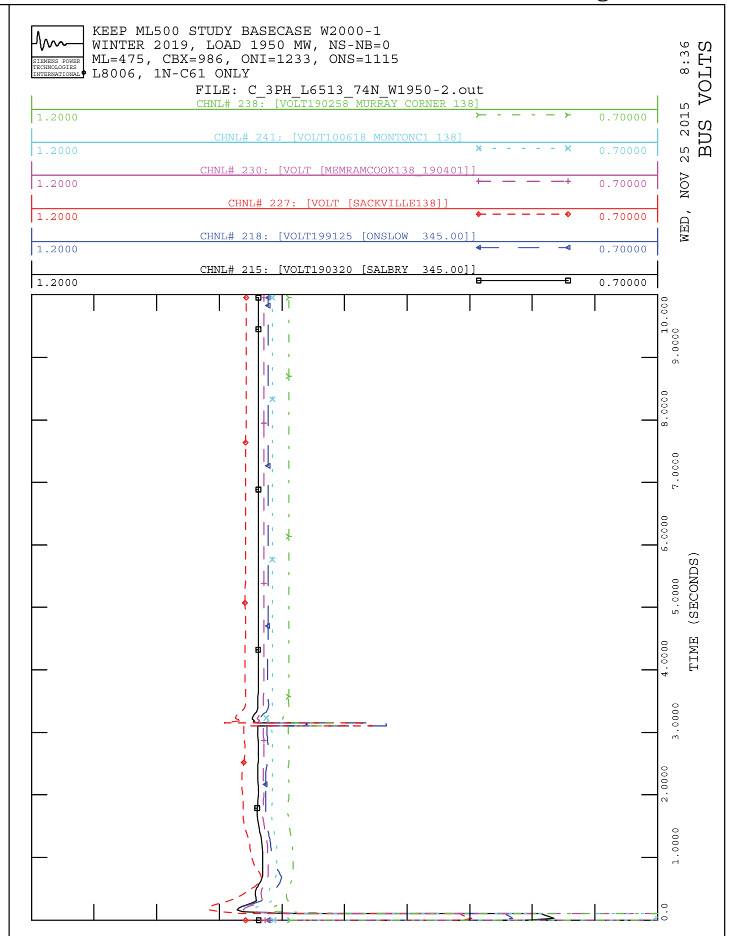
1.0000
-1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6513_74N_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
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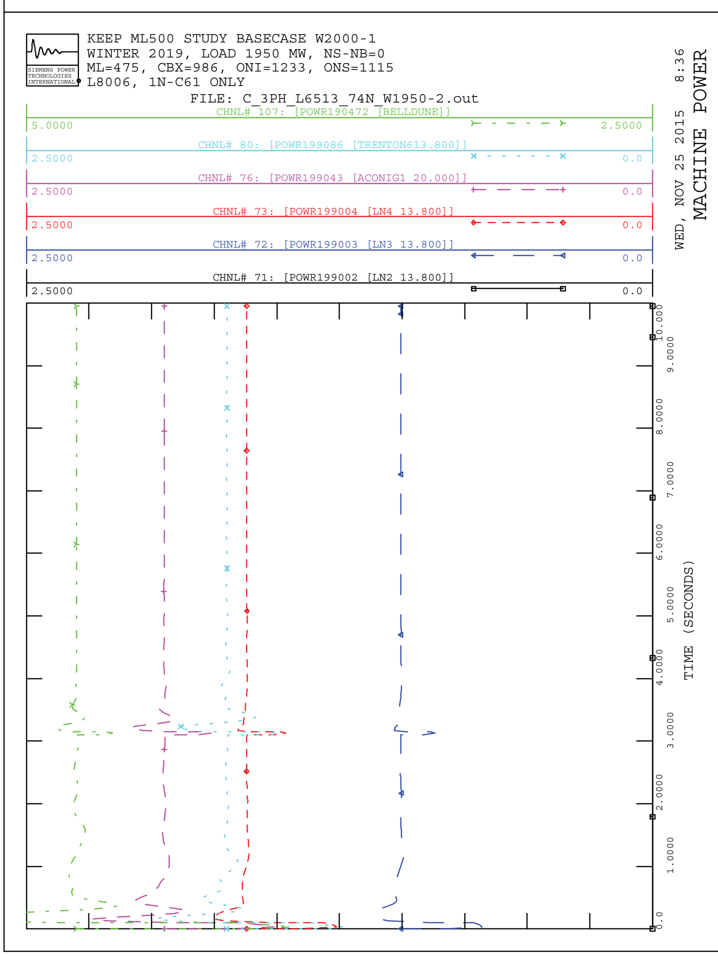
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6513_74N_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
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2.5000
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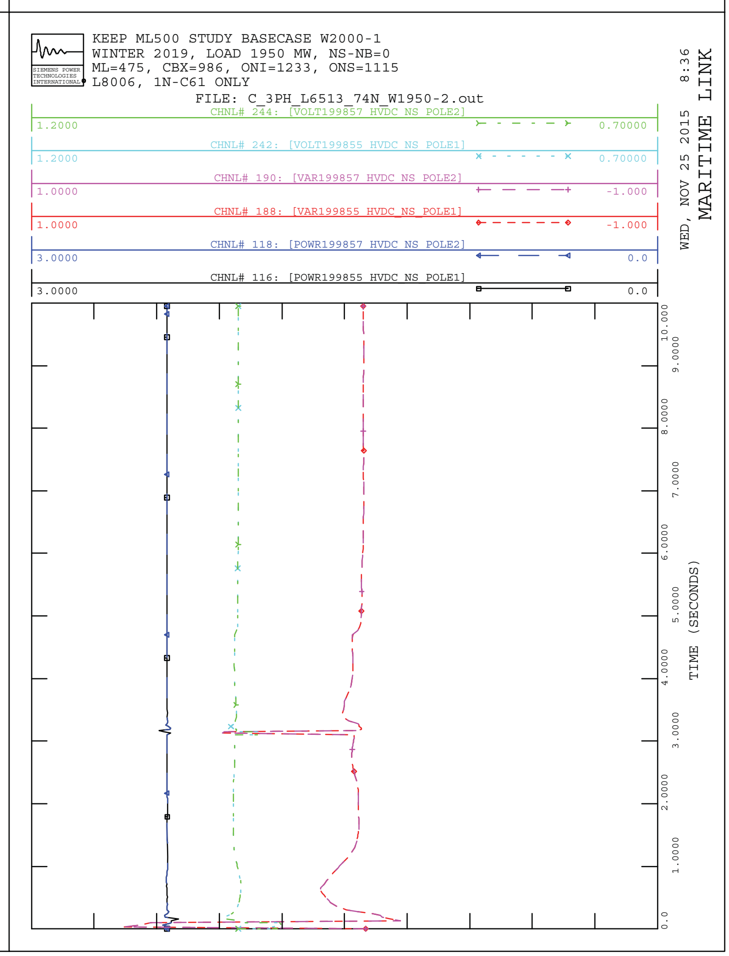
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6513_74N_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
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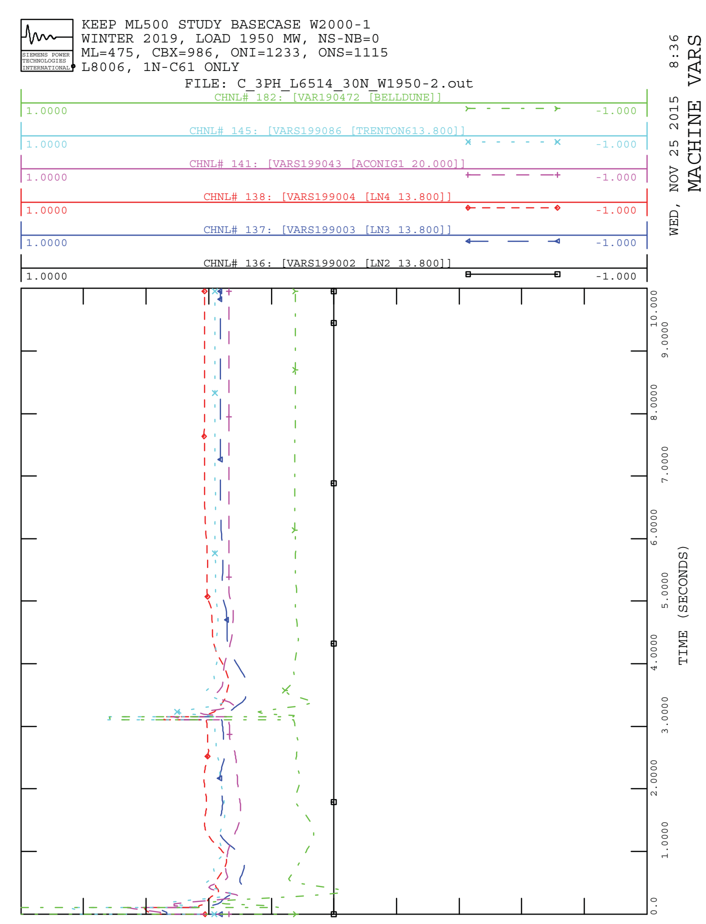
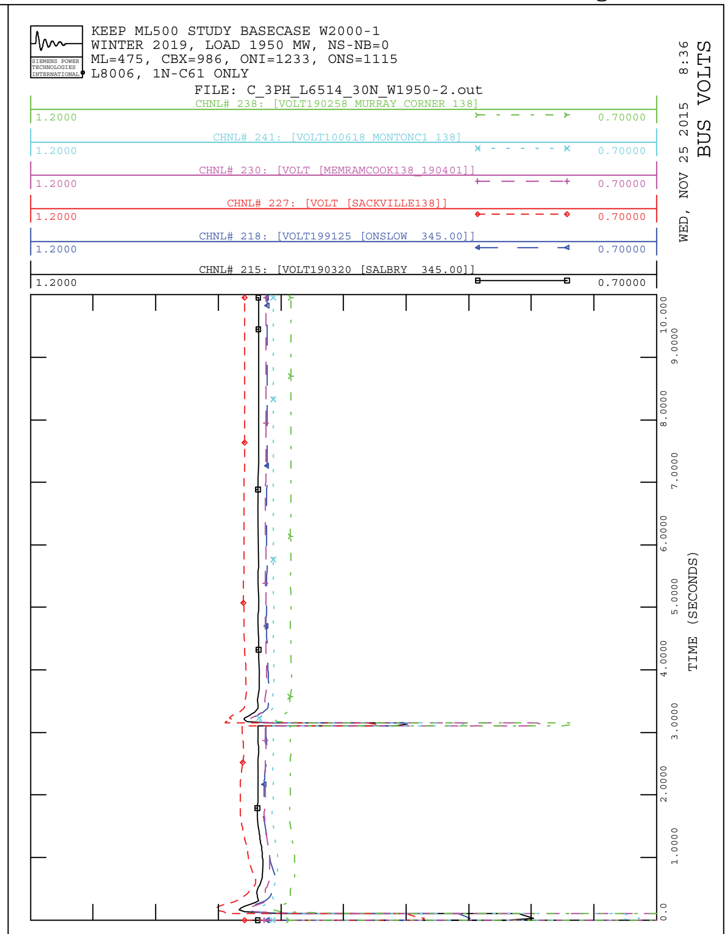
3.0000
0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6514_30N_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6514_30N_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)
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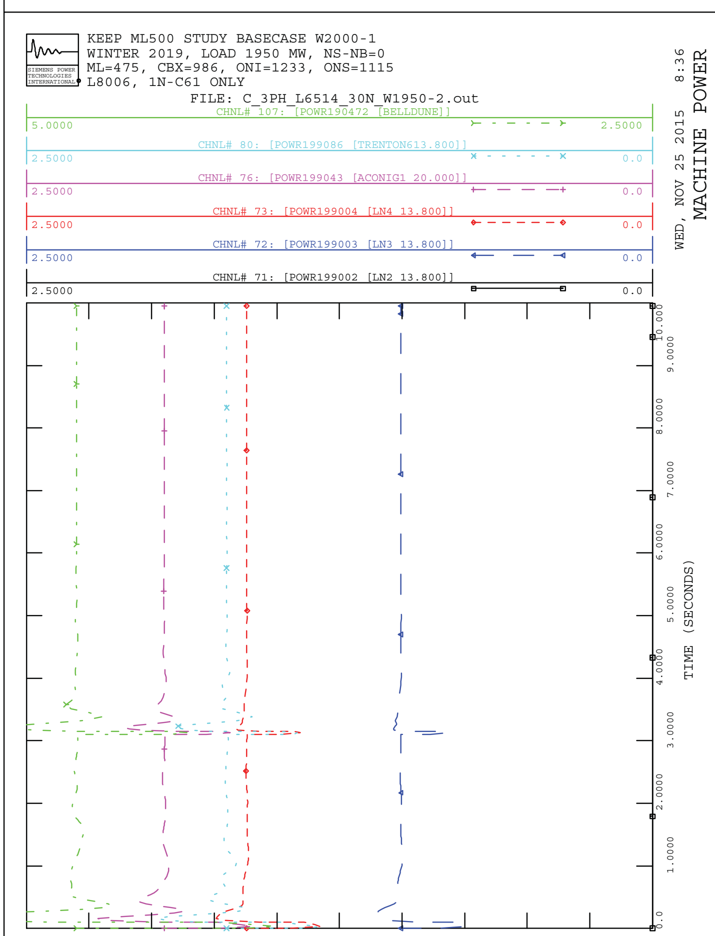
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6514_30N_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)
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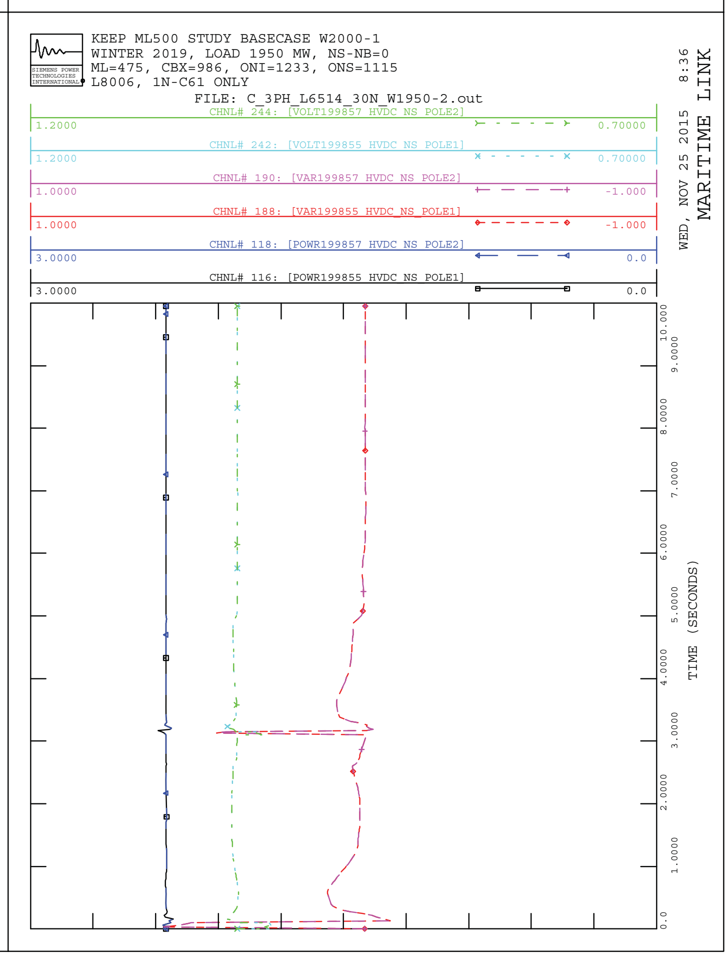
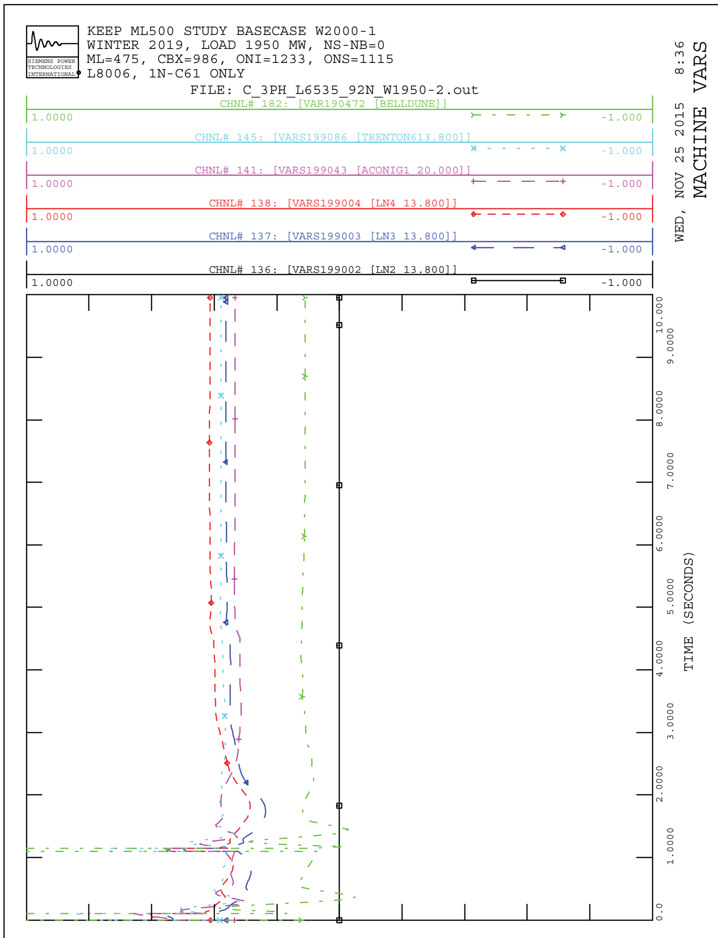

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6514_30N_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6535_92N_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
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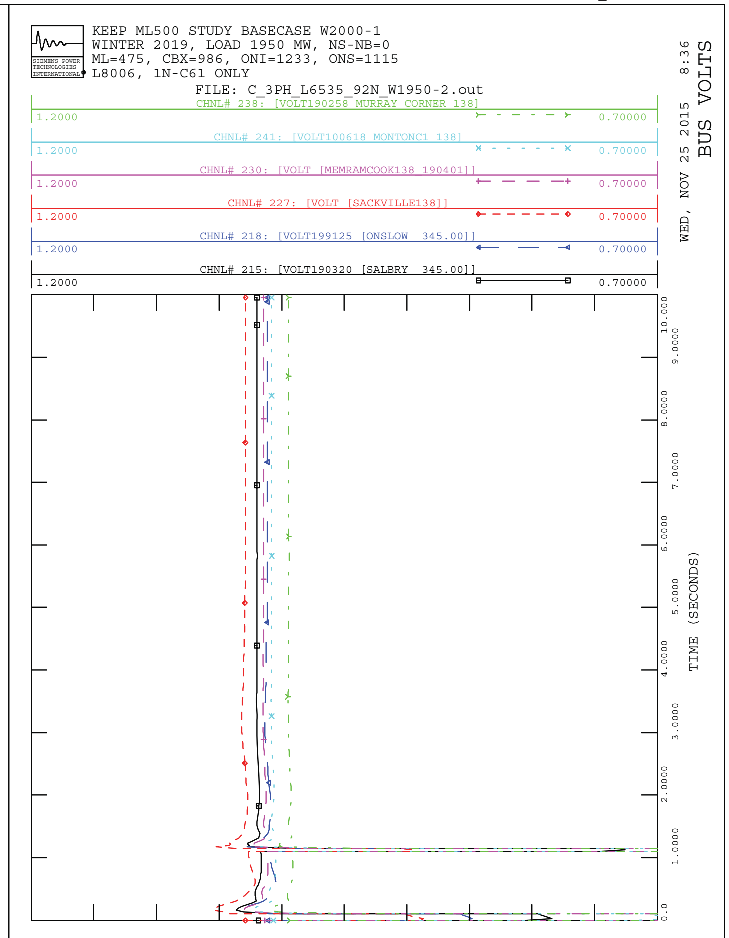
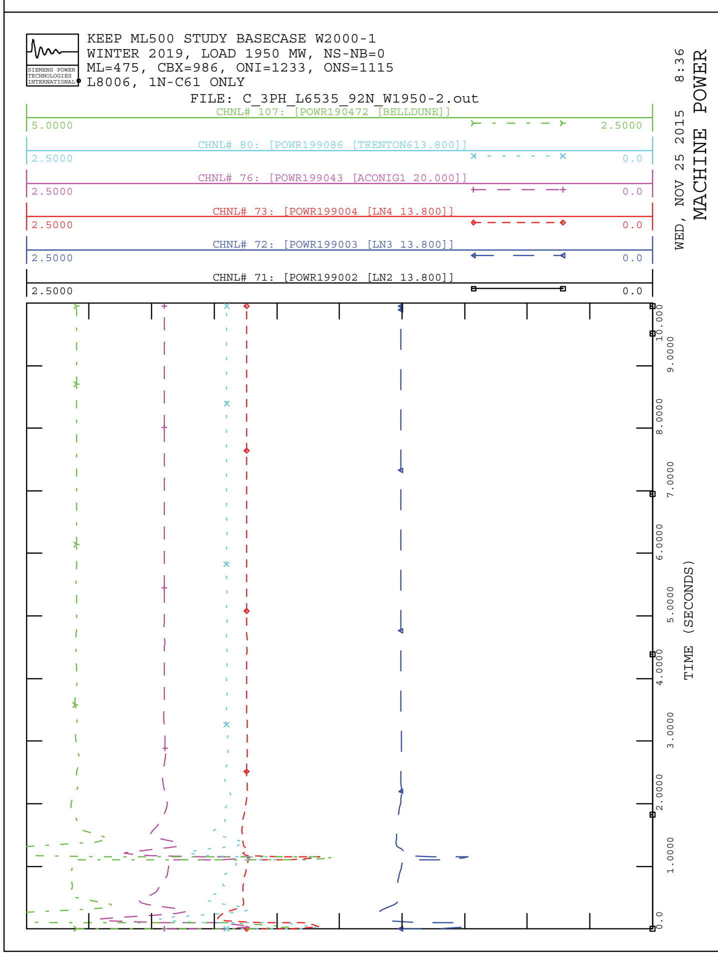
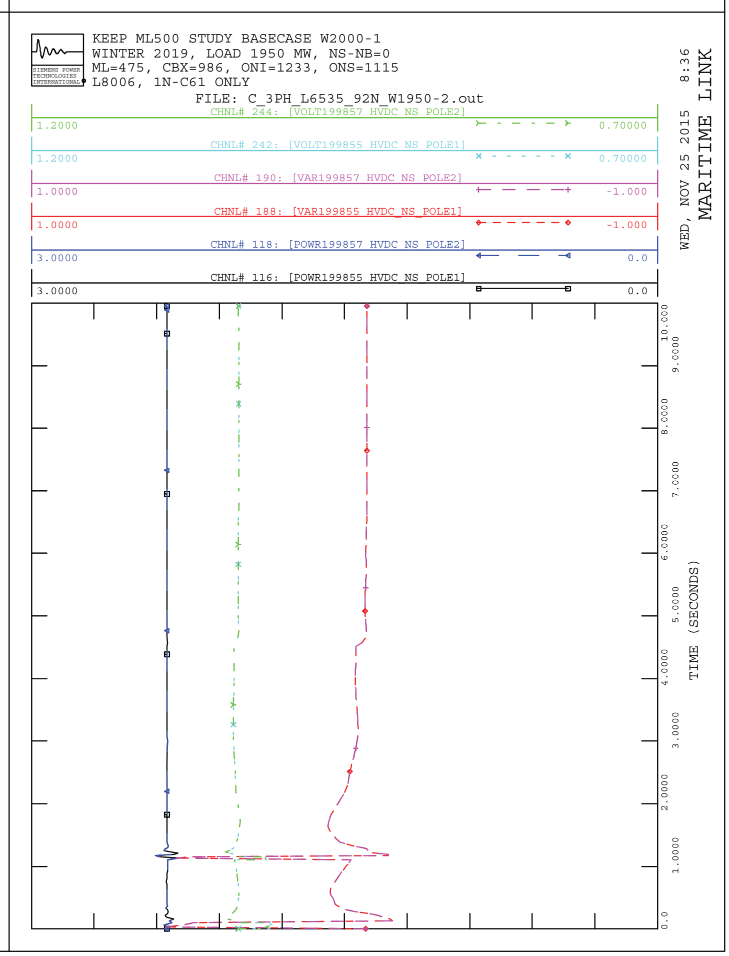
-1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)



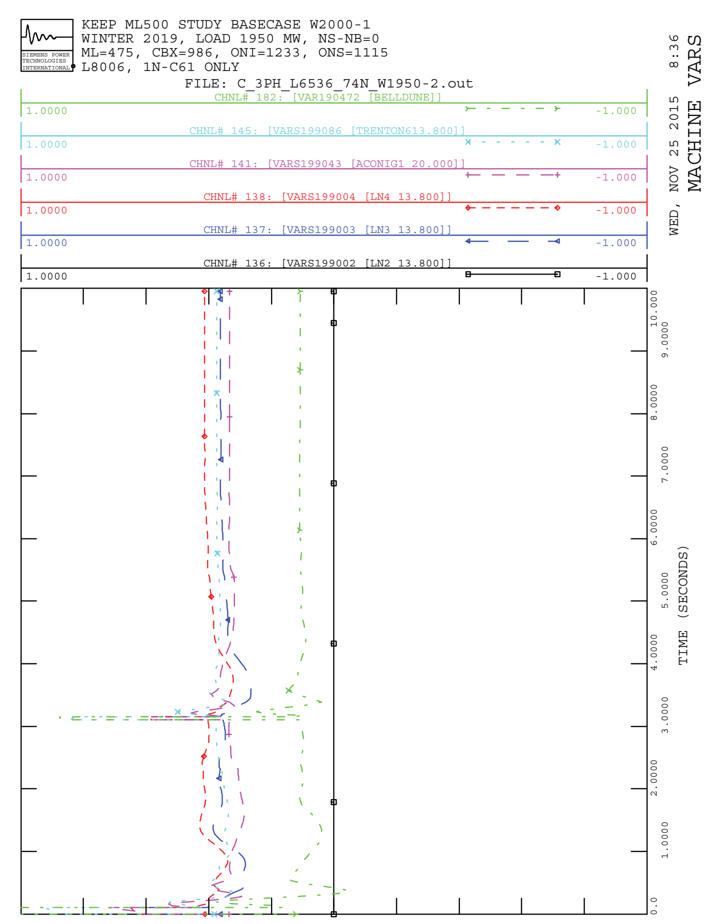
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6535_92N_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6535_92N_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6535_92N_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6536_74N_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)
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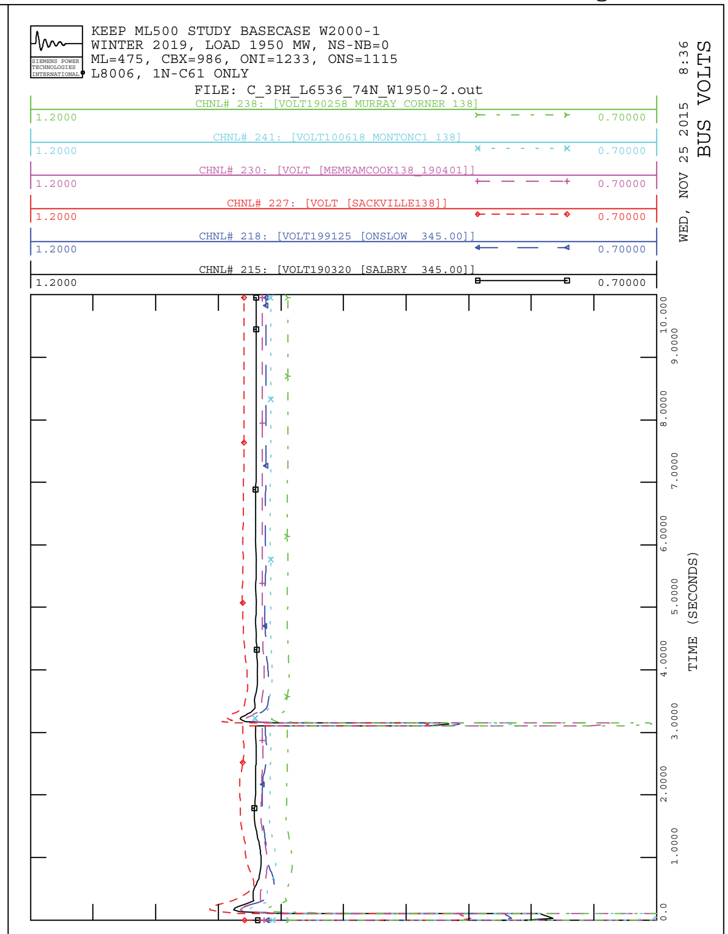
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6536_74N_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)
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1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
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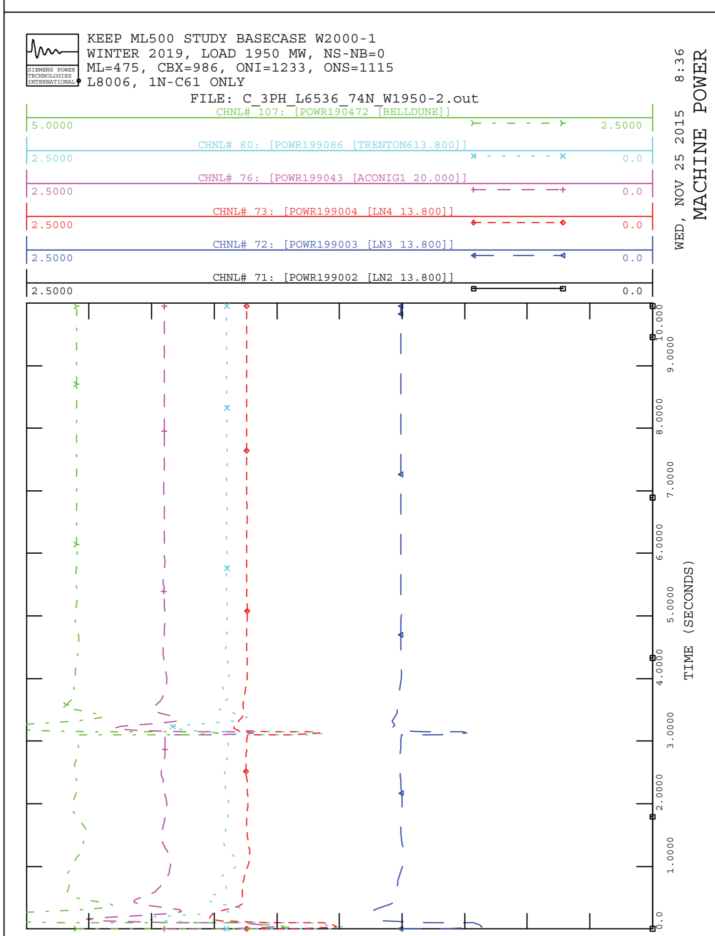
8.0000
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6536_74N_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)
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1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
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8.0000
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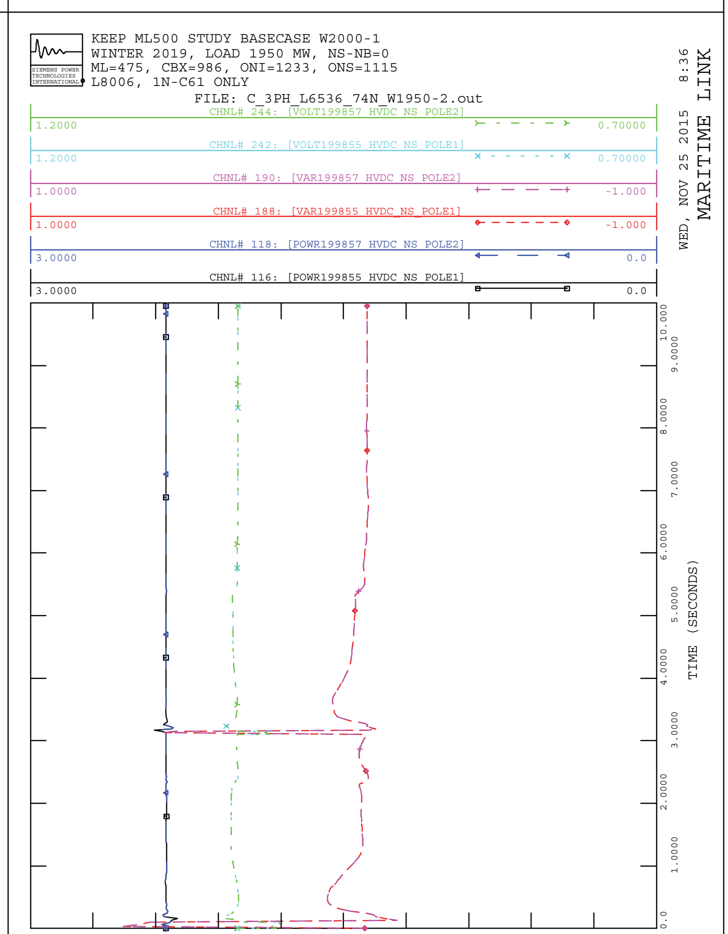
10.000


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L6536_74N_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
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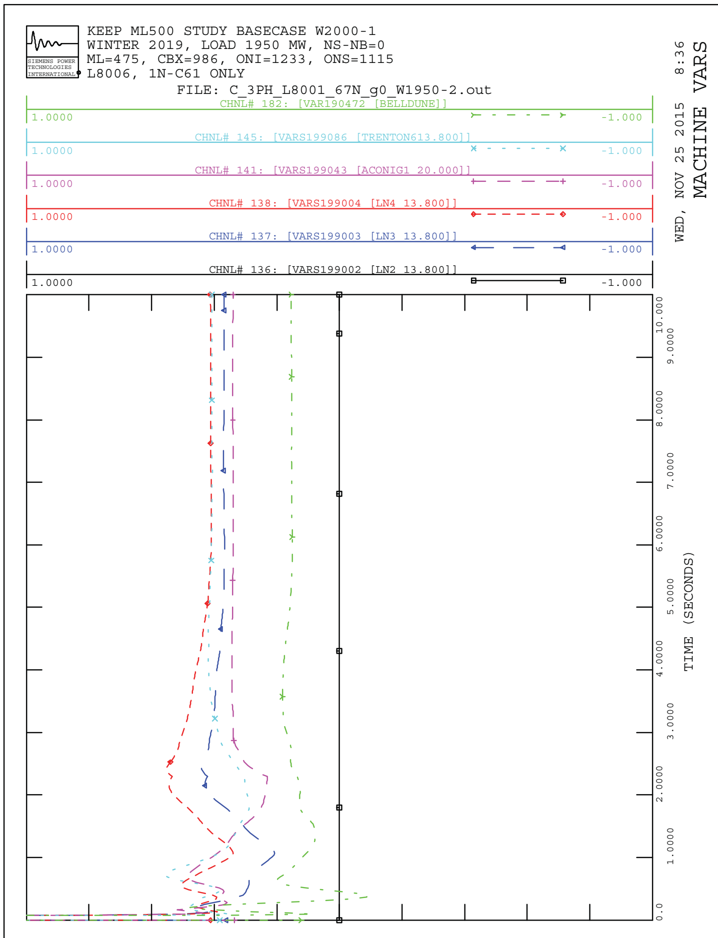
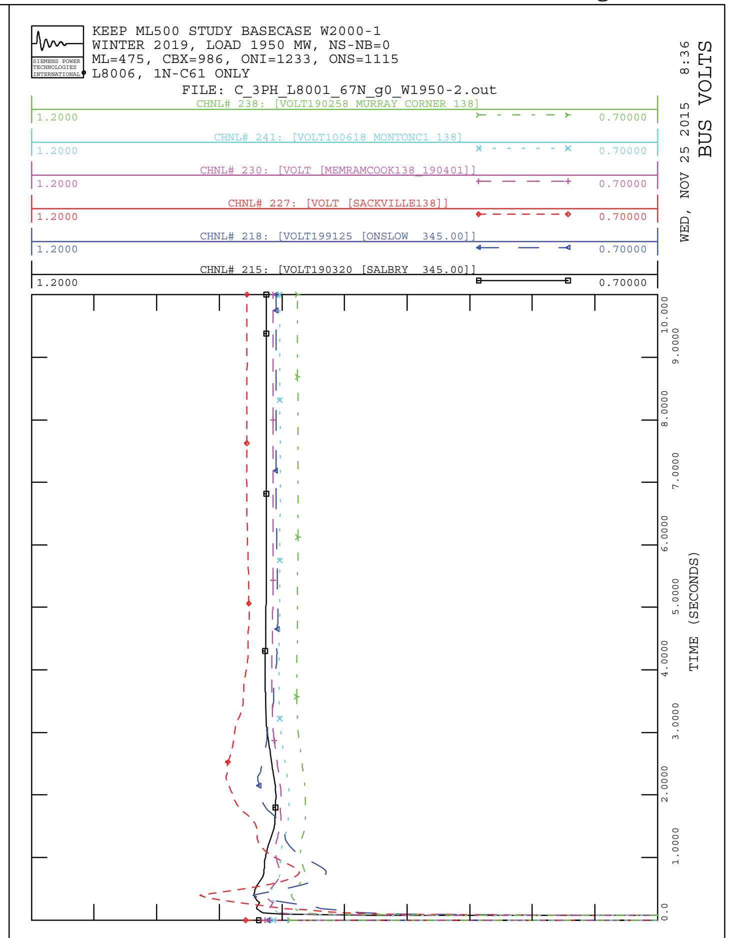
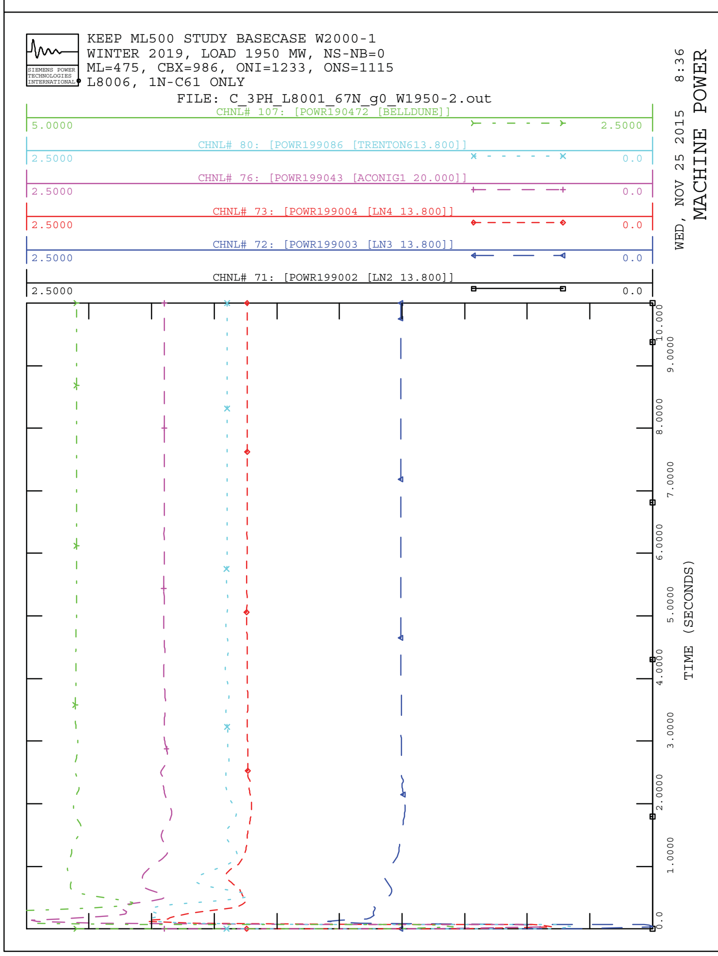
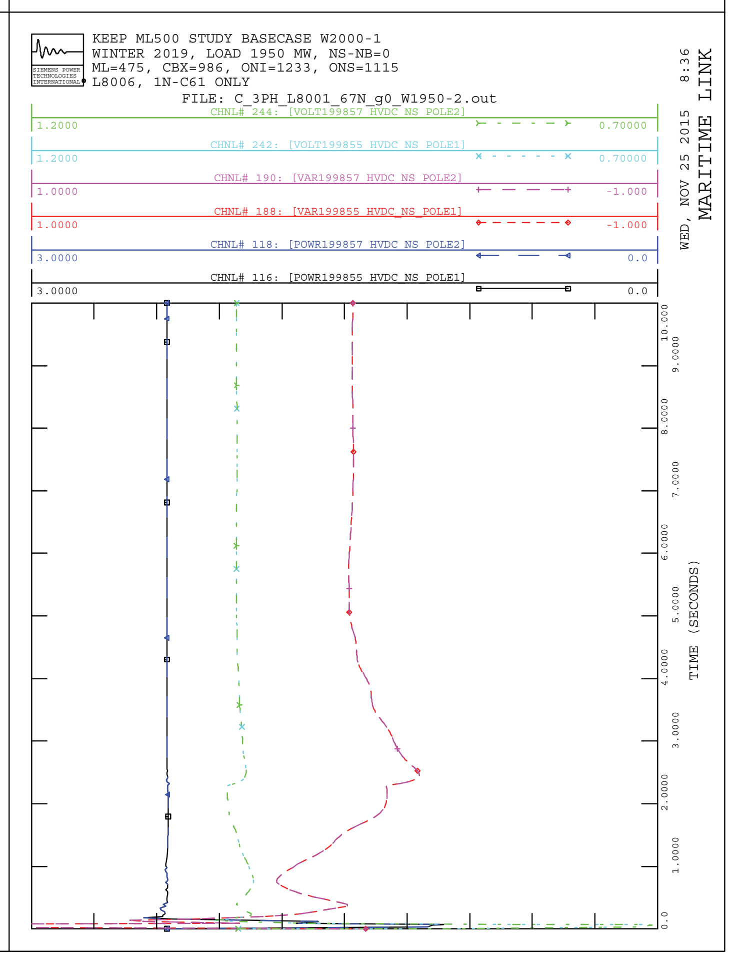
9.0000
10.000

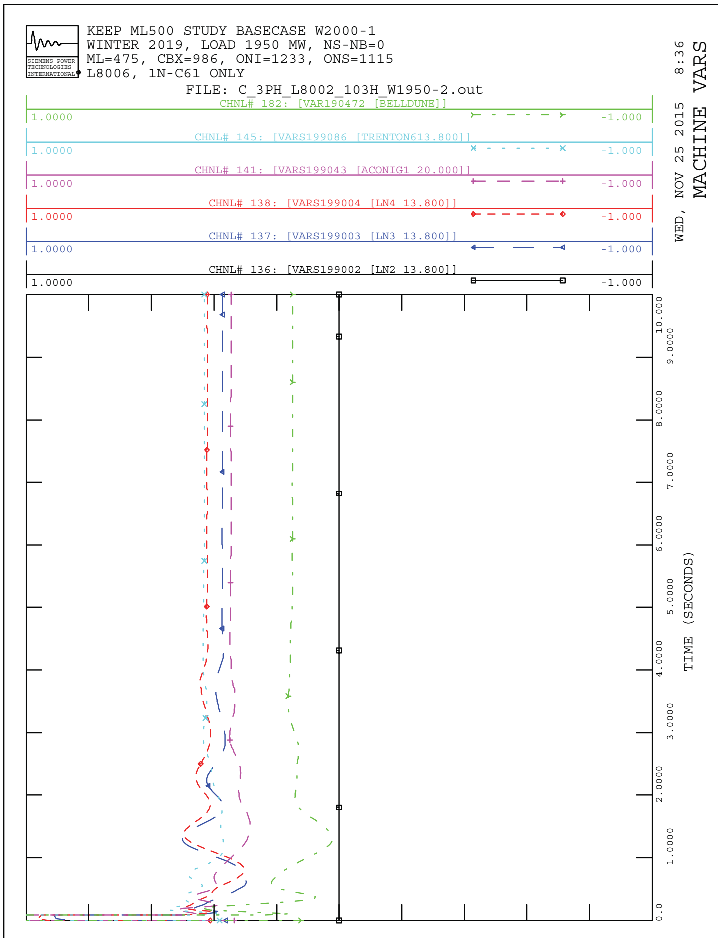
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



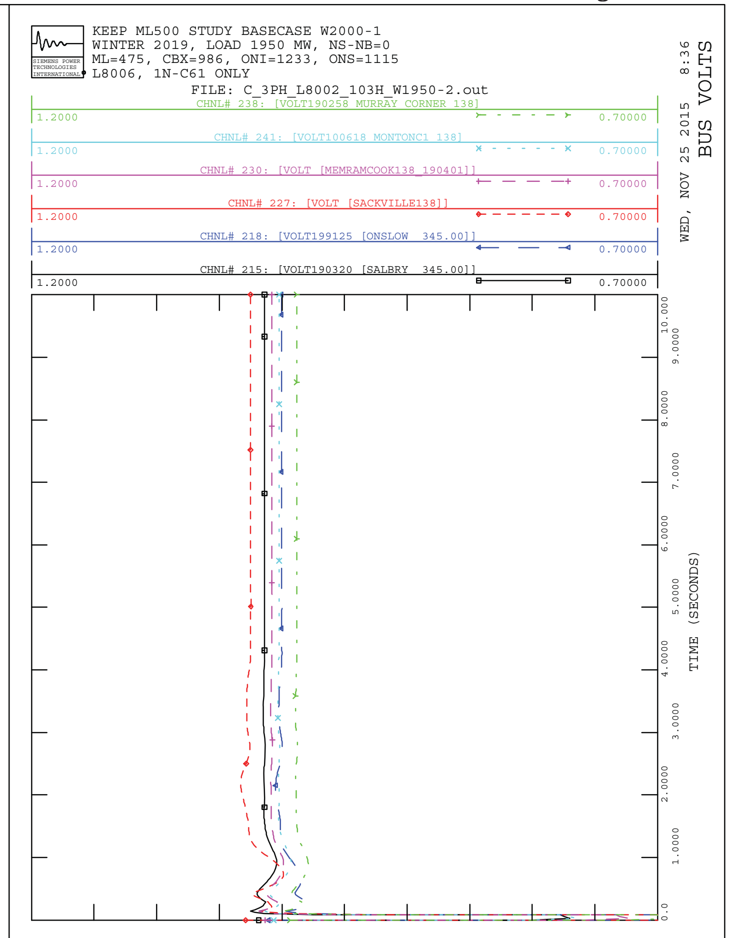




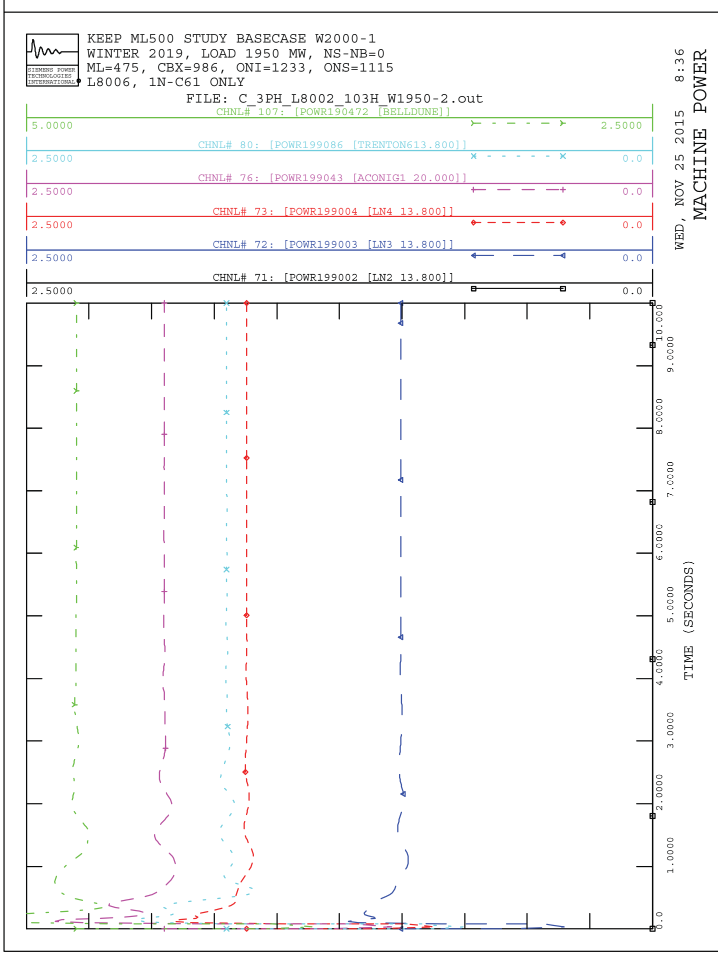




KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8002_103H_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
WED, NOV 25 2015 8:36
MACHINE VARS



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8002_103H_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
WED, NOV 25 2015 8:36
BUS VOLTS



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8002_103H_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
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7.0000
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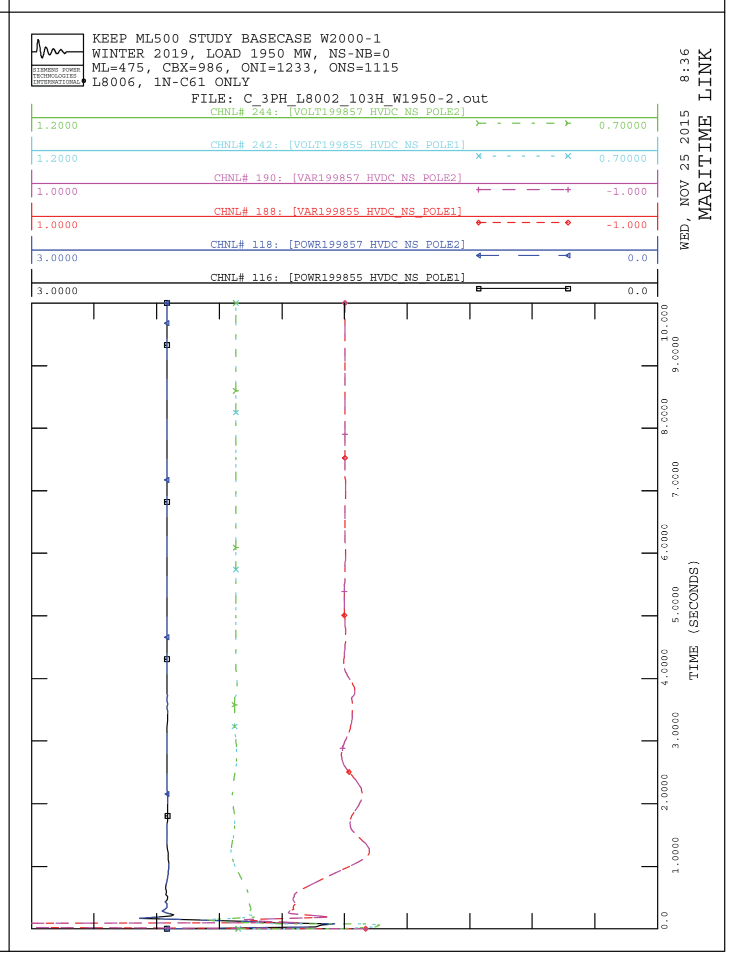
9.0000
10.000
TIME (SECONDS)
WED, NOV 25 2015 8:36
MACHINE POWER



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8002_103H_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
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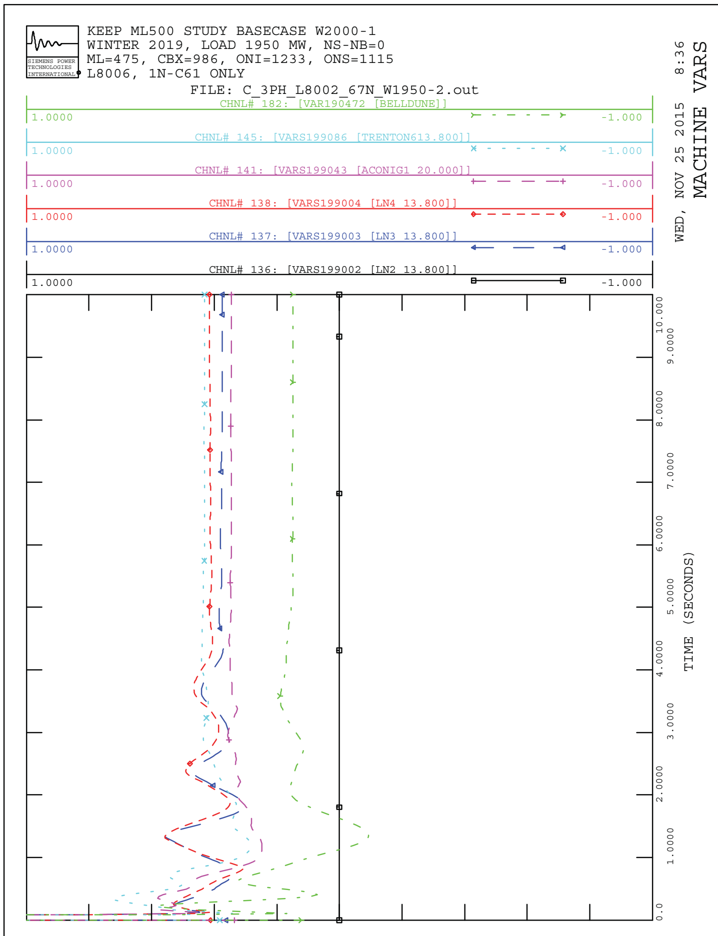
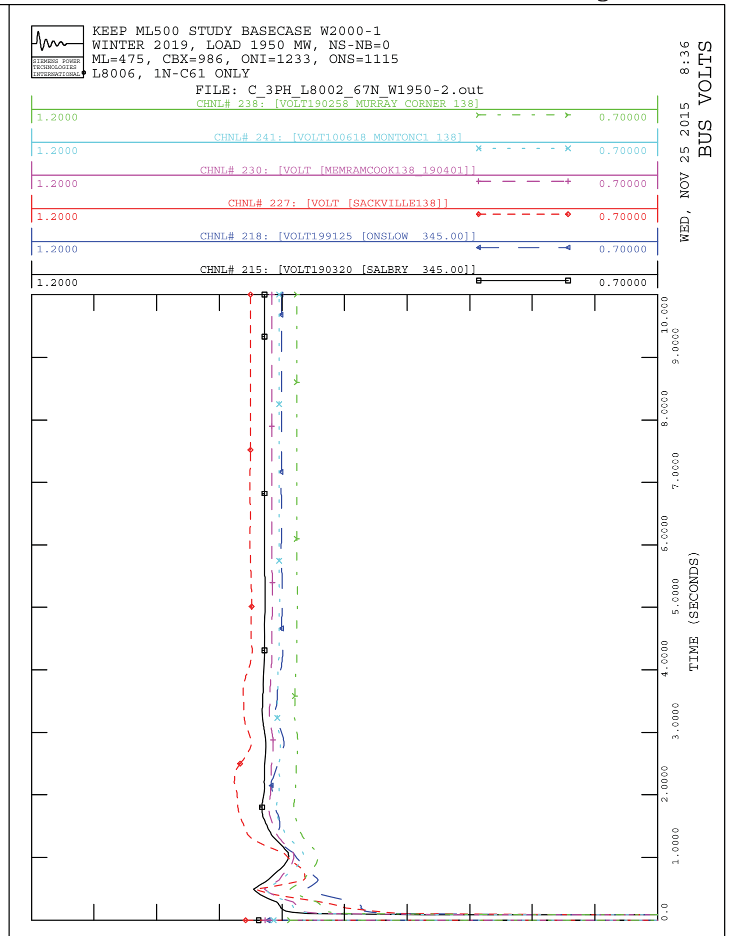
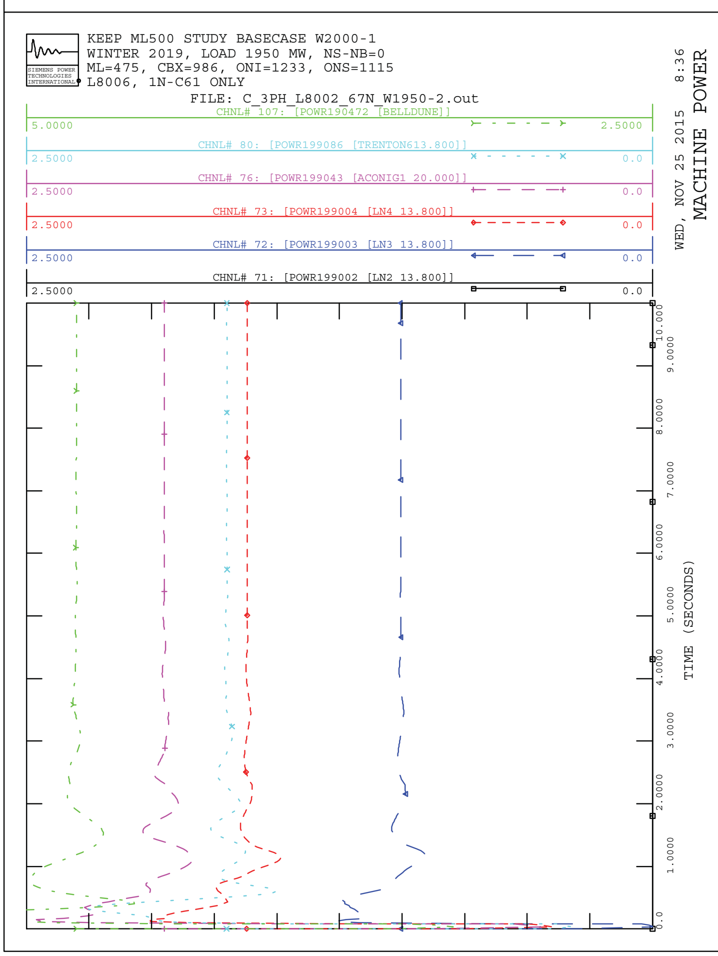
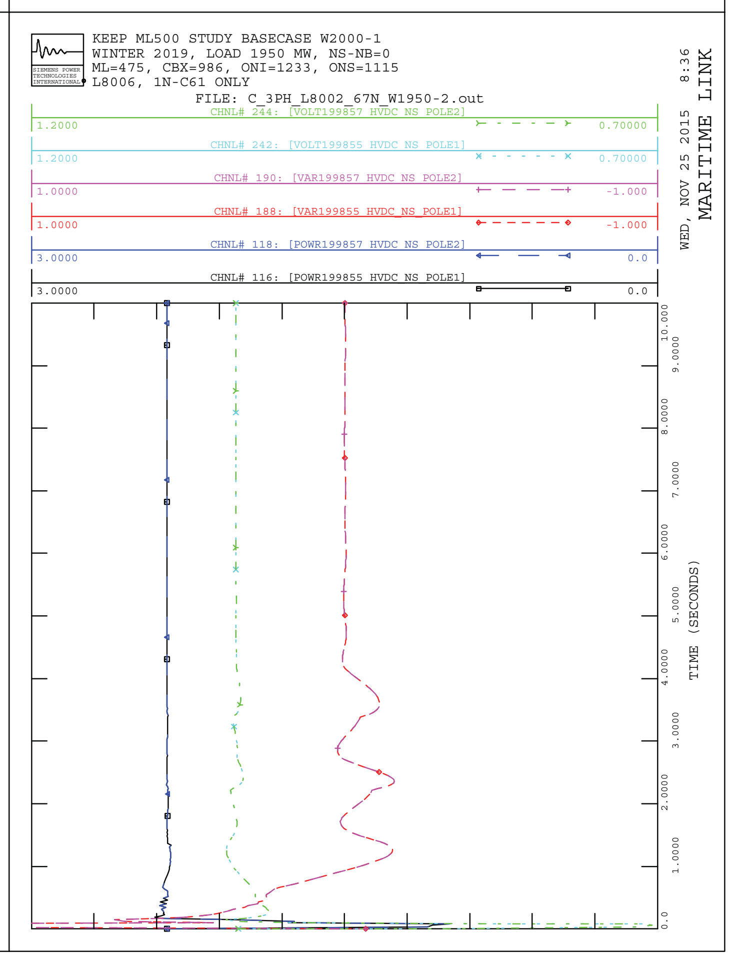
10.000
TIME (SECONDS)
WED, NOV 25 2015 8:36
MARITIME LINK

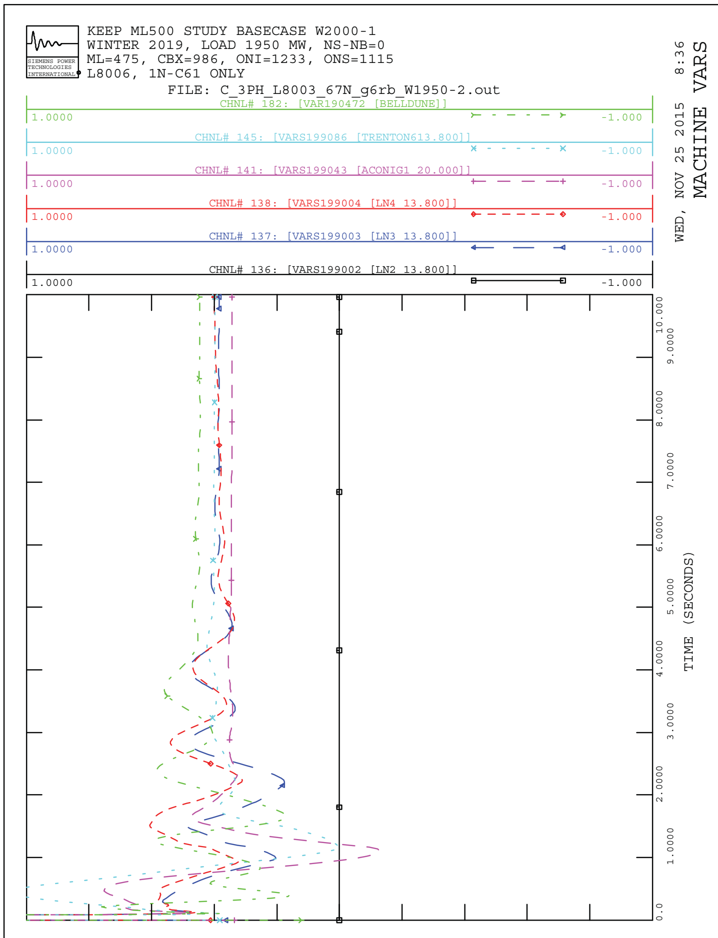
REDACTED (CONFIDENTIAL INFORMATION REMOVED)

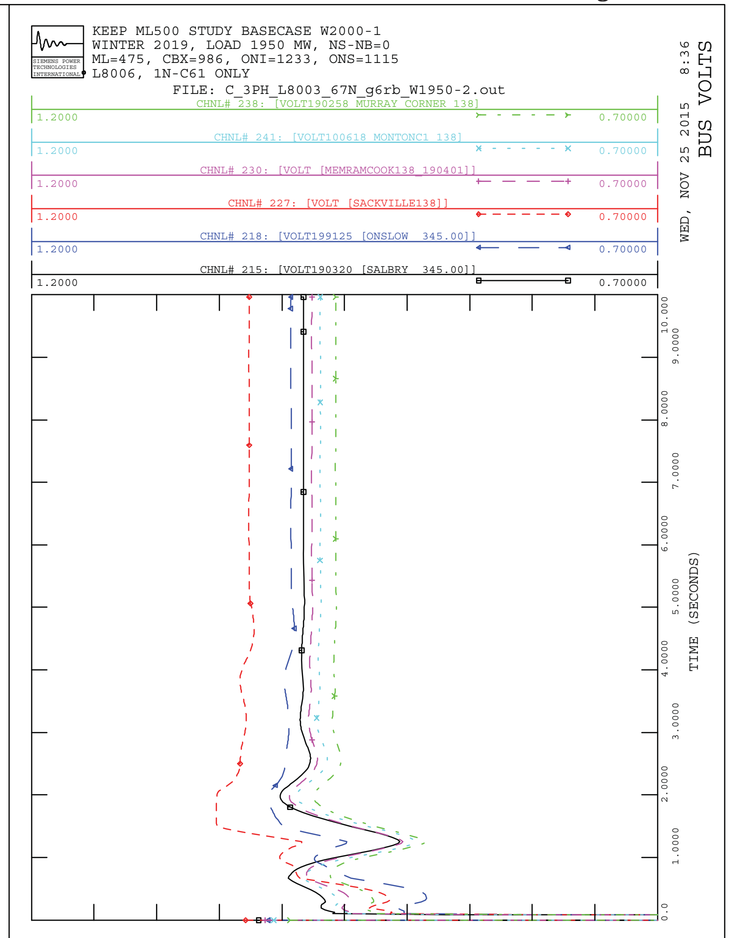


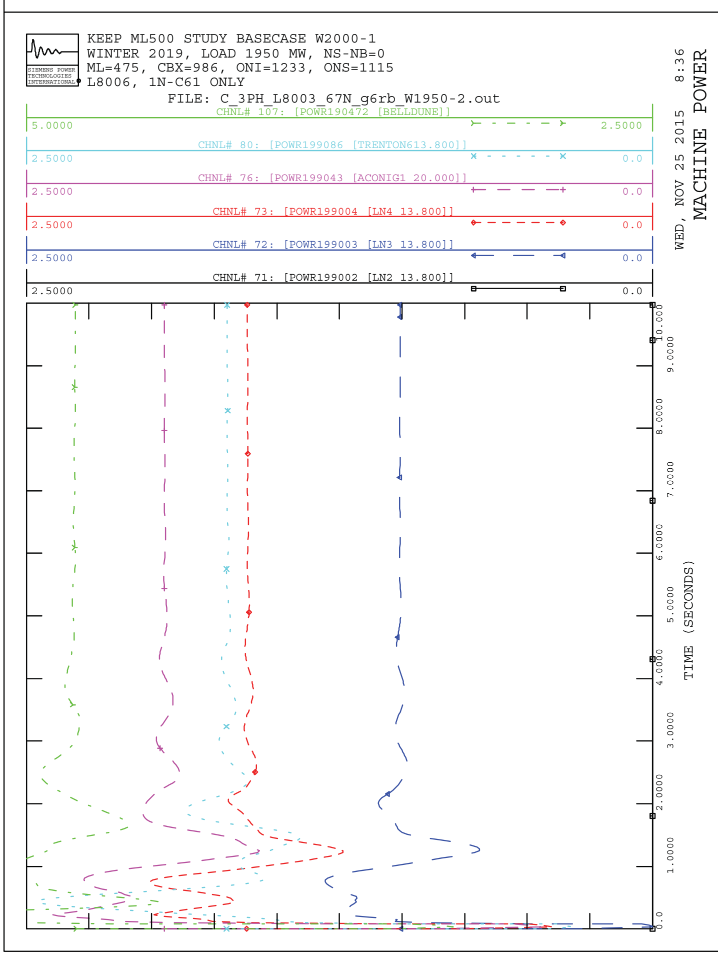


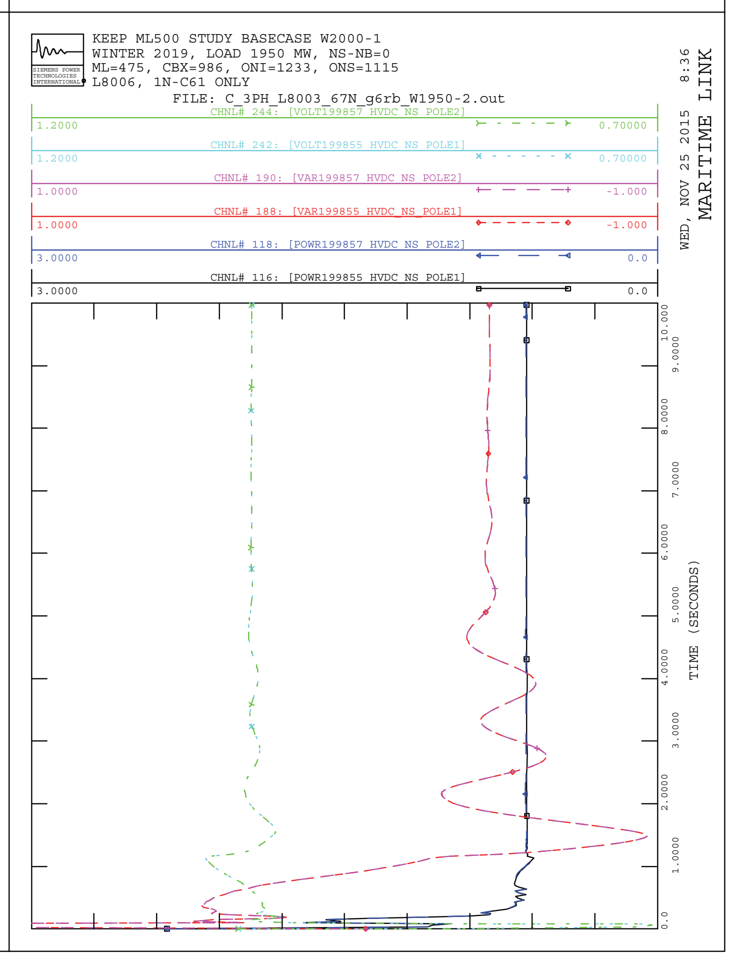


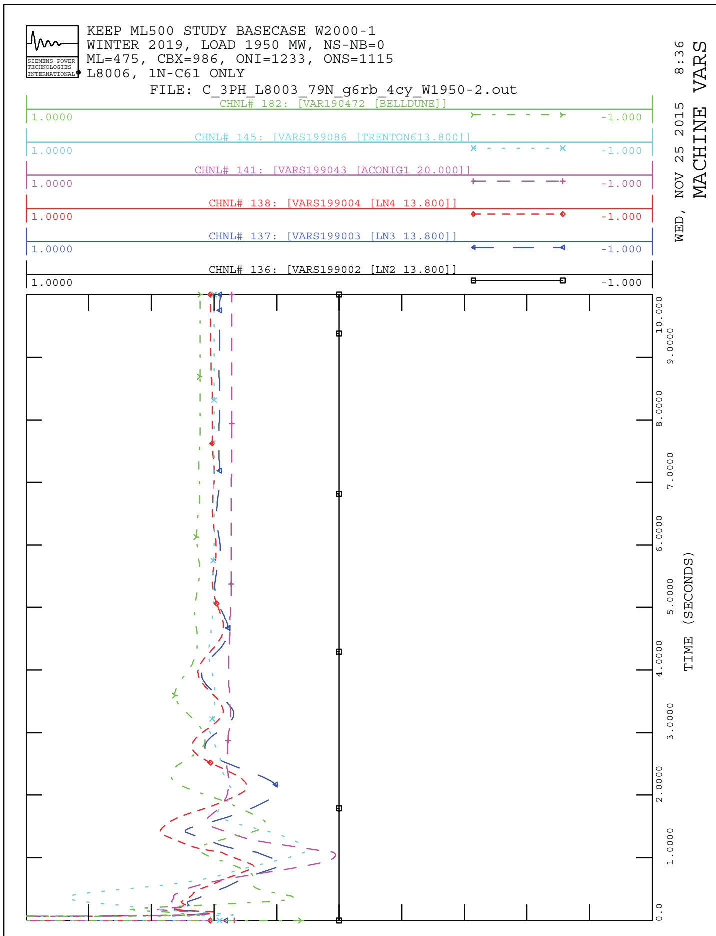



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_67N_g6rb_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)

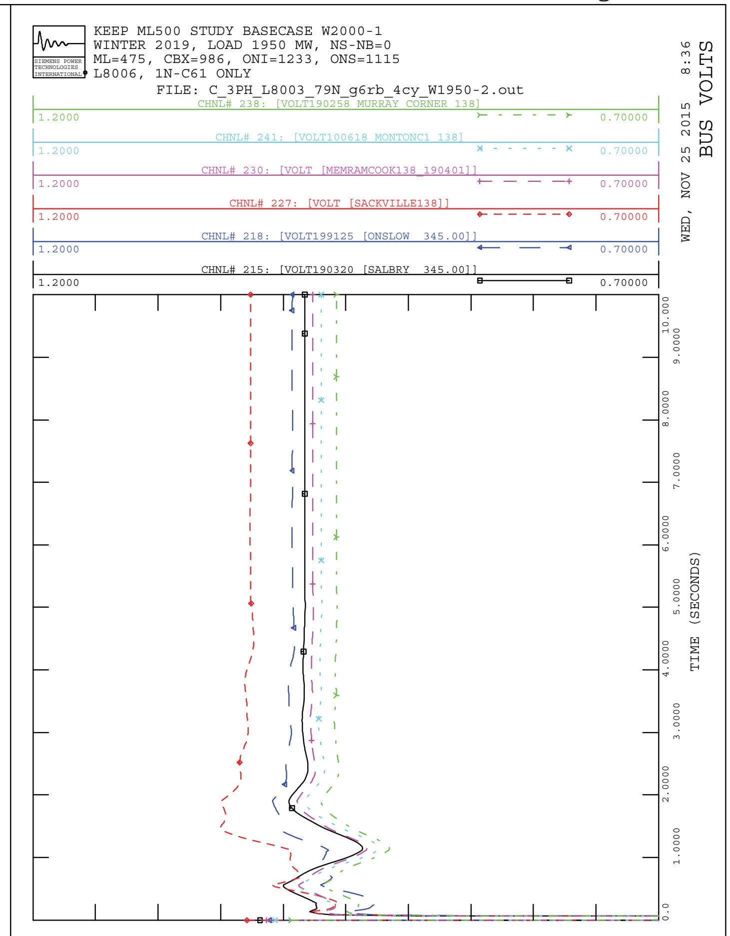

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_67N_g6rb_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_67N_g6rb_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)

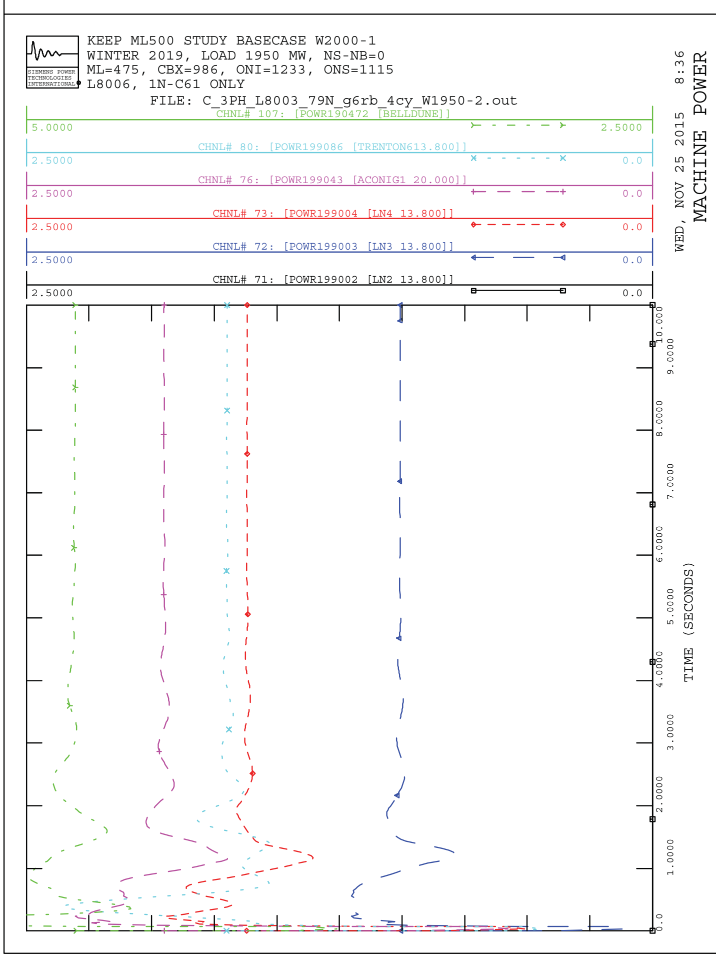

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_67N_g6rb_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)



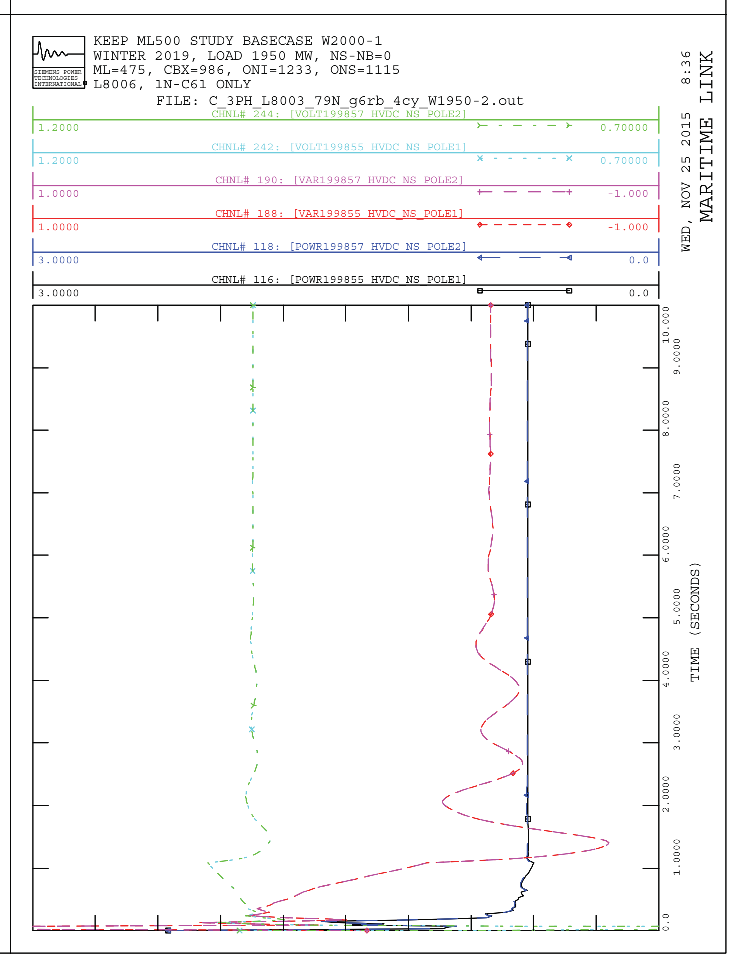
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_79N_g6rb_4cy_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)



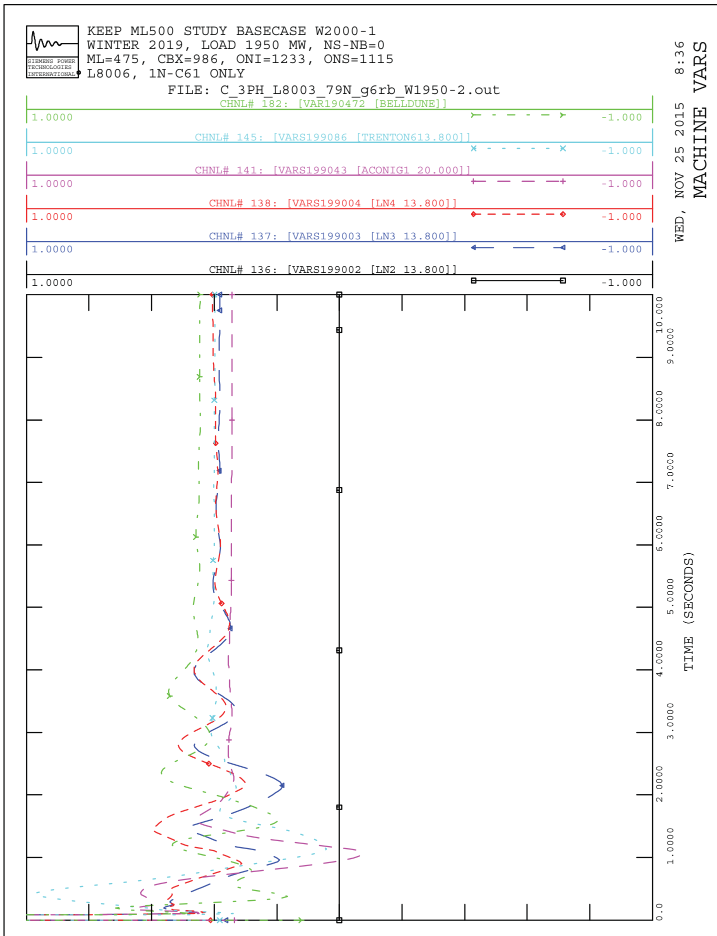
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_79N_g6rb_4cy_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)



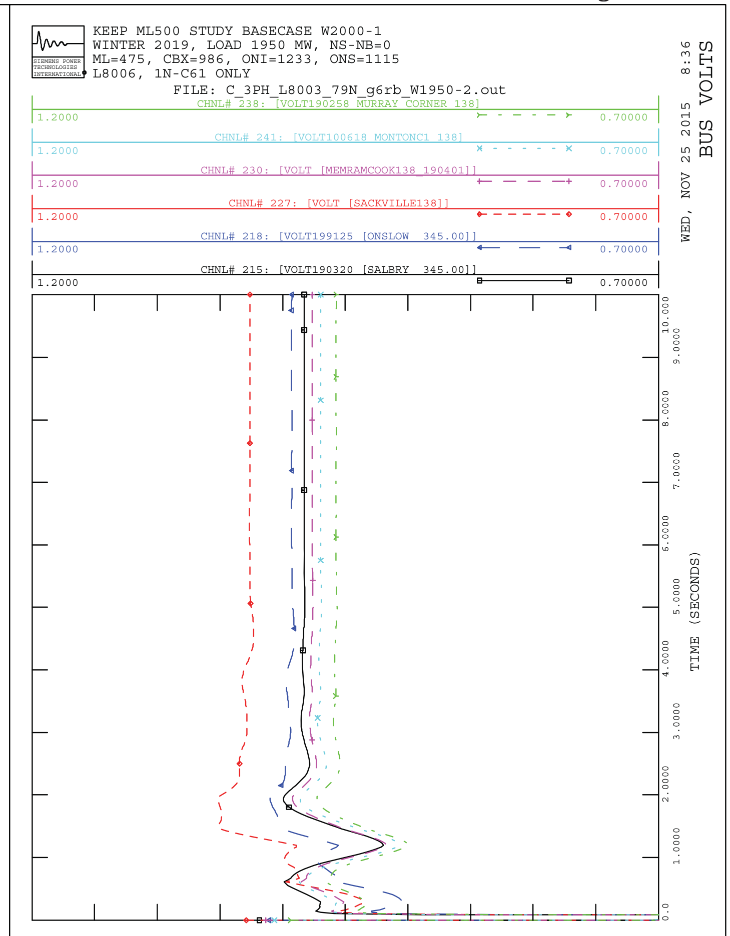
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_79N_g6rb_4cy_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)



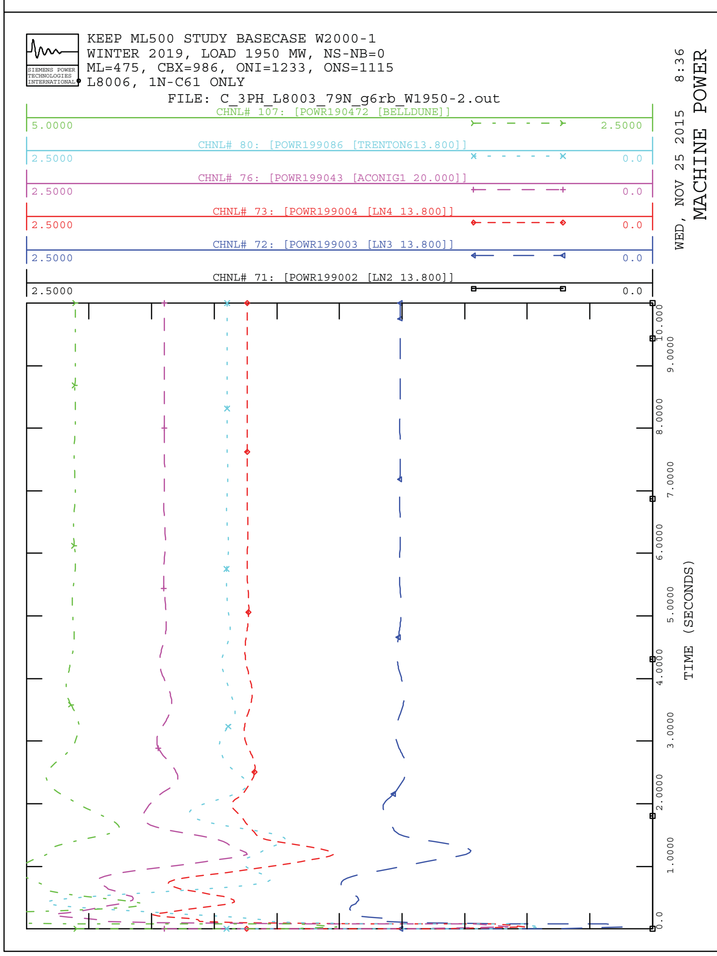
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_79N_g6rb_4cy_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)



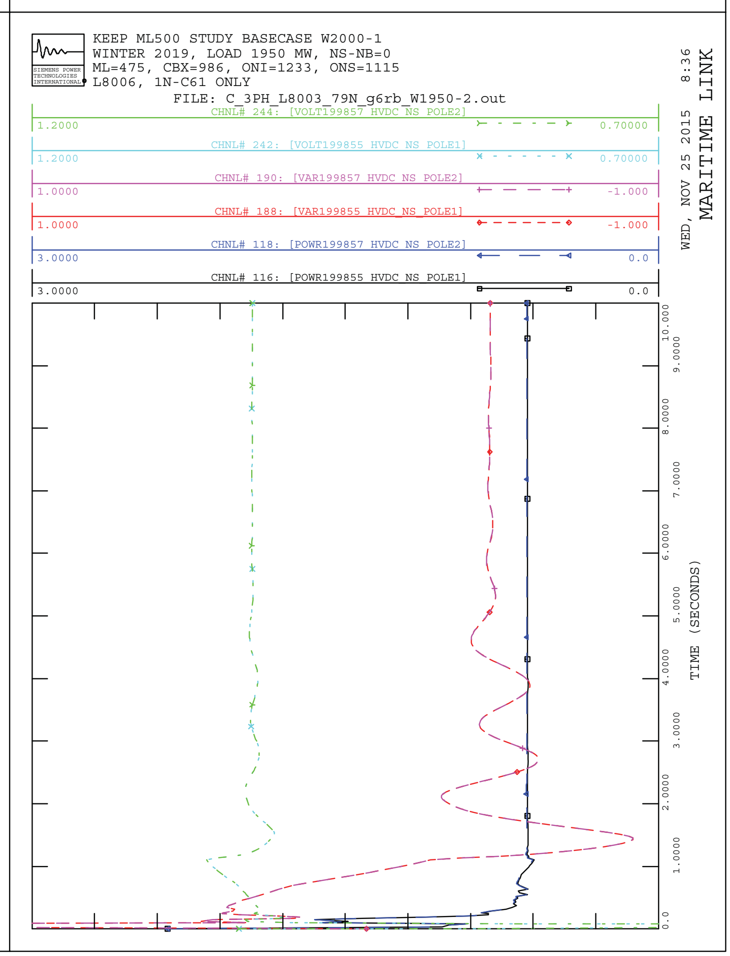
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_79N_g6rb_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
TIME (SECONDS)
WED, NOV 25 2015 8:36
MACHINE VARS



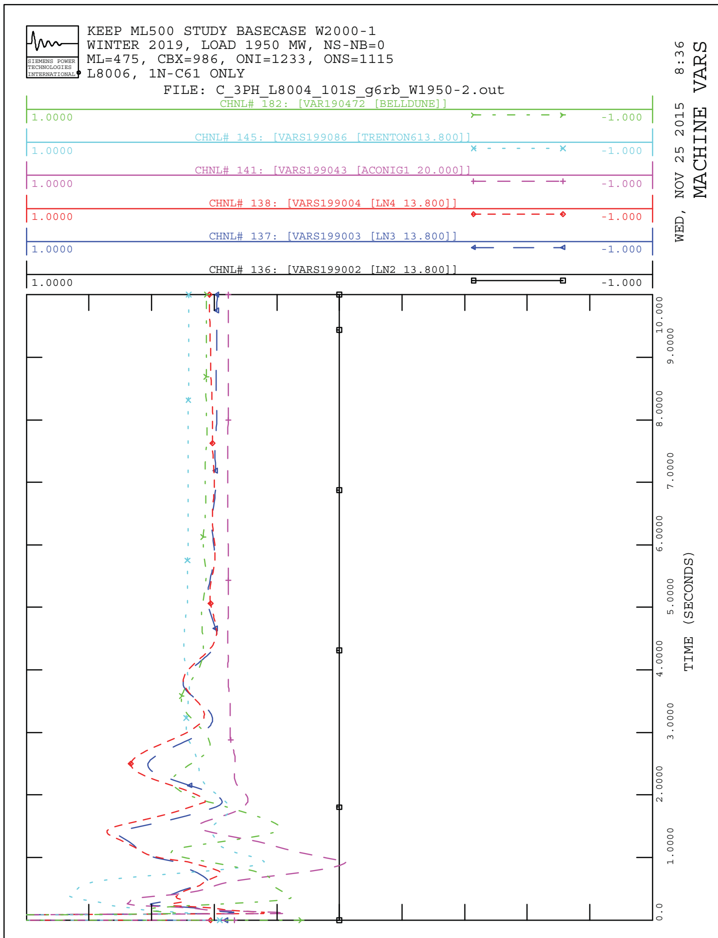
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_79N_g6rb_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
TIME (SECONDS)
WED, NOV 25 2015 8:36
BUS VOLTS



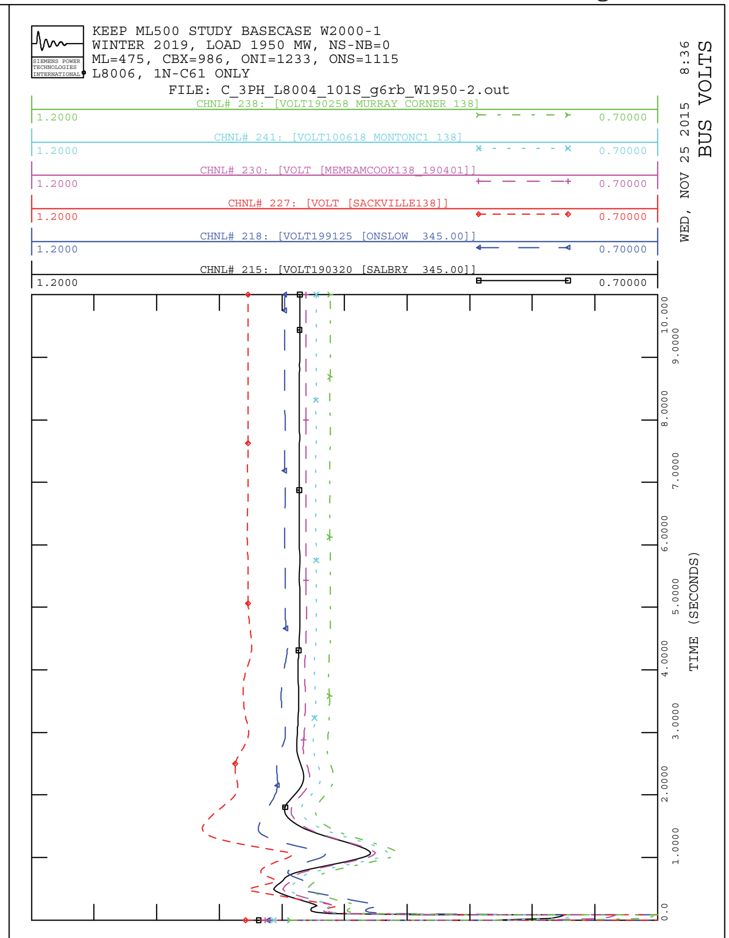
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_79N_g6rb_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
5.0000
2.5000
0.0
TIME (SECONDS)
WED, NOV 25 2015 8:36
MACHINE POWER



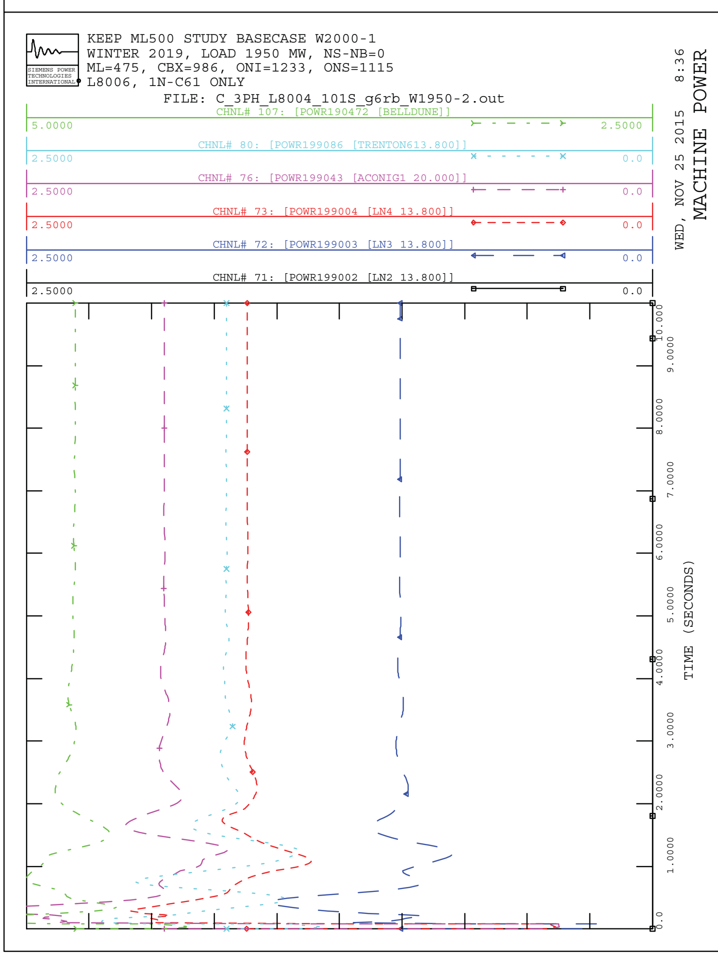
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8003_79N_g6rb_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
1.0000
-1.000
3.0000
0.0
TIME (SECONDS)
WED, NOV 25 2015 8:36
MARITIME LINK



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8004_101S_g6rb_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
TIME (SECONDS)
WED, NOV 25 2015 8:36
MACHINE VARS



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8004_101S_g6rb_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138_190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
TIME (SECONDS)
WED, NOV 25 2015 8:36
BUS VOLTS



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8004_101S_g6rb_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
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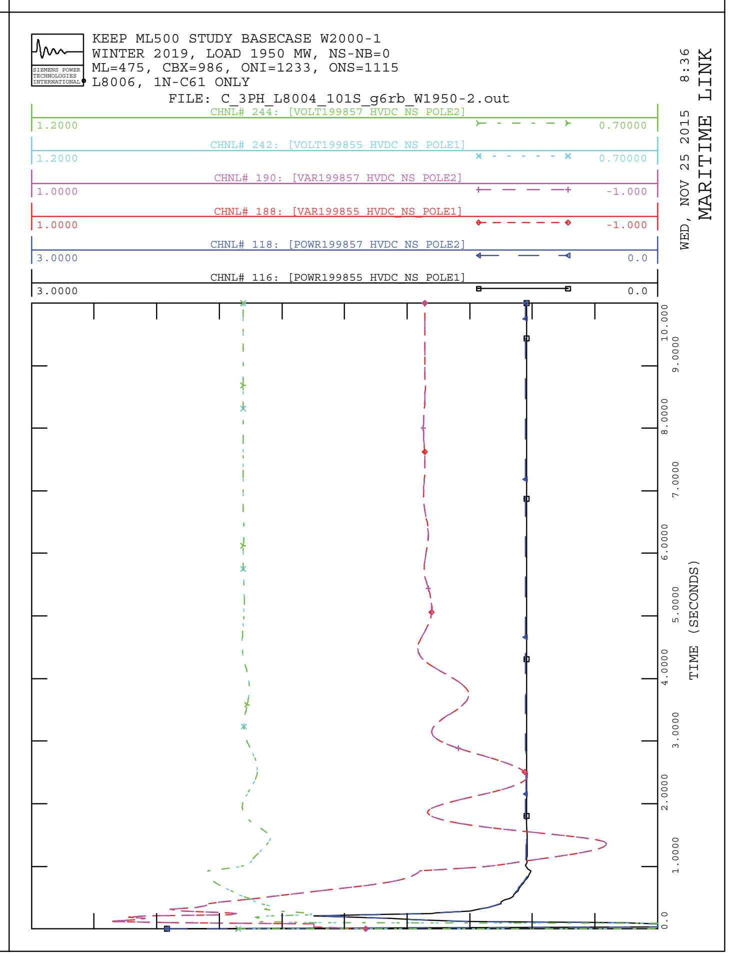
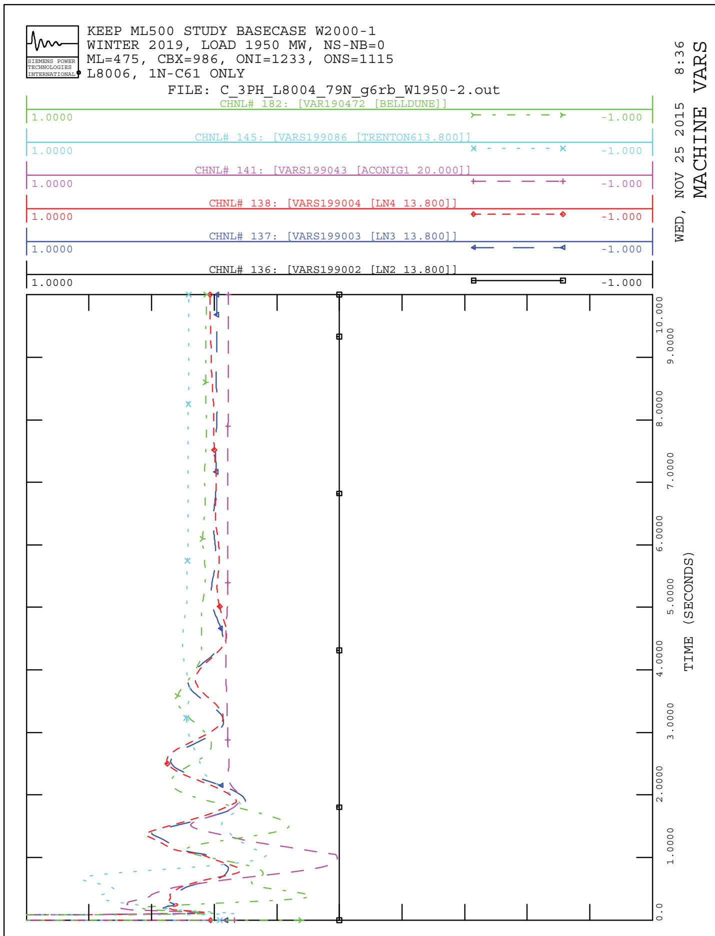
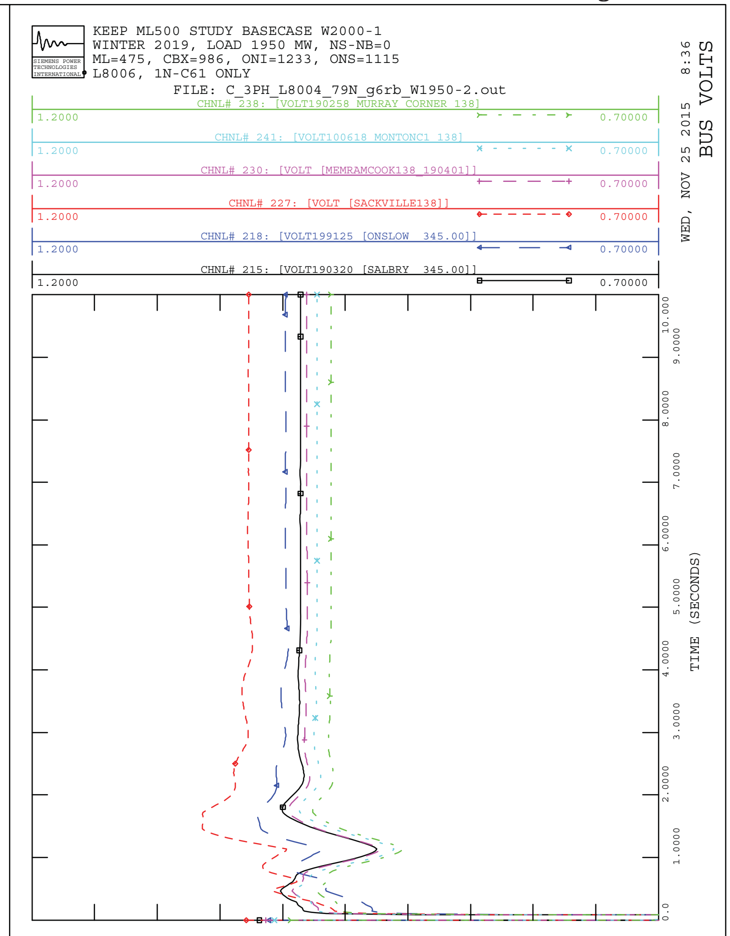
2.5000
0.0
TIME (SECONDS)
WED, NOV 25 2015 8:36
MACHINE POWER



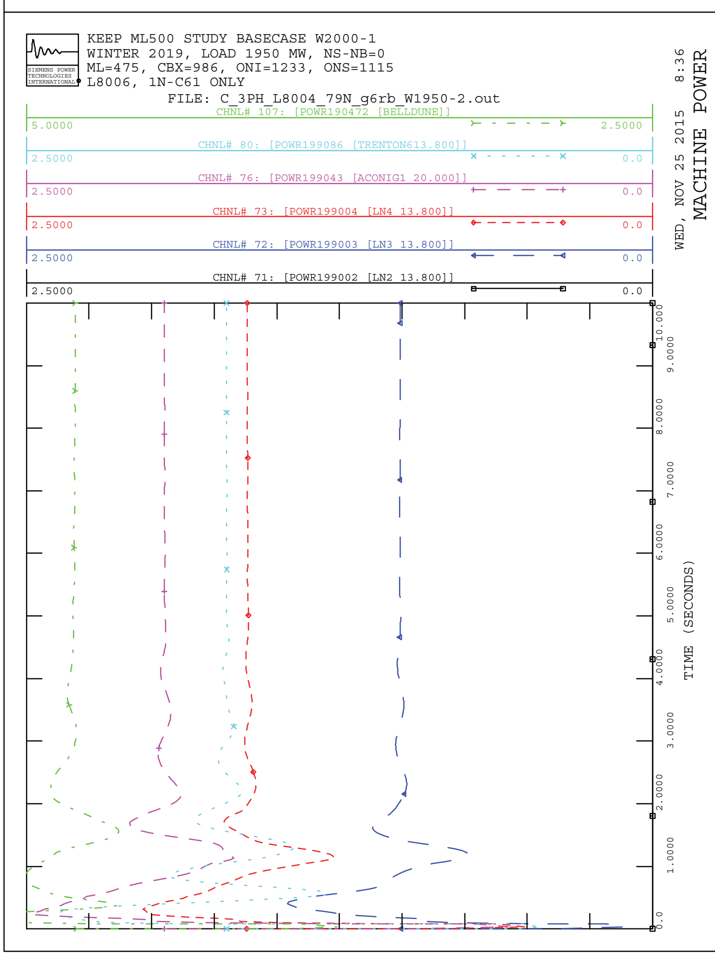
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8004_101S_g6rb_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
1.0000
-1.000
3.0000
0.0
TIME (SECONDS)
WED, NOV 25 2015 8:36
MARITIME LINK



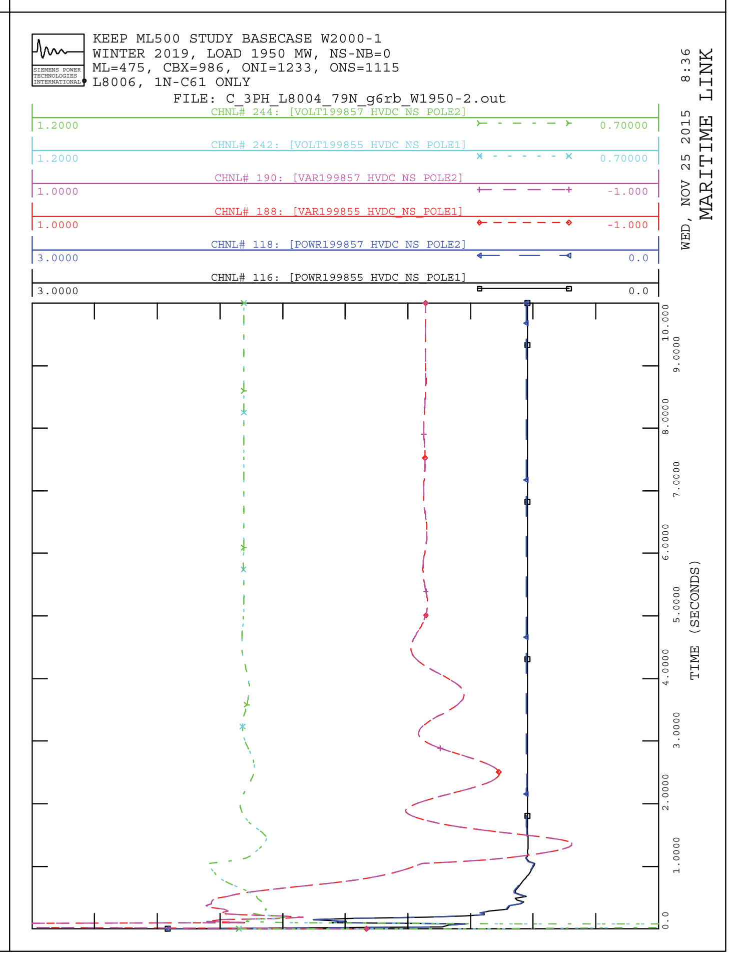
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8004_79N_g6rb_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)



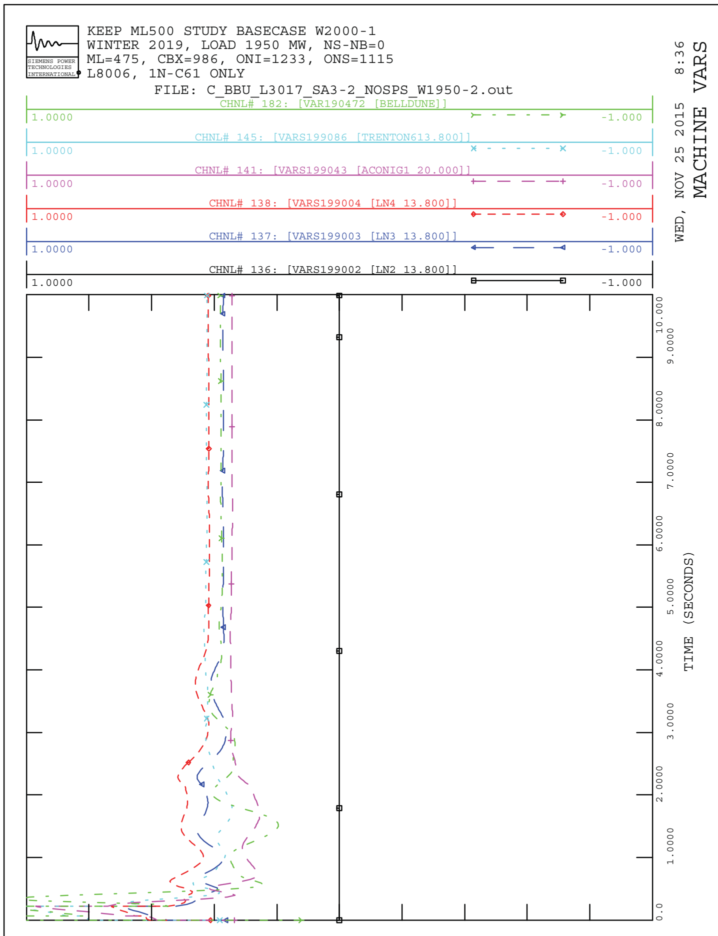
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8004_79N_g6rb_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)

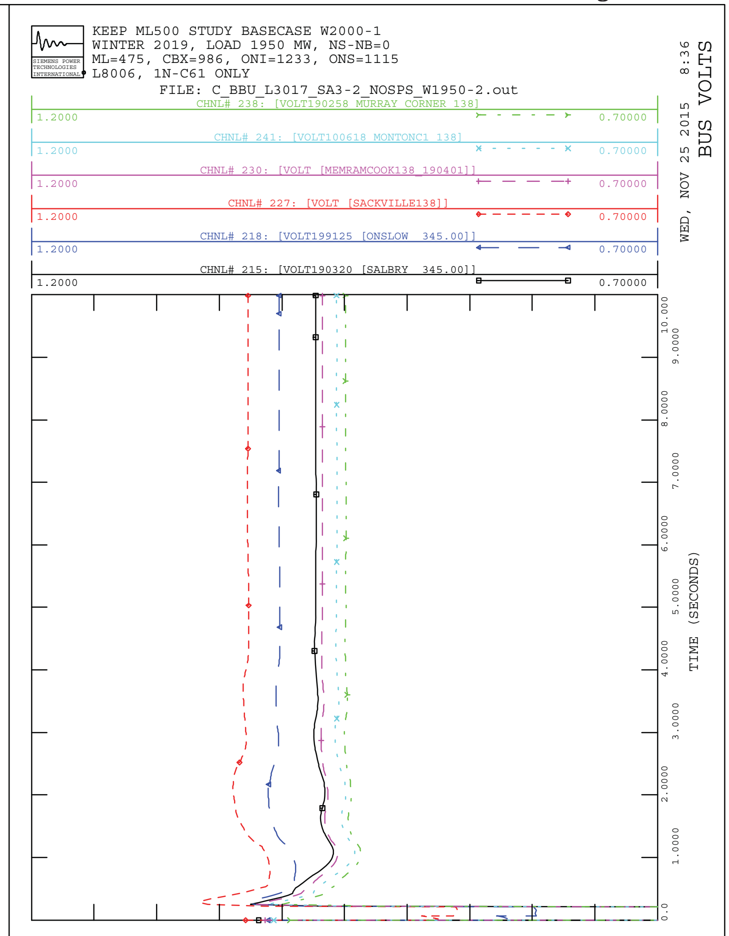


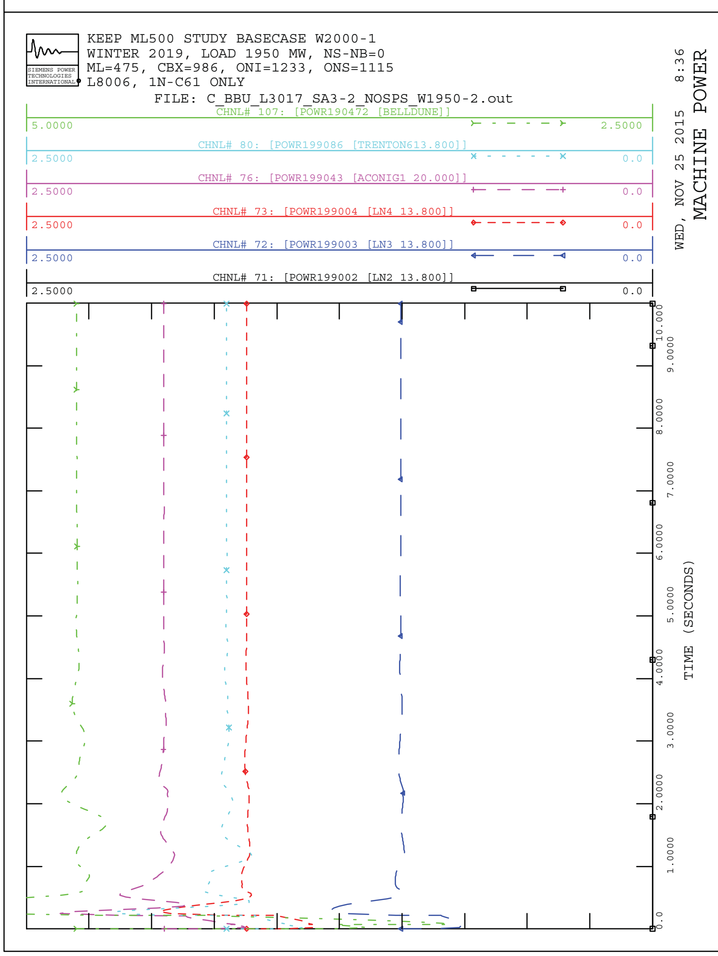
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8004_79N_g6rb_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)

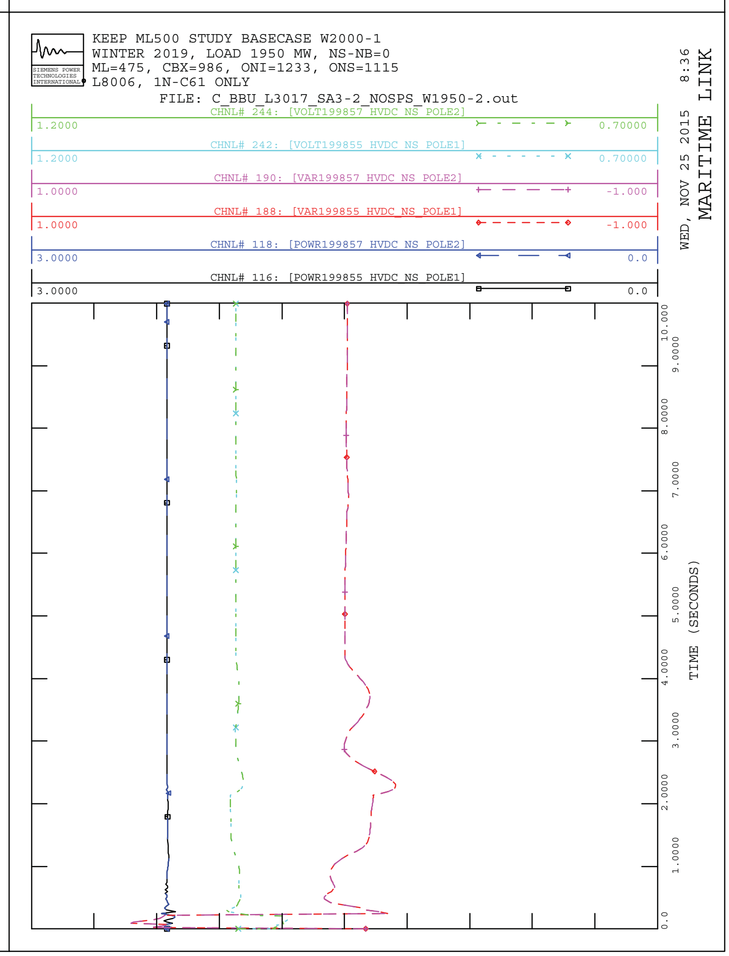


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_3PH_L8004_79N_g6rb_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)

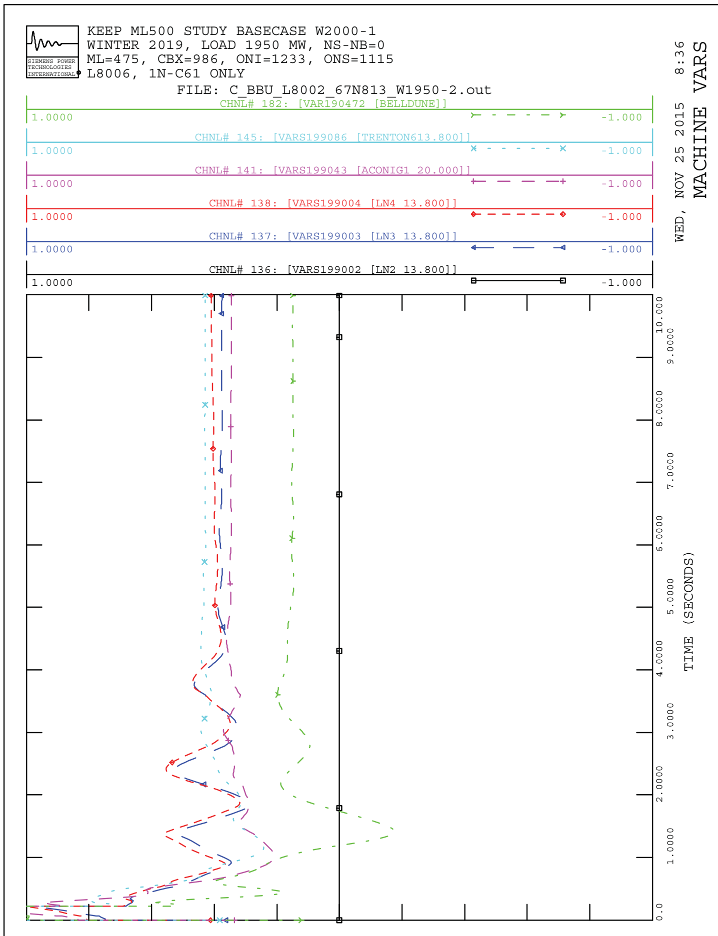

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L3017_SA3-2_NOSPS_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)

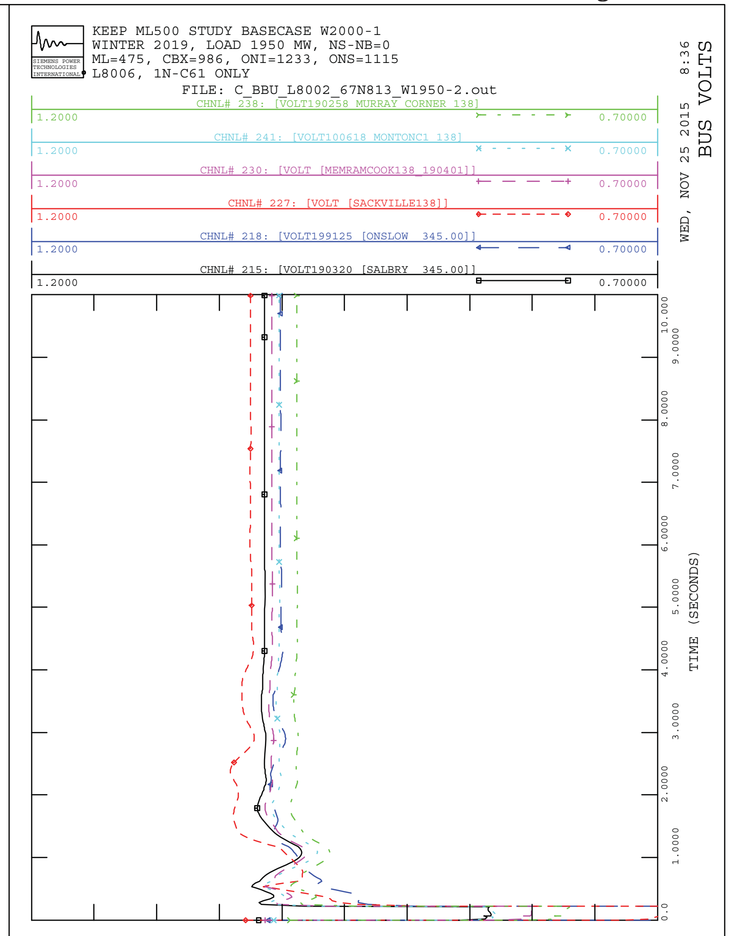

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L3017_SA3-2_NOSPS_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)

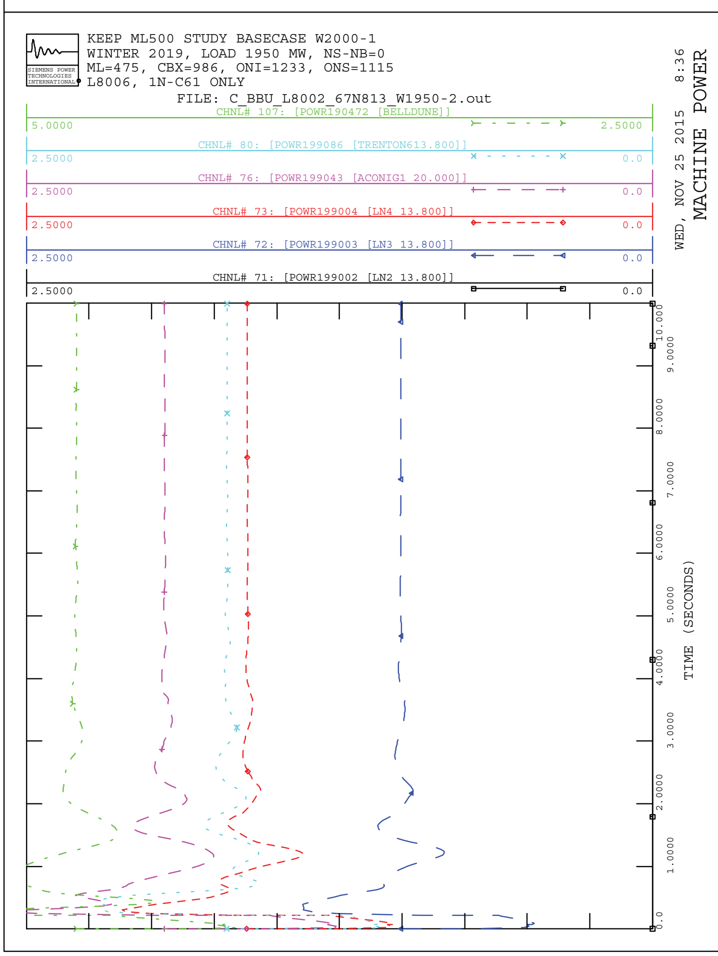

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L3017_SA3-2_NOSPS_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)

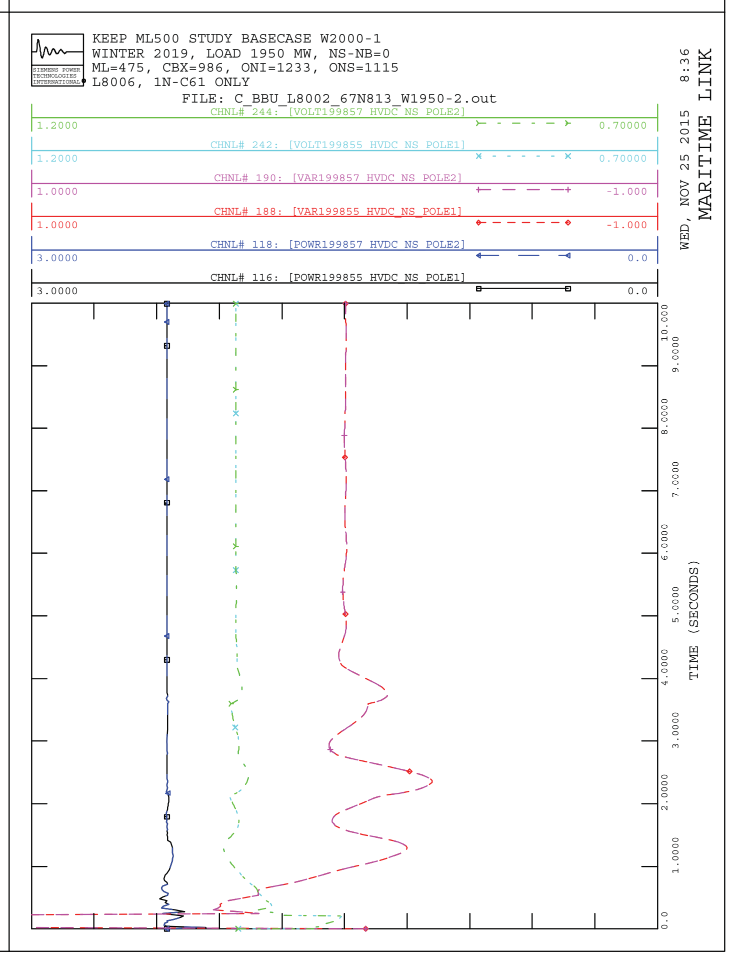

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L3017_SA3-2_NOSPS_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)

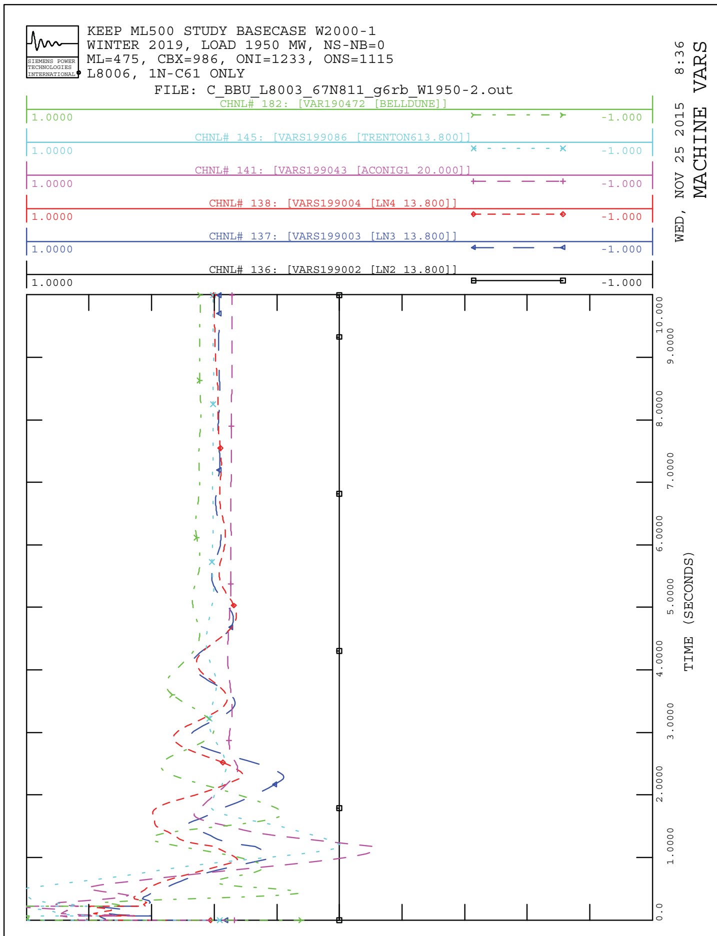
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



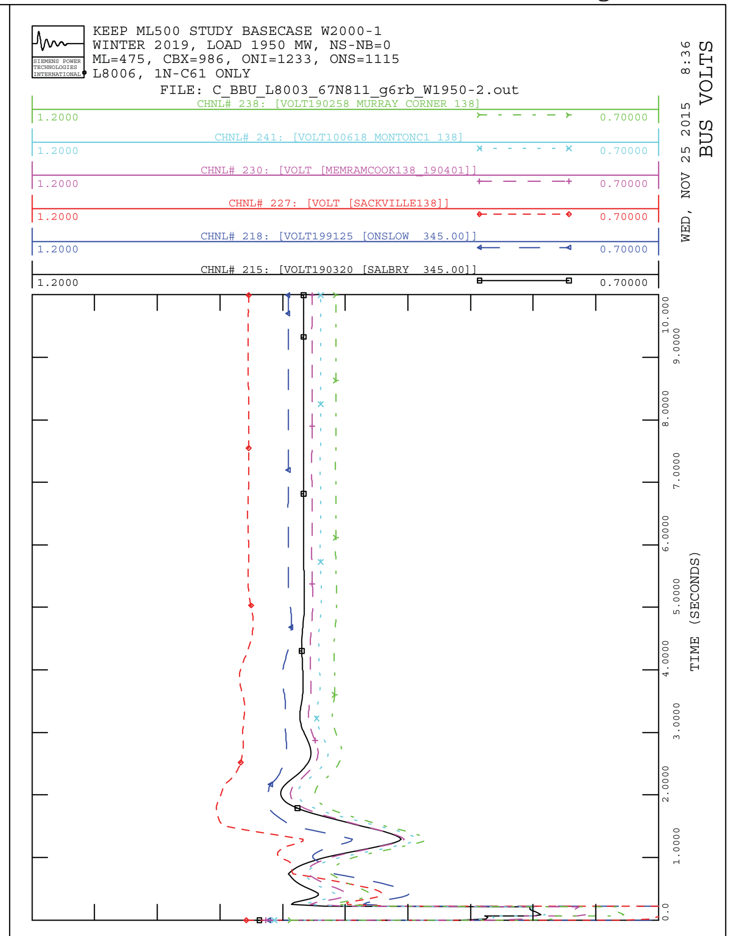




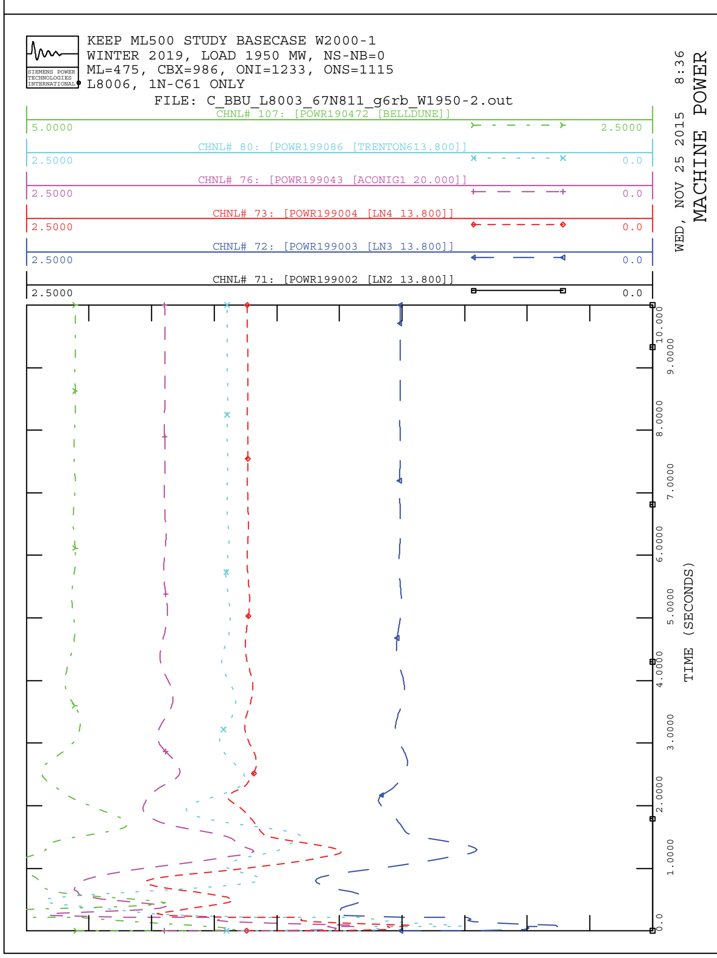




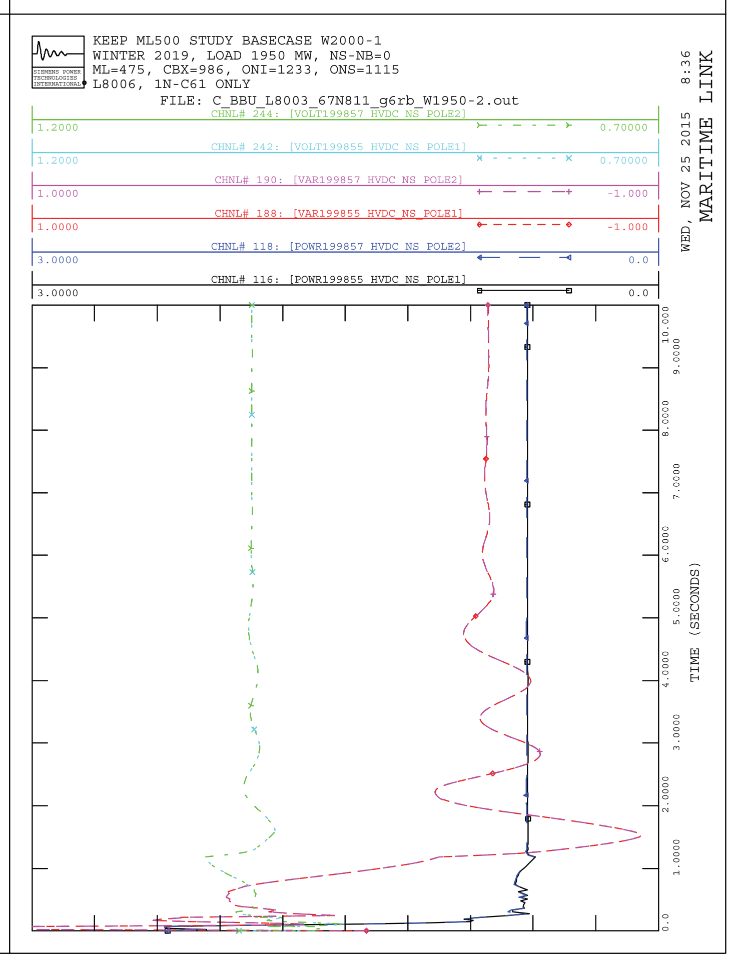
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8003_67N811_g6rb_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)



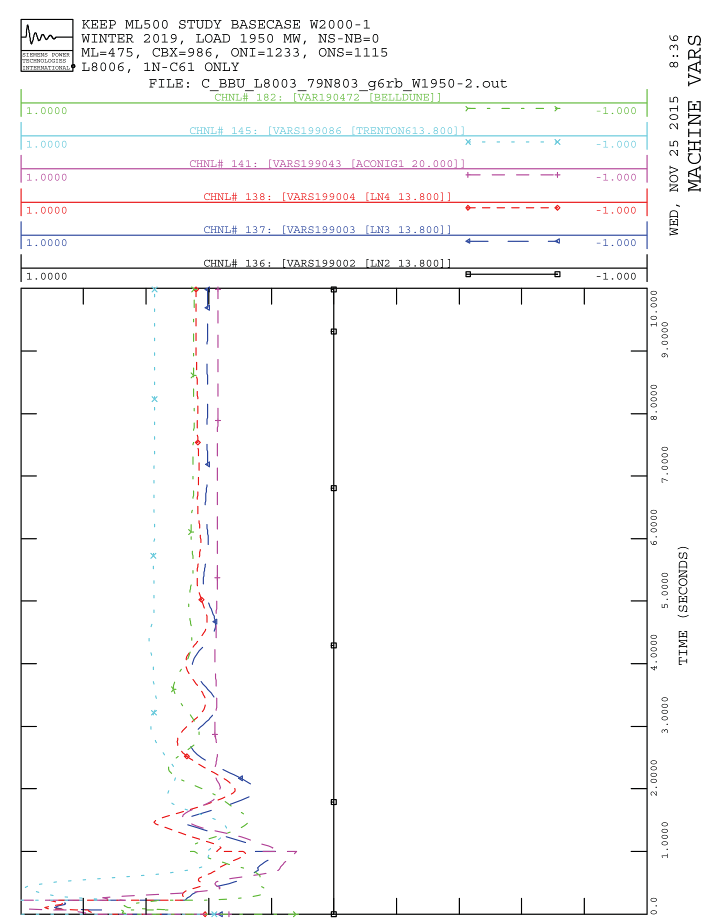
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8003_67N811_g6rb_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)



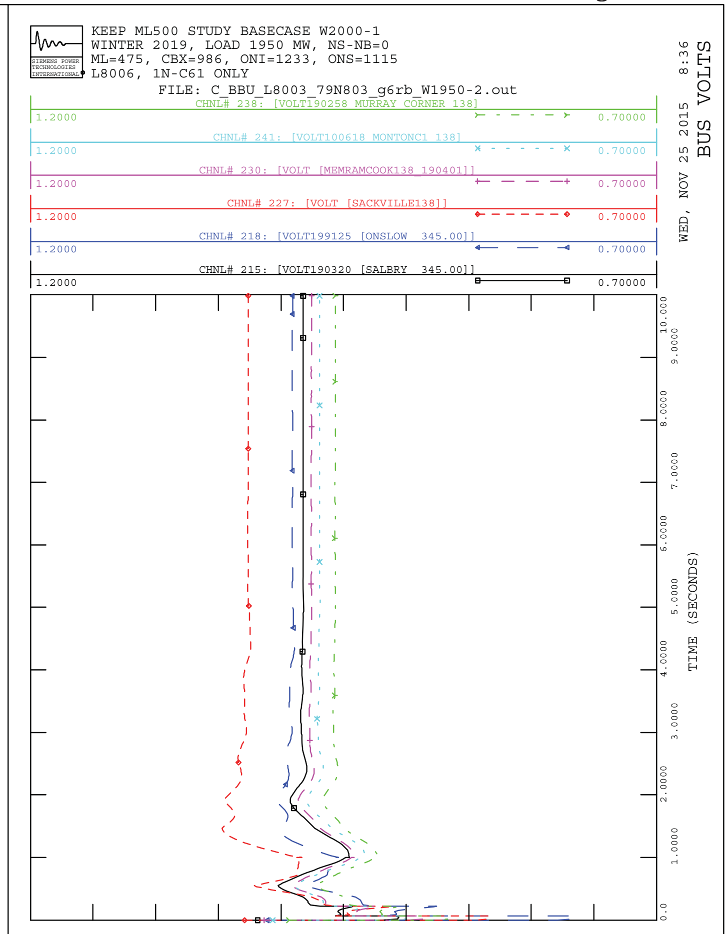
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8003_67N811_g6rb_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)



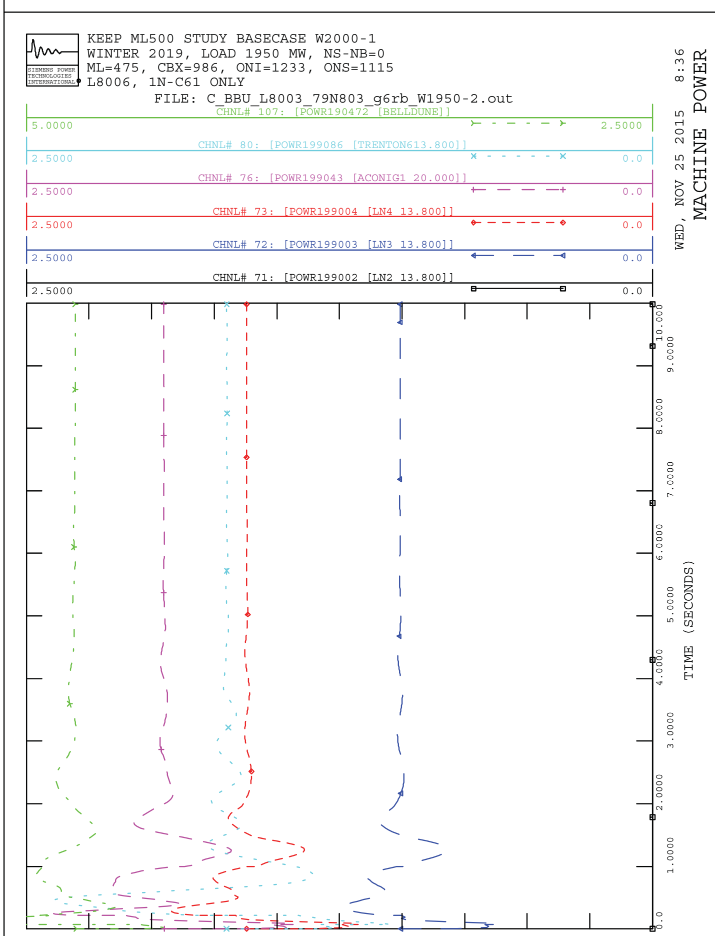
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8003_67N811_g6rb_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)



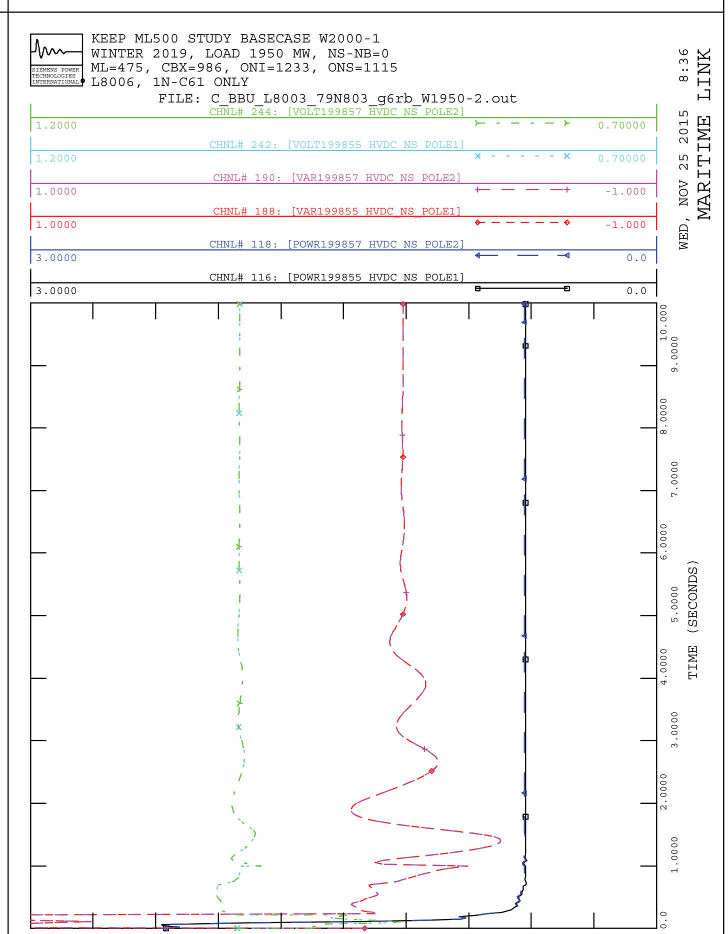
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8003_79N803_g6rb_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)



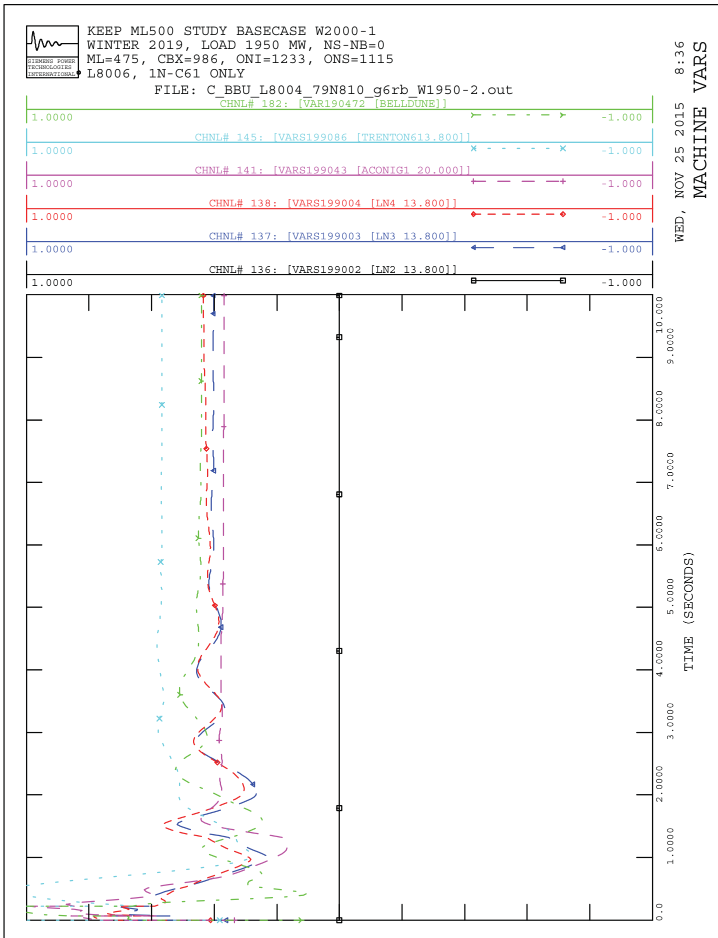
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8003_79N803_g6rb_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)

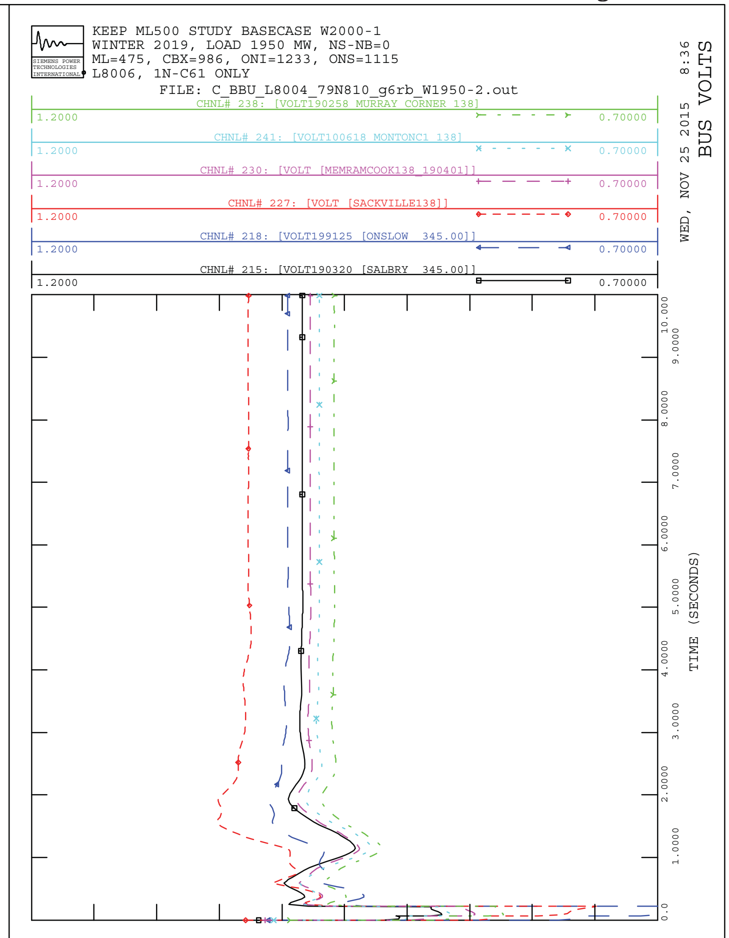


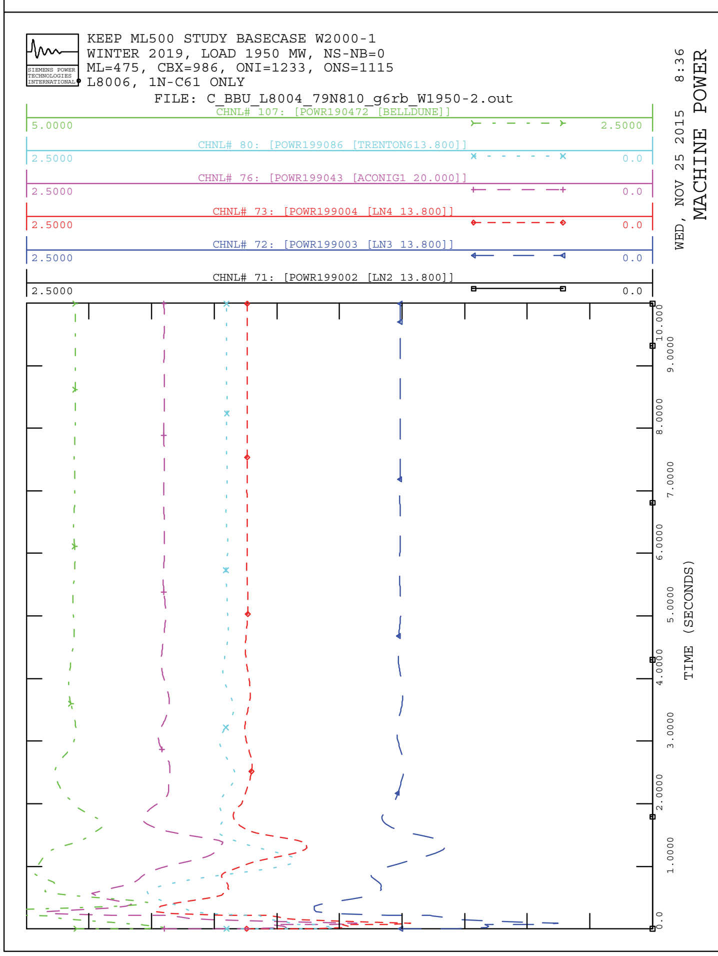
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8003_79N803_g6rb_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8003_79N803_g6rb_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8004_79N810_g6rb_W1950-2.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
WED, NOV 25 2015 8:36
MACHINE VARS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8004_79N810_g6rb_W1950-2.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
WED, NOV 25 2015 8:36
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8004_79N810_g6rb_W1950-2.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
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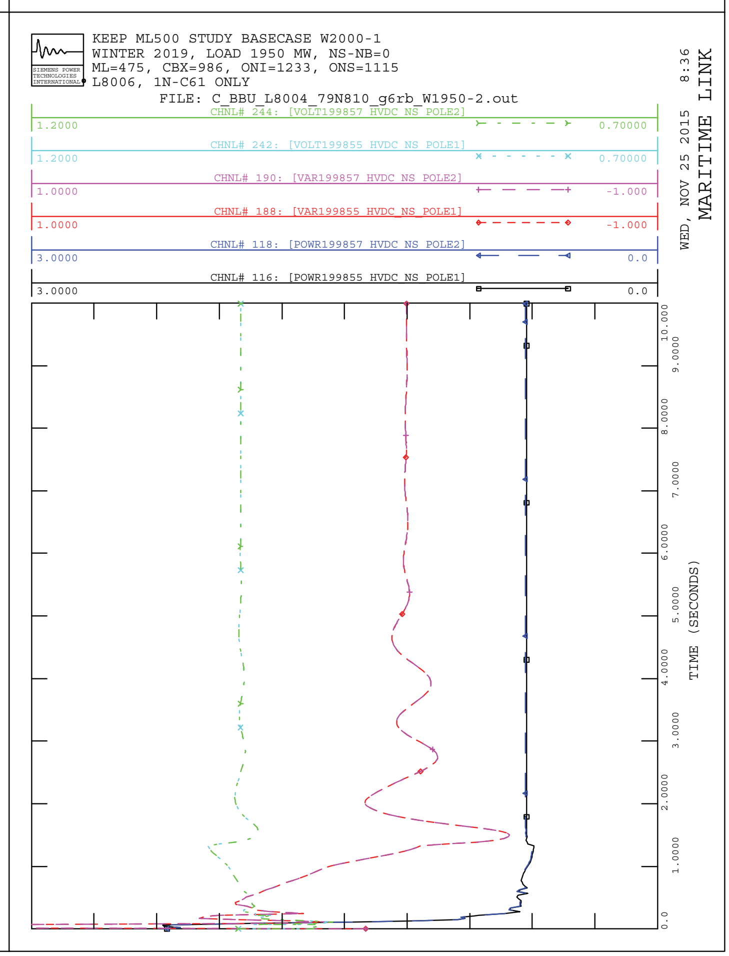
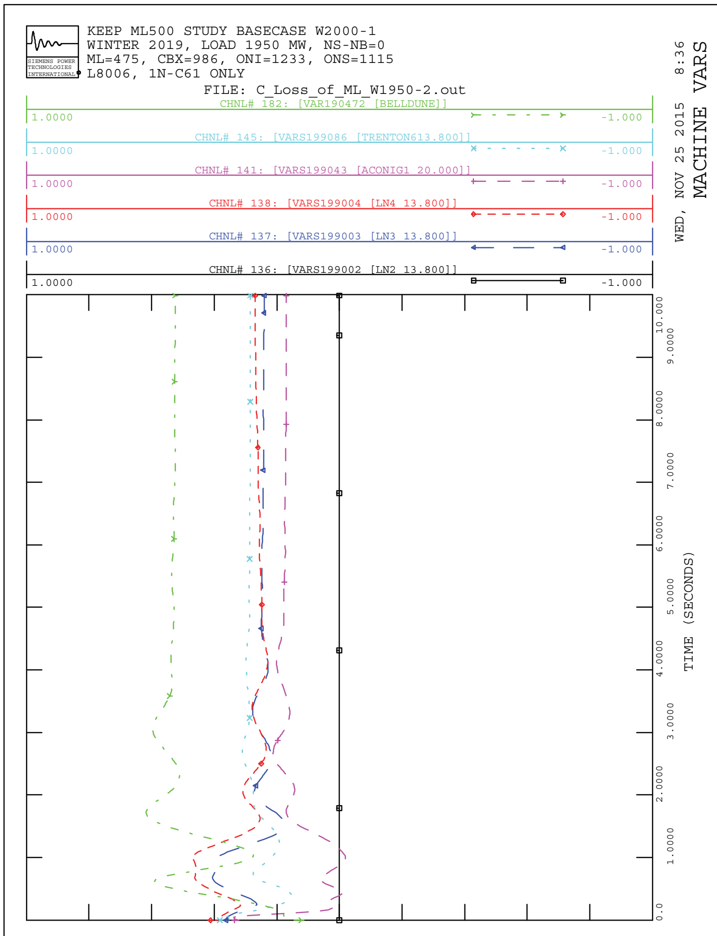
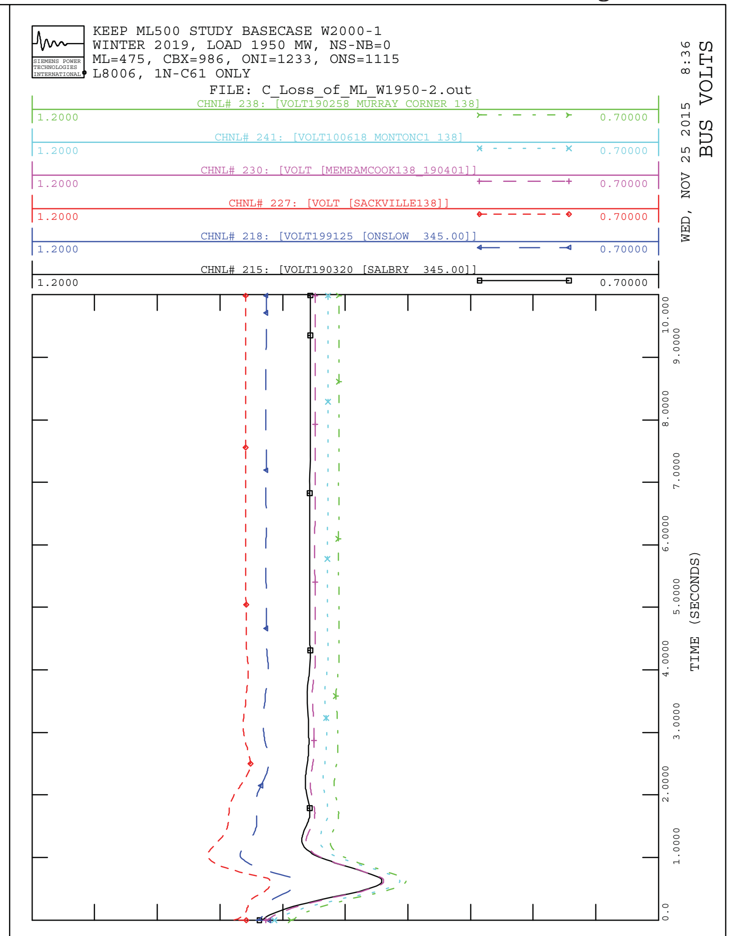
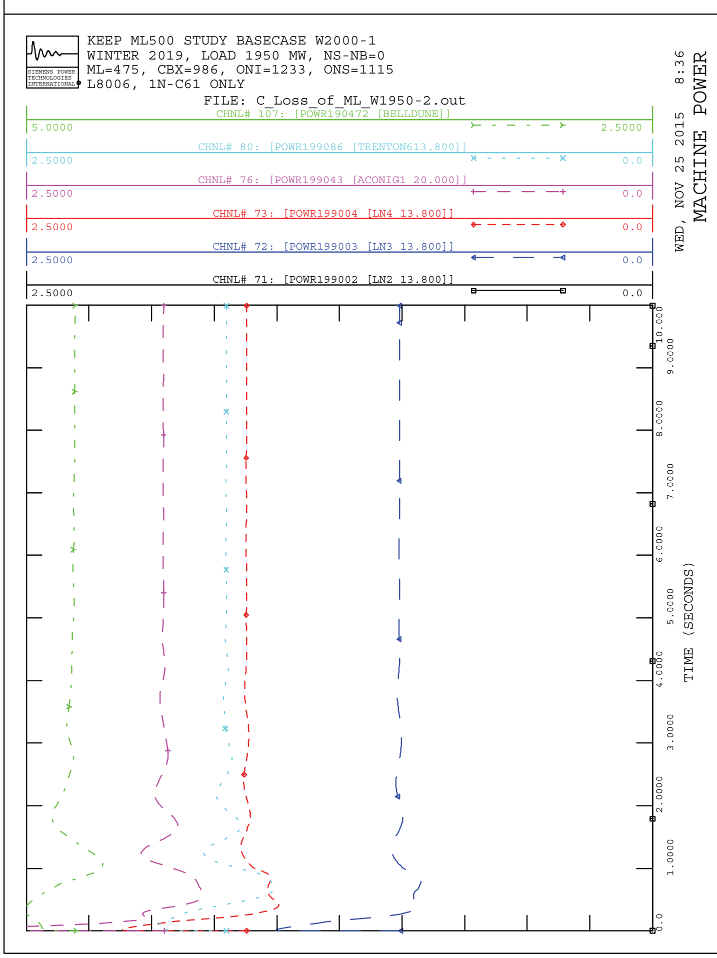
2.5000
0.0
WED, NOV 25 2015 8:36
MACHINE POWER
TIME (SECONDS)

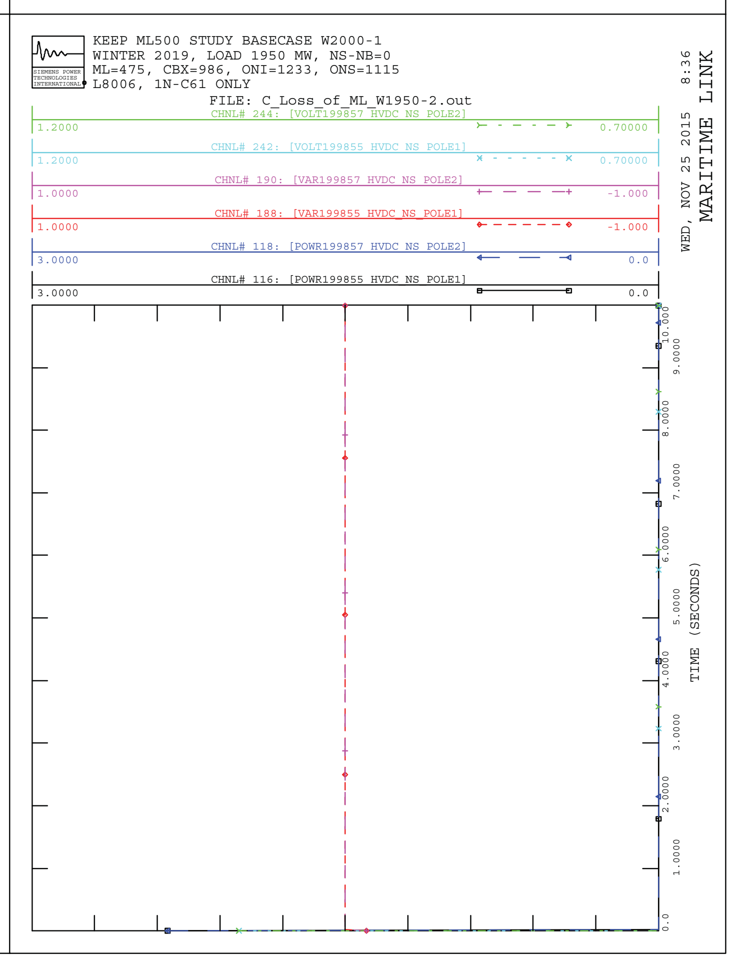

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 1950 MW, NS-NB=0
ML=475, CBX=986, ONI=1233, ONS=1115
L8006, 1N-C61 ONLY
FILE: C_BBU_L8004_79N810_g6rb_W1950-2.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
1.0000
-1.000
3.0000
0.0
WED, NOV 25 2015 8:36
MARITIME LINK
TIME (SECONDS)

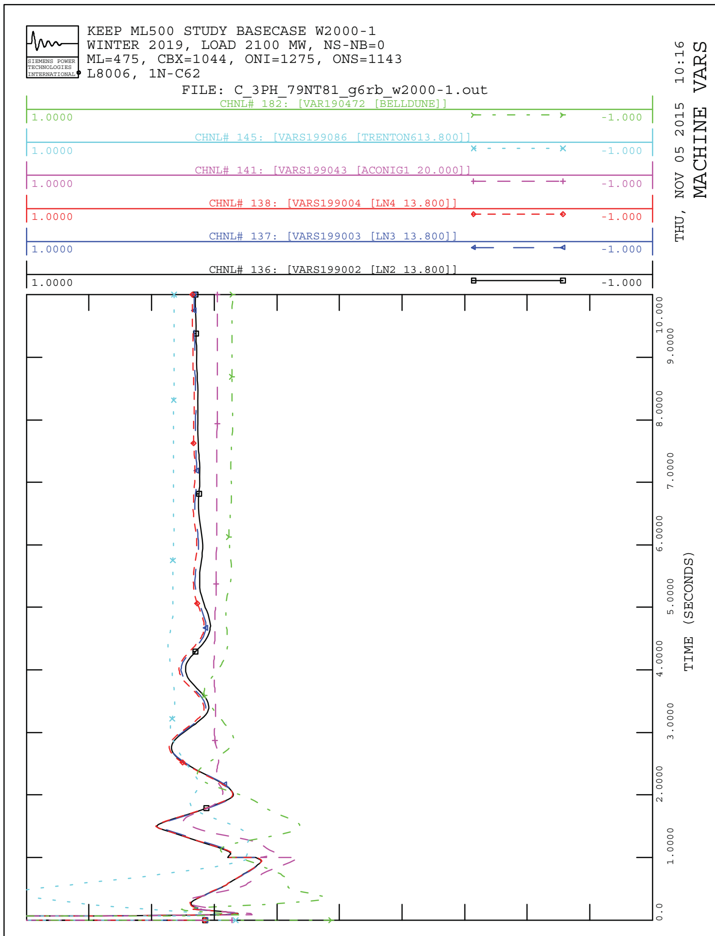
REDACTED (CONFIDENTIAL INFORMATION REMOVED)

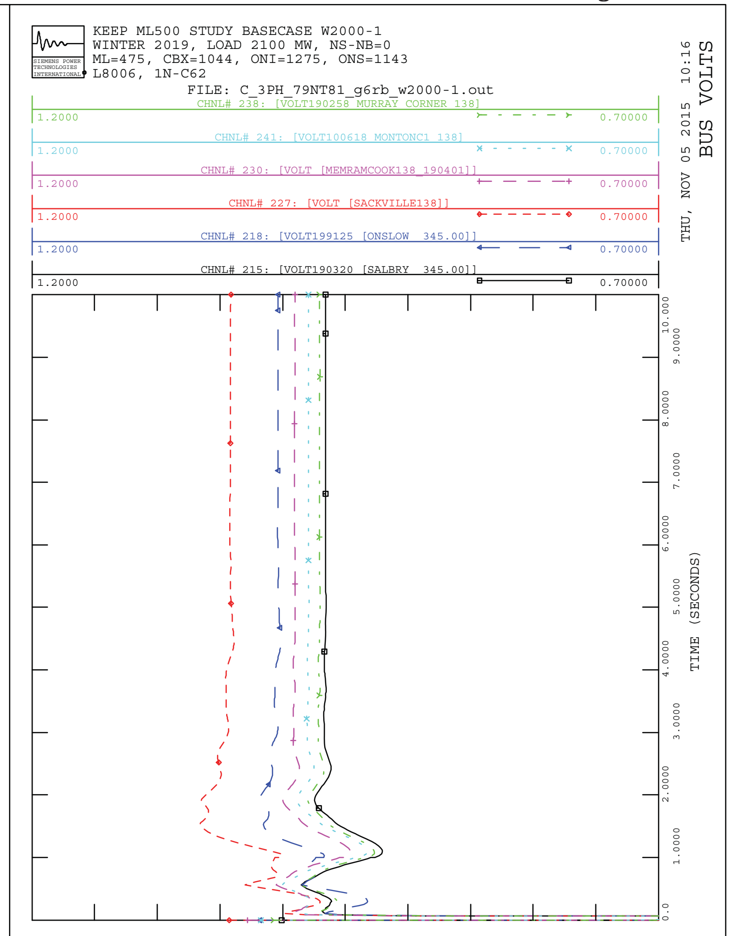









KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_79NT81_g6rb_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
THU, NOV 05 2015 10:16
MACHINE VARS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_79NT81_g6rb_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
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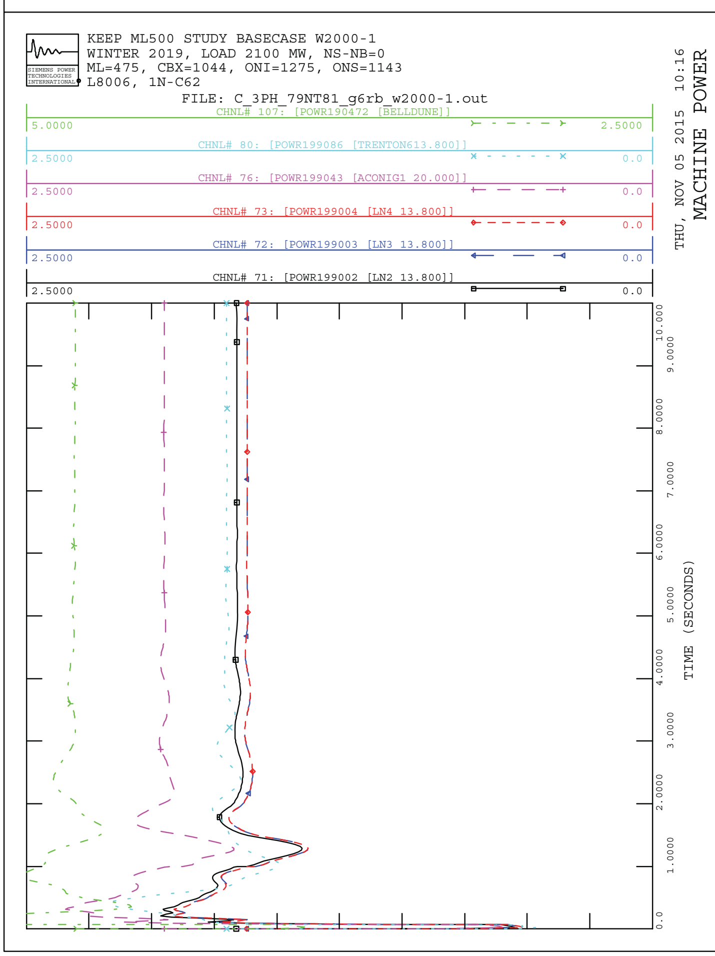
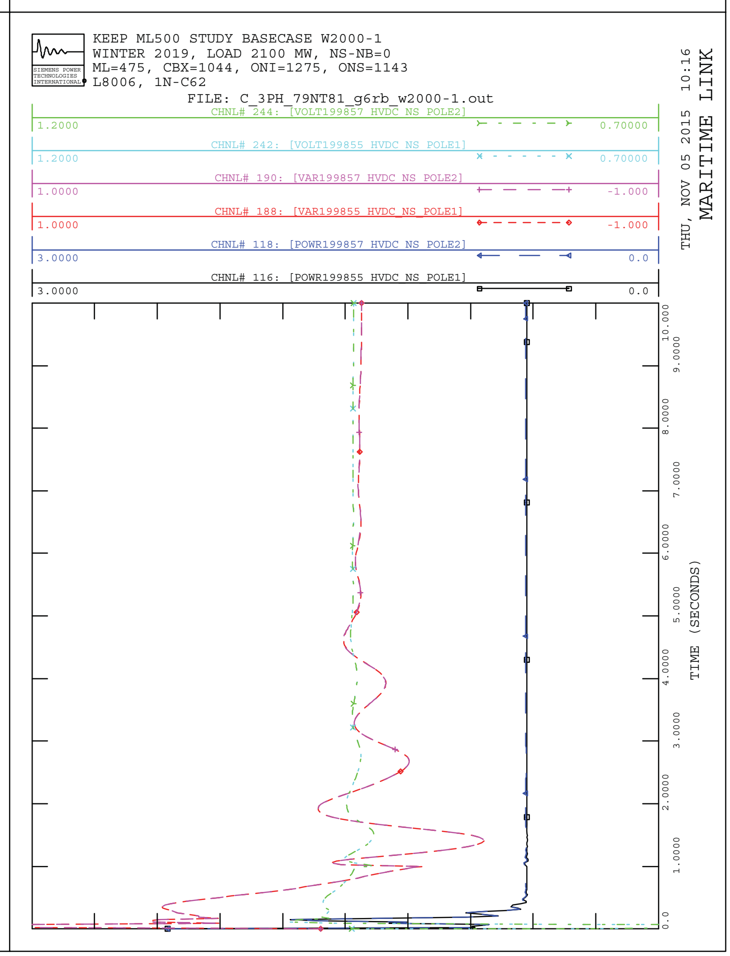
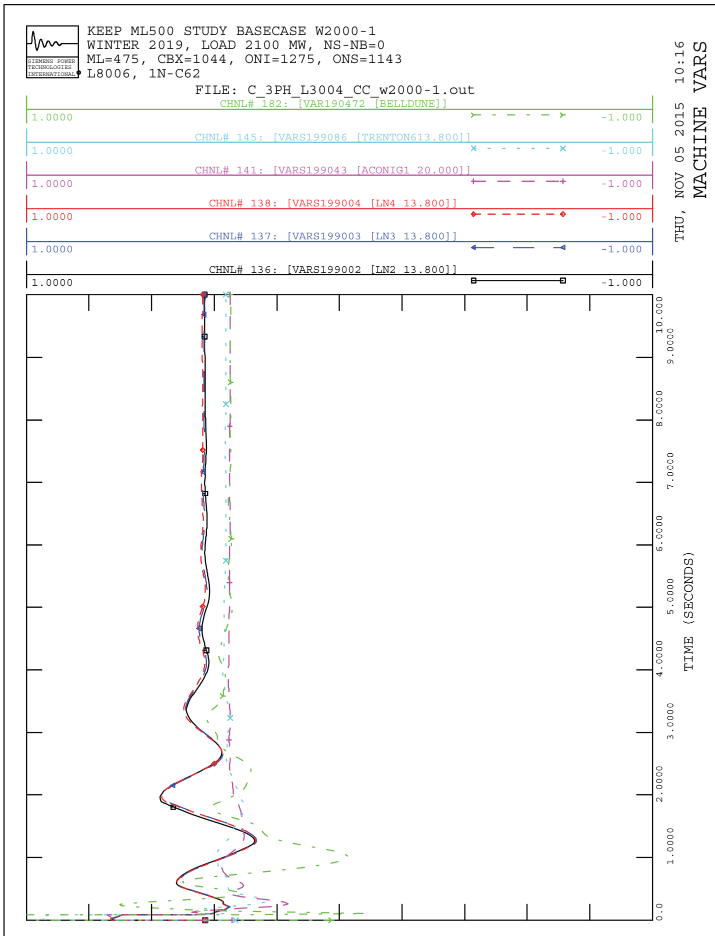
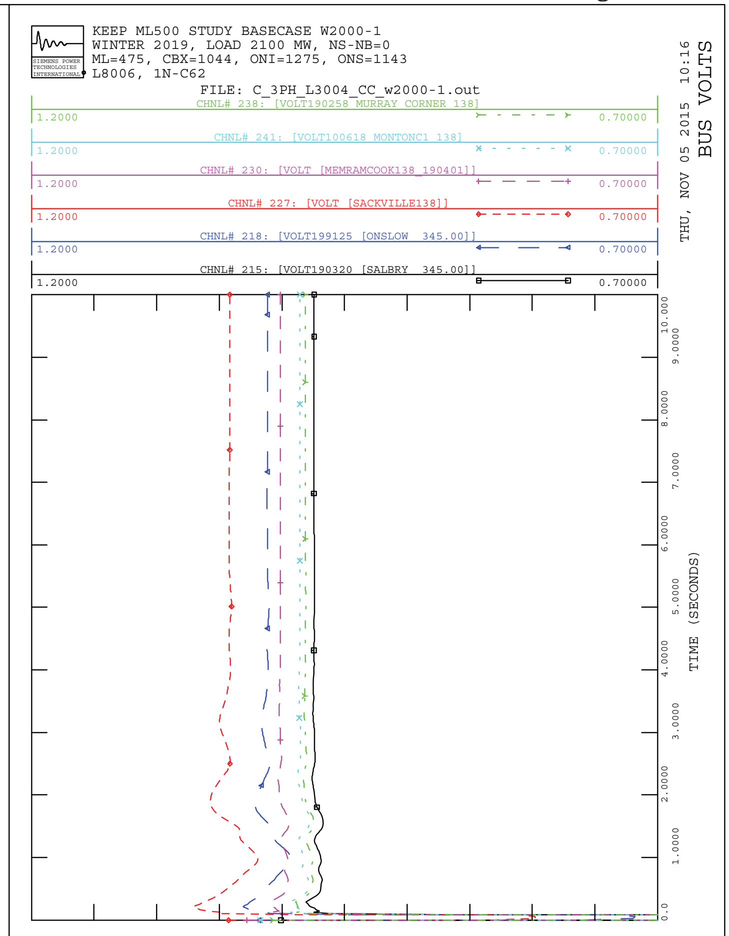
1.2000
0.70000
THU, NOV 05 2015 10:16
BUS VOLTS
TIME (SECONDS)

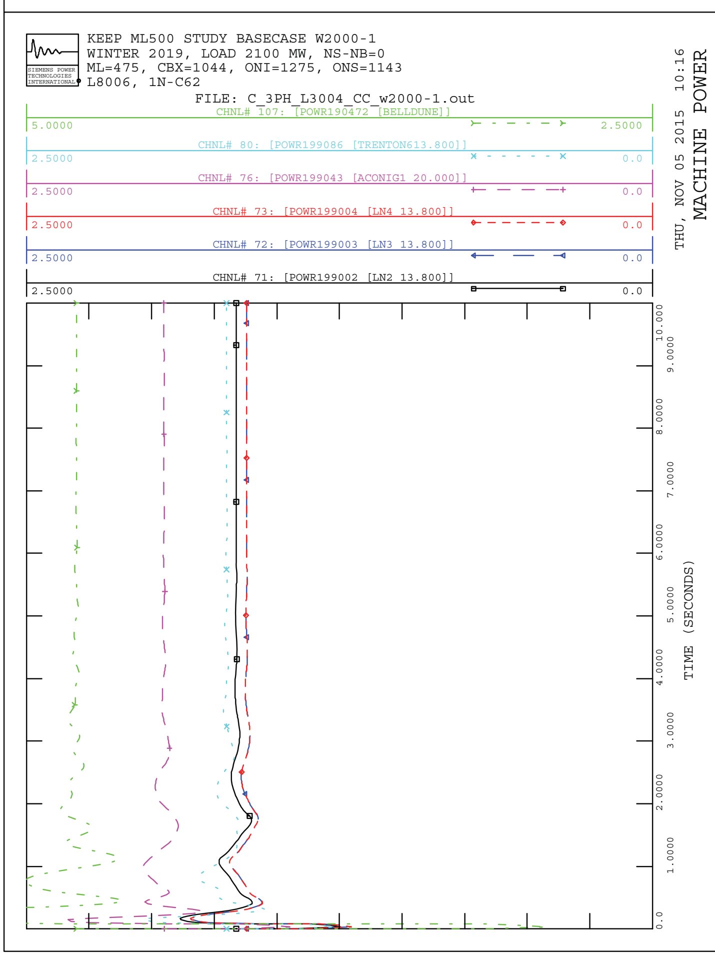

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_79NT81_g6rb_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
5.0000
2.5000
2.5000
0.0
THU, NOV 05 2015 10:16
MACHINE POWER
TIME (SECONDS)

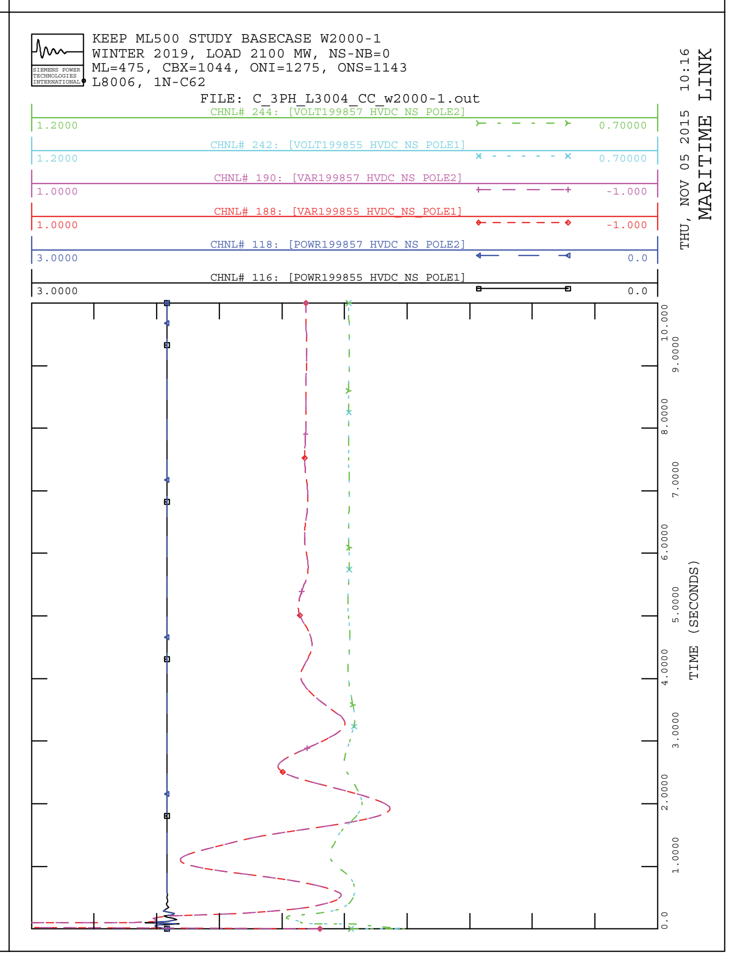

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_79NT81_g6rb_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
1.0000
-1.000
3.0000
0.0
THU, NOV 05 2015 10:16
MARITIME LINK
TIME (SECONDS)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

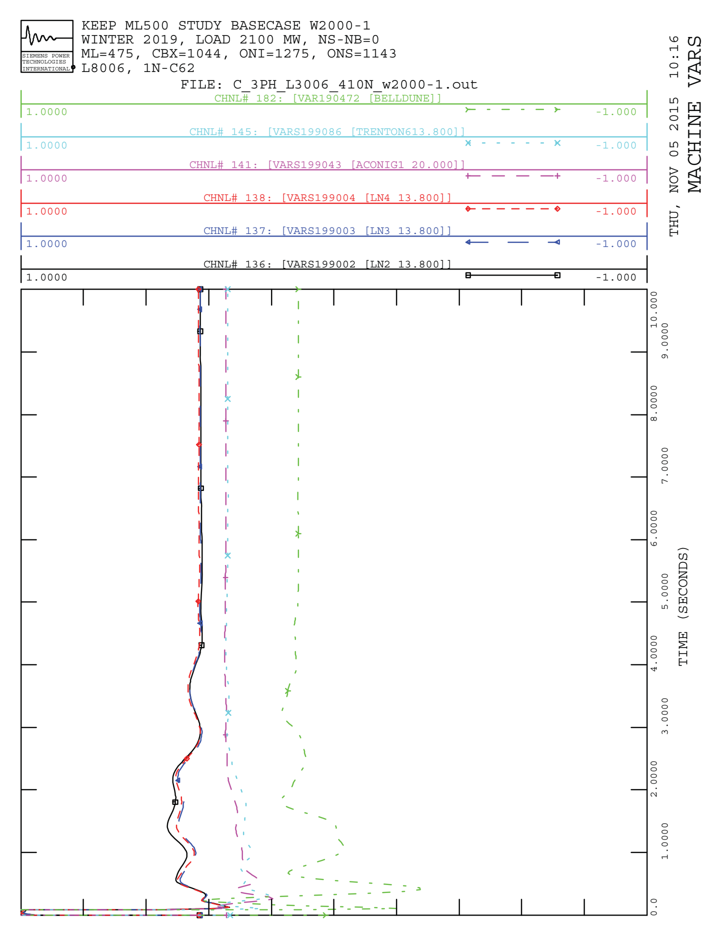


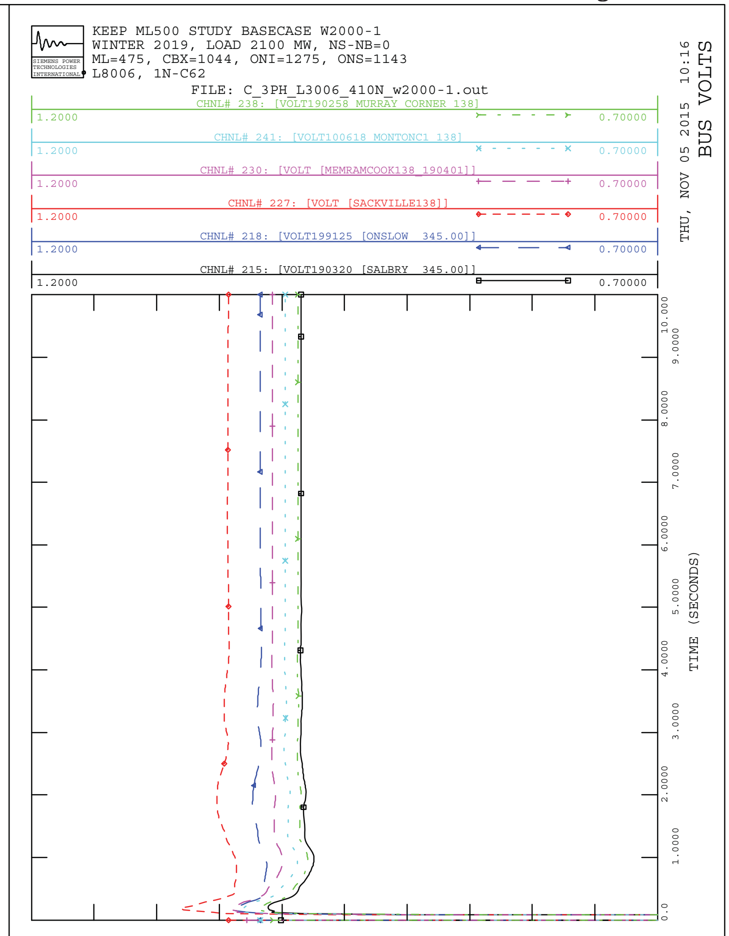


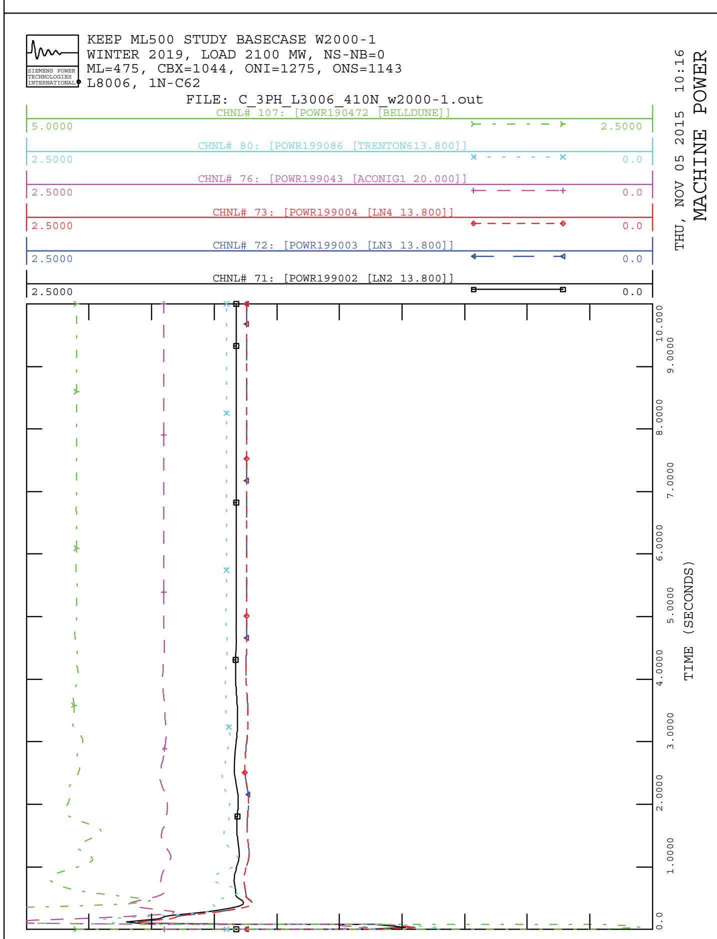


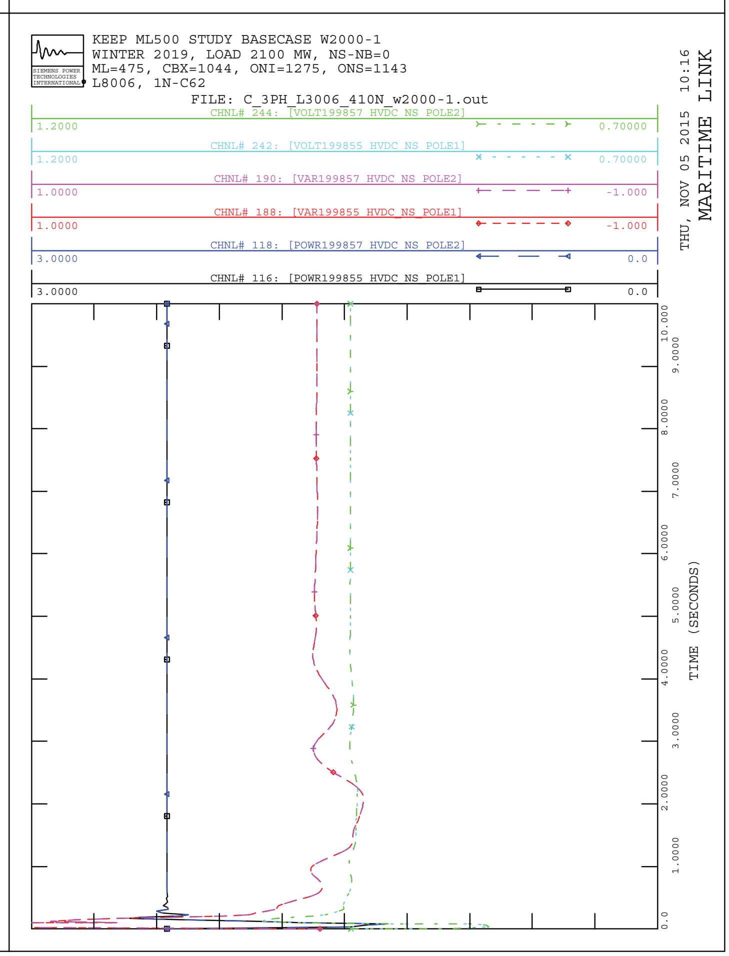


REDACTED (CONFIDENTIAL INFORMATION REMOVED)









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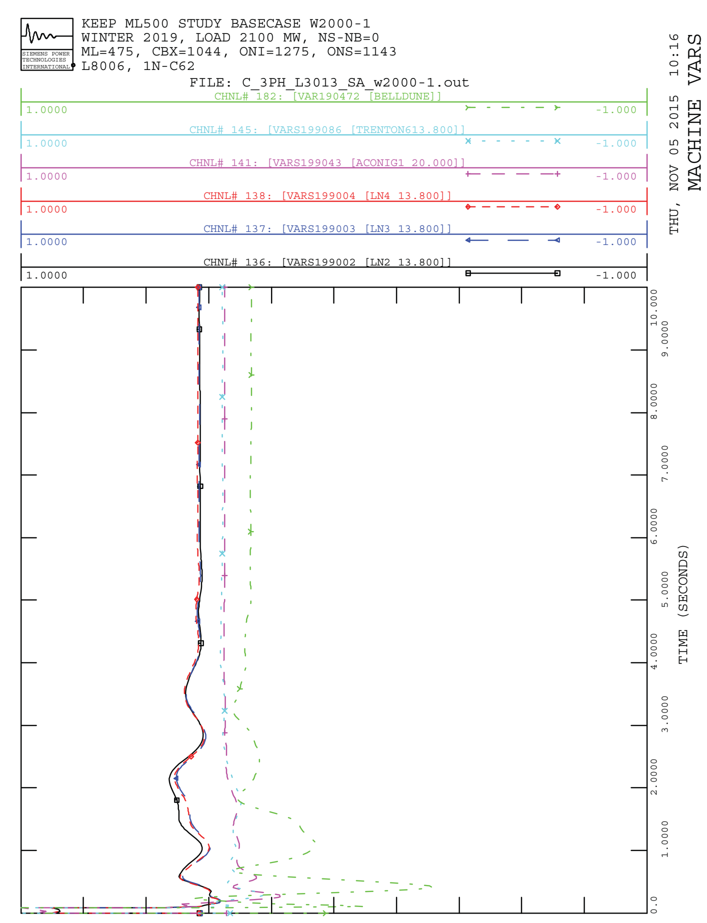

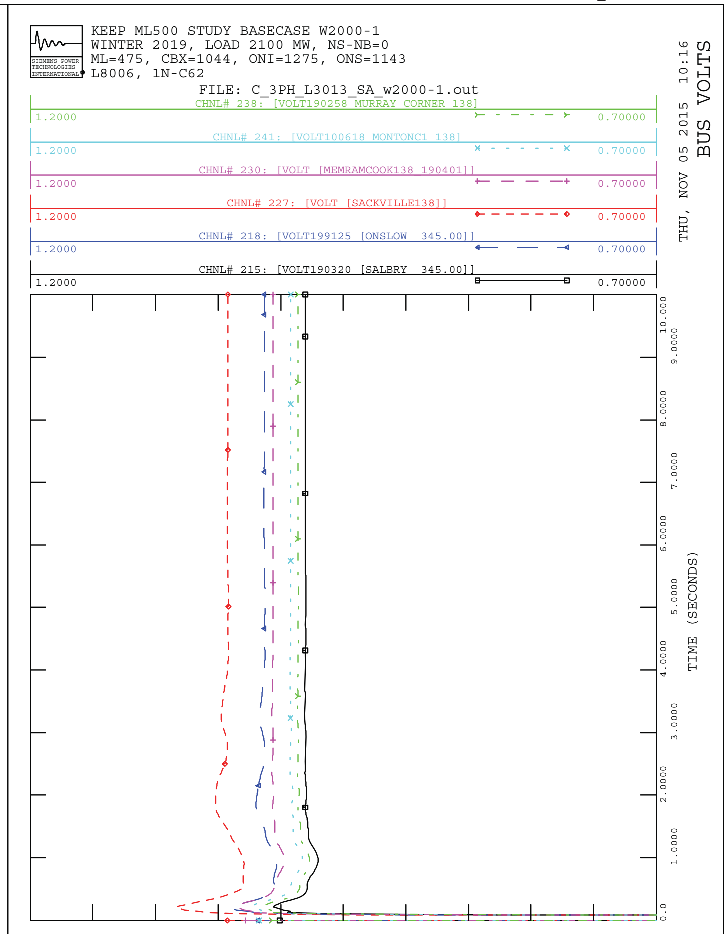

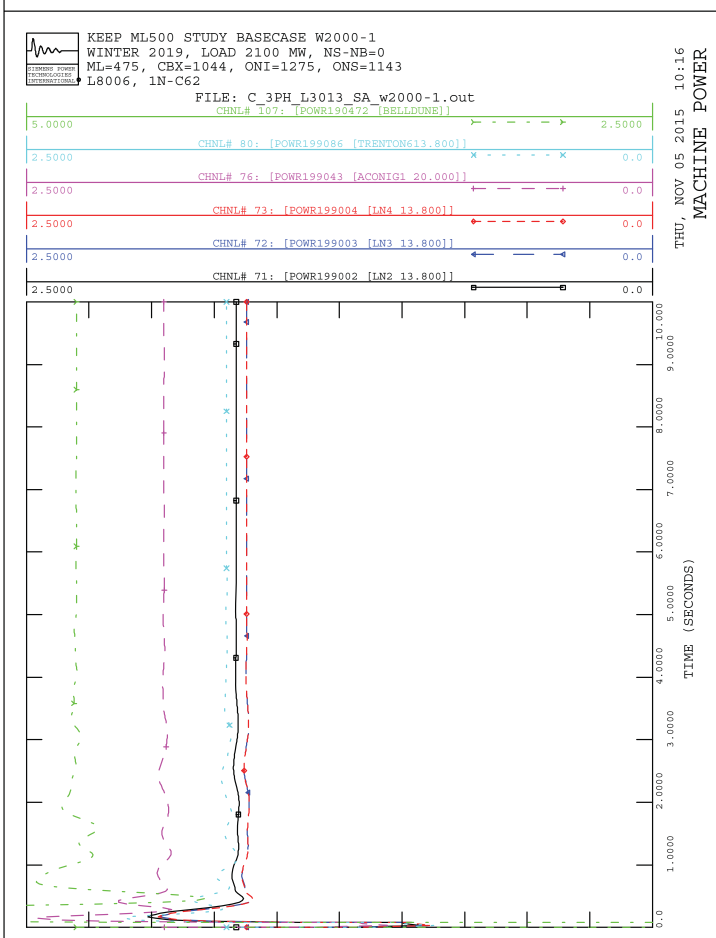

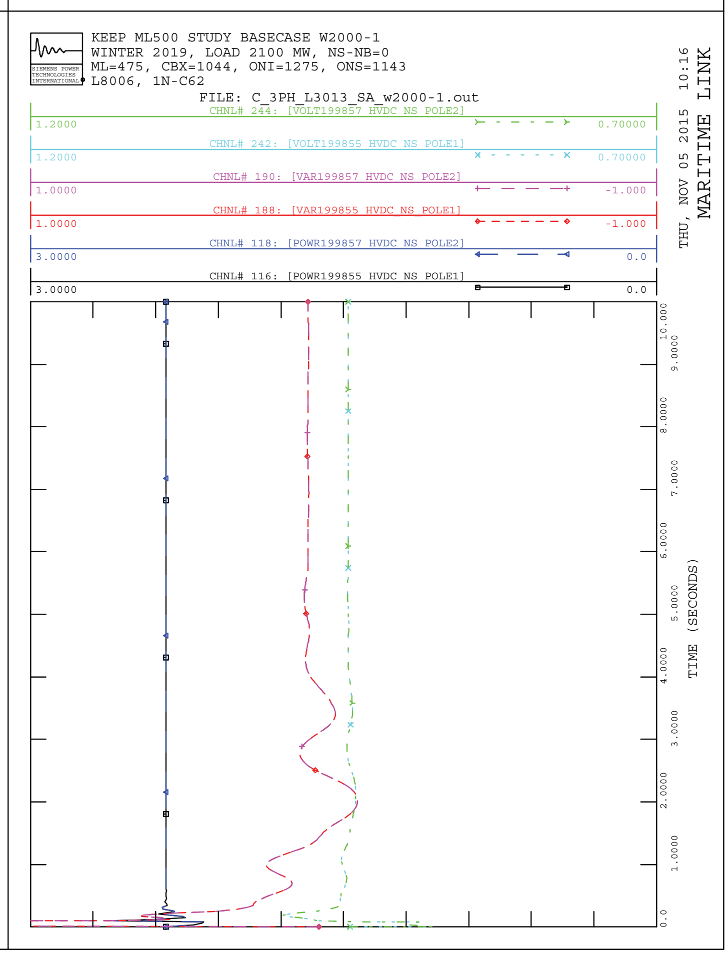

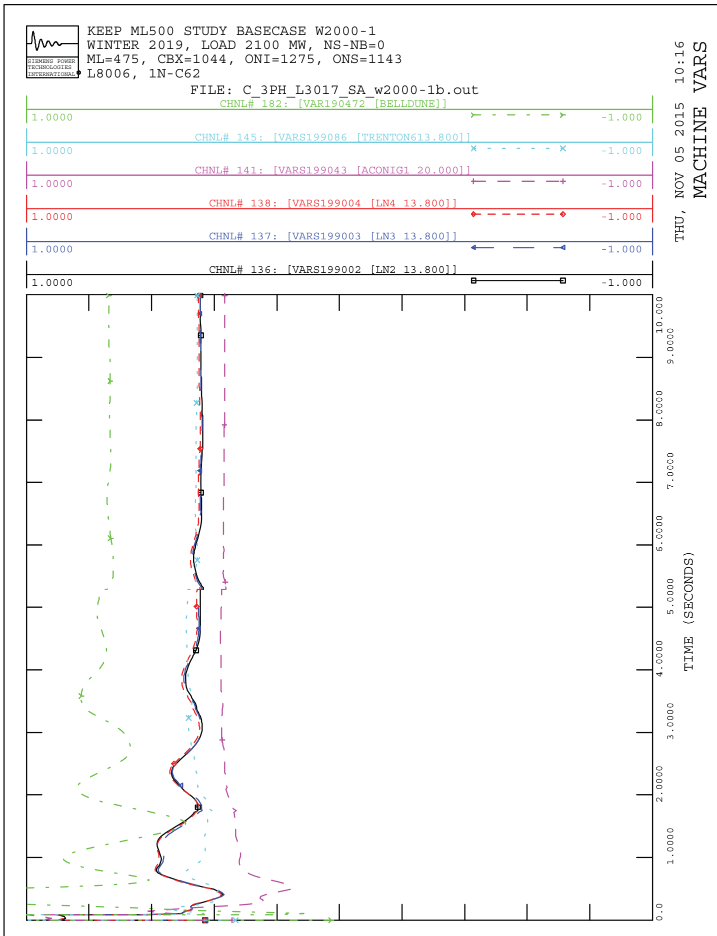
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L3017_SA_w2000-1b.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
THU, NOV 05 2015 10:16
MACHINE VARS
TIME (SECONDS)
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2.0000
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4.0000
5.0000
6.0000
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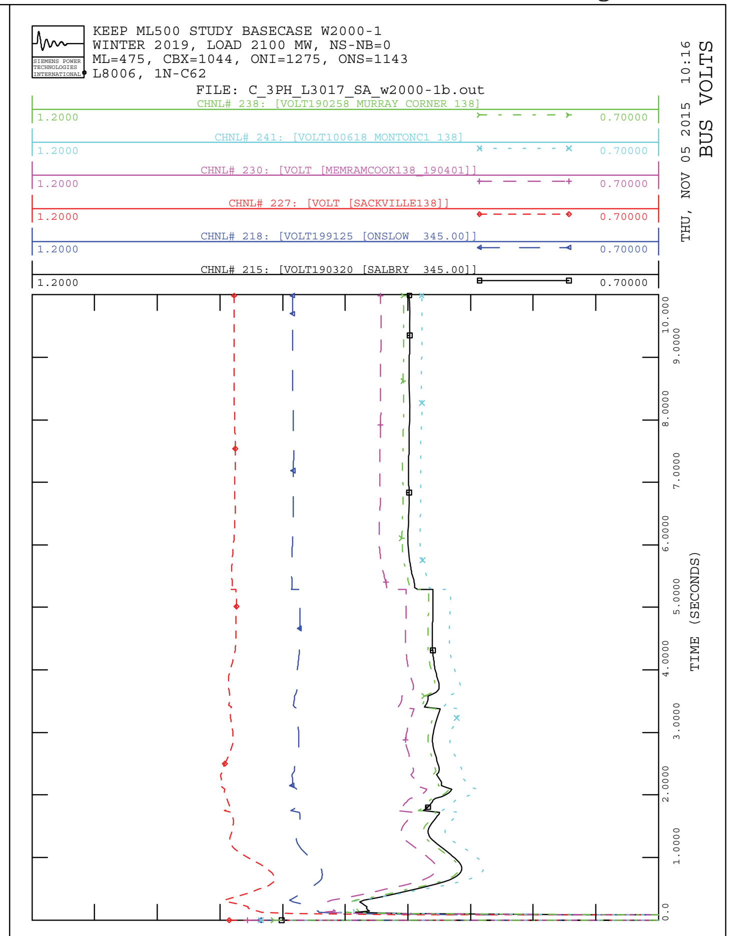
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L3017_SA_w2000-1b.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
THU, NOV 05 2015 10:16
BUS VOLTS
TIME (SECONDS)
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2.0000
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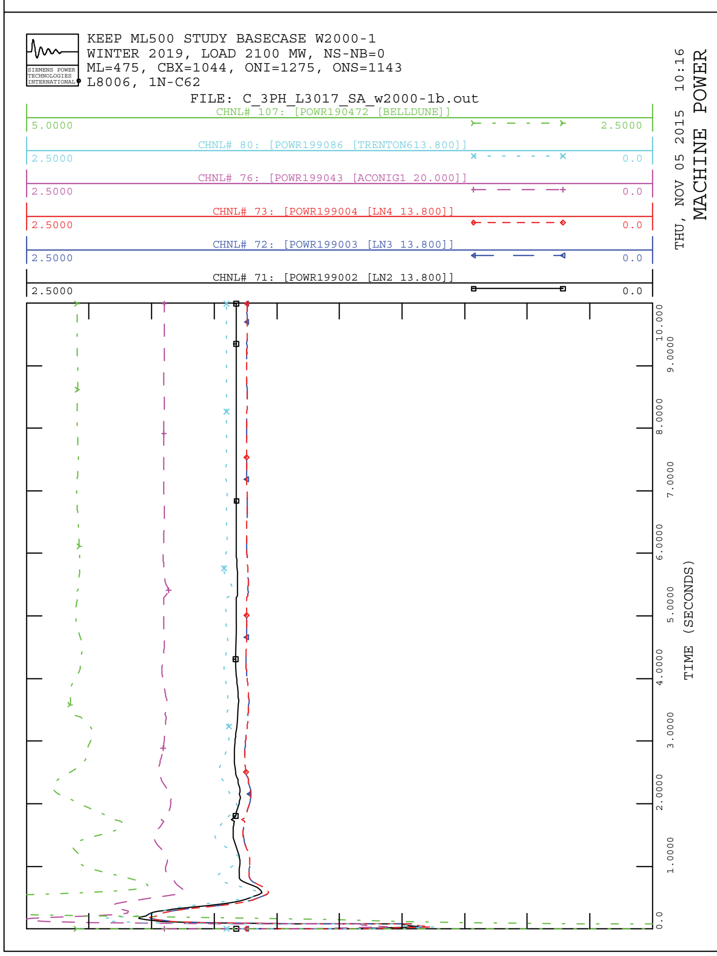
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L3017_SA_w2000-1b.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
THU, NOV 05 2015 10:16
MACHINE POWER
TIME (SECONDS)
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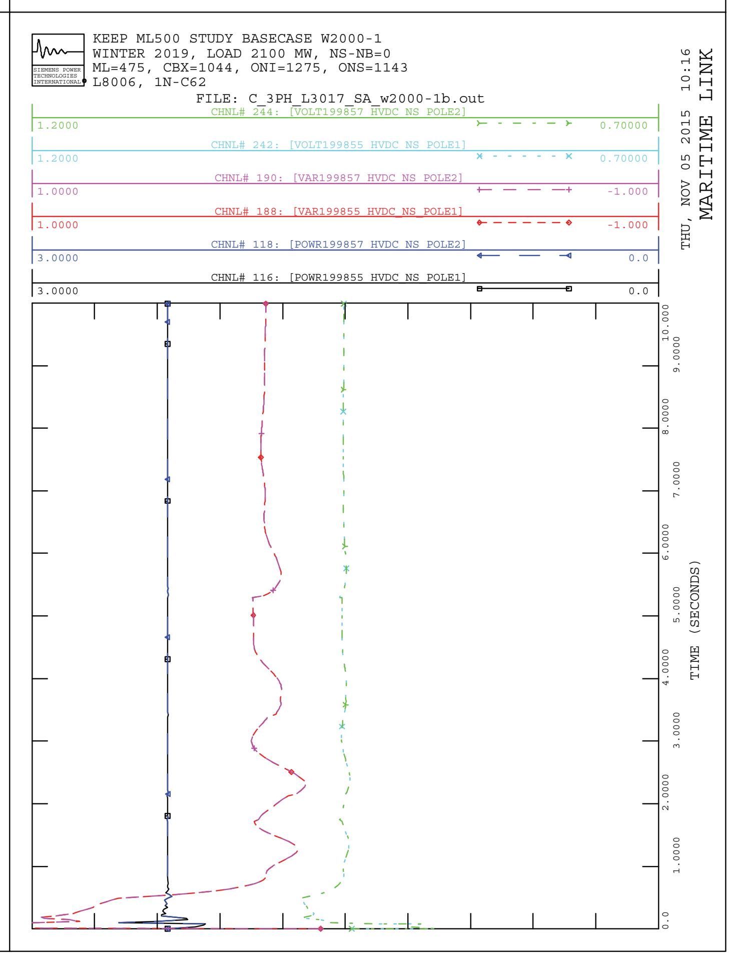
10.000


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L3017_SA_w2000-1b.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
THU, NOV 05 2015 10:16
MARITIME LINK
TIME (SECONDS)
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1.0000
2.0000
3.0000
4.0000
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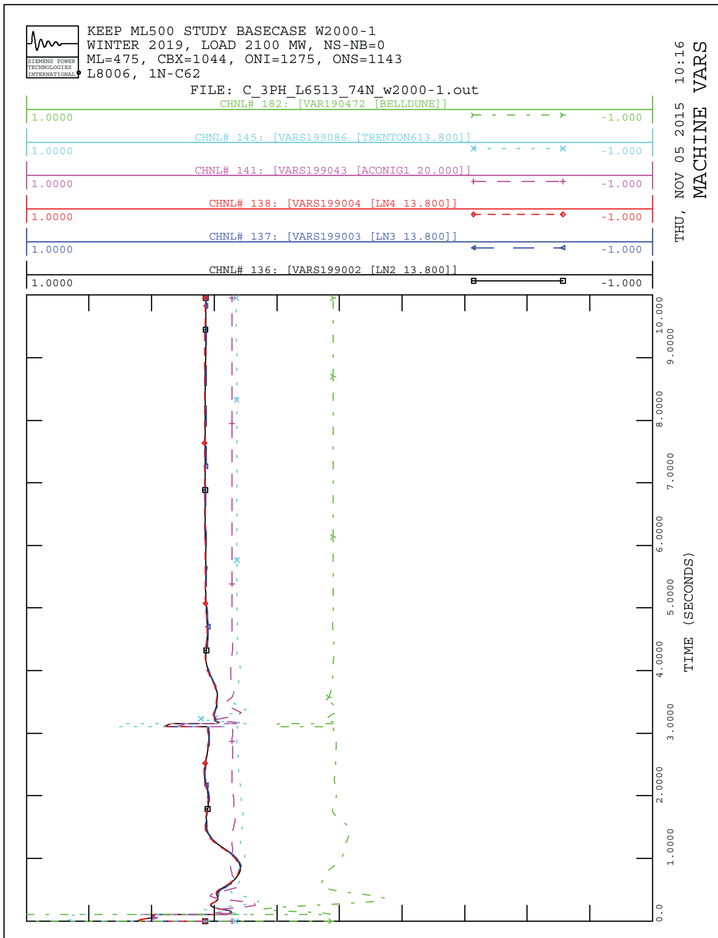
10.000



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6513_74N_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
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-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
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-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
THU, NOV 05 2015 10:16
MACHINE VARS
TIME (SECONDS)
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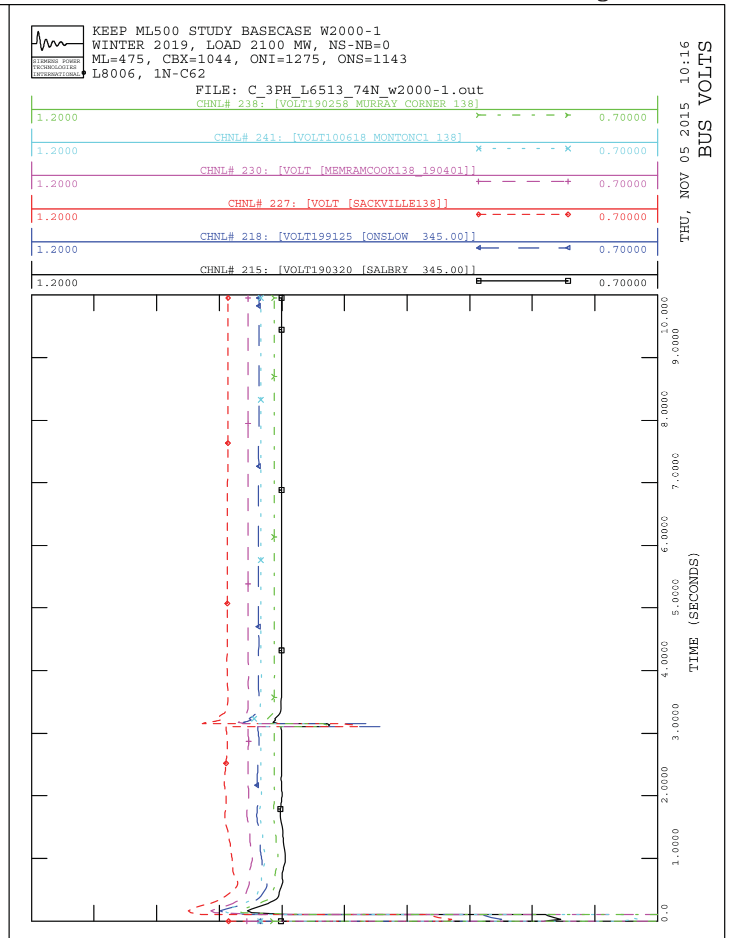

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6513_74N_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138_190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
THU, NOV 05 2015 10:16
BUS VOLTS
TIME (SECONDS)
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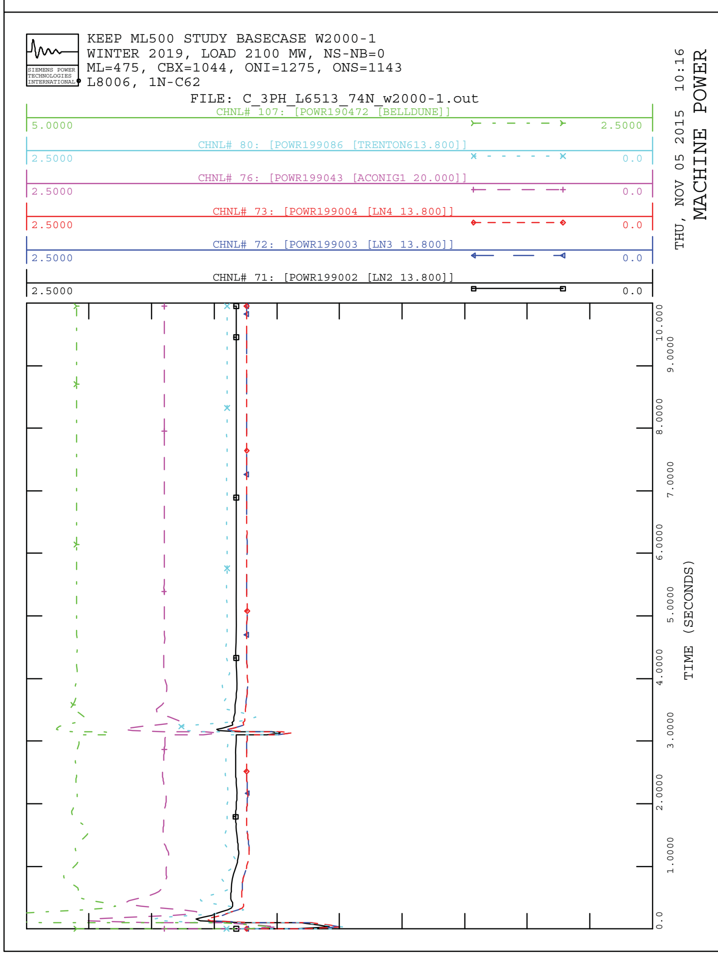

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6513_74N_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
THU, NOV 05 2015 10:16
MACHINE POWER
TIME (SECONDS)
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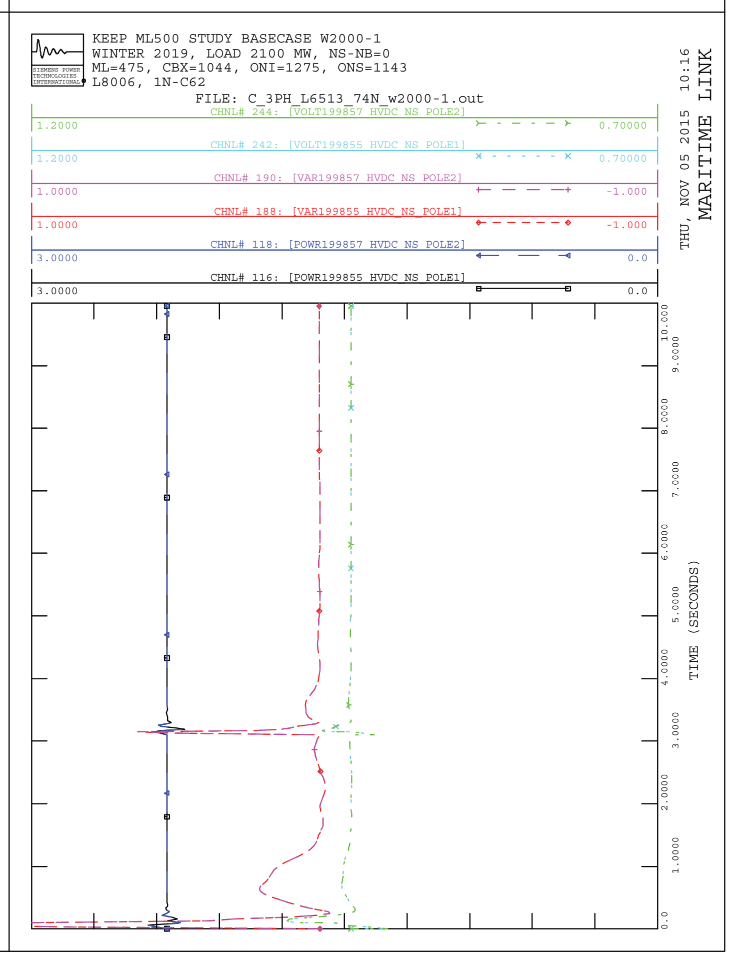

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6513_74N_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
THU, NOV 05 2015 10:16
MARITIME LINK
TIME (SECONDS)
0.0
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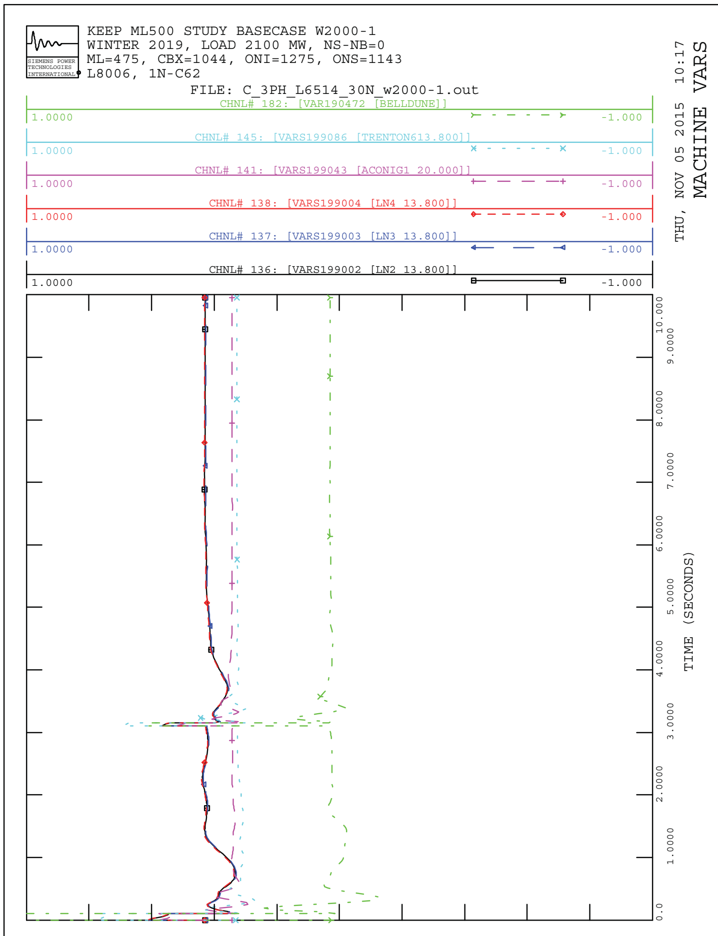
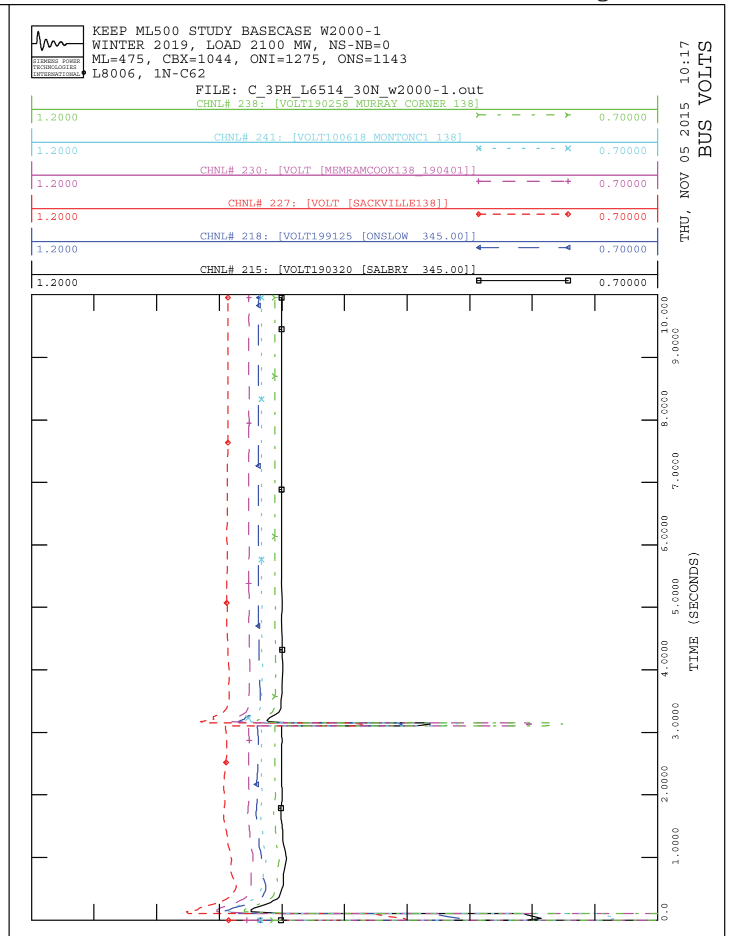
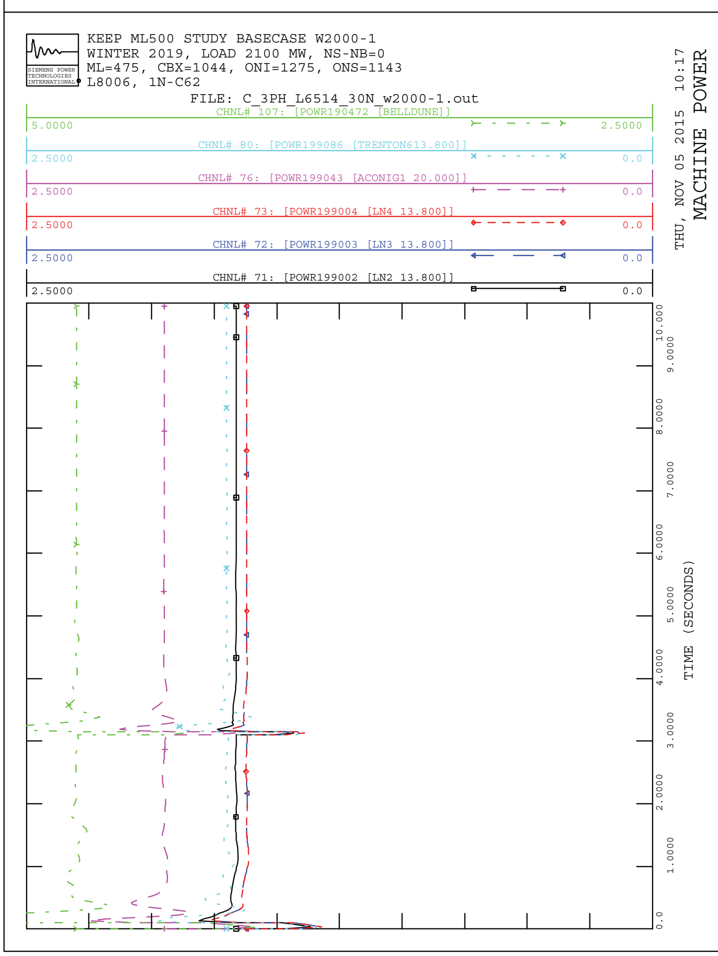
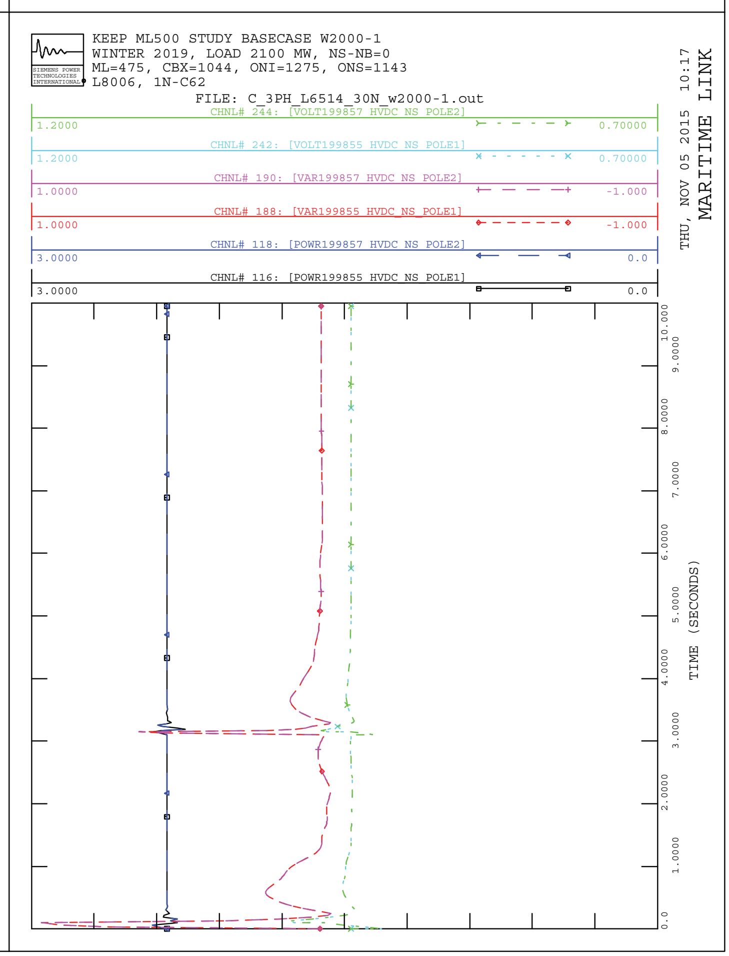
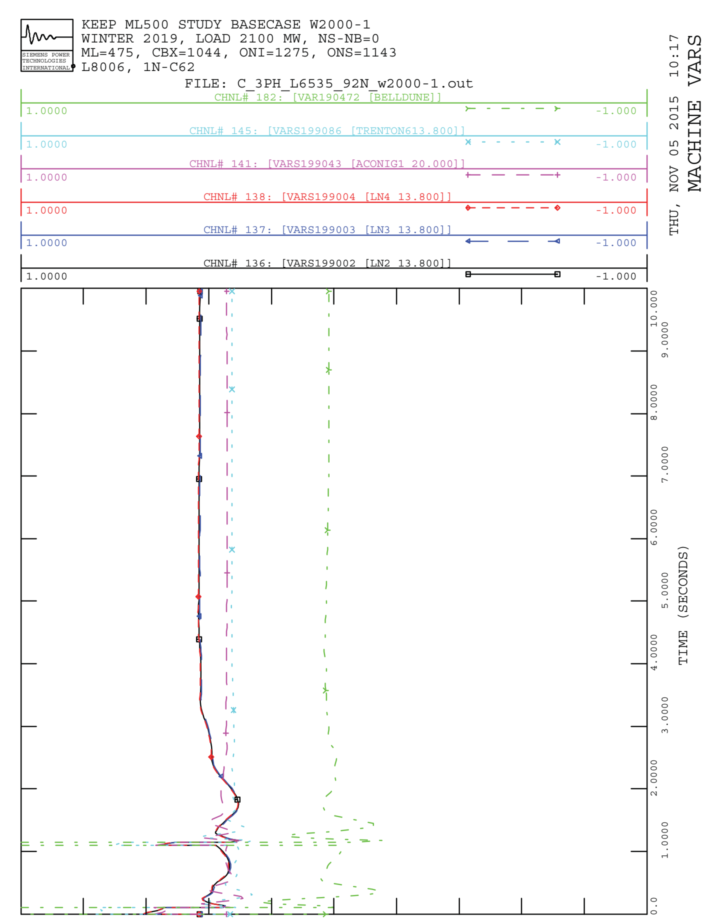
REDACTED (CONFIDENTIAL INFORMATION REMOVED)










KEEP ML500 STUDY BASECASE W2000-1
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CHNL# 145: [VARS199086 [TRENTON613.800]]
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-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
0.0
1.0000
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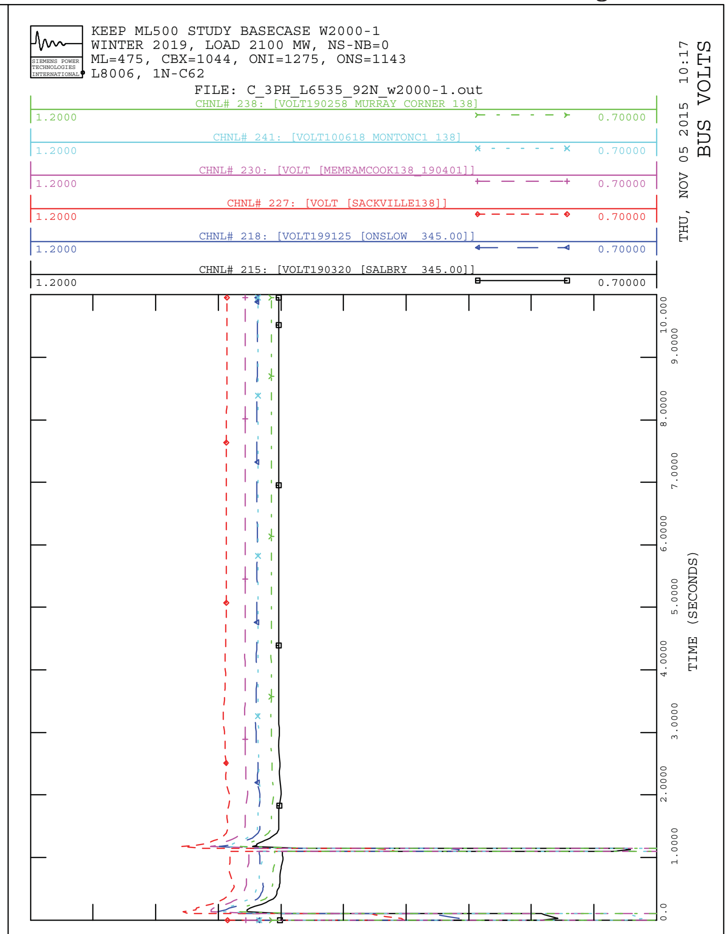
10.000
TIME (SECONDS)
THU, NOV 05 2015 10:17
MACHINE VARS


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6535_92N_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
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CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
0.0
1.0000
2.0000
3.0000
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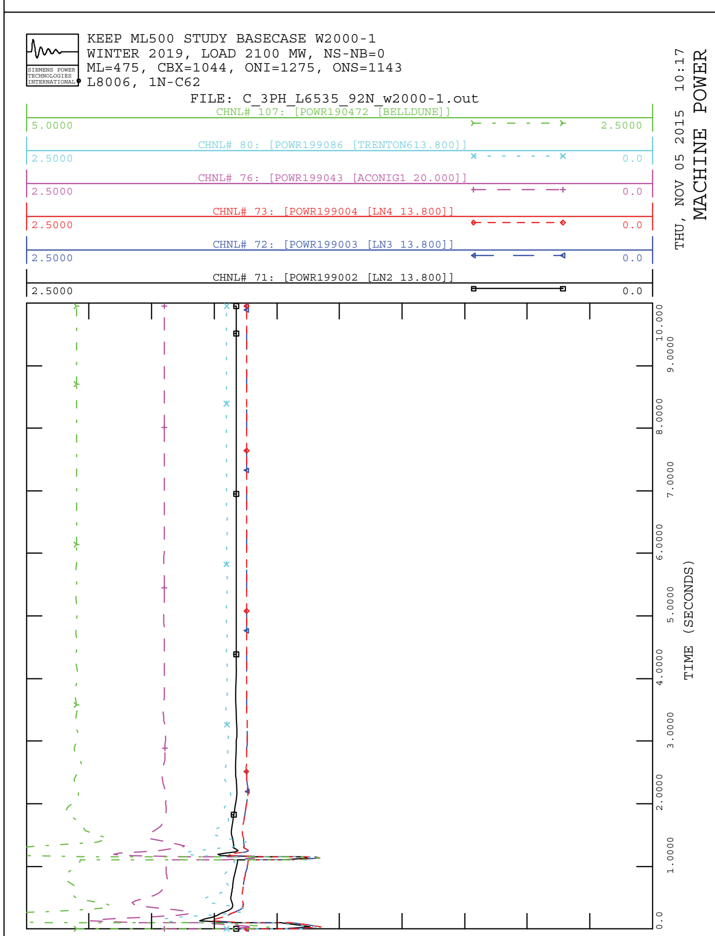
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, NOV 05 2015 10:17
BUS VOLTS


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6535_92N_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
0.0
1.0000
2.0000
3.0000
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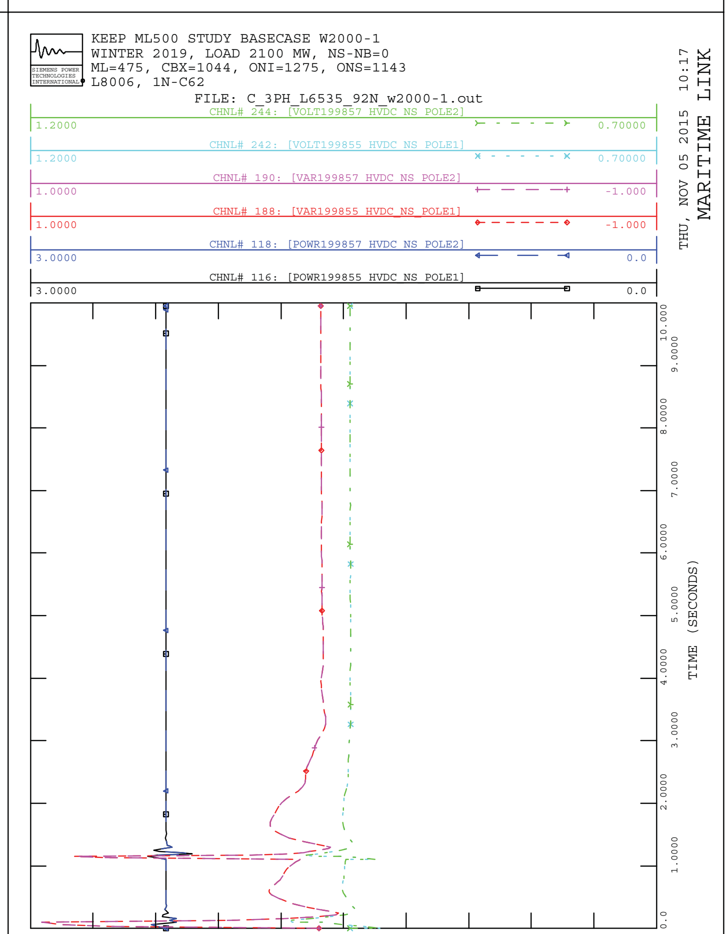
TIME (SECONDS)
THU, NOV 05 2015 10:17
MACHINE POWER


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6535_92N_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
0.0
1.0000
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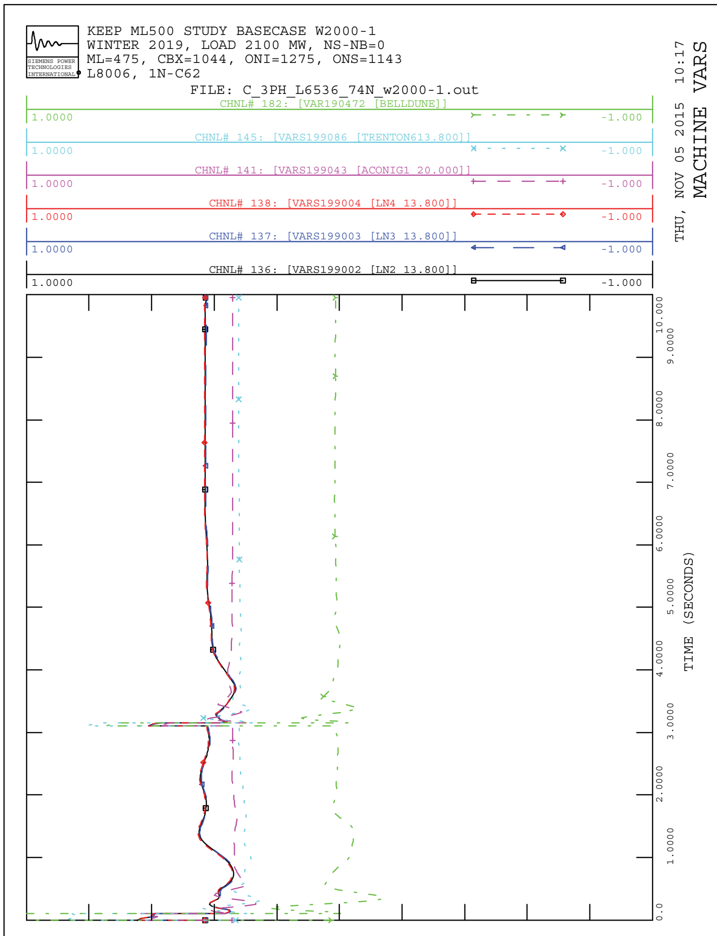
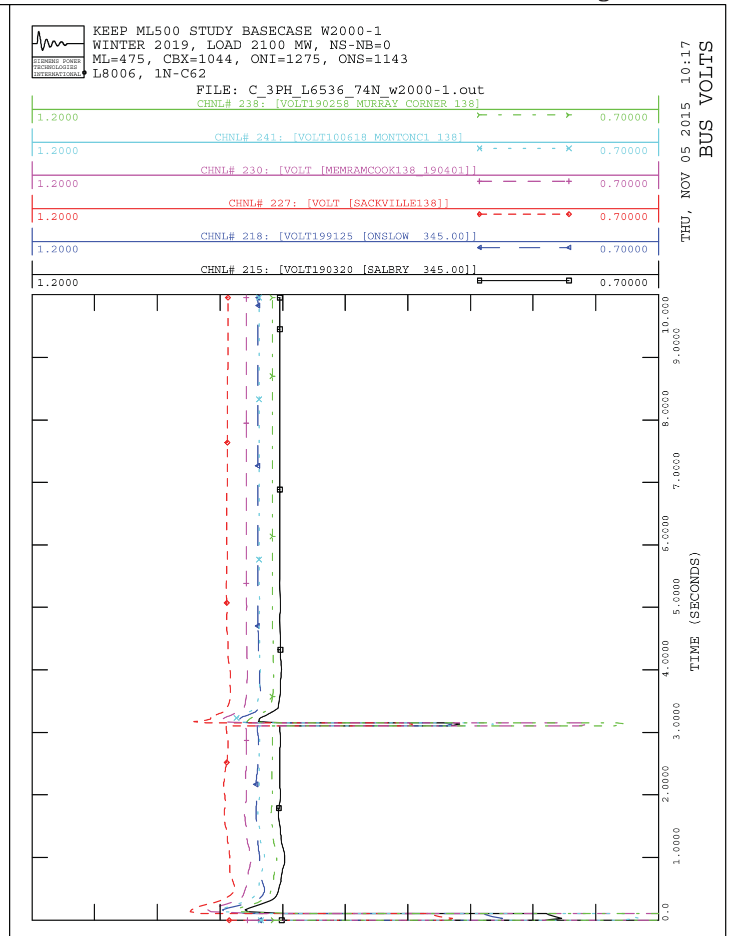
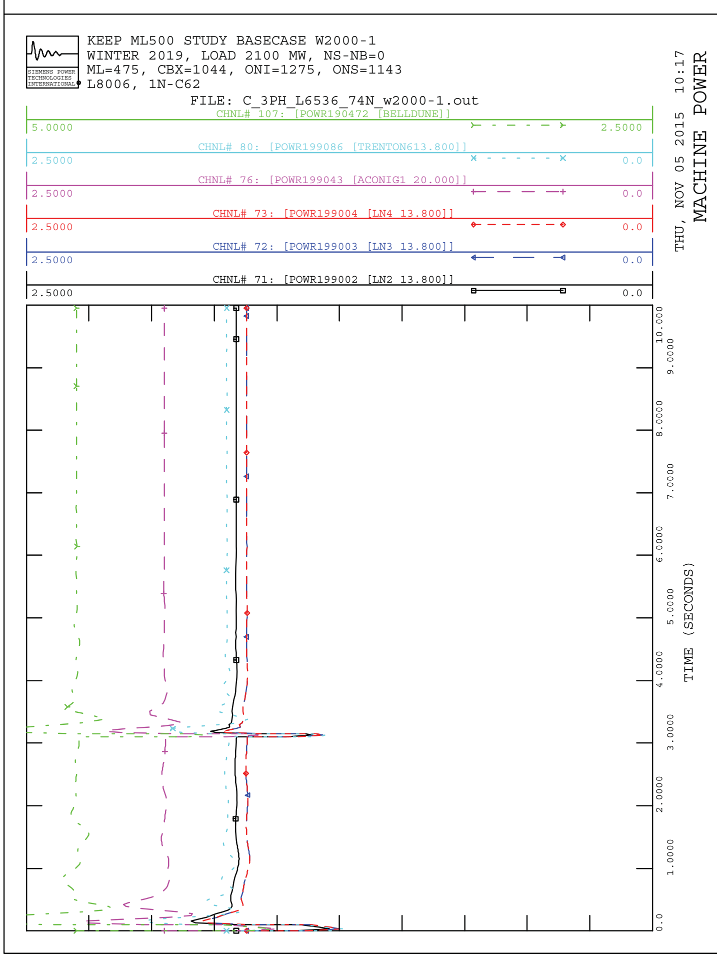
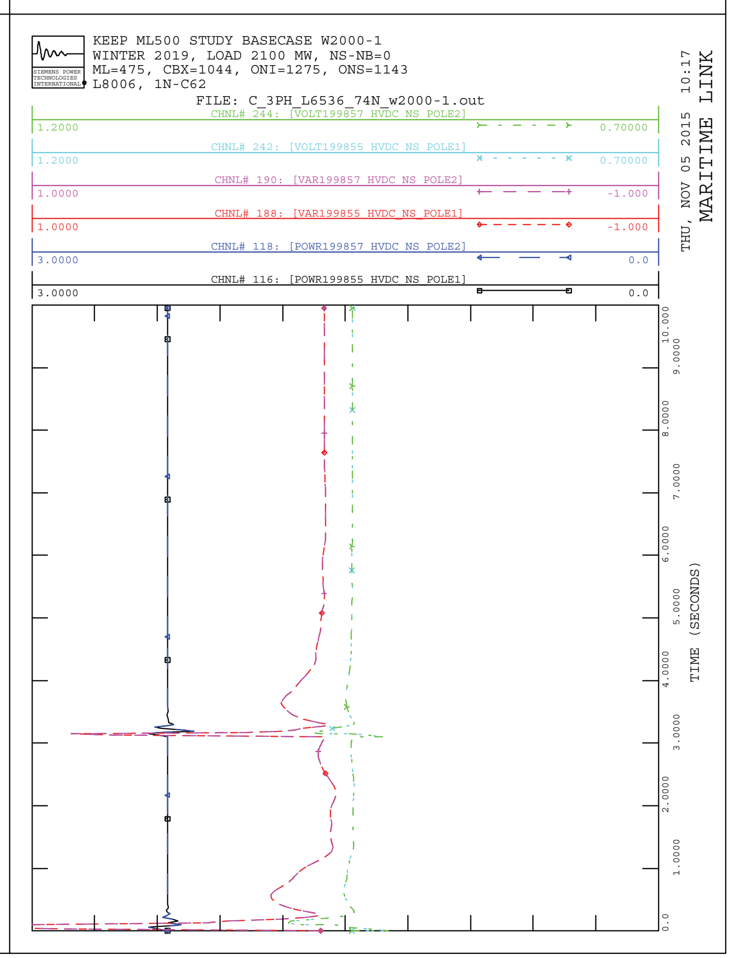
TIME (SECONDS)
THU, NOV 05 2015 10:17
MARITIME LINK

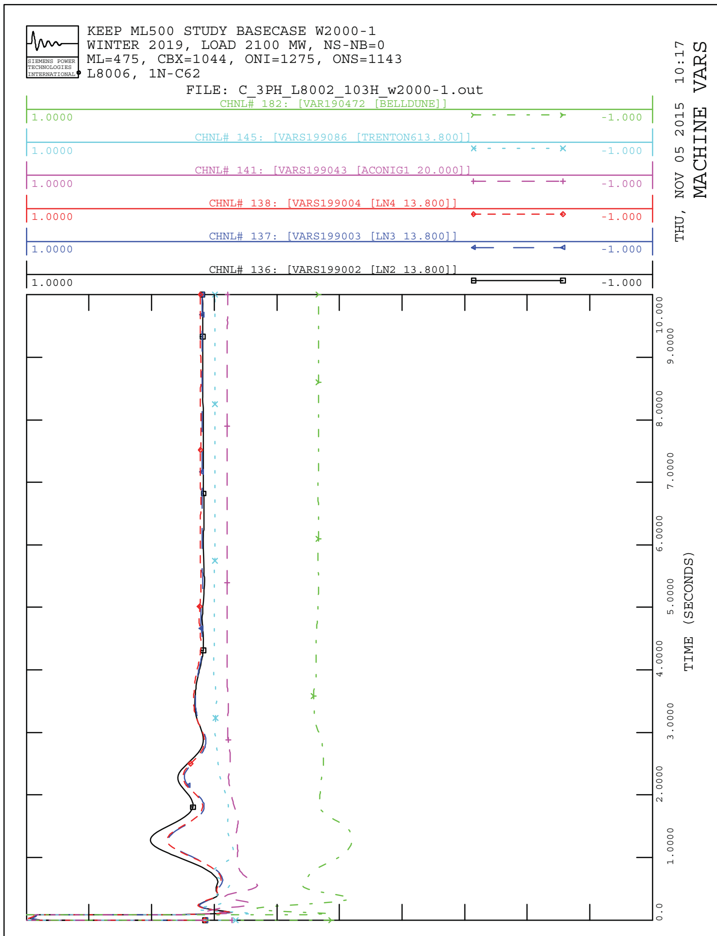

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6536_74N_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)

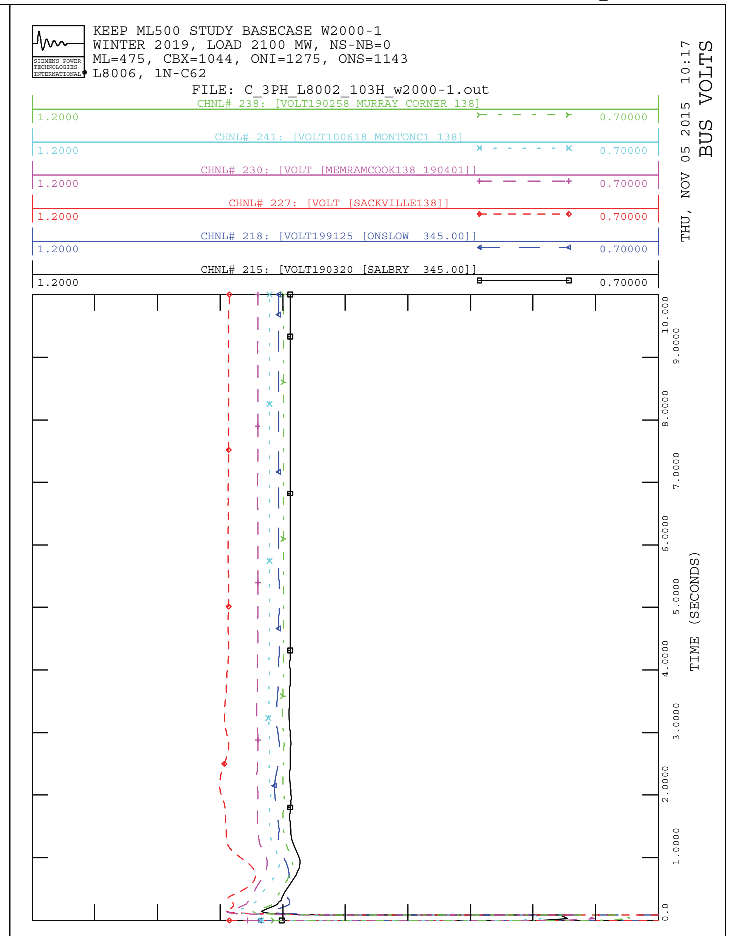

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6536_74N_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)

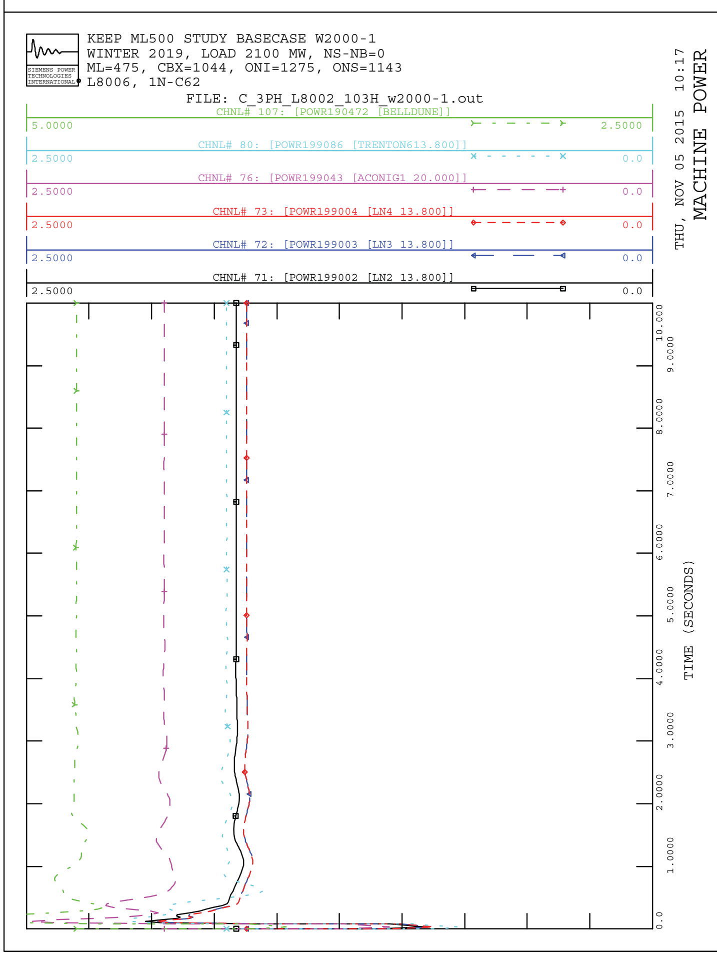

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6536_74N_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)

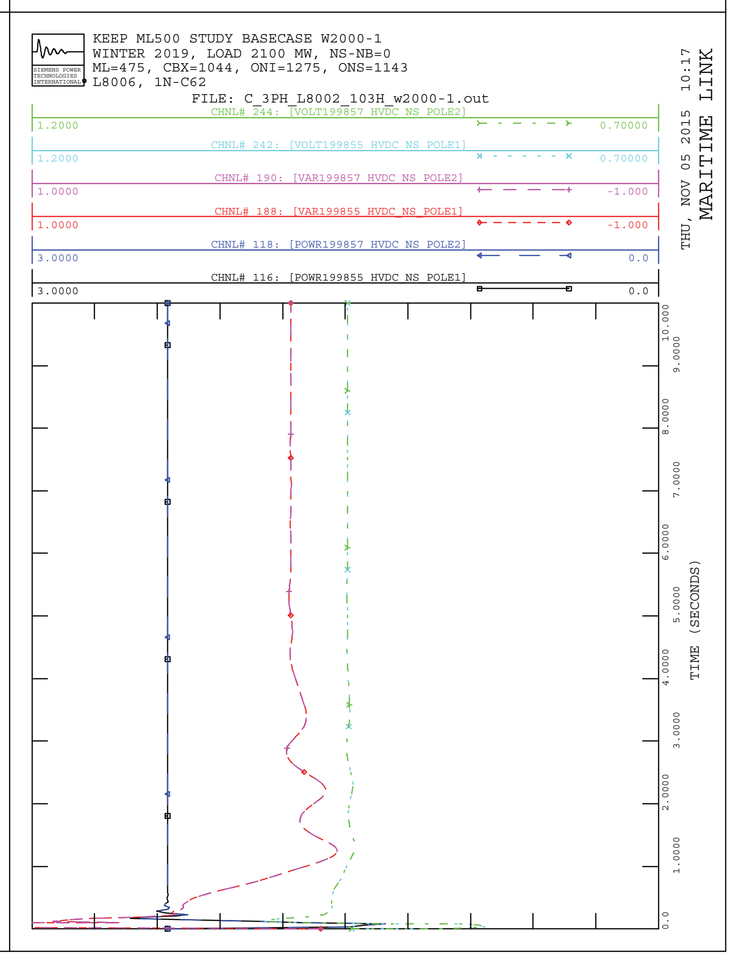

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L6536_74N_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)

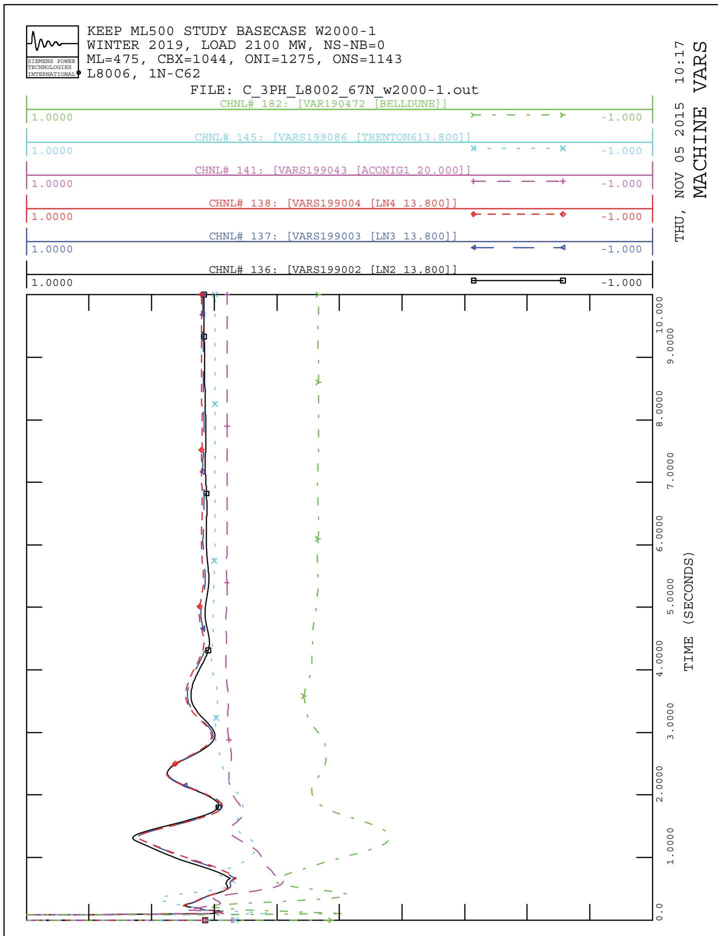
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



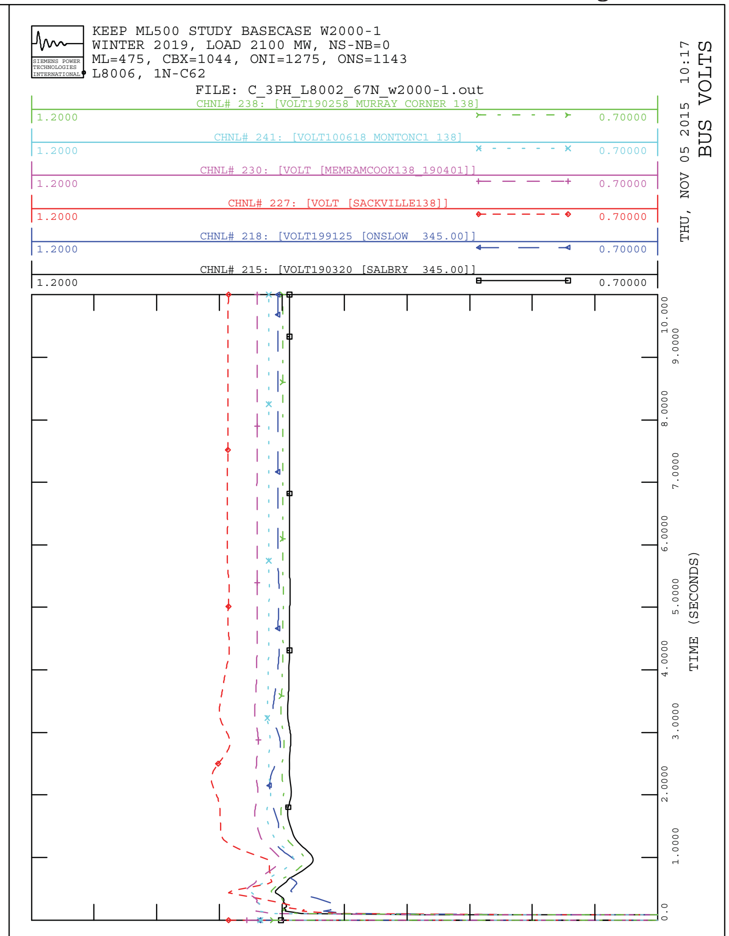








KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8002_67N_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8002_67N_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)
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2.0000
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4.0000
5.0000
6.0000
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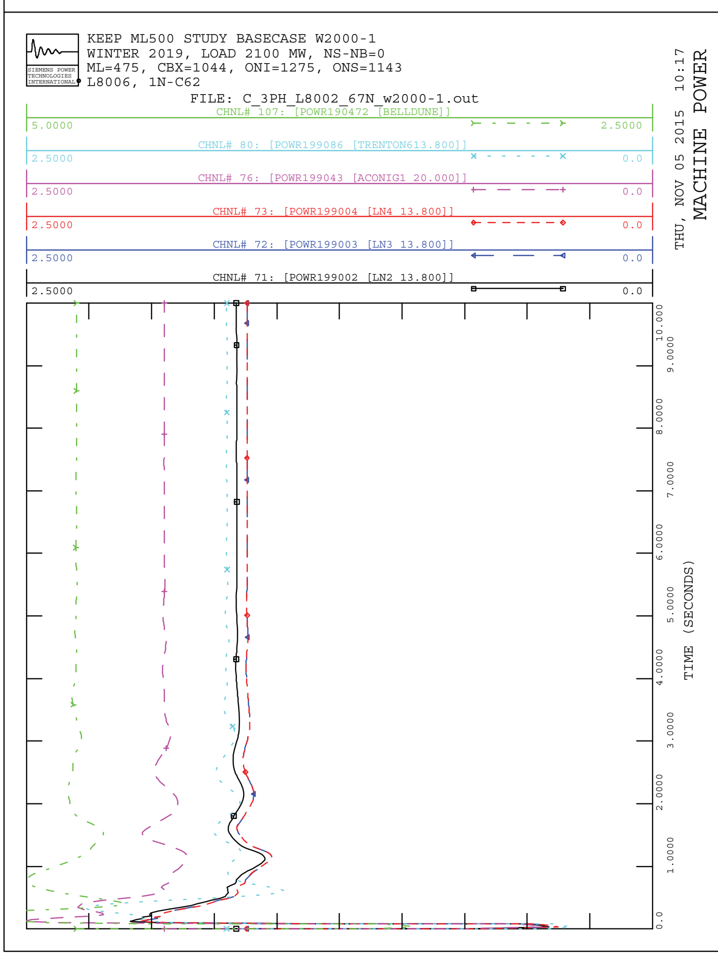
8.0000
9.0000
10.000



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8002_67N_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)
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2.0000
3.0000
4.0000
5.0000
6.0000
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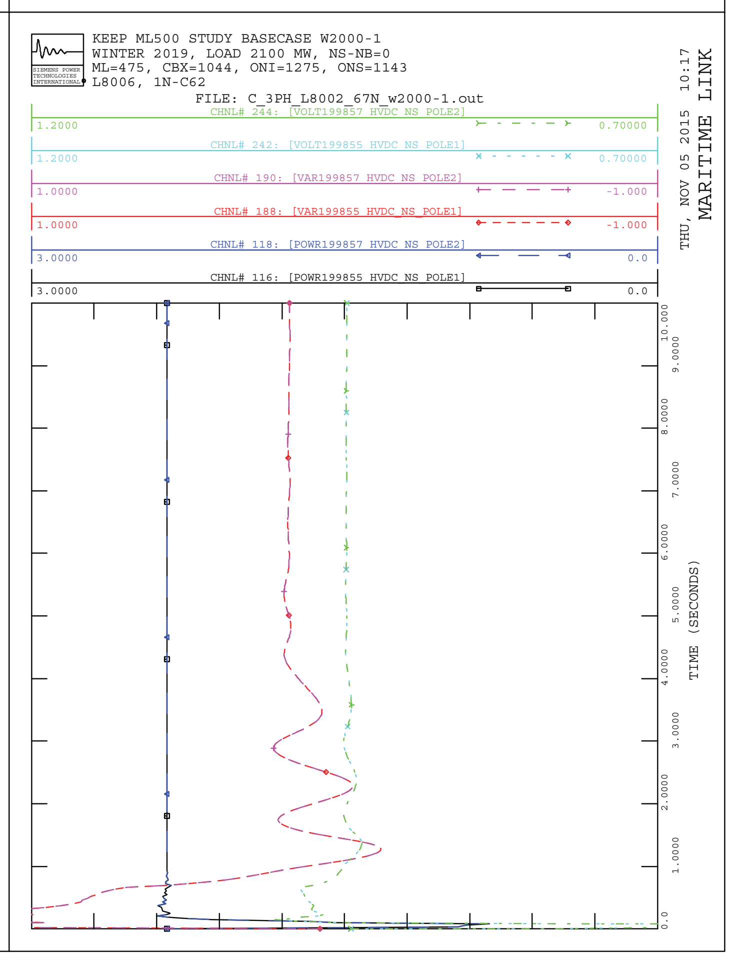
8.0000
9.0000
10.000



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8002_67N_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
2.0000
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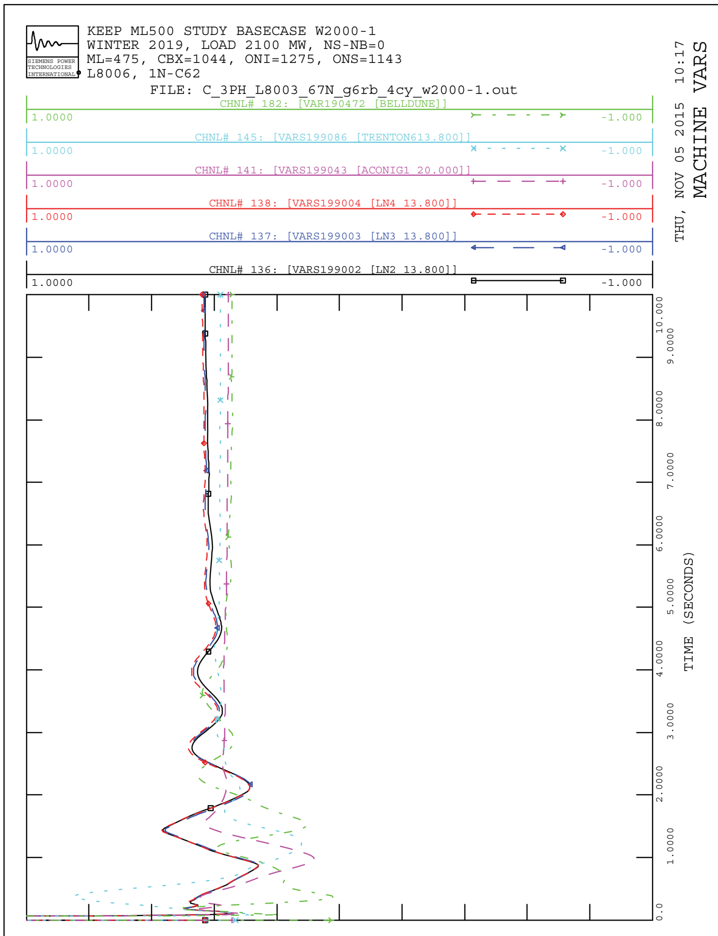
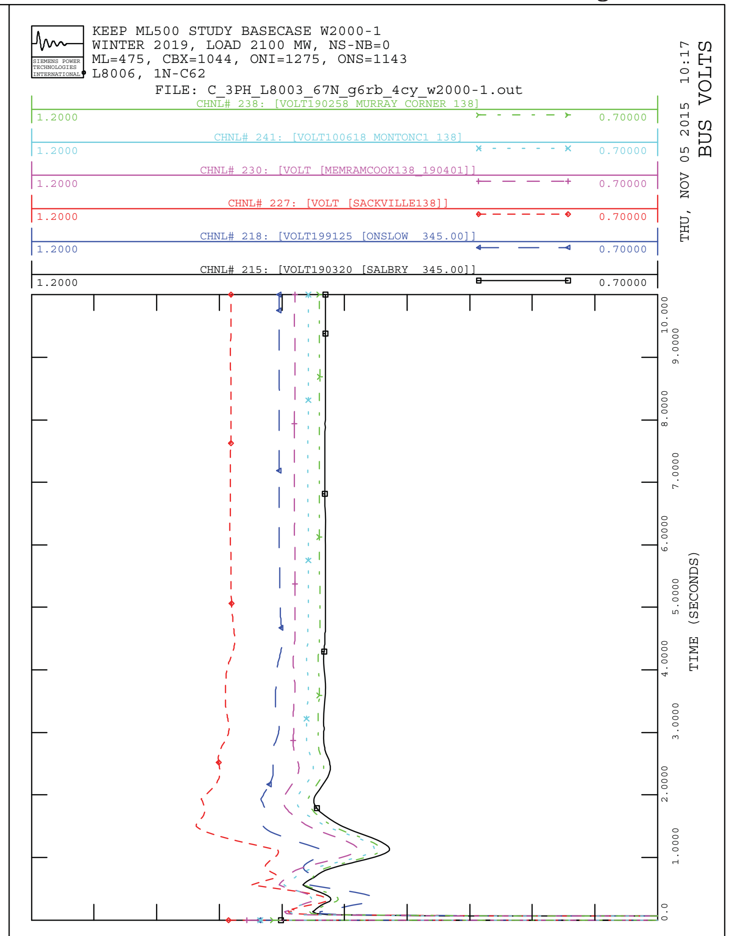
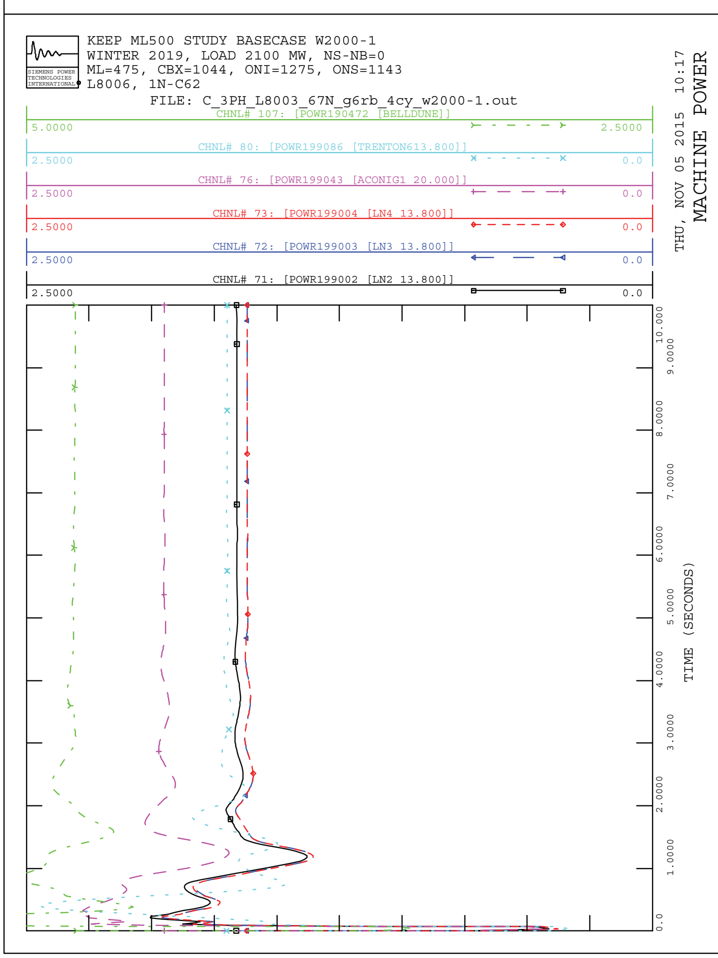
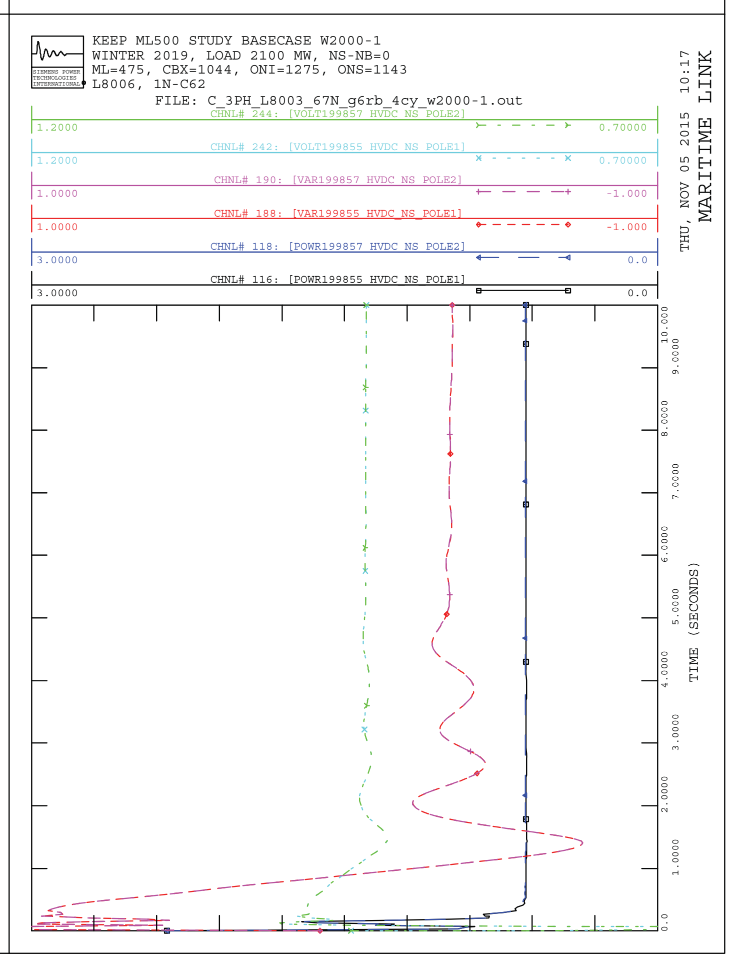
8.0000
9.0000
10.000

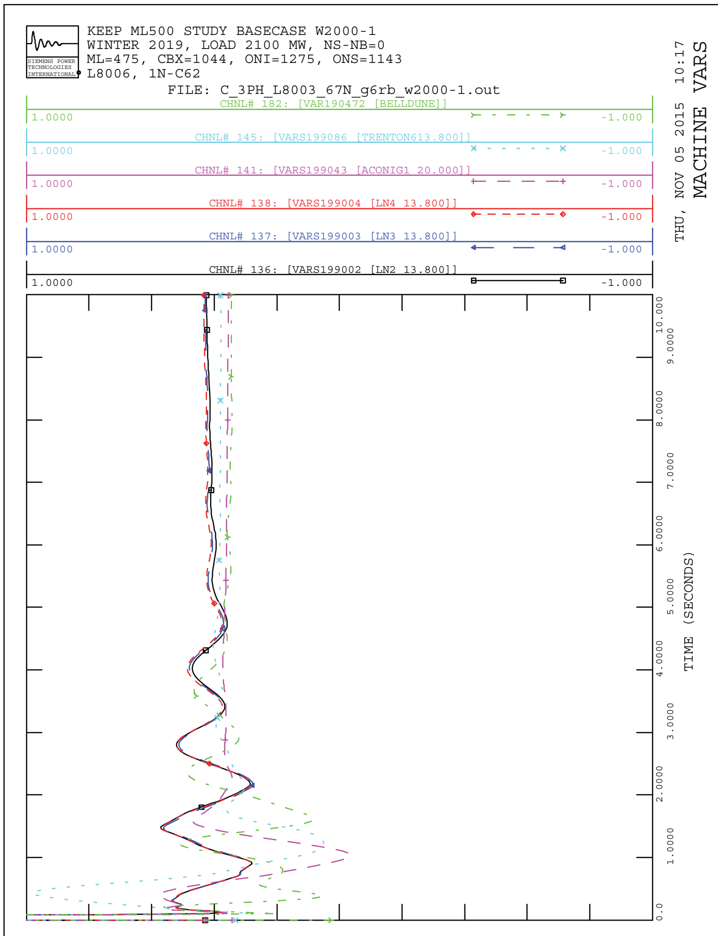
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



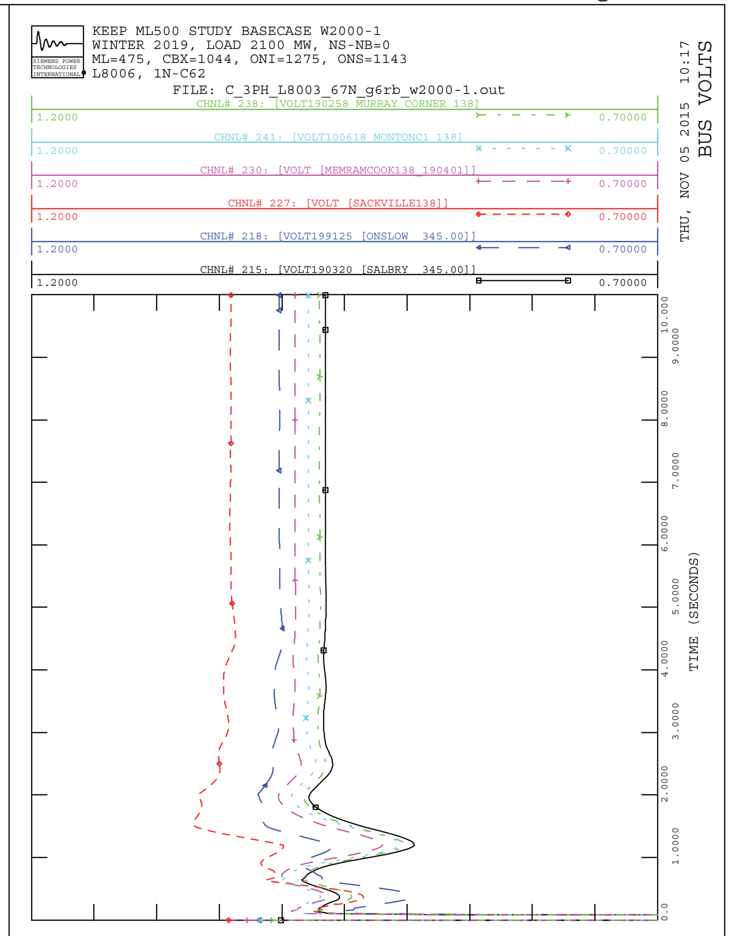




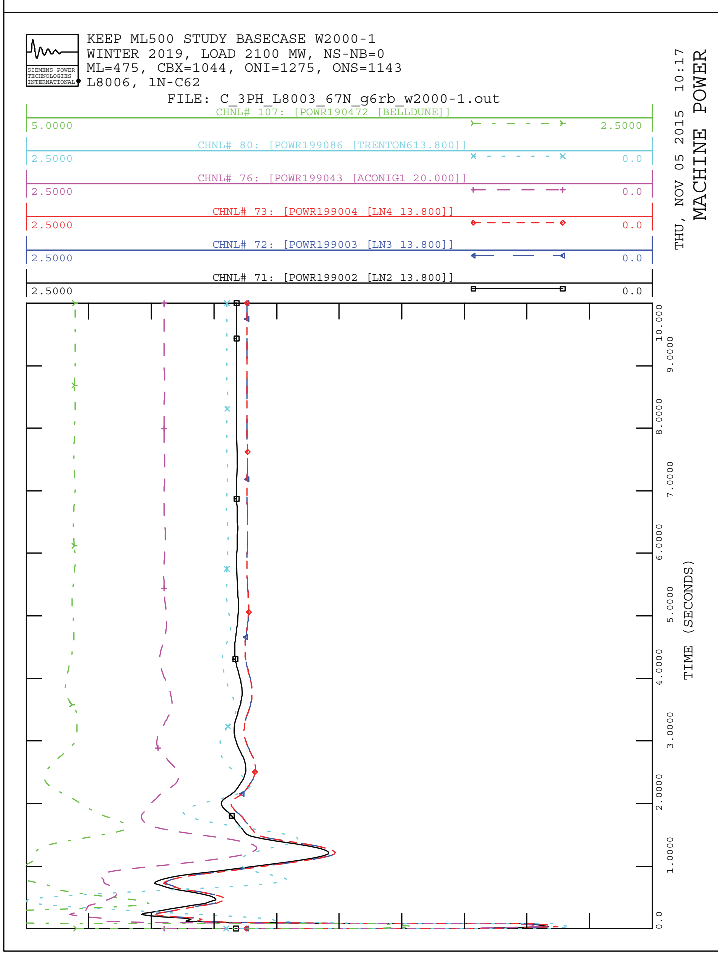




KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_67N_g6rb_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_67N_g6rb_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_67N_g6rb_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)
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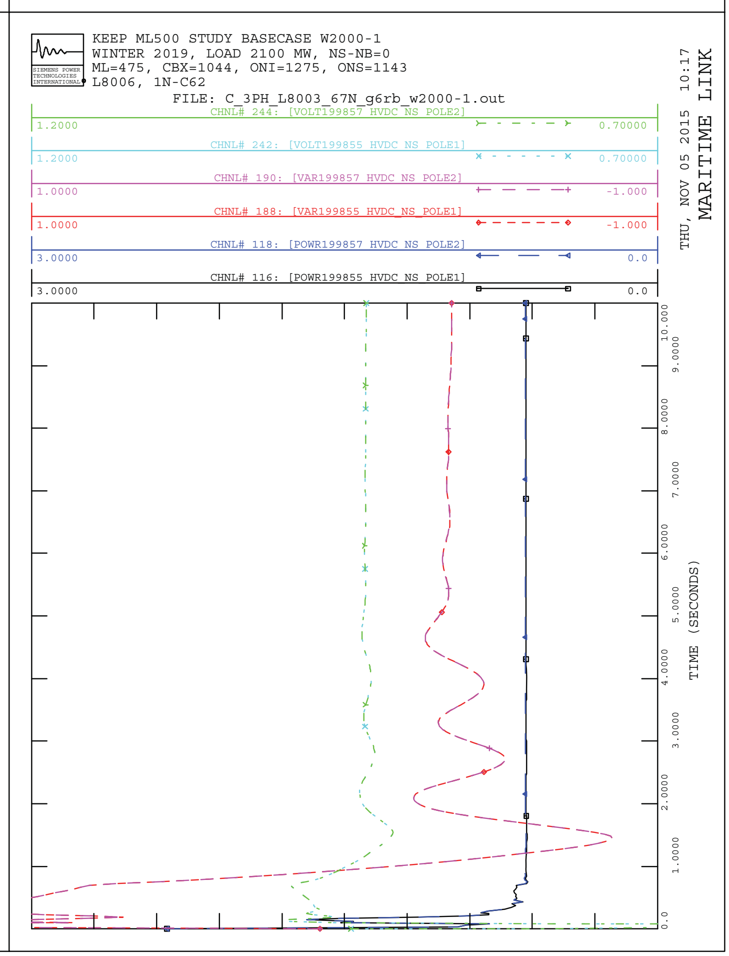
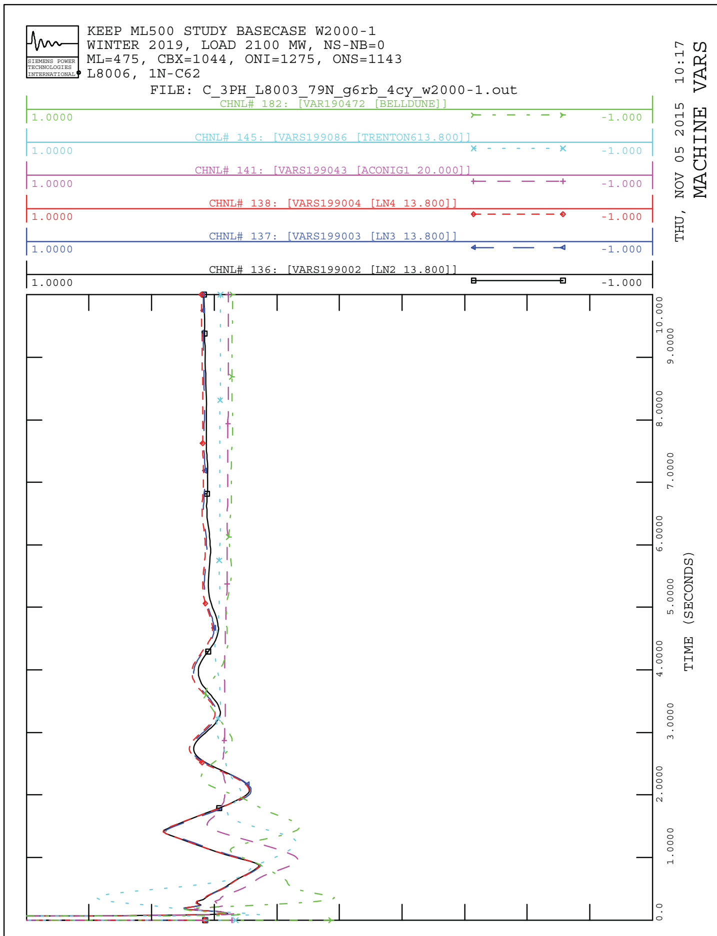
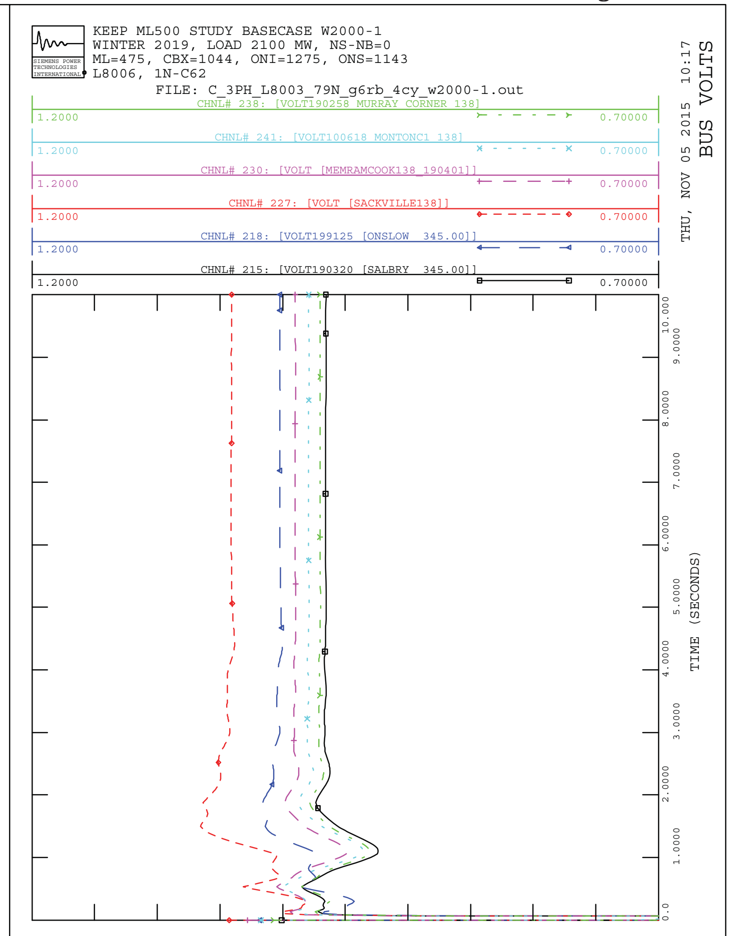


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_67N_g6rb_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_79N_g6rb_4cy_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)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L8006, 1N-C62
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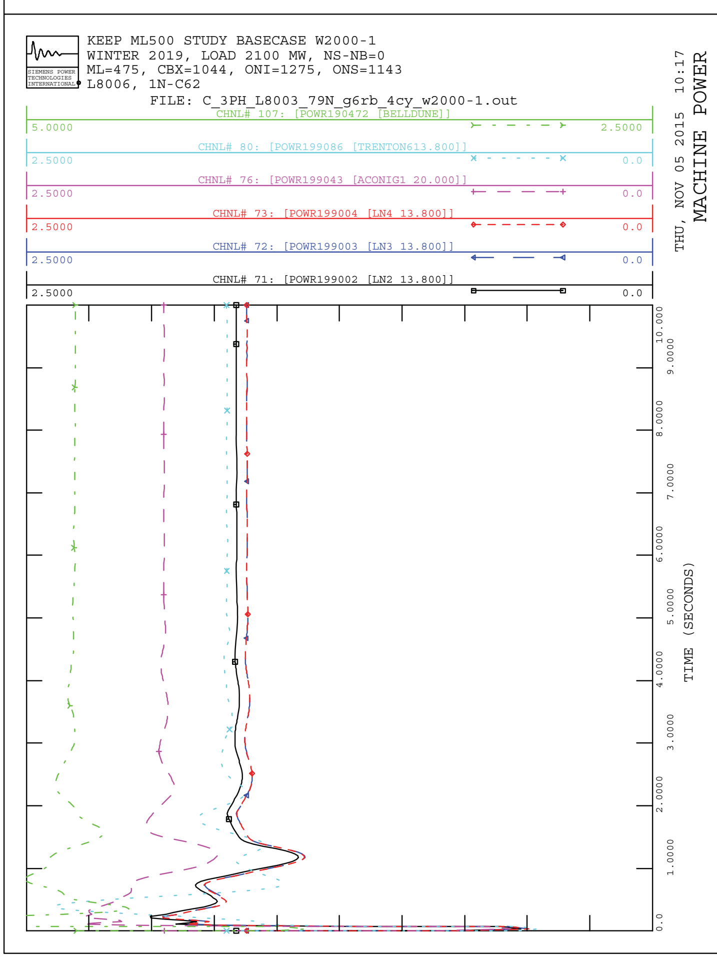
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)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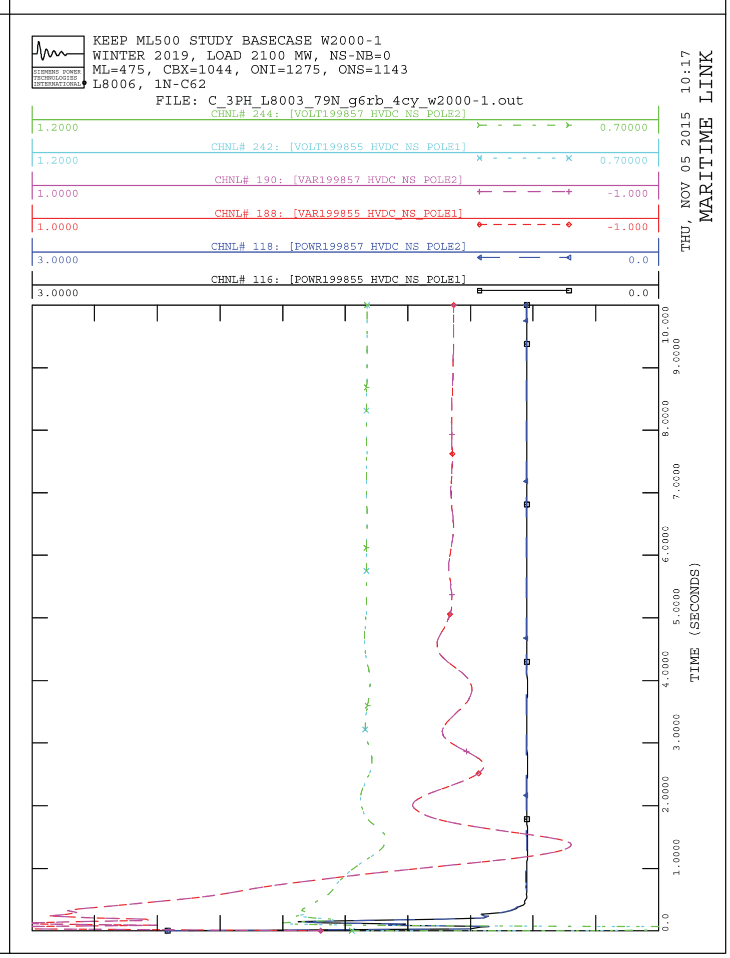
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_79N_g6rb_4cy_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)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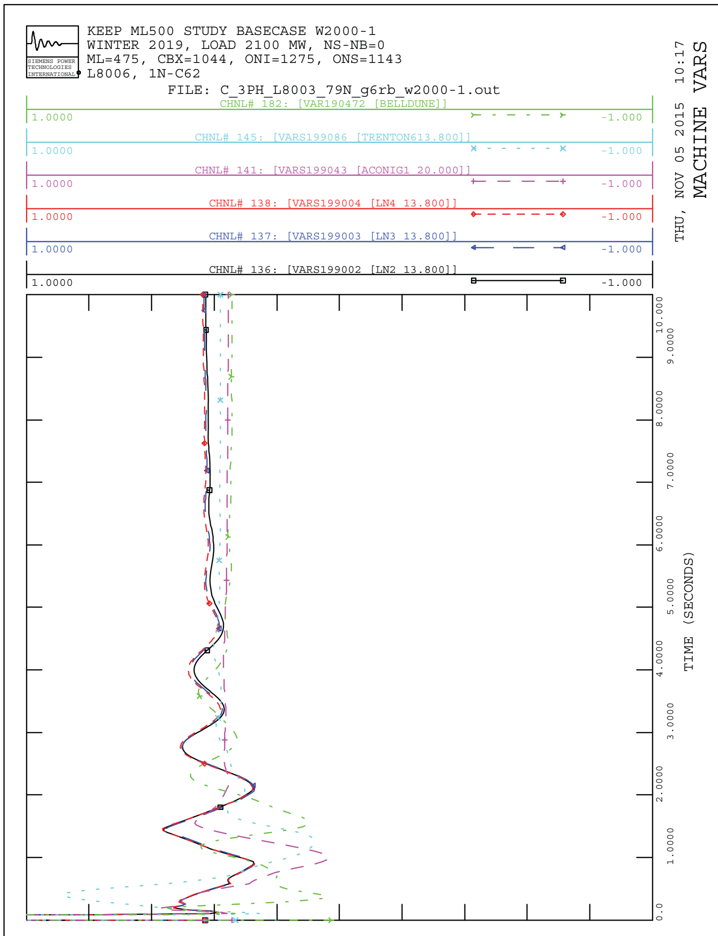
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_79N_g6rb_4cy_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)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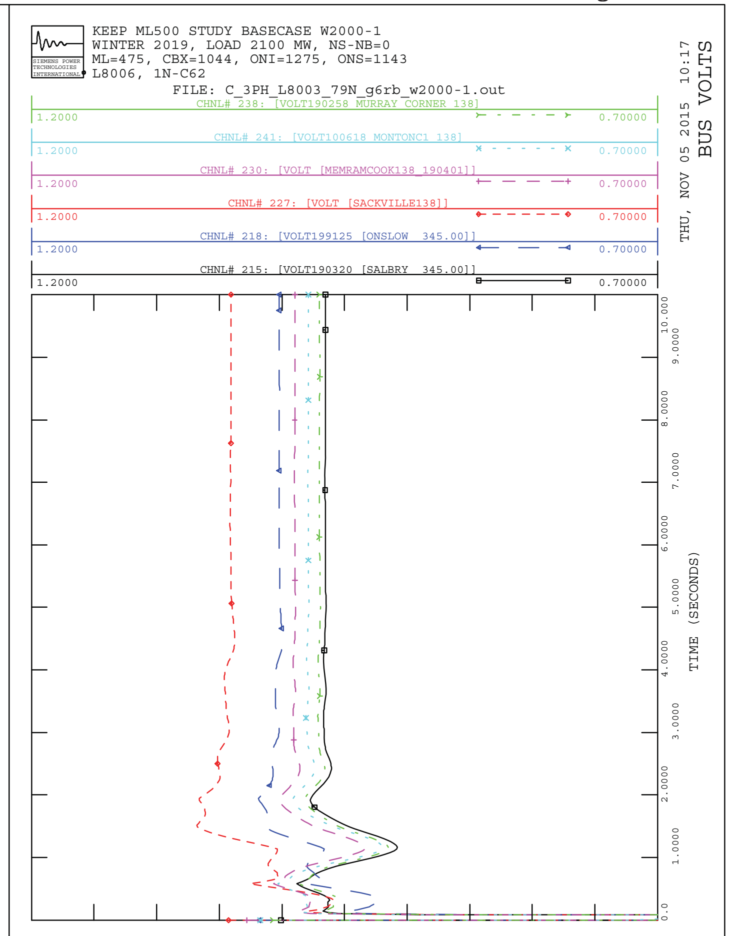
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_79N_g6rb_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)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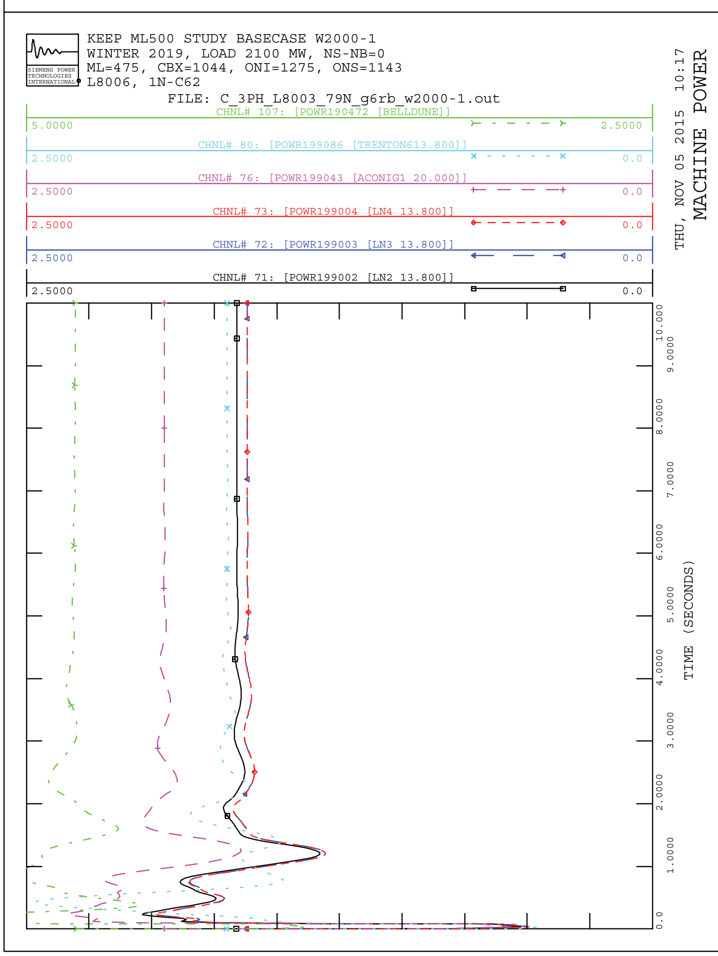
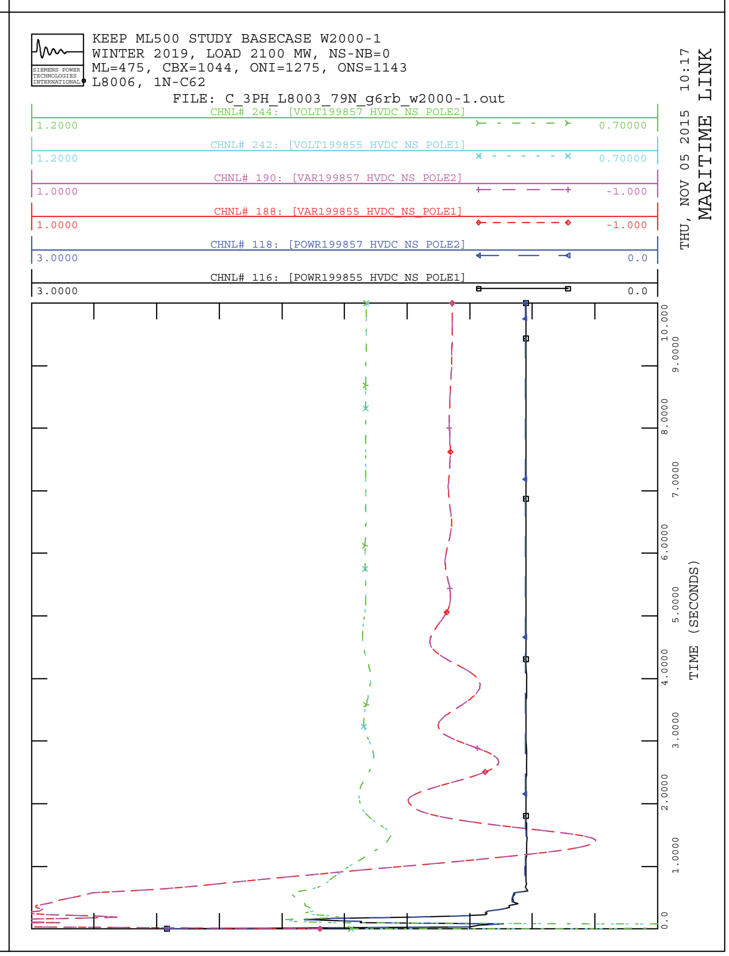
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_79N_g6rb_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_79N_g6rb_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
5.0000
2.5000
2.5000
0.0
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8003_79N_g6rb_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
1.0000
-1.000
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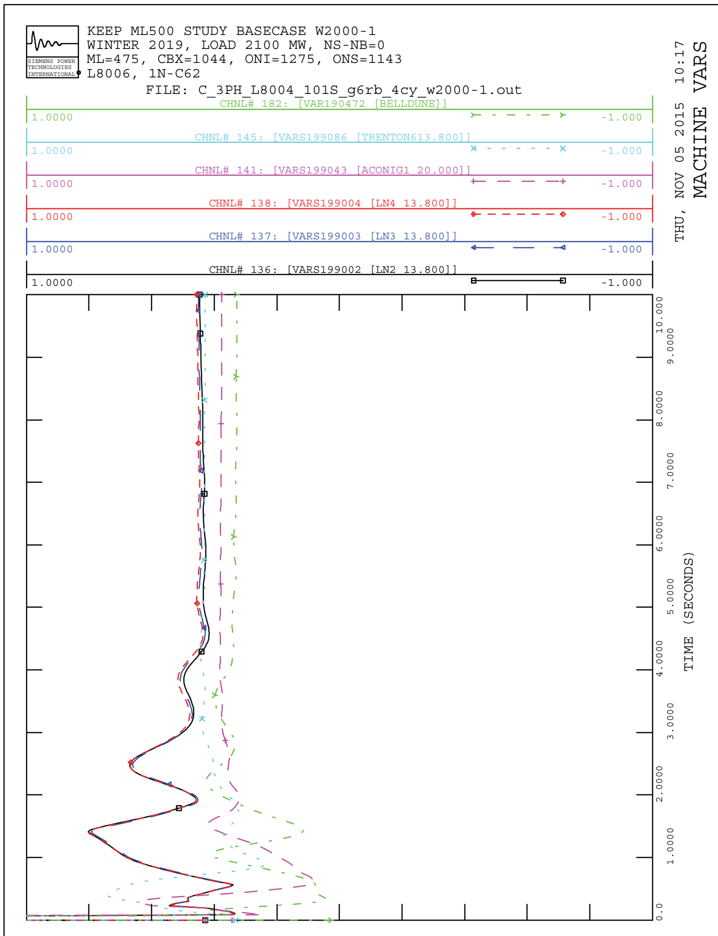
MARITIME LINK
TIME (SECONDS)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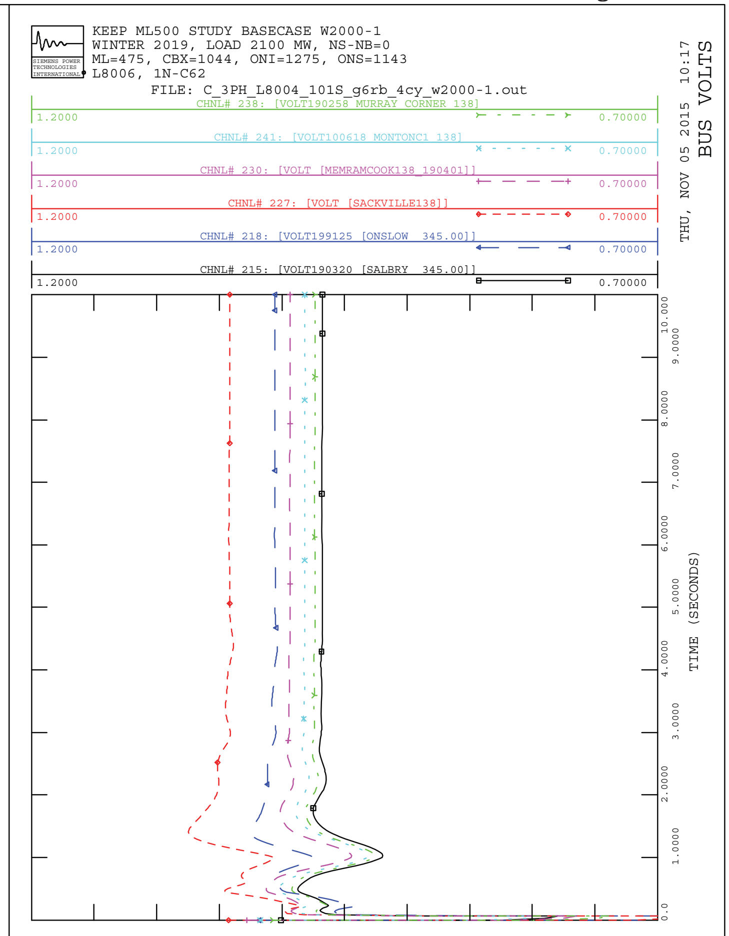
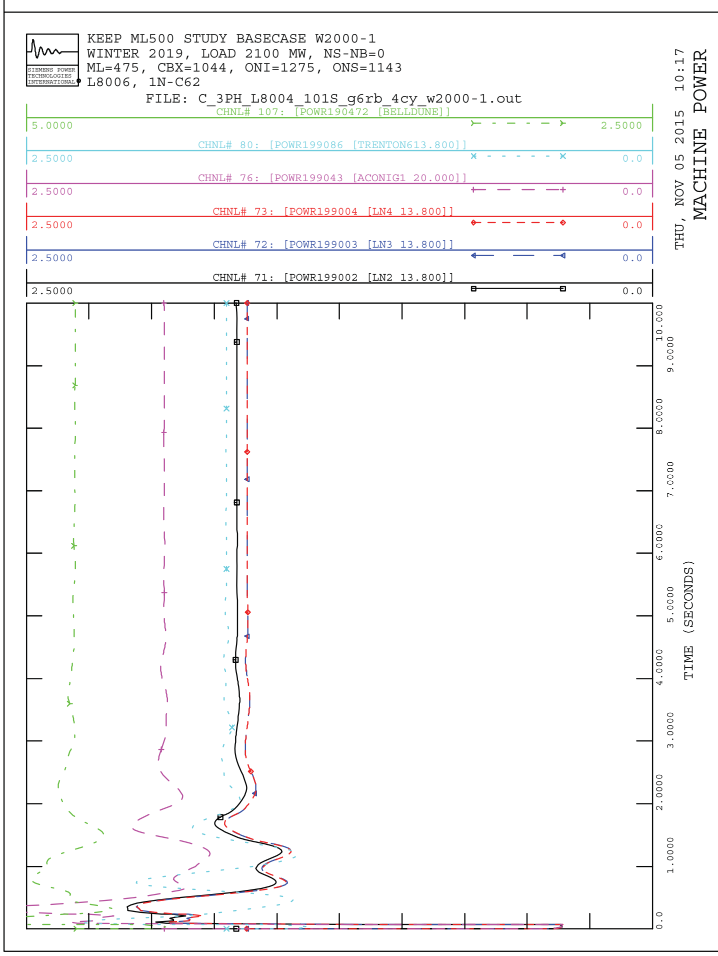
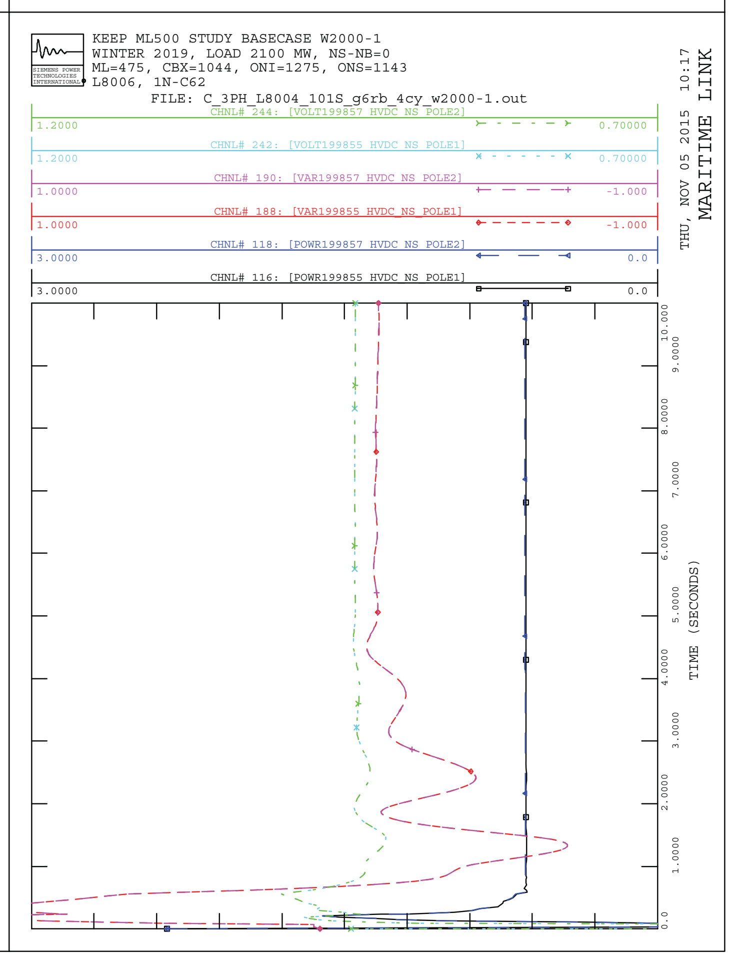
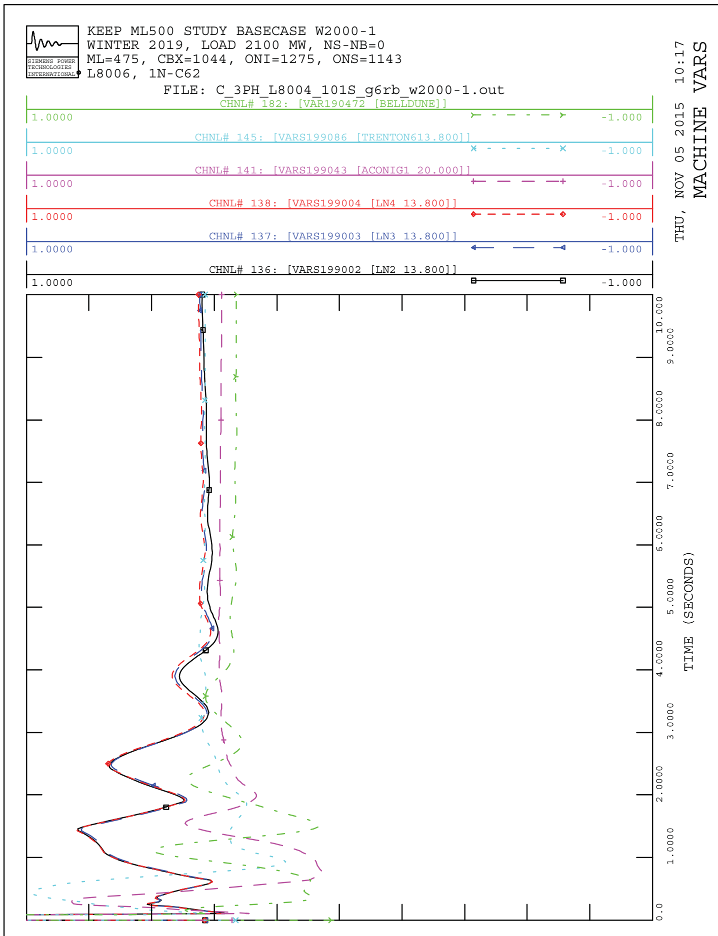
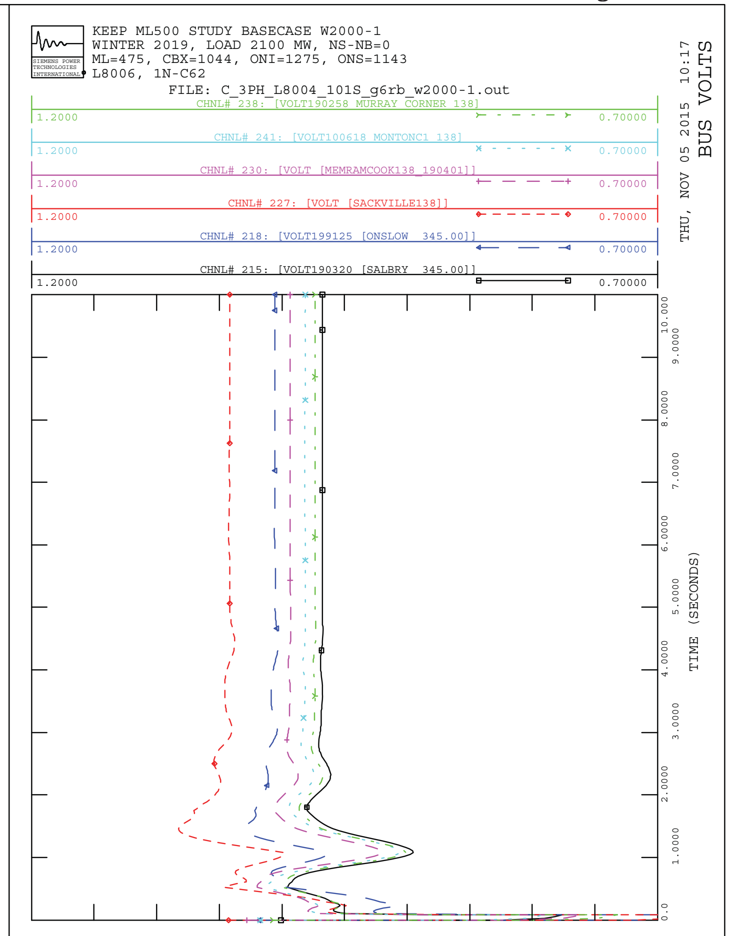
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)

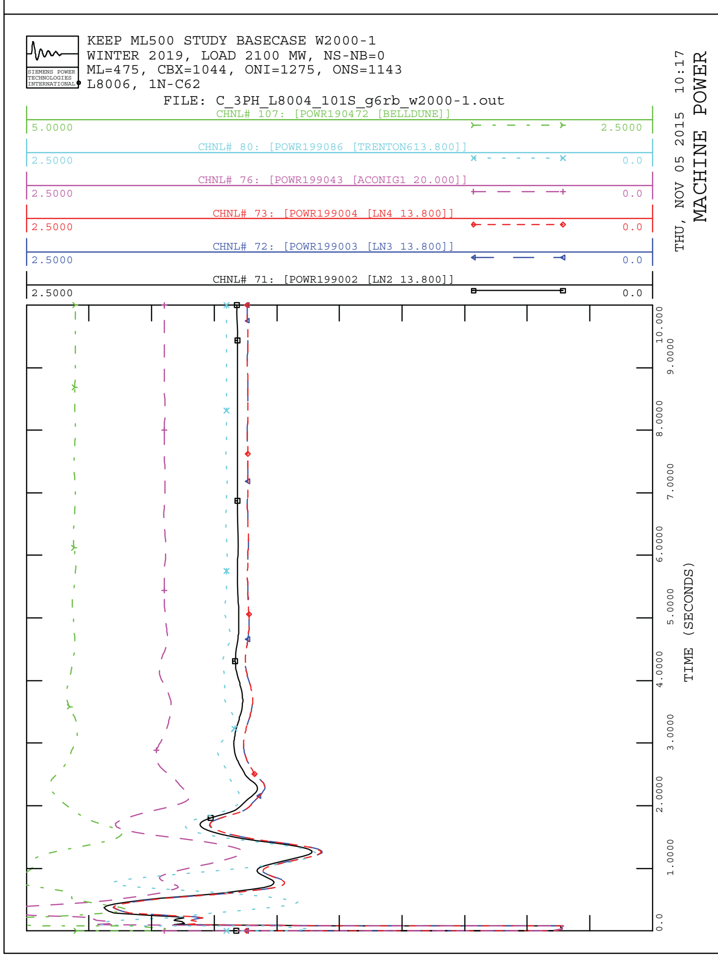

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_101S_g6rb_4cy_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138_190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)

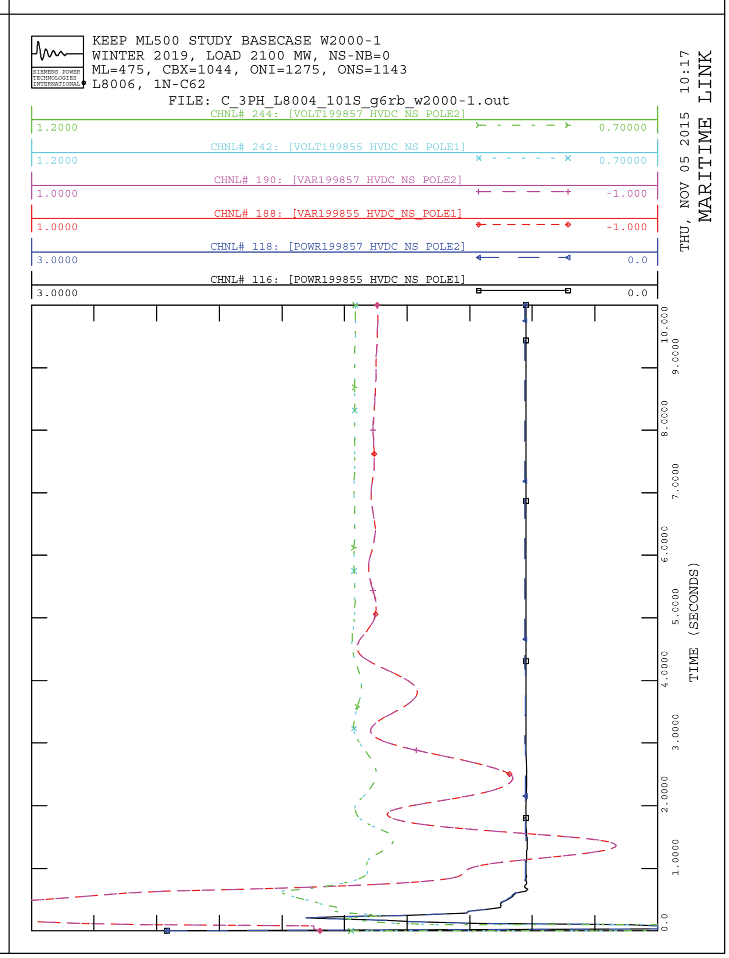

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_101S_g6rb_4cy_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)

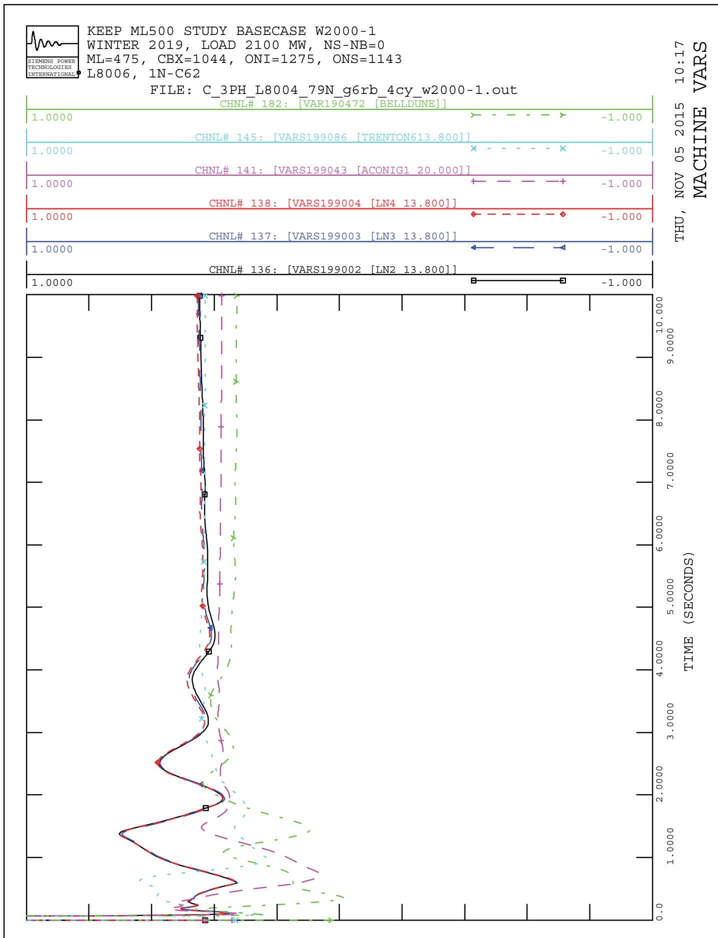

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_101S_g6rb_4cy_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_101S_g6rb_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)

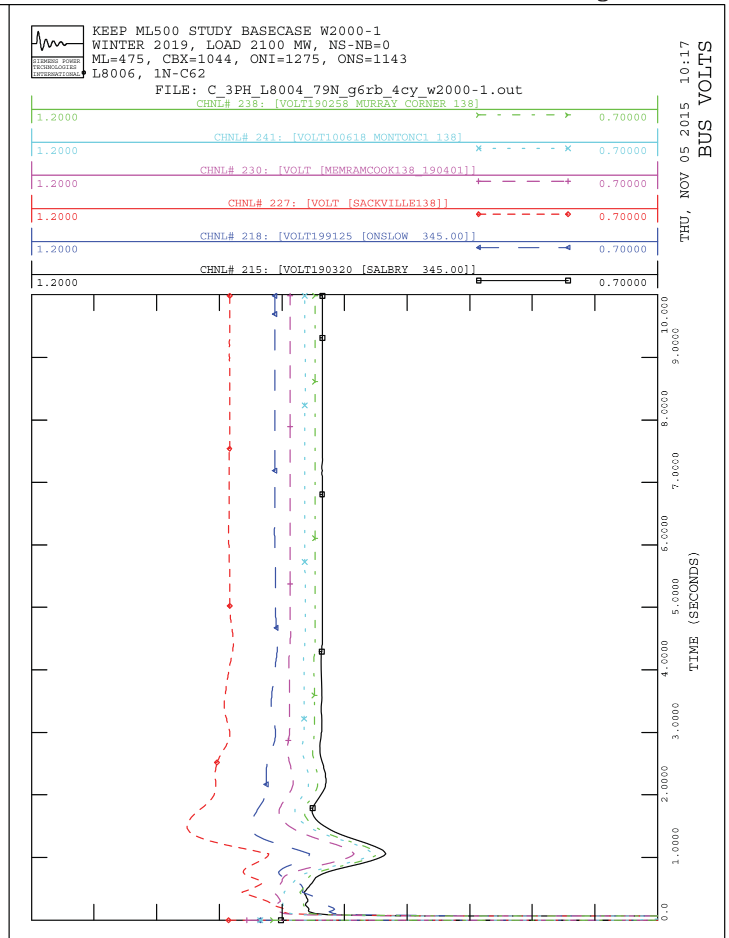

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_101S_g6rb_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_101S_g6rb_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)

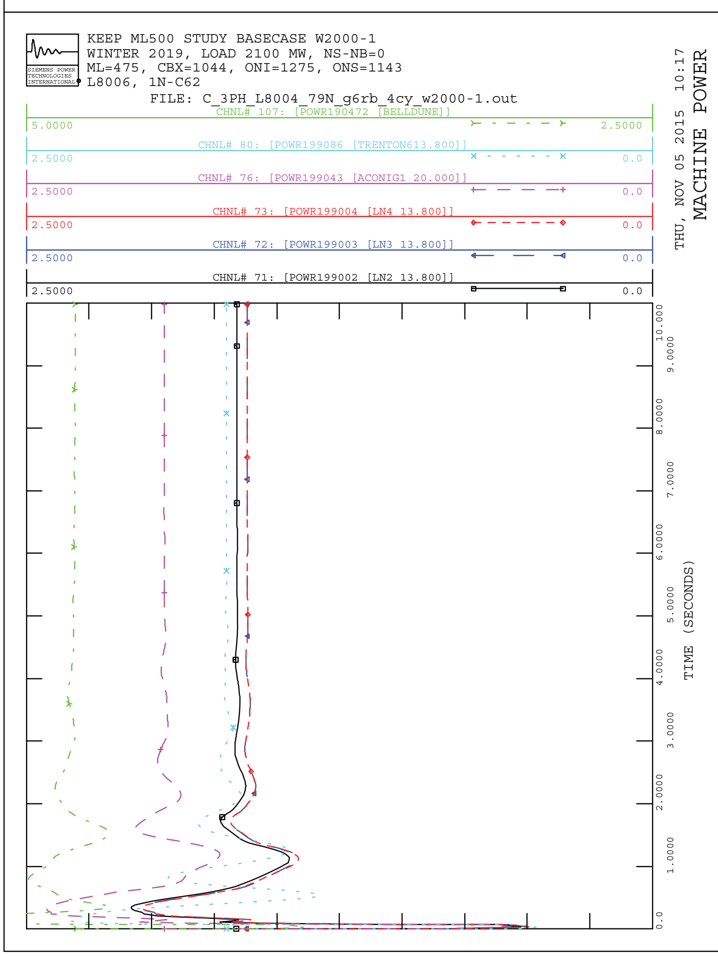

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_101S_g6rb_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)



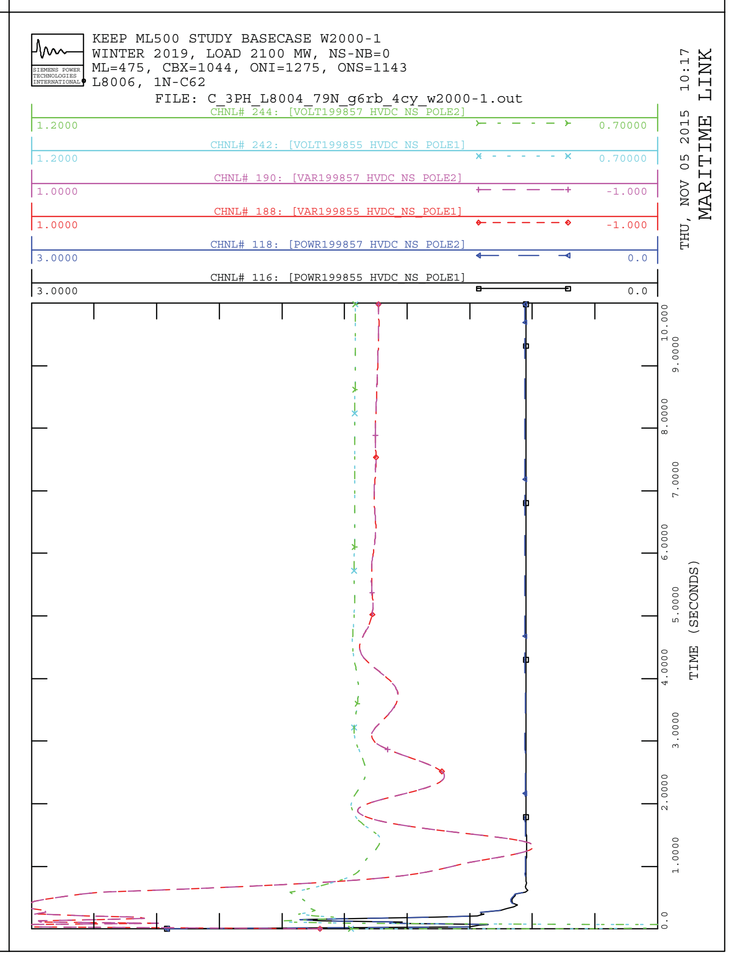
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_79N_g6rb_4cy_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



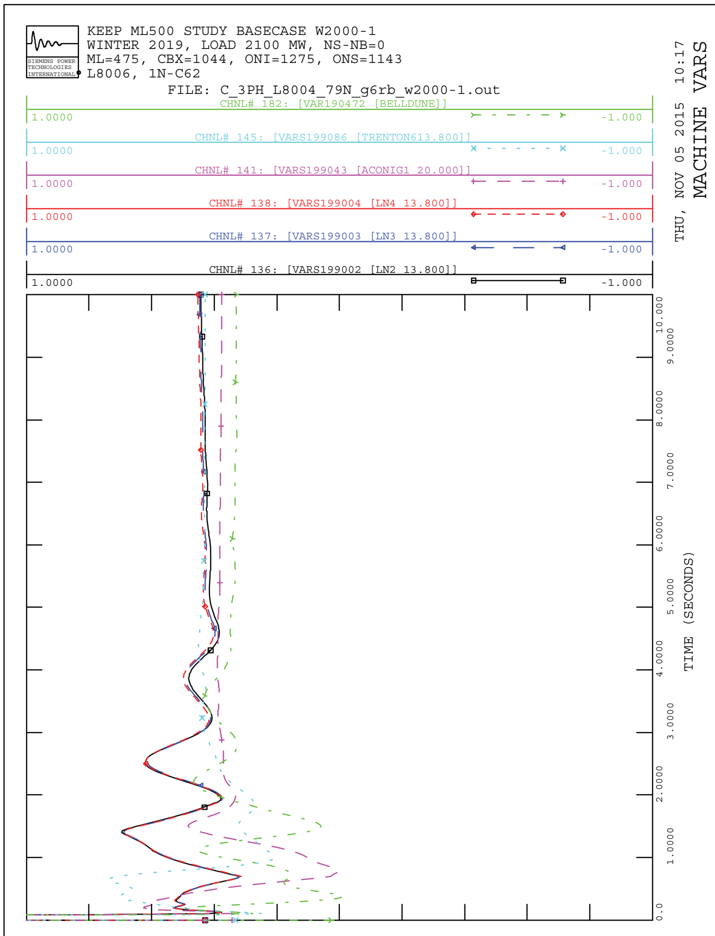
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_79N_g6rb_4cy_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_79N_g6rb_4cy_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_79N_g6rb_4cy_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000


KEEP ML500 STUDY BASECASE W2000-1
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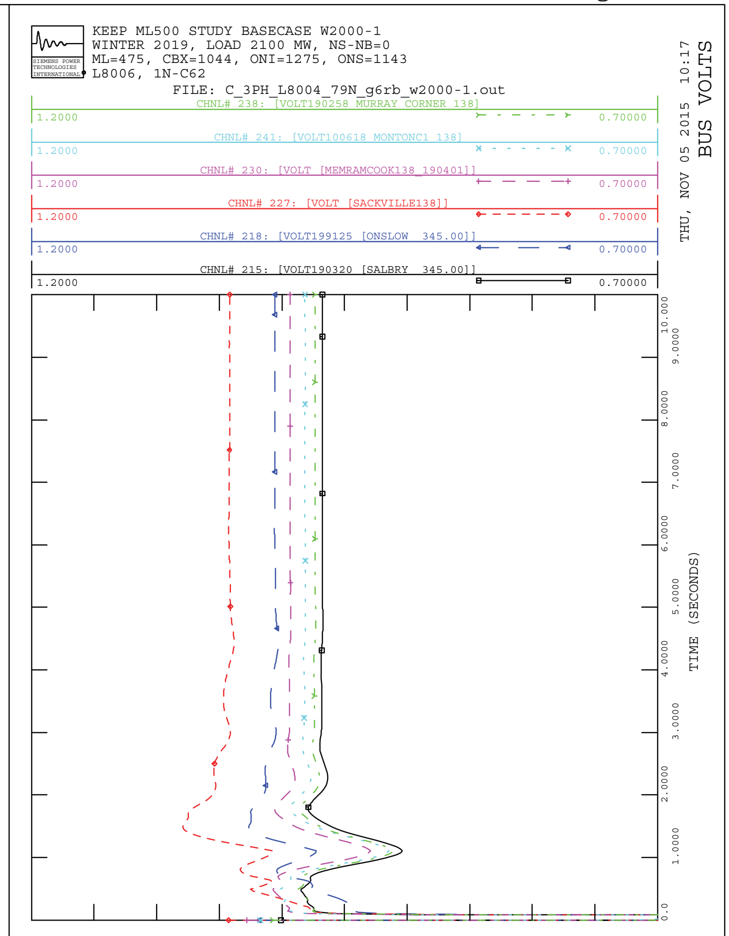
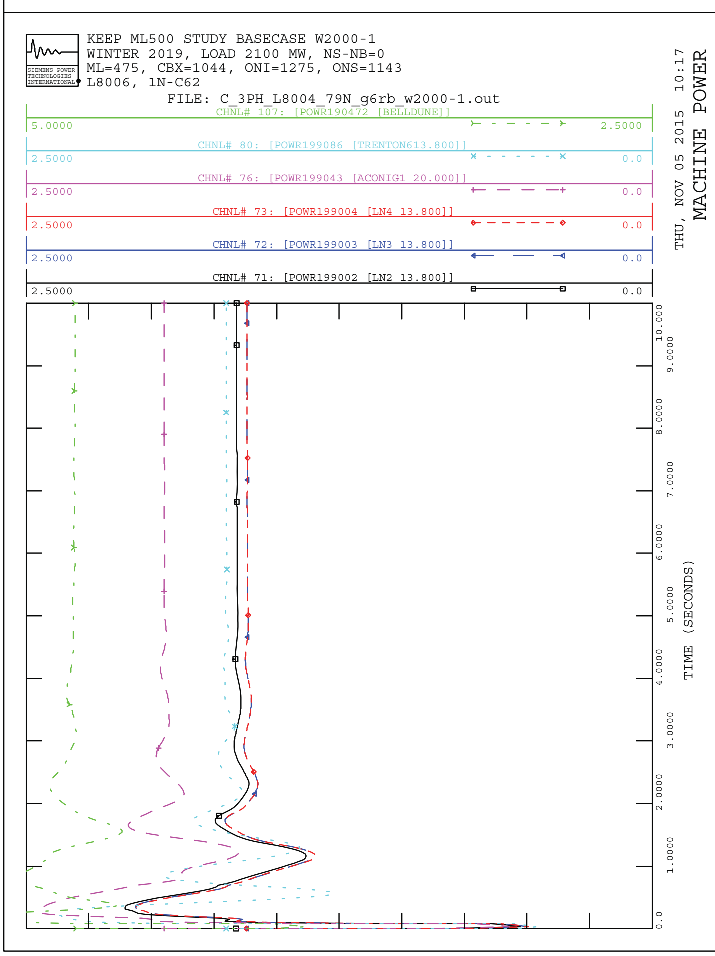
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_79N_g6rb_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_79N_g6rb_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_79N_g6rb_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
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2.5000
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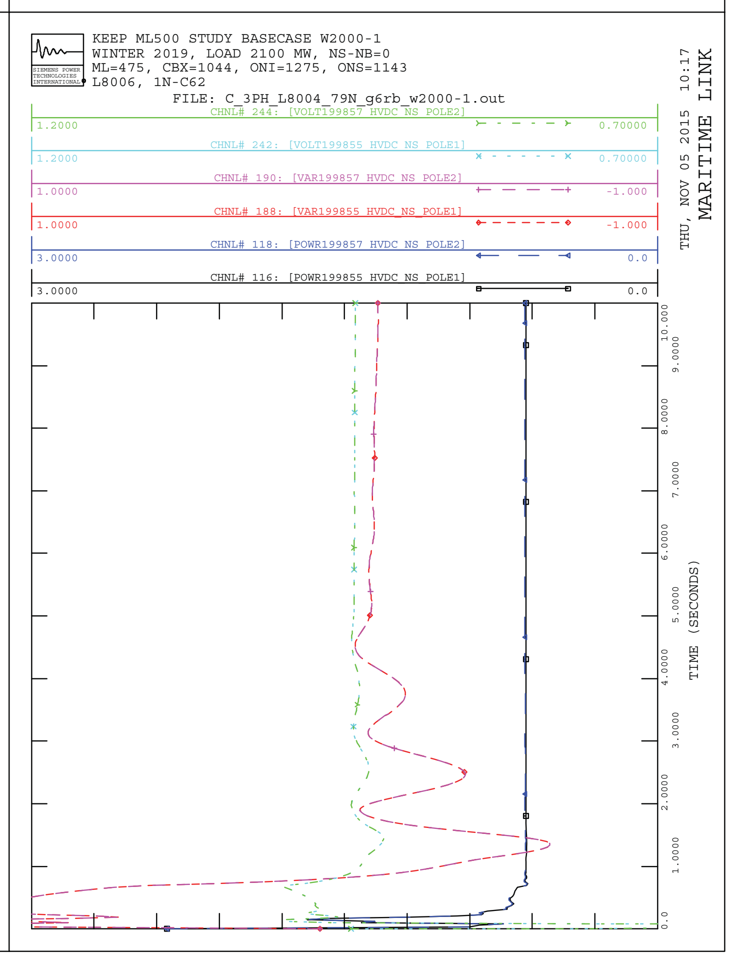
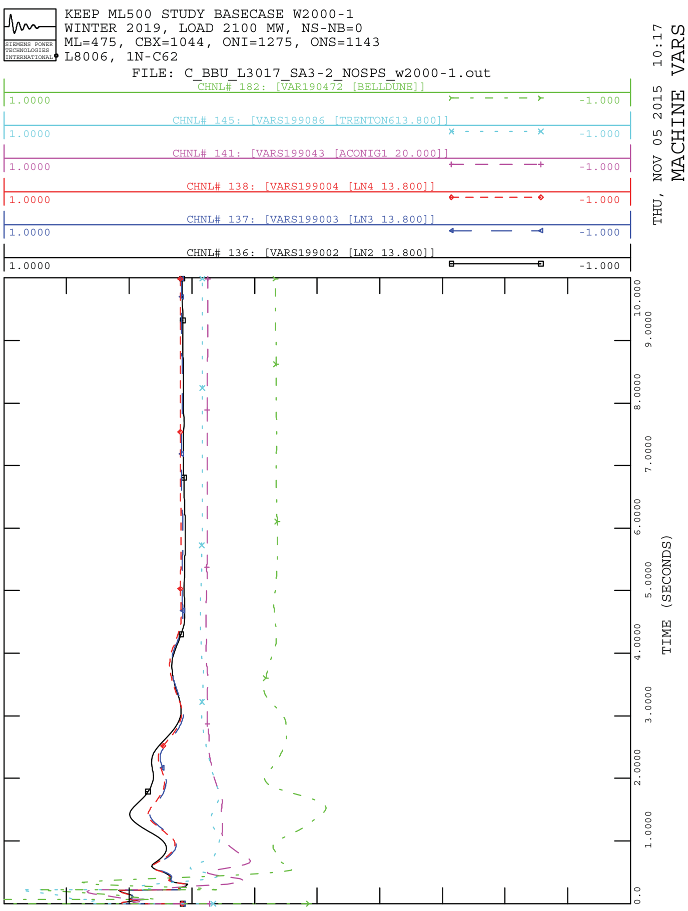
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_3PH_L8004_79N_g6rb_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
1.0000
-1.000
3.0000
0.0
THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-1
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L8006, 1N-C62
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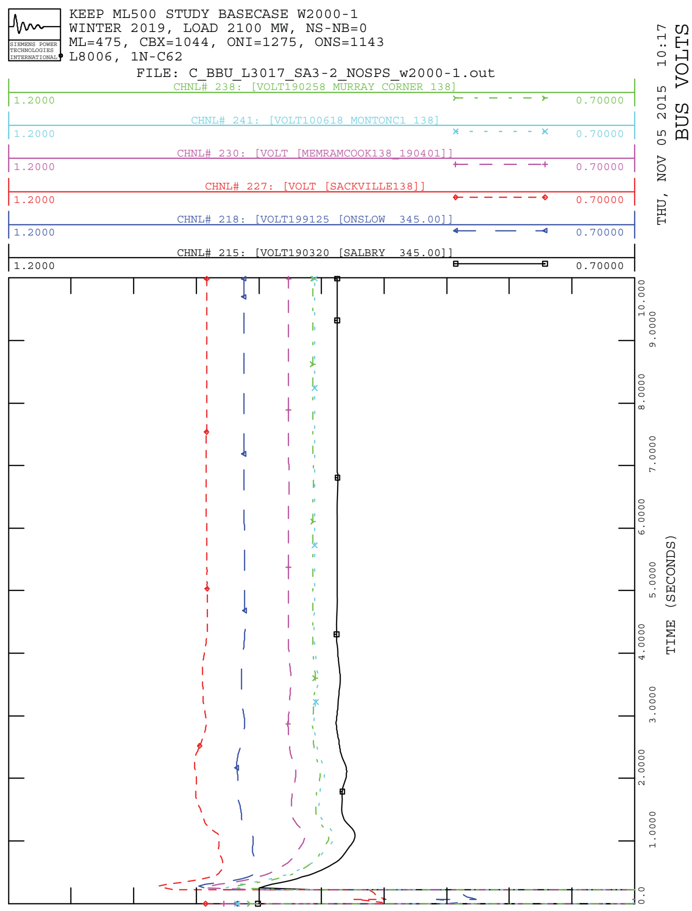
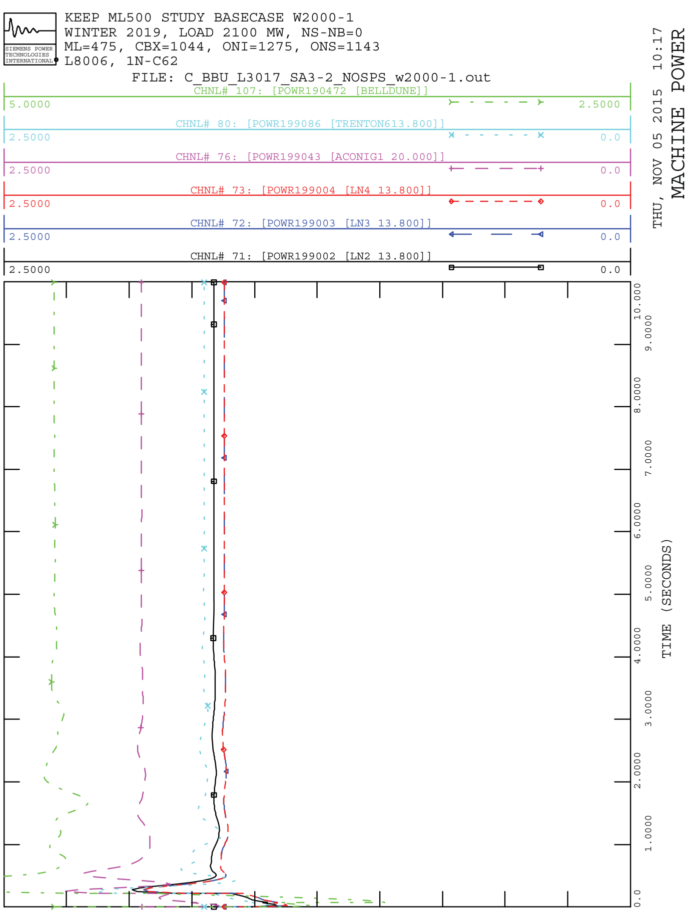
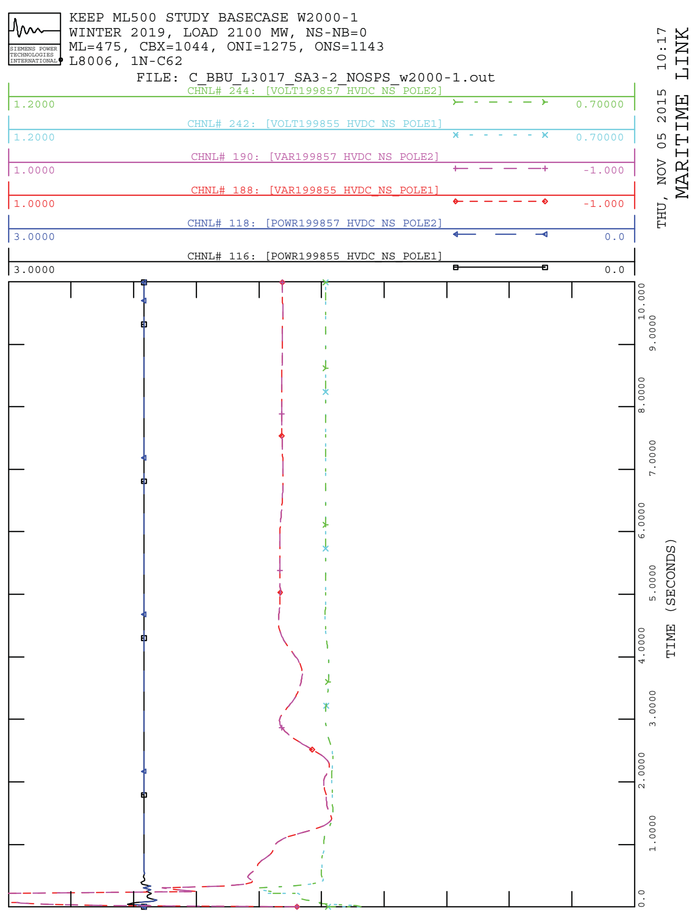
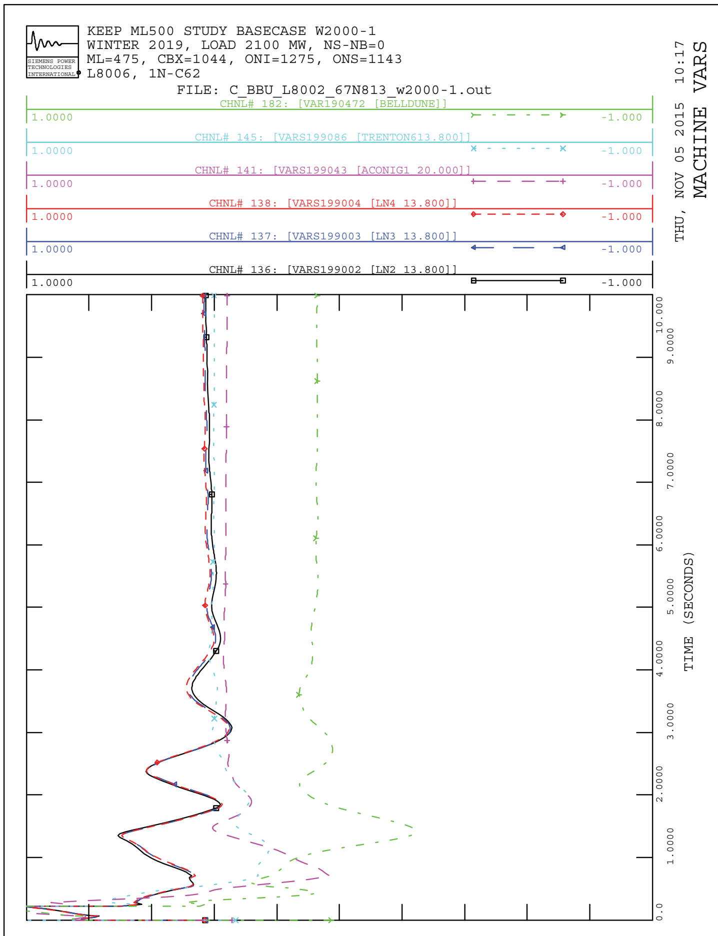
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)

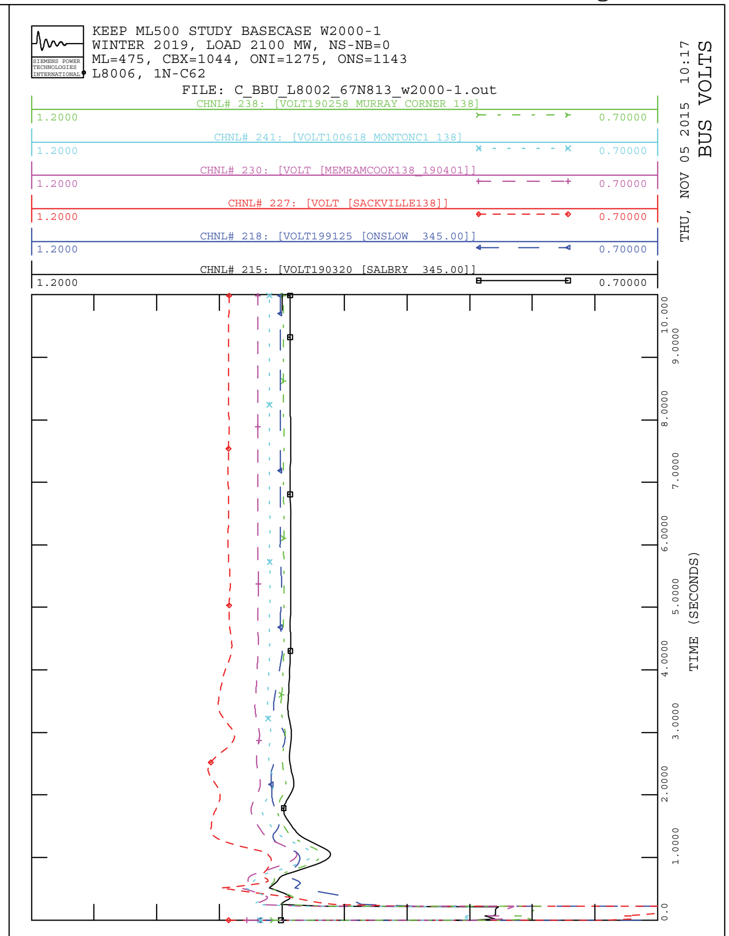

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L3017_SA3-2_NOSPS_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)

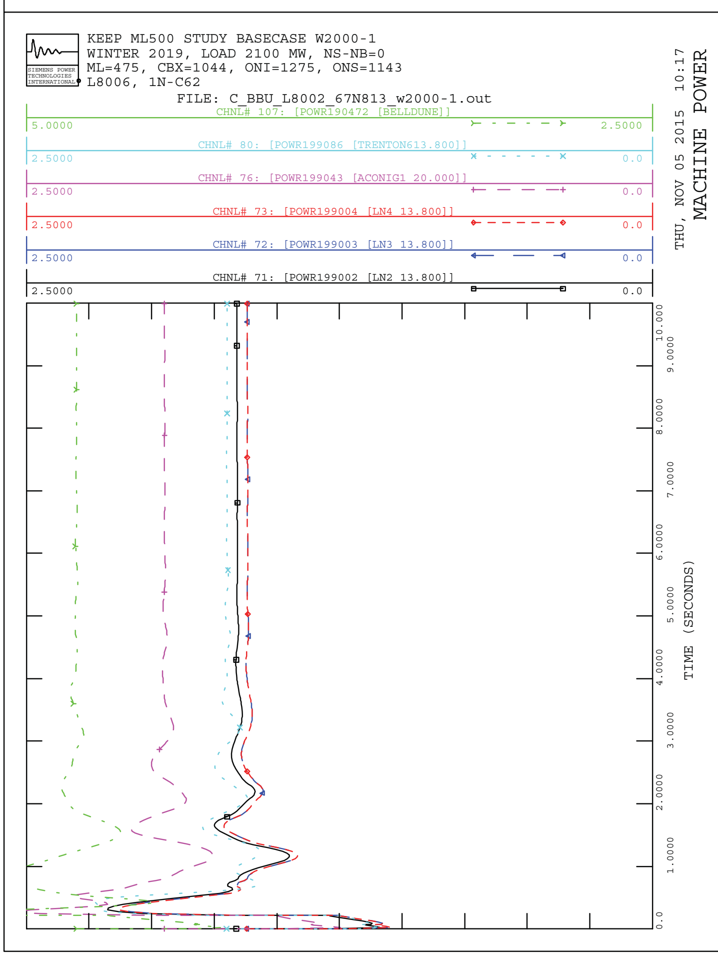

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L3017_SA3-2_NOSPS_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)

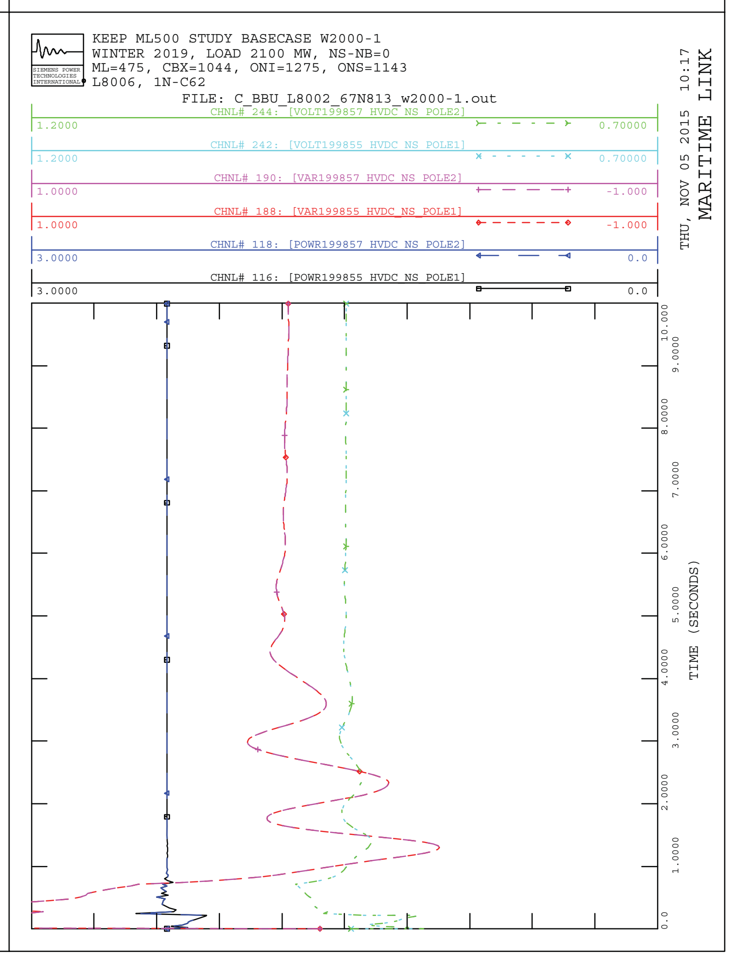

KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L3017_SA3-2_NOSPS_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)

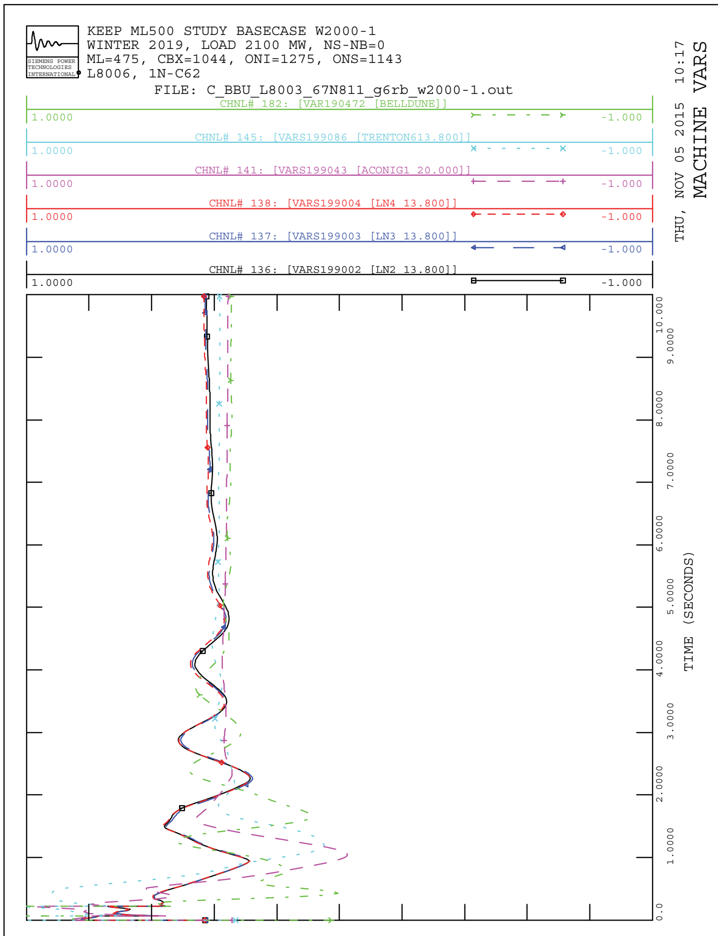
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



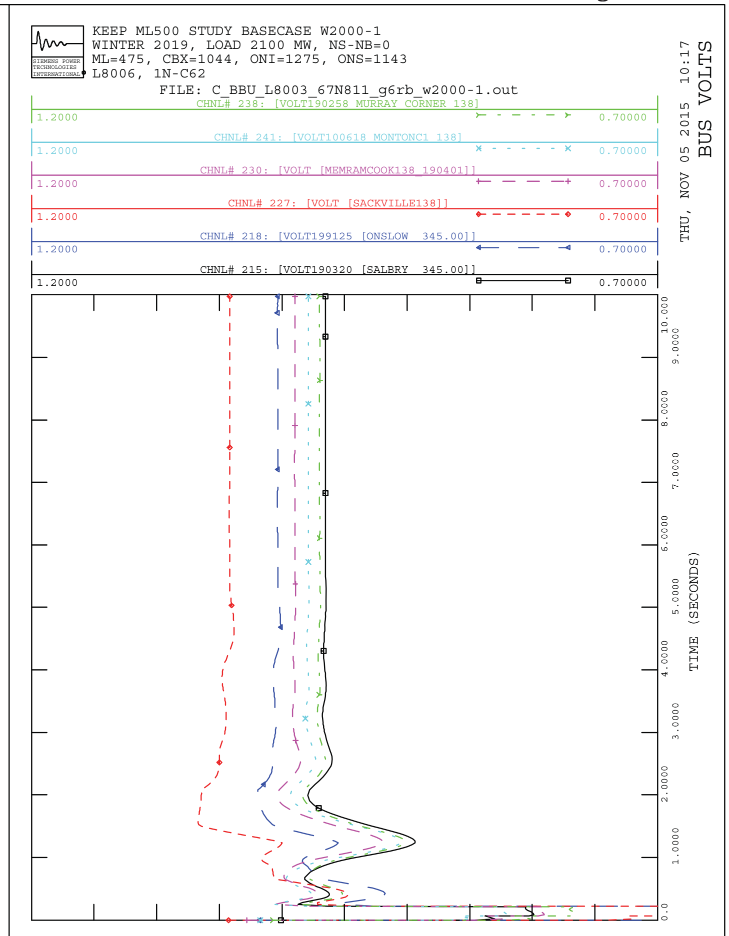




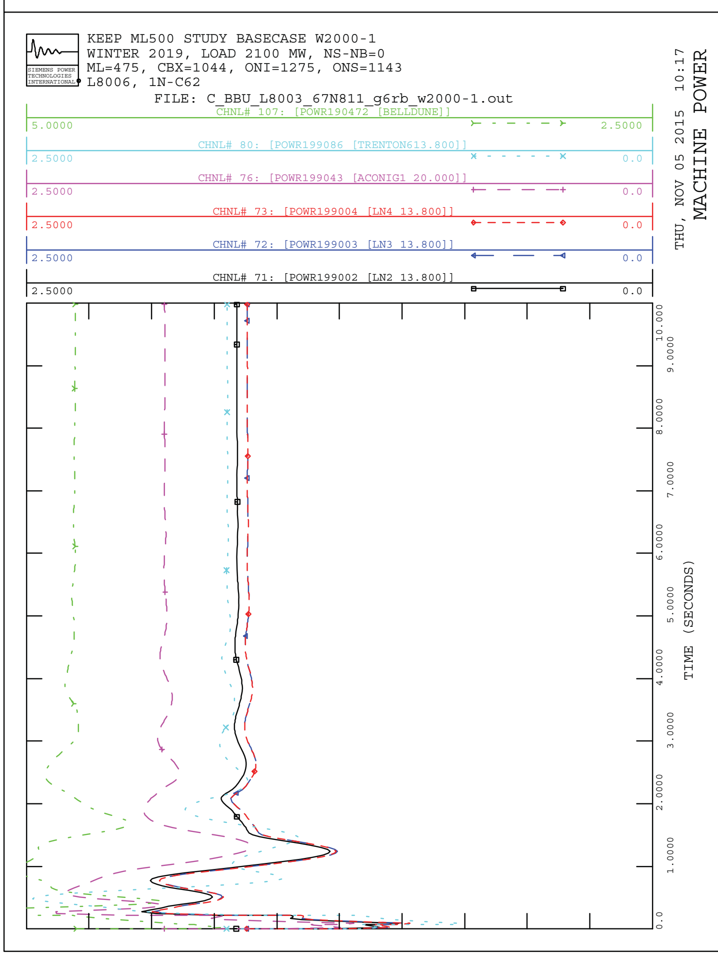




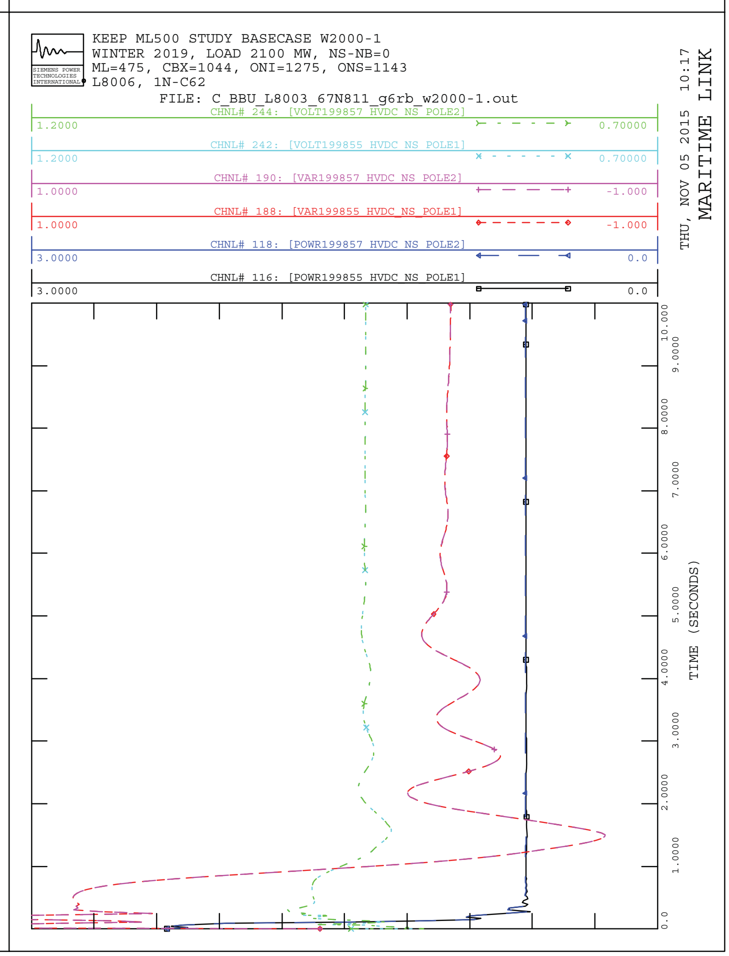
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8003_67N811_g6rb_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8003_67N811_g6rb_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8003_67N811_g6rb_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8003_67N811_g6rb_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
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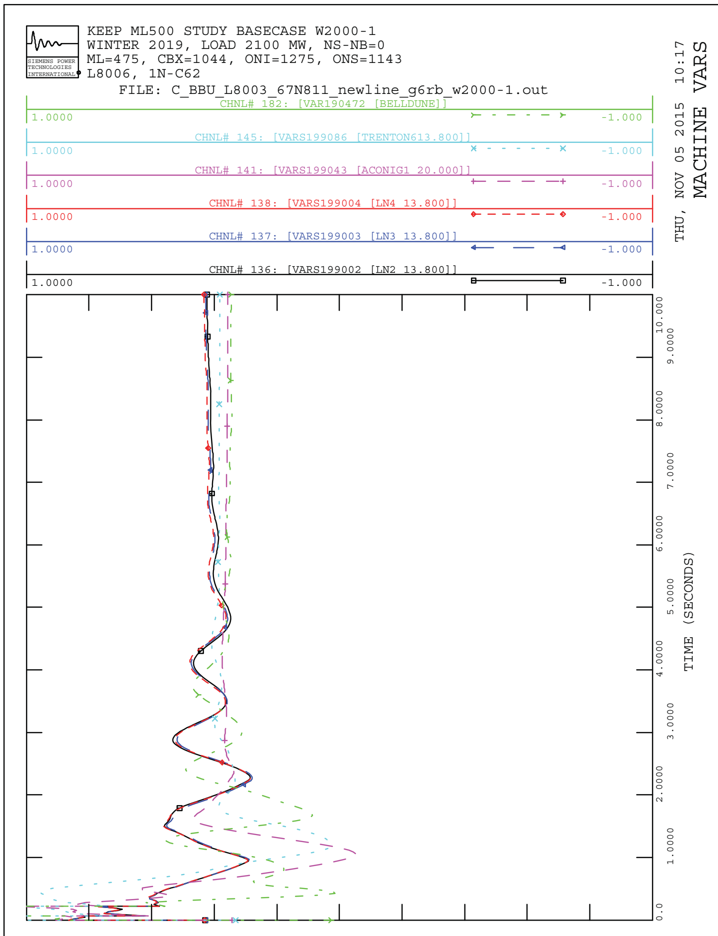
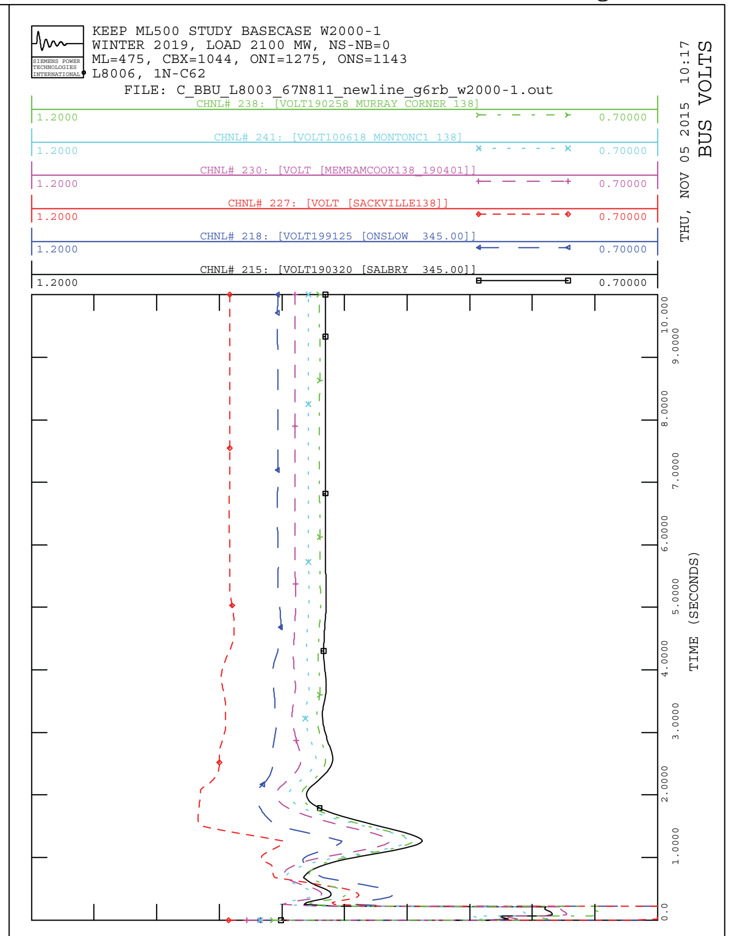
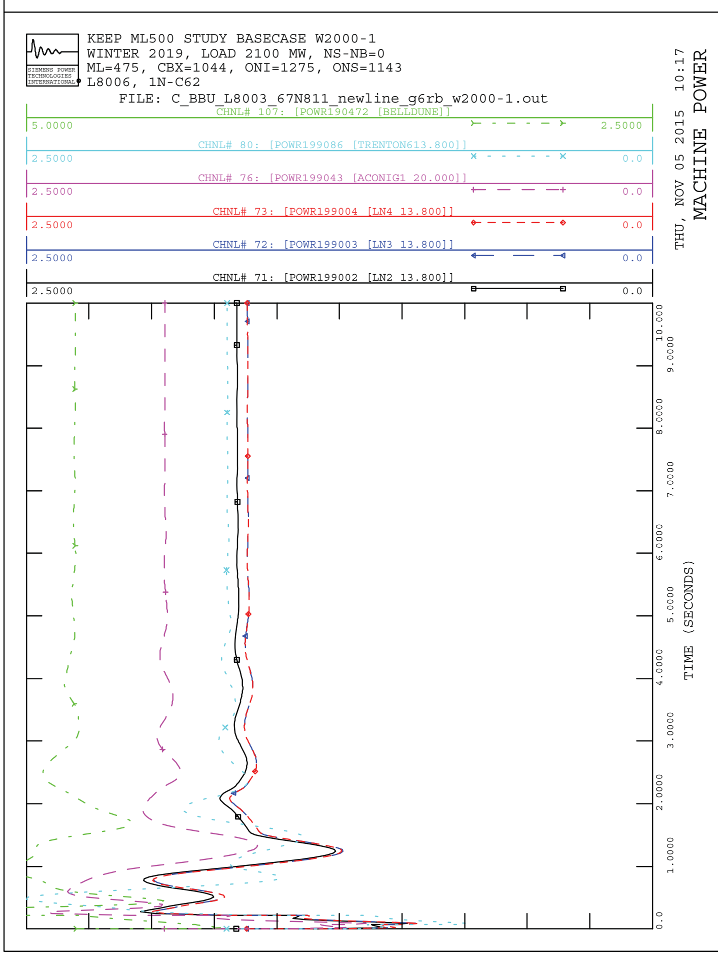
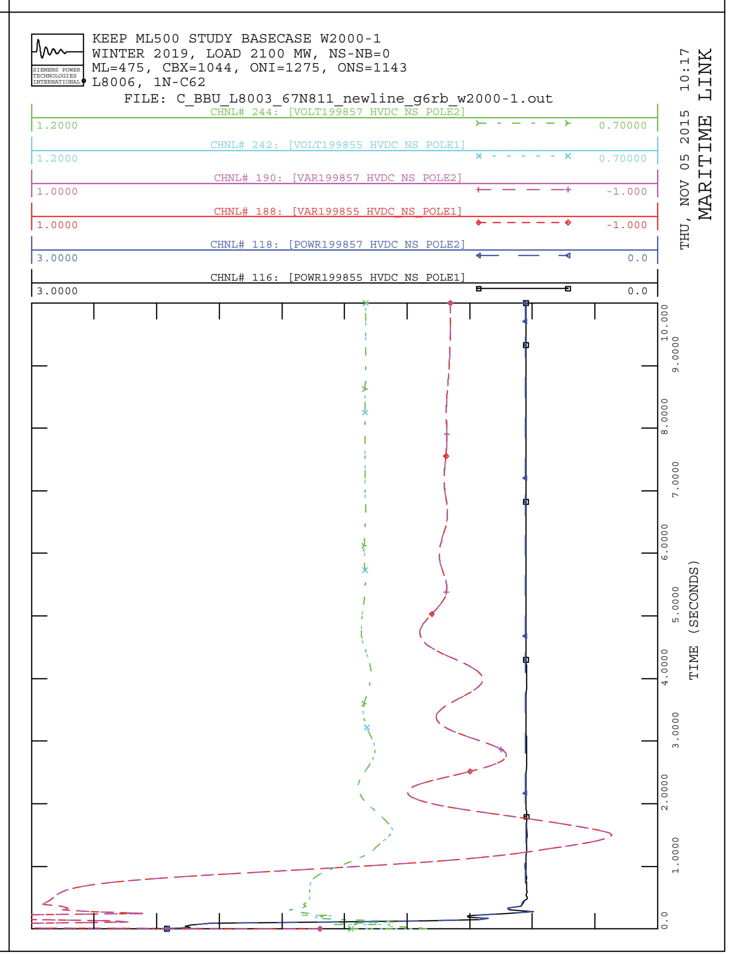
CHNL# 116: [POWR199855 HVDC NS POLE1]
THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)

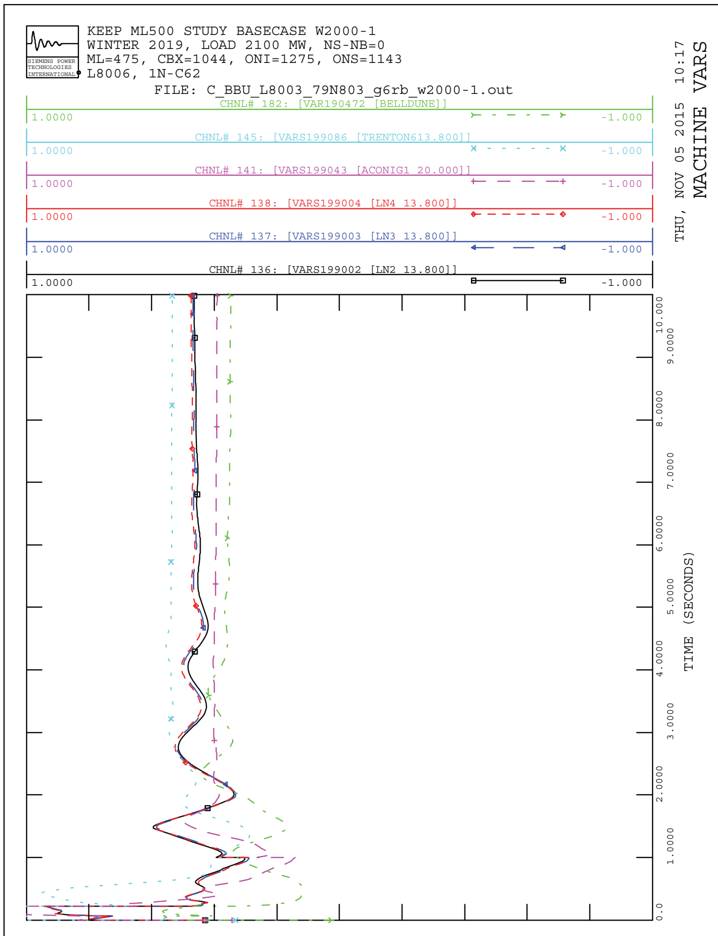
REDACTED (CONFIDENTIAL INFORMATION REMOVED)

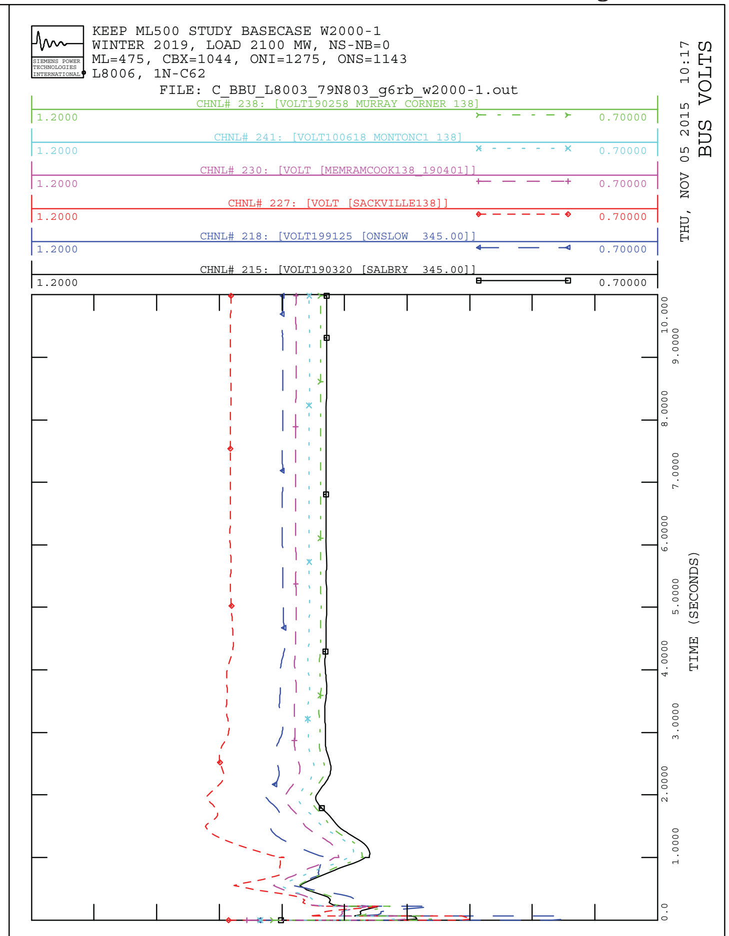


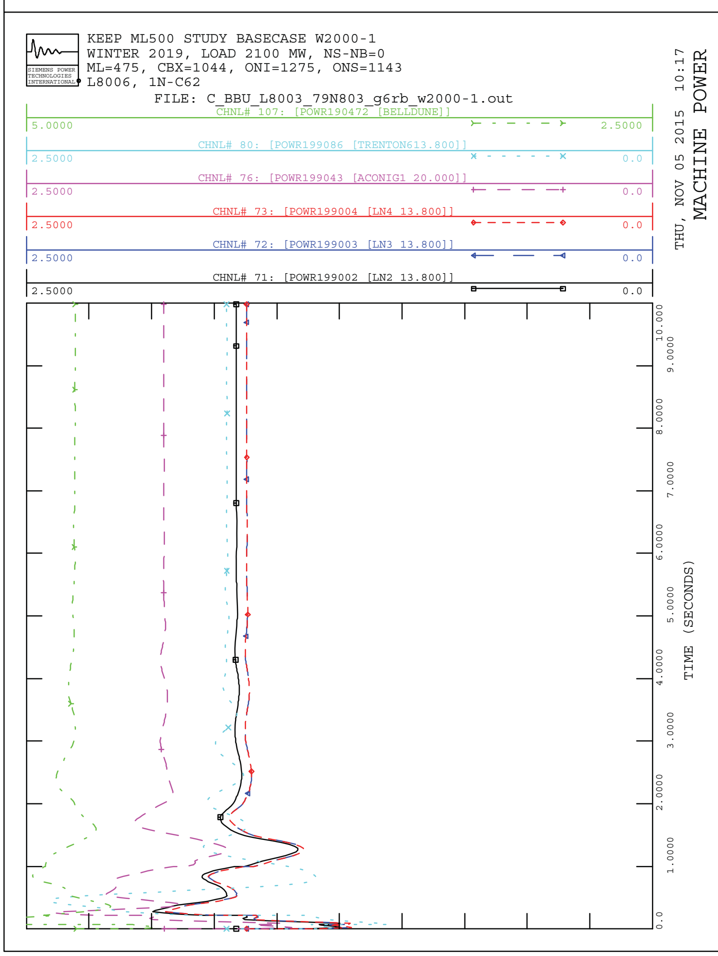







SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8003_79N803_g6rb_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000
TIME (SECONDS)
THU, NOV 05 2015 10:17
MACHINE VARS


SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8003_79N803_g6rb_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138_190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000
TIME (SECONDS)
THU, NOV 05 2015 10:17
BUS VOLTS


SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8003_79N803_g6rb_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
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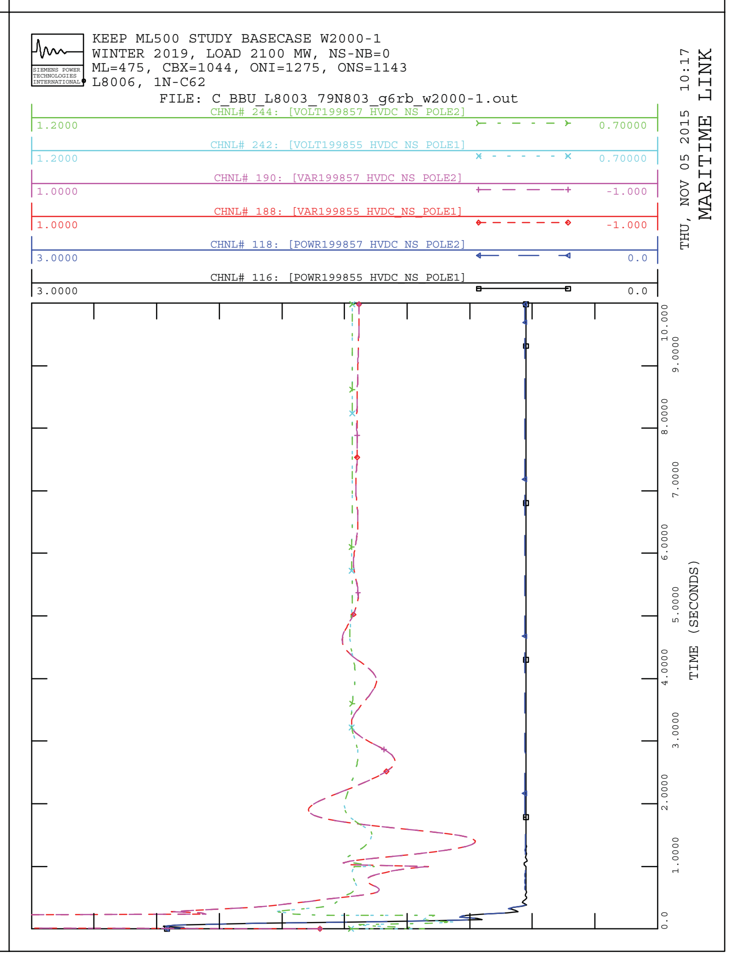
MACHINE POWER


SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8003_79N803_g6rb_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
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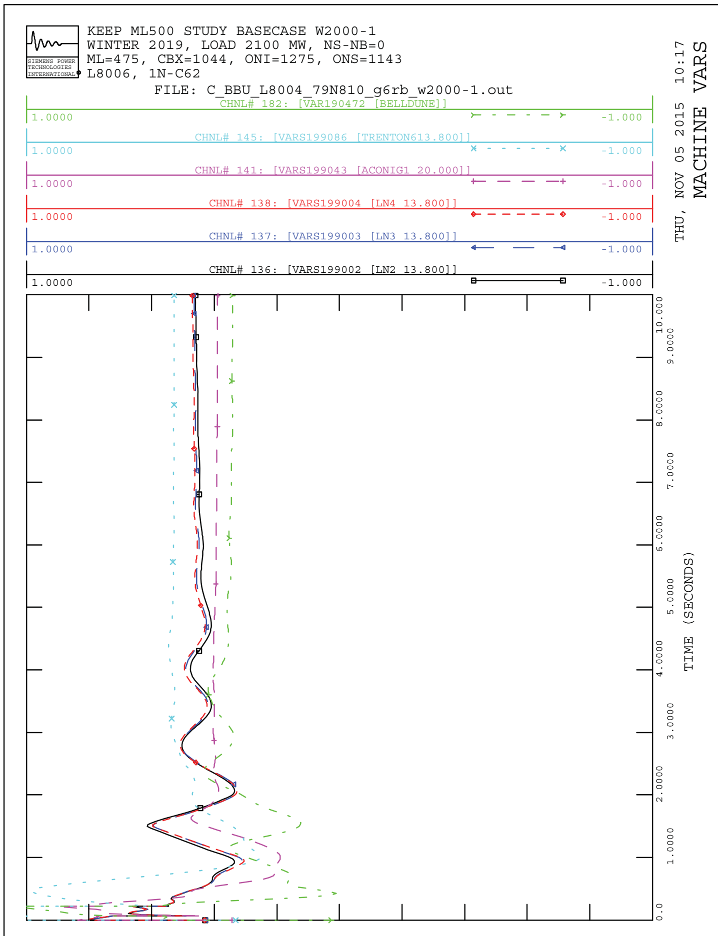
TIME (SECONDS)
THU, NOV 05 2015 10:17
MARITIME LINK



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8004_79N810_g6rb_w2000-1.out
CHNL# 182: [VAR190472 [BELLDUNE]]
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CHNL# 145: [VARS199086 [TRENTON613.800]]
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CHNL# 141: [VARS199043 [ACONIG1 20.000]]
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CHNL# 138: [VARS199004 [LN4 13.800]]
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CHNL# 137: [VARS199003 [LN3 13.800]]
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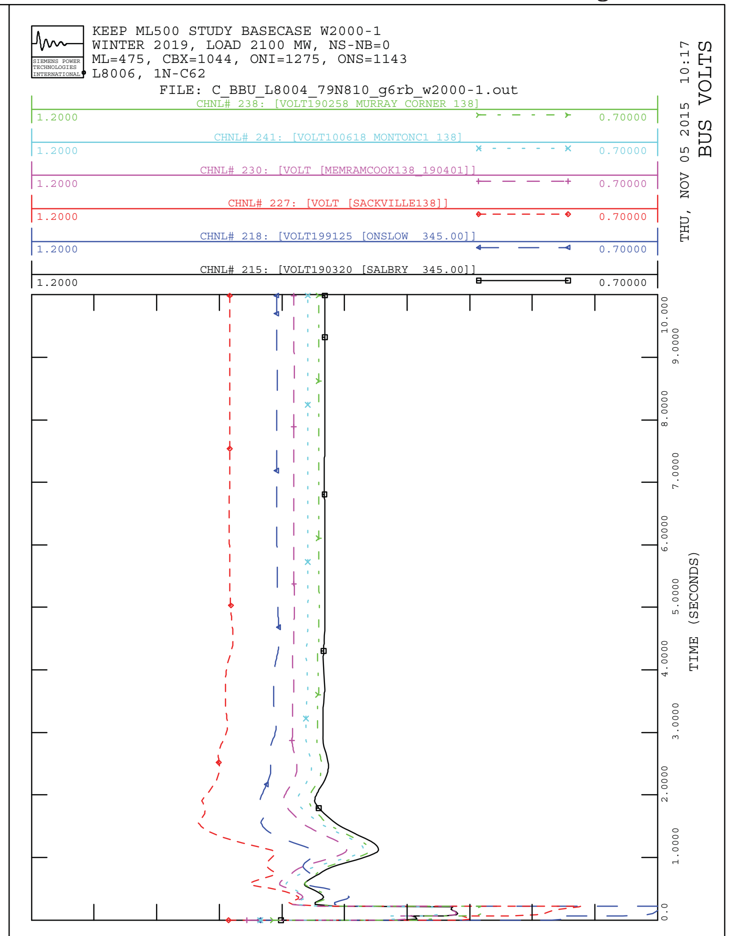
THU, NOV 05 2015 10:17
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8004_79N810_g6rb_w2000-1.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
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CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
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0.70000
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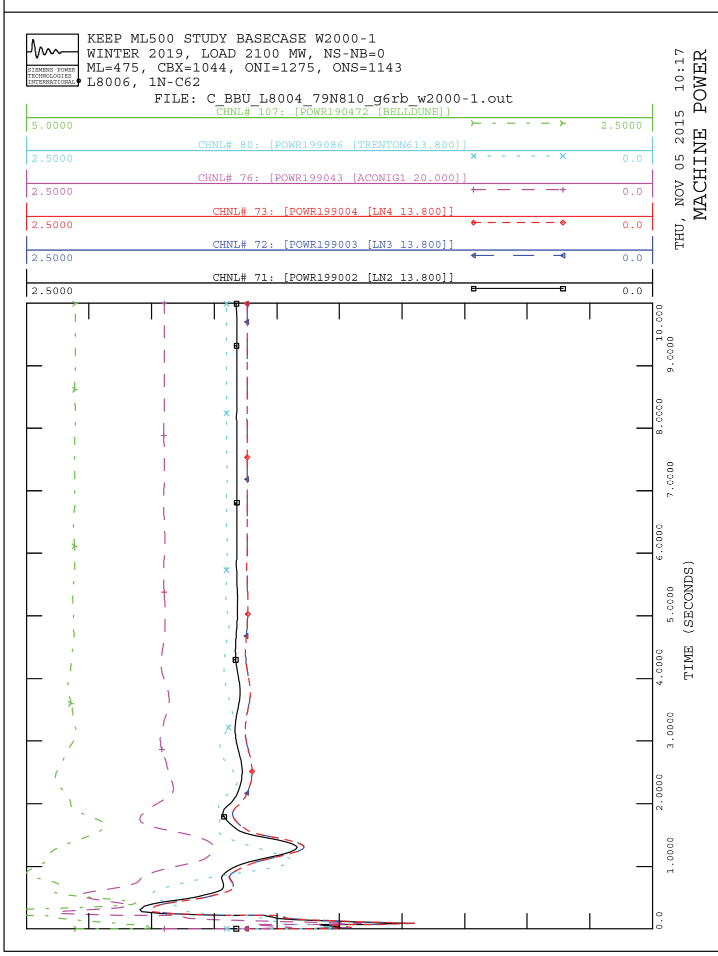
1.2000
0.70000
THU, NOV 05 2015 10:17
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8004_79N810_g6rb_w2000-1.out
CHNL# 107: [POWR190472 [BELLDUNE]]
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2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
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CHNL# 73: [POWR199004 [LN4 13.800]]
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CHNL# 72: [POWR199003 [LN3 13.800]]
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2.5000
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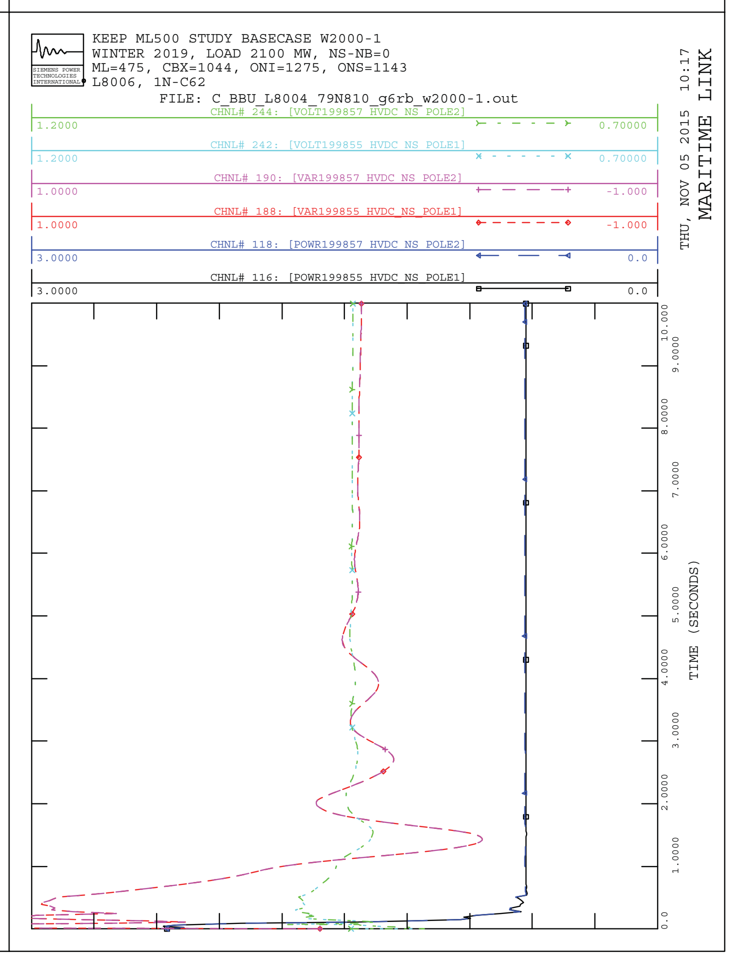
THU, NOV 05 2015 10:17
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-1
WINTER 2019, LOAD 2100 MW, NS-NB=0
ML=475, CBX=1044, ONI=1275, ONS=1143
L8006, 1N-C62
FILE: C_BBU_L8004_79N810_g6rb_w2000-1.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
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THU, NOV 05 2015 10:17
MARITIME LINK
TIME (SECONDS)

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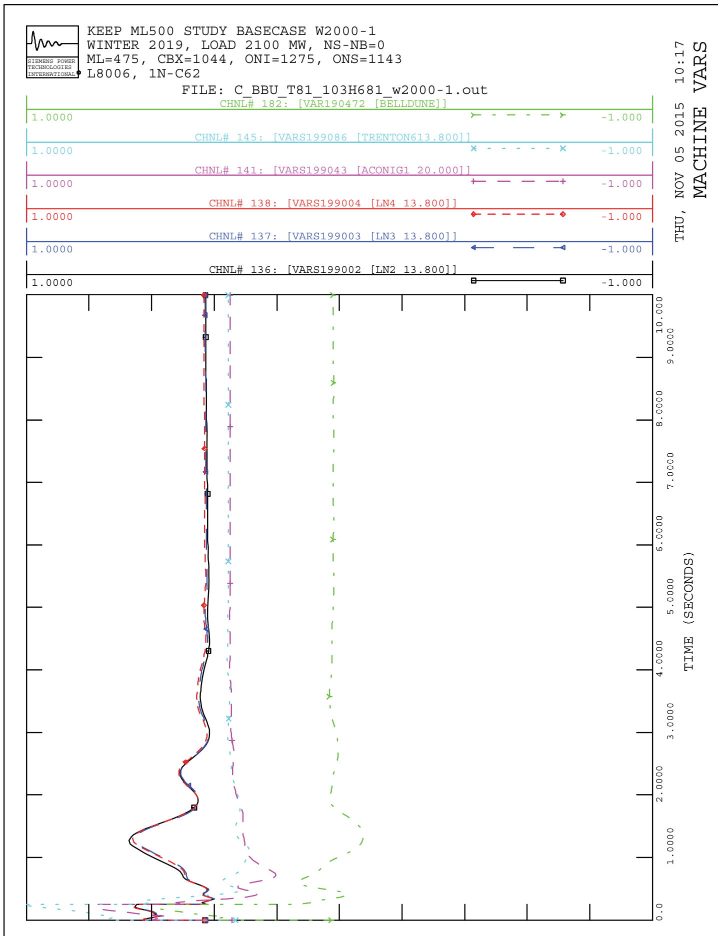

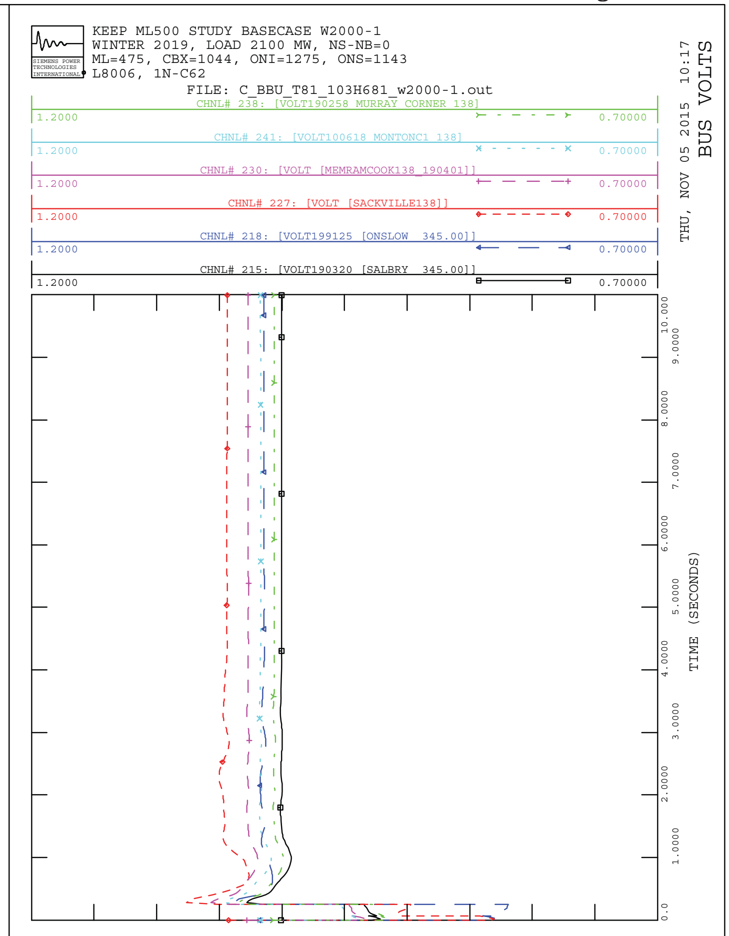

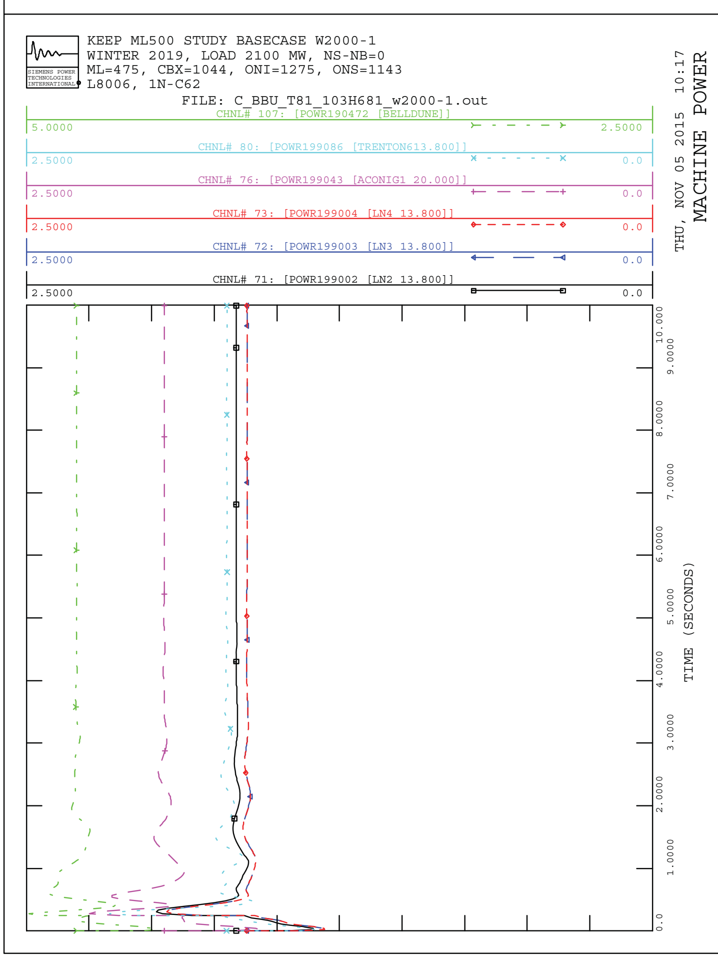

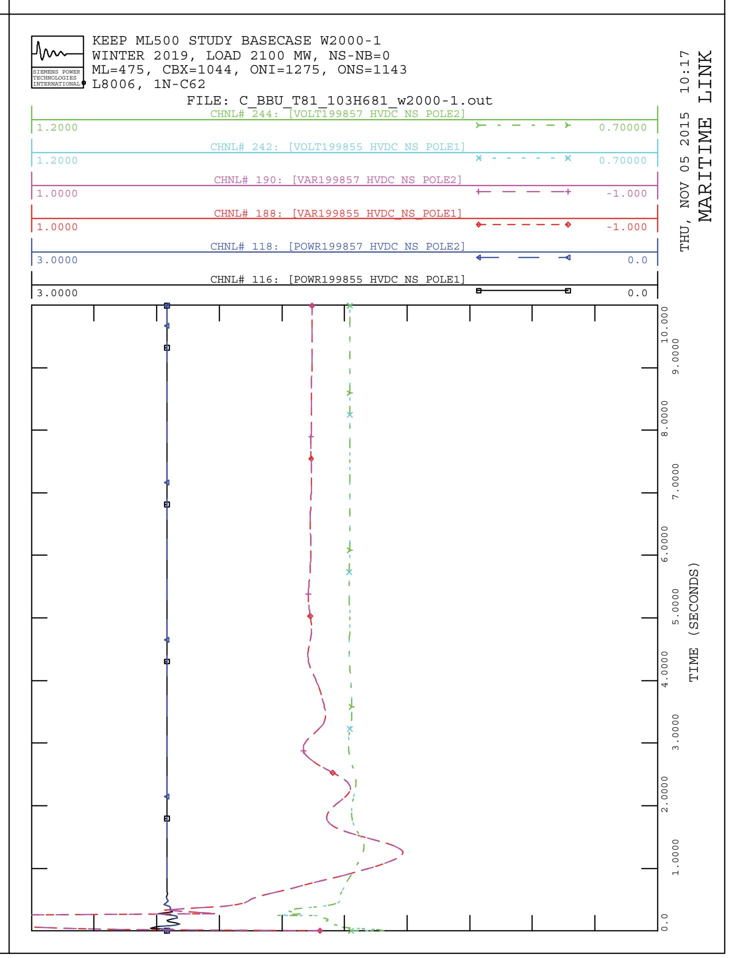

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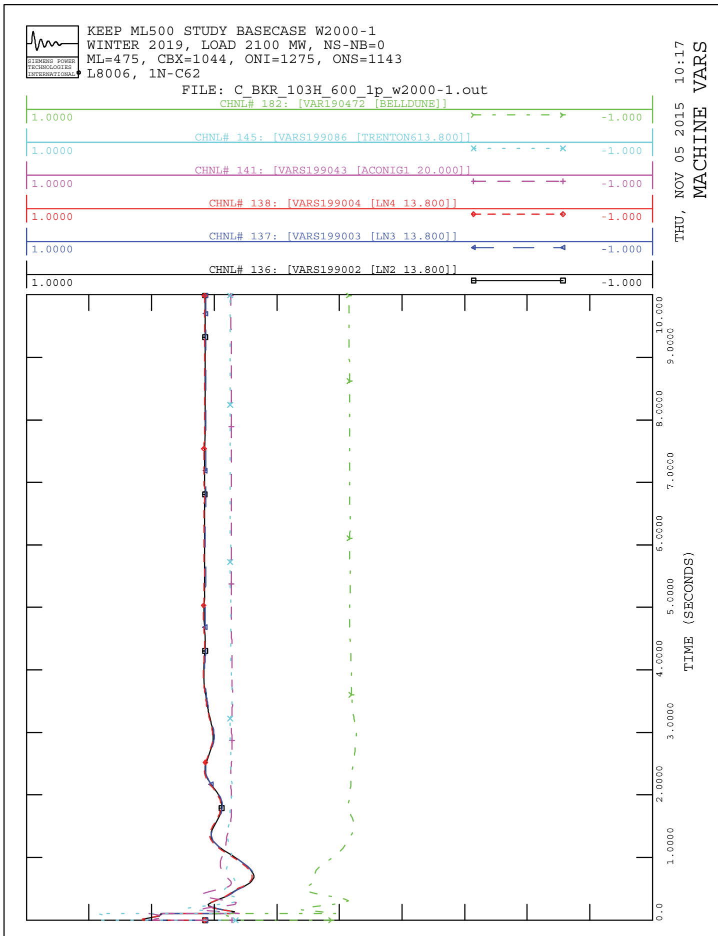

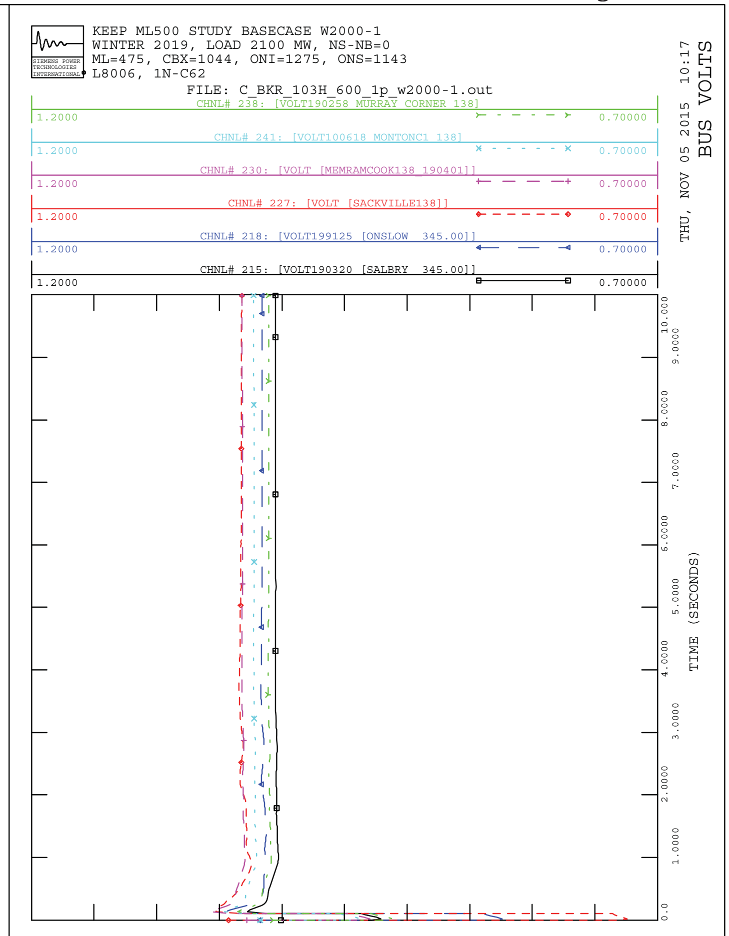

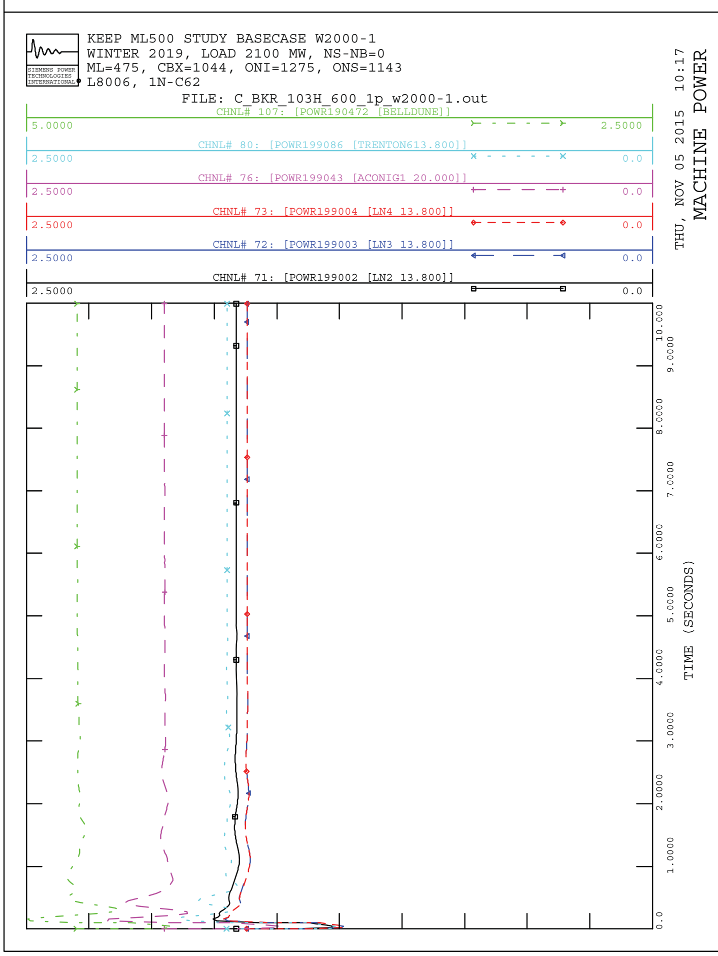

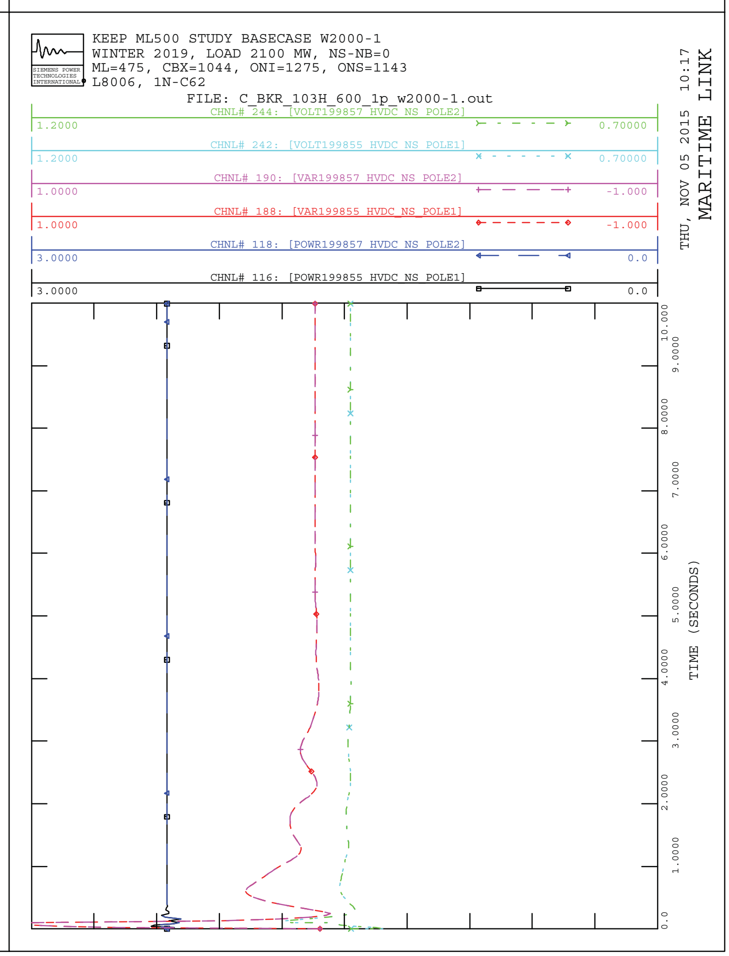

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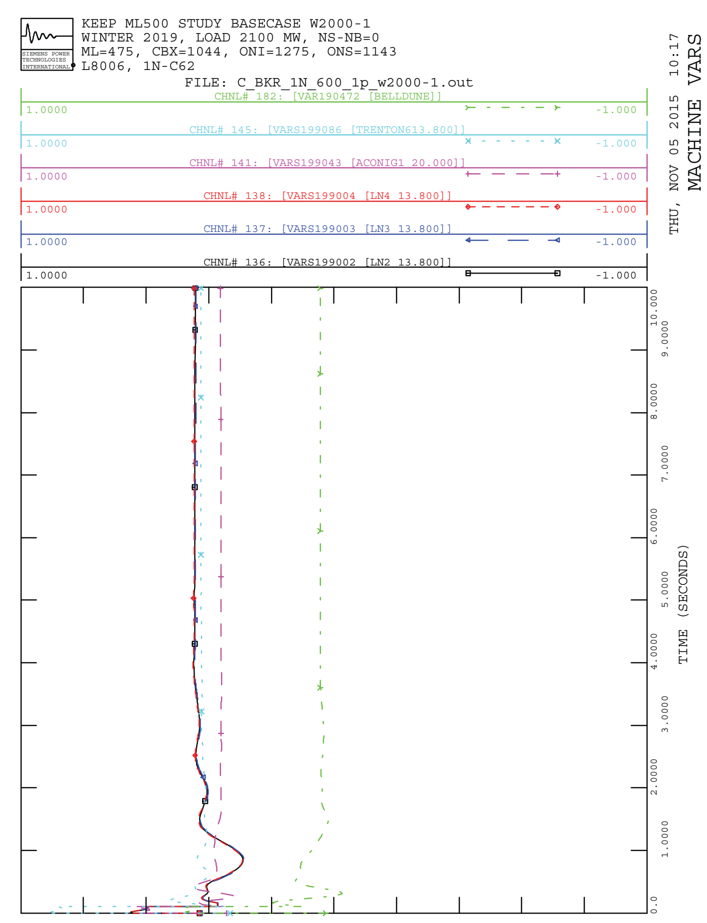

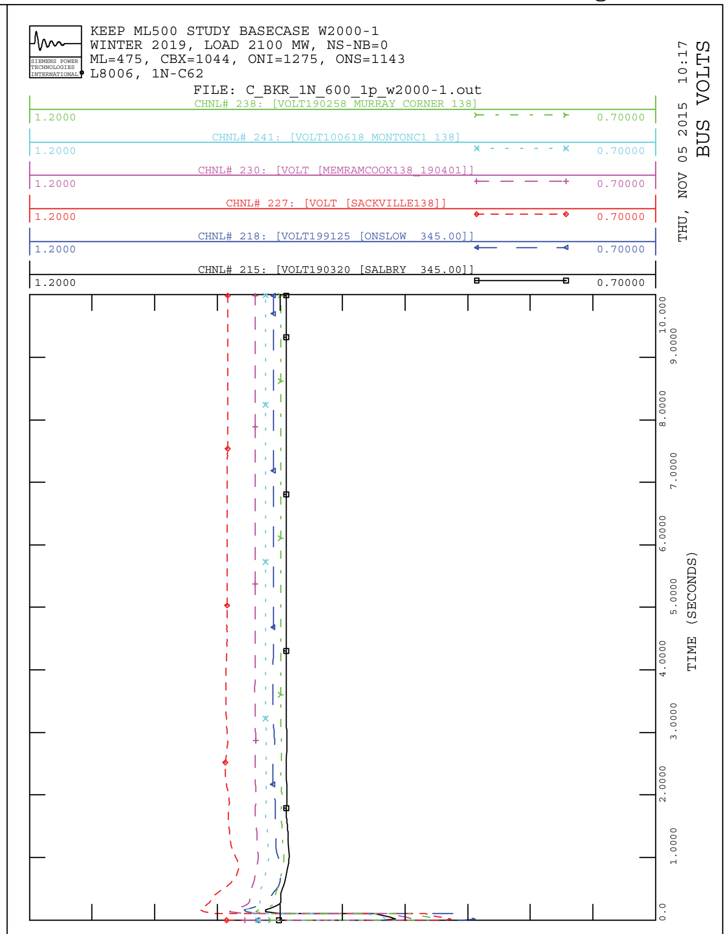

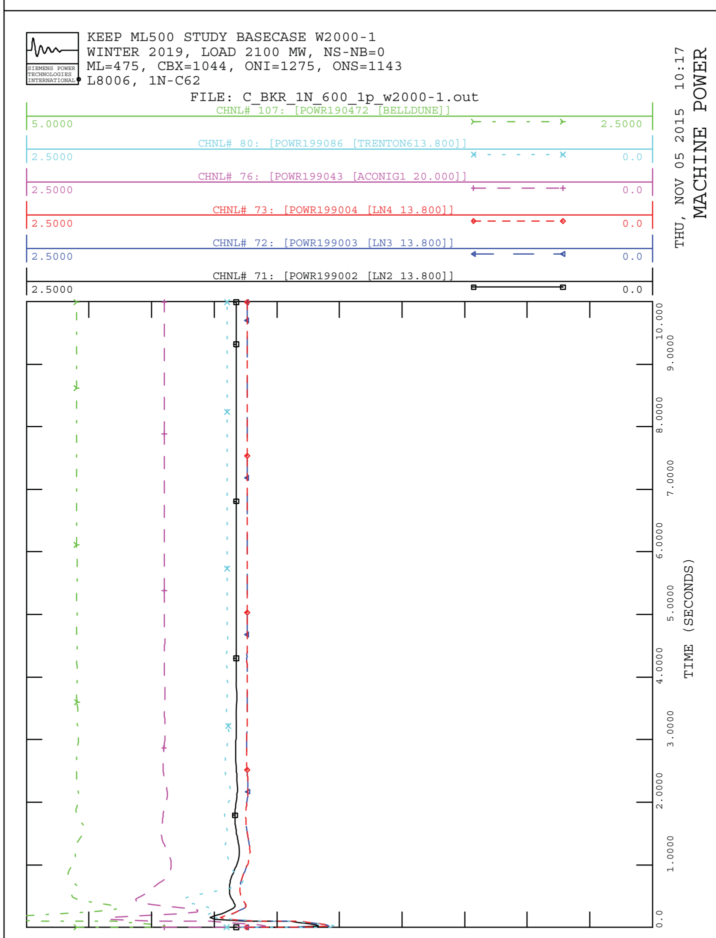

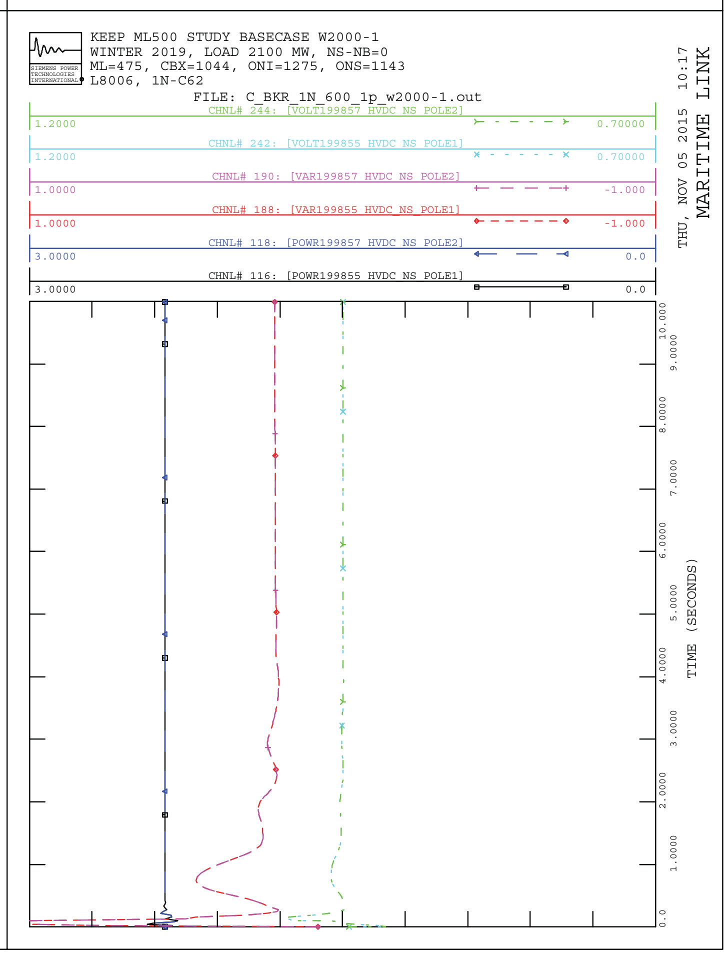

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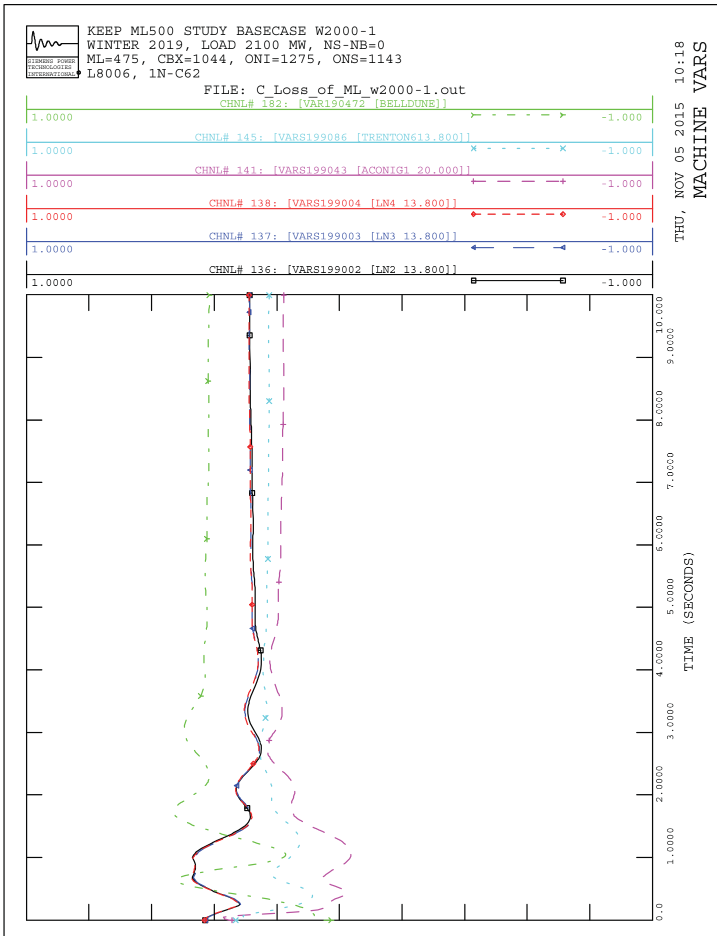

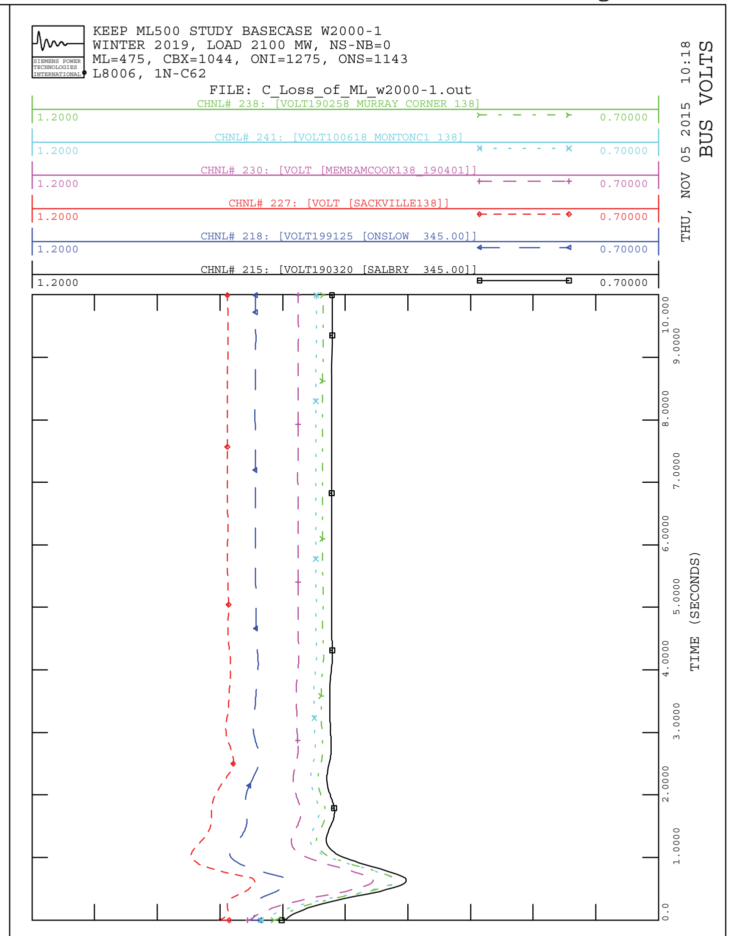

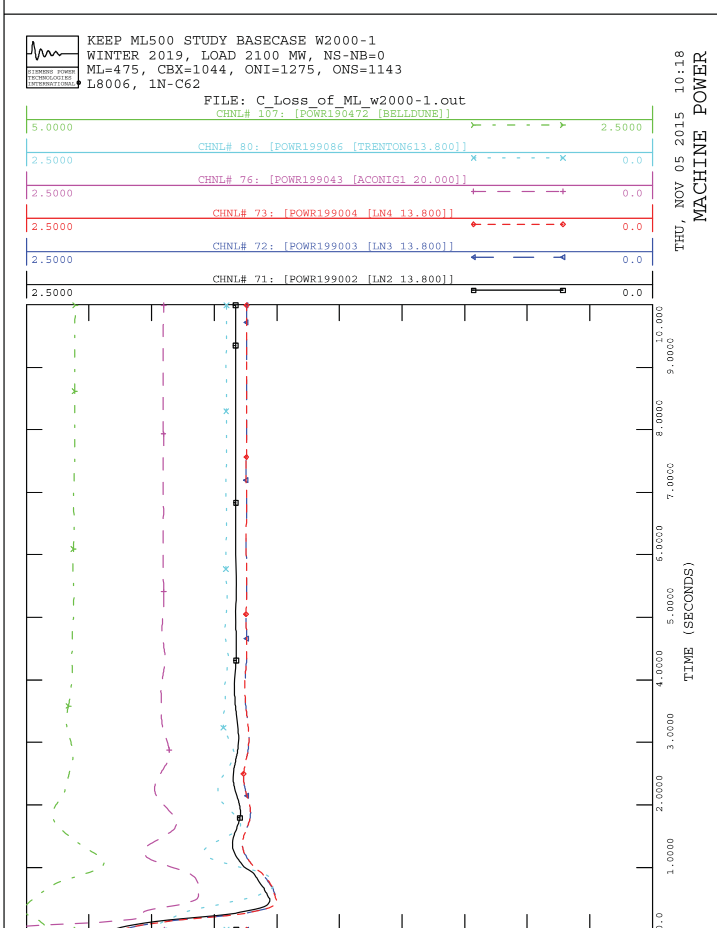

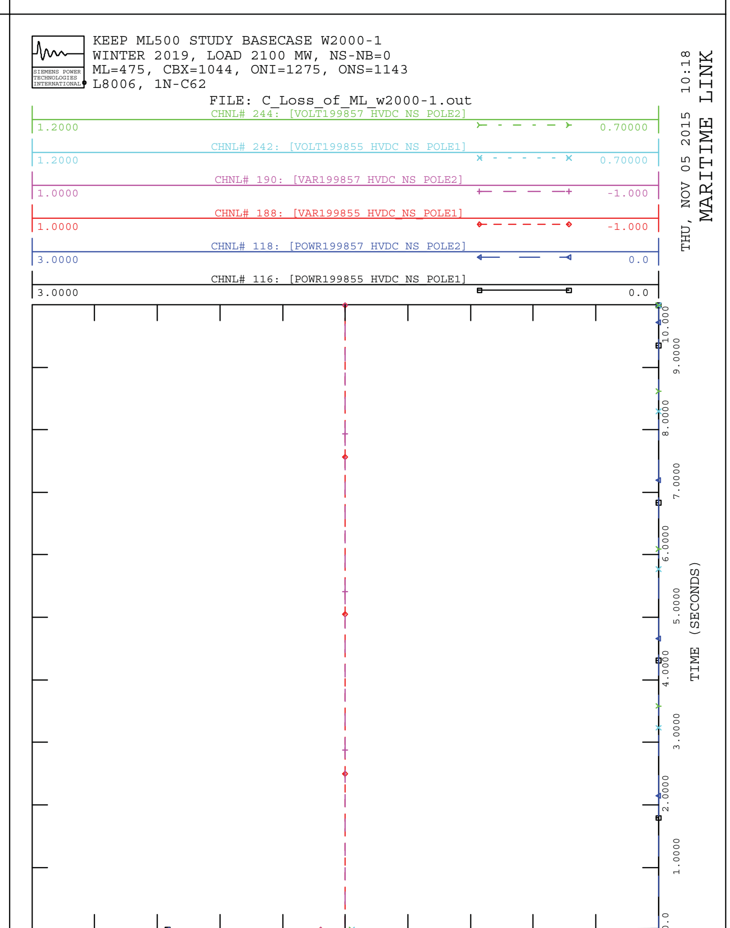

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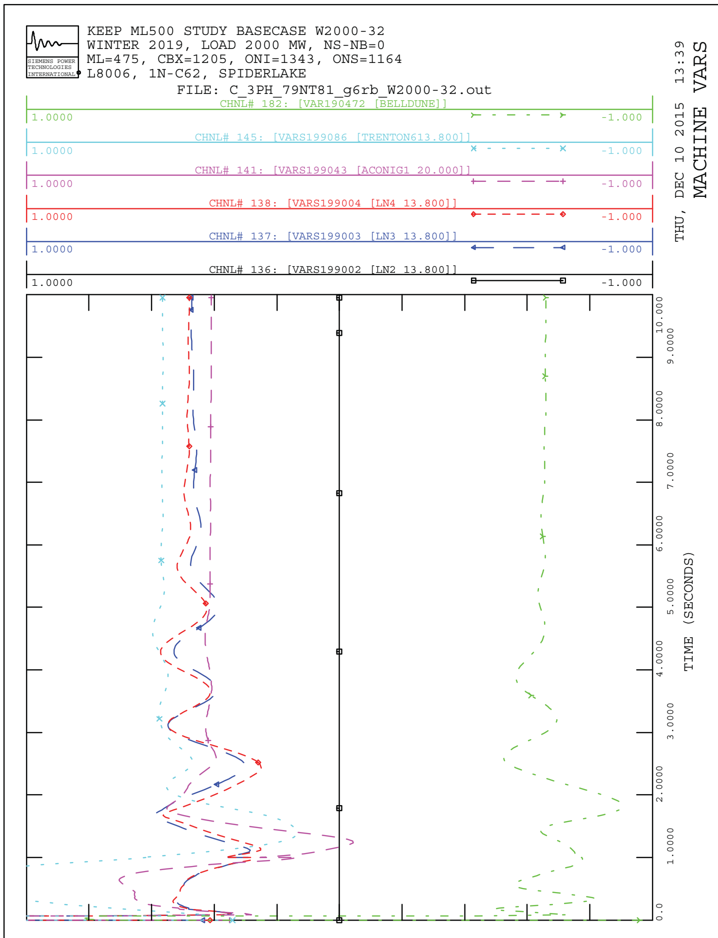
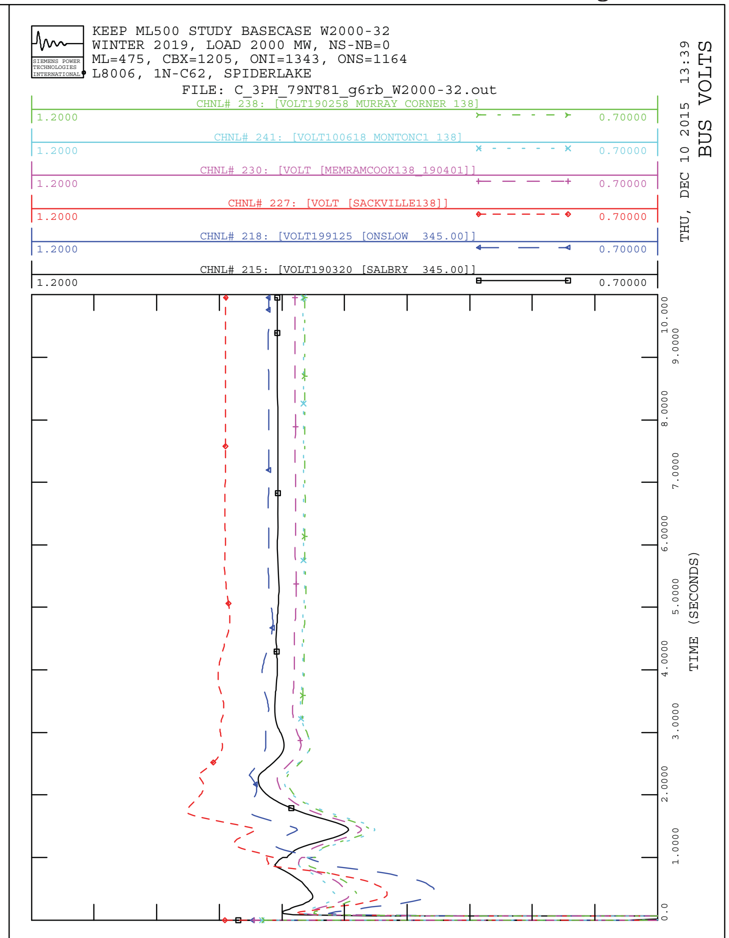
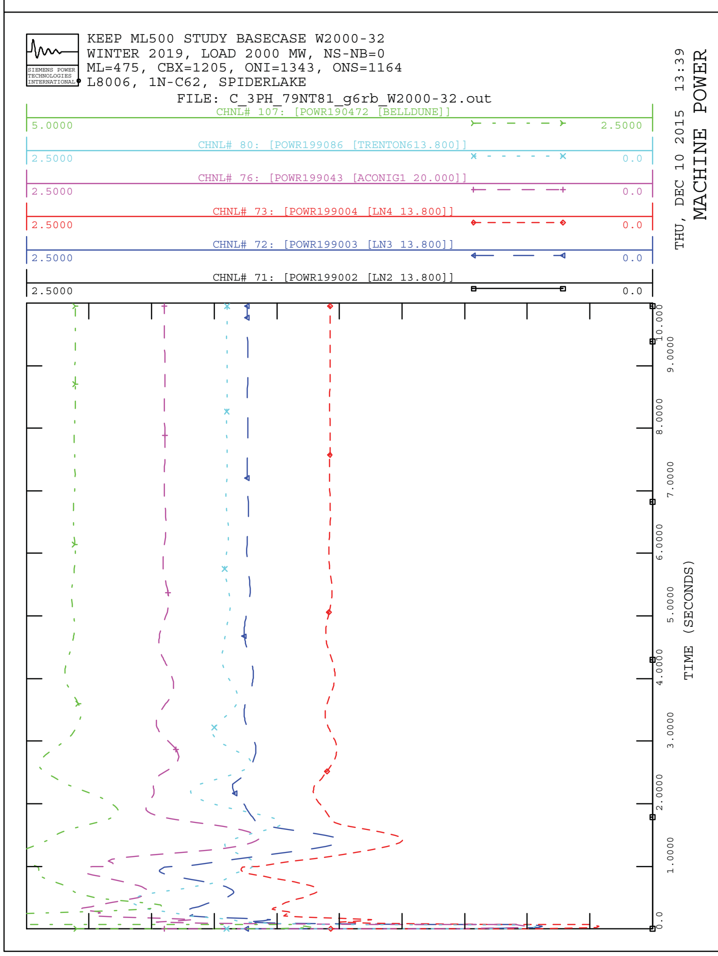
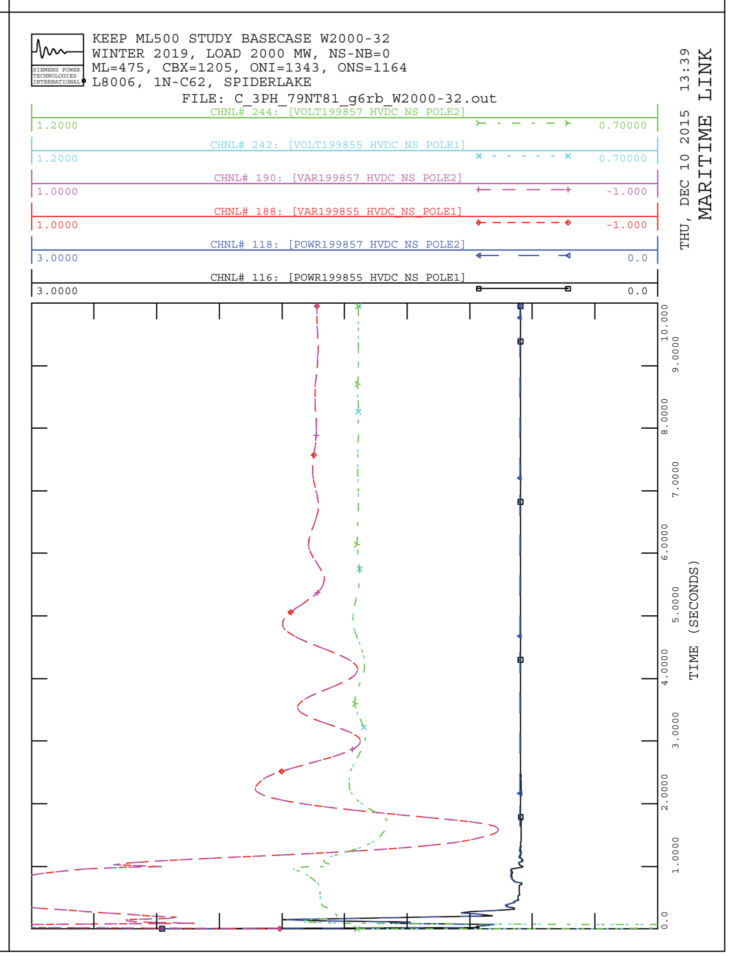
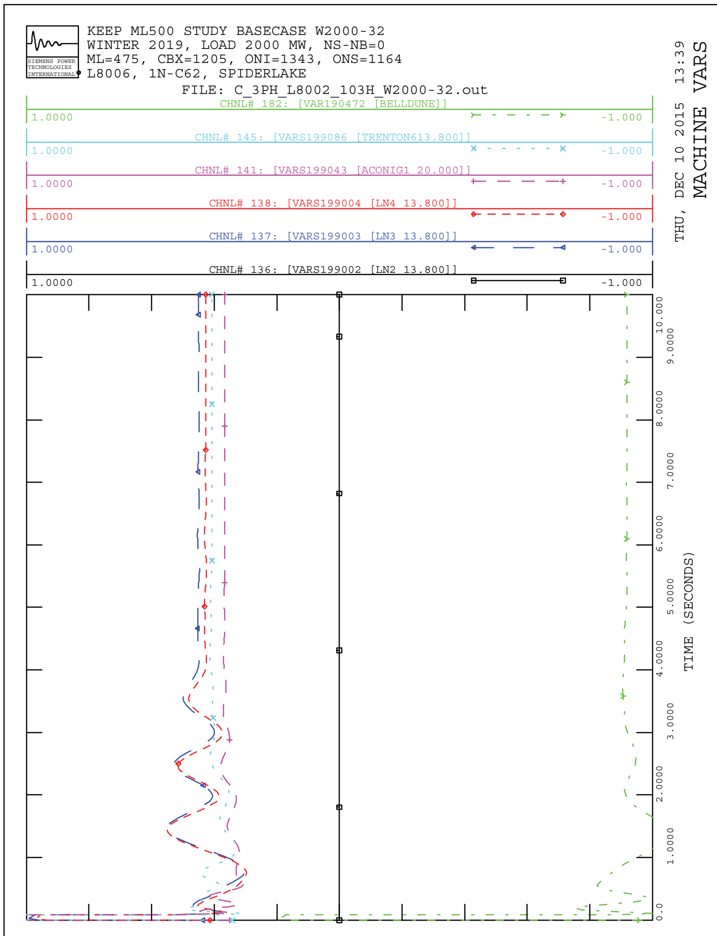
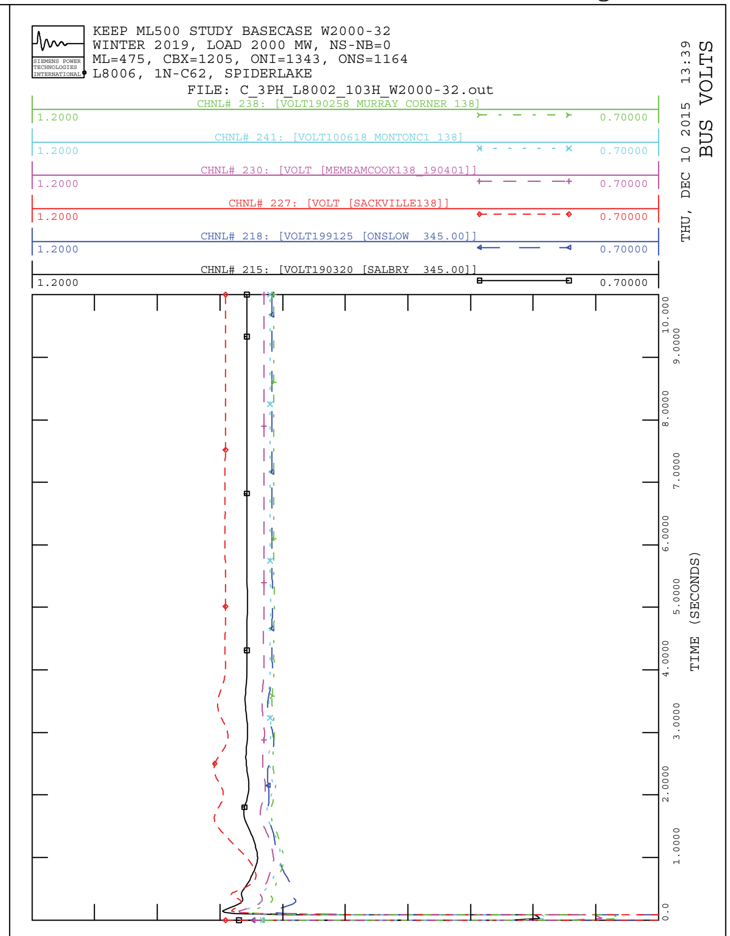


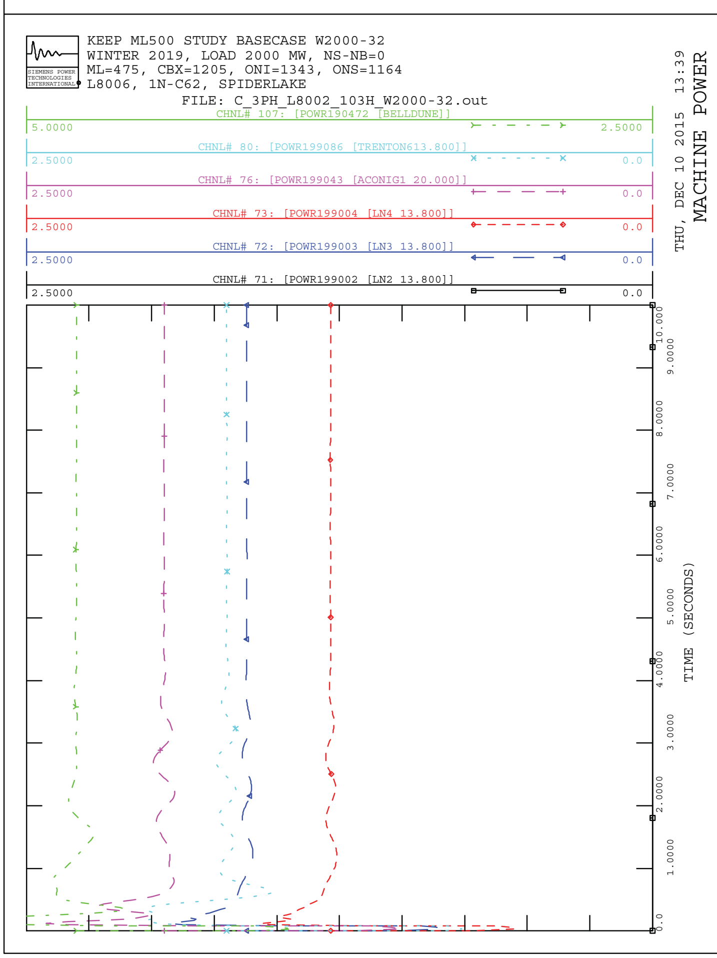







KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8002_103H_W2000-32.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
THU, DEC 10 2015 13:39
MACHINE VARS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8002_103H_W2000-32.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
THU, DEC 10 2015 13:39
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8002_103H_W2000-32.out
CHNL# 107: [POWR190472 [BELLDUNE]]
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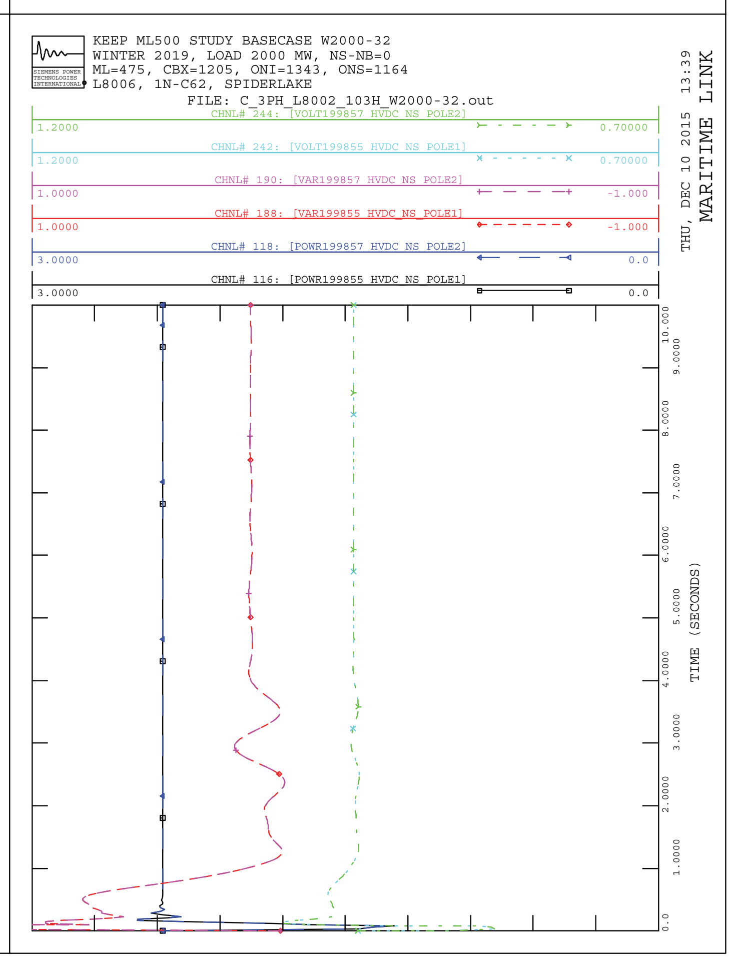
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
THU, DEC 10 2015 13:39
MACHINE POWER
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8002_103H_W2000-32.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
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CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
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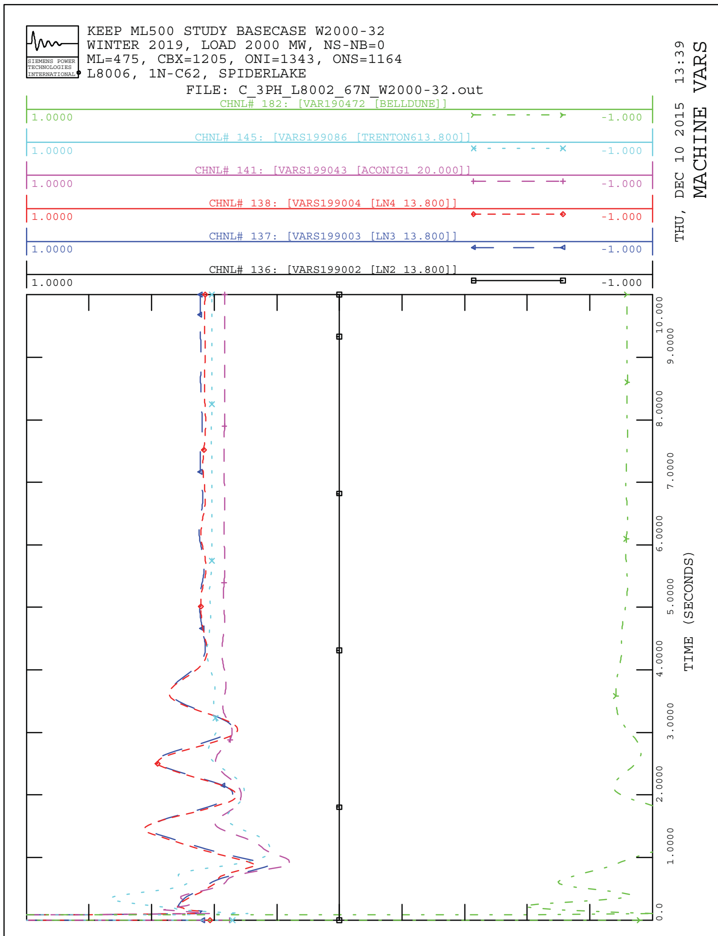
CHNL# 116: [POWR199855 HVDC NS POLE1]
THU, DEC 10 2015 13:39
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8002_67N_W2000-32.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
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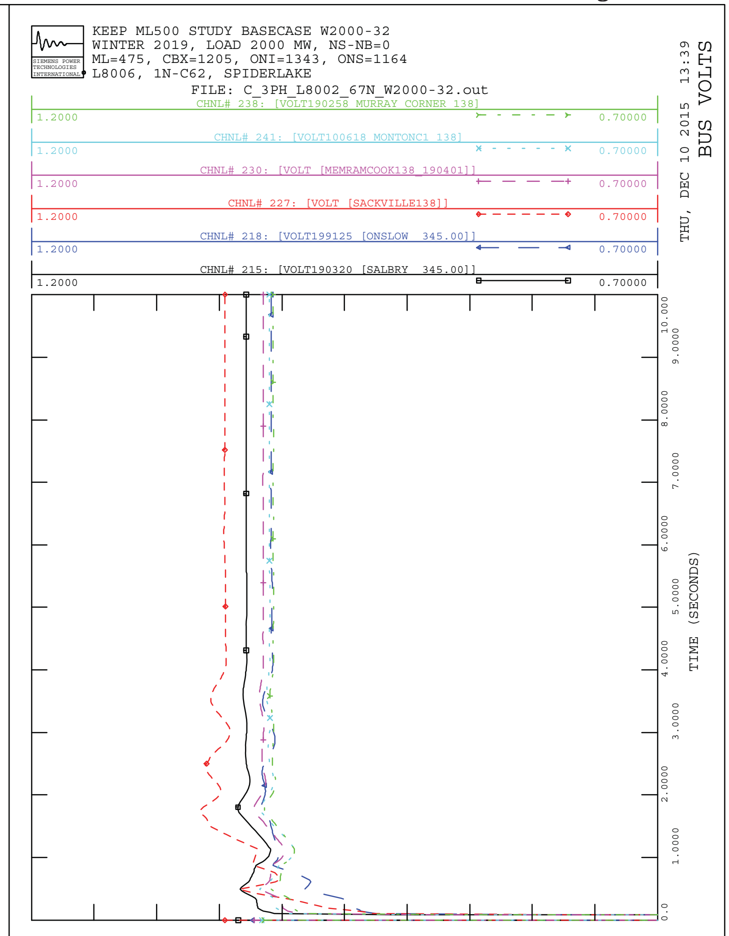
-1.000
THU, DEC 10 2015 13:39
MACHINE VARS
TIME (SECONDS)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WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8002_67N_W2000-32.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
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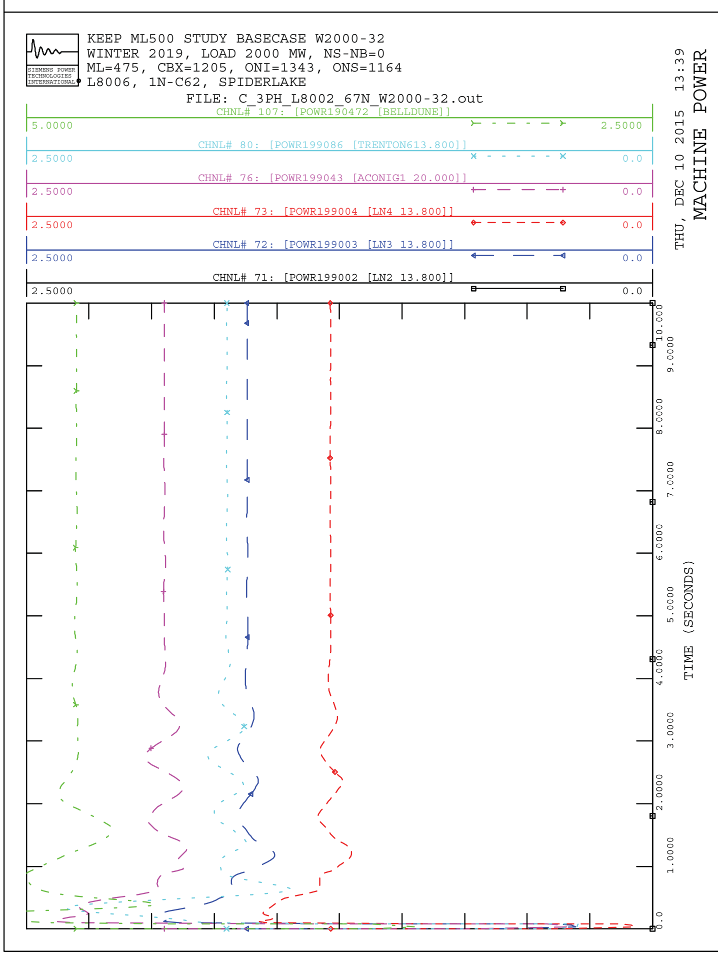
THU, DEC 10 2015 13:39
BUS VOLTS
TIME (SECONDS)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WINTER 2019, LOAD 2000 MW, NS-NB=0
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L8006, 1N-C62, SPIDERLAKE
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CHNL# 107: [POWR190472 [BELLDUNE]]
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2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
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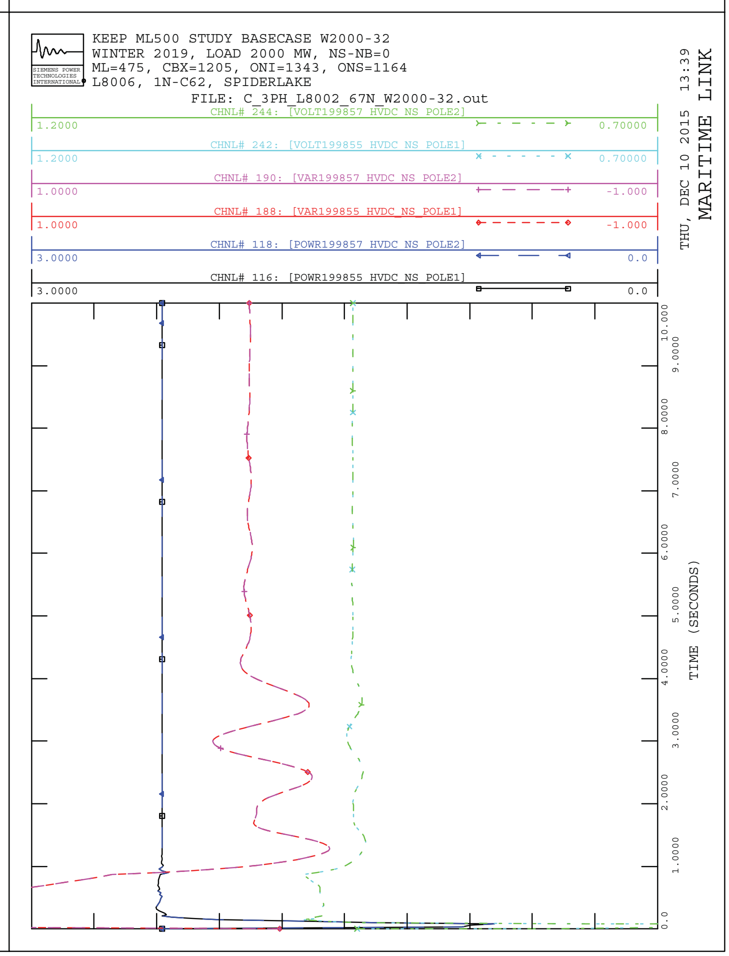
MACHINE POWER
TIME (SECONDS)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WINTER 2019, LOAD 2000 MW, NS-NB=0
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L8006, 1N-C62, SPIDERLAKE
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CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
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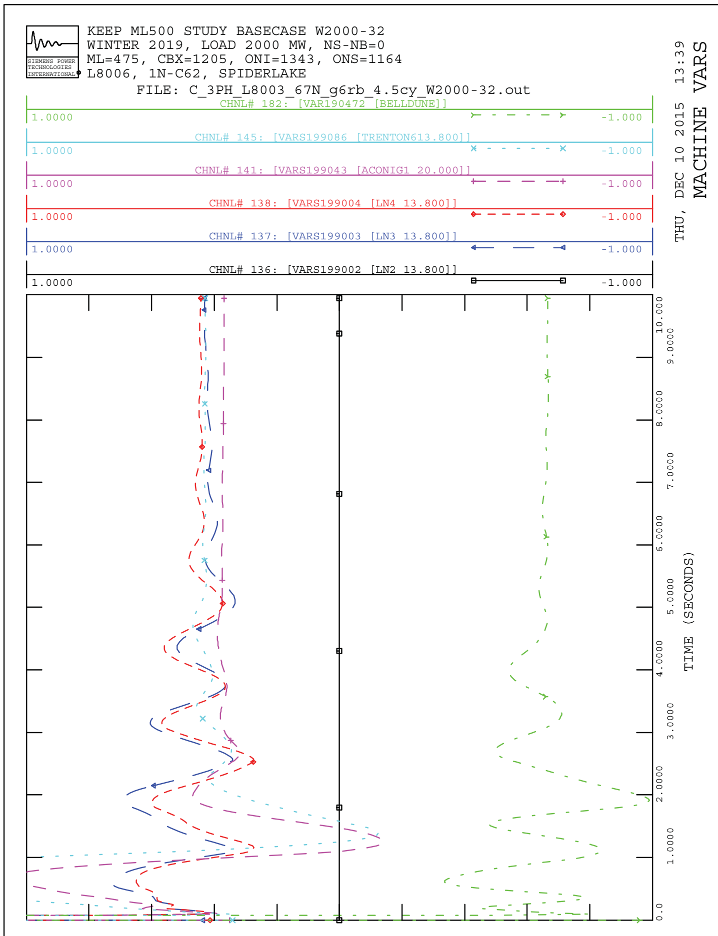
THU, DEC 10 2015 13:39
MARITIME LINK
TIME (SECONDS)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WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
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CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
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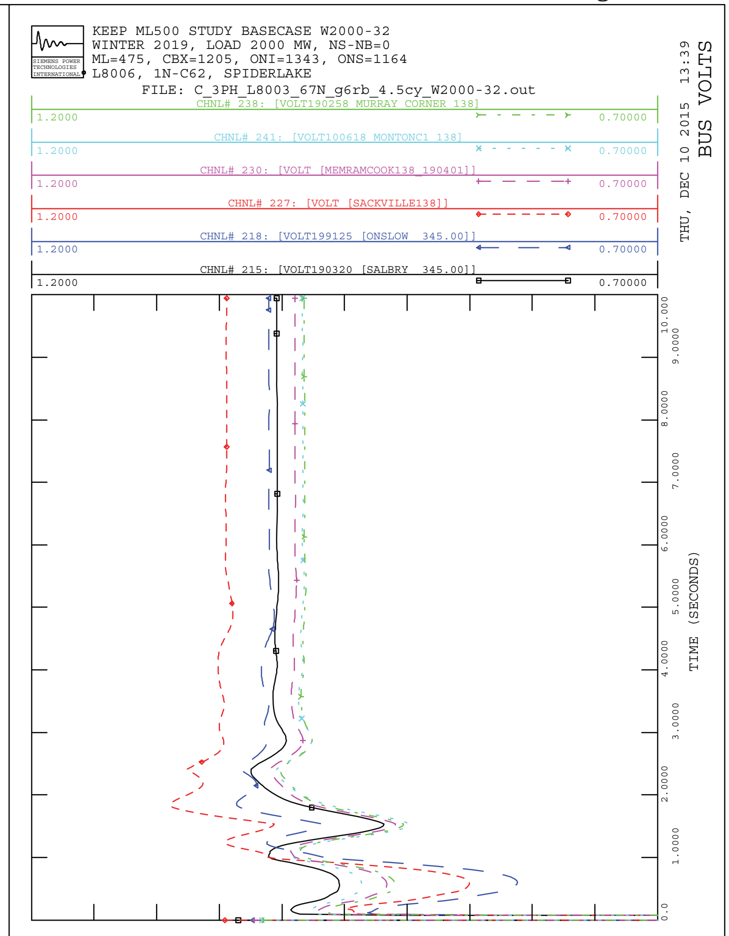
THU, DEC 10 2015 13:39
MACHINE VARS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-32
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L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4.5cy_W2000-32.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
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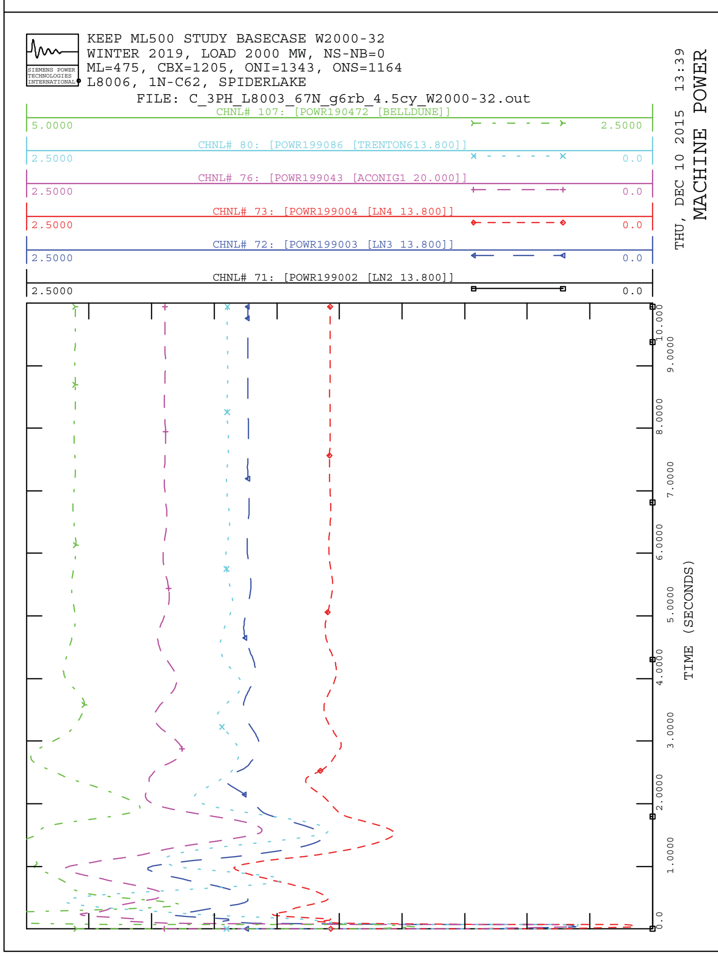
BUS VOLTS
TIME (SECONDS)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L8006, 1N-C62, SPIDERLAKE
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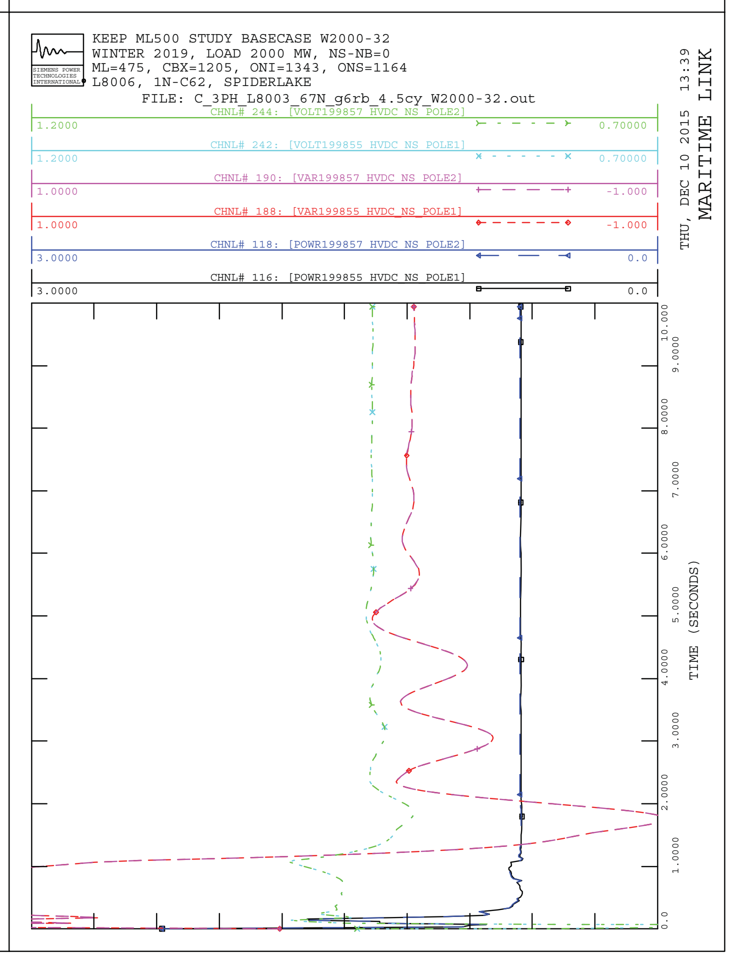
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
THU, DEC 10 2015 13:39
MACHINE POWER
TIME (SECONDS)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WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4.5cy_W2000-32.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
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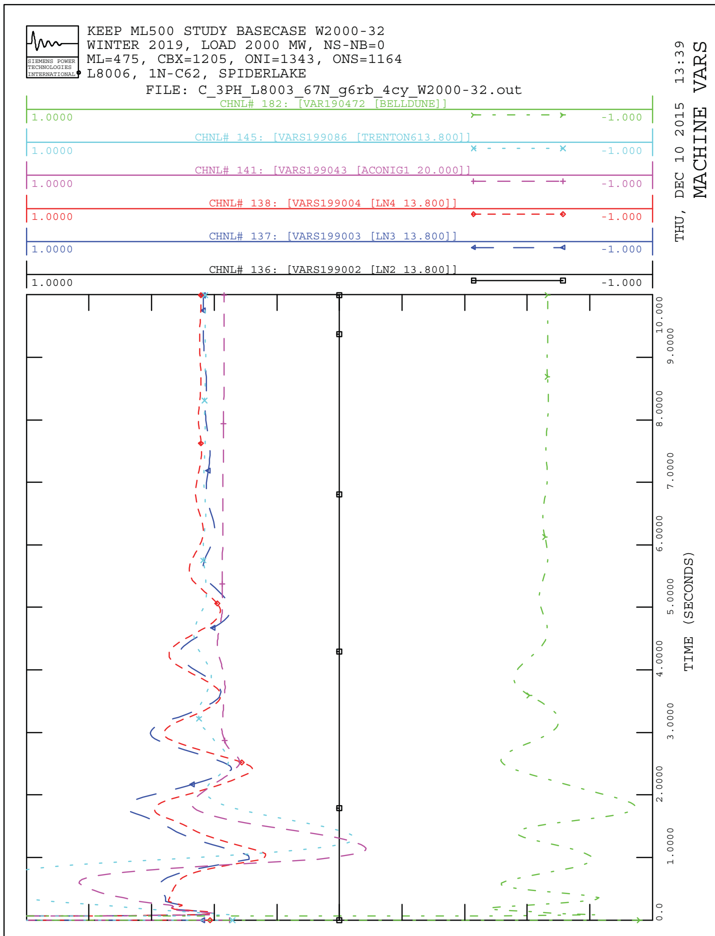
THU, DEC 10 2015 13:39
MARITIME LINK
TIME (SECONDS)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L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-32.out
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CHNL# 145: [VARS199086 [TRENTON613.800]]
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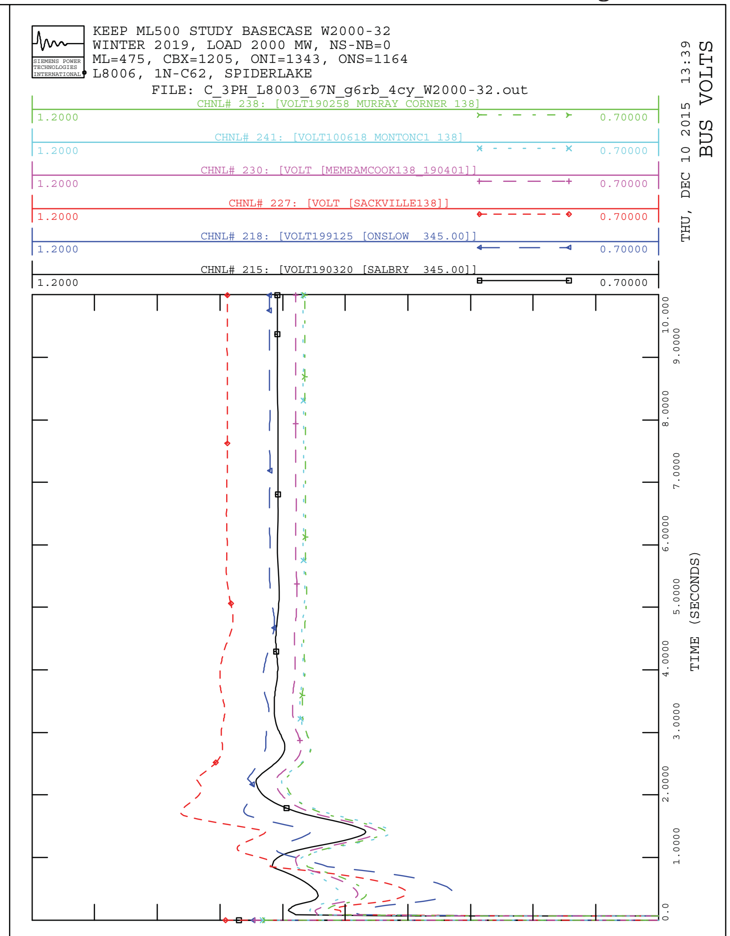
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
THU, DEC 10 2015 13:39
MACHINE VARS
TIME (SECONDS)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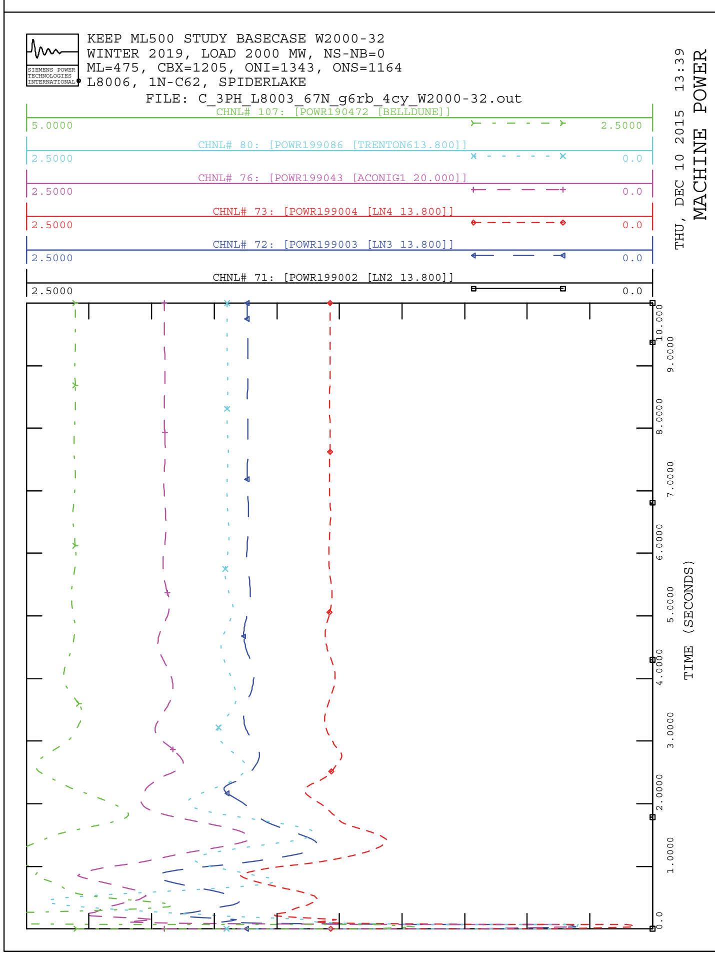
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-32.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
THU, DEC 10 2015 13:39
BUS VOLTS
TIME (SECONDS)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L8006, 1N-C62, SPIDERLAKE
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CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
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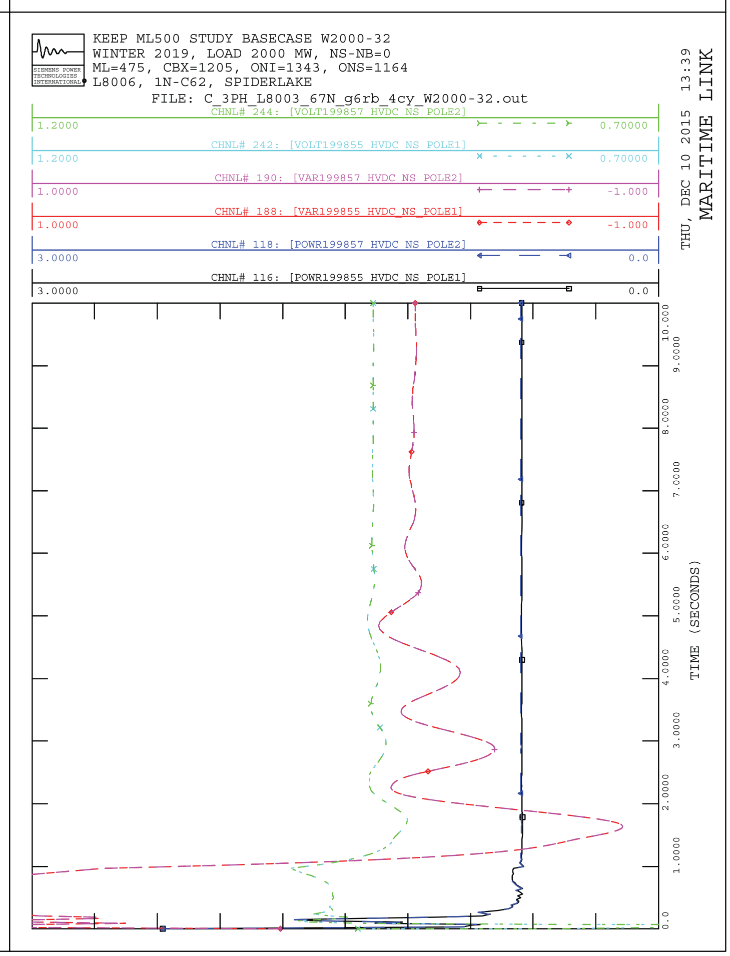
THU, DEC 10 2015 13:39
MACHINE POWER
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-32
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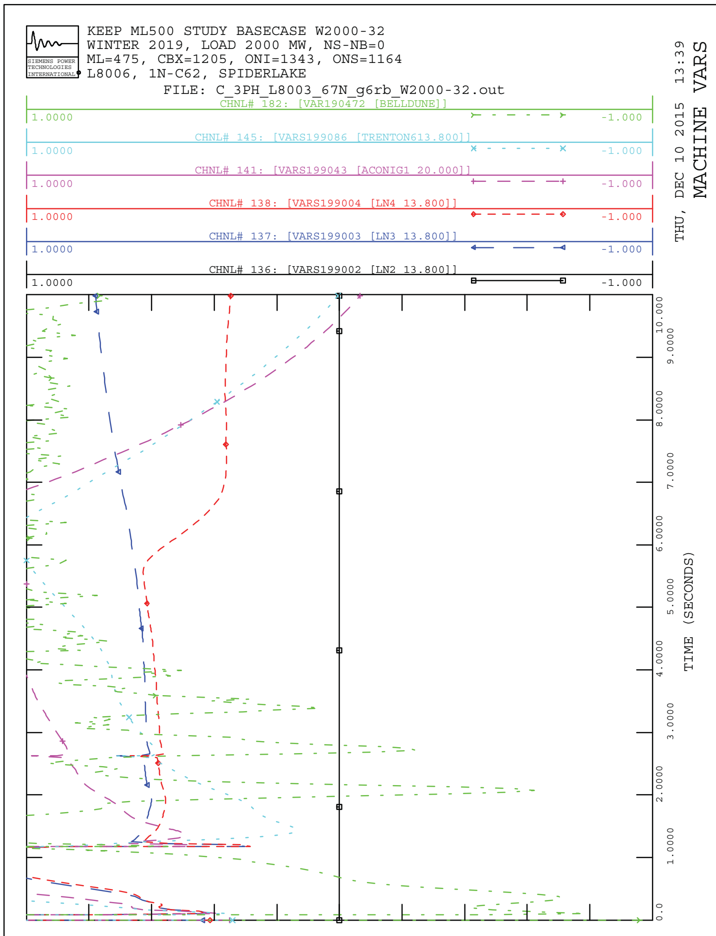
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-32.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
THU, DEC 10 2015 13:39
MARITIME LINK
TIME (SECONDS)



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ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_W2000-32.out
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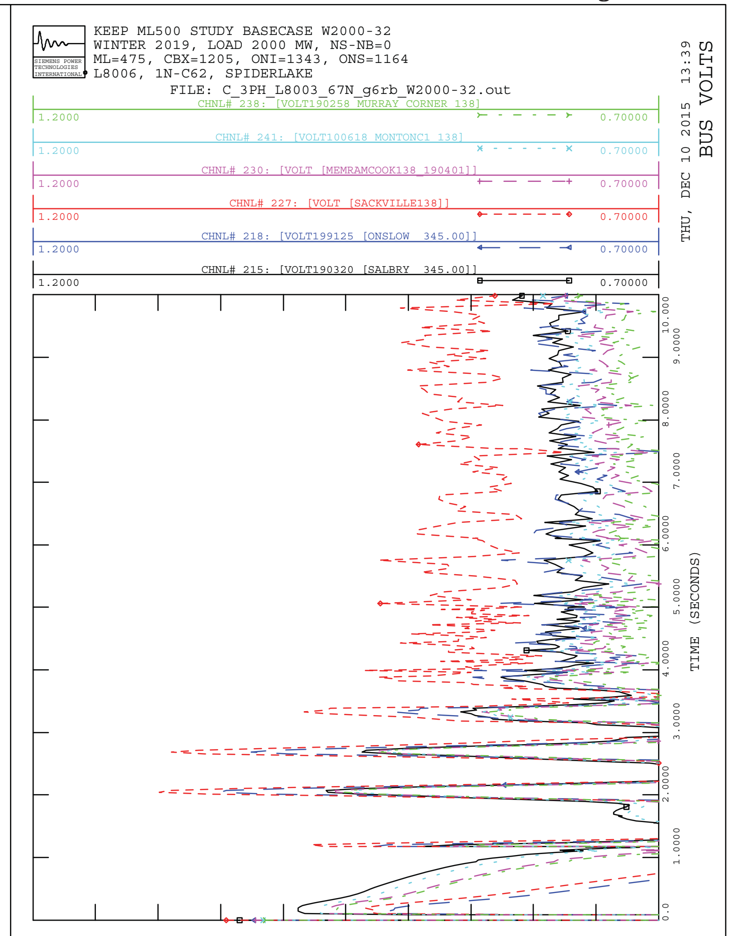
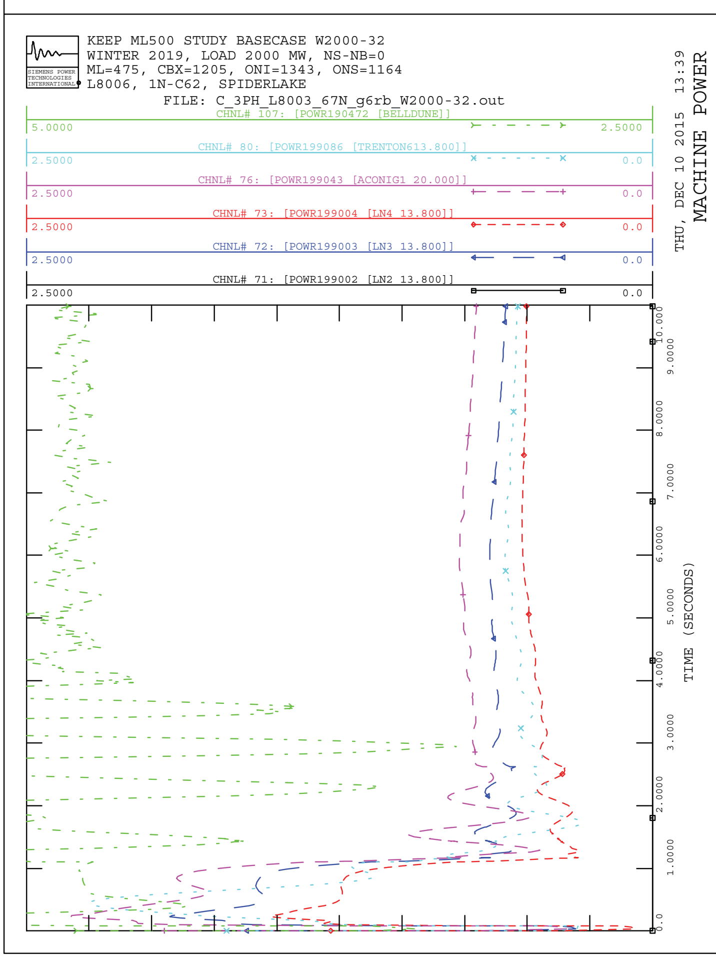
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
THU, DEC 10 2015 13:39
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_W2000-32.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
THU, DEC 10 2015 13:39
BUS VOLTS
TIME (SECONDS)



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ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
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CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
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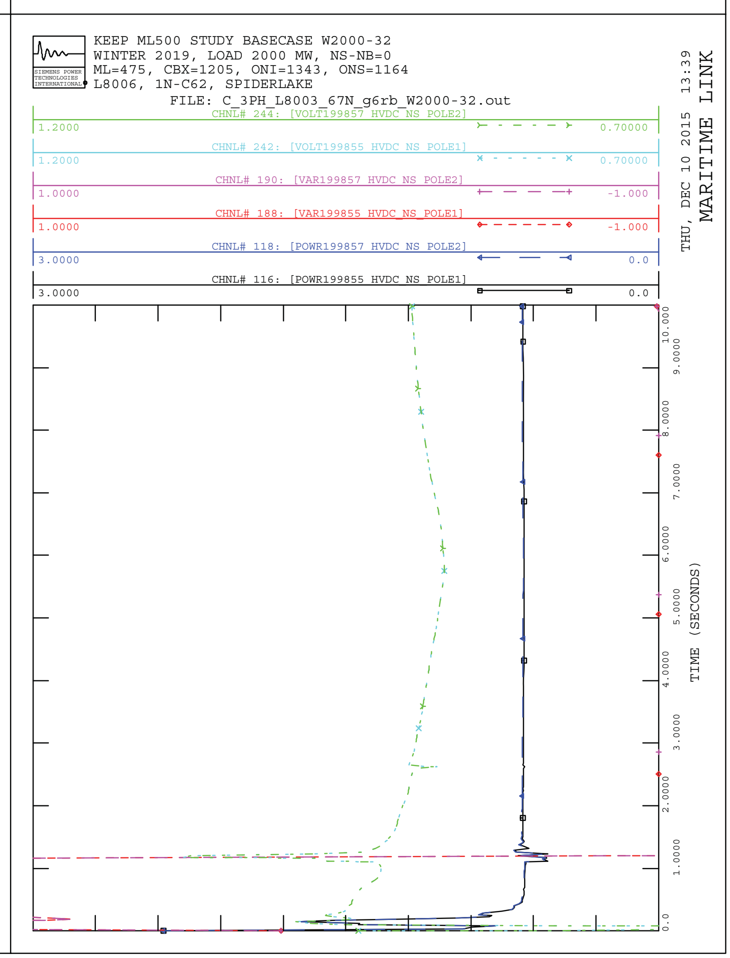
THU, DEC 10 2015 13:39
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-32
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L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_W2000-32.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
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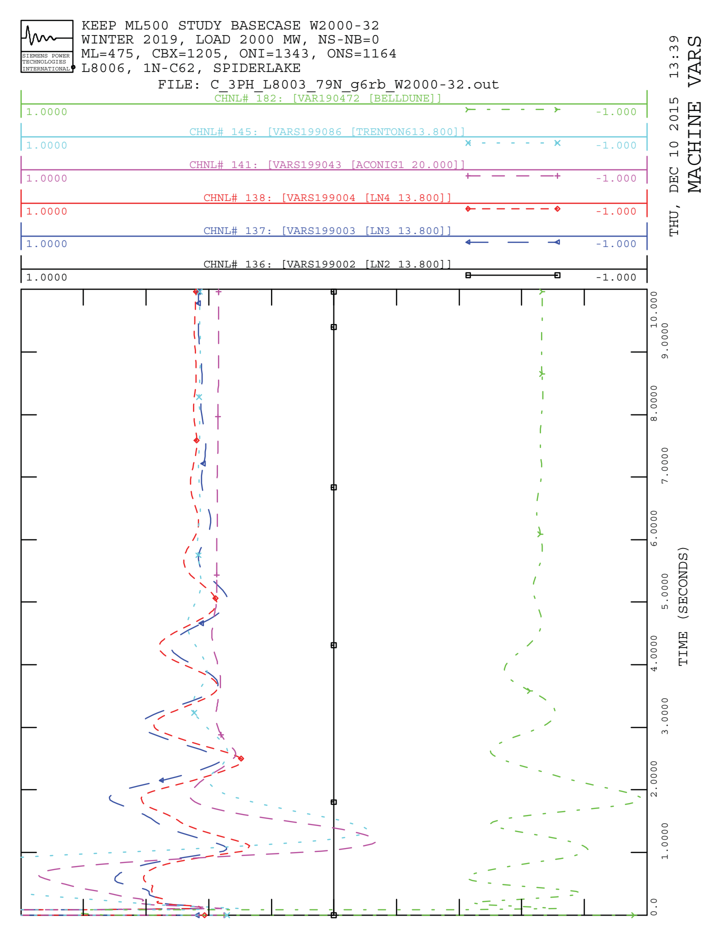
THU, DEC 10 2015 13:39
MARITIME LINK
TIME (SECONDS)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FILE: C_3PH_L8003_79N_g6rb_W2000-32.out
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CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
THU, DEC 10 2015 13:39
MACHINE VARS
TIME (SECONDS)
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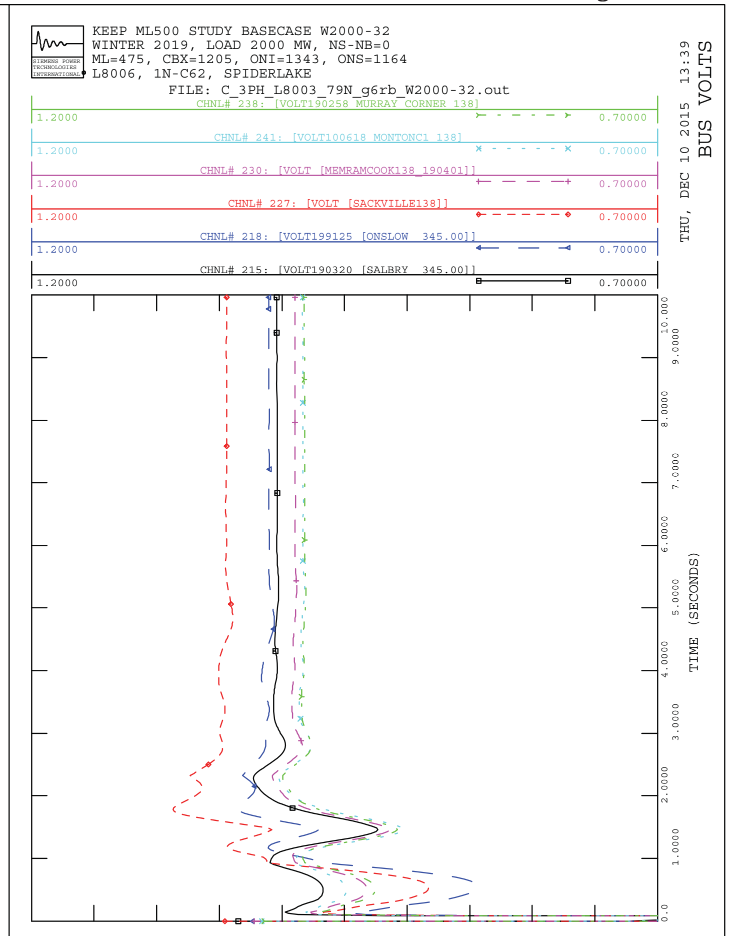
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L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_W2000-32.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
THU, DEC 10 2015 13:39
BUS VOLTS
TIME (SECONDS)
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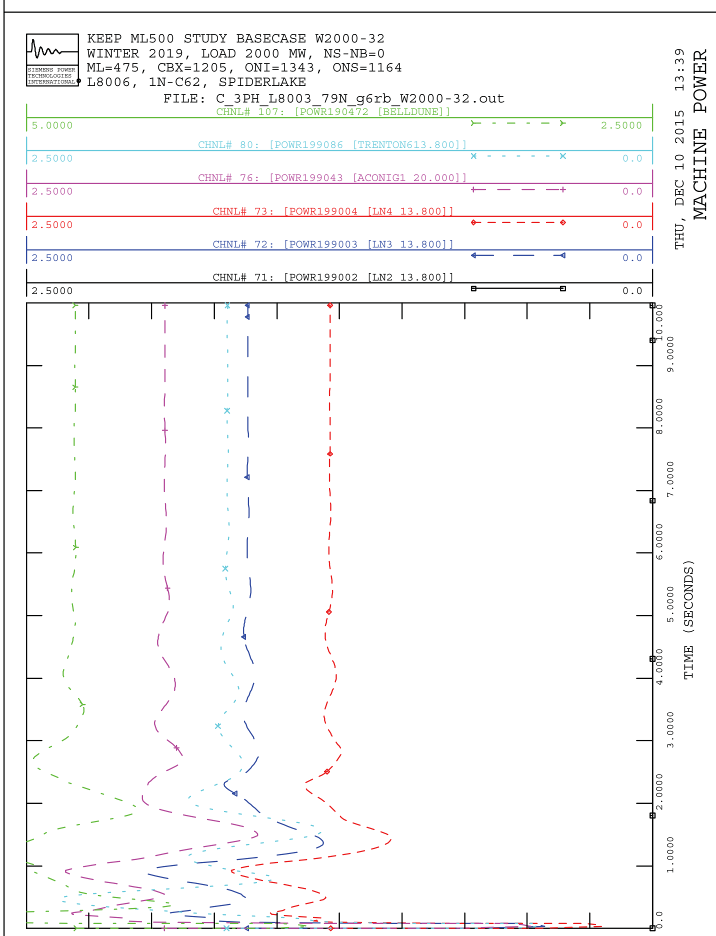
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L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_W2000-32.out
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CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
THU, DEC 10 2015 13:39
MACHINE POWER
TIME (SECONDS)
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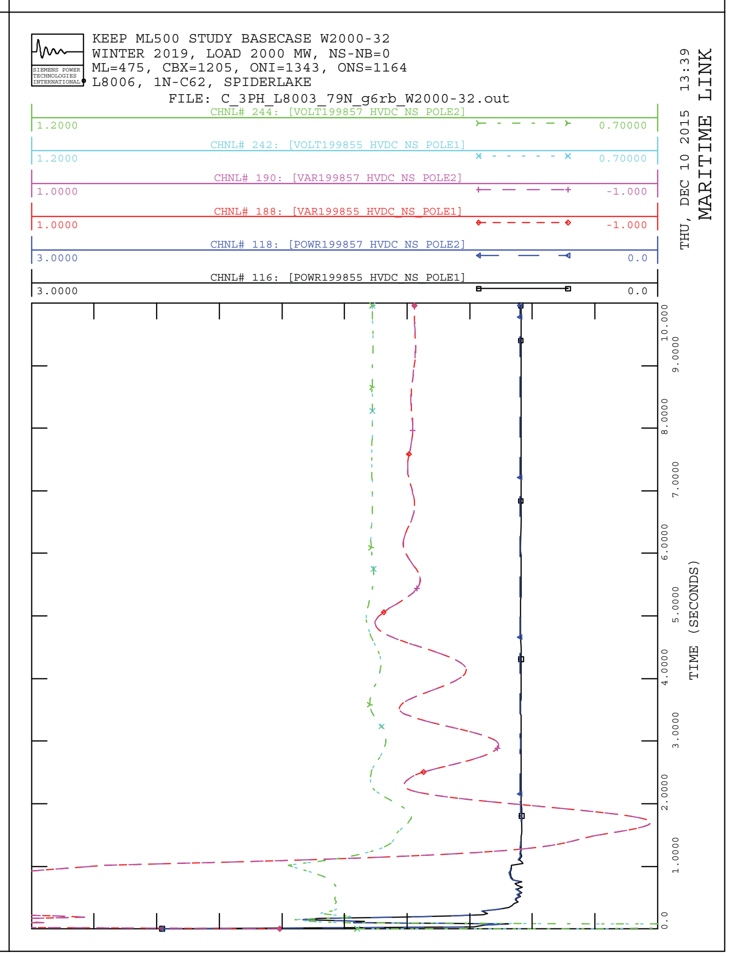
KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_W2000-32.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
THU, DEC 10 2015 13:39
MARITIME LINK
TIME (SECONDS)
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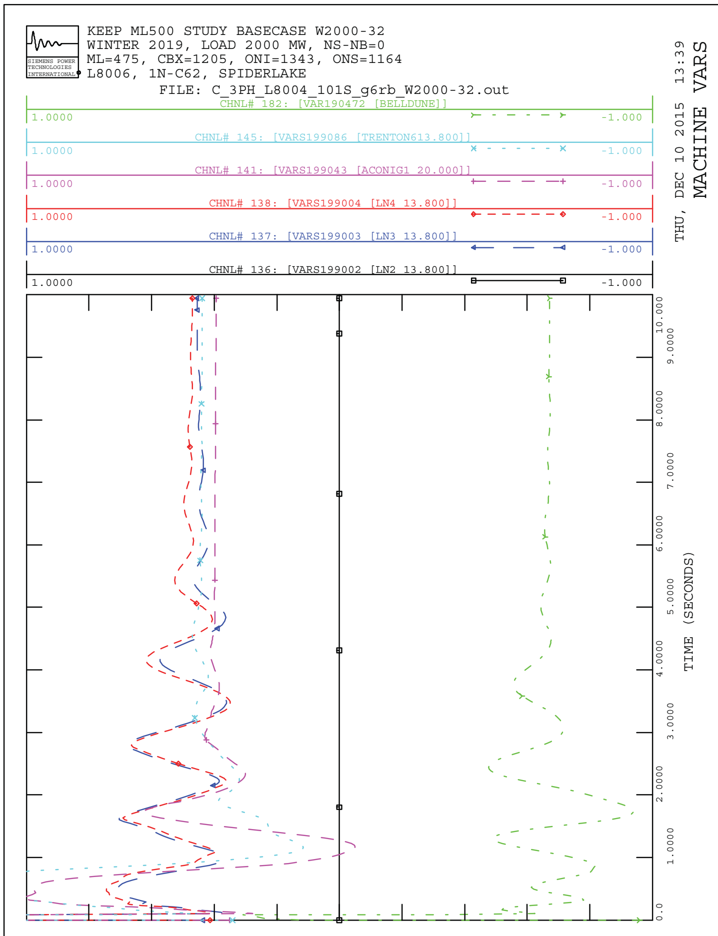
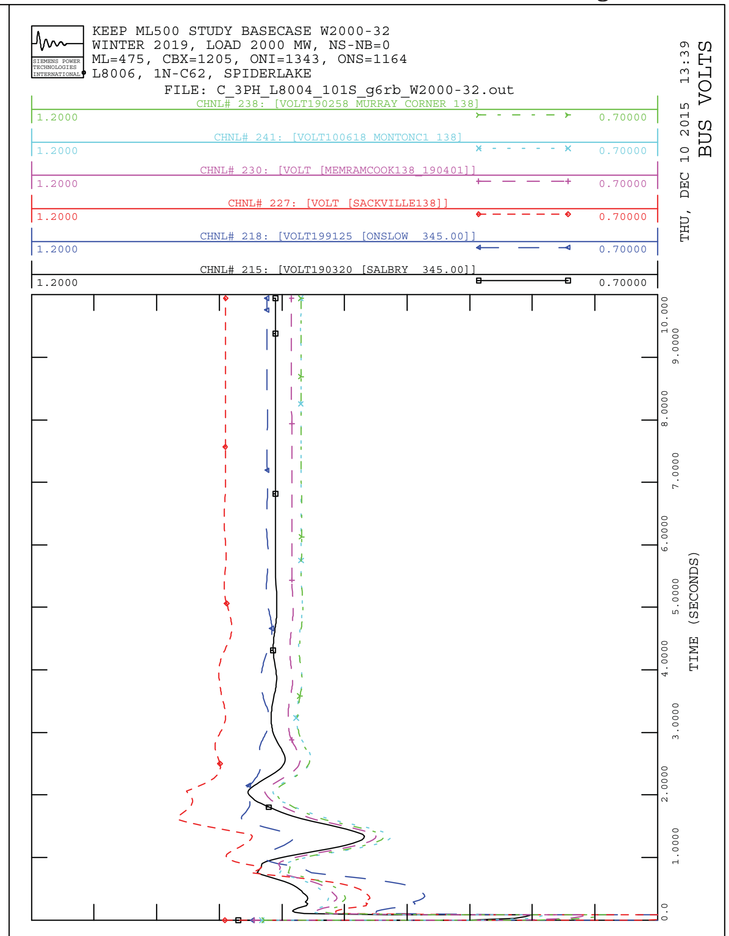
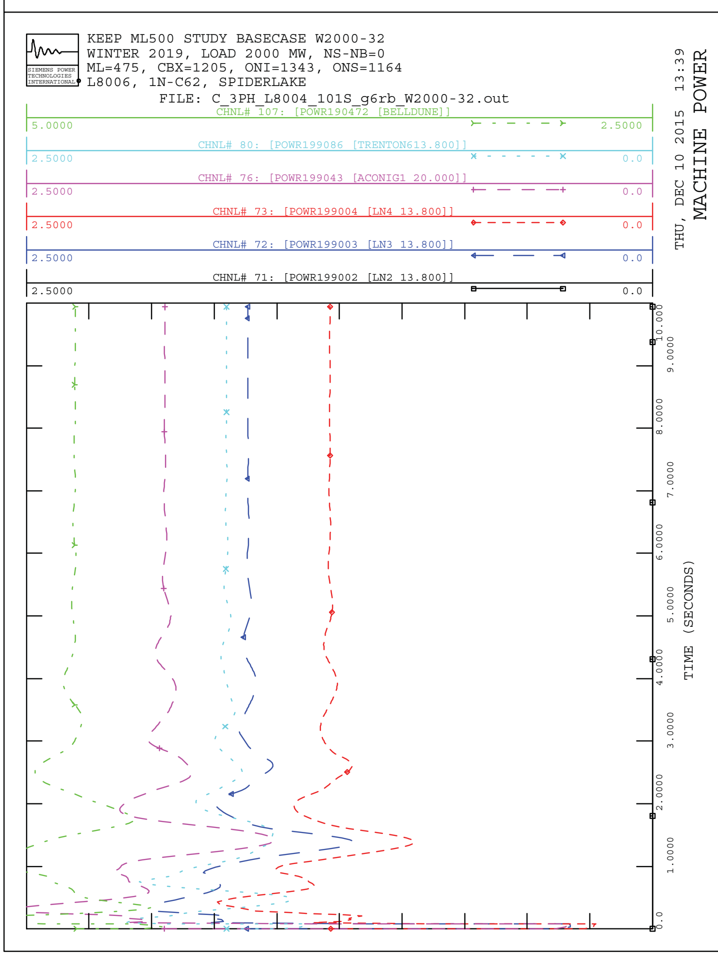
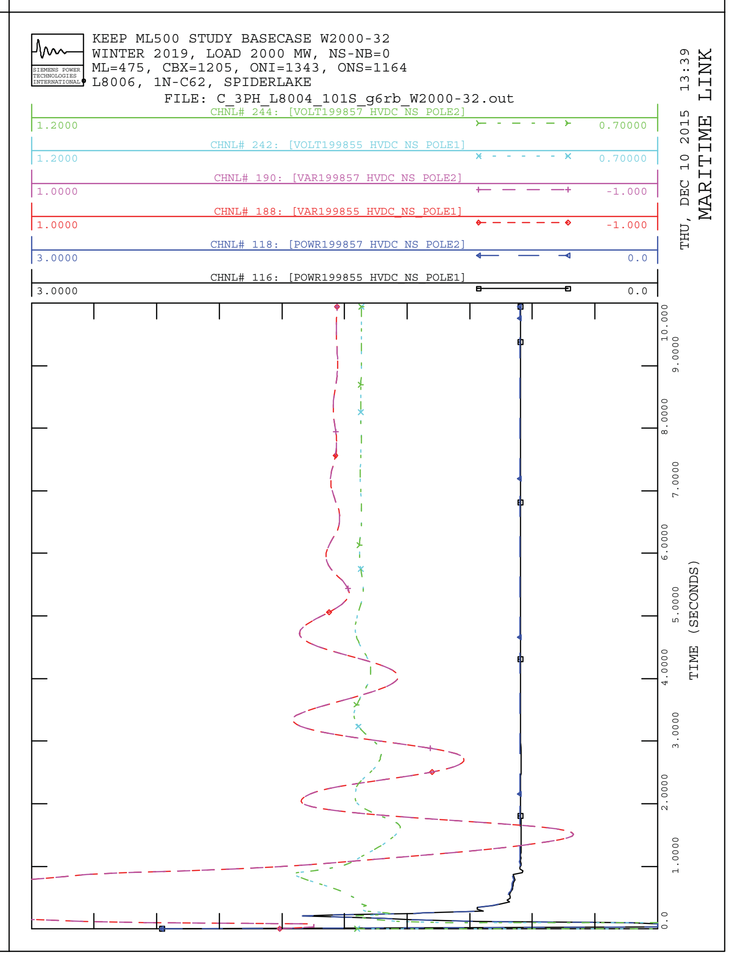
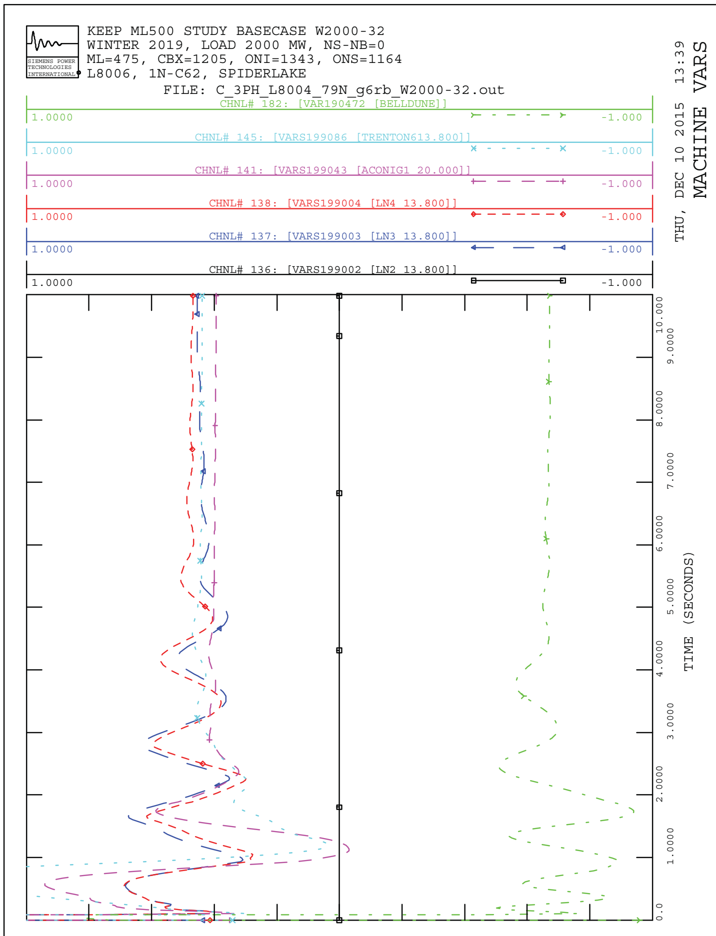
REDACTED (CONFIDENTIAL INFORMATION REMOVED)











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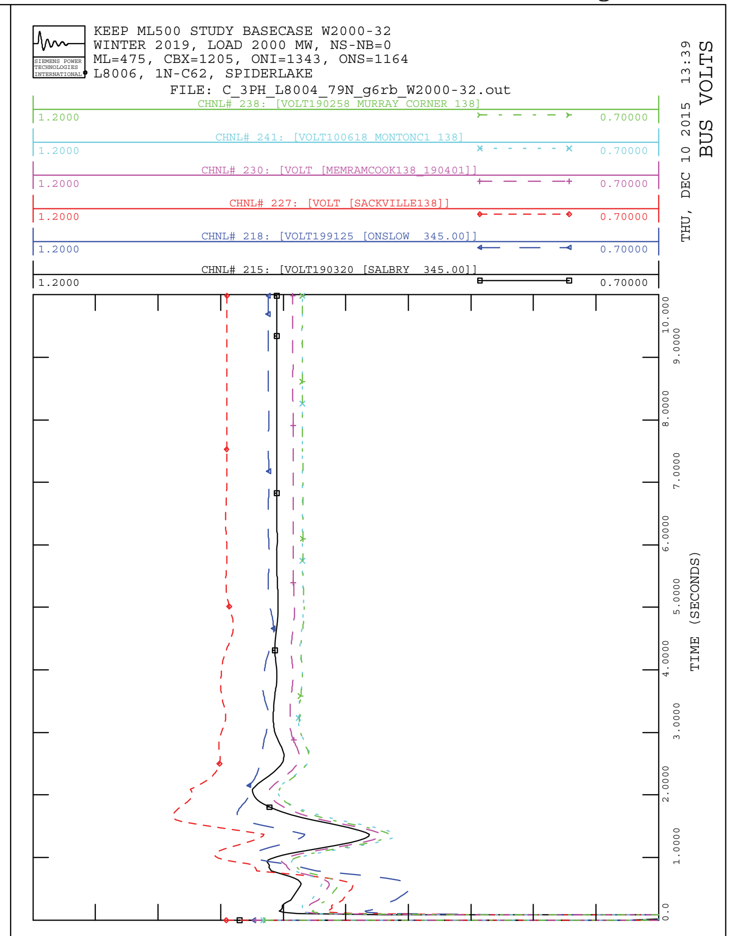
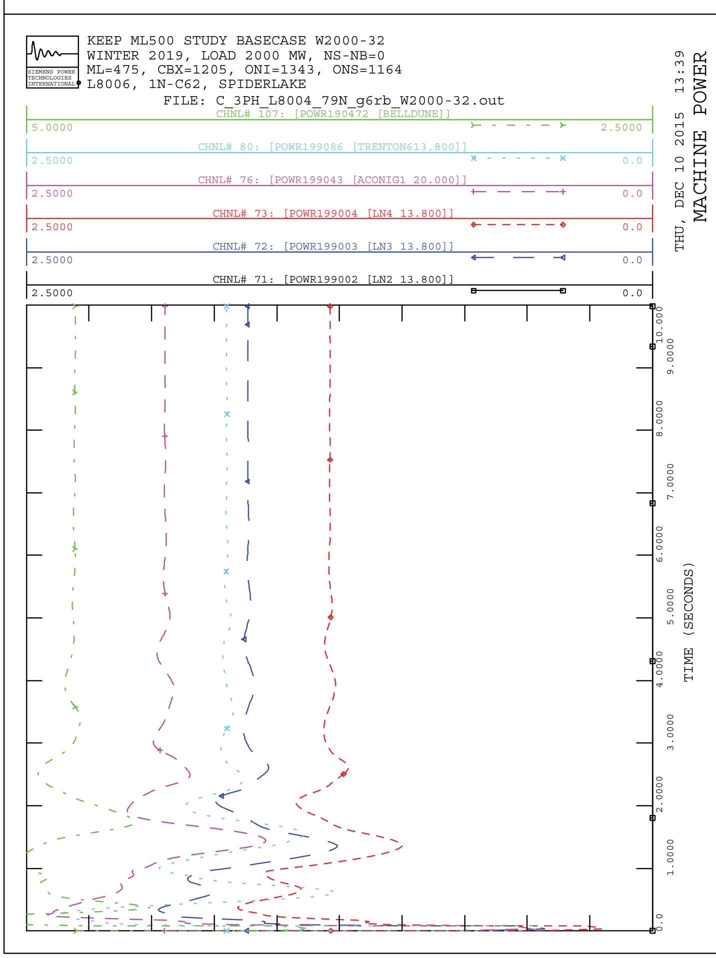
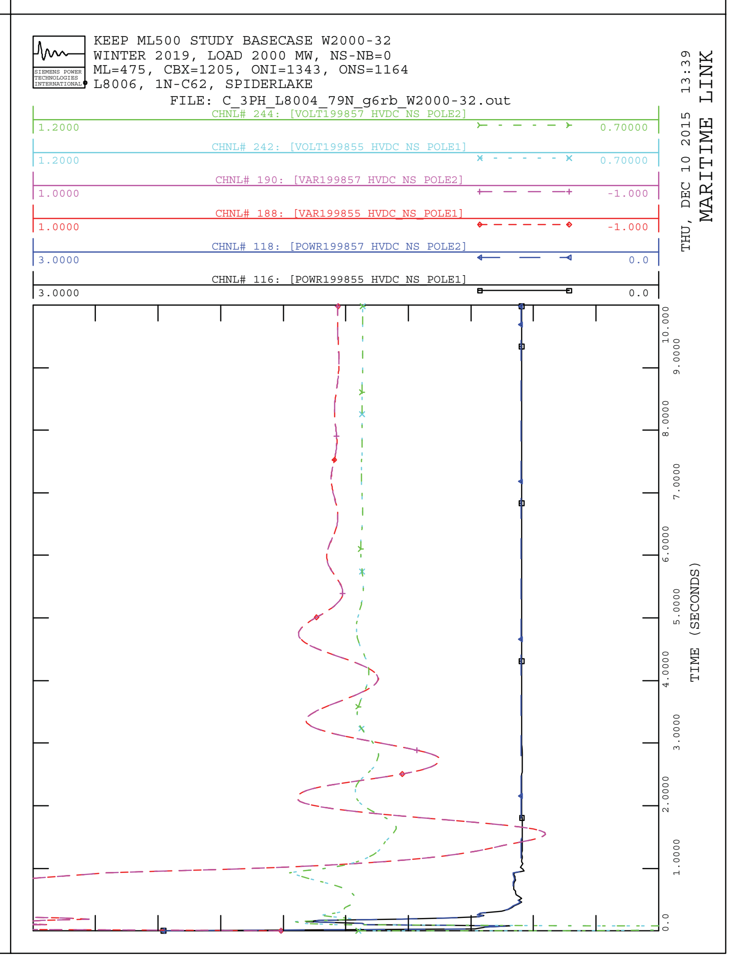
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_W2000-32.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
THU, DEC 10 2015 13:39
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_W2000-32.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
THU, DEC 10 2015 13:39
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_W2000-32.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
THU, DEC 10 2015 13:39
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_W2000-32.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
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THU, DEC 10 2015 13:39
MARITIME LINK
TIME (SECONDS)

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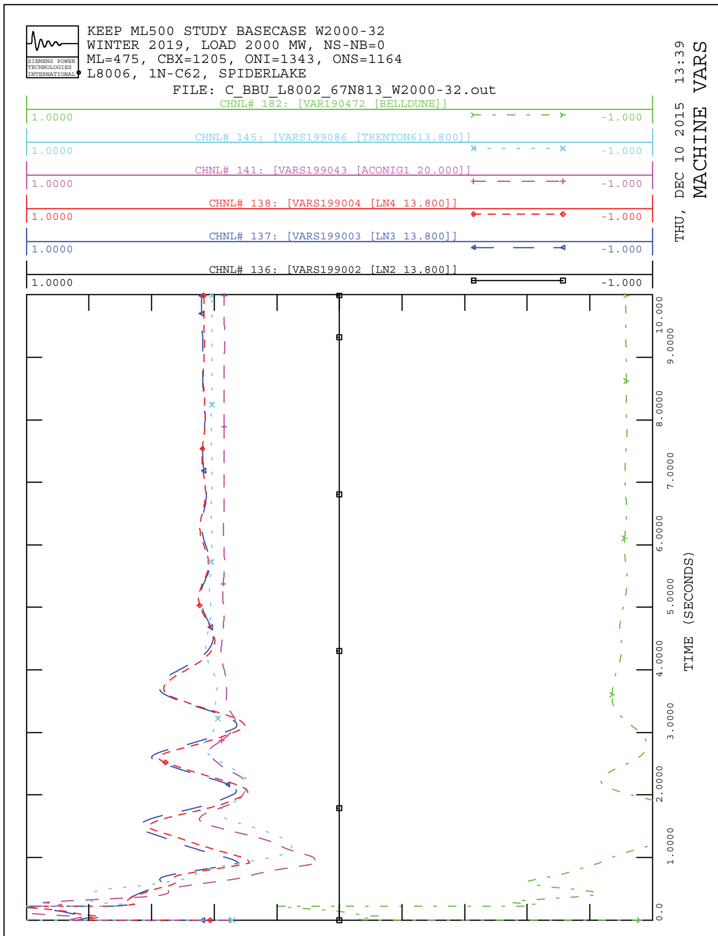

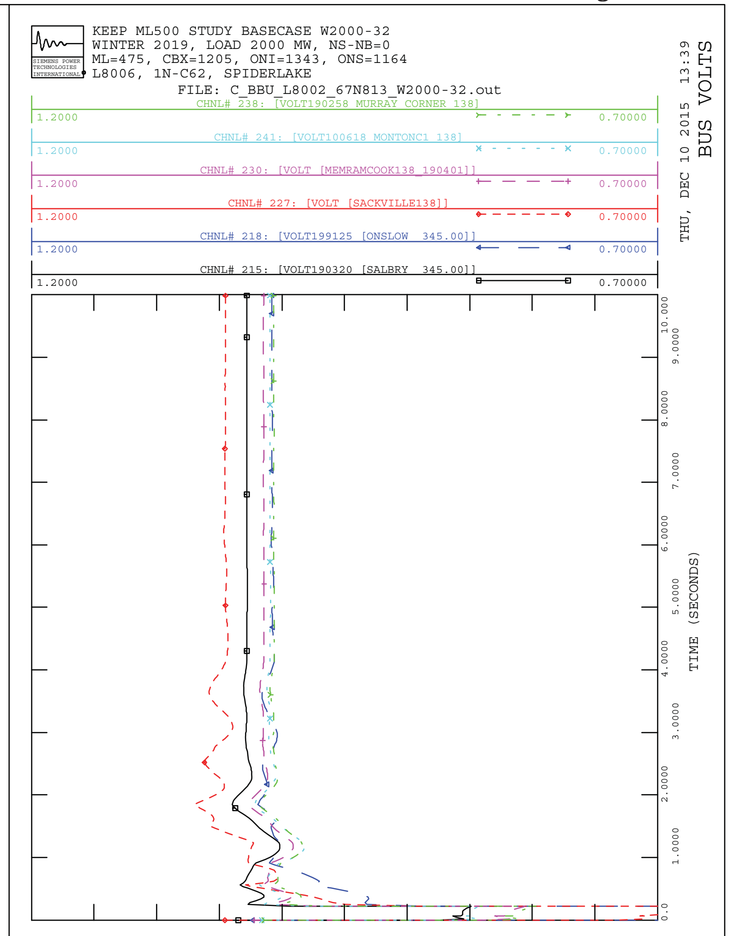

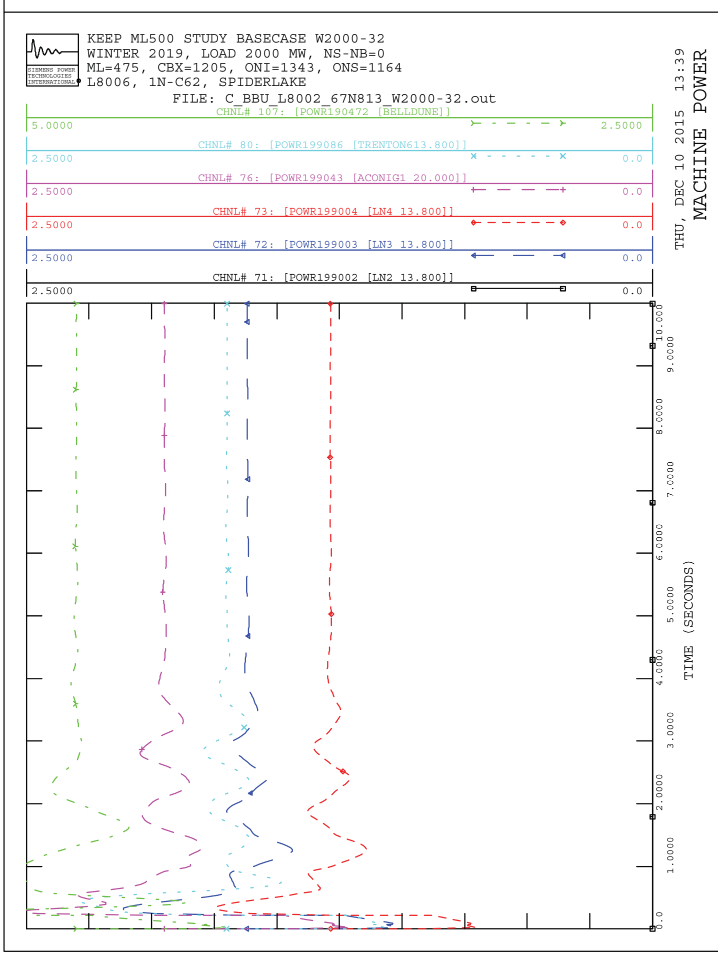

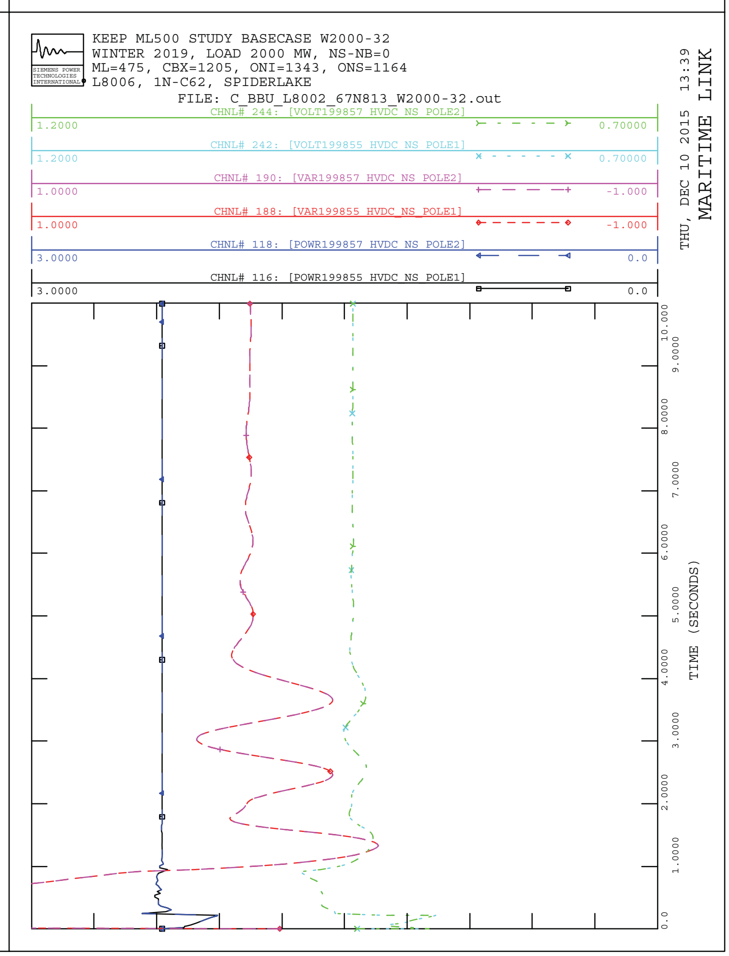

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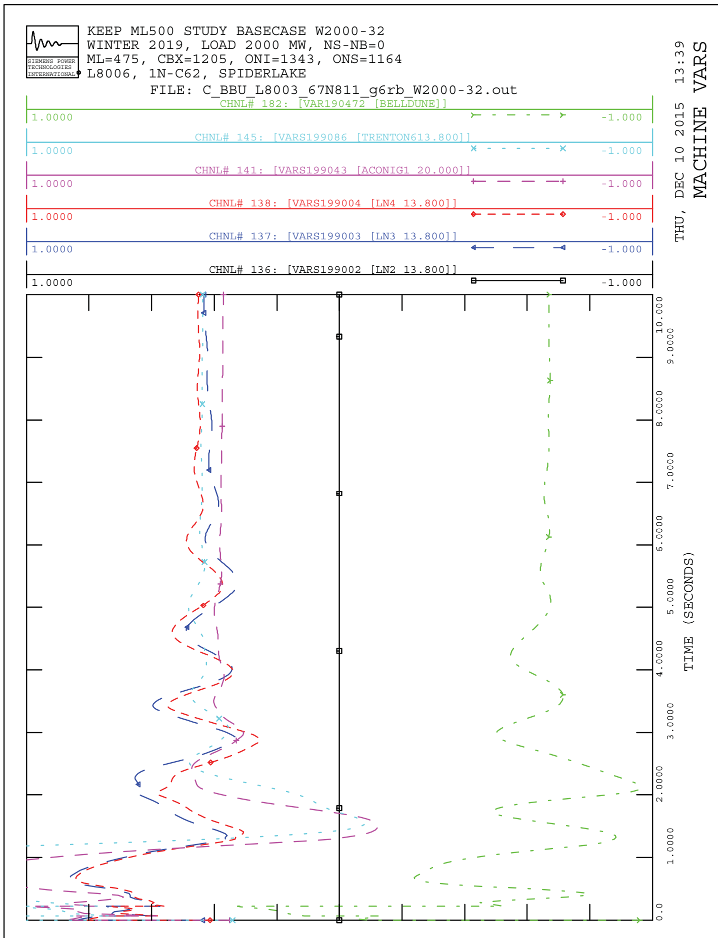
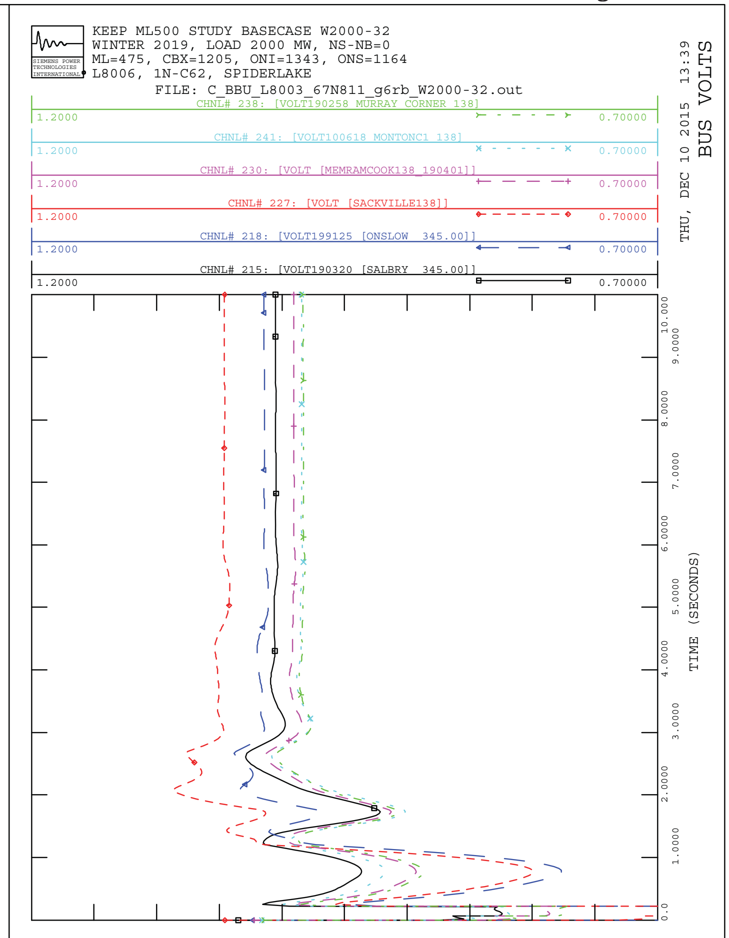
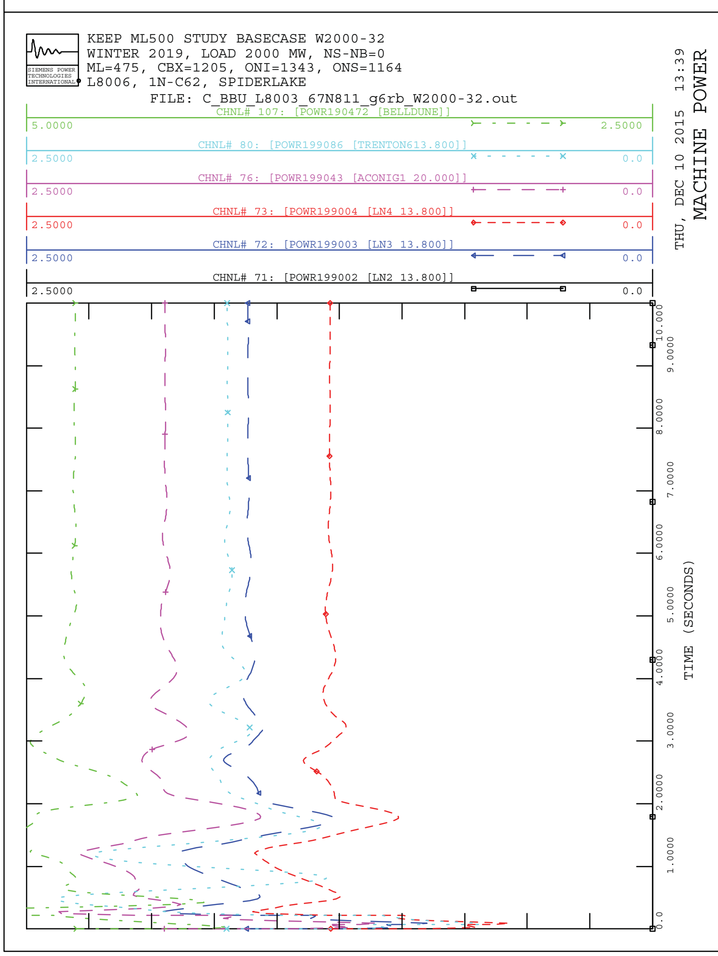
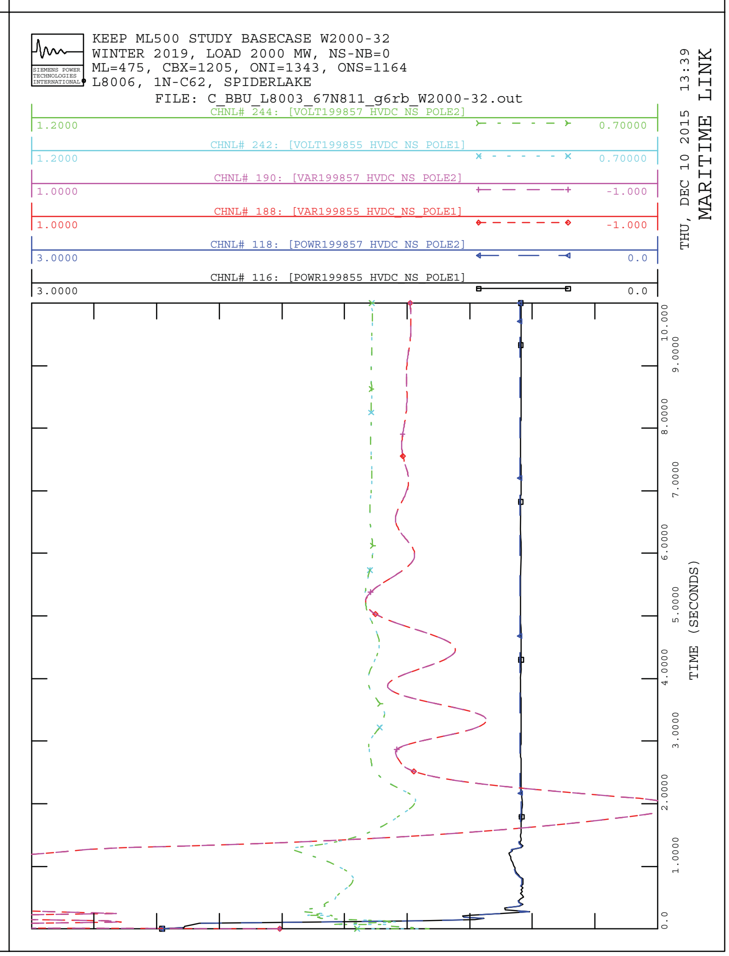
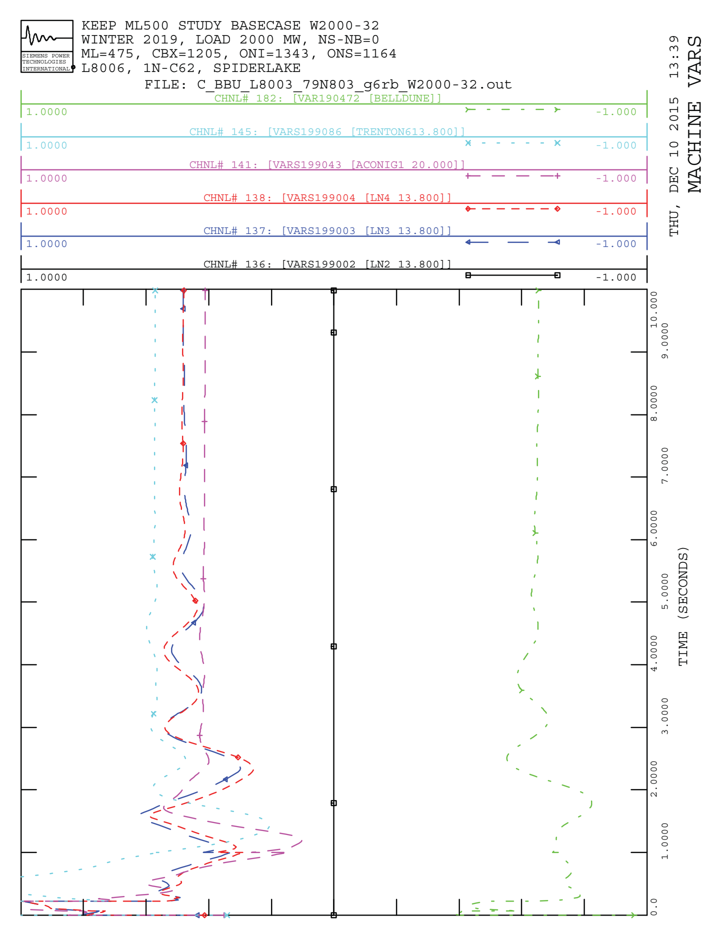
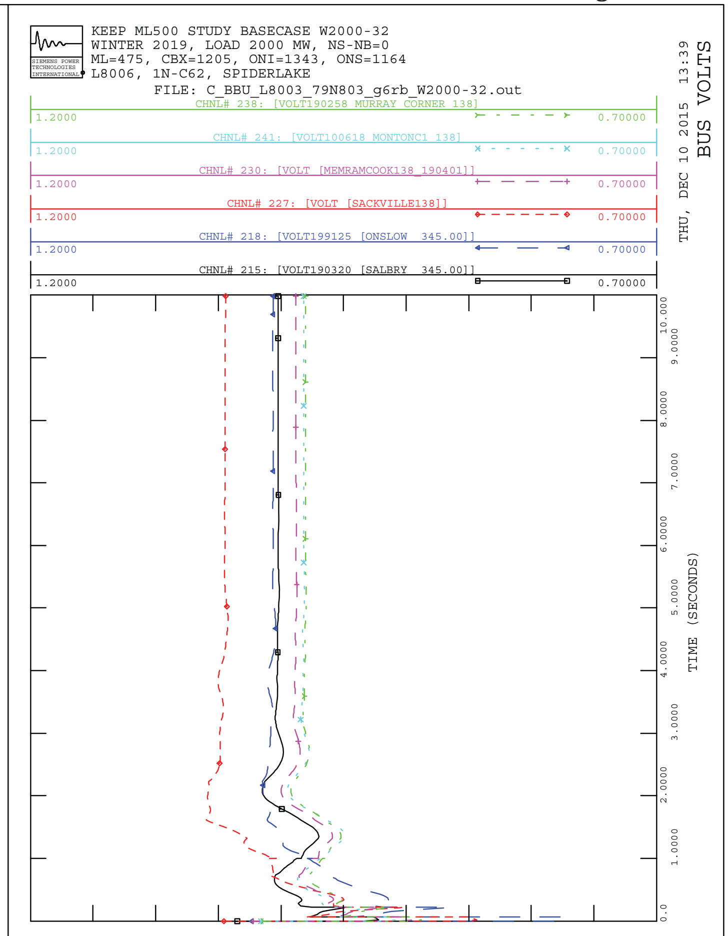


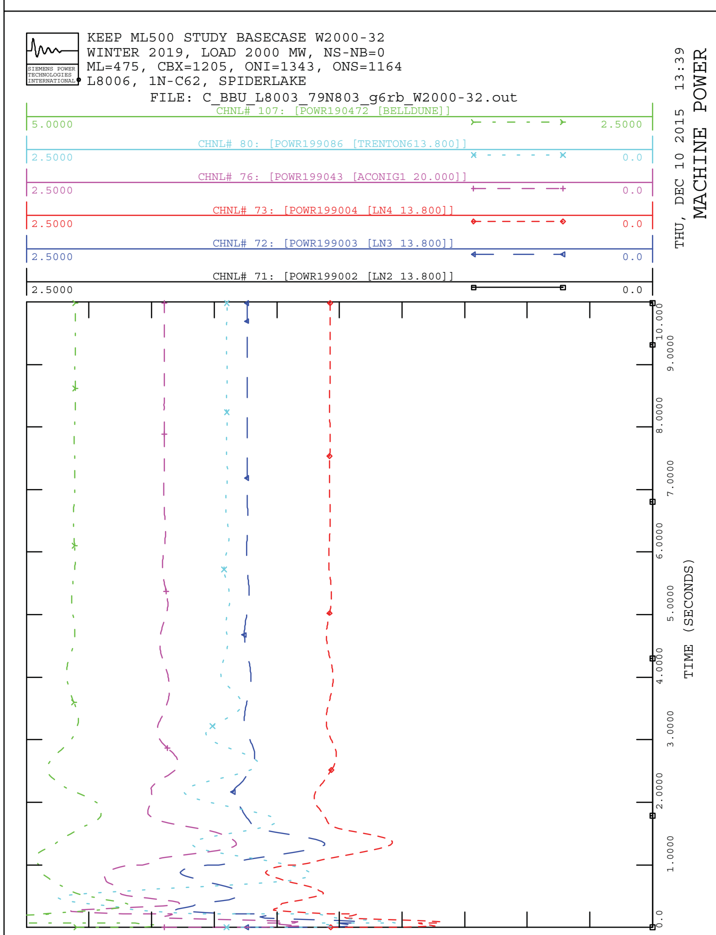


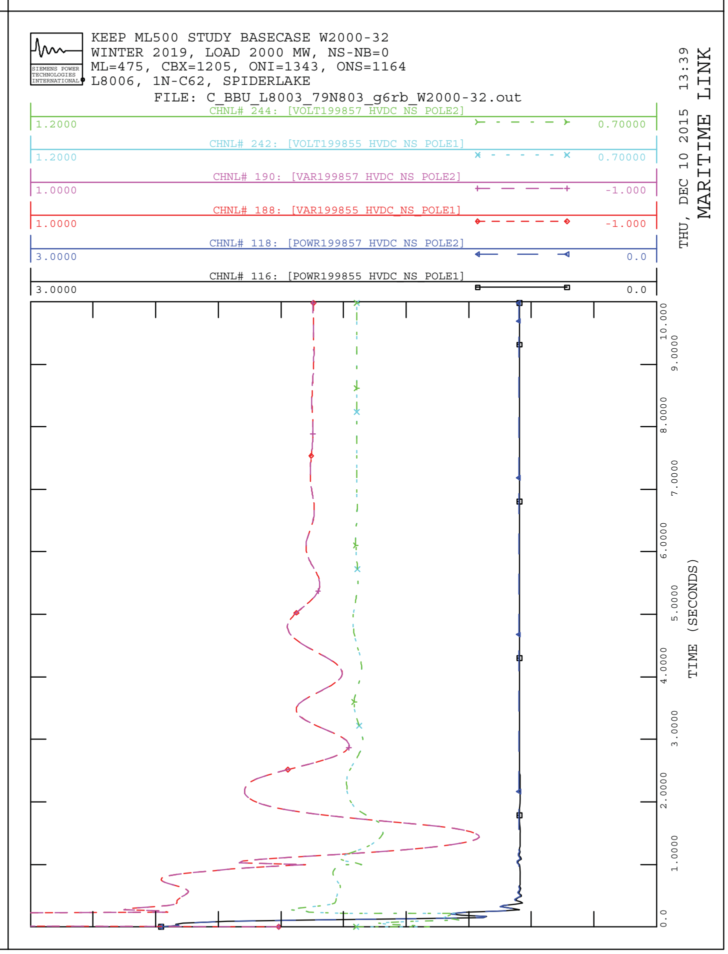





KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_BBU_L8003_79N803_g6rb_W2000-32.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
THU, DEC 10 2015 13:39
MACHINE VARS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_BBU_L8003_79N803_g6rb_W2000-32.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
THU, DEC 10 2015 13:39
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_BBU_L8003_79N803_g6rb_W2000-32.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
THU, DEC 10 2015 13:39
MACHINE POWER
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_BBU_L8003_79N803_g6rb_W2000-32.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
THU, DEC 10 2015 13:39
MARITIME LINK
TIME (SECONDS)

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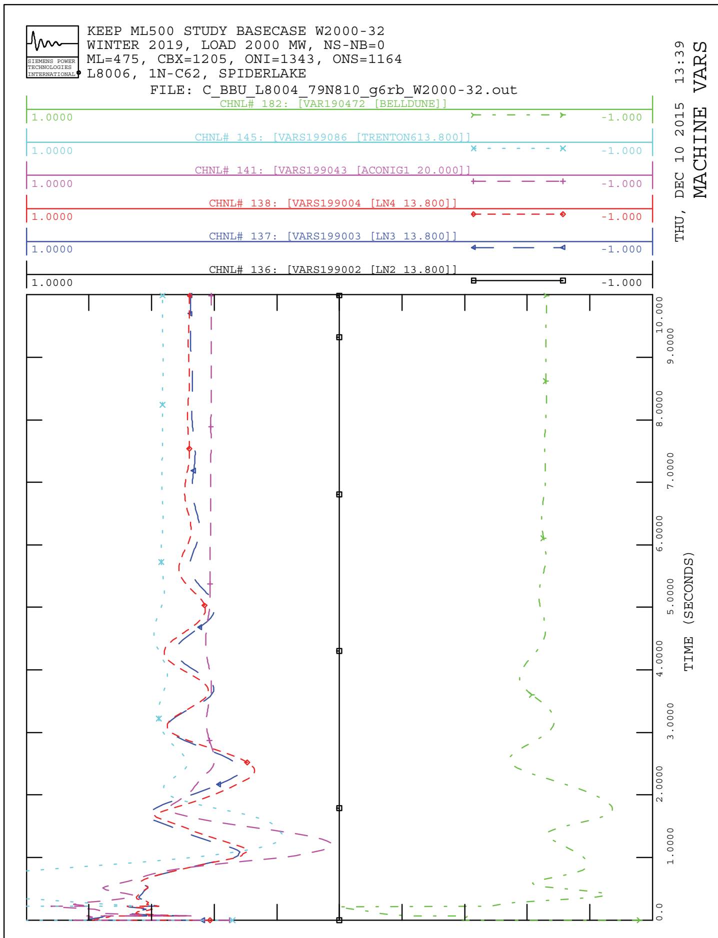
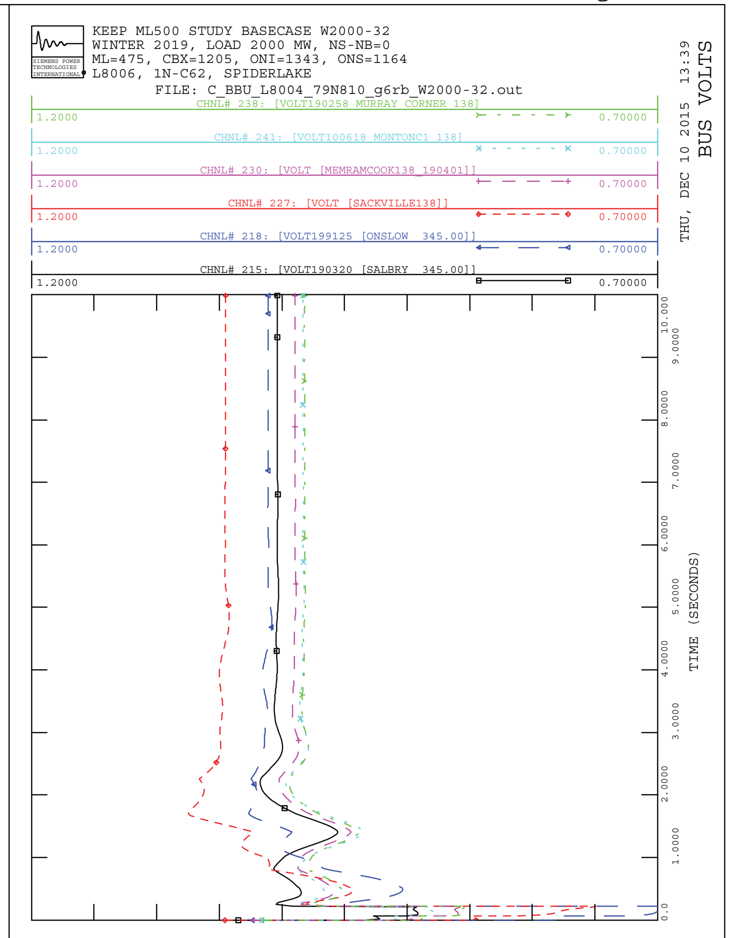
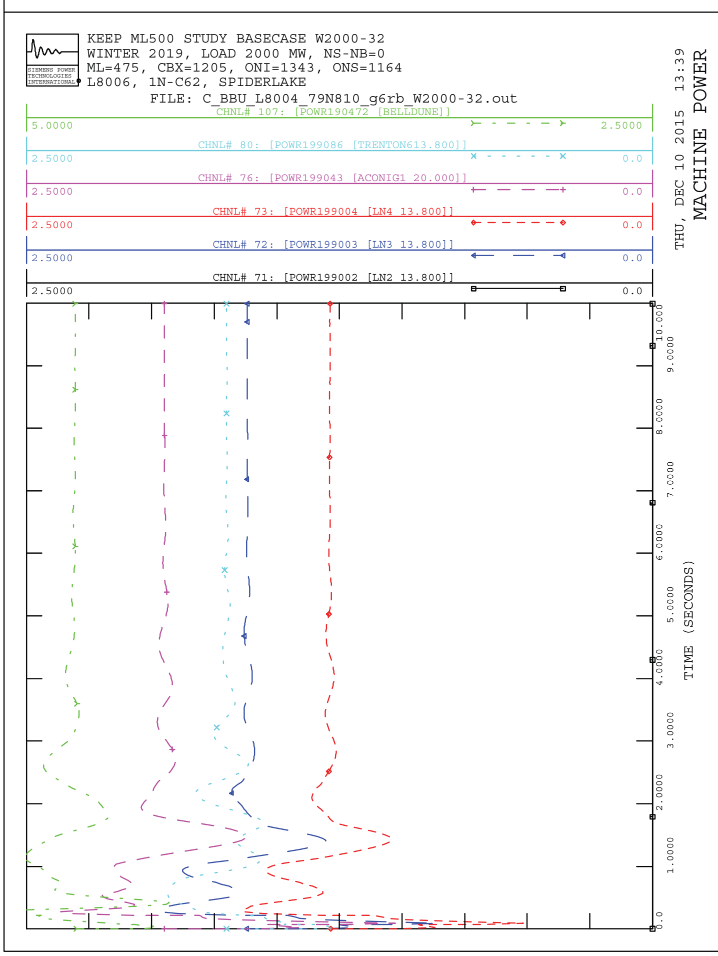
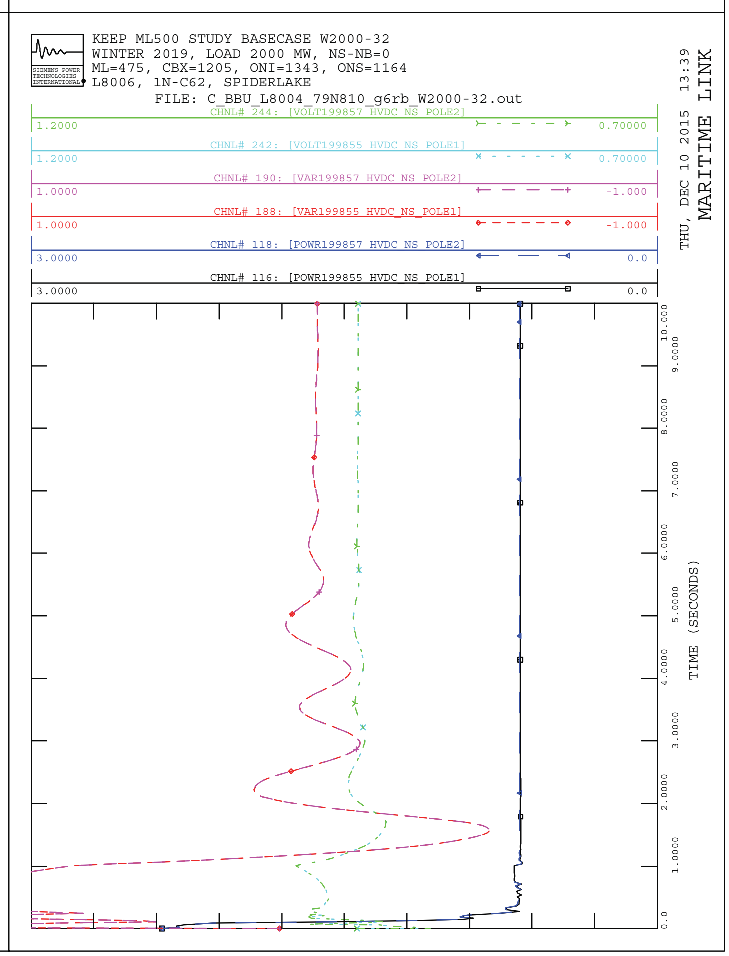
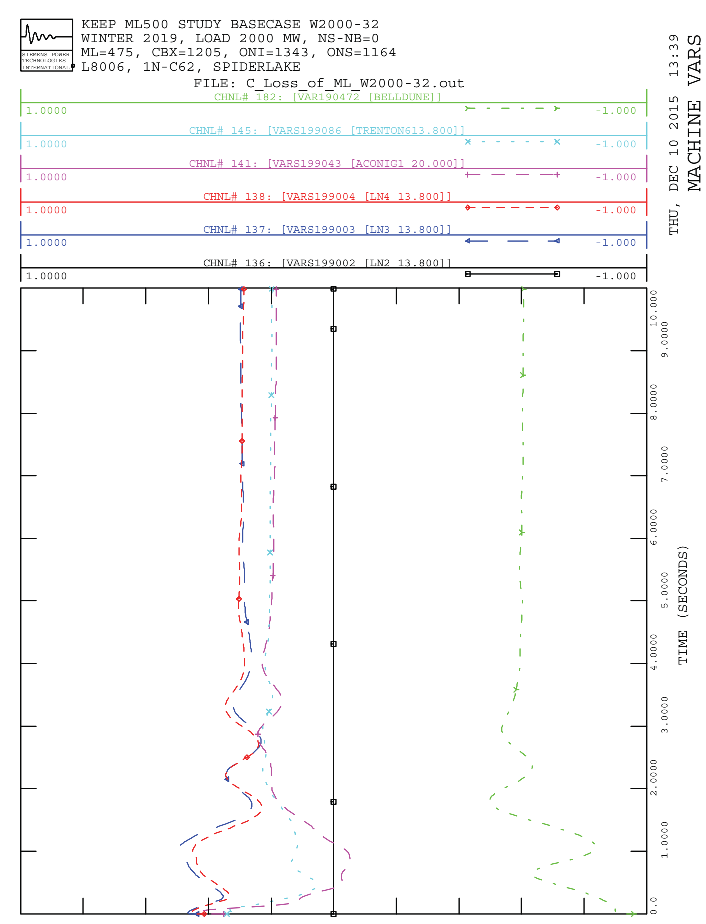


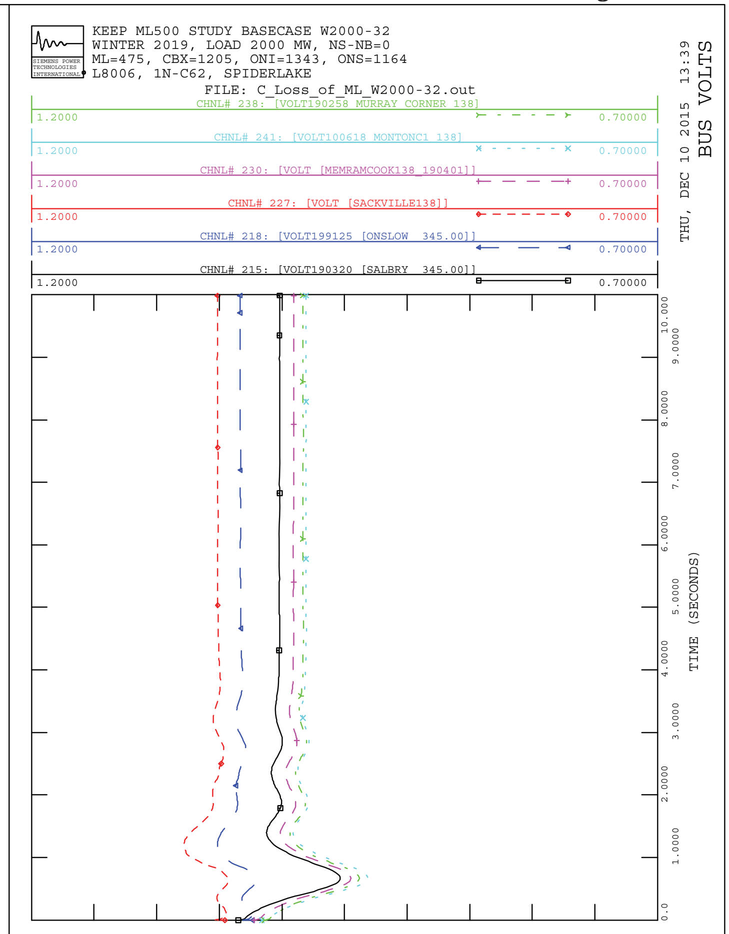




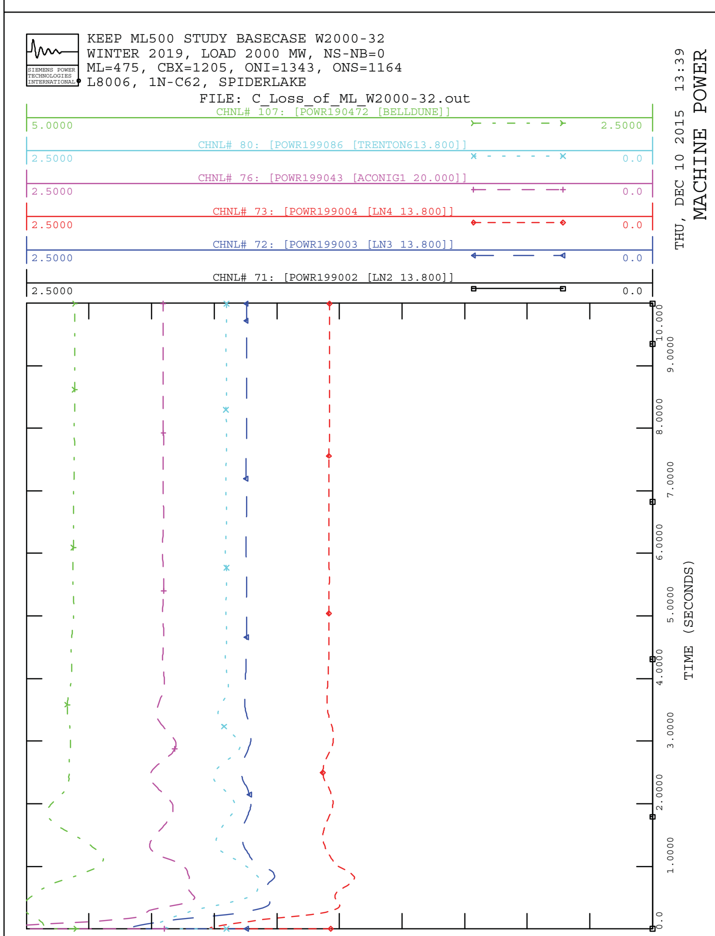




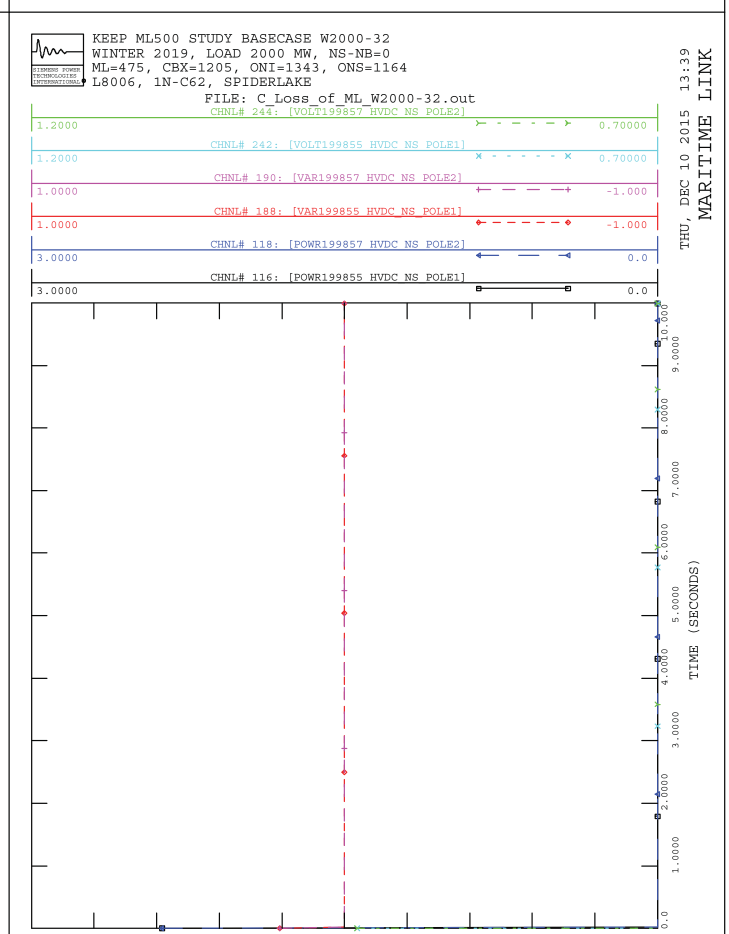
KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_Loss_of_ML_W2000-32.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
THU, DEC 10 2015 13:39
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_Loss_of_ML_W2000-32.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
THU, DEC 10 2015 13:39
BUS VOLTS
TIME (SECONDS)

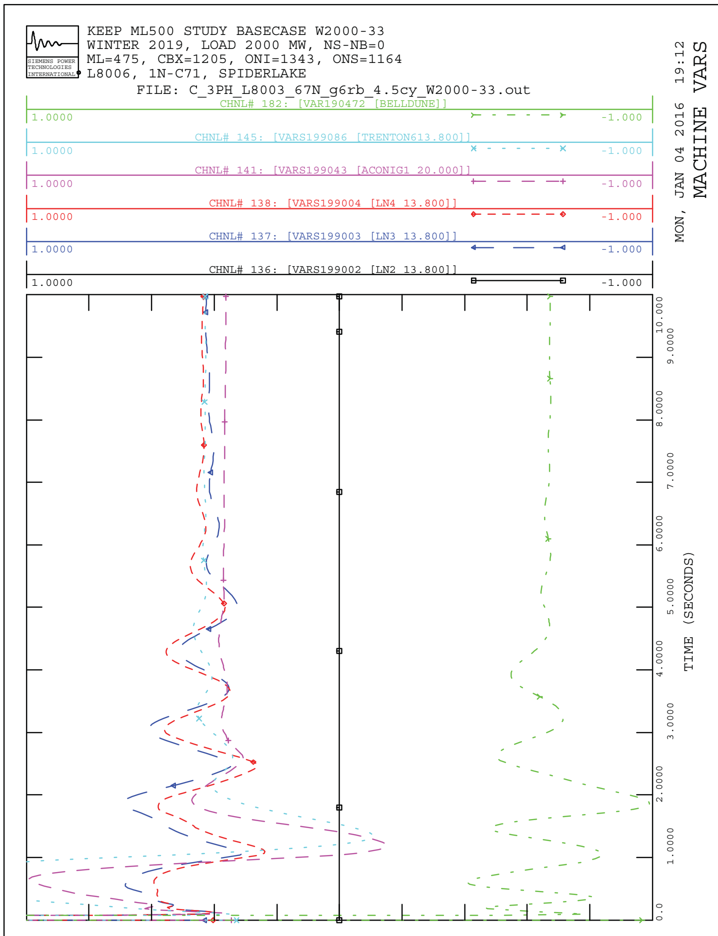


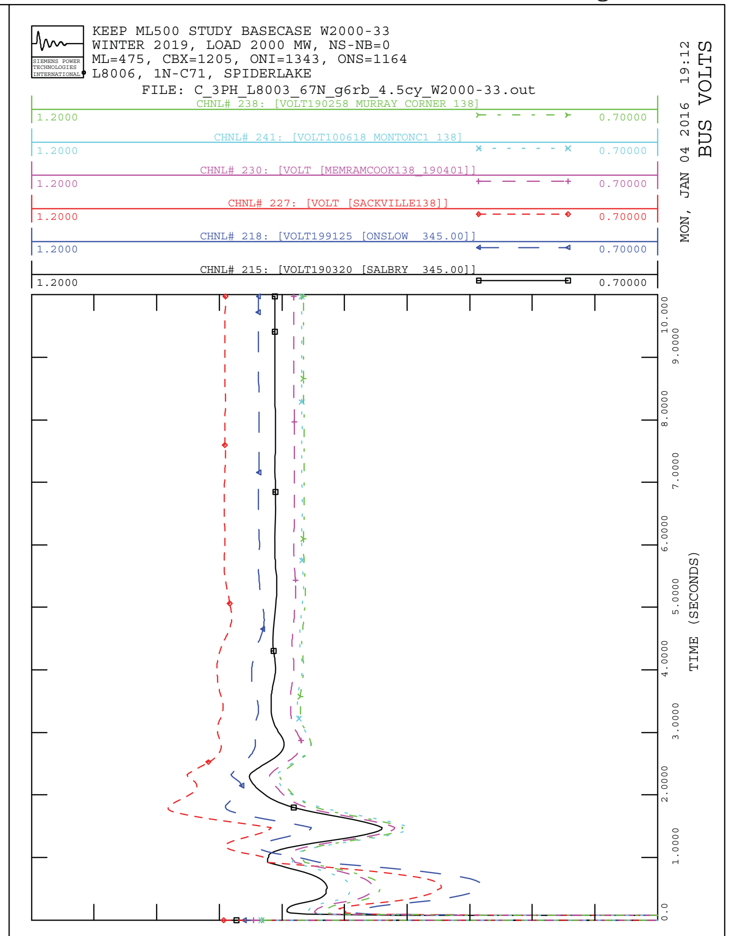
KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_Loss_of_ML_W2000-32.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
THU, DEC 10 2015 13:39
MACHINE POWER
TIME (SECONDS)

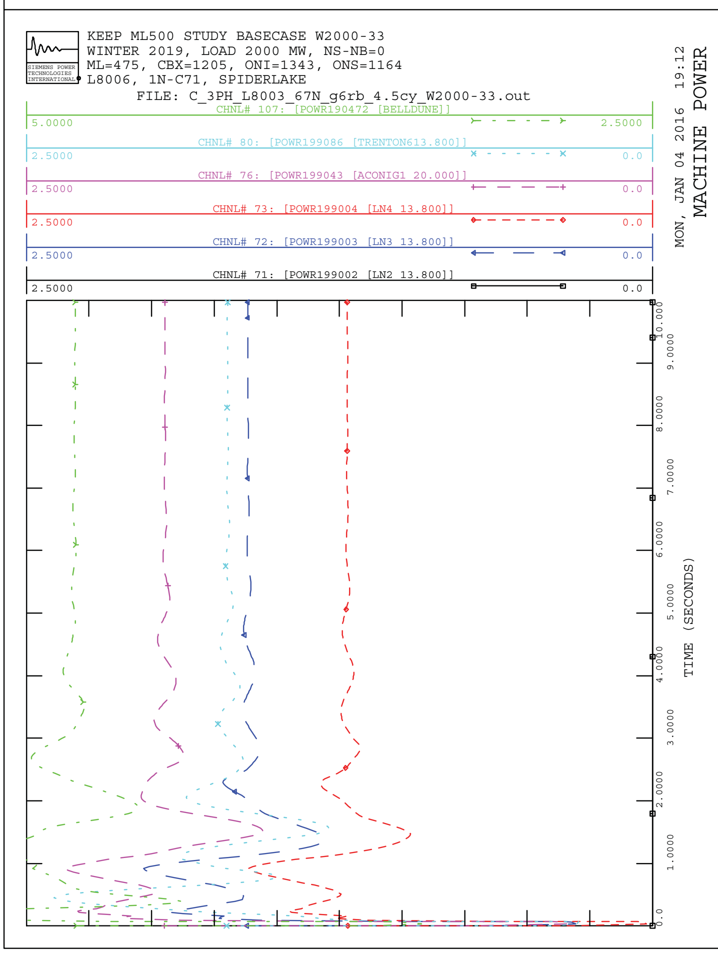


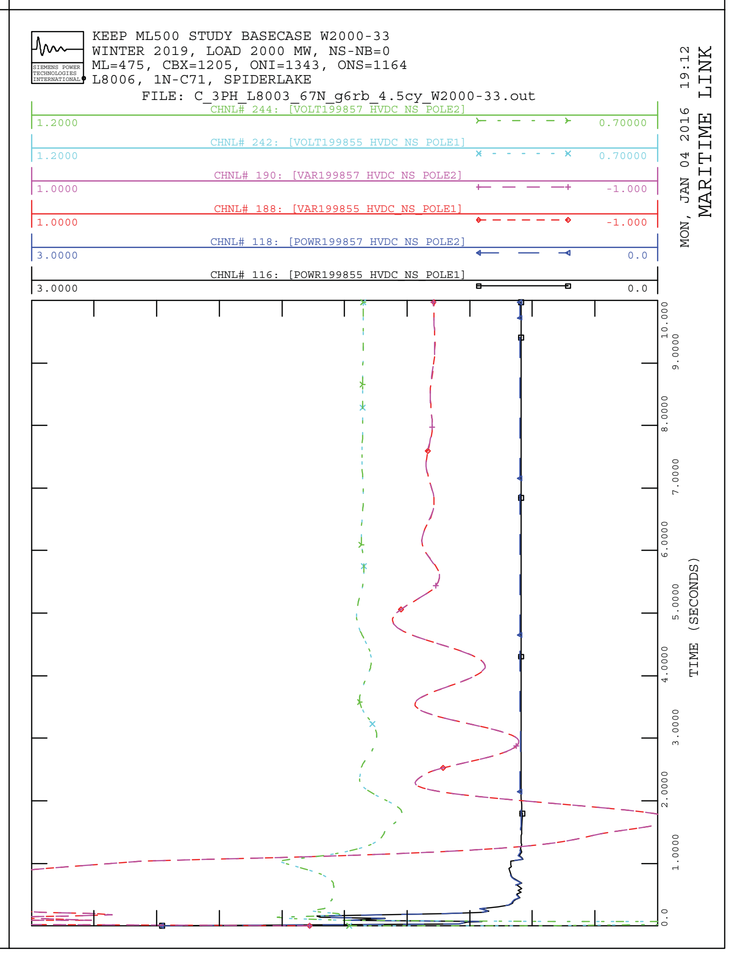
KEEP ML500 STUDY BASECASE W2000-32
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C62, SPIDERLAKE
FILE: C_Loss_of_ML_W2000-32.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
THU, DEC 10 2015 13:39
MARITIME LINK
TIME (SECONDS)

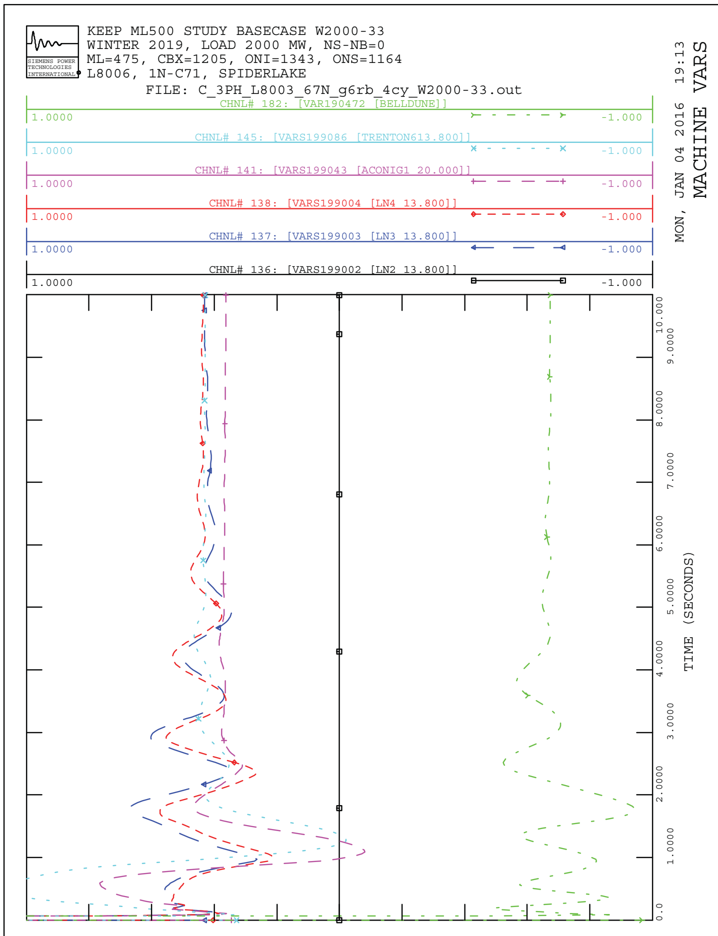
REDACTED (CONFIDENTIAL INFORMATION REMOVED)










KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-33.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
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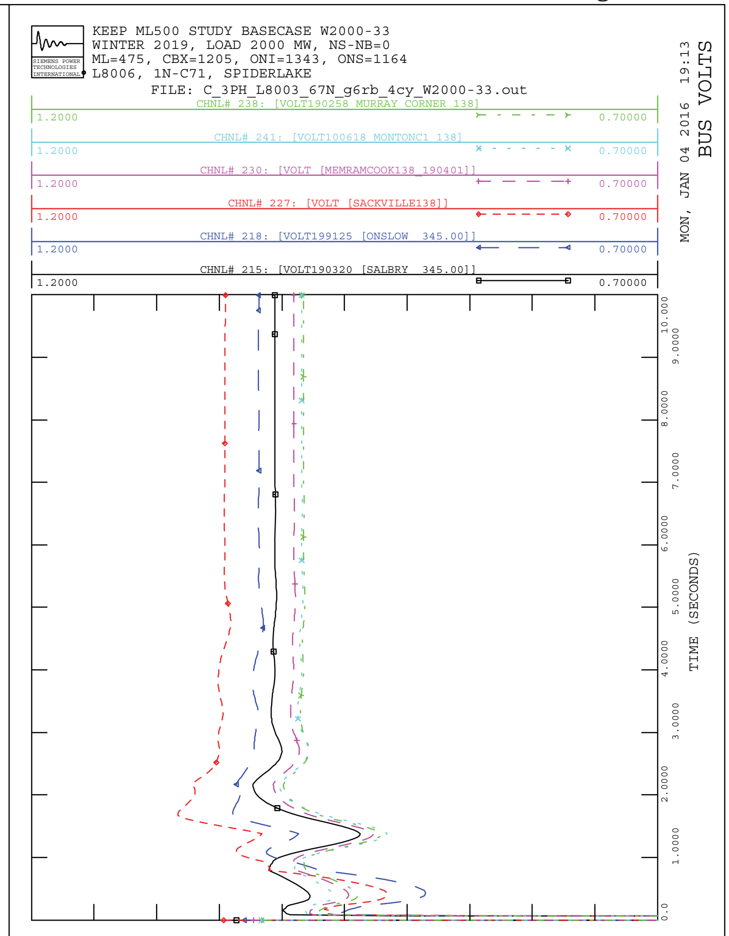
TIME (SECONDS)
MON, JAN 04 2016 19:13
MACHINE VARS


KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-33.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138_190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
0.0
1.0000
2.0000
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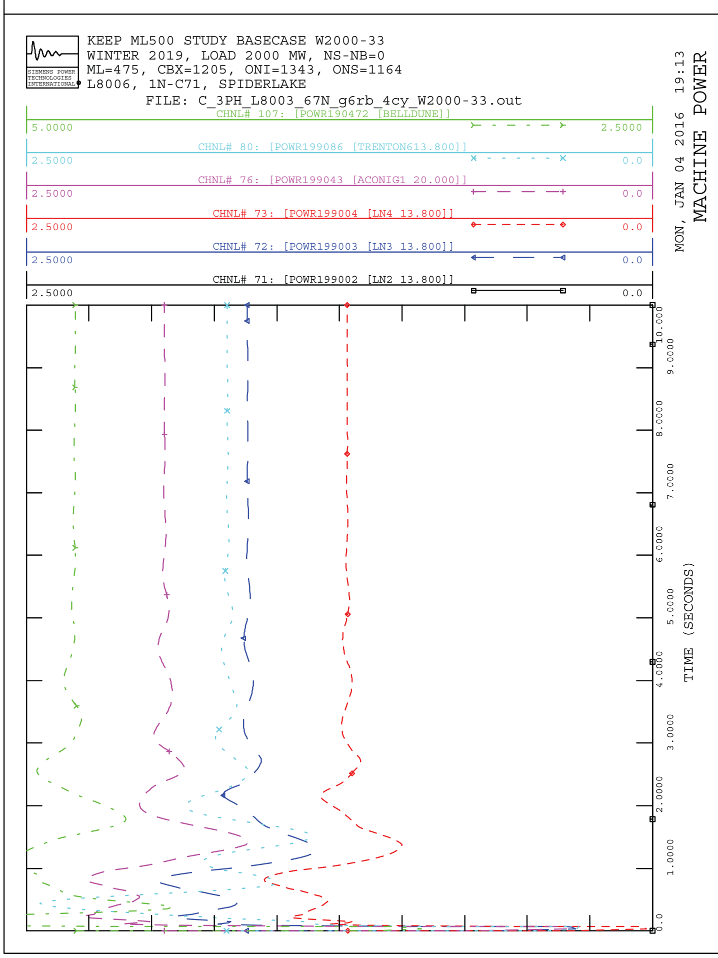
TIME (SECONDS)
MON, JAN 04 2016 19:13
BUS VOLTS


KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-33.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
0.0
1.0000
2.0000
3.0000
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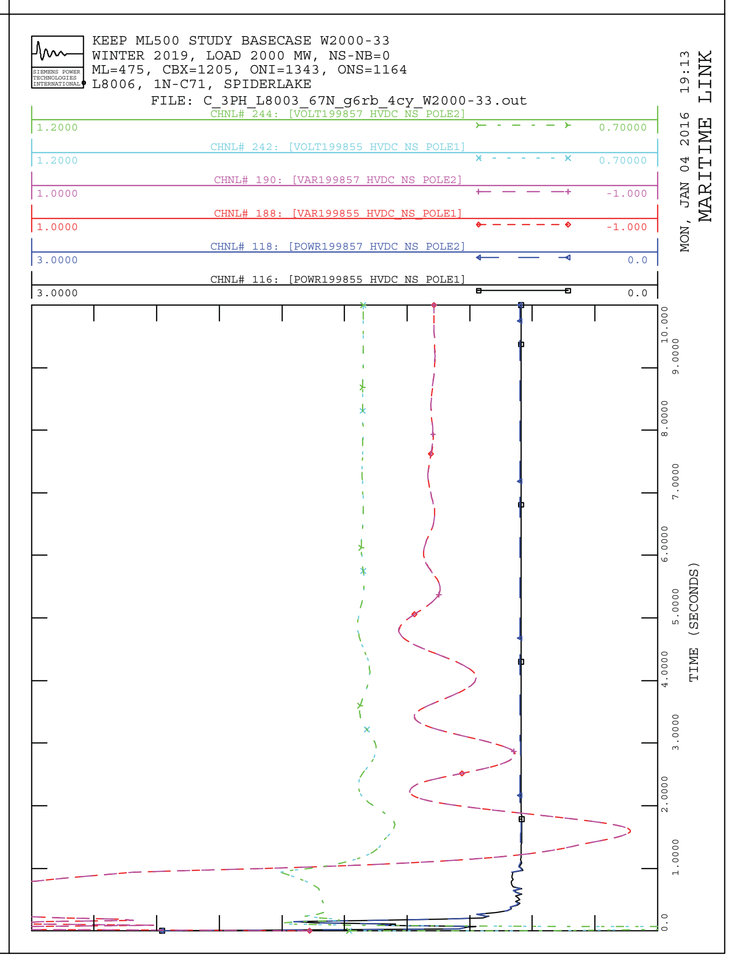
10.000
TIME (SECONDS)
MON, JAN 04 2016 19:13
MACHINE POWER


KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-33.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
0.0
1.0000
2.0000
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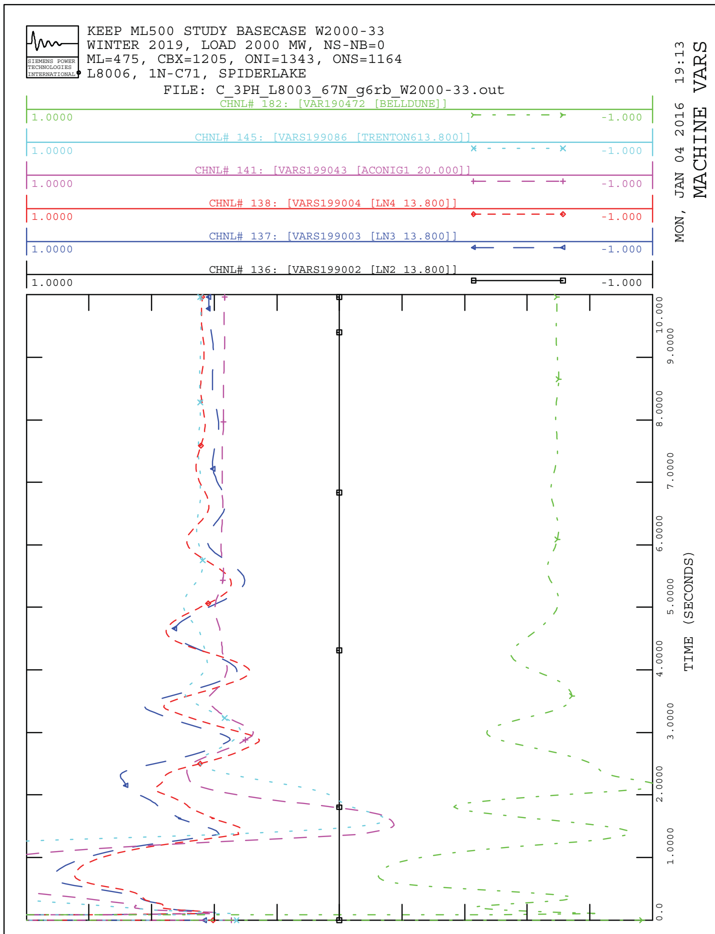
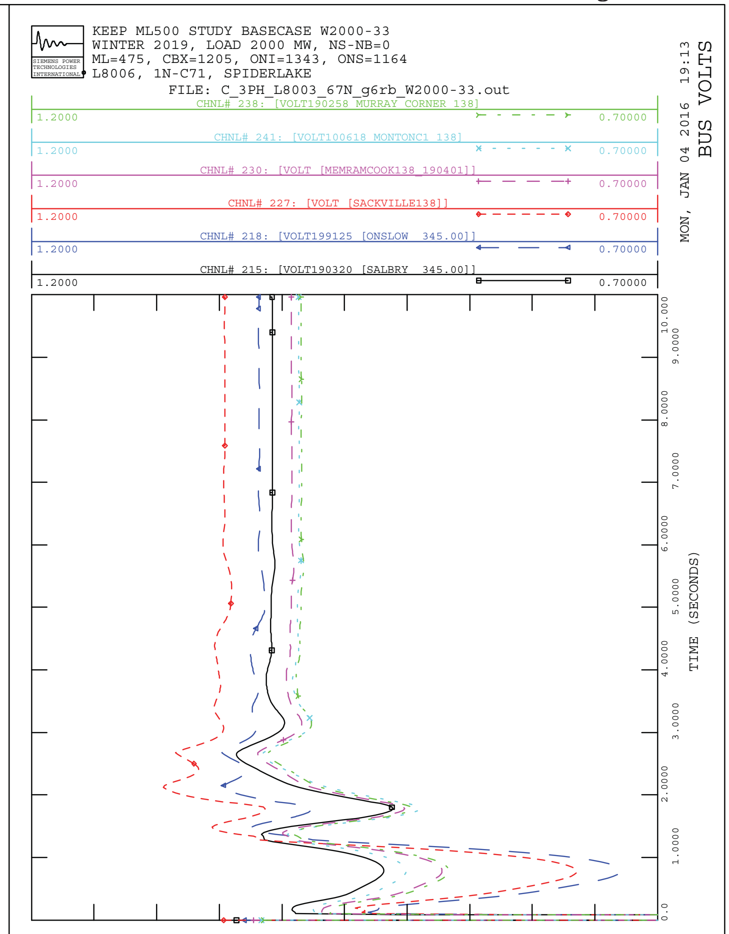
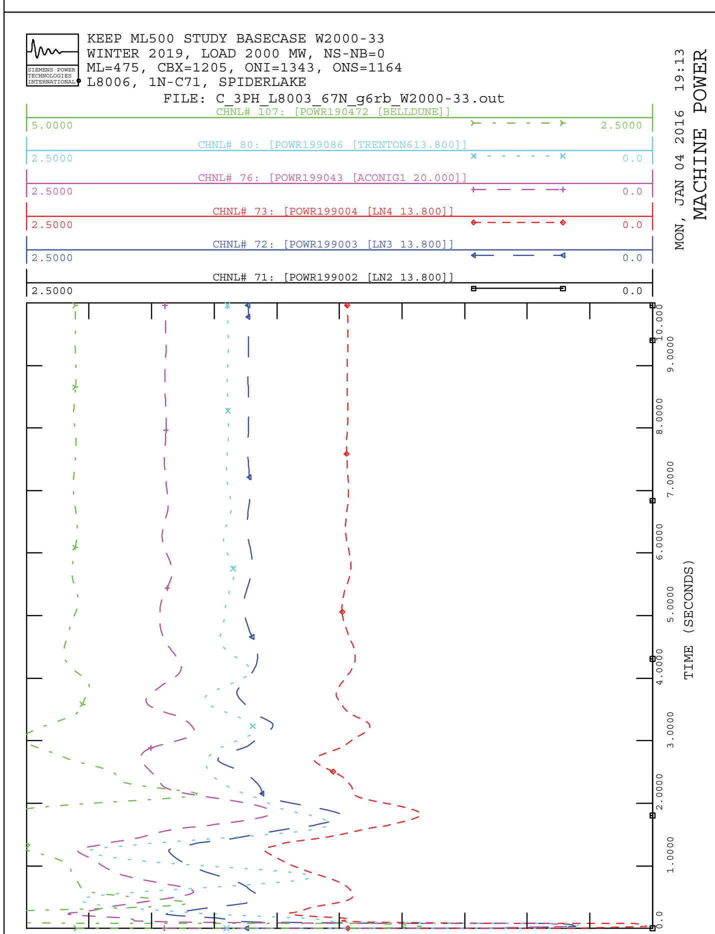
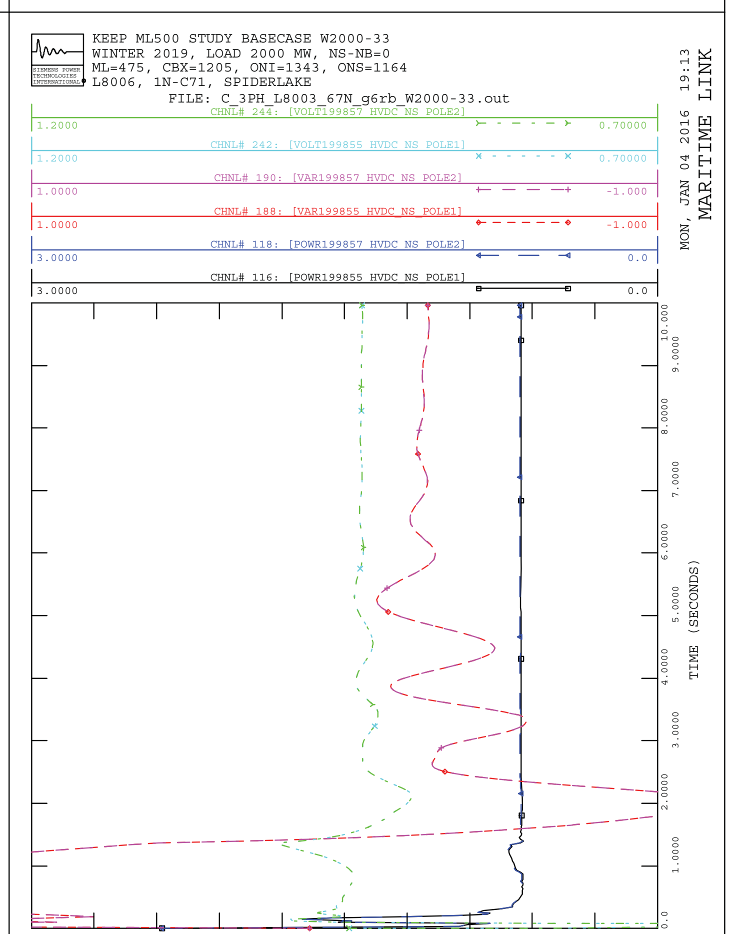
TIME (SECONDS)
MON, JAN 04 2016 19:13
MARITIME LINK

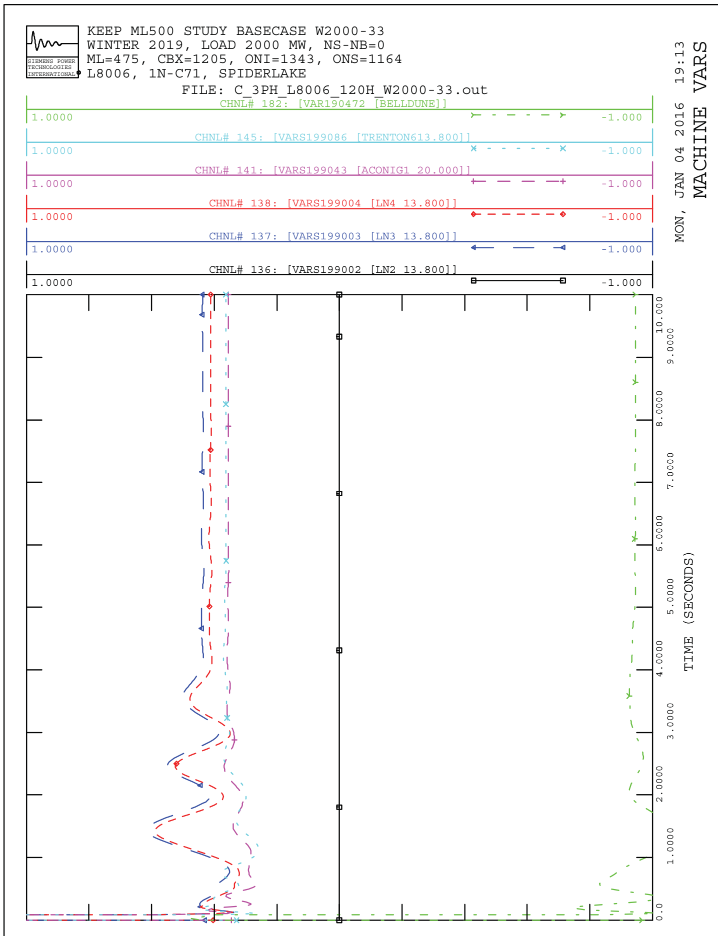
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



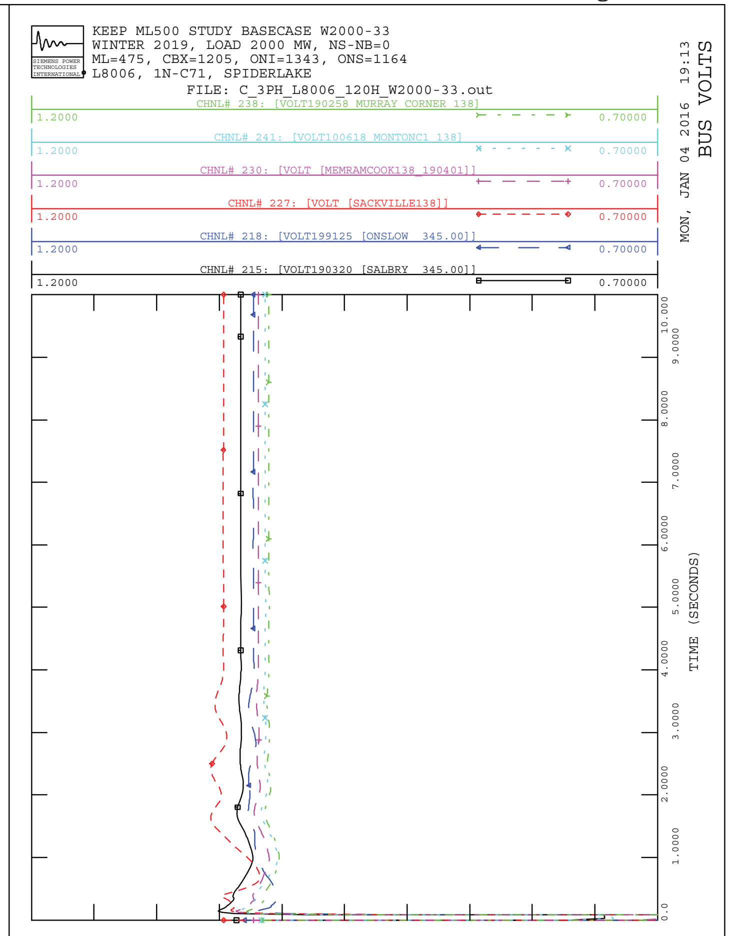




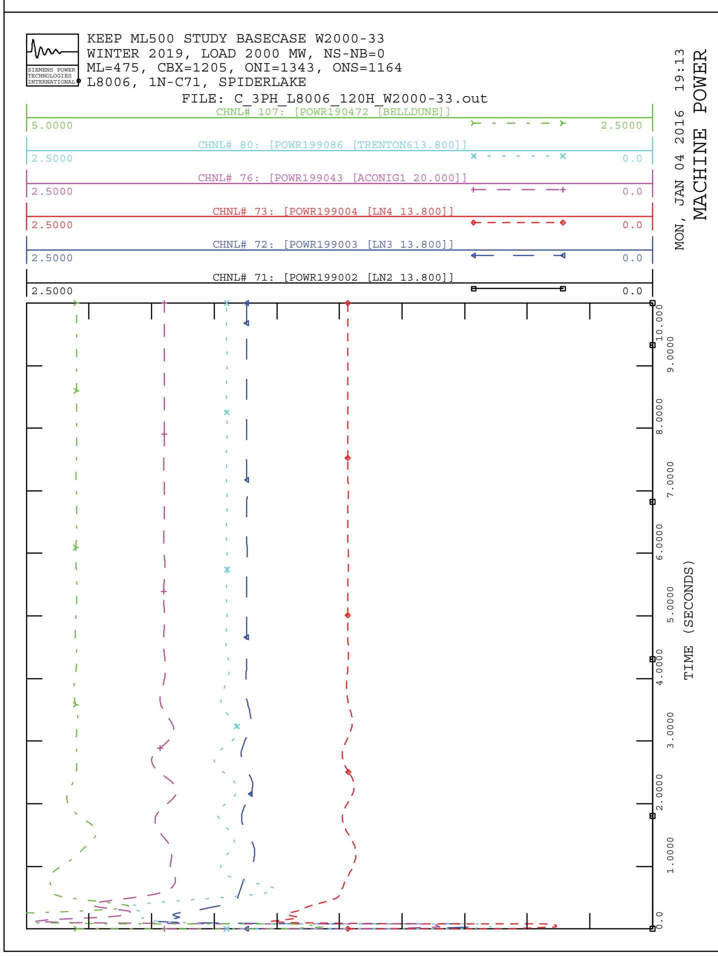




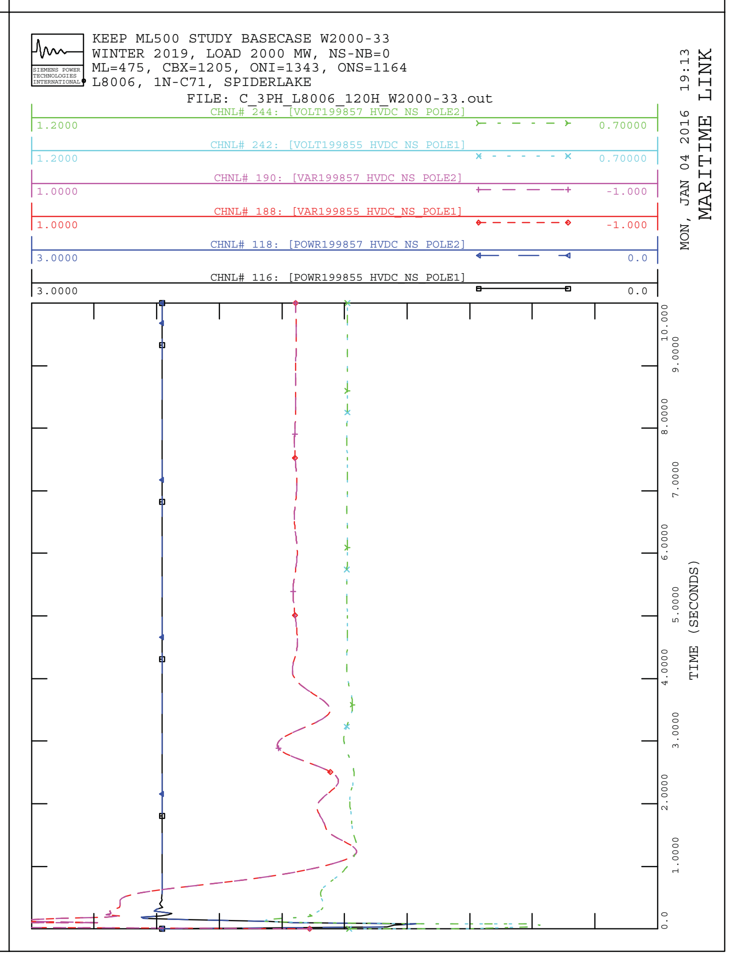
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8006_120H_W2000-33.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
MON, JAN 04 2016 19:13
MACHINE VARS
TIME (SECONDS)



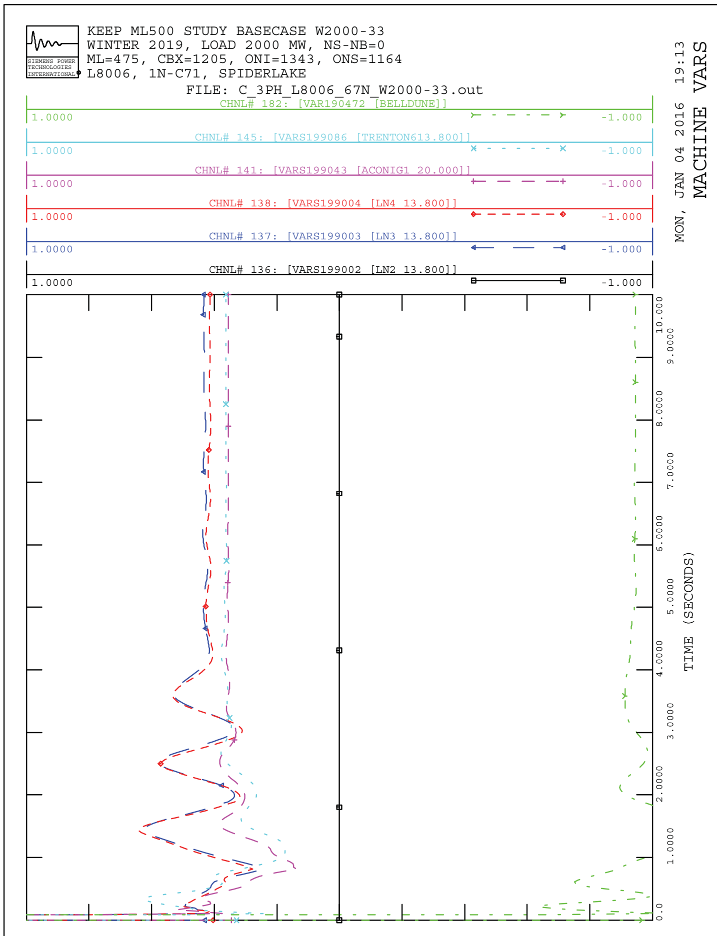
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8006_120H_W2000-33.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
MON, JAN 04 2016 19:13
BUS VOLTS
TIME (SECONDS)

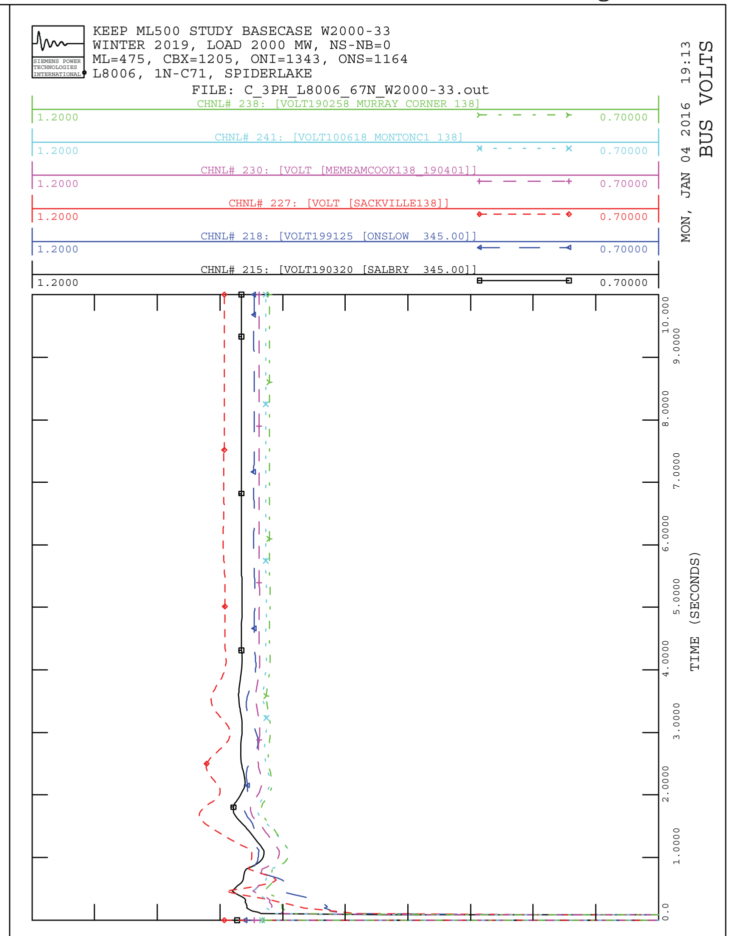


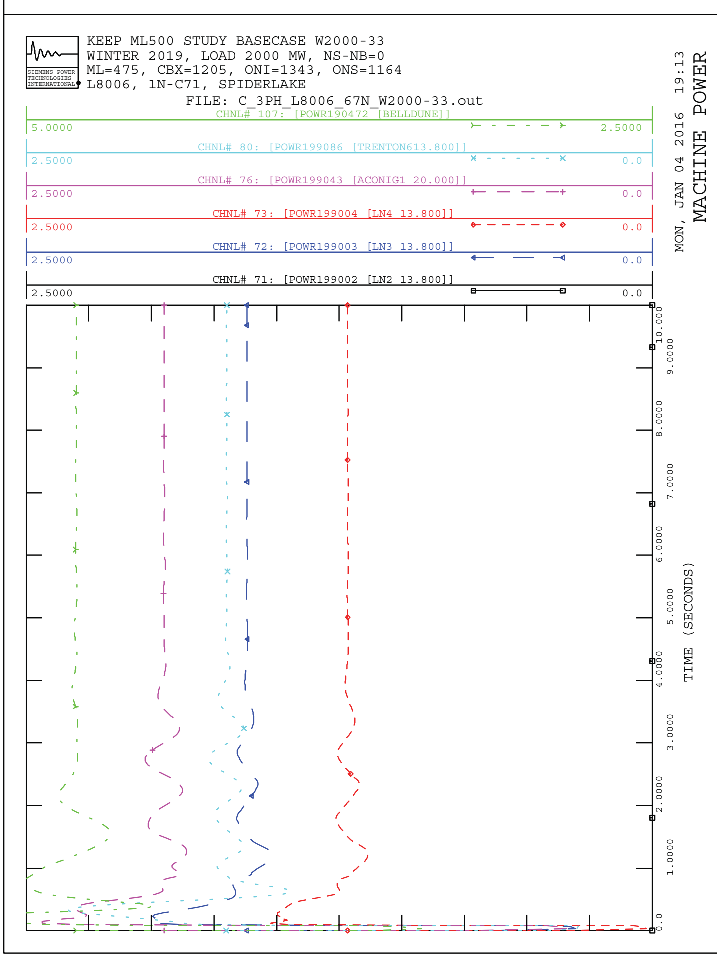
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8006_120H_W2000-33.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
MON, JAN 04 2016 19:13
MACHINE POWER
TIME (SECONDS)

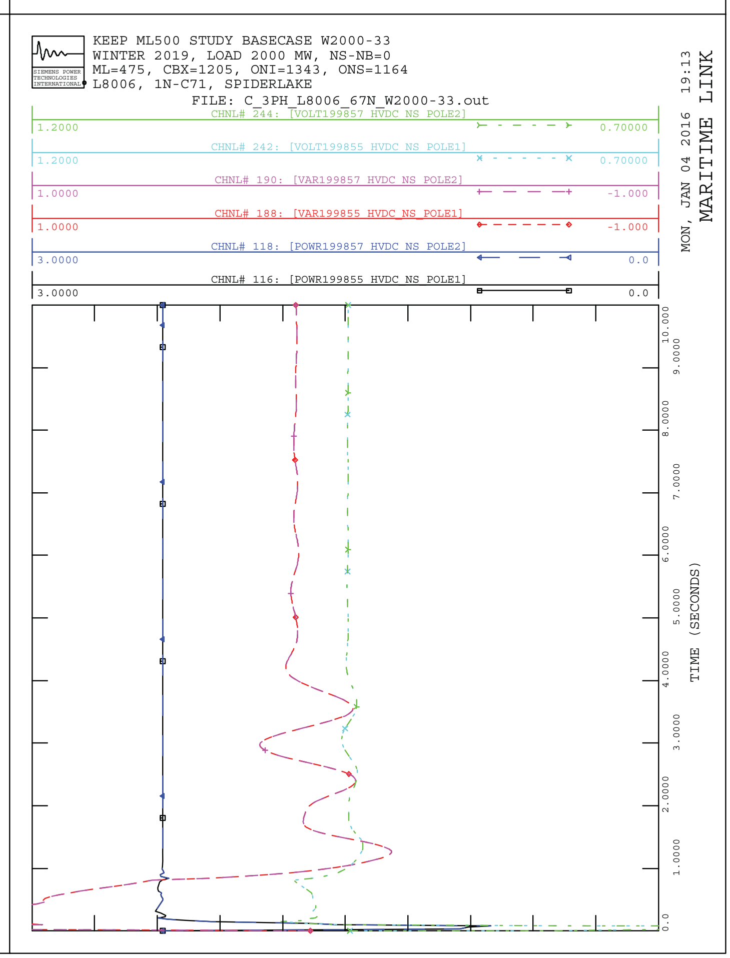


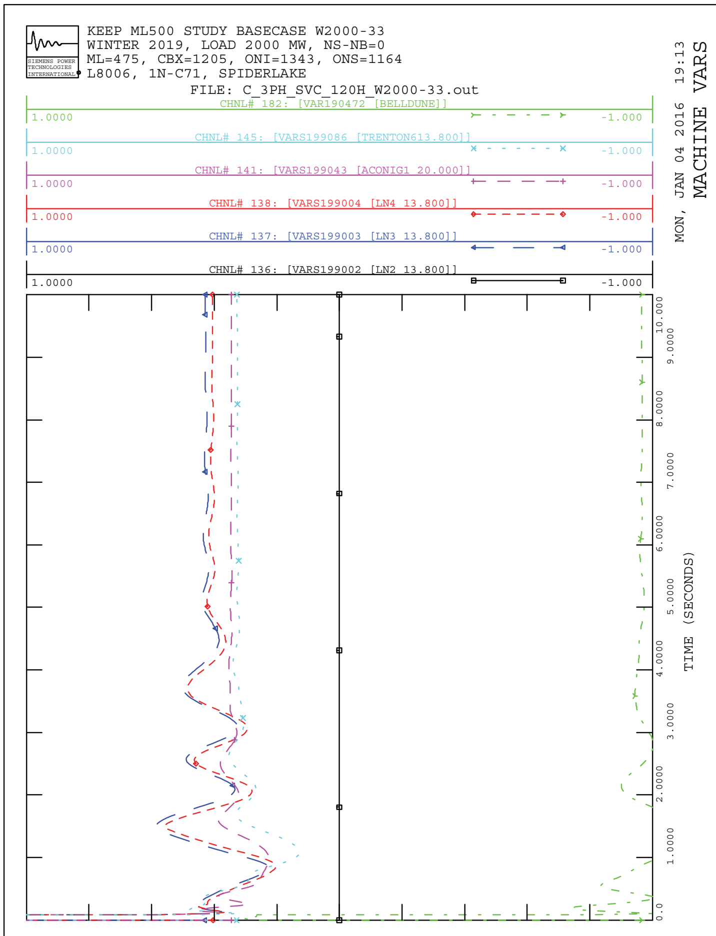
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8006_120H_W2000-33.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
MON, JAN 04 2016 19:13
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8006_67N_W2000-33.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
MON, JAN 04 2016 19:13
MACHINE VARS
TIME (SECONDS)

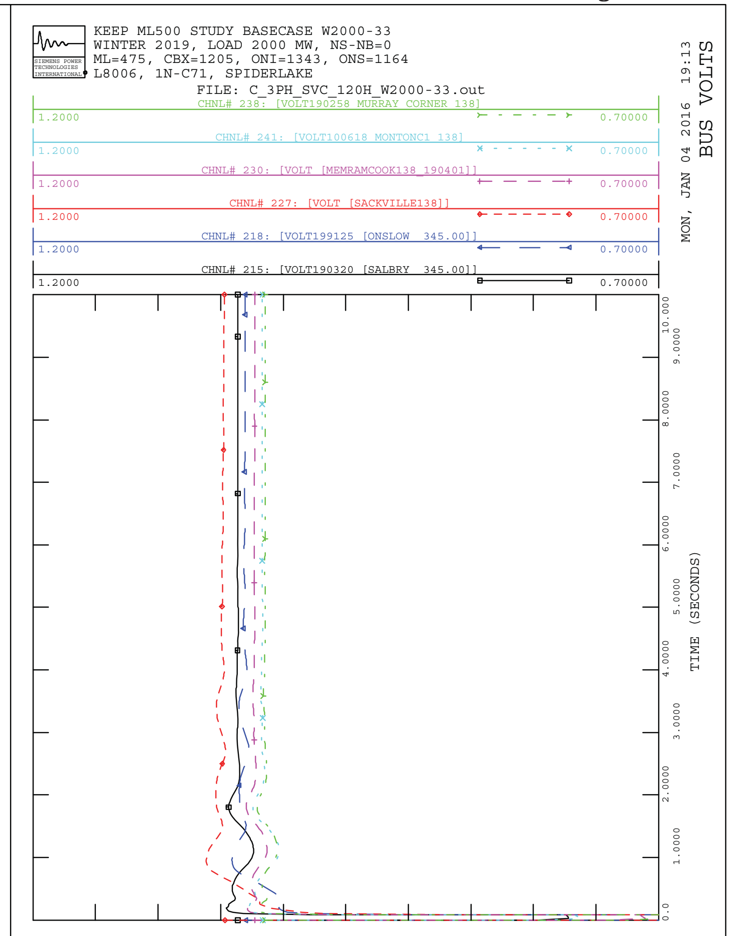

KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8006_67N_W2000-33.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
MON, JAN 04 2016 19:13
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8006_67N_W2000-33.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
MON, JAN 04 2016 19:13
MACHINE POWER
TIME (SECONDS)

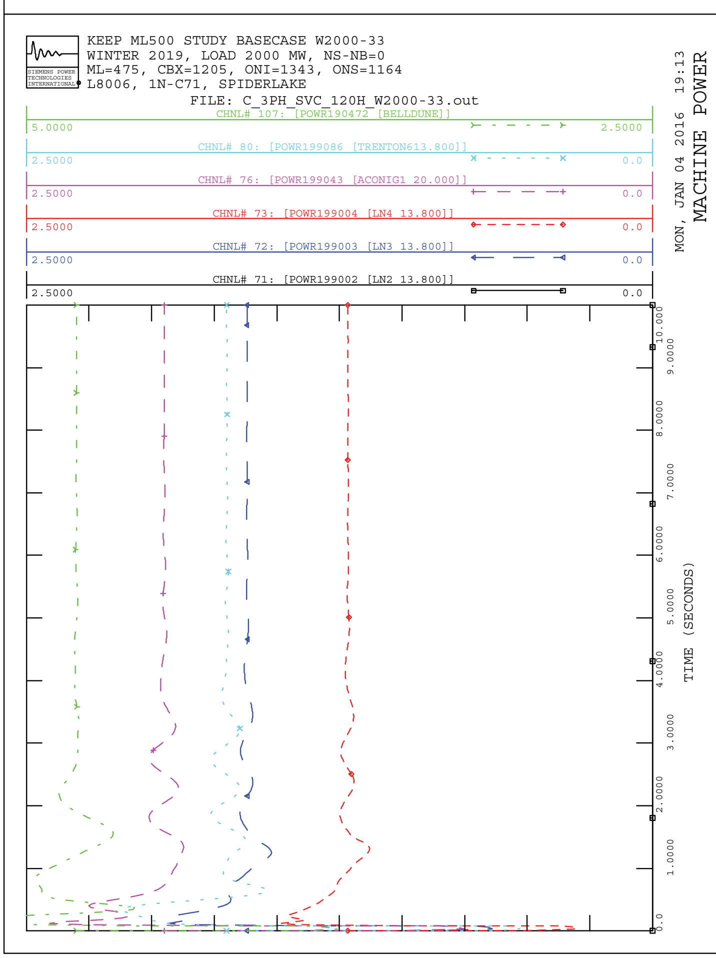

KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_L8006_67N_W2000-33.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
MON, JAN 04 2016 19:13
MARITIME LINK
TIME (SECONDS)



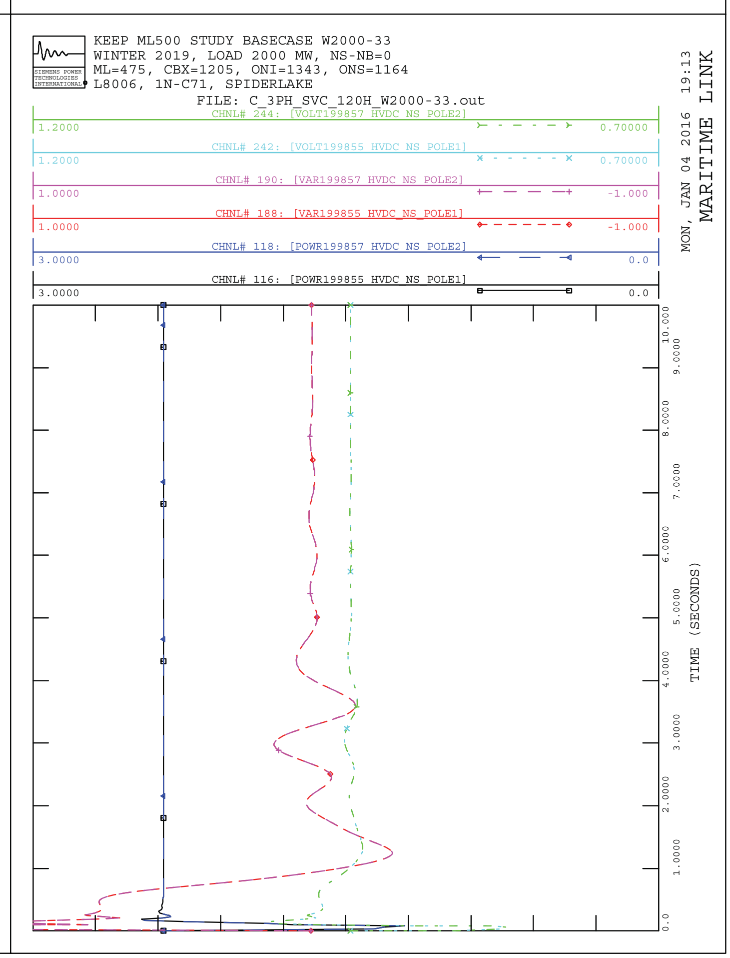
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_SVC_120H_W2000-33.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
MON, JAN 04 2016 19:13
MACHINE VARS
TIME (SECONDS)



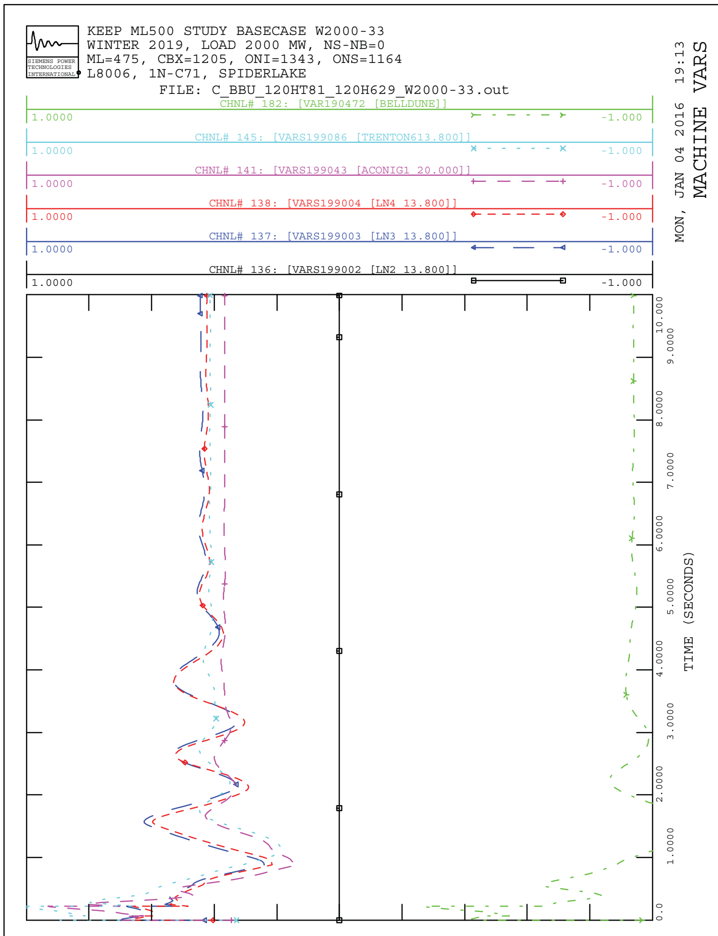
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_SVC_120H_W2000-33.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
MON, JAN 04 2016 19:13
BUS VOLTS
TIME (SECONDS)



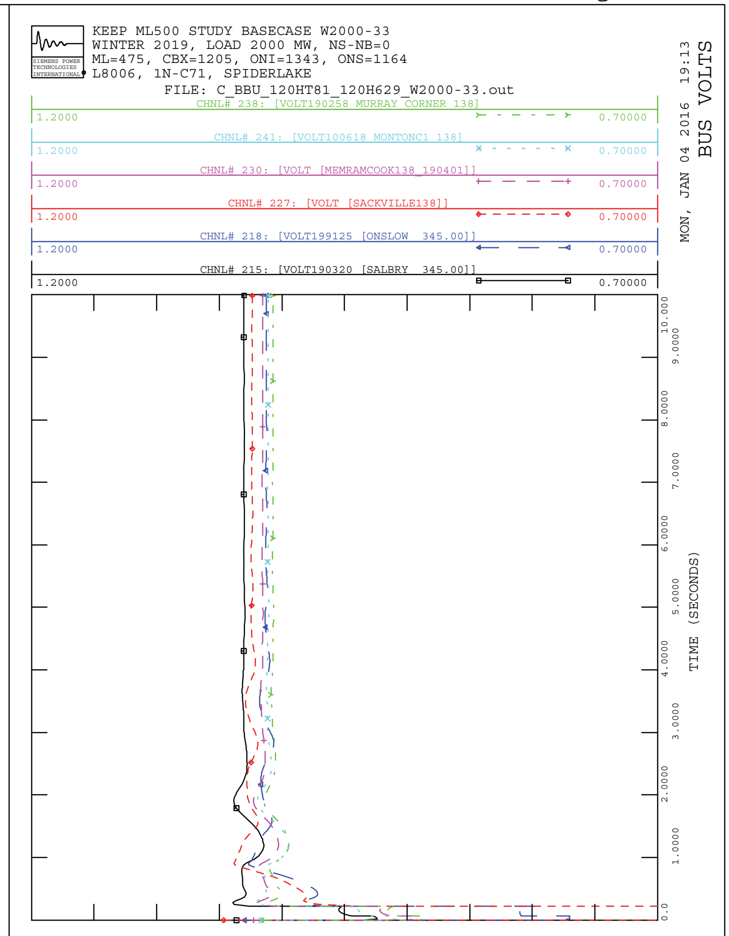
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_SVC_120H_W2000-33.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
MON, JAN 04 2016 19:13
MACHINE POWER
TIME (SECONDS)



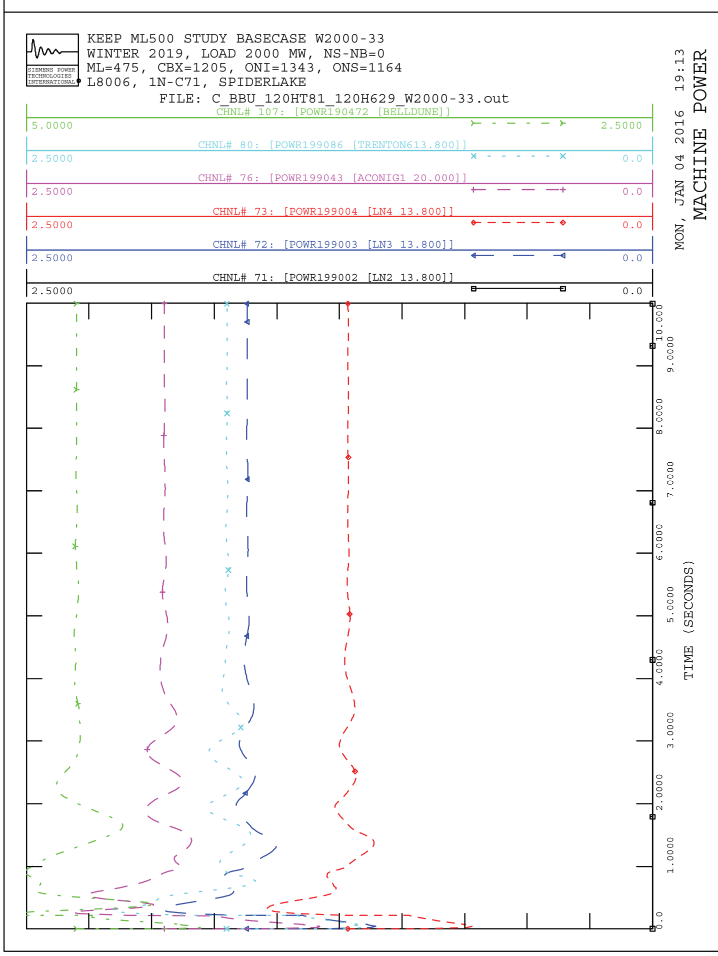
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_3PH_SVC_120H_W2000-33.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
MON, JAN 04 2016 19:13
MARITIME LINK
TIME (SECONDS)



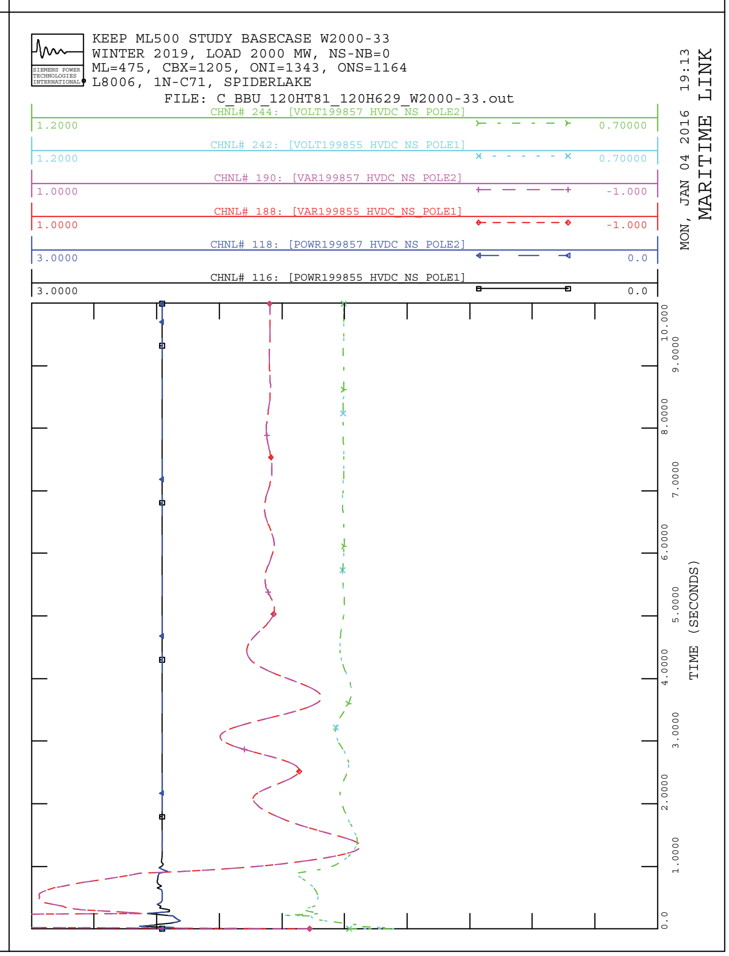
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_120HT81_120H629_W2000-33.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
TIME (SECONDS)
MON, JAN 04 2016 19:13
MACHINE VARS



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_120HT81_120H629_W2000-33.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
TIME (SECONDS)
MON, JAN 04 2016 19:13
BUS VOLTS

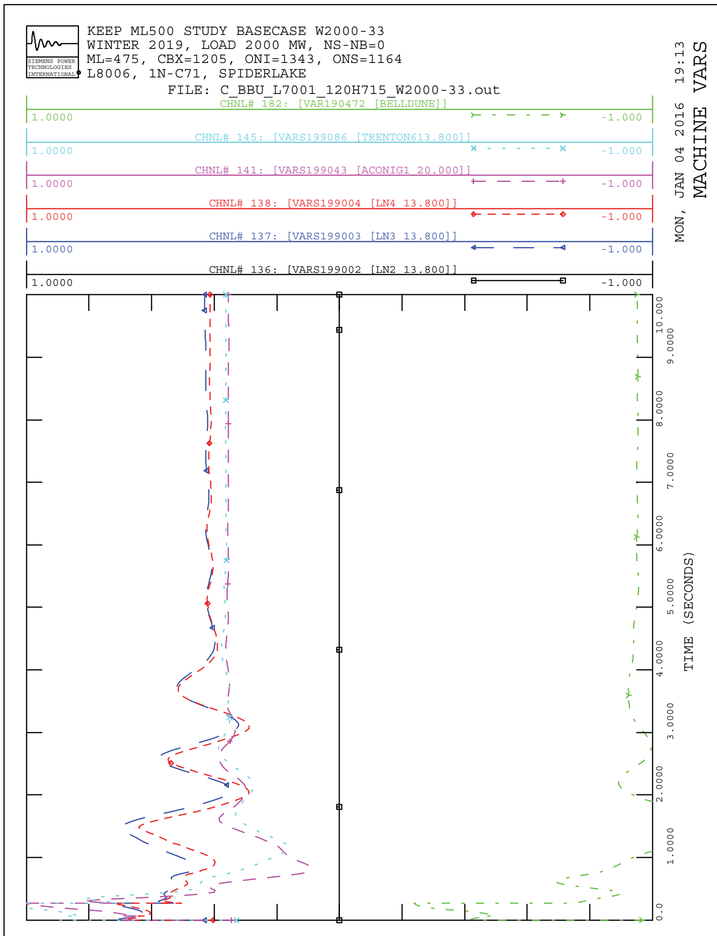


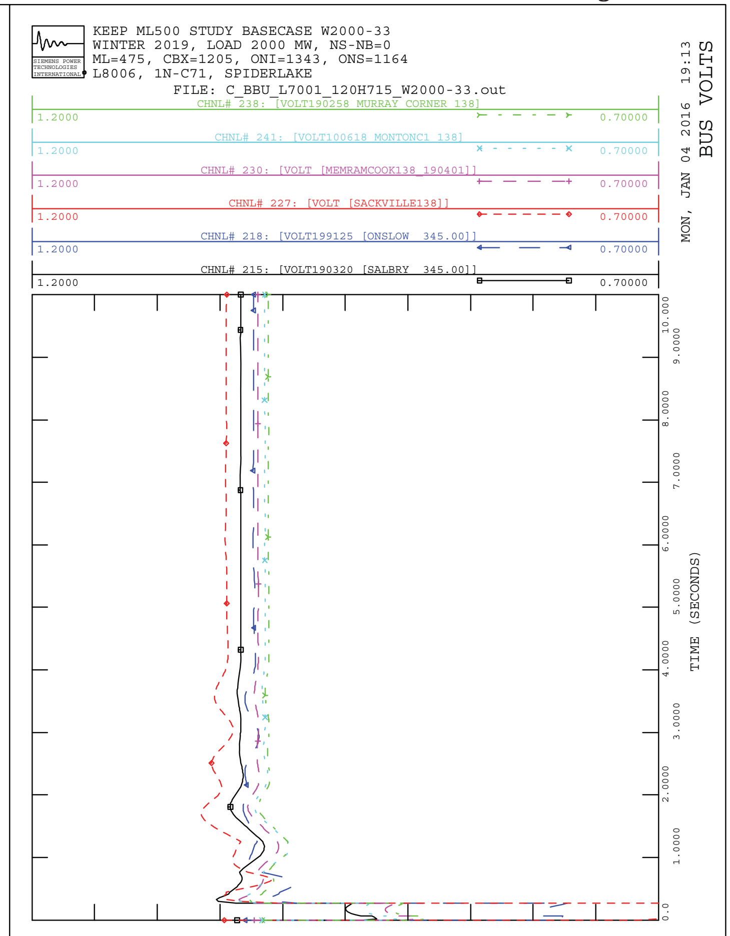
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_120HT81_120H629_W2000-33.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
TIME (SECONDS)
MON, JAN 04 2016 19:13
MACHINE POWER

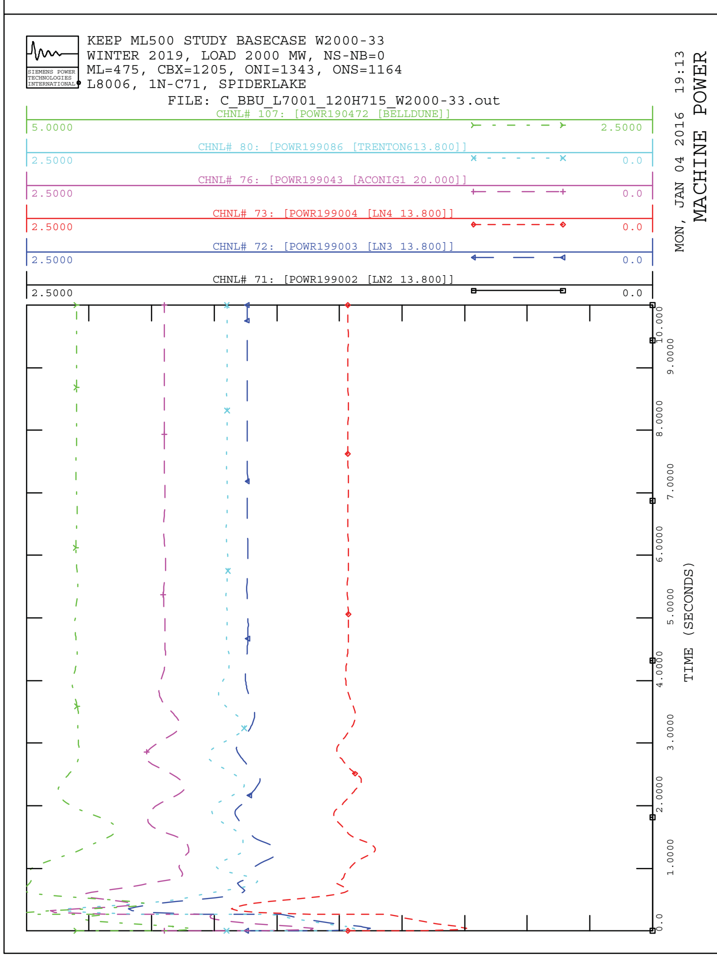


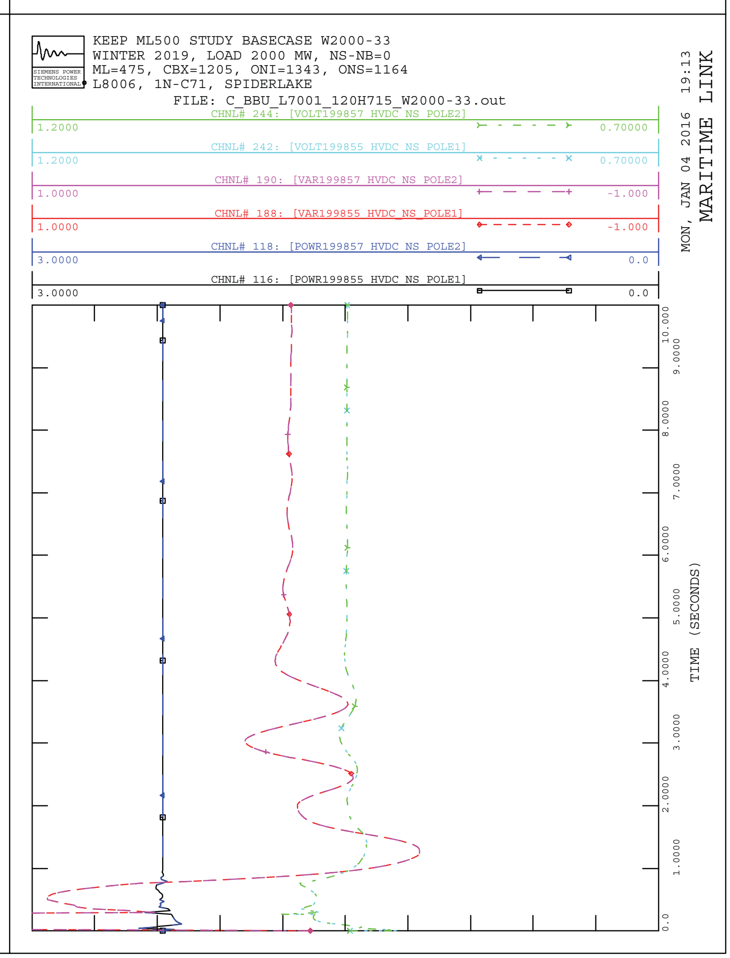
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_120HT81_120H629_W2000-33.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
TIME (SECONDS)
MON, JAN 04 2016 19:13
MARITIME LINK

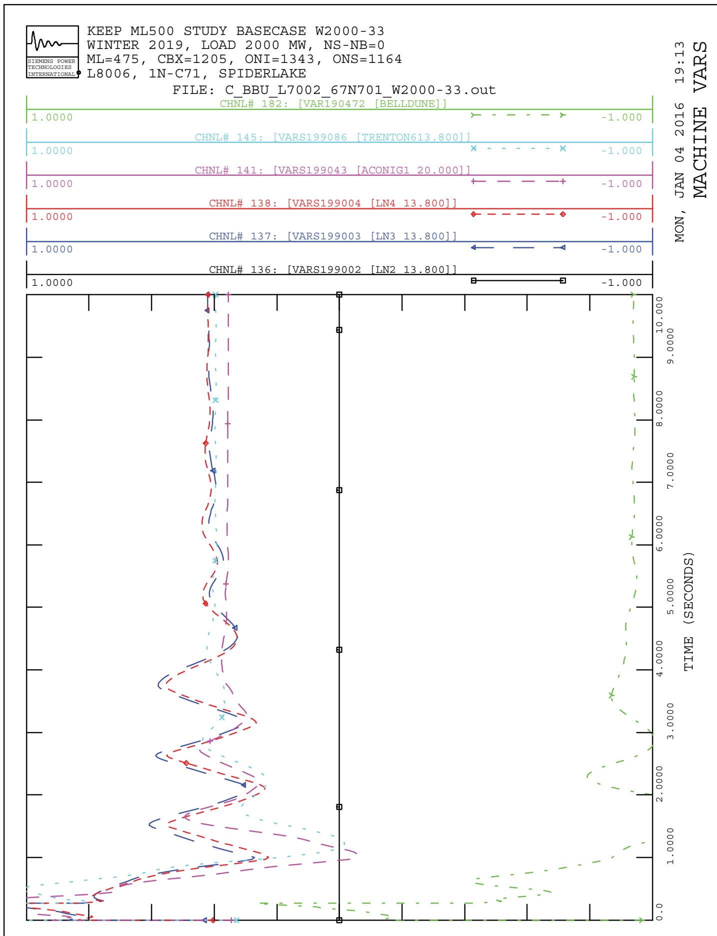
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



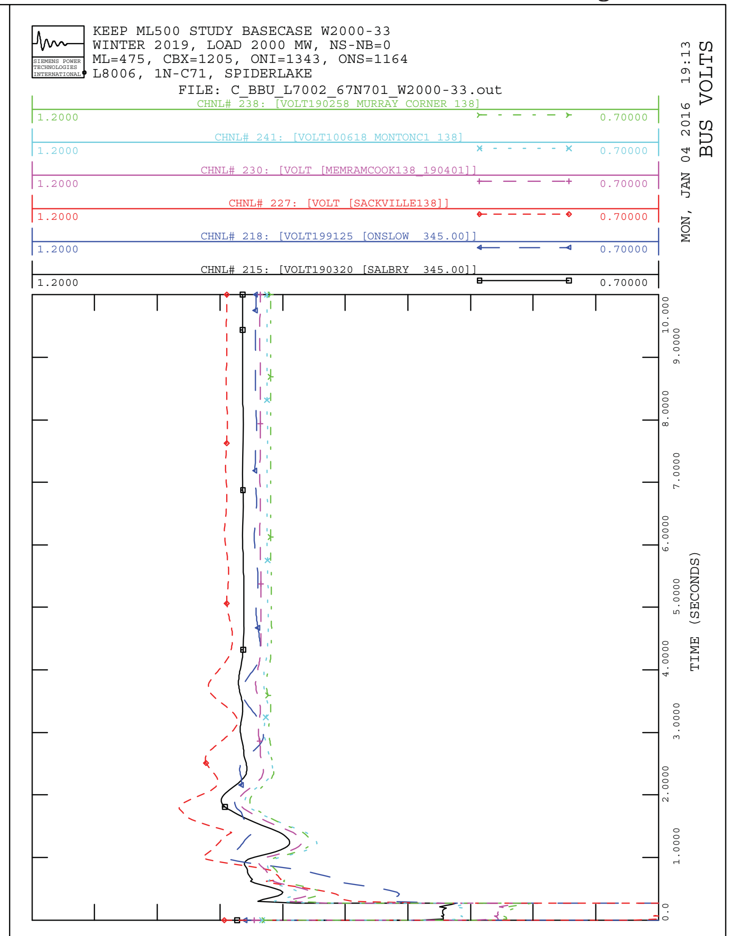




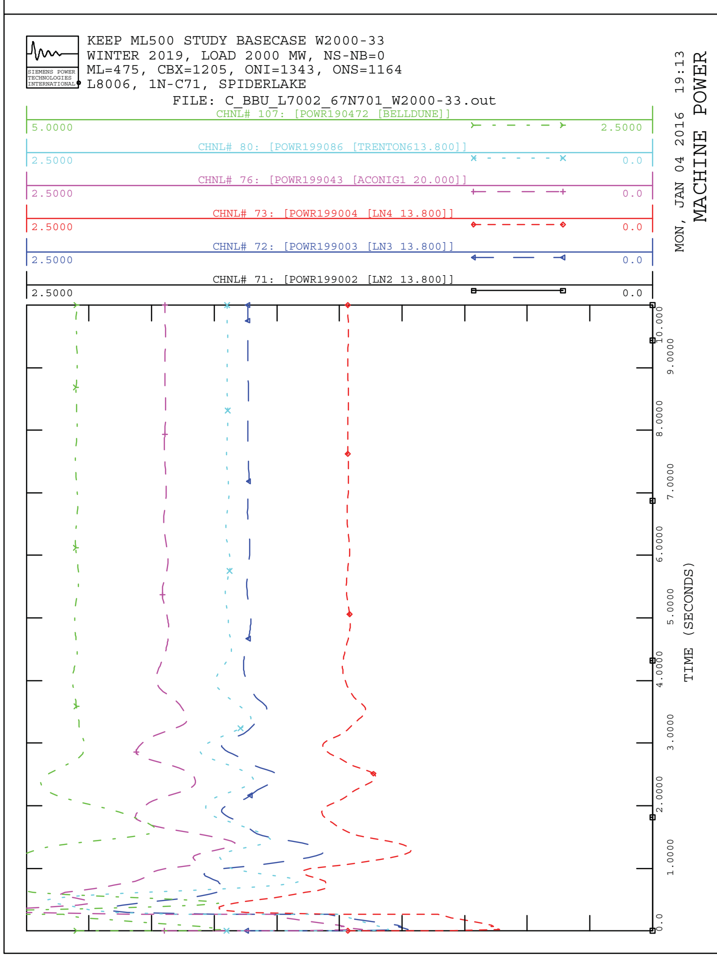




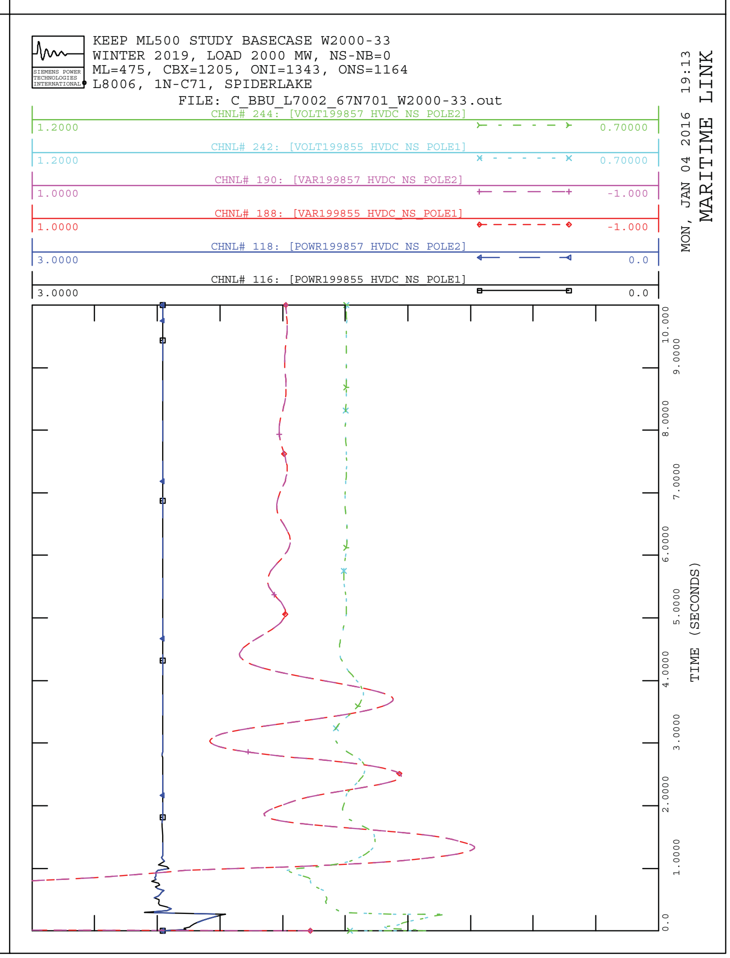
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7002_67N701_W2000-33.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
MON, JAN 04 2016 19:13
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7002_67N701_W2000-33.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
MON, JAN 04 2016 19:13
BUS VOLTS
TIME (SECONDS)

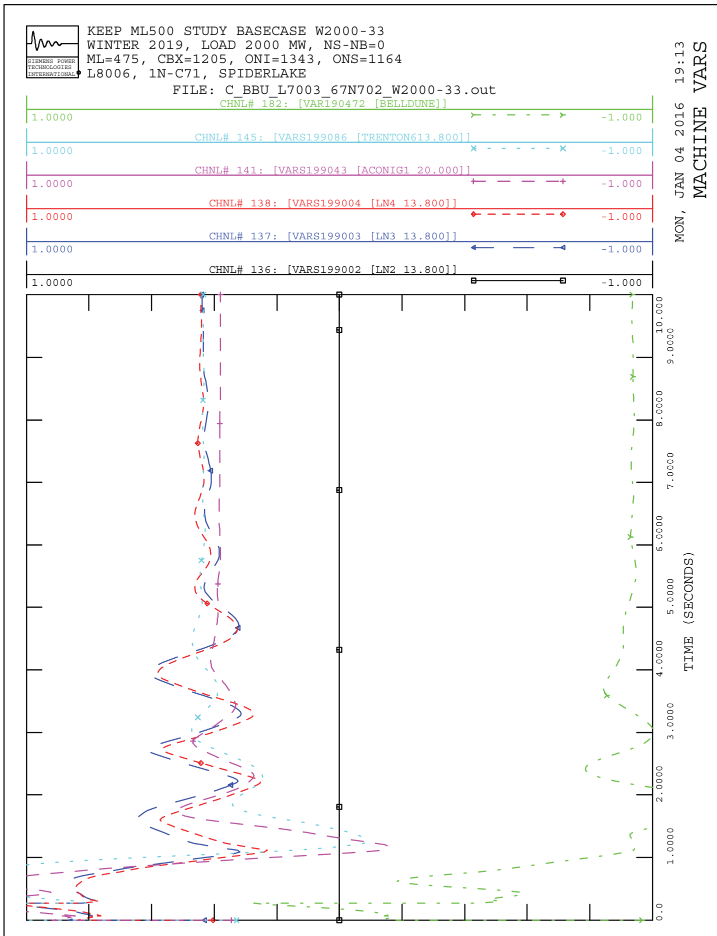


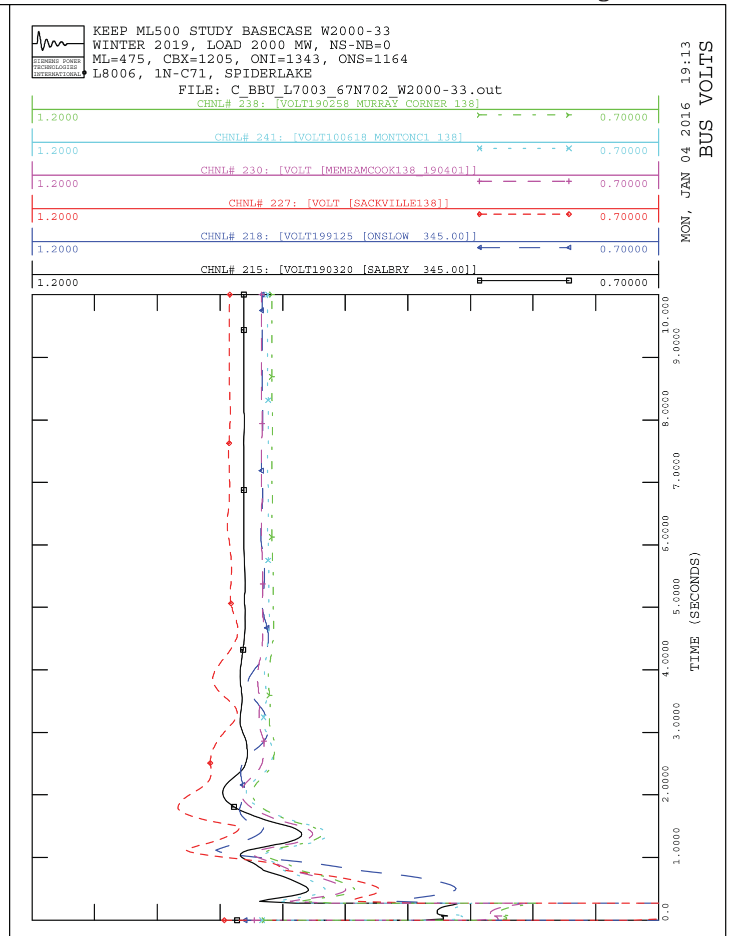
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7002_67N701_W2000-33.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
MON, JAN 04 2016 19:13
MACHINE POWER
TIME (SECONDS)

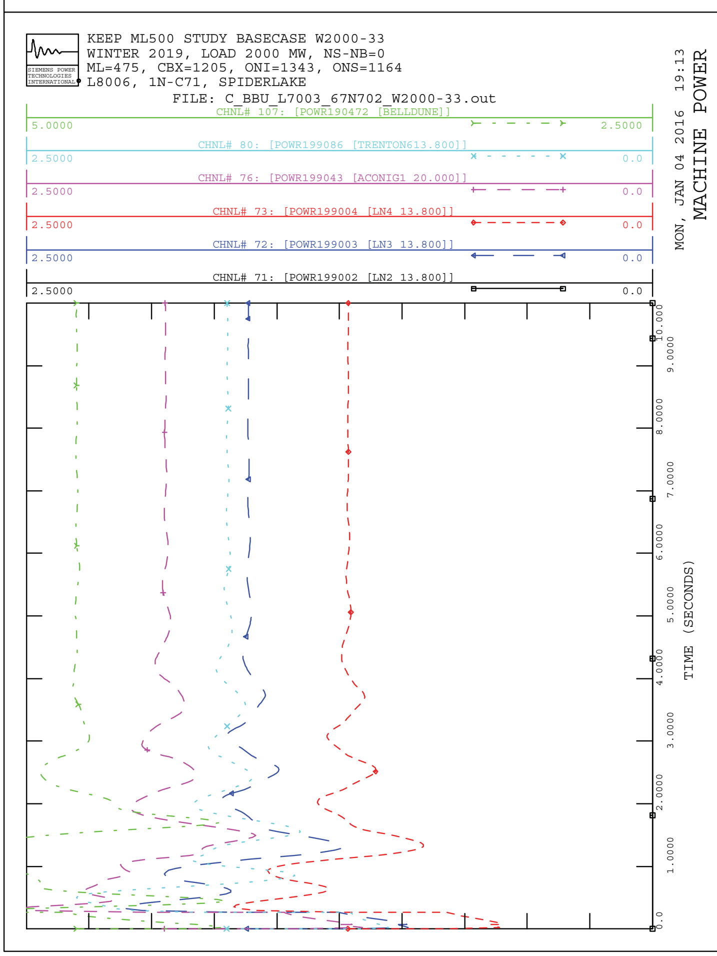


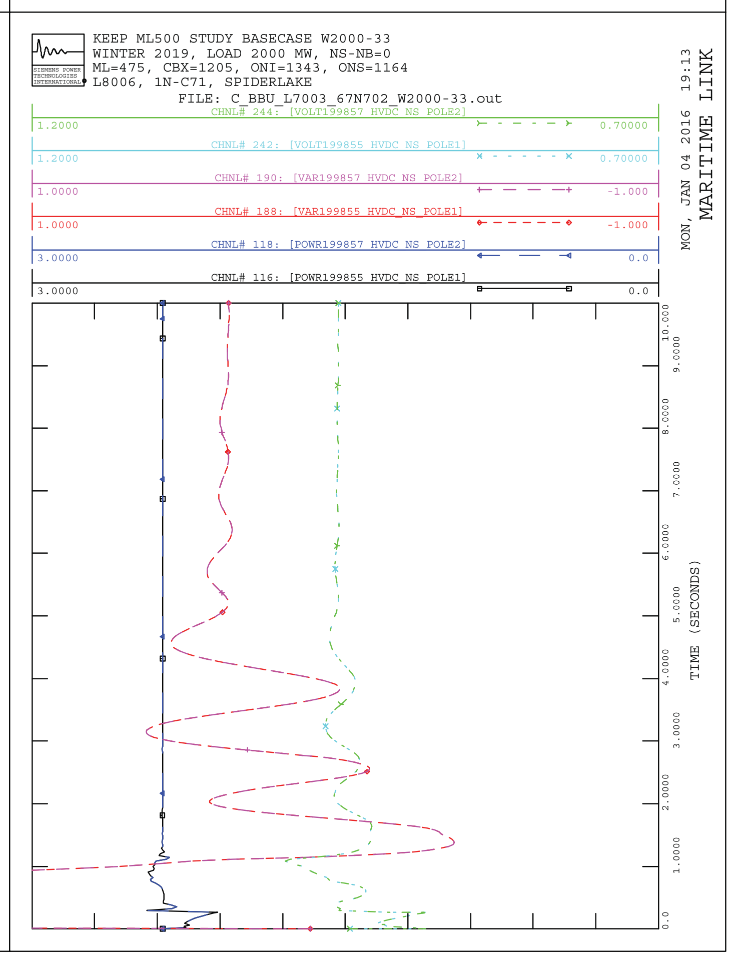
KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7002_67N701_W2000-33.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
MON, JAN 04 2016 19:13
MARITIME LINK
TIME (SECONDS)

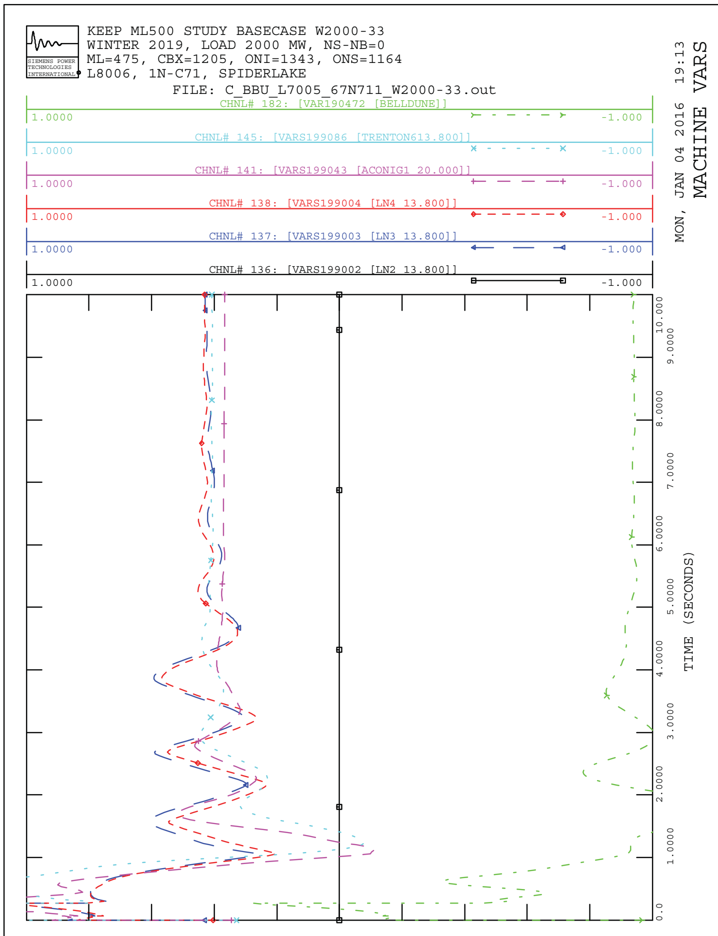
REDACTED (CONFIDENTIAL INFORMATION REMOVED)










KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7005_67N711_W2000-33.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
MON, JAN 04 2016 19:13
MACHINE VARS
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
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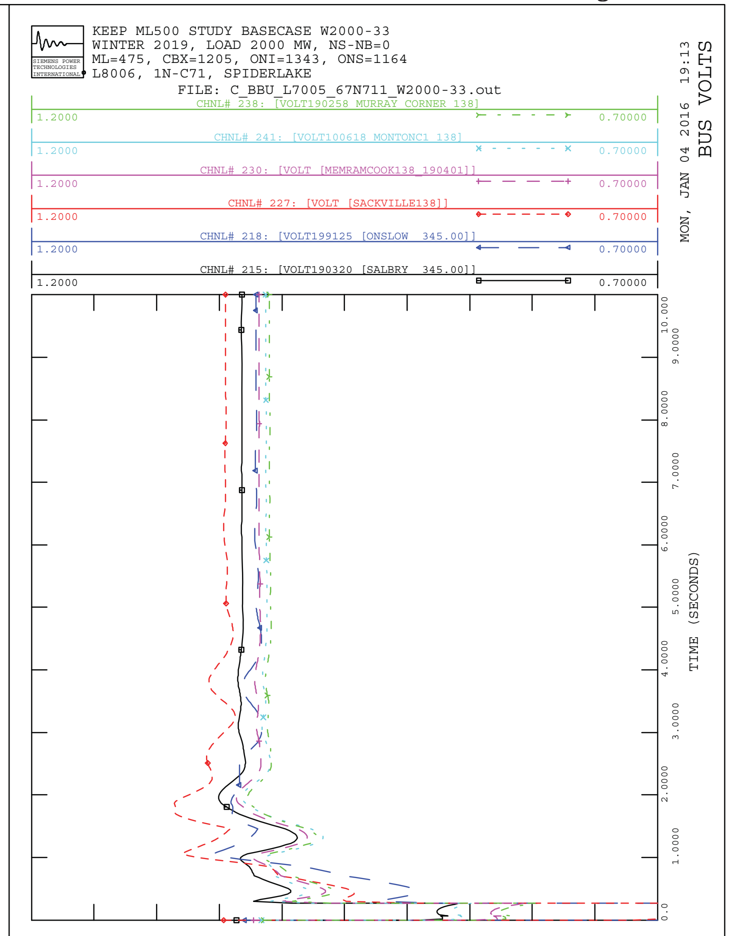
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7005_67N711_W2000-33.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
MON, JAN 04 2016 19:13
BUS VOLTS
TIME (SECONDS)
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1.0000
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3.0000
4.0000
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6.0000
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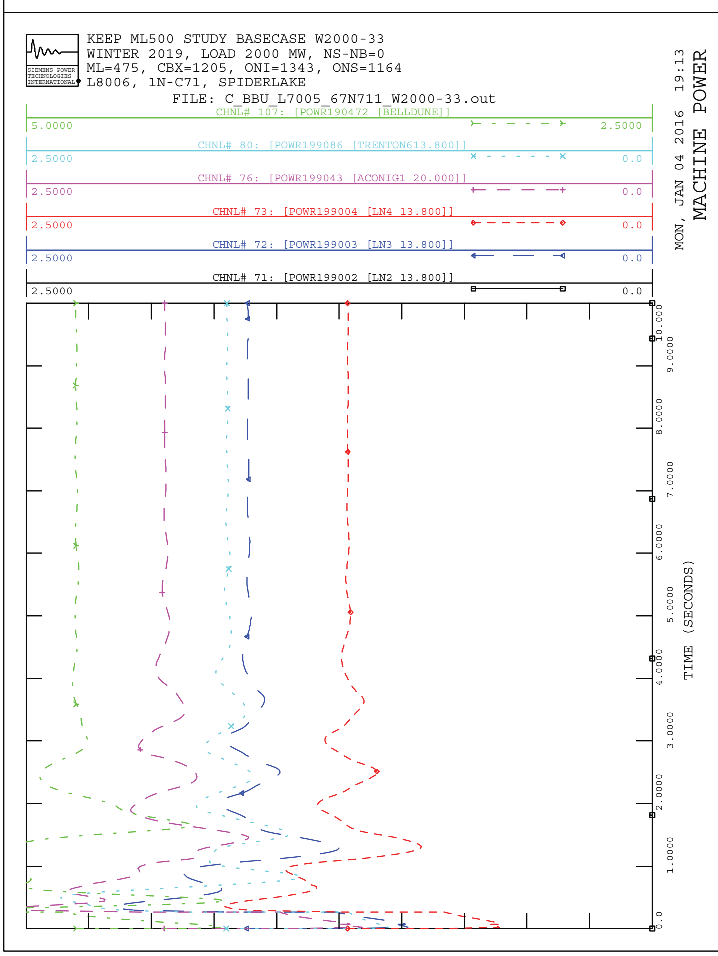
10.000


KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7005_67N711_W2000-33.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
MON, JAN 04 2016 19:13
MACHINE POWER
TIME (SECONDS)
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1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
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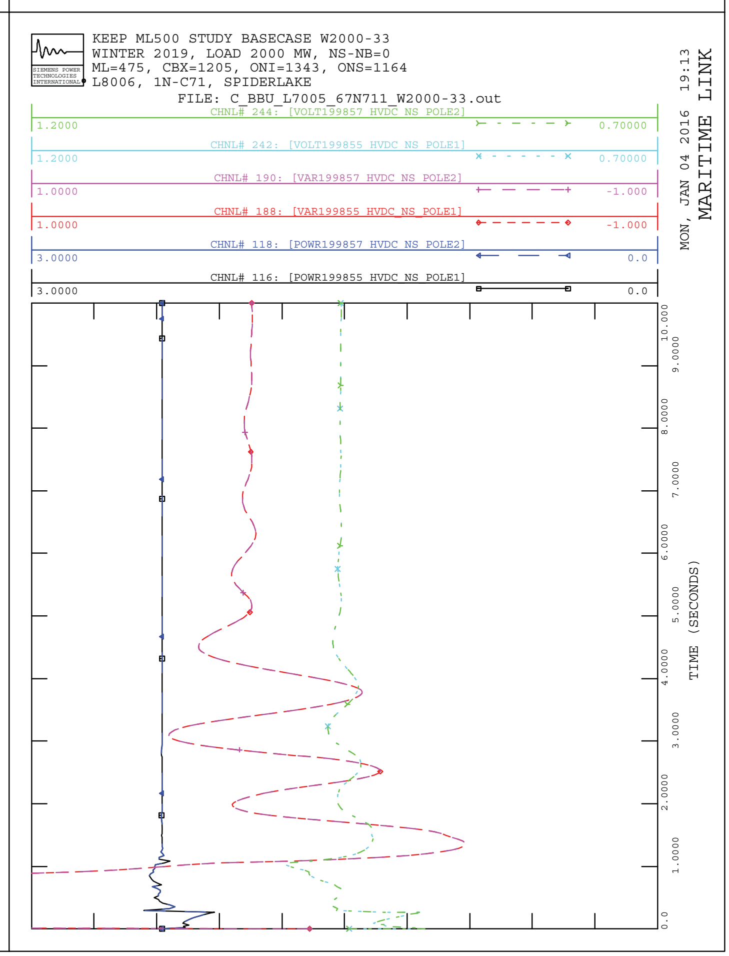
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7005_67N711_W2000-33.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
MON, JAN 04 2016 19:13
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
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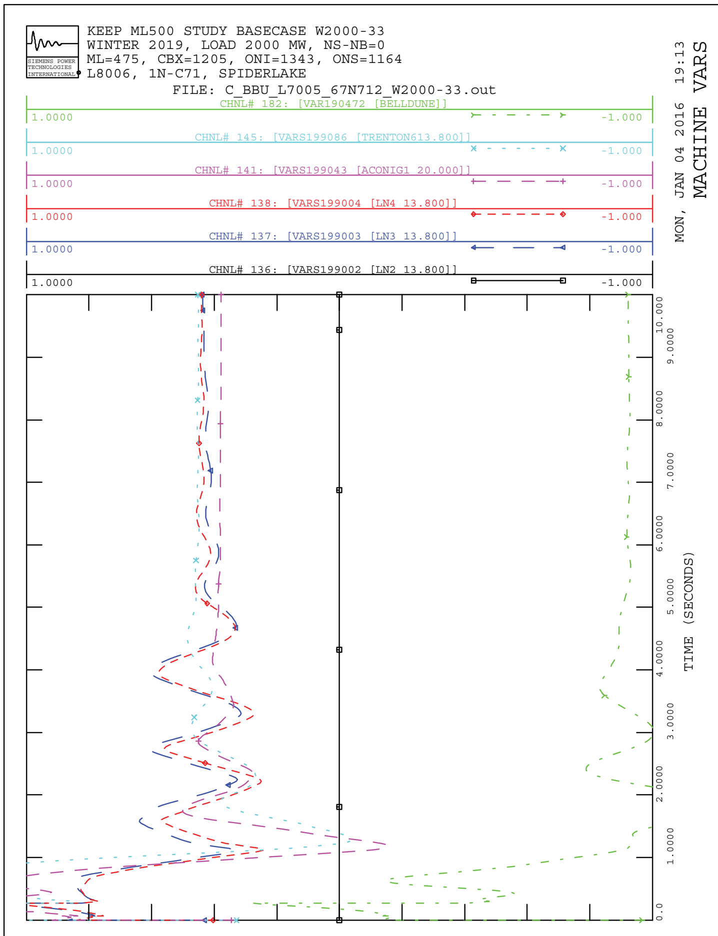
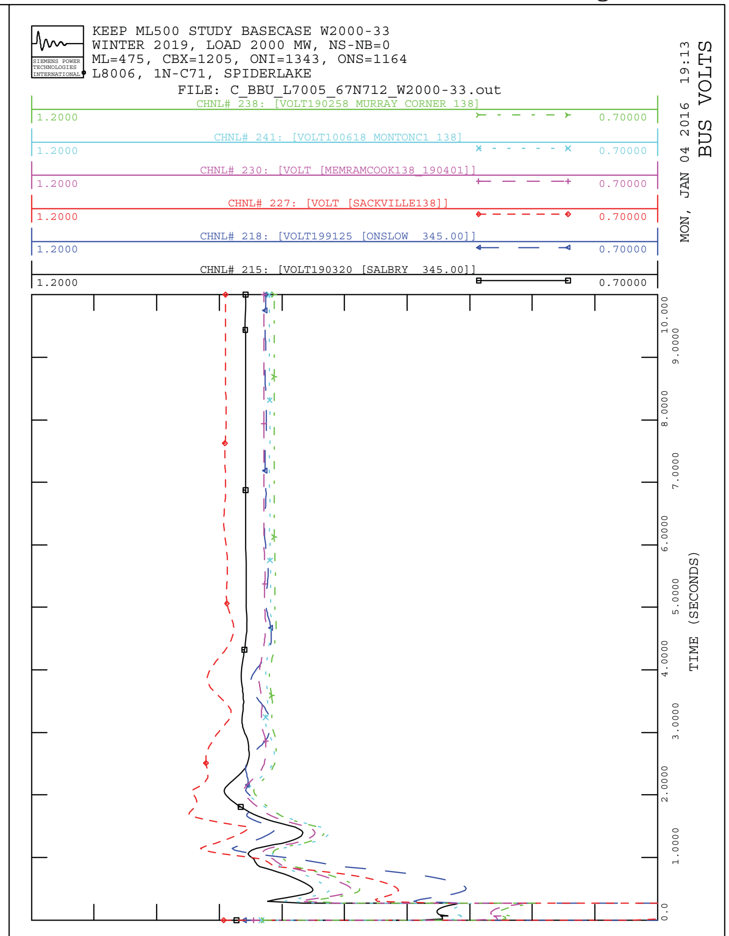
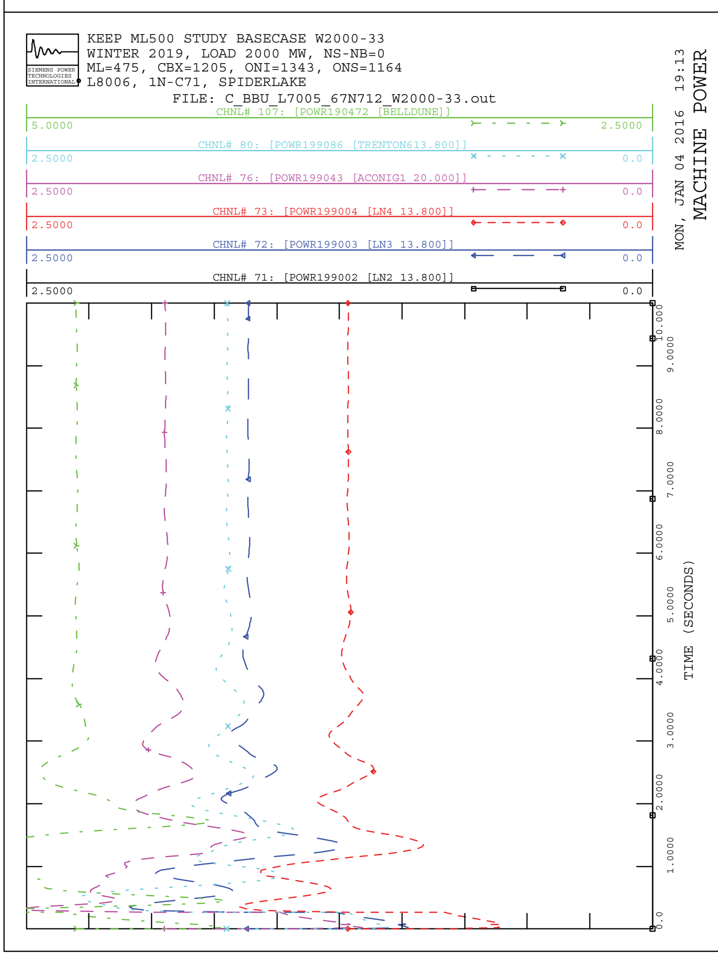
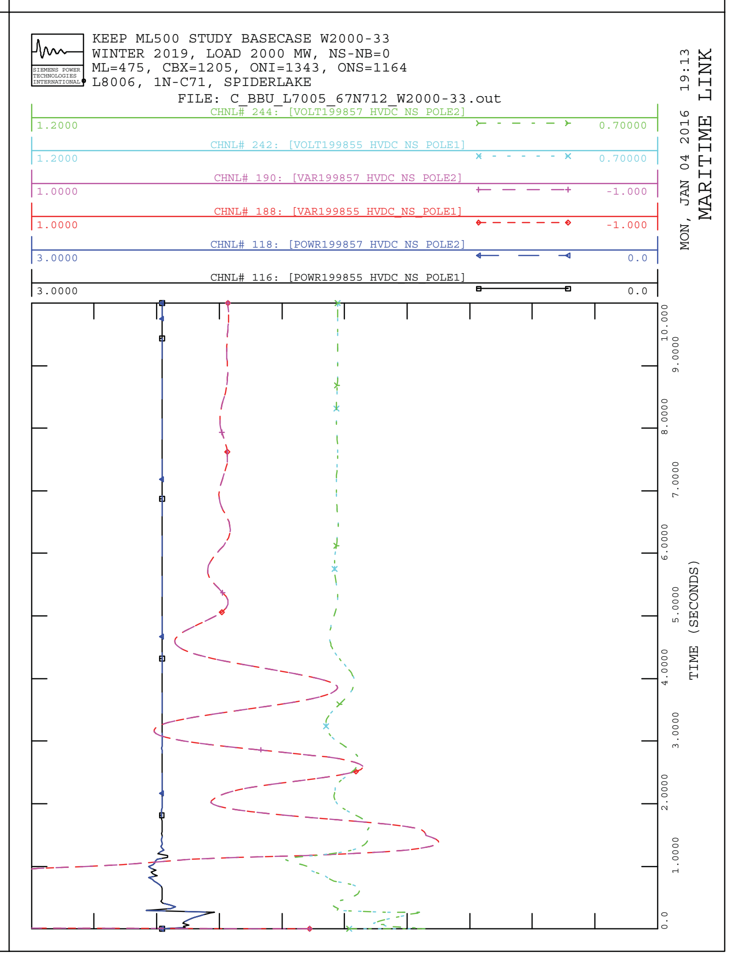
7.0000
8.0000
9.0000
10.000

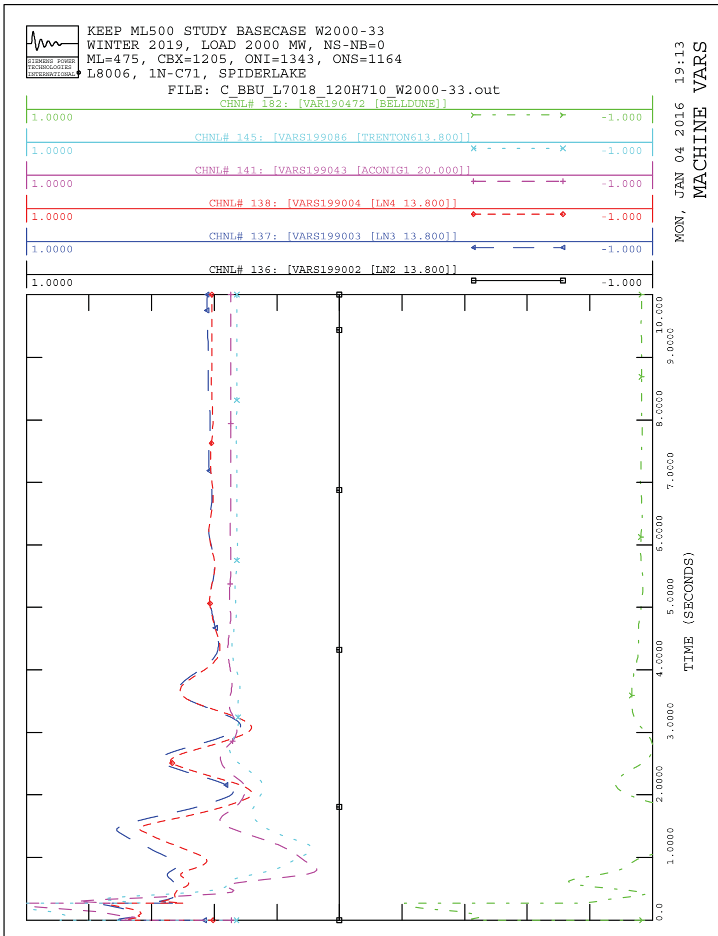
REDACTED (CONFIDENTIAL INFORMATION REMOVED)











KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7018_120H710_W2000-33.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
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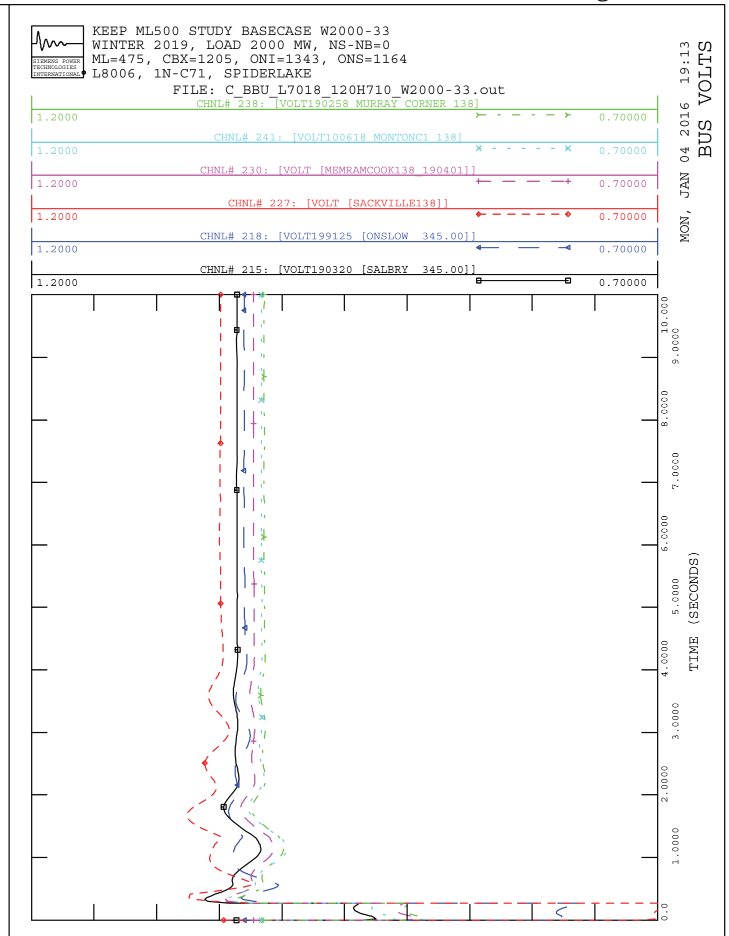
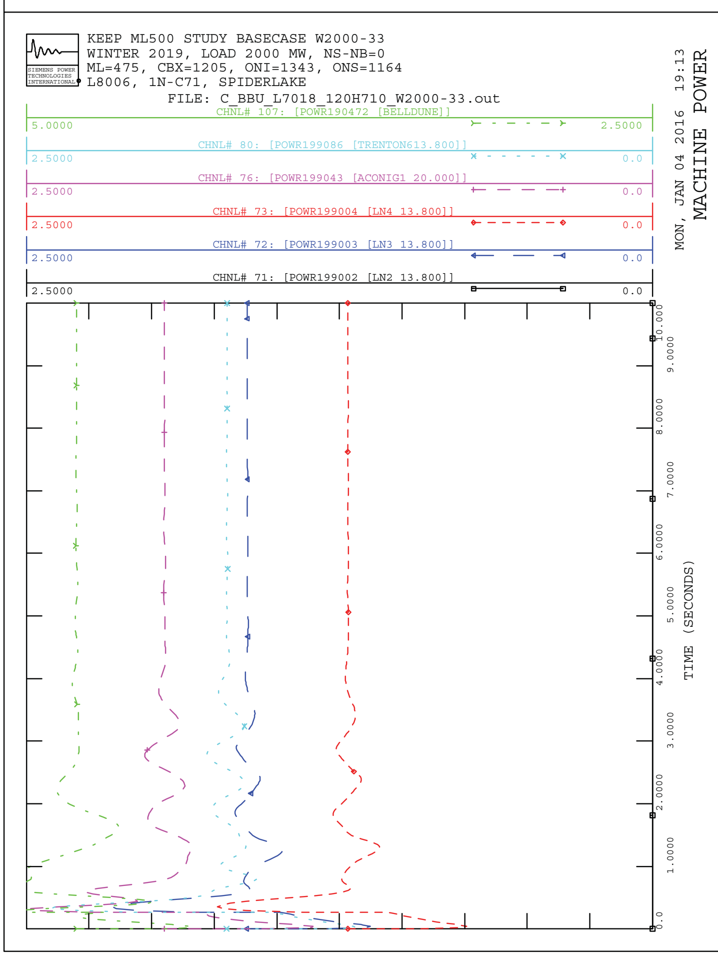
-1.000
MON, JAN 04 2016 19:13
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7018_120H710_W2000-33.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
MON, JAN 04 2016 19:13
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7018_120H710_W2000-33.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
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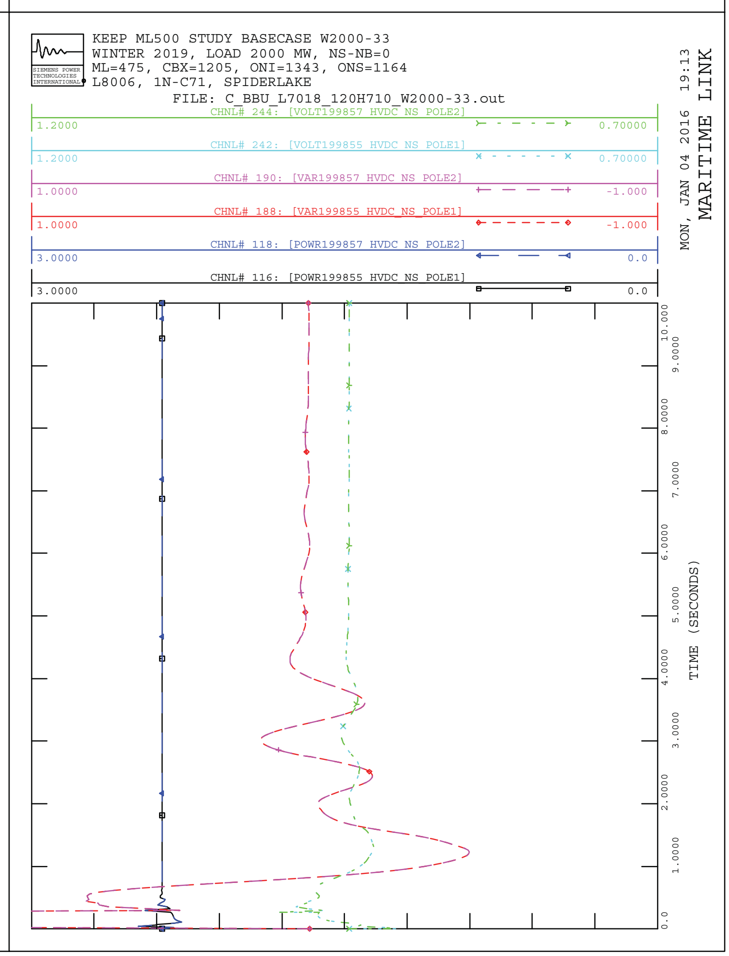
MON, JAN 04 2016 19:13
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7018_120H710_W2000-33.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
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1.0000
-1.000
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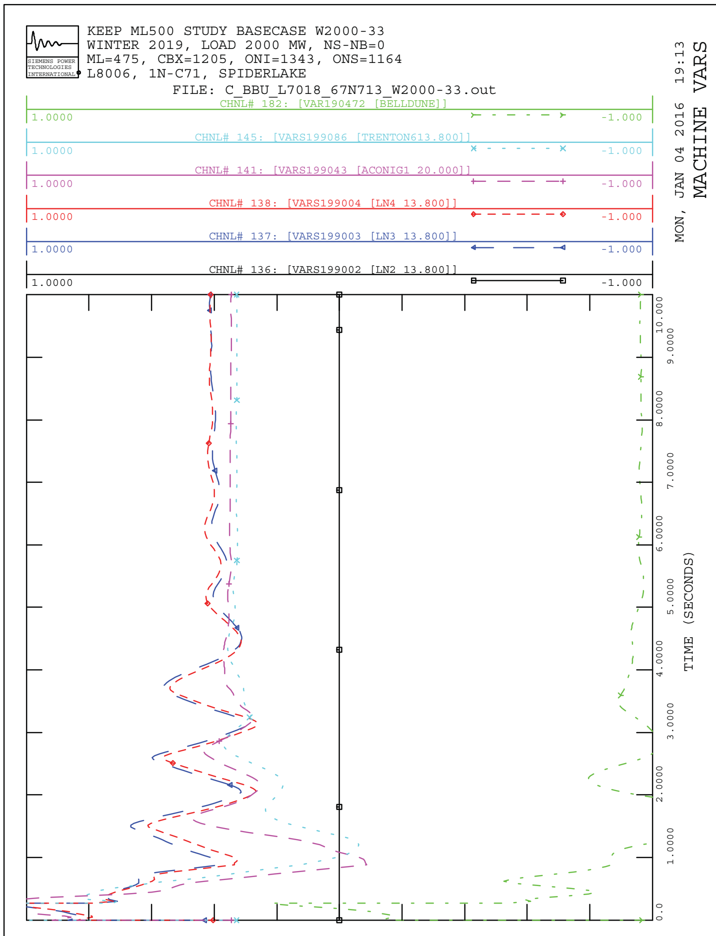
MON, JAN 04 2016 19:13
MARITIME LINK
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
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L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7018_67N713_W2000-33.out
CHNL# 182: [VAR190472 [BELLDUNE]]
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-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
MON, JAN 04 2016 19:13
MACHINE VARS
TIME (SECONDS)
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2.0000
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4.0000
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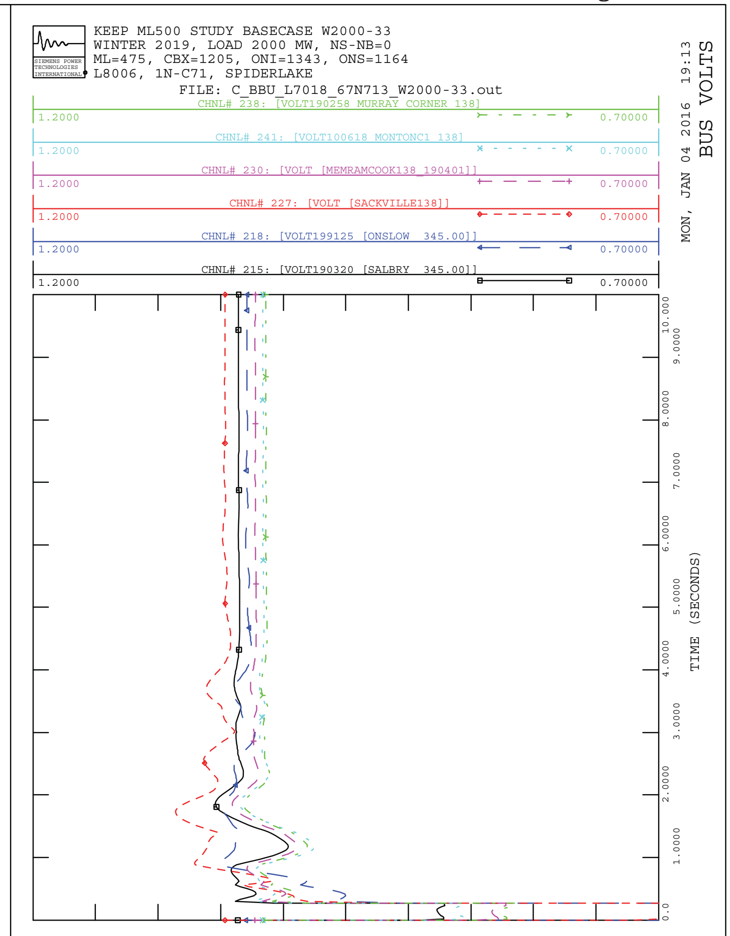
10.000



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7018_67N713_W2000-33.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
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CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
MON, JAN 04 2016 19:13
BUS VOLTS
TIME (SECONDS)
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2.0000
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4.0000
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6.0000
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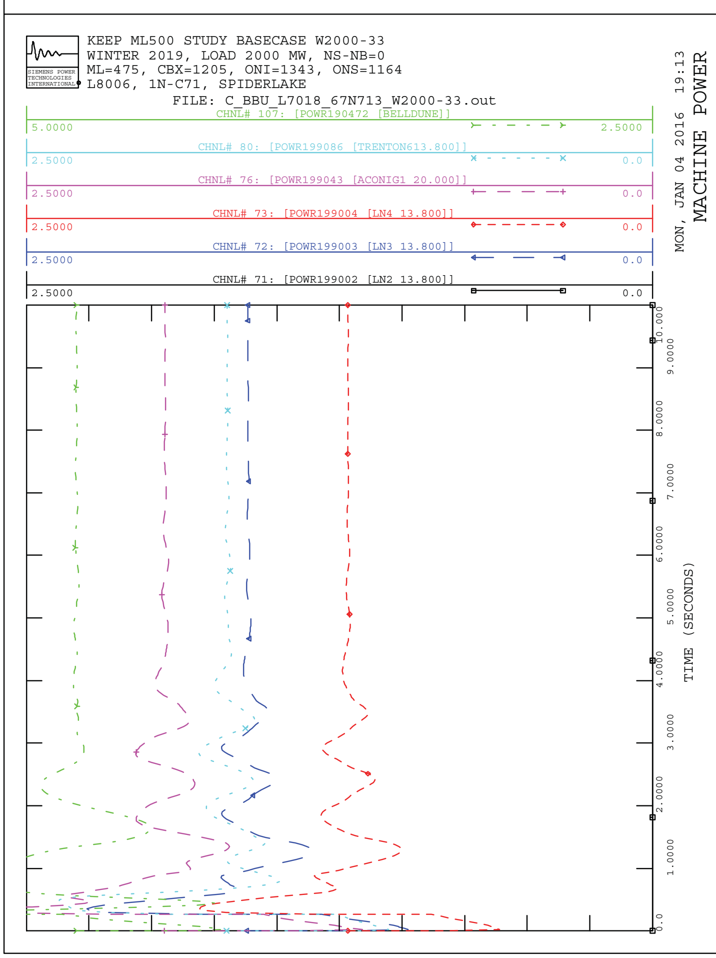
10.000



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7018_67N713_W2000-33.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
MON, JAN 04 2016 19:13
MACHINE POWER
TIME (SECONDS)
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2.0000
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4.0000
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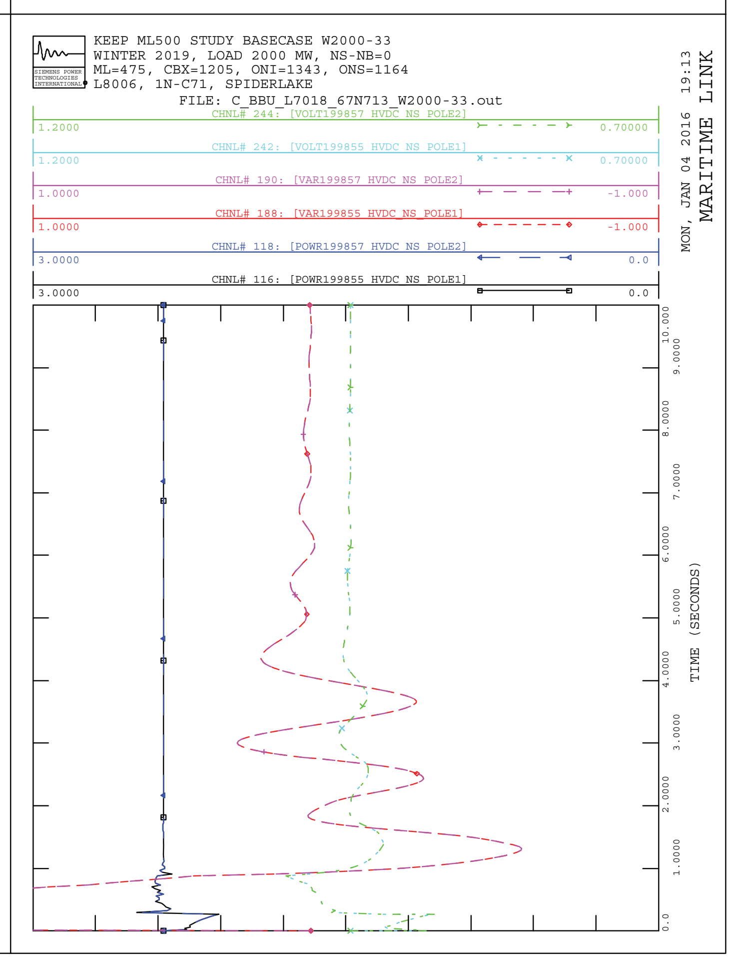
6.0000
7.0000
8.0000
9.0000
10.000



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_L7018_67N713_W2000-33.out
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1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
MON, JAN 04 2016 19:13
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
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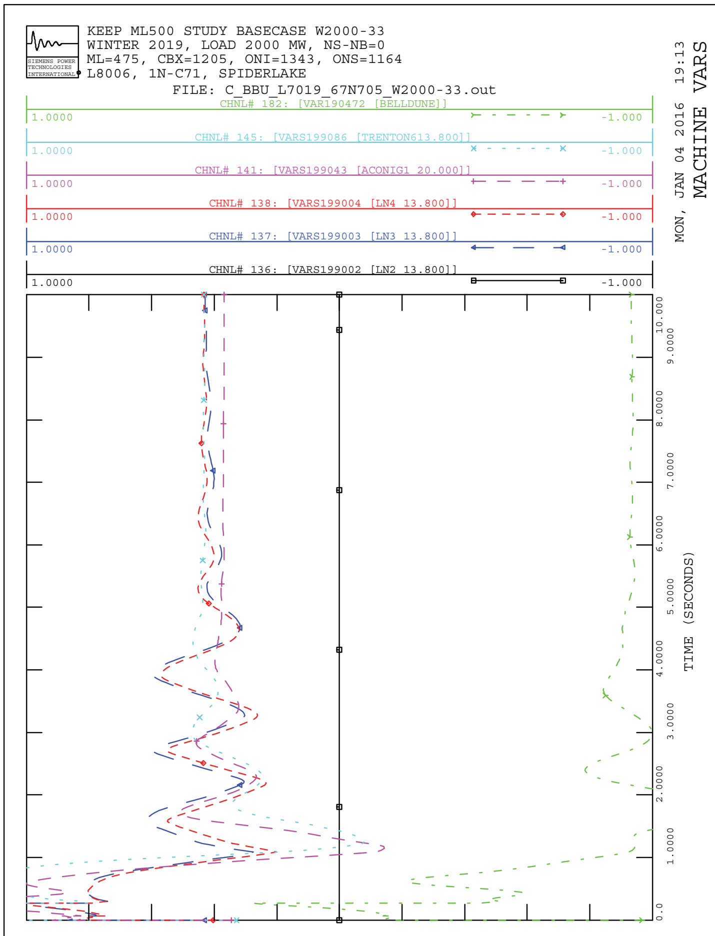
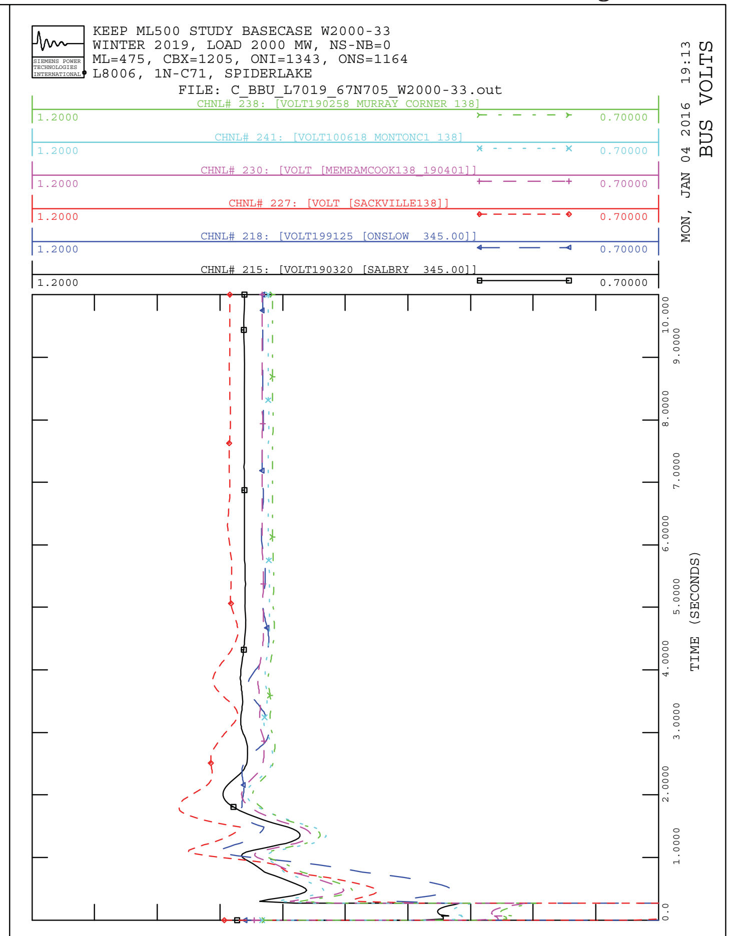
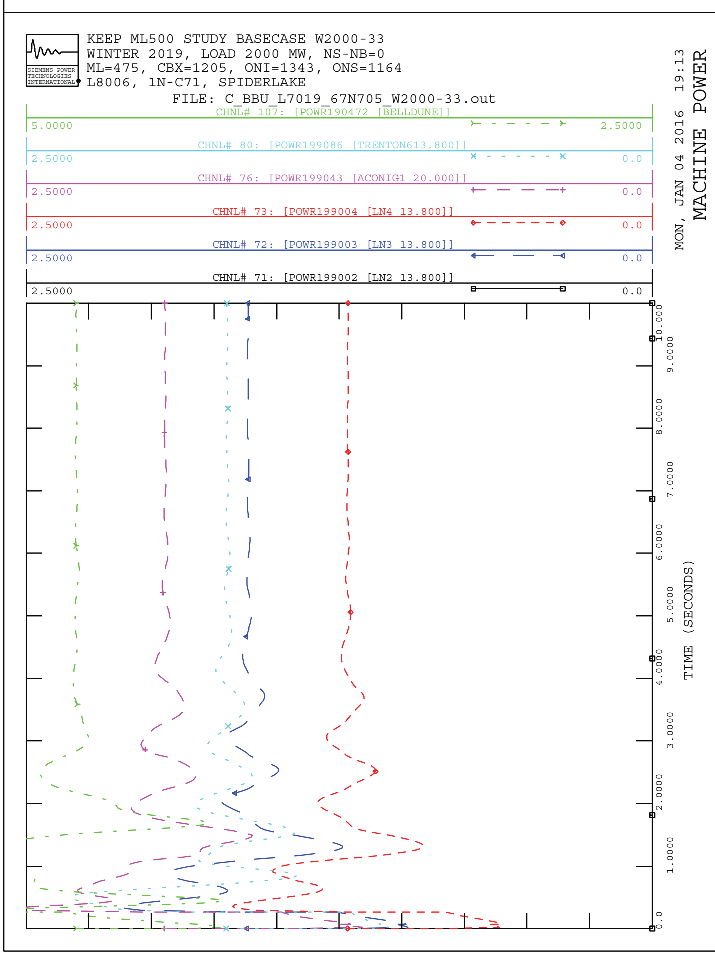
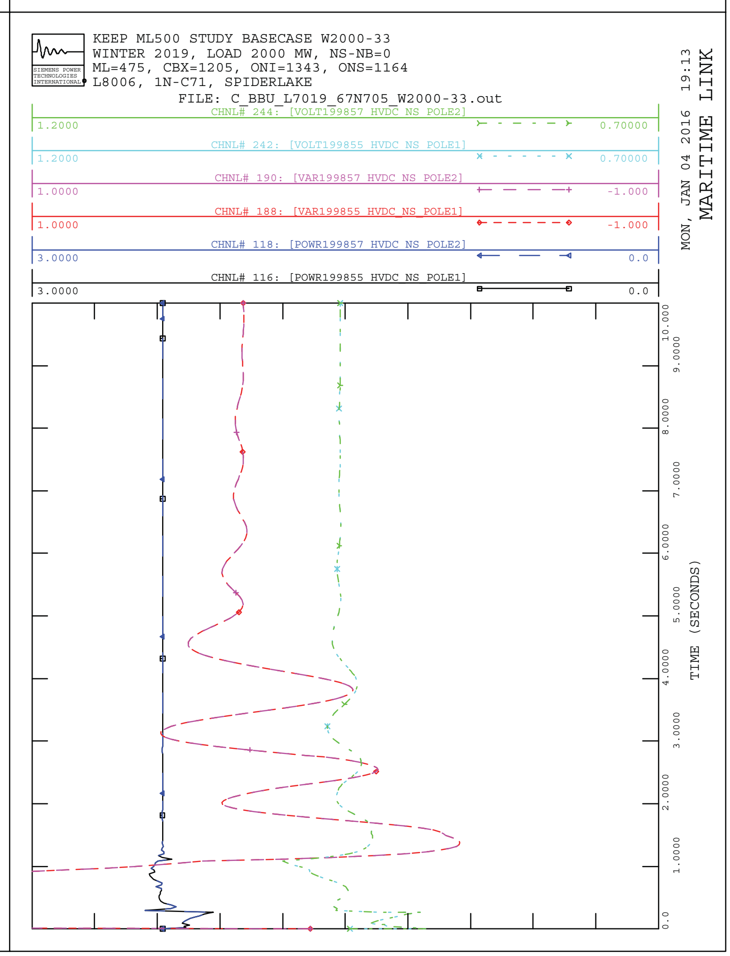
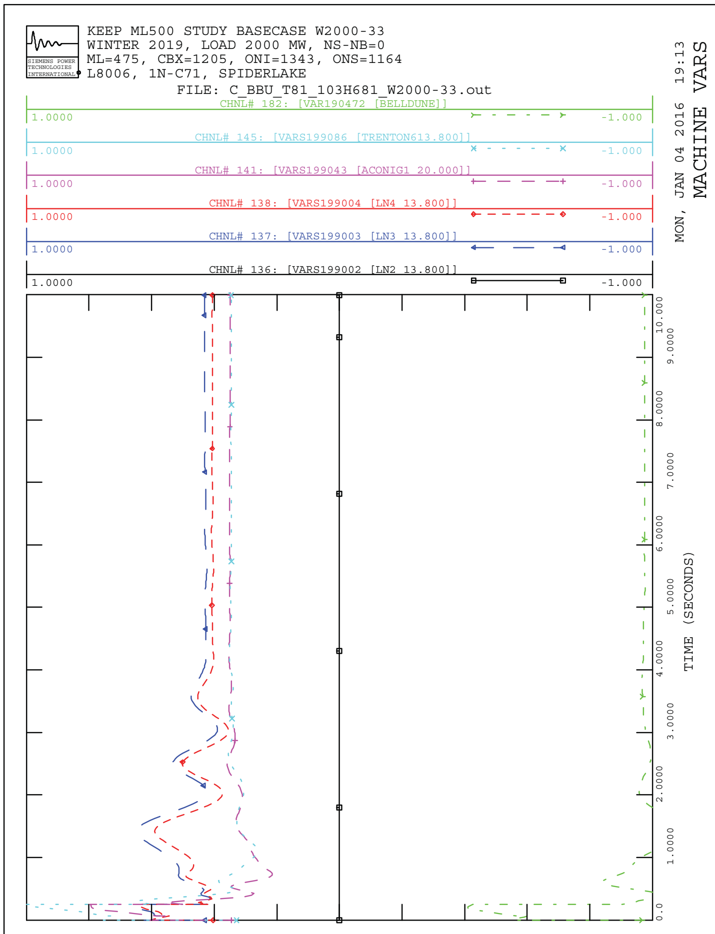
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



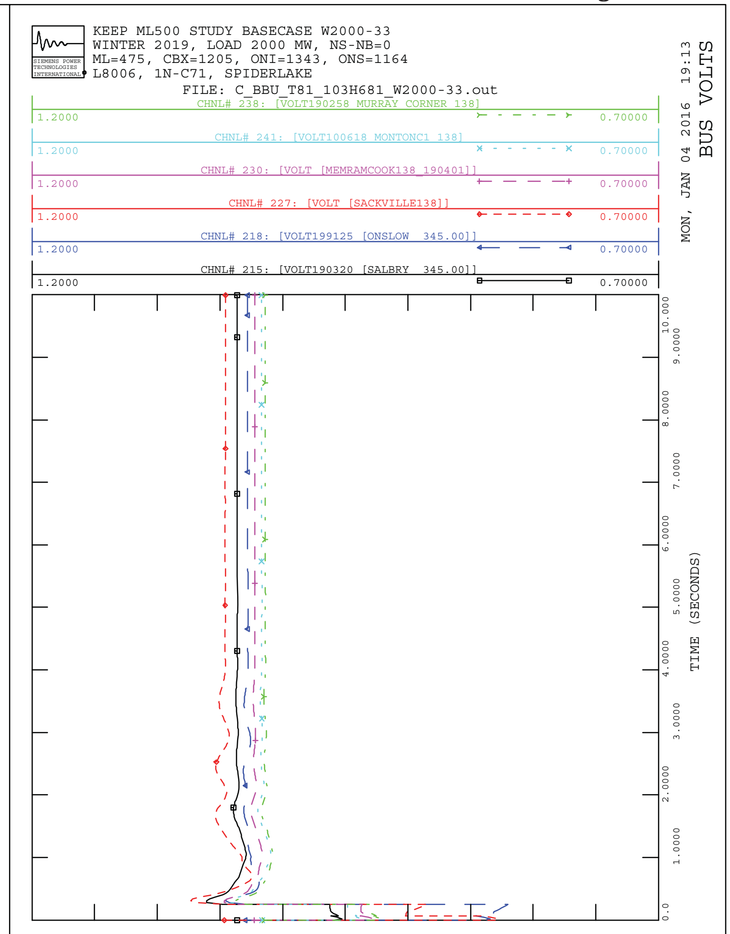




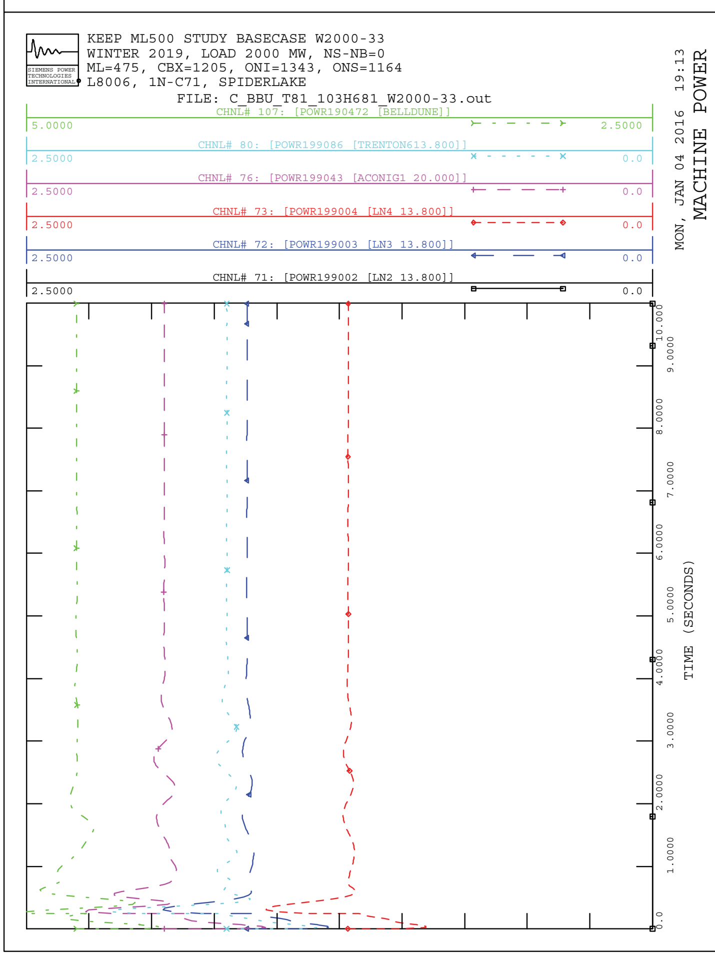




KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_T81_103H681_W2000-33.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
MON, JAN 04 2016 19:13
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_T81_103H681_W2000-33.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
MON, JAN 04 2016 19:13
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_T81_103H681_W2000-33.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
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2.5000
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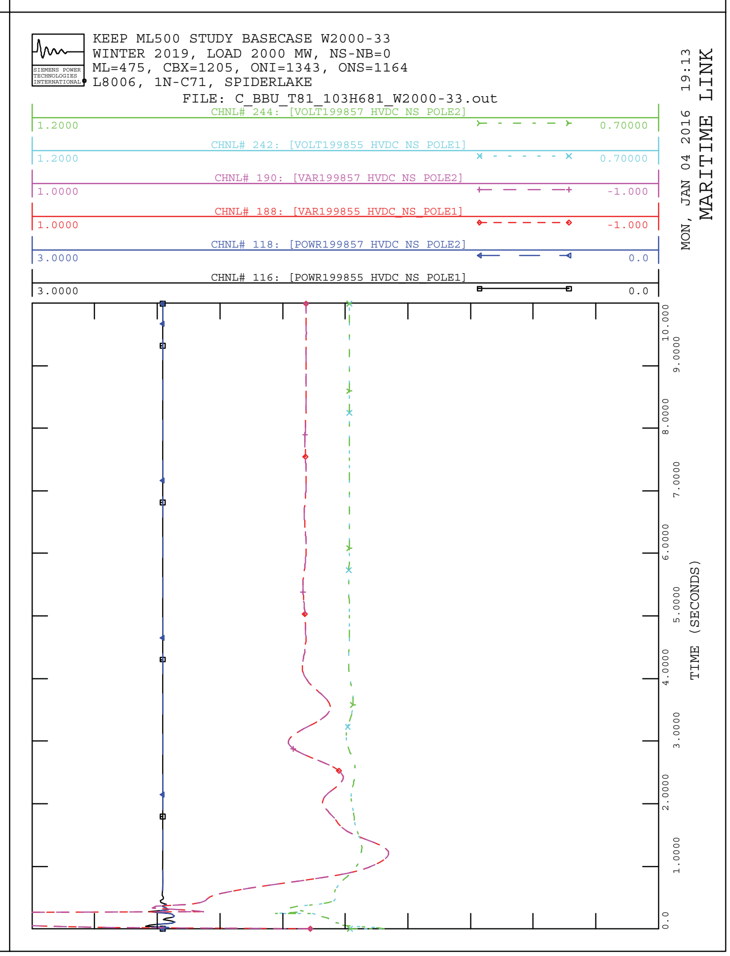
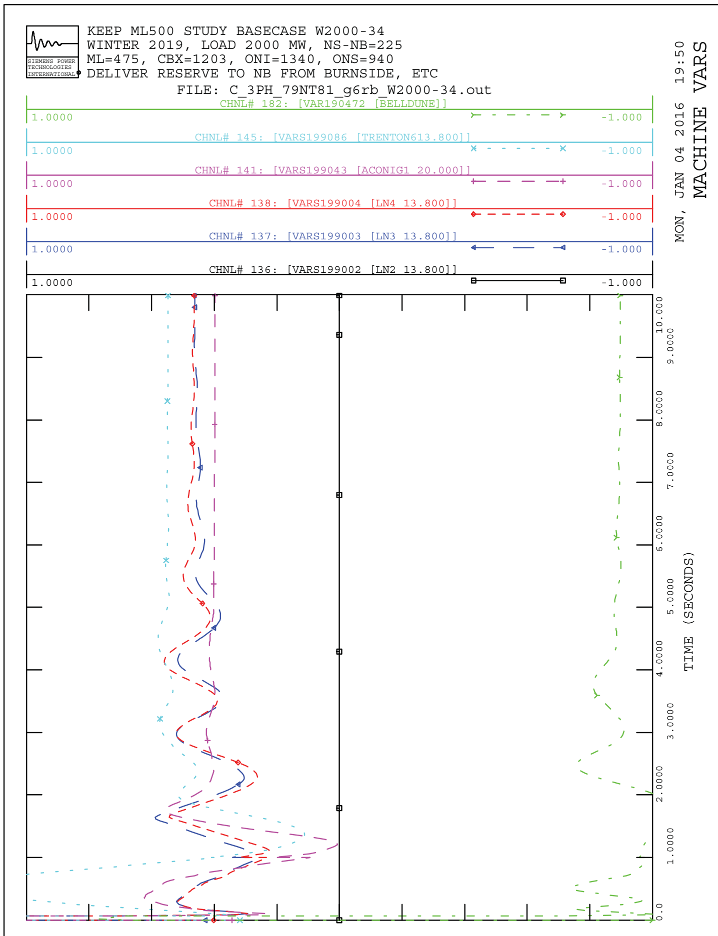
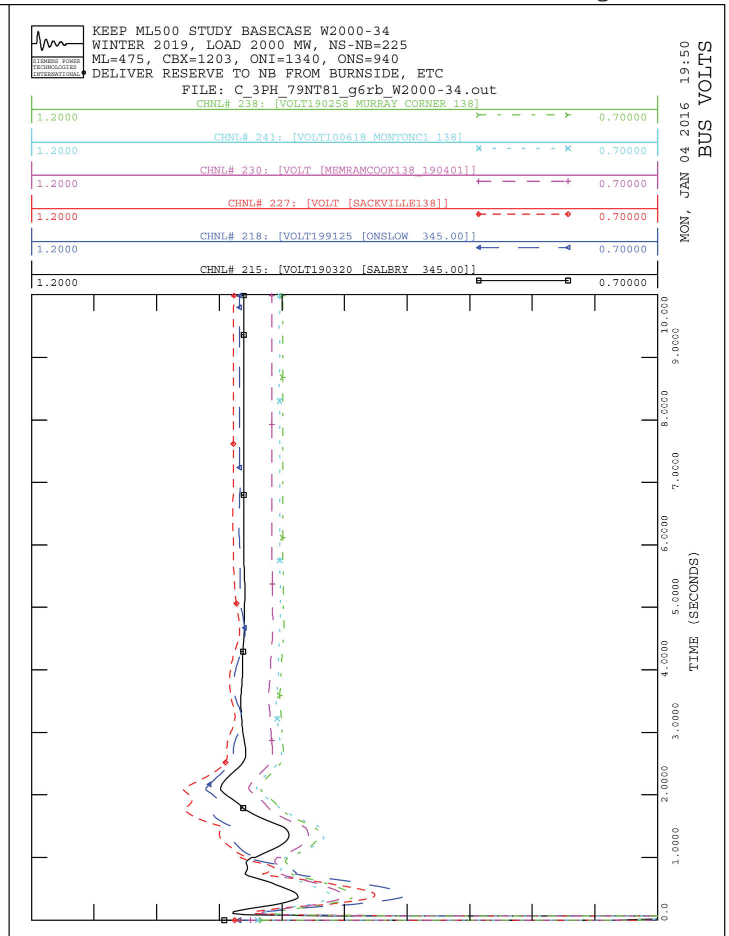
MON, JAN 04 2016 19:13
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-33
WINTER 2019, LOAD 2000 MW, NS-NB=0
ML=475, CBX=1205, ONI=1343, ONS=1164
L8006, 1N-C71, SPIDERLAKE
FILE: C_BBU_T81_103H681_W2000-33.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
1.0000
-1.000
3.0000
0.0
MON, JAN 04 2016 19:13
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_79NT81_g6rb_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
MON, JAN 04 2016 19:50
MACHINE VARS
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_79NT81_g6rb_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
MON, JAN 04 2016 19:50
BUS VOLTS
TIME (SECONDS)
0.0
1.0000
2.0000
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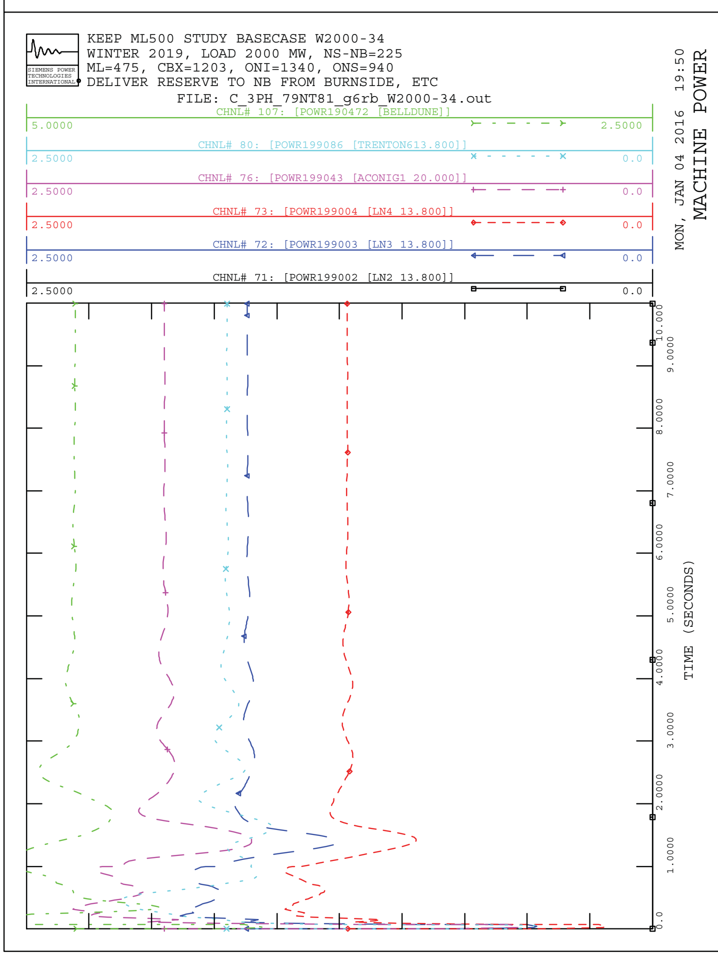
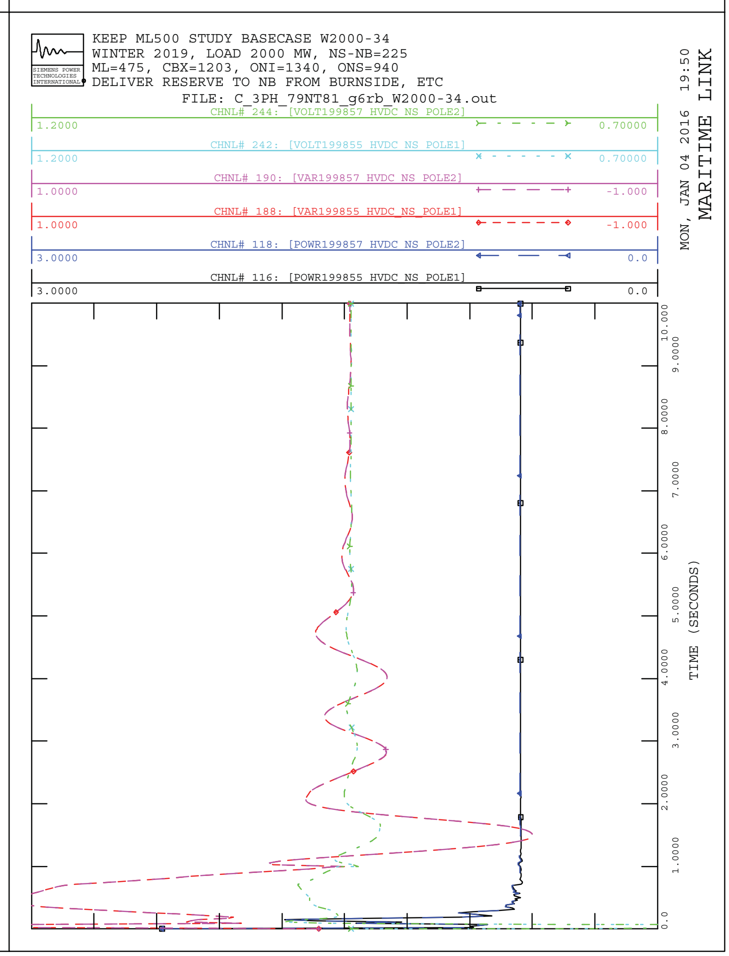
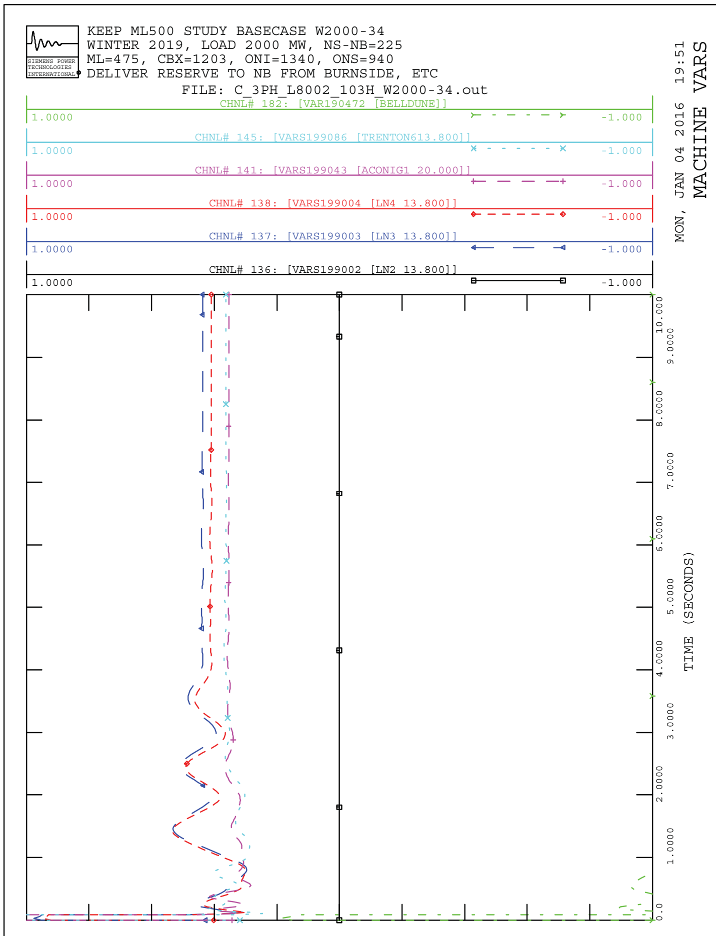
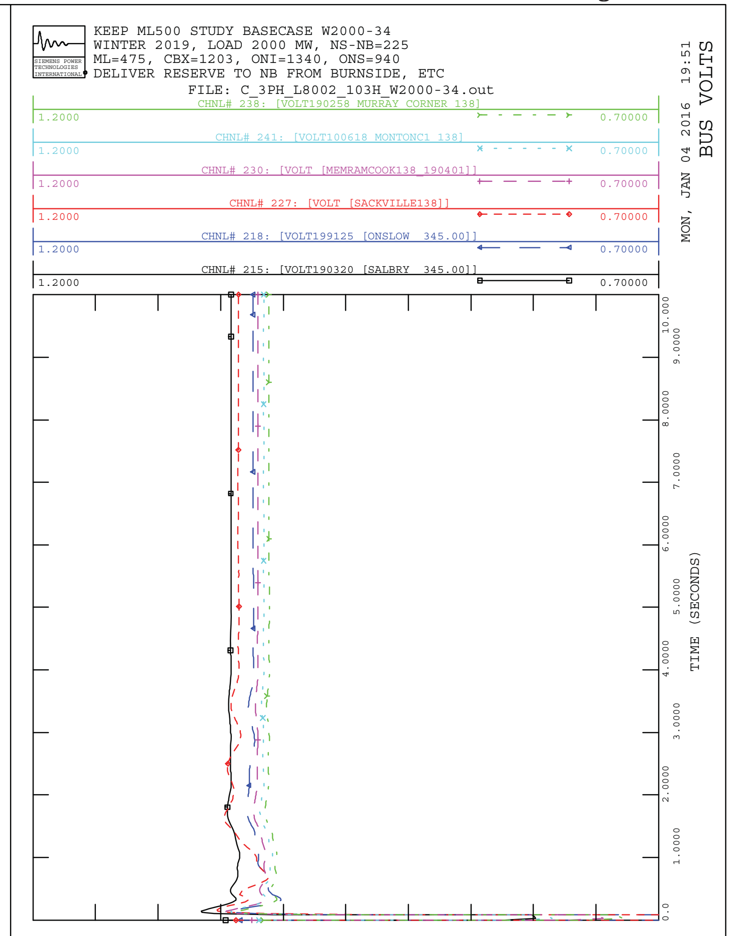
8.0000
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_79NT81_g6rb_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
MON, JAN 04 2016 19:50
MACHINE POWER
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

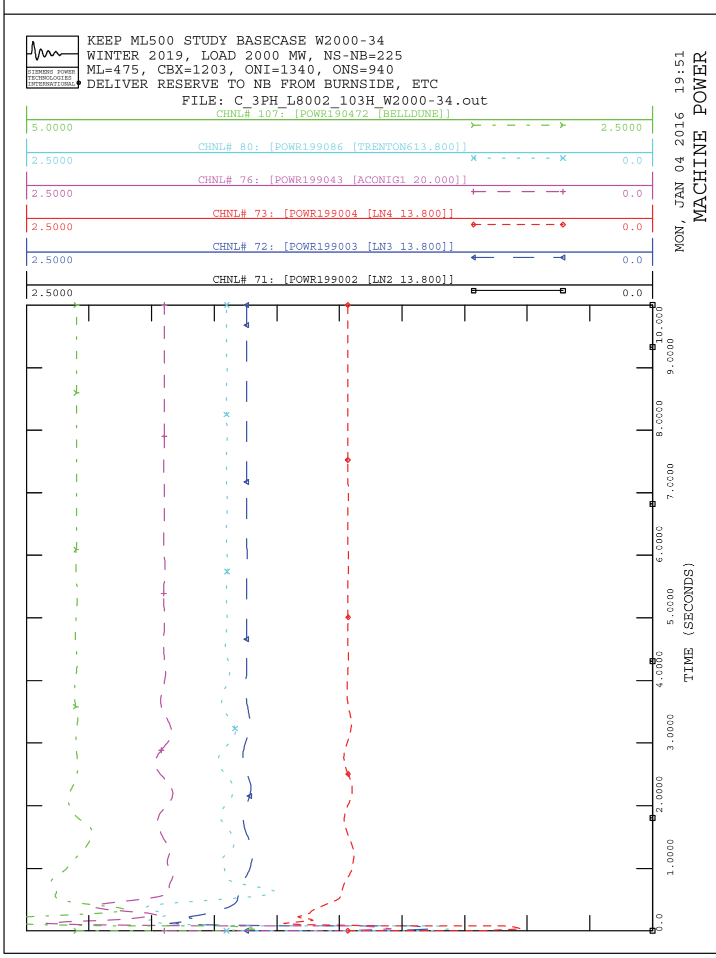

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_79NT81_g6rb_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
MON, JAN 04 2016 19:50
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000



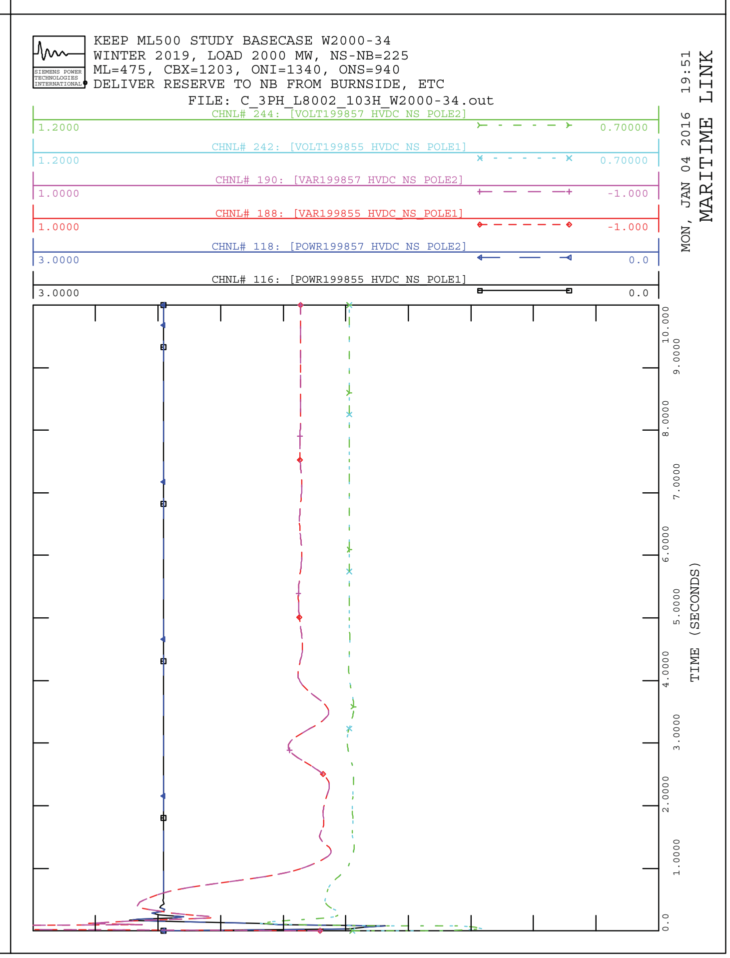
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8002_103H_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)



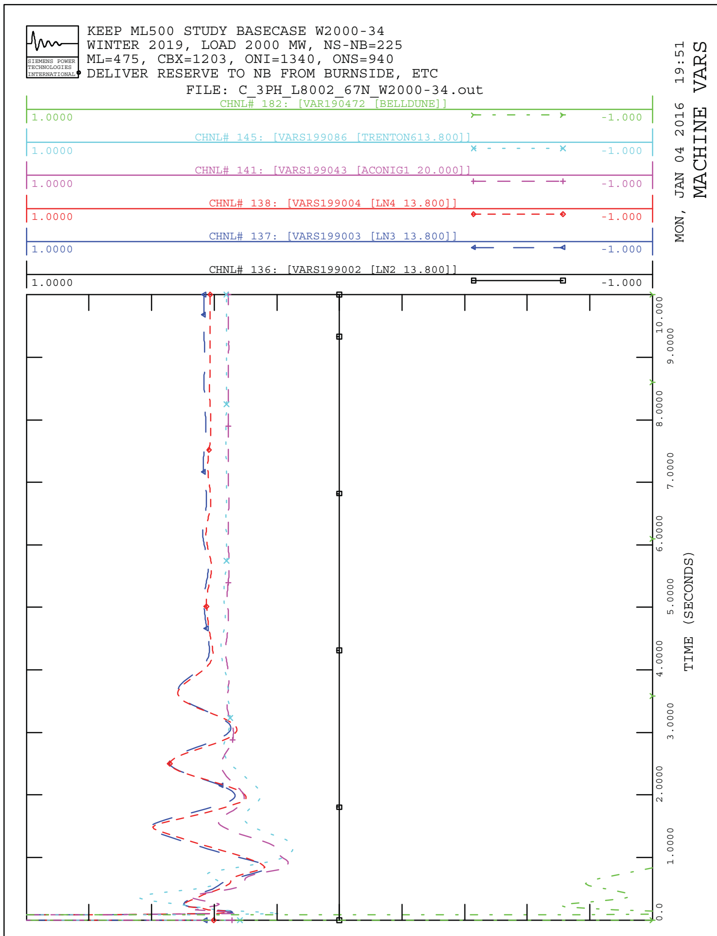
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8002_103H_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)

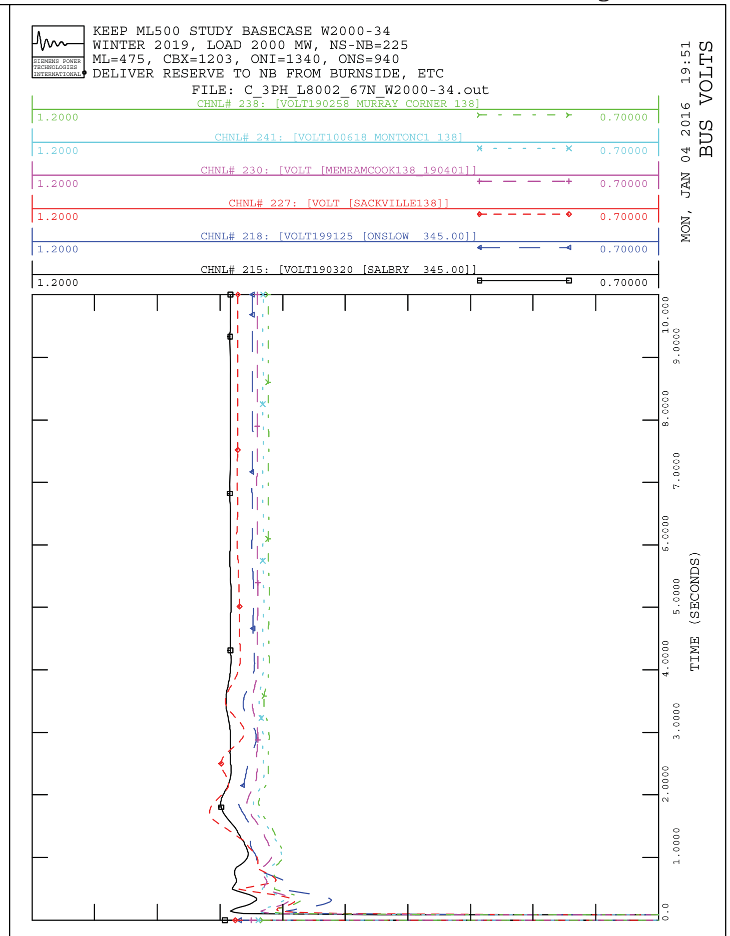


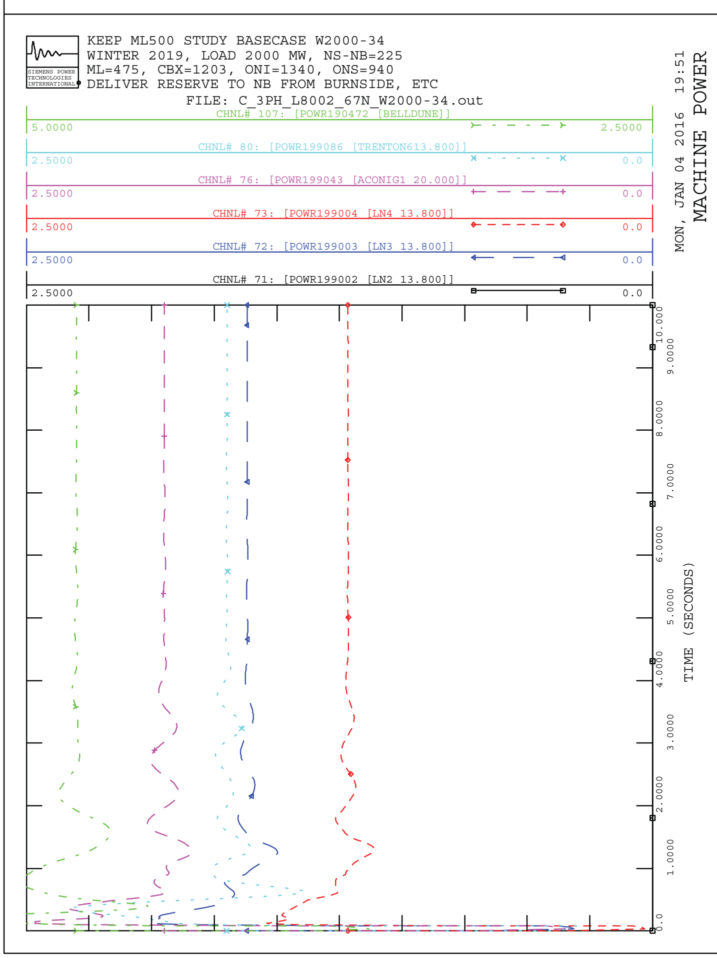
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8002_103H_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
5.0000
2.5000
2.5000
0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)

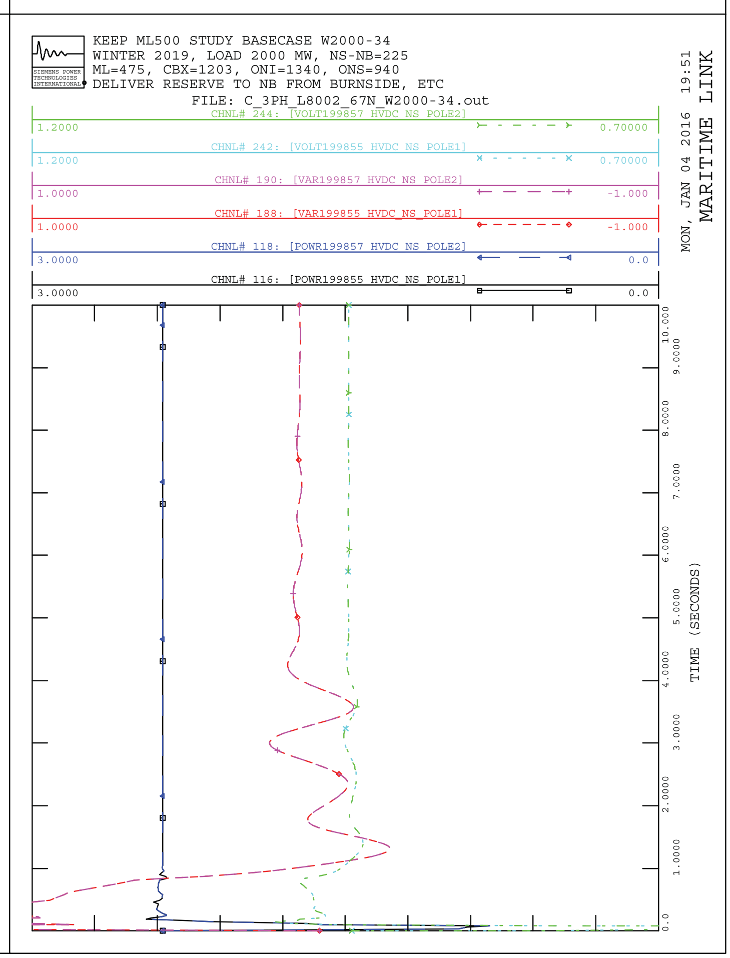


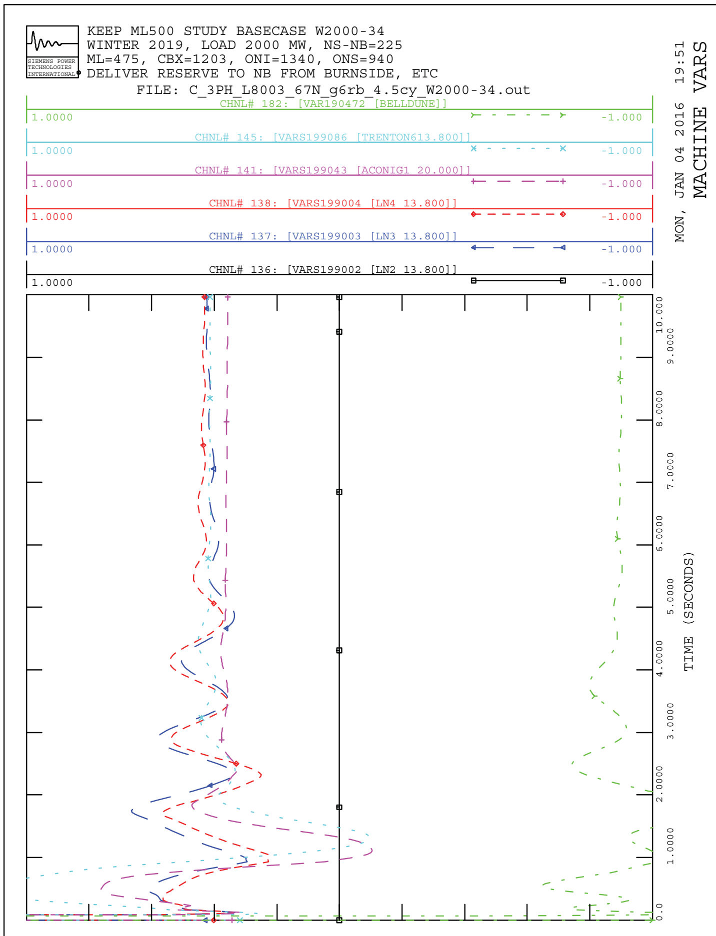
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8002_103H_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
1.0000
-1.000
3.0000
0.0
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)

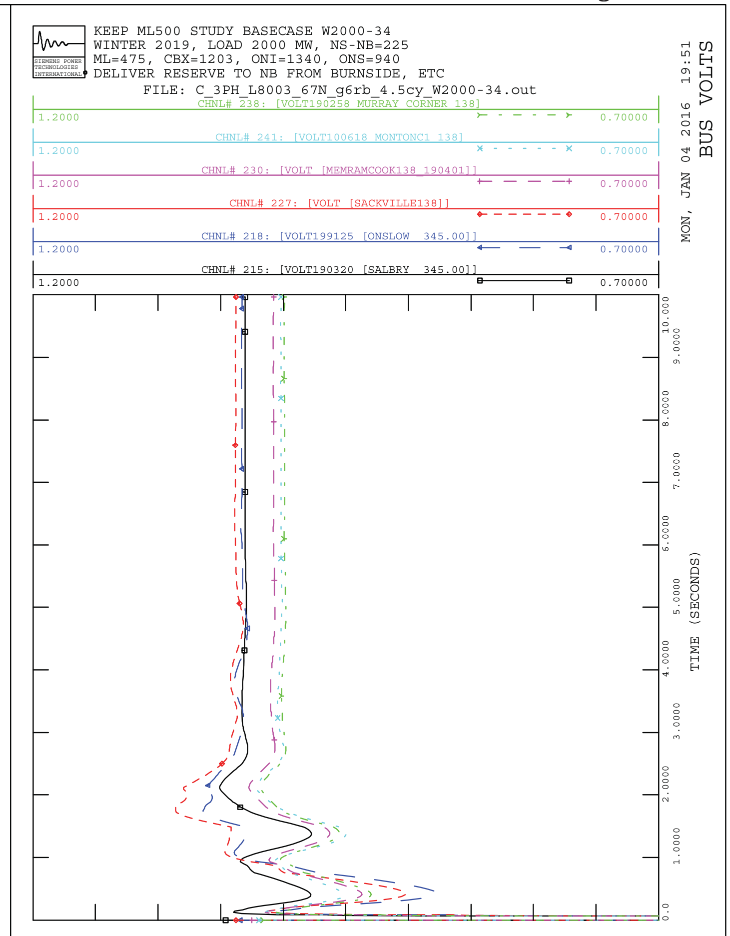

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8002_67N_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
TIME (SECONDS)
MON, JAN 04 2016 19:51
MACHINE VARS


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8002_67N_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
TIME (SECONDS)
MON, JAN 04 2016 19:51
BUS VOLTS


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8002_67N_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
5.0000
2.5000
2.5000
0.0
TIME (SECONDS)
MON, JAN 04 2016 19:51
MACHINE POWER


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8002_67N_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
1.2000
0.70000
1.0000
-1.000
3.0000
0.0
TIME (SECONDS)
MON, JAN 04 2016 19:51
MARITIME LINK


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_4.5cy_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_4.5cy_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)
0.0
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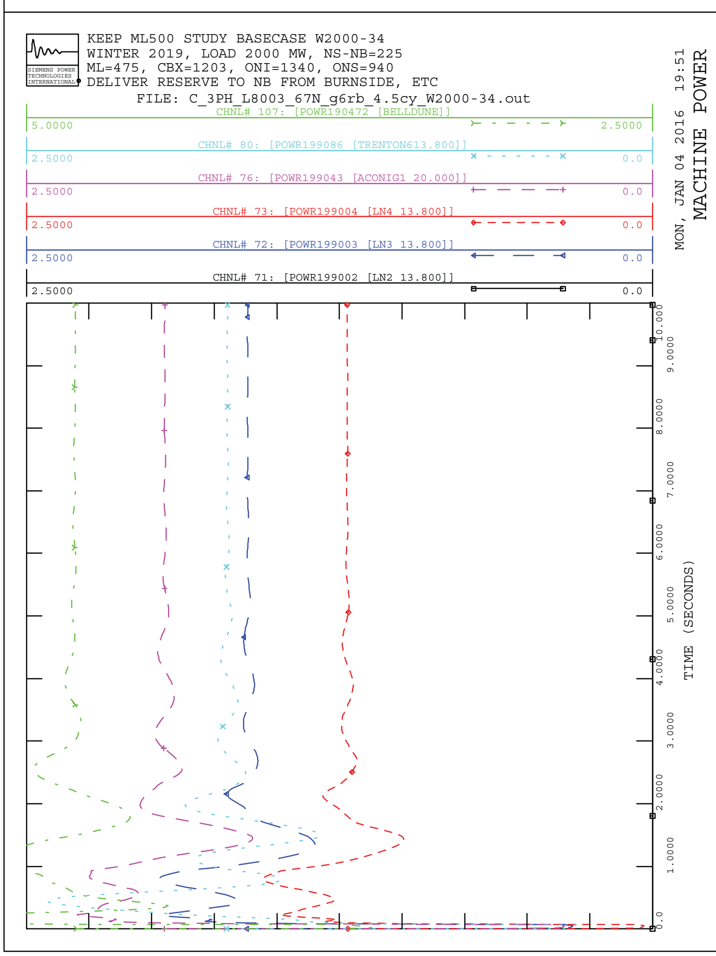
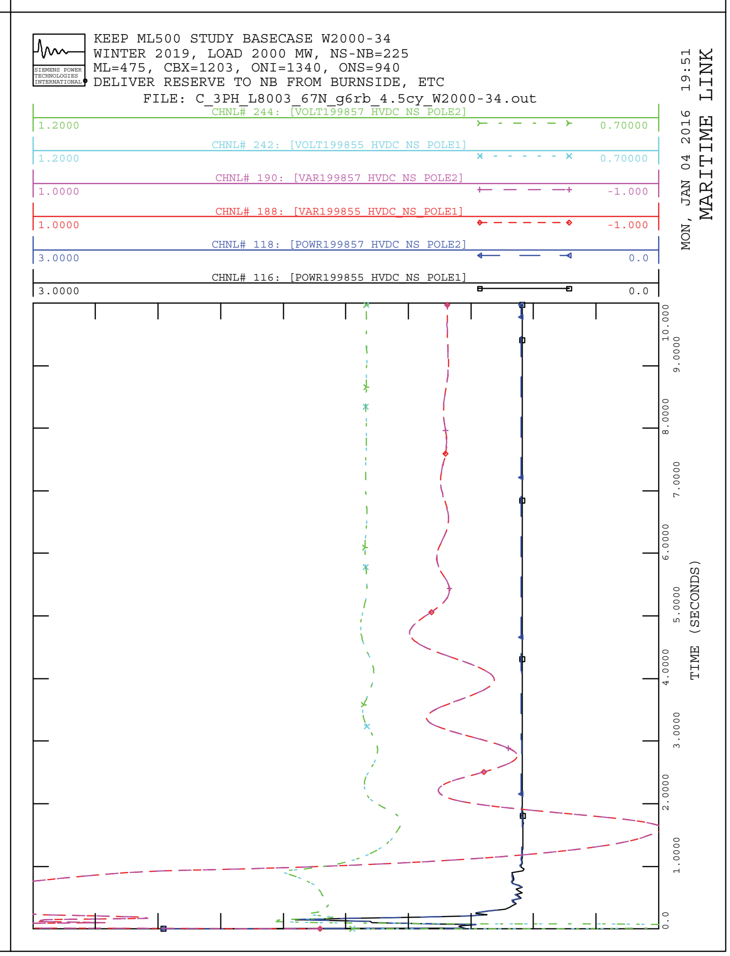
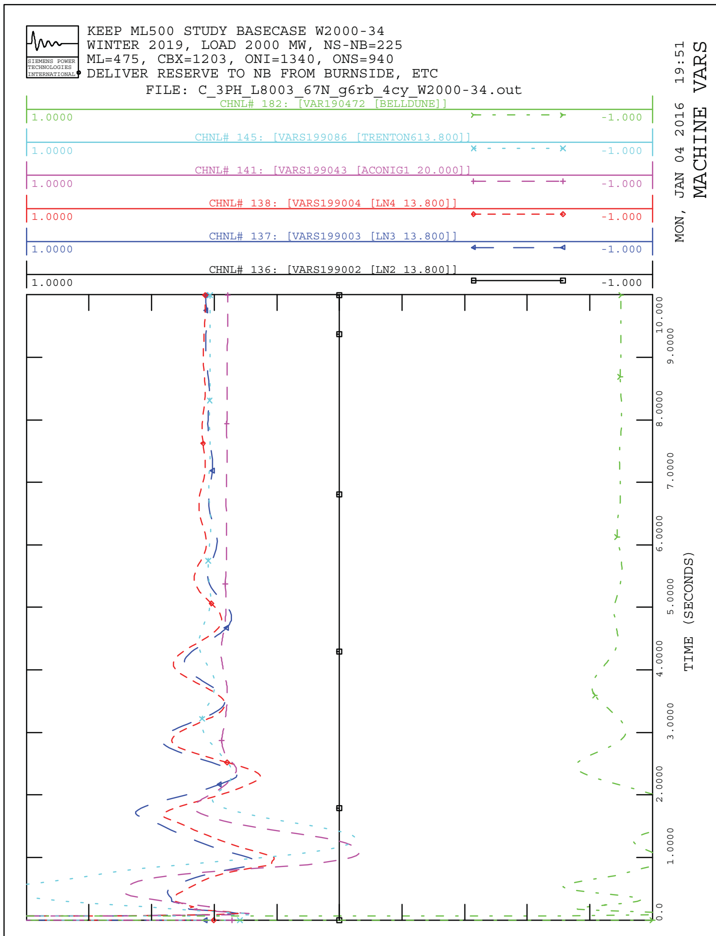
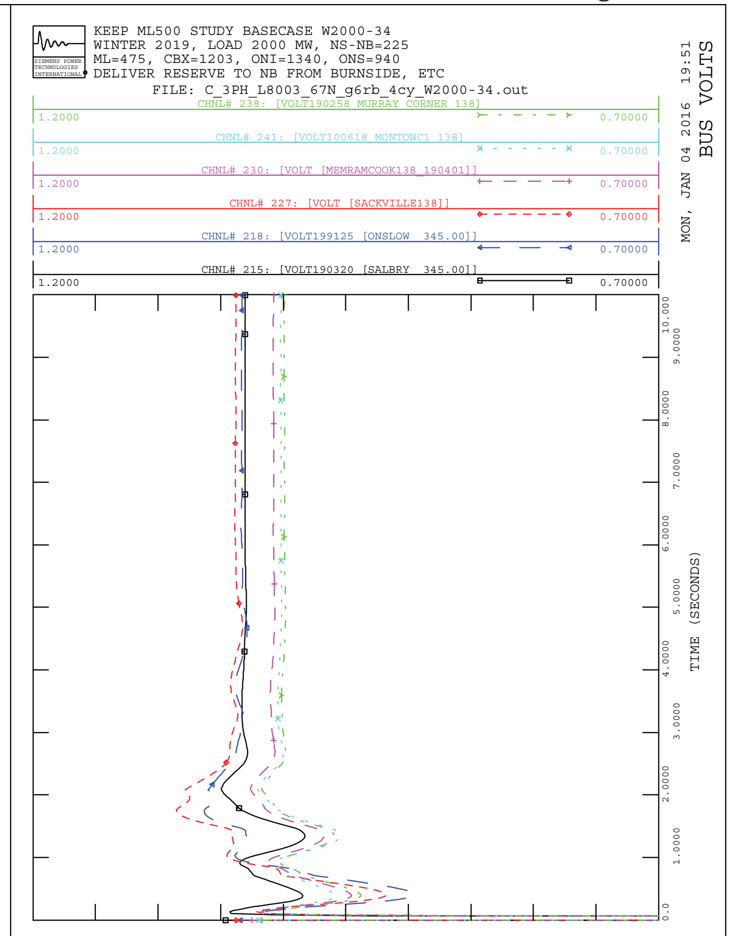
8.0000
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_4.5cy_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

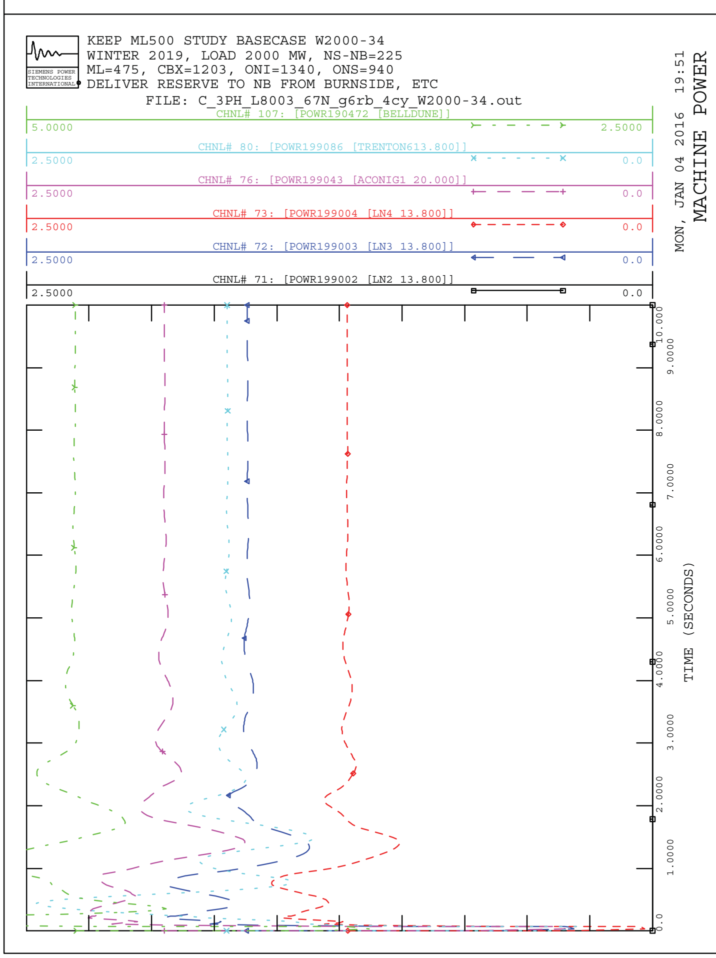

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_4.5cy_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000



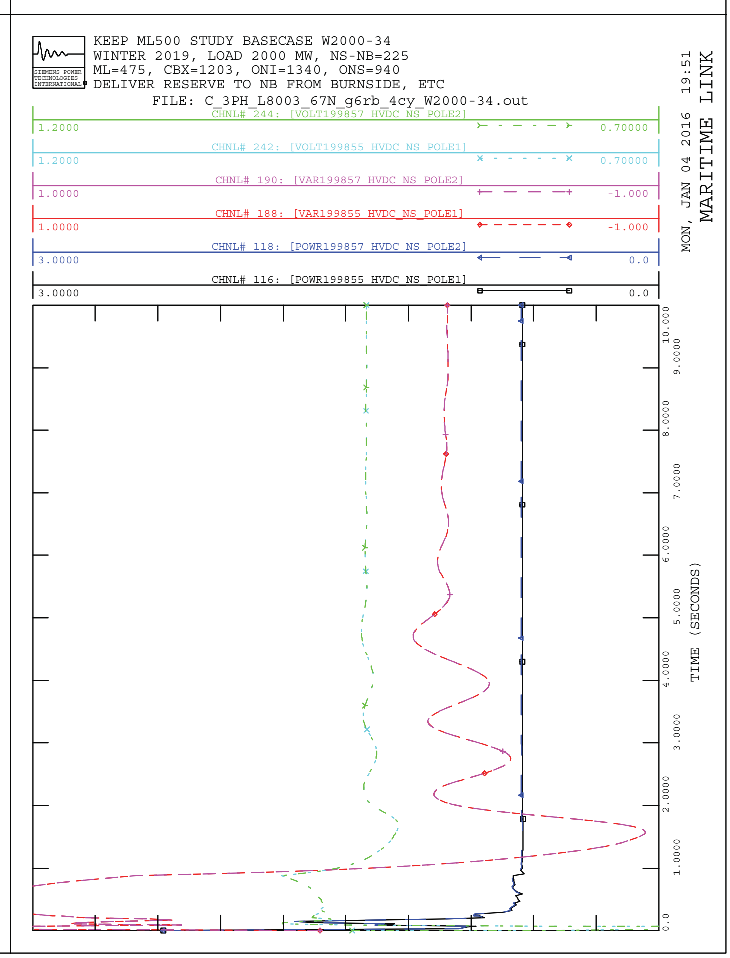
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)



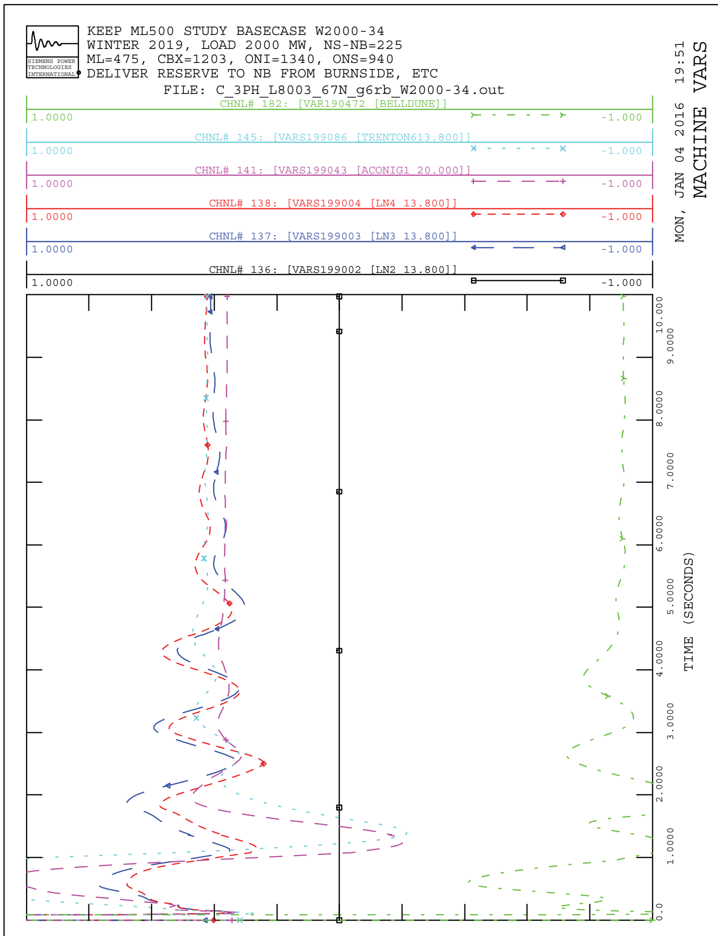
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)

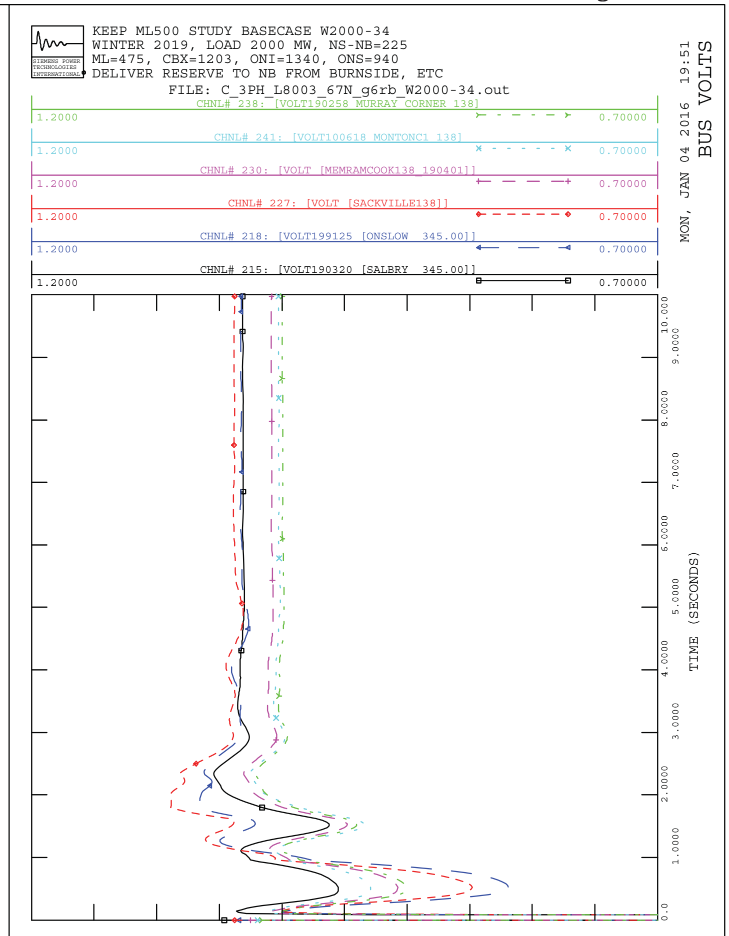


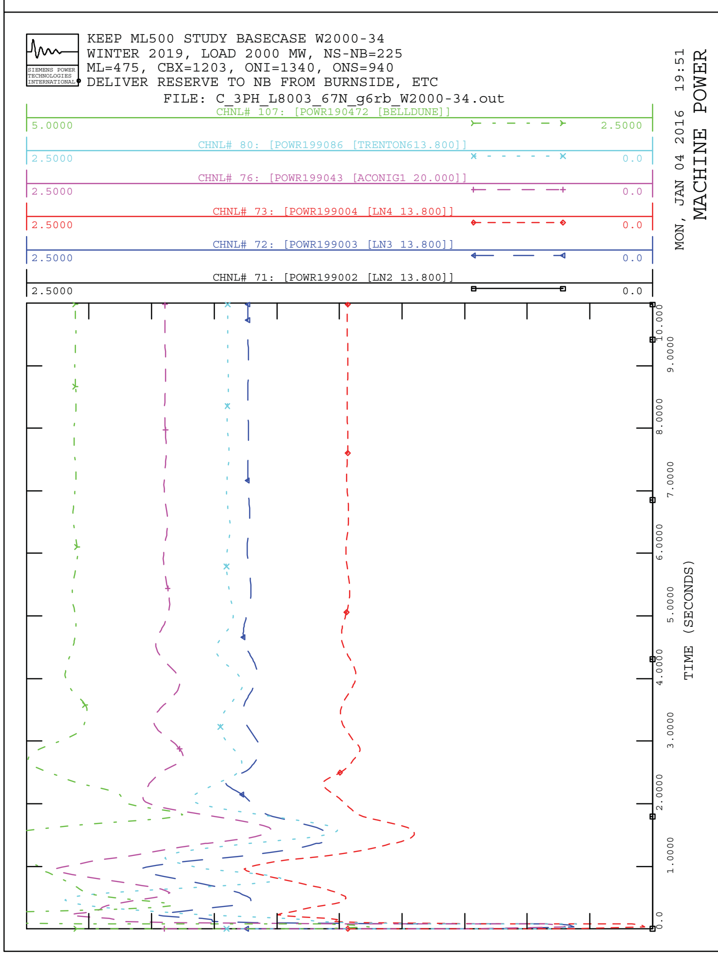
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)

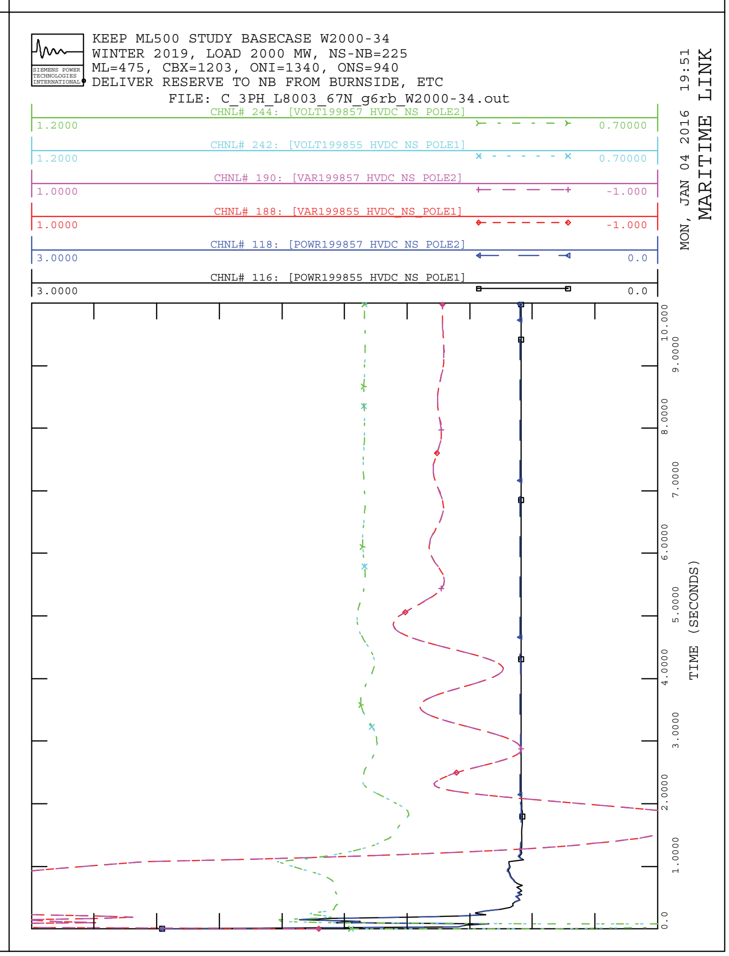


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_4cy_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)

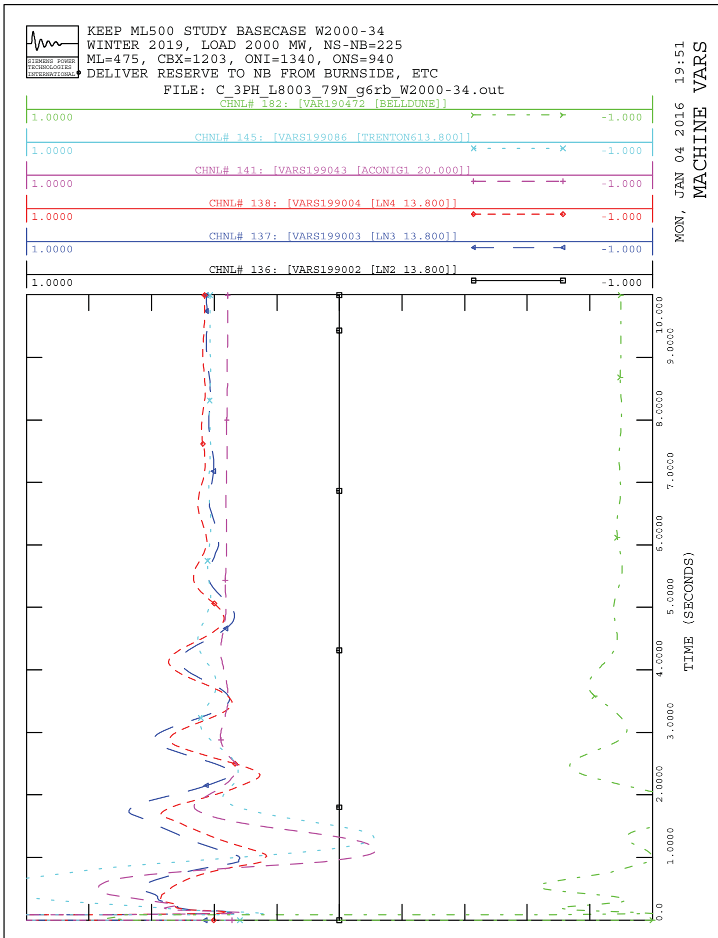

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)

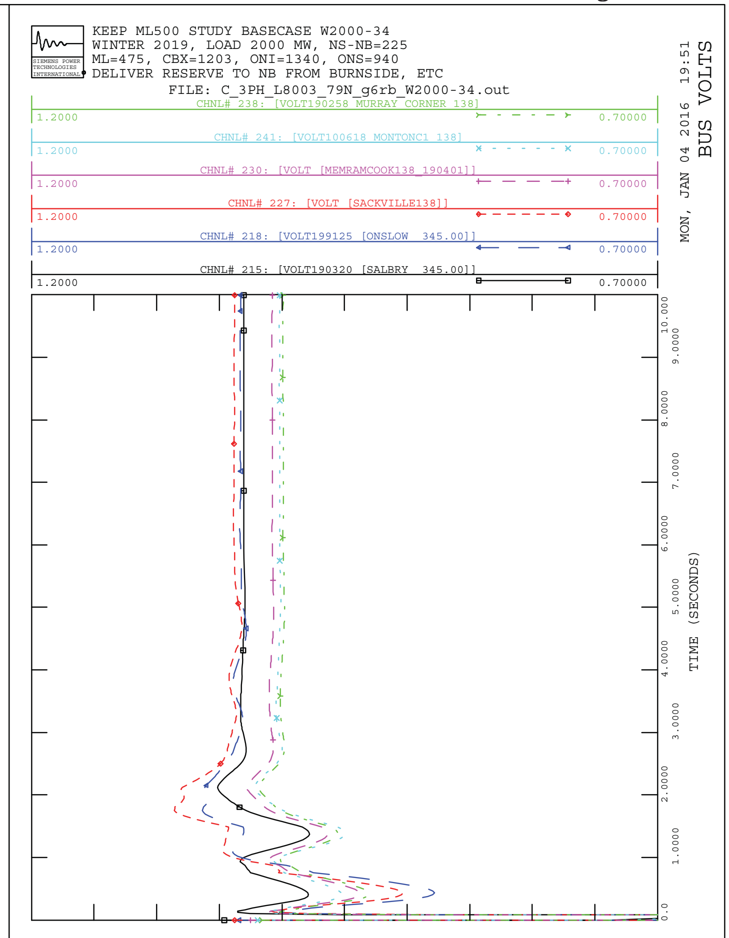

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)

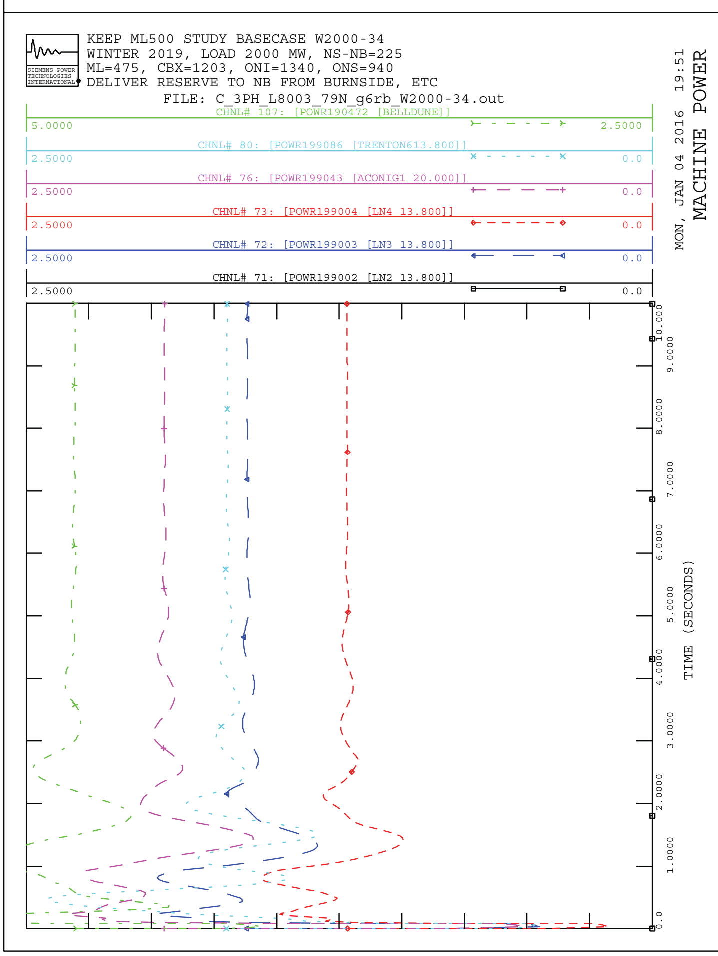

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)

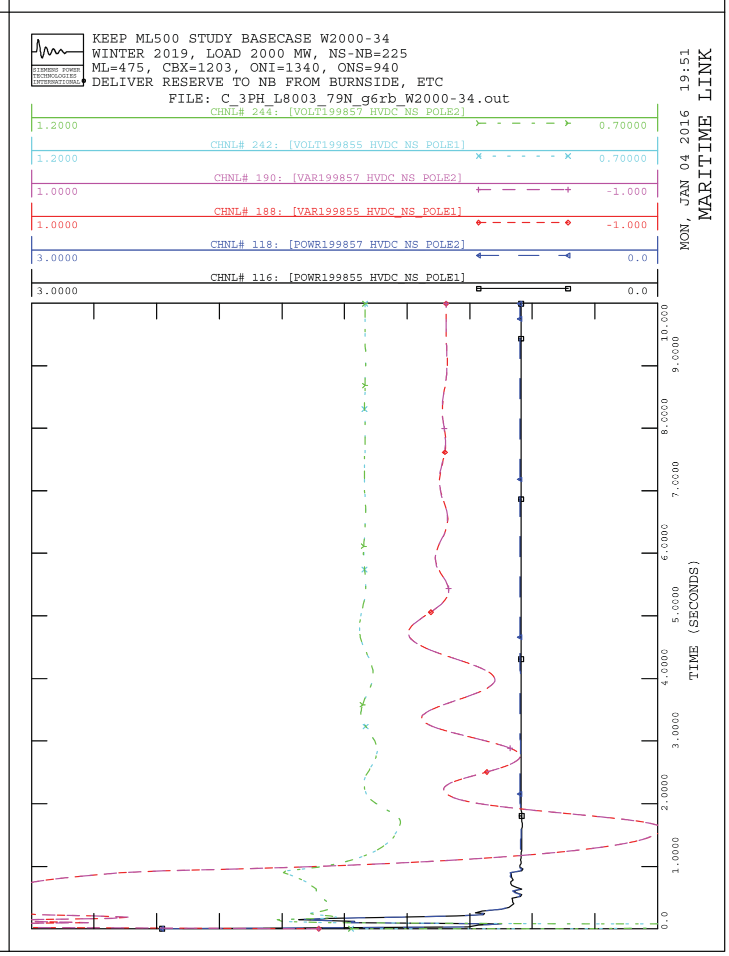

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8003_67N_g6rb_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)

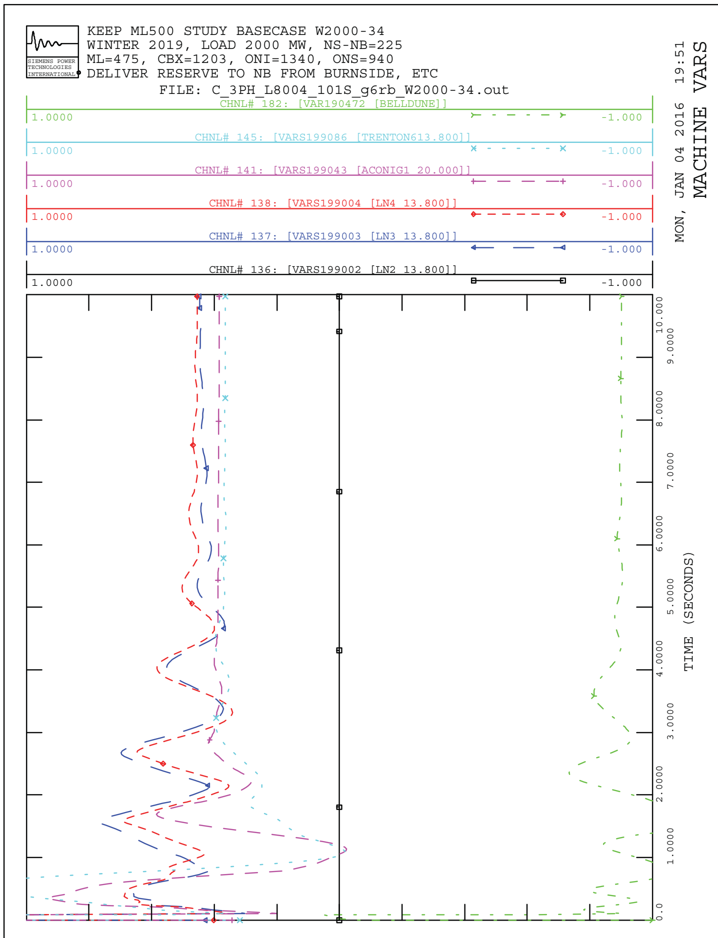
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



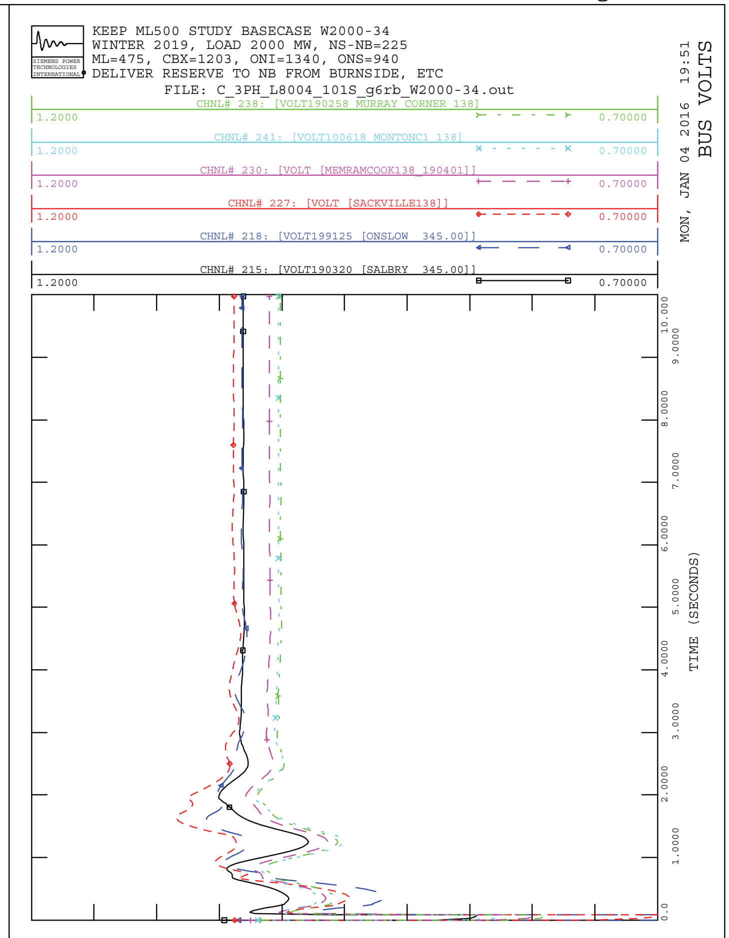




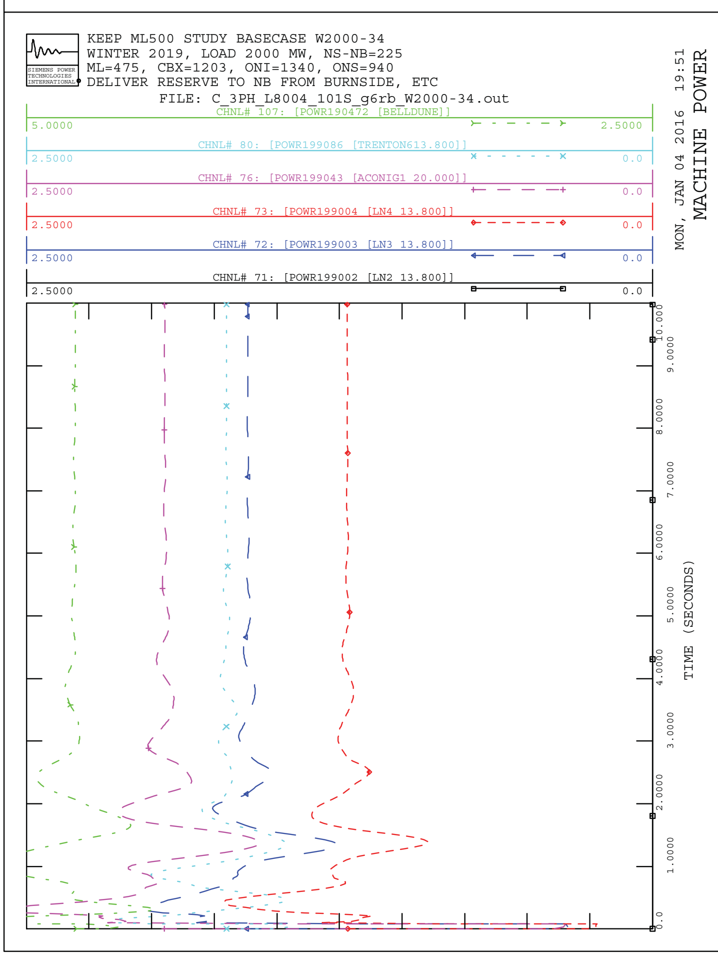




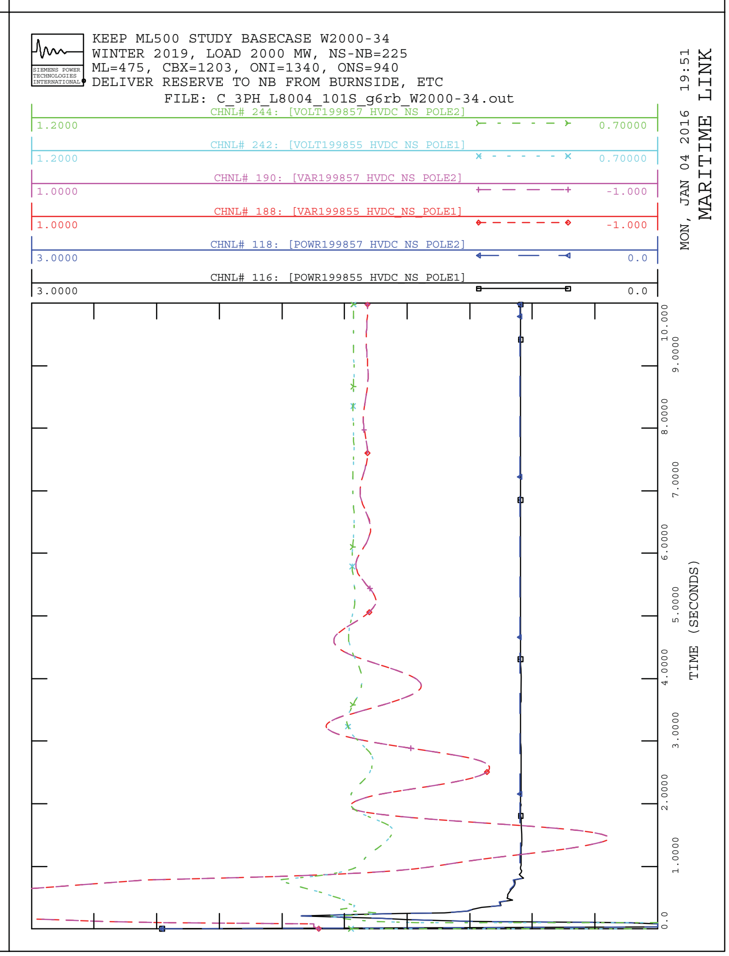
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8004_101S_g6rb_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8004_101S_g6rb_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)

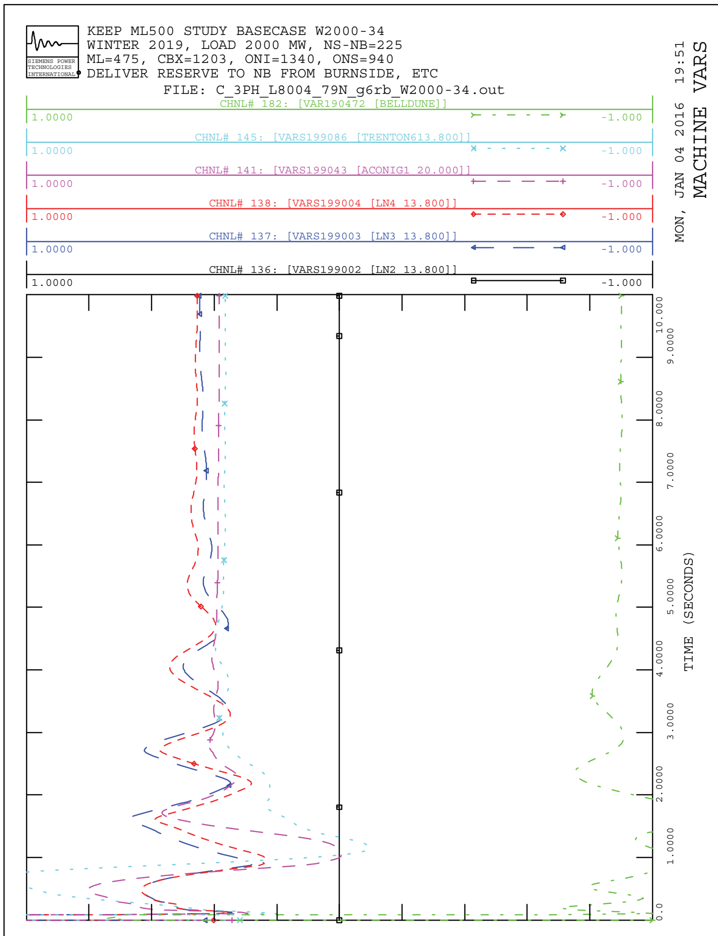


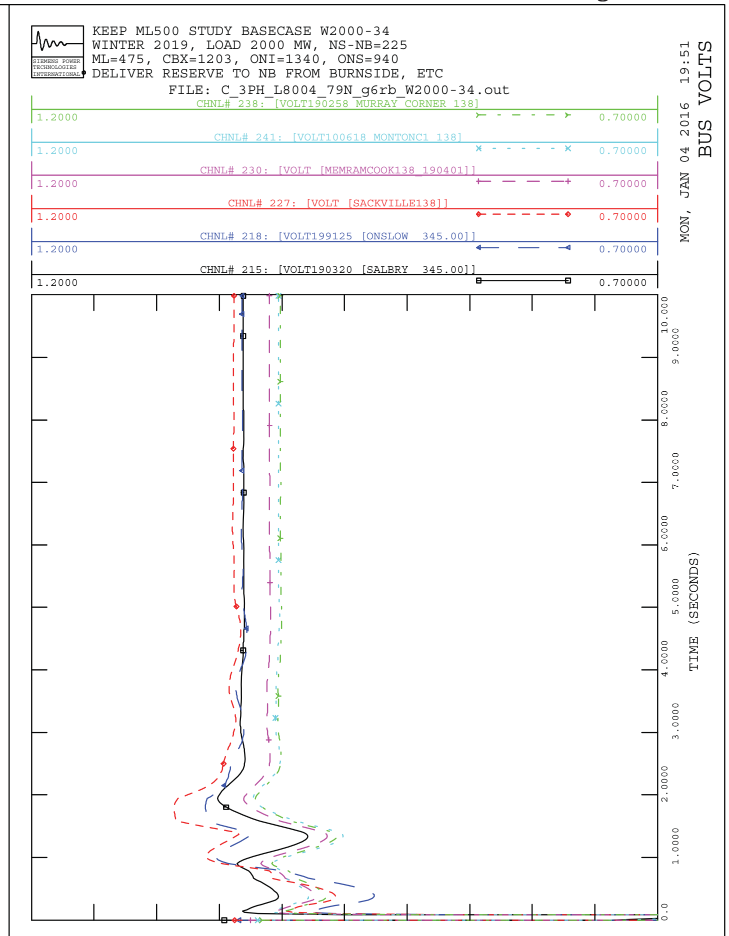
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8004_101S_g6rb_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)

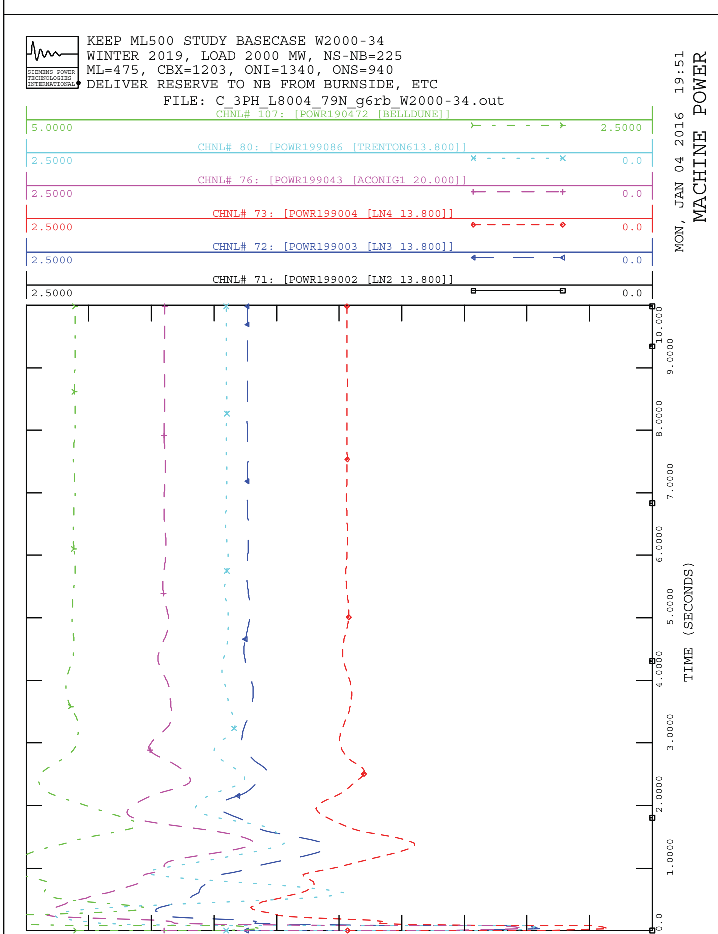


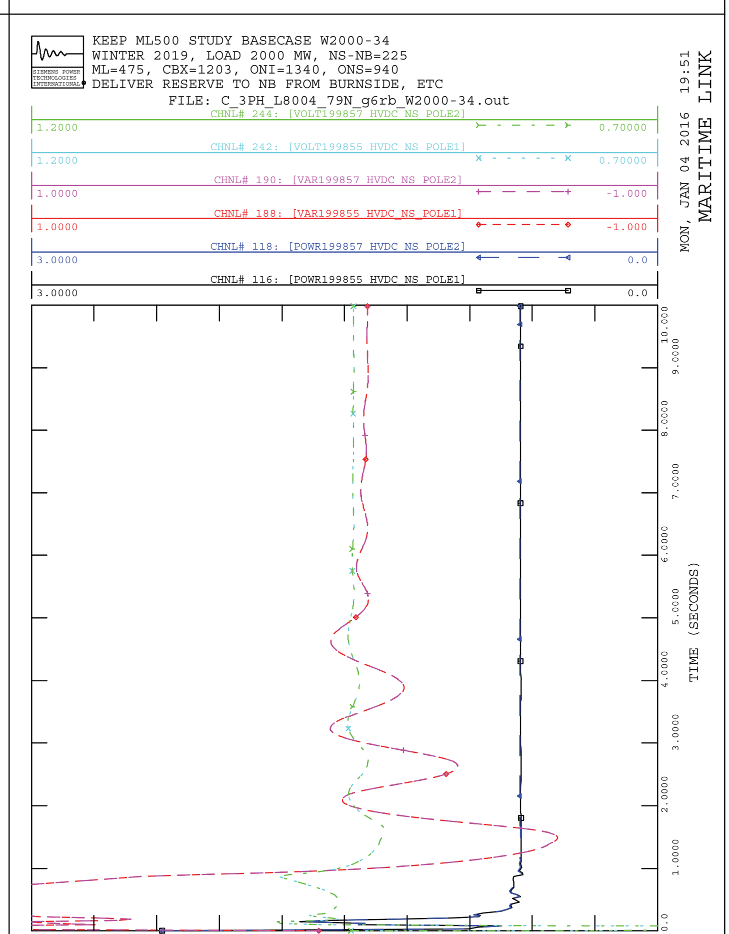
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8004_101S_g6rb_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)

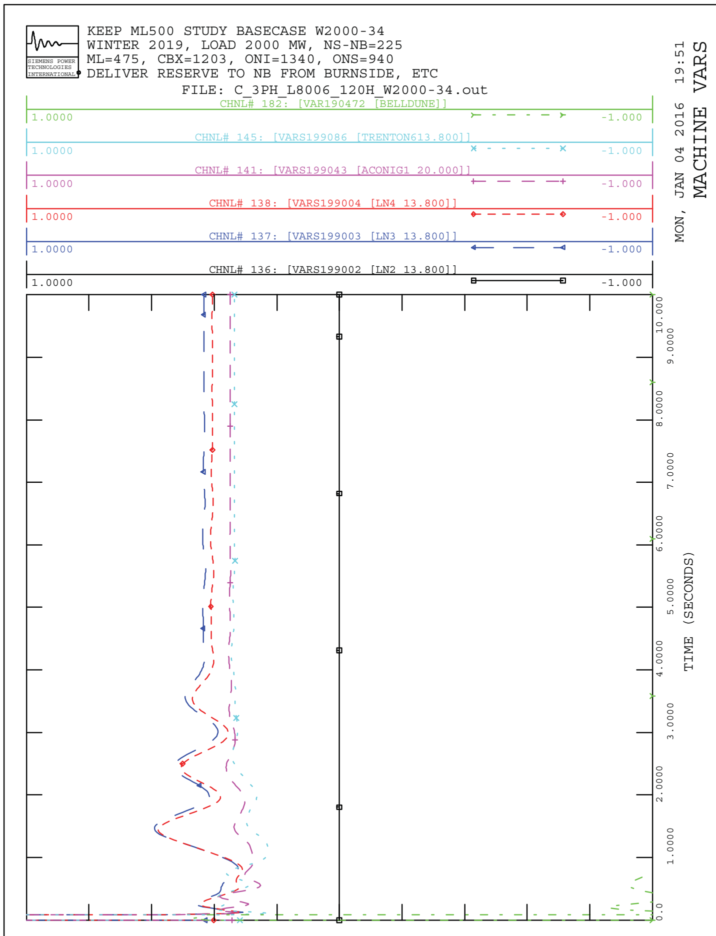
REDACTED (CONFIDENTIAL INFORMATION REMOVED)

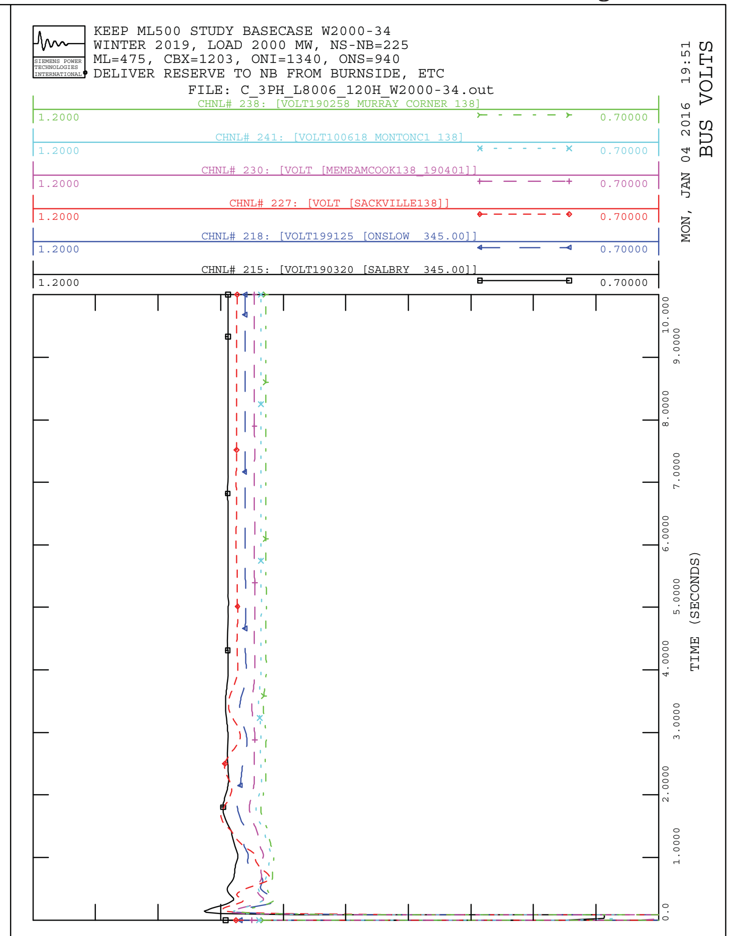


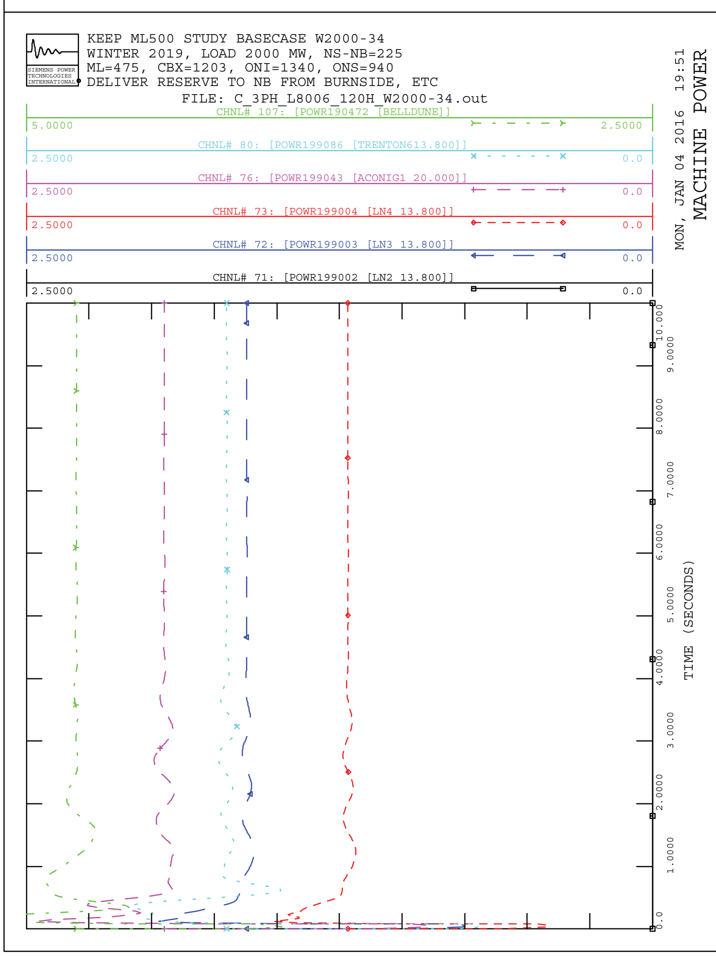


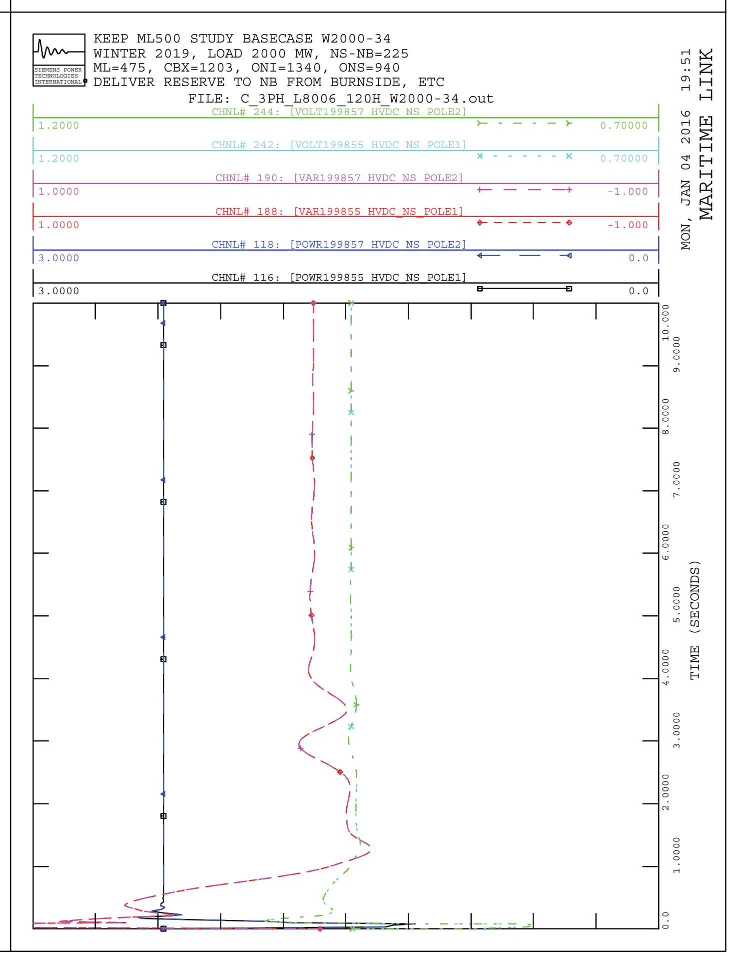


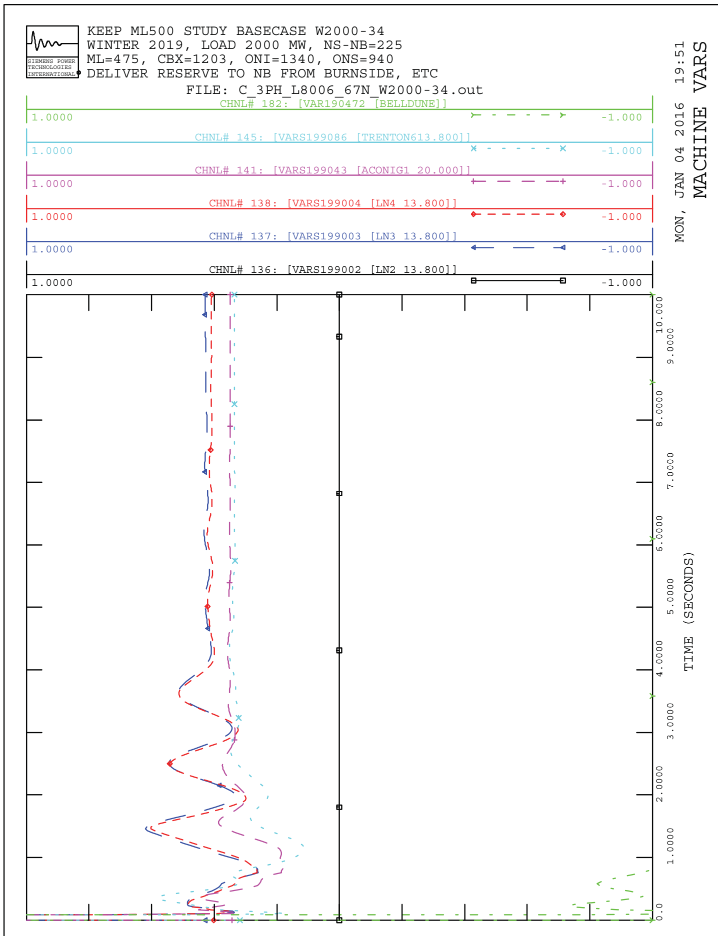



KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8006_120H_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8006_120H_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8006_120H_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8006_120H_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8006_67N_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
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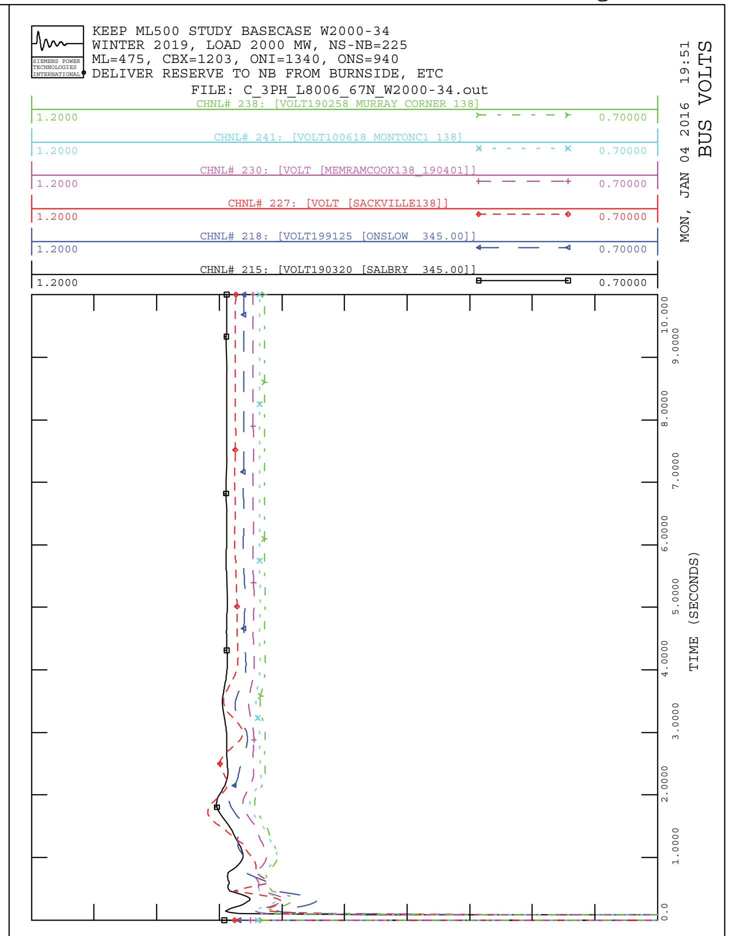
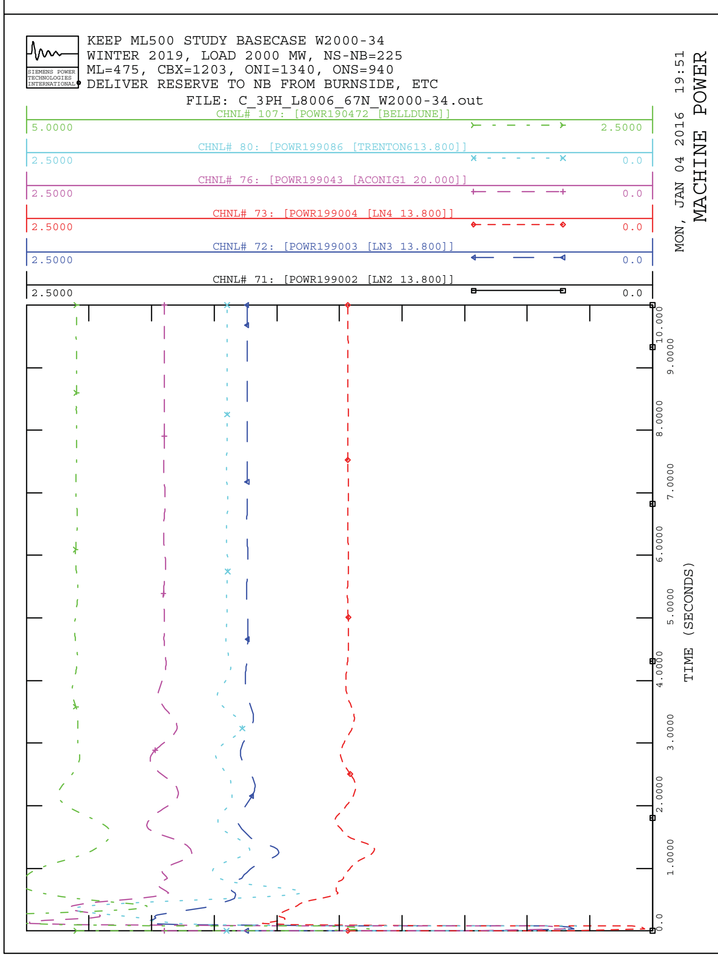
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8006_67N_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8006_67N_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
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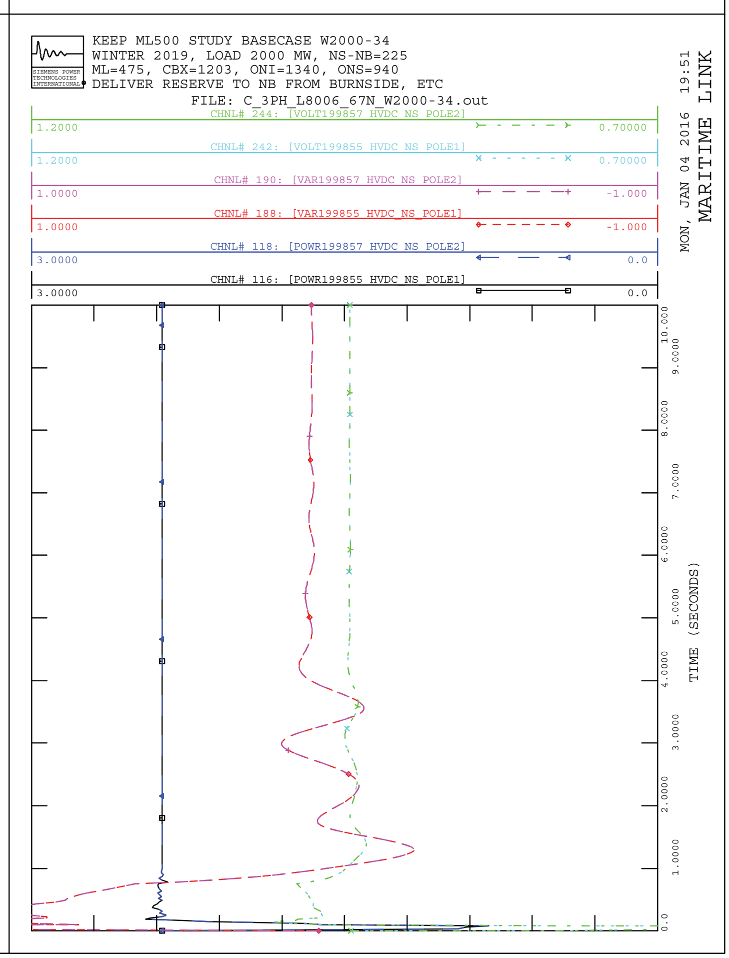
2.5000
0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_3PH_L8006_67N_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
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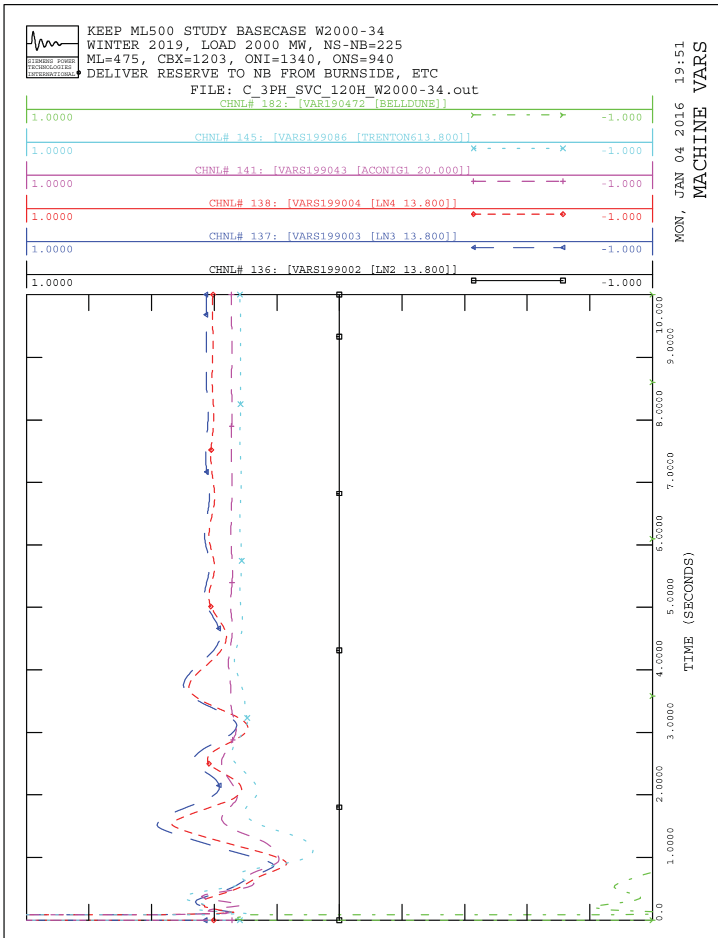
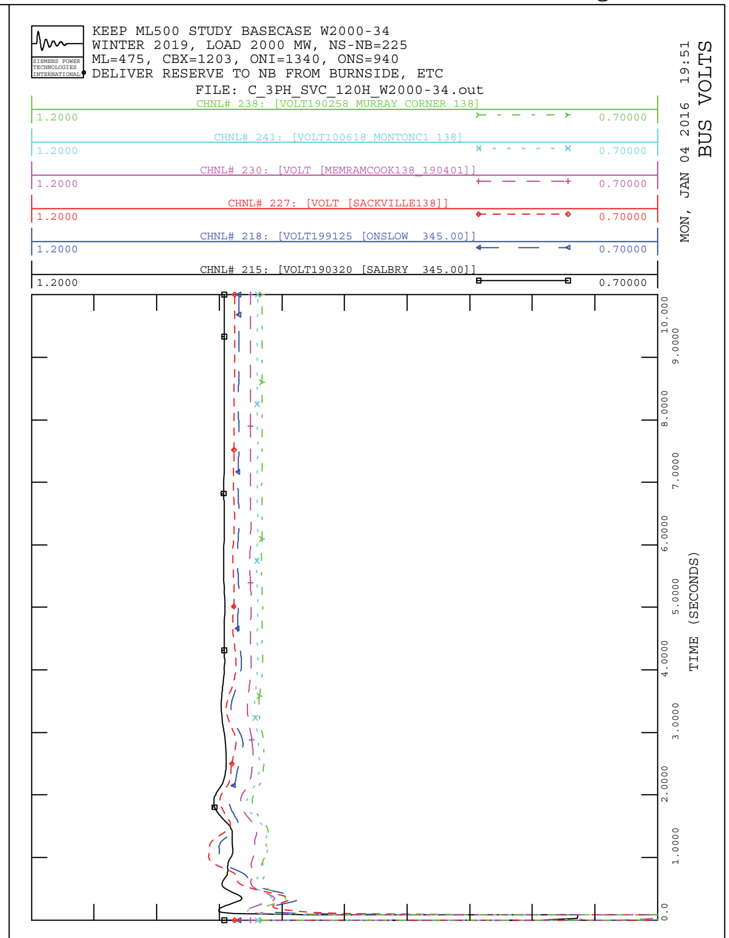
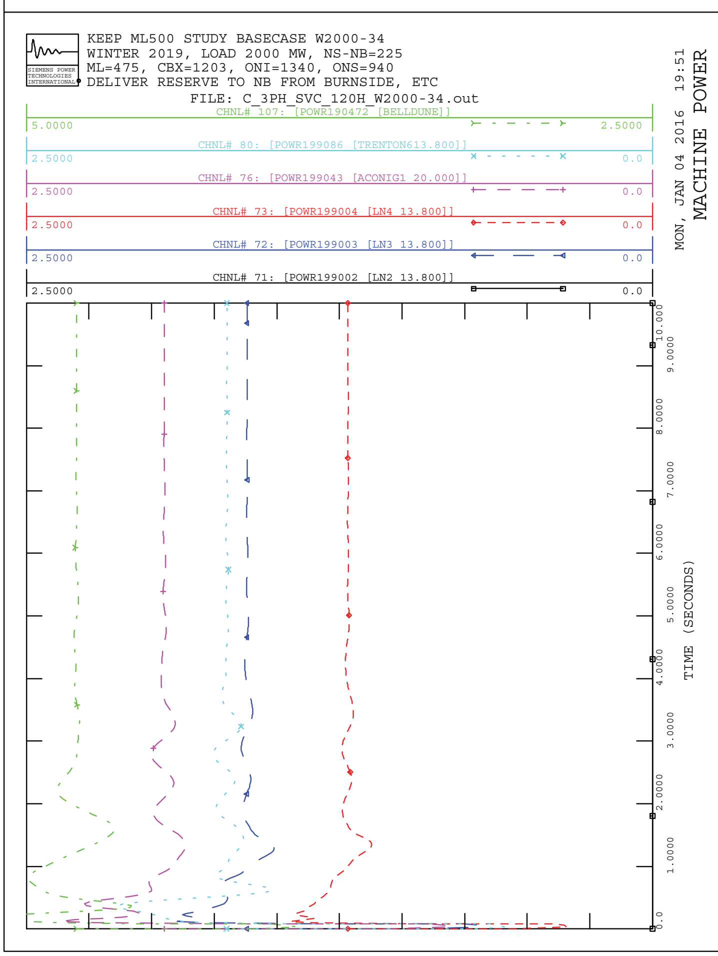
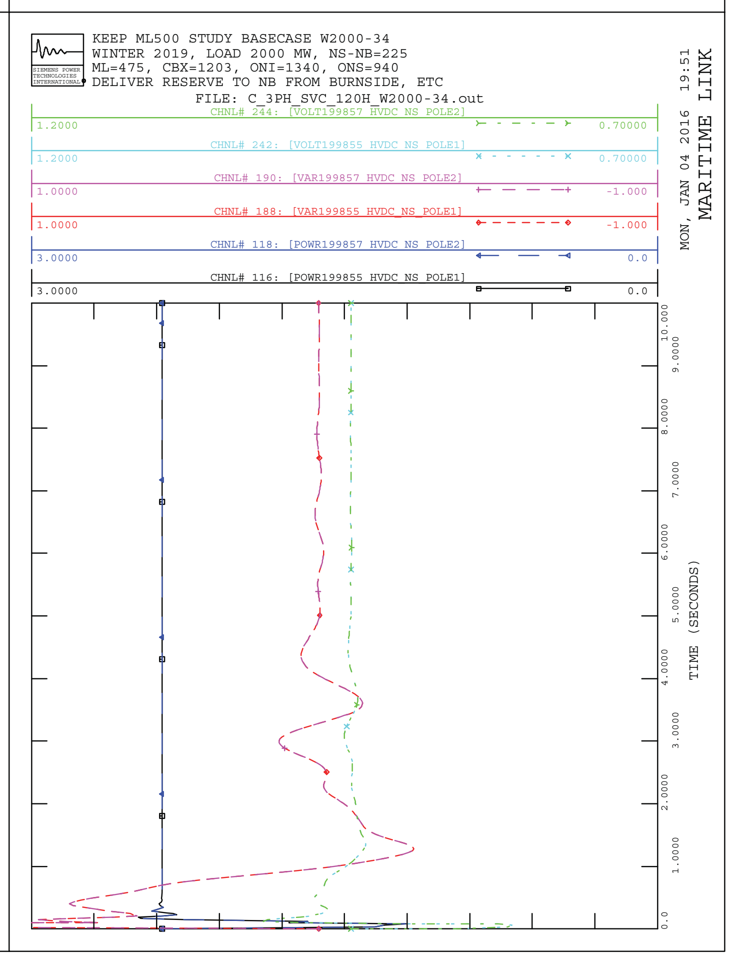
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)

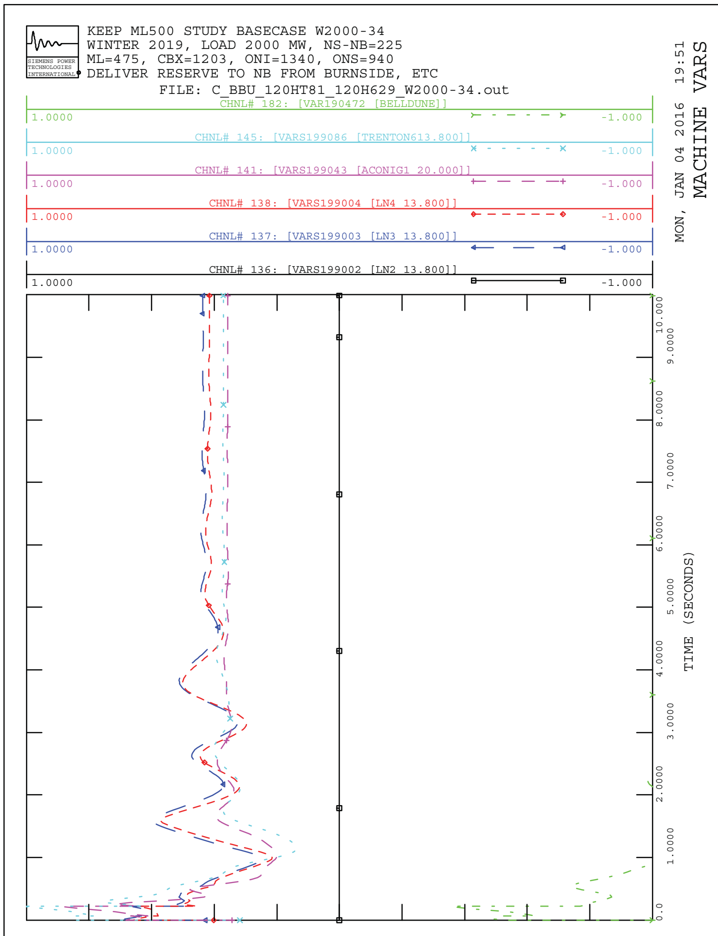
REDACTED (CONFIDENTIAL INFORMATION REMOVED)

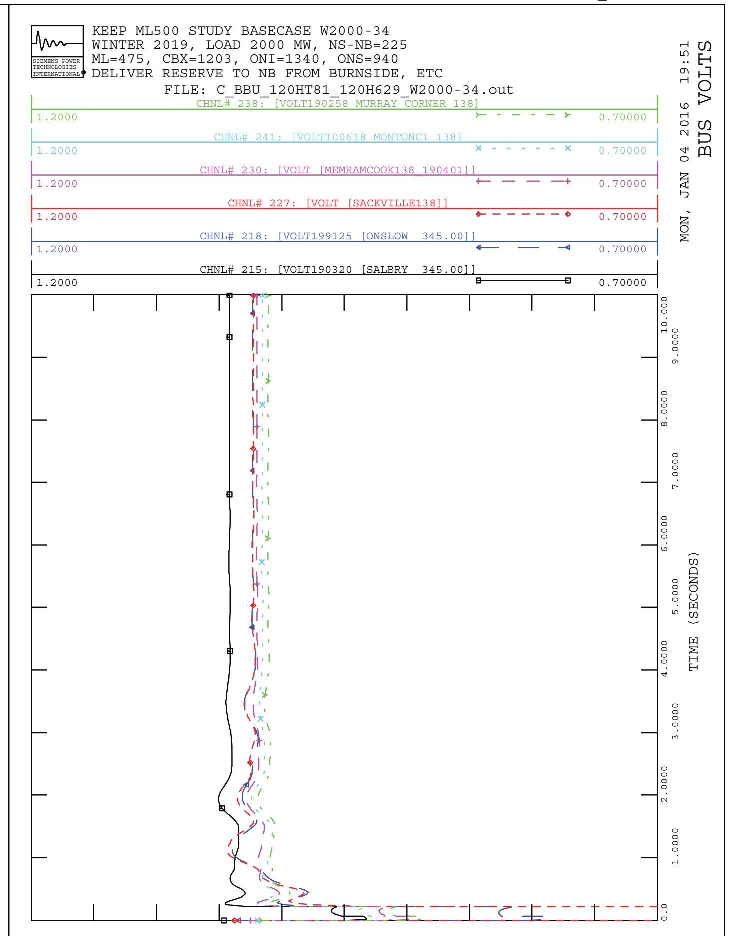


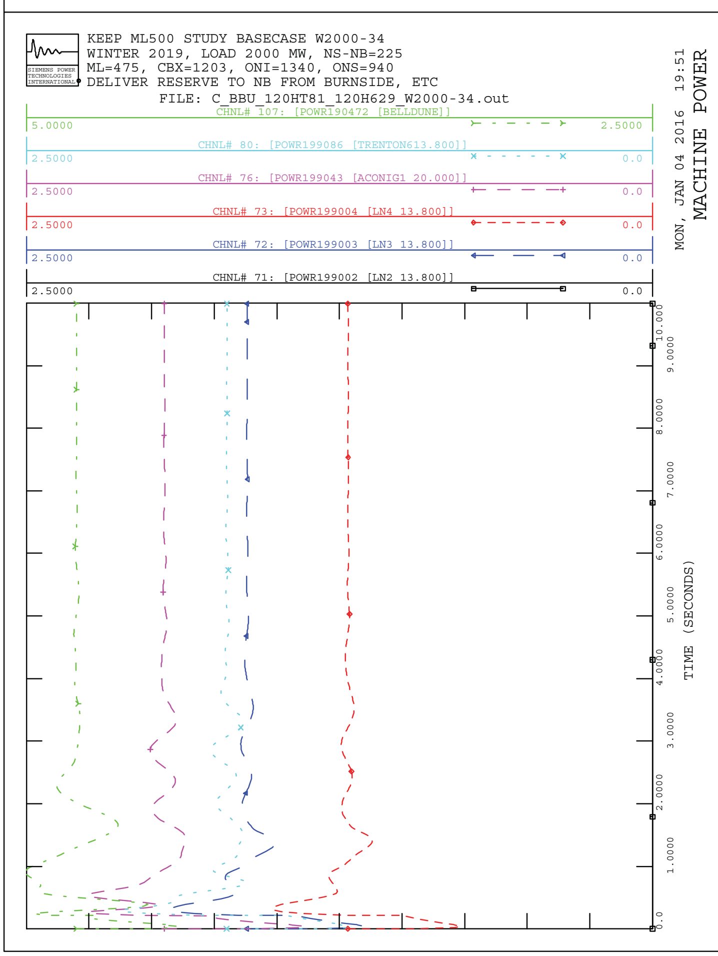


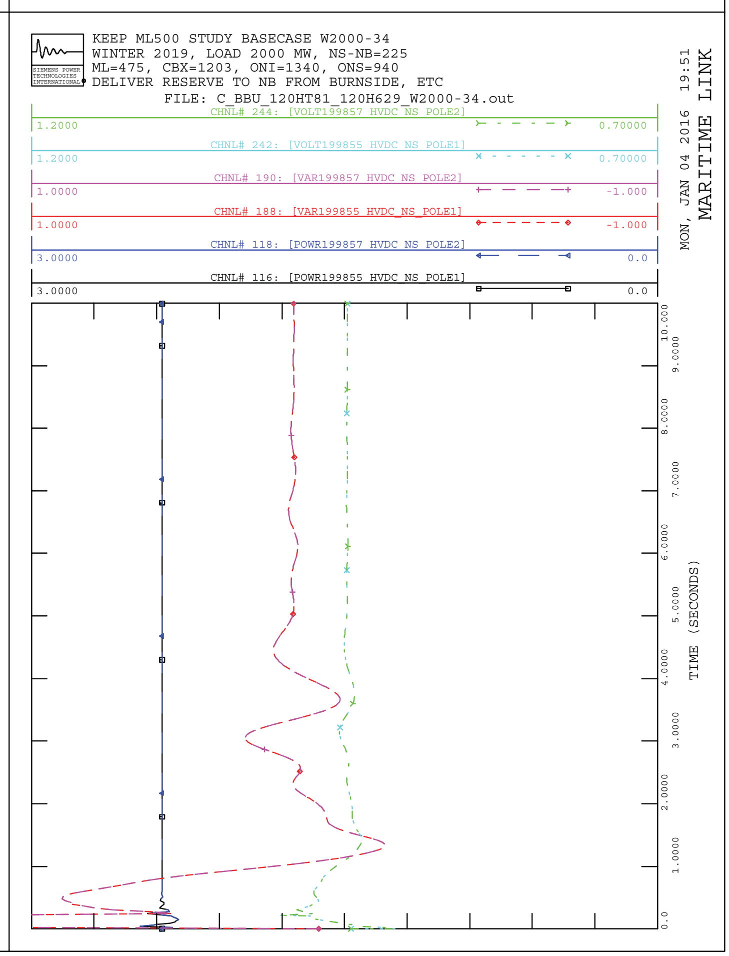


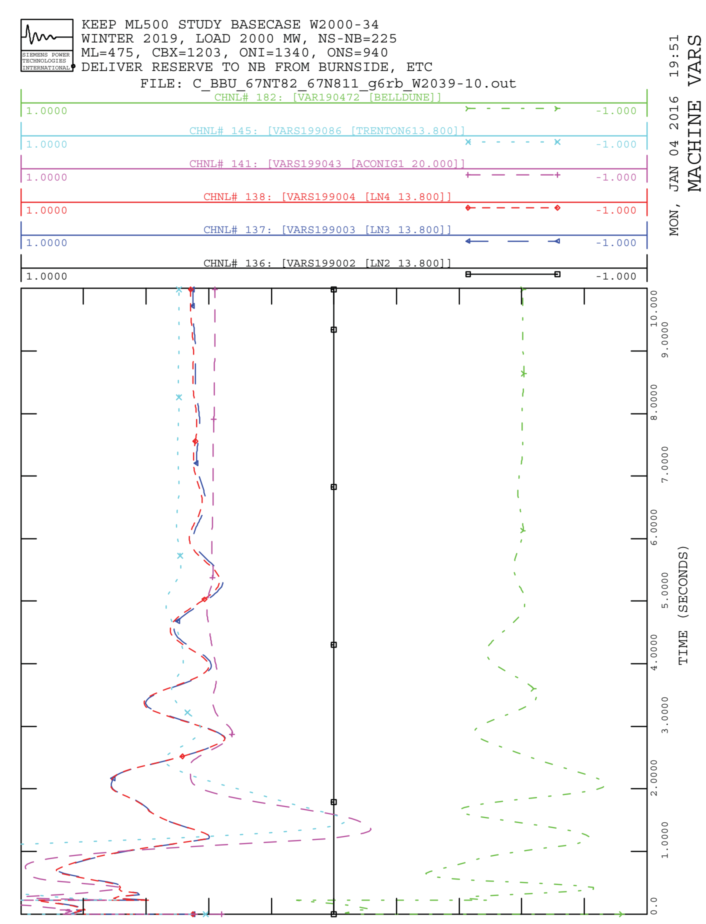


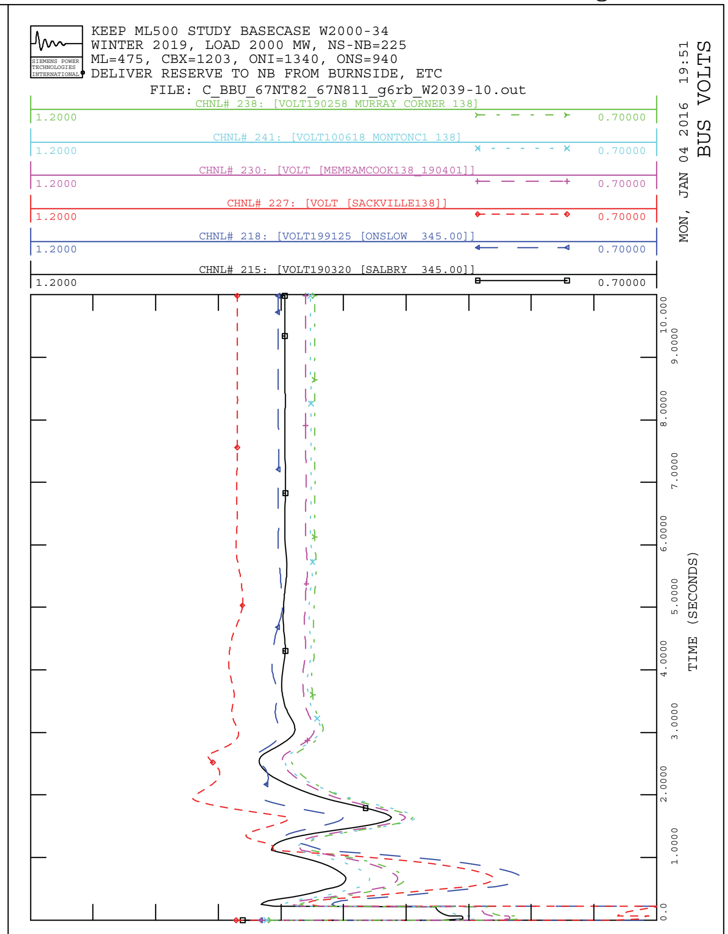

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_120HT81_120H629_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)

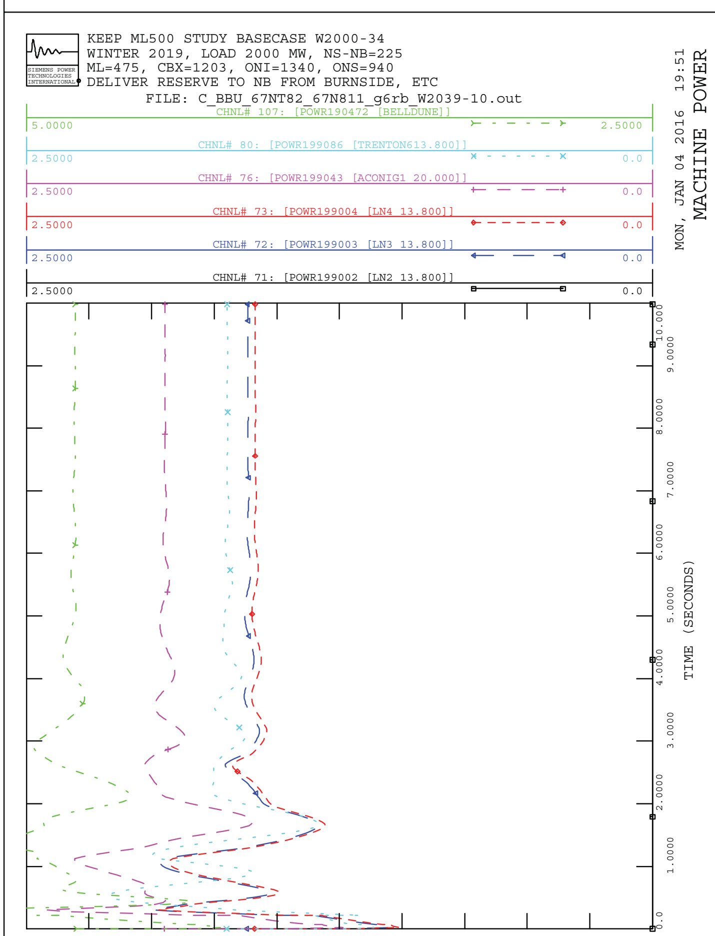

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_120HT81_120H629_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)

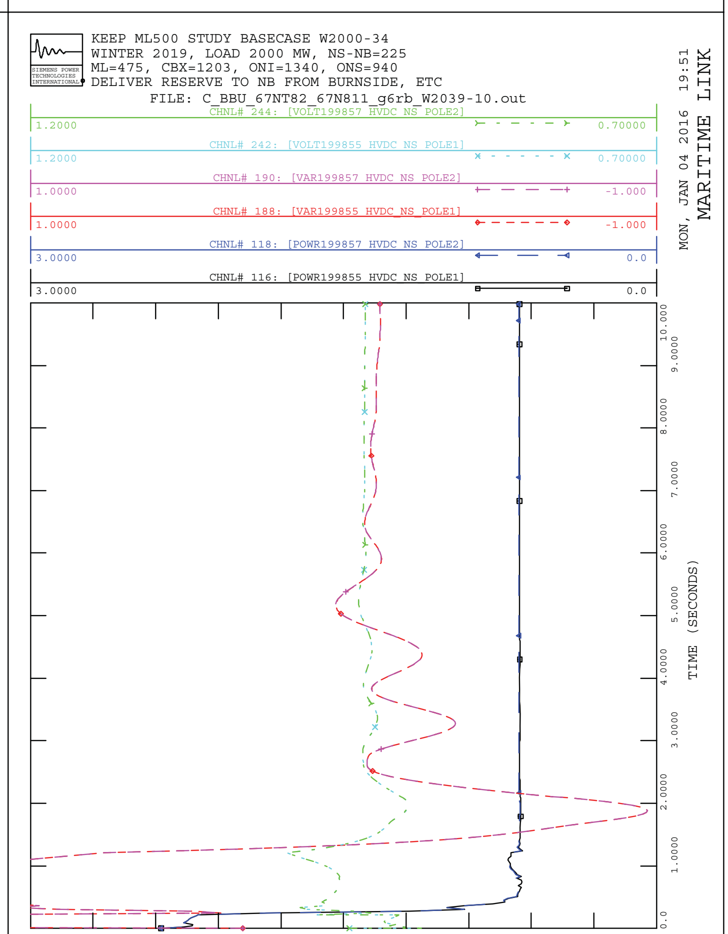

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_120HT81_120H629_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_120HT81_120H629_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)

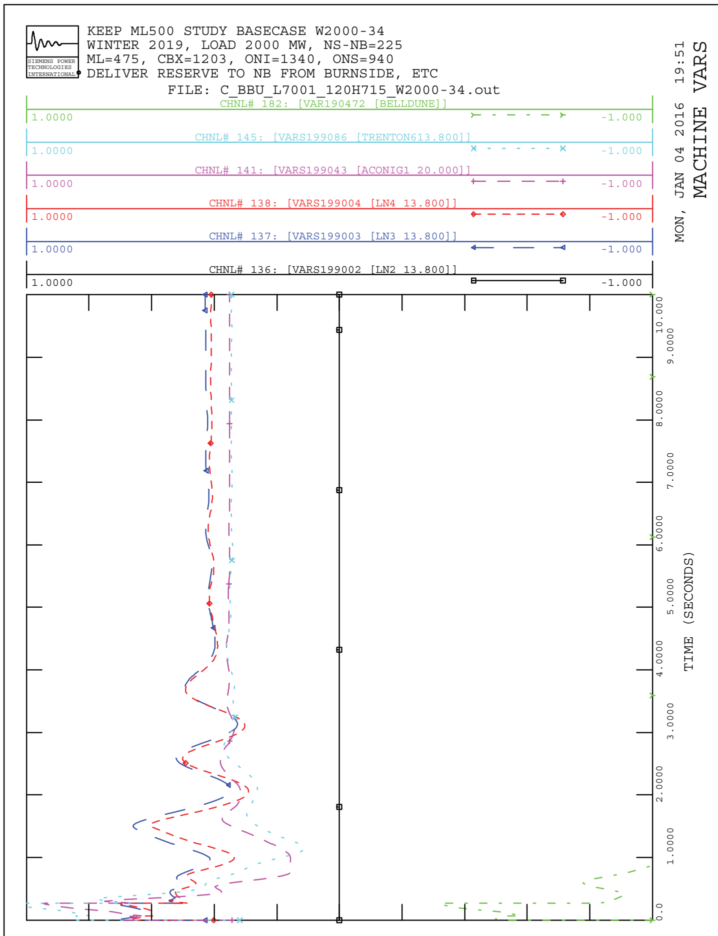

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_67NT82_67N811_g6rb_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)

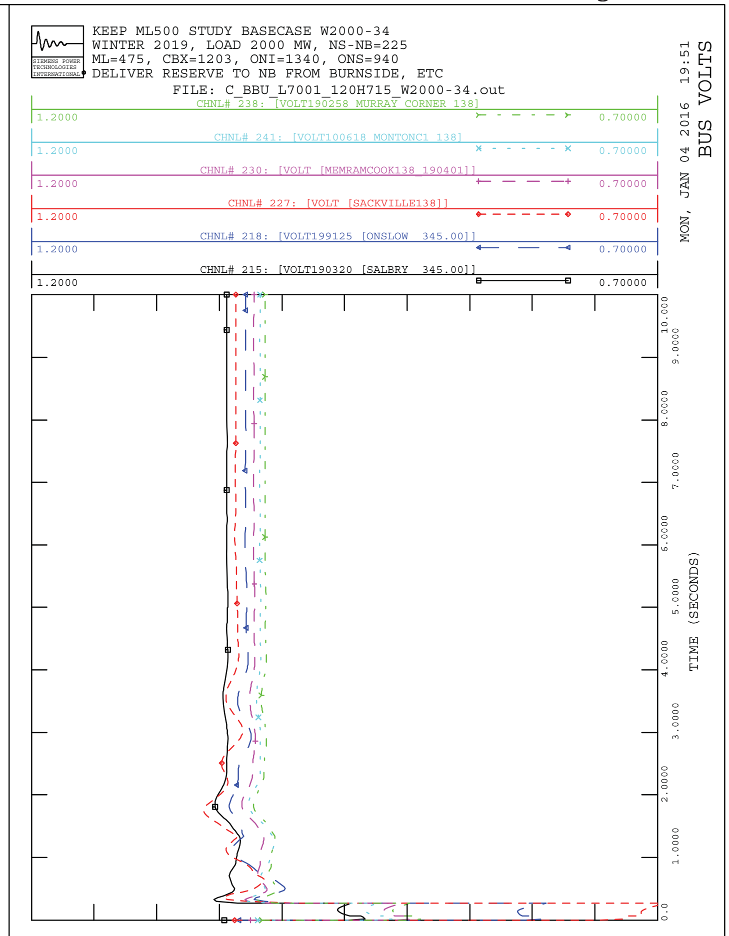

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_67NT82_67N811_g6rb_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)

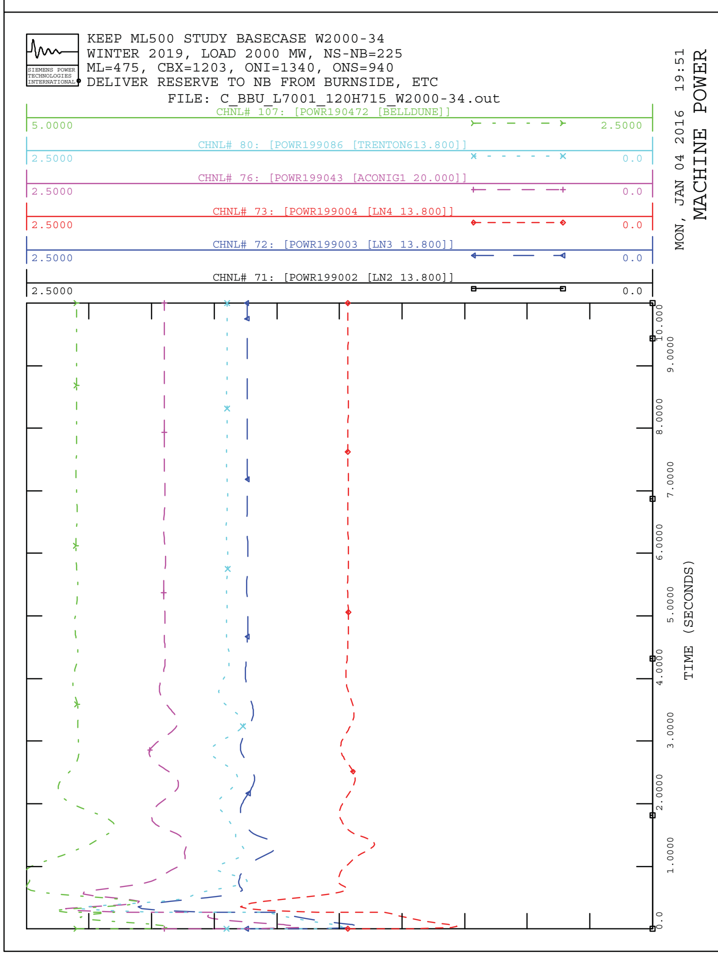

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_67NT82_67N811_g6rb_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)

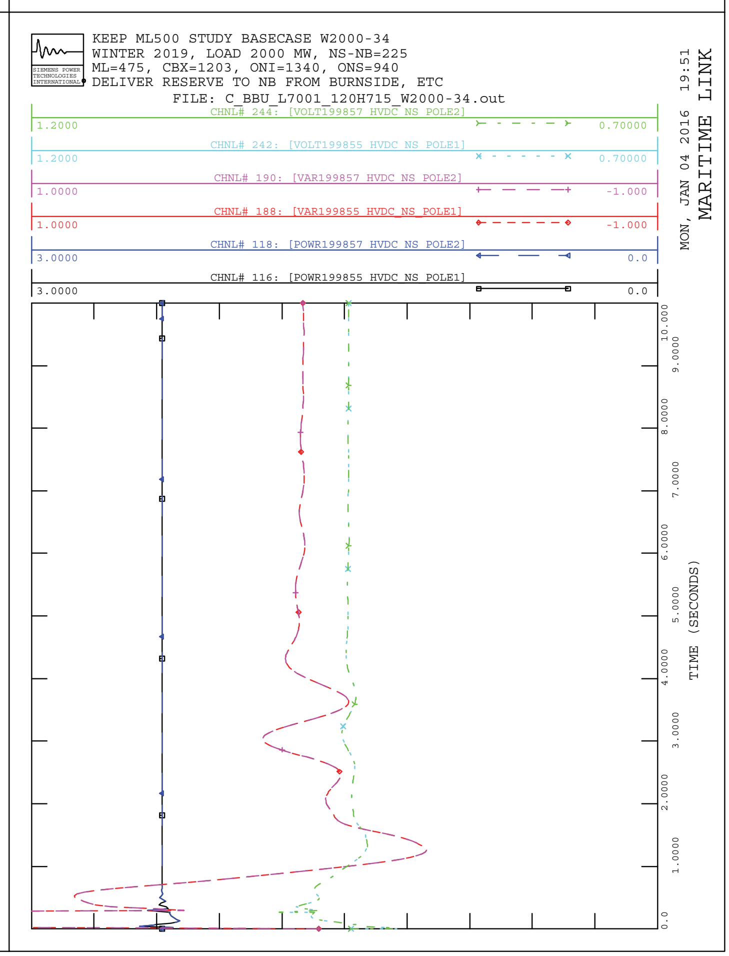

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_67NT82_67N811_g6rb_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

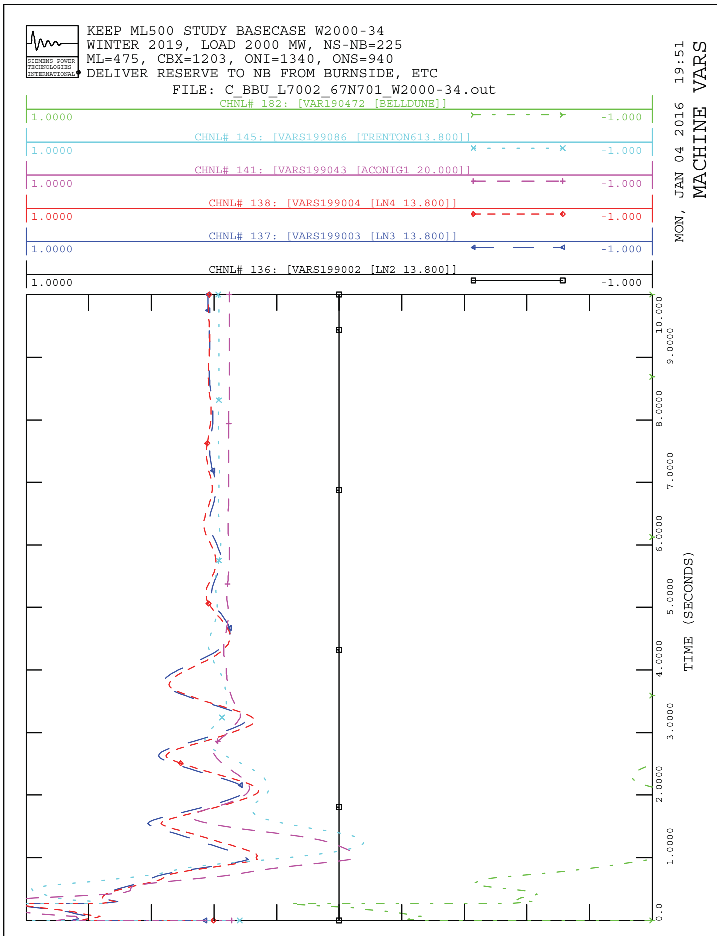


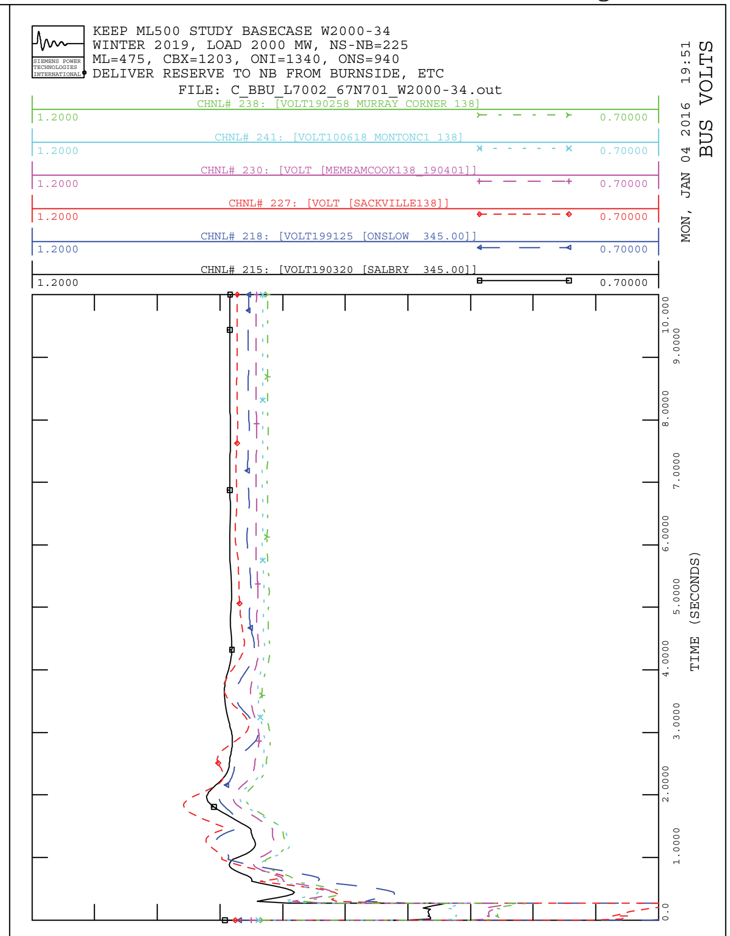


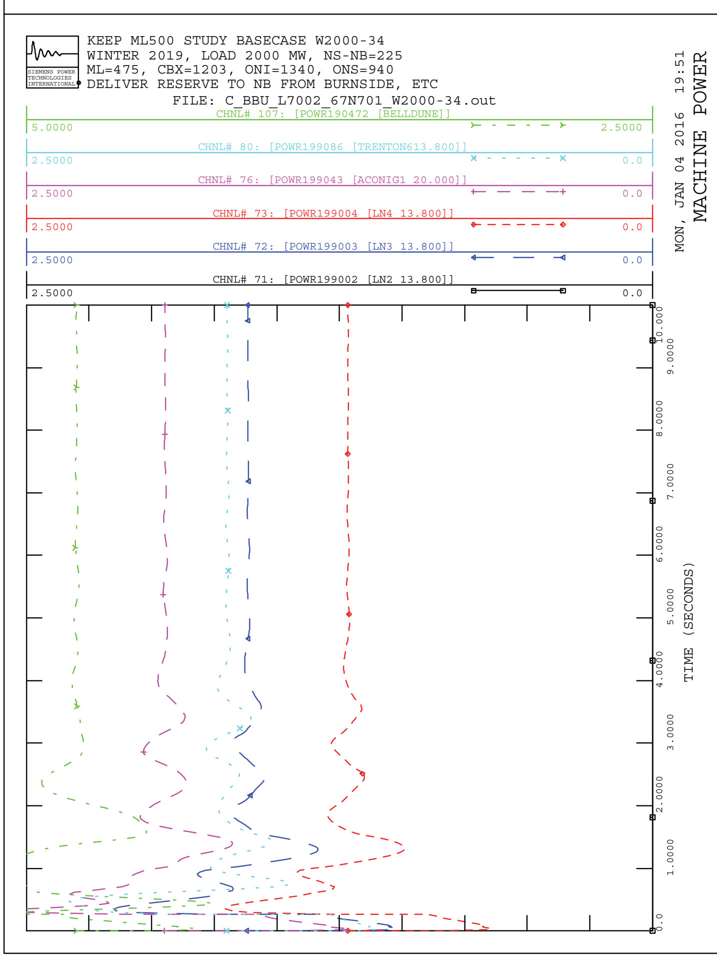


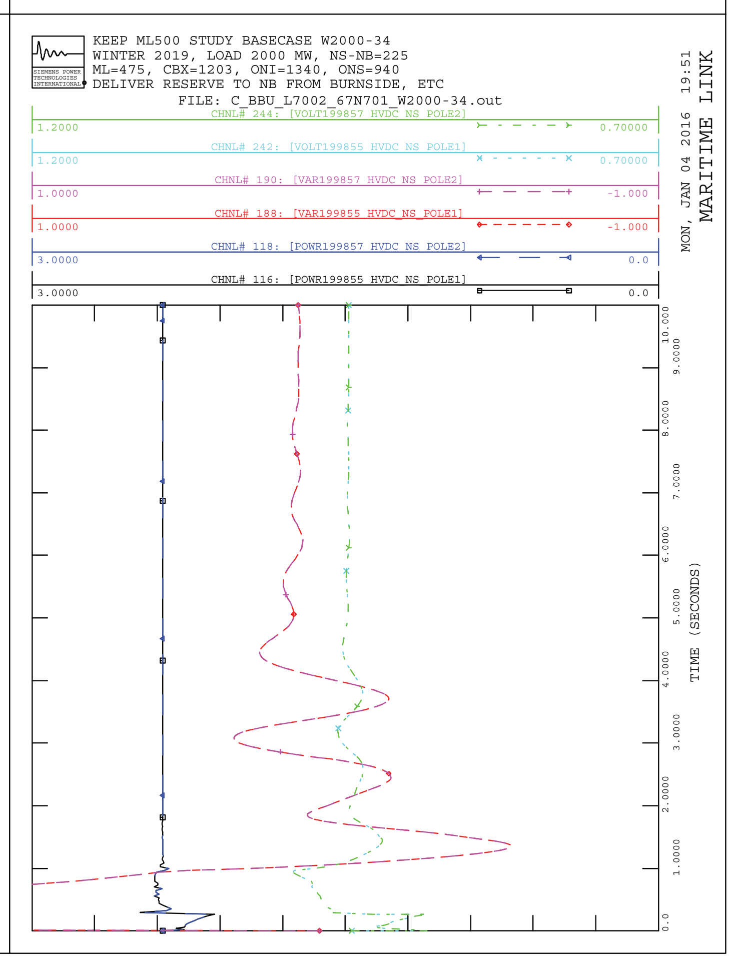


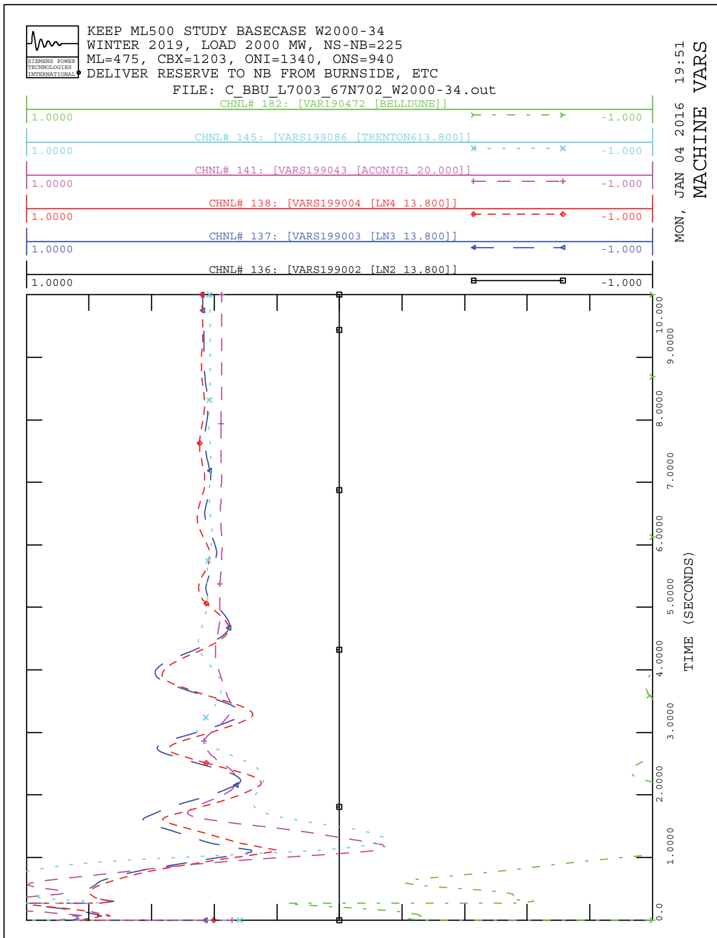
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



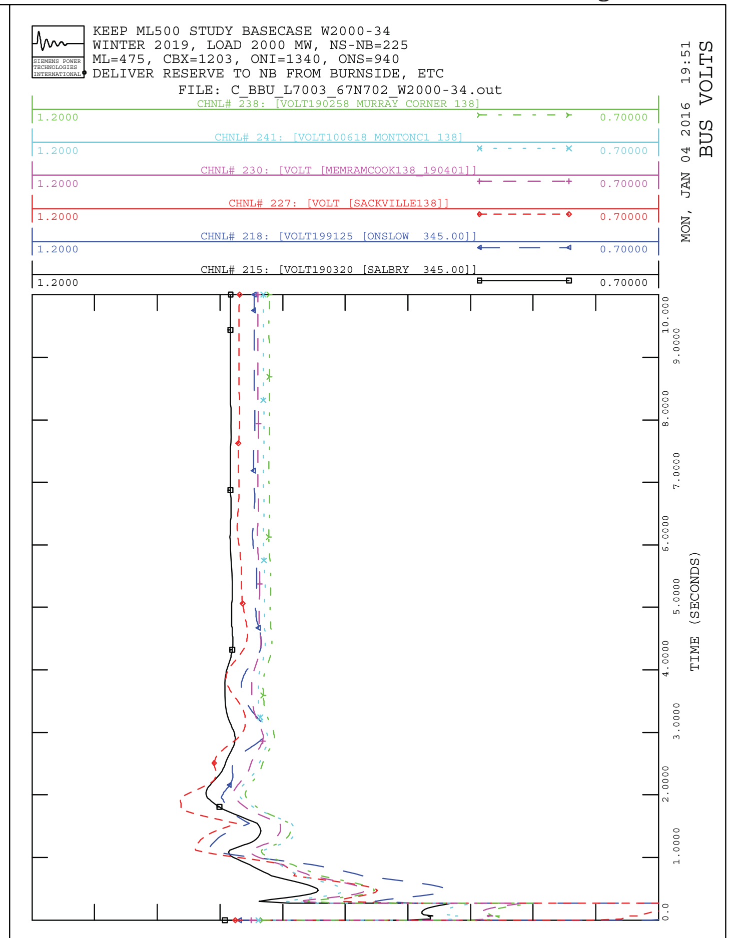




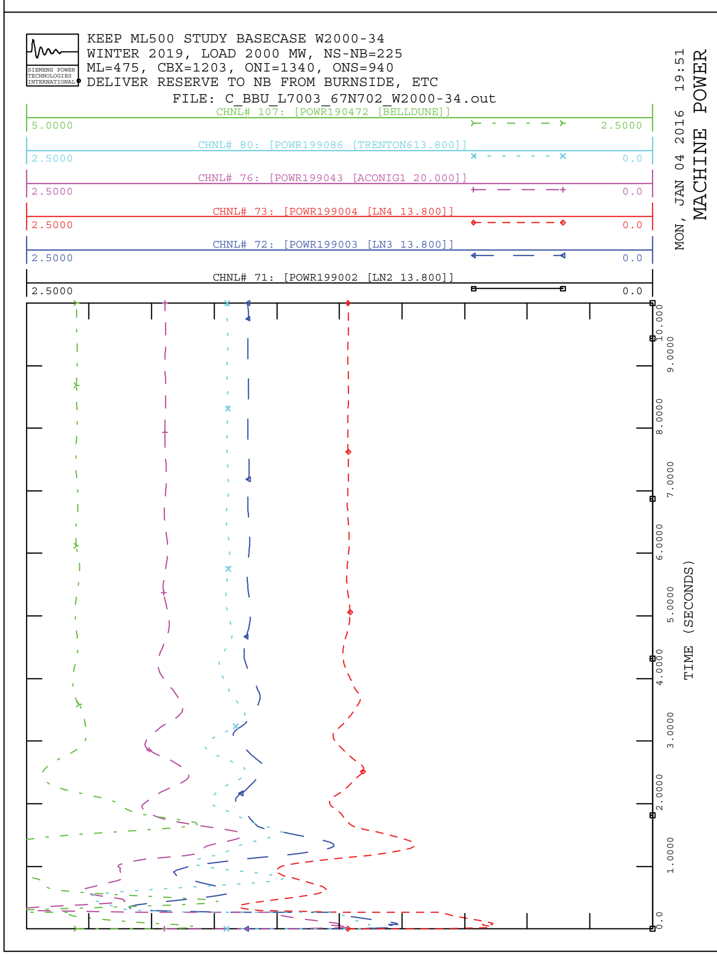




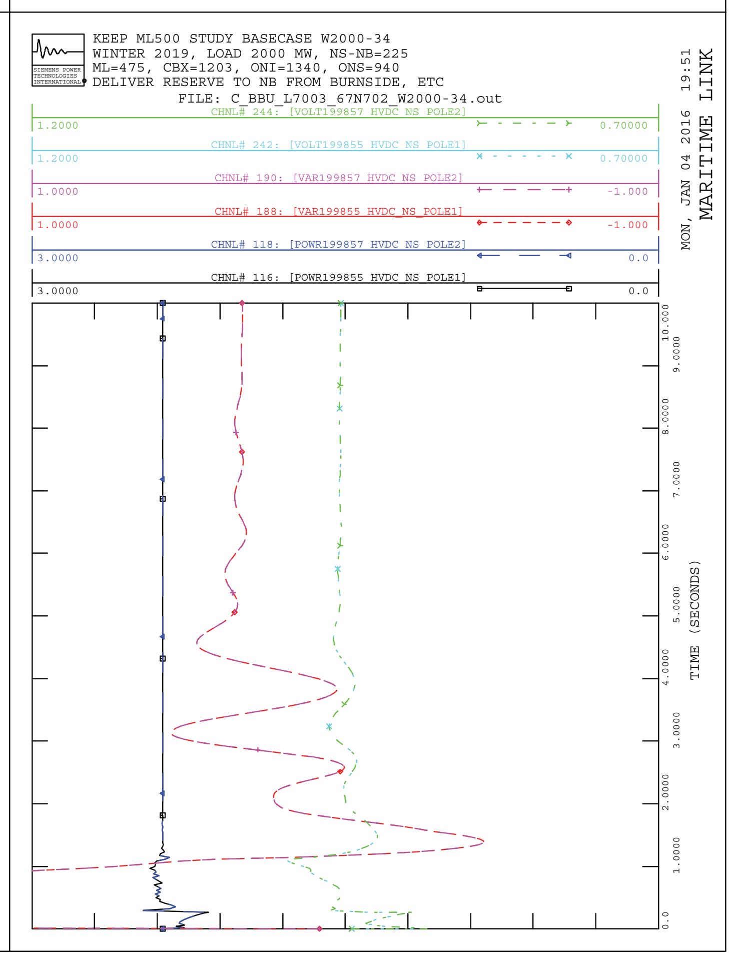
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7003_67N702_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)



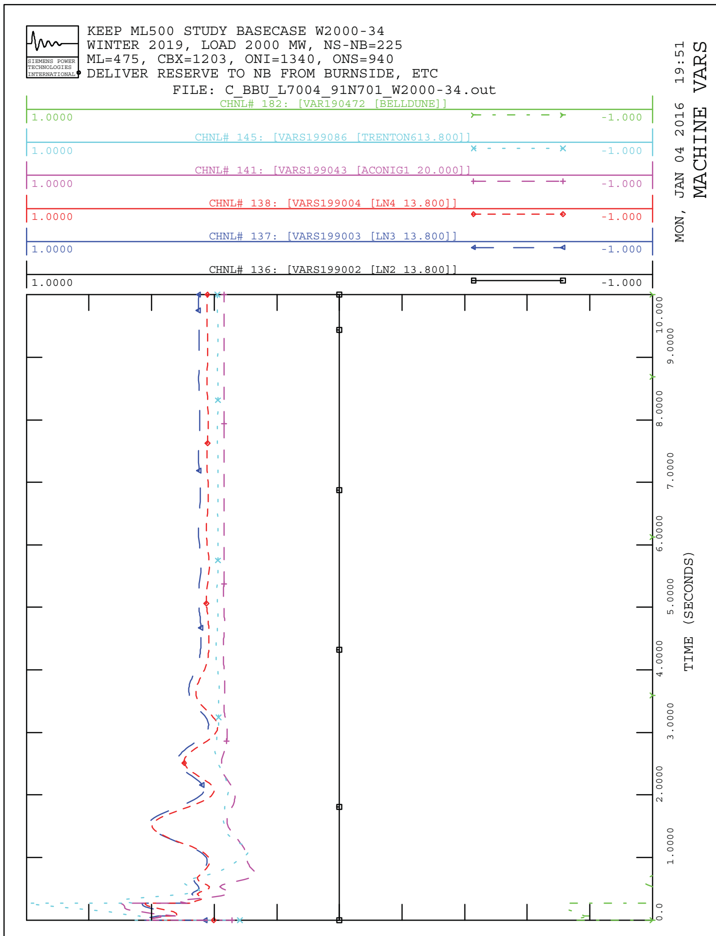
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7003_67N702_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)

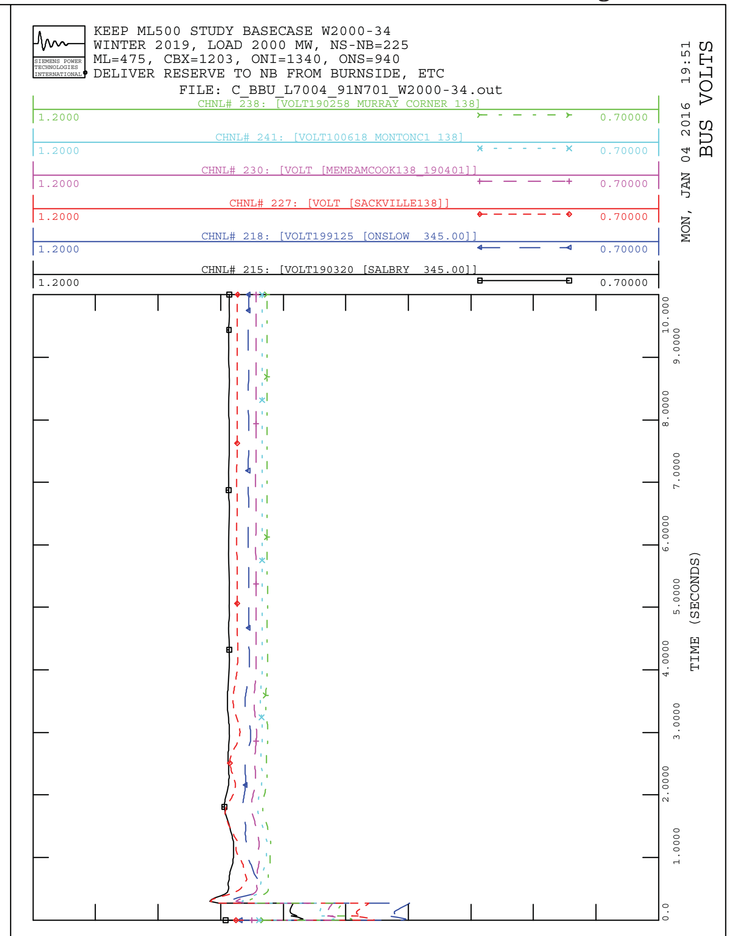


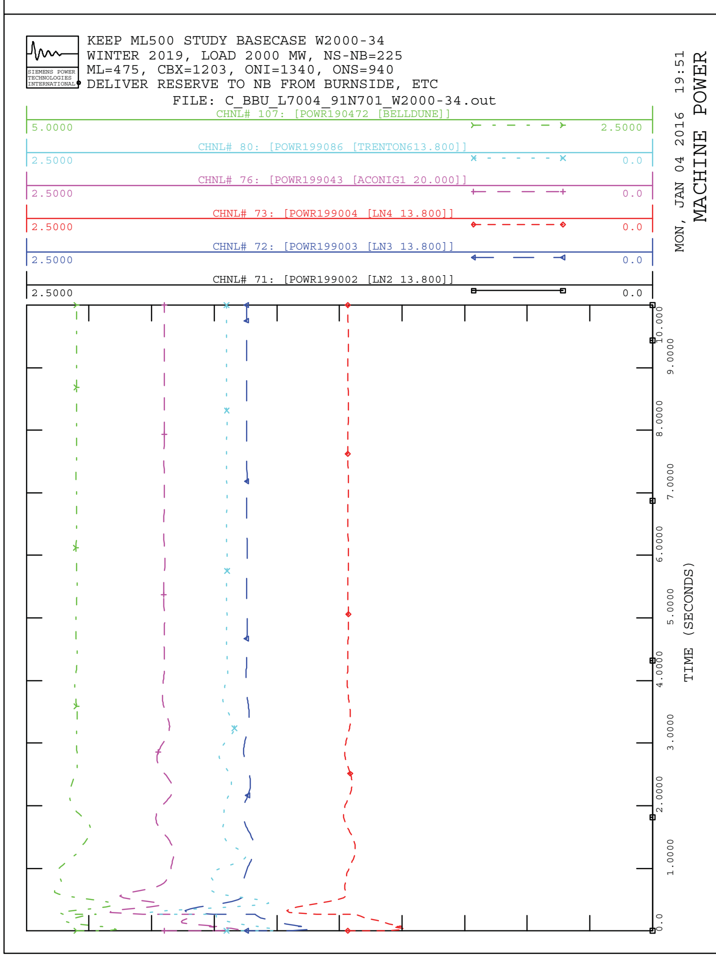
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7003_67N702_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)

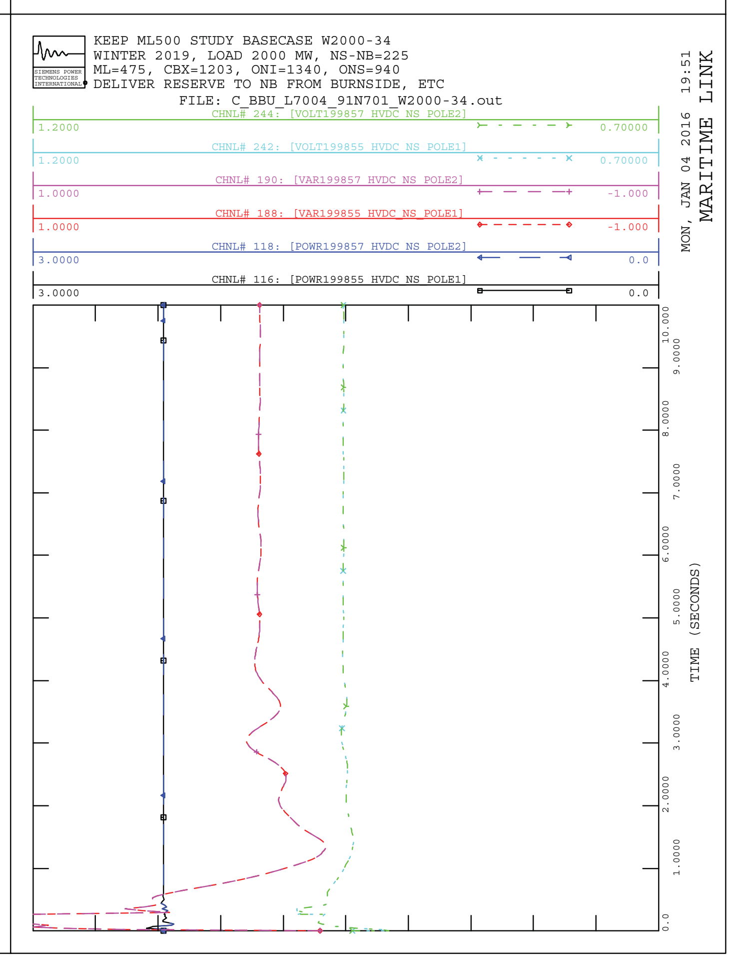


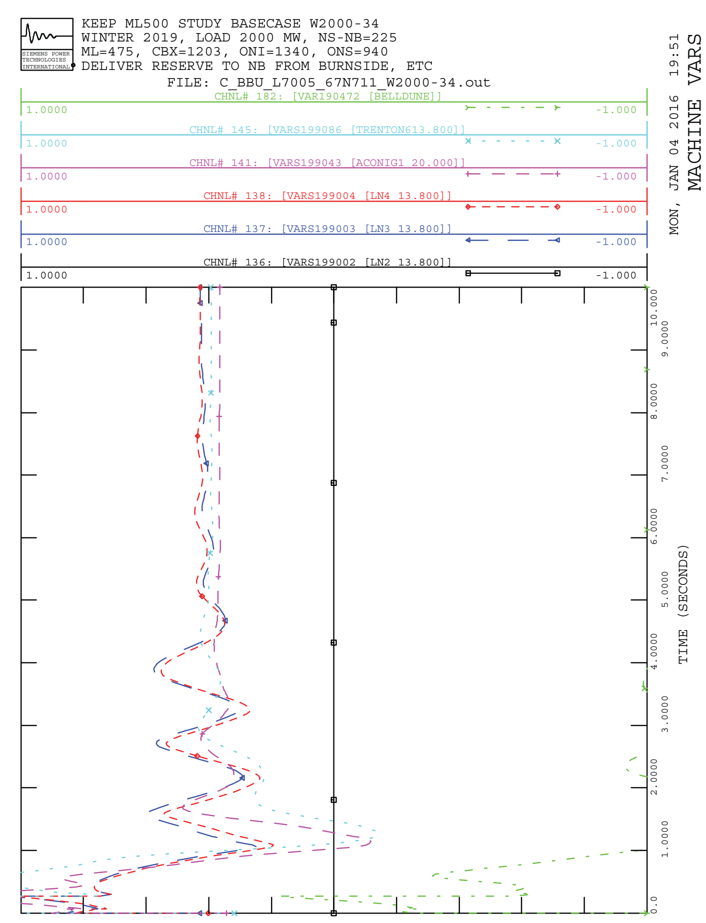
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7003_67N702_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)

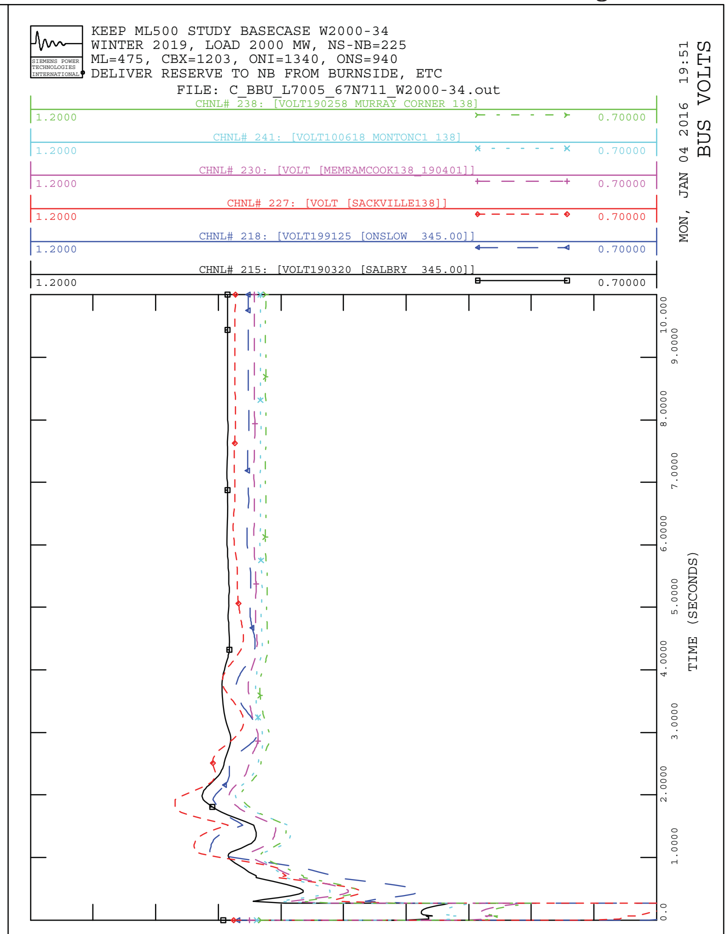

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7004_91N701_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)

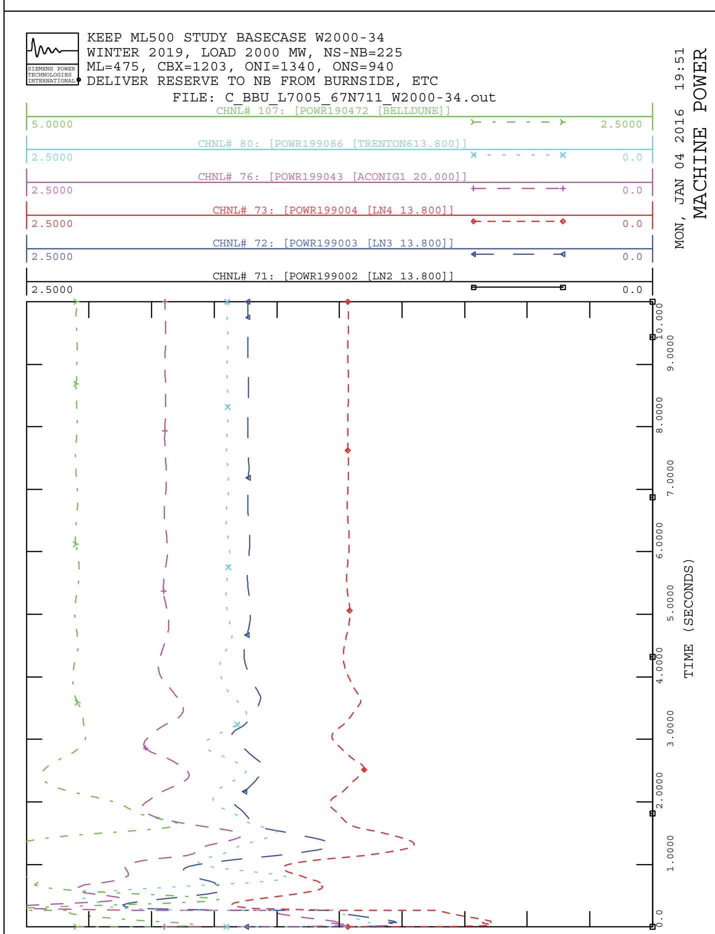

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7004_91N701_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)

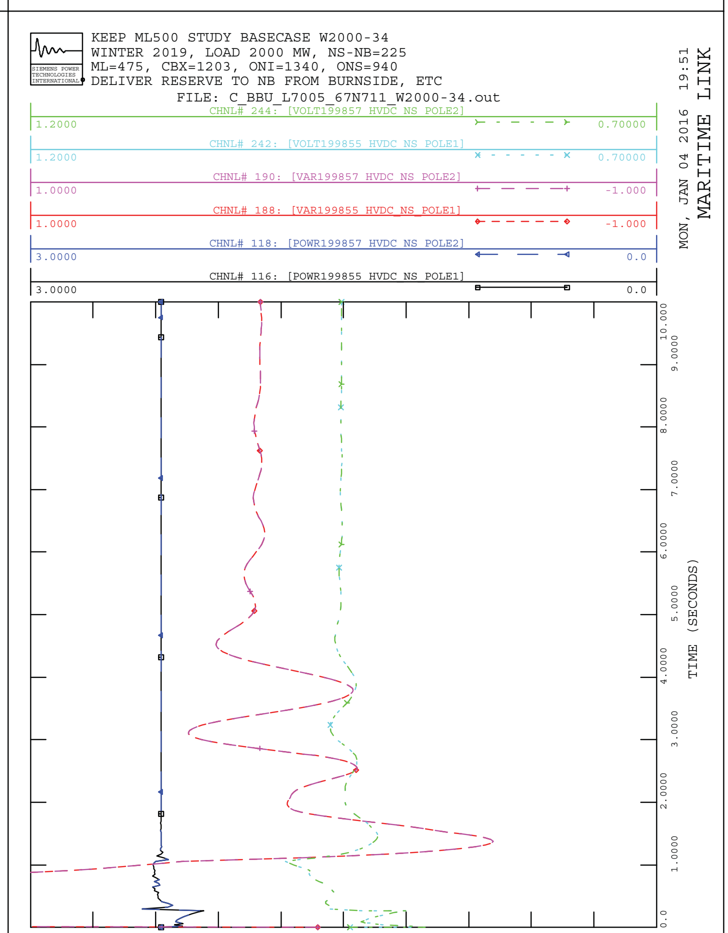

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7004_91N701_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)

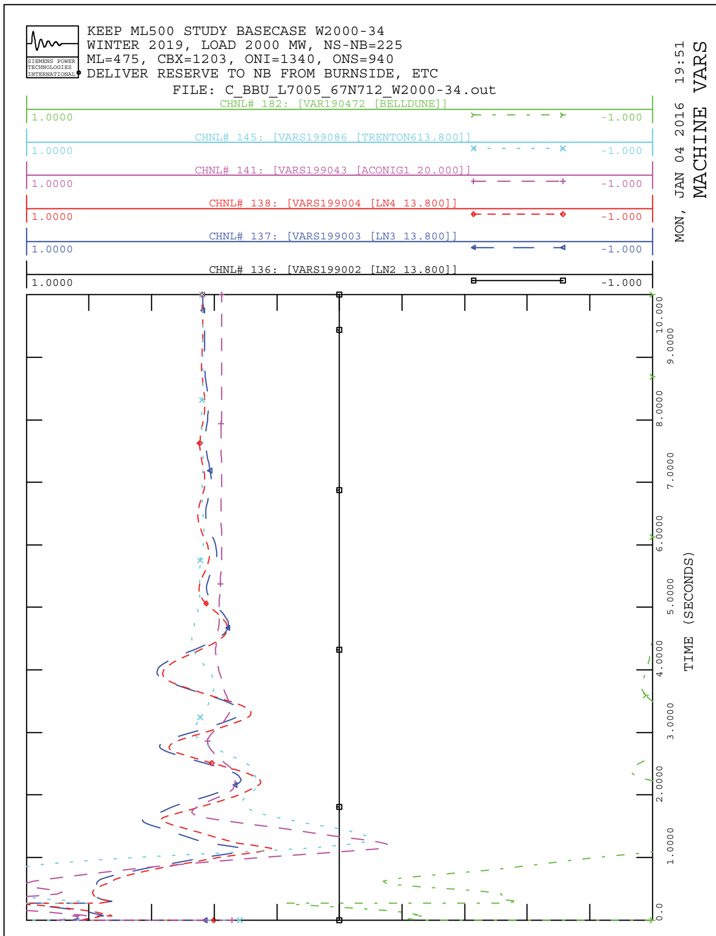

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7004_91N701_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7005_67N711_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

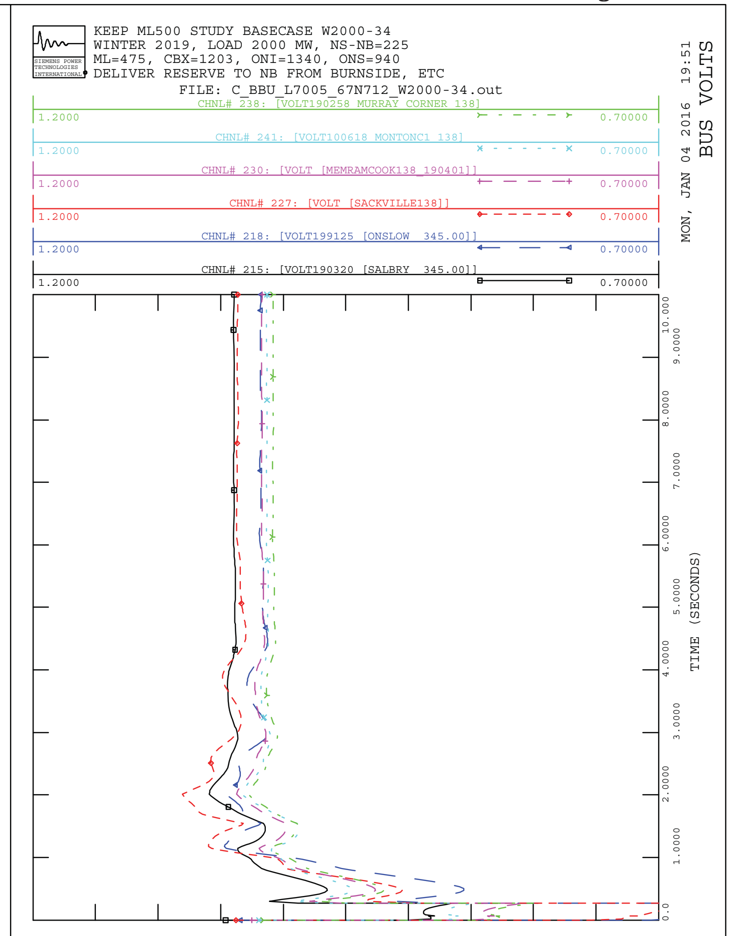

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7005_67N711_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7005_67N711_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7005_67N711_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000



SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7005_67N712_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7005_67N712_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)
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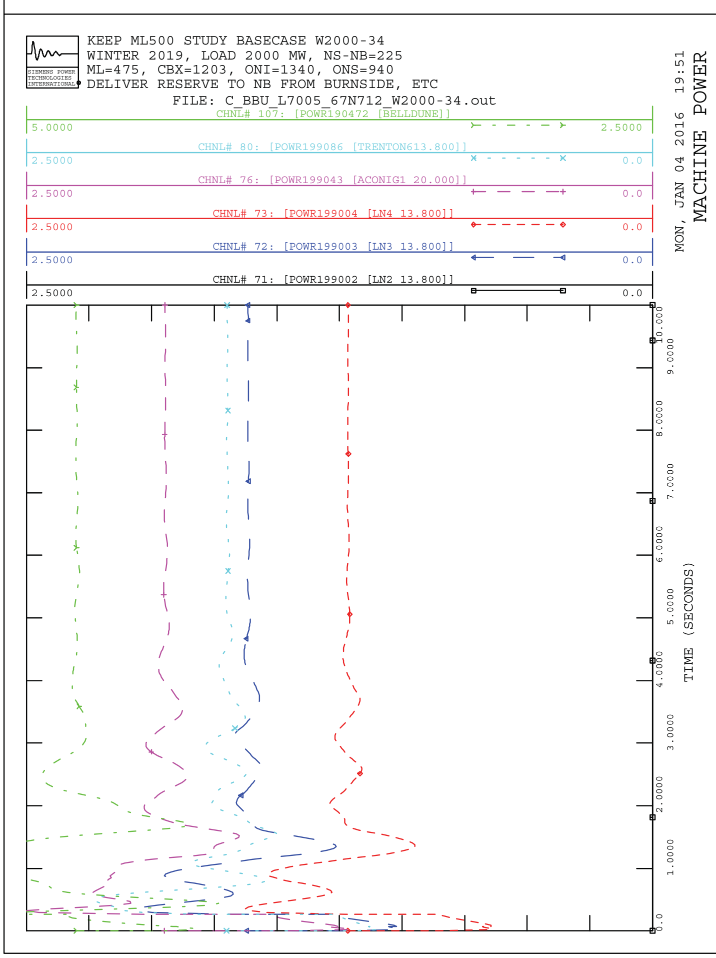

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7005_67N712_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)
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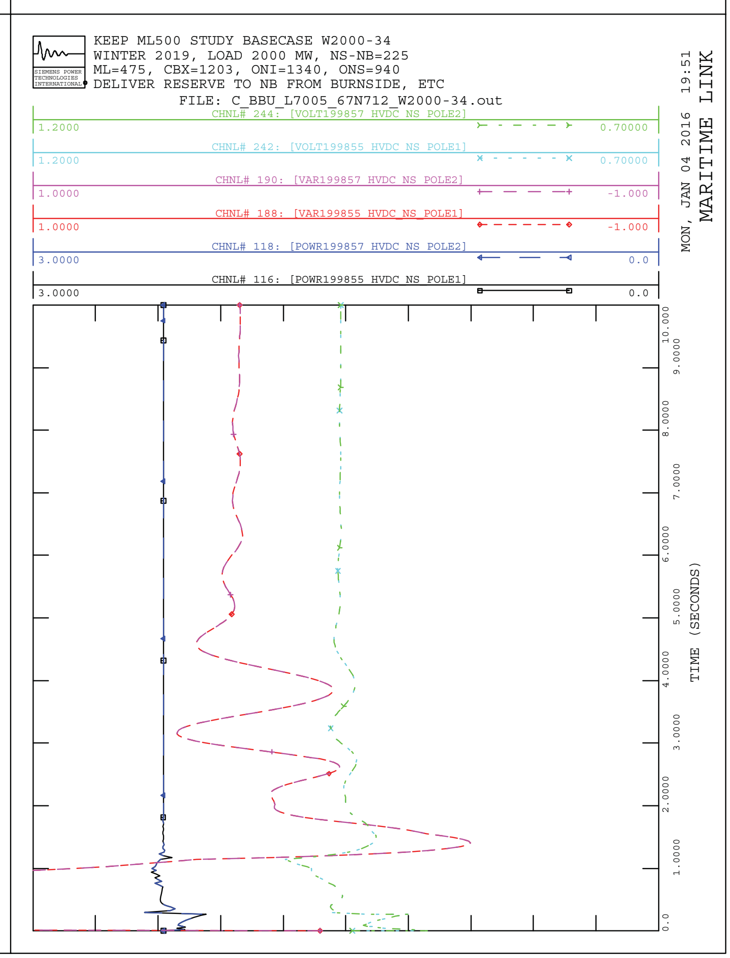

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7005_67N712_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)
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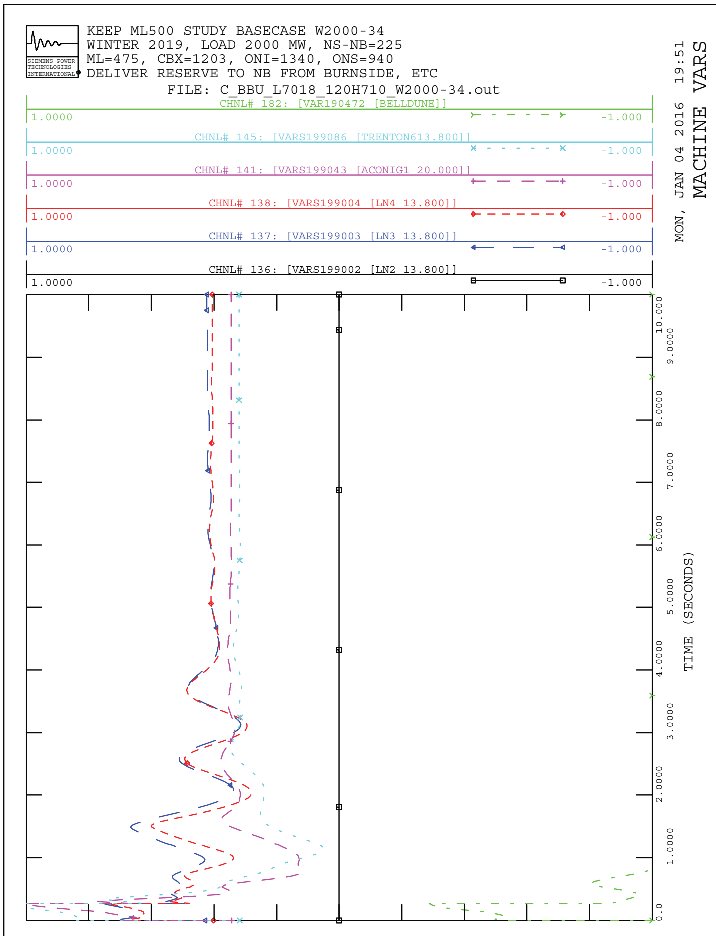
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7018_120H710_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
MON, JAN 04 2016 19:51
MACHINE VARS
TIME (SECONDS)
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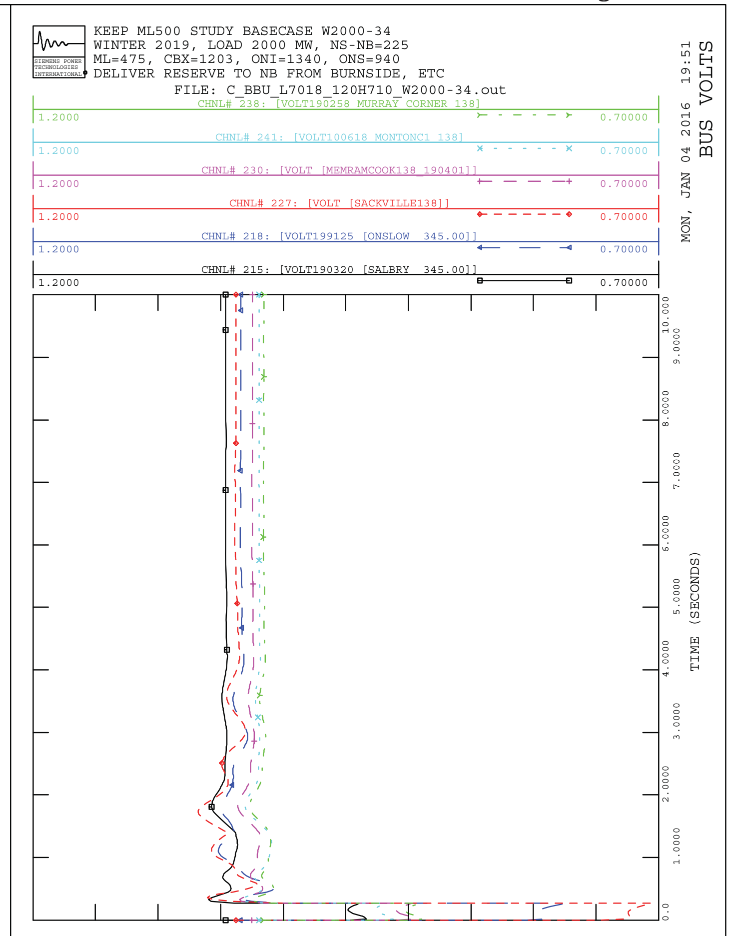
10.000


SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7018_120H710_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
MON, JAN 04 2016 19:51
BUS VOLTS
TIME (SECONDS)
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1.0000
2.0000
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6.0000
7.0000
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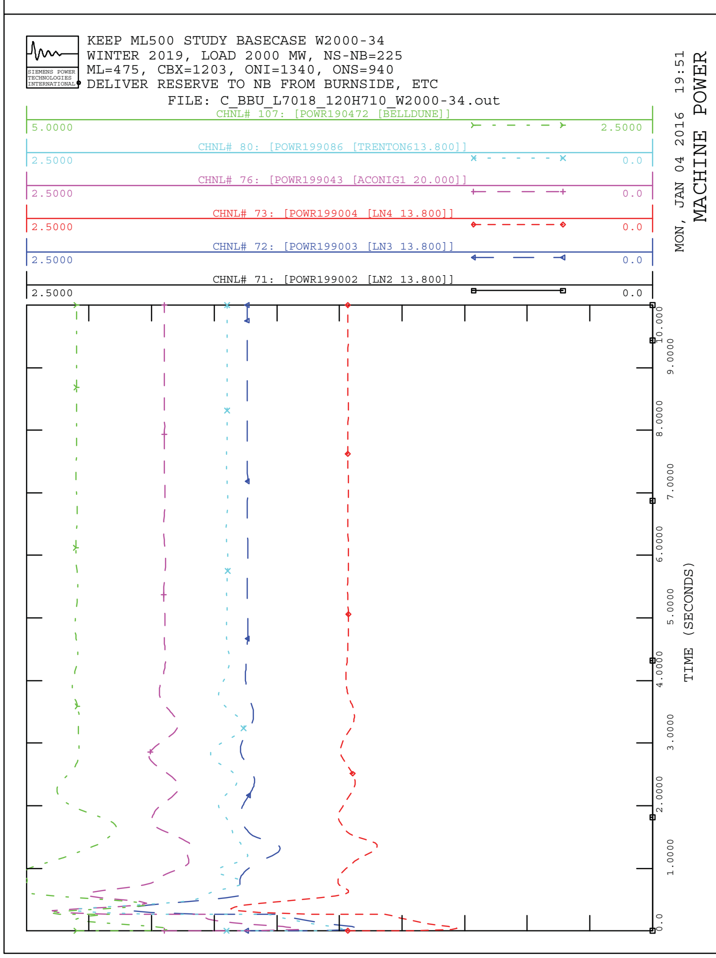
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7018_120H710_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
MON, JAN 04 2016 19:51
MACHINE POWER
TIME (SECONDS)
0.0
1.0000
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6.0000
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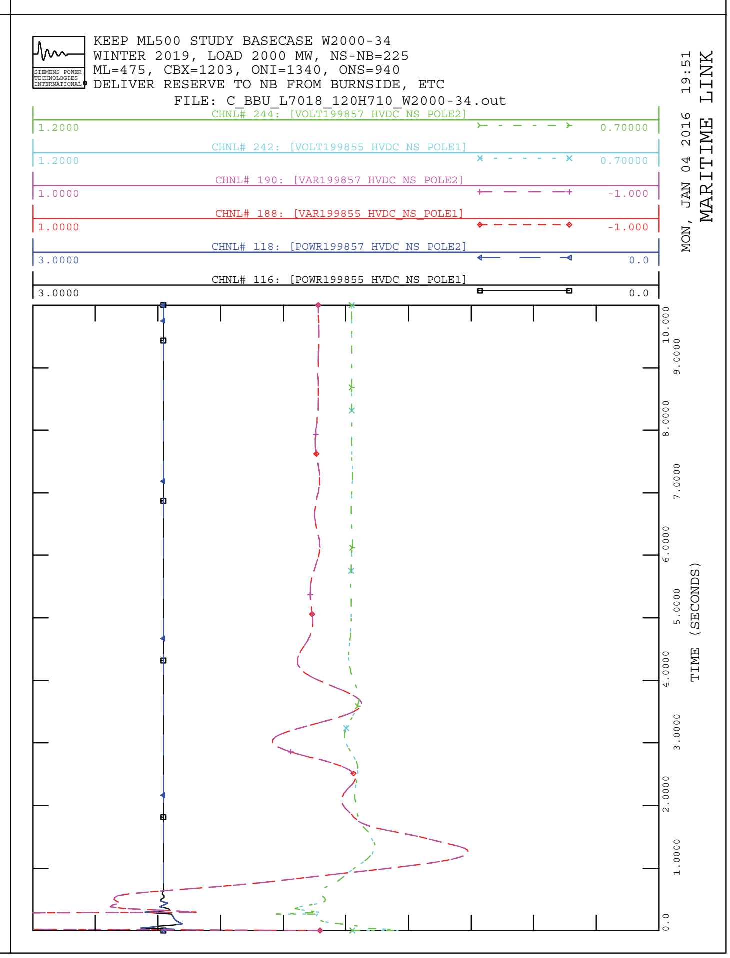
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7018_120H710_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
MON, JAN 04 2016 19:51
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
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5.0000
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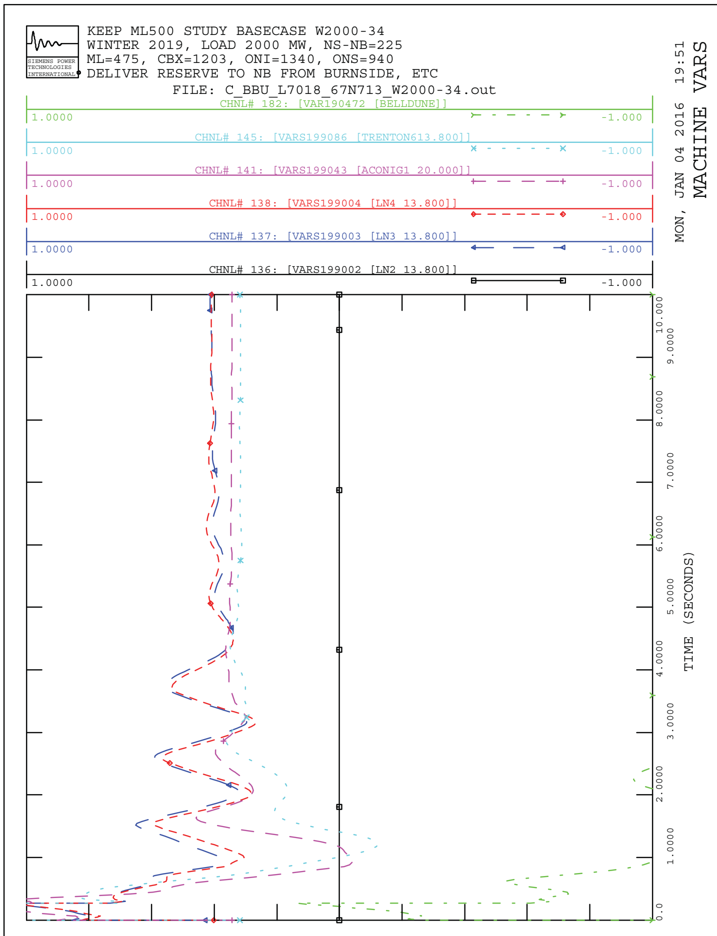
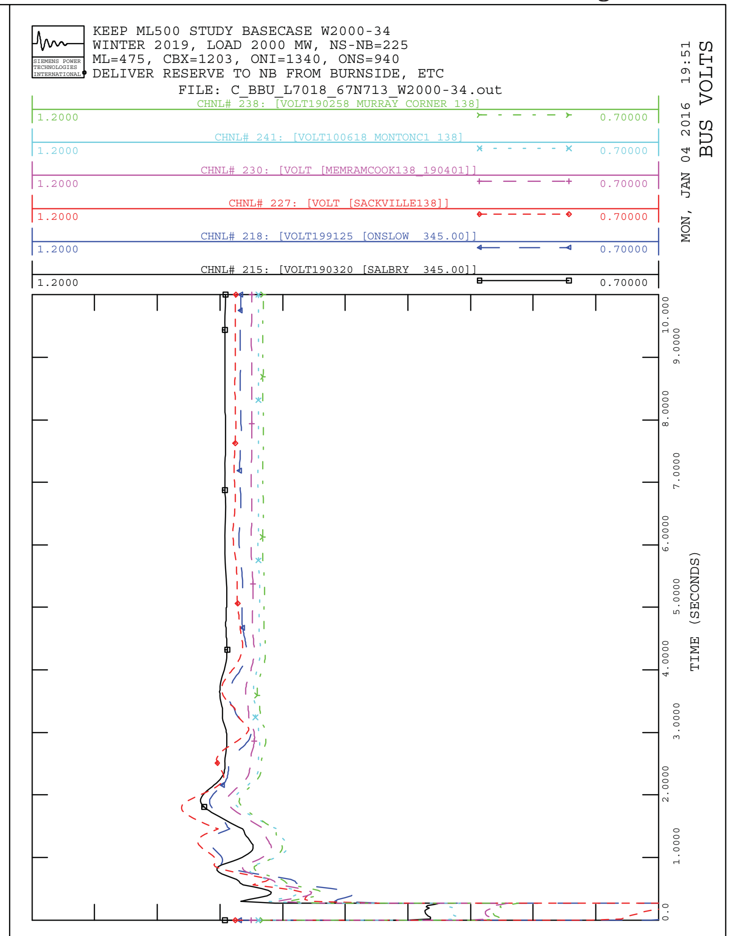
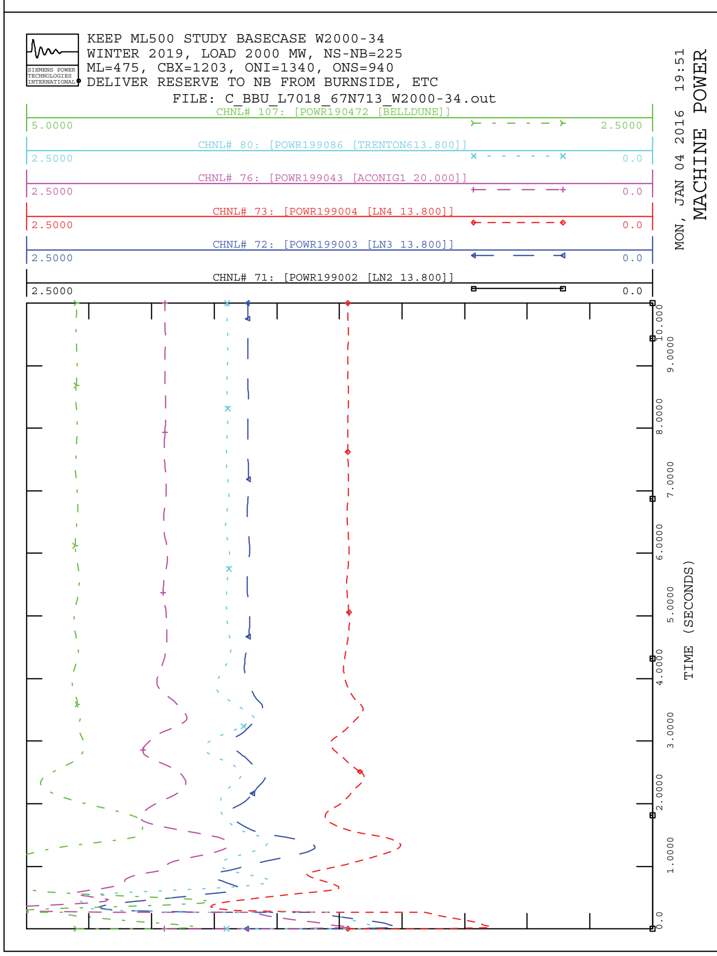
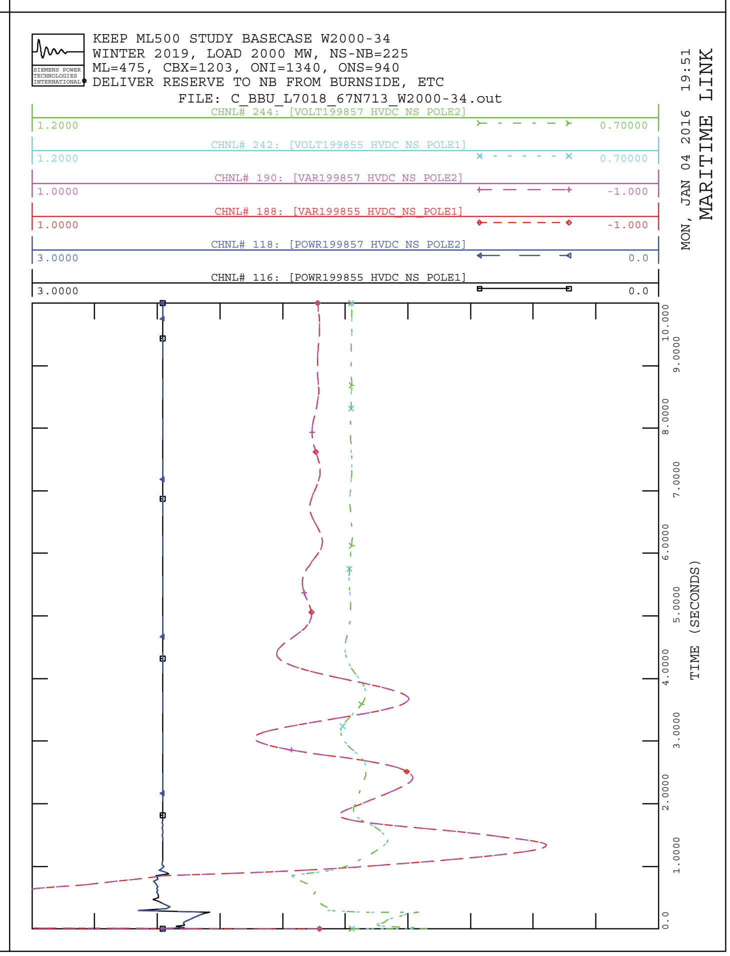
9.0000
10.000

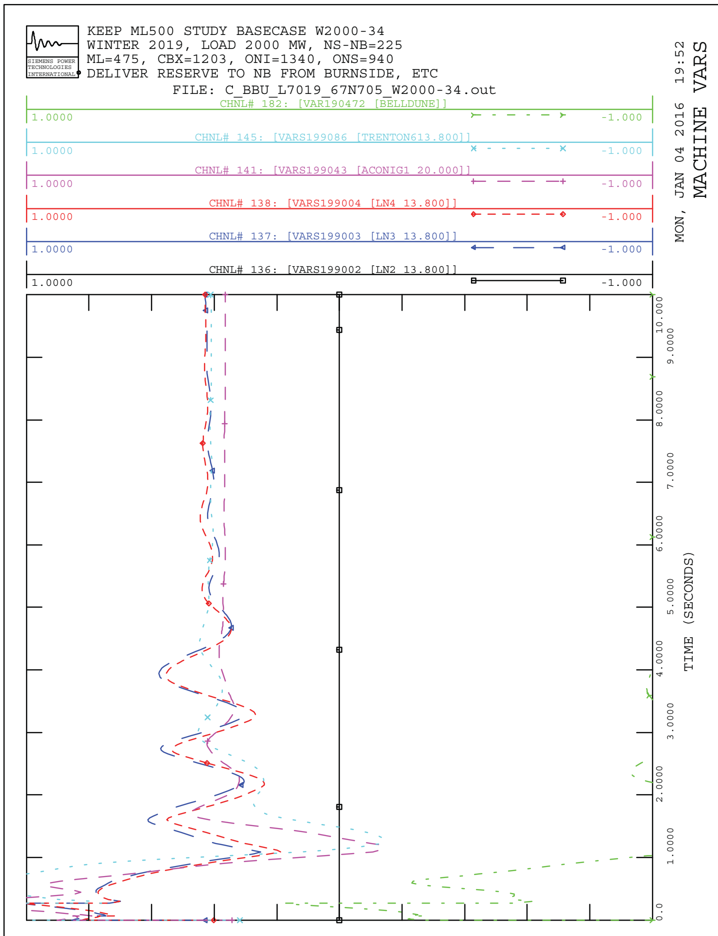
REDACTED (CONFIDENTIAL INFORMATION REMOVED)

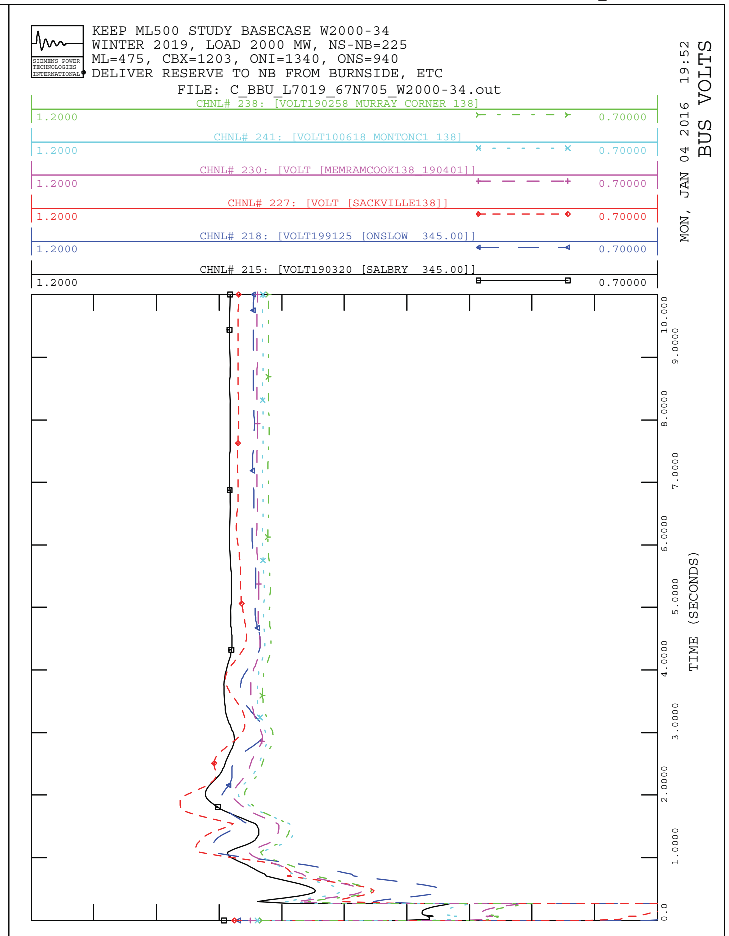


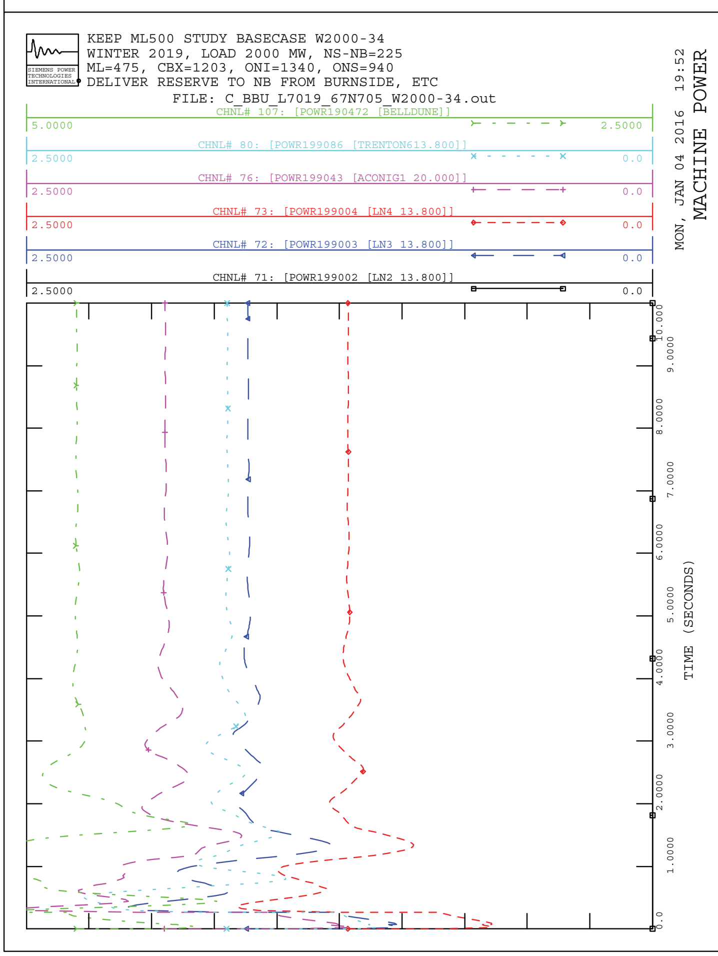


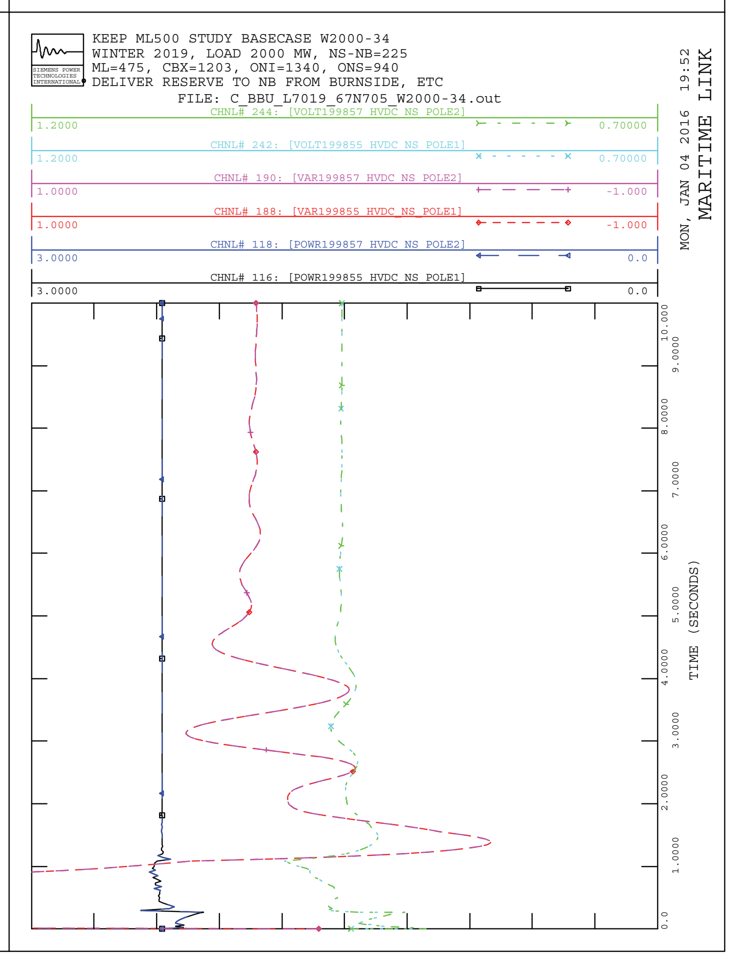




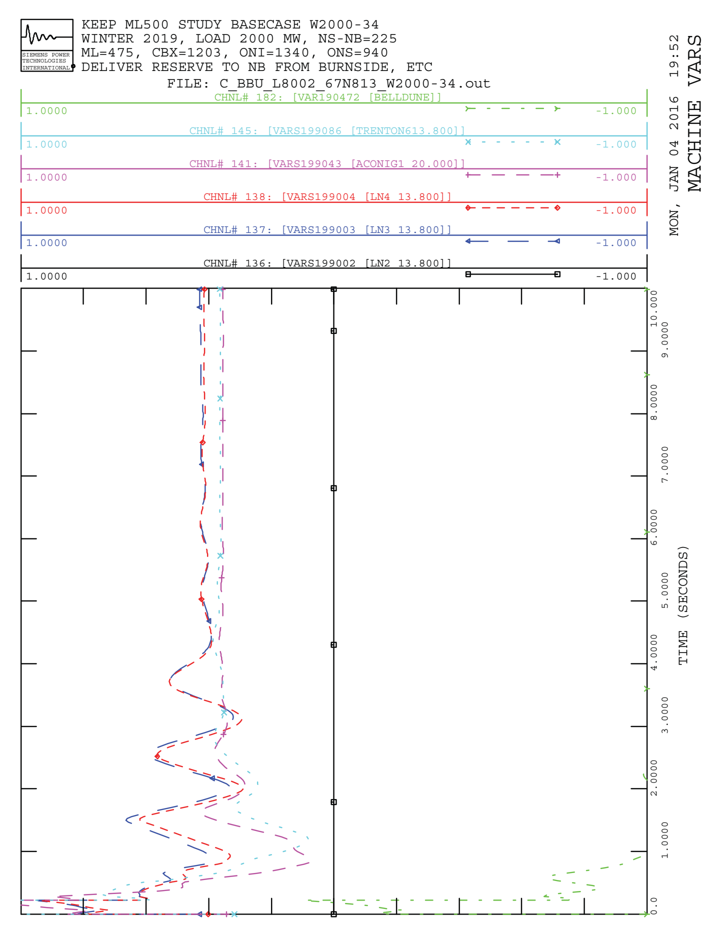

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7019_67N705_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
MON, JAN 04 2016 19:52
MACHINE VARS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000

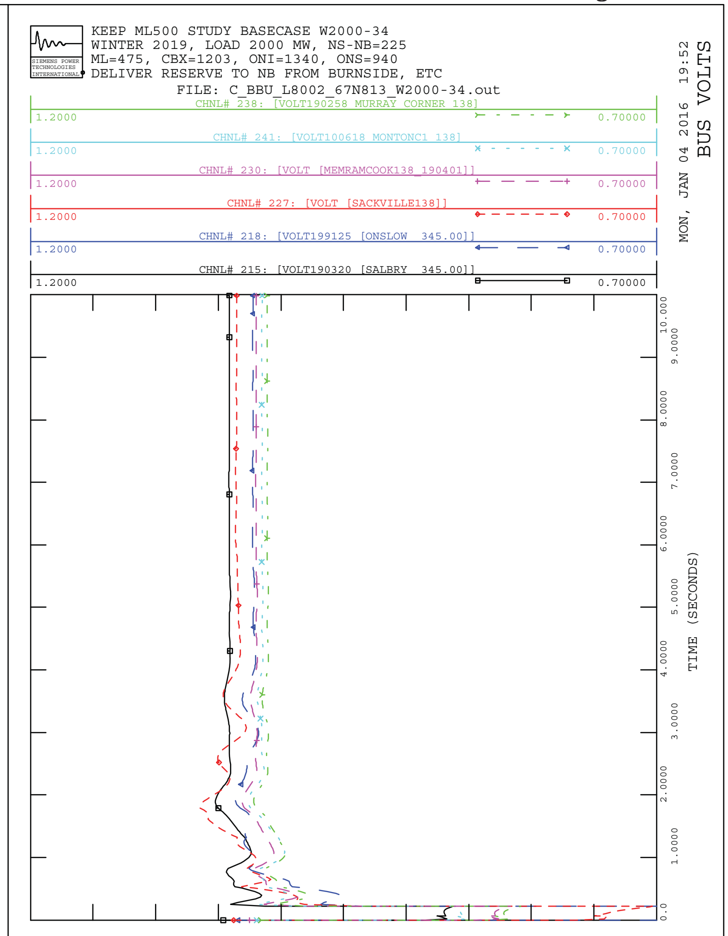

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7019_67N705_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
MON, JAN 04 2016 19:52
BUS VOLTS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000

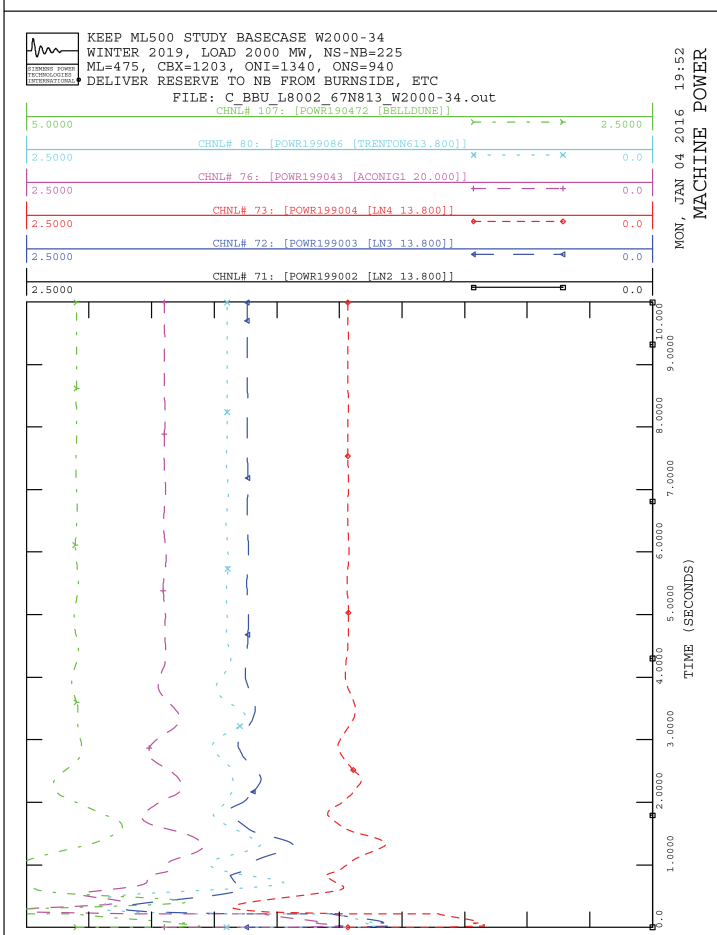

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7019_67N705_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
MON, JAN 04 2016 19:52
MACHINE POWER
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000

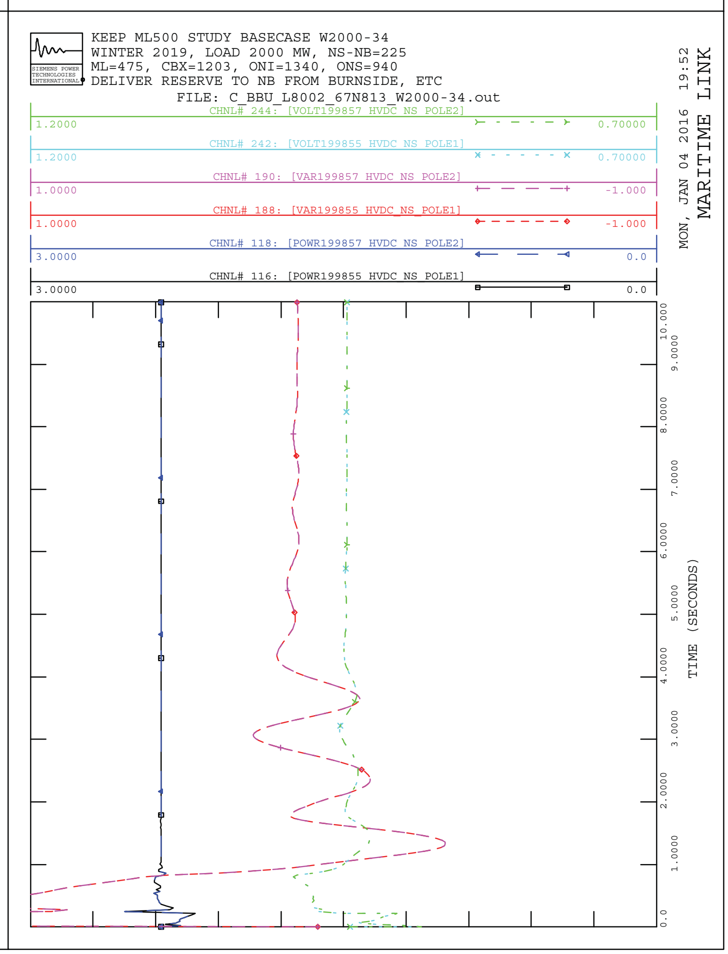

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L7019_67N705_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
MON, JAN 04 2016 19:52
MARITIME LINK
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000

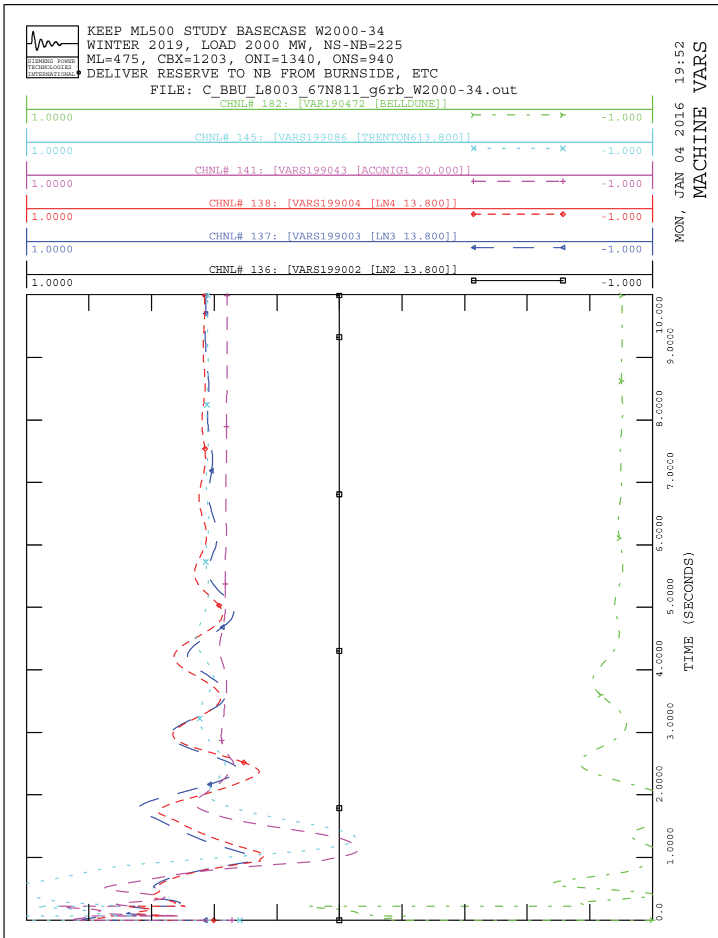
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



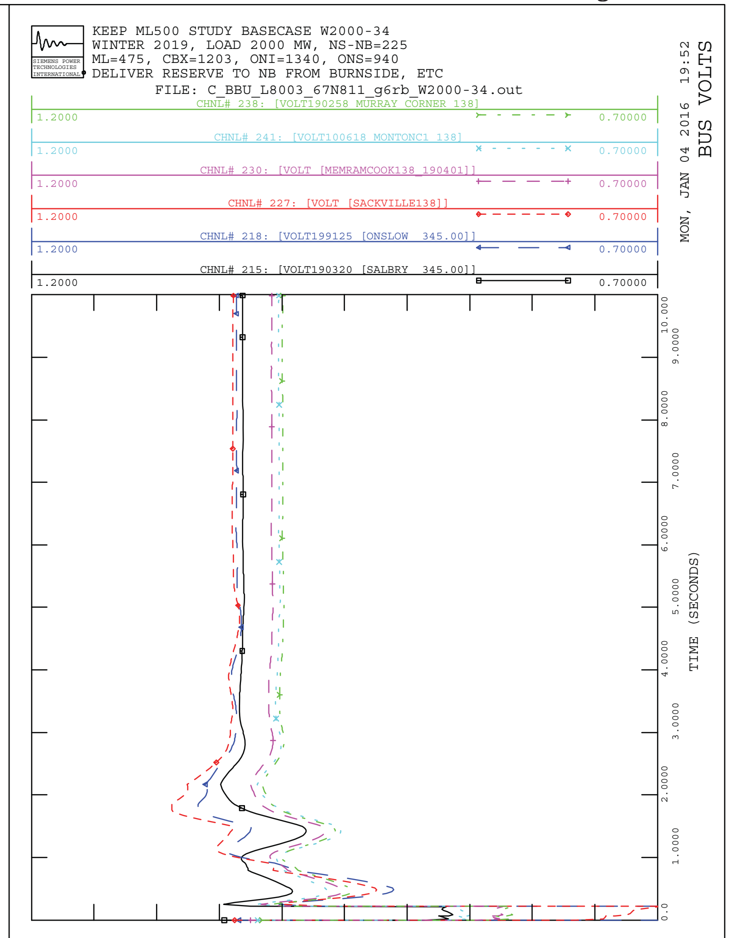




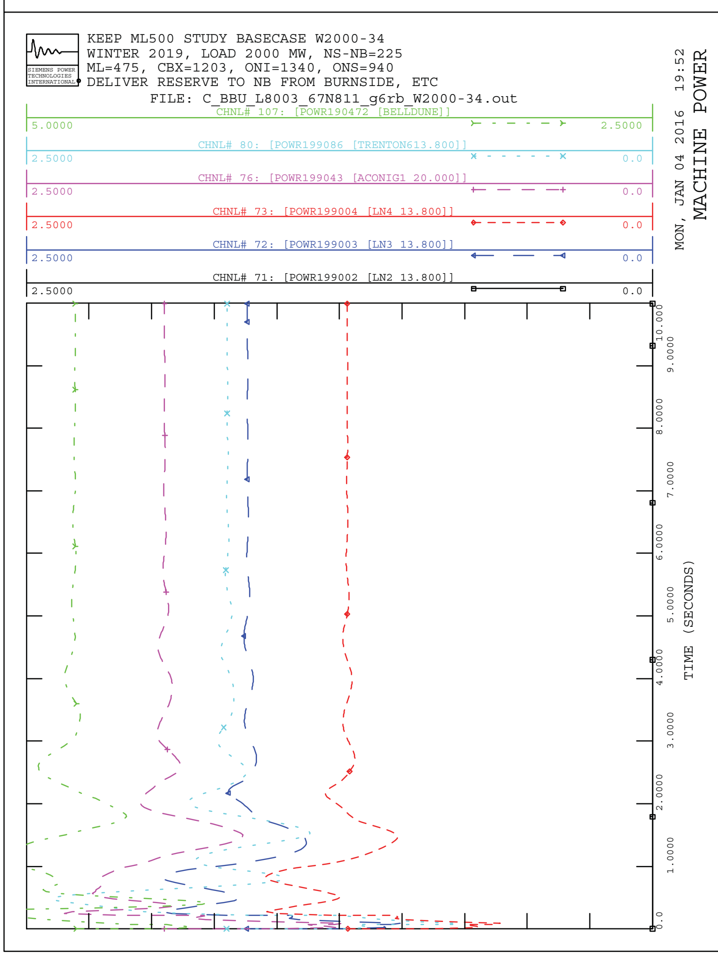




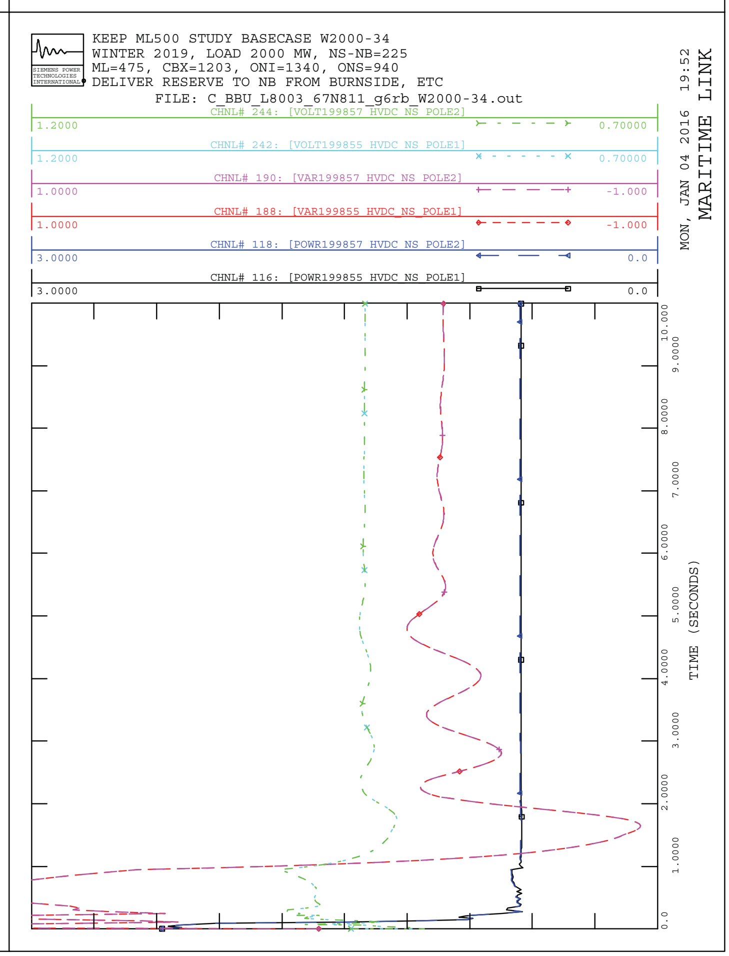
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_67N811_g6rb_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
MON, JAN 04 2016 19:52
MACHINE VARS
TIME (SECONDS)



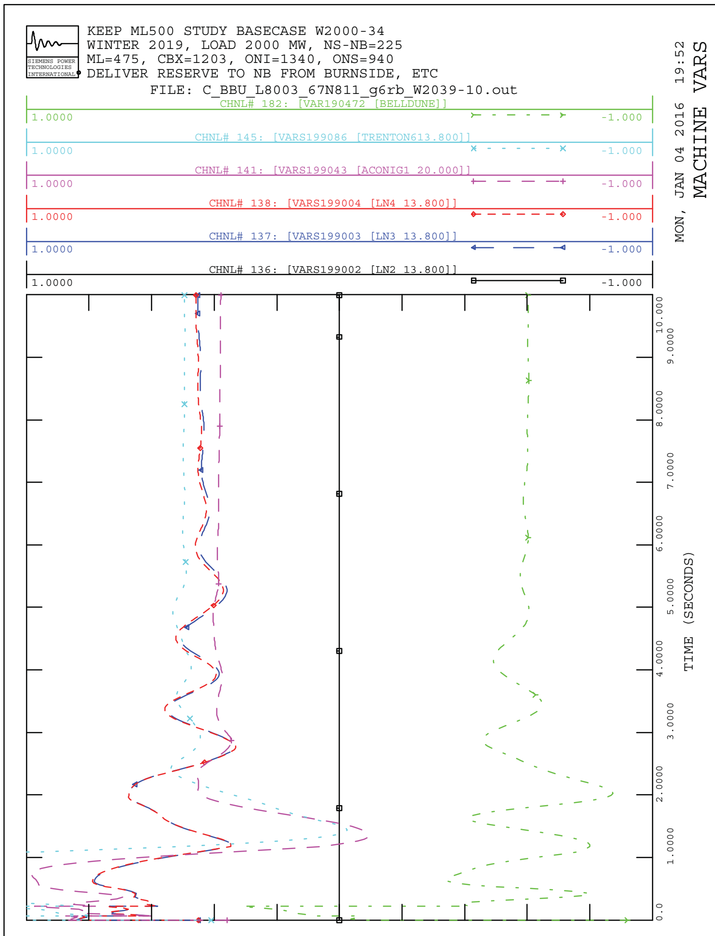
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_67N811_g6rb_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
MON, JAN 04 2016 19:52
BUS VOLTS
TIME (SECONDS)

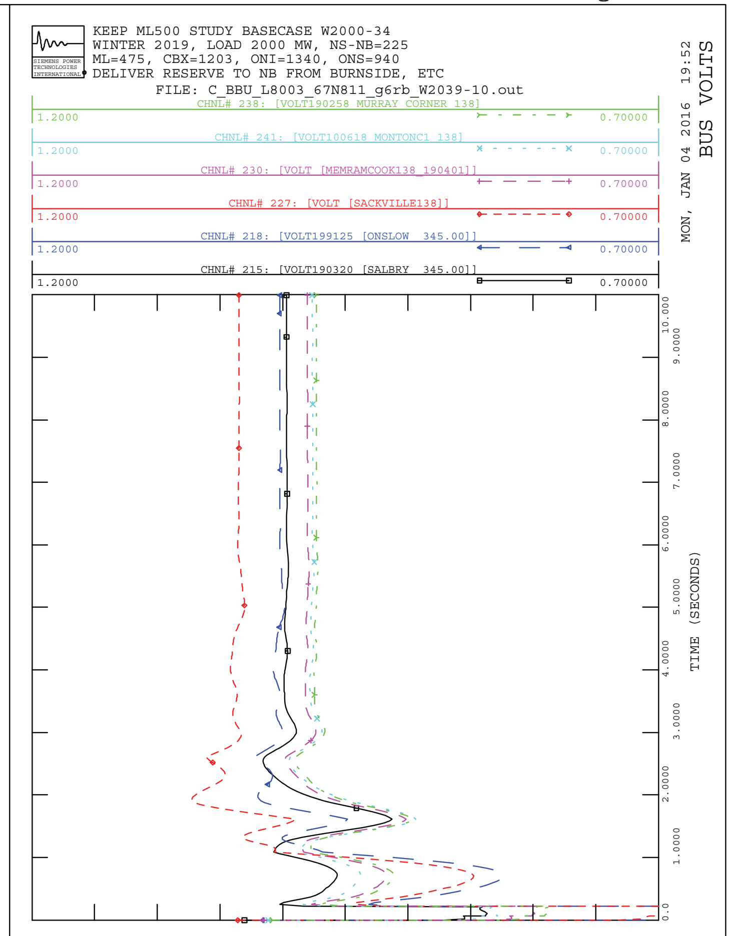


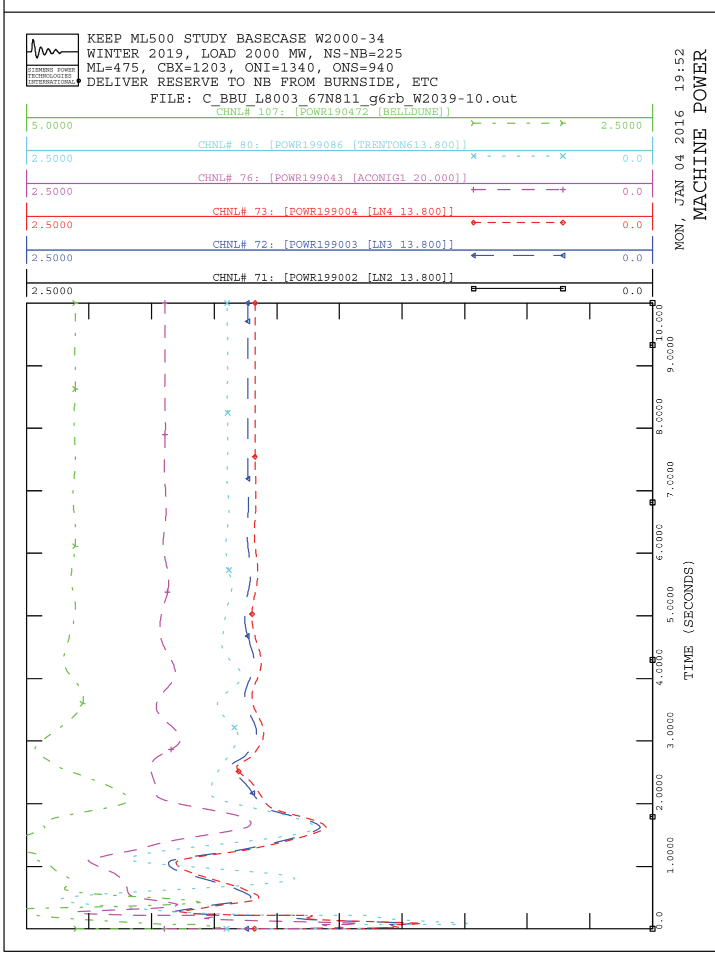
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_67N811_g6rb_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
MON, JAN 04 2016 19:52
MACHINE POWER
TIME (SECONDS)

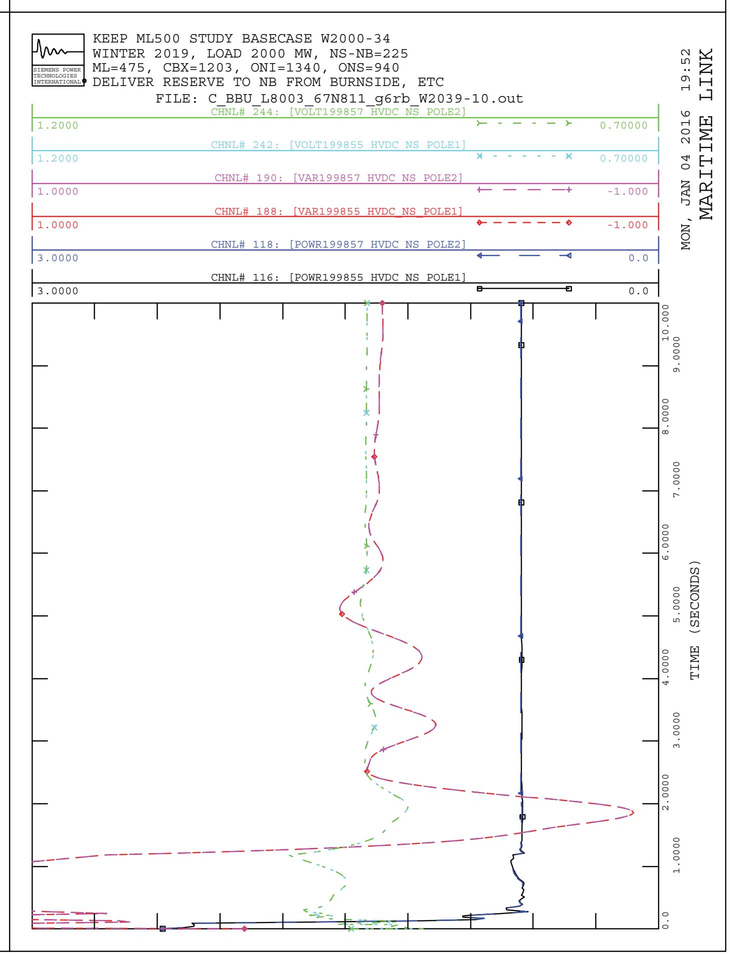


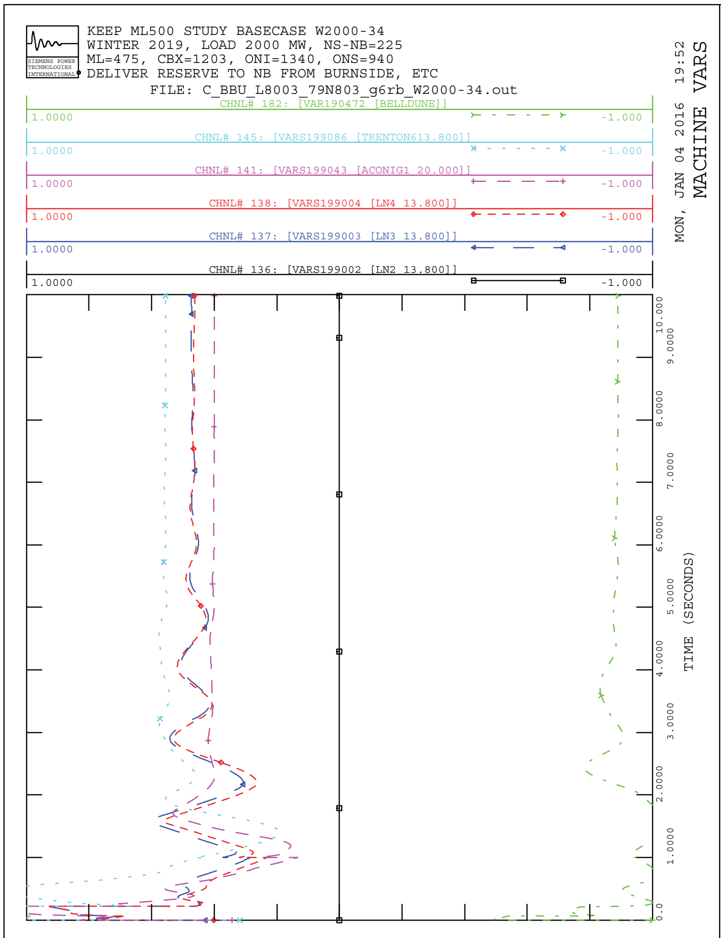
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_67N811_g6rb_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
MON, JAN 04 2016 19:52
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_67N811_g6rb_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
MON, JAN 04 2016 19:52
MACHINE VARS
TIME (SECONDS)

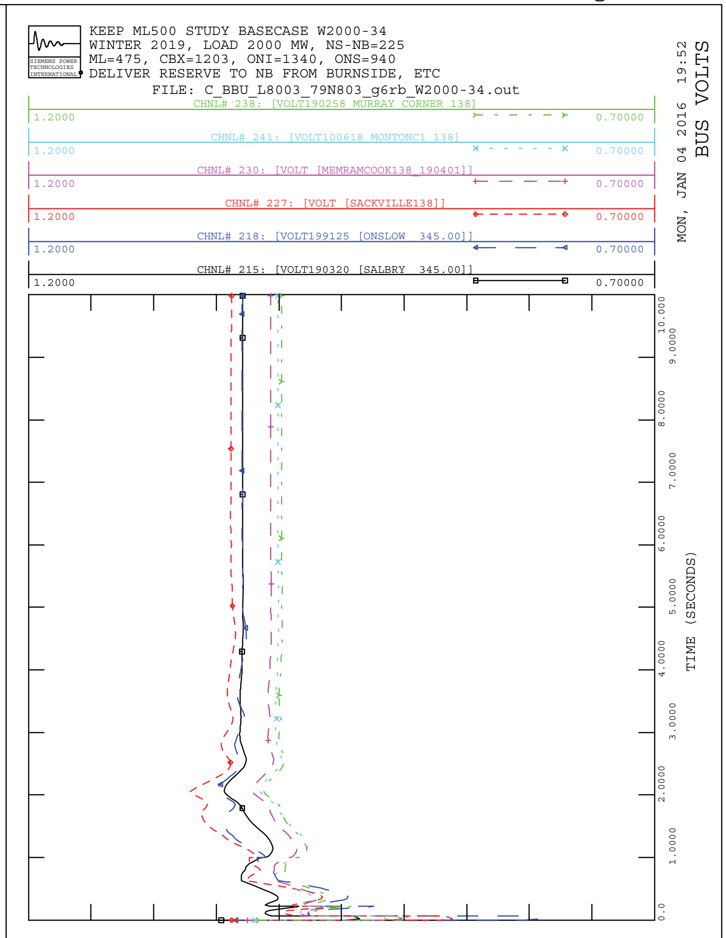

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_67N811_g6rb_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
MON, JAN 04 2016 19:52
BUS VOLTS
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_67N811_g6rb_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
MON, JAN 04 2016 19:52
MACHINE POWER
TIME (SECONDS)

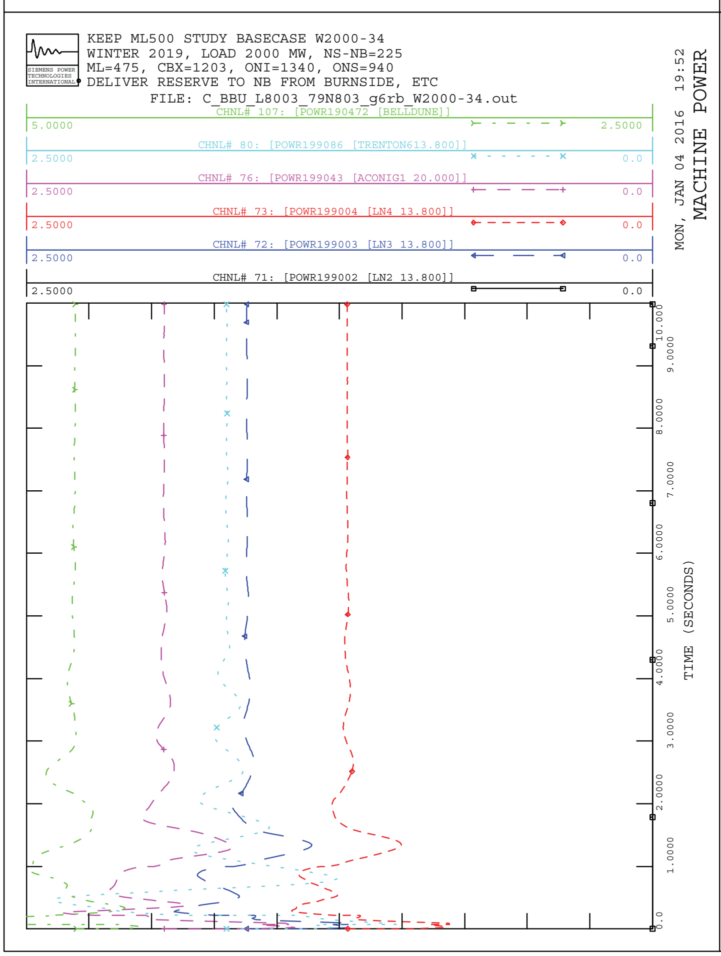

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_67N811_g6rb_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
MON, JAN 04 2016 19:52
MARITIME LINK
TIME (SECONDS)



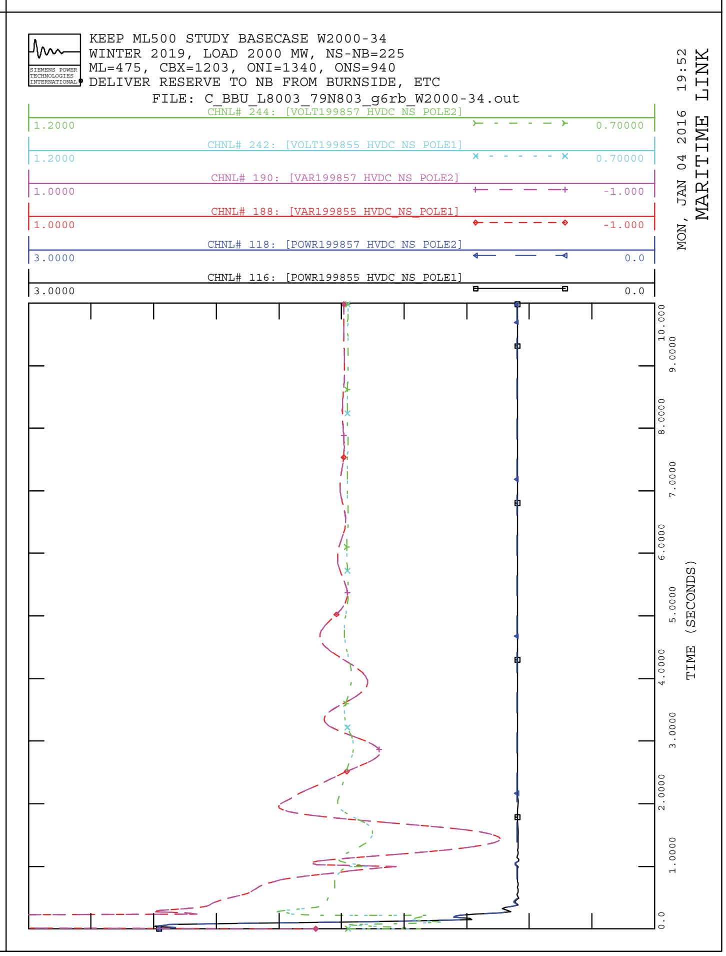
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_79N803_g6rb_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
MON, JAN 04 2016 19:52
MACHINE VARS
TIME (SECONDS)



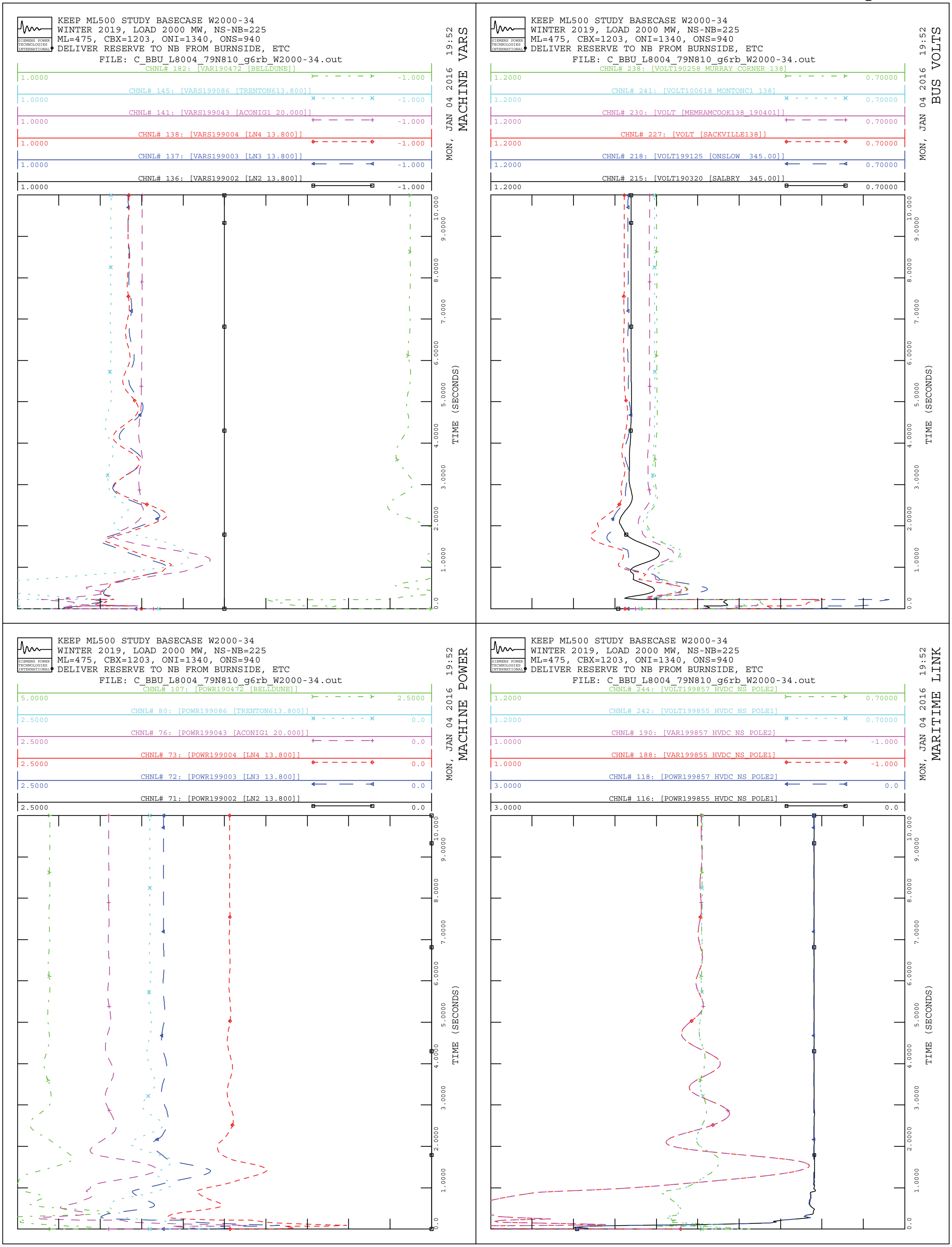
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_79N803_g6rb_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
MON, JAN 04 2016 19:52
BUS VOLTS
TIME (SECONDS)

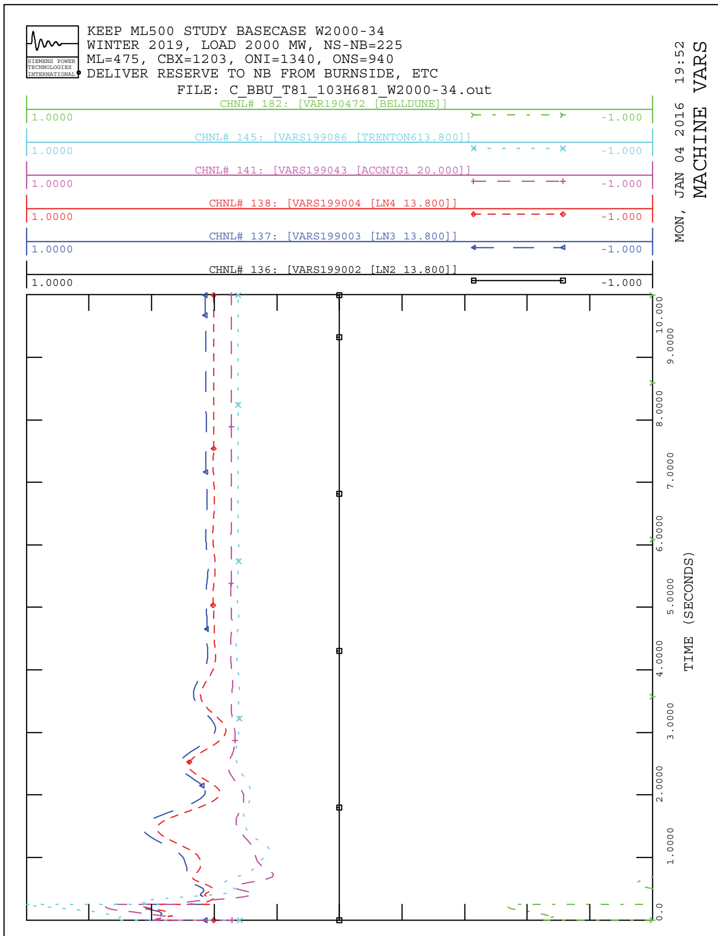


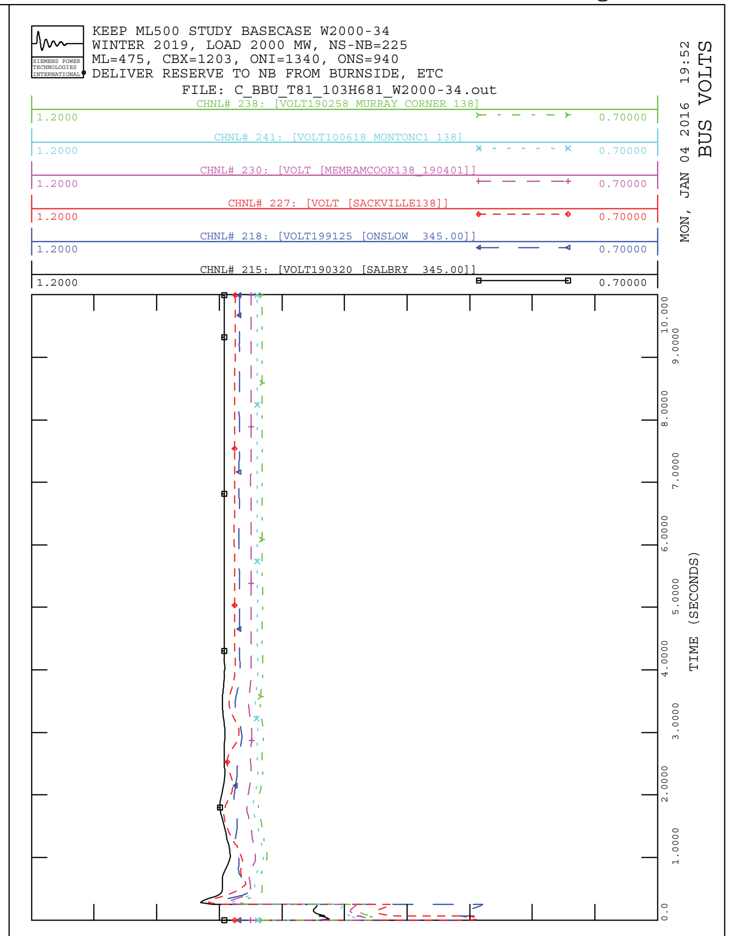
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_79N803_g6rb_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
MON, JAN 04 2016 19:52
MACHINE POWER
TIME (SECONDS)

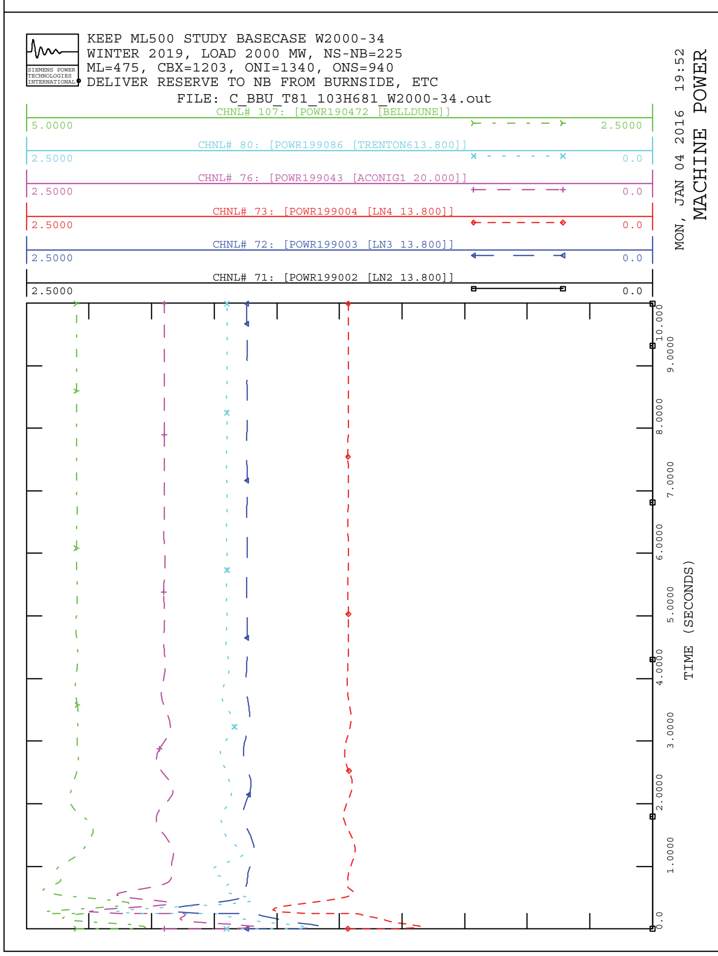


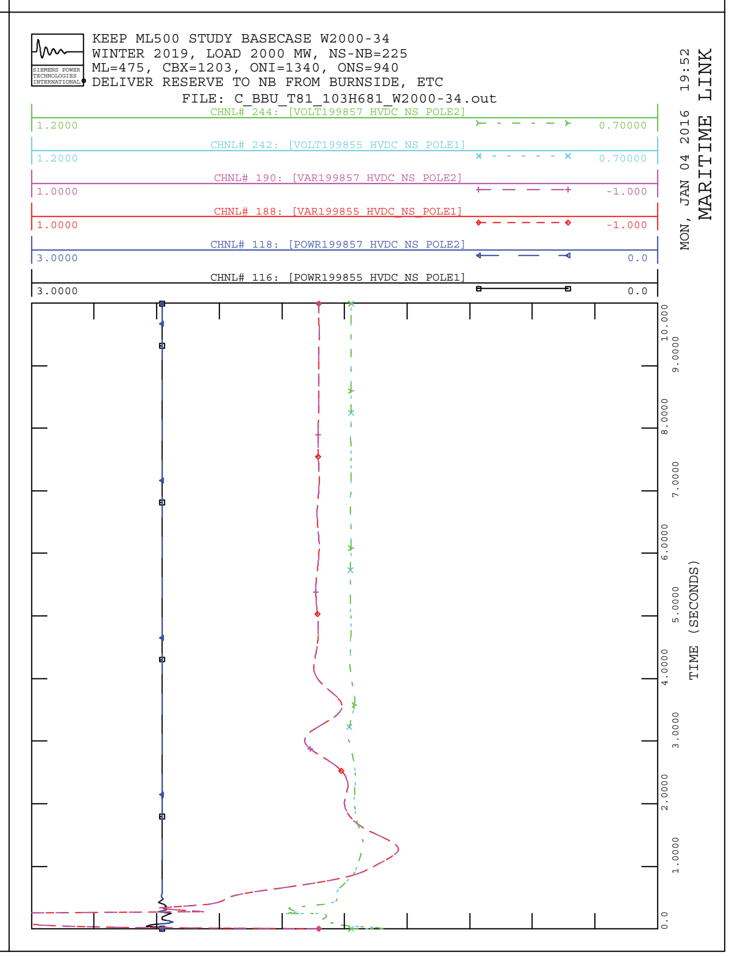
KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8003_79N803_g6rb_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
MON, JAN 04 2016 19:52
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_L8004_79N810_g6rb_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
MON, JAN 04 2016 19:52
MACHINE VARS
TIME (SECONDS)
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
BUS VOLTS
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
MACHINE POWER
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
MARITIME LINK

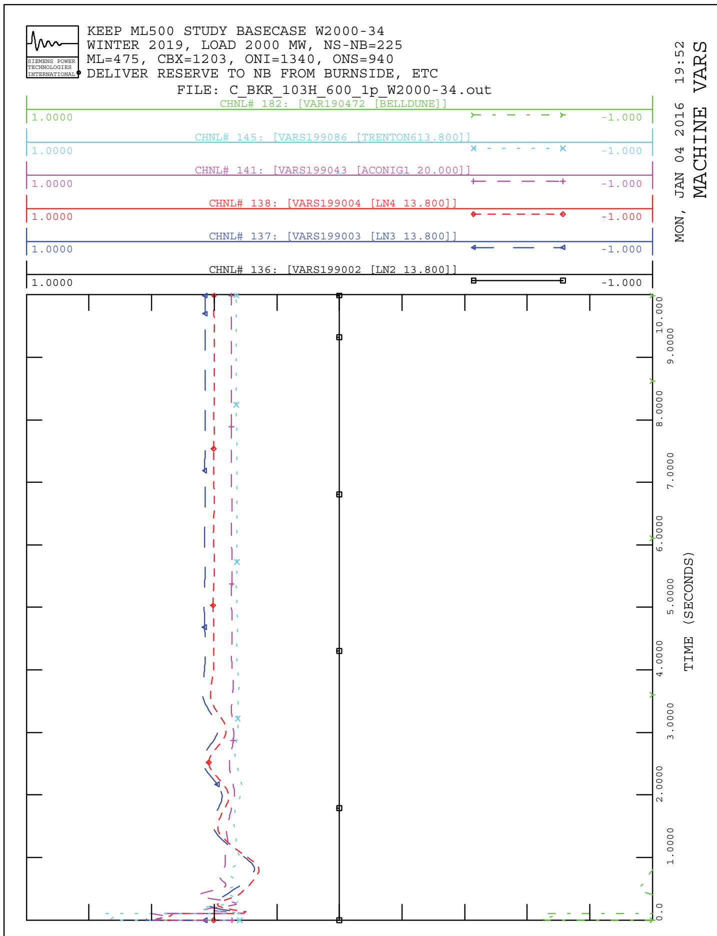

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_T81_103H681_W2000-34.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
MON, JAN 04 2016 19:52
MACHINE VARS
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

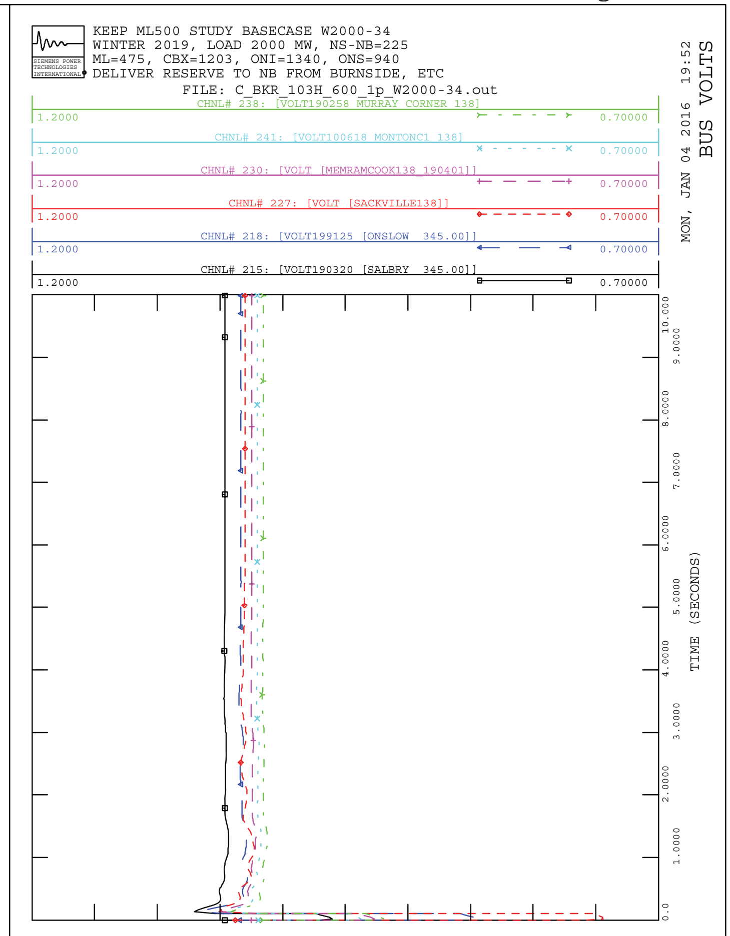

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_T81_103H681_W2000-34.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
MON, JAN 04 2016 19:52
BUS VOLTS
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

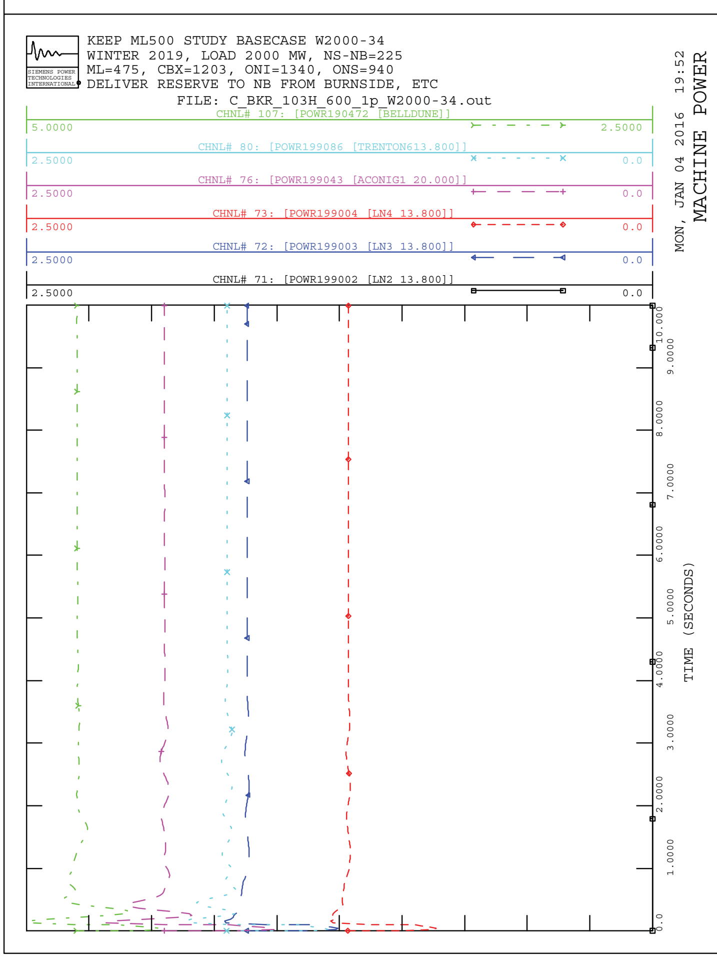

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_T81_103H681_W2000-34.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
MON, JAN 04 2016 19:52
MACHINE POWER
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

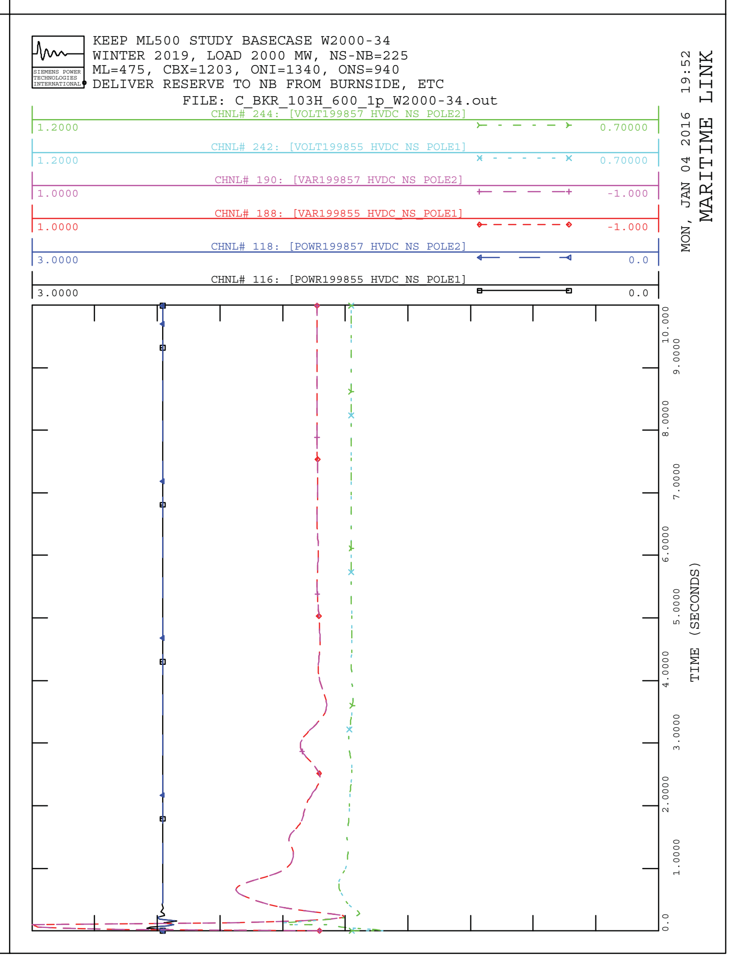

KEEP ML500 STUDY BASECASE W2000-34
WINTER 2019, LOAD 2000 MW, NS-NB=225
ML=475, CBX=1203, ONI=1340, ONS=940
DELIVER RESERVE TO NB FROM BURNSIDE, ETC
FILE: C_BBU_T81_103H681_W2000-34.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
MON, JAN 04 2016 19:52
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

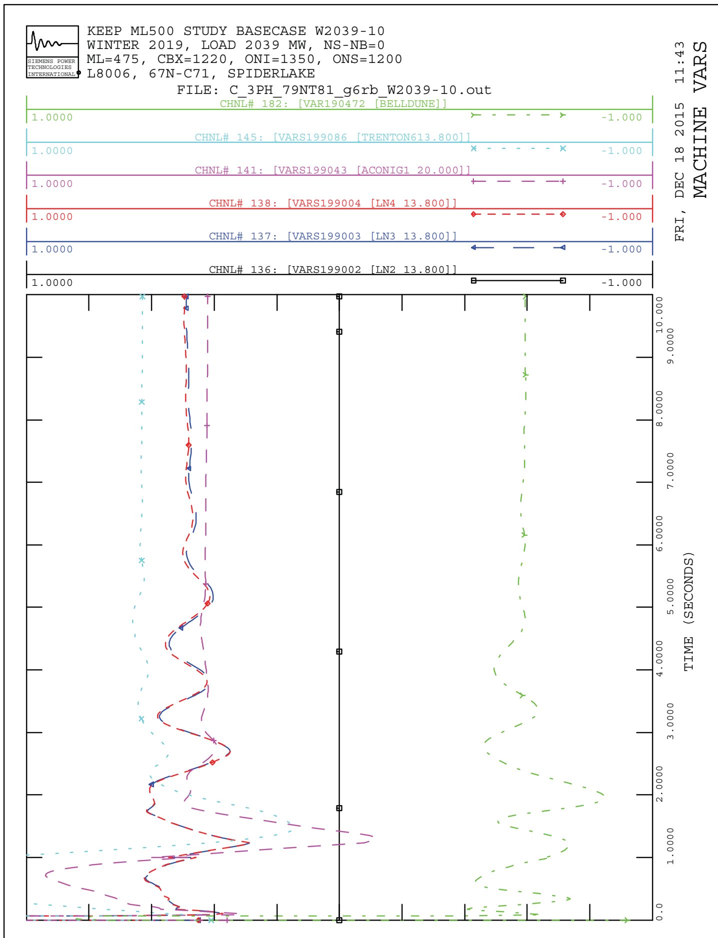
REDACTED (CONFIDENTIAL INFORMATION REMOVED)

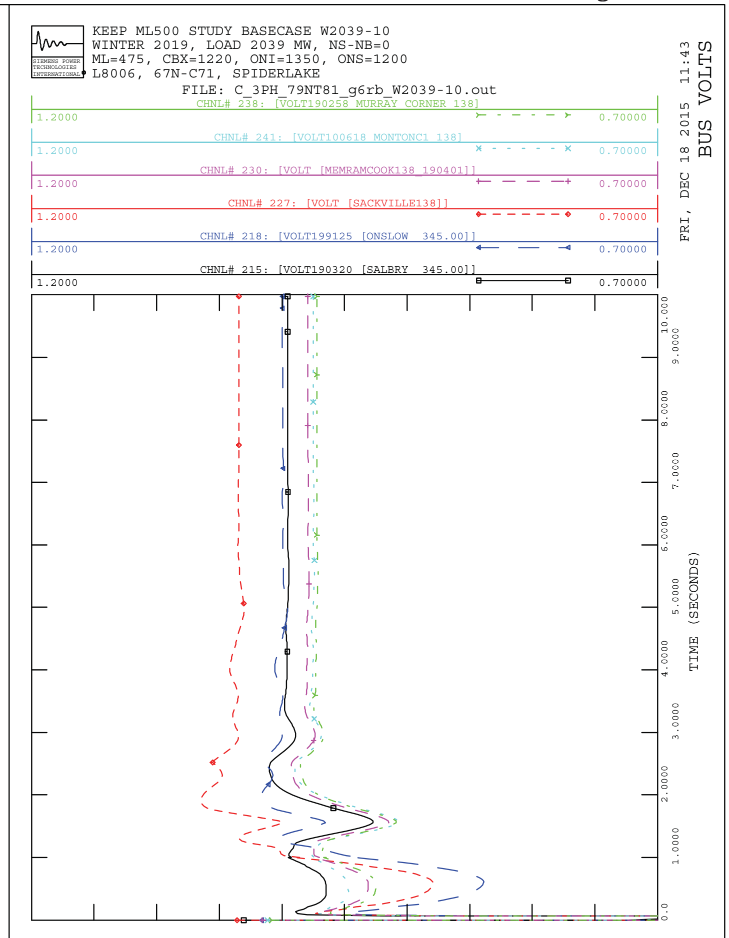


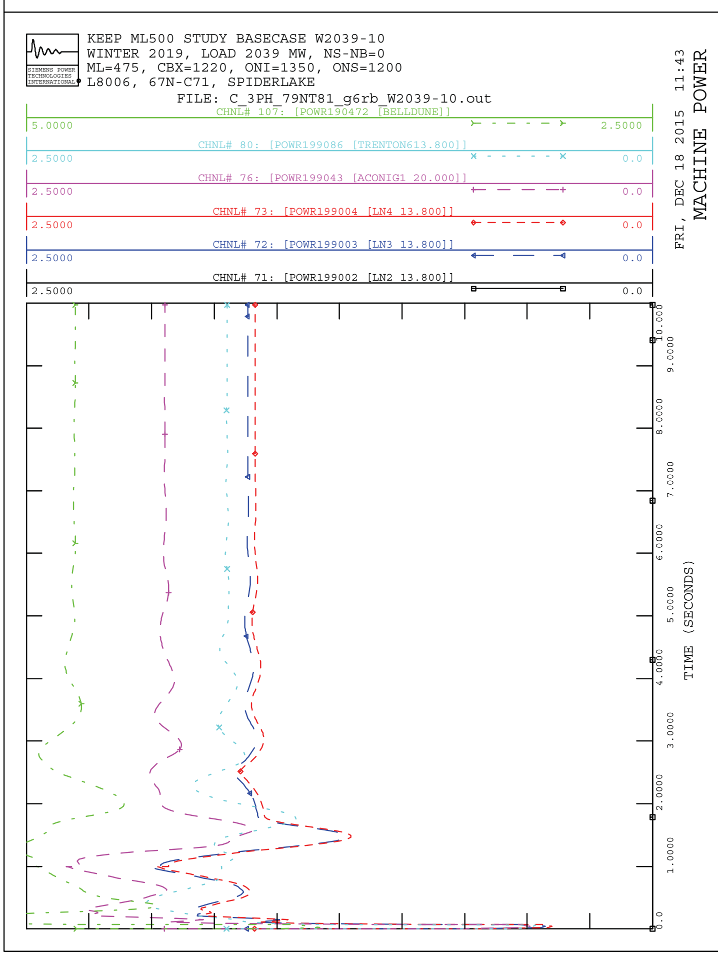


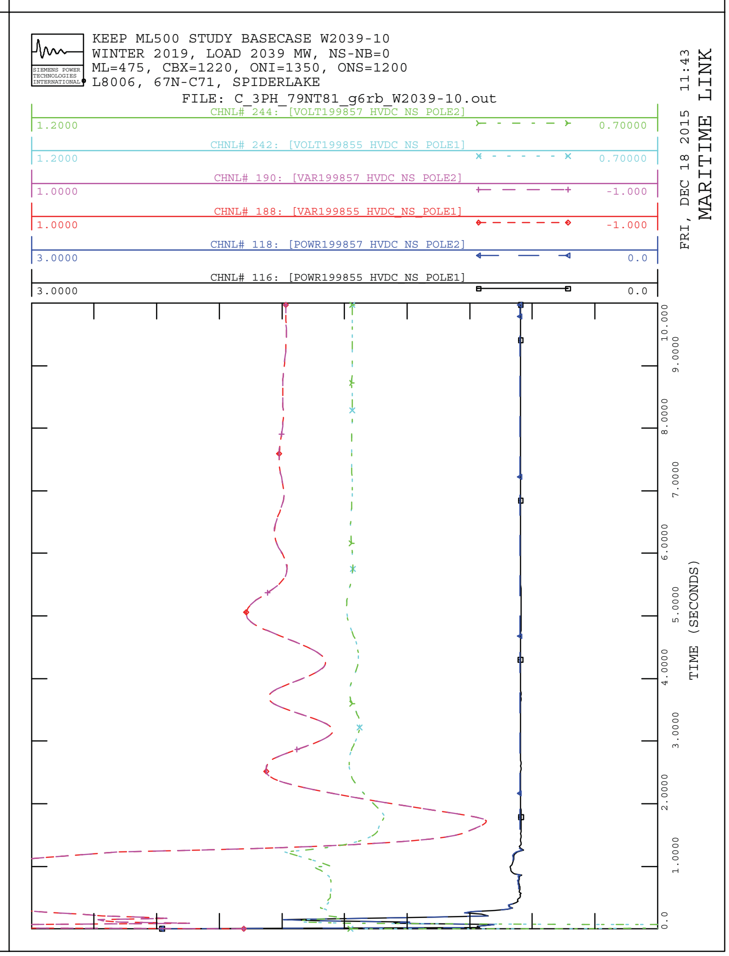


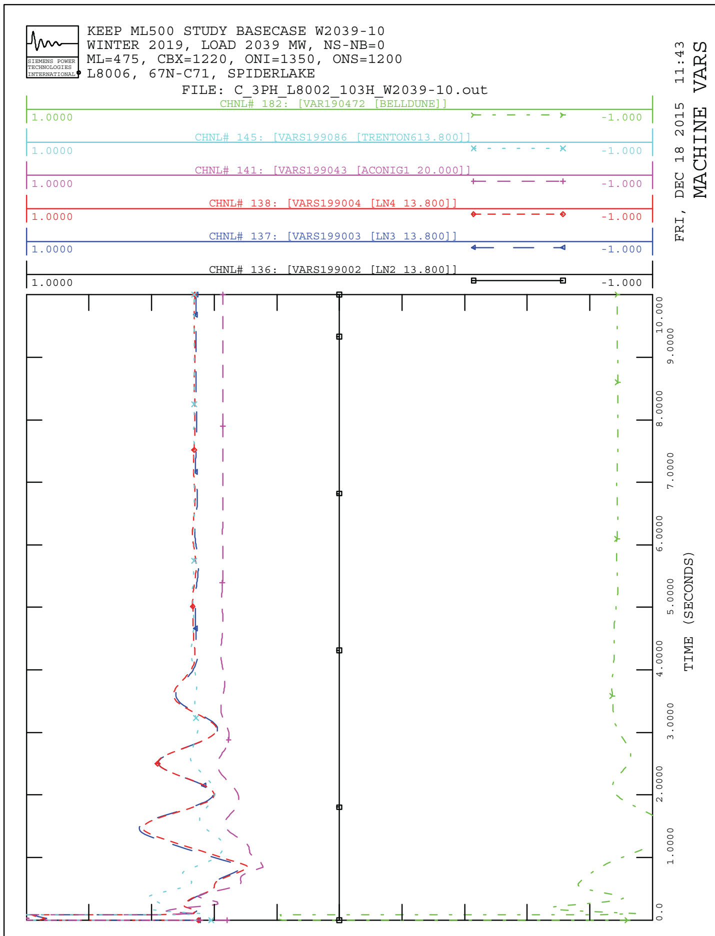


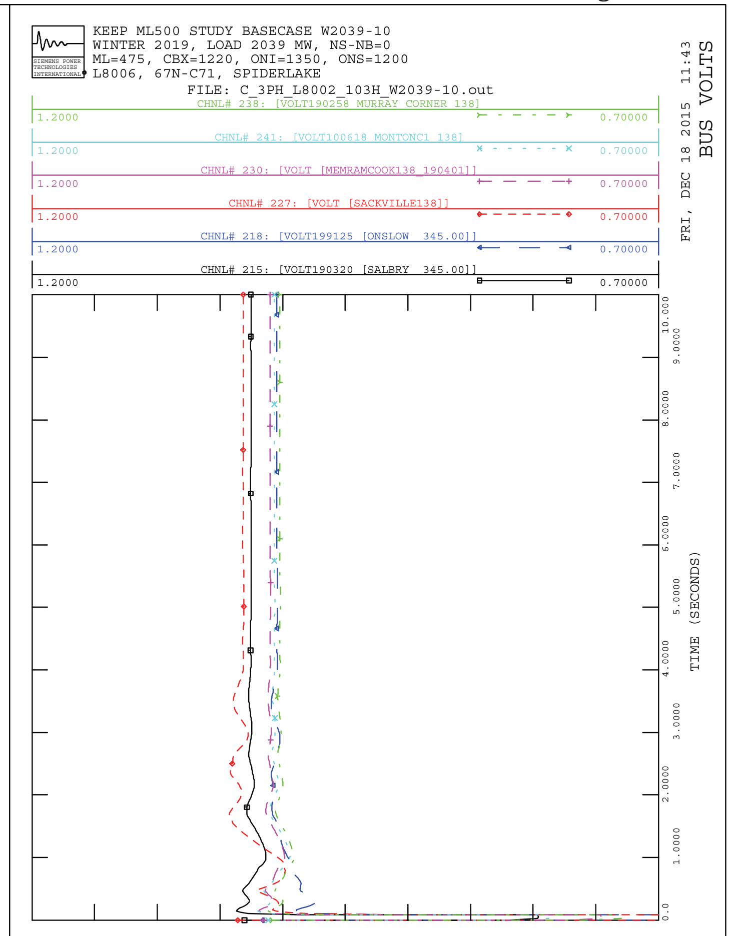

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_79NT81_g6rb_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
TIME (SECONDS)
FRI, DEC 18 2015 11:43
MACHINE VARS

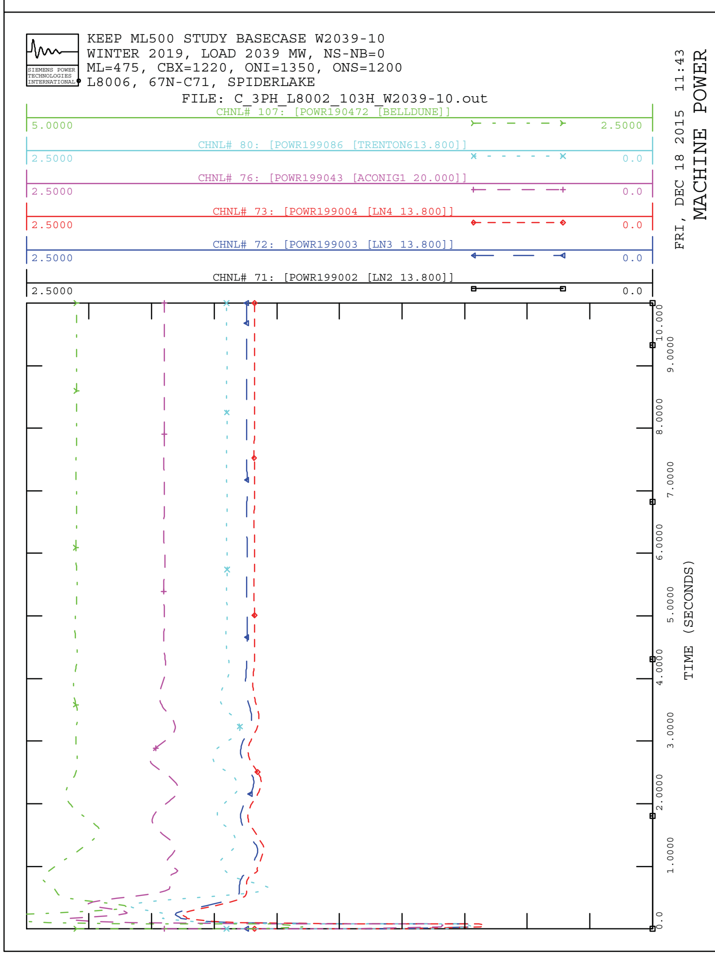

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_79NT81_g6rb_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
TIME (SECONDS)
FRI, DEC 18 2015 11:43
BUS VOLTS

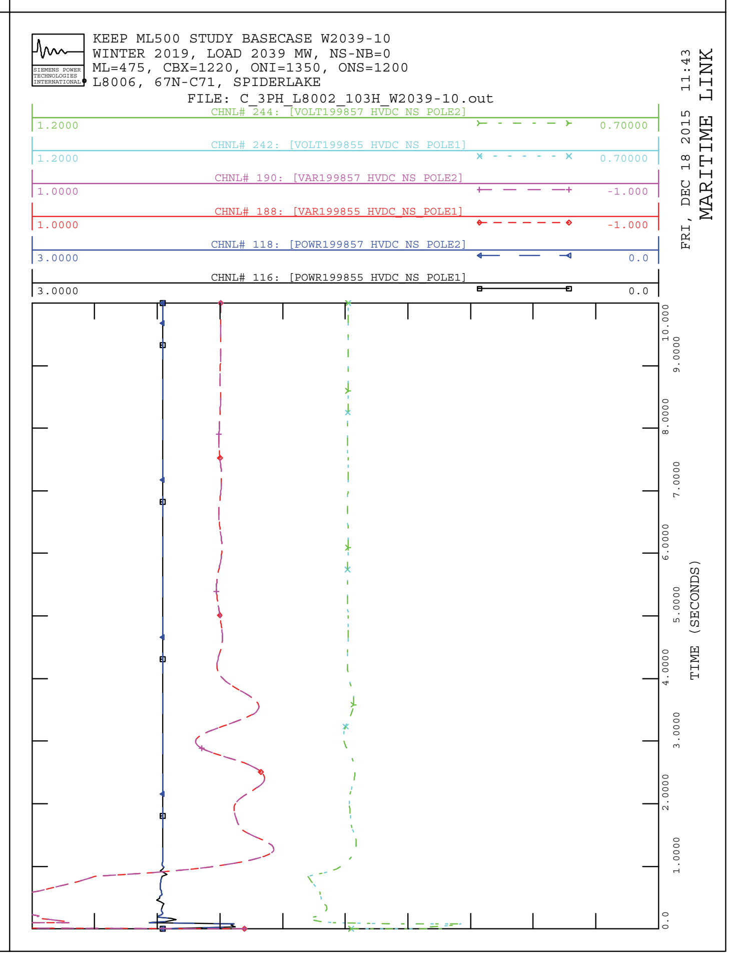

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_79NT81_g6rb_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
TIME (SECONDS)
FRI, DEC 18 2015 11:43
MACHINE POWER

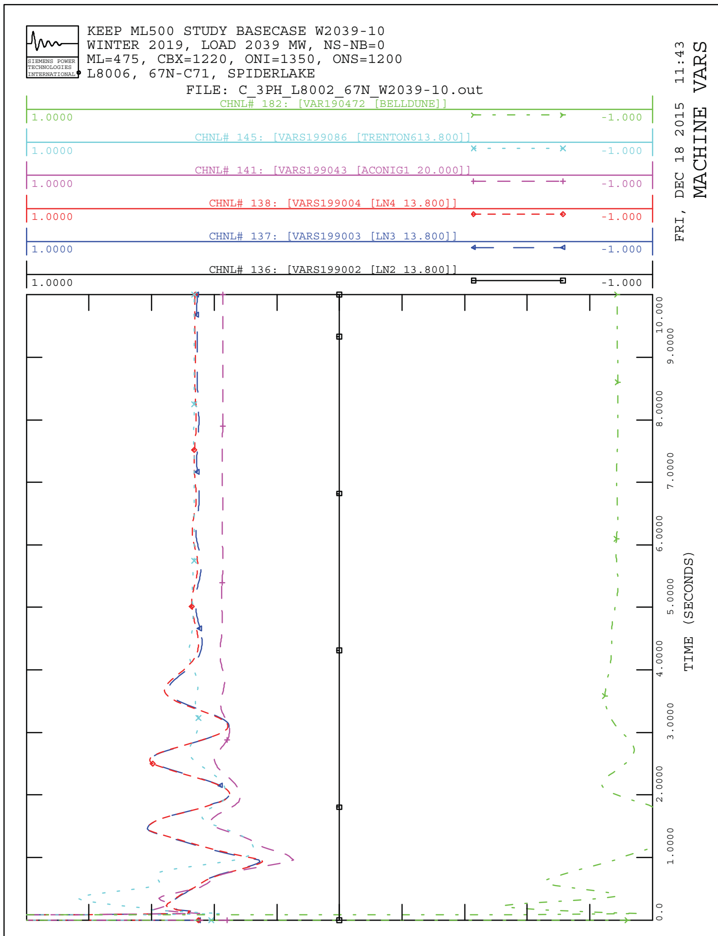

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_79NT81_g6rb_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
TIME (SECONDS)
FRI, DEC 18 2015 11:43
MARITIME LINK

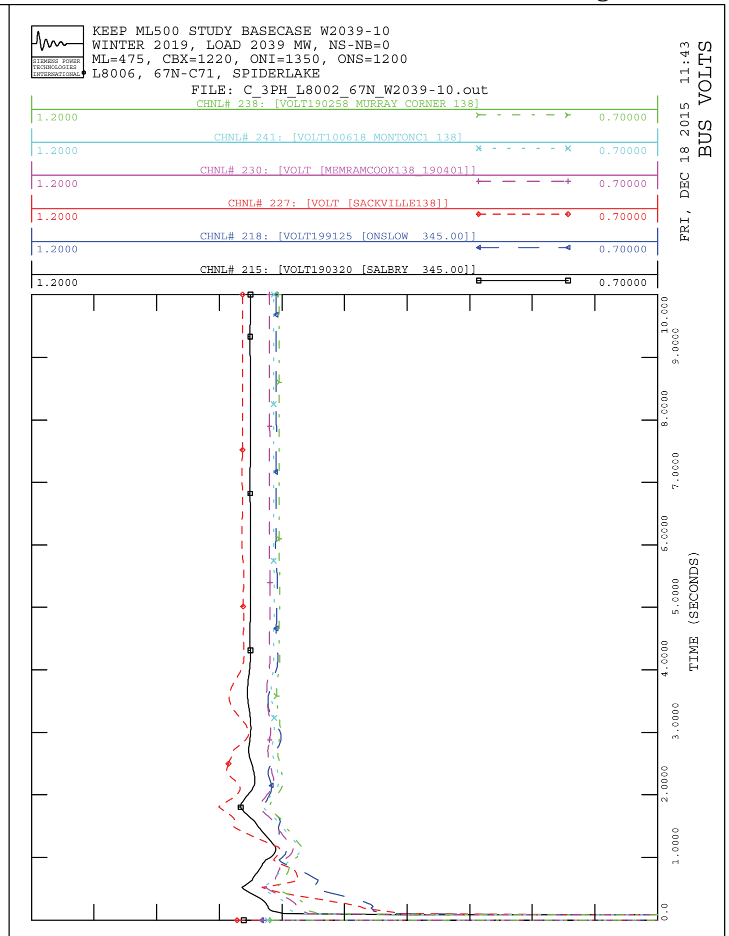

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8002_103H_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
FRI, DEC 18 2015 11:43
MACHINE VARS
TIME (SECONDS)

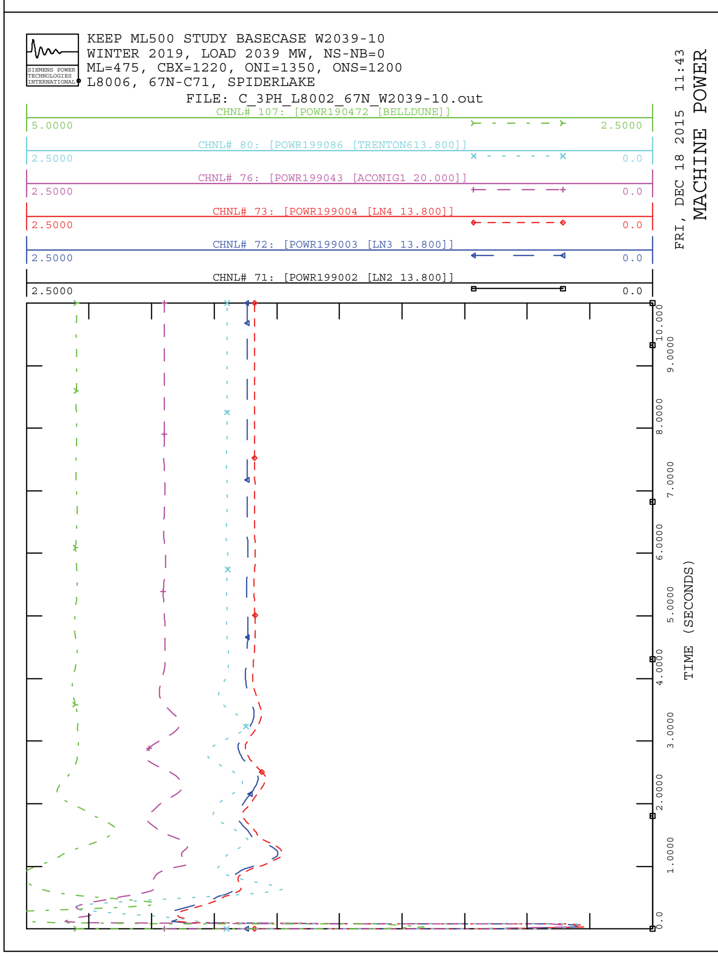

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8002_103H_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
FRI, DEC 18 2015 11:43
BUS VOLTS
TIME (SECONDS)

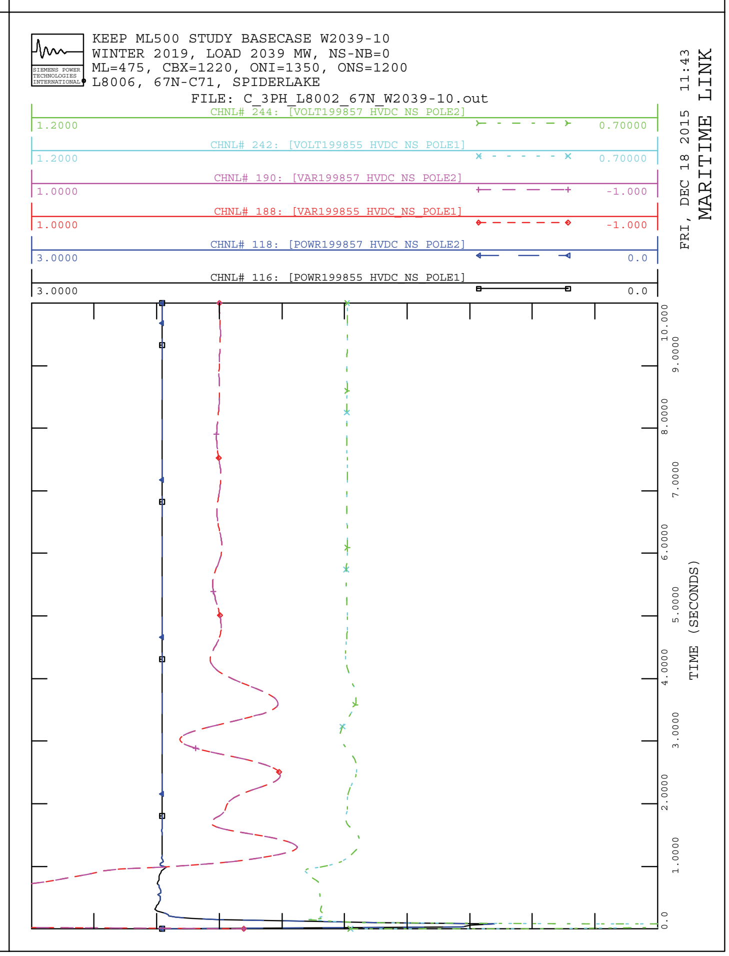

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8002_103H_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
FRI, DEC 18 2015 11:43
MACHINE POWER
TIME (SECONDS)

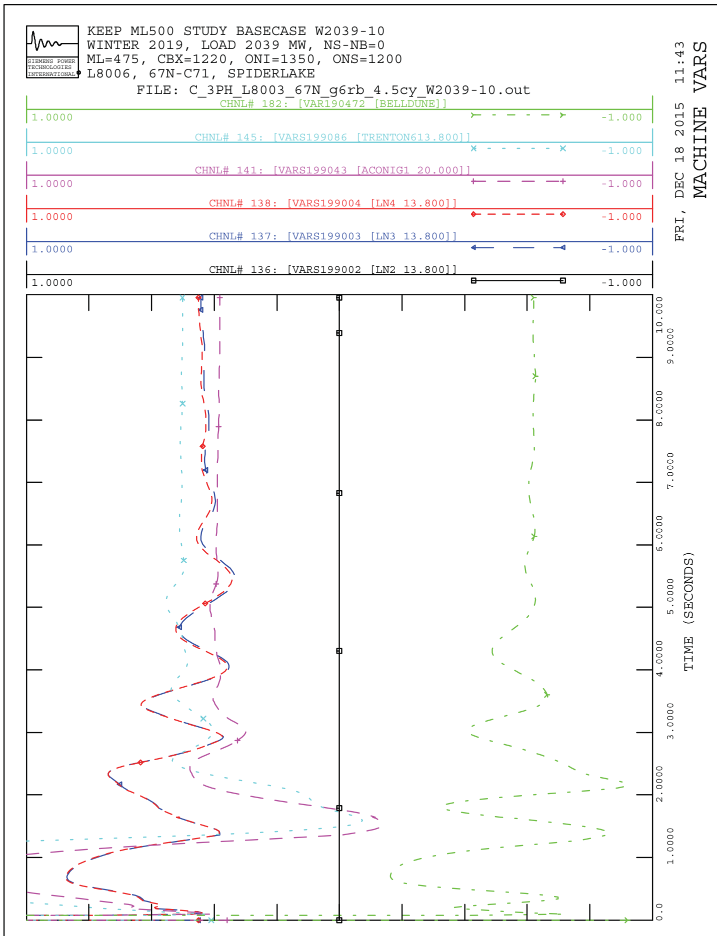

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8002_103H_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
FRI, DEC 18 2015 11:43
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8002_67N_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
TIME (SECONDS)
FRI, DEC 18 2015 11:43
MACHINE VARS

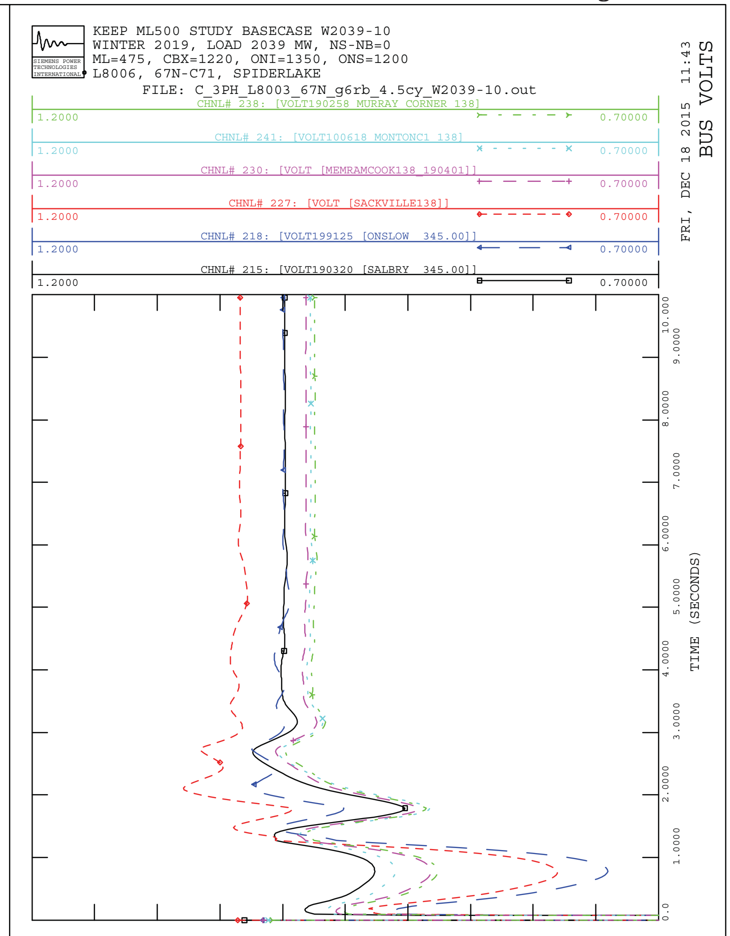

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8002_67N_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
TIME (SECONDS)
FRI, DEC 18 2015 11:43
BUS VOLTS


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8002_67N_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
TIME (SECONDS)
FRI, DEC 18 2015 11:43
MACHINE POWER

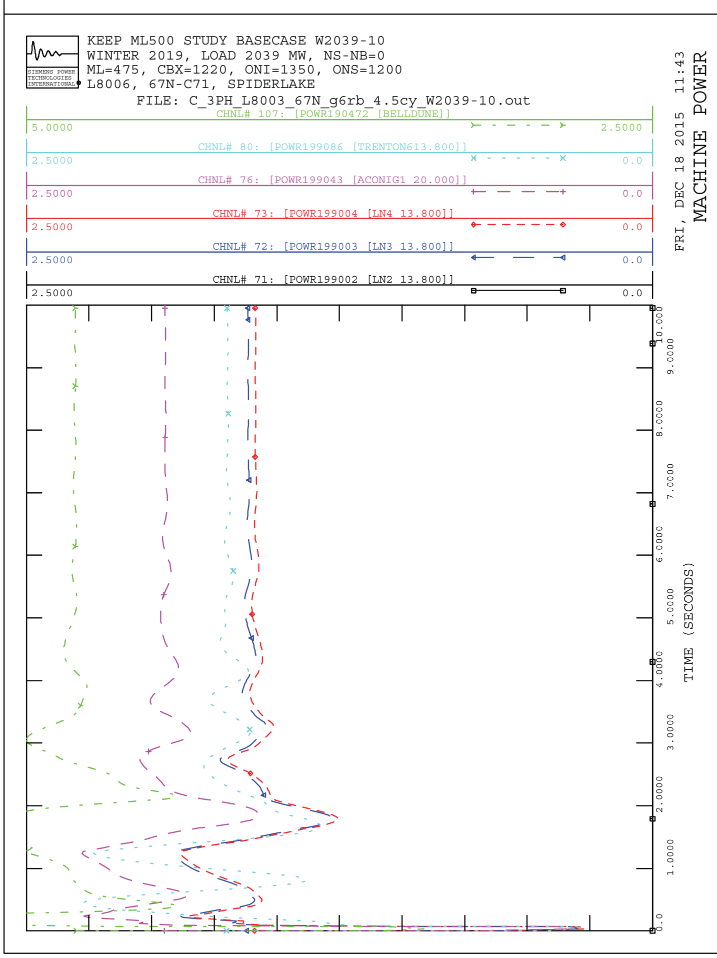

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8002_67N_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
TIME (SECONDS)
FRI, DEC 18 2015 11:43
MARITIME LINK



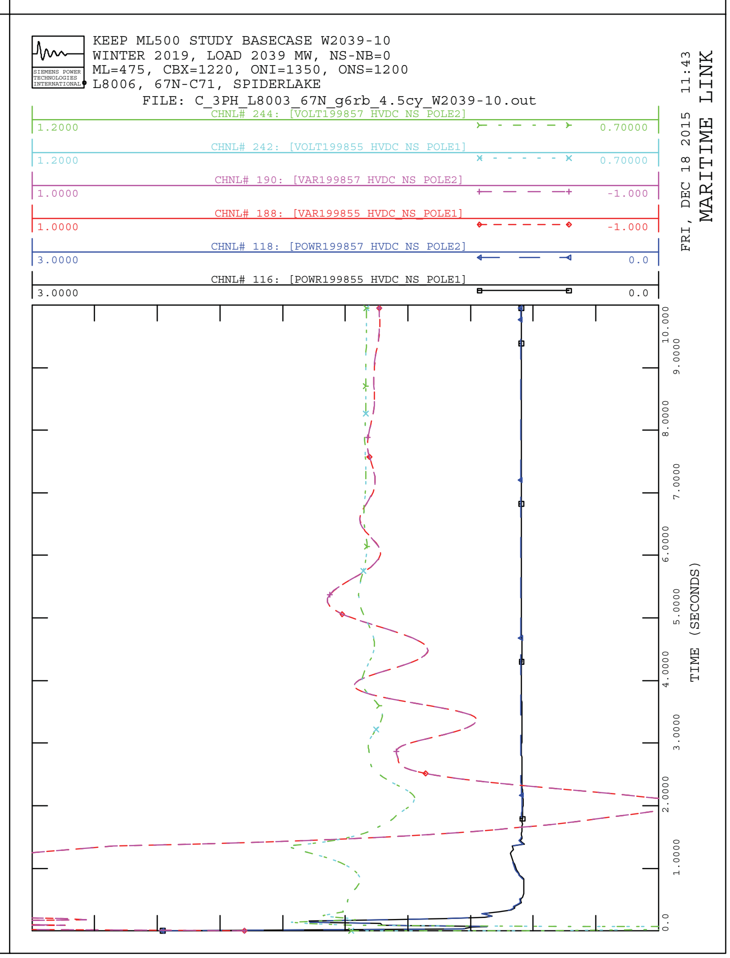
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4.5cy_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
FRI, DEC 18 2015 11:43
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4.5cy_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
FRI, DEC 18 2015 11:43
BUS VOLTS
TIME (SECONDS)

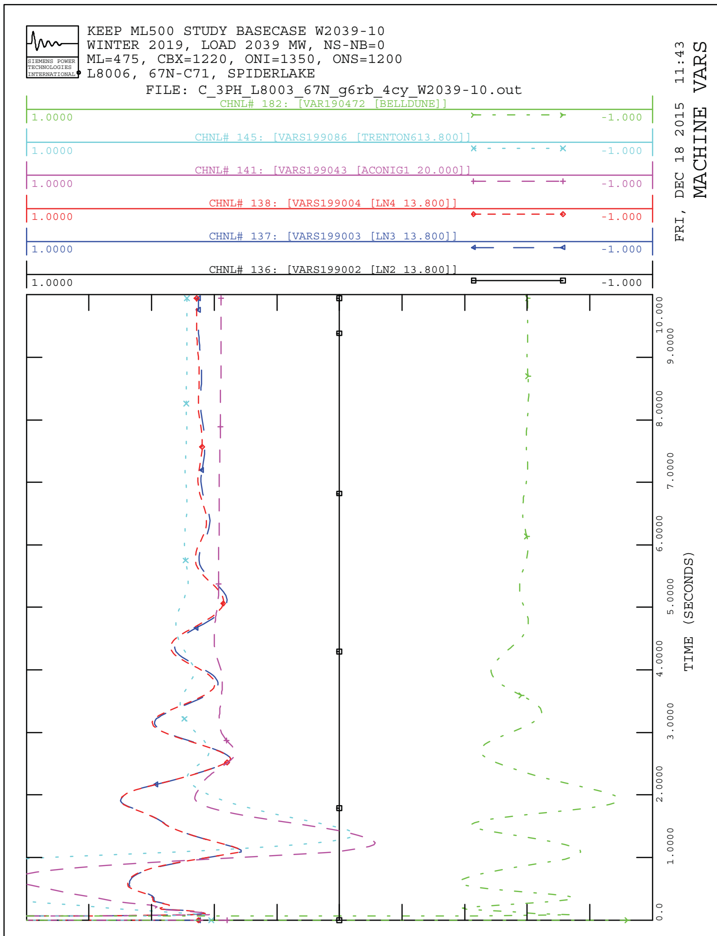


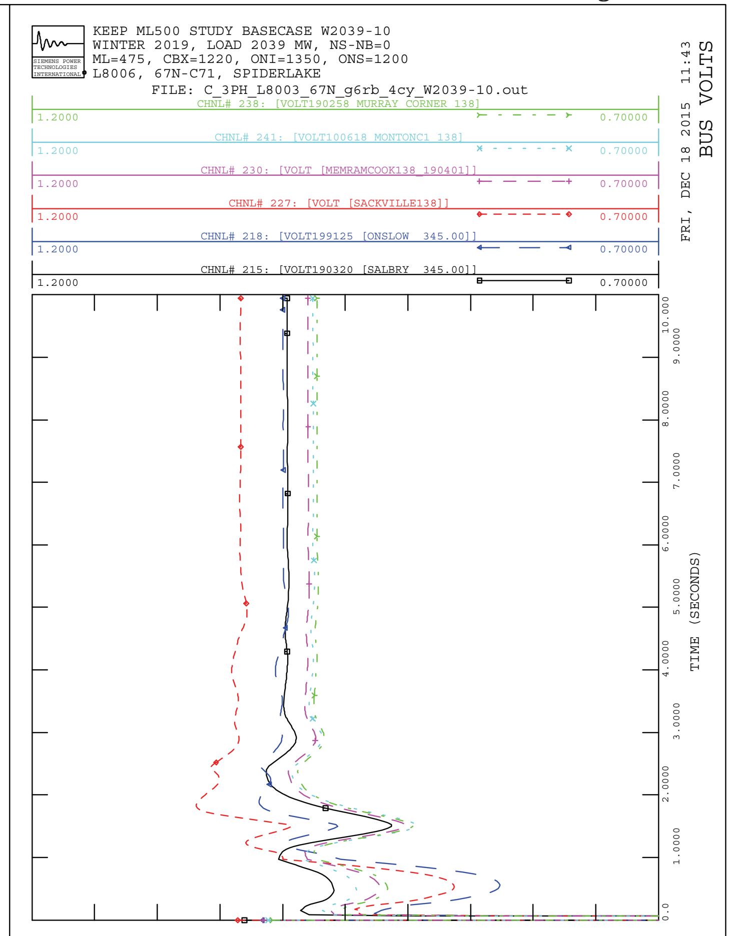
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4.5cy_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
FRI, DEC 18 2015 11:43
MACHINE POWER
TIME (SECONDS)

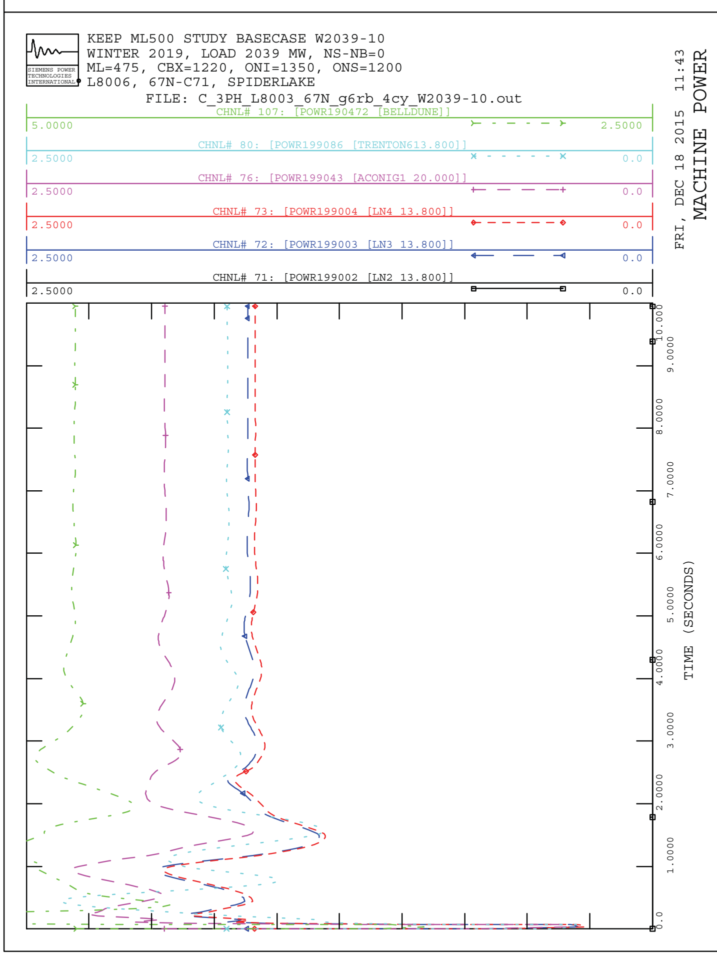


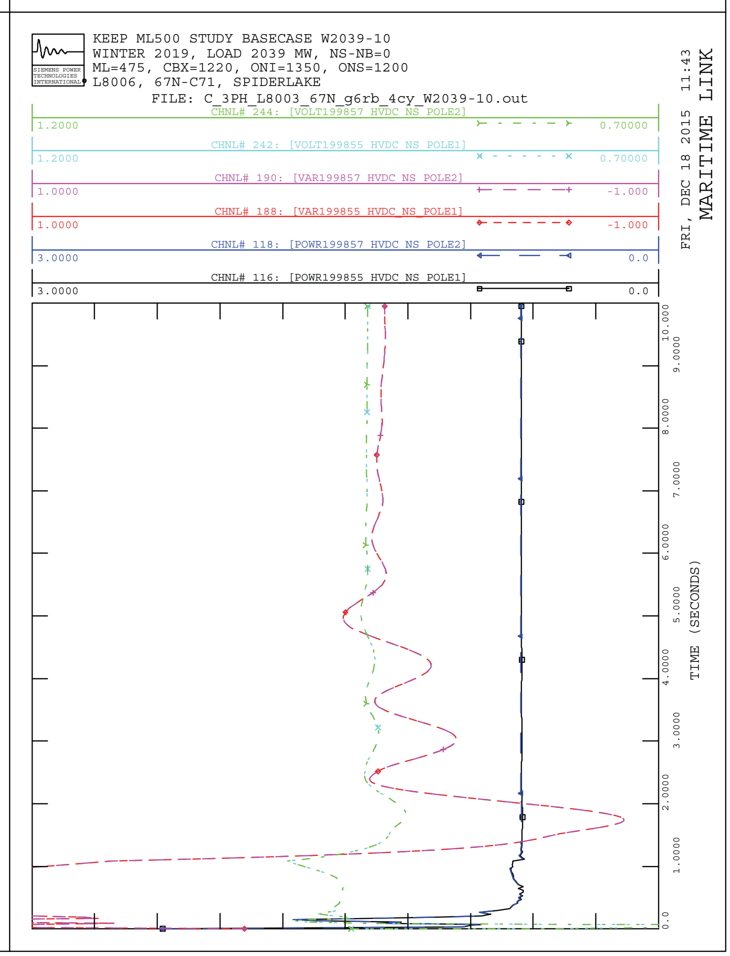
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_67N_g6rb_4.5cy_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
FRI, DEC 18 2015 11:43
MARITIME LINK
TIME (SECONDS)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

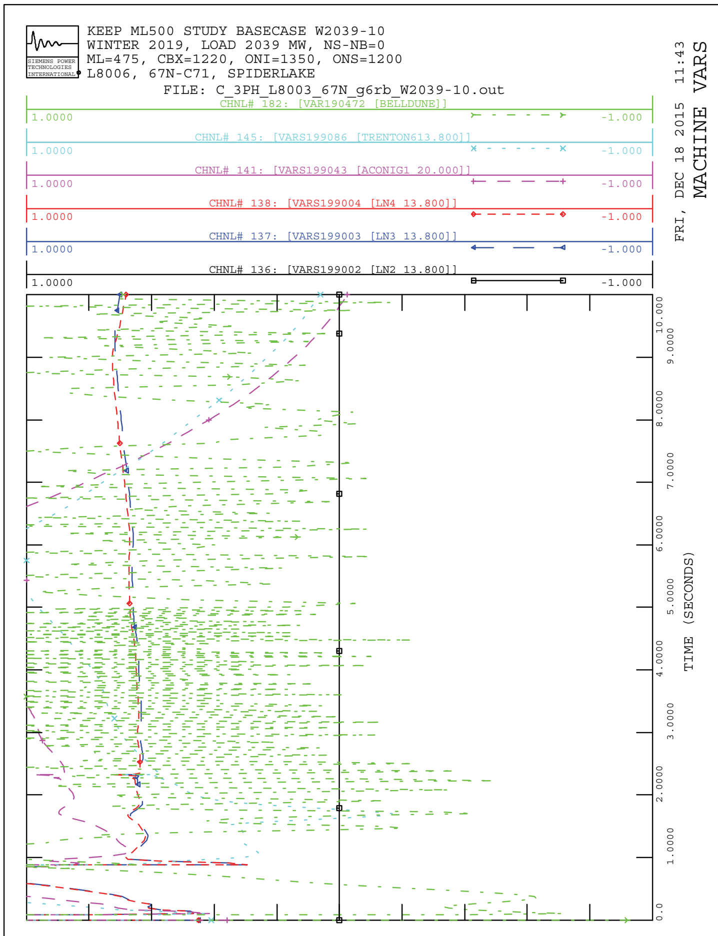


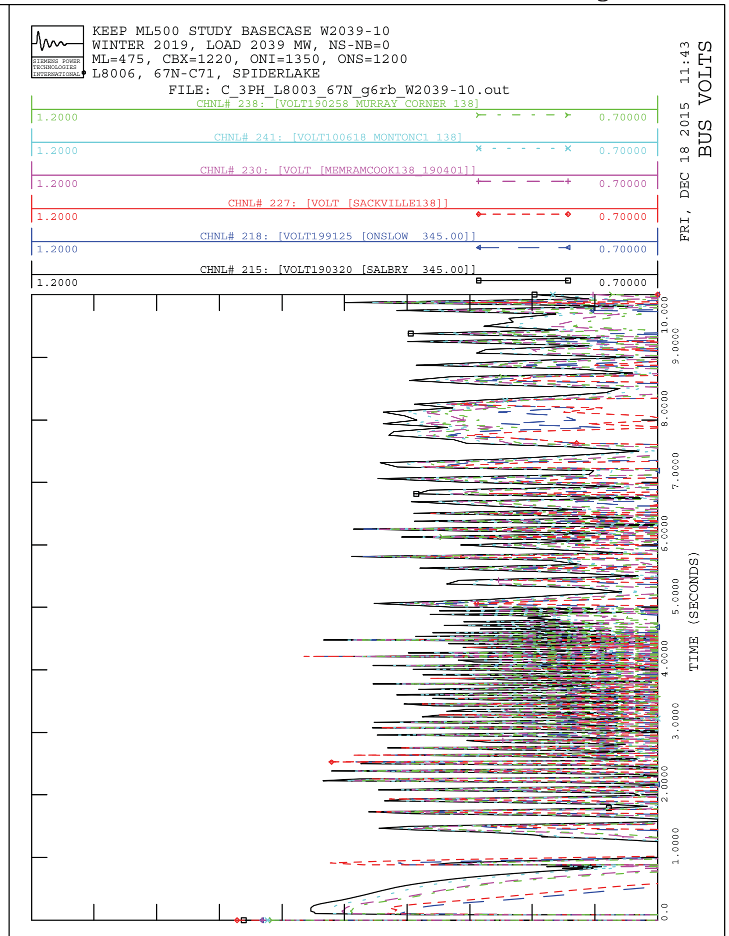


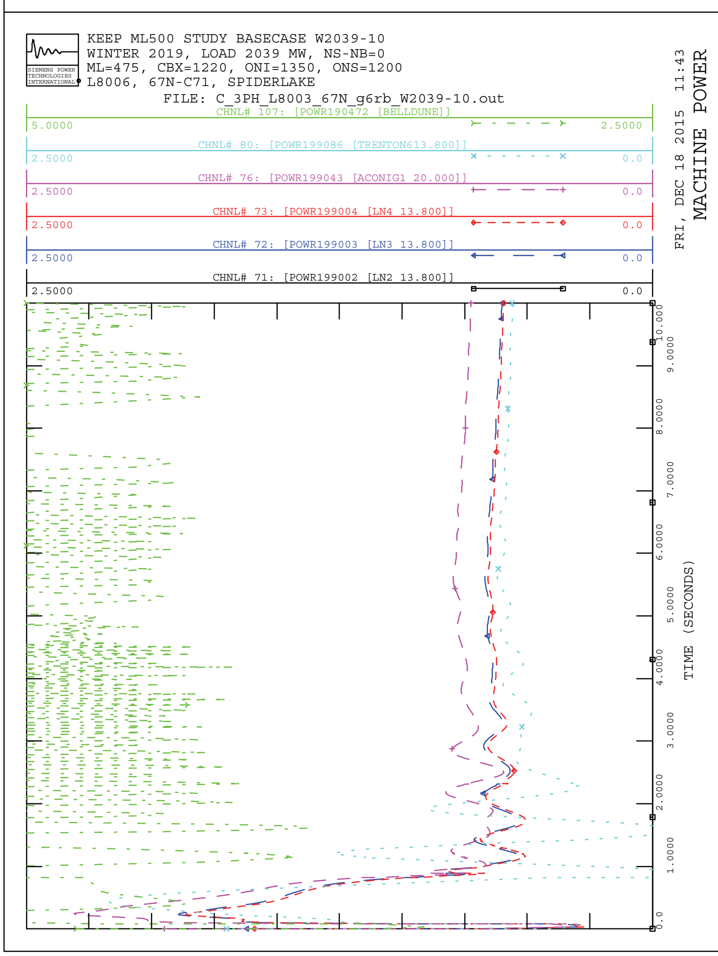


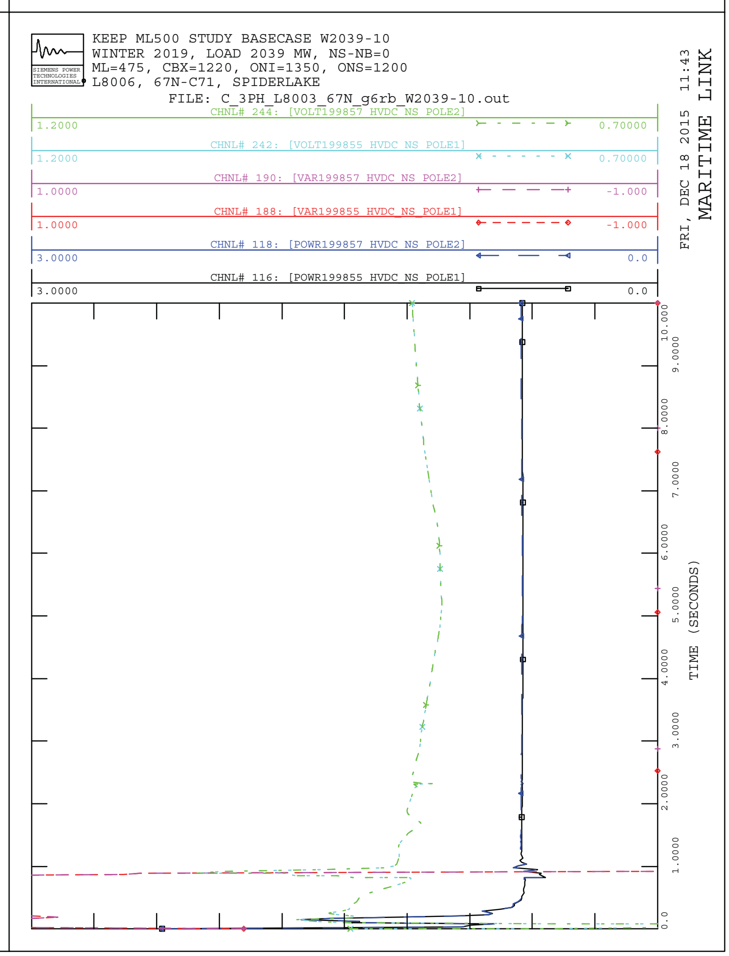


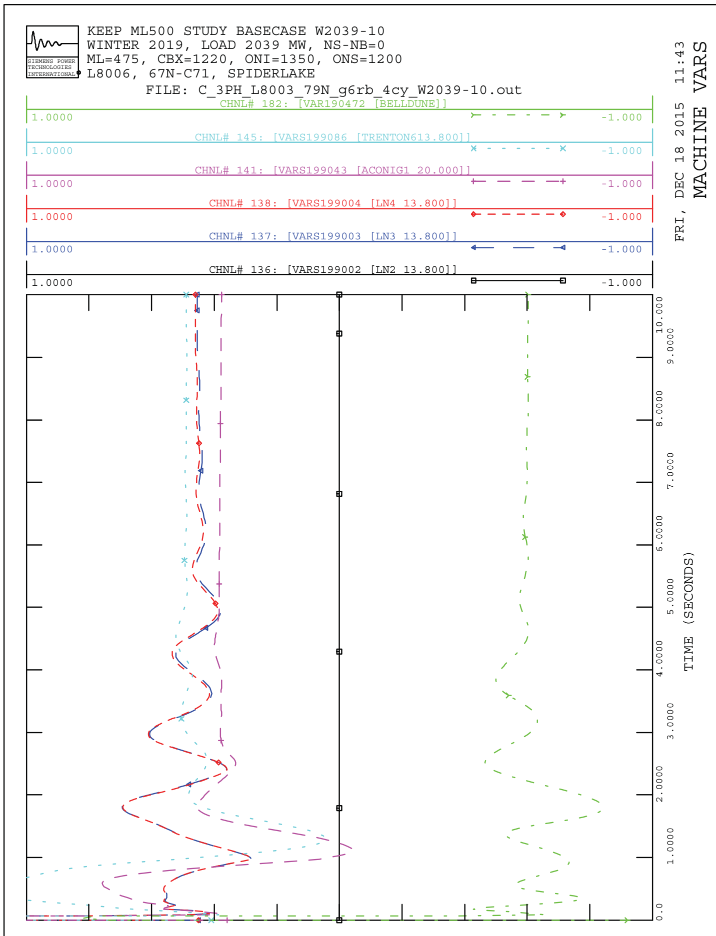
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



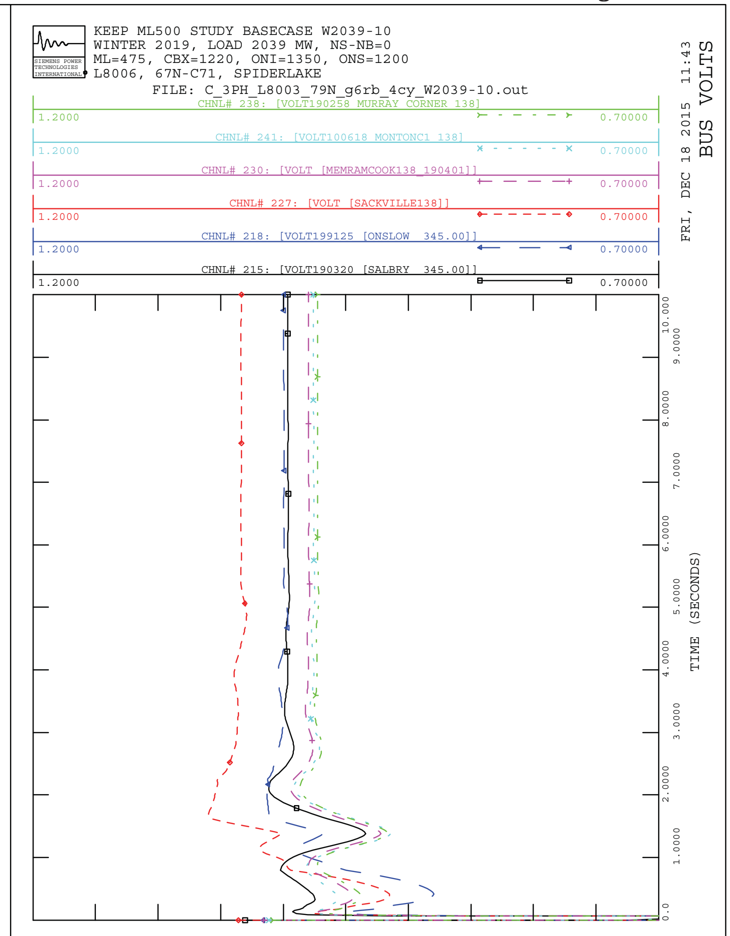




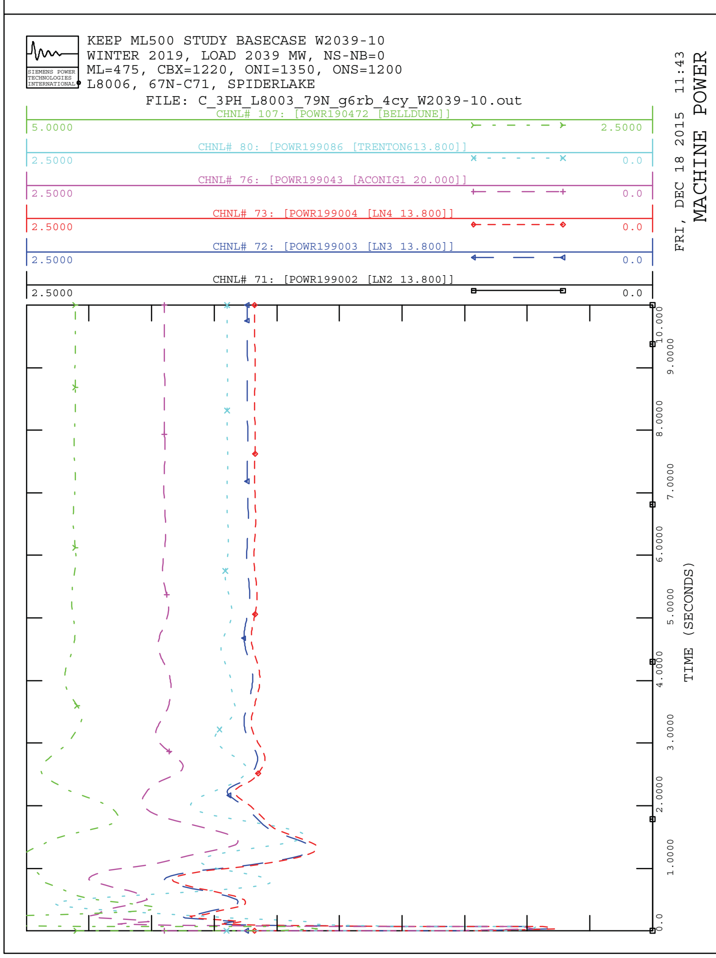




KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_4cy_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
FRI, DEC 18 2015 11:43
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_4cy_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
FRI, DEC 18 2015 11:43
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_4cy_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
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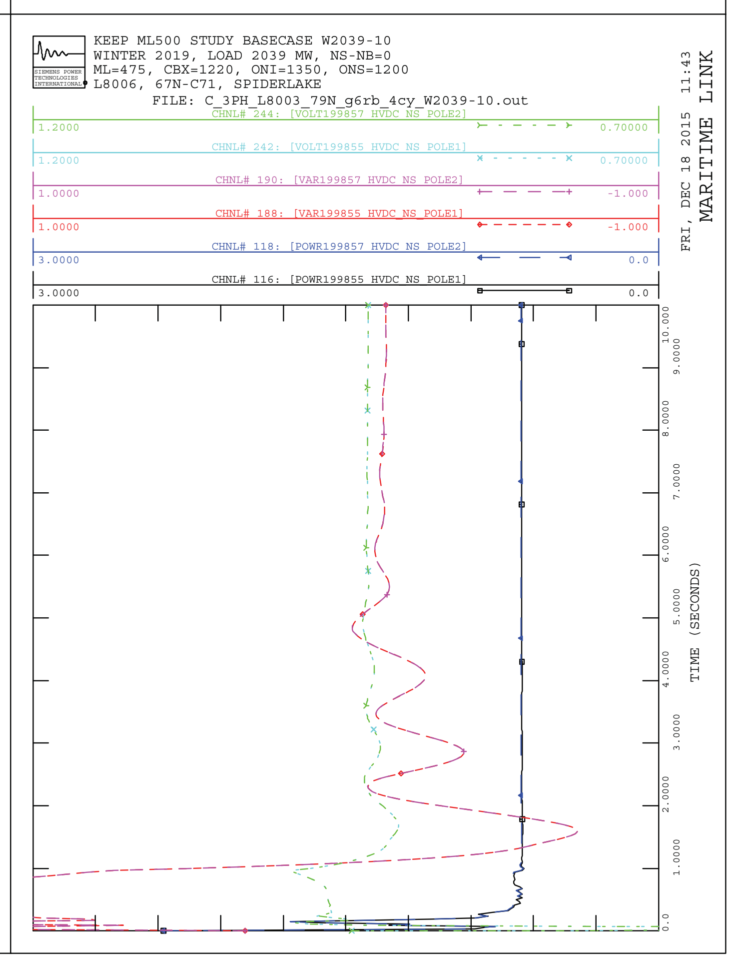
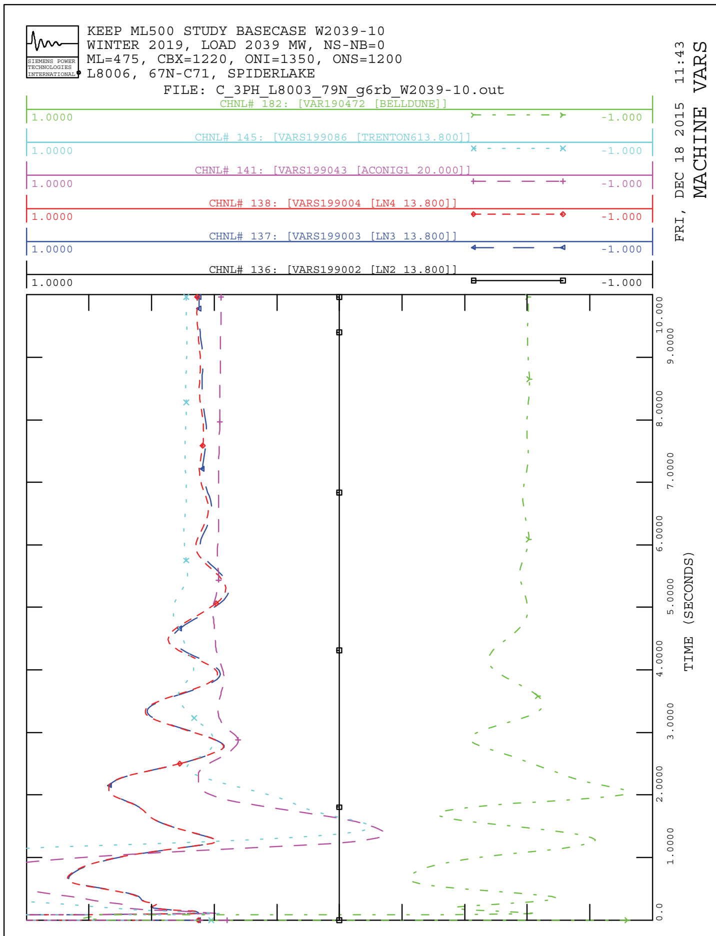
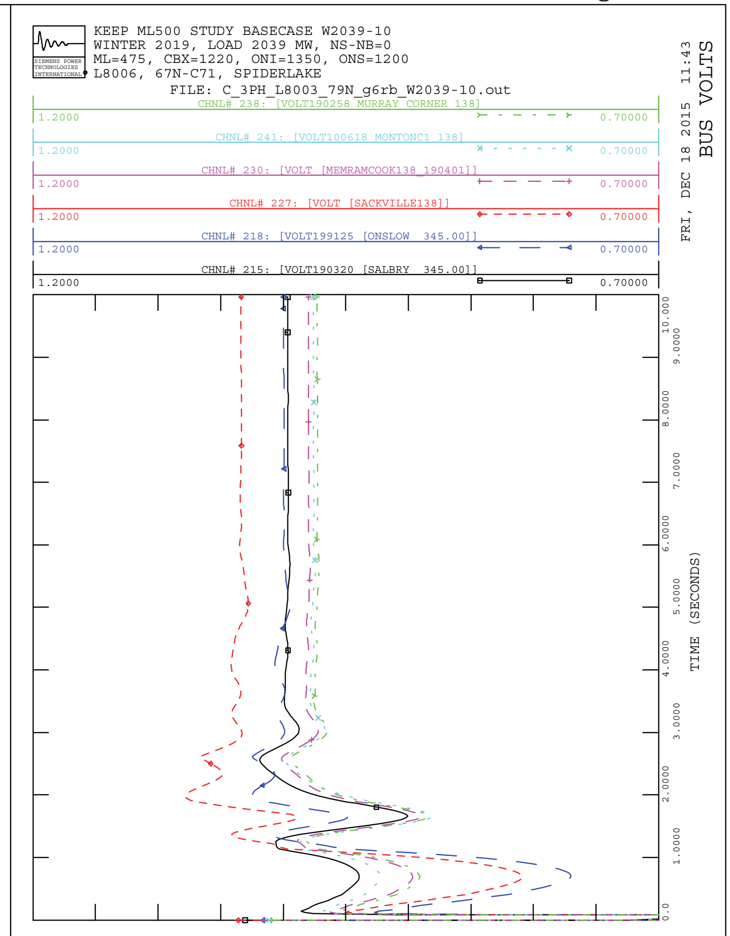
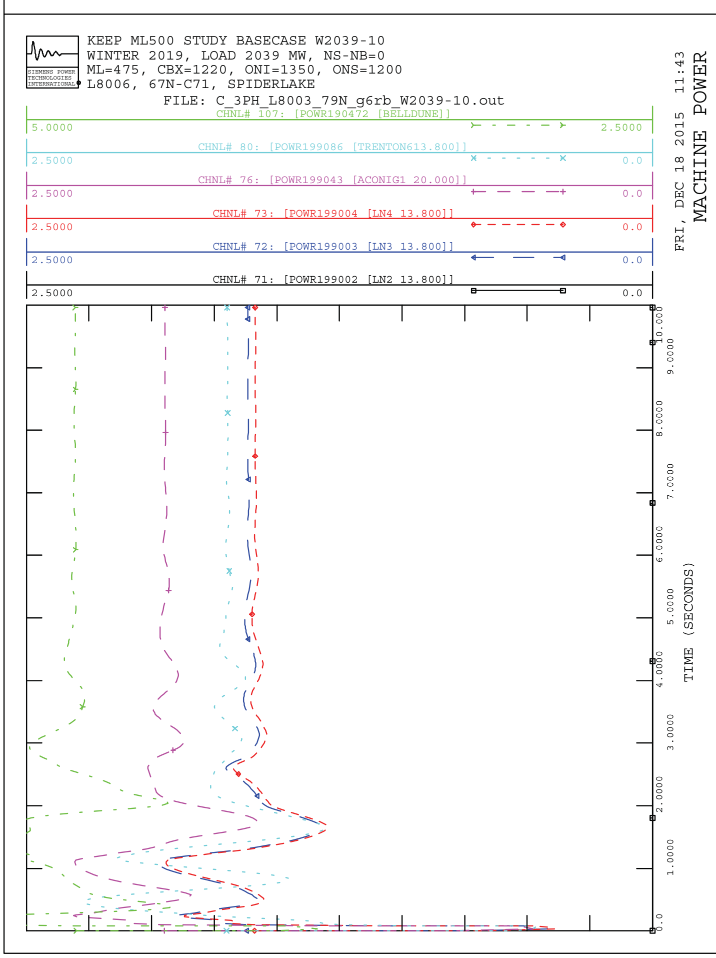
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
FRI, DEC 18 2015 11:43
MACHINE POWER
TIME (SECONDS)

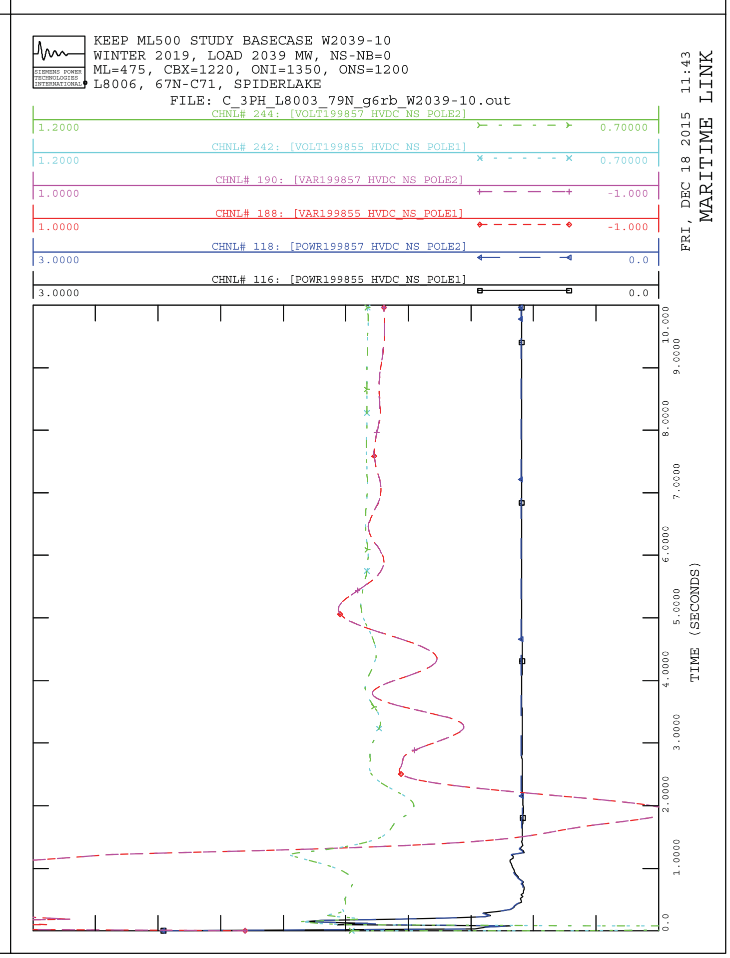


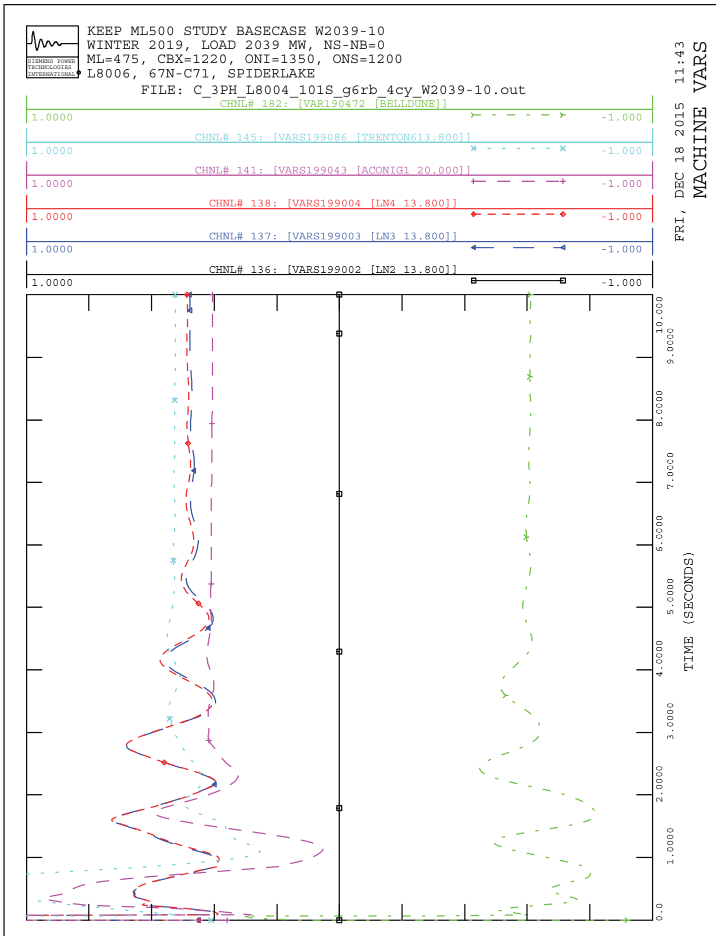
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_4cy_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
FRI, DEC 18 2015 11:43
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
TIME (SECONDS)
FRI, DEC 18 2015 11:43
MACHINE VARS

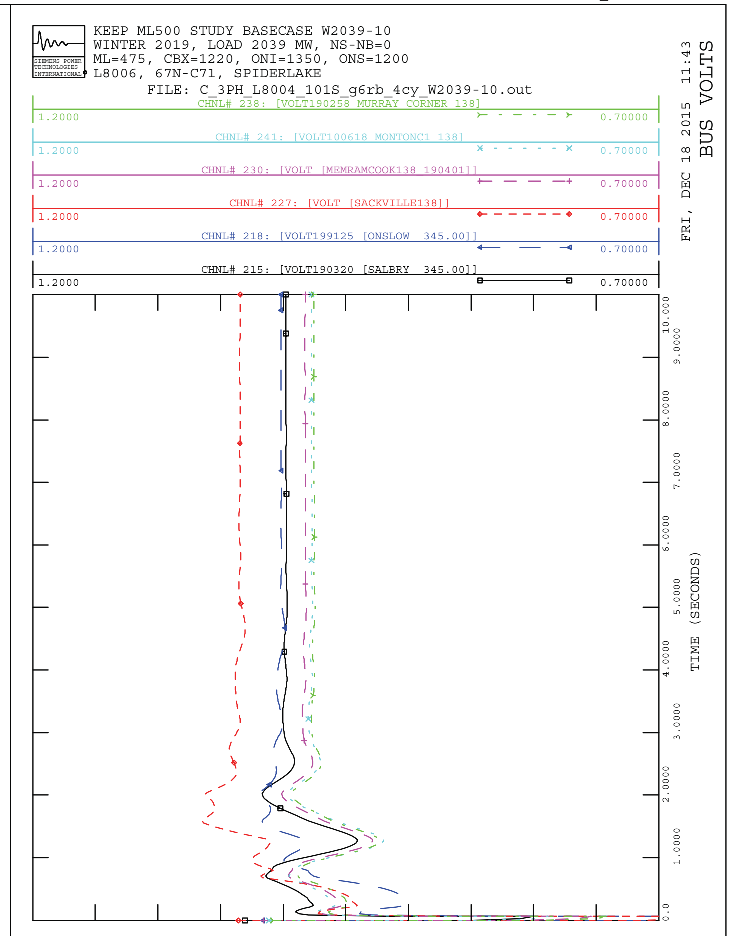

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
TIME (SECONDS)
FRI, DEC 18 2015 11:43
BUS VOLTS


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
TIME (SECONDS)
FRI, DEC 18 2015 11:43
MACHINE POWER

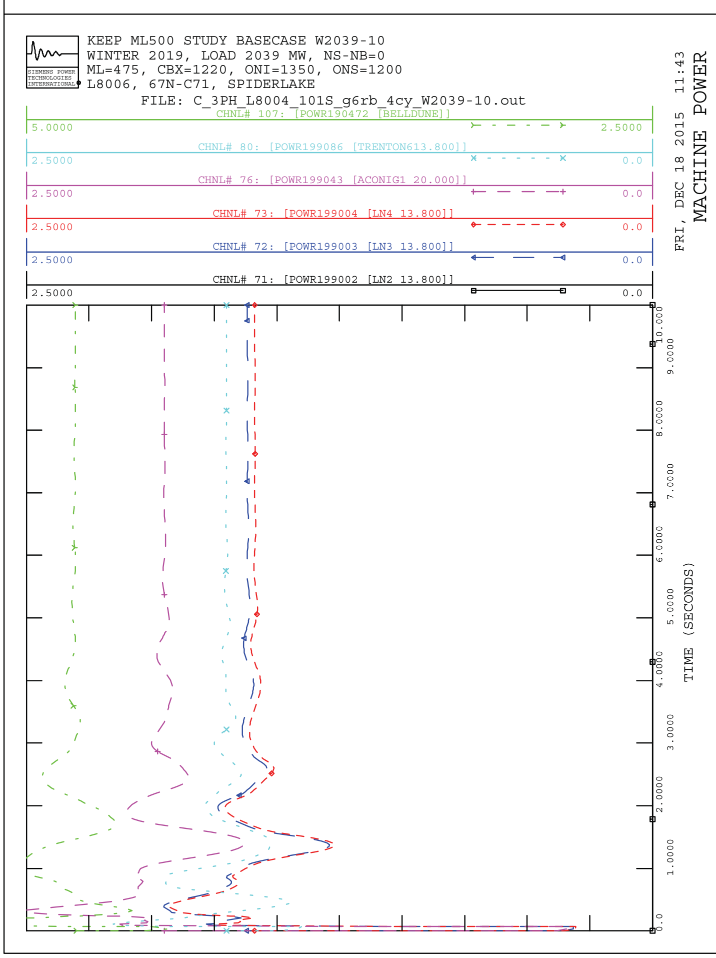

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8003_79N_g6rb_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
TIME (SECONDS)
FRI, DEC 18 2015 11:43
MARITIME LINK



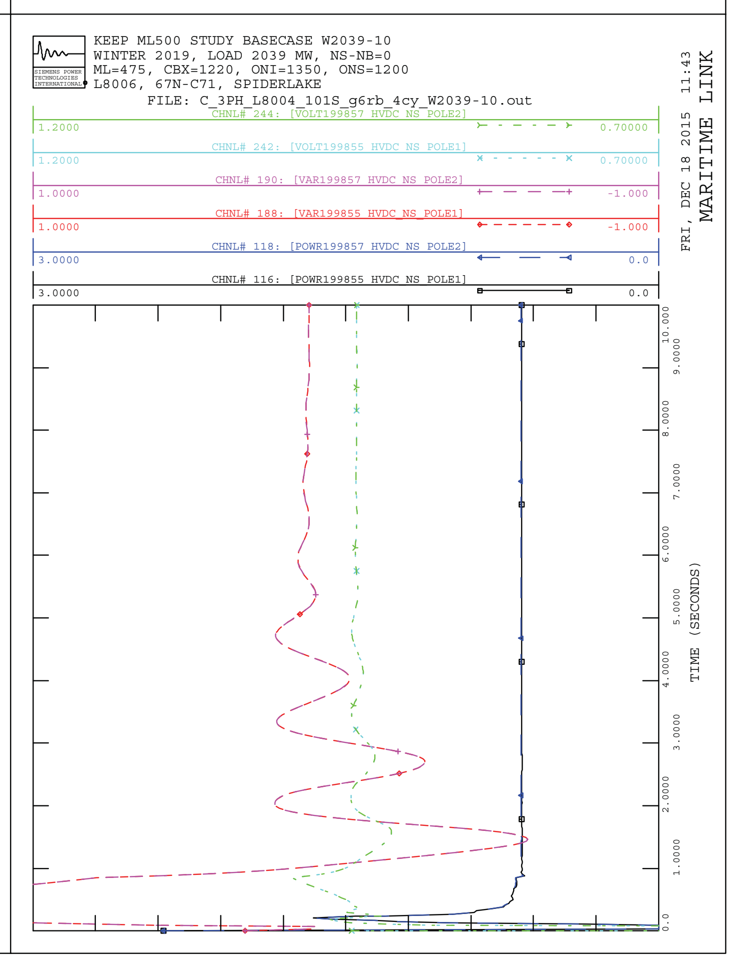
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_101S_g6rb_4cy_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
FRI, DEC 18 2015 11:43
MACHINE VARS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_101S_g6rb_4cy_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
FRI, DEC 18 2015 11:43
BUS VOLTS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_101S_g6rb_4cy_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
FRI, DEC 18 2015 11:43
MACHINE POWER
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_101S_g6rb_4cy_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
FRI, DEC 18 2015 11:43
MARITIME LINK
TIME (SECONDS)
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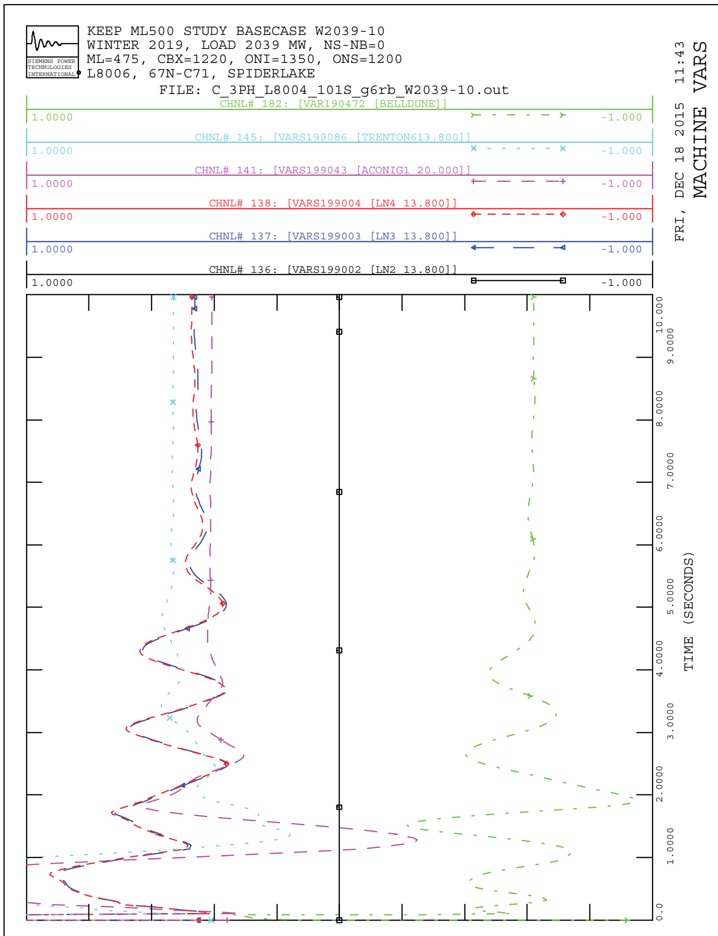
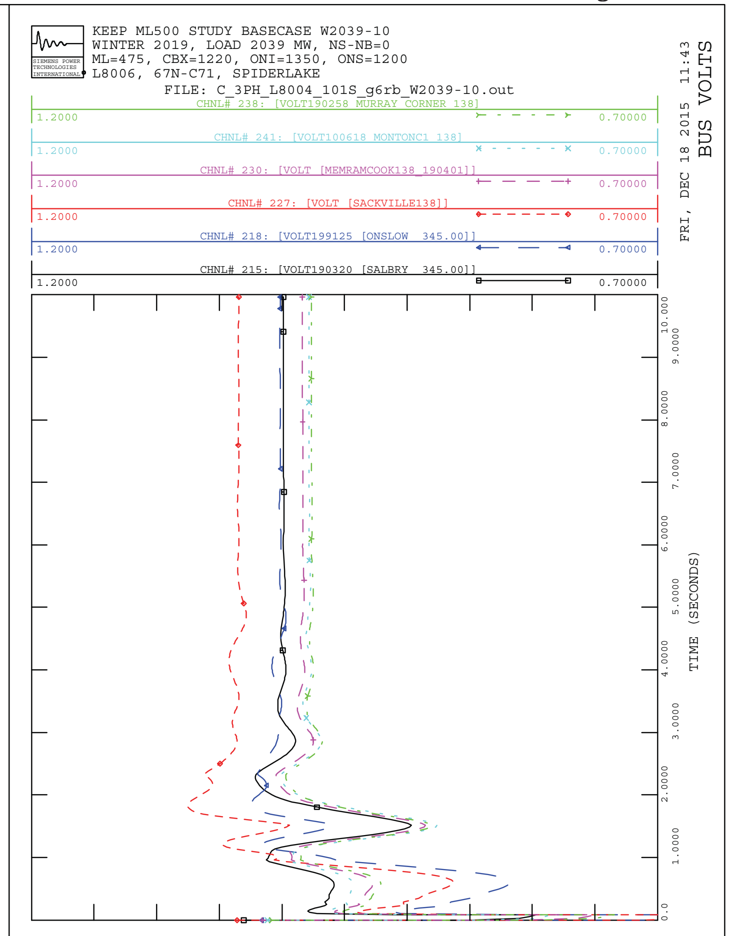
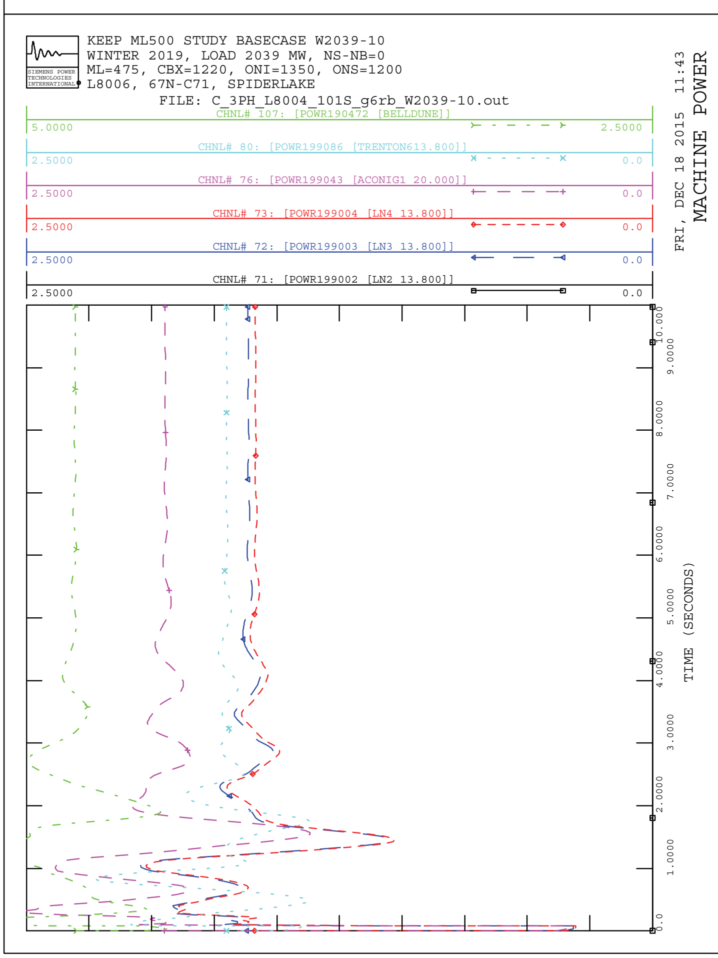
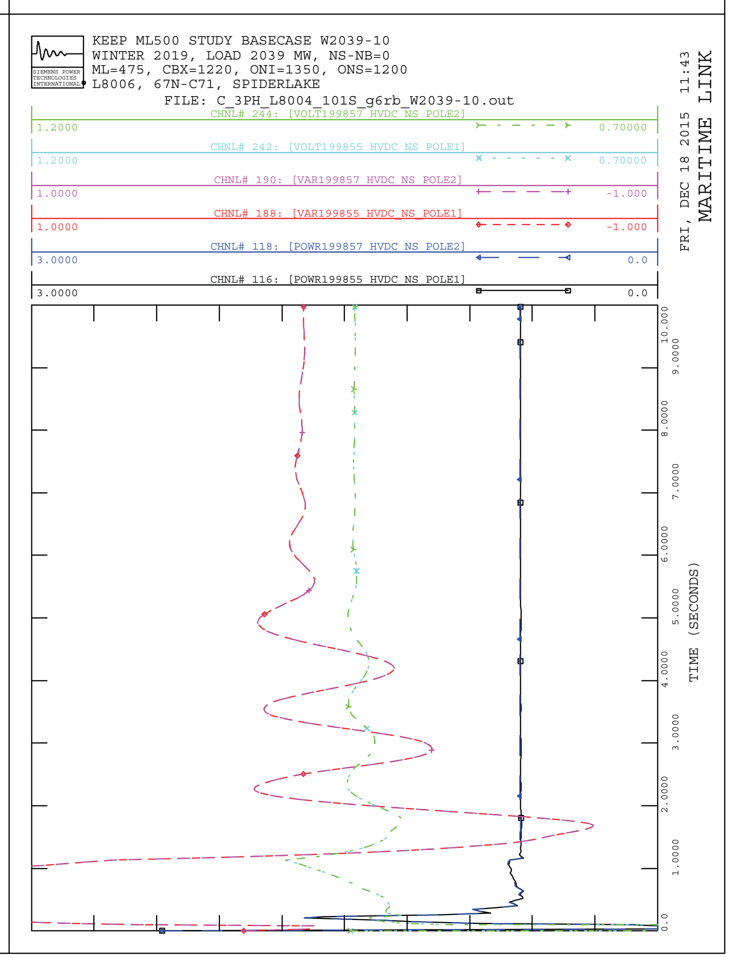
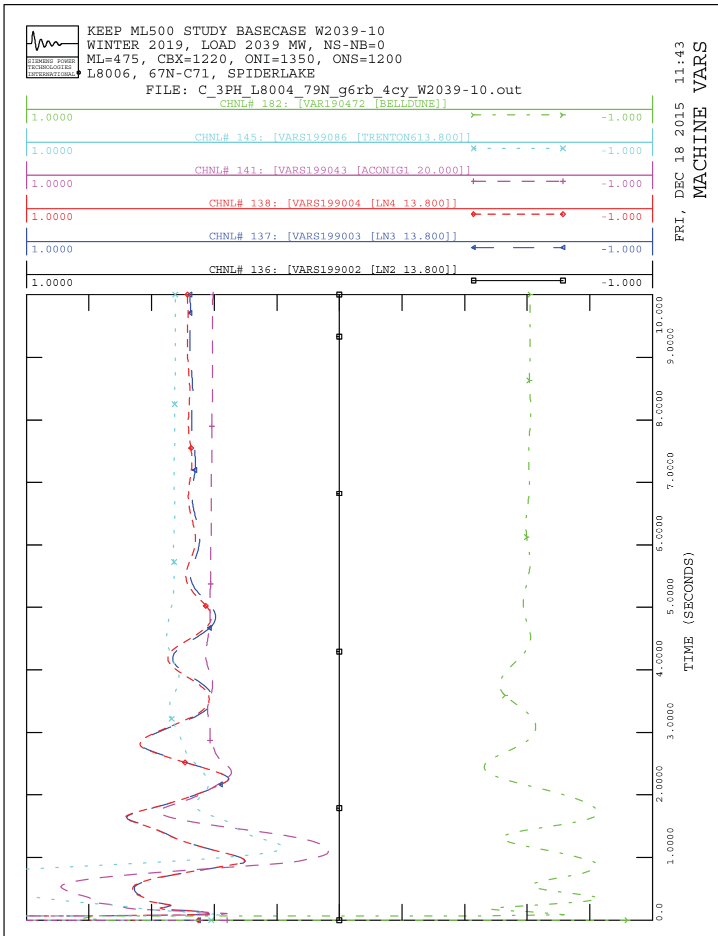
REDACTED (CONFIDENTIAL INFORMATION REMOVED)










KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_4cy_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
FRI, DEC 18 2015 11:43
MACHINE VARS
TIME (SECONDS)
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4.0000
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6.0000
7.0000
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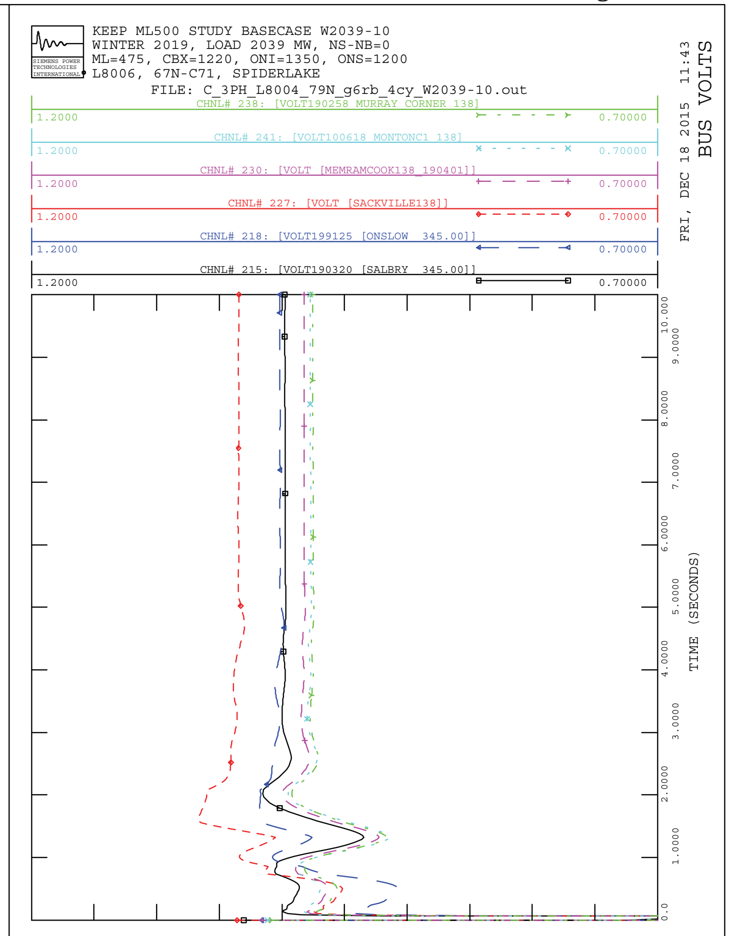
10.000


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_4cy_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
FRI, DEC 18 2015 11:43
BUS VOLTS
TIME (SECONDS)
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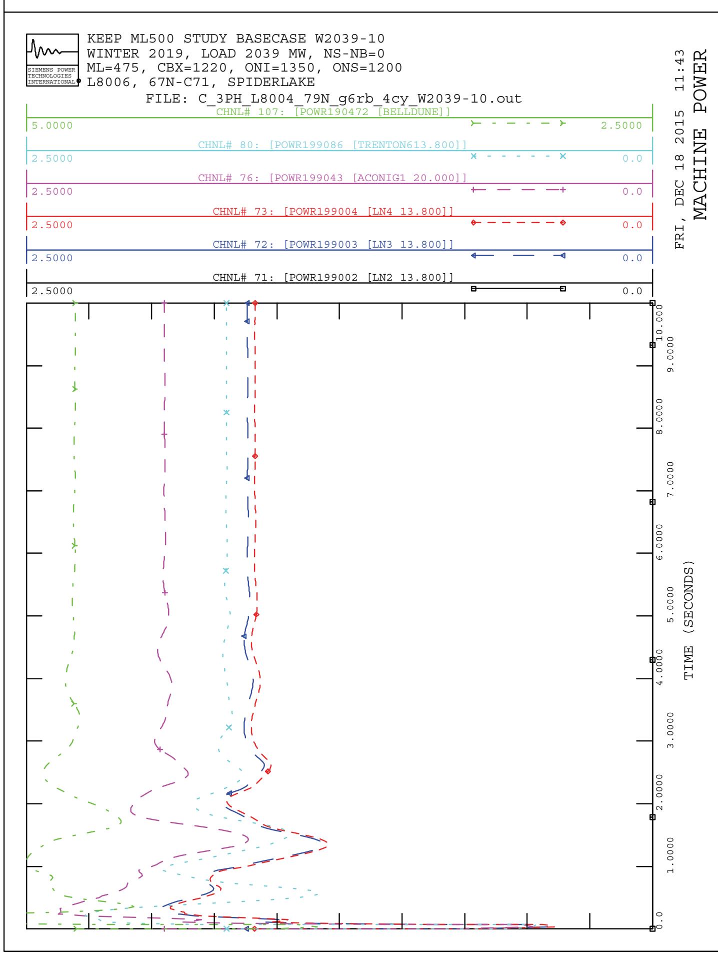
10.000


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_4cy_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
FRI, DEC 18 2015 11:43
MACHINE POWER
TIME (SECONDS)
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6.0000
7.0000
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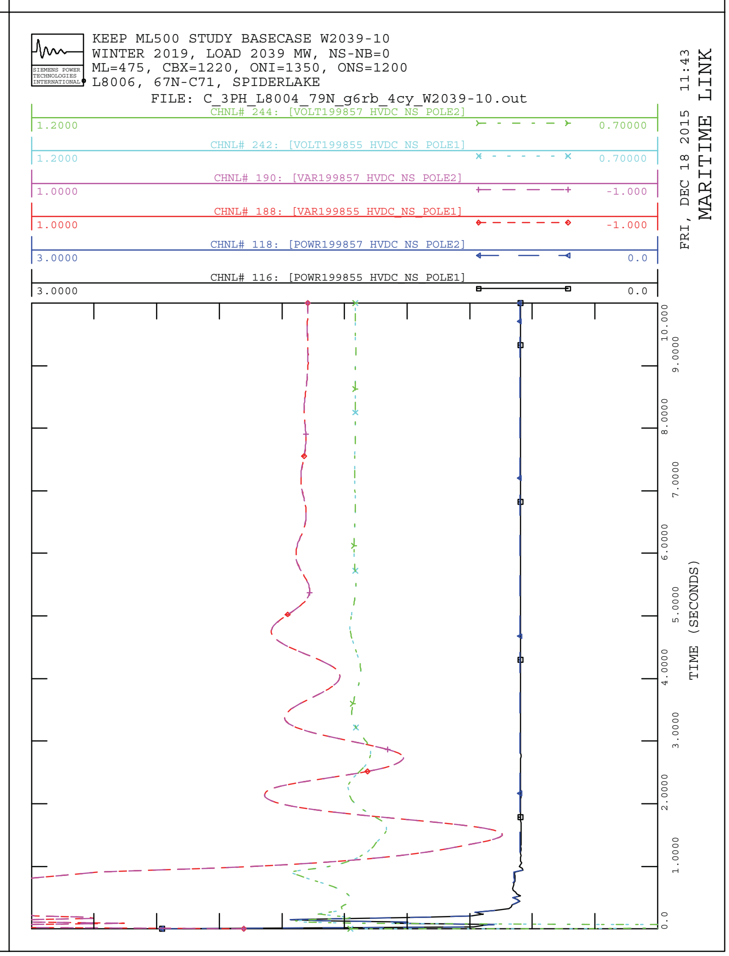
9.0000
10.000


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_4cy_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
FRI, DEC 18 2015 11:43
MARITIME LINK
TIME (SECONDS)
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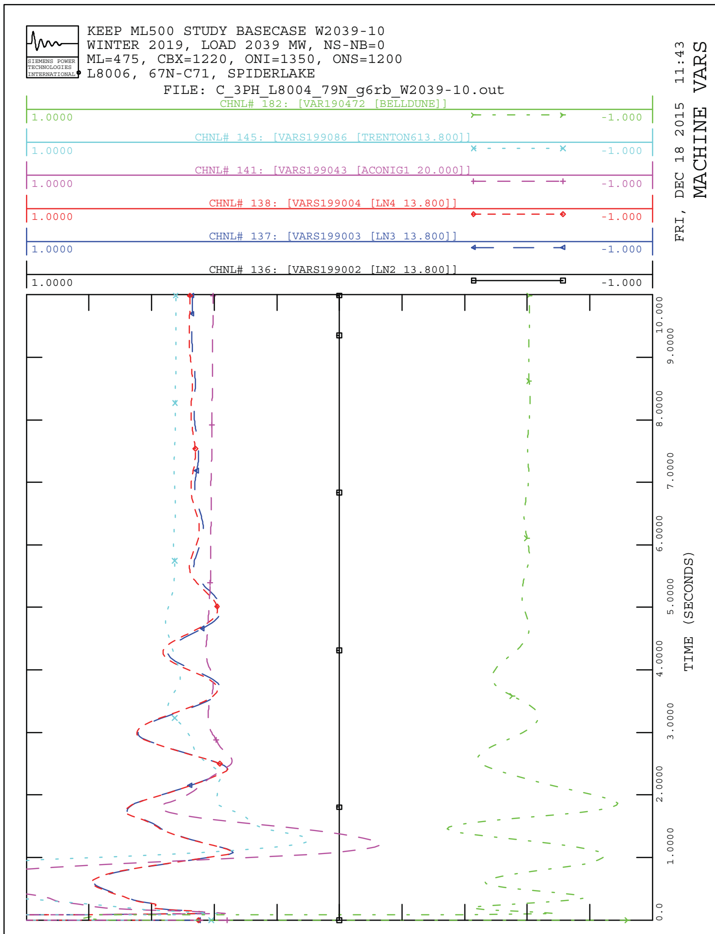
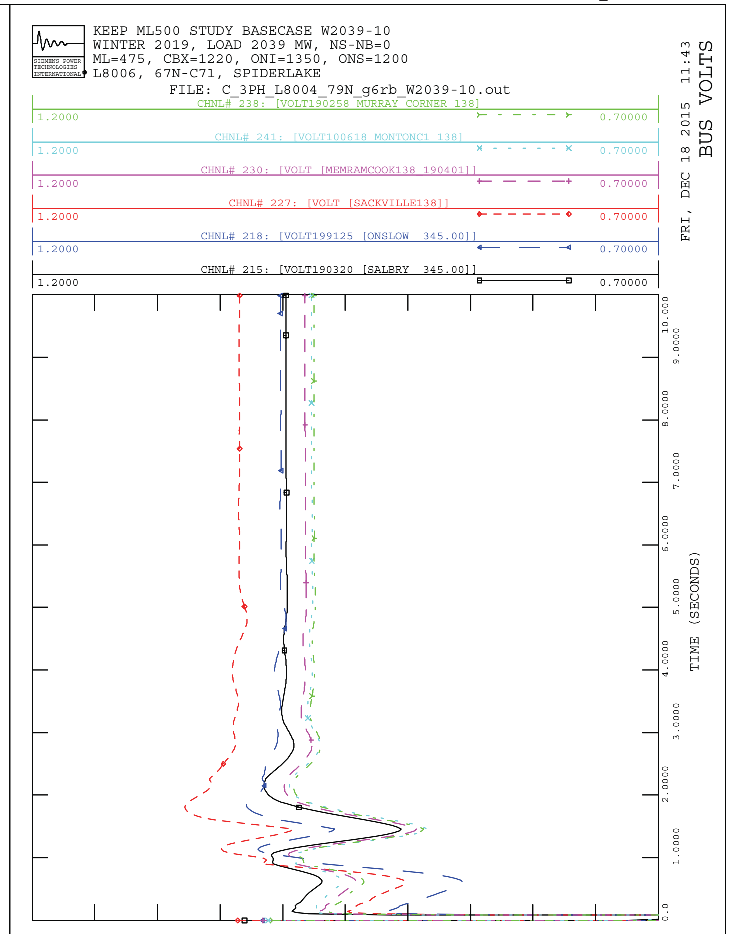
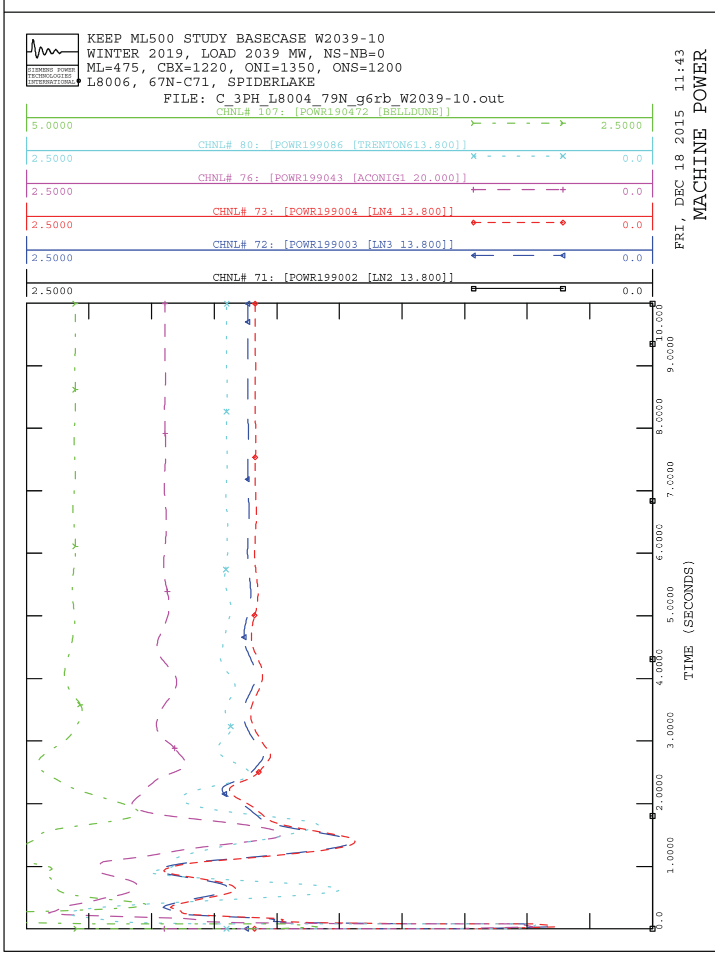
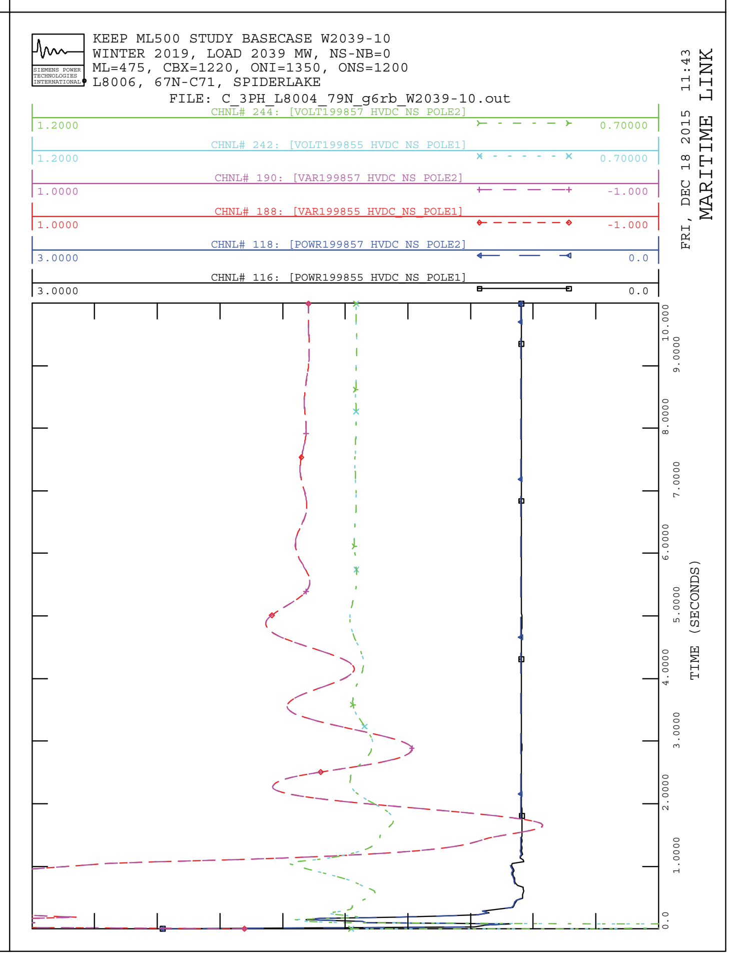
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

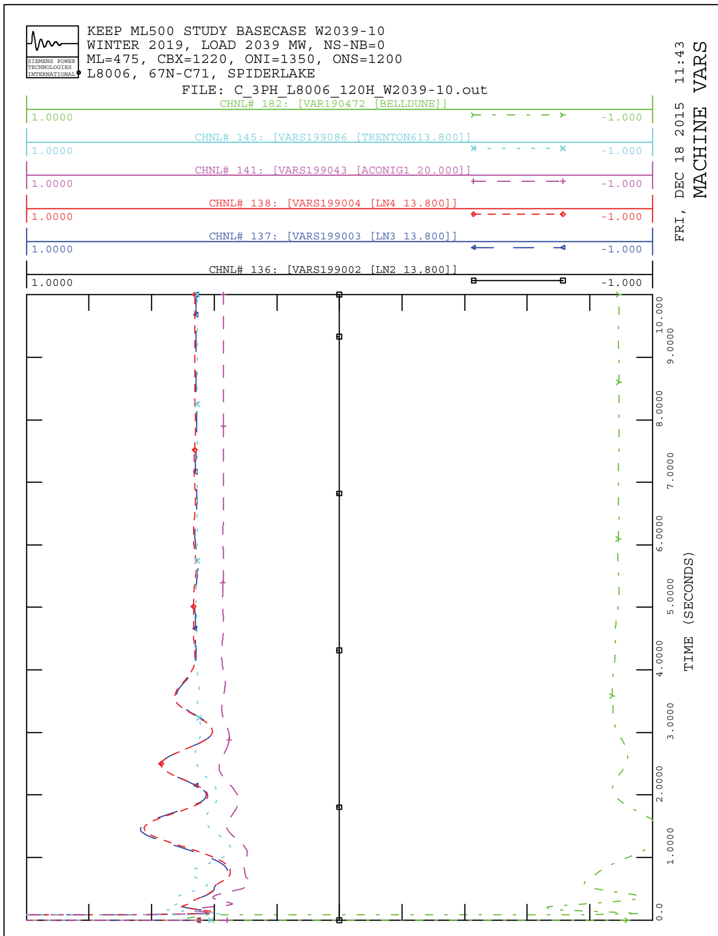

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
FRI, DEC 18 2015 11:43
MACHINE VARS
TIME (SECONDS)

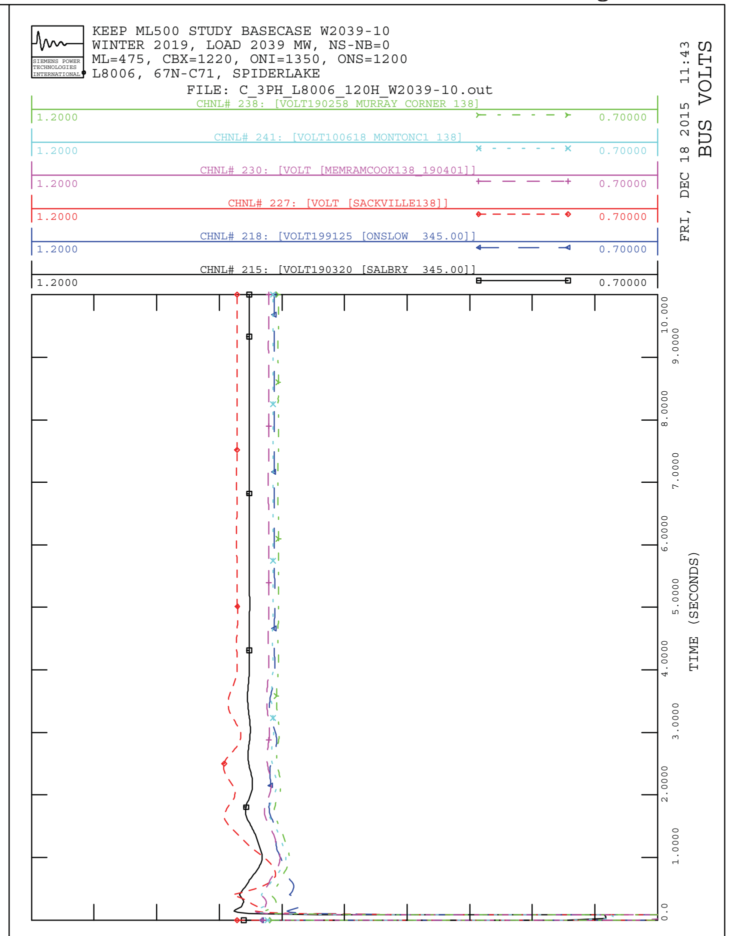

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
FRI, DEC 18 2015 11:43
BUS VOLTS
TIME (SECONDS)

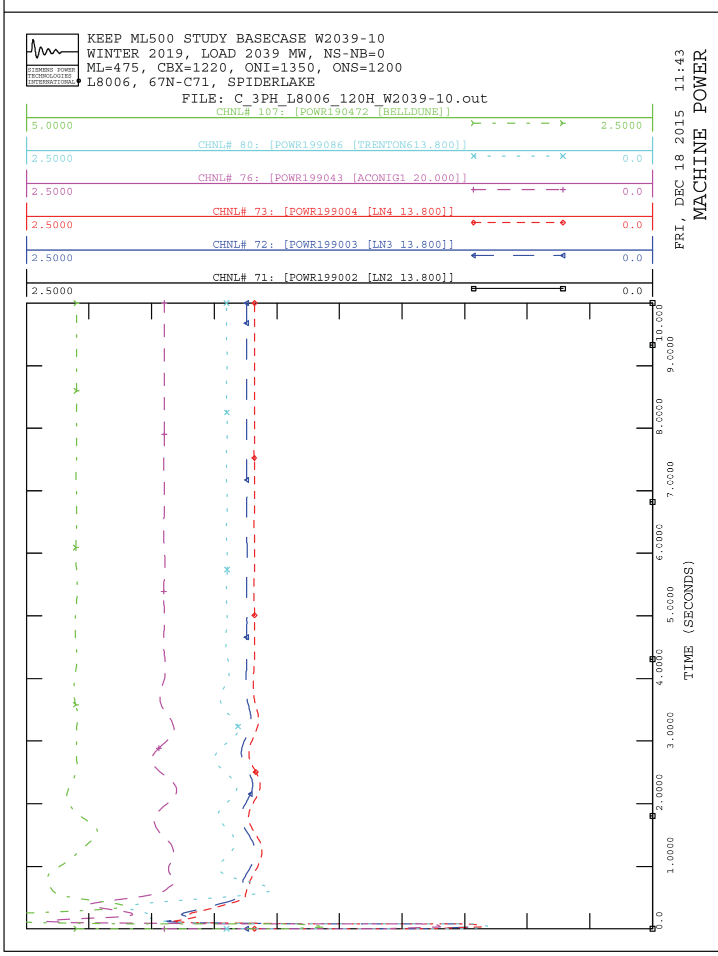

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
FRI, DEC 18 2015 11:43
MACHINE POWER
TIME (SECONDS)

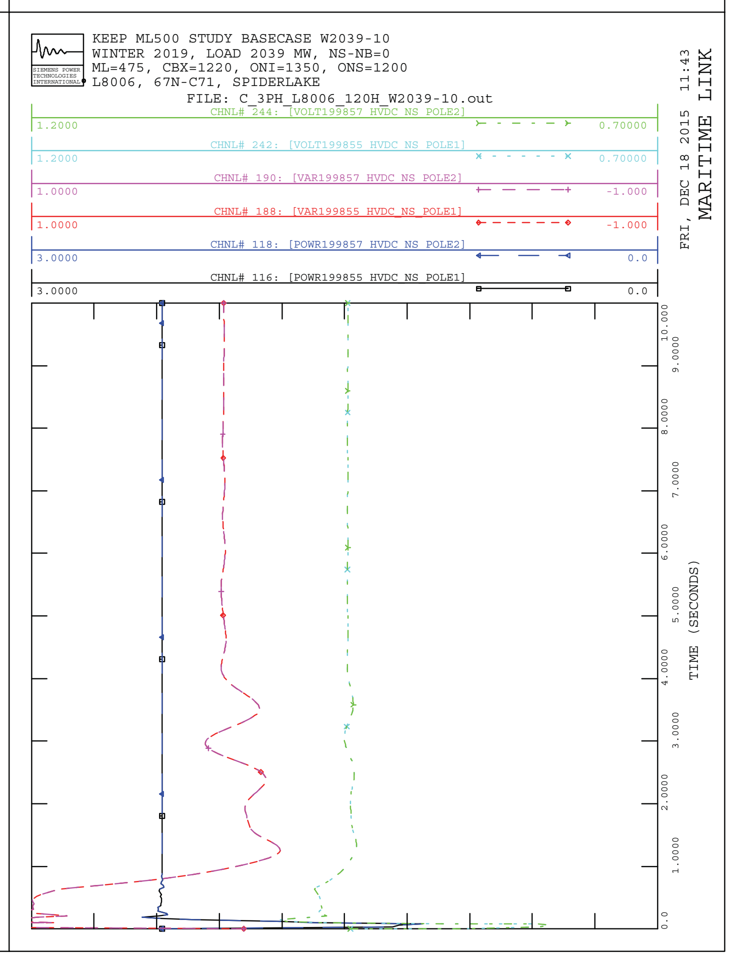

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_L8004_79N_g6rb_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
FRI, DEC 18 2015 11:43
MARITIME LINK
TIME (SECONDS)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)









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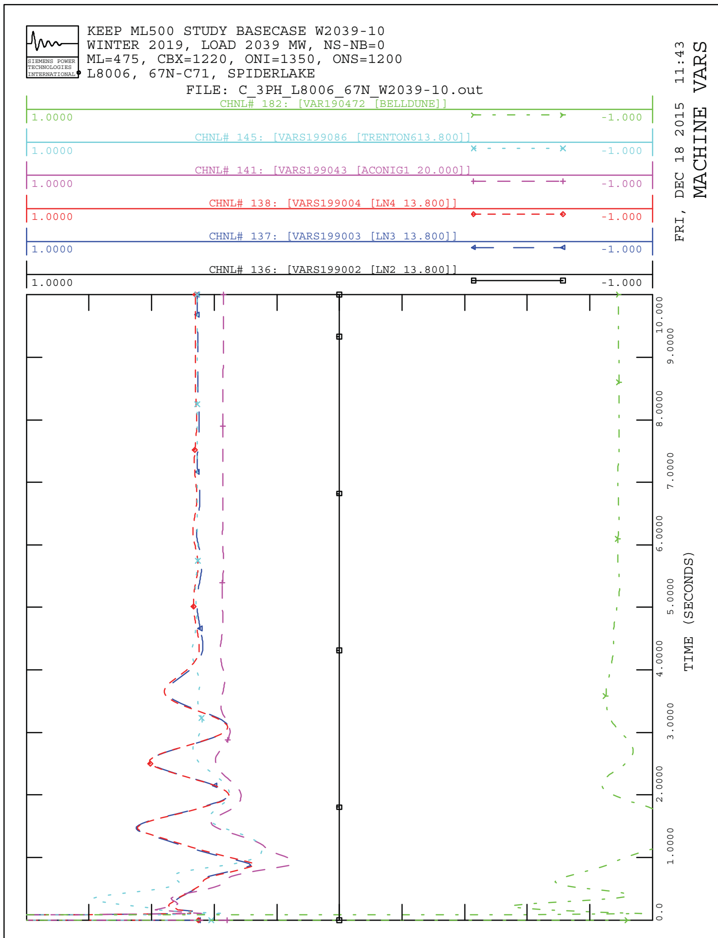
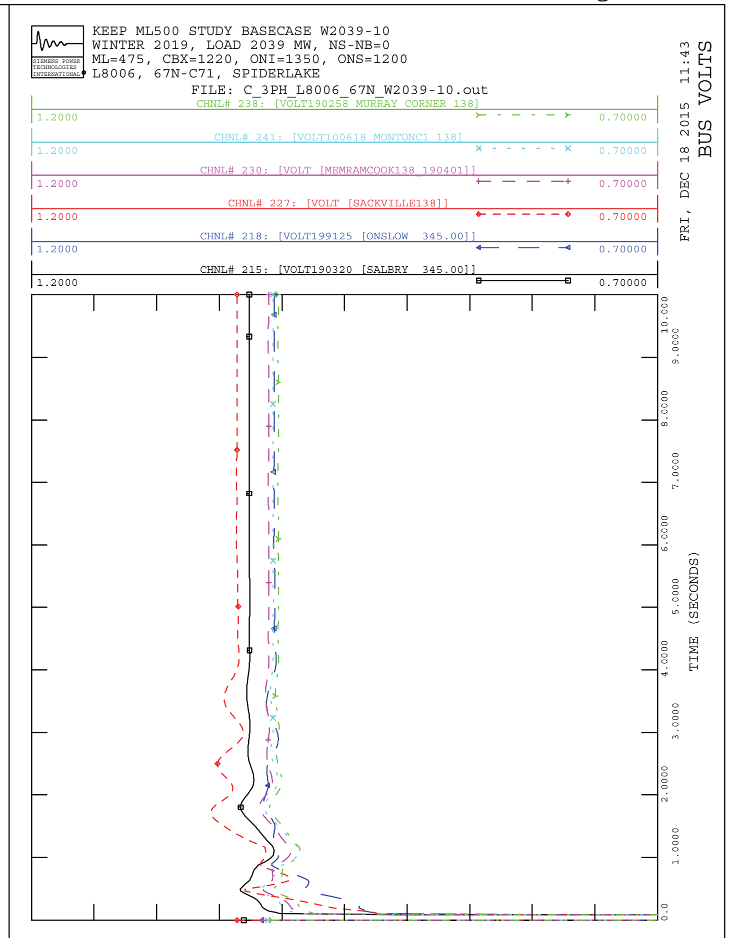
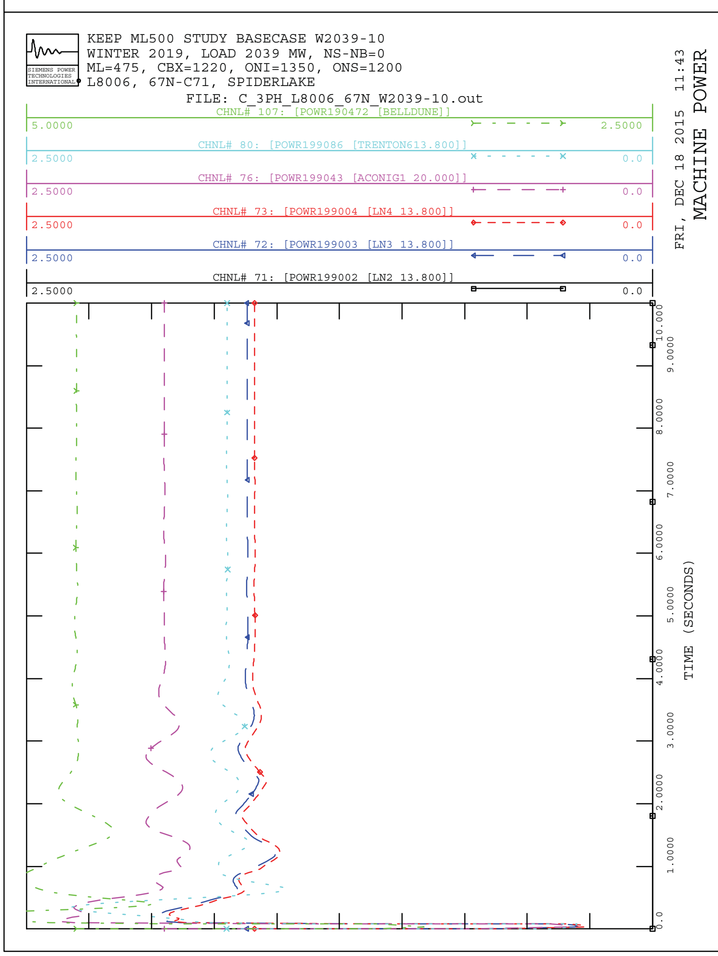
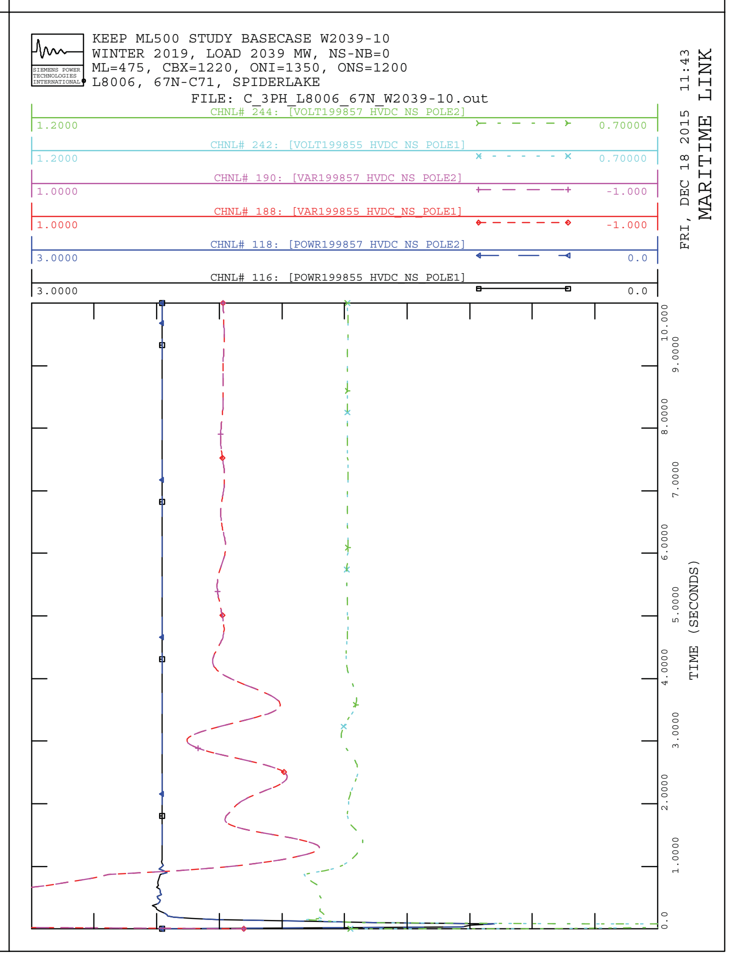
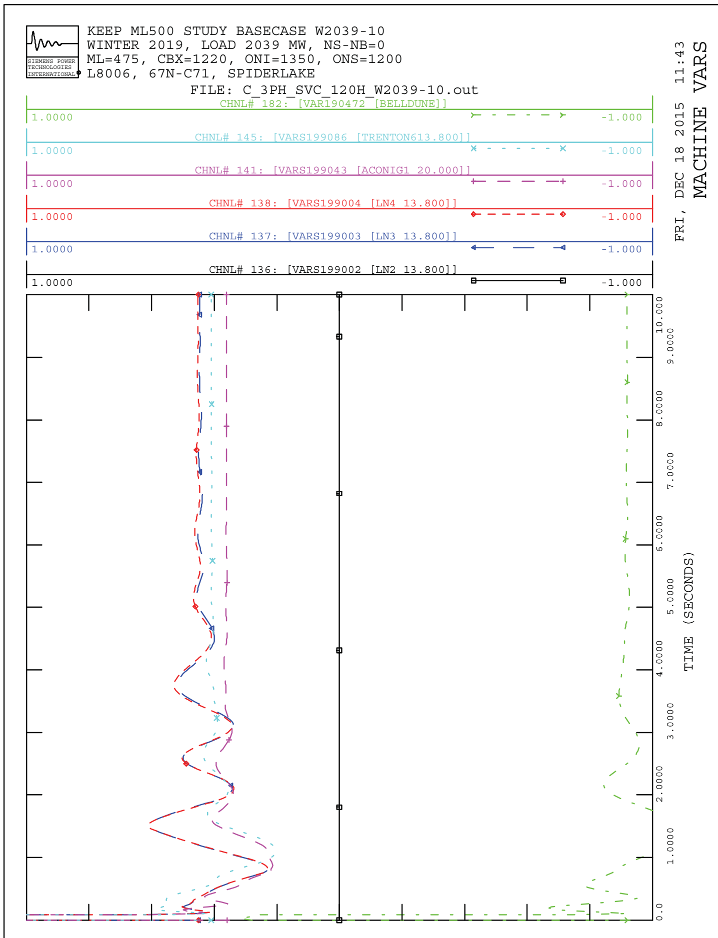


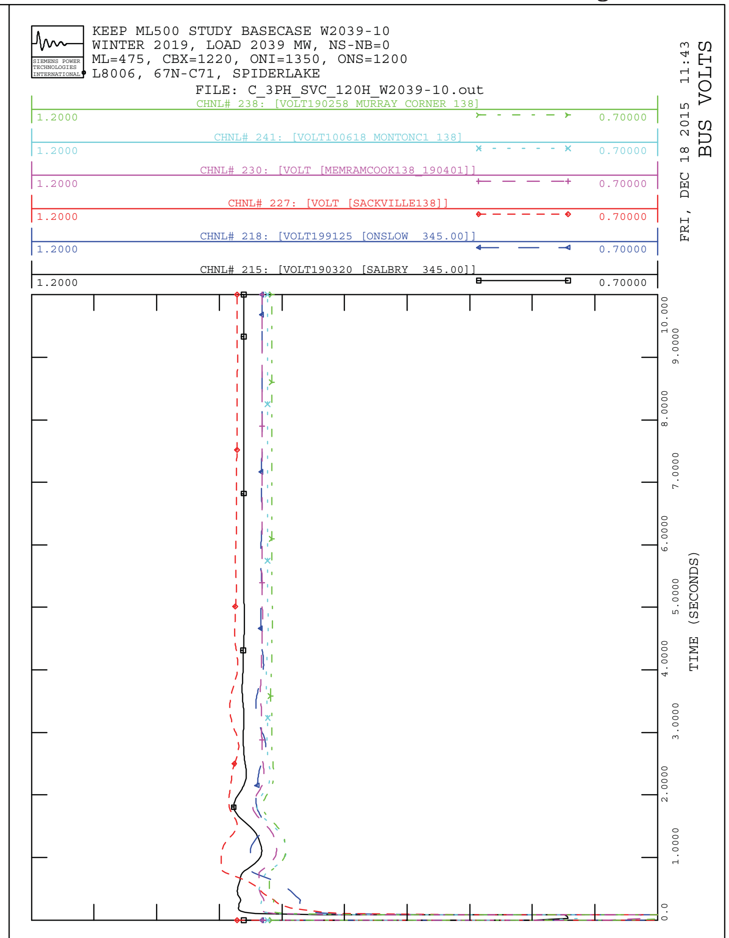




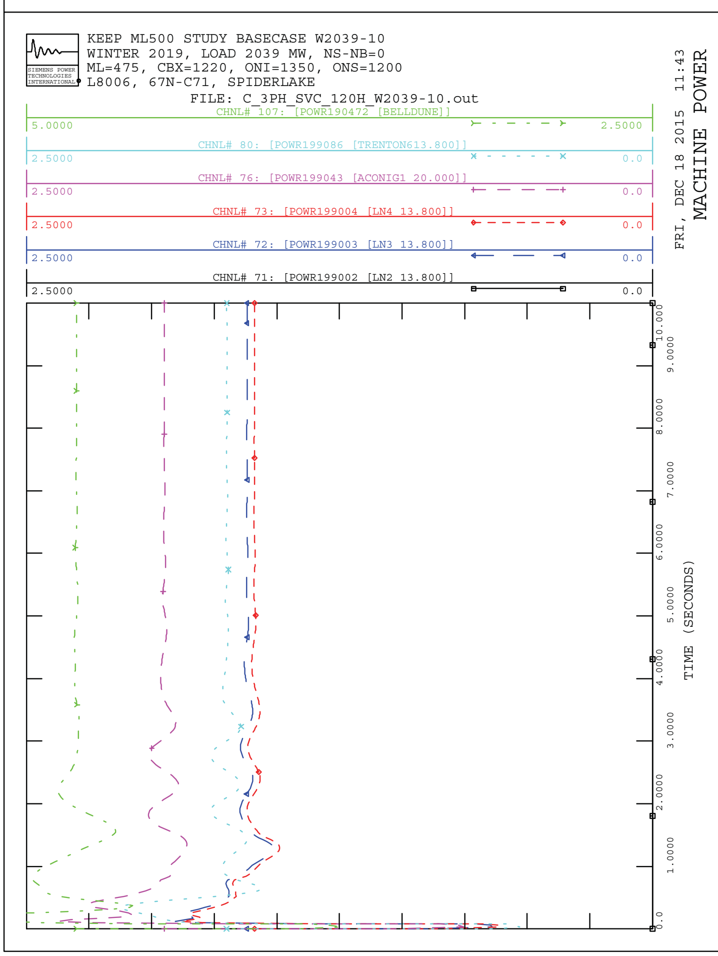




KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_SVC_120H_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
FRI, DEC 18 2015 11:43
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_SVC_120H_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
FRI, DEC 18 2015 11:43
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_SVC_120H_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
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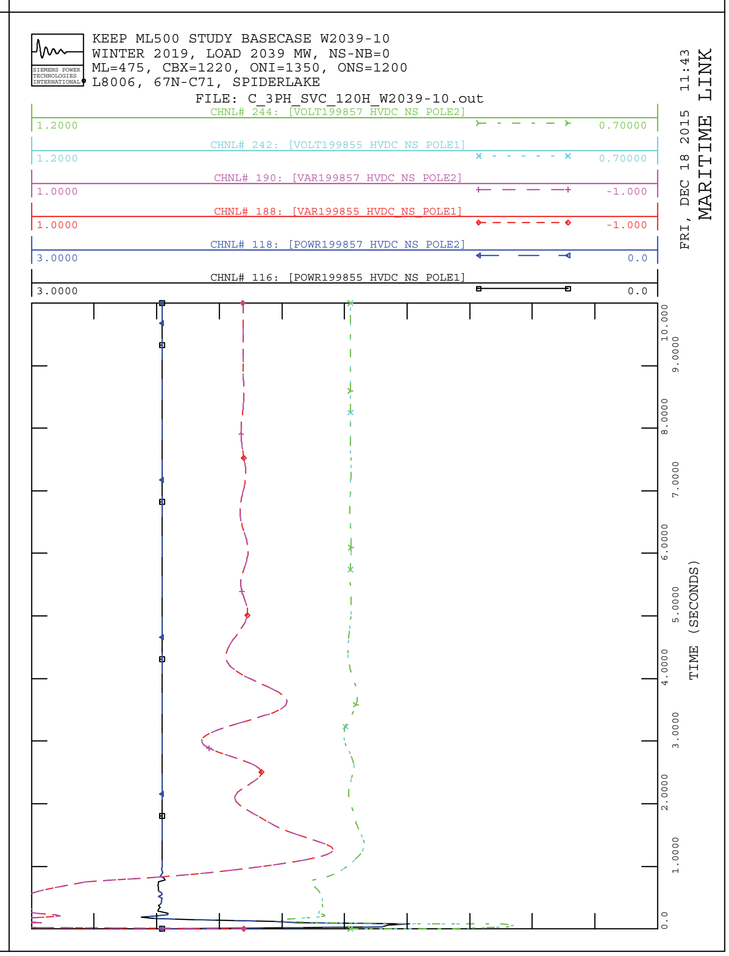
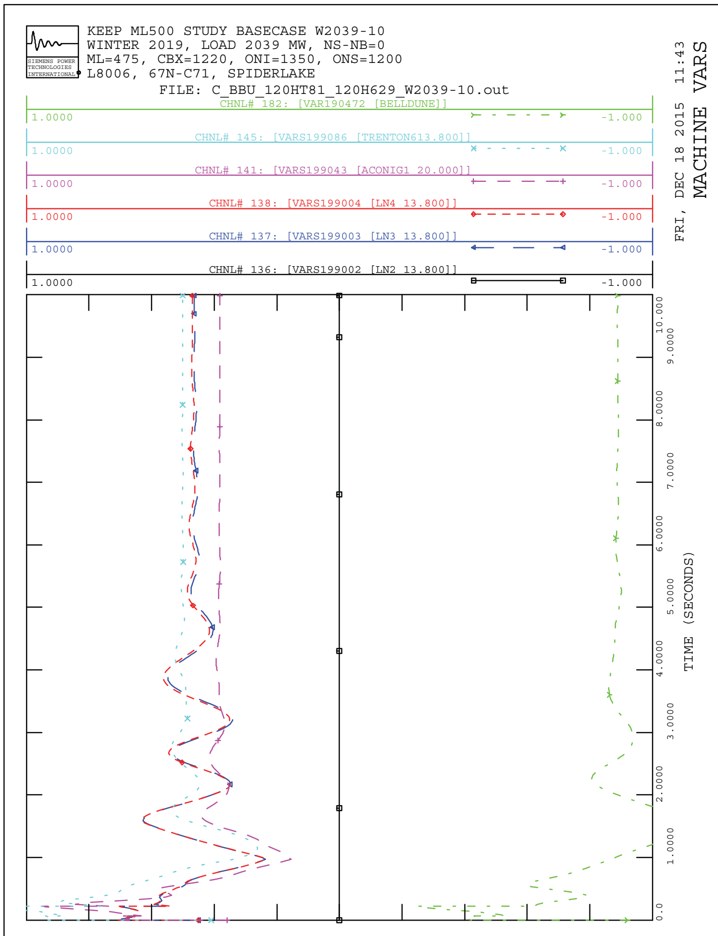
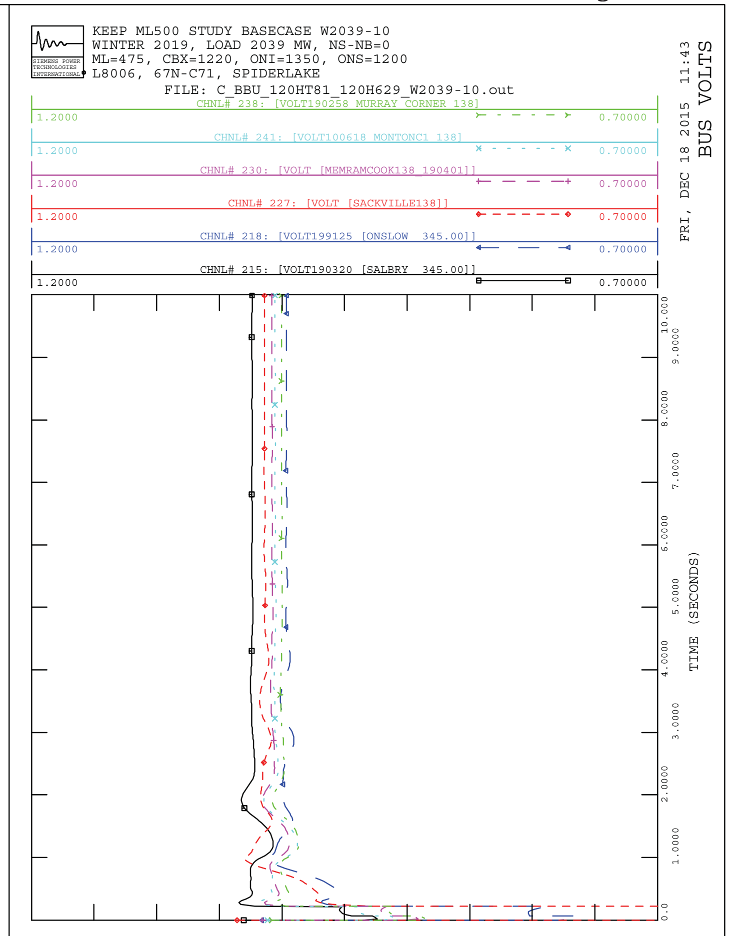
2.5000 0.0
FRI, DEC 18 2015 11:43
MACHINE POWER
TIME (SECONDS)



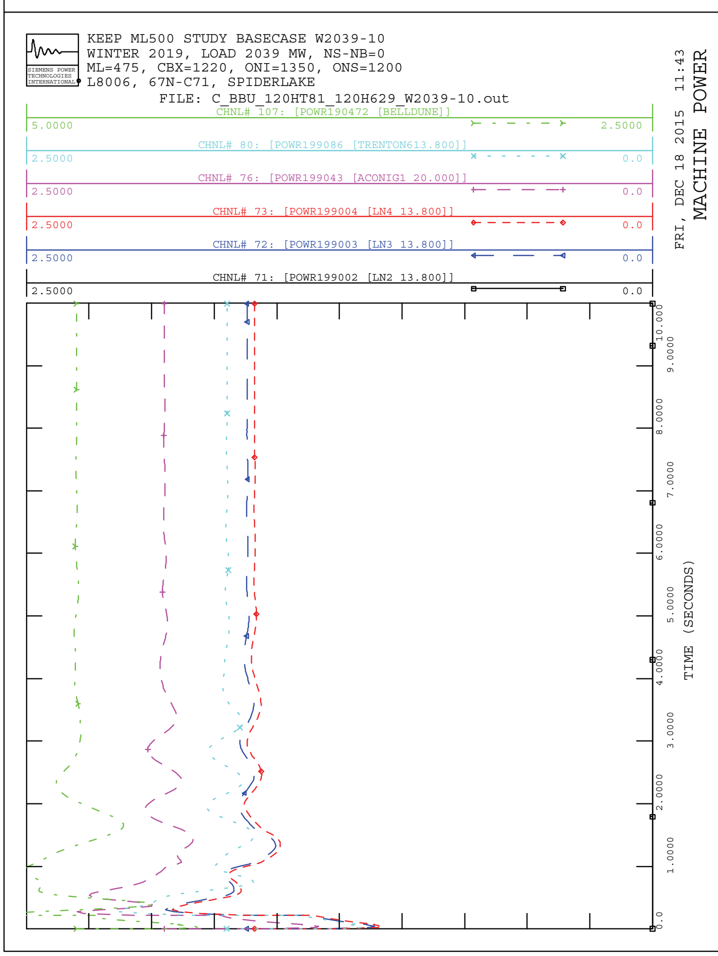
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_3PH_SVC_120H_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
FRI, DEC 18 2015 11:43
MARITIME LINK
TIME (SECONDS)



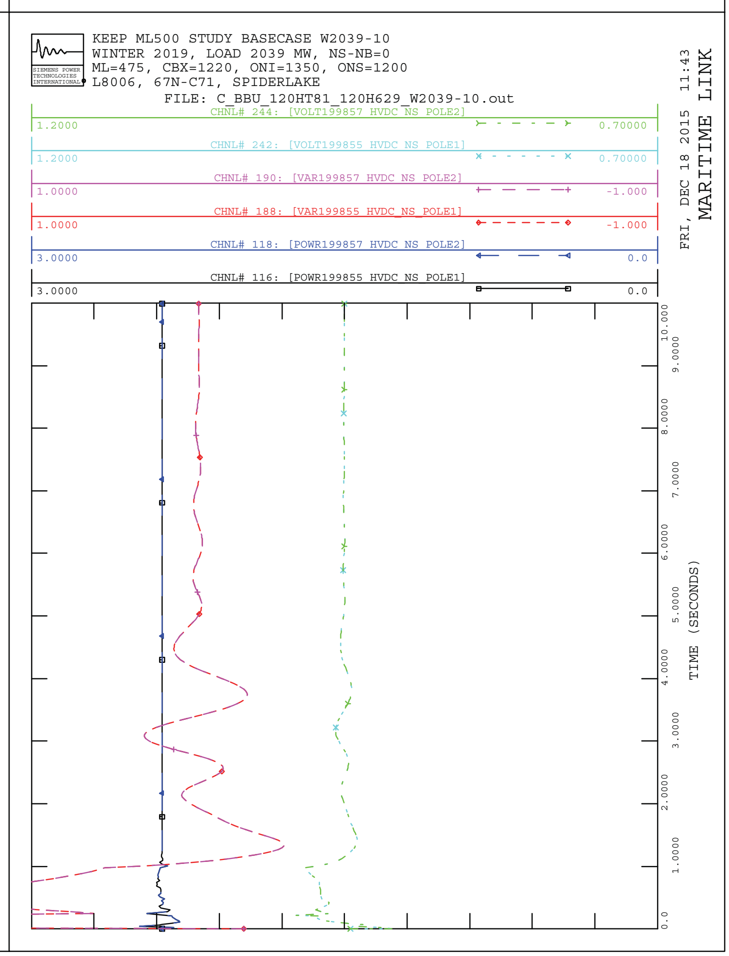
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_120HT81_120H629_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
FRI, DEC 18 2015 11:43
MACHINE VARS
TIME (SECONDS)



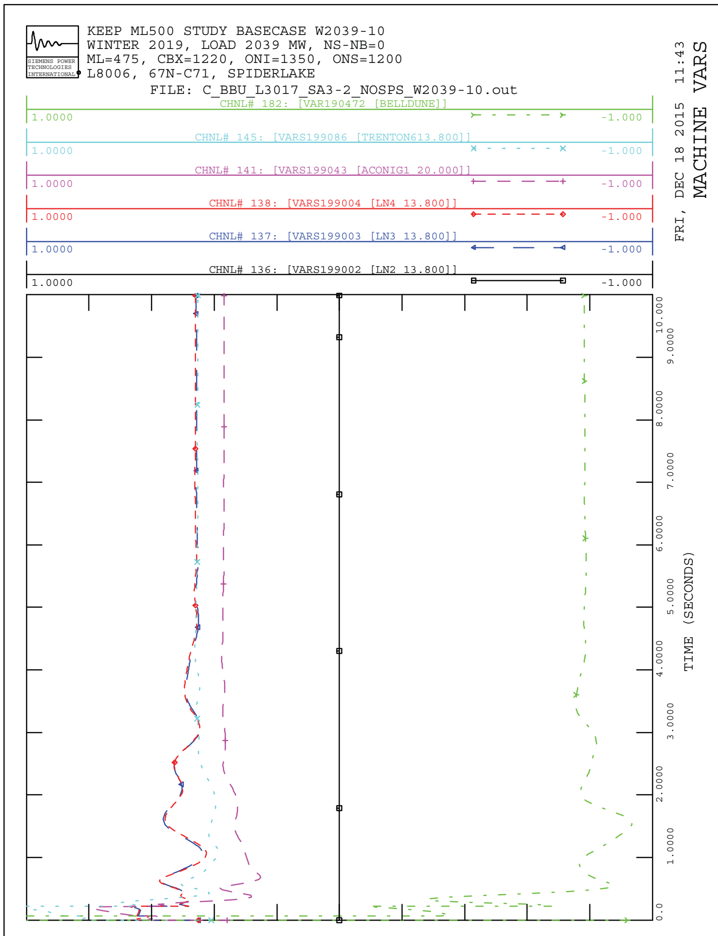
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_120HT81_120H629_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
FRI, DEC 18 2015 11:43
BUS VOLTS
TIME (SECONDS)



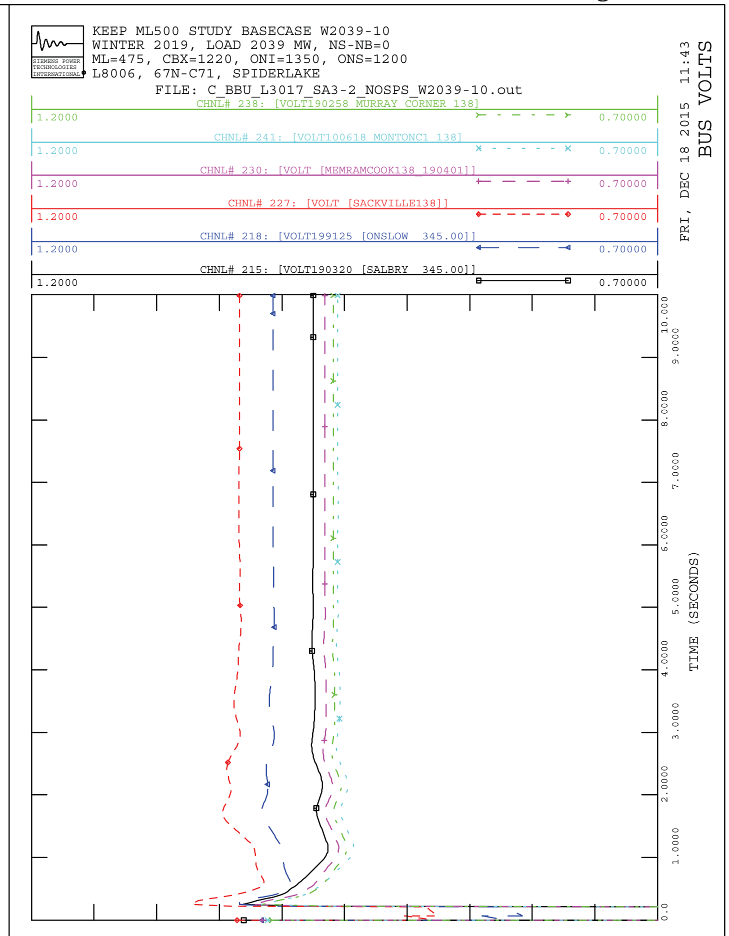
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_120HT81_120H629_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
FRI, DEC 18 2015 11:43
MACHINE POWER
TIME (SECONDS)



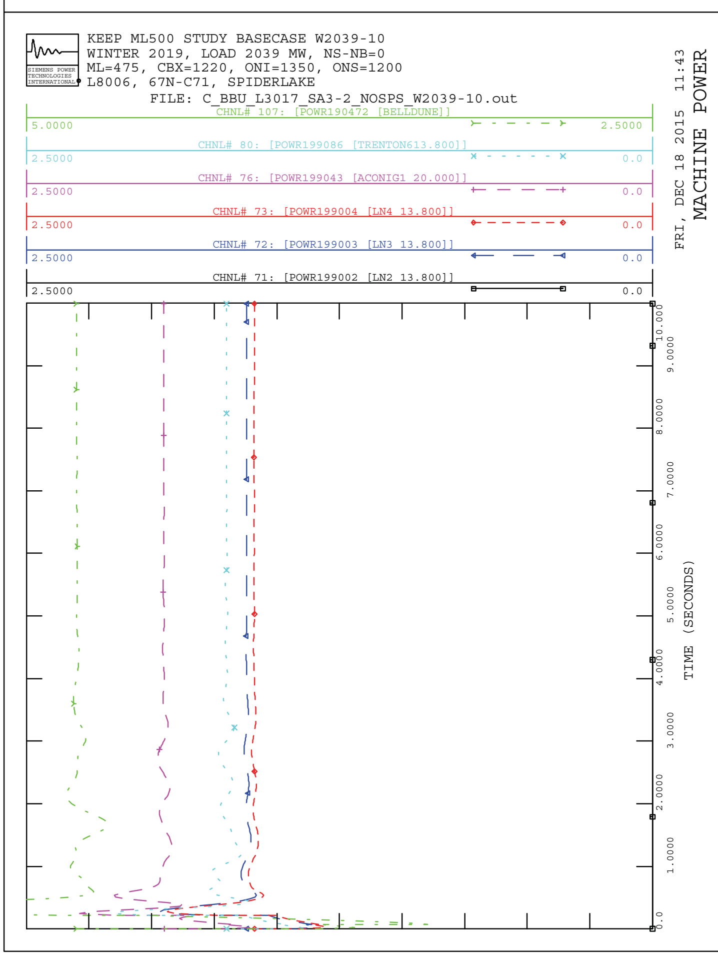
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_120HT81_120H629_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
FRI, DEC 18 2015 11:43
MARITIME LINK
TIME (SECONDS)



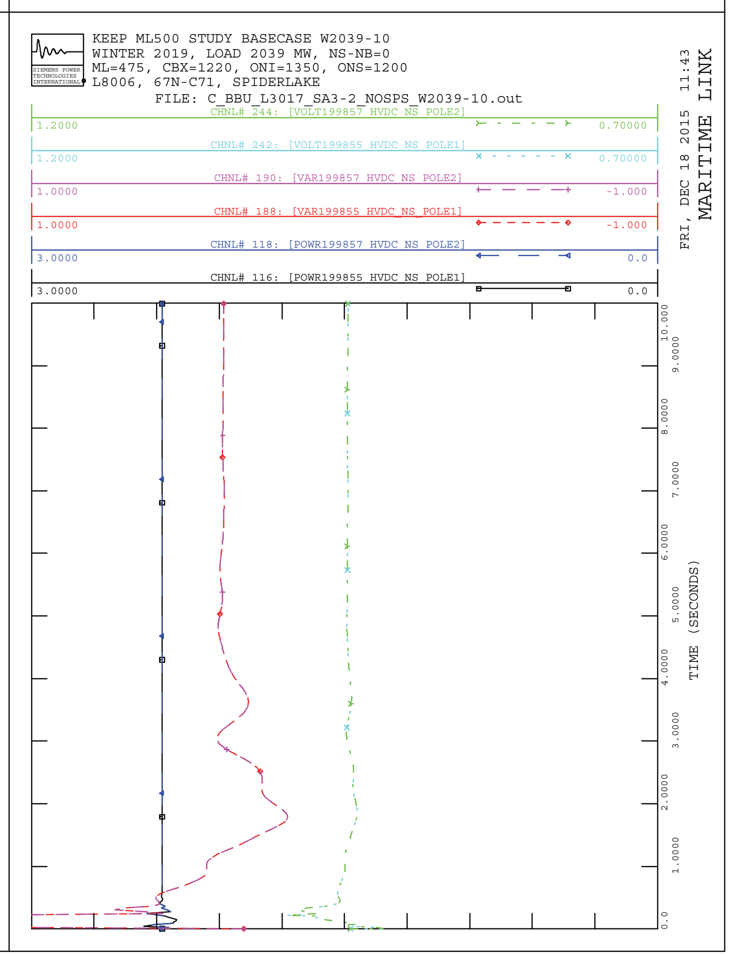
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L3017_SA3-2_NOSPS_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
FRI, DEC 18 2015 11:43
MACHINE VARS
TIME (SECONDS)



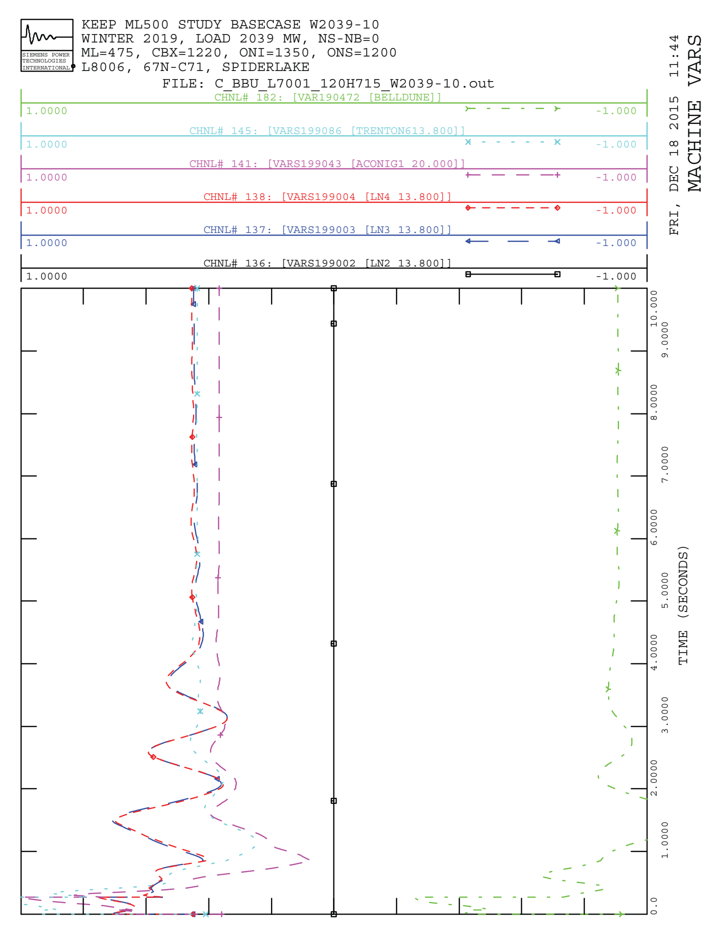
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L3017_SA3-2_NOSPS_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
FRI, DEC 18 2015 11:43
BUS VOLTS
TIME (SECONDS)

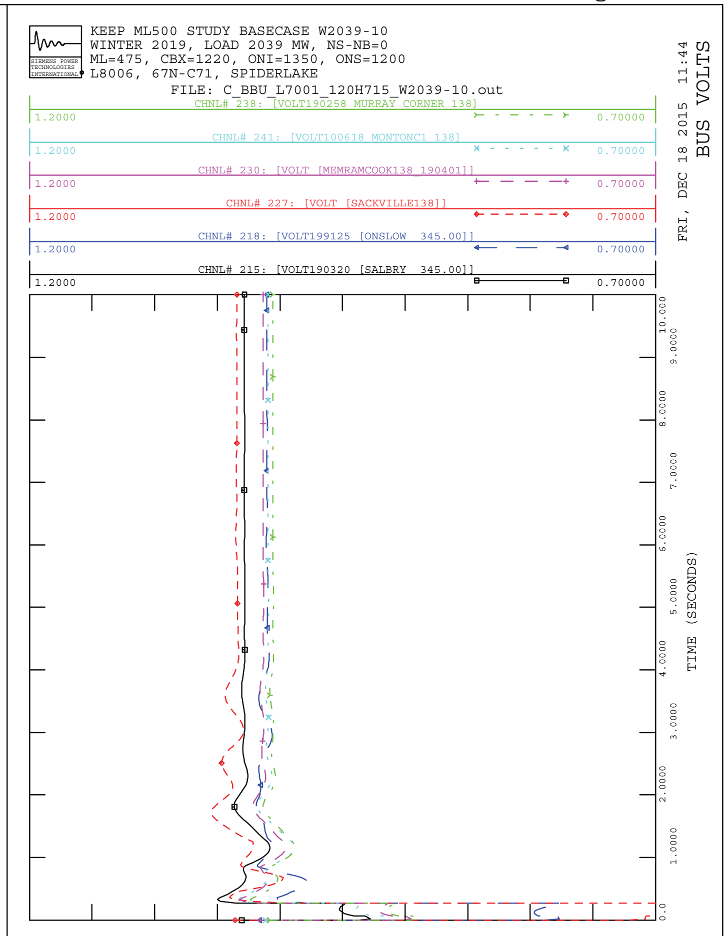


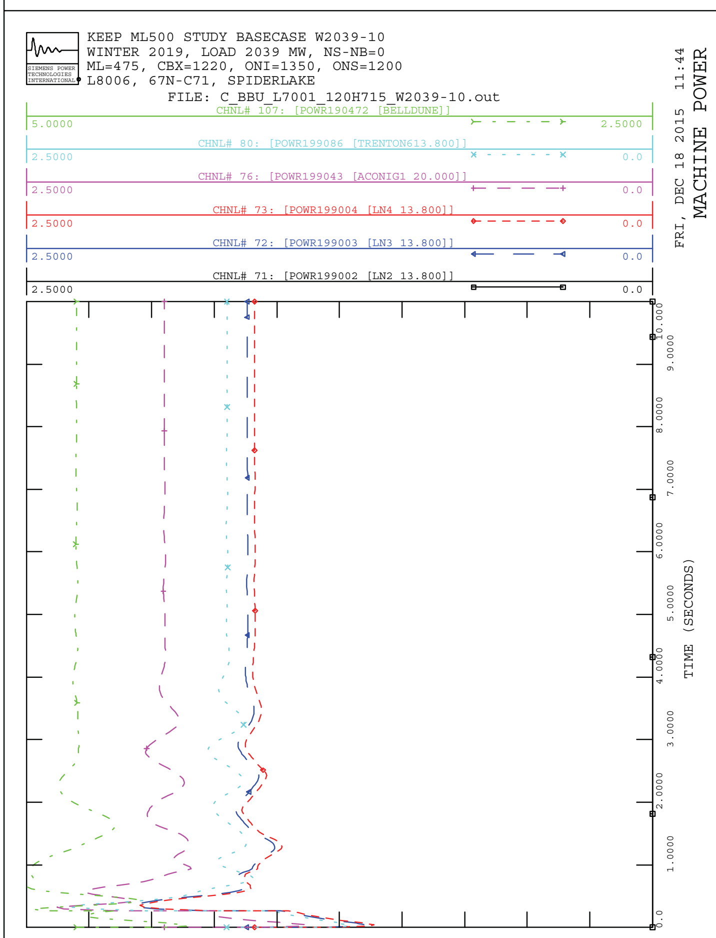
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L3017_SA3-2_NOSPS_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
FRI, DEC 18 2015 11:43
MACHINE POWER
TIME (SECONDS)

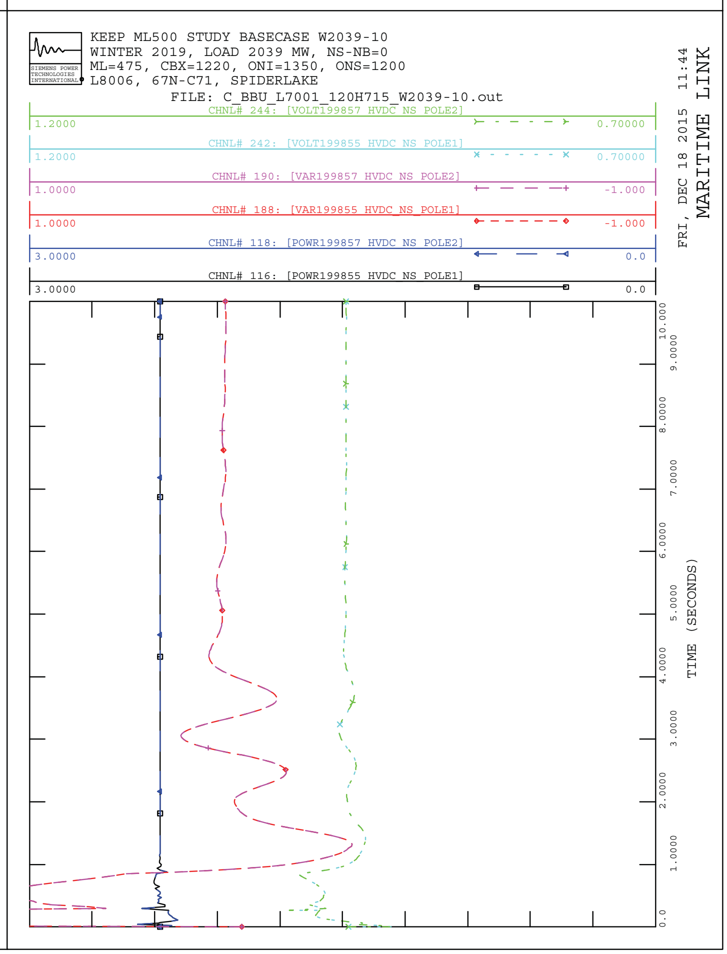


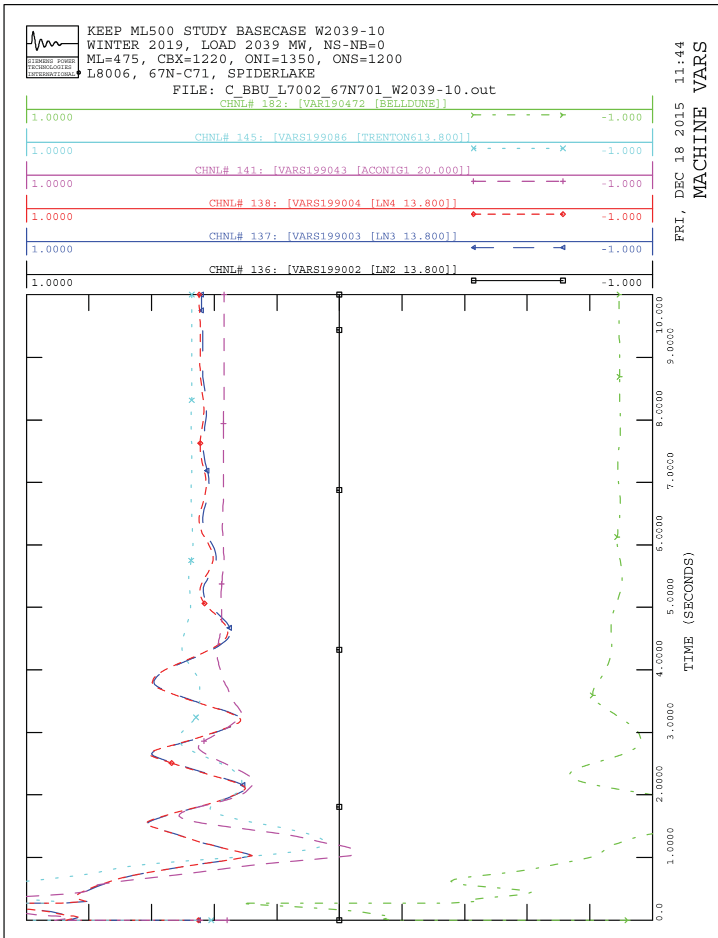
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L3017_SA3-2_NOSPS_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
FRI, DEC 18 2015 11:43
MARITIME LINK
TIME (SECONDS)

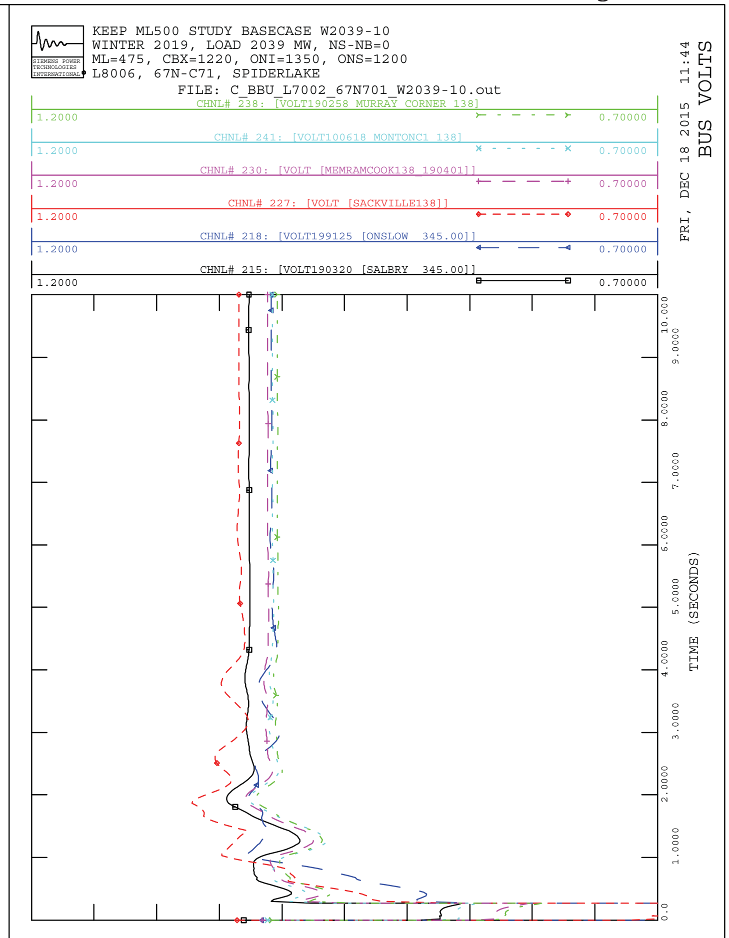

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7001_120H715_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000
-1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000
-1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000
-1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000
-1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000
-1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000
-1.000
FRI, DEC 18 2015 11:44
MACHINE VARS
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

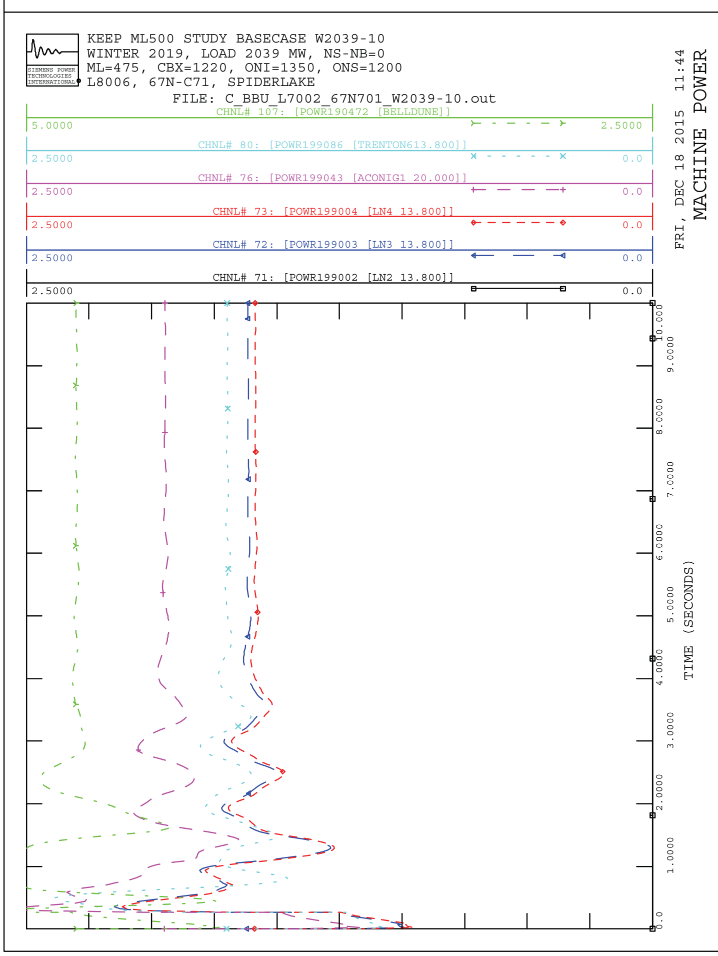

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7001_120H715_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000
0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000
0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000
0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000
0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000
0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000
0.70000
FRI, DEC 18 2015 11:44
BUS VOLTS
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

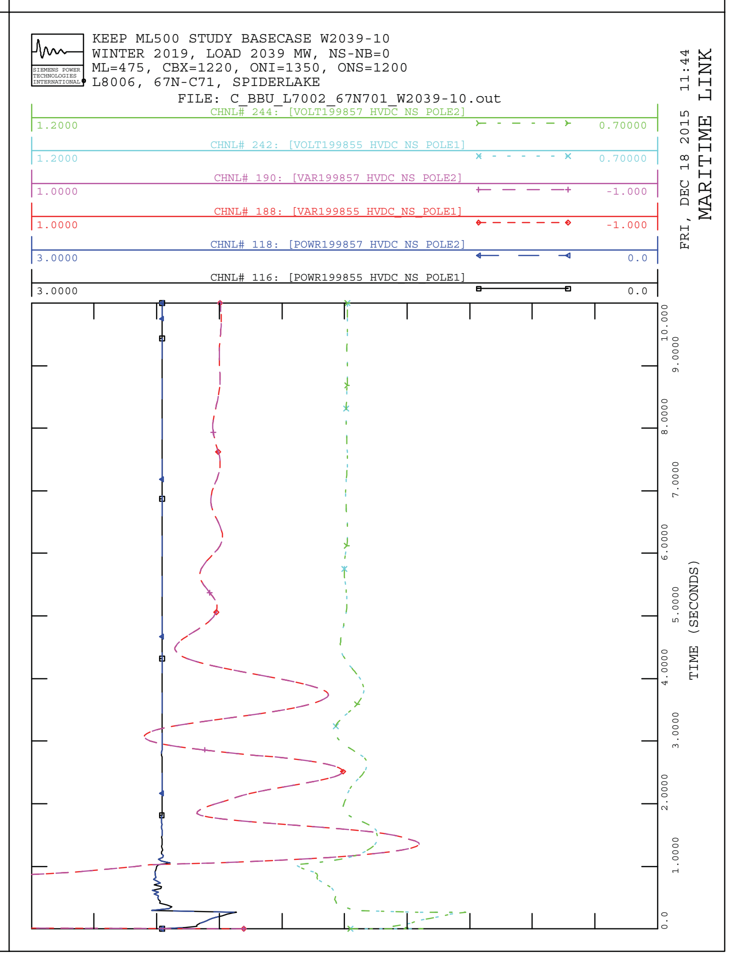

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7001_120H715_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000
2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000
0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000
0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000
0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000
0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000
0.0
FRI, DEC 18 2015 11:44
MACHINE POWER
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7001_120H715_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000
0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000
0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000
-1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000
-1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000
0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000
0.0
FRI, DEC 18 2015 11:44
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

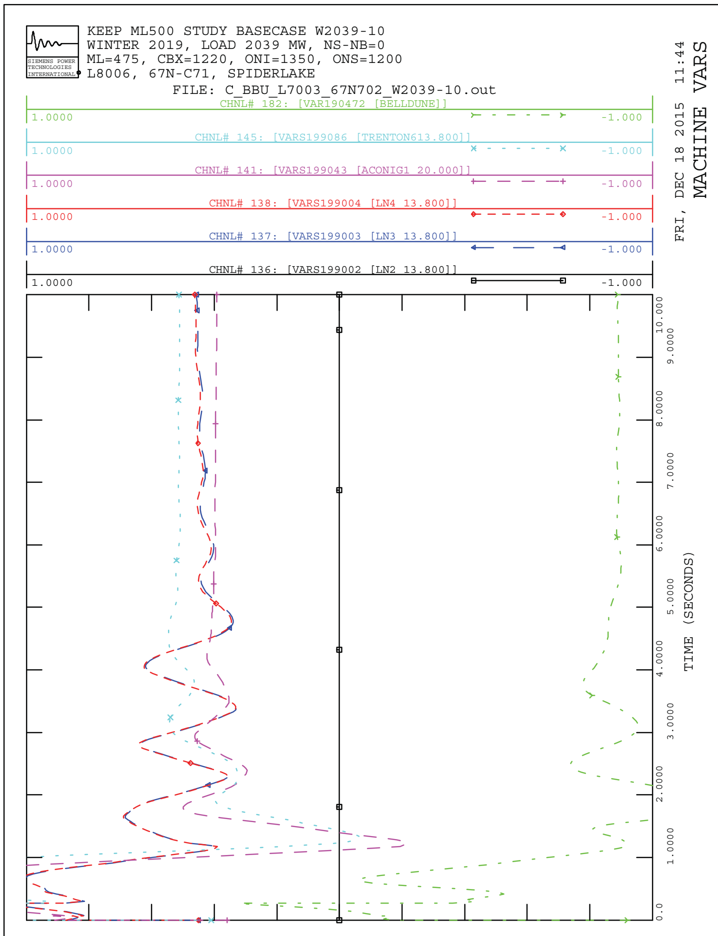

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7002_67N701_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
FRI, DEC 18 2015 11:44
MACHINE VARS
TIME (SECONDS)

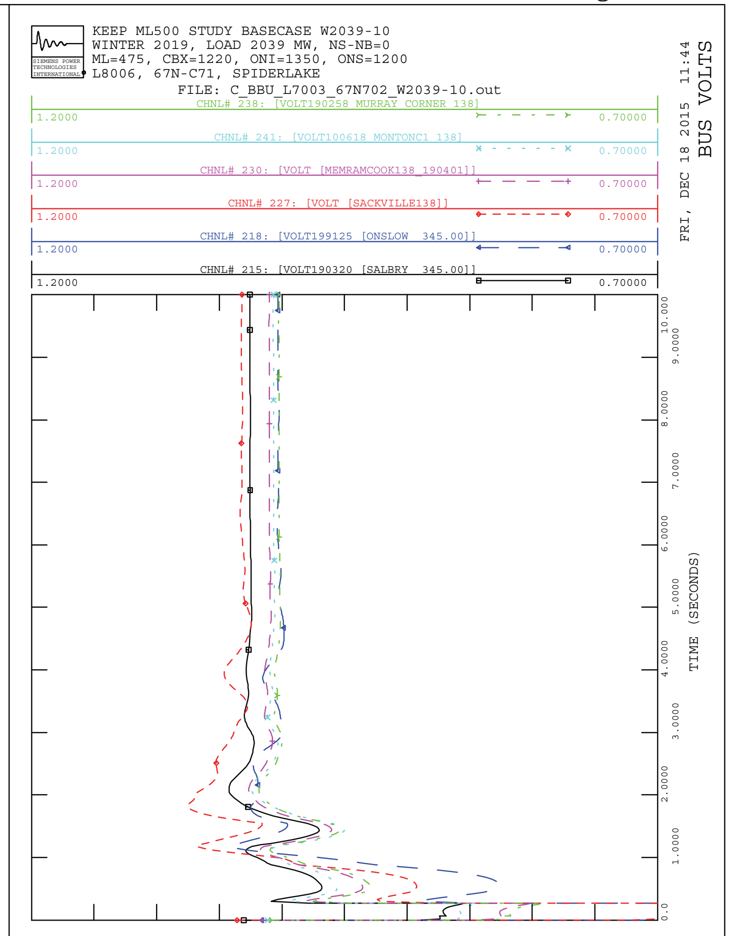

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7002_67N701_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
FRI, DEC 18 2015 11:44
BUS VOLTS
TIME (SECONDS)

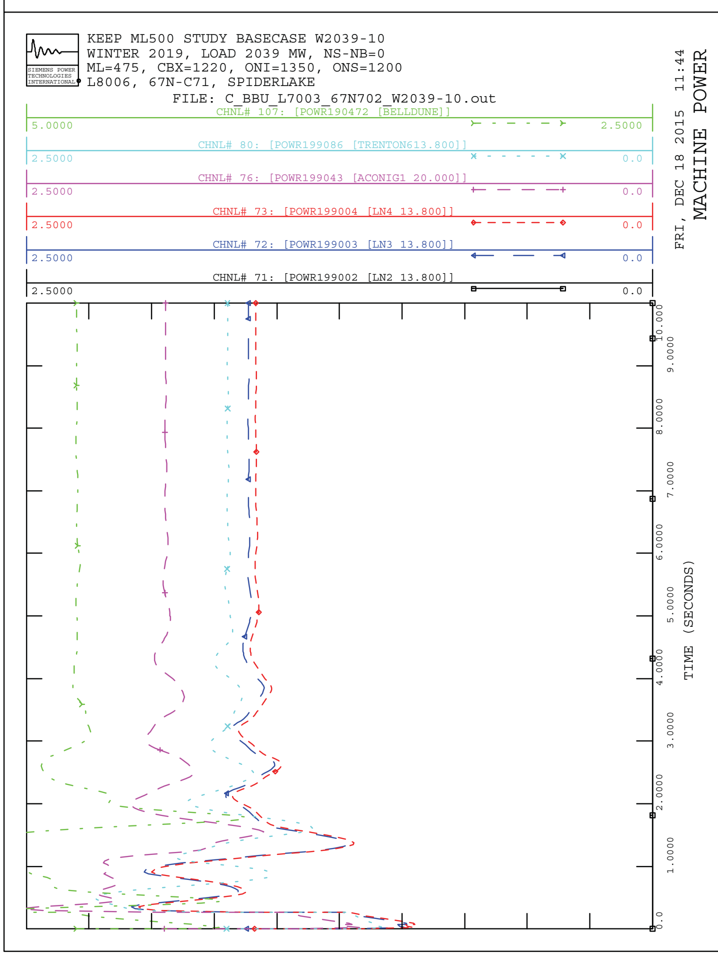

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7002_67N701_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
FRI, DEC 18 2015 11:44
MACHINE POWER
TIME (SECONDS)

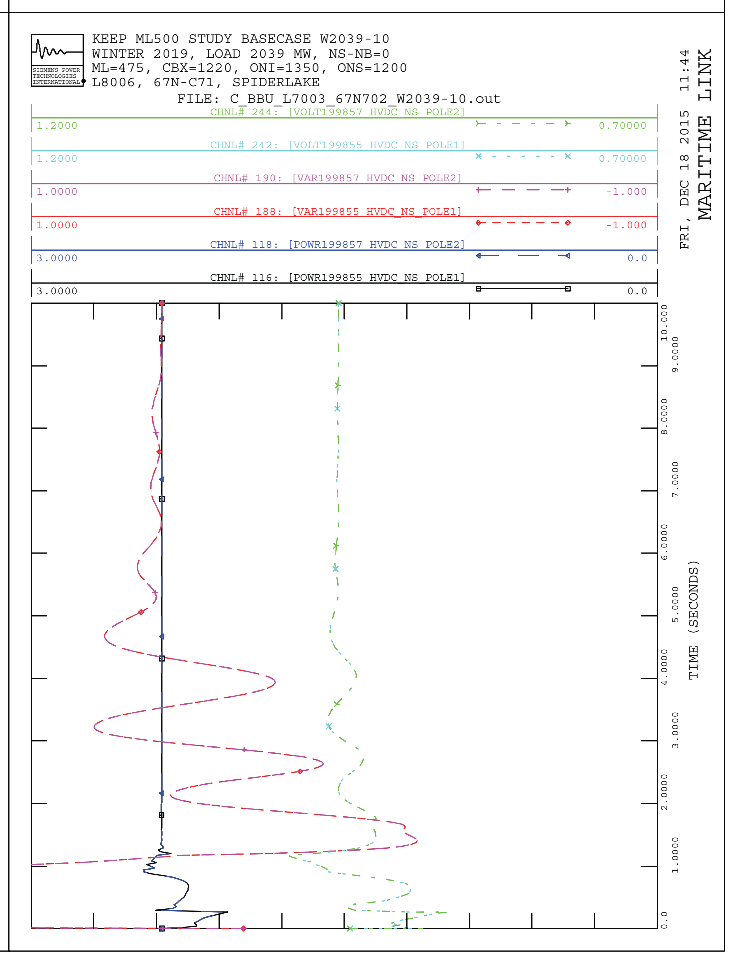

KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7002_67N701_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
FRI, DEC 18 2015 11:44
MARITIME LINK
TIME (SECONDS)

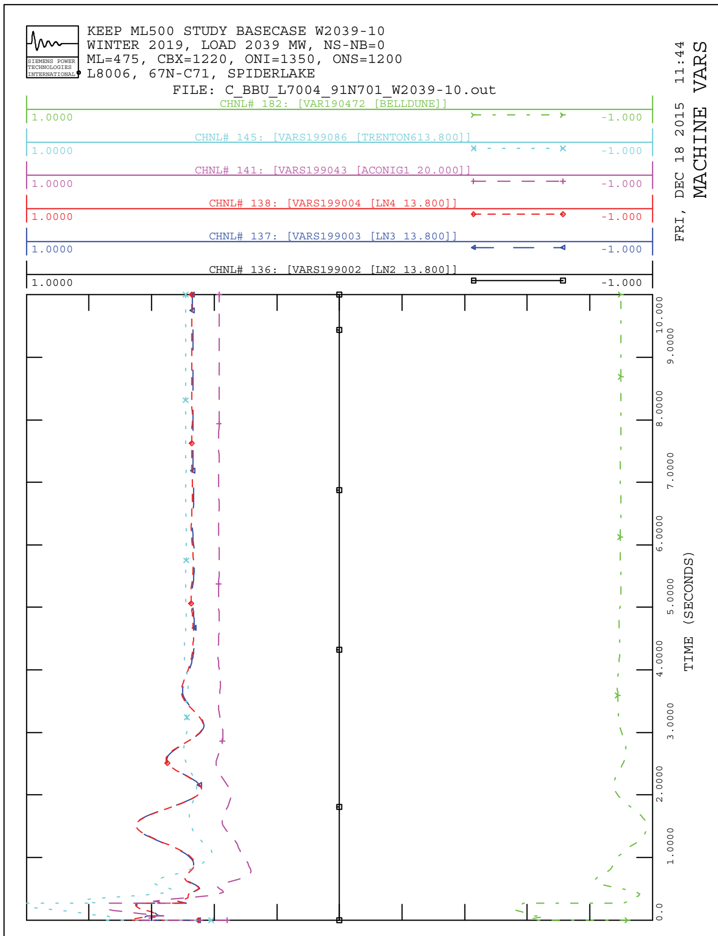
REDACTED (CONFIDENTIAL INFORMATION REMOVED)










KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7004_91N701_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
FRI, DEC 18 2015 11:44
MACHINE VARS
TIME (SECONDS)
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2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
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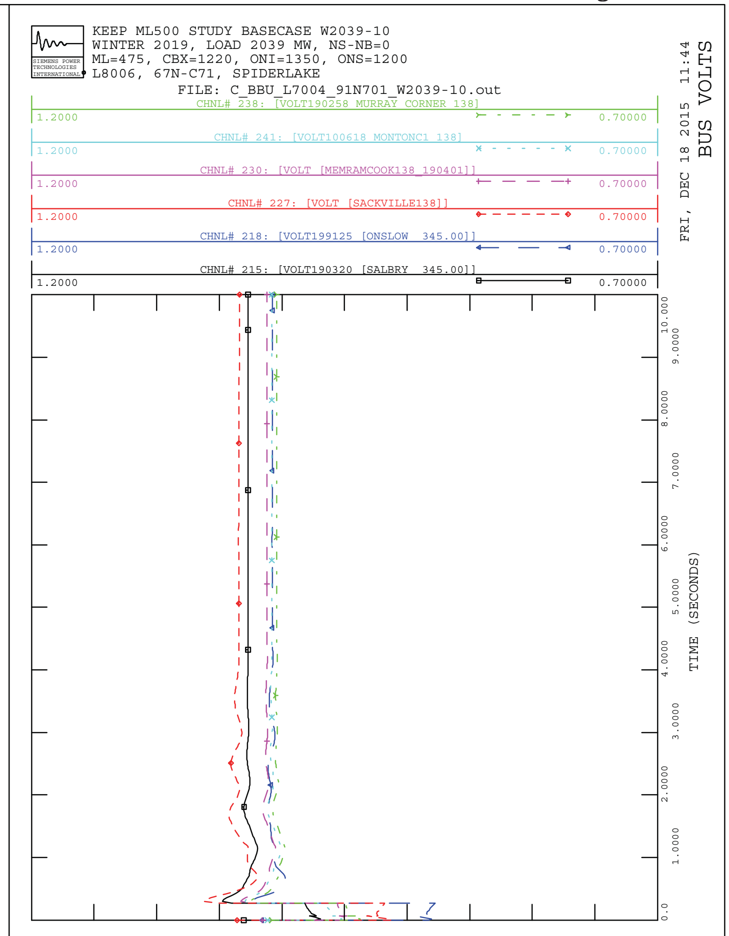
9.0000
10.000


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7004_91N701_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
FRI, DEC 18 2015 11:44
BUS VOLTS
TIME (SECONDS)
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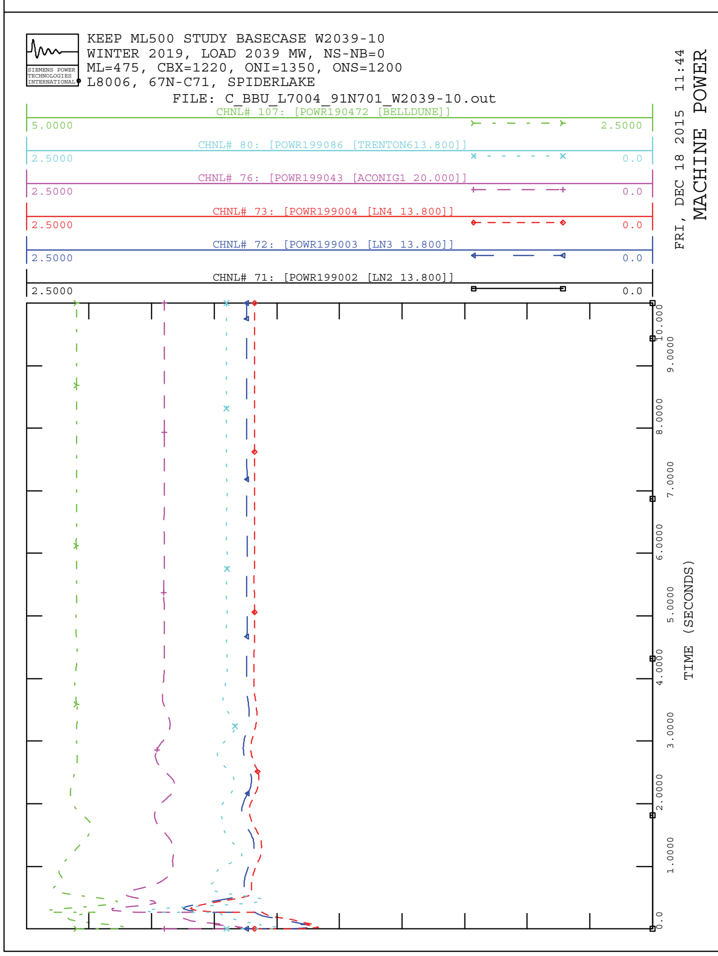
9.0000
10.000


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7004_91N701_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
FRI, DEC 18 2015 11:44
MACHINE POWER
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
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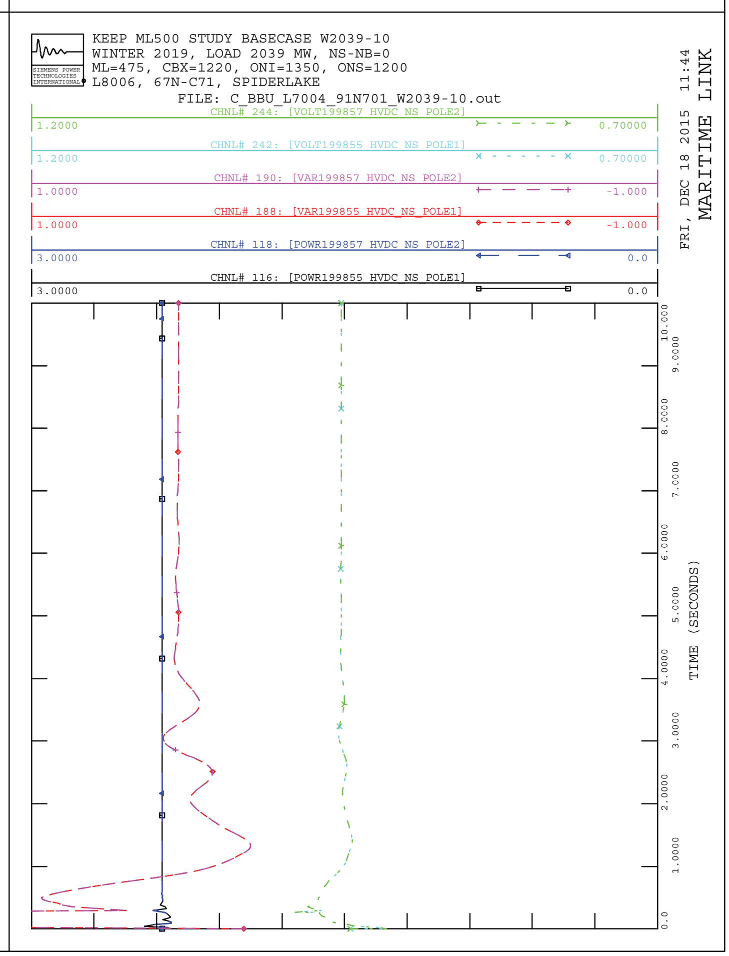
9.0000
10.000


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7004_91N701_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
FRI, DEC 18 2015 11:44
MARITIME LINK
TIME (SECONDS)
0.0
1.0000
2.0000
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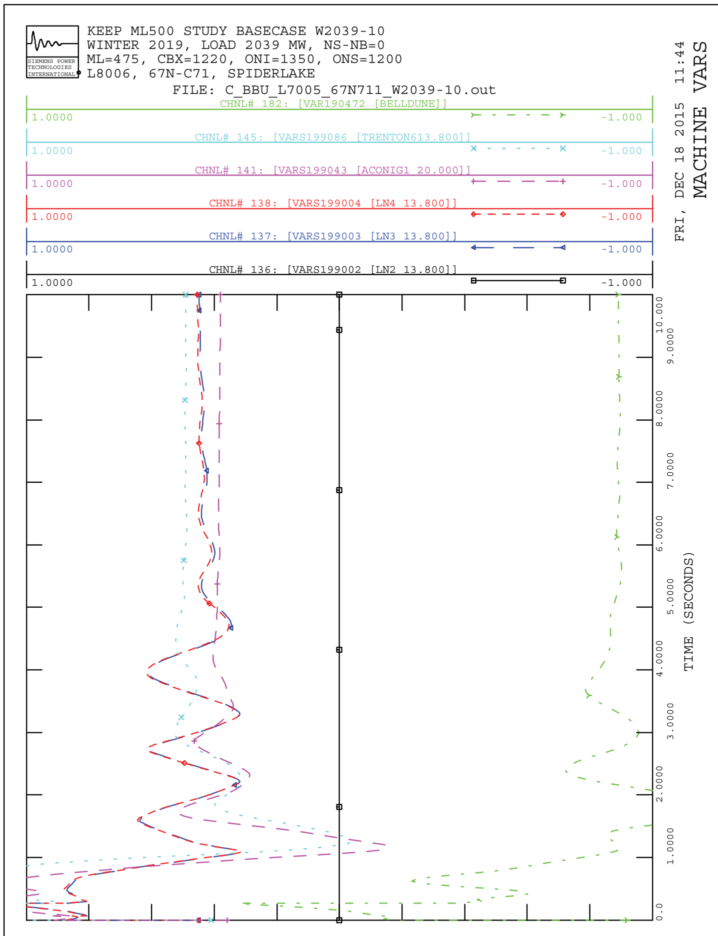
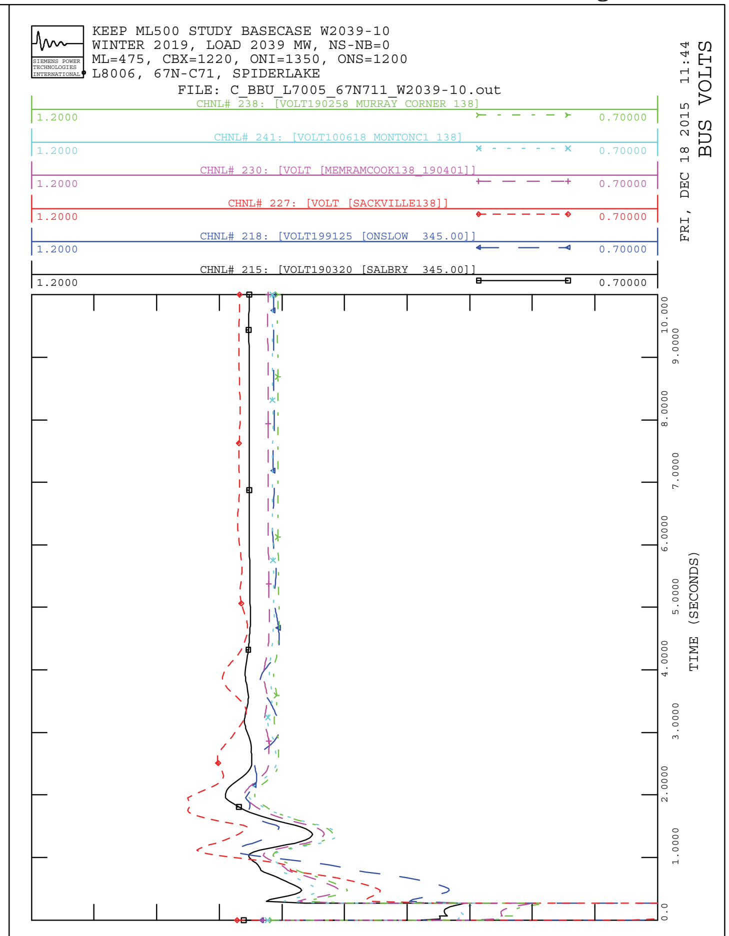
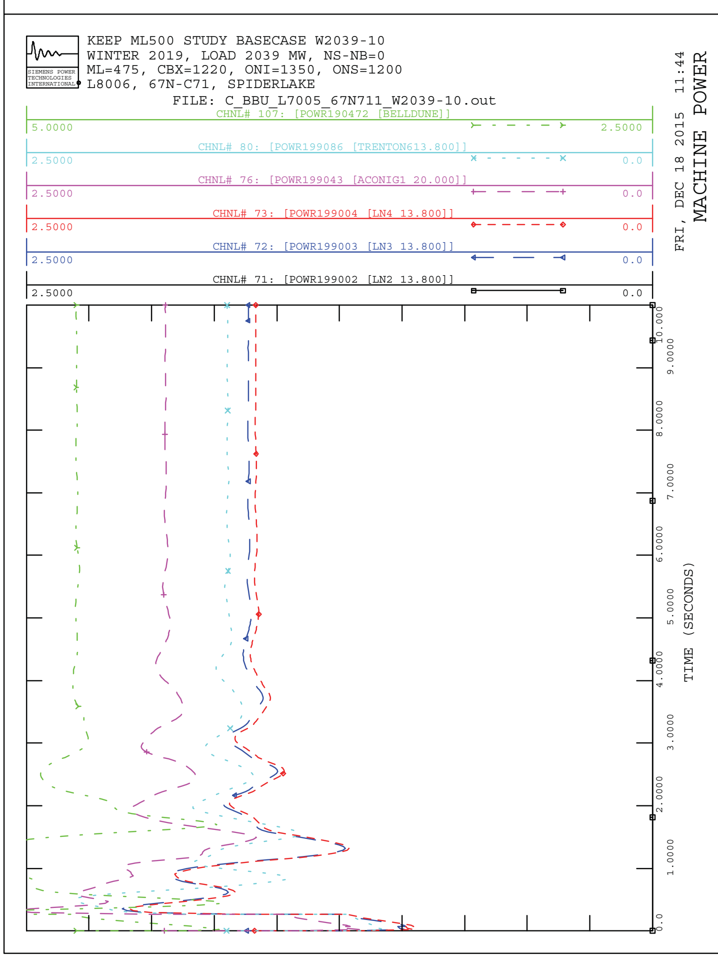
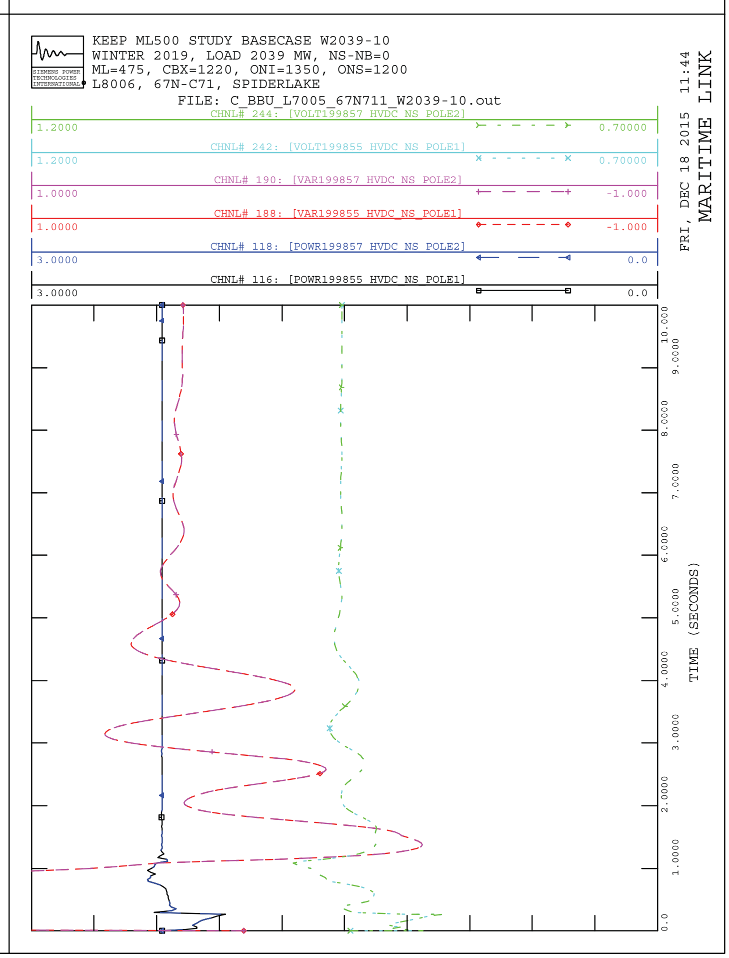
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

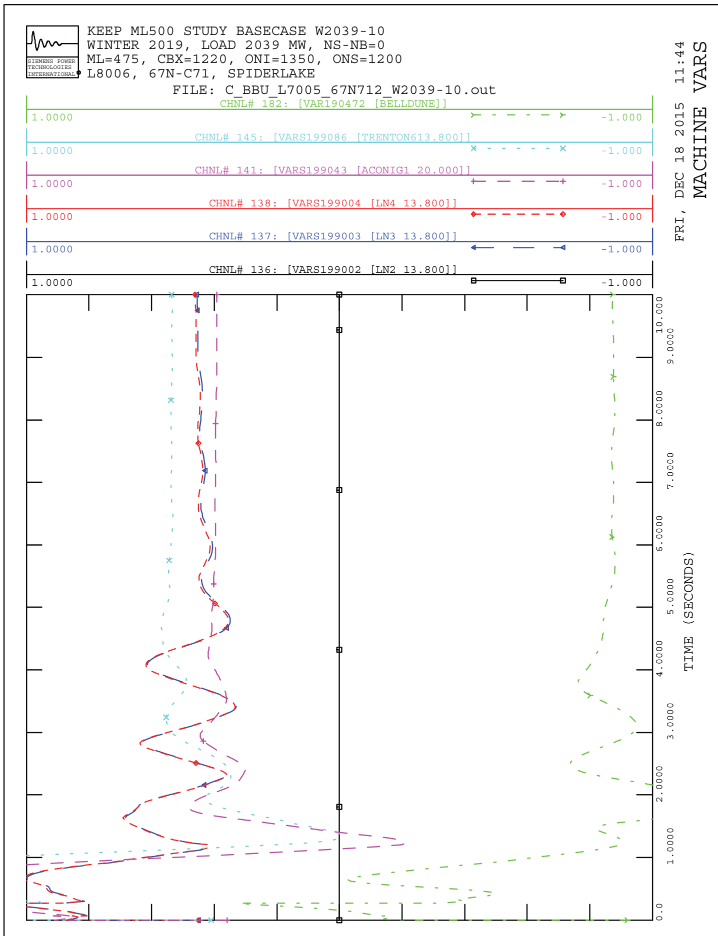
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



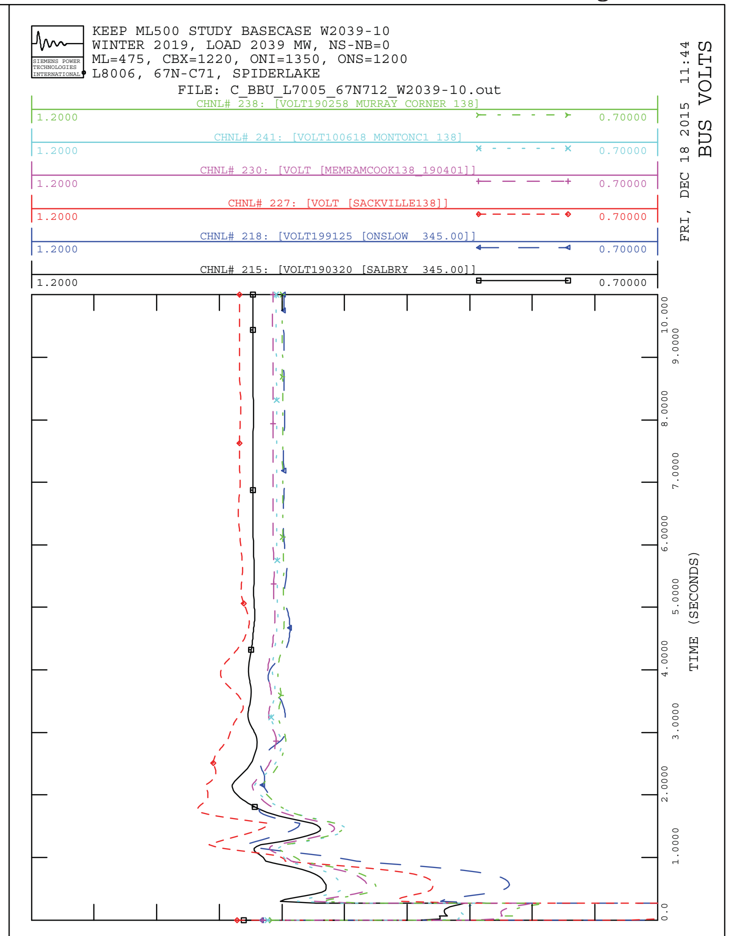




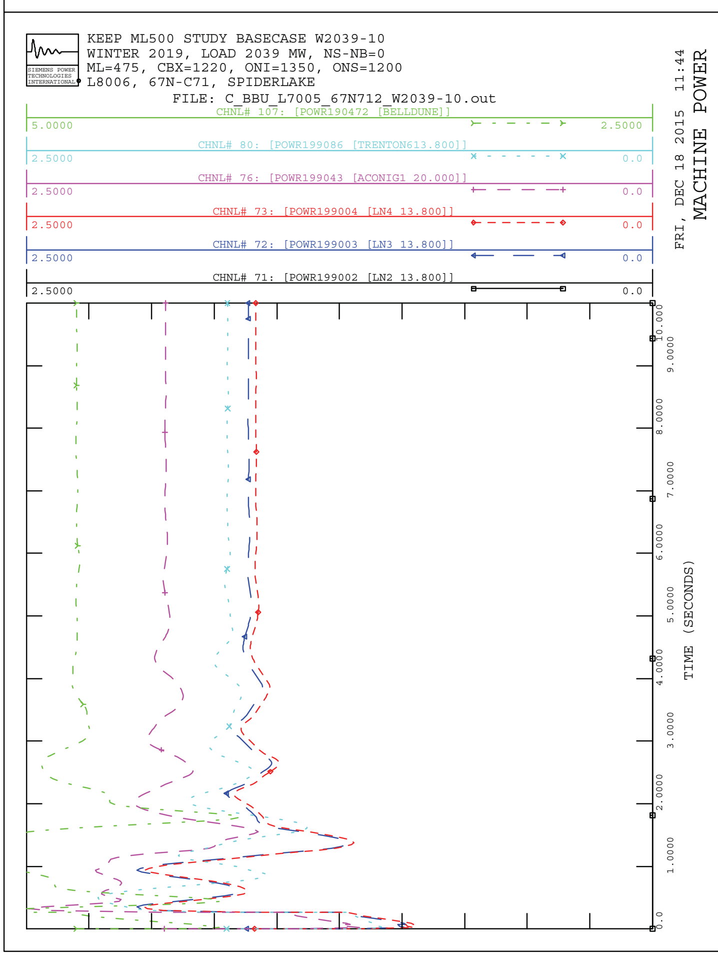




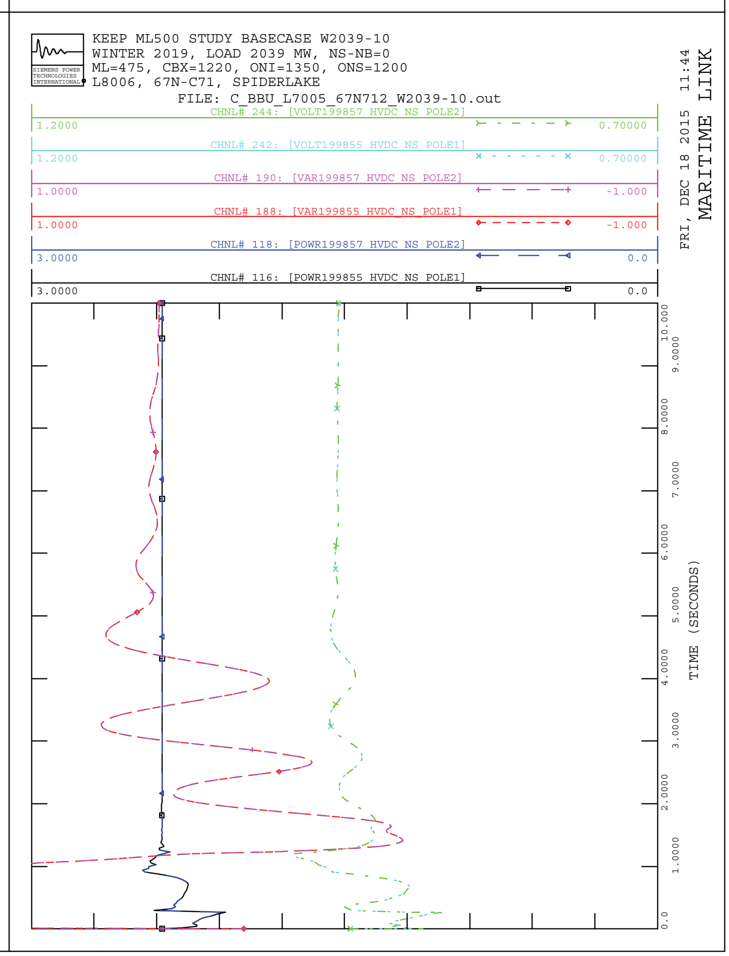
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7005_67N712_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
CHNL# 145: [VARS199086 [TRENTON613.800]]
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
CHNL# 138: [VARS199004 [LN4 13.800]]
CHNL# 137: [VARS199003 [LN3 13.800]]
CHNL# 136: [VARS199002 [LN2 13.800]]
FRI, DEC 18 2015 11:44
MACHINE VARS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7005_67N712_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
CHNL# 241: [VOLT100618 MONTONC1 138]
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
CHNL# 227: [VOLT [SACKVILLE138]]
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
FRI, DEC 18 2015 11:44
BUS VOLTS
TIME (SECONDS)

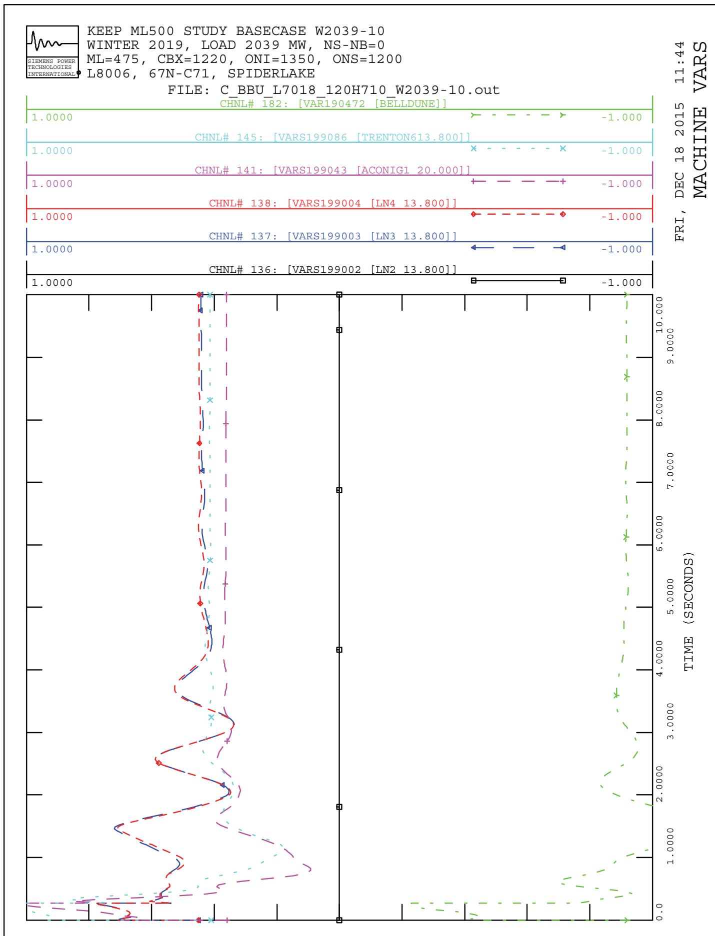


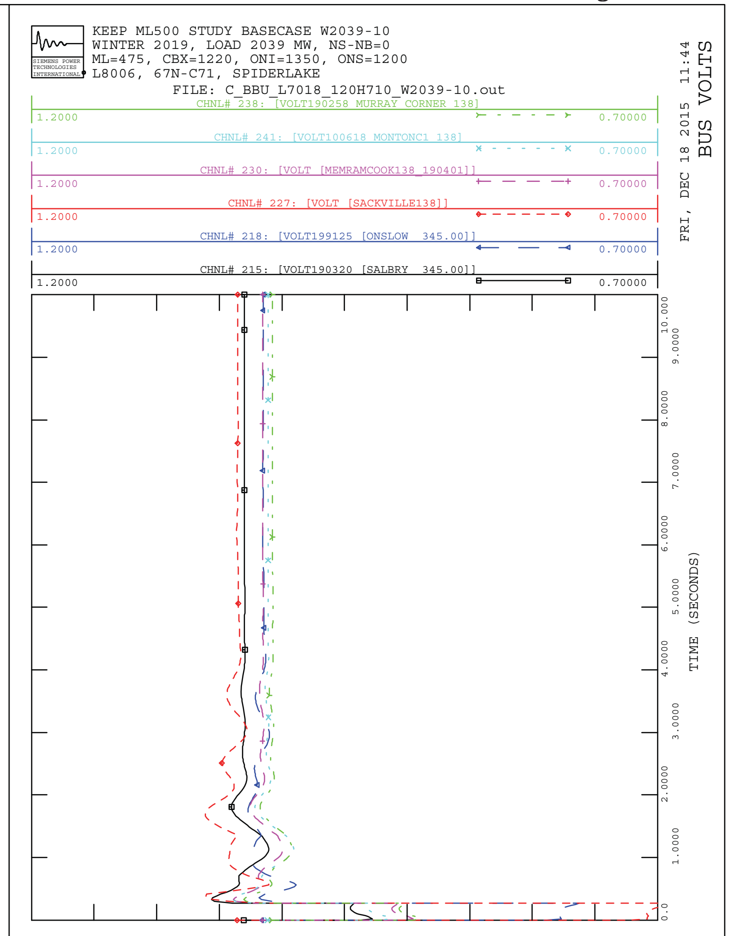
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7005_67N712_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
CHNL# 80: [POWR199086 [TRENTON613.800]]
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
CHNL# 73: [POWR199004 [LN4 13.800]]
CHNL# 72: [POWR199003 [LN3 13.800]]
CHNL# 71: [POWR199002 [LN2 13.800]]
FRI, DEC 18 2015 11:44
MACHINE POWER
TIME (SECONDS)

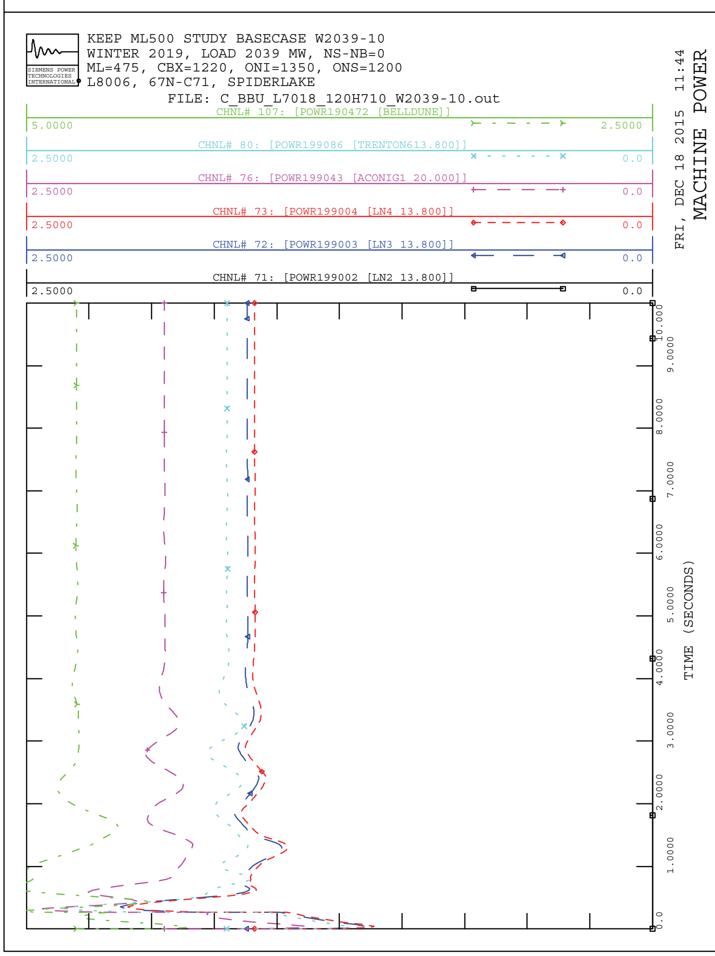


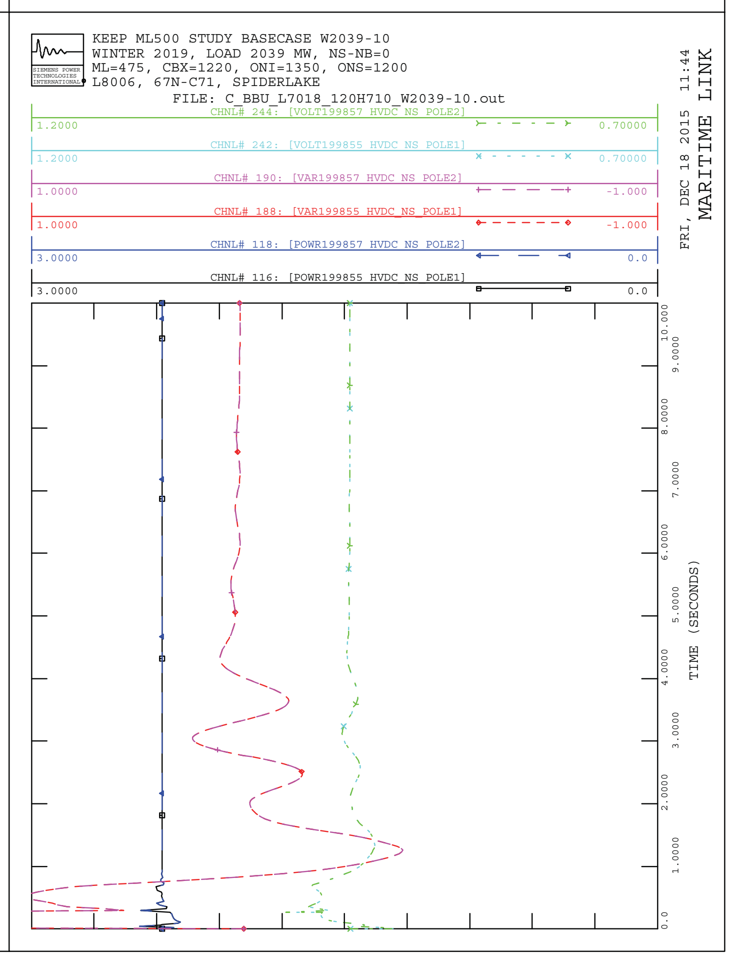
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L7005_67N712_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
CHNL# 242: [VOLT199855 HVDC NS POLE1]
CHNL# 190: [VAR199857 HVDC NS POLE2]
CHNL# 188: [VAR199855 HVDC NS POLE1]
CHNL# 118: [POWR199857 HVDC NS POLE2]
CHNL# 116: [POWR199855 HVDC NS POLE1]
FRI, DEC 18 2015 11:44
MARITIME LINK
TIME (SECONDS)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

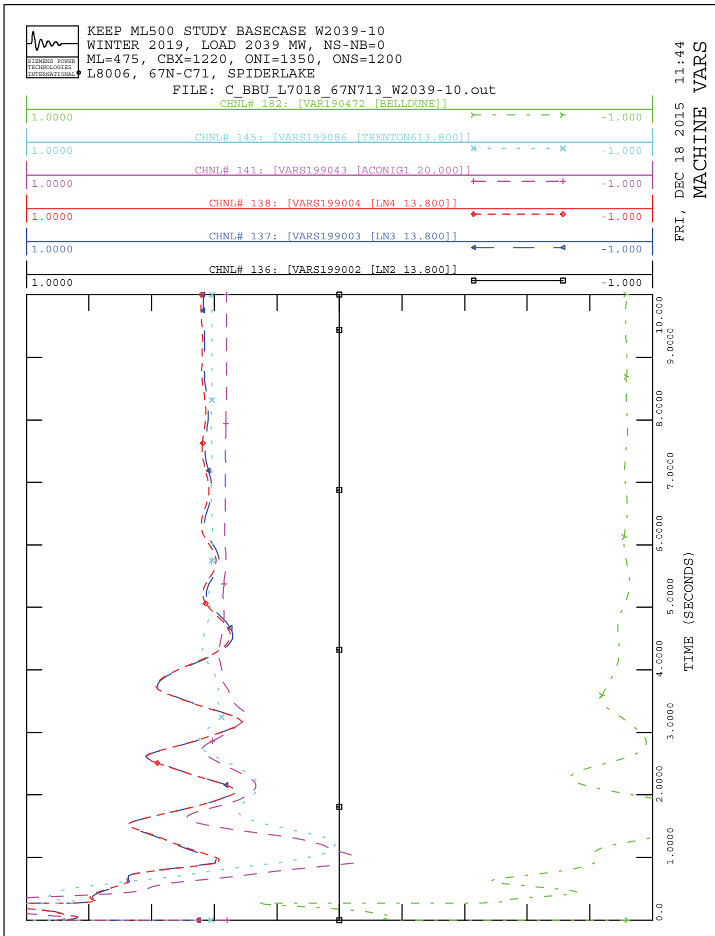


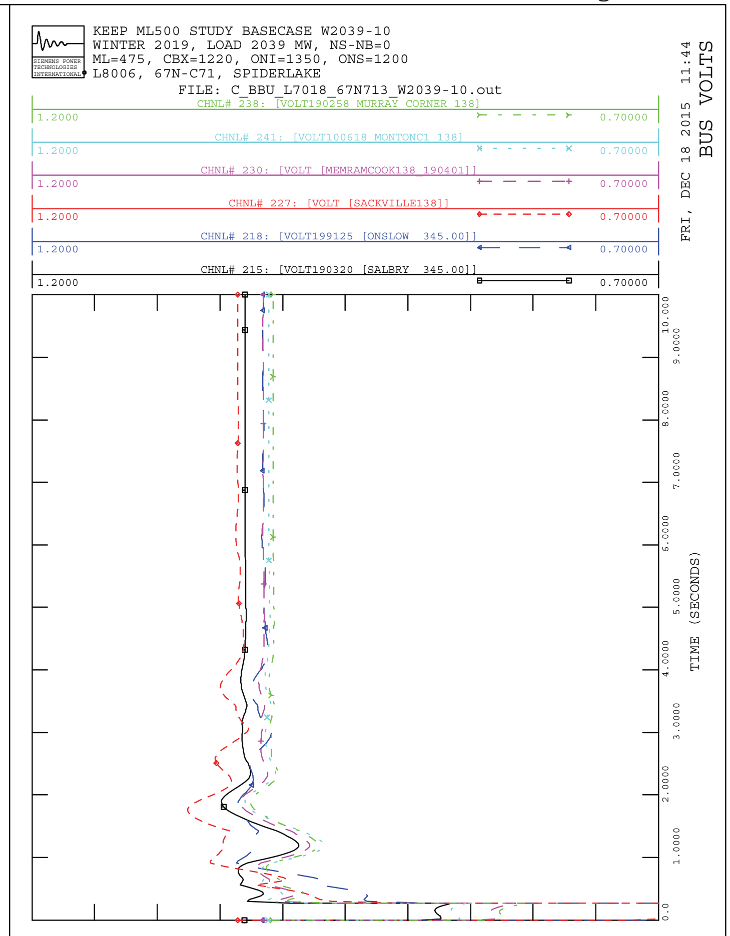


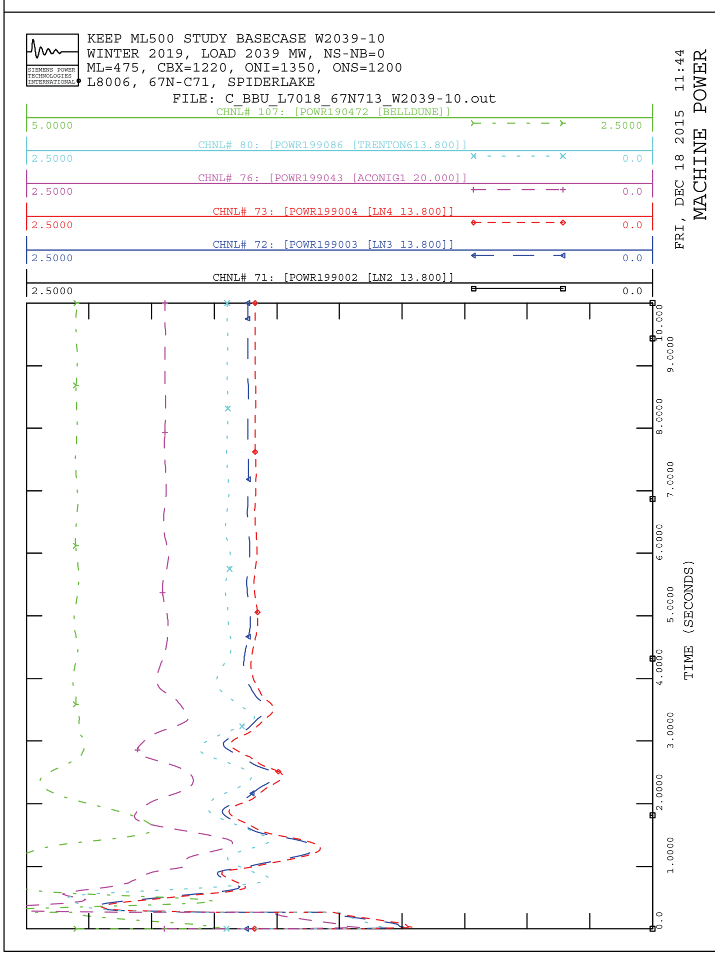


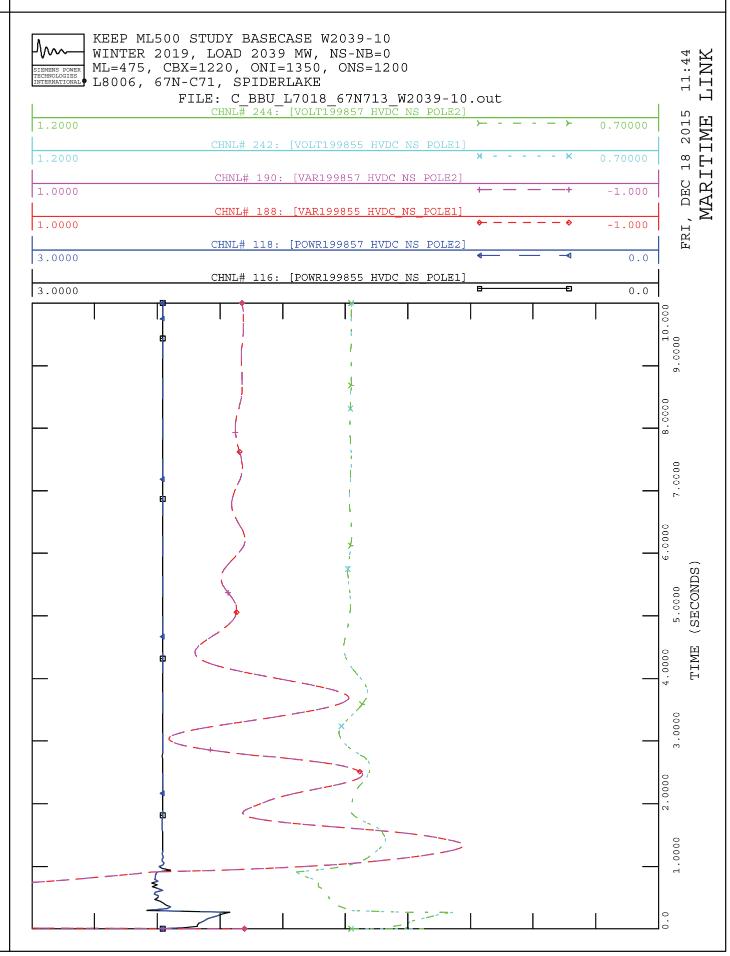


REDACTED (CONFIDENTIAL INFORMATION REMOVED)

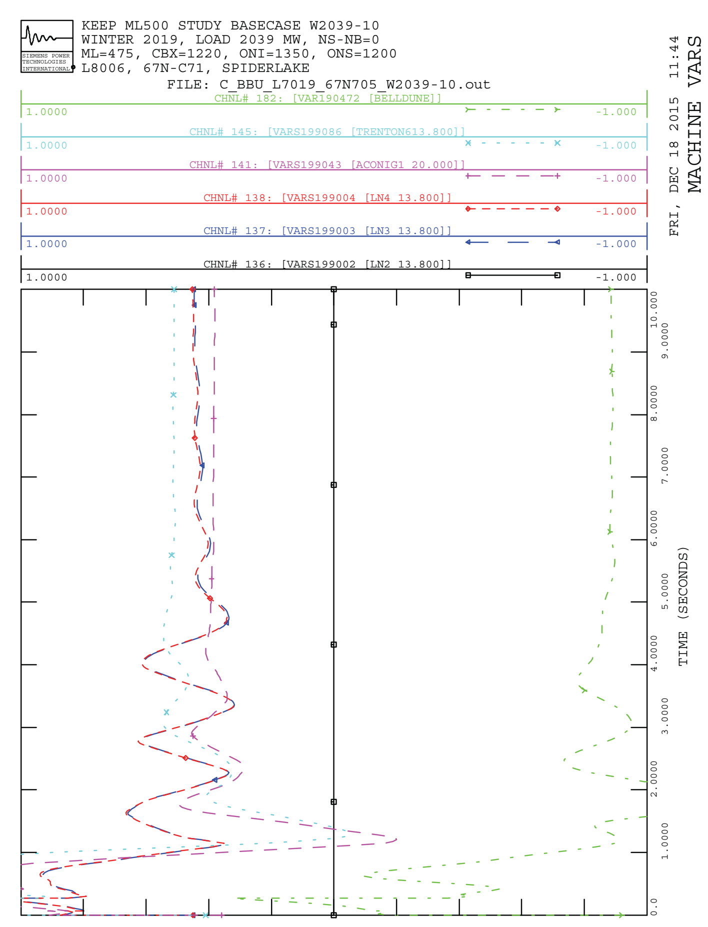


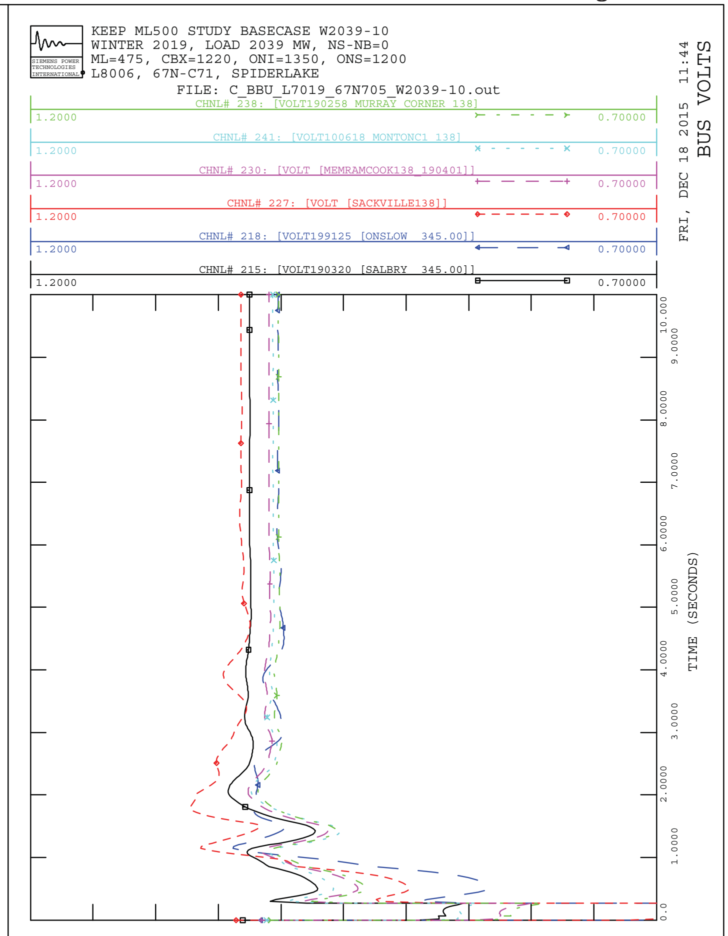


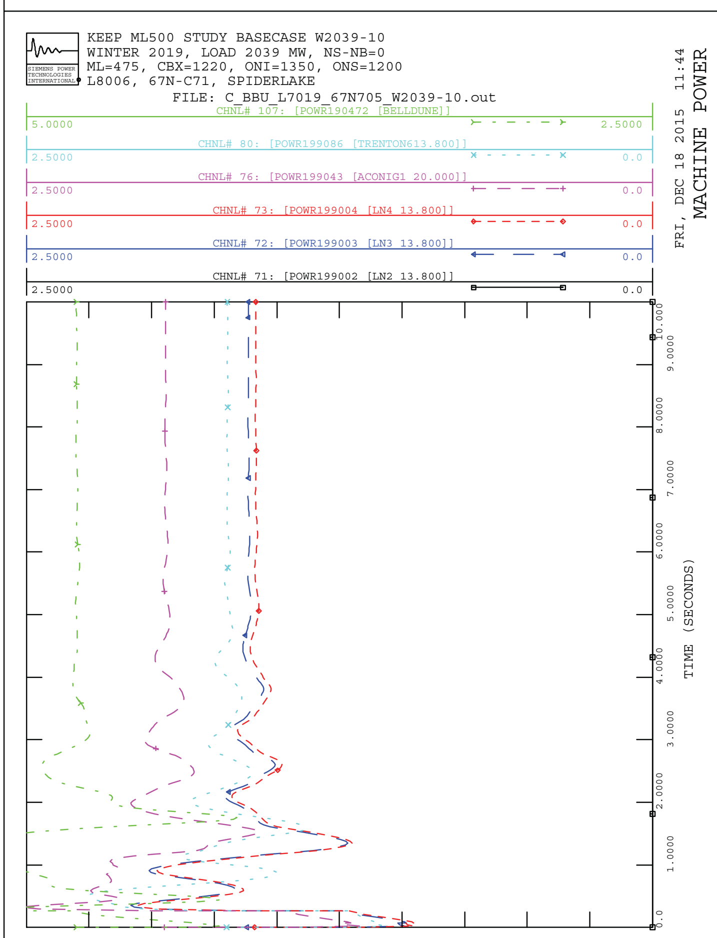


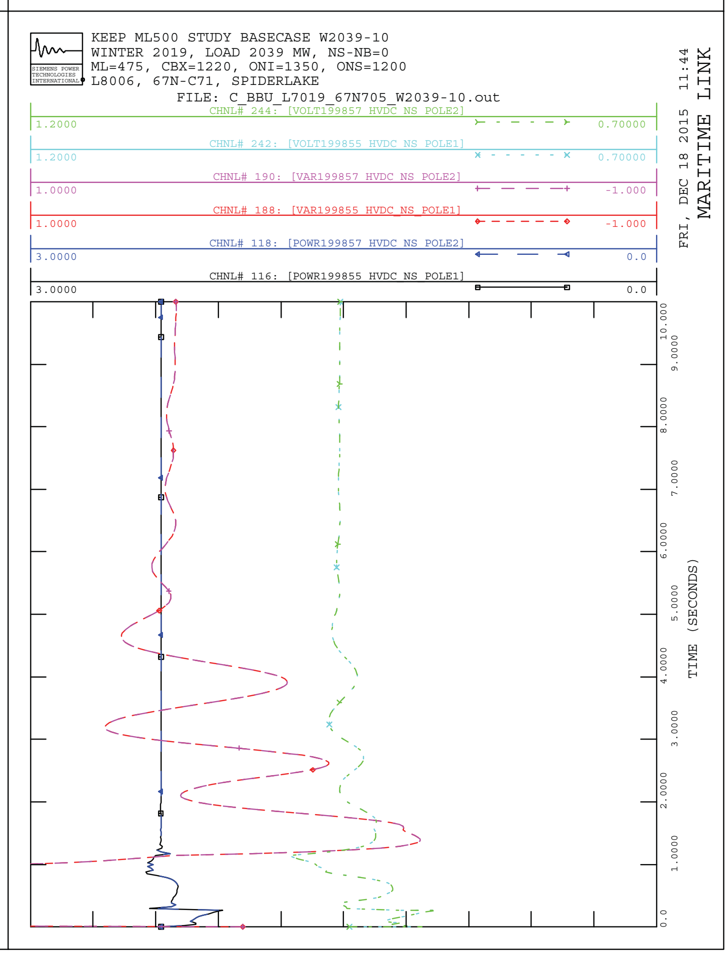


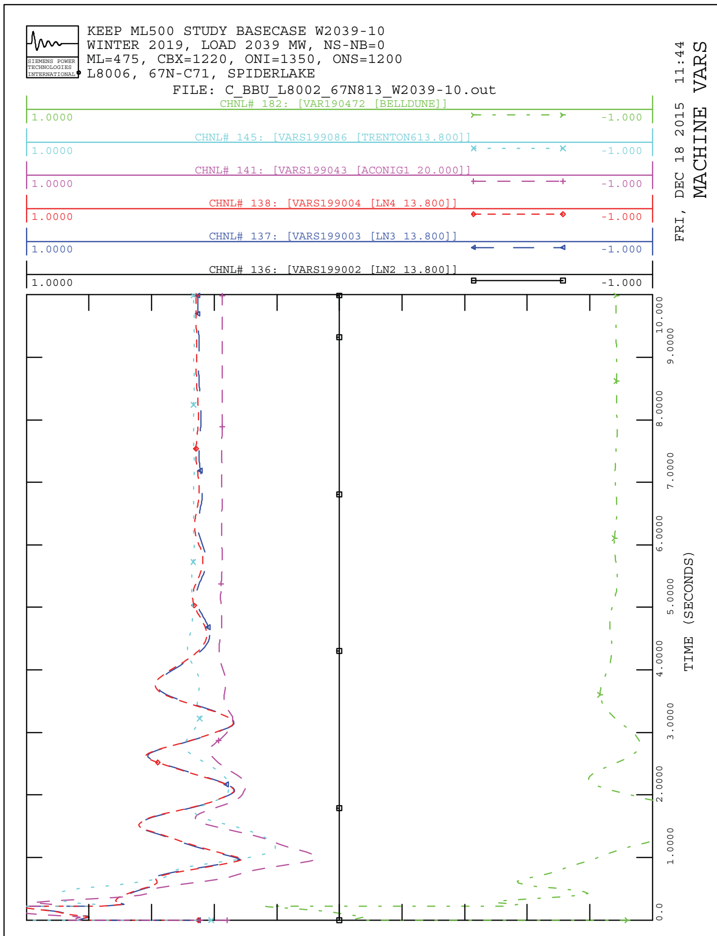
REDACTED (CONFIDENTIAL INFORMATION REMOVED)



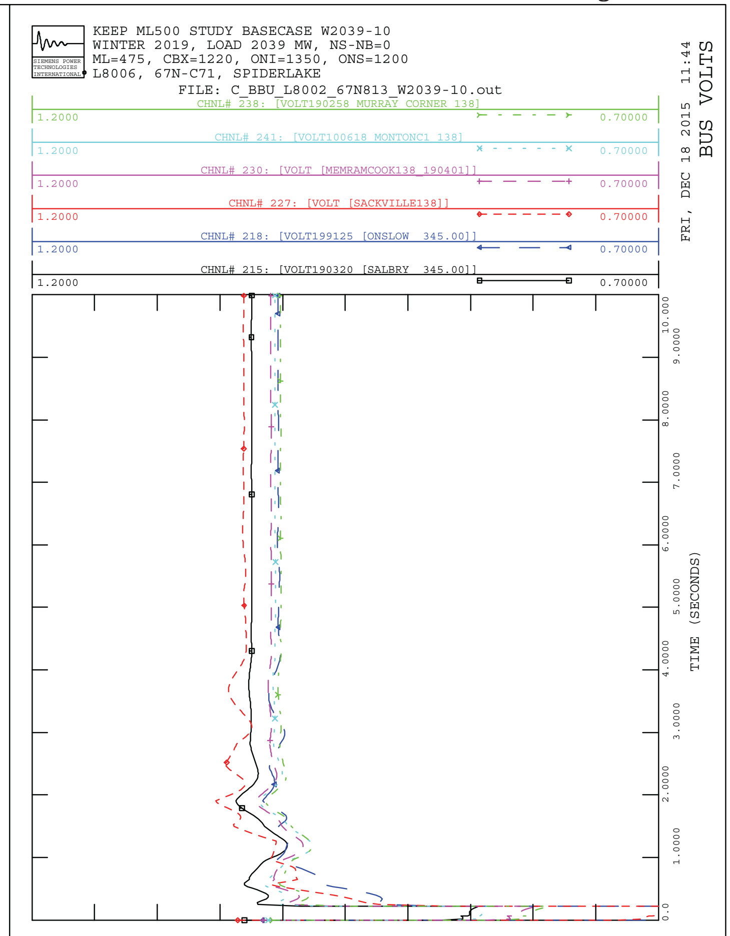




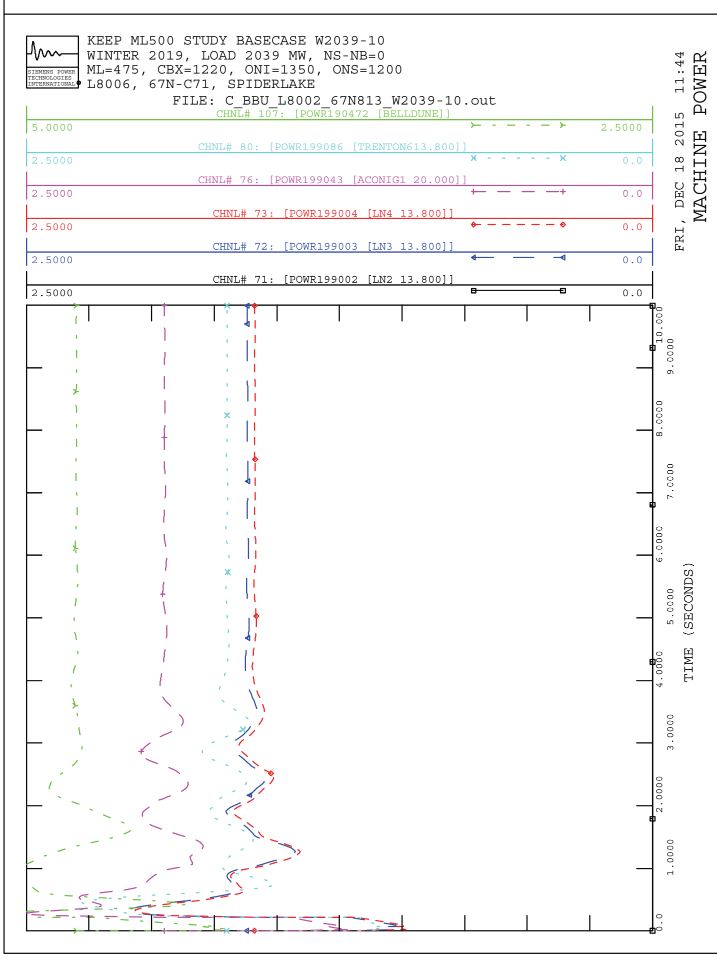




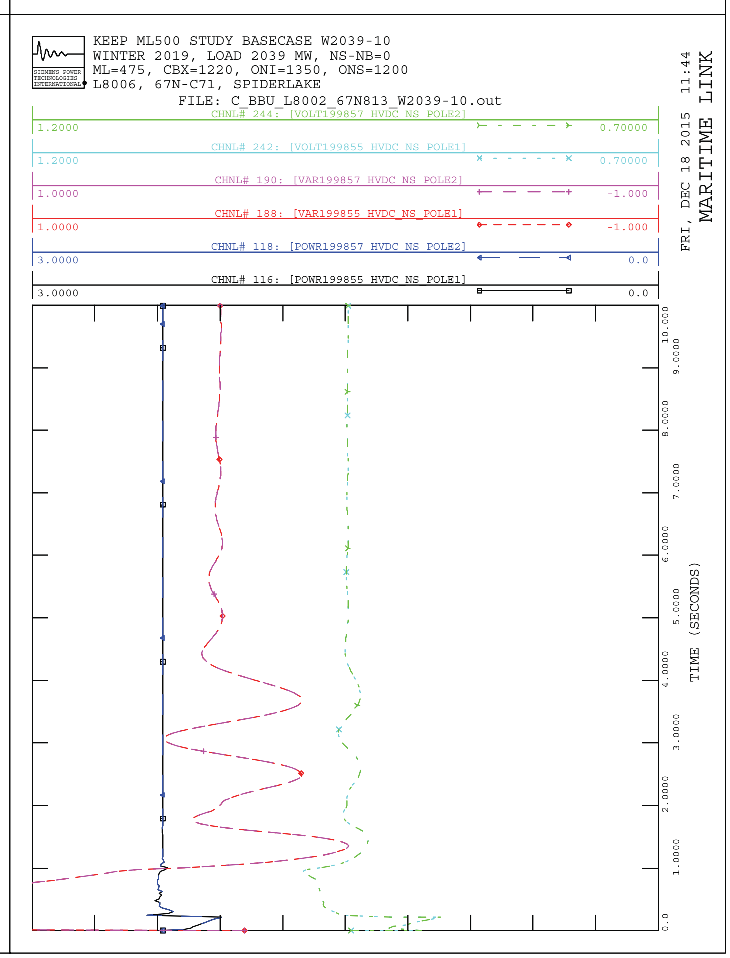
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8002_67N813_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
FRI, DEC 18 2015 11:44
MACHINE VARS
TIME (SECONDS)



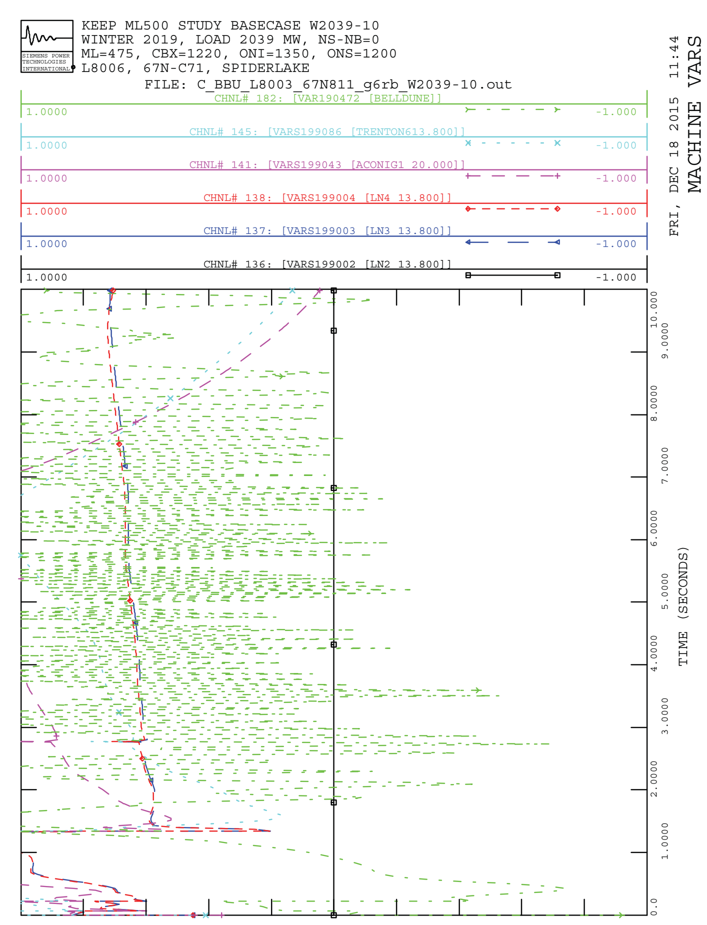
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8002_67N813_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
FRI, DEC 18 2015 11:44
BUS VOLTS
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8002_67N813_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
FRI, DEC 18 2015 11:44
MACHINE POWER
TIME (SECONDS)



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8002_67N813_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
FRI, DEC 18 2015 11:44
MARITIME LINK
TIME (SECONDS)


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8003_67N811_g6rb_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
FRI, DEC 18 2015 11:44
MACHINE VARS
TIME (SECONDS)
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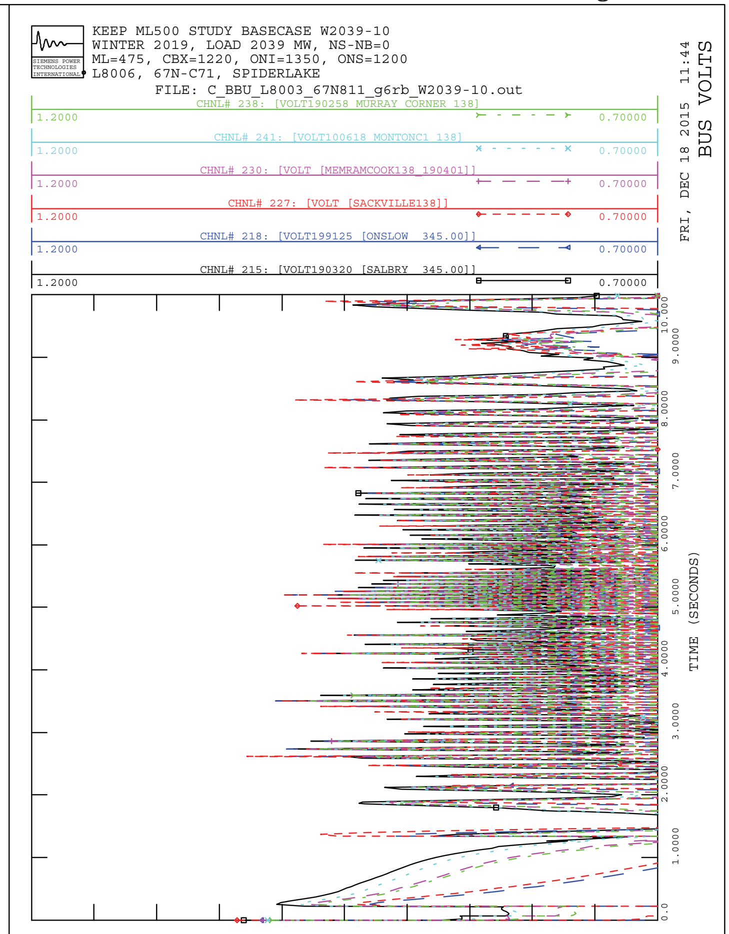
8.0000
9.0000
10.000


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8003_67N811_g6rb_W2039-10.out
CHNL# 238: [VOLT190258 MURRAY CORNER 138] 1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138] 1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]] 1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]] 1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]] 1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]] 1.2000 0.70000
FRI, DEC 18 2015 11:44
BUS VOLTS
TIME (SECONDS)
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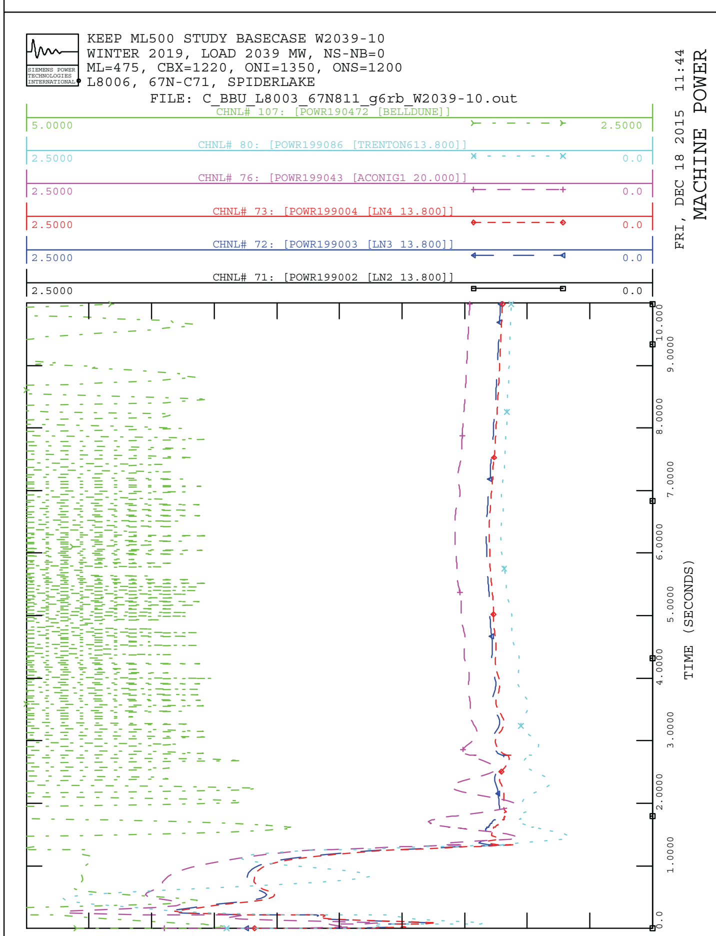
9.0000
10.000


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8003_67N811_g6rb_W2039-10.out
CHNL# 107: [POWR190472 [BELLDUNE]] 5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]] 2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]] 2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]] 2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]] 2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]] 2.5000 0.0
FRI, DEC 18 2015 11:44
MACHINE POWER
TIME (SECONDS)
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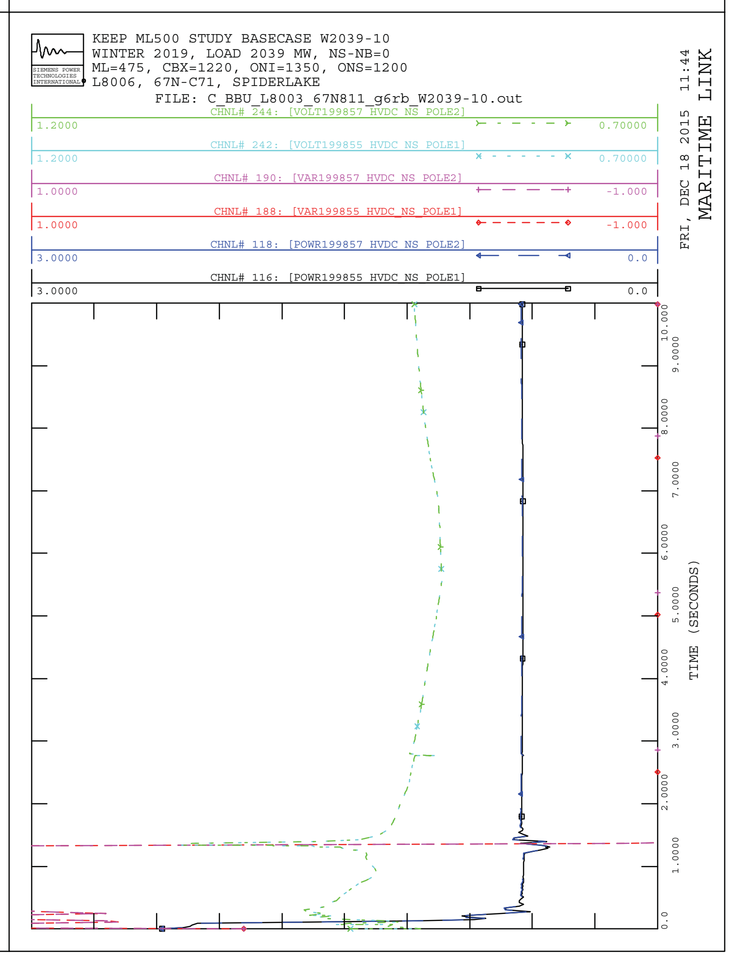
10.000


KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8003_67N811_g6rb_W2039-10.out
CHNL# 244: [VOLT199857 HVDC NS POLE2] 1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1] 1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2] 1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1] 1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2] 3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1] 3.0000 0.0
FRI, DEC 18 2015 11:44
MARITIME LINK
TIME (SECONDS)
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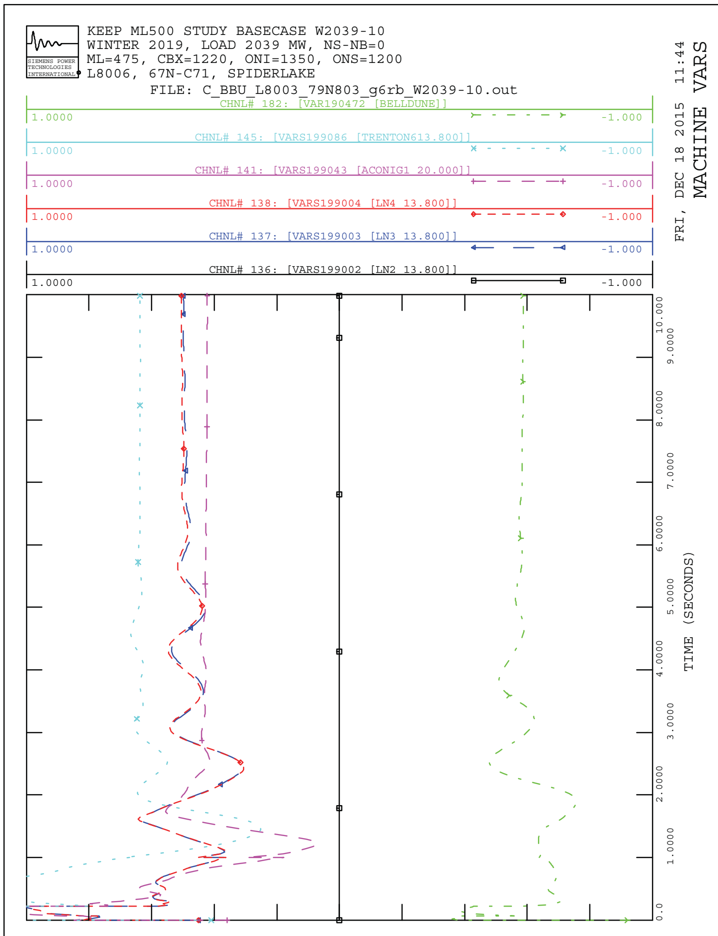
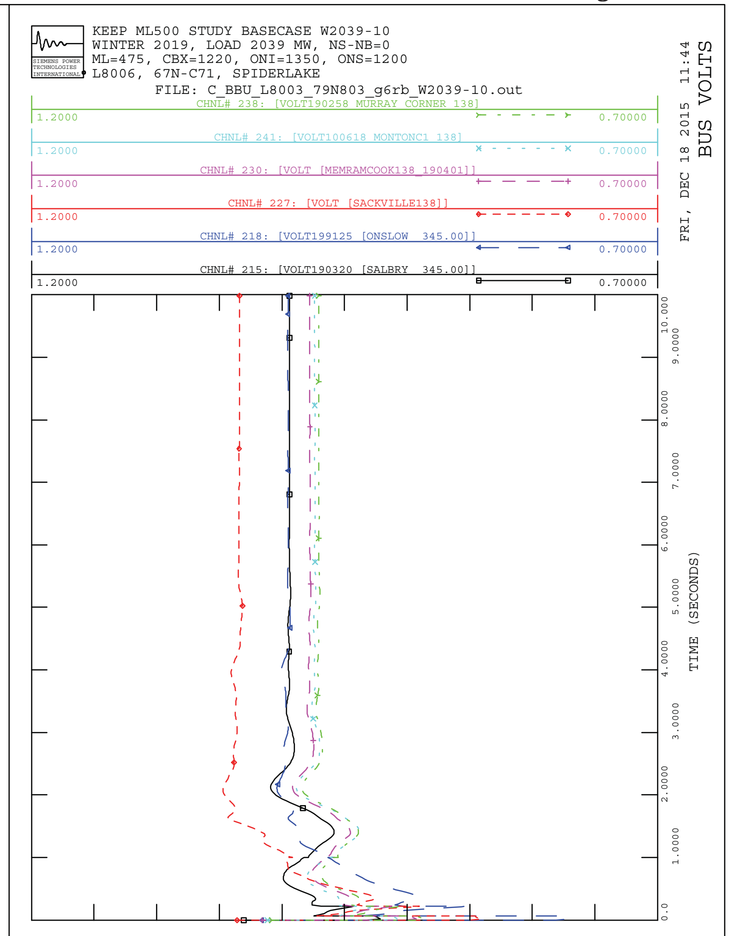
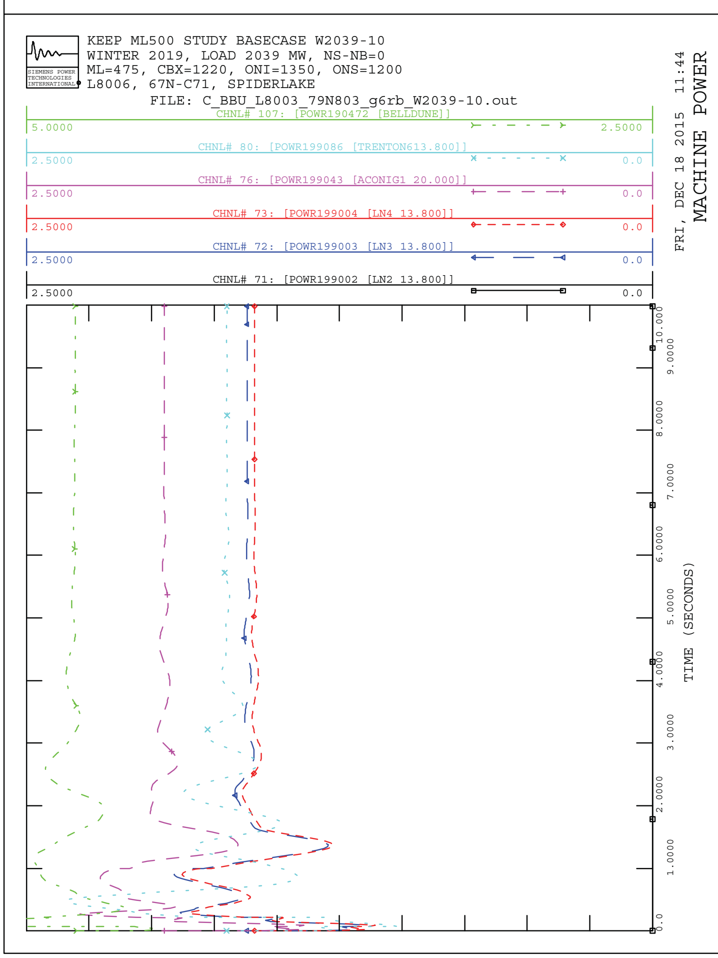
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000



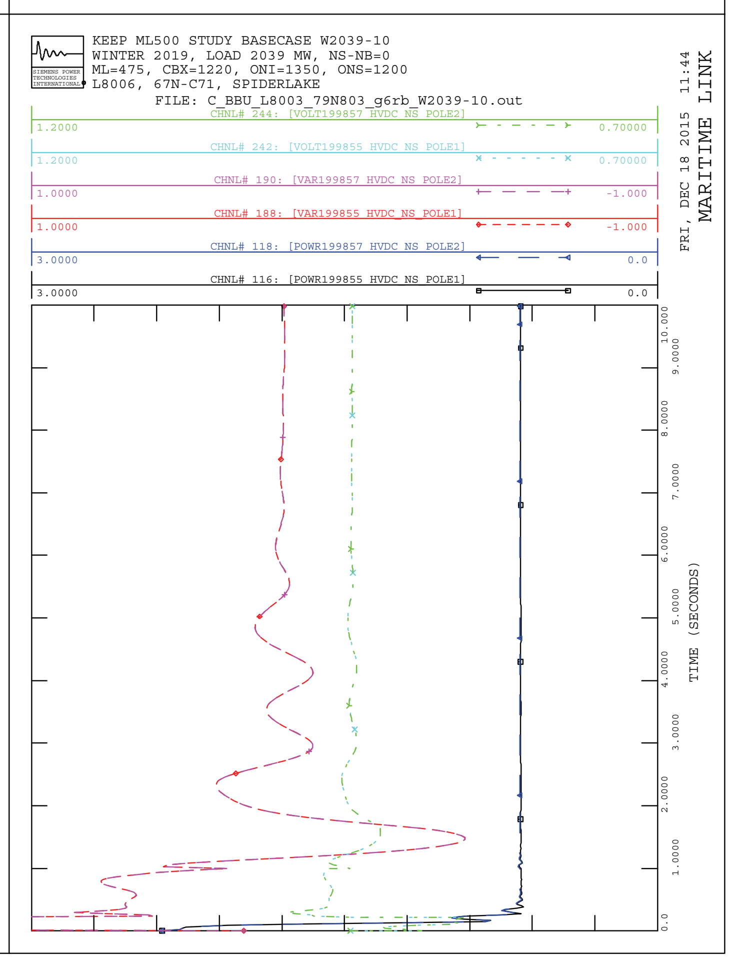
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8003_79N803_g6rb_W2039-10.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 182: [VAR190472 [BELLDUNE]]
1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]]
1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]]
1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]]
1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]]
1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]]
1.0000 -1.000
FRI, DEC 18 2015 11:44
MACHINE VARS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



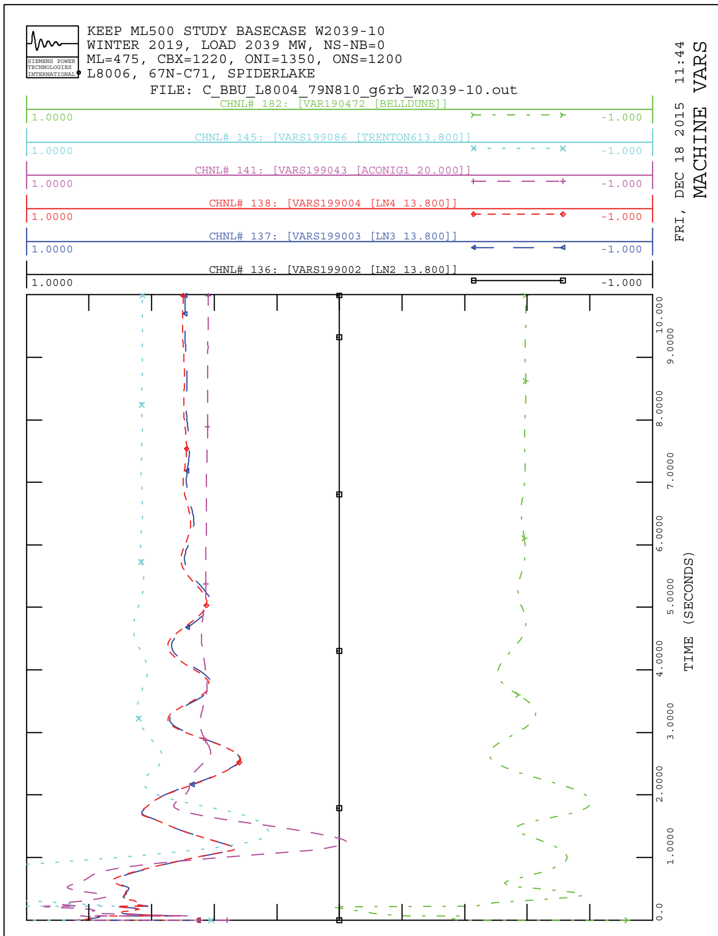
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8003_79N803_g6rb_W2039-10.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 238: [VOLT190258 MURRAY CORNER 138]
1.2000 0.70000
CHNL# 241: [VOLT100618 MONTONC1 138]
1.2000 0.70000
CHNL# 230: [VOLT [MEMRAMCOOK138 190401]]
1.2000 0.70000
CHNL# 227: [VOLT [SACKVILLE138]]
1.2000 0.70000
CHNL# 218: [VOLT199125 [ONSLOW 345.00]]
1.2000 0.70000
CHNL# 215: [VOLT190320 [SALBRY 345.00]]
1.2000 0.70000
FRI, DEC 18 2015 11:44
BUS VOLTS
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



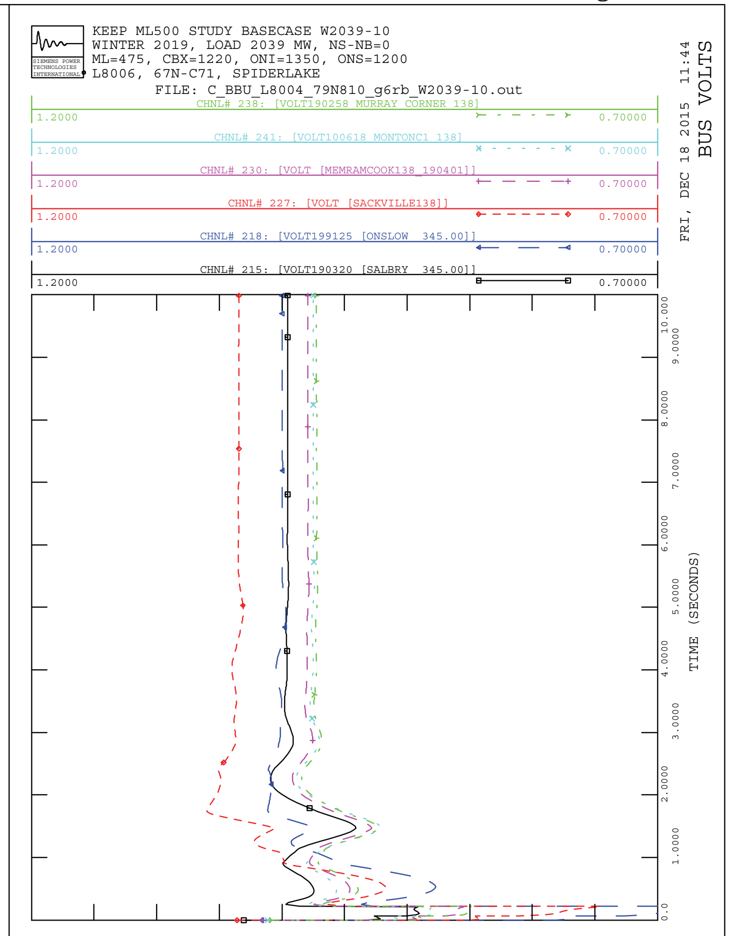
KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8003_79N803_g6rb_W2039-10.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 107: [POWR190472 [BELLDUNE]]
5.0000 2.5000
CHNL# 80: [POWR199086 [TRENTON613.800]]
2.5000 0.0
CHNL# 76: [POWR199043 [ACONIG1 20.000]]
2.5000 0.0
CHNL# 73: [POWR199004 [LN4 13.800]]
2.5000 0.0
CHNL# 72: [POWR199003 [LN3 13.800]]
2.5000 0.0
CHNL# 71: [POWR199002 [LN2 13.800]]
2.5000 0.0
FRI, DEC 18 2015 11:44
MACHINE POWER
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8003_79N803_g6rb_W2039-10.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 244: [VOLT199857 HVDC NS POLE2]
1.2000 0.70000
CHNL# 242: [VOLT199855 HVDC NS POLE1]
1.2000 0.70000
CHNL# 190: [VAR199857 HVDC NS POLE2]
1.0000 -1.000
CHNL# 188: [VAR199855 HVDC NS POLE1]
1.0000 -1.000
CHNL# 118: [POWR199857 HVDC NS POLE2]
3.0000 0.0
CHNL# 116: [POWR199855 HVDC NS POLE1]
3.0000 0.0
FRI, DEC 18 2015 11:44
MARITIME LINK
TIME (SECONDS)
0.0 1.0000 2.0000 3.0000 4.0000 5.0000 6.0000 7.0000 8.0000 9.0000 10.000



KEEP ML500 STUDY BASECASE W2039-10
WINTER 2019, LOAD 2039 MW, NS-NB=0
ML=475, CBX=1220, ONI=1350, ONS=1200
L8006, 67N-C71, SPIDERLAKE
FILE: C_BBU_L8004_79N810_g6rb_W2039-10.out
CHNL# 182: [VAR190472 [BELLDUNE]] 1.0000 -1.000
CHNL# 145: [VARS199086 [TRENTON613.800]] 1.0000 -1.000
CHNL# 141: [VARS199043 [ACONIG1 20.000]] 1.0000 -1.000
CHNL# 138: [VARS199004 [LN4 13.800]] 1.0000 -1.000
CHNL# 137: [VARS199003 [LN3 13.800]] 1.0000 -1.000
CHNL# 136: [VARS199002 [LN2 13.800]] 1.0000 -1.000
TIME (SECONDS)
FRI, DEC 18 2015 11:44
MACHINE VARS



KEEP ML500 STUDY BASECASE W2039-10
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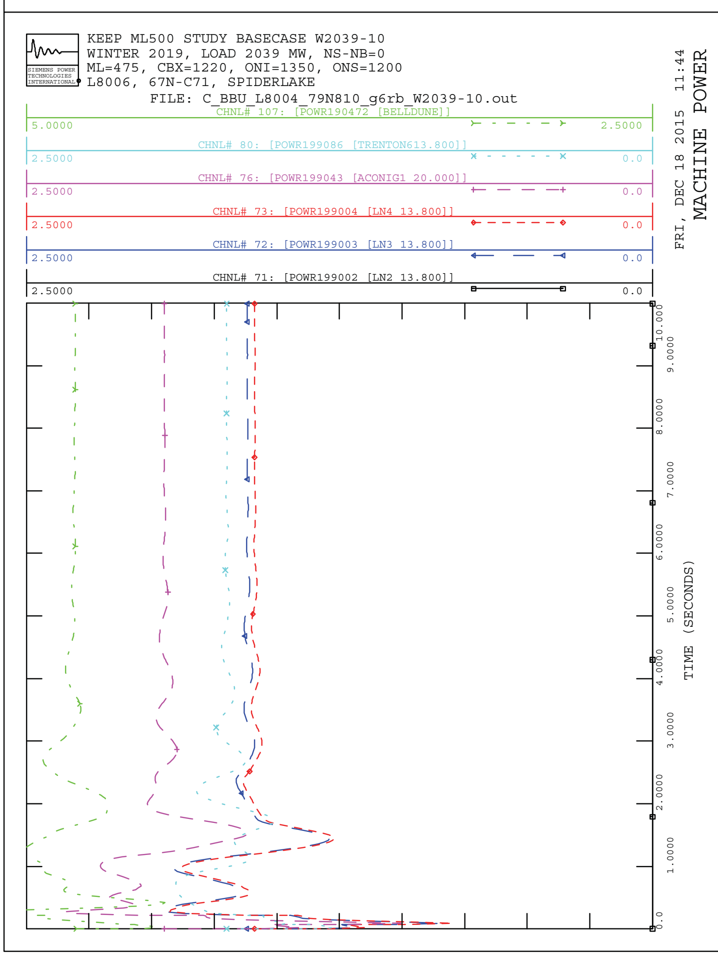

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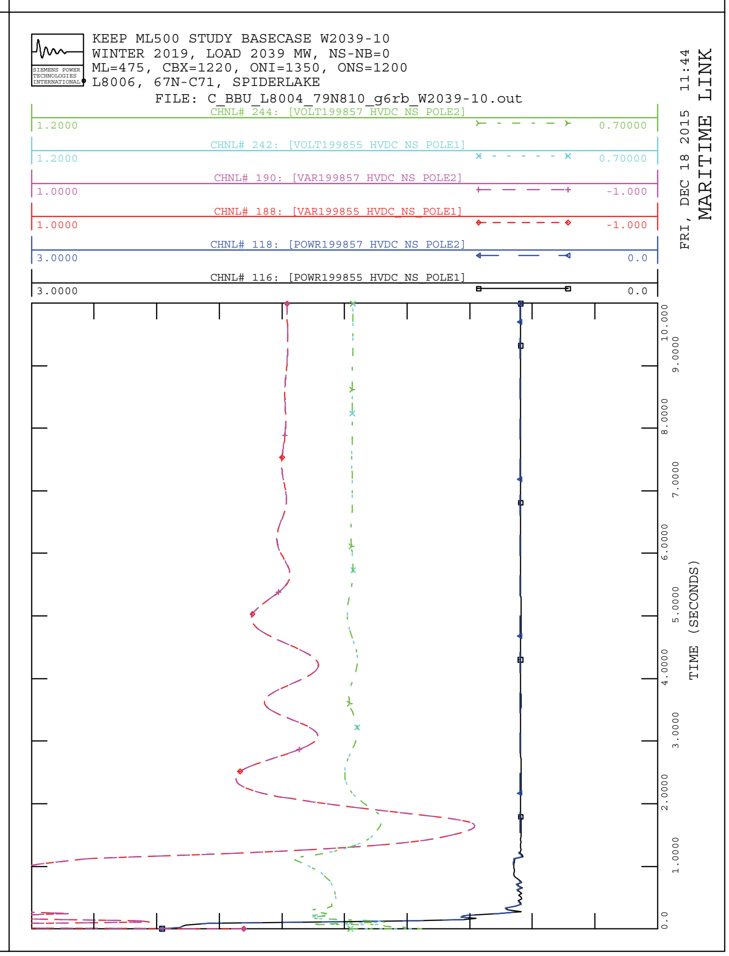

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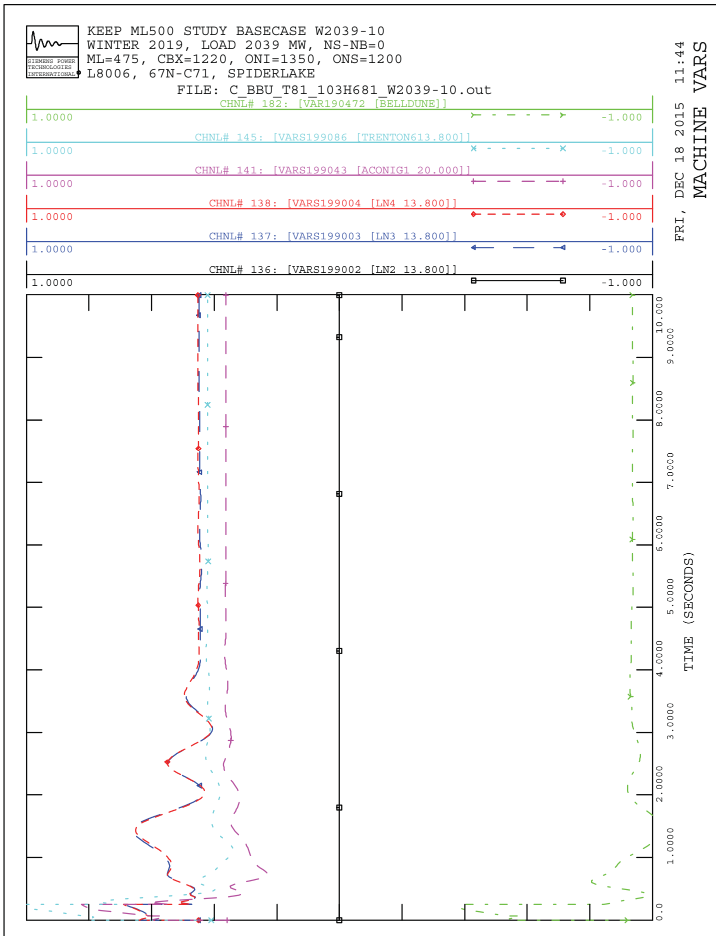

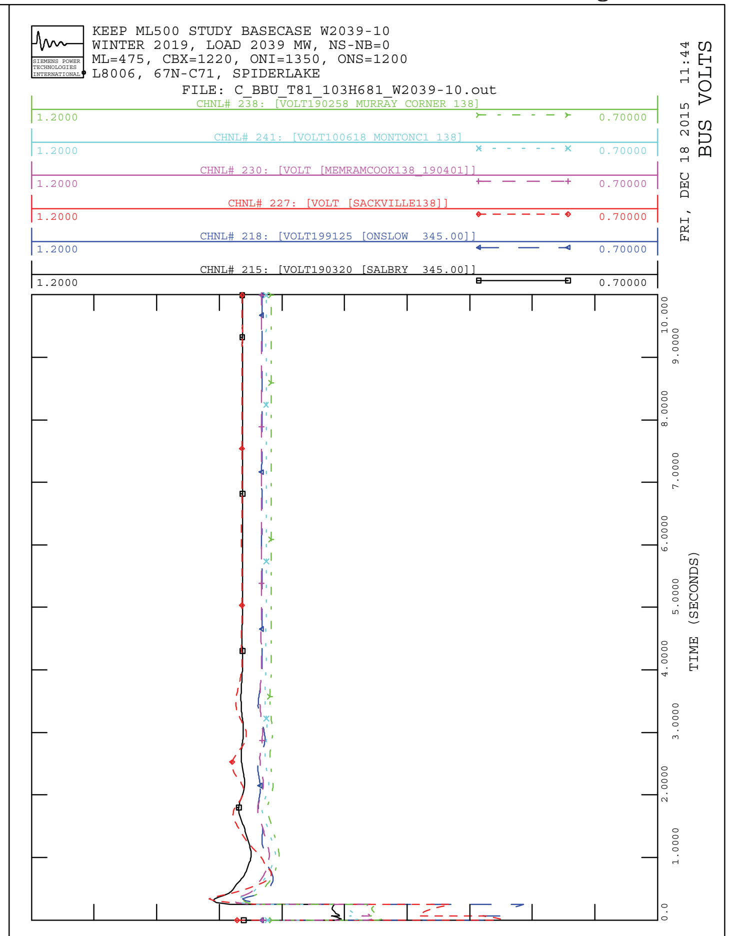

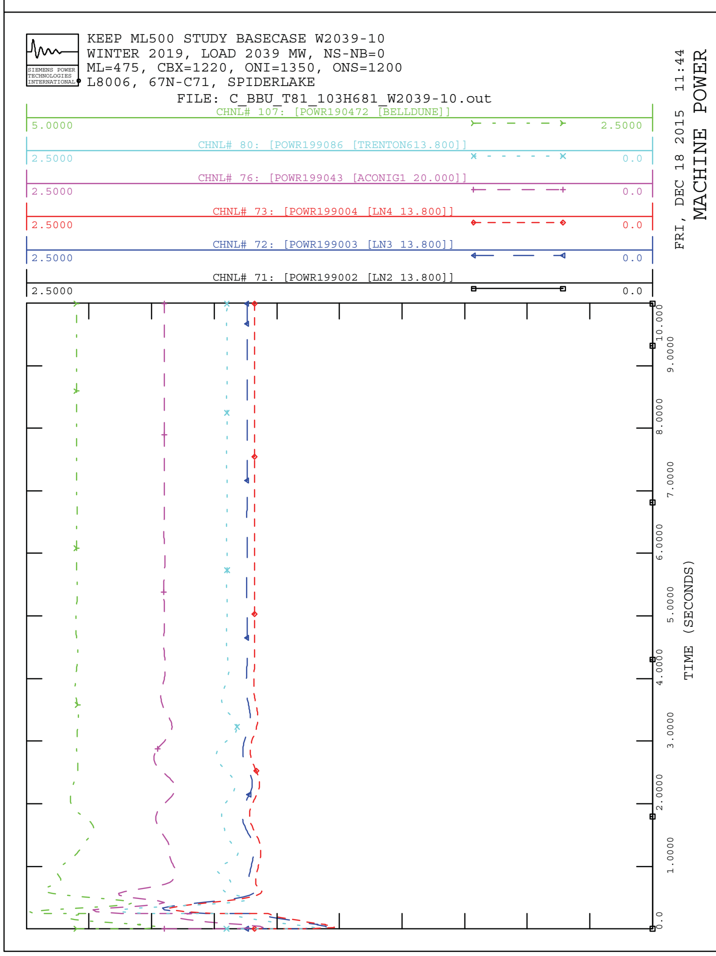

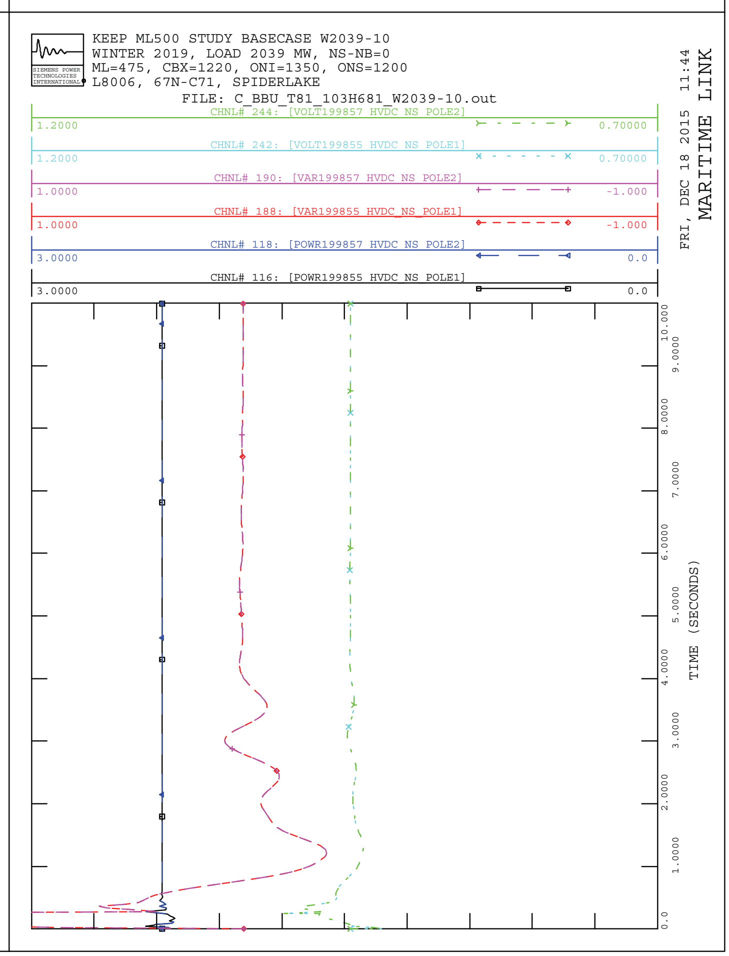

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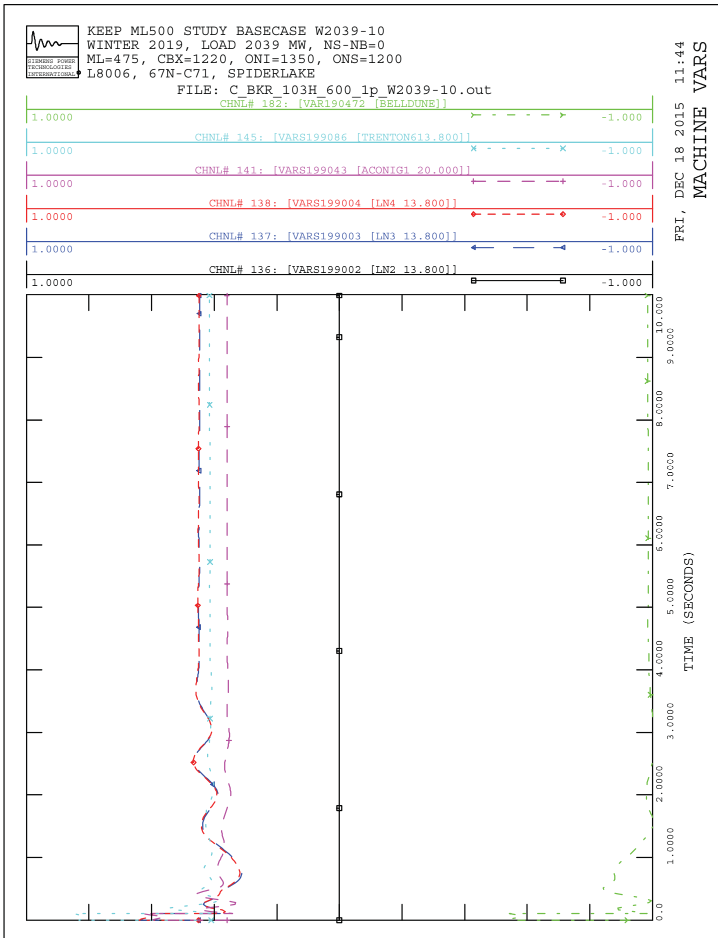

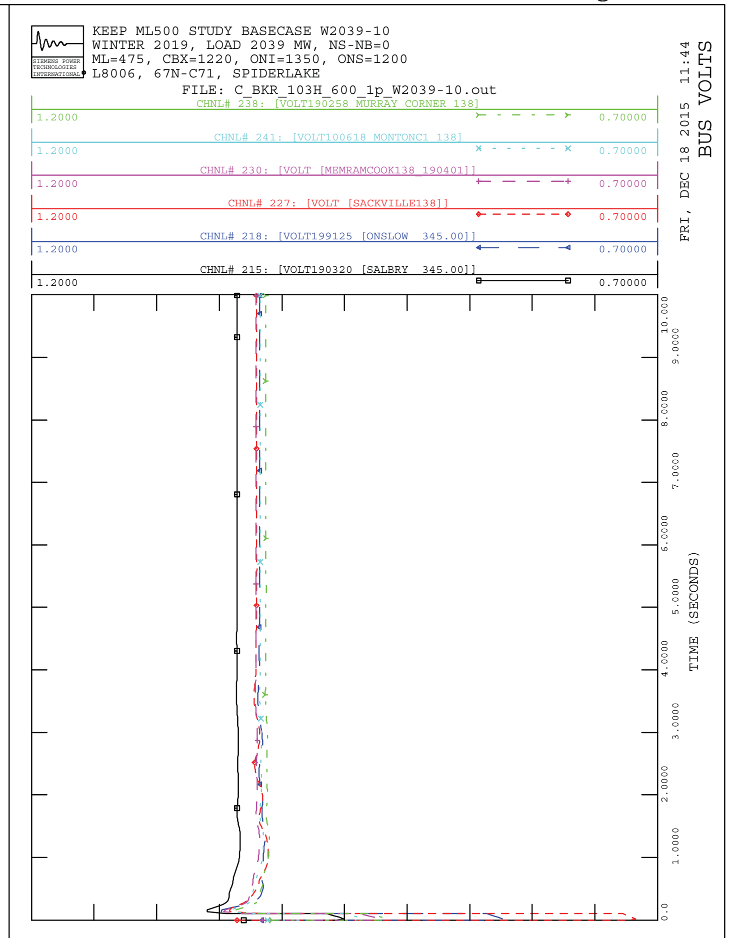

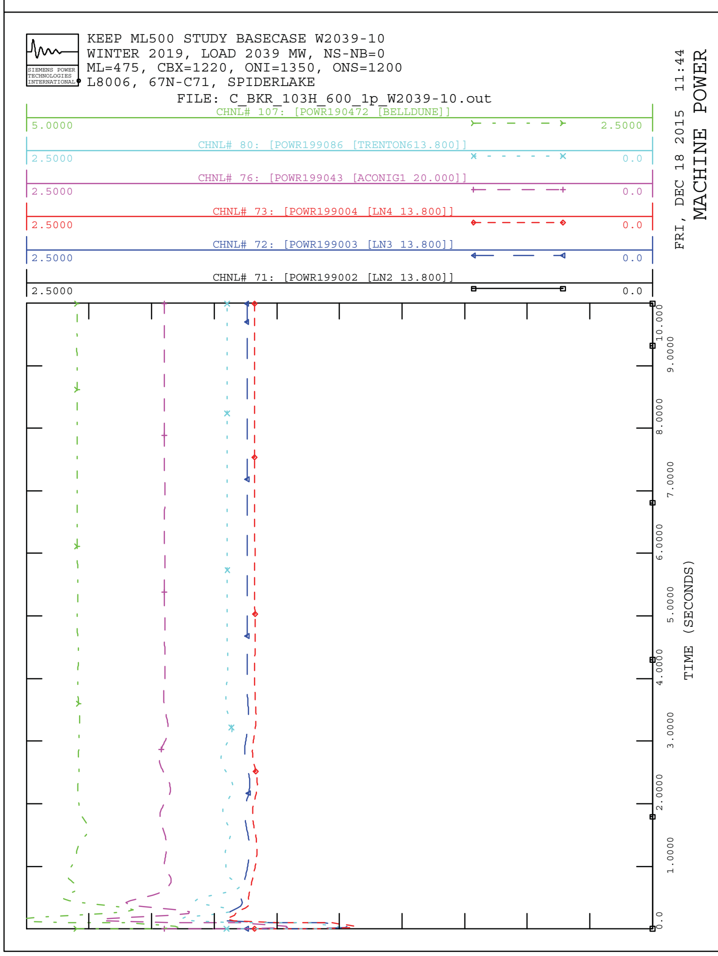

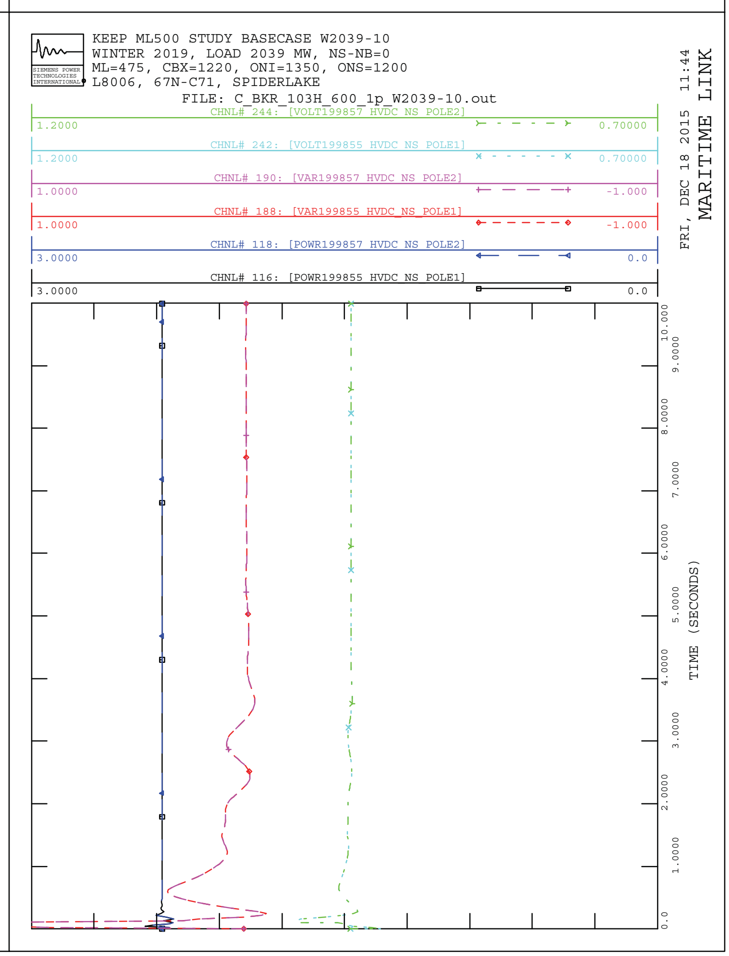

Request IR-15:

With reference to page 30, according to NSPI's response to 2016 ACE Plan UARB IR-21, the Harbour East 138 kV Transmission Line project (CI 41519) was expected to be filed with the Board in February of 2016. This project was also included in the 2015 ACE Plan, among projects for subsequent approval. Please provide a more detailed explanation for the deferral of this project.

Response IR-15:

The filing of project CI 41519 Harbour East 138 kV Transmission Line has been deferred to 2018 for the following reasons:

- Distribution load growth in the eastern Dartmouth area has not materialized as previously forecasted.

- Refined cost estimates for the construction of the Harbour East 138 kV transmission line have prompted the need for restudy to determine if the Harbour East solution remains the least cost alternative to serve load growth in eastern Dartmouth.

A study has been initiated to review options for servicing load on the Dartmouth 25 kV distribution system. Results of the study are expected to be available in 2017 and will set the direction and timeline for CI 41519.

Request IR-16:

With reference to page 32, is the deferral of a NERC project going to cause NPCC compliance problems?

Response IR-16:

No, the deferral of CI 48035 – DL NERC Module does not impact NS Power’s compliance with NPCC (NERC) requirements. This project is not required to achieve compliance with the requirements. The goal of the project is to improve efficiency and increase automation for the management of the diverse activities required to maintain NERC compliance in Power Production. Additional time is needed to find the most appropriate and cost-effective approach.

Request IR-17:

With respect to Section 2.3, 2017 ACE Plan Capital Items Forecast for Subsequent Approval, starting from page 36, please provide NSPI's tentative schedule showing when each of these projects is expected to be filed with the Board.

Response IR-17:

Please refer to Attachment 1.

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Functional Class	CI#	Project Long Title	Project Total	Expected Filing Date
Distribution	49899	10H Halifax 4kV Conversion Year 4	254,608	September 2017
Distribution	47776	111S Prime Brook Feeder Exits & Feeders	1,503,986	Filed - November 18, 2016
Distribution	50341	2017 Substation Recloser Replacements	577,388	March 2017
Distribution	47787	2H Armdale New Feeder	1,285,679	May 2017
Distribution	47760	85S-402 Re-Insulate	1,259,666	March 2017
Distribution	50343	Advanced Metering Infrastructure	111,707,380	October 2017
Distribution	47124	Advanced Metering Infrastructure - Pilot Project	8,274,738	Filed - November 18, 2016
Distribution	44749	Tiverton Tower Refurbishment	1,058,200	March 2017
Gas Turbine	49926	LM6000 TUC4 Airhouse Upgrade	815,633	February 2017
Gas Turbine	49949	LM6000 TUC4 Control System Replacement	710,815	February 2017
Gas Turbine	49940	LM6000 TUC5 Control System Upgrade	1,018,769	February 2017
Gas Turbine	44776	CT - TUC#5 LM6000 Generator Stator Re-wedge	1,073,280	March 2017
Gas Turbine	49273	CT-BGT2 Engine Refurbishment	1,019,832	March 2017
Gas Turbine	49594	LM6000 TUC5 Airhouse Upgrade	833,200	March 2017
Gas Turbine	47118	CT Tusket Hydraulic Starter	317,015	November 2017
General Plant	48044	Bentley Nevada Upgrade and Integration to Fleet Monitoring	401,459	April 2017
General Plant	48837	AMO Fleet Environmental Data Management	317,215	June 2017
General Plant	49787	Intelligent Feeder/Storage Project (SDTC)	2,399,368	February 2017
General Plant	49093	IT - Security Operations Center (SOC) and Security Information Event Monitoring (SIEM)	2,476,976	April 2017
General Plant	49855	Window 10 Migration Project	2,013,034	April 2017
General Plant	49858	IT - Microsoft Exchange Upgrade	1,500,000	August 2017
General Plant	49480	IT - Disaster Recovery	1,483,365	July 2017
General Plant	49094	IT - Identity Access Management Infrastructure	1,711,147	July 2017
General Plant	48773	IT - VOIP Expansion to NSPI sites	1,499,731	July 2017
General Plant	49953	IT - CIS High Availability	354,578	May 2017
General Plant	49856	IT - ITSM Replacement	300,000	October 2017
General Plant	49600	IT - Network Architecture Redesign	1,183,826	October 2017
General Plant	49603	IT - Patch Management	536,350	October 2017
General Plant	49860	IT - SharePoint Upgrade	4,021,915	October 2017
General Plant	49859	IT - Windows Server 2008 Upgrade	2,069,258	October 2017
General Plant	49601	IT - Data loss Prevention	1,199,013	September 2017
General Plant	49857	IT - Storage Infrastructure Upgrade	5,045,955	September 2017
General Plant	50292	FAC - Kempt Road Depot Truck Bay	340,655	February 2017
General Plant	50153	Self Serve Development Phase 2	1,827,720	April 2017
General Plant	48238	Customer Billing Experience Improvements	490,878	Filed - December 16, 2016
General Plant	50113	Customer Experience - Streetlight improvements	679,394	May 2017
General Plant	50112	Consolidated Customer Web Portal	770,977	November 2017
General Plant	50115	Customer Support System Enhancement	332,847	September 2017
General Plant	47751	Dynamic Transmission Limits	537,466	November 2017
General Plant	43202	Replace Mobile Radio System	6,537,700	February 2017
General Plant	49876	Real Time Economic Dispatch	1,161,618	March 2017
General Plant	50132	Joint Regulation	387,704	September 2017
General Plant	48155	2016 SCADA Application Upgrade	400,688	Filed - December 16, 2016
General Plant	50295	Electric Vehicle Infrastructure Deployment	400,000	February 2017
General Plant	46075	IT - Work & Asset Management	28,027,680	April 2017
Hydro	49598	HYD - Gisborne Switchgear Replacement	623,814	April 2017
Hydro	47682	HYD - Lequille Switchgear Replacement	698,659	April 2017
Hydro	48914	HYD - Malay Falls Facility Repair	446,237	April 2017
Hydro	48052	HYD - Annapolis HVAC Upgrade	1,498,367	February 2017
Hydro	47654	HYD - Gulch Penstock & Surge Tank Replacement	3,629,655	February 2017
Hydro	49596	HYD - Hells Gate 2 Overhaul	970,827	February 2017
Hydro	47876	HYD - Lequille Overhaul	1,155,418	February 2017
Hydro	48396	HYD - Bridge Remediation	404,616	May 2017
Hydro	47660	HYD - Dickie Brook Controls Upgrade	307,251	June 2017
Hydro	48913	HYD - Tusket Facility Refurbishment	657,956	June 2017
Hydro	48533	HYD - Lequille Headpond Water Retaining Structures Refurbishment	1,919,166	March 2017
Hydro	47678	HYD - Prince Mine Dam Decommissioning	819,451	March 2017
Hydro	38931	HYD - Harmony Partial Decommissioning	1,106,122	May 2017
Hydro	49039	HYD - Lequille Controls Upgrade	304,121	May 2017
Hydro	47166	HYD - McAskill Brook Decommissioning	562,684	September 2017
Hydro	49835	HYD - Dive Site Risk Mitigation	650,533	June 2017
Hydro	47648	HYD - Lequille Pipeline Replacement	1,384,448	March 2017
Hydro	29807	HYD - Tusket Falls Main Dam	9,940,664	May 2017
Hydro	39472	HYD Mersey Hydro System Re-Development	84,000,000	September 2017
Steam	49111	POT - Air heater refurbishment	471,204	April 2017
Steam	49060	POT - Condenser Dog Bone Expansion Joint Replacement	298,253	April 2017
Steam	49538	TRE6 Generator Refurbishment	411,766	February 2017
Steam	47553	TRE6 Turbine Main Valves	392,887	February 2017
Steam	47531	TRE6 Turbine Refurbishments	2,322,487	February 2017
Steam	48868	AMO Fleet TWIP Upgrades	280,608	June 2017
Steam	46499	Stator Rewind Kit Capital Spare	5,219,939	March 2017
Steam	49438	LIN A Gallery Floor Replacement	593,814	June 2017
Steam	48893	TUC3 IP Turbine Refurbishment	4,798,475	April 2017
Steam	49674	TUC2 Boiler Selective Waterwall Tube Replacements	390,898	February 2017

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Functional Class	CI#	Project Long Title	Project Total	Expected Filing Date
Steam	49499	PHB - Boiler Refurbishment 2017	484,730	March 2017
Transmission	50021	91H Tufts Cove Bus and Line Upgrades	417,178	April 2017
Transmission	49922	Western Switching Upgrades	353,906	April 2017
Transmission	49879	77V-T52 Replacement	775,082	Filed - December 16, 2016
Transmission	45053	69Kv Structure Replacements West	4,818,017	July 2017
Transmission	50342	Western Transmission System Voltage Support	4,000,000	June 2017
Transmission	49928	3S Gannon Rd. Bus Reconfiguration	364,777	March 2017
Transmission	43678	Separate L8004/L7005 on Canso Crossing Double Circuit Tower(DCT)	16,183,691	TBD
Transmission	49929	Tap Changer Replacements	262,526	April 2017

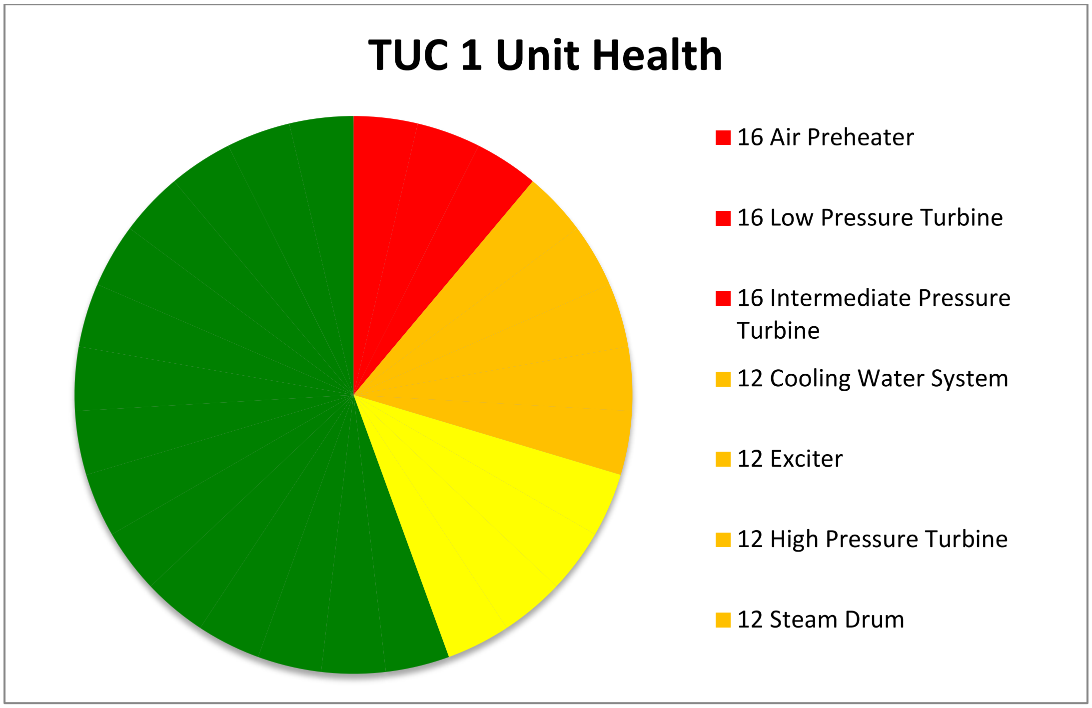
Request IR-18:

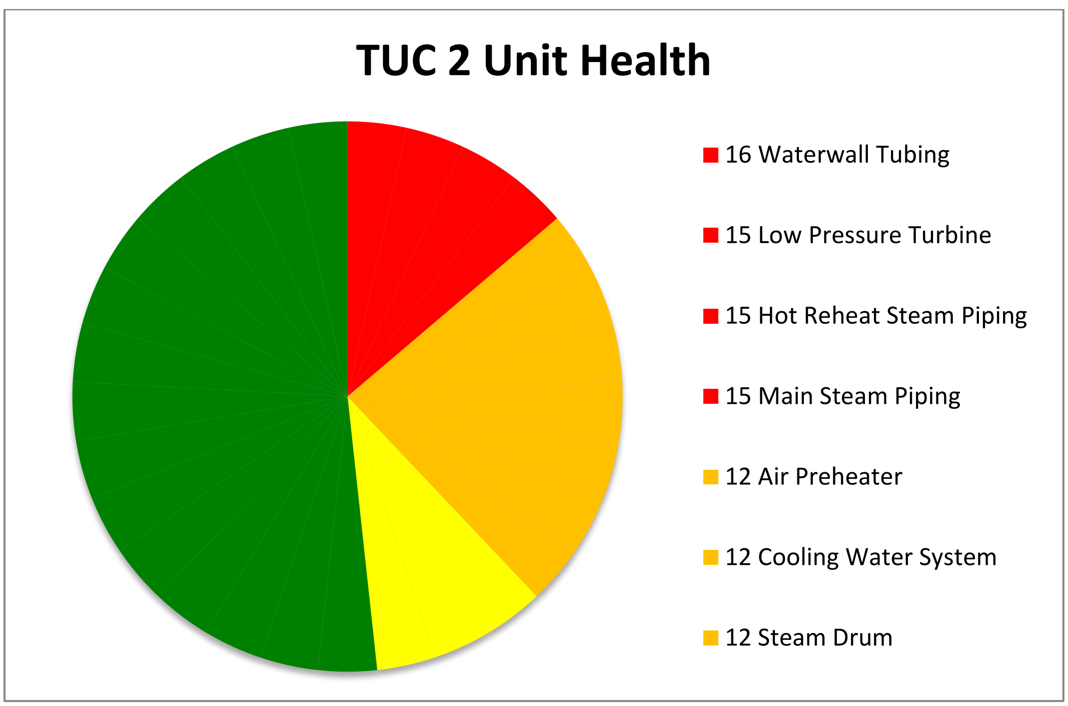
With reference to page 38, CI 48893 – TUC3 - IP Turbine Refurbishment, please provide condition assessments of Tufts Cove Units 1, 2 and 3.

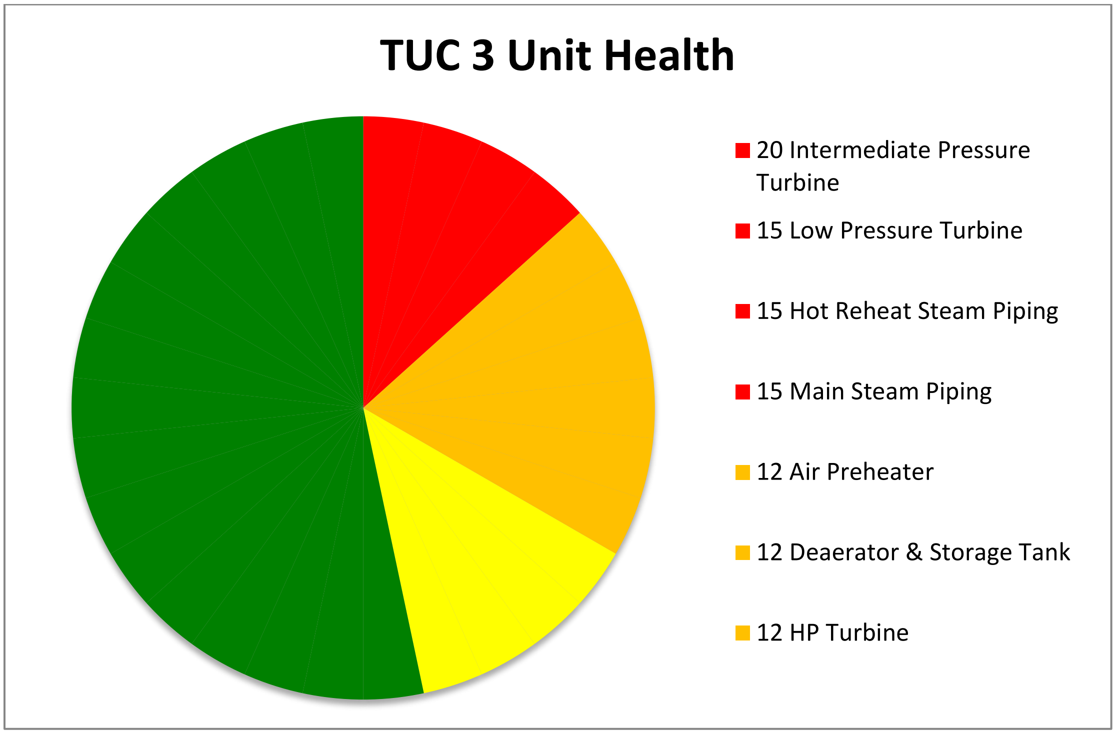
Response IR-18:

The condition assessment of Tufts Cove Units 1, 2 and 3 can be displayed by showing overall risk ranking of multiple asset components on the unit. Consistent with NS Power's capital project ranking methodology, each piece of major equipment is evaluated on condition (1-5) and criticality (1-5) to produce a risk ranking (1-25). These risk rankings are displayed graphically to show an overall Unit Health. The figures below represent the overall condition of Tufts Cove Units 1, 2, 3.

These figures specify risks that are being managed at Tufts Cove 1, 2, 3. Mitigating measures include capital investment, monitoring and diagnostics, maintenance and operations strategies. The colours (Red representing the greatest risk, Green representing the least risk) indicate the number of risk ranked components on that unit.


TUC 1 Unit Health
16 Air Preheater
16 Low Pressure Turbine
16 Intermediate Pressure Turbine
12 Cooling Water System
12 Exciter
12 High Pressure Turbine
12 Steam Drum


TUC 2 Unit Health
16 Waterwall Tubing
15 Low Pressure Turbine
15 Hot Reheat Steam Piping
15 Main Steam Piping
12 Air Preheater
12 Cooling Water System
12 Steam Drum

1 
TUC 3 Unit Health
20 Intermediate Pressure Turbine
15 Low Pressure Turbine
15 Hot Reheat Steam Piping
15 Main Steam Piping
12 Air Preheater
12 Deaerator & Storage Tank
12 HP Turbine

Request IR-19:

With reference to page 38, CI 49499 – PHB - Boiler Refurbishment 2017:

(a) Please provide a list, including budgeted amounts, for all 2017 ACE Plan projects related to the Port Hawkesbury Biomass Generation Station.

(b) Identify which of the above capital items are occurring on an annual basis, and explain why they are necessary to be performed every year.

(c) Does the 2017 capital spending on PHB related work provide benefits to NSPI's customers only, without benefiting any other entity? If not, please elaborate.

Response IR-19:

(a) The table below shows all the 2017 ACE Plan projects related to the Port Hawkesbury Biomass Generation Station.

CI#	Project Title	2017 ACE ($)
49499	PHB - Boiler Refurbishment 2017	484,730
49502	PHB - Fire Suppression Expansion	65,599
49500	PHB - Fuel System Refurbishment 2017	178,127
49501	PHB - Selective Turbine Valve Refurbishment	160,479

(b) The capital projects occurring on an annual basis are the boiler refurbishment (CI 49499) and fuel system refurbishment (CI 49500). Due to the boiler design and fuel type, these projects are required to be completed annually to maintain safe and reliable operation of the unit. Biomass fuel boilers require annual sustaining capital due to multiple damage mechanisms such as erosion/corrosion in the fuel delivery system, generation bank, and gas path systems.

(c) Port Hawkesbury Biomass capital projects allow NS Power to (1) meet its contractual obligation of delivering steam and condensate to Port Hawkesbury Paper; and (2) economically dispatch the unit when required to serve load requirements. As such, Port Hawkesbury Biomass capital projects provide benefits to all NS Power customers, including Port Hawkesbury Paper.

Request IR-20:

With reference to page 40, CI 46075 – IT - Work and Asset Management:

(a) Please provide a more detailed description of this project, and explain why its scope of work now includes a number of previously independent capital items.

(b) CI 46075, which was a 2016 ACE Plan capital item for subsequent approval, is now listed as a 2017 ACE Plan item for subsequent approval. Please explain why this item was omitted from Section 1.6 of the 2017 ACE Plan application, "2016 ACE Capital Items Deferred/Cancelled"?

(c) Please advise if all aspects of CI 48232 – T&D Scheduling & Dispatch; CI 48251 – T&D Field Design; and CI 48073 – 2016 NSPI GIS Upgrade, are now incorporated in CI 46075.

Response IR-20:

(a) NS Power's core Work and Asset Management system, Maximo, is nearing the end of its useful life. To mitigate risks associated with unsupported software platforms, the timing is right to upgrade Maximo. This upgrade requirement for the NS Power Work and Asset Management systems presents the opportunity to consolidate systems, mitigate risks associated with near end-of-life systems faced by the Company, and provides valuable enhanced functionality.

The enhanced functionality will deliver capital and operating cost savings which will be detailed in the capital filing.

The scope of work under CI 46075 now includes work previously planned for separate capital projects. This was done because the work under those capital projects was fundamentally part of the overall work and asset management initiative. , Undertaking a single strategic project to advance T&D work and asset management provides for project outcomes that are aligned with overall objectives and delivered in a way that makes effective use of resources and technology functions. This approach will also provide a comprehensive and transparent application for the Board's review and approval.

The scope of this capital item includes the following:

1. Upgrade of Maximo for Utilities to v7.6
2. Implementation of Maximo Scheduler v7.6
3. Implementation of Maximo Spatial v7.6
4. Implementation of Maximo Anywhere 7.6
5. Upgrade of ESRI ArcGIS to v10.2.2
6. Implementation of ArcFM Designer v10.2.2
7. Retirement of GSIWorx Distribution Staker
8. Business Processes Improvements
9. Supporting Infrastructure
10. Improved Data Management
11. Preparation for Organizational Readiness
12. Project Services

(b) Capital work orders that appear in the subsequent submittal list are those that are intended to be filed before year-end and in the following year. At the time of the 2017 ACE Plan submission, it was contemplated that CI 46075 may be filed with the UARB by the end of 2016. CI 46075 will now be filed sometime in 2017.

(c) All aspects of CI 48232, CI 48251, and CI 48073 are now incorporated into CI 46075.

Request IR-21:

With reference to page 41, CI 49787 – Intelligent Feeder/Storage Project (SDTC), please provide a more detailed description of this project.

Response IR-21:

Please refer to NSUARB IR-38.

Request IR-22:

With reference to Section 2.4, starting from page 43, NSPI's 2017 ACE Plan includes 148 projects with an estimated cost of less than $250,000 each, for a total cost of $22.2 million (Point Aconi excluded). This amount represents over 30% of the total cost for all 2017 ACE Plan capital items submitted for Board approval:

(a) Please provide a comparison of the 2017 figures with those from 2015 and 2016 ACE Plan submissions.

(b) Please elaborate on any significant variances in the above figures.

Response IR-22:

(a) The table below shows the quantity and total cost of projects less than $250,000 in the 2015, 2016 and 2017 ACE Plans:

Items < $250,000	Quantity	Total Cost
2015	85	$12,288,180
2016	112	$15,461,295
2017	167	$22,222,628

(b) The large increase in quantity and total cost of projects less than $250,000 is largely driven by an increase of projects in thermal generation. This is not due to any specific reason as all projects, including those under $250,000, are determined through NS Power's asset management practices in the generation, transmission and distribution functions based on each project's individual ranking. NS Power does not consider the quantity of projects less than $250,000 when evaluating whether a project should proceed or not. NS Power does consider the option of combining these projects when possible, however in the majority of cases, these are standalone capital projects.

Request IR-23:

With reference to pages 46 and 47, capital items 49972, 49971, 49950, and 49951, please elaborate on the regular frequencies of nozzle refurbishments and bushing replacements, and explain why both LM6000 turbines require this work in the same year.

Response IR-23:

Both LM6000s require work in the same year as the condition assessments completed in 2016 indicates that components will reach end of useful life prior to next planned maintenance interval.

Sprint Nozzles:

- Nominal OEM recommendation for replacement of nozzles is 25,000 Fired Engine Hours (FEH).
    - Actual replacement must be based on condition. Annual Inspections are conducted to determine condition.
    - Replacement timing is also optimized with unit maintenance intervals. (If condition indicates that components will reach end of useful life prior to next planned maintenance interval, then replacement would be pulled ahead.)

Variable Stator Vane Bushings:

- Nominal OEM recommendation for replacement of nozzles is 12,500 Fired Engine Hours (FEH).

- Actual replacement must be based on condition. Annual Inspections are conducted to determine condition.

- Replacement timing is also optimized with unit maintenance intervals.

Both LM6000s require work in the same year as the condition assessments completed in 2016 indicates that components will reach end of useful life prior to next planned maintenance interval.

Request IR-24:

With reference to pages 47 and 48, please provide a short description of these projects, and note if there is any relation between them:

- **CI 49615 – AMO Competency Based Training & Procedure Management Phase 2**
- **CI 50016 – AMO Meridium Dashboard Phase 2**
- **CI 48039 – Meridium 4.0**
- **CI 49617 – AMO Handheld Module Additions**
- **CI 49460 – AMO DirectLine Permit Module Additions**

Response IR-24:

The AMO included in the project title refers to the Generation Asset Management Office (AMO) of NS Power. These projects are managed by the AMO for the benefit of the NS Power generating fleet, but the inclusion of "AMO" in the title is not an indication that these projects are related. While each of these projects contributes to improved data collection, reporting, and Operations Excellence, each project scope is unique, and provides standalone benefits. A description for each is provided below.

- CI 49616 – AMO Competency Based Training (CBT) & Procedure Management Phase 2 includes the design and deployment of fleet-wide systems for the management of competency-based training modules and procedures. NS Power has been engaged in a number of efforts focused on Operations Excellence, which this project will support. A Phase 1 project was initiated in 2014 and has been successful at providing a mechanism to manage CBTs and Procedures for Power Production Operations. This Phase 2 project focuses on procedures for Maintenance as well as Hydro. Scoping is ongoing.

- CI 50016 – AMO Meridium Dashboard Phase 2 builds on CI 48029 – Meridium Dashboards, which was included in the 2016 ACE Plan. The Phase 1 project made key linkages between various systems to efficiently and concisely present asset risk and performance to business leaders. The Phase 1 project has been successful, and under the Phase 2 project NS Power is evaluating building similar linkages for other parts of the business including Insurance, Internal Audit, Customer Care and Joint Occupational Health and Safety (JOHS). Each of these initiatives links to a different set of business processes and systems. Scoping is ongoing.

- CI 48039 – Meridium 4.0 is to upgrade the out of date version of Meridium software currently in use at NS Power to Meridium 4.0. Meridium is an Asset Performance Management (APM) software program, used to facilitate data collection, analysis synthesis, and communication across NS Power. The software facilitates many other initiatives including CI 50016 discussed above, and its use continues to grow within the business. NS Power is currently using an outdated version which is user-computer based and requires significant administrative support when compared to Version 4.0, which is a web-based application. Significant improvements have been made in Version 4.0 which are not available in the current version.

- CI 49617 – AMO Handheld Module Additions includes upgrades to expand the use of handheld devices, such as iPads, to improve efficiency and data traceability. Handheld devices are used in NS Power's generating stations for a number of initiatives, including the electronic collection of data which was previously available only via paper-based processes, and in some cases not at all. It is proposed that this project include the development of a Risk Assessment module, as well as a relay record module. These are both currently paper-based exercises. Scoping is ongoing.

- CI 49460 – AMO DirectLine Permit Module Additions has been subsequently retitled to "AMO DL Module Additions". DirectLine is the computerized maintenance management system (CMMS) used in Power Production at NS Power. This project is to facilitate automated reporting of Safe Work Permit status, as well as other enhancements.

Request IR-25:

With reference to carryover capital spending starting from page 52, Sections 3.2, 4.2, 5.2, and 6.2:

(a) Please file the revised tables, including the original Board approval dates and amounts approved.

(b) Identify those projects not yet approved by the Board, and projects with forecasted overspending exceeding the Board approved amount by more than $250,000.

(c) For each of the projects from b), please explain why Board approval has not been requested, and advise on expected filing dates.

Response IR-25:

Projects listed as carryover in the ACE Plans are projects that have been approved by the Board, have been submitted to the Board and are awaiting review and approval, or are under $250,000.

(a) Please refer to Attachment 1.

(b-c) Please refer to the table below.

Projects that have not received UARB Approval		
CI #	**Project Title**	**Status**
43324	L6513 Rebuild / Upgrade Line Terminals	Filed on January 13, 2015
48022	Spider Lake Substation Addition	Filed on July 15, 2016
45066	Upgrade L6511 and L7019 Thermal Rating	Filed on April 24, 2015
45067	67N Onslow 345 KV Node Swap	Filed on November 14, 2014
46366	65V Middleton Substation RTU Addition	Now less than $250k
49611	New Distribution Rights-of-Way Phase 1	Filed on November 1, 2016
44671	IT - Enterprise Resource Plan (ERP)	Filed on November 10, 2016
49043	IT Contact Centre Telephony Infrastructure	Filed on November 1, 2016

Projects that Exceed the UARB Approval by $250,000		
CI #	**Project Title**	**Status**
16374	HYD Gaspereau Dam Safety Remedial Works	Work ongoing to finalize design. Will be filed when this work is complete.
44978	HYD-Wreck Cove Controls Upgrade	Forecasted amount has been updated and is now below UARB approved budget. No filing required.
44267	TRE Ash Lagoon Site Closure	Finalizing increased project estimate. ATO will be submitted in Q1 2017.
46339	120H Brushy Hill - SVC Controls Replacement	Project is still with 5% of UARB approved budget.

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General Plant - Carry Over Spending Summary

Project Number	CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2017 Budget ($)	Subsequent Spending ($)	Total Estimate ($)	UARB Approval Date	UARB Approved Budget	Status
Telecommunications											
P960	46552	Backbone Communications System Upgrade	2015/02	2018/02	5,780,581	2,163,570	577,762	8,521,912	2015/12	8,913,092	in service
P943	43227	2014 RTU Replacements	2014/06	2017/12	700,817	46,729	-	747,546	ACE 2014	687,839	on-going
	Total Telecommunications				**$6,481,397**	**$2,210,299**	**$577,762**	**$9,269,458**			
Computers											
P981	44671	IT - Enterprise Resource Plan (ERP)	2015/08	2017/12	35,267,288	54,396,712	-	89,664,000	Filed - Awaiting Approval		on-going
P967	47477	IT - Next Generation Firewall	2015/05	2017/06	2,690,010	409,787	-	3,099,798	2016/11	3,927,576	on-going
	49043	IT Contact Centre Telephony Infrastructure	2016/03	2017/04	1,774,670	729,439	-	2,504,109	Filed - Awaiting Approval		on-going
	48254	IT - Outage Comm Tech Cap Improvmnt	2015/11	2017/06	1,195,195	677,904	-	1,873,099	2016/11	2,146,081	in service
	46073	IT - Lotus Notes/Oracle Applications Replacement	2015/01	2017/03	667,224	105,395	-	772,619	2016/04	776,331	on-going
P987	48635	IT - Security Enhancements - Endpoint Data Encryption ar	2015/12	2017/03	692,382	64,760	-	757,142	2016/11	813,587	on-going
P108	46365	Maximo Enhancements for Substation Field Mobility	2015/03	2017/11	122,699	140,979	-	263,678	ACE 2015	315,242	on-going
	Total Computers				**$42,409,468**	**$56,524,976**	**$0**	**$98,934,444**			
Other General Plant											
	48072	2016 ADMS Switch Order Management	2016/10	2017/08	159,438	133,672	-	293,109	ACE 2016	304,469	initiated
P946	46411	Hydro Asset Management Implementation	2014/08	2017/09	564,107	26,974	-	591,082	2015/05	590,884	on-going
	Total Equipment Replacement				**$723,545**	**$160,646**	**$0**	**$884,191**			
Total General Plant Carry Over Spending					**$49,614,410**	**$58,895,921**	**$577,762**	**$109,088,093**			

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Generation - Carry Over Spending Summary

Project Number	CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2017 Budget ($)	Subsequent Spending ($)	Total Estimate ($)	UARB Approval Date	UARB Approved Budget	Status
Hydro Generation Plant											
H517	16374	HYD Gaspereau Dam Safety Remedial Works	2007/05	2018/01	7,736,563	6,280,504	12,150	14,029,217	2007/05	4,354,889	on-going
H715	44978	HYD-Wreck Cove Controls Upgrade	2014/01	2018/06	1,945,778	2,284,545	-	4,230,324	2015/12	3,802,446	on-going
H629	12079	HYD - SHH - RUF 1&2 Runner Replacement	2011/10	2017/12	1,011,884	447,079	-	1,458,963	2014/08	1,304,966	in service
H739	47551	HYD - SHH Controls Upgrade	2015/07	2017/12	90,419	1,309,702	-	1,400,121	2016/06	1,749,212	on-going
H685	43128	HYD - Gisborne Gearbox and Bearing Replacement	2015/08	2017/12	561,718	118,358	-	680,076	ACE 2013	360,731	on-going
H729	47163	HYD - Tusket Controls Upgrade	2015/03	2017/12	94,770	550,989	-	645,759	2016/05	906,688	on-going
					$11,441,132	**$10,991,178**	**$12,150**	**$22,444,460**			
Steam Generation Plant											
SB90	44267	TRE Ash Lagoon Site Closure	2013/05	2017/11	6,381,196	2,759,566	-	9,140,761	ACE 2015	7,994,849	in service
	47761	LIN1 Boiler Refurbishment	2017/04	2017/11	-	398,673	-	398,673	ACE 2016	506,845	on-going
SF22	46434	TRE6 Coal Pile Reclaim Markers	2015/12	2017/11	140,524	92,888	-	233,412	Less than $250k		on-going
SG65	47593	TRE Dechlorination System	2016/04	2019/12	12,424	25,179	188,451	226,054	Less than $250k		on-going
SF73	47703	POT - Replace DCS servers	2016/01	2018/06	161,814	37,337	-	199,151	Less than $250k		on-going
SF67	43386	POT - LP dosing automation	2016/01	2017/12	19,047	11,407	-	30,454	Less than $250k		on-going
	Total Steam Generation Plant				**$6,715,004**	**$3,325,051**	**$188,451**	**$10,228,506**			
Gas Turbine Generation Plant											
G180	33142	CT- Burnside #4 Unit Restoration	2014/03	2018/02	4,515,069	3,784,820	-	8,299,889	2016/03	8,320,984	on-going
G181	46191	Tusket Fuel System Upgrade	2014/06	2017/03	864,290	69,934	-	934,223	2016/08	1,952,408	on-going
	Total Gas Turbine Generation Plant				**$5,379,359**	**$3,854,754**	**$0**	**$9,234,113**			
Total Generation Carry Over Spending					**$23,535,495**	**$18,170,982**	**$200,601**	**$41,907,078**			

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Transmission - Carry Over Spending Summary

Project Number	CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2017 Budget ($)	Subsequent Spending ($)	Total Estimate ($)	UARB Approval Date	UARB Approved Budget	Status
Transmission Plant											
T782	43324	L6513 Rebuild / Upgrade Line Terminals	2013/01	2018/06	2,478,851	10,472,566	4,983,508	17,934,924	Filed - Not approved at this time		on-going
T828	46591	88S Lingan Replace 230kV GIS	2014/11	2018/12	567,303	4,835,511	7,102,611	12,505,425	ACE 2 016	14,249,882	on-going
T825	46339	120H Brushy Hill - SVC Controls Replacement	2014/11	2017/06	6,949,629	3,268,919	-	10,218,548	ACE 2015	9,959,330	on-going
T888	48022	Spider Lake Substation Addition	2015/09	2017/12	298,810	5,849,143	-	6,147,953	Filed - Awaiting Approval		on-going
T822	45306	Prime Brook Substation Addition	2014/12	2017/10	2,414,322	973,184	-	3,387,506	2015/08	3,442,582	on-going
T856	46587	Metro Voltage Support Add Capacitor	2014/11	2017/10	2,072,652	1,204,111	-	3,276,763	ACE 2 016	3,373,511	on-going
T867	46757	88S Lingan 230kV BPS Upgrades	2015/09	2018/12	287,487	1,561,855	1,231,321	3,080,663	ACE 2016	3,218,221	on-going
T801	45067	67N Onslow 345 KV Node Swap	2014/03	2017/12	2,775,336	181,185	-	2,956,521	Filed - Not approved at this time		on-going
T802	45066	Upgrade L6511 and L7019 Thermal Rating	2014/02	2017/12	2,527,099	153,847	-	2,680,946	Filed - Not approved at this time		on-going
T872	46811	2H Armdale Transformer Addition	2015/12	2017/09	287,468	2,303,896	-	2,591,364	2016/09	2,566,861	on-going
T884	48061	New Mobile Substation 7.5MVA	2015/12	2018/12	16,561	520,609	1,899,622	2,436,792	2016/09	2,390,744	on-going
T881	47950	L5017 Replacements & Upgrades	2015/12	2017/09	1,305,526	873,013	-	2,178,539	ACE 2016	2,182,142	on-going
T871	44981	2C Port Hastings Transformer Replacement	2015/10	2018/03	217,987	1,695,987	-	1,913,974	ACE 2016	2,053,799	on-going
T893	48114	2016 Steel Tower Life Extension - HRM	2015/12	2017/08	894,195	591,115	-	1,485,310	ACE 2016	1,477,739	in service
T874	47914	L6537 Replacements and Upgrades	2015/12	2017/05	636,124	553,521	-	1,189,645	ACE 2016	1,382,705	on-going
T910	49253	U&U 20V-T1 Transformer Replacement	2016/04	2018/04	457,127	697,343	-	1,154,470	2016/09	1,305,748	on-going
T876	47949	L5028 Replacements and Upgrades	2015/12	2017/10	540,310	473,039	-	1,013,349	ACE 2016	1,144,355	in service
T835	43267	13V Gulch Hydro Replace 13V-GT1 and 13V-VR1	2014/12	2017/12	422,881	414,950	-	837,830	ACE 2013	954,407	on-going
T878	48062	2016/2017 Reactor Breaker Replacements	2015/11	2018/06	285,506	190,330	-	475,836	ACE 2016	384,974	in service
T879	48063	2016/2017 Capacitor Bank Breaker Replacements	2015/11	2017/10	98,358	203,101	-	301,459	ACE 2016	385,850	on-going
T854	46366	65V Middleton Substation RTU Addition	2016/01	2017/12	172,715	79,860	-	252,574	Less than $250k - Shown as greater than $250k in error		on-going
	Total Transmission Plant				**$25,706,247**	**$37,097,083**	**$15,217,061**	**$78,020,391**			
Total Transmission Carry Over Spending					**$25,706,247**	**$37,097,083**	**$15,217,061**	**$78,020,391**			

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Distribution - Carry Over Spending Summary

Project Number	CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2017 Budget ($)	Subsequent Spending ($)	Total Estimate ($)	UARB Approval Date	UARB Approved Budget	Status
Distribution Plant											
D454	40320	LED Street Light Conversion	2012/07	2019/09	20,526,470	2,481,049	12,902,363	35,909,883	2016/01	36,041,594	in service
	49611	New Distribution Rights-of-Way Phase 1	2016/09	2017/12	569,427	1,641,722	-	2,211,149	Filed - Awaiting Approval		on-going
D686	48093	2016 Padmount Transformer Replacement Prog	2015/12	2017/09	1,378,330	425,591	-	1,803,921	ACE 2016	1,911,470	in service
D688	47753	24C-442GB Highway 16 Reconductor Phase 2	2015/11	2017/08	1,379,296	83,353	-	1,462,649	2016/01	1,425,322	in service
D573	43217	24C-442G Hwy 16 Rebuild Phase 1	2014/03	2017/06	830,189	72,259	-	902,447	ACE 2014	800,769	in service
D562	44826	2014 Build-to-Roadside	2014/03	2017/12	718,985	152,425	-	871,410	ACE 2014	791,268	in service
D630	45031	3N Oxford Conversion Phase 1	2015/03	2017/06	839,329	30,593	-	869,922	ACE 2015	721,068	on-going
D758	49311	93V-312 Lower Saulnierville Conductor Overloac	2016/08	2017/12	116,451	463,733	-	580,184	2016/09	549,642	on-going
D704	47765	58C-405 / 11C Belle Cote Phase 2	2015/12	2017/06	250,815	253,027	-	503,843	ACE 2016	477,154	in service
D760	47403	Load Research Sample Update	2016/01	2017/12	390,852	81,190	-	472,042	2016/11	440,453	on-going
	47734	1C-411 Highway 4 Reconductor	2016/12	2018/06	5,585	200,751	228,610	434,946	ACE 2016	437,410	on-going
D762	48195	Halifax 4kV Conversion Ph 3	2016/06	2017/05	204,129	184,822	-	388,951	2016/11	429,235	on-going
D517	43278	Halifax 4kV Conversion Part-1	2013/05	2017/12	274,273	76,760	-	351,033	2014/04	275,390	in service
D476	43195	2013 Remote Communication on Reclosers	2013/03	2017/06	145,781	98,558	-	244,339	Less than $250k		on-going
D666	46623	Rights for Existing Facilities on Railway Lands	2015/06	2017/10	6,719	180,739	0	187,458	Less than $250k		on-going
D766	47774	546C-311 West Bay Upgrade	2016/06	2017/07	109,022	10,816	-	119,838	Less than $250k		on-going
	Total Distribution Plant				**$27,745,653**	**$6,437,388**	**$13,130,973**	**$47,314,014**			
Total Distribution Carry Over Spending					**$27,745,653**	**$6,437,388**	**$13,130,973**	**$47,314,014**			

Request IR-26:

With reference to page 52, what is the current status of the HYD – Gaspereau Dam Safety Remedial Works project, CI 16374?

Response IR-26:

Throughout 2016, NS Power has entered into Engagement Agreements with First Nation groups in regards to the continuation of the Gaspereau Dam Refurbishment project. As a result of this engagement, NS Power received agreement from the Assembly of Nova Scotia Mi'kmaq Chiefs in September 2016 to move forward with archaeological resource mitigation on site in the area related to the design construction footprint. This archaeological work started in October 2016 and is expected to be completed in 2017, and will allow for continued project progression, consistent with what is included in the 2017 ACE Plan.

Request IR-27:

With reference to page 60, please provide information on the current status of the LED Street Light Conversion project, CI 40320.

Response IR-27:

As of November 30, 2016, NS Power has converted approximately 29,850 street lights, which represents approximately 60 percent of the total estimated number of lights to be replaced. This project is on track to have street light LED conversions completed by the December 2019 deadline.

Request IR-28:

With reference to page 79, please explain how the locations for distribution right-of-way widening, set out in the table on page 79 of the Application, were chosen.

Response IR-28:

Locations are prioritized based on:

- Detailed field review;
- Inventory of vegetation condition;
- Lack of existing right-of-way;
- Reliability performance; and
- Ability to obtain easements or permissions.

Widening these locations will create a sustainable right of way condition and improve reliability.

Request IR-29:

According to information provided on page 64, NSPI estimates the total spending related to CI 44671, IT - Enterprise Resource Plant project would amount to $35.3 million by the end of 2016. Please provide expenditures on this project that occurred in each month starting from the project initiation, and provide a short description of the completed work.

Response IR-29:

Capital spend for each month since project initiation, up to the end of November 2016 is included in the table below:

Month	Capital Spend
Dec-15	$534,293
Jan-16	$644,701
Feb-16	$242,528
Mar-16	$81,736
Apr-16	$972,384
May-16	$1,315,045
Jun-16	$6,864,195
Jul-16	$1,028,283
Aug-16	$2,006,289
Sep-16	$2,915,329
Oct-16	$2,060,692
Nov-16	$3,804,458

The following work on this project has been completed:

- Determined business requirements;
- Development of Target Operating Model including a current gap analysis;
- Establishment of technical infrastructure requirements;
- Evaluation and award of RFP for implementation phase;
- Development of change management strategy and organizational impacts inventory;
- Setup and configuration of server hardware and purchased required software licenses to support initial project technical activities;

- Initial ERP system configuration;
- Commenced PowerPlan re-implementation; and
- Development of high level data, integration and test strategies.

The implementation phase of the ERP project has started and is on-going.

Request IR-30:

According to page 86, computers are replaced after 4 years, yet depreciated at 20% (page 165). Should the depreciation rate be adjusted?

Response IR-30:

No, the depreciation rate for computer hardware should not be adjusted on the basis of the useful life of computers being four years.

It is important to consider that NS Power tracks assets in pools, meaning assets are grouped and depreciated with other like assets. Computers belong to the computer hardware asset pool and are replaced after four years. Other assets included in the pool (servers, for example) have a useful life of greater than five years. Overall, the useful life of the assets in this pool is expected to be five years.

Request IR-31:

With reference to page 92, NSPI refers to "…additional fixed cost recovery received from customer growth achieved through capital investments to serve these customers." Please provide support for NSPI's expectations of customer growth to offset revenue requirement.

Response IR-31:

NS Power uses the Conference Board of Canada's forecast for housing starts to forecast the number of new customers in a year. In NS Power's 2016 10-Year Load Forecast Report, the number of housing starts forecast for 2017 was 3,200.[1] This number of customers is aligned with the 45 GWh of new customer load growth that leads to the $4.15 million in fixed cost recovery included on page 92.

[1] M07448, 2016 Load Forecast Report, Figure 5: Residential Economic Drivers, page 14

Request IR-32:

With reference to pages 101 to 105, inclusive:

(a) Please elaborate on most likely impacts of the Federal government carbon policy on capital investment in generation.

(b) Please comment on the impacts of recently announced government policies regarding carbon and greenhouse gases as they relate to NSPI's IRP assumptions and the variances identified on pages 103 to 104.

Response IR-32:

(a) On December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change. This document discusses the Federal Government's vision for reductions in greenhouse gas (GHG) emissions in Canada. Leading up to this release, on November 21, 2016, the Government of Nova Scotia announced that it had reached an agreement in principle with the Federal Government that will allow the province to move from coal to clean energy sources while enabling NS Power's coal fired plants to operate in some capacity beyond 2030; this is contingent on an equivalent total emissions equal to coal closure in 2030. The details of the Federal/Provincial Agreement have yet to be finalized.

In addition to the Federal/Provincial agreement, the Nova Scotia Government has announced plans to create an in-province cap and trade system. The details of this new cap and trade system are still being developed, but it is understood that the cap and trade system will enable credits in the short term (before 2030) to be used post 2030 to meet the carbon pricing requirements of the Federal Government.

NS Power anticipates the terms and conditions of these plans and agreements to be developed through negotiations between the Federal and Provincial Governments in 2017 and 2018. However, based on what is known at this time, these policy developments are not expected to have a near-term impact on NS Power's investment plans for coal fired generation.

(b) The sustaining capital investment assumptions from the 2014 Integrated Resource Plan are provided on Pages 103 and 104 of the 2017 ACE Plan. These long term assumptions are derived from the extrapolation of unit utilization and asset health to establish a 25-year investment forecast for the steam fleet. The 2017 ACE Plan expenditures are developed from detailed condition-based risk assessments of NS Power's generating assets. For the reasons discussed in part a), the IRP assumptions and variances to 2017 spending presented on pages 103 and 104 are not expected to be materially affected by the recent policy announcements.

Request IR-33:

With reference to page 107, CI 47166 – HYD - McAskill Brook Decommissioning, please explain why a project with a ranking of 4 is included in the 2017 ACE Plan.

Response IR-33:

The ranking of 4 was submitted in error. It should be corrected to 12 based on condition 4 and criticality 3. The assessment of this project is ongoing and it will be deferred until a more complete assessment can be concluded.

Request IR-34:

With reference to page 111, CI 45832 – TUC6 Boiler Purge Credit, please explain why a project with a ranking of 12 is included in the ACE Plan (recognizing the budgeted amount is less than $250,000).

Response IR-34:

At the time of the 2017 ACE Plan submission, this project had a ranking of 12. However, there was an assessment of the project ongoing and the ranking was anticipated to increase based on the outcome of that assessment. Therefore the project was included in the 2017 ACE Plan with its current ranking with the expectation that it was going to increase. Since that time, the assessment did not increase the ranking of the project; therefore this project has been deferred to future years.

It's important to note that in most instances, capital projects will have a ranking of 15 and above, projects with rankings of below 15 can still lead to capital investment. This typically occurs when a project (with ranking less than 15) is associated with another larger project with a ranking of 15 or greater. Turbines (Major Outages) is a typical asset class where we would see this situation arise.

With respect to the project value (less than $250,000), this does not enter into the Risk determination process. Risk is determined prior to capital cost being determined and prior to mitigating measure being selected.

Request IR-35:

On page 124 NSPI states the "increased customer interruptions for 2016 is a result of a number of failures of a particular type of in-line disconnect switches in Metro Halifax":

(a) Please explain the nature and cause of these failures.

(b) Are planned replacements the only effective manner of addressing this problem?

(c) Does NSPI have an estimate of how long it will take for the targeted device replacement program to reduce the number of failures to an acceptable level?

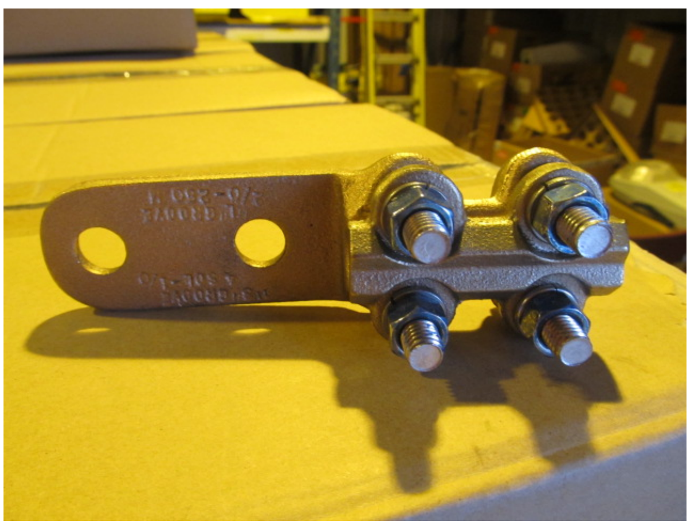
Response IR-35:

(a) The failures are a result of corrosion of the aluminum connectors originally provided with these in-line disconnect switches. The aluminum connectors have since been replaced with copper connectors for new installations. Please refer to the pictures below.

Aluminum connector

Corroded aluminum connector

Copper connector



(b) Yes. Replacement of the aluminum connectors is the only way to prevent failures due to corrosion of the connectors. Alternatively, the in-line disconnect switches could be bypassed or removed from service; however, this would reduce switching capability for load transfer or isolation of outage events.

(c) The targeted in-line disconnect switches identified in Metro Halifax are planned for replacement in 2017, which will reduce the occurrence of failures of the targeted devices.

Request IR-36:

With reference to pages 129 to 139, Plans for Replacement of Aging Transmission and Distribution Equipment, please comment on how the analysis undertaken to identify and prioritize assets for replacement has helped NSPI inform its ACE Plan.

Response IR-36:

In order to scope the overall sustaining investment for Transmission and Distribution replacements, the Iowa State Survivor curves and asset volumes are used to determine an estimated number of sustaining replacements (or equivalent spend) for each asset class. The Iowa State Survivor curves were originally published in 1935 by the Iowa Engineering Experiment Station. The curves were re-published in 1967 by the Industrial Engineering Department at Iowa State University. These curves are utilized by many utilities to determine depreciation rates for asset classes. The Iowa State Survivor Curves are based on historical retirement data for a variety of industrial equipment and human lives. Survivor curves developed using this data can be used to predict expected retirements for a given asset pool within a certain time period. In 2010, these curves were utilized in the Depreciation Study filed by Nova Scotia Power with the Utility and Review Board.

To prioritizing asset replacements within each of these asset classes, potential replacements are ranked through assessment of asset condition, system criticality, and ultimately risk. Recommendations for risk mitigation (whether capital replacement, operating guidelines, or maintenance adjustments) are documented. Assets recommended for risk mitigation through capital replacement are put forward for consideration in the ACE planning process.

Risk mitigation plans are prioritized according to the relative improvement of risk profile considering potential impacts to safety, customers, and the environment among others consistent with the CEJC and addressed in the ACE planning process as appropriate. Based on operational data, failures in the field, and other external influences, the prioritizations of replacements are adjusted as necessary throughout the year.

Request IR-37:

On page 156 of its Application, NSPI states:

> **At this time, there is potential for the incorporation of energy storage technologies in grid operations. However, they are not yet cost effective when compared to traditional transmission and power generation solutions.**

Please provide any quantitative analysis performed by NSPI in reaching this conclusion.

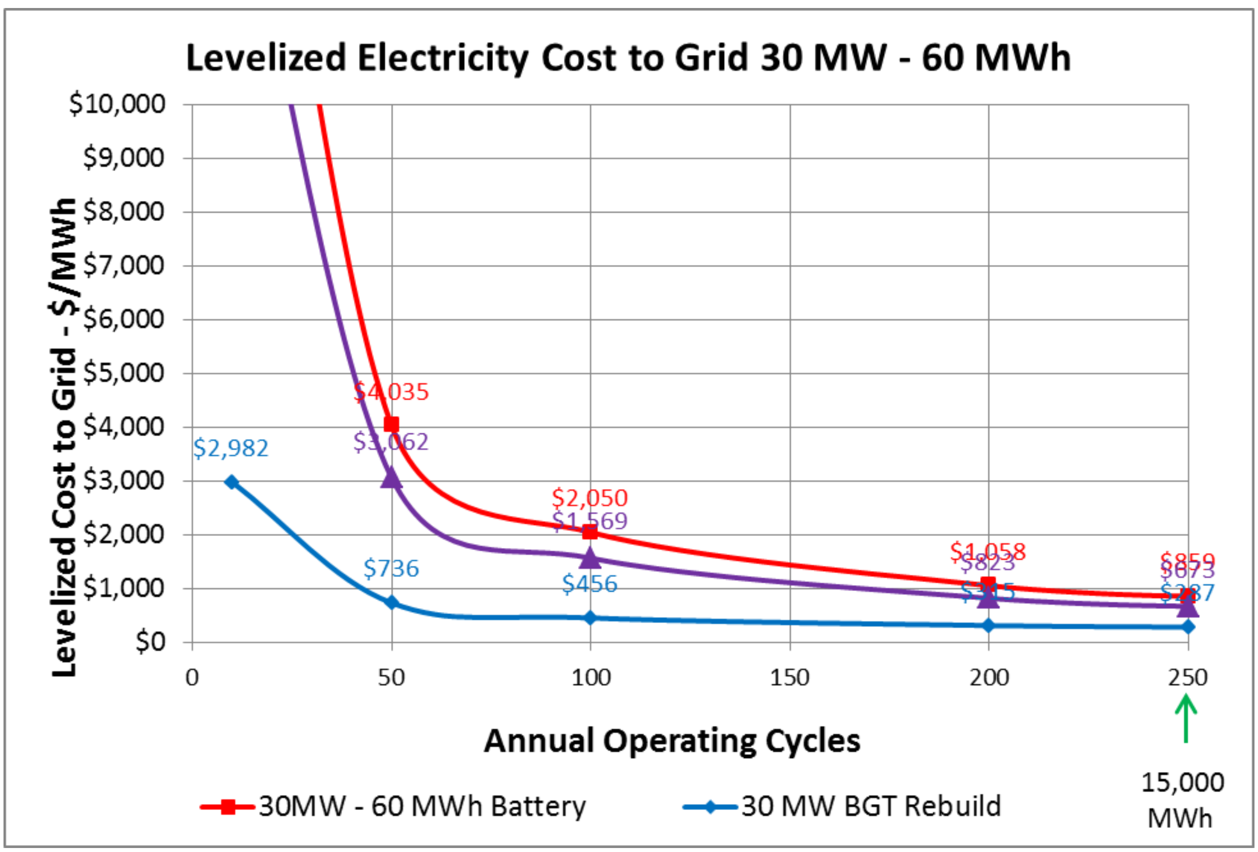
Response IR-37:

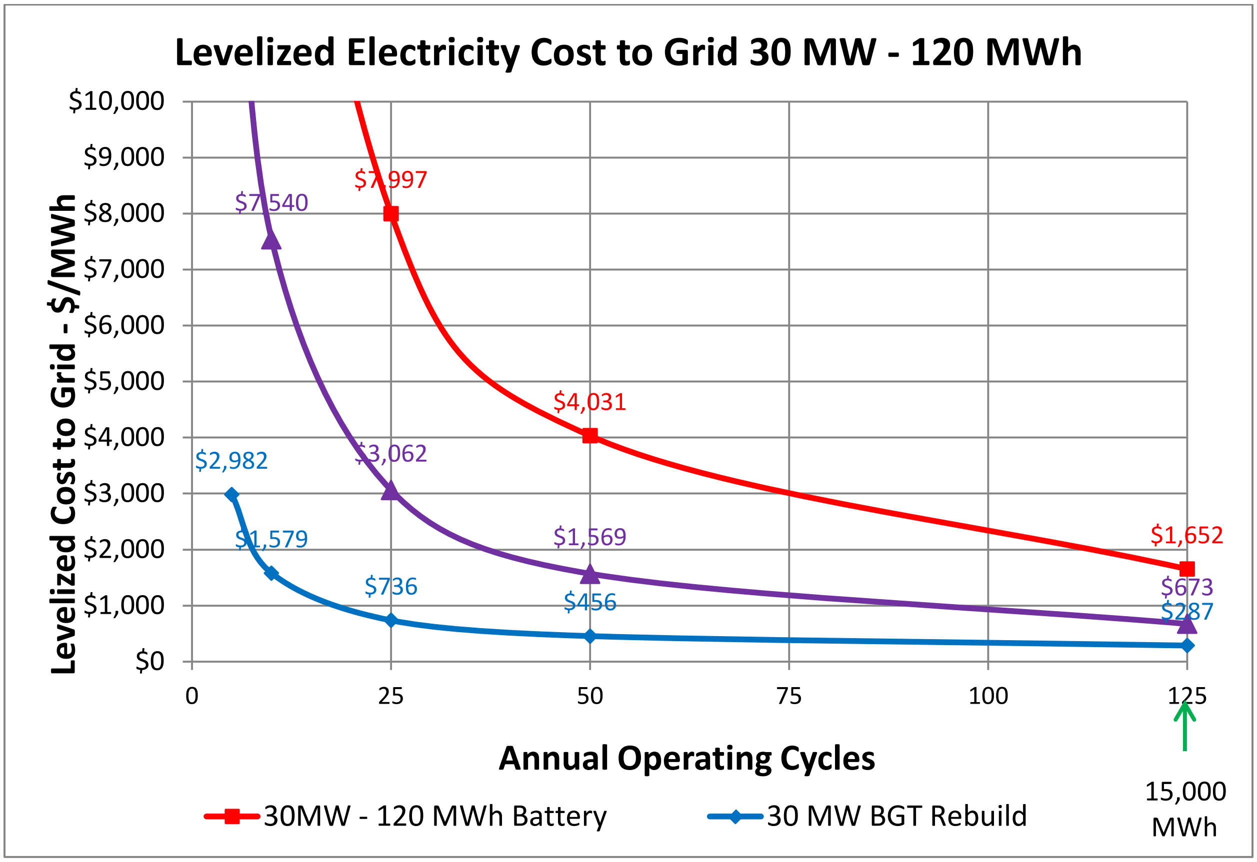
Over the past year, NS Power has been exploring the actual costs of various energy storage technologies and has received information from manufacturers, utilities and other industry sources. Based on the information gathered, NS Power estimates the current installed cost of a battery energy storage system (BESS) to be approximately $1,000/kWh. This installation cost will provide a BESS that can deliver one kilowatt of energy for one hour for a cost of $1,000. A BESS that can deliver two kilowatts for one hour, or one kilowatt for two hours would cost $2,000.

NS Power has conducted a preliminary economic comparison for BESS versus Fast Acting Generation using high level cost estimates based on information received from sources mentioned above. The comparison assessed three possible projects for the supply of fast acting generation that could provide 30 MW of electricity to the grid for three different durations consisting of 2 hours (60 MWh) and 4 hours (120 MWh). In addition, a comparison with the recent NS Power project CI 33142 – Burnside #4 Gas Turbine Restoration was included. For this analysis, the installed cost of new fast acting generation was estimated to be $1,500/kW, while the Burnside #4 Restoration had a cost of $277/kW.

The options were compared using a levelized cost of electricity method using a 20 year project life. The preliminary results of the comparison showed that BESS systems are not cost competitive when compared with a combustion turbine restoration such as Burnside #4 (please refer to the figures below). Based on current operation of the Burnside combustion turbines, used to generate during peak capacity requirements, we would expect the BESS to be used less than 50 operating cycles per year. As the system needs evolve to longer duration energy requirements with a lower frequency of use, the most cost competitive technology shifts toward fast acting, highly flexible generation systems such as reciprocating engines. In all of the technology cases, the greater the frequency of use, the lower the levelized cost of the energy delivered to the grid.

In this example, the Burnside #4 restoration project can be seen to be more economic when compared to new flexible capacity and BESS technology alternatives and would be the most cost effective project to provide stand by power with a low annual use requirement for energy delivery.




Levelized Electricity Cost to Grid 30 MW - 120 MWh
Levelized Cost to Grid - $/MWh
$10,000
$9,000
$8,000
$7,000
$6,000
$5,000
$4,000
$3,000
$2,000
$1,000
$0
0
25
50
75
100
125
$7,997
$4,031
$1,652
$7,540
$3,062
$1,569
$673
$2,982
$1,579
$736
$456
$287
Annual Operating Cycles
15,000 MWh
30MW - 120 MWh Battery
30 MW BGT Rebuild

Request IR-38:

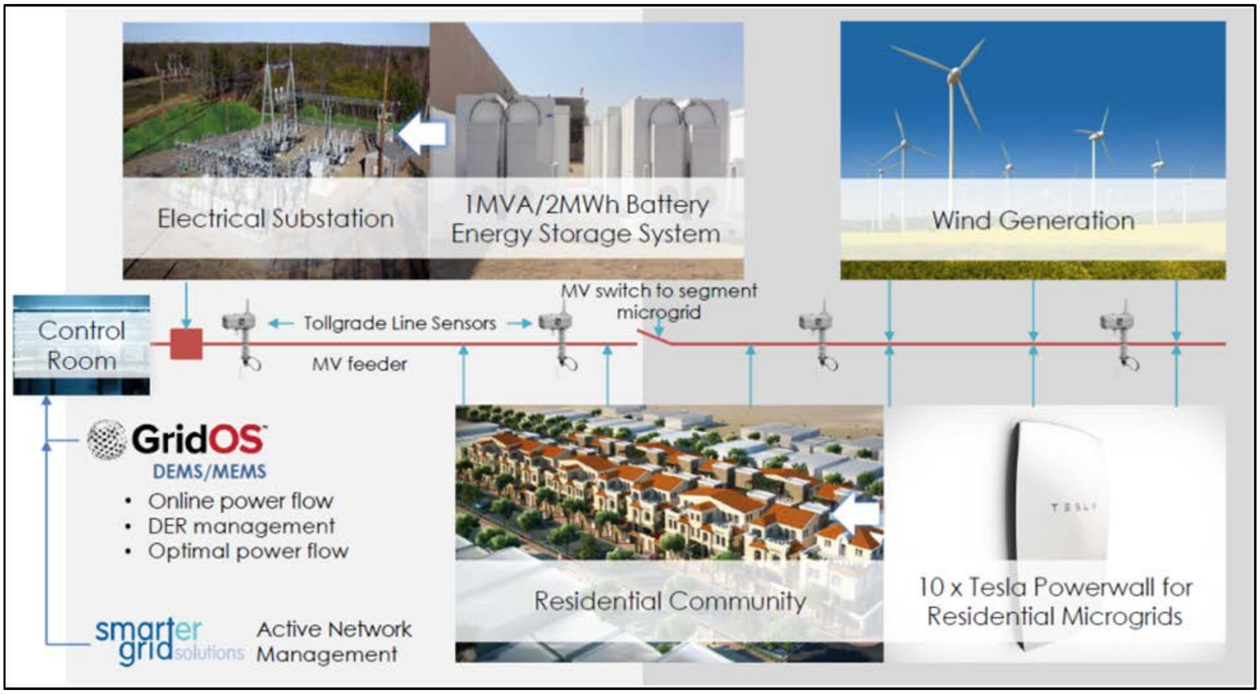
With reference to pages 156 and 157, please provide updated information regarding the two pilot projects for storage technology.

Response IR-38:

CI 49787 - Intelligent Feeder/Storage Project (SDTC)

NS Power is partnering with Tesla and Opus One Solutions to undertake the 'Intelligent Feeder Project', which will involve installing a grid-connected battery (Tesla Powerpack) and up to 10 residential batteries (Tesla Powerwalls) on a feeder partially powered by a variable distributed generation. Line sensors will be placed on the feeder to gather real-time information about system activity and, using the Opus One GridOS system, the batteries will be dispatched, as required, and data will be brought back to NS Power's Control Centre, as illustrated in the diagram below. This Project will inform NS Power on the operational characteristics of grid connected and customer connected battery storage systems. These technologies are expected to assist with the balancing of variable generation resources and could be expected to reduce outages for customers. This project will also identify and demonstrate the value of storage in Nova Scotia at the customer level, distribution and transmission level, and at the generation level. It will assist NS Power in understanding and planning the role of storage in the electricity system going forward and provide the Company with experience and capability in operating and integrating the storage resources.

The project is funded in part by Sustainable Development Technology Canada. Construction is scheduled for 2017 and the project will be active in 2018. NS Power anticipates submitting Capital Work Order CI 49787 in the first quarter of 2017.



Wind Energy Institute of Canada

The Wind Energy Institute of Canada (WEICan) is offering a Wind Integration System Operator Research Program through their Energy Research and Development Program to study how wind and energy storage can be used in order to provide ancillary services such as automated generation control, frequency regulation and voltage control. WEICan has been leading wind industry research in Canada for more than thirty years and comprises a highly qualified and diverse group of wind energy researchers. WEICan owns and operates a 10 MW Wind R&D Park and Storage System, located in Cape North, PEI. This park has five 2 MW turbines and a 1 MW/2 MWh storage system. WEICan is planning to test 4 operating scenarios developed in consultation with utilities and system operators using their Wind R&D Park.

In the Wind Integration System Operator Research Program, various grid operator dispatch scenarios, developed in consultation with industry stakeholders will be tested, using the WEICan facility as a test site. The objective of this research is to evaluate the technical capabilities and economics of using wind energy generators and energy storage devices in grid support and stabilization. WEICan has approached NS Power to participate in the Wind Integration System Operator Research Program. Early discussions on potential operation scenarios to test are distribution feeders with distribution connected wind generation to determine if battery energy storage would be useful in helping with short term voltage support, phase balancing during various load conditions, and/or voltage balancing during high wind / light load periods.

Full project scope, budget and schedule for NS Power's participation in the Wind Integration System Operator Research Program are not yet determined, but are not anticipated to result in a Capital Item.

Request IR-39:

With reference to page 166, would there be any changes to the outcome of any of the economic analysis models submitted as part of the 2017 ACE plan due to a revised life expectancy of the coal plants to be in line with the Federal Government Carbon policy?

Response IR-39:

The recent announcements regarding carbon policy by the Federal Government and the Province of Nova Scotia establish the framework for agreements which will allow for the continued use of NS Power's coal fired generating fleet beyond 2030. Please refer to NSUARB IR-32.

With respect to the 2017 ACE Plan investments in coal fired generation, all of the projects justified in whole or in part on economics have a payback period of 4.2 years or less. This is well within the operating life expectancy of coal fired generation in Nova Scotia as indicated by recent federal and provincial announcements on carbon policy.

Request IR-40:

Please provide the currently estimated 2016 variance in budgeted amount to forecasted actual for routine D005, Unplanned Replacement Deteriorated Equipment, broken down into variance attributable to person days and variance attributable to cost/person day.

Response IR-40:

D005 Unplanned Replacement Deteriorated Equipment	Forecast ($)	Person Days	Average Cost / Person Day ($)
2016 ACE	8,802,794	3,051	2,885
2016 Forecast	10,264,376	3,967	2,588
Variance	1,461,583	916	(298)

The variance in person days is associated with a higher volume of unplanned replacement work. The variance in average cost per person day is associated with a lower proportion of overtime labour and materials.

Request IR-41:

The $3.2 million budgeted in routine D009 (Meters Routine) is higher than the 2016 budget and forecast actual:

(a) Is all this work necessary, given the significant smart meter project being undertaken in the near term?

(b) Will any of the work performed on meters in 2017 be replaced as part of the smart meter capital project?

Response IR-41:

(a) Yes. The D009 (Meters Routine) provides meters for the Government Meter Change Out (GMCO) program, which is required by Measurement Canada, as well as for new meter installs and replacements of damaged meters. This routine work must continue in order to meet regulatory requirements and serve customers, in conjunction with CI 47124 Advanced Meter Infrastructure – Pilot Project.

(b) Yes. In future years the Smart Meter Program will replace meters purchased under routine D009. The work and investments associated with each will be coordinated together in order to avoid duplicate replacements. Details related to the execution of the full Smart Meter Program are in the process of being finalised and will be detailed in CI 50343 Advanced Metering Infrastructure, due to be submitted to the UARB in 2017.

Request IR-42:

With respect to the $726k for streetlight/service removal under routine D055 (Planned Replacement of Distribution Equipment):

(a) Please provide a breakdown of this amount, including the basis of estimate for each sub-amount.

(b) Please explain the significant increase (63%) over the prior year routine amount.

Response IR-42:

(a) The budget for streetlight/service removal under routine D055 is based on historical spending levels. Please refer to the table below for the breakdown by account with the 2014 – 2016 spending levels, which were used in building the budget for 2017.

Account	2014 Actual ($)	2015 Actual ($)	2016 YTD November Actual ($)	2017 ACE Plan ($)
Regular Labour	242,419	327,912	356,114	252,116
Overtime Labour	15,011	26,569	32,180	15,000
Travel	-	-	26	-
Materials	21,602	26,759	57,371	25,137
Contracts	116,172	139,833	158,178	114,497
Overtime Meals	99	540	1,020	-
Meal	-	-	31	-
Other Goods & Services	-	-	18,605	-
Vehicle Overhead	134,216	170,769	167,307	134,054
Administrative Overhead	222,998	296,936	280,336	221,504
Capital Contribution	-	(303)	(41,590)	-
Salvage	-	(20,775)	(26,179)	(36,000)
Total	**752,516**	**968,241**	**1,003,398**	**726,307**

(b) Street Light and Service Removal under D055 (Planned Replacement of Distribution Equipment) is work that is primarily driven by customer requests. The variance from ACE budgets to actuals from 2014 to 2016, and the 2017 ACE budget increase is associated with an increased volume of customer requested work associated with overhead services, rental lights and associated poles.

Request IR-43:

With respect to routine P062 (Work Vehicle Replacements):

(a) Is the estimate of 20 vehicles based on specifically identified vehicles for replacement?

(b) If the answer to part a) is no, why has there been a 25% increase in the estimate over prior year?

(c) Please provide the gross book value of vehicles retired in 2016 (currently forecasted) which would fall under this routine, as well as individually under P006, P061, and P063.

Response IR-43:

(a-b) Yes.

(c) Please refer to the table below.

Routine	Total Forecast Retirements ($)
P006	(73,655)
P061	(1,399,720)
P062	(4,746,469)
P063	(282,718)
Total	**(6,502,562)**

Request IR-44:

With respect to routine P031 (NS Power IT Infrastructure):

(a) Please provide a breakdown for the amount budgeted for new laptop or desktop computers, providing the number of computers (and corresponding dollar amount) and number of mobile devices and tablets (and corresponding dollar amount), if applicable.

(b) Is all this work (particularly network infrastructure and equipment) necessary given the significant IT capital projects being undertaken in the near term?

(c) Will any of this equipment be replaced as part of the upcoming major IT capital projects?

Response IR-44:

(a) A total of 400 personal devices (laptops, desktops, mobile devices and tablets) were included in the budget. The costs included in the budget are meant to represent an average cost per unit across all devices.

(b) With respect to routine P031, IT Infrastructure, the overall amount of investment budgeted in the 2017 ACE Plan has been reduced relative to prior years given the planned increase in IT capital project spend in the near term. Specifically, investments in servers have been reduced in this routine as this work will be completed inside the planned projects. Investments in the overall IT network (local area network, wide area network, storage, power supplies, and data centre operations) will remain as planned.

(c) Investments in servers related to the upcoming major IT capital projects will be refreshed within the respective IT projects and has been excluded from routine P031.

Request IR-45:

With respect to the four new projects under routine P001 (FAC Property Improvements - Energy Control Centre Roof, Lakeside Office/Storeroom Building Roof, ECC Generator Fuel Storage & Electrical, and CN Bridge Massachusetts Avenue):

(a) Please provide a description of the work.

(b) Please explain why it needs to be done now.

(c) Please provide a description of how the cost estimate was derived (including any supporting calculations or documentation).

Response IR-45:

(a) Energy Control Centre Roof – Remove existing roof system down to steel decking and replace entire roof system with a new roof including vapour retarder, insulation and new membrane and flashings.

Lakeside Office/Storeroom Building Roof – Remove existing roof system down to the steel decking and replace entire roof with a new ethylene propylene diene terpolymer membrane (EPDM) system, including a vapour retarder, insulation and a new EPDM membrane and flashings.

ECC Generator & Fuel Storage – Replace the existing fuel system, fuel pumps and day tanks, install new above ground piping system and add transfer switches to enable load bank testing.

CN Bridge Massachusetts Avenue Rail Bridge – Work will involve repairs on the central column and abutment walls. This includes refurbishment of delaminated concrete, cleaning of the reinforcement material and filling the gaps with new concrete.

(b) Energy Control Centre Roof – Please refer to Attachment 1 for an engineering assessment that shows the overall condition of the roof to be in poor condition and has reached the end of its expected life. This will also facilitate electrical infrastructure for full load testing.

Lakeside Office/Storeroom Building Roof – Please refer to Attachment 2 for an engineering assessment that shows the overall condition of the roof to be in poor condition and has reached the end of its expected life.

ECC Generator & Fuel Storage – To enable each generator to be separately load bank tested and to replace single walled fuel tanks that are located underground that do not have an underground containment system. Please refer to Attachment 3 for an engineering assessment of the Generator and Fuel Storage system.

CN Bridge Massachusetts Avenue Rail Bridge – In February 2016, CBCL provided a report to NS Power recommending NS Power undertake these repairs within a year. Please refer to Attachment 4. In March 2016, as an additional precaution and at the recommendation of CBCL, NS Power had the center columns wrapped in steel fencing material to prevent any loose material from coming in contact with passing traffic.

(c) Energy Control Centre Roof – Please refer to Attachment 1 - $516,500 + project management costs = $554,267

Lakeside Office/Storeroom Building Roof – Please refer to Attachment 2 - $1,650,000 + project management costs = $1,742,950

ECC Generator & Fuel Storage – Please refer to Attachment 3 - $448,825 + project management costs = $498,707

CN Bridge Massachusetts Avenue Rail Bridge – Please refer to Attachment 5 - $199,500 + project management costs = $214,800

Project management costs are NS Power estimates for internal and external support in managing these projects.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Roof Condition Assessment

5 Long Lake Drive
Ragged Lake, Nova Scotia

Prepared for:
Nova Scotia Power Inc.
Attention: Kathy Goyetche

Prepared by:
Matt McNeil

April 29, 2016

Stantec Project No: 133430712

Table of Contents

Executive Summary

In March 2016, Stantec Consulting Limited was retained by NSPI to perform a Roof Condition Assessment (RCA) for their facility located at 5 Long Lake Drive, Ragged Lake, Nova Scotia. The site visit was conducted on April 7, 2016 by Matt McNeil and Brian Hines.

The building at this location is a steel framed, single-story (high-ceiling) office building. The overall building footprint is approximately 45 meters long by 45 meters wide (approximately 2,025 m^2) and the building is estimated to be 25-years old.

Overall, the EPDM roof membrane at this facility was found to be in poor condition with the following noted issues;

- The original membrane seams displayed lifting and/or shrinkage at the outer edge, indicative of possible failure in the relative short-term.
- Concrete pavers were used as a wearing surface over a significant portion or the roof. The method of installation of these pavers had resulted in significant damage to the membrane, and possibly the substrate beneath.
- The perimeter cap flashings were recently removed for repair work and not replaced prior to winter of 2015. The flashings were stored on the roof under the stone ballast. This has damaged the flashings and exposed the substrate to water and possible damage.

Based upon the visual evidence of roof membrane system damage, deterioration, patches and remaining exposed flaws, it is our opinion that the existing roof system at 5 Long Lake Drive has reached the end of its Expected Use Life (EUL) and the roof should be replaced within the next 2 years. Retention of the existing system outside of that timeframe will require significant capital output with diminished return and could lead to further problems with other building systems over the long term.

Appendix A includes an Opinion of Probable Cost for the associated Maintenance and Capital Cost Expenditure to achieve the 15-year EUL for this facility, summarized below;

- Roof Maintenance (semi-annual inspection, over 15 years) $42,000
- **Capital Expenditure (short-term roof repairs, Appendix C) $516,500**

It is Stantec's opinion that should the recommendations contain herein be followed, including regular roof maintenance and the noted Capital Expenditures (CapEx) for roof repairs, the 15-year EUL can be achieved for this facility.

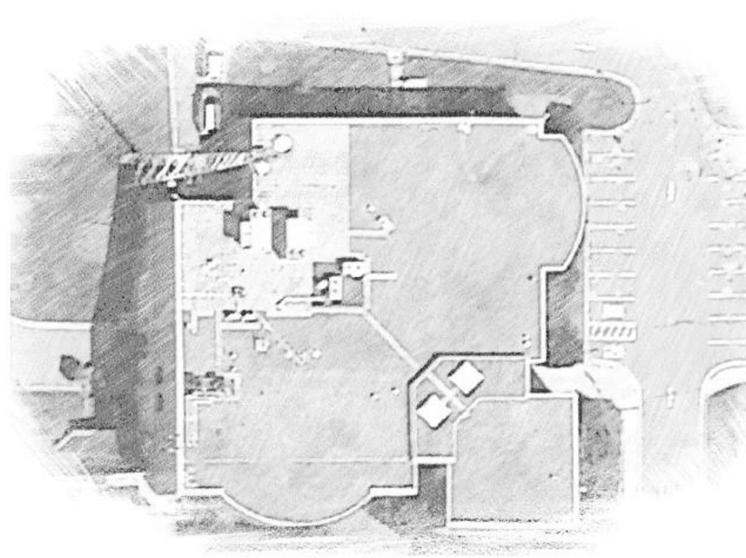
1.0 BACKGROUND

Nova Scotia Power Incorporated (NSPI) wishes to extend the operating life of several of its existing facilities in the Halifax Regional Municipality. In support for this initiative, a Roof Condition Assessment has been commissioned at each of the subject facilities to document the condition of the existing roof system(s) and to develop recommendations with respect to maintenance and capital expenditure required to extend the EUL of the facility by 15-years, where required.

In March 2016, Stantec Consulting Limited was retained by NSPI to perform a Roof Condition Assessment (RCA) for their facility located at 5 Long Lake Drive, Ragged Lake, Nova Scotia. The objective of this report is to summarize the findings of the RCA performed at this facility on April 7, 2016 and provide NSPI with the information required to tender roof maintenance/repair services, as required, to meet the performance goals for the facility over the forecasted use life.

1.1 BUILDING LOCATION / DESCRIPTION

The building located at 5 Long Lake Drive, Ragged Lake, Nova Scotia is a steel framed, single-story (high-ceiling) office building. The overall building footprint is approximately 45 meters long by 45 meters wide (approximately 2,025m^2) and the building is reported to be approximately 25-years old. Access to the roof system of this building was via internal fixed-ladder to a roof access hatch.



5 Long Lake Drive, Ragged Lake, Nova Scotia

ROOF CONDITION ASSESSMENT

BACKGROUND
April 29, 2016

The roof of this building has two levels, the top level being approximately 0.6 meters higher than the lower portions. The elevated roof is near the two skylights above the main foyer of the building. A significant portion (approximately one fifth) of the roof is currently allocated for mechanical equipment and its maintenance. Precast concrete pavers have been placed over the roofing membrane in much of this area, presumably to protect the membrane from damage during maintenance activities.

The roof of this building is considered a 'flat' roof system, incorporating a sloped substrate (sloped structure with flat and/or tapered insulation) to the roof drains located intermittently around the roof.

1.2 INSPECTION METHODOLOGY

Note: Stantec Consulting Ltd. was not provided with any formal data pertaining to the age or maintenance history of the facility under review; no building drawings, specifications, shop drawings, or guarantee information were provided; and no access to facility maintenance personnel or records was granted during the course of this investigation. Due to access limitations, Stantec Consulting Ltd. performed only minimal visual inspection of the underside of the roof system. Further, destructive testing of the roof system was not included in the scope of work for this project. Thus the information contained in this report and the related recommendations are based solely on visual examination of surface of the existing roof system except as specifically noted herein.

The assessment of the roof of this facility was based on a visual inspection; this included a comprehensive walk-around, visually examining the condition of the roof membrane and identifying defects, as well as observing for areas where the roof membrane may have lifted from the substrate or where factory or field seams may have failed. Roof components, such as parapets, flashings, drains, ventilation ducts and other miscellaneous penetrations or build-ups, were also examined as these are typically areas where roof system breakdown can occur with age.

2.0 FINDINGS

2.1 ROOF SYSTEM IDENTIFICATION

The primary roofing system for this building consists of an Ethylene Propylene Diene Monomer (EPDM) membrane with a combination of washed-stone and precast-concrete paver ballast which appears to be mostly original to the building construction. This roof system type is commonly referred to as a "loose laid ballasted" roof system. That is, the vapour retarder, if any, insulation and membrane are laid loose and subsequently secured against wind uplift pressures by the placement of appropriate ballast on the membrane surface. These systems also require that the membrane be mechanically secured at the roof perimeter and penetrations to counteract the tendency of the synthetic rubber membrane to shrink and move over time.

2.2 SYSTEM OBSERVATIONS

2.2.1 ROOFING MEMBRANE

A walk-around of the roof was undertaken to examine the visible seams, penetration details, and the membrane surface. Most of the roof system was covered with stone or paver ballast and it was not possible to fully inspect the portions of the membrane or the seams under the stone or pavers. However some areas of membrane had been left exposed as a result of roof repair work that was reported to have been suspended in the fall of 2015.

We also observed that a portion of the roof had been raised around a new mechanical unit and that a new fully adhered membrane system was installed on an unknown substrate beneath this unit. No visual or reported issues were apparent at these new installations.

In general, the original portions of the EPDM roof membrane at this facility were found to be in poor condition. The following items were noted during our examinations:

- We could not locate any identifying marks on the existing original membrane but it appears to be an unreinforced EPDM material, likely 0.045" in thickness (based on past experience). The membrane manufacturer is unknown.

- The original membrane seams were constructed using liquid applied adhesive technologies typical of the period. Seams of this type are prone to losing their structural and waterproofing integrity over the long term, as evidenced by the lifting and/or shrinkage of the outer edge of the seams apparent at most of the exposed seams on the roof.

- The roof components underlying the membrane were not apparent. However, typical loose laid and ballasted EPDM roof systems installed over steel roof deck in the Halifax market in the early 1990's would have included a kraft laminate or polyethylene sheet vapour retarder, flat or tapered expanded polystyrene(EPS) or extruded polystyrene (XPS) insulation (thickness and number of layers could vary), the EPDM roof membrane, and round stone ballast.

- In this application, the 600mm x 600mm concrete pavers were used over a significant portion or the roof to facilitate the traffic associated with the operation and maintenance of the roof top equipment. These paver panels were set on small squares (200mm x 200mm ±) of XPS positioned at the at the intersecting corners of the pavers or on strips of EPS insulation positioned beneath the edges of the paver panels. Unfortunately, the polystyrene has compacted over time, leaving the panels resting directly on the membrane surface. This has resulted in damage to the membrane, as evidenced by patches corresponding to the panel corner locations. Even where the polystyrene did not completely collapse, scrubbing and fatigue failure of the membrane beneath the supports could occur related to the infiltration of dust and grit beneath the supports and the movement of the membrane related to wind uplift beneath the pavers and between the supports.

- It was also noted that there were areas where 600mm x 600mm concrete pavers had been lifted and stacked to gain access to the substrate for membrane repairs. In some cases the pavers were stacked 6 or more units high, adding significant concentrated loads to some of the roof areas.

- As mentioned previously, there are several large areas of the roof where the membrane was fully exposed due to temporary relocation of the stone or paver ballast. During the inspection, the wind was moderate and the membrane was observed 'fluttering' above the substrate. This is a result of the wind uplift pressures combined with building internal pressures which can cause wear on the membrane, particularly at adjacent restrained components (remaining pavers and supports, perimeter fixations, ballast piles, etc.). Similarly, these pressure differences can cause displacement of the underlying insulation and vapour retarder components in the absence of the ballast.

- Both the stone ballast and the pavers have been removed from much of the roof perimeter, exposing the membrane to wind uplift and exposing the perimeter fixation system which appears to have failed in many areas. Failure of the perimeter fixation results in "tenting" of the roof membrane which increases the stress on the membrane surface, elevates the membrane away from its support, and causes peel failure of the bond between the membrane flashings and the vertical face of the perimeter and penetration curbs.

- The metal cap flashings were removed from many areas of the roof perimeter to facilitate the unfinished repair work. The absence of the metal flashings has exposed the holes in the underlying membrane where the metal flashing fasteners were removed to the weather as well as exposing seams and laps that were intended to be covered by the metal flashings. We also observed locations where the exposed membrane flashings were damaged, deteriorated, and/or inappropriately lapped and/or sealed which could permit moisture penetration.

- Other areas of the flat roof, where issues might be expected (drains and penetrations), were temporarily cleared of stone (if not cleared already) to determine if there were any hidden issues; no notable defects were found in these exposed areas.

2.2.2 ANCILLERY ROOFING COMPONENTS

The roof drains, penetrations, and curbs were found to be in generally good condition with no visible blockages or failures. The membrane boots/flashings around the penetrations were found to be in good condition with no significant fish-mouthing at the seams; a typical sign of a failing transition system due to age and exposure to the elements.

Much of the cap flashing had been removed at the time of inspection and was being stored on the roof (held down by stacked ballast - see Photos B.31/32 in Appendix B). Some of this flashing is showing signs of surface corrosion and damage relating to age as well as to storage location and means.

Several of the precast concrete panels placed on the roof were found to be cut or damaged, particularly around drains. These damaged units introduce sharp edges which could lead to perforation of the membrane over time.

There are several roof-mounted lights located close to the roof perimeter, typically at corners. These units appear to be in good condition. Precast panels are being used as ballast for several of the units at present.

The skylights over the foyer were inspected to determine if there were any issues with the installation. There were no noted deficiencies with these fixtures at the time of inspection.

2.2.3 ROOFING STRUCTURE

There was no visual indication of structural performance issues for the roof system under review. There was no evidence of sagging of the roof substrate or substructure, often visible in the form of water ponding on the surface of the membrane. All the drains appear to be at the localized low-points of the roof system and there was minimal buildup of sediment around the drains, typically indicative of a roof drainage system performing as-intended.

On the day of the inspection, there was a rain event and so some minor water buildup was present in several areas of the roof (see Photo B.21 in Appendix B) however the buildup (<6 mm) was of insufficient quantity to suggest roof sag or underlying structural issues.

2.3 REMAINING EXPECTED USE LIFE (EUL)

Based upon the visual evidence of roof membrane system damage and deterioration, patches, and the remaining exposed flaws, it is our opinion that the existing roof system at 5 Long Lake Drive has reached the end of its EUL and should be removed and replaced within the next 2 years. Retention of the existing system for a longer period of time will require significant capital output with diminished return and could lead to further problems with other building systems.

The opinion of cost associated for this anticipated CapEx work is provided in Appendix A.

3.0 RECOMMENDATIONS

3.1 MAINTENANCE BUDGET

A typical built-up flat-roof system should last in excess of 25-years when properly maintained on a regular basis.

Typical maintenance of a flat roof system involves semi-annual inspection to check for issues such as blocked drainage systems, ponded water, areas of sag or depression and membrane lifting or tearing. After major storm events, the roof should be inspected by maintenance personnel; in the winter months, ensure that snow/ice load does not exceed design parameters. During warmer periods, look for damage or lifting of the membrane and ponding. If a significant depression remains after removal of standing water, have the system reviewed again by a roof membrane professional to ensure no substrate or structural damage has resulted from the transient roof loading. Roof drains may need to be replaced or added in areas where the surface slope has changed such that water can no longer reach the drain; this is also indicative of other issues with the system.

The Opinion of Cost included in Appendix A includes consideration for an ongoing Maintenance Budget for the roof of the facility as a break out item from opinion of cost for CAPEX expenditures. While CAPEX costs will address the immediate and long-term performance issues, as required, the maintenance allowance will ensure that any risks associated with achieving the target duration are minimized over the operating life of the facility.

3.2 CURRENT/FUTURE CAPEX EXPENDITURES

The CAPEX expenditures itemized in Appendix A are based on deficiencies identified during the RCA that in Stantec's professional opinion will require repair within the noted timeframe. These items, if not addressed, will likely contribute to premature roof performance degradation during the target operating life of the facility.

Deficiencies that can be isolated have been itemized to allow for staged expenditure, where possible. Where it is felt that the work cannot be easily segregated, the deficiencies have been listed as sub-tasks of a master work breakdown structure. For example, it would not make sense to replace flashing after replacing a roof membrane system; the flashing work is therefore listed as a sub-task of the membrane replacement work package.

3.2.1 ROOFING MEMBRANE

It is recommended that the following items be considered to achieve the EUL of 15-years for the roof membrane system;

1. Option: Remove existing roof system down to the steel decking and replace entire roof system with a new roof system, including a vapour retarder, enhanced insulation and a new membrane and membrane flashings at perimeters and penetrating elements.

   Considering that the existing roof system is approximately 26 years old and has worked reasonably well without excessive maintenance, the installation of a similar EPDM membrane system which will include many system level improvements (seaming technologies, flashing materials, etc.) may be appropriate although adhered or mechanically-attached single ply roofing options are also available.

2. Option: Removal of the existing membrane, replacement of damaged and deteriorated insulation and membrane substrate components and installation of a new membrane system including associated flashings could also be considered. However, it is our opinion that any potential savings associated with this approach should be balanced against the potential negatives including:

   a. Not being able to examine and repair or replace any inadequate or damaged vapour retarder components; and

   b. Potential for extra cost implications during construction related to unidentified required replacements.

It is Stantec's opinion that Option 1 be carried by NSPI due to the unknowns associated with the substrate and the findings on site. Discussion and costing hereafter are based on full roof system replacement (Option 1).

3.2.2 ANCILLERY ROOFING COMPONENTS

It is recommended that the following items be addressed to achieve the remaining EUL of 15-years for the ancillary roofing components;

1. Replace cap flashings with new around the perimeter of the roof.

2. Remove all broken precast concrete panels from roof and replace with new panels set on proper supports (rubber sleepers) or use other appropriate membrane protection materials around mechanical equipment.

3. Ensure roof-mounted lights are properly mounted and flashed water-tight as part of the membrane replacement along these areas of the roof perimeter.

3.2.3 ROOFING STRUCTURE

No work is anticipated on the roofing structure to achieve the remaining EUL of 15-years.

4.0 STANTEC TEAM

Stantec has completed a Roof Condition Assessment (RCA) of the property located at 5 Long Lake, Ragged Lake, Nova Scotia.

The assessment was performed at the request of Nova Scotia Power Inc. utilizing methods and procedures consistent with industry practice. The findings and recommendations represent Stantec's best professional judgment based on the conditions that existed and the information and data available to us during the course of this assignment. Factual information regarding operations, conditions and test data provided by the client, owner, or their representative has been assumed to be correct and complete.

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5.0 APPENDICES

Appendix A OPINION OF PROBABLE COST TABLE

Appendix B SITE PHOTOS

Appendix C ROOF REPAIR - SCOPE OF SERVICE

APPENDIX A

Opinion of Probable Cost

5 Long Lake Drive Roof Condition Assessment	Maintenance Costs (Ongoing)					Capital Expenditures (CAPEX)					Comments
	Annual Reserve				Total	Immediate	Short Term	Long Term	Long Term	Total	
	Year 1-5	Year 6-10	Year 11-15	Year 16-20		<12 months	Year 1-5	Year 6-10	Year 11-20		
A.1 ROOFING MEMBRANE	**$ 14,000**	**$ 14,000**	**$ 14,000**	**$ -**	**$ 42,000**	**$ -**	**$ 507,500**	**$ -**	**$ -**	**$ 507,500**	
A.1.1 Primary Roof Membrane (EPDM)	$ 14,000	$ 14,000	$ 14,000	$ -		$ -	$ 507,500	$ -	$ -		Short-term replacement of full roof system down to steel decking with new EPDM membrane. Provide paver support system in maintenance areas.
A.2 ANCILLERY ROOFING COMPONENTS	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9,000**	**$ -**	**$ -**	**$ -**	**$ 9,000**	
A.2.1 Fascia	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.2 Soffit	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.3 Flashing	$ -	$ -	$ -	$ -		$ 5,500	$ -	$ -	$ -		Replace cap flashing around the perimeter of the roof.
A.2.4 Gutters / Drains	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.5 Skylights	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.6 Chimneys / Vents	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.7 Fall Arrest Anchors	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.8 Control Zone Access	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.9 Other (see Comments)	$ -	$ -	$ -	$ -		$ 3,500	$ -	$ -	$ -		Remove broken/unused precast concrete pavers from roof, particularly in areas where they are stacked for storage due to maintenance.
A.3 ROOFING STRUCTURE	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
A.3.1 Structural Review	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
TOTALS	$ 14,000	$ 14,000	$ 14,000	$ -	**$ 42,000**	$ 9,000	$ 507,500	$ -	$ -	**$ 516,500**	

Notes:

1. Annual roof maintenance costs carried based on approximately 1.3% of roof value. Industry standard recommends from 1-2%.
2. Recommend that after roof replacement, pavers only be put back in areas that will see heavy foot traffic and only one paver width wide.
3. This Opinion of Probable Cost is based on Class C level costing.
4. Maintenance cost does not include any third-party inspection/assessment wihtin the EUL. It is assumed that this will not be required with regular roof maintenance.

All costs in 2016 dollars. Costs adjusted by 0.00%

APPENDIX B

Site Photos

ROOF CONDITION ASSESSMENT

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April 29, 2016

	
Photo B.1 – Roof surface, northeast facing.	Photo B.2 – Roof surface, north facing.
	
Photo B.3 – Roof surface, north facing.	Photo B.4 – Roof surface, northwest facing.
	
Photo B.5 – Roof surface, west facing.	Photo B.6 – Roof surface, southwest facing.

ROOF CONDITION ASSESSMENT

APPENDICES
April 29, 2016

Photo B.7 – Roof surface, south facing.

Photo B.8 – Typical roof drain.

Photo B.9 – Cantilevered light fixture (note ballast).

Photo B.10 – Precast paver mounting at fixture.

Photo B.11 – EPDM membrane tenting edge.

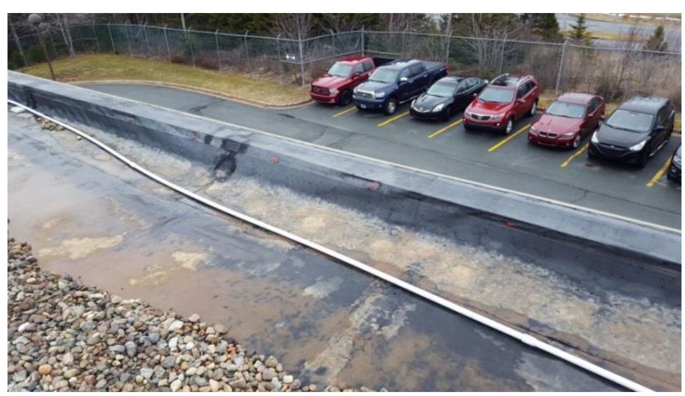


Photo B.12 – Alternate view of Photo B.11.

Photo B.13 – Paver mounting detail (EPS strip).

Photo B.14 – Stacks of pavers near roof edge.

Photo B.15 – Opening in pavers for drains.

Photo B.16 – Cap flashing removed (north corner).

Photo B.17 – Note patch repairs in EPDM.

Photo B.18 – Alternate patch view from B.17.

	
Photo B.19 – Pavers broken and resting on EPDM.	Photo B.20 – Scupper on north side of roof.
	
Photo B.21 – Membrane patches around vent.	Photo B.22 – Membrane patches around vent.

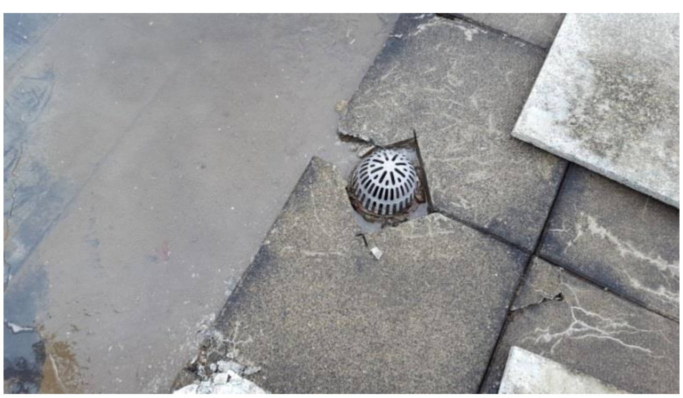



Photo B.23 – Broken pavers on membrane.	Photo B.24 – Ballast securing temporary curb cover.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	
Photo B.25 – Paver trimmed at penetrations, typ.	Photo B.26 – Typical buildup at mechanical curb.
	
Photo B.27 – Typical curbed vent penetration.	Photo B.28 – Ballast and water buildup at new unit.
	
Photo B.29 – Exposed membrane at penetrations.	Photo B.30 – Note equipment on timber sleepers.

ROOF CONDITION ASSESSMENT

APPENDICES
April 29, 2016

	
Photo B.31 – New equipment curb (no issues).	Photo B.32 – Light fixture and boot flashing (SW).
	
Photo B.33 – Note flashing condition (poor jointing).	Photo B.34 - Note flashing condition (poor jointing).
	
Photo B.35 – Cap flashing not present (south edge).	Photo B.36 – Cap flashing removed at entrance.

ROOF CONDITION ASSESSMENT

APPENDICES
April 29, 2016

Photo B.37 – Flashing stored on roof using ballast.

Photo B.38 – More flashing secured with ballast.

Photo B.39 – Exposed membrane joint.

Photo B.40 – Flashing screws and brackets (loose).

Photo B.41 – Exposed flashing screw holes in EPDM.

Photo B.42 – Penetration boot (good condition).

	
Photo B.43 – Sealant patches at flashing screw holes	Photo B.44 – Typical screw hole without sealant.

APPENDIX C

Roof Repair - Scope of Service

5.1 ROOF REPAIR - SCOPE OF SERVICE

It is recommended that the following Scope of Service be included, as a minimum, in the roofing repair tender package to be issued for the building located at 5 Long Lake Drive, Ragged Lake, Nova Scotia;

5.1.1 ROOFING MEMBRANE

1. Remove existing roof system down to the steel decking and replace entire roof system with new EPDM system, including a vapour retarder, enhanced insulation values and a new membrane and membrane flashings at perimeters and penetrating elements.

5.1.2 ANCILLERY ROOFING COMPONENTS

1. Remove existing flashing and replace with new.

2. Remove existing precast concrete ballast/wear pavers in maintenance areas and only replace in areas of high foot traffic around mechanical equipment and at one-paver width wide, unless instructed otherwise. Place pavers on rubber sleepers suited for the application, <u>not</u> on bonded insulation per existing construction.

3. Ensure existing top-mounted roof lighting is properly re-installed to achieve a weather-tight system.

5.1.3 ROOFING STRUCTURE

No work required.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Roof Condition Assessment

25 Lakeside Park Drive
Lakeside, Nova Scotia

Stantec

Prepared for:
Nova Scotia Power Inc.
Attention: Kathy Goyetche

Prepared by:
Matt McNeil

April 29, 2016

Stantec Project No: 133430712

Table of Contents

Executive Summary

In March 2016, Stantec Consulting Limited was retained by NSPI to perform a Roof Condition Assessment (RCA) for their facility located at 25 Lakeside Park Drive, Lakeside, Nova Scotia. The site visit was conducted on April 19, 2016 by Matt McNeil and Michael Frampton.

The building at this location is a steel-framed, high-ceiling (~9 meters) storage facility having a portion of the building assigned as office space. The overall building footprint is approximately 98 meters long by 92 meters wide (approximately 9,016 m^2) and the existing roof system is believed to be approximately 26-years old (circa 1990). Some investigation into this facility has suggested that this existing roof system may have been a replacement for an original built-up roof system, likely installed during original construction.

In general, the EPDM roof membrane system at this facility was found to be in poor condition. The following typical items were noted during our examination:

- Fasteners were observed beneath the membrane that are not associated with the securement of the membrane itself;
- Lifting of the outer edge of the seams is apparent over much of the roof surface. We noted that the seams at one corner of the roof have already been patched with cured membrane tape to address this problem;
- The original membrane flashing installations are displaying indications of impending failure, similar to the field seams;
- We observed numerous elongated cured membrane tape patches on the roof likely related to snow removal operations during the winter of 2014 – 2015;
- Areas adjacent to the air handler and HVAC units felt ‘soft’ which is likely related to the irreversible compression and/or moisture-related deterioration of the substrate (the fibreboard panel); and
- Roof drains were found to be corroded and the strainer baskets missing.

In its present state, it is Stantec’s opinion that with semi-annual maintenance, the Expected Use Life (EUL) for this existing roof system is 2 years, at which point it is felt that this roof system should be replaced to minimize the risk to other key building elements.

To extend the EUL to 15 years, a new EPDM roof system (or alternate) will be required from the steel decking to membrane over the entire roof surface.

Appendix A includes an Opinion of Probable Cost for the associated Maintenance and Capital Cost Expenditures required to achieve the desired 15-year EUL for this facility, as summarized below;

- Roof Maintenance (semi-annual inspection, over 15 years) $180,000
- **Capital Expenditure (short-term roof repairs, Appendix C) $1,650,000**

It is Stantec's opinion that should the recommendations contain herein be followed, including regular roof maintenance and the short-term roof replacement, a EUL in excess of the 15-year forecast can be achieved for this facility.

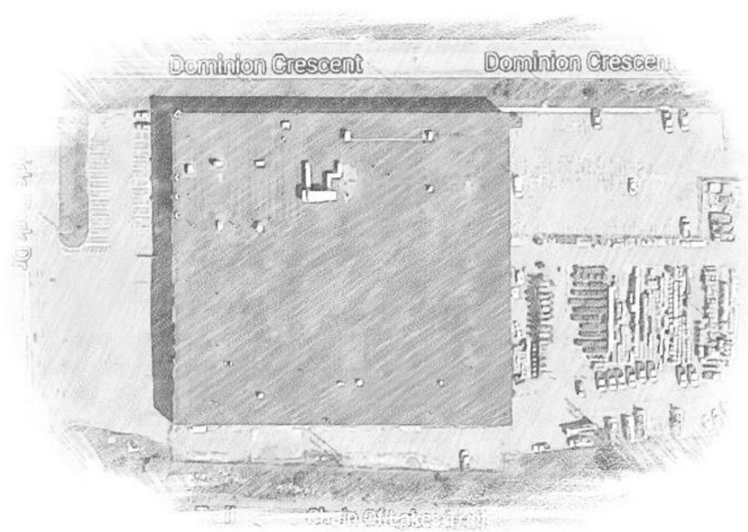
1.0 BACKGROUND

Nova Scotia Power Incorporated (NSPI) wishes to extend the operating life of several of its existing facilities in the Halifax Regional Municipality. In support of this initiative, a Roof Condition Assessment has been commissioned at each of the subject facilities to document the condition of the existing roof system(s) and to develop recommendations with respect to maintenance and capital expenditure required to extend the EUL of the facility by 15-years, where required.

In March 2016, Stantec Consulting Limited was retained by NSPI to perform a Roof Condition Assessment (RCA) for their facility located at 25 Lakeside Park Drive, Lakeside, Nova Scotia. The objective of this report is to summarize the findings of the RCA performed at this facility on April 19, 2016 and provide NSPI with the information required to tender roof maintenance/repair services, as required, to meet the performance goals for the facility over the forecasted use life.

1.1 BUILDING LOCATION / DESCRIPTION

The building located at 25 Lakeside Park Drive is a steel-framed, high-ceiling storage facility having a portion of the building assigned as office space. The overall building footprint is approximately 98 meters long by 92 meters wide (approximately 9,016 m^2) and the existing roof system is believed to be approximately 26-years old (circa 1990). Some investigation into this facility has suggested that this existing roof system may have been a replacement for a built-up roof system, likely installed during original construction. Access to the roof system of this building was via internal fixed-ladder from the second level office space to a roof access hatch.



25 Lakeside Park Drive, Lakeside, Nova Scotia

The roof of this building incorporates a single-elevation 'flat' roof configuration incorporating a sloped substrate (sloped structure with flat or tapered insulation) to the roof drains located intermittently around the roof.

1.2 INSPECTION METHODOLOGY

Note: Stantec Consulting Ltd. was not provided with any formal data pertaining to the age or maintenance history of the facility under review; no building drawings, specifications, shop drawings, or guarantee information were provided; and no access to facility maintenance personnel or records was granted during the course of this investigation. Due to access limitations, Stantec Consulting Ltd. performed only minimal visual inspection of the underside of the roof system. Further, destructive testing of the roof system was not included in the scope of work for this project. Thus the information contained in this report and the related recommendations are based solely on visual examination of surface of the existing roof system except as specifically noted herein.

The assessment of the roof of this facility was based on a visual inspection; this included a comprehensive walk-around, visually inspecting the condition of the roof membrane and identifying defects, as well as observing for areas where the roof membrane may have lifted from the substrate or where factory or field seams may have failed. Roof components, such as parapets, flashings, drains, ventilation ducts and other miscellaneous penetrations or build-ups, were also examined as these are typically areas where roof system breakdown can occur with age.

2.0 FINDINGS

2.1 ROOF SYSTEM IDENTIFICATION

The roofing system for this building consists of a mechanically-fastened Ethylene Propylene Diene Monomer (EPDM) membrane. Manufacturing markings indicated that the membrane is 0.045" thick reinforced EPDM material manufactured by Carlisle Syntec.

Per Section 1.1, Stantec reached out to the supplier that was likely to have been associated with the installation of the roof system installed on this project. We were advised that their records indicated installation of the existing roof system was completed in September of 1990 and that the system components included 7" of expanded polystyrene (EPS) insulation (R = 28±), overlaid with ½" Carlisle HP Recovery Board (a high density wood fibreboard panel) membrane substrate, and an 0.045" reinforced EPDM membrane mechanically fastened through the insulation and membrane substrate to the roof deck. The presence or nature of any vapour retarder was not recorded in their records but they postulated that a kraft laminate or polyethylene vapour retarder was also likely installed on the deck prior to the installation of the insulation panels.

2.2 SYSTEM OBSERVATIONS

2.2.1 ROOFING MEMBRANE

A full walk-over of the roof was undertaken to examine the seams, details, and the membrane surface. Numerous patches were observed at seams and in the field of the membrane. There is a large air handler unit on the roof (see roof plan in Section 1.1) as well as several smaller units and vent penetrations at various locations.

In general, the EPDM roof membrane system at this facility was found to be in poor condition. The following typical items were noted during our examinations:

- Fasteners were observed beneath the membrane that are not associated with the securement of the membrane itself, typical for the mechanical pre-securement of the membrane substrate. It was noted that membrane had been patched over several of these fasteners. Penetration of the membrane over these fasteners is consistent with irreversible compression of the insulation and/or membrane support panel and the fastener plates, possibly associated with wetting and drying, resulting in the membrane rubbing against the head of the fasteners originally recessed into the fastener plates.

- The field seaming of the membrane during its original installation was done using liquid applied adhesive and a small bead of silicone "in-seam sealant" typical of Carlisle installation details in that era. Seams of this type are prone to losing their structural and waterproofing integrity over the long term, as evidenced by the lifting of the outer edge of the seams apparent over much of the roof. We noted that the seams at one corner of the roof (approximately 15% of the total roof area) have already been overlaid with cured membrane tape to address this problem.

- The original membrane flashing installations, also executed using liquid adhesive technologies, are displaying indications of impending failure similar to the field seams. The deterioration includes both membrane flashing to field membrane seams and uncured membrane to field/flashing membrane as well as deterioration of some of the butyl type uncured membrane flashing components themselves likely related to UV degradation.

- We observed numerous newer elongated cured membrane tape patches on the roof. The supplier advised that these patches are repairs to surface damage to the membrane related to snow removal operations during the winter of 2014 – 2015. The impact of this damage on the reinforcing fibres providing the structural strength of the membrane is not known.

- Areas adjacent to the air handler and HVAC units were generally found to be in poor condition. At these locations and at other isolated locations, the substrate felt 'soft' which is also likely related to irreversible compression and/or moisture related deterioration of the insulation and/or membrane substrate (the fibreboard panel), causing settlement and low spots that fill with water with the potential to compound over time.

2.2.2 ANCILLERY ROOFING COMPONENTS

The roof drains, penetrations and curbs were generally found to be in poor condition and in need of maintenance;

- Some drain caps were missing or damaged;

- Some of the drain throats were blocked with corrosion and buildup material; and

- The over-flashings at many of the roof penetrations were rusted with the potential of rust penetration.

The membrane boots/flashings around the vent and stack penetrations were generally found to be in fair condition with no significant fish-mouthing or failures at the seams. The perimeter edge metal flashing was found to be in fair condition with no visible damage however it is recommended that these edge-flashings be replaced as part of the roof membrane replacement so that a weather-tight system is assured.

2.2.3 ROOFING STRUCTURE

There were no visual indications of structural performance issues for the roof system under review. There was no evidence of sagging of the roof steel structure, often visible in the form of generalized water ponding on the surface of the membrane; in this case, most ponding was localized and so not indicative of a larger structural issues.

2.3 REMAINING EXPECTED USE LIFE (EUL)

Based on the visual inspection performed, the roof system at 25 Lakeside Park Drive was generally found to be in poor condition. In its' present state, it is Stantec's opinion that with semi-annual maintenance, the EUL for this existing roof system is 2 years at which point this roof system should be replaced to minimize the risk to other key building systems; this does not meet NSPI's projected operating requirement of 15 years for this facility.

To extend the EUL to 15 years, a new roof system will be required for this facility. The costs associated with this CAPEX expenditure are broken out in Appendix A.

3.0 RECOMMENDATIONS

3.1 MAINTENANCE BUDGET

A typical flat-roof system can last in excess of 25-years when properly maintained on a regular basis.

Typical maintenance of a flat roof system involves semi-annual inspection to check for issues such as blocked drainage systems, ponded water, areas of sag or depression and membrane lifting or tearing. After major storm events, the roof should be inspected for damage by maintenance personnel; in the winter months, ensure that snow/ice loading does not exceed the building design load and flashing height limitations. During warmer periods, look for damage or lifting of the membrane and ponding. If a significant depression remains after removal of standing water, have the system reviewed again by a roof membrane professional to ensure no substrate or structural damage has resulted from the transient roof loading. Roof drains may need to be replaced or added in areas where the surface slope has changed such that water can no longer reach the drain; this is also indicative of other issues with the system.

The Opinion of Cost included in Appendix A includes consideration for an ongoing Maintenance Budget for the roof of the facility as a break out item from opinion of cost for CAPEX expenditures. While CAPEX costs will address the immediate and long-term performance issues, as required, the maintenance allowance will ensure that any risks associated with achieving the target duration are minimized over the operating life of the facility.

3.2 CURRENT/FUTURE CAPEX EXPENDITURES

The CAPEX expenditures itemized in Appendix A are based on deficiencies identified during the RCA that, in Stantec's professional opinion, will require repair within the noted timeframe. These items, if not addressed, will very likely contribute to premature roof performance degradation during the target operating life of the facility.

Deficiencies that can be isolated have been itemized to allow for staged expenditure, where possible. Where it is felt that the work cannot be easily segregated, the deficiencies have been listed as sub-tasks of a master work breakdown structure. For example, it would not make sense to replace flashing after replacing a roof membrane system; the flashing work is therefore listed as a sub-task of the membrane replacement work package.

3.2.1 ROOFING MEMBRANE

It is recommended that the following items be addressed to achieve the EUL of 15-years for the roof membrane system;

RECOMMENDATIONS
April 29, 2016

1. Remove existing roof system down to the steel decking and replace entire roof system with a new roof, including a vapour retarder, enhanced insulation values, and a new membrane and membrane flashings at perimeters and penetrating elements. Considering that the existing roof system is approximately 26 years old, including 26-year old technologies which have since seen significant improvements, and has worked reasonably well without excessive maintenance, the installation of a similar EPDM membrane system may be appropriate although other mechanically-attached single-ply options are available on the market.

2. Removal of the existing membrane, replacement of damaged and deteriorated insulation and membrane substrate components and installation of a new membrane system including associated flashings could also be considered. However, it is our opinion that any potential savings associated with this approach should be balanced against the potential negatives including:

    a. Not being able to examine and repair or replace any inadequate or damaged vapour retarder components; and

    b. Potential for extra cost implications during construction related to unidentified required replacements.

3.2.2 ANCILLERY ROOFING COMPONENTS

It is recommended that the following items be addressed to achieve the EUL of 15-years for the ancillary roofing components;

1. Replace all roof drain baskets with new.

3.2.3 ROOFING STRUCTURE

No work is anticipated on the roofing structure to achieve the EUL of 15-years.

4.0 STANTEC TEAM

Stantec has completed a Roof Condition Assessment (RCA) of the property located at 25 Lakeside Park Drive, Lakeside, Nova Scotia.

The assessment was performed at the request of Nova Scotia Power Inc. utilizing methods and procedures consistent with industry practice. The findings and recommendations represent Stantec's best professional judgment based on the conditions that existed and the information and data available to us during the course of this assignment. Factual information regarding operations, conditions and test data provided by the client, owner, or their representative has been assumed to be correct and complete.

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Appendix C ROOF REPAIR - SCOPE OF SERVICE

APPENDIX A

Opinion of Probable Cost

ROOF CONDITION ASSESSMENT

APPENDICES
April 29, 2016

25 Lakeside Park Drive Roof Condition Assessment	Maintenance Costs (Ongoing)					Capital Expenditures (CAPEX)					Comments
	Annual Reserve				Total	Immediate	Short Term	Long Term	Long Term	Total	
	Year 1-5	Year 6-10	Year 11-15	Year 16-20		<12 months	Year 1-5	Year 6-10	Year 11-20		
A.1 ROOFING MEMBRANE	**$ 60,000**	**$ 60,000**	**$ 60,000**	**$ -**	**$ 180,000**	**$ -**	**$ 1,650,000**	**$ -**	**$ -**	**$ 1,650,000**	
A.1.1 Primary Roof Membrane (EPDM)	$ 60,000	$ 60,000	$ 60,000	$ -			$ 1,650,000		$ -		Full membrane replacement based on SA membrane VR, 2 x 3.0" (6" total) glass faced polyisocyanurate insulation (LTTR 33.6), 0.060" reinforced EPDM
A.2 ANCILLERY ROOFING COMPONENTS	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
A.2.1 Fascia	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.2 Soffit	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.3 Flashing	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		Included above.
A.2.4 Gutters / Drains	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		Included above.
A.2.5 Skylights	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.6 Chimneys / Vents	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.7 Fall Arrest Anchors	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.8 Control Zone Access	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.2.9 Other (see Comments)	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
A.3 ROOFING STRUCTURE	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
A.3.1 Structural Review	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		
TOTALS	$ 60,000	$ 60,000	$ 60,000	$ -	**$ 180,000**	$ -	$ 1,650,000	$ -	$ -	**$ 1,650,000**	

Notes:

1. Annual roof maintenance costs carried based on approximately 1.3% of roof value. Industry standard recommends from 1-2%.
2. This Opinion of Probable Cost is based on Class C level costing.
3. Maintenance cost does not include any third-party inspection/assessment wihtin the EUL. It is assumed that this will not be required with regular roof maintenance.

All costs in 2016 dollars. Costs adjusted by 0.00%

APPENDIX B

Site Photos

	
Photo B.1 – Roof surface, southwest corner.	Photo B.2 – Roof surface, west edge, taped seam.
	
Photo B.3 – Roof surface, west edge, taped seam.	Photo B.4 – Penetration flashing, west side.
	
Photo B.5 – West facing parapet with lifting flashing.	Photo B.6 – Roof surface patch at HVAC removal.

Photo B.7 – Typical seam-damage patches, west.

Photo B.8 – Vent penetration with patching/repairs.

Photo B.9 – West facing parapet.

Photo B.10 – Patching at seam and damage.

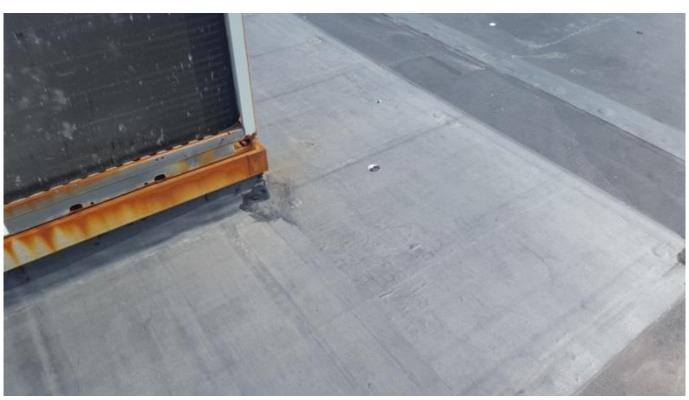

Photo B.11 – Flashing at mech. unit (loose steel)

Photo B.12 – Patch with joint cover strip.

	
Photo B.13 – Flashing boot at capped stack.	Photo B.14 – Typical mechanical attachment seam.
	
Photo B.15 – Parapet at northwest corner.	Photo B.16 – Typical seam cover patch intersection.
	
Photo B.17 – Note blistering in seam cover strip.	Photo B.18 – View of mechanical, looking southeast.

	
Photo B.19 – Edge flashing patch failure.	Photo B.20 – Fasteners sitting proud of substrate.
	
Photo B.21 – Membrane repair around HVAC unit.	Photo B.22 – Typical seam cover, mid roof near AHU.
	
Photo B.23 – Patching adjacent to a roof drain.	Photo B.24 – Patches and standing water stains.

	
Photo B.25 – Patches at seams and in roof field.	Photo B.26 – Wear mat and adjacent patching.
	
Photo B.27 – Roof drain with broken plastic strainer.	Photo B.28 – Typical original seam with lifting edge.
	
Photo B.29 – Chimney curb with rusting flashing.	Photo B.30 – Typical original seams, mid-roof area.

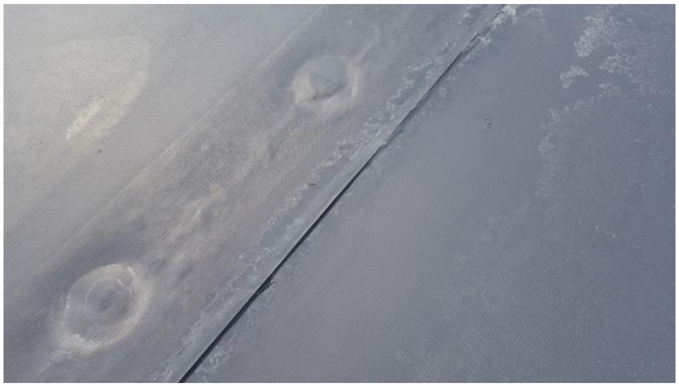	
Photo B.31 – Close-up of failing seam.	Photo B.32 – Patch lifting due to adhesive failure.
	
Photo B.33 – Broken aluminum strainer dome.	Photo B.34 – Recent membrane patches.
	
Photo B.35 – Failing EPDM patch and seams.	Photo B.36 – Failing adhesive at seams & patches.

	
Photo B.37 – Collapsed vent/stack boot (Carlisle).	Photo B.38 – Original cover at seam intersection.
	
Photo B.39 – Patches at northeast corner of roof.	Photo B.40 – Patches over fasteners around vent.
	
Photo B.41 – Noted failures from previous	Photo B.42 – Seal failing on edges of seam cover.

Photo B.43 – Reflective coating test near roof hatch

Photo B.44 – Overview of patches near hatch.

Photo B.45 – Low curb at fan penetration.

Photo B.46 – Long patch cover strip mid-roof.

Photo B.47 – Overlapping patches, mid-roof.

Photo B.48 – Patch lifting, drain strainer missing.

	
Photo B.49 – Air Handler, close to north roof edge.	Photo B.50 – Typical boot at AHU support.
	
Photo B.51 – Secondary HVAC unit pipe supports.	Photo B.52 – Standing water east of AHU (<10mm).
	
Photo B.53 – Booted mech. pipe support system.	Photo B.54 – Roof drain with missing strainer dome.

	
Photo B.55 – Seal edge failure at patch cover strip.	Photo B.56 – Damaged aluminum strainer dome.
	
Photo B.57 – Looking showing long patches.	Photo B.58 – Seal deterioration, south end, mid roof.
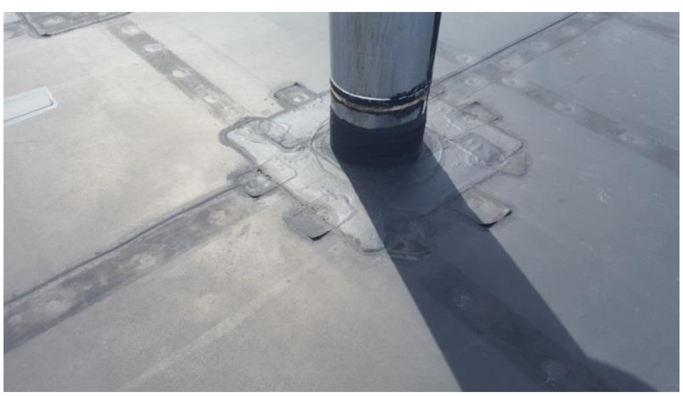	
Photo B.59 – Adhesive failure at penetration flashing.	Photo B.60 – Adhesive failure at edge flashing.

Photo B.61 – Flashing and cover failing at stack.

Photo B.62 – Roof drain with missing strainer dome.

Photo B.63 – Unpatched perforation at fastener.

Photo B.64 – Roof drain with broken plastic strainer.

Photo B.65 – Standing water, northeast corner.

Photo B.66 – Insulation thickness blocking at hatch.

APPENDIX C

Roof Repair - Scope of Service

5.1 ROOF REPAIR - SCOPE OF SERVICE

It is recommended that the following Scope of Service be included, as a minimum, in the roofing repair tender package to be issued for the building located at 25 Lakeside Park Drive, Lakeside, Nova Scotia;

5.1.1 ROOFING MEMBRANE

1. Remove existing roof system down to the steel decking and replace entire roof with a new EPDM system, including a vapour retarder, enhanced insulation, and a new EPDM membrane and membrane flashings at perimeters and penetrating elements.

   The area of the roof is approximately 9016 m^2 (97,050 ft^2).

5.1.2 ANCILLERY ROOFING COMPONENTS

1. Replace all roof drains and baskets with new, as required.

5.1.3 ROOFING STRUCTURE

No work required.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia Power
Energy Control Center
Diesel Generator and Fuel System Replacement Analysis

Stantec

Prepared for:
Nova Scotia Power
25 Lakeside Park Drive
Halifax, NS B3J 2W5

Prepared by:
Stantec Consulting Ltd.
845 Prospect Street
Fredericton, NB E3B 2T7

File: 133547049_3_8, Rev.0

REGISTERED PROFESSIONAL ENGINEER
Nov 10/15
DATE
R. M. Forbrigger
5088
PROVINCE OF NOVA SCOTIA

November 10, 2015

NOVA SCOTIA POWER
ENERGY CONTROL CENTER
DIESEL GENERATOR AND FUEL SYSTEM
REPLACEMENT ANALYSIS

Table of Contents

1.0 BACKGROUND

Nova Scotia Power's Energy Control Centre (ECC) at Ragged Lake is the utility's hub to remotely monitor and control its generation, transmission, and distribution systems. Its operation is essential for Nova Scotia Power (NSP) to effectively deliver power to its customers, and its reliability is therefore of paramount importance to NSP.

The ECC currently has two (2) back-up diesel generators which are intended to ensure continued operation of the ECC in the event of a power outage. The generators and auxiliaries (including the associated diesel fuel storage and delivery system) have been in operation since 1987.

NSP engaged Stantec Consulting Ltd. (Stantec) to define the required construction scope and prepare an associated Opinion of Probable Capital and Engineering Costs (AACE Class 5 level) to replace both emergency diesel generators along with their associated fuel system. NSP provided Stantec with two (2) existing reports (prepared by F.C. O'Neill, Scriven and Associates Ltd.) for information; one related to the electrical system and one related to the fuel system.

2.0 EVALUATION

2.1 FUEL SYSTEM

Stantec has reviewed the F.C. O'Neill, Scriven and Associates Ltd. (ONSA) report, dated August 30, 2015, which recommends the two exterior Underground Storage Tanks (UST) and underground piping be replaced and upgrades be made to the piping inside the generator room. However, the report failed to discuss two major concerns noted by Stantec during the October 28 site visit, they are:

- Age of the single wall steel day tanks: While not a code requirement, it is industry practice to replace single wall steel, domestic style petroleum storage tanks every ten years. These tanks are assumed to be 25 to 30 years old. Corrosion is always a concern and with single wall steel, no warning mechanism is present to alert operations if the tank shell fails. Furthermore, if a release occurs, no containment system is present.
- Valves in the day tank overflow/vent piping: Several valves are located in the overflow/vent piping which returns to the main USTs from the day tanks. Valves are prohibited in return and vent piping as per the National Fire Code of Canada (2010) and the B-139 Series 15, Code for Oil Burning Equipment.

It also should be noted the report stated there were two monitoring wells adjacent the USTs. The items adjacent to the USTs are not monitoring wells; they are dip ports with direct access to the USTs. Stantec did not observe any monitoring wells near the USTs.

2.2 DIESEL GENERATOR SYSTEM

Stantec has reviewed the F.C. O'Neill, Scriven and Associates Ltd. (ONSA) report, dated August 30, 2015, which discusses the electrical system and the testing requirements for the generator. The pertinent observations based on our review of the report are as follows:

- The report does not explicitly state that the generators should be replaced.
- The report identifies that the testing methods are not in-line with current industry standards. Of particular concern is that testing the generators under no-load can lead to glazing of the piston heads which is not desirable.
- The report identifies the need for the generator testing program to follow CSA C282, which is a current industry standard.
- The existing emergency and normal power circuit breakers have no indication of their last service cycle, and therefore should be serviced.

NOVA SCOTIA POWER
ENERGY CONTROL CENTER
DIESEL GENERATOR AND FUEL SYSTEM
REPLACEMENT ANALYSIS

November 10, 2015

Stantec conducted an onsite evaluation of the existing diesel generators and noted the following:

- Each generator has less than 300 total running hours, which is considered minimal usage in industry.
- The existing generator circuit breakers appear to be in good condition and it is suspected they have very low usage (very few cycles on them).
- The existing power cabling between each generator and its corresponding circuit breaker is undersized relative to what the current electrical code (CSA C22.1-15) stipulates. It is believed the power cabling met the code requirements in place when the units were installed, but if modifications to the electrical system are to occur, this cabling will need to be made compliant with current codes and standards.
- The current system allows either generator to carry the entire electrical load in the event of an outage providing 100% redundancy.
- The generator room was observed to be large enough to accommodate the anticipated equipment required (e.g., one manually operated transfer switch per generator) to allow for the generators to be connected to an external load bank so testing could occur under load.
- Although Stantec did not gain access to the roof level to visually assess the condition of the radiators, it is suspected that they are original to the units, and have therefore been exposed to the outdoor environment for over 25 years.
- The existing housekeeping pads for each generator may need to be modified to accommodate a new generator. However, there is enough space in the generator room to allow for this.

Following Stantec's site visit, we contacted Sansom Equipment, who services the ECC generators. The following is a summary of the discussions:

- The existing generators are considered to be in good working condition.
- Replacement parts for the existing generators are readily available.
- Major overhauls to these generator models are generally only required every 10,000 hours of run time, as per the manufacturer's recommendations. The run hours on the units are considered a much better indicator of their condition versus their age, especially where these units have been installed in a controlled (clean) environment.
- Sansom Equipment recommended that the engine oil be sampled and analyzed, and that a full CSA C282 test be conducted on the generators.

3.0 RECOMMENDATIONS

Based on our evaluation of the existing diesel generators and fuel system, Stantec recommends the following for NSP's consideration:

3.1 FUEL SYSTEM

- Replace the existing fuel system its entirety including a new 10,000 litre (or larger if required), double wall steel, vacuum monitored, aboveground storage tank near the fill pipes to the existing underground storage tanks.
- Replace the existing fuel transfer pumps.
- Replace the existing day tanks with new Fiberglass Reinforced Plastic (FRP) day tanks in the generator room.
- Demolish the existing fuel piping system and install a new (double walled) aboveground piping system.
    - While not a code requirement for aboveground piping, a double wall aboveground piping system would offer NSP the peace of mind that the entire exterior petroleum storage tank system has a means to detect and contain a leak (including the proposed aboveground double wall vacuum monitored storage tank). This is an emerging market and there are now several ULC approved products available, including one that is local to Nova Scotia.
- Install an automatic Fuel Filtration unit in the main aboveground storage tank.
    - Fuel systems for back-up or emergency generators are typically not used on a regular basis which can cause problems with the fuel quality as moisture can build up at the bottom of a petroleum storage tank due to temperature variations and humidity in the air, especially with aboveground storage tank systems. With the introduction of water into a fuel tank, bacteria can grow and spread which can plug filters and foul the quality of the fuel. A large percentage of emergency generator failures are a result of poor quality fuel. An automatic fuel filtration unit would circulate the fuel in the main aboveground storage tank on a pre-programmed regular cycle and would be completely independent of the generator fuel supply. This regular cleaning of the diesel fuel would minimize clogging of the fuel filters on the generator itself and help to ensure diesel start-up when needed.

3.2 DIESEL GENERATOR SYSTEM

- Do not replace the existing generators, but have the oil sampled and analyzed to assess if there are any issues with the engines (which is not suspected).
- Test each generator to CSA C282.
- Replace the existing power cables for each generator with larger gauge cables which are rated for the required electrical current as per the most recently adopted version of the Canadian Electrical Code (2015).
- Inspect, test, and clean (but do not replace) the existing generator circuit breakers.
- Replace the existing radiators, fan units, and coolant with new.
- Install new electrical infrastructure to facilitate full load testing of the generators by use of an outdoor load bank (which can be rented when required).

4.0 PROJECT SCOPE

Based on our evaluation and recommendations as described in Sections 2 and 3, Stantec proposes the following project scope:

4.1 FUEL SYSTEM

- Remove the existing fuel storage system.
- Install a new 10,000 Litre (or larger if required), double wall steel, vacuum monitored, aboveground storage tank near the fill pipes to the existing underground storage tanks.
- Replace the existing fuel transfer pumps, piping (double wall), and Fiberglass Reinforced Plastic (FRP) day tanks in the generator room.
- Install an in-line automatic fuel filtration system.

4.2 DIESEL GENERATOR SYSTEM

- Have generator oil sampled and tested.
- Fully test each generator to the CSA C282 standard and start a scheduled testing plan.
- Inspect, test and clean the existing generator circuit breakers.
- Replace the existing generator power cables with larger gauge cables that have sufficient current carrying capacity (as per the 2015 Canadian Electrical Code).
- Replace each roof top radiator and integral fan a new radiator and fan unit of equal cooling and fluid capacity.
- Empty the glycol from cooling system, clean the coolant piping, and replace the glycol once the new radiators are installed. It is anticipated that the existing coolant piping from the radiators to the generators can be reused.
- Install two (2) manual transfer switches and two (2) outdoor rated disconnects (one transfer switch and one disconnect per generator) to allow for testing of each generator under load in accordance with CSA C282 using a load bank. The load bank can be rented on an as needed basis and placed outdoors for the duration of the tests.

5.0 CAPITAL COST

Based on our recommendations in Section 3 and the defined project scope in Section 4, Stantec has completed an AACE Class 5 Opinion of Probable Capital Construction Cost. The following are a list of inclusions:

5.1 FUEL SYSTEM

- Removal of the existing fuel system in its entirety.
- Installation of a new 10,000 litre (or larger if required), double wall steel, vacuum monitored, aboveground storage tank near the fill pipes to the existing underground storage tanks.
- Replacement of the existing transfer pumps, piping (double-walled), and two new FRP day tanks in the generator room.
- Removal of 100 tonnes of impacted soil and up to 10,000 litres of impacted water.
    - With the removal of any underground storage tank system there is the potential of encountering petroleum impacted soil and/or water. In this case the two (2) USTs and their associated piping is reportedly single wall FRP which represents a lower risk, but the presence and degree of impacted soil cannot be easily determined until the storage tank system is removed from the site. In the case of the water disposal, the water may not be impacted but if there is water in the excavation, it would require removal to facilitate backfilling and proper compaction.
- Installation of a fuel filtration system at the main fuel storage tank.

5.2 DIESEL GENERATOR SYSTEM

- Removal of the existing generator power cables and installation of new, larger gauge, cables from the existing generator circuit breaker to a new wall-mounted transfer switch (this applies to each unit).
- Physical inspection, testing, and cleaning of the generator circuit breakers.
- Supply and installation of electrical infrastructure to allow for generator testing under load.
- Rental and temporary installation of a 300kW outdoor generator, transfer switch, and associated cabling for two (2) months to provide 100% redundancy during the generator upgrades.

- Replacement of the two (2) roof top radiators and integral fan units with new radiators and fan units of equal cooling and fluid capacity.
- Flushing of the glycol from the coolant system, cleaning of the associated piping, and replacement of the glycol once the new radiators are installed.
- Rental of cranes and roof protection during removal and installation of the radiators.

5.3 OPTIONAL PRICING

Stantec has included optional pricing in the summary sheet of our Opinion of Probable Capital Cost (OoPCC) for NSP's information as follows:

- We have included an adder price in the event NSP chooses to replace the existing diesel generators.
- We have included a deduct price in the event NSP chooses not to proceed with the recommended fuel filtration system.
- We have included a deduct price in the event NSP chooses not to proceed with the recommended double-walled aboveground piping and opts instead for a single-walled aboveground piping system.

6.0 ENGINEERING COST

Based on the project scope outlined in Section 4; the construction cost allowances included in Section 5; and our current understanding of NSP's preferences regarding project approach and consulting services, Stantec recommends the following major engineering activities:

- Provide detailed design service and create technical drawings (e.g., layouts, schematics) and specifications for the new systems.
- Provide tender support to NSP (e.g., bid evaluations, recommendation for award, answer bidder technical questions).
- Review and approve shop drawings submitted by the successful contractor.
- Provide onsite and office-based construction support for UST removals and environmental sampling including creating a final report summarizing the observations and results of the UST removals.
- Provide onsite and office-based construction support of removals and installation of new electrical components (e.g., cabling, switches, disconnects, etc.) including start-up and commissioning support.
- Provide construction schedule, construction sequencing plan, and commissioning plan.
- Provide project management services to liaise with stakeholders (e.g., NSP engineering, NSP operations, contractor).
- Review installation, create and manage deficiency lists to ensure the contractor's work (scope) meets their contracted scope.
- Create as built drawings of the installed system and turn over to NSP in desired drawing formats.

7.0 APPENDICES

Appendix A Opinion of Probable Engineering Cost

APPENDIX A

Opinion of Probable Engineering Cost

Client: **Nova Scotia Power**
Project: **ECC Generator Replacement**
Project No: **133547049**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary

Prepared by: **MAK**
Date: **4-Nov-15**
Revision No.: **0**
Issue Date: **10-Nov-15**
Checked: **JCS**

Area	Line	Rev.	Description	Labour Hours	Labour Cost	Mat'l/Commodity Cost	Equipment Cost	Sub-Contractor Cost	Total Cost
-	**0**	-	**PROJECT TOTAL STANTEC RECOMMENDED SCOPE**	**245 hrs**	**$26,144**	**$239,342**	**$0**	**$21,600**	**$448,825**
-	1	-	Fuel System Replacement	00 hrs	$0	$103,450	$0	$0	$149,950
-	2	-	Keep Existing Generator & Provide Load Bank Connection	245 hrs	$26,144	$135,892	$0	$21,600	$183,636
-	3	-	Engineering Cost						$115,239
-	**4**	-	**Optional Pricing**						
-	5	-	Deduct if Fuel Filtration System not Installed	00 hrs	$0	$22,500	$0	$0	-$22,500
-	6	-	Deduct if Aboveground Double Wall Piping not used	00 hrs	$0	$46,500	$0	$0	-$32,500
-	7	-	Adder Price to Replace The Generators (Including associated Engineering Adder)	373 hrs	$38,944	$400,392	$0	$26,600	$312,864

Client: **Nova Scotia Power**
Project: **ECC Generator Replacement**
Project No: **133547049**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical

Prepared by: **JS**
Date: **4-Nov-15**
Revision No.: **0**
Issue Date: **10-Nov-15**
Checked: **CS**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour: hr per Unit	Labour: Prod. Factor	Labour: Total Hours	Labour: Rate	Labour: Cost	Mat'l/Commodity: Unit Cost	Mat'l/Commodity: Cost	Equipment: Unit Cost	Equipment: Cost	Sub-Contractor: Unit Cost	Sub-Contractor: Cost	Total Cost
	0			**TOTAL - NOT INCLUDING VALUE ADDED OPTIONS**					**0**		**0**		**103,450**		**0**		**0**	**149,950**
	1			**Fuel System - Installation of New A/G Diesel Tank and Piping**					**0**		**0**		**24,000**		**0**		**0**	**24,000**
	2			Concrete Slab / Retaining Wall	1	ea.			0		0	15,000	15,000		0		0	15,000
	3			Bollards	8	ea.			0		0	250	2,000		0		0	2,000
	4			Gauge / Vent / Fill / Overfill	1	ea.			0		0	4,500	4,500		0		0	4,500
	5			Supply and Return	1	ea.			0		0	2,500	2,500		0		0	2,500
	6			12500 L A/G Tank Installed	1	ea.												
	7																	
	8			**Installation of New Day Tanks, Pumps, Controls and Piping**					**0**		**0**		**28,500**		**0**		**0**	**28,500**
	9																	
	10			900 L Day Tanks Installed	2	ea.			0		0	3,000	6,000		0		0	6,000
	11			Duplex Pump Skids	2	ea.			0		0	6,800	13,600		0		0	13,600
	12			Supply and Return	1	ea.			0		0	2,500	2,500		0		0	2,500
	13			Gauges / Controls	2	ea.			0		0	3,200	6,400		0		0	6,400
	14																	
	15			**Removal and Disposal of Existing Tanks**					**0**		**0**		**21,450**		**0**		**0**	**21,450**
	16																	
	17			Utility / Service Locates	1	ea.			0		0	1,200	1,200		0		0	1,200
	18			Remove / Reinstall Stairway	1	ea.			0		0	5,000	5,000		0		0	5,000
	19			Fuel Transfer and Gas Freeing	1	ea.			0		0	4,500	4,500		0		0	4,500
	20			Removal and Disposal	2	ea.			0		0	4,000	8,000		0		0	8,000
	21			Backfill and Compact	1	ea.			0		0	2,750	2,750		0		0	2,750
	22																	
	23			**Landscaping**					**0**		**0**		**7,500**		**0**		**0**	**7,500**
	24																	
	25			Landscaping Allowance	1	ea.			0		0	7,500	7,500		0		0	7,500
	26																	
	27			**Temporary Facilities / Construction Supervision**					**0**		**0**		**22,000**		**0**		**0**	**22,000**
	28																	
	29			Washroom	1	ea.			0		0	500	500		0		0	500
	30			Site Office	1	ea.			0		0	1,500	1,500		0		0	1,500
	31			Supervision	4	ea.			0		0	5,000	20,000		0		0	20,000
	32																	
	34			**Removal and Disposal of Contaminated Soil (Tank Nest) / Contaminated Water**					**0**		**0**		**14,000**		**0**		**0**	**14,000**
	35																	
	36			Contaminated Soil (Tonnes)	100				0		0	110	11,000		0		0	11,000
	37			Contaminated Water (Litres)	10,000				0		0	0.3	3,000		0		0	3,000
	38																	

Client: **Nova Scotia Power**
Project: **ECC Generator Replacement**
Project No: **133547049**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Mechanical

Prepared by: **JS**
Date: **4-Nov-15**
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Issue Date: **10-Nov-15**
Checked: **CS**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	33			**TOTAL - OPTIONS**					**0**		**0**		**46,500**		**0**		**0**	**32,500**
	39			**ULC Approved Automatic Fuel Filtration System**					**0**		**0**		**22,500**		**0**		**0**	**22,500**
	40																	
	41			Filtration Unit	1	ea.			0		0	15,000	15,000		0		0	15,000
	42			Supply and Return	2	ea.			0		0	2,500	5,000		0		0	5,000
	43			Electrical	1	ea.			0		0	2,500	2,500		0		0	2,500
	44																	
	45			**ULC Approved A/G Doublewalled Piping**					**0**		**0**		**10,000**		**0**		**0**	**10,000**
	46																	
	47			Supply and Return	4	ea.			0		0	2,500	10,000		0		0	10,000
	48																	

Client: **Nova Scotia Power**
Project: **ECC Generator Replacement**
Project No: **133547049**
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STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical

Prepared by: **MAK**
Date: **4-Nov-15**
Revision No.: **0**
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Checked: **JCS**

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	1			**Option 1 - Keep Existing Generators**					**245**		**26,144**		**135,892**		**0**		**21,600**	**183,636**
	2																	
	3			**Manual Transfer Switch**														
	4			400A Manual Transfer Switch	2	ea.	8.00	1.00	16	100.00	1,600	10,000.00	20,000		0		0	21,600
	5			400A NEMA 4X Disconnect Switch (Mounted On Building Exterior	2	ea.	8.00	1.00	16	100.00	1,600	6,000.00	12,000		0		0	13,600
	6			4 x 1C# 350kcmil Teck Cable From Manual Transfer Switch to NEMA 4X Disconnect	60	ft.	0.13	1.00	8	100.00	756	15.16	910		0		0	1,666
	7			4 x 1C# 350kcmil Teck Cable Terminations	2	ea.	12.18	1.00	24	100.00	2,436	319.68	639		0		0	3,075
	8			4 x 1C #350kcmil Teck Cable From Generator Breaker to Manual Transfer Switch	200	ft.	0.07	1.00	14	100.00	1,440	15.16	3,032		0		0	4,472
	9			4 x 1C# 350kcmil Teck Cable Terminations	2	ea.	12.18	1.00	24	100.00	2,436	319.68	639		0		0	3,075
	10			4 x 1C #350kcmil Teck Cable From Manual Transfer Switch to Generator	200	ft.	0.07	1.00	14	100.00	1,440	15.16	3,032		0		0	4,472
	11			4 x 1C# 350kcmil Teck Cable Terminations	2	ea.	12.18	1.00	24	100.00	2,436	319.68	639		0		0	3,075
	12			Demolish Existing Cables Between Generator and The Generator Breaker	4	ea.	2.00	1.00	8	100.00	800		0		0		0	800
	13																	
	14																	
	15			**Emergency & Normal Power Circuit Breaker Cleaning/Inspection & Testing**														
	16			Allowance for Cleangin/Inspection and Testing	4	ea	8.00	1.00	32	150.00	4,800	5,000.00	20,000		0		0	24,800
	17																	
	18																	
	19			**Generator Testing**														
	20			Equipment Service Technician to Take Oil Samples for Testing and Load Bank the existing Generators	2				0		0		0		0	5,000	10,000	10,000
	21			Generator Rental (Rental Allowance is based on 2 months)	2	ea	16.00	1.00	32	100.00	3,200		0		0	5,800	11,600	14,800
	22																	
	23			**Radiators**														
	24			Replace existing Radiators with new	2	ea			0		0	10,000.00	20,000		0		0	20,000
	25			Replace the existing Glycol with new Glycol	2	ea	16.00	1.00	32	100.00	3,200	5,000.00	10,000		0		0	13,200
	26			Crane Rental and Rigging To Protect The Roof	2	ea			0		0	15,000.00	30,000		0		0	30,000
	27																	
	28			**Fuel System**														
	29			Electrical Installation Allowance	1				0		0	15,000.00	15,000		0		0	15,000
	30																	

Client: **Nova Scotia Power**
Project: **ECC Generator Replacement**
Project No: **133547049**
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STANTEC CONSULTING
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Date: **4-Nov-15**
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Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Mat'l/Commodity		Equipment		Sub-Contractor		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
	31			**Option 2 - Replace Existing Generators**					**373**		**38,944**		**400,392**		**0**		**26,600**	**465,936**
	32																	
	33			**Manual Transfer Switch**														
	34			400A Manual Transfer Switch	2	ea.	8.00	1.00	16	100.00	1,600	10,000.00	20,000		0		0	21,600
	35			400A NEMA 4X Disconnect Switch (Mounted On Building Exterior	2	ea.	8.00	1.00	16	100.00	1,600	6,000.00	12,000		0		0	13,600
	36			4 x 1C# 350kcmil Teck Cable From Manual Transfer Switch to NEMA 4X Disconnect	60	ft.	0.13	1.00	8	100.00	756	15.16	910		0		0	1,666
	37			4 x 1C# 350kcmil Teck Cable Terminations	2	ea.	12.18	1.00	24	100.00	2,436	319.68	639		0		0	3,075
	38			4 x 1C #350kcmil Teck Cable From Generator Breaker to Manual Transfer Switch	200	ft.	0.07	1.00	14	100.00	1,440	15.16	3,032		0		0	4,472
	39			4 x 1C# 350kcmil Teck Cable Terminations	2	ea.	12.18	1.00	24	100.00	2,436	319.68	639		0		0	3,075
	40			4 x 1C #350kcmil Teck Cable From Manual Transfer Switch to Generator	200	ft.	0.07	1.00	14	100.00	1,440	15.16	3,032		0		0	4,472
	41			4 x 1C# 350kcmil Teck Cable Terminations	2	ea.	12.18	1.00	24	100.00	2,436	319.68	639		0		0	3,075
	42			Demolish Existing Cables Between Generator and The Generator Breaker	4	ea.	2.00	1.00	8	100.00	800		0		0		0	800
	43																	
	44			**Generator Protection & Controls**														
	45			Replace Existing Conrtol Panel (Includes Removal of the existing Control Panel)	2	ea	16.00	1.00	32	100.00	3,200	20,000.00	40,000		0		0	43,200
	46			Control Panel Testing and Commissioning (Vendor Allowance)	2	ea			0		0		0		0	2,500	5,000	5,000
	47			Replace existing PT's and CT's complete with cabling as required	2				0		0	8,000.00	16,000		0			16,000
	47																	
	48			**Emergency & Normal Power Circuit Breaker Cleaning/Inspection & Testing**														
	49			Allowance for Cleangin/Inspection and Testing	4	ea	8.00	1.00	32	150.00	4,800	5,000.00	20,000		0		0	24,800
	50																	
	48			**Generator Replacement**														
	49			Remove Existing Generator	2	ea	16.00	1.00	32	100.00	3,200	500.00	1,000		0		0	4,200
	50			Supply and Install New 300kW Generator Pacakge	2	ea	16.00	1.00	32	100.00	3,200	100,000.00	200,000		0		0	203,200
	51			Generator Commissioning and Training (Vendor Allowance)	2	ea			0		0		0		0	5,000	10,000	10,000
	52			Generator Rental (Rental Allowance is based on 2 months)	2	ea	16.00	1.00	32	100.00	3,200		0		0	5,800	11,600	14,800
	53																	
	54			**Generator Housekeeping Pads**														
	55			Allowance for Modification of Housekeeping Pads	2	ea	16.00	1.00	32	100.00	3,200	3,750.00	7,500		0		0	10,700
	56																	
	57			**Radiators**														
	58			Replace existing Radiators with new	2	ea			0		0	10,000.00	20,000		0		0	20,000
	59			Replace the existing Glycol with new Glycol	2	ea	16.00	1.00	32	100.00	3,200	5,000.00	10,000		0		0	13,200
	60			Crane Rental and Rigging To Protect The Roof	2	ea			0		0	15,000.00	30,000		0		0	30,000
	61																	
	62			**Fuel System**														
	63			Electrical Installation Allowance	1				0		0	15,000.00	15,000		0		0	15,000
	64																	

February 9, 2016

Mr. Adam Flick
Real Estate Specialist
Nova Scotia Power
1223 Lower Water Street
Halifax, NS B3J 3S8

Dear Mr. Flick:

RE: Report – Condition Assessment on Former CN Railroad Bridge

1. Introduction

Nova Scotia Power Incorporated (NSPI) obtained the former CN railway bridge over Massachusetts Avenue in Halifax, NS (Figure 1) an unspecified number of years ago. The structure was obtained from the Canada Lands Company (CSC) presumably to maintain an overhead transmission corridor. It is assumed from the imprint on the south abutment that the bridge was originally constructed in 1971 but it is unclear when the structure was decommissioned for railway use.

Figure 1: Former CN Railway Bridge.

In recent years, the structure has experienced deterioration, most notably on the central piers, and there has been some public concern over potential safety hazards associated with the bridge. On December 22, 2015 CBCL Limited (CBCL) was contacted by NSPI to perform a condition assessment of the structure, estimate costs of rehabilitation, and investigate the costs associated with complete removal of the structure. This report contains a summary of the condition assessment and recommended repairs and associated cost estimates. The feasibility of removing the structure has not been investigated.

As discussed later in this report, the concrete at the top of the pier columns were delaminated to a degree that was potentially dangerous to traffic. Following the inspection CBCL contacted NSPI regarding this by email. It is understood that NSPI has hired a contractor to install wire fencing around these areas to prevent concrete from falling into traffic while a more permanent solution is being determined.

2. Condition Assessment

On January 15, 2016, following approval to proceed from NSPI's Adam Flick on January 11, CBCL performed an inspection of the structure over Massachusetts Avenue. As proposed, the structure was inspected on foot, with more rigorous access methods to be recommended if deemed necessary from the inspection.

Figure 2: Top of deck on day of inspection.

On the date of inspection much of the deck top was under snow cover and, as such, was not visible (Figure 2). The sky was clear and the temperature was approximately -6° C with a wind chill of -15° C.

We have utilized a simplified rating system (i.e. Excellent, Very Good, Good, Fair, Poor) which is indicative of the 'non-hands on' inspection performed. A more detailed rating system would require an inspection with a higher level of rigour.

<u>2-1. Substructure</u>

North Abutment

The inspection was performed on foot therefore hammer blows to detect delamination (unbonded concrete beneath the surface, often due to corroding steel reinforcing) were restricted to approximately
8 feet from the ground.

The inspection identified:

- Two locations of delamination (Figure 3);
- Two locations of exposed reinforcing (Figure 4);
- Several locations of wide cracks, both vertically and transversely;
- Evidence of spalling near beam seat (out of reach from inspector); and
- Light to medium scaling with evidence of Alkali - Aggregate Reactions (AAR) and mineral deposits throughout.

Due to the proximity to traffic the inspectors did not include the wall adjacent to the road approaching the MacKay Bridge, but it is suspected that the condition is very similar to the wall directly beneath the superstructure.
The concrete of the north abutment is considered in fair to poor condition.

Figure 3: North abutment delamination and exposed rebar.

Figure 4: Close up of exposed rebar.

South Abutment

The south abutment (Figure 5) appears in considerably better condition than the north. The inspection identified:

- Light to medium scaling and evidence of AAR with mineral deposits throughout;
- Several locations of full height wide cracks; and
- One location of delamination (Figure 6).

Although in better condition than the north abutment, the south abutment is considered to be in fair condition.

Figure 5: South abutment.

Figure 6: Delamination on south abutment.

Pier

In a similar fashion to the abutments the assessment was performed on foot and only the lower 8 feet was accessible for a hands on inspection. In general, the pier columns are sound. The exception is a large area of concrete that is in an advanced stage of spalling off the structure. This is found near the bearing on the southeast side of the pier (Figure 7). Because of this the condition of the pier has been rated as poor. Large cracks have also formed on the top northwest pier (Figure 8) and appears to be progressing towards a condition similar to the southeast.

Figure 7: Cracking, delamination, and spalling of concrete on southeast pier.

Figure 8 - Cracking on the northwest pier.

Bearings and Beam Seat

Inspection of the bearings and beam seats was performed from the ground. The north abutment beam seat has large cracks on the west side adjacent to the bearing (Figure 9). The bearing assembly at this location appears to have undergone a displacement, which may have caused the cracking observed. On the south abutment, the beam seat appears to be in fair condition with minor cracking. However, significant snow and debris had accumulated on the beam seat due to the geometry and detailing of the abutment and expansion joint (Figure 10). Snow clearing operations of the areas surrounding the south side of the structure may have also contributed to the accumulation of snow. The accumulation of snow and other debris will accelerate the degradation of the beam seat. At the pier the bearing assembly appeared to be slightly overhanging the edge of the pier (Figure 11). Any anchorage of the bearing assembly into the pier could not be seen at the time of the inspection.

Figure 9: Cracking at northwest bearing seat.

Figure 10: Snow collecting on south beam seat.

Figure 11: Overhang of pier bearing assembly.

2-2. Superstructure

Girders

Deep steel girders estimated to be over 8 feet deep each are found on each side of the deck. The flanges are varying thicknesses along the length of the girder. Peeling of the paint coating on the underside of the girders was found (Figure 12), exposing the bare steel to atmospheric conditions. Surface corrosion was noted on the bottom of the girder at the locations of peeling paint. The remaining area of the girders had minor surface corrosion. Overall the girders are considered to be in fair to good condition (Figure 13).

Figure 12: Peeling of paint on south girder.

Figure 13 - Typical girder condition

Floor beams and Stringers

The floor beams span between the two girders, transferring load from the deck to the girders. Stringers are found spanning between floor beams and located in a single row parallel to the girders. Light to medium corrosion was found on the floor beams and stringers (Figure 14). Areas in close proximity to expansion joints have considerably more corrosion due to leaking of the joints and the constant wetting and drying cycle these areas are exposed to. The floor beams and stringers are rated in fair condition.

Figure 14: Floor beam and stringer condition.

Deck

As noted previously, the top of the deck was snow covered and unable to be inspected. Inspection of the deck soffit (underside of the deck) was completed from the ground. Minor spalling of the soffit was found at the edge of the deck, located directly above the floor beams (Figure 15). Further, hairline cracking was found in various locations across the deck (Figure 16). The deck soffit is considered in fair condition.

Figure 15: Spall on concrete deck above floor beam.

Figure 16: Cracking of concrete deck.

3. Recommended Repairs and Cost Estimates

It is CBCL's opinion that the superstructure is performing satisfactorily and does not require any immediate repairs under its' current use. The deck soffit does not appear to have any delamination or areas which may break off and fall onto the roadway below. However, the **substructure has several issues requiring attention**. The substructure repair types are detailed below, with the corresponding locations noted and associated quantities. Repair of the concrete to the pier columns and north abutment beam seat are recommended to be **completed in less than one year.** An estimate of probable costs is included as well.

a) **Delaminated and Spalling Concrete, and Exposed Reinforcing**
The quantity of delaminated concrete will likely grow larger than measured since inspection was limited to what could be measured safely on foot without traffic control. To repair, CBCL recommends chipping away all delaminated concrete until reaching sound material. Concrete surrounding the exposed reinforcing steel should be removed to a depth approximately 25 mm beyond reinforcing bar. Following cleaning of the reinforcing, new concrete shall be placed in the void and brought flush to abutment face, to match the existing structure. Special consideration is required in locations around the bearings. Adequate load transfer from the girder to the substructure (abutments and piers) is required to maintain safety and stability of the structure during repairs.
Locations: North abutment, south abutment, pier.
Estimated Quantity: ~10 m^2
Class D Cost Estimate: $13,000

b) **Cracking in Concrete**
Any cracks exceeding 0.2 mm in width shall be injected with an epoxy adhesive to prevent any ingress of water. Any locations with loose concrete shall be repaired as delaminated concrete.
Locations: North abutment, south abutment, pier.
Estimated Quantity: 150 m
Class D Cost Estimate: $13,000

Further to the estimates provided above there are incidental activities that will significantly impact the total construction costs. The costs above, along with the incidental costs are summarized in the table below:

Item	Estimated Cost
Traffic Control	$23,400
Temporary Hoarding	$5,300
Zoom Boom (Access)	$1,200
Concrete Repair	$13,000
Crack Repair	$13,000
Design Development Contingency (40%)	$22,300
Post Award Construction Contingency (%10)	$7,800
Total Construction Costs	**$86,000**

The total estimated cost to complete the repairs is $86,000 excluding HST. Note that a 40% design development contingency is applied to account for the limited inspection. It is very likely that once concrete starts being chipped away, more deterioration will become exposed. There are also likely other areas of delamination that will be identified during construction that were not accessible during the inspection and therefore not included in the estimated quantities. It is recommended that prior to the preparation of tender documents that a detailed inspection be performed to gain a more accurate representation of the scope of work.

This opinion of probable costs is presented on the basis of experience, qualifications, and best judgement. It has been prepared in accordance with acceptable principles and practices. Market trends, non-competitive bidding situations, unforeseen labour and material adjustments and the like are beyond the control of CBCL. As such, we cannot warrant or guarantee that actual costs will not vary from the opinion provided.

4. Additional Repairs

CBCL has the opinion that additional repairs can be completed in order to extend the service life of both the recommended repairs, as well as the structure. These repairs are not required to address any immediate safety concern, such as spalling concrete. The repairs are listed below:

a) **Replacement of Expansion Joints**
The joints on the bridge are not water tight and allow leaking of water directly on top of the beam seat and bearings (Figure 17). At the pier location the leaking expansion joint contributed to the delamination and spalling of the concrete, as well as corrosion of the floor beams at this location.

Figure 17: Existing leaky expansion joints. Icicles observed on day of inspection.

b) Coating of Steel

Though most of the steel superstructure is in fair condition, repainting of key areas, especially adjacent to the expansion joints, will protect the steel from additional corrosion and section loss.

5. Structure Removal

NSPI had indicated the structure is not required for their operations and removal of the structure was of interest. It should be noted that any removals would include the superstructure and piers only as the abutments would be required to remain as retaining walls for the land adjacent to the roadway. If removal of the superstructure is to be considered an analysis would be required to determine the stability of the abutment retaining structures without the weight of the steel superstructure resting on top. Locating original as-built drawings would be key for further analysis. With the south abutment date stamped in 1971, drawings likely exist, but locating them may pose a challenge. Though technology exists to determine the concrete wall thickness and reinforcing size and layout, determining information about the buried portion of the structure, such as the footing size, is difficult. It should be noted that regardless of whether or not the superstructure is removed, repairs to the structure concrete are still recommended, although perhaps to a lesser degree. Following NSPI review of this report, CBCL would be pleased discuss pursuing this matter further.

6. Conclusion

An inspection of the former CN railway bridge over Massachusetts Avenue in Halifax, NS found the substructure requires repairs to address delamination and spalling, exposed rebar, and cracking, in the concrete. CBCL recommends the repairs discussed in Section 3, specifically repairs to the north abutment beam seat and pier columns be performed in **less than one year** as they are potential hazards to the travelling public**.** CBCL would be pleased to offer additional services on this project, whether it be to investigate the feasibility of superstructure removal or to complete a detailed design of the repairs.

We trust that the above provides the information required by NSPI. Please don't hesitate to call if you would like to discuss further.

Yours very truly,

CBCL Limited

Colin Jim

Prepared by:
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Reviewed by:
Colin Jim, P.Eng.
Structural Engineer

Project No: 160201.00

June 27, 2016

Mr. Adam Flick
Real Estate Specialist
Nova Scotia Power
1223 Lower Water Street
Halifax, NS B3J 3S8

Dear Mr. Flick:

RE: Former CN Railroad Bridge, Massachusetts Avenue – Supplement

This letter is intended to supplement the condition assessment report and Structure Options Report provided by CBCL Limited (CBCL) on February 9, 2016 and May 12, 2016 respectively.

Nova Scotia Power Incorporated (NSPI) obtained the former CN railway bridge over Massachusetts Avenue in Halifax, NS an unspecified number of years ago. The structure was obtained from the Canada Lands Company (CSC) presumably to maintain an overhead transmission corridor. It is assumed from the imprint on the south abutment that the bridge was originally constructed in 1971 but it is unclear when the structure was decommissioned for railway use.

In recent years, the structure has experienced deterioration, most notably on the central piers, and there has been some public concern over potential safety hazards associated with the bridge. On December 22, 2015 CBCL Limited (CBCL) was contacted by NSPI to perform a condition assessment of the structure, estimate costs of rehabilitation, and investigate the costs associated with complete removal of the structure.

Prior to submitting a condition assessment report CBCL performed a ground level inspection on January 15, 2016. This inspection led to the recommendation of immediate mitigation repairs to the central piers which posed a danger to the traveling public. A more detailed inspection was performed on March 29 and 30, 2016 and was followed by a report detailing the feasibility of removing the steel superstructure. Associated with that report were cost estimates for required repairs to the structure. Those costs are summarized below:

Repair		$179,000
Tender Documents		$14,000
Construction Administration		$6,500
	TOTAL	**$199,500**

I trust that this is the information you require, based on our telephone conversation on June 24, 2016. If you have any question, or require anything further, please do not hesitate to contact me.
Yours very truly,

CBCL Limited

Colin Jim, P.Eng.
Structural Engineer
Tel: (902) 421-7241 Ext 2307
E-Mail: cjim@cbcl.ca

Project No: 160201.01

Request IR-46:

With respect to routine P012 (HYD Security Improvement):

(a) Please provide a description of the work.

(b) Please explain why it needs to be done now.

(c) Please provide a description of how the cost estimate was derived (including any supporting calculations or documentation).

Response IR-46:

(a) P012 is used for security improvements around hydro and wind sites. Improvements include fencing, road gates, signage, caution booms, alarms and access improvements.

(b) This work needs to be done now to address safety and security risks, such as signage to inform the public of safety risks and installation/upkeep of preventative measures such as fencing and road gates. These measures are particularly important given that recreational activities take place in locations that surround the hydro site. Ongoing spend is required to ensure the site continues to be safe and that risks are mitigated. The mitigation measures also help NS Power align with its compliance recommendations presented by the Canadian Dam Associated with respect to Public Safety.

(c) Please refer to Attachment 1.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	A	B	C	D	E	F	G
1	Area	System	Site	Project Title	Type	Primary Justification	Estimate
2	Annapolis	Nictaux	Curl Hole wooden spillway	Install Safety booms in front of spillway	boat booms	public Safety	$ 9,300
3	Annapolis	Nictaux	Macgill Gate	Install Safety booms in front of gates	boat booms	Public Safety	$ 6,200
4	Annapolis	Nictaux	Curl Hole main dam	Install Safety booms in front of intake	boat booms	Public Safety	$ 13,950
5	Annapolis	Paradise	Paradise intake	Install Safety booms in front of intake	boat booms	Public Safety	$ 8,525
6	Annapolis	Annapolis	Tidal Plant	Annapolis Tidal Plant fencing / signage requirements	Fencing	Public Safety	$ 25,000
7	Annapolis	Lequille	Grand Lake Spillway	Fencing required to prevent access to spillway	Fencing	Public Safety	$ 7,500
8	Annapolis	Nictaux	Scragg spillway & gate	Fencing required to prevent access to spillway	Fencing	Public Safety	$ 4,000
9	Annapolis	Paradise	Paradise spillway	Fencing required to prevent access to spillway	Fencing	Public Safety	$ 3,000
10	Annapolis	Paradise	Paradise Lake	Fencing required to prevent access to spillway	Fencing	Public Safety	$ 6,500
11	Annapolis	Nictaux	Macgill Gate	Fencing required to prevent access to gates	Fencing	Public Safety	$ 6,500
12	Annapolis	Nictaux	Curl Hole main dam	Fencing required to prevent access to intake	Fencing	Public Safety	$ 5,500
13	Annapolis	Paradise	Paradise intake	Fencing required to prevent access to intake	Fencing	Public Safety	$ 3,500
14	Fundy	Ridge	Ridge	Install Safety booms in front of intake.	boat booms	Public Safety	$ 7,500
15	Fundy	Weymouth	Weymouth	Install Safety booms in front of intake.	boat booms	Public Safety	$ 12,400
16	Fundy	Tusket	Tusket	Install Safety booms to prevent access to discharge.	boat booms	Public Safety	$ 7,750
17	General	General	General	Fabricate Road Gates for various systems Materials plus shop labour	Shop Fabrication	Security	$ 15,000
18	Sheet Harbour	Marshall Falls	Antidam Spillway	Install Safety booms in front of spillway	boat booms	Public Safety	$ 19,375
19	Sheet Harbour	Dickie Brook	Donahue Lake	Install Safety booms in front of intake.	boat booms	Public Safety	$ 11,625
20	Sheet Harbour	Marshall Falls	Sloan lake intake / Spillway	Install Safety booms in front of spillway	boat booms	Public Safety	$ 7,750
21	Sheet Harbour	Ruth Falls	RUT Gatehouse	Fencing required to prevent vandalism at gatehouse	fencing	Security	$ 5,000
22	Wreck Cove	Gisborne	Generator	Audible alarm required when remotely operated unit starts.	Alarm	Public Safety	$ 12,500
23	Wreck Cove	Gisborne	GIS Intake	Install Safety booms in front of intake.	boat booms	Public Safety	$ 30,000
24	Wreck Cove	Wreck Cove	D1 (Cheticamp)	install road gate	Gate	Security	$ 6,500
25	General	General	General	Access Road Improvements	Road	Security	$ 297,692
26						**P012 - HYD Security Improvements Total**	**$ 523,267**

Request IR-47:

With respect to routine D010 (Distribution Right of Way Widening), how does the estimated $18,000 average cost per kilometer compare to the average cost per kilometer achieved in 2016 (year-to-date)?

Response IR-47:

The average cost per kilometer achieved in 2016 year-to-date is approximately $17,500.

Request IR-48:

Please provide an update on anticipated retirement dates for all thermal generating units, as well as their recent and anticipated annual capacity factors.

Response IR-48:

The most recently issued information concerning thermal generating unit retirement dates and capacity factors is from the 2014 IRP, included in the 2016 10 Year System Outlook and information presented in the 2016 Base Cost of Fuel regulatory proceeding. Please refer to the tables below.

<u>2016 10 Year System Outlook report (2014 IRP)</u>

Unit	Commissioning Year	2014 IRP Retirement[1]	Year Fully Depreciated[2]	Federal Coal Regs Retirement[3]
Lingan 1	1979	2039	2023	2029
Lingan 2	1980	2018	2021	2029
Lingan 3	1983	2039+	2039+	2029
Lingan 4	1984	2039+	2039+	2029
Point Aconi	1994	2039+	2039+	2044
Point Tupper	1972/1987	2039+	2039+	2021
Trenton 5	1969	2035	2039+	2019
Trenton 6	1991	2039+	2039+	2041
Tufts Cove 1	1965	2025	2027	N/A
Tufts Cove 2	1972	2032	2033	N/A
Tufts Cove 3	1976	2036	2039+	N/A

1 The retirement assumptions used for the 2014 IRP. Units with retirements beyond 2039 (the planning horizon) were not given specific retirement years for modeling purposes.
2 The year in which the unit is fully depreciated at the current rates of depreciation.
3 The retirement dates of the coal units under the Federal GHG Regulations (if the Equivalency Agreement were not in effect).

Unit	Actual 2015	Year to Date	2017 (%)	2018 (%)	2019 (%)	2020 (%)

	(%)	**2016 (%)**				
Lingan 1	52	55	39	47	35	22
Lingan 2	29	18	26	23	0	0
Lingan 3	41	49	61	61	50	41
Lingan 4	58	33	74	71	57	36
Pt. Aconi	76	73	83	81	77	77
Pt. Tupper	74	74	82	83	60	73
Trenton 5	59	54	9	14	24	19
Trenton 6	78	75	72	79	53	57
Tufts Cove 1	23	6	17	6	7	23
Tufts Cove 2	39	22	34	36	16	21
Tufts Cove 3	41	47	31	26	7	8

As discussed in response to NSUARB IR-32, the capacity factors of NS Power's thermal generating units over the next two decades will be influenced by the developing federal and provincial government policies concerning greenhouse gas (GHG) emissions. The Company's view is that a new Equivalency Agreement will allow the utility to maintain the option of utilizing its solid fuel generators beyond 2030. This will benefit our customers in the near to mid-term as it will allow NS Power to continue to extract value from these generation units thereby reducing our capital and operating costs.

The retention of solid fuel generators is influenced by existing steam unit characteristics, demand growth, and planning flexibility. This requires the continued optimization of existing generation assets utilizing an integrated approach across the generation and transmission systems including:

- Repurposing certain generation assets with falling capacity factors to focus on providing reliability services and meeting peak across the day and throughout the year;
- Changing generating unit operating regimens (e.g. two-shifting) where this is economically viable;
- Deferring/delaying major decisions such as unit retirements as long as significant uncertainty remains and/or opportunities may exist to continue to extract value from past investment;

- Working with policy makers to present alternatives to achieve public objectives at the lowest possible cost to our customers (e.g. the Equivalency Agreement).

Consistent with this, other than Lingan 2 which NS Power expects to retire once it is displaced by generation from Muskrat Falls, and Tufts Cove 1 which pursuant to the 2014 IRP is forecasted to retire in 2025, the Company's current plan does not anticipate retirement of any of its thermal generating units prior to 2030. However, NS Power will continue to monitor the performance of these units and ongoing investment requirements as well as system constraints, market forecasts and other planning projections. Should an opportunity be identified to reduce costs for our customers by retiring a thermal unit, this will be identified to the Board and stakeholders by the Company with a strategy to address this.

Request IR-49:

Please provide the following copies of the thermal and large hydro unit maintenance schedules, in standard NSPI Gantt chart format:

(a) Maintenance schedule used in the development of 2017 ACE Plan.

(b) Actual maintenance schedule for 2016.

Response IR-49:

(a) Please refer to Confidential Attachment 1 for the 2017 schedule.

(b) Please refer to Attachment 2 for the 2016 schedule.

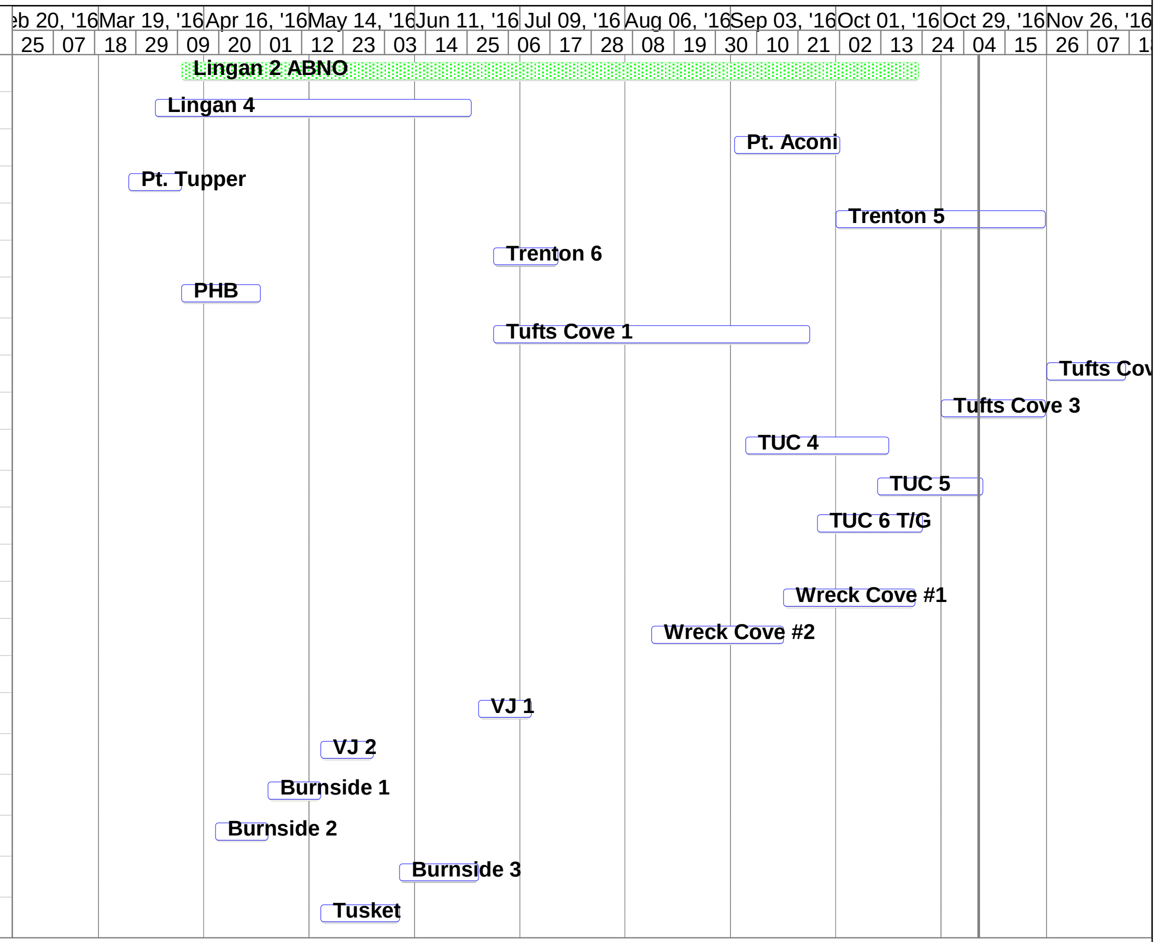
NSUARB IR-49 Attachment 1
has been removed due to confidentiality.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

DRAFT

2016 Thermal Maintenance Schedule (As of October 31, 2016)

ID	Task Name	Duration	Start	Finish
1	Lingan 2 ABNO	28 ewks	Sat 4/09/16	Sat 10/22/16
2	Lingan 4	12 ewks	Sat 4/02/16	Sat 6/25/16
3	Pt. Aconi	4 ewks	Sat 9/03/16	Sat 10/01/16
4	Pt. Tupper	2 ewks	Sat 3/26/16	Sat 4/09/16
5	Trenton 5	7.9 ewks	Sat 10/01/16	Fri 11/25/16
6	Trenton 6	2.4 ewks	Fri 7/01/16	Mon 7/18/16
7	PHB	3 ewks	Sat 4/09/16	Sat 4/30/16
8	Tufts Cove 1	12 ewks	Fri 7/01/16	Fri 9/23/16
9	Tufts Cove 2	3 ewks	Sat 11/26/16	Sat 12/17/16
10	Tufts Cove 3	3.9 ewks	Sat 10/29/16	Fri 11/25/16
11	TUC 4	5.4 ewks	Tue 9/06/16	Fri 10/14/16
12	TUC 5	4 ewks	Tue 10/11/16	Tue 11/08/16
13	TUC 6 T/G	4 ewks	Sun 9/25/16	Sun 10/23/16
14				
15	Wreck Cove #1	5 ewks	Sat 9/17/16	Sat 10/22/16
16	Wreck Cove #2	4.91 ewks	Sat 8/13/16	Fri 9/16/16
17				
18	VJ 1	2 ewks	Mon 6/27/16	Mon 7/11/16
19	VJ 2	2 ewks	Mon 5/16/16	Mon 5/30/16
20	Burnside 1	2 ewks	Mon 5/02/16	Mon 5/16/16
21	Burnside 2	2 ewks	Mon 4/18/16	Mon 5/02/16
22	Burnside 3	3 ewks	Mon 6/06/16	Mon 6/27/16
23	Tusket	3 ewks	Mon 5/16/16	Mon 6/06/16



Intergrated Outage Planning Comittee

TC1 Major (Extended)
Lingan 4 Major

TC3/TC2 delayed
TR5 extended

Request IR-50:

For each of the thermal generating plants and units, please provide a list of all projects that are included in the proposed 2017 ACE Plan, together with their individual budgeted costs.

Response IR-50:

Please refer to Attachment 1. This information can also be found in the Master Database EXCEL file that was filed alongside the 2017 ACE Plan.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

CI#	Project Long Title	ACE Filing Type	Major Location	2017 ACE	Project Total
33142	CT- Burnside #4 Unit Restoration	Carryover	Burnside Combustion Turbine	3,784,820	8,299,889
49937	CT - BGT 1 Exterior Coating Refurbishment	Less than $250k	Burnside Combustion Turbine	52,117	52,117
49938	CT - BGT 2 Exterior Coating Refurbishment	Less than $250k	Burnside Combustion Turbine	52,117	52,117
49939	CT - BGT 3 Exterior Coating Refurbishment	Less than $250k	Burnside Combustion Turbine	52,117	52,117
49976	CT - BGT 4 Exterior Coating Refurbishment	Less than $250k	Burnside Combustion Turbine	52,117	52,117
49874	CT-BGT Replace Halon Fire Protection	Less than $250k	Burnside Combustion Turbine	226,366	226,366
49273	CT-BGT2 Engine Refurbishment	Subsequent Submittal	Burnside Combustion Turbine	908,102	1,019,832
47761	LIN1 Boiler Refurbishment	Carryover	Lingan Generating Station	398,673	398,673
41226	LIN - Boiler Feed Pump Proportional Valve Replacements - Unit #1	Less than $250k	Lingan Generating Station	207,980	207,980
41229	LIN - Cable Spreading Rooms Fire Protection	Less than $250k	Lingan Generating Station	161,946	200,252
49440	LIN 1&2 GSCW Piping Reconditioning	Less than $250k	Lingan Generating Station	247,116	247,116
49428	LIN Ash Site Capping	Less than $250k	Lingan Generating Station	195,122	195,122
50020	LIN CEM Replacement Phase 1	Less than $250k	Lingan Generating Station	170,281	170,281
49443	LIN Coal System Guard Upgrade Phase 3	Less than $250k	Lingan Generating Station	120,131	120,131
47870	LIN Cofferdam Outer Cell Refurbishment	Less than $250k	Lingan Generating Station	44,692	44,692
49442	LIN Facilities Upgrade	Less than $250k	Lingan Generating Station	104,630	104,630
49445	LIN Feeder Controls Upgrades	Less than $250k	Lingan Generating Station	93,733	93,733
49151	LIN Grating Refurbishment	Less than $250k	Lingan Generating Station	246,871	246,871
49449	LIN GSCW Line Replacement	Less than $250k	Lingan Generating Station	121,615	121,615
49435	LIN Heavy Oil Line Refurbishment Phase 2	Less than $250k	Lingan Generating Station	210,252	210,252
48776	LIN PA Plant Lighting Upgrade	Less than $250k	Lingan Generating Station	222,312	222,312
47116	LIN PE Flyash Surge System Bypass	Less than $250k	Lingan Generating Station	187,126	244,923
49432	LIN PF Line Refurbishment	Less than $250k	Lingan Generating Station	215,899	215,899
49439	LIN Plant Siding Replacement	Less than $250k	Lingan Generating Station	233,859	233,859
49436	LIN Reclaim Refurbishment	Less than $250k	Lingan Generating Station	233,494	233,494
49873	LIN Seaweed Picker Upgrade	Less than $250k	Lingan Generating Station	242,227	242,227
49453	LIN Stores Fire Protection Upgrade	Less than $250k	Lingan Generating Station	104,232	104,232
47963	LIN Waster Water Stand Pipe Refurbishment	Less than $250k	Lingan Generating Station	152,791	152,791
49455	LIN1 Bus Duct IR Window and Temperature Sensor Installation	Less than $250k	Lingan Generating Station	135,782	135,782
47960	LIN1 Control Valve Rebuild	Less than $250k	Lingan Generating Station	237,623	237,623
49456	LIN1 Electric Motor Refurbishment	Less than $250k	Lingan Generating Station	113,171	113,171
49444	LIN1 Misc. Valve Refurbishment	Less than $250k	Lingan Generating Station	210,463	210,463
49457	LIN3 Electric Motor Refurbishment	Less than $250k	Lingan Generating Station	111,829	111,829
49454	LIN3 Generator Bus Duct Temperature Sensors	Less than $250k	Lingan Generating Station	73,153	73,153
49452	LIN3 Heater Level Controls Upgrade	Less than $250k	Lingan Generating Station	235,135	235,135
49459	LIN34 HMI TSC Upgrades	Less than $250k	Lingan Generating Station	106,912	106,912
43239	LIN4 BFP Proportional Recirculation Line Control	Less than $250k	Lingan Generating Station	160,757	160,757
49458	LIN4 Electric Motor Refurbishment	Less than $250k	Lingan Generating Station	111,829	111,829
49429	LIN Coal Pile Run Off Pond Expansion	Request Approval	Lingan Generating Station	311,793	311,793
49427	LIN Coal Plant Structural Refurbishment Phase 3	Request Approval	Lingan Generating Station	365,003	365,003
49430	LIN CW Pump Refurbishment 2017	Request Approval	Lingan Generating Station	516,270	516,270
49434	LIN CW Screen Refurbishment 2017	Request Approval	Lingan Generating Station	347,062	347,062
49431	LIN Mill Refurbishment 2017	Request Approval	Lingan Generating Station	665,839	665,839
47953	LIN Railcar Positioner Upgrade	Request Approval	Lingan Generating Station	566,619	566,619
49437	LIN Vacuum Pump Cooler Refurbishment	Request Approval	Lingan Generating Station	282,034	282,034
49433	LIN1 SH5 Boiler Tube Replacement	Request Approval	Lingan Generating Station	493,396	493,396
27857	LIN-ROOFING ROUTINE	Routine	Lingan Generating Station	400,000	400,000
10626	LIN - Routine Equipment Replacements	Routine	Lingan Generating Station	383,162	383,162
33863	LIN - Heat Rate Routine	Routine	Lingan Generating Station	76,439	76,439
49438	LIN A Gallery Floor Replacement	Subsequent Submittal	Lingan Generating Station	593,814	593,814
49972	CT - LM6000 191-253 HPC Stages 3-5 Bushing Replacement	Less than $250k	LM6000 - Tufts Cove	238,547	238,547
49971	CT - LM6000 191-332 HPC Stages 3-5 Bushings Replacement	Less than $250k	LM6000 - Tufts Cove	237,952	237,952
49974	CT - TUC 4 LM6000 Metal Scan Upgrade	Less than $250k	LM6000 - Tufts Cove	44,304	44,304
49932	CT - TUC 4 LM6000 Roof Skid Access	Less than $250k	LM6000 - Tufts Cove	33,161	33,161
49975	CT - TUC 5 LM6000 Metal Scan Upgrade	Less than $250k	LM6000 - Tufts Cove	44,304	44,304
49933	CT - TUC 5 LM6000 Roof Skid Access	Less than $250k	LM6000 - Tufts Cove	33,161	33,161
49950	LM6000 TUC4 SPRINT Nozzle Refurbishment	Less than $250k	LM6000 - Tufts Cove	166,061	166,061
49951	LM6000 TUC5 SPRINT Nozzle Refurbishment	Less than $250k	LM6000 - Tufts Cove	166,061	166,061
44776	CT - TUC#5 LM6000 Generator Stator Re-wedge	Subsequent Submittal	LM6000 - Tufts Cove	1,041,614	1,073,280
49926	LM6000 TUC4 Airhouse Upgrade	Subsequent Submittal	LM6000 - Tufts Cove	815,633	815,633
49949	LM6000 TUC4 Control System Replacement	Subsequent Submittal	LM6000 - Tufts Cove	710,815	710,815
49594	LM6000 TUC5 Airhouse Upgrade	Subsequent Submittal	LM6000 - Tufts Cove	833,200	833,200
49940	LM6000 TUC5 Control System Upgrade	Subsequent Submittal	LM6000 - Tufts Cove	1,018,769	1,018,769
47846	POA Ash Cell 4 Stage 3	Pt. Aconi	Point Aconi Generating Station	3,283,105	5,753,846
49477	POA ID Fan Motor Replacement	Pt. Aconi	Point Aconi Generating Station	902,961	902,961
49473	POA Boiler Refurbishment	Pt. Aconi	Point Aconi Generating Station	857,179	857,179
49469	POA Boiler Refractory Replacement	Pt. Aconi	Point Aconi Generating Station	727,515	727,515
49475	POA Air Heater Tube Replacement Phase 2	Pt. Aconi	Point Aconi Generating Station	584,171	584,171
49476	POA SH3 Tube Replacement Phase 3	Pt. Aconi	Point Aconi Generating Station	513,967	513,967
47859	POA CEM Replacement	Pt. Aconi	Point Aconi Generating Station	375,062	375,062
49482	POA Coal System Refurbishment	Pt. Aconi	Point Aconi Generating Station	279,400	279,400
49494	POA CW 4160V Cable Replacement	Pt. Aconi	Point Aconi Generating Station	263,426	263,426
49478	POA Pedestrian Bridge Replacement	Pt. Aconi	Point Aconi Generating Station	253,729	253,729
49490	POA SA Compressor Controls Upgrade	Pt. Aconi	Point Aconi Generating Station	241,187	241,187
49483	POA Ash System Refurbishment	Pt. Aconi	Point Aconi Generating Station	240,180	240,180
43114	POA - Screw Cooler Trough Replacement	Pt. Aconi	Point Aconi Generating Station	48,366	229,684
10718	POA - Routine Equipment Replacements	Pt. Aconi	Point Aconi Generating Station	225,568	225,568
49470	POA Boiler Arrowhead Replacement	Pt. Aconi	Point Aconi Generating Station	207,515	207,515
49487	POA Turbine Valve Refurbishment	Pt. Aconi	Point Aconi Generating Station	202,062	202,062
49468	POA Boilerhouse Window Upgrade Phase 1	Pt. Aconi	Point Aconi Generating Station	199,397	199,397
49493	POA Reheat Bypass Actuator Upgrade	Pt. Aconi	Point Aconi Generating Station	198,749	198,749
50142	POA Frontwall Pipe Replacement	Pt. Aconi	Point Aconi Generating Station	189,061	189,061

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

CI#	Project Long Title	ACE Filing Type	Major Location	2017 ACE	Project Total
49496	POA Lime Stone Fan Replacement	Pt. Aconi	Point Aconi Generating Station	160,124	160,124
49471	POA Expansion Joint Replacement	Pt. Aconi	Point Aconi Generating Station	147,883	147,883
49486	POA Cable Spreading Room Fire Stop	Pt. Aconi	Point Aconi Generating Station	145,788	145,788
50143	POA BA Center Drain Valve Replacement	Pt. Aconi	Point Aconi Generating Station	134,194	134,194
49472	POA Valve Component Replacement	Pt. Aconi	Point Aconi Generating Station	126,391	126,391
50131	POA Coal Cracker Refurbishment	Pt. Aconi	Point Aconi Generating Station	111,286	111,286
27858	POA-ROOFING ROUTINE	Pt. Aconi	Point Aconi Generating Station	110,759	110,759
49481	POA Plant Access Replacement	Pt. Aconi	Point Aconi Generating Station	105,315	105,315
49474	POA Coal System Guard Upgrade Phase 3	Pt. Aconi	Point Aconi Generating Station	91,943	91,943
49484	POA Diesel Generator Controls Upgrade	Pt. Aconi	Point Aconi Generating Station	82,646	82,646
49491	POA ISO Phase Buss Temperature Monitor	Pt. Aconi	Point Aconi Generating Station	72,009	72,009
43243	POA - Wellfield Communication	Pt. Aconi	Point Aconi Generating Station	65,673	69,766
49495	POA 4160v Motor Refurbishment	Pt. Aconi	Point Aconi Generating Station	67,125	67,125
49492	POA 4KV 600V Breaker Refurbishment	Pt. Aconi	Point Aconi Generating Station	63,924	63,924
33865	POA - Heat Rate Routine	Pt. Aconi	Point Aconi Generating Station	44,725	44,725
47703	POT - Replace DCS servers	Carryover	Point Tupper Generating Station	37,337	199,151
43386	POT - LP dosing automation	Carryover	Point Tupper Generating Station	11,407	30,454
49467	POT - SSC refurbishment	Less than $250k	Point Tupper Generating Station	142,988	142,988
49519	POT - Asbestos management 2017	Less than $250k	Point Tupper Generating Station	213,811	213,811
49279	POT - Bay door replacements 2017	Less than $250k	Point Tupper Generating Station	98,378	98,378
43033	POT - Breaker replacements and refurbishments	Less than $250k	Point Tupper Generating Station	67,757	67,757
49464	POT - E Coal Conveyor Refurbishment	Less than $250k	Point Tupper Generating Station	103,388	103,388
49514	POT - LP heaters level controls	Less than $250k	Point Tupper Generating Station	79,992	79,992
49420	POT - Plant siding 2017	Less than $250k	Point Tupper Generating Station	211,116	211,116
49512	POT - PLC Migration - Coal system	Less than $250k	Point Tupper Generating Station	125,038	125,038
49510	POT - Refurbish travelling screens and replace panels	Less than $250k	Point Tupper Generating Station	98,297	98,297
49511	POT - Replace ID fan damper drives	Less than $250k	Point Tupper Generating Station	92,186	92,186
49515	POT - Replacement of Graver valves and solenoids	Less than $250k	Point Tupper Generating Station	59,496	59,496
44587	POT - Selective Ash Site Capping	Less than $250k	Point Tupper Generating Station	76,971	76,971
49897	POT - Fire System Upgrades 2017	Request Approval	Point Tupper Generating Station	538,437	538,437
47687	POT Boiler Chemical Recondition	Request Approval	Point Tupper Generating Station	794,560	974,604
49419	POT Boiler Refurbishment 2017	Request Approval	Point Tupper Generating Station	969,292	969,292
49463	POT Coal Mill Overhauls 2017	Request Approval	Point Tupper Generating Station	328,410	328,410
10645	POT - Routine Equipment Replacements	Routine	Point Tupper Generating Station	266,813	266,813
27855	POT-ROOFING ROUTINE	Routine	Point Tupper Generating Station	163,963	163,963
33867	POT - Heat Rate Routine	Routine	Point Tupper Generating Station	84,967	84,967
49111	POT - Air heater refurbishment	Subsequent Submittal	Point Tupper Generating Station	462,168	471,204
49060	POT - Condenser Dog Bone Expansion Joint Replacement	Subsequent Submittal	Point Tupper Generating Station	298,253	298,253
49502	PHB - Fire Suppression Expansion	Less than $250k	Port Hawkesbury Biomass	65,599	65,599
49500	PHB - Fuel System Refurbishment 2017	Less than $250k	Port Hawkesbury Biomass	178,127	178,127
49501	PHB - Selective Turbine Valve Refurbishment	Less than $250k	Port Hawkesbury Biomass	160,479	160,479
43646	PHB - Routine Equipment Replacements	Routine	Port Hawkesbury Biomass	170,000	170,000
45206	PHB - Roofing Routine	Routine	Port Hawkesbury Biomass	98,675	98,675
49499	PHB - Boiler Refurbishment 2017	Subsequent Submittal	Port Hawkesbury Biomass	484,730	484,730
48868	AMO Fleet TWIP Upgrades	Subsequent Submittal	Steam General	257,442	280,608
46499	Stator Rewind Kit Capital Spare	Subsequent Submittal	Steam General	2,668,808	5,219,939
49516	PTMT - Fire system refurbishment	Less than $250k	Strait Marine Terminal	109,189	109,189
49517	PTMT - Replace Dock Transformer	Less than $250k	Strait Marine Terminal	65,784	65,784
49466	PTMT - Dock and Inhaul Conveyor Replacement	Request Approval	Strait Marine Terminal	467,607	467,607
44267	TRE Ash Lagoon Site Closure	Carryover	Trenton Generating Station	2,759,566	9,140,761
46434	TRE6 Coal Pile Reclaim Markers	Carryover	Trenton Generating Station	92,888	233,412
47593	TRE Dechlorination System	Carryover	Trenton Generating Station	25,179	226,054
49553	TRE Asbestos Abatement 2017	Less than $250k	Trenton Generating Station	226,451	226,451
49554	TRE Ash Site Management 2017	Less than $250k	Trenton Generating Station	157,989	157,989
49556	TRE Excavator GPS System	Less than $250k	Trenton Generating Station	129,416	129,416
47602	TRE Oil Forwarding Pump Area Fire Protection	Less than $250k	Trenton Generating Station	157,695	157,695
49547	TRE5 5-1 BFP Refurbishment	Less than $250k	Trenton Generating Station	185,294	185,294
49549	TRE5 5-3 Mill Refurbishment	Less than $250k	Trenton Generating Station	180,147	180,147
49551	TRE5 CEMS Replacement	Less than $250k	Trenton Generating Station	162,647	162,647
49544	TRE5 Conveyor Refurbishments	Less than $250k	Trenton Generating Station	78,098	78,098
49545	TRE5 DCS Server Upgrade	Less than $250k	Trenton Generating Station	200,031	200,031
49550	TRE5 FW Heater Level Controls	Less than $250k	Trenton Generating Station	169,776	169,776
49542	TRE5 Main Boiler Stop Valves Rebuild	Less than $250k	Trenton Generating Station	205,883	205,883
49921	TRE6 6-4, 6-5, 6-6 Feedwater Heater Refurbishments	Less than $250k	Trenton Generating Station	110,358	110,358
49541	TRE6 6B Hydrogen/Water/Water Cooler Replacement	Less than $250k	Trenton Generating Station	207,072	207,072
49540	TRE6 6C Hydrogen/Water/Water Cooler Replacement	Less than $250k	Trenton Generating Station	208,260	208,260
49539	TRE6 Burner Automation System Replacement	Less than $250k	Trenton Generating Station	207,072	207,072
49558	TRE6 Bus Bar Repairs/IR Windows	Less than $250k	Trenton Generating Station	62,478	62,478
49557	TRE6 Coal Feeder Gauge Replacements	Less than $250k	Trenton Generating Station	78,098	78,098
49543	TRE6 Conveyor Refurbishments	Less than $250k	Trenton Generating Station	130,163	130,163
47642	TRE6 Feeder Controls Upgrade	Less than $250k	Trenton Generating Station	171,040	171,040
49546	TRE6 FW Heater Level Control	Less than $250k	Trenton Generating Station	187,434	187,434
49536	TRE5 Boiler Refurbishments 2017	Request Approval	Trenton Generating Station	717,589	717,589
41511	TRE6 - Condenser Waterbox and Cooling Water Piping Refurbishment	Request Approval	Trenton Generating Station	700,809	700,809
49532	TRE6 Air Heater Refurbishment	Request Approval	Trenton Generating Station	1,428,236	1,428,236
49537	TRE6 Analytical Panel Upgrade	Request Approval	Trenton Generating Station	438,216	438,216
49533	TRE6 Boiler Refurbishment	Request Approval	Trenton Generating Station	1,259,454	1,259,454
47597	TRE6 Bottom Ash Chain Replacement	Request Approval	Trenton Generating Station	793,792	793,792
49057	TRE6 Excitation System Replacement	Request Approval	Trenton Generating Station	474,066	904,011
49535	TRE6 Mills Refurbishment 2017	Request Approval	Trenton Generating Station	822,141	822,141
10673	TRE - Routine Equipment Replacements	Routine	Trenton Generating Station	377,929	377,929
27856	TRE-ROOFING ROUTINE	Routine	Trenton Generating Station	100,000	100,000

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

CI#	Project Long Title	ACE Filing Type	Major Location	2017 ACE	Project Total
33869	TRE - Heat Rate Routine	Routine	Trenton Generating Station	80,000	80,000
49538	TRE6 Generator Refurbishment	Subsequent Submittal	Trenton Generating Station	411,766	411,766
47553	TRE6 Turbine Main Valves	Subsequent Submittal	Trenton Generating Station	392,887	392,887
47531	TRE6 Turbine Refurbishments	Subsequent Submittal	Trenton Generating Station	1,500,000	2,322,487
49684	TUC 4kv/600V Breaker Replacement	Less than $250k	Tufts Cove Generating Station	232,694	232,694
49662	TUC Aquarian Migration	Less than $250k	Tufts Cove Generating Station	48,757	48,757
49716	TUC Asbestos Abatement	Less than $250k	Tufts Cove Generating Station	222,812	222,812
49653	TUC Dehumidifier Air Unit	Less than $250k	Tufts Cove Generating Station	51,073	51,073
49680	TUC Heavy/Light Oil Pump Area Fire Protection	Less than $250k	Tufts Cove Generating Station	143,448	143,448
49693	TUC HFO Piping Refurbishments	Less than $250k	Tufts Cove Generating Station	219,022	219,022
49711	TUC Low Load Oil Operation, Flue Gas monitoring	Less than $250k	Tufts Cove Generating Station	130,429	130,429
47909	TUC Nat Gas Valves Refurbishment	Less than $250k	Tufts Cove Generating Station	54,153	54,153
49663	TUC Nitrogen Generator	Less than $250k	Tufts Cove Generating Station	74,658	74,658
49695	TUC Paint Roofs of HFO Storage Tank 2&4	Less than $250k	Tufts Cove Generating Station	81,390	81,390
49654	TUC Refurbishment Gas Compressor 6A/6B	Less than $250k	Tufts Cove Generating Station	133,870	133,870
49715	TUC Upgrade PLC Control Panel	Less than $250k	Tufts Cove Generating Station	99,875	99,875
46485	TUC1 - Gas Block Valves	Less than $250k	Tufts Cove Generating Station	98,418	127,619
49670	TUC1 4kv/600V Breaker Replacement	Less than $250k	Tufts Cove Generating Station	104,851	104,851
49991	TUC1 CEMS Replacement	Less than $250k	Tufts Cove Generating Station	159,167	159,167
49673	TUC1 Extraction Pump Rotork Valve Actuator	Less than $250k	Tufts Cove Generating Station	48,479	48,479
49667	TUC1 Oil Purifier I&C Heater Replacement	Less than $250k	Tufts Cove Generating Station	160,593	160,593
49671	TUC1 Rotating Element Extraction Pump Refurbishment	Less than $250k	Tufts Cove Generating Station	60,000	60,000
49666	TUC1 South Boiler Feedpump Refurbishment	Less than $250k	Tufts Cove Generating Station	226,025	226,025
49681	TUC2 Boiler Modulation Control Upgrades	Less than $250k	Tufts Cove Generating Station	79,641	79,641
49683	TUC2 Bus Bar Inspection/Repair IR Windows	Less than $250k	Tufts Cove Generating Station	57,644	57,644
49676	TUC2 CEMS Replacement	Less than $250k	Tufts Cove Generating Station	150,374	150,374
49708	TUC2 HEP/FAC Surveys	Less than $250k	Tufts Cove Generating Station	125,409	125,409
49682	TUC2 HP Heater Level Controls	Less than $250k	Tufts Cove Generating Station	105,984	105,984
47903	TUC2 Lube Oil Coolers' Inlet/Outlet Waterbox Replacement	Less than $250k	Tufts Cove Generating Station	54,494	54,494
49677	TUC2 Replace Bailey Control Valves	Less than $250k	Tufts Cove Generating Station	156,173	156,173
49709	TUC2 Replace Coils	Less than $250k	Tufts Cove Generating Station	116,612	116,612
49697	TUC2 Replace Oil Purifier I&C Heater	Less than $250k	Tufts Cove Generating Station	135,621	135,621
49678	TUC2 Replace Secondary Air Damper Drives	Less than $250k	Tufts Cove Generating Station	130,404	130,404
49688	TUC3 Analytical Panel Upgrades	Less than $250k	Tufts Cove Generating Station	55,050	55,050
49686	TUC3 Boiler Modulation Control Upgrade	Less than $250k	Tufts Cove Generating Station	80,024	80,024
49705	TUC3 Bus Bar IR Windows	Less than $250k	Tufts Cove Generating Station	52,995	52,995
49687	TUC3 Bus Duct/Gen Terminal Monitoring System	Less than $250k	Tufts Cove Generating Station	64,674	64,674
49672	TUC3 Feedwater Valve Replacement	Less than $250k	Tufts Cove Generating Station	232,799	232,799
49689	TUC3 HP Heater Level Controls	Less than $250k	Tufts Cove Generating Station	106,055	106,055
49704	TUC3 Replace Coils	Less than $250k	Tufts Cove Generating Station	137,236	137,236
49699	TUC6 Access Doors	Less than $250k	Tufts Cove Generating Station	64,304	64,304
45832	TUC6 Boiler Purge Credit	Less than $250k	Tufts Cove Generating Station	138,577	138,864
49701	TUC6 Turbine Control Valves	Less than $250k	Tufts Cove Generating Station	50,584	50,584
49700	TUC6 Vacuum Cooler	Less than $250k	Tufts Cove Generating Station	54,610	54,610
47907	TUC6 Vacuum Pumps' Seal Water Cooler Upgrade	Less than $250k	Tufts Cove Generating Station	40,501	40,501
49675	TUC2 Cooling Water Piping Refurbishment	Request Approval	Tufts Cove Generating Station	568,673	568,673
49707	TUC2 High Voltage Bushing	Request Approval	Tufts Cove Generating Station	440,082	440,082
47893	TUC3 PE Generator Hydrogen Panel Replacement	Request Approval	Tufts Cove Generating Station	421,182	423,798
10621	TUC - Routine Equipment Replacements	Routine	Tufts Cove Generating Station	327,423	327,423
27854	TUC-ROOFING ROUTINE	Routine	Tufts Cove Generating Station	63,228	63,228
33871	TUC - Heat Rate Routine	Routine	Tufts Cove Generating Station	47,690	47,690
49674	TUC2 Boiler Selective Waterwall Tube Replacements	Subsequent Submittal	Tufts Cove Generating Station	390,898	390,898
48893	TUC3 IP Turbine Refurbishment	Subsequent Submittal	Tufts Cove Generating Station	4,338,274	4,798,475
46191	Tusket Fuel System Upgrade	Carryover	Tusket Combustion Turbine	69,934	934,223
49973	CT - TUS Control Room Halon Replacement	Less than $250k	Tusket Combustion Turbine	84,304	84,304
49961	CT - TUS Exhaust Stack Grating Replacement	Less than $250k	Tusket Combustion Turbine	25,205	25,205
10634	CT - Routine Equipment Replacements	Routine	Tusket Combustion Turbine	144,000	144,000
47118	CT Tusket Hydraulic Starter	Subsequent Submittal	Tusket Combustion Turbine	317,015	317,015
49936	CT - VJ 2 Enclosure Coating Refurbishment	Less than $250k	Victoria Junction Combustion Turbine	57,550	57,550
49960	CT - VJ Exhaust Stack Grating Replacement	Less than $250k	Victoria Junction Combustion Turbine	41,500	41,500
49959	CT - VJ Varec Gauges Upgrade/Refurbishment	Less than $250k	Victoria Junction Combustion Turbine	29,904	29,904
49935	CT - VJ1 Enclosure Coating Refurbishment	Less than $250k	Victoria Junction Combustion Turbine	55,933	55,933

Request IR-51:

Please provide a table listing the work NSPI plans to complete on hydro generation assets in 2017 and beyond, such as the one provided in the response to 2016 ACE Plan UARB IR-47(g). Please include an estimated cost for each project, if available.

Response IR-51:

Please refer to Attachment 1. Detailed estimates are still being developed for projects on the 2017 ACE Plan subsequent submittal list, and are "order of magnitude" only for 2018 and beyond.

Future Capital Work Planning

Ser	River System	CI #	Project Title	Planned Year				
				2017	2018	2019	2020	2021
1	Annapolis	49214	HYD - Annapolis Septic Replacement	$ 141,000				
2	Annapolis	47650	HYD - Annapolis Overhaul			$ 8,000,000		
3	Annapolis	48052	HYD - Annapolis HVAC Upgrade	$ 1,500,000				
4	Avon	49036	HYD - AVO Controls Upgrade			$ 750,000		
5	Bear River	49037	HYD - BER Controls Upgrade		$ 400,000	$ 400,000		
6	Bear River	47654	HYD - Gulch Surge Tank/ Pipeline Replacement	$ 2,500,000				
7	Bear River	47652	HYD - Ridge Surge Tank Refurbishment			$ 1,500,000		
8	Bear River	48631	HYD - Gulch Spillway Refurbishment		$ 400,000			
9	Black River	49596	HYD - Hells Gate 2 Overhaul	$ 1,000,000				
10	Black River	16374	HYD - Gaspereau Lake Dam	$ 6,000,000				
11	Black River	47649	HYD - Salmon Tail Gate Pedistal Replacement		$ 300,000			
12	Black River		HYD - Hells Gate Butterfly Valve Replacement					
13	Black River		HYD - Hells Gate Surge Tank Refurbishment				$ 2,400,000	
14	Black River		HYD - Lumsden Stator Rewind			$ 600,000		
15	Black River		HYD - BLK Contols Upgrade			$ 1,000,000	$ 1,000,000	
16	Black River		HYD - Methals Dam Refurb			$ 1,000,000		
17	Black River		HYD - White Rock Canal Refurb			$ 1,500,000		
18	Dickie Brook	47660	HYD - DIB Controls Upgrade	$ 100,000	$ 300,000			
19	Dickie Brook	49944	HYD - Penstock Recoating		$ 450,000			
20	Fall River	47659	HYD - FAR Controls Upgrade	$ 50,000	$ 200,000			
21	Fall River		HYD - PE Miller Lake Dam Refurbishment			$ 1,000,000		
22	Harmony	38931	HYD - PE Harmony partial Decommissioning	$ 600,000				
23	Hydro	47166	HYD - MacAskils Brook Dam Decommissioning	$ 400,000				
24	Hydro	47678	HYD - Prince Mine Dam Decommissioning	$ 400,000				
25	Hydro	11622	HYD - Equipment Replacement (H001)	$ 700,000	$ 700,000	$ 700,000	$ 700,000	$ 700,000
26	Hydro	11611	HYD - Hydro Production Tools, Test Equipment (P015)	$ 90,000	$ 90,000	$ 90,000	$ 90,000	$ 90,000
27	Hydro	48396	HYD - Bridge Improvements	$ 250,000	$ 250,000			
28	Hydro	48712	HYD - Dam Instrumentation Upgrade	$ 400,000				
29	Hydro	49835	HYD - HYD Dive Access Improvements	$ 250,000				
30	Hydro		HYD - Overhaul		$1,000,000			
31	Hydro		HYD - Overhaul		$1,000,000			
32	Hydro		HYD - Overhaul			$ 1,000,000		
33	Hydro		HYD - Overhaul			$ 1,000,000		
34	Hydro		HYD - Overhaul			$ 1,000,000		
35	Hydro		HYD - Overhaul				$ 1,000,000	
36	Hydro		HYD - Overhaul				$ 1,000,000	
37	Hydro		HYD - Overhaul				$ 1,000,000	
38	Hydro		HYD - Overhaul					$ 1,000,000
39	Hydro		HYD - Overhaul					$ 1,000,000
40	Hydro		HYD - Overhaul					$ 1,000,000
41	Hydro	35584	HYD - Gate Refurbishment Routine (H006)	$ 190,000	$ 190,000	$ 190,000	$ 190,000	$ 190,000
42	Hydro	35583	HYD - Oil Release Risk Assessment Remediation (H005)	$ 200,000	$ 200,000	$ 200,000	$ 50,000	$ 50,000
43	Hydro	27867	HYD - Roofing Routine (H004)	$ 150,000	$ 150,000	$ 150,000	$ 150,000	$ 150,000
44	Hydro	20706	HYD - Security Improvements (P012)	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
45	Hydro		HYD - Dam Deficiency Refurb					$ 1,500,000
46	Hydro		HYD - Dam Deficiency Refurb					$ 1,500,000
47	Hydro		HYD - Dam Deficiency Refurb					$ 1,500,000
48	Lequille	46296	HYD - Main Dam and Spillway Refurbishment	$ 2,500,000				
49	Lequille	49039	HYD - Lequille Controls Upgrade	$ 400,000				
50	Lequille	47876	HYD - Lequille Overhaul	$ 1,000,000				
51	Lequille	47648	HYD - Lequille Pipeline Replacement	$ 1,600,000				
52	Lequille	47682	HYD - Lequille Switchgear Replacement	$ 900,000				
53	Lequille	46253	HYD - Lequille Tailrace Gate sturcture	$ 300,000				
54	Mersey	47091	HYD - Big Falls Dam Refurbishment					
55	Mersey		HYD - Dam Deficiency Refurb (Mersey)		$2,000,000	$ 2,000,000		
56	Mersey	47092	HYD - Dam Deficiency Refurb (Mersey)			$ 2,000,000	$ 2,000,000	
57	Mersey	45957	HYD - Dam Deficiency Refurb (Mersey)				$ 2,000,000	$ 2,000,000
58	Mersey		HYD - Dam Deficiency Refurb (Mersey)					$ 2,000,000
59	Milton	48774	HYD - Hydro Shop HVAC Upgrades	$ 564,347				
60	Nictaux	39800	HYD - PE Scragg Lake Dam - Dam Safety	$ 1,000,000				
61	Nictaux		HYD - Nictaux Canal Embankment	$ 1,000,000				
62	Nictaux		HYD - Nictauc Main Dam Refurb			$ 1,500,000		
63	Paradise	47655	HYD - PAR Controls Upgrade	$ 100,000	$ 400,000			
64	Paradise		HYD - Paradise Surge Tank Refurbishment					$ 2,200,000
65	Paradise	46297	HYD - Neives Lake Dam Refurbishment				$ 1,000,000	
66	Roseway	38927	HYD - PE Roseway Re-development		$ 400,000			
67	Sheet Harbour		HYD -Ruth Main Dam Refurbishment		$4,000,000			
68	Sheet Harbour	48914	HYD - Malay Falls Facility Repairs	$ 400,000				
69	Sheet Harbour	12079	HYD - Ruth Falls 1 and 2 Runner Replacement	$ 450,000				
70	Sheet Harbour	49945	HYD - Malay Falls Switchgear Replacement		$2,000,000			
71	Sheet Harbour	49943	HYD - Ruth Falls Facility Repairs		$ 400,000			
72	Sheet Harbour		HYD - Ruth Falls Switchgear Replacement			$ 2,000,000		
73	Sheet Harbour	49756	HYD - Marshall Falls Dam Refurbishment			$ 3,500,000		
74	Sheet Harbour	44668	HYD - Ruth Falls 2 Stator Rewind				$ 600,000	
75	Sheet Harbour		HYD - Anti Dam Refurbishment				$ 1,000,000	

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76	Sissiboo	44596	HYD - Sissiboo Falls Dam Refurbishment		$2,500,000			
77	Sissiboo	43125	Fourth Lake Butterfly Valve Actuator Replacement		$ 130,000			
78	Sissiboo	43127	HYD - 4th Lake Penstock Refurbishment		$ 500,000			
79	Sissiboo		PE Sissiboo Falls Headgate Refurbishment		$1,000,000			
80	Sissiboo		PE Weymouth Falls #1 and #2 Headgate Refurbishment and Hoist Replacement			$ 2,000,000		
81	Sissiboo		HYD - SIS Controls Upgrade		$ 400,000	$ 1,100,000		
82	Sissiboo		HYD - 4th Lake Wing dam 3 Spillway refurb				$ 1,000,000	
83	St Margaret's Bay	46254	HYD - Mill Lake Surge Tank Replace		$2,500,000			
84	St Margaret's Bay	49942	HYD - Tidewater Facility Repairs		$ 700,000			
85	St Margaret's Bay		HYD - STM Controls Upgrade			$ 400,000	$ 1,100,000	
86	Tusket	48397	HYD - Mink Lake Dam Repair	$ 200,000				
87	Tusket	47163	HYD - TUS Controls Upgrade	$ 800,000				
88	Tusket	48913	HYD - Tusket Facility Repairs	$ 400,000				
89	Tusket	49595	HYD - Tusket No 1 Overhaul		$1,000,000			
90	Wind	41830	WND - Wind Routine (W001)	$ 100,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000
91	Wreck Cove	48536	HYD - WRC D9 Refurbishment		$1,000,000			
92	Wreck Cove		HYD - D5, D61, D62, D10, D11 remedial works		$3,000,000			
93	Wreck Cove	49598	HYD - Gisborne Switchgear Replacement	$ 750,000				
94	Wreck Cove		HYD - WRC HVAC Upgrades		$ 750,000			
95	Wreck Cove	48791	HYD - WRC Life Safety Upgrades		$2,000,000			
96	Wreck Cove		HYD - Plant Lighting Upgrades		$ 300,000			
97	Wreck Cove		HYD - WRC Unit 1 Overhaul			$ 5,000,000		
98	Wreck Cove	37702	PE - Wreck Cove Overhaul (LEM)			$15,000,000	$15,000,000	$15,000,000
99	Wreck Cove	49033	HYD - Wreck Cove Civil LEM			$ 2,500,000	$ 2,500,000	$ 2,500,000
100	Wreck Cove		HYD - WRC Unit 1 Switchgear Replacement			$ 2,000,000		
101	Wreck Cove		HYD - WRC Unit 2 Overhaul				$ 5,000,000	
102	Wreck Cove		HYD - WRC Unit 2 Switchgear Replacement				$ 2,000,000	

Ser	River System	CI #	Project Title	Comments
1	Bear River	47432	HYD - Ridge Overhaul	Complete
2	Wind	47175	WIN - Haight's Brook Bridge Widening	Complete
3	Mersey	45189	Upper Lake Falls unit # 2 Overhaul	Deferred
4	Nictaux		HYD - PE Curl Hole Lake Dam - Dam Safety	Deferred
5	Nictaux	39799	HYD - PE MacGill Lake Dam - Dam Safety	Deferred
6	Sheet Harbour	48020	HYD - RUT 3 Generator Refurbishment	Complete
7	Sissiboo	17581	HYD - Weymouth Falls Electrical Refurbishment	Complete
8	Sissiboo	20571	HYD - Weymouth Falls Tailrace Deck Refurbishme	Complete
9	Hydro	47651	HYD - Maccan spillway study	Cancelled
10	Mersey	45957	HYD - LLF Sluiceway Repair	Complete
11	Nictaux	47396	HYD - Nictaux Powerhouse Dam Refurb	Complete
12	Sissiboo	43136	HYD - Weymouth Headcover Replace	Complete
13	Sheet Harbour	44668	HYD - Ruth Falls 2 Stator Rewind	Deferred
14	Sissiboo	43125	Fourth Lake Butterfly Valve Actuator Replacement	Deferred
15	St Margaret's Bay	46298	HYD - 5 Mile Dam Refurb	Complete
16	St Margaret's Bay	45888	HYD - Mill Lake Unit 1 Refurbishment	Deferred
17	St Margaret's Bay	47167	HYD - Sandy Lake Surge Tank Replace	Complete
18	Wreck Cove	45330	HYD - WRC C3 Culvert Replacement	Complete
19	Wreck Cove	47397	HYD - Gisborne Dam D4 Upgrade	Complete

Request IR-52:

With respect to G01 (CI 48535 – Scragg Lake Dam and Spillway Refurbishment):

(a) The noted "Start Date" of this project was December 2015. Please describe the work completed in 2015 and 2016, and the related spending.

(b) Please confirm whether the depreciation class is identified in error, and if so please identify the correct depreciation class.

(c) According to "Capital Project Detailed Estimate", cost estimates related to Power Production Contracts are based on the costs incurred for CI 20758. Please explain why this item is considered a "similar" project, and elaborate on the estimated accuracy level of these cost estimates.

(d) With respect to "Capital Project Detailed Estimate", please describe the process that was, or will be used, to award Power Production Contracts.

Response IR-52:

(a) The Request for Proposal (RFP) process was started in December 2015 for the engineering design portion of the project. The design work was awarded in March 2016 and the design work was undertaken throughout the remainder of 2016. $68,130 has been spent as of November 30, 2016 on the design phase.

(b) Yes, the depreciation class is incorrect. The correct depreciation class is Hydraulic Production Plant, Nictaux River Hydro.

(c) CI 20758 would be considered a similar project, when used in developing a part of the cost estimate, as CI 48535 as mobilization, water controls, environmental controls, concrete and earthworks costs are items that may have similarities from site to site. Baseline costs are typically developed by using historical unit costs and information from project sites that have similar types of construction activities, i.e. concrete works or earthworks. In addition to the location of the sites, both projects include the construction of concrete structures, and the haulage and placement of earth fill material for the embankment sections. Unit costs for construction items are estimated based on costs incurred in on-going or completed projects, such as CI 20758 to determine certain cost estimates. Since the cost estimates are typically based on conceptual level designs for unit quantities, the estimated level of accuracy is +/- 10% to 20%.

(d) The Power Production Contract will be awarded based on a RFP process. Contractors will be invited to submit a proposal for undertaking the proposed work. The proposals will be evaluated and a preferred contractor will be selected based on the information provided in their submission including, scope of work, adherence to RFP requirements, costs and personnel.

Request IR-53:

With respect to G02 (CI 48631 – Gulch Spillway Refurbishment):

(a) It appears this capital item was not included in the table showing planned hydro capital work for 2016 and beyond, provided in the response to 2016 ACE Plan UARB IR-47(g). If so, please explain why?

(b) Could the economic considerations related to other projects, planned for the next several years on this hydro system, have any impact on the scope of work for this project? Please elaborate.

Response IR-53:

(a) This item was not included in the table. A site visit and concrete investigation carried out after the 2016 ACE Plan proceedings revealed that the concrete deterioration was greater than originally determined, and therefore the project was subsequently added to the 2017 ACE Plan.

(b) No, this project is being completed due to Dam Safety considerations and is not being completed based on economics. This system will be operated well into the future therefore this spillway refurbishment must be completed.

Request IR-54:

With respect to G03 (CI 49532 – TRE6 - Air Heater Refurbishment):

(a) What is the normal life expectancy of the air heater components that will be replaced as part of this capital item?

(b) What is the normal life expectancy of the air heater components that were replaced as part of CI 46300, TRE6 - Air Heater Refurbishment?

(c) Have all the above components reached the end of their originally expected service life before being replaced? If not, please elaborate.

Response IR-54:

(a) The air heater components to be replaced in this project include the hot end, intermediate and cold end baskets, support grids, axial seals and miscellaneous mechanical systems related to the Trenton Unit 6 air heaters. The life expectancy of the baskets and support grids is 8 to 10 years and the life expectancy of the axial seals is 6 to 8 years based on plant experience and consultation with the OEM. The normal life expectancy of the sector plates is 20 to 25 years and seals are 4 to 5 years. These life expectancies will vary with the fuel type, unit load, and frequency of soot blowing.

(b) In 2015, the hot and cold end sector plates were replaced, along with several seal components (circumferential seals, stationary T-bar seal surfaces, rotor post seals and guide bearing shaft seal assemblies). The normal life expectancy of the sector plates is 20 to 25 years and the seals are generally 4 to 5 years based on plant experience and consultation with the original equipment manufacturer.

(c) All of the air heater components that will be replaced as part of this capital item have reached the end of their expected service life. The baskets were last replaced in 2004 (cold end) and 2005 (hot/intermediate end), bringing the service life to 12 to 13 years, which is beyond the expectancy of 8 to 10 years.

Request IR-55:

With respect to G05 (CI 47687 – POT Boiler Chemical Recondition), NSPI determined a deferral of this project was not economically justified. Please show and explain the calculation that led to the conclusion that a one year delay in the initiation of this project is not economically justified.

Response IR-55:

Based on a boiler tube condition assessment, an estimated annual tube failure rate was used in the economic model that resulted in a payback period of 1.9 years. As can be seen in the electronic filing of the project EAM, NS Power assumed four tube leaks would occur in 2017 if this project is not completed. The avoided replacement energy costs associated with these tube failures outweigh the capital costs incurred in 2017 from completing this work. Delaying this project by one year is not feasible due to the sensitivity of corrosion rate analysis. Metallurgical analysis was conducted and revealed an active corrosion mechanism that required mitigation by chemical reconditioning. A third party industry expert was engaged who recommended reconditioning the unit during the next planned outage period to prevent unplanned outages and the associated replacement energy costs.

Request IR-56:

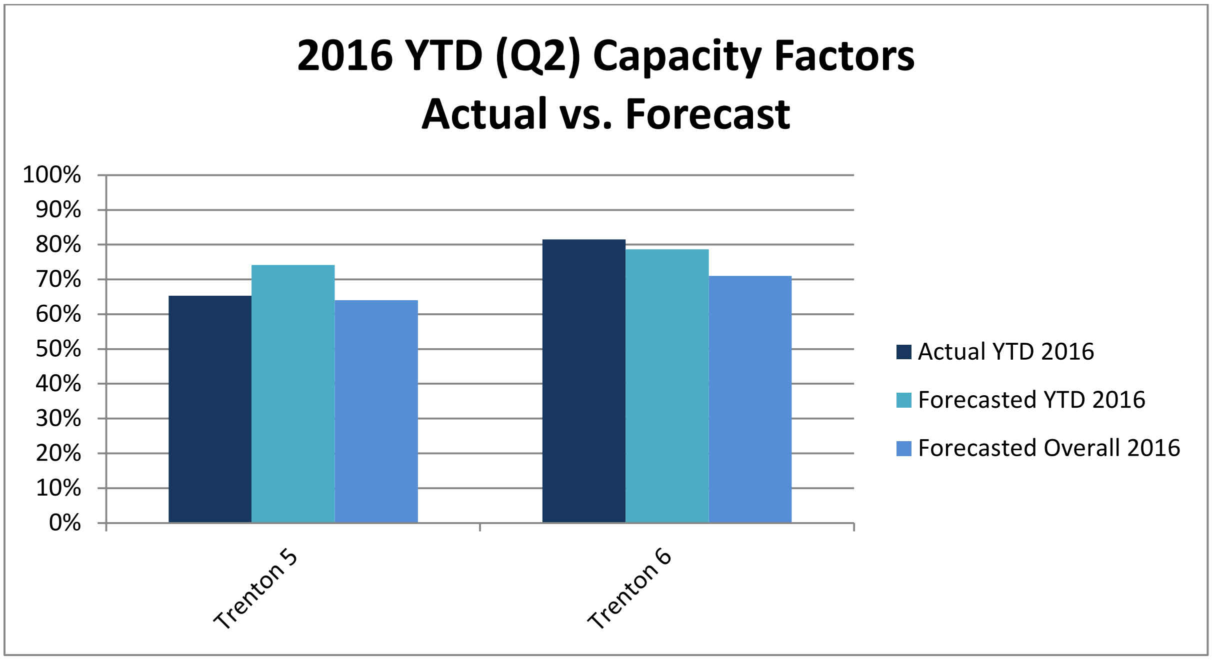
With respect to G07 (CI 49536 – TRE5 Boiler Refurbishments 2017):

(a) Please compare the actual and planned utilization levels, as well as the scopes of boiler refurbishments of TRE5, with the TRE6 unit.

(b) Did the actual and planned annual utilization levels of the TRE5 unit have any effect on the frequency and scope of the work related to boiler refurbishments? If so, please elaborate.

Response IR-56:

(a) The figure below shows the actual and planned utilization levels of Trenton 5 and 6 for 2016. The scopes of the Boiler Refurbishment projects are determined as part of the boiler condition assessments. Trenton 5 is forecasted to require 8 tube cut-outs and Trenton 6 will require 40 tube cut-outs. Both units will require shielding and pad welding at high erosion zones. Work scope may be modified based on inspection at time of outages.



(b) Unit Utilization is always considered when developing boiler refurbishment projects. The unit utilization factor determines the mitigating approach for an identified risk. For example, Lingan 2 and Lingan 4 could have different mitigating measures for the same identified risk due to the fact that Lingan 2 has limited forecasted operating hours. With respect to Trenton 5, the difference between the actual and planned utilization for 2016 is not substantial so it did not have any effect on the frequency and scope of the work related to boiler refurbishments in 2017.

Request IR-57:

With respect to G13 (CI 47893 – TUC3 PE Generator Hydrogen Panel Replacement), please provide support of the cost estimate for Hydrogen Control Panel in the amount of $250,000.

Response IR-57:

The $250,000 for the Hydrogen Control Panel is an estimate by NS Power engineering based on prior discussions with vendors of this product and the industry knowledge of NS Power engineering. NS Power is confident in the estimate for this equipment.

Request IR-58:

With respect to G14 (CI 49535 – TRE6 Mills Refurbishment 2017), please explain the 23.6% increase in the cost of this project compared with the 2015 TRE6 Mills Refurbishment project (CI 46301).

Response IR-58:

The difference in cost compared to the 2015 project is due to the requirement to replace two sets of trunnion bearings resulting in an additional material cost of $115,000. Additionally, the actual cost of the 2015 TRE6 Mills Refurbishment project (CI 46301) was higher than the submitted budget by $130,000, which was factored into the budget for the 2017 TRE6 Mills Refurbishment project.

Request IR-59:

With respect to G19 (CI 49897 – POT Fire System Upgrades 2017), please provide a copy of NSPI's recent "Multi-Year Fire Protection Plan".

Response IR-59:

Please refer to Attachment 1 for the five year Fire Protection capital investment plan**.**

FIRE PROTECTION MULTIYEAR PLAN

NSPI	Revision Control								
	Release Date:	2-Jun-2016							

Generating Station	Area	Protection	Estimated Investment Timeframe 2010 - 2015	2016	2017	2018	2019	2020	Current Status
		Annual Total	$4,666,149	$2,099,500	$1,690,000	$1,155,000	$1,150,000	$375,000	
Lingan									
	Unit 1 Turbine - Generator Sprinkler System	Pre-Action Water Sprinkler	**** $300,336						Complete
	Fire System Electrical Panel Upgrades		**** $43,982						Complete
	Fire System Valve Replacement		**** $111,509						Complete
	Unit 1 Burner Front	Wet Automatic Sprinkler	**** $25,000						Complete
	Unit 2 Burner Front	Wet Automatic Sprinkler	**** $25,000						Complete
	Unit 2 Turbine - Generator Sprinkler System	Pre-Action & Wet Automatic Water Sprinkler	**** $245,623						Complete
	Unit 3 Turbine - Generator Sprinkler System	Pre-Action & Wet Automatic Water Sprinkler	**** $303,705						Complete
	Unit 3 Burner Front	Wet Automatic Sprinkler	**** $25,791						Complete
	Unit 4 Burner Front	Wet Automatic Sprinkler	**** $25,791						Complete
	Coal Conveyor - E Belt Repairs	Dry / Refurbishments		$83,000					Complete
	Unit 1/2 Cable Spreading Room Elev. 112.5 m, Area 324 m^2, Volume 1296 m^3. Unit 1/2 Cable Spreading Room Elev. 120.2 m, Area 590 m^2, Volume 1770 m^3. Unit 3/4 Cable Spreading Room Elev. 112.5 m, Area 432 m^2, Volume 1728 m^3. Unit 3/4 Cable Spreading Room Elev. 120.2 m, Area 507 m^2, Volume 1523 m^3. Seal openings at all penetrations in walls & Floors.	VEWFD, Fire Rated sealant	**** $21,193	$100,000					In Progress
	Reclaim / Crusher / Dumper	Dry / Refurbishments	**** $107,128	$150,000					In Progress
	Heavy/Light Oil Forwarding Pump Areas Units 1/2/3/4, and Lube Oil Reservior area.	Automatic Dry-Pilot Deluge Sprinkler, w/curbing	**** $192,669	$25,000					In Progress
	Dumper Building MCC	Monitored Fire Detection System		**** $10,000					In Progress
	Precipitator Houses - Monitored fire protection	Monitored Fire Detection System		**** $35,000					In Progress
	Lube Oil / Pressurized Oil piping	Installation of Spray Fire Shields at potential leak paths / connections.		**** $15,000					Pending
	Stores Area under Mezzanine - Powerhouse on elevation 106	Wet Automatic Sprinkler			**** $75,000				Pending
	The turbine-generator units steel columns Fire protoection.	PE required to determine scope and level of protection. - Sprinklers or fireproofing.				**** $25,000	**** $300,000		Pending
	Diesel / HFO / Light oil supply lines	Installation of Emergency Shut-off valves to limit relase of hydrocarbon. Scope clarification required to determine number and locations of value installations.				**** $75,000			Pending

FIRE PROTECTION MULTIYEAR PLAN

NSPI	Revision Control								
	Release Date:	2-Jun-2016							
		Annual Total	$4,666,149	$2,099,500	$1,690,000	$1,155,000	$1,150,000	$375,000	
Generating Station	Area	Protection	Estimated Investment Timeframe 2010 - 2015	2016	2017	2018	2019	2020	Current Status
Point Aconi									
	Unit 1 Burner Fronts	Wet Automatic Sprinkler	**** $25,000						Complete
	Unit 1 Switch Gear Room Elevation 107.2 m (25 m X 11.2 m X 6 m	Double-Interlock Pre-Action Wet Sprinkler tie	**** $155,785						Complete
	Unit 1 Relay Room Elevation 107.2 m (25 m X 11.2 m X 6 m) Area	Double-Interlock Pre-Action Wet Sprinkler tie	**** $155,785						Complete
	Unit 1 Turbine - Generator Sprinkler System	Double-Interlock Pre-Action Water Sprinkler per NFPA 850. Wet and deluge around Oil hazards, and under turbine pedestal.	**** $379,635						Complete
	Fire Pump Area (suction lines)	Upgrade pipe coupling on each of the fire pump suction lines to metal or braided. Eliminate use of rubber to prevent cracking/leaks/failure.		**** $10,000					In Progress
	Lube Oil / Pressurized Oil piping	Installation of Spray Fire Shields at potential leak paths / connections.		**** $15,000					In Progress
	Address intakes/vents/window in powerhouse walls near transformers.	– system interlock of intakes/vents near transformers with transformer deluge or heat activated systems, OR – Operating Procedure to shut intakes/vents in the event of a transformer fire. AND -Window protection (2hr fire rated or louvered)			**** $60,000				Pending
	Cable Spreading/Relay Room	Firestop / Seal all through wall/ceiling penetrations, to provide fire resistance and smoke barrier.			**** $35,000				Pending
	Seal Oil Tank	Spill containment and fire Protection			**** $50,000				Pending
	Diesel / HFO / Light oil supply lines	Installation of Emergency Shut-off valves to limit relase of hydrocarbon. Scope clarification required to determine number and locations of value installations.				**** $50,000			Pending
	Control Room	Replace Window with Fire Rated pane or install heat activated cover or remove and replace with material with fire rating equal to wall				**** $20,000			Pending

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FIRE PROTECTION MULTIYEAR PLAN

NSPI	Revision Control	
	Release Date:	2-Jun-2016

Generating Station	Area	Protection	Estimated Investment Timeframe 2010 - 2015	2016	2017	2018	2019	2020	Current Status
		Annual Total	$4,666,149	$2,099,500	$1,690,000	$1,155,000	$1,150,000	$375,000	
Point Tupper	Unit 1/2 Cable Spreading Room Elevation (100 m X 5 m X 2.5 m) 1250 cubic metres, 45,000 cubic feet	Pre-Action	**** $91,378						Complete
	Dust Collector	Installed New explosion panels with new hoods. Flashback arrestor valve with explosion detection to DCS, duct upgrades.	**** $300,000						Complete
	Fire Pump Discharge Header (8" in WTP) replacement	Upgrade piping for capacity and reliability.	**** $50,000	$100,000					In Progress
	Replace Fire Pumps - More Capacity		**** $15,000	**** $90,000	**** $450,000				In Progress
	Unit 2 Turbine - Generator Sprinkler System	Pre-Action Water Sprinkler	**** $2,000	**** $15,000		**** $350,000			In Progress
	Lube Oil / Pressurized Oil piping	Installation of Spray Fire Shields at potential leak paths / connections.		**** $15,000					In Progress
	Fire System Electrical Panel Upgrade				**** $35,000				Pending
	Diesel / HFO / Light oil supply lines	Installation of Emergency Shut-off valves to limit relase of hydrocarbon. Scope				**** $50,000			Pending
	Fuel valves at boiler front						**** $50,000		

FIRE PROTECTION MULTIYEAR PLAN

NSPI	Revision Control	
	Release Date:	2-Jun-2016

Generating Station	Area	Protection	Estimated Investment Timeframe 2010 - 2015	2016	2017	2018	2019	2020	Current Status
		Annual Total	$4,666,149	$2,099,500	$1,690,000	$1,155,000	$1,150,000	$375,000	
Trenton									
	Fire System Upgrades		**** $402,000						Complete
	Unit 5 Burner Front	Wet Automatic Sprinkler	**** $47,652						Complete
	Unit 6 Burner Front	Wet Automatic Sprinkler	**** $39,075						Complete
	Unit 6 Turbine - Generator Sprinkler System	Pre-Action Water Sprinkler	**** $297,135						Complete
	Unit 6 4160 Switchgear Cable Spreading Room Elevation 29.8 m (1	Clean Gaseous (Novec 1230, Inergen), Victaulic Vortex or VEWFD with Pre-Action	**** $39,546						Complete
	Unit 6 MCC Cable Spreading Room Elevation 22.7 m (7.6 m X 37.8	Clean Gaseous (Novec 1230, Inergen), Victaulic Vortex or VEWFD with Pre-Action	**** $39,546						Complete
	Unit 5 Turbine - Generator Sprinkler System	Pre-Action Water Sprinkler, and Wet System.	**** $274,706						Complete
	Unit 5 4160 v Switch Gear Cable Area Elev. 57' 6" (100' X 20' X 15') 30,000 cubic feet	VEWFD with Pre-Action							Removed
	Lube Oil / Pressurized Oil piping	Installation of Spray Fire Shields at potential leak paths / connections.		**** $15,000					Pending
	Heavy/Light Oil Forwarding Pump Areas Units	Automatic Sprinkler (Wet or Dry). Possible conversion of existing deluge piping system?			**** $150,000				Pending
	Coal Conveyors	Install interlocks to shutdown conveyor system upon activation of fire protection system.			**** $25,000				Pending
	Unit 5 Relay Room Elev 42 ft (50 ft X 30 ft X 12 ft) 18,000 cubic feet	VEWFD, Fire Rated sealant: Seal all penetrations in walls/ceilings with appropriate firestop.				**** $50,000			Pending
	Unit 5 4160 v Switch Gear Room Elev. 73' 0" (100' X 20' X 15') 30,000 cubic feet	VEWFD, Fire Rated sealant; Seal all penetrations in walls/ceilings with appropriate firestop.				**** $50,000			Pending
	Diesel / HFO / Light oil supply lines	limit relase of hydrocarbon. Scope clarification required to determine number and locations of value installations.				**** $50,000			Pending
	Control Room Air Intake	Consider options to get air intake from outside of building in lieu of STG Hall, to reduce smok ingress during fire in STG.					**** $75,000		Pending
		Consider – system interlock of intakes/vents near					**** $25,000		Pending
	The turbine-generator units steel columns Fire protoection.	PE required to determine scope and level of protection..					**** $25,000	**** $150,000	Pending

FIRE PROTECTION MULTIYEAR PLAN

NSPI

Revision Control		
Release Date:	2-Jun-2016	

Generating Station	Area	Protection	Estimated Investment Timeframe 2010 - 2015	2016	2017	2018	2019	2020	Current Status
		Annual Total	$4,666,149	$2,099,500	$1,690,000	$1,155,000	$1,150,000	$375,000	
Tufts Cove									
	Unit 1 Burner Front	Wet Automatic Sprinkler	**** $18,477						Complete
	Unit 2 Burner Front	Wet Automatic Sprinkler	**** $18,477						Complete
	Unit 3 Burner Front	Wet Automatic Sprinkler	**** $18,477						Complete
	TUC 6 Turbine-Generator and Lube Oil Sprinkler, Transformer Del	Pre Action Water Sprinkler and Deluge	**** $350,000						Complete
	Unit 3 Turbine - Generator Sprinkler System	Pre-Action Water Sprinkler	**** $116,169						Complete
	Fire System Electrical Panel Upgrade	New Panel, and addressible sensors, in areas such as Precip and hoppers, Burner Fronts, Relay Room, Stores, etc.	**** $120,000						Complete
	Unit 2 Turbine - Generator Sprinkler System	Pre-Action Water Sprinkler	**** $90,580	**** $210,000					In Progress
	Unit 2 Oil Reservoir	Spill containment.		**** $20,000					In Progress
	Heavy/Light Oil Forwarding Pump Areas Units	Curbing & Containment		**** $7,500					Pending
	Unit 3 Lube Oil tank area / Legs T/G detection upgrade	Additional sprinklers/deluge conversion around lube oil area, and pnuematic detation upgrade			**** $100,000				Pending
	Unit 2 Precipitator transformers oil system - Secondary containment.				**** $25,000				Pending
	Heavy/Light Oil Forwarding Pump Areas Units	Wet Automatic Sprinkler			**** $150,000				Pending
	Diesel / HFO / Light oil supply lines	Installation of Emergency Shut-off valves to limit relase of hydrocarbon. Scope clarification required to determine number and locations of value installations			**** $90,000				Pending
	Unit 1 Turbine - Generator Sprinkler System	Pre-Action Water Sprinkler				**** $350,000			Pending
	Cable Spreading/Relay Room	Firestop / Seal all through wall/ceiling penetrations, to provide fire resistance and smoke barrier. Also VEWFD					**** $75,000		Pending
	The turbine-generator units steel columns Fire protoection.	PE required to determine scope and level of protection. - Sprinklers or fireproofing.				**** $25,000		**** $225,000	Pending
	Stores Area	Automatic Sprinkler system				$60,000			

FIRE PROTECTION MULTIYEAR PLAN

NSPI

Revision Control	
Release Date:	2-Jun-2016

Generating Station	Area	Protection	Estimated Investment Timeframe 2010 - 2015	2016	2017	2018	2019	2020	Current Status
		Annual Total	$4,666,149	$2,099,500	$1,690,000	$1,155,000	$1,150,000	$375,000	
PH Biomass	Chip Silo	Upgrade fire water supply to deluge system, for quick connection of muncipal fire department.	**** $2,000						Complete
	General Site	Misc. refurbishments of existing systems, resulting from Annual Inspection Report.	**** $11,000						Complete
	Lube Oil / Pressurized Oil piping	Installation of Spray Fire Shields at potential leak paths / connections.	**** $15,000						Complete
	Turbine - Generator	Expand and reinforce sprinkler system below T/G.			**** $65,000				Pending
Comb. Turbines	CT - VJ	Replacement of Halon Fire Protection System.		**** $200,000					In Progress
	CT - BGT	Replacement of Halon Fire Protection System.	**** $20,000		**** $300,000				Pending
	CT - TUS	Replacement of Halon Fire Protection System.			**** $80,000				
Sydney Coal Railway	Rail House Area	Sprinkler protection reinstatement. Installation of private Water Supply and equipment. PE study with later construction.		**** $40,000			**** $600,000		In Progress
Sydney Int'l Coal Pier	Main Buildings	Fire Detection: MCC rooms, Control rooms, Garage, Pumphouse, Office Building		**** $80,000					In Progress
Wreck Cove	Tank Supply	Tank Replacement / Alarm upgrades / Deluge valve replacement	**** $144,000	**** $864,000					In Progress

Request IR-60:

With respect to G25 (CI 49429 – LIN Coal Pile Run Off Pond Expansion), the proposed capital project is said to be required to avoid any potential overflows from a coal pile run off pond during a 1 in 100-year storm. Please advise of the source for the 1 in 100-year storm standard.

Response IR-60:

The utilization of the 1 in 100 year storm criteria was determined by third part experts in waste water pond design. NS Power retained an independent consultant who obtained the most recent rainfall Intensity-Duration-Frequency (IDF) curves from Environment Canada and calculated the rainfall intensity for the site based on the specified 1 in 100 year storm criteria. The 1 in 100 year storm is used to define a precipitation event that statistically has a 1 percent chance of occurrence in any given year.

Request IR-61:

Please list all transmission projects, including those contained within Routines, expected to be completed by NSPI affiliates and/or external contractors. Please include the contract and the total cost for each project.

Response IR-61:

Please refer to table below:

Capital Item	Project	Title	Total Contract ($)	Affiliate / External Contractor	Total Project Cost ($)
23115	T001	Provincial - Transmission Line Replacements (Unplanned)	530,956	Affiliate	882,026
23120	T003	Provincial - Transmission Substation Primary	313,869	External Contractor	2,199,801
23121	T004	Provincial - Substation Additions and Replacements	184,171	External Contractor	870,603
43827	T010	Transmission Right Of Way Widening	498,836	External Contractor	598,698
23118	T011	Provincial - Planned Transmission Line Replacements	3,789,482	Affiliate	5,121,873
14841	T016	Protection Modifications and Replacements	20,600	External Contractor	449,111
43324	T782	L6513 Rebuild/upgrade line terminal	10,477,252	Affiliate / External Contractor	17,934,924
43678	T800	Separate L8004/L7005	8,682,916	External Contractor	16,183,691
45067	T801	67N Onslow 345 KV Node Swap	483,091	External Contractor	2,956,521
45066	T802	Upgrade L6511 and L7019	1,310,222	Affiliate / External Contractor	2,680,946
45053	T818	69KV Structure Replacements West	1,713,258	Affiliate	4,818,017

Capital Item	Project	Title	Total Contract ($)	Affiliate / External Contractor	Total Project Cost ($)
45306	T822	Prime Brook Substation Addition	648,254	Affiliate / External Contractor	3,387,506
46339	T825	120H Replace SVC Controls	4,769,972	External Contractor	10,218,548
46591	T828	88S Lingan Replace 230kV GIS	3,222,926	External Contractor	12,505,425
43267	T835	13V Gulch Replace 13V-GT1 & 13V-VR1	210,887	External Contractor	837,830
46366	T854	65V Middleton Substation RTU Add	25,539	External Contractor	252,574
46587	T856	Metro Voltage Support Add Capacitor	1,083,107	External Contractor	3,276,763
46757	T867	88S Lingan 230kV BPS Upgrades	670,034	External Contractor	3,080,663
44981	T871	2C Port Hastings Transformer Replacement	331,731	External Contractor	1,913,974
46811	T872	2H Armdale Transformer Addition	925,125	External Contractor	2,591,364
47914	T874	L6537 Replacements and Upgrades	786,763	Affiliate	1,189,645
47949	T876	L5028 Replacements and Upgrades	670,101	Affiliate	1,013,349
48062	T878	2016 Reactor Breaker Replacements	29,771	External Contractor	475,836
48063	T879	2016 Capacitor Bank Breaker Repl.	39,348	External Contractor	301,459
47950	T881	L5017 Replacements & Upgrades	1,346,604	Affiliate	2,178,539
48022	T888	Spider Lake Substation Addition	2,319,881	Affiliate / External Contractor	6,147,953
48114	T893	2016 Steel Tower Life Extension	930,796	External Contractor	1,485,310
49253	T910	U&U 20V-T1 Transformer Replacement	159,460	External Contractor	1,154,470
49818	T923	2017/2018 Tx Switch & Breaker Replacement	292,664	External Contractor	1,074,472
49838	T924	2017 Substation PCB Equip Replacement	886,295	External Contractor	4,127,023
49789	T925	L6515 Replacements and Upgrades	1,529,368	Affiliate	2,340,989

Capital Item	Project	Title	Total Contract ($)	Affiliate / External Contractor	Total Project Cost ($)
49813	T926	2017 Sacrificial Anode Installation	1,050,000	Affiliate / External Contractor	1,532,340
49775	T927	L5004 Replacements and Upgrades	639,534	Affiliate	995,712
49879	T928	77V-T52 Replacement	158,440	External Contractor	775,082
43200		2017 Wood Pole Retreatment	609,250	External Contractor	841,821
47915		L5053 Replacements and Upgrades	446,508	Affiliate	692,706
47954		L7012 Replacements and Upgrades	2,923,516	Affiliate	4,428,520
47956		L7004 Replacements and Upgrades	428,722	Affiliate	672,131
48057		Replace 69kV cables between 2S& 83S	8,600	External Contractor	459,931
49774		L5527 Replacements and Upgrades	964,015	Affiliate	1,537,852
49776		L7008 Replacements and Upgrades	505,281	Affiliate	876,277
49778		L5535 Replacements and Upgrades	792,604	Affiliate	1,261,920
49782		L5027B Replacements and Upgrades	747,271	Affiliate	1,093,542
49790		L5505 Replacements and Upgrades	754,166	Affiliate	1,223,571
49792		2017 Line Retirement Program	376,604	Affiliate	526,064
49793		L7011 Replacements and Upgrades	2,067,566	Affiliate	3,343,484
49795		100C Cape Porcupine Switch Addition	10,050	External Contractor	128,441
49798		2017 Capacitor Bank Breaker Replace	30,798	External Contractor	378,150
49814		2017 Steel Tower Life Extension	920,000	External Contractor	1,462,100
49815		2017 Steel Tower Refurbishment	1,317,327	Affiliate / External Contractor	2,003,317
49821		Mersey River Hydro Spare Transformer	86,500	External Contractor	519,994

Capital Item	Project	Title	Total Contract ($)	Affiliate / External Contractor	Total Project Cost ($)
49833		2017 Oil Containment Program	124,573	External Contractor	432,518
49878		2017 Substation Insulator Replace	55,500	Affiliate	508,893
49922		Western Switching Upgrades	116,217	Affiliate	353,906
49928		3S Gannon Rd. Bus Reconfiguration	105,560	External Contractor	364,777
49929		Tap Changer Replacements	6,000	External Contractor	262,526
49948		2017/2018 Isolated Structure Replace	2,642,866	Affiliate / External Contractor	3,822,487
49992		2017 Transmission ROW Widening	4,500,000	External Contractor	5,400,855
50021		91H Tufts Cove Bus & Line Upgrades	145,634	External Contractor	417,178
50342		West Transmission System Voltage Support	750,000	External Contractor	4,000,000

Request IR-62:

Please identify all capital items included in the 2016 ACE Plan related to the Maritime Link project.

Response IR-62:

The four capital items in the 2016 ACE Plan related to the Maritime Link are as follows:

CI#	Project Title	Section Included in ACE 2017
43324	L6513 Rebuild / Upgrade Line Terminals	Carryover
45067	67N Onslow 345 KV Node Swap	Carryover
45066	Upgrade L6511 and L7019 Thermal Rating	Carryover
43678	Separate L8004/L7005 on Canso Crossing Double Circuit Tower(DCT)	Subsequent Submittal

These projects are also included in the 2017 ACE Plan.

Request IR-63:

With respect to T01 (CI 49992 – 2017 Transmission Right of Way Widening) and 2016 routines T010 (Transmission Right-of-Way Widening):

(a) How do the cost estimates of $12,800/km and $11,070/km compare to actual achieved in 2016?

(b) Has there been any revision to this initial cost estimate?

(c) Please provide the variance of budget to actual (by transmission line) for all work completed year-to-date in 2016.

(d) It was noted on pg. 146 of the 2017 ACE plan that savings have been achieved in easement costs.

(i) What was the actual average easement cost per property achieved in 2016?

(ii) Has the previously used estimate for easement costs been revised in the 2017 budget amount due to these cost savings?

(e) Please provide any reliability statistics available by transmission line for 2015 versus 2016 for any 69kV transmission lines with right of way widening work completed in 2016.

(f) NSPI identified an amount of $4.5 million increased to $5.0 million due to AO in the 8 year program the Board directed NSPI to include in future ACE Plans; however, the amount included in this CI is $4.5 million increased to $5.4 million due to AO. Please explain the increased AO from initial estimate.

Response IR-63:

(a) The overall average cost for Right of Way widening completed in 2016 was $11,884/km. This includes widening on both single pole and H-frame structures.

(b) No.

(c) Please refer to the table below. Work was completed on lines other than those originally identified in the 2016 ACE Plan as a result of longer than expected easement negotiations on some of those lines. Funds were diverted to conduct widening on lines that had minimal easement requirements and had known outages as a result of tree contacts.

Line Number	2016 ACE ($)	YTD Actual (November) ($)	Variance YTD Actual vs 2016 ACE ($)
Labour & Expenses	183,664		(183,664)
L-5023	17,570		(17,570)
L-5024	178,133	121,455	(56,678)
L-5039	230,273		(230,273)
L-5040	1,363,940	523,299	(840,641)
L-5502	236,273	46,656	(189,617)
L-5510	2,320,813	608,116	(1,712,697)
L-5524		89,200	89,200
L-5053	872,170	581,503	(290,667)
L-5501		38,845	38,845
L-5564		34,814	34,814
L-5003		48,671	48,671
L-5004		30,995	30,995
L-5011		80,972	80,972
L-5047		9,002	9,002
L-5539		186,771	186,771
L-5511		59,479	59,479
L-5576		376,580	376,580
L-5014		34,284	34,284
L-5021		4,712	4,712
L-5020		28,700	28,700
L-5512		98,012	98,012
L-5531		169,753	169,753

Line Number	**2016 ACE ($)**	**YTD Actual (November) ($)**	**Variance YTD Actual vs 2016 ACE ($)**
L-5532		207,164	207,164
L-5530		39,161	39,161
L-5535		518,552	518,552
L-5547		43,281	43,281
TOTAL	**5,402,836**	**3,979,977**	**(1,466,140)**

(d) (i) The actual easement costs for the full year in 2016 have not yet been finalized. The average cost estimate for easements per acre of property as of November 2016 is [redacted].

(ii) No. Easement costs vary by property, therefore the estimate for 2017 remains unchanged. Negotiations with landowners owning property adjacent to existing rights of way have not commenced for the lines planned in 2017.

(e) Please refer to the table below for the number of interruptions caused by tree contacts in 2015 and 2016.

Line	**2015**	**2016 Pre Widen**	**2016 Post Widen**
L-5003	0	0	0
L-5004	0	0	0
L-5011	0	0	0
L-5014	0	0	0
L-5020	0	0	0
L-5021	0	0	0
L-5024	0	0	0
L-5033	1	1	0
L-5040	0	0	0
L-5047	0	0	0
L-5053	0	1	0
L-5501	0	0	0
L-5502	0	0	0

REDACTED

Line	2015	2016 Pre Widen	2016 Post Widen
L-5510	0	0	0
L-5511	0	0	0
L-5512	0	1	0
L-5524	1	0	0
L-5530	0	0	0
L-5531	0	0	0
L-5532	0	1	0
L-5535	1	1	0
L-5539	0	1	0
L-5547	0	1	0
L-5564	0	0	0
L-5576	0	0	0

(f) The statement '$4.5 million increased to $5.0 million per year due to AO' that is referenced on pages 72 and 462 of the ACE Plan, should have been '$4.5 million increased to $5.4 million per year due to AO'. The forecast amount in the CI 49992 submission is correct at $5 4 million and is consistent with the amount detailed on page 20 of the Post-Tropical Storm Arthur Progress Report filed on February 1, 2016.[1] Please also refer to SBA IR-29 part (a).

[1] M06321, Exhibit A-28, February 1, 2016

Request IR-64:

With respect to T03 (CI 49838 – 2017/2018 Substation Polychlorinated Biphenyl (PCB) Equipment Removal Program):

(a) How are the number of items requiring removal estimated?

(b) Has NSPI calculated the average number of items requiring replacement per number tested historically for various types of equipment?

(i) If so, has this information or any other related historical statistics been used to inform estimated future costs?

(ii) If not, why not?

(c) What portion of the equipment requiring testing will have been tested by the end of 2017?

(d) What does NSPI estimate will be the total increased costs over all years due to the change to the Federal PCB regulations?

(e) Has NSPI relied on the results of the historical testing to determine the estimated increase in the budget in 2017 due to the change to the Federal PCB regulations?

(f) If the answer to part e) is no, how was this increase estimated?

(g) Please advise whether NSPI is on target for the replacement of all applicable PCB contaminated substation equipment before the 2025 deadline.

Response IR-64:

(a) The majority of equipment requiring replacement has now been identified through the screening process which involves using manufacturer information and/or sampling to confirm PCB potential. In 2017, the program plans for the removal of 13 breakers with PCB bushings, 80 additional bushings, 21 potential transformers and 21 current transformers.

(b) No, at this point of the program the majority of equipment remaining in the substation PCB program has been tested or cannot be tested and requires destruction and replacement.

(i) N/A

(ii) NS Power's estimates on replacement equipment are based on actual sampling results.

(c) It is estimated that 98 percent of equipment requiring testing will have been tested by the end of 2017. The remaining 2 percent of testing will extend beyond 2017 to align with substation maintenance outage scheduling.

(d) There is no substantial change in cost caused by the amended regulations. To clarify, the change in regulations was an extension to allow the remaining greater than 500 mg/kg equipment to be removed by 2025 as opposed to 2015 previously required in the regulation. Greater than 50 mg/kg equipment had always been required for removal by 2025 under the regulations.

The statement in CI 49838:

> The annual investment on this asset has increased from 2015 and 2016 as the regulations around the removal of substation devices went from 500 mg/kg to 50 mg/kg.

Should have read:

> The annual investment on this asset has increased from 2015 and 2016 as a result of NS Powers shift in focus from replacing devices with greater than 500 mg/kg to devices with greater than 50 mg/kg; as well as the shift from sampling to asset replacements.

NS Power apologizes for the confusion on this matter.

(e) Yes, historical sampling results are used to determine project budgets. Please refer to part (d).

(f) N/A

(g) Yes, NS Power is on target to meet the 2025 deadline.

Request IR-65:

With respect to T04 (CI 49948 – 2017/2018 Isolated Transmission Structure Replacements):

(a) Please confirm if this is a new project, and if not provide information regarding previous similar projects.

(b) How are the transmission structures identified and prioritized?

Response IR-65:

(a) Confirmed.

(b) Transmission structures requiring replacement are identified through the Transmission Line Inspection Program. Structure replacements are prioritized based on asset condition and criticality, consistent with the project risk ranking methodology outlined in the CEJC. Access to structures is also evaluated during the inspections and isolated structures are identified.

Request IR-66:

With respect to T22 (CI 49878 – 2017 Substation Insulator Replacement Program):

(a) Please compare the number of replacements in the 2016 program to the number proposed in 2017.

(b) How has NSPI prioritized the substation insulators to be removed and replaced?

Response IR-66:

(a) The number of replacements proposed in 2017 is 973. In 2016, there were 684 substation insulators replaced. The increased number of replacements planned for 2017 is due to the higher number of insulator failures experienced in 2016. Please refer to SBA IR-39 (a) for a list of insulator failures from 2011-2016.

(b) NS Power prioritizes substation insulator replacement based on the condition and criticality of the insulator consistent with the project ranking methodology outlined in the CEJC. Work is scheduled in coordination with planned shutdowns of generation plants or installations of mobile substations.

Request IR-67:

Please list all distribution projects, including those contained within Routines, expected to be completed by NSPI affiliates and/or external contractors. Please include the contract and the total cost for each project.

Response IR-67:

Please refer to the table below:

Capital Item	Project	Title	Function Class	Total Contract ($)	Affiliate / External Contractor	Total Project Cost ($)
26716	D004	New Customer Upgrades	Distribution	1,327,505	Affiliate / External Contractor	7,740,351
23158	D005	Unplanned Replacement Deteriorated Equipment	Distribution	1,541,243	External Contractor	8,443,160
23135	D006	Regulatory Replacements	Distribution	408,819	Affiliate / External Contractor	1,078,010
23136	D007	Joint Use	Distribution	148,892	External Contractor	508,021
23361	D008	Provincial Storm	Distribution	741,150	Affiliate / External Contractor	2,418,069
23127	D010	Distribution Right Of Way Widening	Distribution	498,836	External Contractor	598,698
29038	D051	System Performance Improvement	Distribution	176,360	Affiliate / External Contractor	599,717
23137	D055	Planned Replacement of Distribution Equipment	Distribution	1,716,860	Affiliate / External Contractor	7,724,405
39766	D061	New Customers - Residential	Distribution	1,810,727	External Contractor	8,422,167

Capital Item	Project	Title	Function Class	Total Contract ($)	Affiliate / External Contractor	Total Project Cost ($)
39770	D062	New Customers - Commercial	Distribution	747,353	External Contractor	6,045,087
40320	D454	LED Street Light Conversion	Distribution	3,319,099	External Contractor	35,909,883
43195	D476	2013 Remote Communication on Recloser	Distribution	548	External Contractor	244,339
43278	D517	Halifax 4kV Conversion Part-1	Distribution	85,995	External Contractor	351,033
44749	D527	Tiverton Tower Refurbishment	Distribution	399,978	Affiliate / External Contractor	1,058,200
44826	D562	2014 Build-to-Roadside	Distribution	305,723	Affiliate / External Contractor	871,410
43217	D573	24C-442G Hwy 16 Rebuild Ph 1	Distribution	521,423	Affiliate / External Contractor	902,447
45031	D630	3N Oxford Conversion Phase 1	Distribution	79,520	Affiliate / External Contractor	869,922
46623	D666	Rights for Facility on Railway Land	Distribution	19,999	External Contractor	187,458
48093	D686	2016 Padmount Replacement Program	Distribution	96,906	Affiliate / External Contractor	1,803,921
47753	D688	24C-442GB Hwy 16 Reconductor Ph 2	Distribution	832,189	Affiliate / External Contractor	1,462,649
47760	D691	85S-402 Re-Insulate	Distribution	782,039	Affiliate / External Contractor	1,259,666
47765	D704	58C-405 Belle Cote Phase 2	Distribution	364,358	Affiliate	503,843
47777	D705	70W-321 Wile Lake Road	Distribution	35,216	Affiliate / External Contractor	99,942
49056	D746	65V-302HAA Old Liverpool Rd Rebuild	Distribution	98,497	Affiliate / External Contractor	154,653

Capital Item	Project	Title	Function Class	Total Contract ($)	Affiliate / External Contractor	Total Project Cost ($)
49311	D758	93V-312 Lower Saulnierville Conduct	Distribution	149,918	External Contractor	580,184
47776	D761	111S Prime Brook Feeder Exits & Fee	Distribution	815,761	Affiliate / External Contractor	1,503,986
48195	D762	Halifax 4kV Conversion Ph 3	Distribution	64,211	External Contractor	388,951
49591	D763	3S Feeder Exit Cable Replacement	Distribution	153,893	External Contractor	335,842
47774	D766	546C-311 West Bay Upgrade	Distribution	35,822	Affiliate / External Contractor	119,838
47734	D775	1C-411 Highway 4 Reconductor	Distribution	292,961	Affiliate / External Contractor	434,946
49919	D778	2017 PCB Pole Top Trans. Replacement	Distribution	1,097,320	Affiliate / External Contractor	2,446,051
49918	D779	54H-303 Underground Device Replacement	Distribution	51,271	External Contractor	469,604
49611	D780	New Distribution ROW Phase 1	Distribution	1,841,303	External Contractor	2,211,149
41350		16W-301 Hebron Rebuild Phase 2	Distribution	396,949	Affiliate / External Contractor	904,732
46305		103W-311G Gold River Reconductor	Distribution	68,196	Affiliate	118,563
47769		509V-301 Overcove Rd Rebuild	Distribution	282,998	Affiliate / External Contractor	402,493
47787		2H Armdale New Feeder	Distribution	706,321	External Contractor	1,285,679
49791		3N Oxford Conversion Phase 3	Distribution	40,744	External Contractor	358,369
49799		532N Elm Street Conversion Phase 1	Distribution	281,063	Affiliate	548,688
49806		2017 Padmount Replacement Program	Distribution	109,203	Affiliate / External Contractor	1,703,774

Capital Item	Project	Title	Function Class	Total Contract ($)	Affiliate / External Contractor	Total Project Cost ($)
49836		11S-302 11S-401 Rebuild Coxheath	Distribution	535,504	Affiliate / External Contractor	807,456
49841		23H-Rockingham Voltage Conversion	Distribution	174,491	External Contractor	743,213
49862		50N-410 Rebuild Trenton	Distribution	159,957	Affiliate / External Contractor	247,773
49863		73W-411H New Germany Recloser	Distribution	9,983	External Contractor	53,820
49866		512N-Toney River Upgrade	Distribution	27,211	External Contractor	285,219
49867		55V-313-Berwick North Upgrade	Distribution	199,080	Affiliate / External Contractor	345,565
49868		2017 Hydraulic Recloser Replacement	Distribution	22,350	External Contractor	248,578
49877		23H-302 Clayton Park Rebuild Ph II	Distribution	141,269	Affiliate / External Contractor	215,859
49891		509V Recloser and Voltage Regulator	Distribution	79,155	External Contractor	319,649
49899		10H Halifax 4kV Conversion Year 4	Distribution	112,611	Affiliate / External Contractor	254,608
49956		505V Station Retirement	Distribution	6,573	External Contractor	33,049
49957		93V Feeder Expansion	Distribution	36,655	External Contractor	165,912
50073		4S-332 Bernard Lind Drive Rebuild	Distribution	152,838	Affiliate / External Contractor	302,893
50341		2017 Substation Recloser Replacements	Distribution	122,400	External Contractor	577,388
50343		Main -Advanced Meter Infrastructure	Distribution	60,000	External Contractor	111,707,380

1

Request IR-68:

Please provide a list of the worst performing feeders for the last three years.

Response IR-68:

The following tables list the 20 worst performing feeder sources based on reliability data from January 1, 2014 to November 30, 2016. The feeders are ranked by CKAIFI and CKAIDI values. The data excludes Major Event Days and Extreme Event Days as defined by the IEEE 2.5 Beta Methodology.

The following table ranks the 20 Worst Performing Feeders by CKAIFI:

Major and Extreme Days Removed (2014-2016)		
Feeder	**Annual CKAIFI**	**Annual CKAIDI**
65V-301	8.47	7.44
11S-301	6.78	8.82
82S-302	6.42	8.12
3S-301	5.27	10.34
57C-422	5.25	15.55
50N-410	5.18	18.87
82V-403	5.13	7.90
85S-401	5.12	17.91
82V-401	4.93	5.23
37N-412	4.83	14.24
24C-442	4.81	9.20
56N-414	4.61	13.19
1C-411	4.42	7.56
85S-402	4.38	14.84
11S-411	4.32	9.10
57S-401	4.26	7.60
54H-301	4.24	7.59
100C-422	4.17	4.78
46W-301	4.12	13.24
15S-301	4.11	3.12

The following table uses the same data as above, but ranks the 20 Worst Performing Feeders by CKAIDI:

Major and Extreme Days Removed (2014-2016)		
Feeder	**Annual CKAIFI**	**Annual CKAIDI**
84S-304	1.92	23.58
50N-410	5.18	18.87
85S-401	5.12	17.91
16V-314	4.10	16.63
103C-311	1.26	16.07
57C-422	5.25	15.55
103C-314	3.33	15.38
85S-402	4.38	14.84
37N-412	4.83	14.24
67C-412	3.89	13.75
59C-402	2.56	13.48
4C-424	3.75	13.31
30N-412	3.65	13.28
46W-301	4.12	13.24
56N-414	4.61	13.19
77V-401	2.51	12.35
36V-301	1.80	11.73
56N-401	3.15	11.66
22N-402	2.49	11.23
16V-315	2.43	10.44

Request IR-69:

With respect to D01 (CI 49919 – 2017 PCB Pole Top Transformer Replacements):

(a) **Please confirm whether the 2017 project will complete testing of all 45,000 pole top transformers which NSPI estimates may contain PCBs.**

(b) **Please advise whether NSPI is on target to replace all PCB contaminated transformers by December 31, 2025.**

Response IR-69:

(a) The initial estimate of 45,000 transformers was calculated prior to identifying the PCB-potential pole-top transformers through the Due Diligence Distribution Feeder Inspection Program. The revised estimated number of total PCB-potential pole-top transformers identified for testing based on current inspections results is 27,100.

NS Power has tested approximately 16,000 pole-top transformers to date. CI 49919 - 2017 PCB Pole Top Transformer Replacements will target 7,000 pole-top transformers out of the 11,100 that are outstanding. This will leave approximately 4,100 transformers to be tested in future projects.

(b) Yes. NS Power is on target to replace all PCB-contaminated pole-top transformers by December 31, 2025.

Request IR-70:

With respect to D02 (CI 49806 – 2017 Padmount Replacement Program):

(a) Please provide a table with the most recent age profile distribution of padmount transformers.

(b) Please provide and elaborate on the average cost to replace a padmount transformer in each of the recent five years.

(c) Please advise how NSPI proposes to identify and prioritize the padmount transformers to be replaced in 2017.

Response IR-70:

(a) Please refer to the padmount transformer age profile provided on page 138 of the 2017 ACE Plan.

(b) Please refer to the table below.

Project Year	CI	Total Project Actuals ($)	Padmounts Replaced	Average Cost Per Padmount Replacement ($)
2012	41398	777,646	45	17,281
2013	43273	294,092	19	15,479
2014	45739	681,996	48	14,208
2015	46292	1,461,242	84	17,396
2016 Forecast*	48093	1,717,738	90	19,086
2017 ACE*	49806	1,573,814	80	19,673
Total		**6,506,528**	**366**	**17,777**

* Excludes contingency.

The variance year-to-year is primarily associated with the variance in size and type of padmounts replaced, the mix of residential and commercial customers, and the amount of contract resources required.

(c) NS Power inspects padmount transformers on an annual basis. Engineering reviews the collected data, identifies the required replacements, and prioritizes them accordingly. Replacements are prioritized based on transformer condition, level and location of rust, deterioration, reliability, safety, and environmental risk, PCB levels, and non-standard connections.

Request IR-71:

Please submit a copy of NSPI's most recent Information Technology ("IT") Business Plan, as well as copies of the most relevant external or internal documents NSPI used in the development of its 2017 IT capital budget.

Response IR-71:

Attached is NS Power's 2017 IT Business Plan along with the key documents used in the development of the plan.

Attachment 1	NS Power 2017 IT Business Plan
Attachment 2	Accenture report – The New Energy Consumer: Unleashing Business Value in a Digital World
Attachment 3	Institute for Electric Innovation – Key Trends Driving Change in the Electric Power Industry
Attachment 4	Canadian Electricity Association – Electric Utility Innovation: Toward Vision 2050

2017 Information Technology

Investment Plan

Table of Contents

Purpose

The purpose of the Information Technology (IT) Investment Plan is to outline the IT priorities for the year and ensure the link to business objectives. These priorities will drive the associated capital and resource planning for the year.

Current Environment

The current electricity environment is being re-defined by significant changes.

- An increase in the expectations of customers and stakeholders to access information, control services and conduct business with NS Power on their technology platform of choice.
- New and enhanced consumer based services leveraging web-based platforms to provide more information and control for customers to manage their energy.
- A change in the production of electricity from fossil fuel to renewable energy in the form of large-scale and distributed renewable energy production.
- A more digital and distributed electricity grid enabling the connection of renewable energy sources to the grid. It also supports a more reliable transmission and distribution system with smart sensors providing more two-way information, advanced automation and more technical integration.
- An increase in the level of integration across traditional business processes and with external businesses and agencies.
- Increased regulatory and legal compliance requirements and implementation of new and improved controls to protect customer and corporate information
- Software vendors increasing the frequency of patches and releases and expanding the business functionality to address new business opportunities.
- Increasing cyber security requirements as new threats to disrupt business operations continue to grow.

IT Strategy Overview

Technology will play a significant role in the advancement of the electricity marketplace in Nova Scotia and North America. To meet and enable the new business market, NS Power must revise the way technology is managed and delivered. The traditional model of managing technology by optimizing and enabling each business unit must evolve to a more integrated and optimized technology platform across all business units.

This also includes evolving the traditional cyber security model from protecting customer and corporate information with strong perimeter policies and technology to a more complex tiered approach that allows NS Power to share information with customers, vendors and stakeholders in a transparent and secure manner.

Governance of technology must also evolve to include information technology; operational technology and customer-side technology to ensure the planning, design and implementation of solutions going forward are integrated and can deliver the required benefits in a secure and timely manner.

This must all be accomplished in a cost-efficient manner, respecting the principles of affordability and the business capacity for change. NS Power has designed, implemented and maintained a low cost technology environment over the last decade. This has contributed to NS Power's ability to manage costs and allowed the business to execute on other priorities. NS Power's historical spending levels to deliver technology based services will no longer be sustainable. To meet new expectations NS Power must update technical standards and policies to ensure new threats and risks are managed in a manner that ensures on-going operations can meet customer expectations.

Scope

The management of technology includes the following two primary roles:

1. Technology Asset Manager – The overall management of technology assets throughout their lifecycle from acquisition to retirement. This includes scanning for technology advancement, recommendations for technology investments and development of longer term technology roadmaps.

2. Service Provider – The provisioning and delivery of services to ensure the on-going effective use of technology to run business operations. This includes request fulfillment, break-fix, technology change management, portfolio and project management, Data Centre operations, cyber security and overall technical infrastructure management.

The scope of responsibility includes the following technology based assets:

1. Technology Infrastructure
2. Cyber Security
3. Business Applications
4. Voice and data network
5. End User devices (Desktop, laptops, mobile…)
6. Information Management

IT Strategic Principles

IT strategic principles are utilized to guide decision making across the enterprise. The following principles form the basis of the IT Investment Plan:

1. Deliver on customer expectations as technology advances around our customers.
2. Technology must enable and be aligned with business objectives and accepted risk levels.
3. Utilize accepted industry standards when available.
4. Leverage commercial off-the shelf solutions where possible.
5. Rationalize the number of technology solutions.
6. Standardize in key technology areas for ease of integration, flexibility and cost.
7. Utilize solutions that meet business requirements at the lowest total cost of ownership.

2017 Priorities

The following outline the top priorities for 2017:

1. Support the 2017 Business Objectives by:
    a. Successfully implementing the upgraded Enterprise Resource Planning (ERP) solution.
    b. Successfully implementing the Automated Meter Infrastructure (AMI) pilot.
    c. Beginning the project to upgrade the T&D Work and Asset Management technology.
    d. Successfully completing targeted customer experience improvements.
    e. Successfully implementing targeted cyber-security improvements.

2. Prepare IT for Future Business Requirements by:
    a. Completing the plan to manage enterprise data.
    b. Completing and beginning to implement an updated enterprise technology governance model.
    c. Building a long term investment and resource plan.

3. Improve IT Service Delivery Costs by:
    a. Developing and implementing enterprise computing standards.
    b. Implementing an improved IT service and asset management methodology.
    c. Implementing an improved standardized methodology for executing technology intensive projects.

Refer to Appendix A for a list of 2017 planned IT capital projects.

Conclusion

The increased pace of change in the electricity industry driven and supported by technology means that NS Power must update its approach to managing technology. The 2017 IT Investment Plan begins that process. It will mean a significant change in the management of technology across the business to implement more cost effective solutions that build a solid foundation to enable NS Power to better serve customers, drive increased benefits, become more mature in IT asset management, provide a safe and secure technology environment, and transform IT skills to work in this environment.

The current investment in replacing ERP and improving cyber-security are important first steps.

Appendix A

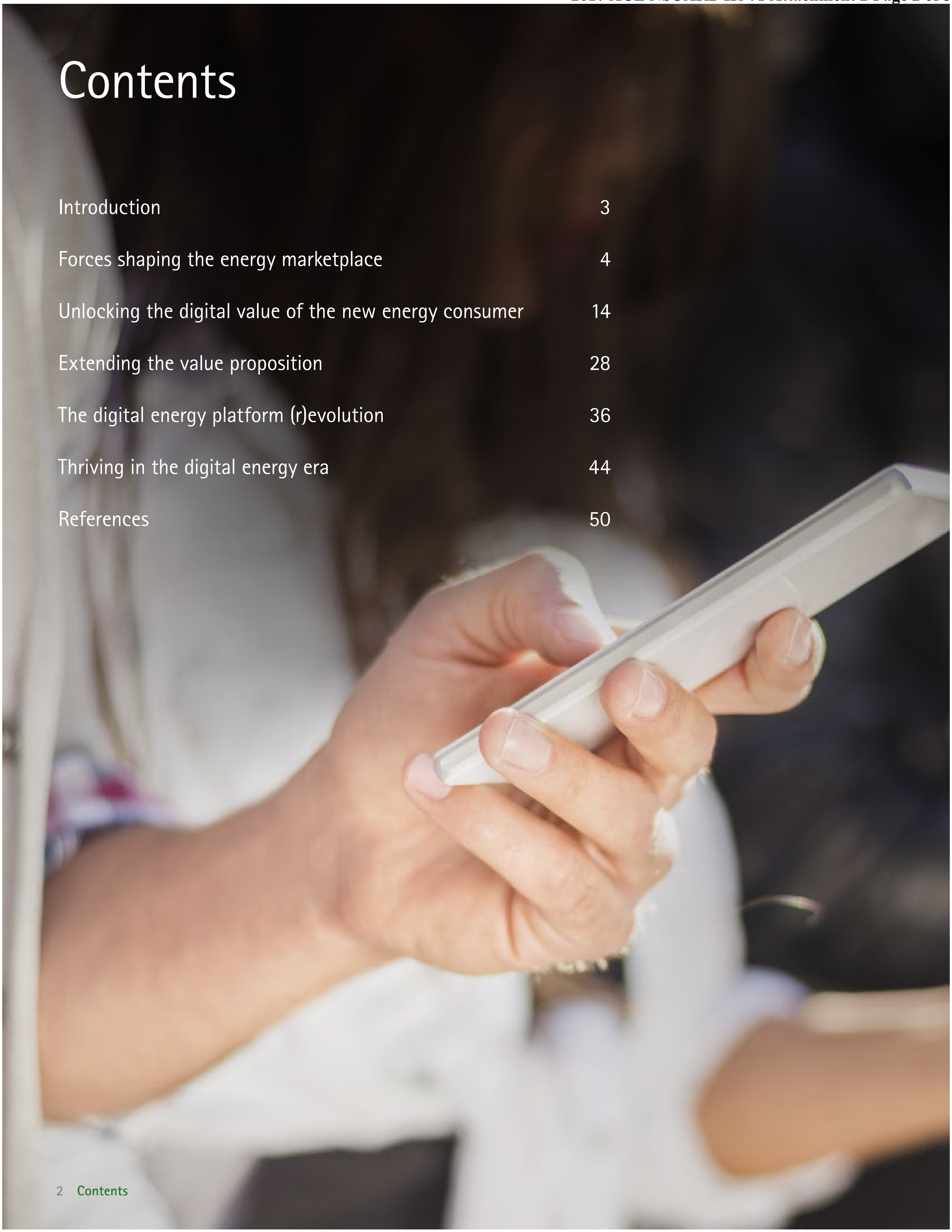
Portfolio	Project
Corporate Productivity	SharePoint Upgrade (CI 49860)
	Windows Server 2008 Upgrade (CI 49859)
	Windows 10 Migration Project (CI 49855)
	Microsoft Exchange Upgrade (CI 49858)
	VOIP Expansion to NS Power Sites (CI 48773)
Customer Service	Customer Experience Self-Serve Development Phase 2 (CI 50153)
	AMI Pilot (CI 47124)
	Customer Experience Consolidated Customer Web Portal (CI 50112)
	Customer Experience Streetlight Improvements (CI 50113)
	Electric Vehicle Infrastructure Deployment (CI 50295)
	CIS High Availability (CI 49953)
	Customer Support System Enhancements (CI 50115)
Cyber Security	Security Operations Centre and Security information Event Monitoring (CI 49093)
	Identity and Access Management Infrastructure (CI 49094)
	Disaster Recovery (CI 49480)
	Data Loss Protection (CI 49601)
	Patch Management (CI 49603)
IT Infrastructure	Storage Infrastructure Upgrade (CI 49857)
	Network Architecture Redesign (CI 49600)
	ITSM Replacement (CI 49856)
Power Production	AMO Fleet Environmental Data Management (CI 48837)
Transmission and Distribution	T&D Work and Asset Management Upgrade (CI 46075)
	Intelligent Feeder / Storage Project (CI 49787)
	SCADA Application Upgrade (CI 48155)
	Real Time Economic Dispatch (CI 49876)
T&D and Power Production	IT PI System Upgrade (CI 49861)
Enterprise Resource Planning	IT – Enterprise Resource Planning (CI 44671)

The New Energy Consumer

Unleashing Business Value in a Digital World

accenture

Strategy | Consulting | Digital | Technology | Operations



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Introduction

Energy providers around the globe are operating in a whole new world. Everything and everyone is increasingly connected. Energy consumers are embracing innovative technologies and taking on new roles as both buyers and sellers of energy. At the same time, a host of threats—from traditional competitors as well as new market entrants—are challenging utilities to become more innovative and more agile.

In *The New Energy Consumer: Unleashing Business Value in a Digital World*, Accenture shares the latest results of our multiyear New Energy Consumer research program. Our findings and analysis point to important shifts and highlight growing opportunities for forward-thinking energy providers. Above all, they reinforce the importance of the digitally engaged consumer and the need for energy providers to stake their claims in the digital energy ecosystem.

Forces shaping the energy marketplace

Electric, gas and water utilities are surrounded by change—from rapid advancements and widespread adoption of distributed generation and smart technologies to product innovation, game-changing partnerships and converging markets. At the same time, consumers' values and preferences continue to evolve. In the face of so much change, where will energy providers find new growth? How will they reduce costs? And what new approaches can they adopt to better serve consumers?

While opportunities and challenges vary by region, every provider needs to take deliberate action—embracing a bold vision and reformulating strategies for understanding, reaching and engaging energy consumers. In doing so, it is crucial to keep a keen eye on four key forces shaping energy markets around the world:

- Connected everything
- Personalized energy
- Asymmetric competition
- Shifting regulatory frameworks

Connected everything

From wearable computers to sensors in sports clothing, the physical world is coming online—altering how consumers live and work and driving new opportunities for energy providers.

Everyday objects are being embedded with sensors and combined with intuitive visualization, yielding new insights into consumer habits and behaviors. A growing number of consumers are filling their homes with connected devices and, in some cases, they may not even realize it. Kitchen appliances, thermostats, lights, locks, phones and televisions are becoming smarter and more interconnected. In fact, almost all energy consumers now use some type of connected device in their day-to-day lives. Doing so offers easy access to information, empowering consumers to make faster, better decisions on their own terms. With smart devices, consumers can choose between being highly informed and influential or adopting a simple, effortless set-and-forget mindset.

All the while, the digitization of everything is becoming a reality. The *2015 Accenture Technology Vision* cites organizations' unprecedented leap forward in the journey to becoming digital businesses.[1] Together, such organizations are creating a hyper-connected world—a "We Economy"—in which companies, consumers and everyday objects can digitally interact with each other.

The We Economy offers savvy companies new strategies to compete and win in a digital world. It also offers rich opportunities for businesses to collaborate with other players and consumers to place bets—on new products, services and experiences—that were not possible one or two years ago. Today, the We Economy can shape new markets at scale.

Connected everything has raised the bar, with consumers who now expect choice, control and convenience. Leading energy providers are leveraging digital capabilities to meet those expectations—while strengthening consumer engagement and delivering tailored experiences that ultimately support long-term consumer satisfaction. In the We Economy, winning energy providers will be those that think and act differently. No longer relying on a single idea, technology or organization to achieve success, they will position themselves at the center of the emerging digital energy ecosystem.

Personalized energy

As a broad spectrum of energy products and services becomes interconnected, consumers' awareness and needs are on the rise.

Ease of access and energy self-sufficiency are becoming top of mind for consumers—opening opportunities but also posing threats for energy providers.

Energy is reaching new levels of convenience for consumers and energy is becoming less centralized, with consumers tapping into non-traditional sources of energy. Evidence of personalized energy is everywhere—from the increasing consumer adoption of home generation solutions via solar panels and electric vehicles (EVs) combined with increasing battery storage to the emergence of microgrids. Some refer to this as the "democratization of energy" and anticipate that, in the future, the majority of energy will be generated in the home with only back-up needs and large industrial power being produced centrally.

With personalized, convenient energy top of mind, retailers are getting into the act: IKEA now offers a line of wireless charging furniture that lets consumers charge their smartphone by simply setting it on their desk,[2] while BirkSun has equipped backpacks with a solar panel for charging cell phones.[3] Energy consumers on the move in San Francisco and London have the ability to charge their smartphones wirelessly at their local Starbucks coffee shop.[4] There is also a new technology that can turn any window or sheet of glass into a photovoltaic (PV) solar cell—suggesting a not-too-distant world in which new homes and office buildings, new cars, and even new smartphones and tablets could generate their own energy.[5]

While that world may still be in the future, the current reality includes declining solar technology prices, new leasing and financing models to become power self-sufficient, and growing adoption among consumers. Solar can be found everywhere—across rooftops and awnings, as well as roadways and in EVs. As solar grows in popularity, prosumers (those who not only consume but also generate and sell energy) are gaining critical mass. At the same time, EVs are creating a new breed of prosumers who use energy services in various places and in varying quantities. From an energy provider's viewpoint, EVs represent an opportunity to increase load and revenue generation while extending reach beyond the home.

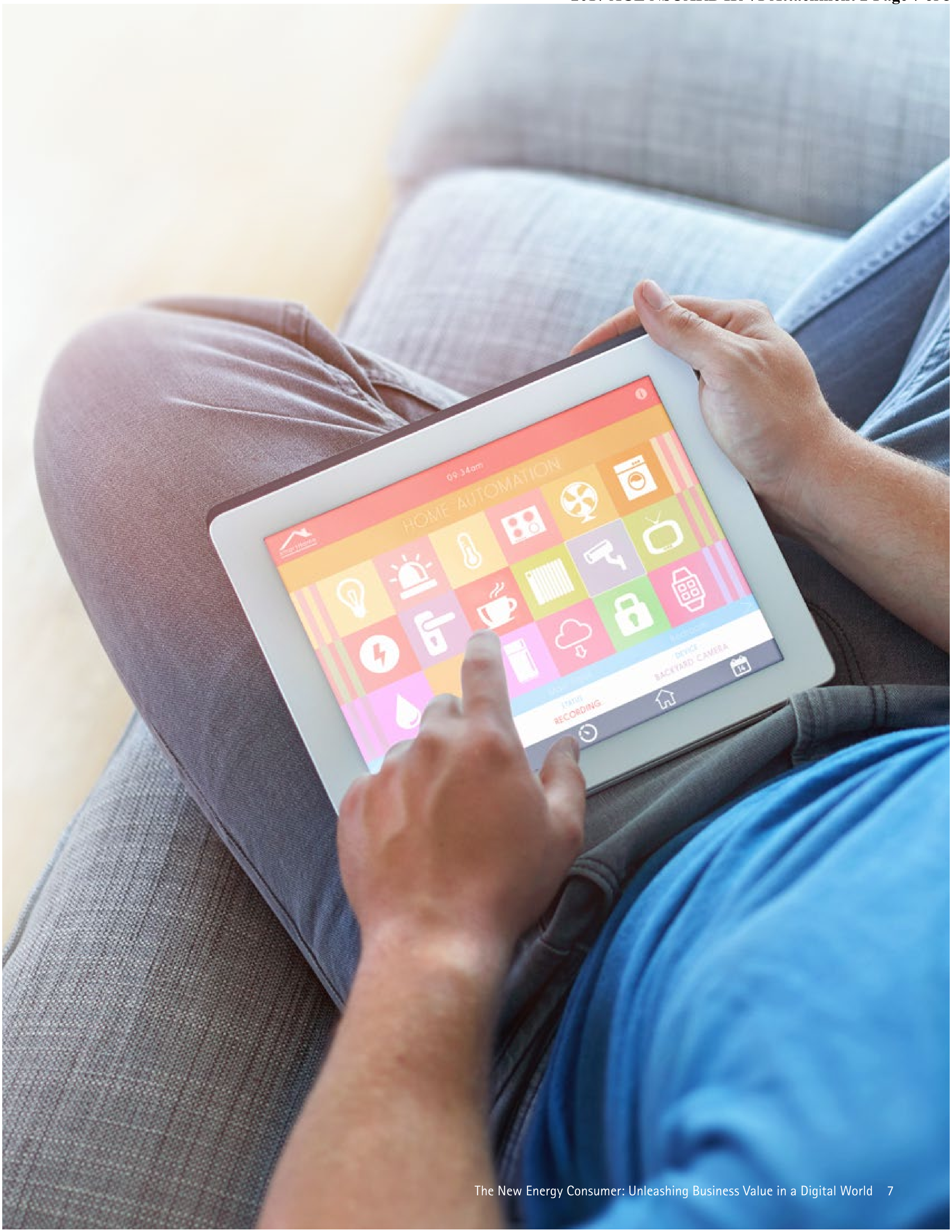
As digital technologies are increasingly applied to the energy infrastructure and prosumers adopt distributed generation and storage solutions, grid technologies will become increasingly more distributed. Utilities executives are expecting to see greater growth in the development of microgrids in the next five years. In 2014, the number of utilities executives expressing that view nearly doubled to 66 percent from 35 percent in the 2013 survey.[6] However, according to *The New Energy Consumer: Unleashing Business Value in a Digital World*, consumer knowledge of microgrids is low: two-thirds of consumers do not know what a microgrid is. Engaging prosumers to advance their knowledge and understanding of distributed energy resources will become increasingly important as these solutions are proliferating. With companies such as Alevo[7] offering battery back-up systems, Tesla's Powerwall Home Battery with 7kWh or 10kWh of storage, and the 100kWh Powerpack can only serve to accelerate energy storage adoption.[8]

Emerging platforms will likely facilitate direct transactions between energy consumers and distributed energy producers, such as homeowners with solar panels or farmers with wind turbines, who often generate more power than they need.

In much the same way that Airbnb's platform disrupted the hospitality industry by directly connecting hosts and travelers, platforms will enable neighbors to buy and sell power directly from each other. As more energy solutions emerge, consumers may shop around for the best deal on their electricity, especially if local generation offers a more compelling value proposition. Utilities have an opportunity to decide whether to participate and what role they will play in maintaining platforms or otherwise facilitating these local, peer-to-peer transactions.

For energy providers, the prosumer segment is quickly advancing from simply an interesting concept to a multifaceted reality. As more consumers become power generators and the traditional one-way flow of power becomes bi-directional, more complex and interactive relationships with consumers are required.

In short, all consumers have opportunities to play a more dominant, pivotal role in the energy ecosystem. They enjoy growing choice around the source of their electrons—wind, solar or even landfill generation—and, in competitive markets, they can select their energy provider. Personalized energy will continue changing how consumers interact with utilities and, ultimately, how a utility runs its business.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HOME AUTOMATION
RECORDING
BACKYARD CAMERA

Asymmetric competition

What energy provider would have anticipated competing with Apple or Google for consumer mindshare around home energy management?

For core energy and new products and services, energy providers now face competition from all directions—startup digital retailers, telecom giants and prosumers, as well as incumbent utilities. In some markets, incumbent providers have adopted a strategy to pursue a dual-fuel bundle offering consumers extended products and services. However, with the cost of innovation at an all-time low, new players are entering both regulated and deregulated markets:

- In a bid to capture the behind-the-meter market, a growing list of blue-chip vendors, including Apple, ADT, Google (after it acquired Nest), Samsung, Verizon and Walmart, are partnering with incumbent hardware and software providers to develop home Internet-of-Things ecosystems to usher in a new phase of home energy management solutions.[9]
- A visit to Kickstarter[10] reveals numerous startup companies seeking funding for home entertainment/security systems, smart house keys and a hands-free Voice over IP (VoIP) call recorder—any of which could theoretically be connected to a utility-owned platform to deliver a simpler and better consumer experience.
- Pure digital competitors, such as Bounce Energy[11] in Texas and Powershop[12] in New Zealand, may be unencumbered by legacy investments and regulatory requirements with which traditional utilities must contend. Using a digital platform, these new companies deliver a modern experience, offering energy packages consumers value—and their significantly above-average customer satisfaction scores validate their innovative approaches.
- Solar solution companies are offering compelling value propositions to consumers that may require energy providers to innovate to deliver renewable products and services in a new way, such as offering community-based solar services. The complexity of helping consumers understand their energy context will be compounded as more consumer-grade storage technologies become available.
- New entrants in some competitive markets are leveraging automated comparison of retail versus wholesale market prices to gain market share through robotic switching and collection switching services.

The playing field for these diverse competitors is far from level, and these differences in capabilities and constraints within the market epitomize asymmetric competition. Although utility incumbents have the edge when it comes to economies of scale and years of experience in refining energy delivery, digital energy startups benefit from agility and risk tolerance and may not have responsibility for energy delivery. They are also well positioned to take advantage of new technologies for a seamless consumer experience across digital channels.

By nature, digital startups benefit from the proverbial clean slate. Able to design internal operations and processes around consumer needs, they can choose where, when and how to automate transactional processes. In addition, as new energy retailers, they avoid many of the overhead costs borne by a traditional utility. This lower cost of entry has made it easier for digital energy retailers to enter the market. In the United Kingdom, for example, the number of retailers has been growing, with some playing the market by buying energy in the spot market and then passing those savings on to consumers. Admittedly, not every utility can be a pure digital retailer, but almost every provider can learn from how these retailers interact with their consumers.

In addition to threats from digital energy retailers, energy providers are now sparring with telecommunications giants, tech innovators and other competitors that would have been unthinkable a decade ago. In the quest for consumers, these new entrants are offering a variety of energy and home management products and services—and leveraging consumer information to provide valuable insights and recommendations. Apple's HomeKit[13] and Google's Nest[14] are currently vying to become the smart thermostat of choice. They are pursuing this market not because controlling a home's temperature is lucrative but because each wants to become the platform on which all of a consumer's in-home interactions occur.

In Europe, Deutsche Telekom is testing its Qivicon product[15]—an open platform intelligent home automation system that can unite products from a number of companies, including electricity suppliers and manufacturers of household appliances and consumer electronics, as well as producers of health-oriented solutions. The Qivicon platform creates a link between the various devices and functions that can then be accessed through an application on a smartphone, tablet or computer.

Asymmetric competition reflects a host of new and, in some cases, unexpected threats. For innovative energy providers, however, it also creates a market for new products and services.

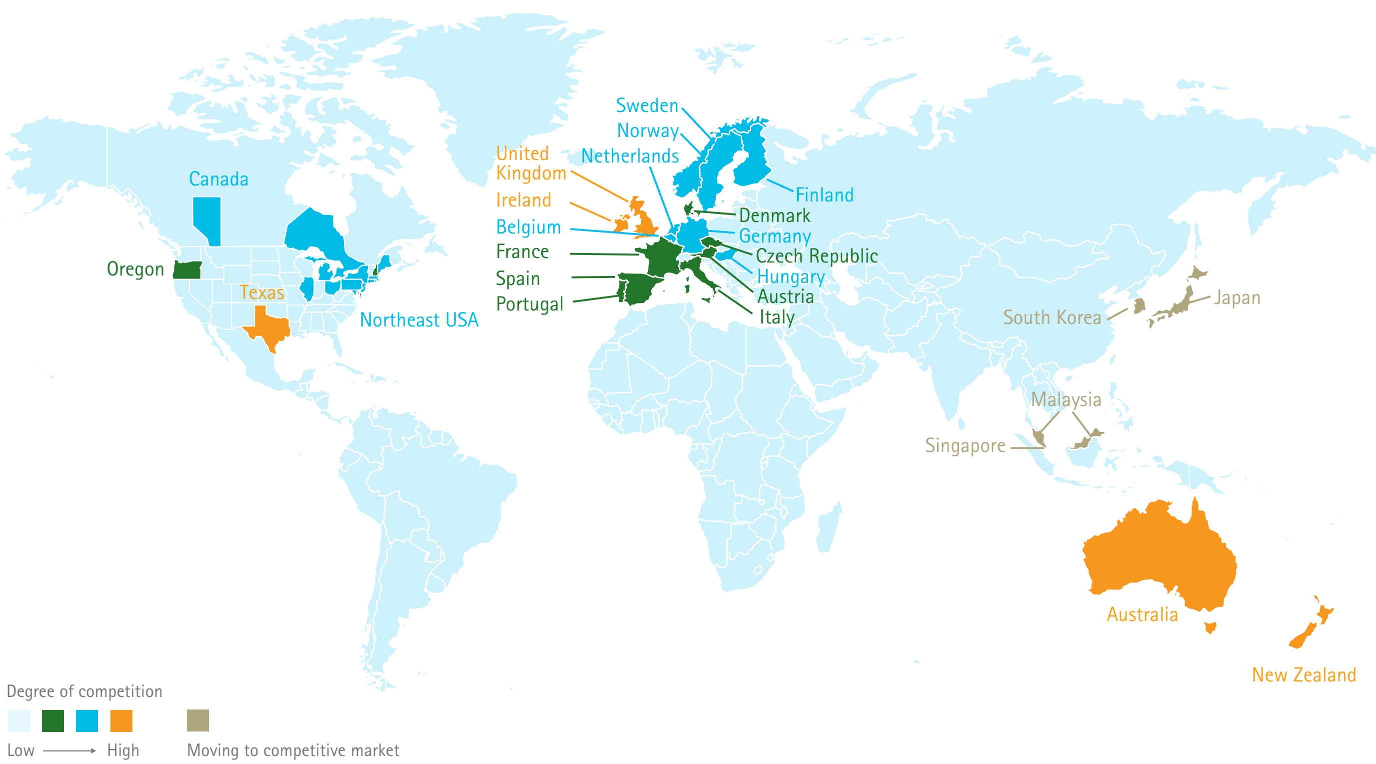
Shifting regulatory frameworks

Around the world, regulatory frameworks are being rewritten to anticipate rapidly changing consumer and industry needs.

Regulatory bodies are facing continued pressure to confirm reliability, security of supply, energy efficiency, affordability and long-term market predictability. Among the key drivers of change: rising energy prices and higher consumer awareness; increased adoption of distributed energy resources and the integration of renewables; growing reliance on demand response; the needs of the modernized grid; and infrastructure investment recovery. In response, many jurisdictions are driving fundamental change through retail market liberalization, alternative utility revenue models and performance-based remuneration. While each country has distinctive priorities, common challenges and opportunities exist around the implications of the new energy consumer.

In many markets, changing policies around price regulation, affordability and consumer information transparency are driving change. Competitive market structures are continuing to expand globally. The journey to retail competition underway in a number of countries (see Figure 1) is bringing a wave of change for consumers and energy providers alike.

Figure 1. State of global retail competitive electricity markets.



Source: Accenture analysis.

For some, the journey is already underway. For example, Portugal has been implementing its competitive market structure since 1995, and eliminated the regulated tariff to end consumers in 2013. For consumers with contracted power up to 10.35kVA, a transition period is in place through December 31, 2015.[16] Elements of consumer engagement are yet to be determined; for example, how quickly and to what degree prosumers will emerge, and what will drive consumers to implement energy-efficiency initiatives. However, the removal of the regulated tariff is consistent with a well-functioning retail market in which customers can benefit from competition and innovation.

While Japan is also ramping up its open, competitive retail market structure, it is much earlier in its journey. Japan is considering allowing residential and small and medium businesses (SMBs) to choose their gas suppliers by 2017,[17] as well as opening up electricity markets[18] in the hope of encouraging greener energy, reducing costs and preventing future power shortages. Japanese energy consumers have shown interest in finding ways to reduce household energy use, save money on their bills and buy power from 100-percent renewable sources. Deregulation will create opportunities for new providers to help customers meet these goals.

In the United Kingdom, the focus has recently been on long-term consumer value with the introduction of new market rules to simplify the choices offered to consumers and to increase price transparency. The goal is to encourage higher levels of consumer choice. Each of the six large incumbent energy providers may offer no more than four tariffs per fuel type and must inform consumers of the best deal. In addition, consumer churn or switching has increased in 2015 over previous years, with a larger percentage of customers who switched opting for smaller players.[19] This appears to be the result of the changes and the proliferation of comparison sites that are making information consistently more transparent to consumers.

Another interesting development in the United Kingdom is the evolution to principle-based regulation following a similar approach to the financial services industry. The regulator has introduced standards of conduct that require suppliers to treat their customers fairly. Energy providers are accountable for implementing the principle, embedding fair treatment of customers throughout their organizations.[20]

While there are many benefits to a competitive market model for consumers and providers, distributed energy resources and systems are fundamentally reshaping competitive and regulated markets. As technologies advance and their price points become more palatable for consumers, pressure on existing systems is increasing. Deutsche Bank estimates that rooftop solar will reach grid parity in all 50 states in the United States by 2016[21] and, by 2017, grid parity will be realized in 80 percent of global markets.[22] In response to rising consumer adoption, the speed and scale of regulatory change will influence the long-term value available to both customers and energy providers. Multiple markets around the globe are making fundamental regulatory changes, affecting business and recovery models.

In New York, regulators have undertaken the Reforming the Energy Vision (REV) initiative aimed at reorienting the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets.[23] The vision is to develop a "distributed system platform" to animate a market where distributed energy and traditional energy organizations can compete to promote system-wide efficiency and reliability, regardless of preferred energy source, and increase consumer knowledge of energy management.

Recently, the California Public Utilities Commission (CPUC) revisited the approach to plug-in electric vehicle (PEV) charging infrastructure within its jurisdiction. In December 2014, the CPUC endorsed an expanded role for the incumbent utilities in developing and supporting the PEV charging infrastructure. The intent is to encourage expansion of electric vehicle-related infrastructure and the widespread deployment and use of PEVs.[24] Further, Colorado recently introduced Bill 1250, which prioritizes developing a performance-based regulatory system that will drive innovation and promote economic development in a variety of technologies.[25]

As other jurisdictions grapple with emerging technology, renewable energy or approaches to electrifying rural areas, we continue to see regulatory interventions. For example, as Germany learns from its experiences undergoing an energy transition, it is now looking to reforms to protect consumers and further advance market innovation. Last year, the German government approved a sweeping change to its well-known green energy transformation to reduce subsidies for renewables and stem rising electricity prices. Under the plan, Germany plans to meet 80 percent of its energy needs through renewables, while producers will gradually have to sell their green energy competitively on the market rather than enjoying regulatory protection.[26]

Lastly, in response to the impact of rising retail prices, the advent of distributed energy and growing concerns around consumer protection, Australia has moved to change network pricing rules. The ultimate goal of the reform: network prices that better reflect the costs of providing network services to individual consumers. This move will likely allow consumers to make more informed decisions about how they want to use energy services and the technologies they invest in to help manage their consumption.[27]

Current regulatory activity demonstrates that both the pace of change and the approach will vary by jurisdiction. However, the power of the consumer to influence the energy marketplace is universal. More than ever, market structure developments are having profound implications on the energy provider's ability to maintain and enhance the consumer relationship, as well as the strategies and business models of the future. Leading energy providers are proactively engaging regulators and a host of stakeholders to help shape the energy ecosystem.

Moving forward

The We Economy, greater consumer choice and access, diverse competitive threats and market environments are radically shaping the energy marketplace today.

In architecting a future-forward strategy, every energy provider should consider not only the implications of these macro forces, but also the evolving values and preferences of each new energy consumer.

How can energy providers address changing consumer values and preferences? Unlocking the digital value of the new energy consumer is key. The sections that follow explore the ways in which energy providers can better understand and capture digital value. Opportunities for energy providers to extend the value proposition are also identified, including innovative offerings to engage energy prosumers and the growing potential of platform-based models in the digital energy ecosystem.

Unlocking the digital value of the new energy consumer

Digital is changing the nature of consumer engagement across the customer life cycle. Whether to educate consumers, sell new products, encourage self-service or create value with new services, digital must be considered as part of every initiative.

It is no secret that digital has transformed how consumers behave, learn, research and engage with companies. Digital continues to disrupt customer service delivery, as well as product and service development. Energy consumers are increasingly embracing digital on their own—going digital for customer service and, in competitive markets, for comparing and switching providers.

In some industries, the distinction between a digital consumer and a non-digital consumer no longer exists. Consumers have passed a tipping point of mass adoption of self-serve and digital engagement and yet, in this industry, energy providers may not yet be seeing consumers adopt digital at the same levels. Accenture's latest research shows that only 44 percent of consumers are currently digitally engaged (digitally engaged consumers are those who have interacted through digital channels over the past year). So why should energy providers further invest in capabilities to digitally engage consumers?

Our survey results show that digitally engaged energy consumers can unleash significantly more business value for energy providers than those who do not use digital channels (see Figure 2):

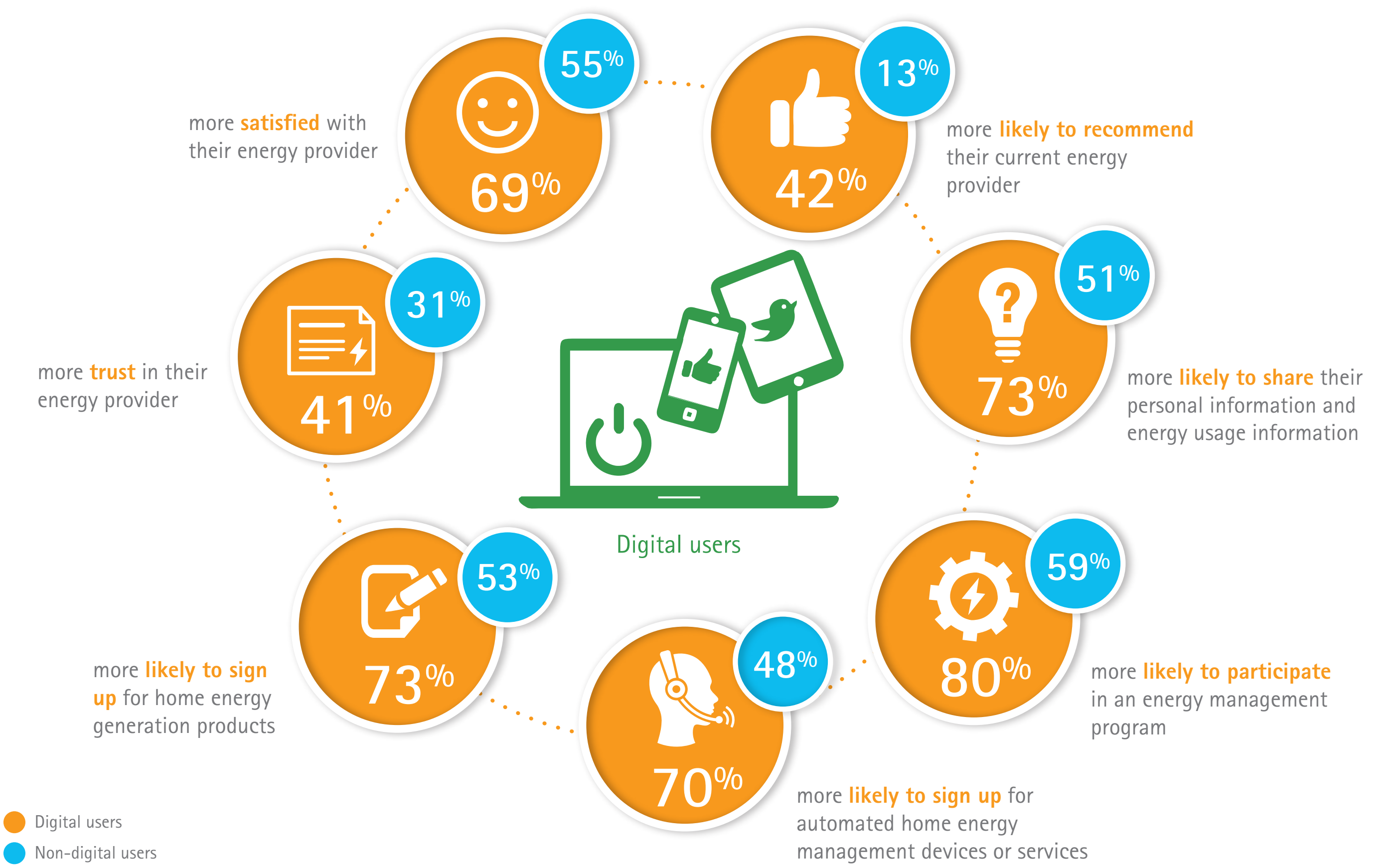
Higher trust. 41 percent of digital consumers state that they trust their energy provider to help them optimize their energy consumption, versus 31 percent of non-digital users.

Higher satisfaction. 69 percent of digital consumers indicate that they are satisfied with their energy provider—14 percentage points higher than those who do not use digital channels.

Higher likelihood to recommend. 42 percent of digital consumers indicate that they would be willing to recommend or promote their energy provider, compared to just 13 percent of non-digital users.

Higher likelihood to share personal information. Digital consumers are about 1.5 times more likely to share their personal or energy usage information than non-digital users.

Figure 2. The digitally engaged energy consumer unleashes more business value for energy providers.



Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Higher likelihood to participate. 80 percent of digital consumers indicated they would participate in an energy management program, compared to 59 percent of non-digital users.

Higher likelihood to sign up for energy-related products and services. 70 percent of digital consumers indicated they would sign up for automated home energy management devices, compared to just 48 percent of non-digital consumers. Digital consumers are nearly 1.4 times more likely to sign up for home energy generation products compared to non-digital users.

Clearly, energy providers have much to gain from building a stronger digital relationship with consumers. Many providers have invested in improving website designs, developing mobile applications, building social media engagement and strengthening digital marketing capabilities. Yet, digital needs to be the engine of every business.

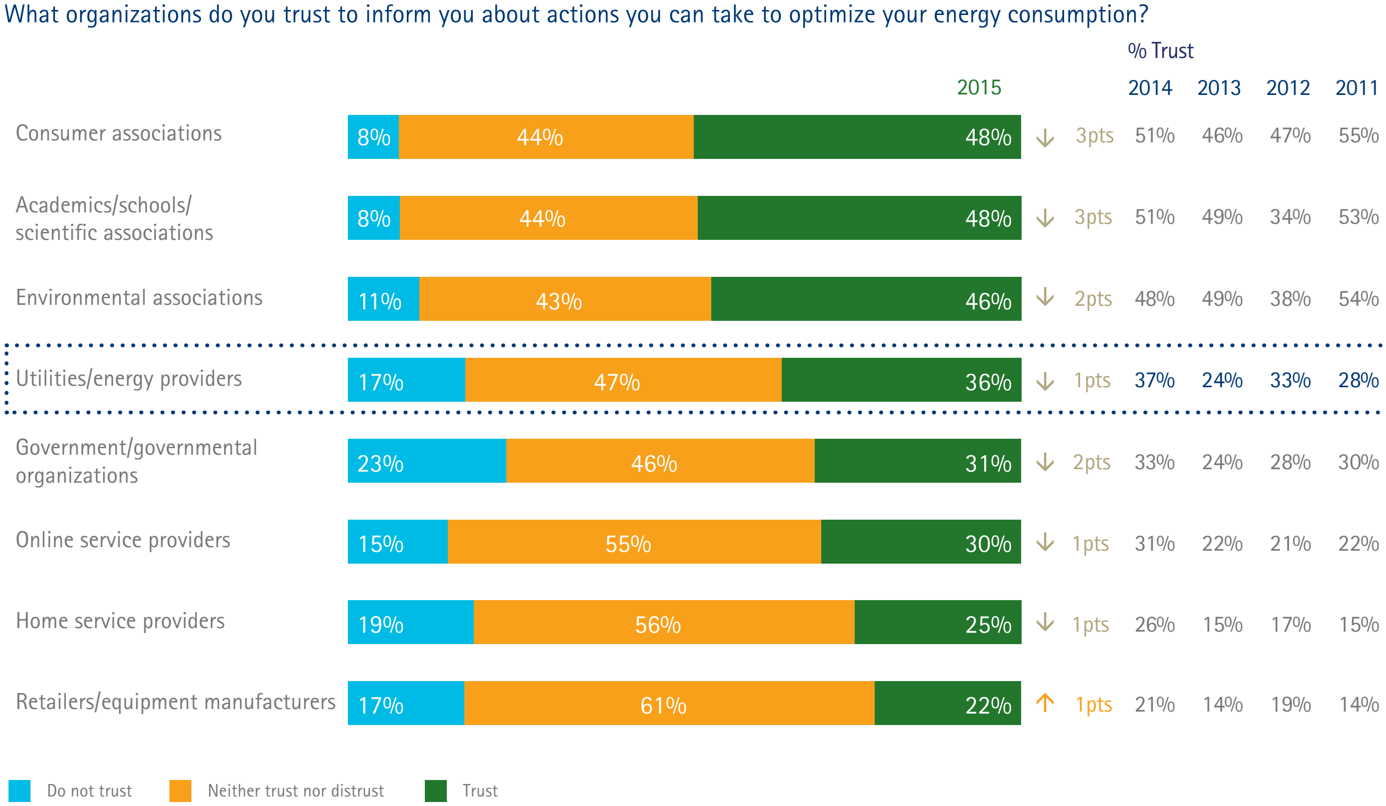
Now is the time for energy providers to take a strategic, systematic approach to transforming their operations—so they can unlock the value of digital energy consumers.

Trust is a must

With many energy providers redefining their role in consumers' lives and moving to the digital world, a foundation of consumer trust and satisfaction is increasingly paramount to success. Accenture's research shows that, overall, energy providers remain well-positioned in the minds of consumers as trusted advisors on optimized energy consumption (see Figure 3). As the energy ecosystem continues to expand and new products and services are introduced, the trust advantage can be a valuable asset that provides strategic advantage over new market entrants. Further, it positions energy providers as potential strategic partners for retailers, equipment manufacturers and other home service providers that have lower levels of consumer trust.

Figure 3. While the opportunity to improve consumer trust remains, utilities/energy providers are still better positioned than alternative providers.

What organizations do you trust to inform you about actions you can take to optimize your energy consumption?



Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

There is a marked difference in consumers' trust in their energy provider to inform them about actions they can take to optimize their energy consumption between competitive and non-competitive markets. In competitive markets, consumer trust was 28 percent whereas, in regulated markets, trust was 44 percent. Regardless of market structure, utilities and energy providers remain better positioned than alternative providers (see Figure 4).

What factors matter most to consumers in building trust with their energy provider? The vast majority of consumers surveyed indicated consistently getting the bill correct (92 percent), receiving reliable energy delivery (91 percent), and getting clear and easy-to-understand pricing information (91 percent) were the most important.[28]

Looking into customer satisfaction, 61 percent of consumers noted that they are satisfied with their energy provider. Trust and satisfaction are both significantly higher for digitally engaged consumers versus non-digital consumers (see Figure 5).

Trust and satisfaction are key components, no matter which strategy an energy provider pursues (for more information, see sidebar: "The four keys to digital trust" on page 18). By focusing on getting the basics right and eliminating areas of dissatisfaction, energy providers can establish a strong foundation for enhancing the customer relationship.

Figure 5. Digitally engaged consumers have more trust and are more satisfied with their energy providers.

Digital channel users

41% Trust

69% Satisfaction

Non-digital channel users

31% Trust

55% Satisfaction

Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Figure 4. There is a marked difference in trust of utilities/energy providers across competitive and regulated markets.

What organizations do you trust to inform you about actions you can take to optimize your energy consumption?

	% Trust 2015 Competitive markets	% Trust 2015 Regulated markets	% Trust 2014 Competitive markets	% Trust 2014 Regulated markets
Consumer associations	51%	46%	53%	49%
Academics/schools/scientific associations	44%	54%	44%	59%
Environmental associations	41%	53%	40%	55%
Utilities/energy providers	28%	44%	29%	46%
Government/governmental organizations	27%	36%	29%	38%
Online service providers	22%	39%	23%	39%
Home service providers	19%	32%	19%	33%
Retailers/equipment manufacturers	18%	26%	18%	25%

Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

The four keys to digital trust

For many companies—financial services, healthcare and energy providers—digital trust is central to the customer relationship. As consumers rapidly adopt new devices, unprecedented levels of personal information about consumers and their habits, preferences and households are available to businesses and their partners. The amount of information businesses can collect and leverage is exploding—magnifying the importance of digital trust.

Accenture defines digital trust as the confidence placed in an organization to collect, store and use the digital information of others in a manner that benefits and protects those to whom the information pertains. Increasingly, customer operations are the digital face to consumers. Energy providers' websites are portals for self-service and, in competitive markets, they are fast becoming the first stop for researching offers.

A breach of digital trust or a cybersecurity incident can quickly result in harmful business consequences—from brand erosion to consumer alienation and churn. As energy providers look to drive further digital self-service adoption and even create new businesses based on digital platforms, all four keys to digital trust—security, accountability, privacy/data control and benefit/value—should be on management's agenda (see Figure 6).

Figure 6. The four keys to digital trust.

Security

- Malware/virus protection
- Proactive data integrity/hacking prevention
- Data permissions and user identity
- Data encryption standards
- Data access logs and key storage standards
- Data connections (VPN, SSL, etc.)
- Architecting resiliency

Privacy/Data Control

- Company data policies
- Third-party data sharing
- M2M data sharing
- Regional cultural expectations
- Government access

Accountability

- Self-governance
- Reactive data integrity/legal resource
- Global and regional data standards
- Government requisition

Benefit/Value

- Customer value
- Services in-kind
- Revenue
- Brand value/loyalty
- Customer service

Source: The Four Keys to Digital Trust, Accenture, 2014.

Data privacy and security

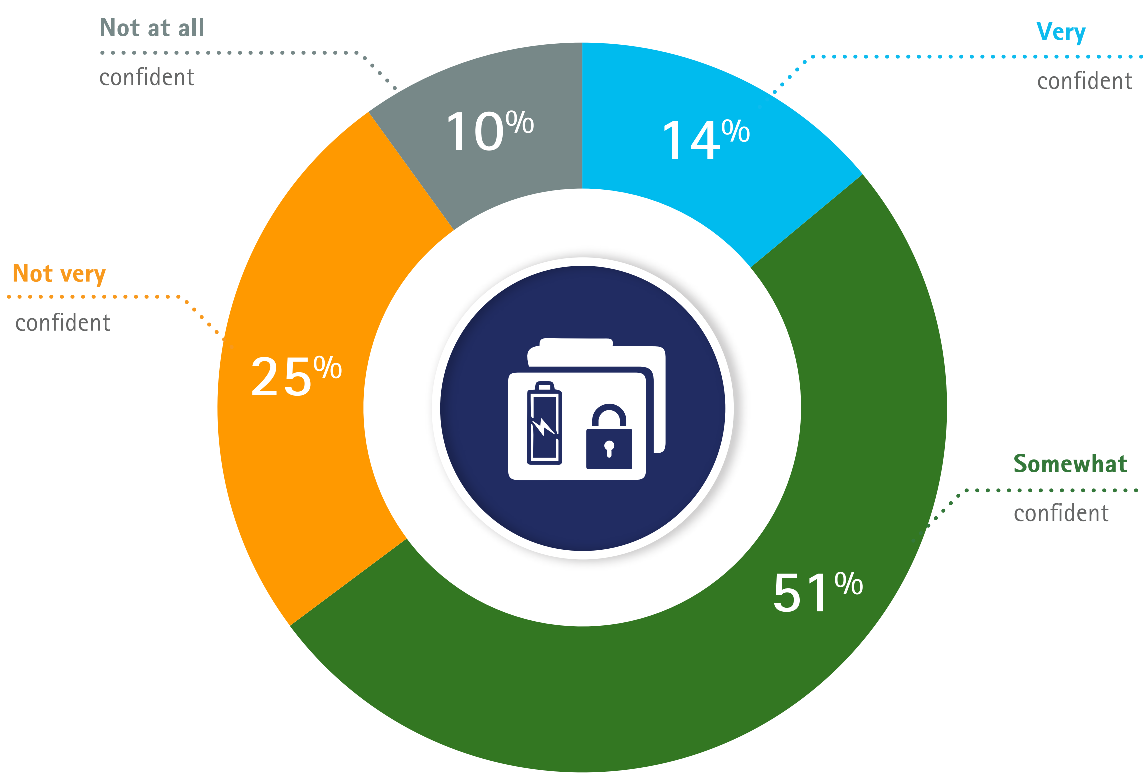
Digital channels are just one aspect of the shifting digital landscape. Smart meters and smart grid technologies are digitizing supply and distribution, providing vast amounts of customer-related usage information. Consumers, regulators and governments need to feel confident that customer information is safe—particularly because smart meter and connected home data often provides unprecedented insight into consumers' personal lives. With such data, analysts can determine the number of people in the home and how they behave when they are there.

However, consumers are willing to share personal information if they trust the energy provider's privacy and security standards and if they see value in sharing the information. Sixty-five percent of consumers are confident that their energy provider protects their personal and energy usage data and information (see Figure 7). That level of trust is relatively high, considering that only 45 percent of consumers have confidence in the security of their personal data when shared across providers.[29]

In addition to further increasing consumers' confidence in their data protection and security, energy providers have the chance to begin testing and using this data—identifying new ways to deliver value for themselves and for consumers. Data monetization is a growing industry. As just one example, Accenture estimated that while the global market for monetization of data by telecom in just a handful of applications (retail audits, location-based advertising and card fraud, among others) was $22 billion in 2013, it could reach $37 billion in 2015.[30]

Figure 7. Energy providers have an opportunity to enhance consumers' confidence in data privacy and security.

How confident are you that your energy provider secures and protects your personal data and information on your energy usage?



Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

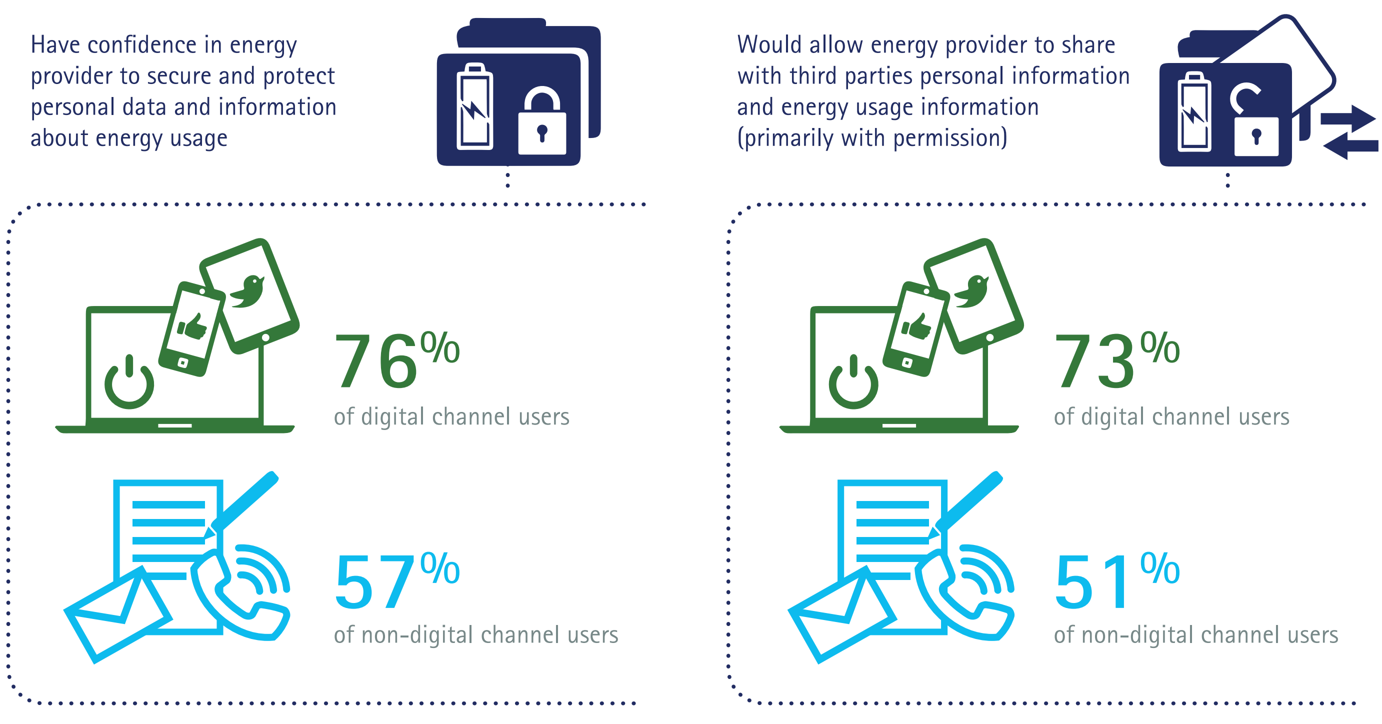
Interestingly, our 2015 survey revealed that digital consumers are more comfortable sharing their personal data and have a greater degree of confidence in their energy provider's ability to safeguard their data. About three-quarters of digital consumers indicate that they are confident that their energy provider secures and protects their data and would allow that data to be shared with third parties (primarily with permission). By contrast, only a little more than half of non-digital energy consumers express that sentiment (see Figure 8).

As consumers become more digitally engaged, there may be growing opportunities to leverage customer data. To comply with regulations while building trust with consumers, energy providers need to be very transparent about how they are using consumer data and whether and how that data will be shared with third-party providers.

Energy providers can put the decision of sharing information back into the hands of consumers with simple, convenient approaches. For example, San Diego Gas & Electric® (SDG&E®) has more than 15 certified third parties that are part of its Green Button Connect My Data program. Through the program, residential and business customers can authorize SDG&E to share their usage information with specified third parties on an ongoing basis. Some of these third parties charge a fee for value-added services, such as energy audits or analytics, while others are free.[31]

As consumers—especially those who are digitally engaged—become more comfortable sharing their energy-related data with third parties, energy providers that get bogged down in the data privacy debate may miss opportunities. Google, through the Nest Learning Thermostat, is gathering a wealth of home-energy and other behavioral information. To create and capture value over the long term, energy providers need to stop debating and start formulating a deliberate and proactive data and analytics strategy.

Figure 8. Digitally engaged energy consumers are more confident about their energy provider's ability to secure and protect their data and more willing to share their information.



Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Service design is a new critical capability

As energy providers look to create more enticing digital experiences—those that will drive stickiness of current digital consumers and attract new consumers—they need to reframe the problems and reimagine the possibilities. One viable approach is service design. Service design embraces a holistic view of problems and objectives that considers the situation, context, business objectives and consumer behaviors to redesign how consumers interact with the world around them. It yields digital experiences that are simple, innovative and empowering for consumers.

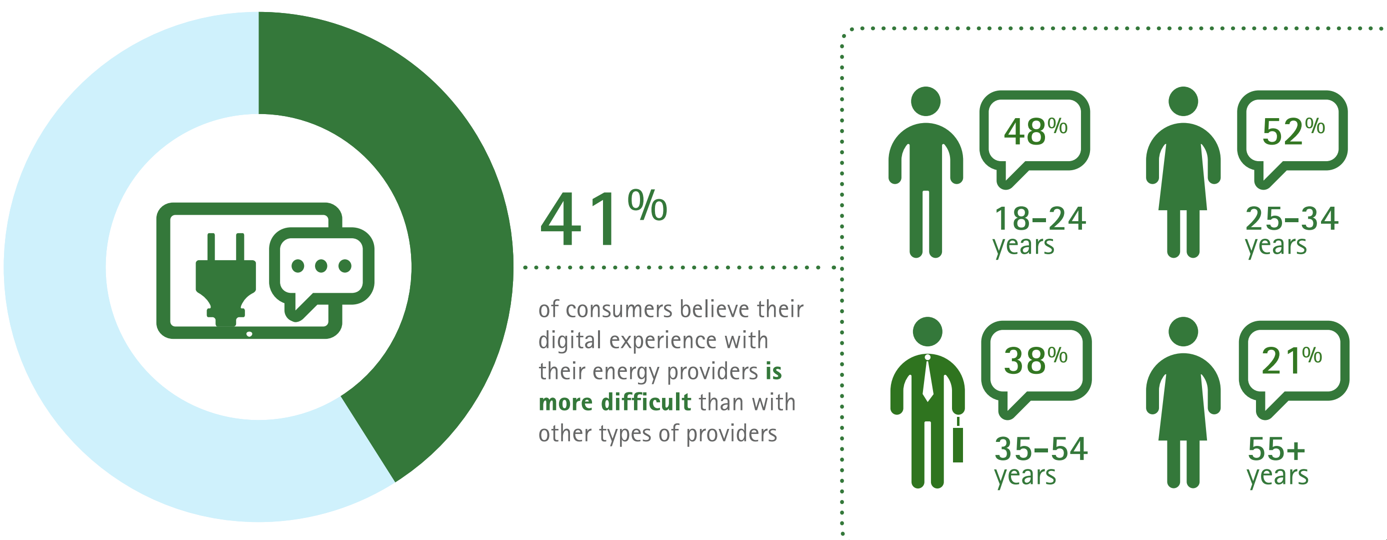
When it comes to engaging digital consumers, design is a critical capability. Well-designed experiences go beyond enhancing consumer engagement; they actually simplify by anticipating services and experiences for consumers and energy providers alike. For example, Internet television network Netflix used micro data to predict that the show *House of Cards* would be successful before they started filming it.[32]

Accenture conducted a pilot with a large telecommunications company to effectively resolve customer inquiries through a digital assistant that combines live monitoring, artificial intelligence and automation to optimize customer interaction across channels. Live agents supervise and collaborate with robots—which handle the majority of routine interactions—only intervening opportunistically or as needed. Combining humans and automation resulted in more than 80 percent of inquiries resolved online, and employee engagement and satisfaction increased as their focus shifted to high-value, non-repetitive customer interactions.[33]

To date, typical approaches to digital user experience, system design and development have reinforced a current state and inward-looking mindset defined by today's processes, systems and operations. The No. 1 reason customers would want to use their energy provider's digital channels is quick, convenient service. Yet, 41 percent of consumers still believe the digital experience with their energy provider is more difficult than with their other service providers, with younger consumers more likely to have that perception (see Figure 9).

Figure 9. Energy providers have an opportunity to improve consumers' digital experience compared to other providers.

When considering Web and mobile interactions with your energy provider, do you believe your digital experience with your energy provider is more difficult than interacting with other types of providers (e.g., telecommunications, retailers, cable providers)?



Base: All respondents who interacted with their energy provider through online portal/website or mobile application over the past year.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Leading providers will move to a progressive service design experience, one that begins where the consumer starts and leads them logically through the various methods of service available: online, social, mobile, voice and in-person. Winning digital brands will seek to bridge the gaps between experiences, services, devices and places. Such gaps cannot be avoided, but they can be managed more effectively through scalable platforms.

For evidence of the power of service design, consider Scandinavian mobile operator 3. The company engaged Fjord to help increase self-service adoption and improve customer satisfaction by helping consumers truly understand their bills. To that end, 3 used a service design approach to develop a mobile application that reinvented how its customers view their mobile phone usage and bills (for more on this approach, see sidebar: "Putting design at the heart of your digital business").

Recognizing that phones are all about connection with family and friends, the app offers a view of recent social history, a dynamic phonebook of favorite friends, a view of typical daily usage, and engaging visualizations of the bill.

This breakthrough innovation has led to significant customer adoption, higher engagement (with 70 percent of customers using the app monthly) and lower call volumes (half of users report calling customer support less often because of the app).[34]

Whether energy providers want to engage digitally oriented consumers or wish to increase digital adoption, digital service design is a core capability that transcends traditional channel strategy (for an example, see sidebar: "Future-proofing a retail energy business").

Putting design at the heart of your digital business

Fjord, a design agency that is part of Accenture Interactive, believes that effective digital design services are essential in this era of the digital transformation of everything. To meet ever-growing consumer demands, energy providers will benefit from an emotional, customer-centered approach combined with rational business analysis and underpinned by technology and organizational transformation.

The *2015 Trends Impacting Design & Innovation* report, Fjord's annual edition, highlights the impact of digital on the real world and explores how digital is shaping both consumer expectations and service design.

It also distills Accenture's thinking on nine core ideas and trends aimed at provoking, informing, inspiring and, above all, providing actionable insight.

Future-proofing a retail energy business

New Zealand's Powershop claims to be the world's first retail online energy market.[35] When launched in 2009, the energy retailer set out to establish a profitable new business model—one that would future-proof it against disruptive market forces, including the risks of new entrants, inevitable and ongoing technology change, and intensifying regulatory pressures.

Leveraging a smartphone app, analytics and a strong brand, Powershop is winning energy consumers not only in New Zealand, but also in the highly competitive Australian retail market. Powershop recognizes that to capitalize on commodity sales, it needs to be responsive to the needs and values of its consumer base. From their smartphones, customers can monitor home energy consumption, be notified when a consumption spike occurs and choose the source of their electricity. Sources include alternative energy projects such as wind, solar or even sugarcane processing and landfill generation.

Powershop's social media strategy is designed with a primary focus on customer choice, convenience and control. All of its social media channels, including Facebook and Twitter, offer consumers effortless access and support, making it easy to do business with the company. Powershop also uses its social media channels to build its fun and quirky personality and brand.

Customers can also take advantage of energy specials, such as energy that is discounted for a period of time or a monetary incentive for recommending Powershop to friends. These specials are not emailed to consumers; instead, they are shared publicly on social media. This reflects the company's preference to engage consumers in a two-way conversation and incent them to use social media by rewarding them for their "like" or "follow" actions. The retailer is also exploring the potential to use its platform to feature quasi-crowdfunding programs, where consumers could invest in energy projects to offset future energy costs.

Powershop's brand and digital campaigns are disruptive, relevant and entertaining, turning many apathetic consumers into passionate followers. These digital consumer-centric capabilities and offerings have fueled Powershop's success in acquiring and retaining consumers.

Mobile on the move

As energy providers work to transform the digital consumer experience, mobility remains central to the digital landscape. Smartphones have become nearly ubiquitous across geographies and consumer segments. *The Accenture Digital Consumer Tech Survey 2014* found that, globally, 69 percent of consumers own a smartphone, and more than half (52 percent) plan to buy a new smartphone in the next 12 months.[36] The dramatic growth in mobility adoption—particularly of smartphones—means that consumers now consider anytime, anywhere access as a basic expectation. What's more, satisfaction with digital experiences is increasingly defined by what consumers can or cannot do through their mobile devices.

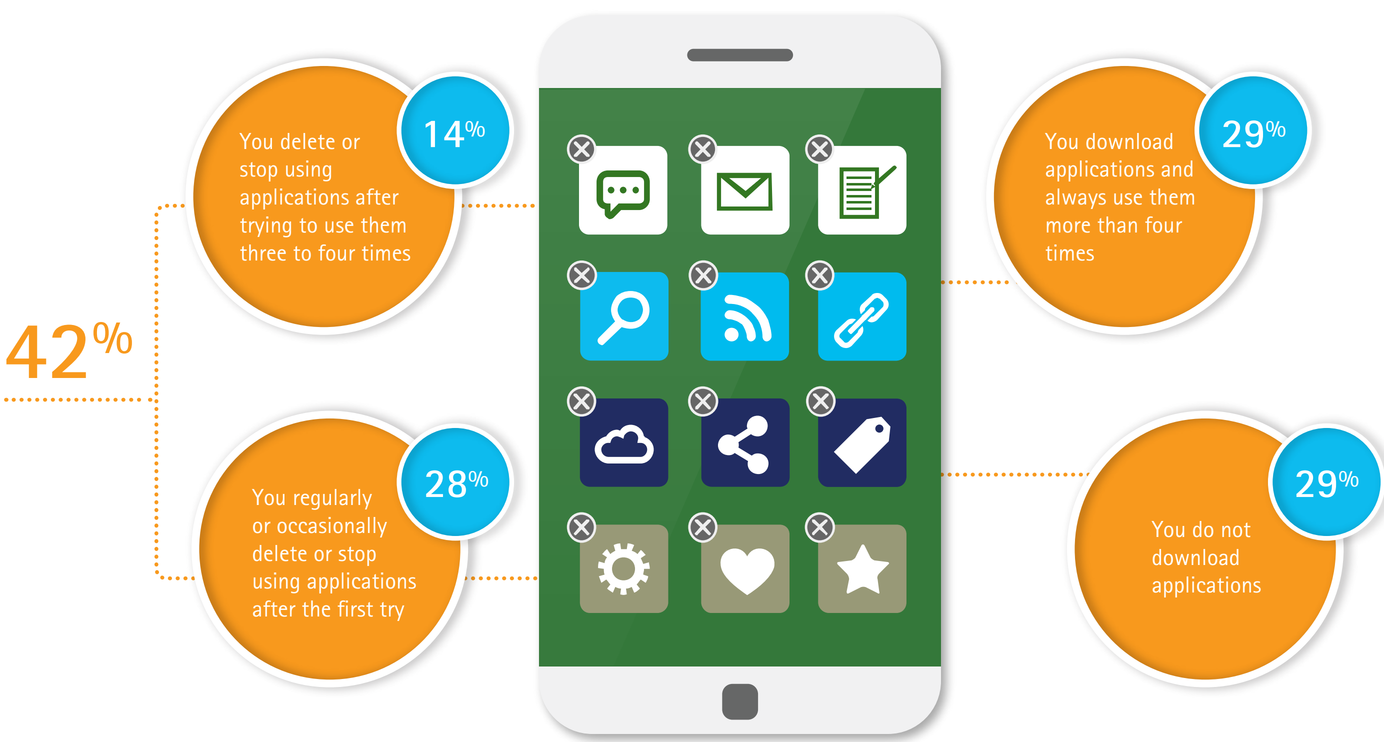
Of course, mobility also creates an extremely comparative experience. With just the swipe of a finger, consumers can shift between mobile websites or applications. Energy provider apps live alongside banking apps that have simplified nearly every routine transaction. In addition to viewing account balances and transferring funds to different accounts or people, consumers can snap pictures of checks to deposit them. They also can set savings targets and monitor progress, as well as make appointments with bank employees for more complex interactions. Consumers increasingly expect that same level of convenience and ease from all providers. The bar for mobile experiences will continue to rise, with a recent Accenture C-suite survey revealing that mobility is the top area of digital focus among cross-industry executives.[37]

In the utilities industry, the potential for mobility has not gone unnoticed. The number of providers with mobile-enabled websites and mobile applications has grown exponentially in recent years. Some providers have achieved considerable success, particularly in geographies where storms and other dramatic weather events have paired well with mobile outage capabilities.

In many situations, however, energy providers face a battle for share of screen. In the United States, for example, consumers spend more than 30 hours a month using phone apps and use, on average, 27 different apps each month.[38] Standing out in this digital ecosystem is no easy task—and our research shows that consumers are quick and unforgiving in their judgment of mobile applications. In fact, 42 percent of consumers say they routinely delete or stop using mobile applications after just a few tries (see Figure 10).

Figure 10. Getting the mobile app experience right is critical.

Which of the following best describes your use of mobile applications?



Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

The top two reasons are related to functionality issues (see Figure 11). Consumers expect energy providers to seamlessly deliver the appropriate functionality in a way that is simple, intuitive and very responsive. Getting the mobile app experience right the first time is critical.

While energy providers may be inclined to take a wait-and-see or piecemeal approach to mobility, our research suggests this approach is becoming risky, as consumers' interest in mobility has reached a tipping point. Sixty percent of energy consumers say they would use a simple and intuitive mobile app from their energy provider. More specifically, billing and outage capabilities top consumers' list of expectations, followed closely by energy usage information (see Figure 12).

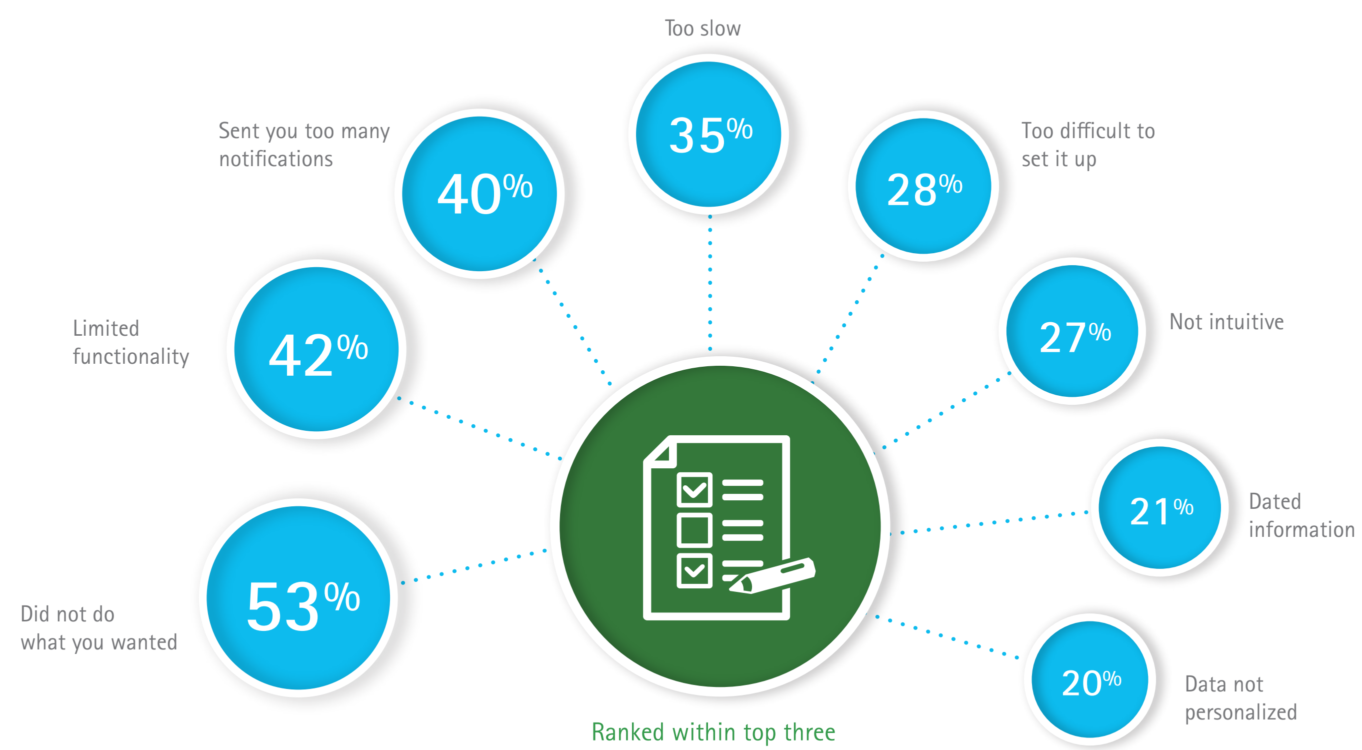
Consumers expect their energy provider to deliver a personalized experience that helps them in some way. That expectation has been shaped by consumers' daily experiences with other industries—including health bands and fitness monitors for tracking and improving health; banking apps that monitor financial goals and monitor progress; and music streaming services, such as Pandora,[39] which learns an individual's preferences and produces playlists based on those insights. In our latest research, 62 percent of consumers said they would allow their utility's mobile application to leverage their location information via GPS for value-added services. Specifically, they would support such usage for reporting or receiving outage notifications and updates, identifying the closest payment center, and receiving retail promotions and coupons for energy-related products and services while shopping.

As mobile apps continue to proliferate, the issue of consumers' mobile real estate becomes a consideration. Successful mobile app designers not only consider the implications of adding real estate, but also determine how the wider ecosystem would work with an addition. Providers also have the ability to offer mobile solutions across the spectrum such as responsive Web, or leveraging social apps to custom apps.

Mobility can enable new value and help redefine the energy provider value proposition. The key is making sure that consumers are able to successfully address their needs.

Figure 11. A wide range of mobile dissatisfiers need to be addressed.

Usually, what are the main reasons for deleting or not using an application after the first try?



Base: Respondents that regularly delete or stop using applications after the first try.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Social @ scale

Energy providers have noticed the growing power of social networks. In mass outages and natural disasters, social networks have become the primary vehicle for customer communication and message broadcasting. Social media also has become an integral part of public relations, corporate communications and branding. However, energy providers continue to work to develop a holistic approach that delivers tangible benefits.

Social can be leveraged as a platform for engaging consumers, gathering data and driving new revenue. American Express has pioneered several successful online initiatives that monetized the features of social media. They included discounts for location check-ins via Foursquare, as well as discounts through Facebook.[40] Texas-based Bounce Energy has taken a similar approach, using Facebook and Twitter as core customer acquisition channels. In addition to special offers for followers, Bounce maintains an ambassador program that rewards consumers for sharing corporate marketing content.[41]

Importantly, social media is not just about marketing. It also can be a valuable mechanism for gathering consumer feedback. Energy providers have largely embraced social listening as a way to judge sentiment and identify early warnings of media and customer service issues.

Social networks can also be a vehicle for crowdsourcing ideas. Over a one-year period, ComEd ran a social media campaign to help redesign its bill. It created a Facebook app to allow customers to provide feedback on potential designs. When it launched the new bill, the entire journey was driven through social channels.[42]

Figure 12. Consumers prioritize bill display and outage information as "must haves" for mobile apps.

Which features or functionalities would you expect when considering using a mobile application to interact with your energy provider?

Bill display	64%
Outage information	60%
Report an outage in your location	59%
Energy usage information	58%
Account settings and controls	56%
Immediate access to phone support if you aren't able to navigate the mobile experience	53%
Bill payment	52%
Meter reading submission (submit manually or via photo)	51%
Account profile information	50%
Starting or stopping your service (move-in-move-out)	46%
Help functions within the app	40%
Control and monitor appliances	39%
Energy audit information	34%
Personalized energy-efficiency tips	32%
Online shopping for new appliances with rewards and/or points	28%
Option to split bill between tenants-roommates	26%
A game that improves your understanding of energy and offers you rewards	19%

Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Such social programs will become increasingly important to engaging energy consumers. Accenture research shows that the number of consumers interacting with their energy providers through social media is set to double in the next two years (see Figure 13).

For consumers, social is becoming another channel for learning about products and services and receiving customer service. Energy providers need to approach these networks accordingly. Success hinges on understanding the relevant social audience, mapping customer needs to a social experience the organization can deliver and, most importantly, confirming the organization has the appropriate capabilities to execute. Successful energy providers will confirm that social monitoring reports are not treated as interesting reading. Instead, they will deliver such reports—along with actionable insights—to stakeholders across the organization. In addition, they will treat socially-based service not as a side job, but as an integrated channel with tracking and performance monitoring. And they will approach social marketing not as an afterthought, but as a central element in planning and designing every campaign.

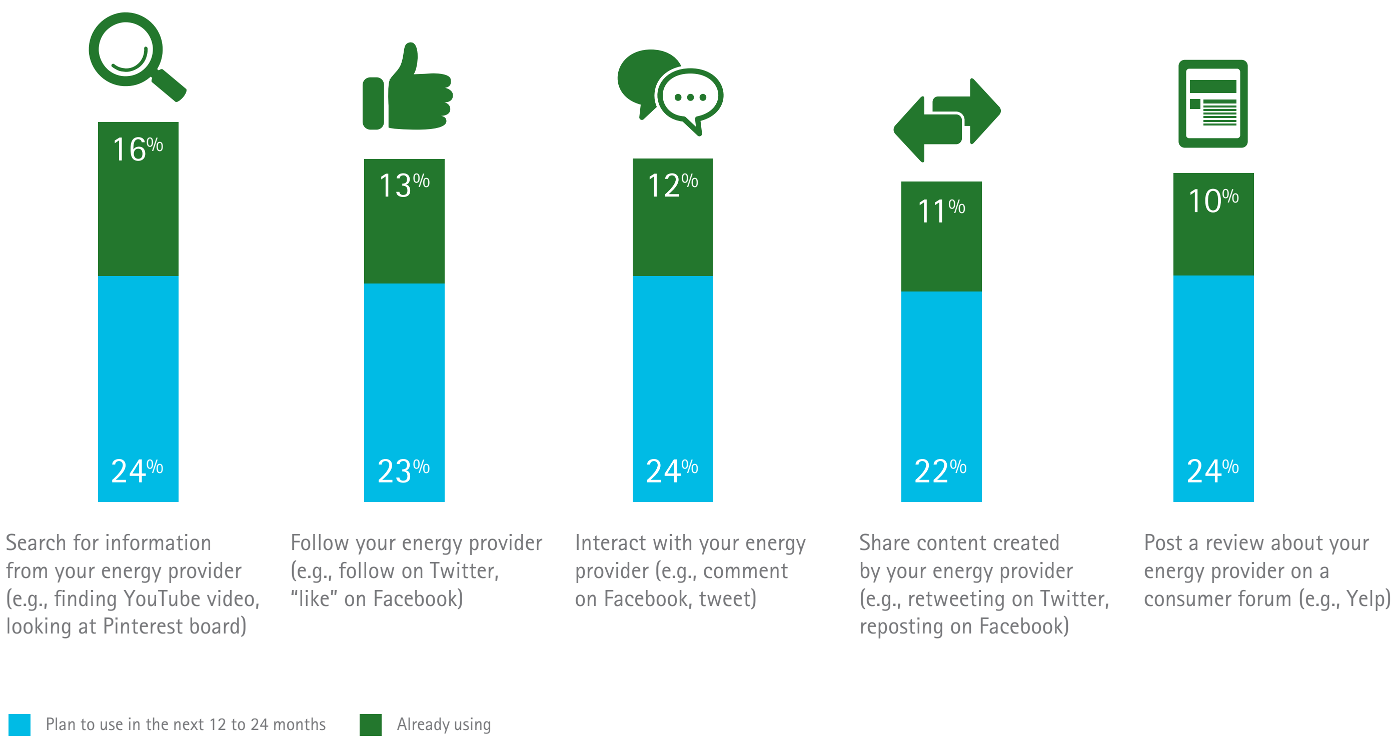
With this integrated approach, energy providers can reap the benefits of social—and may even be able to do so without significant additional cost or processes.

Creating digital dividends

Even with progress to date, energy providers have room to improve the digital experience—and now is the time to accelerate digital adoption. As energy providers seek to strengthen and expand digital consumer engagement, they will need to change the fundamentals of the digital experience, from building digital trust to designing services to integrating digital experiences. Doing so will not only unlock value from current business models, but also unleash opportunities to offer new products and services.

Figure 13. Consumers using social media in the next two years could double.

Are you already using or do you plan to use your energy provider's social media (e.g., Facebook, Twitter, blogs, discussion forums) for any of the following actions?



Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Extending the value proposition

As adoption of rooftop solar and other distributed generation technologies increases, consumers' knowledge and interest in home energy management solutions is on the rise. Energy providers have the opportunity to forge new paths to value by expanding their portfolio of products and services.

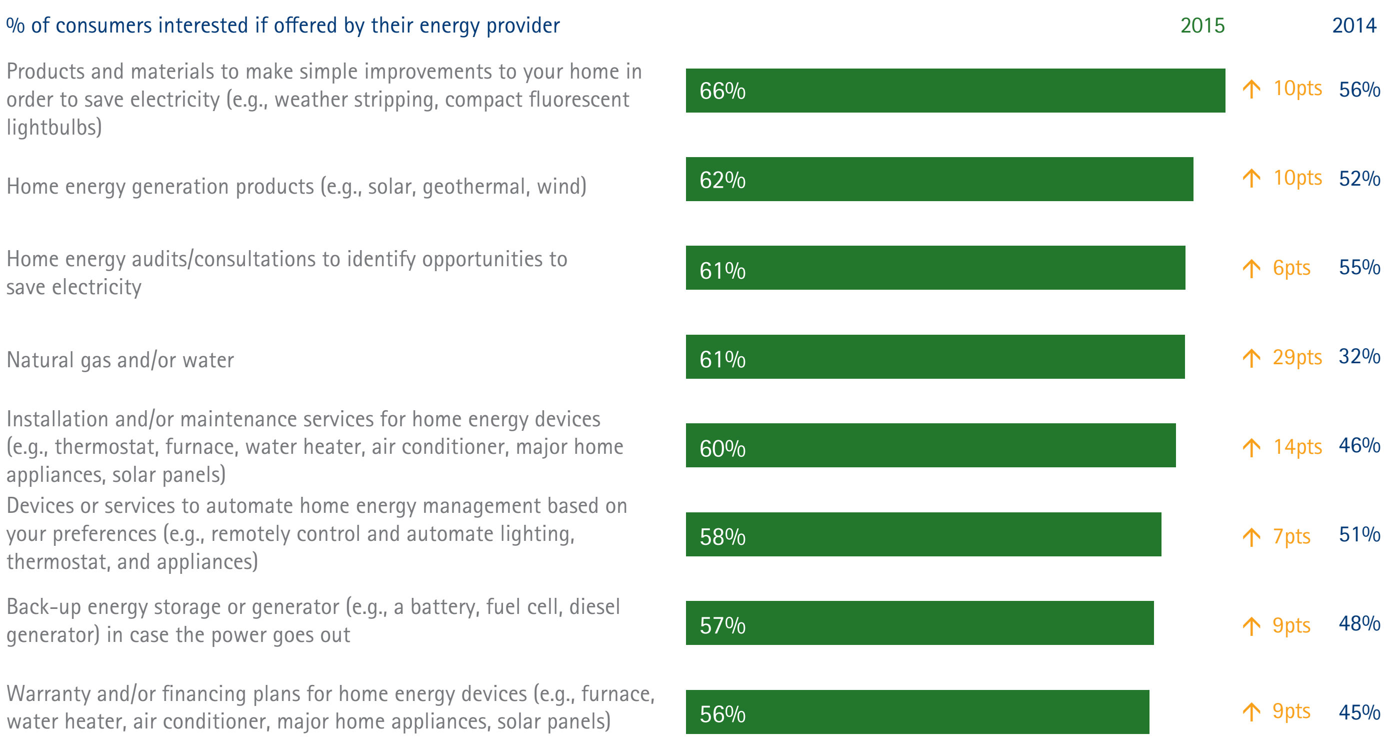
Extending traditional consumer value

As consumer and energy provider relationships become more multifaceted, so does the availability and range of products and services that energy providers can offer. In competitive markets, leaders are blazing the trail with bundled offerings and connected home solutions. For example, Endesa is offering a wide range of home-related services, such as EV charging stations and smart communication portals.[43]

Through our research program, Accenture has been tracking consumer interest in value-added products and services and has witnessed a substantial rise. Driven perhaps by technology convergence or consumers' broader view of the energy ecosystem, consumer interest in signing up for energy-related products and services appears to be gaining momentum across the board—with more than half of consumers interested in a wide range of products and services from their energy providers (see Figure 14).

No longer are value-added products and services niche market opportunities. In competitive markets, there are opportunities to create significant new revenue streams by offering additional home-related products and services, extending the value proposition to dual fuel and providing financing plans or maintenance services. In a regulated marketplace, opportunities also exist for utilities. Energy providers should consider innovative partnerships or information services as a way to create more value for consumers—and extend the mindshare for energy-related products and services.

Figure 14. Interest in energy-related products and services has significantly increased over the past year.



Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

While interest is high among all energy consumers, digitally engaged consumers may represent even greater value. Digitally engaged consumers consistently express a higher level of interest, up to 22 percentage points higher than their non-digital counterparts (see Figure 15).

Accenture believes that we have "turned a corner" with consumer interest in energy-related products and services on the rise, creating new opportunities for energy providers.

Expanding energy consumerism

As consumers' interest in energy-related products and services increases, the real question is around when and how energy consumers will expand their purchasing behaviors beyond the commodity. When thinking about home energy management, home energy generation, or other such solutions and services, approximately three times as many digitally engaged consumers say they will invest in the next year (see Figure 16). Energy consumers who indicate their intention to purchase or sign up for energy-related products and services are highest for home energy management reports and in-home energy management solutions, followed by home energy generation–related products and services and, finally, EV charging solutions. Interestingly, consumers also indicate an interest in financing services for energy-related products and services. As consumer adoption of energy-related products and services continues to evolve, energy providers will need to determine their products and services portfolio strategy.

Nurturing the multifaceted solar prosumer

Rooftop and small-scale solar installations are one of the first technologies to become a cost-effective micro-generation solution for residential and commercial consumers. With the cost of producing, installing and managing solar panels falling exponentially in recent years, certain geographies have already reached grid parity.

Our New Energy Consumer research program has sought to understand the increasing market for solar-related generation options, as well as the opportunity available for energy providers. Overall knowledge of solar energy products and services appears to be low, with only about a third of customers knowledgeable about rooftop solar products and even fewer claiming knowledge of community solar projects or solar services. Nevertheless, while only a handful of respondents (9 percent) had solar products in 2014, 55 percent said they were considering purchasing or signing up in the next five years.[44]

Given rising adoption and consumer interest, a variety of innovative companies are entering the market in an effort to disrupt the traditional utility value chain. We also see a growing array of solar home solutions and community solar projects, as well as a host of supporting services—from automated support to financing instruments. In many geographies, energy providers have moved quickly to offer solar products and services directly or via partnerships in an effort to prevent margin erosion and/or increase customer engagement.

Based on our findings, energy providers are well positioned to capture value by deploying solar-related products and services. While consumers' top choice (in 2014) may be specialized providers (74 percent), energy providers were a very close second at 71 percent. Further reinforcing these trends are consumers' "moments of truth" when making decisions to sign up for solar products and services. With 46 percent saying they would engage in a discussion when their energy bill is higher than expected, energy providers already have a significant opportunity to leverage existing relationships and data in order to connect with consumers in a more meaningful manner.[45]

In this context, it is clear that distributed energy resource solutions like solar are set to be game changers. Consequently, a growing number of utilities' consumers should be viewed as partners—which introduces a host of complexities around billing, customer support and field maintenance. Successful energy providers will be those currently building a prosumer-centric approach and a new platform for creating and delivering consumer value.

Getting comfortable in the connected home

The connected home has become a reality and consumers have become increasingly accustomed to connected devices. These devices are proliferating and, with greater intelligence embedded within them, consumers can select a set-and-forget approach, manual control or a happy medium to suit their preferences. Appliances, televisions, thermostats, lights, locks, phones and computers are all getting smarter—with energy remaining the primary connector.

In *The New Energy Consumer: Architecting for the Future*, Accenture highlighted that while consumer knowledge of connected home devices was relatively low, 53 percent were likely to purchase monitoring and control services from their energy provider. Consumers indicated that, second only to companies that specialize in connected products and services, energy providers are the most preferred providers for monitoring and controlling these devices.

Some energy providers and non-utility players are already entering the connected home market through innovation, partnerships and acquisitions. For instance, Facebook has announced it will offer a software development kit for the Parse platform to developers building connected devices,[46] and Apple has announced its HomeKit solution.[47] And while the connected home remains a fragmented market, exciting opportunities are emerging to make energy management so seamless that, in time, it will be invisible to consumers. A number of utilities and other providers are already working to make that vision a reality:

British Gas. In a deal worth $100 million, British Gas acquired AlertMe, a developer of platforms for running smart home devices. British Gas now owns AlertMe's Hive product, which allows consumers to control their heating and hot water remotely. The acquisition allows British Gas to launch a family of smart home products to bring consumers innovative ways to help them reimagine how they live in their homes.[48]

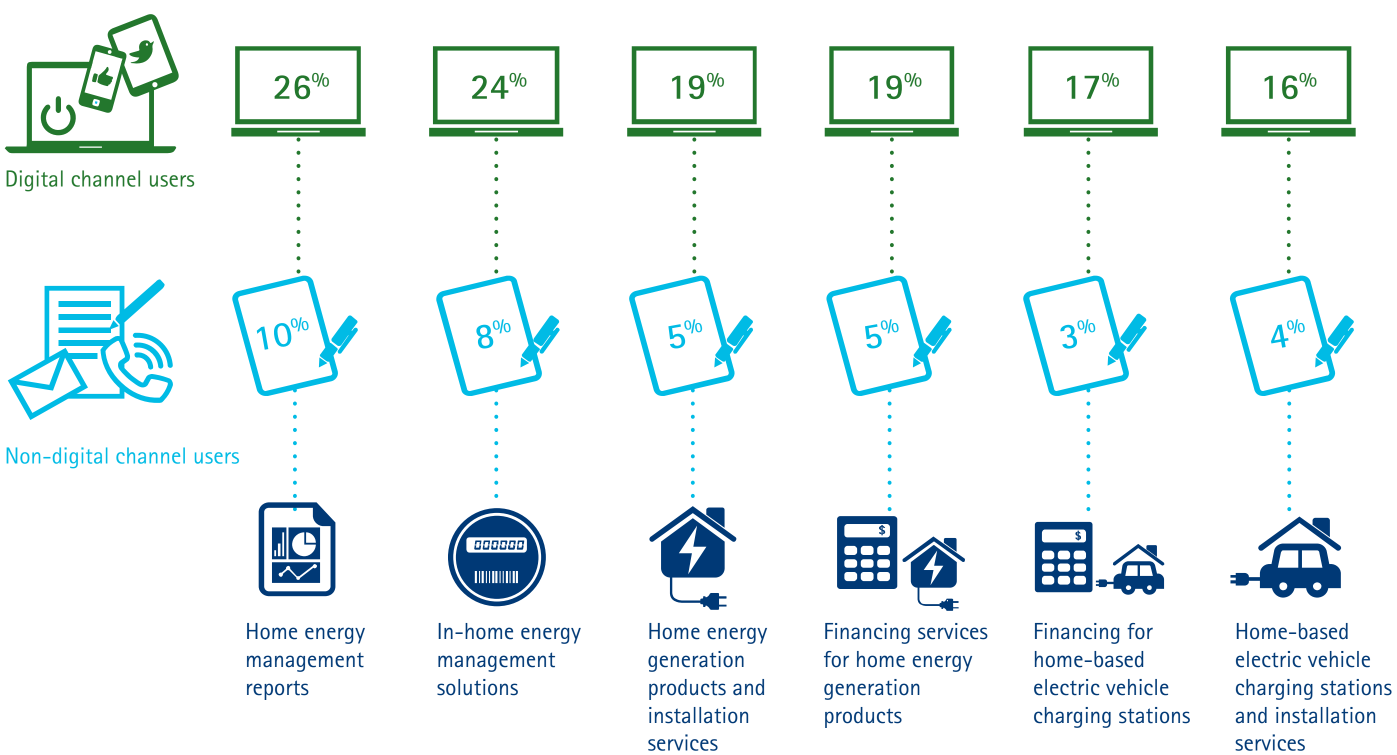
Figure 15. Digitally engaged energy consumers are significantly more interested in signing up for products and services.

% of digital and non-digital users interested in signing up for	Digital channel users	Non-digital channel users
Products and materials to make simple improvements to your home in order to save electricity	76%	57%
Home energy generation products	73%	53%
Home energy audits/consultations to identify opportunities to save electricity	72%	52%
Natural gas and/or water	72%	52%
Installation and/or maintenance services for home energy devices	71%	51%
Devices or services to automate home energy management based on your preferences	70%	48%
Back-up energy storage or generator	67%	49%
Warranty and/or financing plans for home energy devices	67%	48%

Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Figure 16. Digitally engaged energy consumers are significantly more likely to purchase or sign up for home energy products and services in the next 12 months.

Share of respondents that plan to purchase within the next 12 months



Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Home Depot. Home Depot has launched a series of connected home appliances compatible with its Wink platform. Wink-enabled products are operated either through the Wink app or the Wink Hub. Through the app, consumers can control their air conditioners, blinds, door locks and garage doors. There are no monthly fees to use the app service and Wink is compatible with a number of wireless technologies—Wi-Fi, Bluetooth LE, Z-Wave, ZigBee and Lutron Clear Connect.[49]

Although there are currently no clear winners in the increasingly crowded connected home environment, many players are vying for different parts of the ecosystem, ranging from platforms to hardware. Energy providers can play a role in the connected home by determining whether it is "owning" the home or engaging with the ecosystem—to support their primary business objectives.

Plugging in to the EV market

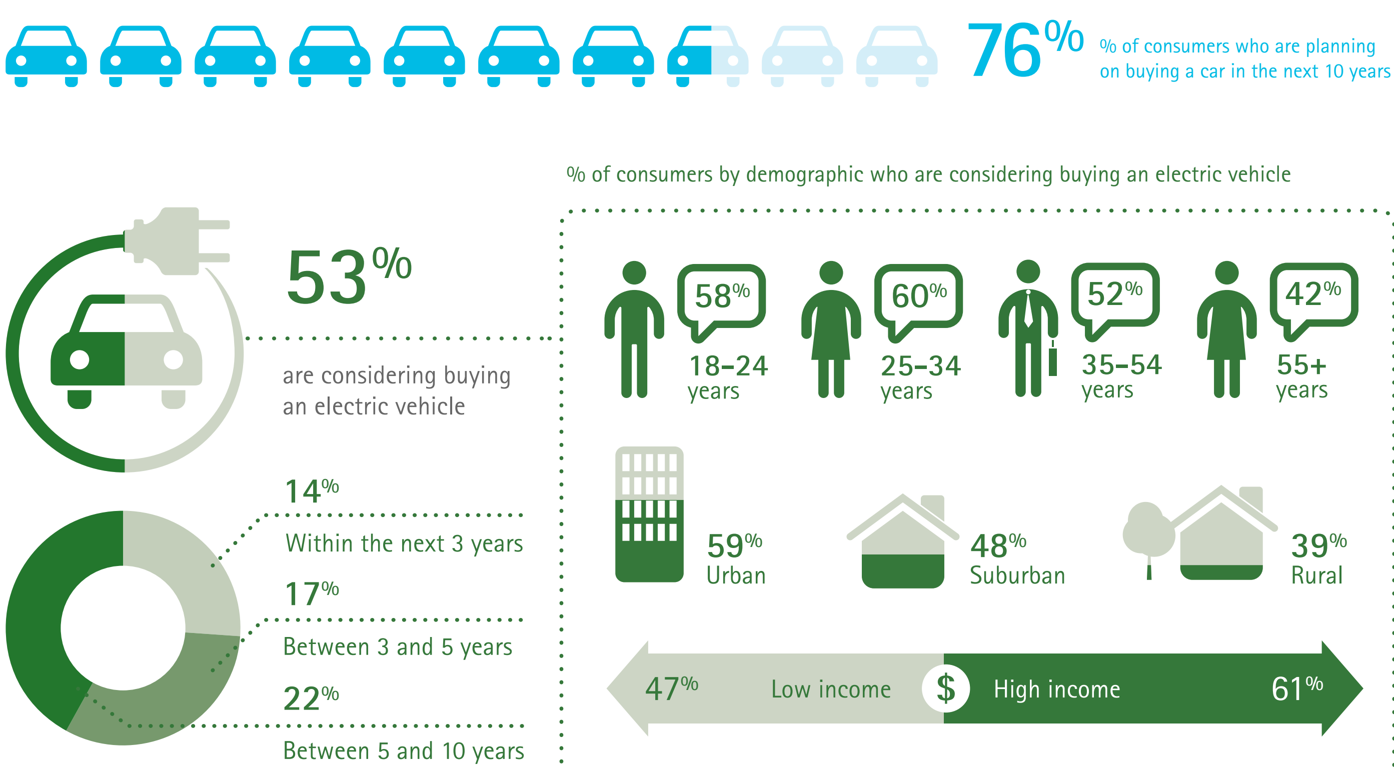
Global sales of electric vehicles (EVs) have been increasing. Investments from firms such as Tesla are driving technological advances, decreasing costs and increasing mileage capabilities—removing many of the traditional barriers to EV adoption. Meanwhile, Apple is among the major new players potentially spurring EV innovation and consumer adoption.[50]

In *The New Energy Consumer: Architecting for the Future*, Accenture explored the rising interest in EVs and consumer preferences around related products and services. While EV adoption has continued to grow steadily, forecasts call for demand to increase sharply over the next five to 10 years. More than half of consumers were considering an EV for their next car purchase, representing a continuing opportunity for energy providers to increase revenues and engage consumers (see Figure 17).

When considering the rising interest in connected home technology and micro-generation, the electric vehicle may be considered the unifying technology, providing a true solution for daily energy engagement.

Energy providers have opportunities to establish their presence in the EV market. In fact, energy providers are well positioned to be a preferred vendor of home-based EV products and services, such as those for installation, maintenance and energy management.

Figure 17. More than half of consumers are considering an electric vehicle for their next car purchase.



Base: All respondents.
Source: *The New Energy Consumer: Architecting for the Future*, Accenture, 2014.

According to our 2015 research, when it comes to EV home-based charging solutions from their energy provider, consumers responded with the following level of interest:

- 42 percent in a home-based solution that automatically charges the EV during times of the day when electricity is cheapest
- 39 percent in the installation of an EV home-based charging station
- 26 percent in maintenance services for an EV home-based charging station

Some progressive energy providers are collaborating with fellow energy providers or local governments to provide charging station products and services. For example, CLEVER is a leading provider of EV charging stations in Denmark.[51] Owned by five large Danish energy providers that together service more than 60 percent of the Danish market (SEAS-NVE, SE, NRGi, EnergiMidt and Energi Fyn), CLEVER provides public and home-based charging solutions.

Consumers are beginning to realize that their EV batteries could be used to store excess solar generation during the day for use at night. The Tesla Model S battery can reportedly already store enough energy to power the average US household for three and a half days.[52]

EV manufacturers and energy providers are forming strategic alliances to develop a common platform to communicate between EVs and the smart grid.[53] As consumers begin to use the batteries in their EVs as a power source for their home, the energy provider could expand its offerings to these consumers to include home energy management solutions that help maximize the charge and life of the battery.

Power "on demand"

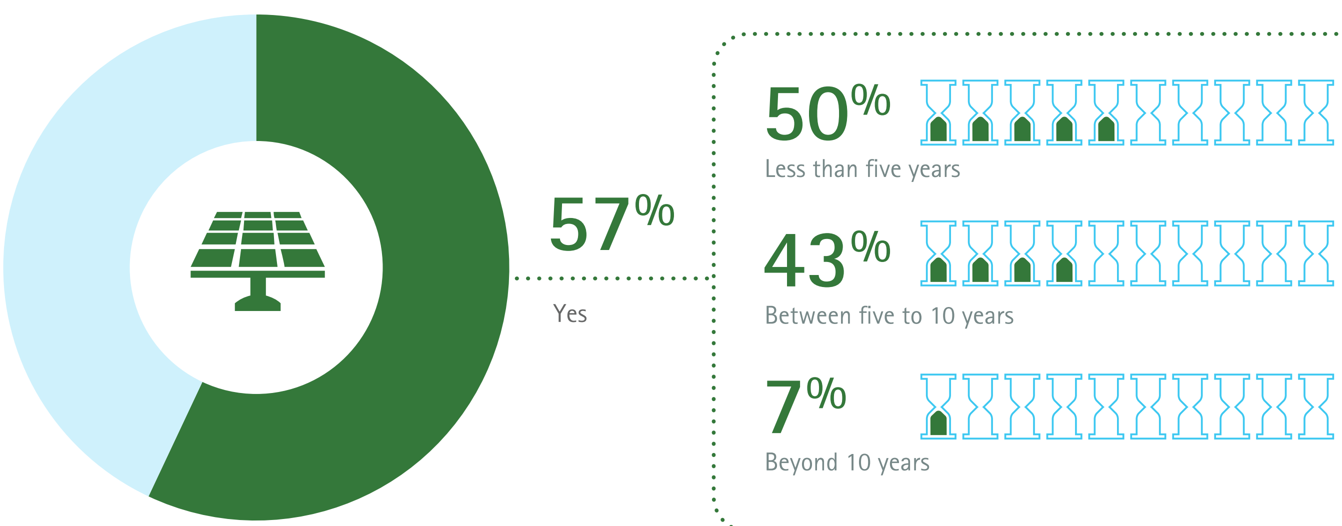
New business models have emerged that enable consumers to get services "on demand." When you consider home entertainment, the traditional approach of offering a standard cable package and optional bundles has been overtaken by alternate forms of media consumption (e.g., YouTube, Apple TV, Netflix) where consumers choose what, when and how they watch. "On-demand" consumption of products and services, coupled with the emergence of the sharing economy, are beginning to impact how consumers perceive and consume energy.

Consumer interest in energy independence is significant, with 57 percent of consumers globally saying they would consider investing in becoming power self-sufficient (see Figure 18).

Figure 18. More than half of consumers are looking for a short investment payback period for becoming power self-sufficient.

Would you consider investing in becoming power self-sufficient so you would not have to buy energy from your energy provider (e.g., by installing solar panels and storage)?

What would be the acceptable payback period (i.e., the time it takes to recover your initial investment) for you to invest in technologies to become power self-sufficient?



Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Base: Interested in investing to become power self-sufficient.

Interest is highest in the 18- to 34-year-old range, which may provide an early indication of a growing market for distributed generation and storage technologies. However, the switch to self-sufficiency needs to make financial sense for the consumer. Indeed, half of interested consumers would like a payback period of fewer than five years, with more than 90 percent looking for a payback period of less than a decade.

As discussed in Accenture's Digitally Enabled Grid 2014 research, the feasibility of achieving sustained power self-sufficiency is currently out of reach due to the current maturity and cost of energy technologies. A large number of consumers have practical limitations on roof availability, such as building ownership, or lack the appropriate orientation of roof space for solar PV. In addition, the amount of storage capacity required to be self-sufficient is prohibitively large. However, the evolutionary improvements in technology efficiency and the associated cost reductions may make energy independence a viable option in the future.

Despite consumers' interest in increasing energy independence, they also recognize the need to remain connected to their energy provider to address what Accenture calls "outage anxiety." Consumers expect that their relationship with their energy provider would be focused on back-up power services. Of the 57 percent of consumers willing to consider investing to become power self-sufficient, 89 percent would look to mitigate the risk of having to go without power (see Figure 19). By developing products and services that meet prosumers' specific needs, energy providers can reposition themselves as the go-to source for reliable energy support.

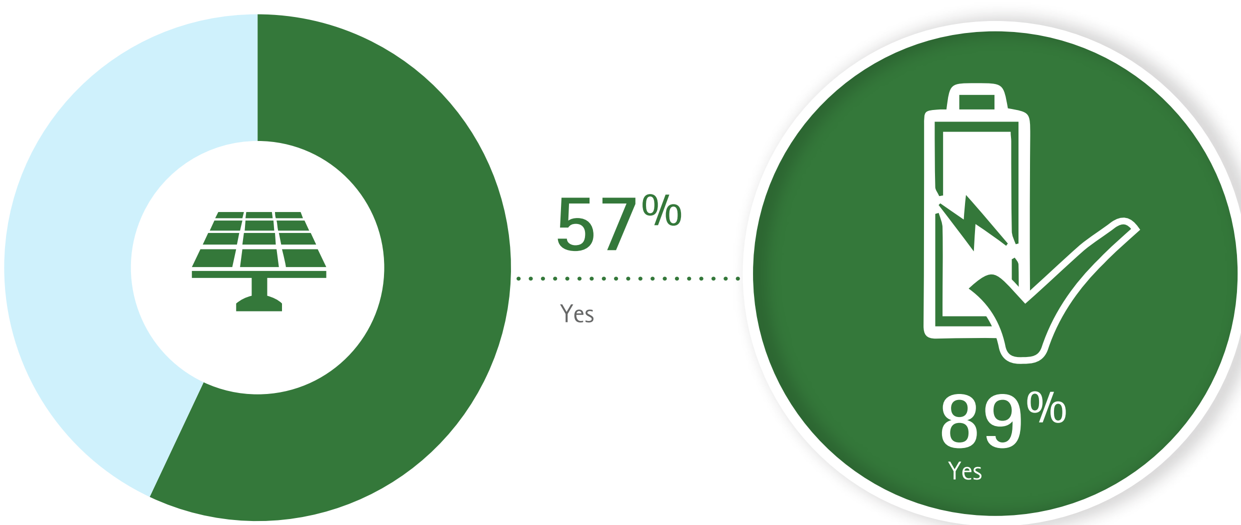
Building digital value

Digitally enabled consumers have a higher interest and likelihood to be first movers, and acquiring their share of spend is pivotal. In competitive markets, digitally enabled consumers are likely to become the battleground in the hunt for value and additional revenue. In regulated markets, these consumers offer prime opportunities to engage around energy management. As consumer interest and propensity to purchase energy-related products and services grow, energy providers have the opportunity to realize new value. Leading energy providers are already architecting for the future and considering the cultural, business and technology impacts of new products and services.

Figure 19. Consumers are interested in back-up power services from their utility/energy provider to minimize the risk of having to go without energy.

Would you consider investing in becoming power self-sufficient so you would not have to buy energy from your energy provider (e.g., by installing solar panels and storage)?

If you were to install technologies to become power self-sufficient, would you be interested in back-up power services that may be offered by your energy provider to minimize the risk of running out of power?



Base: All respondents.
Source: Accenture, New Energy Consumer research program, 2015 consumer survey.

Base: All respondents who would consider investing in becoming power self-sufficient.

The digital energy platform (r)evolution

While product and service opportunities abound, the future will not be about a single product, process, service or solution. Rather, it will be shaped through digital industry platforms and ecosystems that fuel breakthrough innovation and disruptive growth.

While many businesses are using digital initiatives to harness social, mobile, analytics and cloud technologies, forward-looking leaders are offering consumers more by unifying such initiatives under a platform. The *2015 Accenture Technology Vision* identifies the platform (r)evolution as one of five key trends fueling the next generation of breakthrough innovation and disruptive growth. Already, platform-based companies are capturing more of the digital economy's opportunities for strong growth and profitability. In fact, according to the Massachusetts Institute of Technology, "In 2013, 14 of the top 30 global brands by market capitalization were platform-oriented companies—companies that created and now dominate arenas in which buyers, sellers and a variety of third parties are connected in real time."[54]

For companies across sectors, it is no longer enough to simply develop and launch digital tools and products with the expectation that consumers will adopt them. Rather, companies need to apply their industry knowledge to build flexible platforms that enable rapid innovation—including development and deployment of the products and services needed to drive their digital business strategies. Such a foundation supports more effective ways of operating and creates opportunities for new revenue streams and customer satisfaction.

Digital platforms enable developers to build applications that facilitate collaboration, workflow and value across industries and geographies more seamlessly and more quickly than ever before. In fact, 81 percent of industry executives surveyed as part of The *2015 Accenture Technology Vision* believe that in the future, industry boundaries will dramatically blur as platforms reshape industries into interconnected ecosystems. In short, platform-based ecosystems represent new competitive arenas for meeting consumer demands.

While digital industry platforms have unleashed tremendous value and disruption in other industries, Accenture believes that when it comes to gas, electricity and water, the industry is poised on the brink of a platform (r)evolution.

For energy providers, the imperative is not determining how to fit digital into an established ecosystem—it's recognizing that companies in nearly every industry are already beginning the process of creating these new digital ecosystems. Bringing these ecosystems to life in the utilities industry will require thoughtful consideration.

Shift in mindset from "me" to "we"

As enterprises move to platform-based models, their technology capabilities are rapidly changing—and so are their ambitions. Innovative companies are embracing platforms as a way to increase their capabilities so they can attack larger opportunities, solve bigger problems and serve their customers better. Innovators know they cannot do all of that alone. They realize that their fortunes depend not only on their own successful efforts ("me"), but also on the success of all players in their platform-driven ecosystems ("we").

Whether players include competitors, vendors, employees, consumers or all of the above, digital platforms are creating a level playing field and facilitating competition as well as coordination. As one example, China's smart city platform approach is enabling Siemens and major providers such as Schneider Electric to take an integrated, scalable and repeatable approach to addressing complex urban transportation, building and energy management challenges.[55]

Digital technologies by their very nature require rapid, modular, agile, flexible capabilities. The best digital solutions take the power of information technology and put it in the hands of the broader ecosystem—and this ecosystem includes management, front-line users, end customers, partners and developers. The fundamental shift in mindset from me to we means that utilities and energy providers must embrace a mantra of not building it themselves, but instead leveraging what is available through the broader ecosystem to address their business requirements (see sidebar: "Nest Thread weaves together connected home 'web'" on page 38). The power of collaboration continues to be a fundamental current of change in the industry.[56] Energy providers need to build a core competence in partnering with a variety of players within the digital energy ecosystem.

Ecosystem as an innovation sandbox

Admittedly, it may not be easy for large, established companies to innovate rapidly. Increasingly, leading companies have begun to drive innovation in an unusual way: allowing others to innovate for them. By opening their platforms to external companies, organizations can further expand such efforts—with platforms serving as an "innovation sandbox" in which alliance partners, startups and even consumers can safely and creatively experiment.

With digital, businesses can more easily find fresh talent to solve new and complex challenges. Consider Kaggle[57] —the largest community forum for data scientists worldwide. Participants compete to solve analytical problems, and a quick search of energy-related contests shows topics such as load forecasting, solar or wind energy forecasting, and energy disaggregation. Those who offer a successful solution may be invited to consult on interesting projects for some of the world's largest companies. Businesses are not just outsourcing operations; they are now crowdsourcing problem solving and tapping into a much broader talent pool than they may have been able to access in the past.

Teaming up with third parties can create value in a number of areas. For example, Eneco has partnered with Tesla to offer consumers a charging service for electric vehicles. With the consumer's specified timeline and battery preferences, the service automatically charges the car battery when the price is low. Eneco plans to extend the platform to other car manufacturers.[58] Another example is MeterHero, which lets smartphone users pool their water, electricity and natural gas usage data to more effectively manage consumption across the three commodities. The tool helps users monitor real-time usage and offers cash rebates to consumers who conserve energy.[59]

Nest Thread weaves together connected home "web"

In the connected home market, Nest has partnered with Samsung and four other companies to offer consumers Thread.[60] This new wireless IP protocol is designed to integrate the growing numbers of connected home devices being adopted. The Google-owned company launched this new IP protocol as a wireless mesh standard for the smart home. By using a low-power platform and existing radio hardware (courtesy of ZigBee devices),[61] Thread does away with the traditional hub-and-spoke model where multiple devices rely on one centralized device to communicate with one another.

Nest Thread links together supported smart home devices to work in harmony with each other without requiring additional hardware in the home or burdening existing home wireless networks with more devices. The platform manipulates frequencies into a true lattice network, introducing the possibility for standardization to the connected home market. Although the mesh network can already support more than 250 connected devices, the Thread platform has been designed for long-term extensibility as new devices emerge and are adopted.[62]

Such innovative solutions can benefit energy providers and consumers alike (see sidebar: "Mosaic: Crowdfunding community solar projects"). The network multiplier effect—which states that a product or service becomes more valuable overall as its adoption increases—comes into play here. Apple's App Store is a prime example. The quantity and variety of apps encourage more users to join the platform and more developers to build apps for it. As the shift to a shared economy and innovation ecosystems continues, we will see more adoption of alternate business models and next-generation solutions.

Real-time (consumer) business models

Real-time operations are nothing new for the energy trading and delivery side of the business. For the consumer side of the business, however, real time represents new territory. Digital platforms enable breakthrough consumer capabilities—including buying and selling excess energy, providing outage updates, and enabling alerts for switching providers when prices reach a certain threshold.

The ability to transact in real or near-real time will enable new value creation and fundamentally disrupt business models of the past.

Energy providers have a unique opportunity to provide real-time (or near-real-time) demand-response services to consumers through a platform that leverages smart meter and other data. In Accenture's research, *Delivering the New Energy Consumer Experience*, 93 percent of consumers reported they would like to learn more about smart meter functionalities. More specifically, they cited a desire for personalized advice on actions, products and services to reduce bills, as well as early notifications when the bill may be higher than normal.[63]

As machine-to-machine communications become more prevalent in consumer energy technologies, devices will be able to exchange information and make decisions based on specified parameters. Machine-to-machine communications could enable real-time energy exchange for energy consumers: a homeowner's solar panels produce more energy than required, but the neighbor's home needs power, and the homeowner, neighbor and energy provider could all benefit from such a value proposition. Devices that can transact with each other based on predefined business rules will enable seamless, peer-to-peer information exchange and transactions in (near) real time.

For energy providers, operations will also be required to address consumer expectations, needs and preferences in (near) real time. In a very short period of time, digital enablement has transformed some processes and interactions for utilities. Consider outage notifications: for mass outages, mobility and social media have become the preeminent channels for real-time updates and even service interactions. In day-to-day operations, the real-time ability to understand customer journeys in digital channels, to resolve customer requests, and to take proactive actions in customer-facing online environments is becoming more critical. Consumers' continued move to online channels and their digital experiences are creating an environment where real time is the new normal.

Mosaic: Crowdfunding community solar projects

As consumers become more comfortable with online investing—including peer-to-peer investment platforms—Mosaic[64] has found success with crowdfunding community-based solar projects. Through the Mosaic platform, consumers can pledge funds and offer crowdfunding loans for solar development projects.

It offers benefits beyond investment returns—namely, a sense of contribution to uptake of clean, sustainable energy for the future. In addition to facilitating investments, Mosaic enables consumers to apply for solar financing at any time, on any device.

Energy platforms for the future

From peer-to-peer platforms to storage, EVs and renewables, a variety of technology advances are creating new ways for consumers to obtain, store and even sell energy. Many of these options no longer require the traditional utility role. As energy storage becomes more viable and widely adopted, dependence on centralized electricity generation decreases, and consumers are able to move toward energy independence. Online communities are emerging to help connect local consumers with renewable producers in their area—bypassing the need to use the utility.

These changes are beyond evolutionary. In fact, they represent the broader transition of the utilities industry to operations that are digitally enabled and integrated with renewables. Such operations include:

- Offerings that extend beyond traditional services; examples include remote monitoring, home energy management solutions and smart metering.
- The ability to manage real-time demand and supply and optimize grid performance using location, asset and consumer information.
- Real-time energy usage information to enable consumers to track, manage, optimize and automate energy usage decisions.

Value-added industry platforms and digitally enabled offerings and services can span the entire industry value chain and extend beyond traditional boundaries (see sidebar: "Energy platform characteristics"). Consider online retailer Amazon: it has upended traditional industries like books and publishing, cloud-computing and video streaming and continues to innovate, pushing its own boundaries into smartphones.[65] The digital platform has enabled Amazon to transform how other players in the value chain interact and realize value, extend its core business capabilities into offering new revenue, and explore value at the edge of its platform. In fact, it has extended the boundary of the platform beyond what may have originally been intended. The challenge for each energy provider is to determine where it can provide value and where it has the capabilities to deliver. While there are a number of distribution-oriented platform opportunities, from a consumer value perspective, Accenture sees a range of platform types emerging.

Data and information services – using an interoperability platform and Web portal or other channels to provide energy usage information and associated insights to consumers.

- In Texas, mytruecost[66] energy Web portal compares prices and deals offered by 24 utilities, with side-by-side comparisons to help consumers choose the best plan for their household. The portal allows users to create a personal account and provide their smart meter information. Based on their previous consumption pattern, the portal generates a comparison of the available electricity plans. The mytruecost portal also includes all surcharges and any hidden charges from each utility, giving consumers an accurate estimate of their monthly bill if they were to sign up.
- Energy Vikings,[67] an initiative of Alphacomm Energy Solutions BV in the Netherlands, is an independent smart meter monitoring application that offers consumers direct insights into their electricity and gas consumption. Users can remotely read their smart meters to quickly see how much their past usage has cost them. They also can access day-by-day spend to help manage bill cost, access information about available utilities and assess whether or not solar would be a wise investment for them.

Home management services – offering products (such as smart devices) and services (such as home automation systems, security systems or demand-response programs) to manage all aspects of the home.

- RWE SmartHome[68] offers consumers a smart home solution for the heart of their intelligent home. When used with smart home appliances, RWE's home automation device offers maximum convenience and optimized energy management. The platform offers consumers peace of mind—integrating in-home management services with home security features to control door and window sensors, motion and smoke detectors, and remote shutter controls. It also syncs with lighting, heating and other in-home smart devices that consumers want to control from their mobile phones, and is designed for extensibility as consumers bring more devices home.
- As part of its three-pronged strategy toward "Sustainable, Decentralized Together" by 2030, Eneco has developed the TOON platform.[69] Initially offering a smart thermostat, the platform has the capability to manage a large range of home devices—such as lighting, home security, electric vehicle charging, carbon monoxide alerts, supply interruption alerts and information about solar panel performance. TOON is Eneco's play in the smart home management market, but it is also the provider's preparation for the impact of technology on energy as a service.

Energy aggregator – aggregating multiple energy sources (including consumers) into a virtual power plant to manage supply and demand.

- In the United Kingdom, Flexitricity[70] can be described as a "virtual power station" or aggregator, giving sites with smaller flexible capacity the chance to be involved in demand-side balancing reserve. It takes the individual capacity contributions of a number of smaller businesses and offers the reductions to National Grid in a large, useable way.[71]

Energy platform characteristics

To become a standard and widely accepted solution in the marketplace, an energy platform must create value both for consumers and for the utility. Enhancing speed, efficiency and transparency can create value for all platform participants and beneficiaries: businesses, energy providers and consumers.

Regardless of a platform's specific value proposition, well-rounded platforms should reflect or support these characteristics:

Choice. Consumers value choice and want a selection of products and services that meet their needs. Platforms offering more choice increase the likelihood of both the "network multiplier effect" and consumer stickiness. Streamlined search and an easy-to-use interface will be critical to consumers' ability to navigate through a range of products and easily make a selection.

Level. A strong platform can level the playing field. A utility of any size can succeed as long as it has the basic capabilities for creating, implementing and supporting the platform. Similarly, any third party or partner may also develop successful applications for the platform—just as Apple's App Store offers applications from large players, such as Zynga, as well as individual developers.

Open. A platform will create a new marketplace for businesses and consumers to interact and transact. While Amazon and Alibaba are well-known examples of this type of solution at scale, Airbnb has similar characteristics in that it has created a marketplace for hospitality services and revenue that provides a value proposition for homeowners and travelers.

Standardized. Standardization encourages cooperation and information sharing across platforms, applications and data sources. It also can encourage consumer adoption of the platform through the ease of linking data across applications. As the industry platforms evolve, efforts to establish standards are underway. In the United States, the Green Button[72] initiative is setting the standard for sharing smart meter data. When a platform is widely adopted, its developers may be able to establish the standard; in any case, standards enable participants in the ecosystem to maximize the reach and effectiveness of their platforms.

Networked. The parts that make up the whole of any platform are as important as the whole itself. Developing a platform ecosystem approach that encourages coopetition and third-party involvement will lead to a platform that provides increased choice, a richer experience and potentially greater consumer adoption.

Secure. To support personalization, any platform is likely to collect location, personal, transactional and other data. To safeguard it—and maintain consumer trust—platforms must protect against unauthorized access of content by third parties and also reflect a strong governance approach for access to personal consumer data.

Energy marketplace – facilitating a marketplace open to all energy participants to buy and sell offerings and to trade supply and demand.

- With the region's growing interest in renewables, Netherlands-based Vandebron[73] created a (disruptive) platform that lets local consumers buy energy—including wind, solar, biofuel and gas—directly from local producers. Its Web portal even offers profiles about local energy producers.

Customer service platforms – collaborating with consumers remotely, providing customer relationship management (CRM) and pricing capabilities.

- The British Gas smartphone app[74] lets HomeCare consumers book, manage and track engineer callouts. Consumers can make new appointments and specify whether they need routine maintenance or a repair. Consumers also enjoy visibility to their designated crew's location and can reschedule or cancel an appointment through the app.

Energy solutions optimizer – combining technologies, transactions and insights (for example, distributed generation, demand response, storage and real-time notifications) in one easy-to-use consumer solution.

- Reposit Power,[75] based in Canberra, Australia, has launched a platform that uses solar grid storage on residential premises to monitor and trade power back to the network. The company believes that consumers will realize the benefits of greater independence from grid pricing and greater control over energy flow. Reposit's platform helps consumers identify the optimal strategy to feed power back into the grid from their solar photovoltaic or battery storage—helping to ensure that consumers maximize the financial benefits of selling their surplus energy.

Digital transactional processing – enabling more seamless processing of energy-related transactions. These platforms could be a combination of business-to-business and/or business-to-consumer, including other providers participating through a variety of digital payment mechanisms.

- Simple Energy[76] has launched Marketplace, an online e-commerce portal that offers consumers a fast, easy and convenient way to shop for appliances, including the ability to receive energy-efficiency rebates instantly. Simple Energy intends for partner utilities to white-label the platform, enabling access to consumers' usage profiles and identification of personalized recommendations and savings.

While a range of platform types are emerging, digital innovation will continue to expose gaps in the market and opportunities to bridge platforms. In the future, we expect the differing platform types to blur as providers push beyond industry boundaries.

Enabling the agile business

For many energy providers, a platform solution will be a fundamental shift in the way the business and IT work together. When architected with flexibility in mind, digital technologies enable rapid, modular and flexible environments where the power of the technology can be placed in the hands of participants outside the IT department. Further enhancing consumer choice, convenience and control, successful digital platforms will be based on application protocol interfaces (APIs) that enable communication with other solutions within and outside the utility.

To truly understand the evolutionary shift a platform approach can unlock for the business, consider the recent Accenture experience building a platform for a large, global mining company. The platform was built in approximately two months—a very short timeframe compared to traditional IT development—and without buying new hardware or software. The tablet-based solution features an intuitive user interface and leverages the vast data already available—putting insights and analytics in the hands of the front line. Leveraging a devOps approach (see sidebar: "Building agile platform capabilities" on page 43), operators in the mine (not the IT department) are able to restart the server when required at the click of a button. By looking at the available data, infrastructure and business in a new way, the platform fundamentally changed the way they operate.

Reimagining the enterprise

The implications of a platform solution on a business can fundamentally affect its strategy, business model, operating model and capabilities for the future. Envisioning future value propositions and the interactions with new energy consumers in the context of the shifting industry landscape will require a nimble, learning mindset and a culture of continuous innovation. While strategic decisions about future business models will require some thoughtful consideration, energy providers should not wait for "perfect" information. Others will choose and launch their business model, enabled by digital, and stand to disrupt existing businesses and customer relationships.

Building agile platform capabilities

When developing and delivering innovative IT solutions for digital industry platforms, energy providers are wise to consider DevOps and Agile approaches to accelerate time to market and improve IT agility.

Information technology capabilities are a critical enabler of success with a platform-based value proposition. As the pace of digital change accelerates, one of the key capabilities needed is agility in IT development, implementation and continual improvement. To unleash value, energy providers need the appropriate combination of people, skills and technologies.

Using a "DevOps" approach to communication, collaboration and integration can unlock previously untapped value for an organization. DevOps seeks to close the gap between software development and IT infrastructure/operations. It enables developers to create their own environments—standing up software solutions in less time and automating techniques for deployment, environment setup, configuration, monitoring and testing. It can also put the power of IT in the hands of end users. DevOps can deliver value to energy providers in the form of lower costs, increased speed to market, reduced delivery risks and higher rates of throughput.

Combining DevOps with an Agile software development approach can increase quality and efficiency. Agile, which some organizations have already adopted, is a flexible, lean software development methodology. While traditional waterfall or iterative software development methods may remain appropriate in certain situations, Agile is particularly useful when implementing consumer-facing Web-enabled platforms. It enables developer teams to iteratively and continuously improve software products—reducing time to market, eliminating inefficiencies and increasing quality. Agile approaches allow the utility application world to operate at the speed of the business: fast operations, with developers empowered to deliver secure, business outcome–oriented development.[77]

Thriving in the digital energy era

The utilities industry is undergoing a fundamental, unprecedented transformation. Devices are getting smarter and consumers' worlds are becoming more digitally connected. Competitive forces are at play, regardless of market structure, with new entrants and traditional competitors offering differentiated products and services.

Consumers' interest in energy is growing and energy is increasingly ubiquitous, with the ability to charge devices in public spaces becoming more seamless and more commonplace.

Consumers already prefer online, mobile and social media as channels for interaction—and their broader online digital experiences are continually refining and resetting digital customer experience expectations. That reality makes service design a critical capability to continuously enhance an effortless customer experience.

While solar technologies, smart home offerings and EVs are all gaining traction, consumers' overall interest in energy-related products and services is on the rise—and energy providers are uniquely positioned in consumers' minds to extend their value propositions.

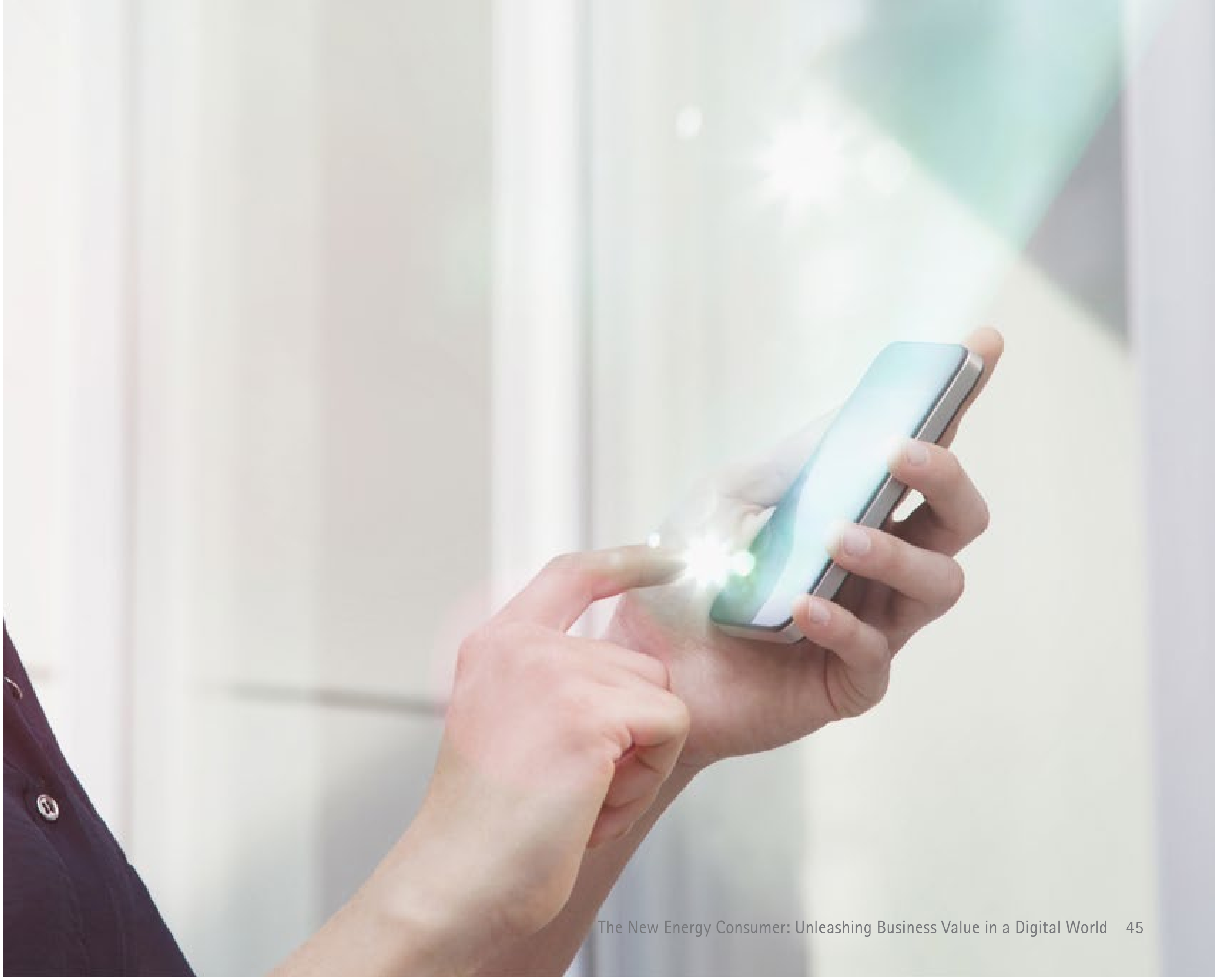
Digital is unleashing new opportunities for value, especially when it comes to industry platforms. Leading energy providers will identify the market opportunities most relevant for their business strategies to build, collaborate and participate in industry platforms. Furthermore, non-traditional energy providers will implement platform solutions in the market and may further disrupt the industry value chain.

Despite disruption and uncertainty, energy providers can apply a digital lens to identify ways to drive profitable growth, reduce costs and improve customer experiences. Digital tools, systems, capabilities and skills will be critical to enabling success in the years ahead, and providers must consider how the tectonic market shifts will impact future operating models.

Energy providers must consider six key imperatives in their future-forward strategies:

- Build "digital DNA"
- Deliver effortless experiences
- Architect resilient platforms
- Drive analytics-powered insights
- Innovate at speed
- Strengthen strategic partnerships

Successful providers will embrace the challenges and opportunities unleashed through digital. A critical first step will be selecting digital business models for the future, and changing the organizational mindset to break down traditional operating models and methods. Leading energy providers of the future will be completely different than those we see today.



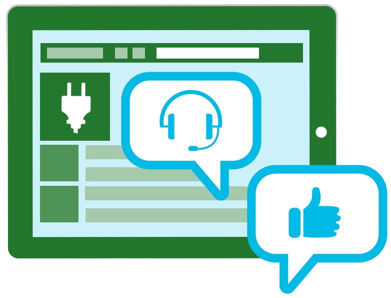
Key strategic imperatives

Build "digital DNA"

Apply a digital lens to reinvent the business—from strategy and business models to operating and governance models.

Consider:

- How will digital help us grow and reinvent our business, enter new markets and strengthen our position in the market?
- What are our core strengths? How do they lend themselves to digital?
- How can we leverage digital disruption to reinvent our business model?
- How does our digital strategy integrate with our business and IT strategies?
- How will we align business units, talent and priorities to govern digital across the organization?



Deliver effortless experiences

Enhance the customer experience by advancing next-generation digital customer capabilities, optimizing self-service interactions and proactively addressing consumers' needs.

Consider:

- How can we minimize consumer effort when using digital or self-service channels?
- How can we effectively and proactively deploy digital customer technologies?
- How can we attract and retain consumers to digital self-service solutions?
- How can we deploy digital solutions to improve business process efficiency and reduce channel complexity?
- How can digital create an effortless customer and employee experience?

Architect resilient platforms

Establish digital platforms for real-time business models, emerging energy solutions and customer-powered innovation.

Consider:

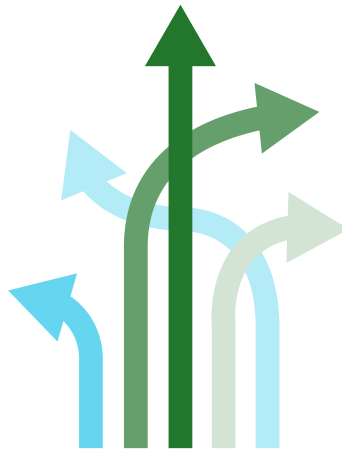
- How would a value-based platform impact and benefit our business strategy, business model, operations and consumers' experience?
- How resilient is our technology architecture?
- How will our architecture be able to support emerging energy solutions and customer-powered innovation?
- How can we leverage our core strengths and others' capabilities to enable new platform-based value?
- How could a platform extend the boundaries of our capabilities?

Drive analytics-powered insights

Improve customer-centric decision making and business effectiveness with real-time actionable insights and analytics capabilities.

Consider:

- How do we maximize the value of data to support decision making?
- How are we using real-time actionable insights to build business effectiveness and consumer relevance?
- What analytics capabilities do we need to develop or enhance to derive the desired data insights?
- What strategies do we need in place to proactively address cybersecurity?
- What is the most effective way to organize our analytics capabilities to drive the most business value quickly?



Innovate at speed

Fuel growth and realize greater long-term value by seizing new opportunities, empowering consumers as marketers and co-creators for the rapid development and launch of new products and services.

Consider:

- How do we prevent existing cultural values from stifling innovation? What are the core utilities industry beliefs about what customers want? What if the opposite were true?
- How does our culture support innovation? Does it support risk taking, reward success and encourage teams to learn from failures?
- How will we assess innovative ideas that may cannibalize the existing business or require re-prioritizing investments?
- How will we organize our innovation capabilities?
- If we could hire an innovation team, what unconventional skills would they have and why?

Strengthen strategic partnerships

Accelerate value creation by partnering with other providers and forming unconventional alliances.

Consider:

- How could other providers strengthen or complement our capabilities?
- How are we leveraging service providers on shore, nearshore and offshore?
- How could we team up with competitors and new entrants to create new market opportunities?
- How should we set up, manage, track and measure our alliances and partnerships to maximize benefits for all stakeholders?
- How willing are we to consider completely new ways of working with others?

The New Energy Consumer research program

Accenture undertook the multiyear New Energy Consumer research program to help gas, electricity and water utilities understand emerging consumer needs and preferences, to identify new challenges and opportunities, and to bring focus to the critical competencies required to succeed in the evolving energy marketplace.

Collecting consumer insights from interviews with more than 60,000 end consumers around the world, the initiative has explored a range of topics.

2010

Understanding Consumer Preferences in Energy Efficiency offers a consumer view to support the increasing industry focus on smart metering and demand management. This first study produced valuable insights into consumer preferences in energy efficiency, awareness, readiness and willingness to take action.

2011

Revealing the Values of the New Energy Consumer explores the emergence of a new energy marketplace through a worldwide end-consumer survey looking at preferences, opinions and priorities in beyond-the-meter products and services offered by utilities or other providers.

2012

Actionable Insights for the New Energy Consumer focuses on developing actionable insights and tactical implications for the emerging energy marketplace. This study explores consumer choice, connection and loyalty, and provides a fresh view of how consumers want to interact with their energy providers, the products they value and what drives their purchasing and loyalty behavior.

2013

The New Energy Consumer Handbook looks to the path ahead for energy providers addressing key consumer "dissatisfiers" and offers views to help deliver on the diverse expectations and needs of residential consumers and small and medium businesses (SMBs).

2014

The New Energy Consumer: Architecting for the Future explores new opportunities in virtual customer interaction, the connected consumer, distributed energy, and new products and services. It also offers Accenture's view of the energy consumer of the future.

2015

The New Energy Consumer: Unleashing Business Value in a Digital World explores the ways in which energy providers can capture digital value. It discusses opportunities for energy providers to extend the value proposition through innovative offerings and new ways of engaging energy prosumers. The research explores the growing potential of platform-based models in the digital energy ecosystem.

The New Energy Consumer research methodology and sample

Accenture's global research surveys are based on questionnaire-led interviews with end consumers. Surveys were conducted online in native languages for Accenture by Harris Interactive. The selected countries represent a range of regulated and competitive markets.

For residential consumers, the survey sample was statistically representative of the general population in each country, with the exceptions of Argentina, Brazil, China, Indonesia and South Africa, where the sample was representative of the urban populations. For countries with large and/or diverse populations, participants were selected from a broad spectrum of locations. The surveys included attitudinal, behavioral and demographic questions.

A total of 11,298 interviews in 21 countries

interviews by country

500

Argentina*	Japan
Australia	Netherlands
Belgium	Norway
Brazil*	Portugal
China*	Singapore
France	South Africa*
Germany	Spain
Indonesia*	Sweden
Italy	Thailand

584 Canada

640 United Kingdom

1,074 United States

Breakdown by gender, age, income:

Gender

48%

52%

Age

17% 18–24 years

24% 25–34 years

34% 35–54 years

25% 55+ years

Income

25% Low (bottom 25% in every country)

52% Medium

23% High (top 25% in every country)

Regulated markets: Argentina, Brazil, Canada (some provinces), China, Indonesia, Japan, Portugal, Singapore, South Africa, Thailand, United States (some states)
Competitive markets: Australia, Belgium, Canada (some provinces), France, Germany, Italy, The Netherlands, Norway, Spain, Sweden, United Kingdom, United States (some states)

Notes:
*Sample representative of the urban population
The maximum margin of error is of +/- 1 point on the total sample and +/- 4.5 points at the country level
Trend data: Countries have been added/removed from the scope in the 2015 survey compared with previous years; however, this change does not impact trends

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About Accenture Energy Consumer Services

Accenture Energy Consumer Services delivers energy provider customer solutions for both competitive and regulated markets globally. We help our clients achieve three key business imperatives: cost effectiveness, revenue assurance and extension, and customer satisfaction. Guided by New Energy Consumer insights, our electricity, gas and water clients can realize higher value through industry-specific strategy, digital, technology and operations capabilities and world-class expertise, assets, tools and accelerators.

About Accenture Research

Accenture Research is Accenture's global organization devoted to economic and strategic studies. The staff consists of 200 professionals in economics, surveys and data modeling from Accenture's principal offices in America, Europe, Africa and Asia/Pacific. The New Energy Consumer research program involved our experts in survey research.

About Accenture

Accenture is a global management consulting, technology services and outsourcing company, with more than 323,000 people serving clients in more than 120 countries. Combining unparalleled experience, comprehensive capabilities across all industries and business functions, and extensive research on the world's most successful companies, Accenture collaborates with clients to help them become high-performance businesses and governments. The company generated net revenues of US$30.0 billion for the fiscal year ended Aug. 31, 2014. Its home page is www.accenture.com.

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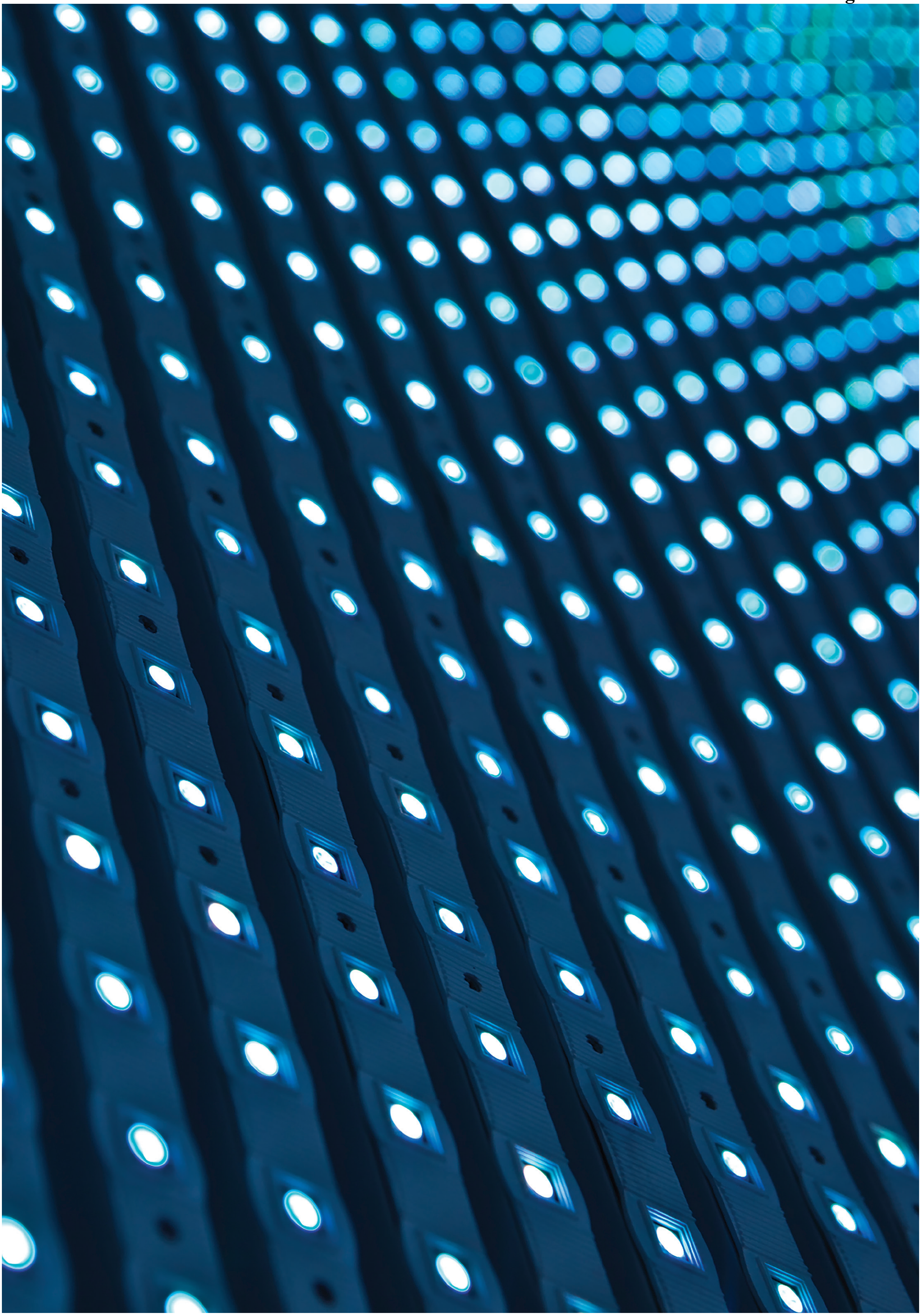
THOUGHT LEADERS SPEAK OUT:

Key Trends Driving Change in the Electric Power Industry

The Edison Foundation
INSTITUTE for ELECTRIC INNOVATION



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"As this transition unfolds in the regulated electric power industry, it is about balancing affordability, reliability, clean energy, and individualized customer services."

–LISA WOOD

Introduction

LISA WOOD
Vice President, The Edison Foundation and
Executive Director, Institute for Electric Innovation

America's electric utilities—which provide the critical infrastructure that enables all other infrastructures—are at the beginning of a profound but quiet transformation. That transformation, more evolutionary than revolutionary, is largely invisible but it is underway and is being driven largely by:

- Technological innovation;
- Federal and state policies that favor competition in some aspects of providing electricity service;
- Regulation of the non-competitive components of electricity service; and
- Changing customer needs and increasing expectations.

KEY TRENDS DRIVING CHANGE

Three "megatrends" are at the core of this transformation.

The transition to a clean energy future

The energy mix we use to generate electricity is changing. By investing in renewable energy, transitioning from coal to natural gas, and pursuing energy efficiency, the U.S. electric power industry has already reduced carbon dioxide emissions 15 percent below 2005 levels; other emissions have also been reduced. At the same time, modernization and digitization of the grid enables the integration of more carbon-free renewables, both large-scale and distributed. In fact, we expect exponential growth in solar over the next decade, in all sizes. Wind energy, already competitive with other fuels, is projected to increase substantially as tower heights increase to produce more energy. Today, the electric power industry is the largest investor in carbon-free renewable energy in the U.S.

A more digital and distributed grid

The power grid itself is changing, becoming "smarter" by virtue of a digital communication overlay, with millions of sensors that will make the grid more controllable and potentially self-healing. The electric power industry is investing more than $20 billion per year in the distribution grid alone, which will enable the connection of distributed energy resources as well as devices in our homes and businesses. Many of these resources and devices will interact with the grid, resulting in more efficient grid operations. The digital grid is evolving into a multi-path network of power and information flows that will use data analytics for grid management and optimization from end-to-end.

Individualized customer services

As the grid becomes increasingly digital and distributed, customization of services for electricity customers will continue to grow. Here are some examples. Large commercial customers increasingly want renewable energy to meet their corporate sustainability goals. Cities and towns are requesting customized services such as help with micro-grids, smart city services, or renewable energy. Some residential customers want rooftop solar to generate their own electricity. And, residential customers increasingly want to manage their energy use using connected devices like iPhones and Nest Learning Thermostats, and through web-based platforms. At the same time, for many, many customers, safe, reliable, and affordable electricity will continue to be the preferred service option.

Although these mega-trends are driving change, it's important to recognize that the speed of transformation will depend to a great extent on whether regulation evolves to accommodate these changes. Just as the business model of electric utilities must change because the power mix is undergoing transformation, the grid is more complex, and customers have different expectations, so too must the regulatory model change. Regulation will have to provide a glide path for utilities to achieve corporate and policy goals, while also setting incentives and penalties for utilities based on meeting agreed-upon performance objectives.

THE NEXT DECADE

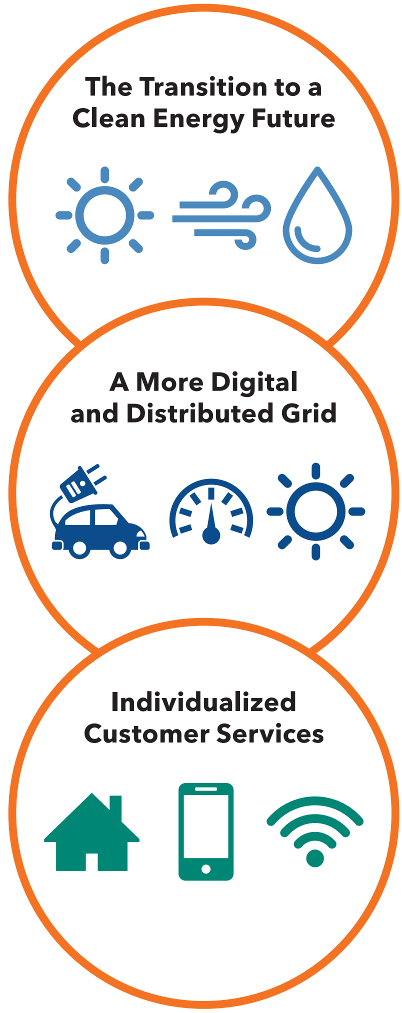
Many of us would agree that, a decade from now, the U.S. electric power industry and energy services will look something like the following:

- We will have a cleaner electricity generation mix, with lower carbon emissions;
- The power grid will increasingly integrate a mix of central and distributed resources;
- The grid will become more digital, more controllable, and more interconnected. PG&E aptly calls this the Grid of Things™;
- A mix of entities—both utilities and other companies—will provide distributed energy resources both on the supply side and the demand side; and
- Suppliers—both utilities and others—will offer customers a wide range of individualized and customized services.

Ultimately, as this transition unfolds in the regulated electric power industry, it is about balancing affordability, reliability, clean energy, and individualized customer services. This is largely the job of regulators and other policy makers. But the ultimate challenge is to make this transition of the electric power industry affordable to all Americans! And this is the job of all stakeholders.

*****

The authors of the essays that follow provide their unique views on the three key trends that underpin the profound transformation of the electric power industry—increasingly clean electricity generation; a more digital and distributed grid; and individualized customer services. These essays are an important addition to the conversation.



Fact Sheet: Transition to a Clean Energy Future

National Power Generation Mix

	COAL	NATURAL GAS	NUCLEAR	HYDRO AND OTHER RENEWABLES	OTHER
2005	49.6%	18.8%	19.3%	8.8%	3.7%
TODAY	38.6%	27.5%	19.5%	13.2%	1.4%

Wind

5 STATES generate **MORE THAN 50%** of wind energy nationwide

22% Texas

9% Iowa

8% California

7% Colorado

6% Oklahoma

Solar

Over the past 2 years, **SOLAR CAPACITY ALMOST doubled** in the U.S.

SOLAR accounted for **28%** of all capacity additions in the last year

U.S. Installed Solar Capacity

2011: **3.9GW**

2015 Q2: **19.6GW**

TRANSITION TO A CLEAN ENERGY FUTURE

Electric utilities have moved with vision and agility, away from carbon-based fuels and toward carbon-free and low-carbon resources in a very short time, and ahead of policy mandates. In just ten years, the nation's power generation mix has changed dramatically—adding significant amounts of natural gas, wind, and most recently solar. The authors of the essays in this chapter not only examine the transition toward a clean energy future but point to the fact that it is well underway.

The Southern Company is on the cutting edge. As CEO Tom Fanning's essay makes clear, Southern has cut its coal use from 70 percent to 36 percent, while quadrupling its natural gas use from 11 percent to 46 percent. Also, it has added or announced 3,600 megawatts of renewable energy projects since 2012.

Nancy Pfund and Mark Perutz of DBL Partners, a sustainability-oriented venture capital firm, focus on the clean energy transition, observing that advances in software are "eating [the grid] from the edge"—the space between the distribution system and the customer. The grid edge is where innovation will uncover previously undiscovered clean resources, both on the supply and demand side.

Xcel Energy Vice President Frank Prager is proud of the wind energy in the company's mix. Renewables comprise more than 20 percent of Xcel Energy's energy portfolio, most of it wind. "We have more than 5,700 megawatts of wind power on our system today," he says. In fact, Xcel Energy has been the nation's top utility provider of wind energy for 11 years, as wind displaces millions of tons of carbon dioxide (CO_2) and protects Xcel customers from variable natural gas prices.

Finally, SunPower CEO Tom Werner focuses on the exponential growth in solar energy, the fastest-growing source of renewable energy in the U.S. Already solar reduces CO_2 emissions by 23.5 million metric tons each year—the equivalent of taking 4.9 million cars off the road. He urges focus on R&D to drive down costs further.

"If we embrace the challenges presented by a changing fuel mix and an increasingly cleaner generation portfolio, we will have succeeded in delivering value to customers."

–THOMAS A. FANNING

Using the Full Energy Portfolio

THOMAS A. FANNING
Chairman, President and CEO, Southern Company

Southern Company's commitment to providing a full portfolio of energy resources—including nuclear, natural gas, a lignite-fired integrated gasification combined-cycle (IGCC) carbon capture and storage (CCS) project, wind and solar energy and other renewable energy, as well as energy efficiency and demand response—to our customers remains paramount. The Southern Company has always been laser-focused on providing the best combination of safe, reliable, affordable, and environmentally responsible energy to the people and businesses we serve.

Our shift from coal-based generation to natural gas has been fundamental and significant, and has resulted in greater availability and lower prices. Where ten years ago the Southern Company system relied on coal for about 70 percent and natural gas for about 11 percent of our generation, we are now at about 36 percent coal and 46 percent natural gas. For a company that serves more than 4.5 million customers, that is a remarkable turnaround in a short period of time.

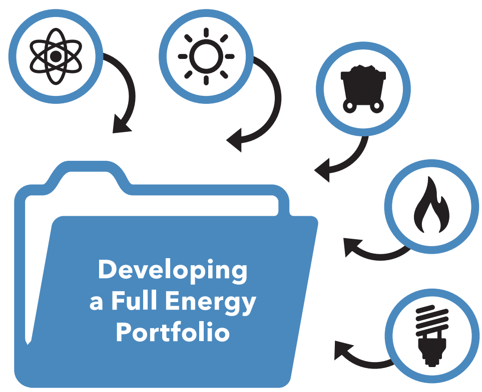
Nuclear energy, which today provides 63 percent of America's emission-free electricity, must be a dominant solution in a lower-carbon world. We are, through our Georgia Power subsidiary, constructing two new units at Plant Vogtle, which when complete, will supply enough safe and emission-free electricity to serve a half-million homes and businesses. These new nuclear units are expected to offer economic benefits to our customers and, in view of the goal of the Environmental Protection Agency's Clean Power Plan, will discharge no carbon into the atmosphere, as compared with what gas-based or coal-based plants of equivalent size would have emitted. We need more nuclear in America and in the world, but not every utility can build nuclear generation: it takes scale, operational credibility, a strong balance sheet, cooperative regulation, and financial integrity.

Coal use is on the decline in the United States, but coal still is used to provide more than one-third of the nation's electricity and is widely deployed elsewhere around the world. The IGCC coal gasification facility being built by our Mississippi Power subsidiary represents a way to keep coal viable while capturing most of the emitted carbon and using it for enhanced oilfield recovery. This Kemper County energy facility is designed to produce electricity from locally mined lignite with 65 percent carbon capture—a carbon profile better than a similarly sized natural gas plant. In countries with high natural gas prices and significant coal reserves, such as in Eastern Europe and Asia, the IGCC technology we are pioneering could contribute to a global solution that is good for customers and for the environment.

Renewable energy is also an important and fast-growing part of our full portfolio. Across the Southern Company system, we have added or announced more than 3,600 megawatts of renewable energy projects since 2012. That includes solar and wind facilities in six states, one of the nation's top biomass plants and, in Georgia, the largest voluntary solar program of any state.

The Southern Company system is also partnering with all four major branches of the United States military to develop renewable energy projects both on- and off-base. To date, that includes 11 solar projects totaling 310 megawatts. As Dennis McGinn, Assistant Secretary of the Navy, Energy, Installations and Environment, said about the Naval Submarine Base at Kings Bay, Georgia, such efforts have many benefits, including physical security, energy diversity, and regional resiliency.

All this activity underscores our belief that customers' energy needs are best met by a balanced portfolio of electricity generation resources, each of which offers its own distinct advantages.



Our vision of the balanced portfolio also embraces energy efficiency. If we can produce and deliver electricity more efficiently and help customers use it wisely, we can do more to harness energy's great potential to grow the economy and improve people's standard of living. Among the ways we do this is by partnering with customers—for example, helping businesses and local governments switch to high-efficiency LED lighting systems, which have longer life spans and much reduced energy requirements as compared with conventional lighting. We also offer customers who drive electric vehicles lower electricity rates for off-peak usage to save on their charging costs. These kinds of solutions make a real difference for customers.

Developing the full portfolio is a central component of our broader commitment to strengthening a culture of innovation at Southern Company. Initiatives such as SO Prize—a recent internal ideas competition—and the new Energy Innovation Center in Atlanta seek to engage all of our employees and are driven by a desire to deliver the best reliability, the lowest prices, and the cleanest technologies for the benefit of our customers. It's about integrating new thinking in how electricity is used in homes, businesses, and factories. If we embrace the challenges presented by a changing fuel mix and an increasingly cleaner generation portfolio, we will have succeeded in delivering value to customers. That is where our focus is and should be—transforming our business to benefit our customers.

"With respect to the power grid, software is eating it from the edge, as distributed energy resources of both energy supply and demand are bringing the grid from its cable TV past into its Internet future."

–NANCY PFUND & MARK PERUTZ

Modernizing and Decarbonizing the Grid From the Outside In

NANCY PFUND
Managing Partner, DBL Partners

MARK PERUTZ
Partner, DBL Partners

As venture capital investors in the energy sector, the biggest (and still accelerating) change that we've seen to the power grid over the past decade is the transformation from a centralized broadcast-based system like cable TV to a network-based system like the Internet. This transformation is largely driven by the dramatic evolution happening at the edge of the grid: behind-the-meter customer proliferation of new distributed energy resources and the growing application of energy-saving software. To borrow a phrase from Marc Andreessen, software is eating the world.[1] With respect to the power grid, software is eating it from the edge, as distributed energy resources of both energy supply and demand are bringing the grid from its cable TV past into its Internet future.

The first digitization wave of behind-the-meter resources began with smart meters (introduced by companies like CellNet, Itron, Silver Spring and eMeter), which opened the door to myriad policies, programs, and applications. Some of them are still at an early stage, including: time-of-use rates, net energy metering, demand charges, demand response, and energy disaggregation diagnostics.

The second behind-the-meter digitization wave is the accelerating rollout of the Internet of Things (IoT) in homes and businesses.

Adoption of IoT in homes (introduced by companies like Google/Nest and Apple) is likely to be driven by the homeowner's desire to have control over all her home appliances, lighting, temperature, media and home security from a mobile phone, as well as for energy choice (particularly clean energy), rather than by her desire to help modernize the grid. It will, however, have just that valuable side effect by enabling the widespread deployment of automated demand response—an often unnoticeable demand adjustment that will neatly and automatically help to balance supply and demand on the grid while providing energy bill savings to the homeowner. IoT in the home will also enable effective integration of electric vehicles (EVs), eventually allowing large-scale distributed EV charging and discharging to help stabilize the power grid.

The rollout of IoT in businesses is likely to be driven by the motivation to reduce energy costs. By using sensors and software to measure and see their energy usage profile, businesses can execute an informed deployment of solar, storage, load reshaping, and energy efficiency retrofits to evolve their facilities into "hybrid-electric" buildings that reduce their electricity bills and optimize comfort for building occupants, while having the key side effects of improving grid operation and facilitating achievement of state-level renewable energy targets and energy conservation goals. This commercial behind-the-meter evolution (introduced by companies like Advanced Microgrid Solutions, Stem, SCIEnergy, Enbala, and Renew Financial) brings these benefits to the power grid: peak shaving by automated demand response (obviating the need to retain old or build new fossil-fueled peaker power plants), new dispatchable capacity, avoidance or deferral of transmission and distribution upgrades, mitigation of energy islanding, and integration of renewables and EV charging. Case in point: In October 2015, for the first time, energy storage resources aggregated across multiple commercial buildings were bid into the California ISO real-time market as a demand response resource.

The grassroots proliferation of distributed energy resources—supported by software and IoT in behind-the-meter deployments—is crucial to the transformation from a centralized to a networked power grid. Generating renewable energy close to load is the most efficient and sustainable approach to establishing a flexible power grid for the future, and complements utilities' larger centralized power plants. This combination of distributed and centralized generation will help reduce the need for new transmission and distribution (T&D) infrastructure.

Obtaining permitting and public support for new T&D infrastructure is challenging, and contributes to rising grid operating costs on customer bills. In 2014, separate studies of the effects of behind-the-meter solar generation conducted for the Nevada PUC and for the Mississippi PUC—although controversial and much debated—found that distributed solar provided a net benefit for all ratepayers, both those with and without solar. The net benefit in both cases was driven by savings on the cost of energy and generation capacity, savings on maintenance and upgrades to transmission and distribution infrastructure, and reduced transmission losses.

The strong desire of consumers and brand-conscious businesses to play an active role in producing and consuming clean energy is an added driver toward the growth of distributed renewables. This is reflected in the sizeable and growing renewable energy goals of state governments. For example, in October 2015, California increased its renewable energy mandate to 50 percent renewables by 2030. Finally, when the scale of job creation from the deployment of distributed energy systems is taken into account, along with health benefits resulting from fewer fossil fueled power plants under the Obama Administration's Clean Power Plan, and the environmental benefits of reduced greenhouse gases, the benefits of a future with both utility-scale and widely deployed distributed renewable resources becomes even clearer.

The fundamental construct of the power grid, which has remained remarkably unchanged for most of the past century, despite tremendous advances in nearly every other industry, is now transforming from a rigid, unidirectional, and centralized system to a more flexible, networked system. This transformation is powered in large part by customers' new behind-the-meter approaches. Innovative private and public companies are tapping into a variety of motivations to sell IoT software and distributed energy resources to homeowners and businesses, and to evolve the power grid, beginning at the grid edge.

Continuing this evolution inward from the grid edge will require some regulatory changes, such as allowing utilities to purchase (and add to the rate base) infrastructure-as-a-service, rather than only adding infrastructure via capital expenditures. By purchasing operational services such as capacity, power quality, voltage control, and frequency support from the grid edge, and by adding software at the utility level to manage this infrastructure-as-a-service on demand, utilities could lower their costs and increase the overall resiliency of the grid.

* * * * *

Going forward, everyone will benefit when utilities, regulators, energy companies, and software companies work together to extend this transformation from the grid edge throughout the entire electric system for a power grid that is more robustly and efficiently designed for the 21st century.

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1. Marc Andreessen, *Why Software Is Eating The World*, THE WALL ST. JOURNAL, Aug. 20, 2011. *Available at* http://www.wsj.com/articles/SB10001424053111903480904576512250915629460.

"Xcel Energy's strategy to decarbonize rests on three principles: renewable energy leadership, system modernization, and sound regulatory policy."

–FRANK PRAGER

Clean Energy is Good Business

FRANK PRAGER
Vice President, Policy and Federal Affairs, Xcel Energy

Xcel Energy, which serves Minnesota, Colorado, the Texas Panhandle, and parts of five other states, is located adjacent to some of the best wind energy resources in the nation. Beginning in 2005, we committed to a path of clean energy and environmental leadership. Ten years later, we have reduced our carbon dioxide (CO_2) emissions by more than 20 percent and are on track to achieve a 30-percent reduction by 2020. Our strategy to decarbonize rests on three principles: renewable energy leadership, system modernization, and sound regulatory policy.

RENEWABLE ENERGY LEADERSHIP

Renewable energy now makes up more than 20 percent of Xcel Energy's energy portfolio, with the majority coming from wind. We have more than 5,700 megawatts of wind power on our system today and have been the nation's number one utility provider of wind energy for 11 years.

Our wind portfolio has displaced millions of tons of CO_2 while protecting our customers from the risk of volatile natural gas prices. In the last several years, we have acquired new wind energy at prices below the cost of the next-best natural gas alternative. This wind energy acts as a hedge against volatile gas prices, while saving our customers money today.

Xcel Energy has adapted its system to accommodate this extraordinary amount of renewable energy resources. Working with the National Center for Atmospheric Research, we developed forecasting expertise that enabled us to integrate unprecedented amounts of wind energy. On October 2, 2015, 54 percent of the electricity supplied to our Colorado customers was generated by wind energy for the entire day.

Customers want renewables in their energy mix, and we're happy to oblige. Our renewable energy portfolio is growing and helping to reduce CO_2 emissions at low cost.

SYSTEM MODERNIZATION STRATEGY

Xcel Energy began modernizing its generation resources over a decade ago. In Minnesota, we implemented the Metro Emission Reduction Project (MERP), which retired aging coal-fired power plants and replaced them with efficient natural gas facilities. We worked with our stakeholders, including customers and environmental groups, to craft a plan that reduced emissions and met the needs of the community.

In Colorado, we followed a similar approach. In 2010, the Colorado Legislature passed the Clean Air-Clean Jobs Act (CACJA), requiring Xcel Energy to develop a plan for reducing emissions. By 2018, we will have retired or switched to natural gas more than 1,000 megawatts of coal-fired generation. As with the MERP, CACJA grew from a collaborative effort. We took advantage of changes in the natural gas marketplace to reduce CO_2 emissions from our Colorado operations with minimal cost increases to customers.

Our carbon reduction strategy extends to other initiatives.

- We have some of the nation's most aggressive customer energy efficiency programs, which last year avoided the emission of about 550,000 tons of CO_2.
- Our decision to relicense and upgrade our zero-carbon nuclear plants in Minnesota avoids about six million tons of CO_2 emissions annually (compared to the most efficient fossil-based alternative).
- And, we have made substantial investments in our transmission system in Texas, Minnesota, and Colorado to deliver renewable energy to customers. As distributed and new grid technologies advance, we are committed to enabling interested customers to access more distributed low-carbon energy.

GOOD PUBLIC POLICY

Decarbonization requires substantial investment in the electric system, and appropriate regulatory strategies are critical to its success. Xcel Energy's success in reducing emissions depends on partnerships with regulators and other policy makers that encourage financially sound emission-reduction programs. For example:

- In Minnesota and Colorado, we helped design renewable portfolio standards that enabled competitive renewable energy acquisition and protection of customers from excessive rate increases.
- The state statutes that authorized our MERP and CACJA plans set the parameters for the programs and ensured timely, fair recovery of costs.

- We developed regulatory programs like CapX 2020 to create the framework for critical transmission investments in North Dakota, Minnesota, and Wisconsin that help integrate wind into the regional resource mix.
- In Minnesota, we are engaged in the collaborative "e21" effort with other stakeholders to consider regulatory policies that will facilitate a low-carbon grid transformation.

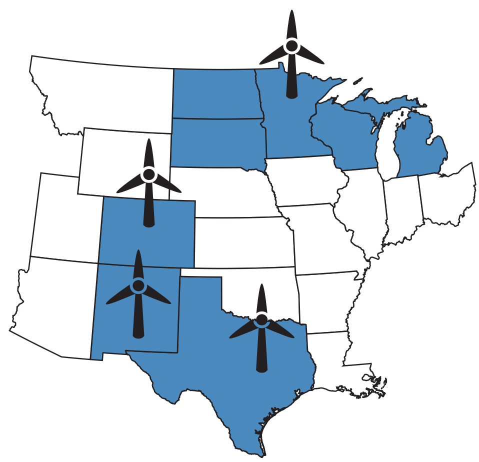
THE FUTURE

Today, we are working with our states to prepare plans to meet the requirements of the EPA's Clean Power Plan (CPP). We are committed to the approach that has proven so successful in the past: collaboration and good public policy. Xcel Energy will continue to grow its renewable energy portfolio, reducing emissions along the way.

In fact, we have already started. In the Upper Midwest, we've proposed a new resource plan that will result in the retirement of more than 1,000 megawatts of coal capacity and the construction of new natural gas generation and 3,500 megawatts of large-scale wind and solar. This plan will bring economic development opportunities to Minnesota, North Dakota, South Dakota, and our other states while helping to meet CPP obligations. For our Minnesota system, the plan will result in a 60-percent reduction in CO_2 from 2005 levels by 2030.

* * * * *

By looking for economic and efficient ways to decarbonize our energy portfolio while recognizing and respecting the unique differences of the jurisdictions we serve, our approach has resulted in significant emission reductions at a reasonable cost.



Xcel Energy's Wind Resources

"We are entering an unprecedented solar revolution that will forever transform how we power communities, businesses both large and small, individual households, and governments."

–TOM WERNER

An Energy Road "Less Traveled By" Begins With Solar

TOM WERNER
President and CEO, SunPower

In one of his most famous poems, "The Road Not Taken," the 20th century poet Robert Frost is famously remembered for his concluding passage: Two roads diverged in a wood, and I – I took the one less traveled by. And that has made all the difference."

By all accounts, the U.S. is on the cusp of a "less traveled by" road as it relates to energy sourcing and delivery. According to estimates by the Energy Information Administration, roughly two-thirds of U.S. electricity consumption is met by fossil fuels. The rest–comprised of nuclear, solar, wind, hydro, geothermal and other sources–has steadily increased in recent years, with solar increasingly playing a leading role in the transition to a low-carbon economy.[1]

We are entering an unprecedented solar revolution that will forever transform how we power communities, businesses both large and small, individual households, and governments. At SunPower, we have the privilege of being on the front lines of this transformation every day, and our partnerships with utilities are critical to decarbonizing electricity generation.

The United States currently has enough solar capacity installed to power approximately 4.6 million homes. Solar is the fastest-growing source of renewable energy in the U.S. Already it reduces carbon dioxide emissions by 23.5 million metric tons each year–the equivalent of taking 4.9 million cars off the road.

According to the International Energy Agency, solar energy could supply more than one-quarter of the world's electricity by 2050. This projection would have been easily dismissed just a few years ago.

Fortunately, the world continues to move in this direction. President Obama's recently published Clean Power Plan is a significant step forward, creating a tangible strategy for reducing carbon emissions—and along with it, other pollutants. Subsequent commitments by the U.S. and China to work together to reduce emissions and promote clean energy have helped set the tone for a more forward-looking discussion and actions.

Without question, solar adoption in the U.S. can help provide a blueprint for the rest of the world as we shift our focus from rhetorical conversation to accomplishments. Three key areas should help guide our collective strategy:

First, we must learn from what is working. From large businesses to utilities to universities to individual households, every solar installation serves as a learning experience and a series of data points that can help inform our shared efforts going forward.

For example, the University of California, Davis now has the largest solar power installation in the UC system, a 16.3-megawatt SunPower system that is also the largest solar power plant to meet the electricity demands of a U.S. university campus. The project is playing an important role in helping the UC system achieve its goal of carbon-neutrality by 2025, a commitment that establishes UC as a role model for other universities.

Similarly, utilities across the U.S. are launching innovative new programs to support the development of distributed solar generation in their service areas. These include community solar and local capacity requirement programs, as well as partnering with solar providers to market solar power systems directly to homeowners. New York's "Reforming the Energy Vision" proceeding is an interesting model encouraging participation by third-party providers; and utilities have responded with initiatives like Con Edison's proposed 'solar plus storage' pilot with SunPower.

Second, it's critical that we reduce the barriers to access for anyone who stands to benefit from solar energy.

16.3 MW
SunPower solar system at UC Davis Campus

Recent momentum in the solar market creates an ongoing opportunity to highlight the economic potential of solar energy. By partnering with our customers to develop new business and financing models, SunPower is helping to lead the conversation with households, businesses and utilities.

For the solar market to maintain the level of growth it is experiencing, we must prioritize public policies. The solar investment tax credit, as an example, has done its job in spurring the transition to a clean energy economy. We must make clear how long-term certainty in public policy aligns with what customers value.

Third, it's critical that we double down on industry-wide innovation in deployment of solar technologies and related energy services such as battery storage and energy management. We are on the cusp of significant breakthroughs similar to what we've seen in information technology, focusing on high performance, fully integrated system solutions to accelerate the mainstreaming of solar. A laser focus on R&D and its role in continuing to lower the cost of owning and operating solar systems will help cement this transition.

* * * * *

Ten years from now, we will look back at this moment in time when we took the road 'less traveled by.' We'll contemplate the difference it has made in how we manage and control energy, and the positive effect it has had on our planet and prosperity. The goals have been set and the blueprint is in place. It's not a question of whether the world goes solar. It's a matter of how fast it will happen—and the difference it will make.

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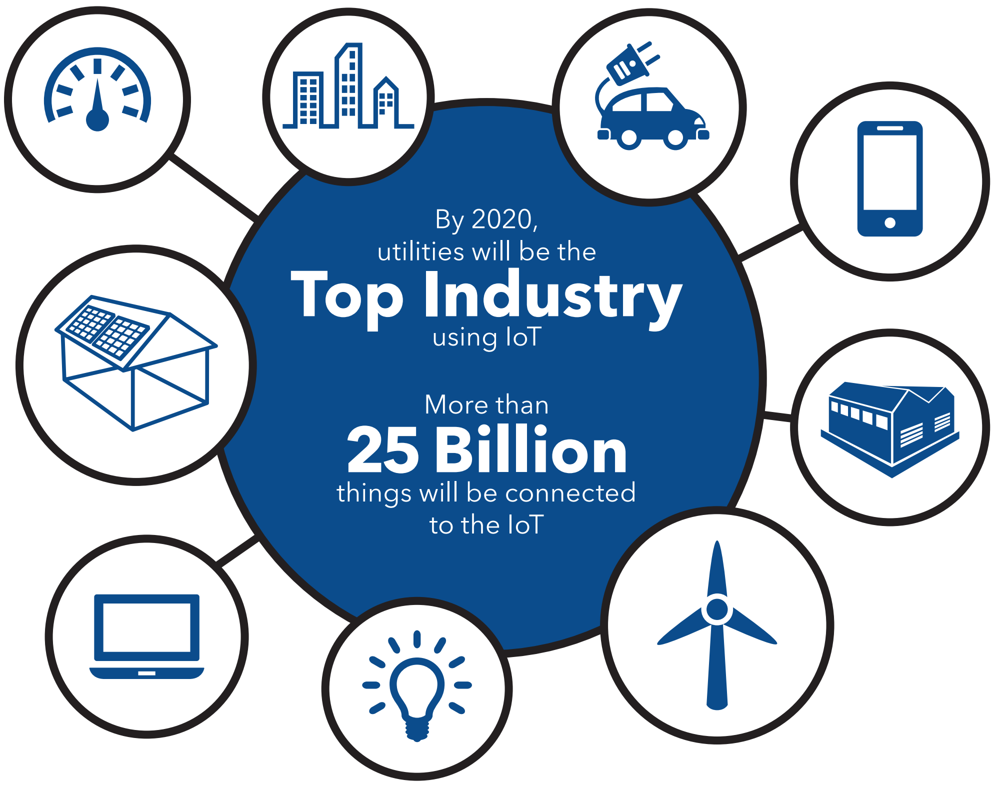
1. *See* U.S. Dept. of Energy, Energy Information Agency, ANNUAL ENERGY OUTLOOK 2015, Table A8.

Fact Sheet: Digital and Distributed Grid

Grid of Things™



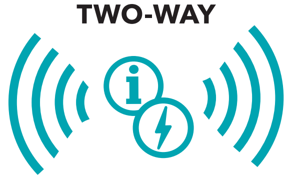
Digital and Distributed

As of 2015,
utilities deployed

SMART METERS

Utilities are investing
$ MORE THAN
20B
ANNUALLY
in the distribution grid

Digital grid enables
TWO-WAY



power and information flows

DIGITAL AND DISTRIBUTED GRID

In the U.S., the movement toward a more digital and distributed power grid is well underway. The need for more reliable and resilient grid operations, for greater efficiency and control, and for the connection and interaction with the "Internet of Things" (IoT)—every device with an IP address—creates new challenges, roles, and opportunities. The deployment of more than 60 million digital smart meters is one key building block. The authors of the essays in this chapter point to utilities as becoming the top industry using IoT by 2020, partnerships for smart cities, and the grid as an integrating platform. Today, U.S. utilities are investing more than $20 billion annually in the distribution grid—they have a central role to play as the integrators and enablers of the evolving Grid of Things™.

Scott Lang, Executive Chairman of Silver Spring Networks, sees utilities and cities partnering to bring the benefits of a digitized distribution system to urban centers—smart cities. ComEd is leveraging its AMI canopy in Chicago to create a distribution automation program that is preventing significant numbers of customer outages and is connecting other digital assets.

Southern California Edison's Pedro Pizarro and Erik Takayesu see the landscape of SCE's distributed energy future unfolding as each year more customers install solar arrays and use smart phones to control devices in their homes and businesses. Tomorrow's digital and distributed grid will manage centralized generation and hundreds of thousands of distributed energy resources (DERs). SCE expects to be the critical integrator of the technologies that link customers and resources.

The IoT is transforming the grid infrastructure, says C3 CEO Thomas Siebel. By 2020, 25 billion connected things will be in use and utilities will be the top industry using IoT. Big data, elastic cloud computing, and machine learning are already being applied to solve utilities' business challenges.

Oracle Utilities Senior Vice President and General Manager Rodger Smith notes that consumers, businesses, and utilities are adopting DERs—and far faster than anticipated. The utility of the future, he says, is the platform for delivering new processes and programs, integrating data and analytics to model and manage the new grid.

"Utilities are now in a position to partner with, if not lead, cities to perform functions together that were not possible before the smart grid became a reality."

–SCOTT LANG

In the Transformation of Smart Grids Into Smart Cities, the Only Limit is Imagination

SCOTT LANG
Executive Chairman, Silver Spring Networks

The McKinsey Global Institute estimates that between now and 2025, the world's urban population will grow by 65 million people a year, or almost 179,000 each day. Virtually every major city projects itself as an innovation hub, a "smart city." The consensus among stakeholders is that a smart city involves disruptive technology and that utilities are essential in implementing it. Today, utilities have an opportunity to do far more than provide reliable, ubiquitous electricity to consumers. They can dramatically improve the quality of life in their communities.

Electric utilities across the country are transitioning to a new, technological, business, and social environment largely defined by advanced information technology. The evolution of the smart grid, right down to the device level (and the consequent ability to transform what once was a static structure into a dynamic, information-based interactive system) means the infrastructure is in place to perform functions in real-time, and in a systemic way, to achieve significant cost and energy efficiencies.

It also means that utilities are now in a position to partner with, if not lead cities to perform functions together that were not possible before the smart grid became a reality—provide clean and reliable energy, alleviation of congestion and improved transportation networks, adaptive street and area lighting, the conservation and efficient use of resources, among many others.

As customers—retail, commercial, industrial, and municipal—evolve from passive consumers to active participants in managing how and when they use power, utilities are finding that they must radically redefine their role to focus more on the critical infrastructure that powers their customers and communities. This not only provides utilities an opportunity to realize new efficiencies and define new revenue streams, it also positions them as the platform on which to build smarter cities.

Utilities and cities are becoming aware that their continued success and relevance are best served by working together toward the common goal of providing innovative, highly reliable, safe, and responsive services. Both are moving from a centralized, top-down model to a distributed, horizontal structure; their relationships with customers and constituents are becoming much more collaborative. In the process, their digitized interactions with customers will yield massive amounts of information in real-time. At the core of the challenge that both face—but particularly utilities—is how to make effective use of this data.

Smart City

Smart grid technology has driven operational efficiency, dramatically improving outage response and restoration time and managing distributed and intermittent generation. That same technology platform, particularly its advanced communication and control capabilities, can also be harnessed by municipalities to create a platform upon which they can deploy additional smart city services over time.

Silver Spring Networks partners with customers around the world to implement smart energy and smart city platforms. In the course of that work, we have seen incredible results when utilities and cities collaborate.

Street lighting can easily account for up to 40 percent of a city's energy budget. That's a very large chunk of a municipal budget at a time of increasing demand for city services and severe budget constraints. To cut costs and improve quality of service, Florida Power and Light (FPL) in South Florida, including Miami, is leveraging its existing smart grid to connect and manage a network of 500,000 street lights, creating the largest smart Internet Protocol (IP) networked street light deployment in the world.

In the past, almost all the lights in their network had to be manually inspected to see if they were functioning properly. Now, the network will save what were thousands of wasted man-hours, and outages and voltage problems will be much more quickly addressed, improving reliability and quality of service for customers.

The lesson here is the importance of networking. Replacing aging lights with LEDs is not enough. When networked, LED lights can save approximately 65 percent in energy costs and reduce maintenance by as much as 90 percent.

Smart grid networking can also provide communities with a wide variety of quality of life benefits as well as cost savings. In Chicago, ComEd is leveraging its AMI canopy for a very progressive Distribution Automation program that has already prevented more than 1.2 million customer outages, and is beginning to connect street lights and other digital assets across its territory. Denmark, Copenhagen, often called the most livable city in the world, is networking street lights to enable automatic dimming or illumination at dangerous road junctions and in inclement weather.

These and other "smart city" smart grid infrastructures provide immediate quality of life benefits to residents and a source of cost-savings for the city. They also establish a city-wide network canopy upon which additional smart city services can quickly and cost-effectively be deployed in the future, allowing cities to quickly recoup their investment and deliver additional value to their citizens.

This canopy, for example, can be extended to connect other smart-city assets including smart water networks, pollution and environmental sensors, EV chargers, parking meters, and traffic lights, among many others. Intelligent traffic systems can detect vehicle volume in all directions and quickly adjust to allow the most efficient flow. Estimates say 70 percent of all wasted fuel results from sitting at traffic lights in a city, so using this intelligent, interconnected system could significantly cut pollution and waste.

As utilities continue to rapidly install the infrastructure and software essential to manage a smart grid, and as cities compete with one another to attract new, technology-dependent industries, it's clear that a partnership between the two is more than mutually beneficial—it's critical.

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In many cases the infrastructure to support these partnerships is already in place or quickly being deployed to support other assets. What's needed now is the imagination to take full advantage of a new, highly cooperative environment to build smarter cities today.

"The evolving DER landscape offers companies like SCE a rare opportunity to redefine what it means to be an electric utility in the 21st century."

–PEDRO J. PIZARRO & ERIK TAKAYESU

Building Tomorrow's Digital and Distributed Power Grid Today

PEDRO J. PIZARRO
President, Southern California Edison

ERIK TAKAYESU
Director, Electric System Planning, Southern California Edison

Driven by accelerated technological innovation, electric utilities today have the opportunity to redefine and modernize the electric grid, making it even more secure, reliable, resilient, efficient, interactive, and clean. This next generation power system will enable our customers to seamlessly integrate distributed energy technologies and contribute directly to effective, efficient grid management. This system will also maximize energy from integration of renewable and low-carbon energy sources such as solar and energy storage, thereby lowering greenhouse gas emissions from the electric sector.

Southern California Edison (SCE) has launched efforts to prepare our employees and our grid for this more customer-driven, distributed, clean energy future. As these efforts move forward, we will continue fulfilling our commitment to safely provide reliable, affordable, and clean energy to all of our customers. These concurrent responsibilities require us to implement this transition thoughtfully, engaging with and enabling our customers at the forefront of technology adoption, while continuing to control costs.

At SCE, the landscape of a distributed energy future is easy to envision. Each year, more of our customers are installing photovoltaic solar arrays and using intelligent devices like smart phones to control temperature, lighting, and even appliance operations in their homes and businesses. They are buying electric vehicles and battery storage units. They will connect to community solar and community storage units in ever greater numbers. Our customers—more than 14 million people across a 50,000 square mile service territory—expect us to be ready for that future.

Tomorrow's digital and distributed power grid will manage centralized generation in concert with hundreds of thousands of distributed energy resources (DERs). We anticipate the development of local retail markets, which will be a platform for DERs to provide grid services in order to maximize the value for both DERs and other customers. These markets could include both aggregators and direct participants who will create their own programs and contracts and compete to provide services. Future markets may also include multiple customers and devices interacting in micro-transactions to share supply and demand across the grid.

The State of California and our Public Utilities Commission (CPUC) recognize that grid modernization is essential to realizing energy and environmental goals. In July 2015, California's investor-owned utilities filed Distribution Resources Plans (DRPs) with the CPUC that detail necessary actions to realize the vision of a 21st century power grid.

SCE's job, as a utility and distribution system operator, will be to project future grid needs, maintain a grid that enables customers to seamlessly connect any resource or device, and operate a market that creates opportunities for customers to provide grid services and be appropriately compensated. Some key elements of the 21st century power grid include:

PLANNING & OPTIMIZATION

To support the DRP, SCE is developing methods to plan for and integrate DERs, including:

- *Integrated Capacity Analysis* to systematically model, study, and publicly display circuit capacity for the integration of DERs;
- *Modernized Planning Processes* that identify optimal locations to encourage DER adoption, forecast future DERs on the distribution system, and zero in on areas that require additional grid reinforcement to support higher penetration;
- *Integration of Smart Inverters* that optimize the regulation of voltage and provide additional stability during outage events; and
- *Distribution Volt/VAR Control* (DVVC) that regulates voltage through advanced capacitor control technology. By reducing and tightly managing voltage on the distribution system, SCE expects to lower customer energy consumption by one to four percent. Integrating DVVC technology into the grid could save customers hundreds of millions of dollars.

ADVANCED AUTOMATION

SCE is testing and preparing to install new automated technology solutions that improve the reliability, flexibility, and resilience of the grid, such as:

- *Real-time Visibility* that utilizes more state-of-the-art digital sensors and intelligent circuit devices to provide system operators greater visibility into the real-time status of load, DERs, and multi-directional flows. Improving situational awareness for operators should reinforce reliability and power quality.

- *Self-Healing Distribution Circuits* that use new intelligent switches with sensing capabilities to automatically detect and isolate faults and instantly reroute power from DERs to other functioning circuits—reducing the number of utility customers affected by outages, and facilitating faster repairs and service restoration.
- *Substation Automation 3* (SA3), the latest automation package that will improve the responsiveness of the system and enable broader implementation of new customer technologies on the grid. SCE plans to deploy SA3 to some 400 distribution substations over the next decade.

IT PLATFORMS, COMMUNICATIONS, & SOFTWARE

SCE will deploy advanced tools and systems that enable the grid to serve as a DER platform, and for operators to manage more complexity, including:

- *New Grid Analytic Tools* to support asset management decisions, leveraging data from sensors and smart meters; and new long-term planning tools to better forecast the ability of DERs to meet grid needs.
- *Communication Systems* with higher bandwidth, faster backhaul, and field area networks to support additional data flow from sensors and smart meters to enable better control of grid components.
- *Grid Management Systems* based on innovative architecture that ultimately would replace current legacy technology to support both operations and market functions.

This evolving DER landscape offers companies like SCE a rare opportunity to redefine what it means to be an electric utility in the 21st century, and to transform our industry and our relationship with our customers.

With more renewable energy generated by both power producers and customers, and shared by all, the grid will be much more complicated to operate. Utilities like ours will be critical integrators of these technologies, linking customers and resources. In this scenario, the role of the utility will be like that of a conductor, bringing each component of an orchestra into harmony, with each participant's contribution benefiting the whole in a system that is interactive, efficient, and reliable.

* * * * *

Like the engineers who constructed the 20th century electric grid, SCE is developing a 21st century grid today that will provide the platform for a future energy model that is only beginning to be conceived. We are truly excited about the road ahead.

"By 2020, 25 billion connected things will be in use, and utilities will be the top industry using the 'Internet of Things'."

–THOMAS M. SIEBEL

How the "Internet of Energy" is Driving the Digital and Distributed Power Grid

THOMAS M. SIEBEL
CEO, C3 Energy

The "Internet of Things" (IoT) is transforming the next generation of global energy grid infrastructure. Simply put, the IoT leverages the Internet to connect machines, devices, systems, and other "things," resulting in a convergence of physical and virtual worlds. Gartner predicts that by 2020, 25 billion connected things will be in use, and utilities will be the top industry using IoT, followed by manufacturing and government, driven partially from investments in smart meters.[1]

This decade, an estimated $2 trillion will be invested in upgrading electric grid infrastructure globally, including the addition of millions of sensors to devices throughout the grid. More than 400 million smart meters have been installed globally as of 2015; that number will double in the next ten years. Although smart meters receive much industry attention, they represent just a fraction of the sensors being deployed on the physical grid infrastructure. Consider smart thermostats, home appliances, HVAC equipment, factory equipment and machinery, transformers, substations, distribution feeders, power management units, and power generation and control components. These sensored devices can send and receive information across a computer network, and collectively generate massive amounts of information—an increase of six orders of magnitude.

To optimize the power value chain, utilities require next-generation technologies to integrate and aggregate data, apply sophisticated analytics in real time, and generate actionable insights in a way that directs business outcomes through a common data- and intelligence-driven solution.

NEW TECHNOLOGIES FOR GRID OPERATORS

Big data, elastic cloud computing, and machine learning are now being applied to solve utilities' business challenges, such as improving customer engagement, managing the operational health of advanced metering infrastructure (AMI) assets, preventing revenue loss due to theft and meter malfunctions, optimizing the maintenance of network assets, and increasing grid resilience.

For example, utilities now can use machine learning—the ability of computers to learn without being explicitly programmed and to continually improve their predictive precision—to classify network assets at high risk of failure, segment customers for targeted marketing campaigns, predict load, and manage the complexities of distributed energy resource management.

Just as a credit card company uses historical spending data to flag potential fraud, utilities can use historical and real-time data to identify energy theft. Baltimore Gas and Electric Company (BGE) proved this when it deployed the C3 Revenue Protection™ application across its full service territory of two million meters. In just six months, the solution identified more than 8,000 cases of potential theft with approximately 90 percent accuracy.

By leveraging machine learning and the science and tools of big data, a new generation of smart grid analytics is enabling grid operators to predict future demand, distributed generation capacity, technical and non-technical losses, electric vehicle load, and variable generation capacity across the entire energy value chain.

In another BGE example, the utility used the C3 AMI Operations™ application to identify 3,600 meter health issues with 99 percent accuracy to streamline critical maintenance of AMI assets.

By correlating and analyzing the dynamic interactions associated with the end-to-end power infrastructure as a fully interconnected and sensored network, utilities are realizing dramatic advances in safety, reliability, cost efficiency, and environmental benefits.

PREDICTIVE ANALYTICS HAVE GLOBAL IMPACT

With the European Union's recommendation of 80 percent smart meter penetration by 2020, EU member countriesareseeingstrongdriversfornext-generation analytics solutions, including large smart meter deployments in Italy, the United Kingdom, France, and Spain. Such large-scale deployments may yield lessons for the United State's energy sector, which has deployed more than 60 million smart meters to date.

Enel, a leading integrated player in the global power and natural gas markets serving 61 million customers, was the first utility in the world to replace traditional electromechanical meters with digital smart meters. By 2006, Enel had installed 32 million smart meters across Italy. With 38 million smart meters today, Enel is on track to deploy approximately 46 million across Europe by 2019. Enel represents more than 80 percent of all smart meters on the continent.

To unlock operational value from big data in the smart grid, Enel deployed two of C3 Energy's data analytics applications across an initial set of ten million smart meters and grid sensors in Italy and Spain—the largest deployment of a machine learning-based analytics platform to date.

Deployed in just eight months, the solution integrated, normalized, and aggregated seven trillion rows of data from 13 unique data sources—customer information, billing, and work order systems; outage management, producer, and meter data management systems; and SCADA and validated theft case data, as well as weather data and Google terrain information—into a 700 terabyte data image updated in near-real time. More than 2,500 analytics generate ten million predictions per day to identify anomalous meter activity and predict asset failure to improve Enel's grid reliability, reduce energy loss, and decrease maintenance operating costs. The initial deployments proved that the data analytics solution could readily handle Enel's smart grid data processing and aggregation needs, and deliver more than 200 million Euros in operational efficiencies to Enel. C3 Energy and Enel are working to expand the deployment of this solution widely across Enel's distribution network.

McKinsey & Co. estimates the value of C3 Energy's end-to-end smart grid analytic solutions for a typical integrated U.S. utility and its customers is approximately $300 per meter per year, based on lower operational expenses, more efficient use of capital, higher customer value, and improved safety and reliability of energy delivery.

* * * * *

Utilities are realizing significant returns by embracing cutting-edge technologies, such as cloud-scale computing, advanced smart grid analytics, and machine learning, to benefit their communities, consumers, other stakeholders, and the environment. With continued innovation, the energy industry is rapidly driving toward the Internet of Energy.™

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1. *Gartner Says 4.9 Billion Connected 'Things' Will Be in Use in 2015*, November 11, 2014 (www.gartner.com/newsroom/id/2905717).

"The utility of the future needs to become the platform for delivering new processes and programs, integrating data and analytics to manage the new grid."

–RODGER SMITH

Leading at the Edge of the Grid: An Integrated Platform for the Future

RODGER SMITH
Senior Vice President and General Manager, Oracle Utilities

We are now at the leading edge of what has long been thought of as unachievable, part of a very distant future: grids that can readily accommodate distributed generation of all types; solar generation at all size levels; battery storage; electric vehicles that can be used as load balancing tools; and more, including combined heat and power, wind, and demand response.

Now apply an accelerant to that change: data produced by the growth of connected devices. A new concept—the Internet of Things (IoT)—has been coined to describe this phenomenon, one of the most profound technological growth periods in human history. As these distributed resources continue to interconnect and add data to the distribution grid, utilities are being tasked with providing infrastructure and keeping pace, and ensuring that the data from these resources can be made actionable.

Meanwhile, severe weather, solar flares, and cyber threats to the system are prompting increased interest in cybersecurity, micro-grids, and improving grid resiliency.

These are indeed challenges, but they also present a bridge to innovation and business renewal, as utilities and wider society explore solutions where the greatest change is occurring—at the grid edge. Many utilities are beginning to turn these challenges into opportunities. They are embracing a smarter, digitized grid and leveraging it to improve reliability and outage response, while delivering high value services to customers and gaining new revenue in doing so.

EMBRACING AND LEVERAGING THE DIGITAL GRID

Empowered by technology innovation and supported by policy, consumers, businesses, and even some utilities are choosing to adopt distributed energy resources (DERs) at a pace far faster than anticipated. Not so long ago, the International Energy Agency (IEA) projected solar and other DER growth out to 2030, but the development IEA forecasted was actually achieved by 2012, almost two decades faster than expected.[1]

These DERs may enable utility customers to manage their energy choices with little or no input from the utility. If customers do this, however, they introduce more reliability and service quality risks into the picture as many DERs produce energy intermittently. Alternatively, if utilities support customers' growing adoption of DERs, integrating them into the overall network, they can leverage the DERs as on-demand, low-cost tools for improving reliability and outage response.

By proactively integrating these resources into an intelligent network model, utilities can use DERs to:

- Predict asset risk and reduce capital and maintenance expense;
- Improve energy capacity to meet demand;
- Reduce customer minutes of interruption through more accurate load profiling;
- Deliver flexibility to meet peak demand; and
- Improve utility resource planning.

Oracle is a key partner in helping utilities mitigate the risks of rapid DER integration. Our connected solutions enable DER lifecycle management through operations, data management, risk analysis and planning, service and maintenance, outage management, and customer interaction. Our tools enable utilities to profile DER load by location and condition of use, which is a necessary step to understanding and managing the impacts—both positive and negative—that DER can have on the distribution grid.

CONNECTING CONSUMERS WITH VALUE-CENTERED SERVICES

Energy consumers are showing greater interest in products and services to help them use electricity wisely and cost-effectively. The number of new entrants in the home energy management (HEM) solutions market in recent years is indicative of the growing interest by consumer technology vendors. But this market shift actually offers utilities a pathway to advising customers about HEM solutions.

With an unparalleled window into consumption data and consumer behavior, utilities can expand the scope of their mission by facilitating and enabling energy consumption choices. Indeed, regulatory bodies are becoming more willing to consider the role of utilities as the provider of the enabling infrastructure in a dynamic, real-time marketplace, as seen in emerging market rules and legislation around the globe in places such as California, New York, Hawaii, Germany, Australia, and New Zealand.

By connecting consumers with value-centered services, utilities can:

- Expand revenue potential by providing consumers with lifestyle-based energy services;
- Harness the value of real-time data to increase sales of excess and stored DER generation into other markets; and
- Offer new services, such as segmentation, energy trading, and construction and operation of community-owned DER services.

Unlocking Value in Data

THE FUTURE REAL-TIME UTILITY ENVIRONMENT

The new technology infrastructure being developed is critical to managing the digital power grid going forward and creating new business opportunities for utilities. Within today's real-time utility environment, operational technology (OT), consumer technology (CT), and informational technology (IT) business models and processes are overlapping and converging.

Customers are no longer complacent and disengaged. They are becoming increasingly engaged in monitoring and managing their usage; having a 24/7, multi-platform, real-time connection with their utilities; and connecting DERs to the utility's distribution grid. The utility that maintains a siloed approach to these newly engaged consumers stands to lose them.

Integrating OT, CT, and IT business models and processes to deliver customer-focused solutions will be critical for the utility to succeed in this evolving system. The utility of the future needs to become the platform for delivering new processes and programs, integrating data and analytics from across the enterprise to model and manage the new grid. A utility that falls short will be bypassed by competitors. It's time to stop looking at today's rapid changes as challenges, and turn them into opportunities.

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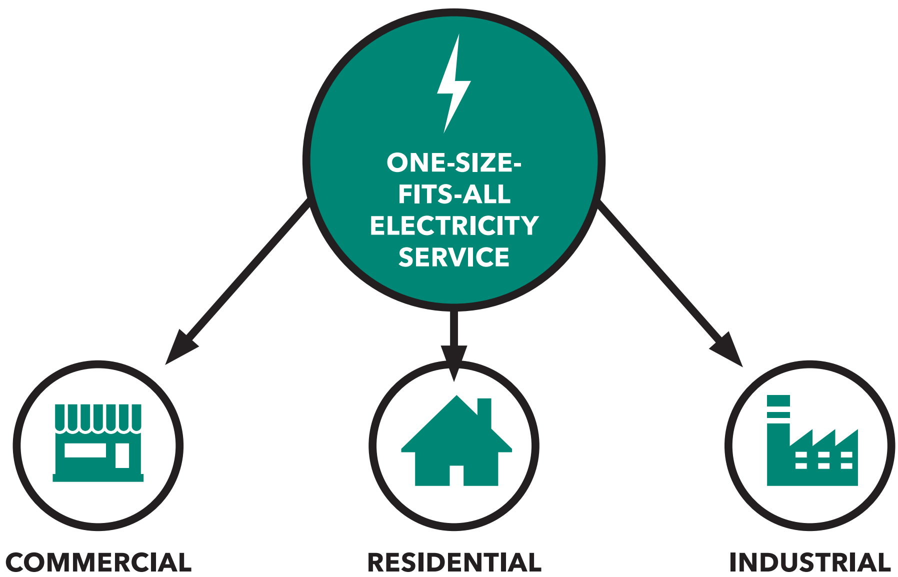
1. International Energy Agency, World Energy Outlook 2012.

Fact Sheet: Individualized Customer Services

Past



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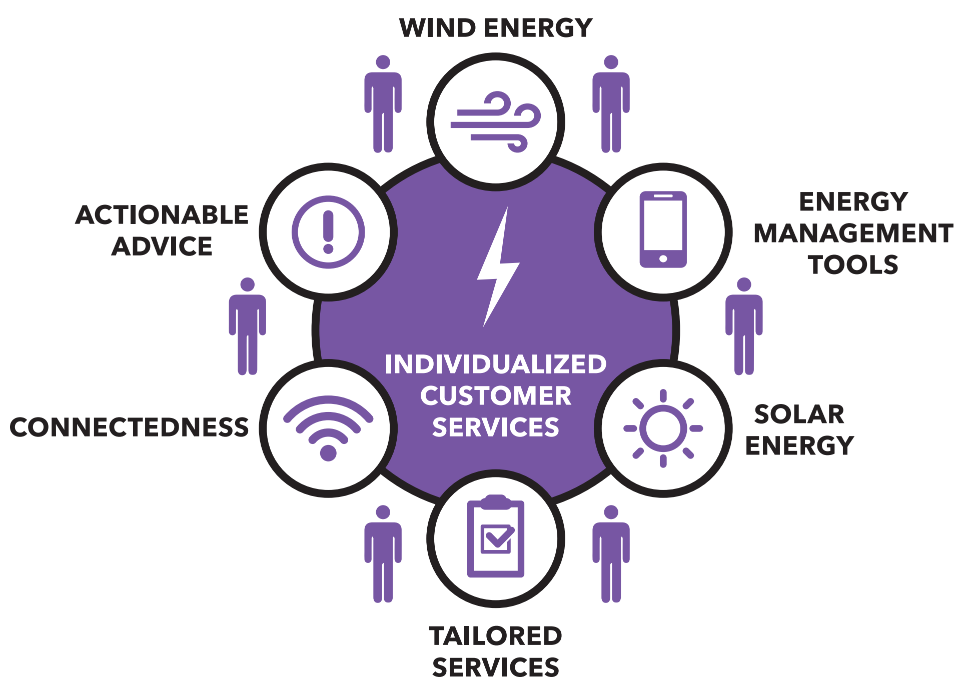


INDIVIDUALIZED CUSTOMER SERVICES

Increasingly, electricity customers want customized services. Some large commercial customers want 100 percent renewable energy to meet corporate sustainability goals. Cities and towns want help establishing clean city initiatives. Many customers want tools to manage and control their energy use. And most customers still want basic electricity service—safe, reliable, and affordable electricity. The authors of the essays in this chapter point to how technology, innovative solutions, and policy leadership all will play a role in providing changes that customers want.

Former Colorado regulator Ron Binz reminds us that a new generation of Americans—those born after 1980 and sometimes called "digital natives"—are comfortable with the digital world. By 2020, they will comprise more than half the U.S. population. Digital natives will be demanding and leading the change to which both utilities and policy makers must respond.

Mary Anne Brelinsky, president of EDF Energy Services, describes how her company is putting the energy value chain pieces back together. "We are knocking down the walls between our retail business teams and the wholesale markets that support them," she says. EDF is also stirring its trading operation into the mix of services it offers larger customers.

In "Making Energy Personal," Tony Fadell, CEO of Nest, says people give Nest Learning Thermostats as gifts. They're fascinated with them and often check on the data they generate. This interactive technology opens the door to more personalized service, as utilities and customers collaborate to find solutions that customers want.

To truly realize the potential of electricity service in 2025, writes Peter Kind, policy makers must chart the path forward. In this "reformed" industry model, utilities will be incented to provide customers the advice and services they want, while meeting regulators' and policy makers' goals and metrics.

Opower President Alex Laskey reminds us that utilities lag behind most other industries in providing a responsive customer experience. Customers want actionable advice, not data, on ways to lower their bills and other service options. Companies like Opower are using cloud software and data analytics to help utilities forge those improved customer relationships.

"For electric service, advances in clean energy technology, changing demographics, and how utilities are regulated will determine the speed of change."

—RON BINZ

No More Average Customers

RON BINZ
Past Chair, Colorado Public Utilities Commission

Think of the many ways you can configure your home entertainment: broadcast, cable, satellite, or phone company TV; streaming Netflix, Roku, Hulu, Sling TV, Apple TV and Amazon TV, just to mention a few. We're a long way from the days when baby boomers had three broadcast TV channels and a few squirrelly UHF options.

This array of choices is made possible by the combination of digitization and massive connectivity. Those two characteristics describe the Internet, which has fundamentally changed many U.S. institutions—entertainment, shopping, banking, libraries, travel, personal communications, and even social relationships. Something similar is coming to electricity service as the Internet meets the electric grid.

It's too early to predict exactly what the change will look like, but we can make some educated guesses based on the industries that have been reinvented by the Internet. Almost certainly there will be energy products and services that we "didn't know we needed and now can't live without"—think about smart phones, iPads, texting, and Google!

For electric service, advances in clean energy technology and changing demographics are driving the change. A third factor will determine the speed of the change: how utilities are regulated.

Let's start with demographics. People born after 1980 are often called "digital natives," since they were born into a digital world. When the first digital natives turned four, compact discs had just arrived in the U.S.; at age six, they witnessed the widespread use of personal computers; and when they reached age 11, web browsers were invented and the World Wide Web as we know it began to emerge.

Digital natives probably don't perceive the rapid growth in digital-ness because they've known nothing else. Expectations of what can be done and what should be done are much different for them, compared to people born in the analog era. Digital natives are the new baby boomers. By 2020, digital natives will comprise more than half the U.S. population. Fifteen years after that, two-thirds of the country will have been born after 1980.

Digital Natives Think Different

What's this got to do with electricity?

Simply put, digital natives, in the words of Apple Computer, "think different." Marketing experts report that digital natives adapt easily to advanced technologies, show a "contentedness with complexity," and "have a desire to control their own lives." Back in the day, everyone knew to ask a ten-year-old to program the VCR. (Remember VCRs?) We can safely predict that this generation—which will be the first to use self-driving automobiles—will also be comfortable trusting digital "expert systems" to assist with complex choices and complicated decisions. In short, the skills and predilections of digital natives match up well with the coming changes in the electric sector.

The second factor propelling change in the consumer electric sector is on the hardware side: the pace of clean energy and grid technology. Even the most bullish projections two years ago did not foresee the recent breathtaking decline in costs of photovoltaic electricity. And there is no end in sight: "Swanson's Law" asserts that, with every doubling of new solar capacity, the cost of solar generation falls 20 percent. While the trajectory of this "law" is not as steep for solar as "Moore's Law" is to electronics, it does describe a sector with exponential cost declines, while costs for traditional energy sources are going the other way. This also means that small-scale, distributed energy resources will continue to evolve even as their costs drop.

Within 10 to 15 years, we should expect that every device that touches the electric grid—from power plants to rooftop solar systems, from batteries to street lights, from toasters to transformers to electric vehicles—will have an internet address. This will be the "Internet of Things" and it will completely remake the physical electric grid. Any device will be able to "see" any other device on the grid. With complete connectivity, electricity producers (large and small) will communicate real-time "prices to devices,z" and electricity users will convey supply or demand "offers" to the grid operator or directly to generators.

The resulting web of transactions among billions of nodes in the electric grid is called "transactive" energy. It sounds complex, but don't worry: consumers will be spared the task of managing electric imports and exports for their freezers, hot water heaters, and vehicle batteries. Those tasks will be performed by an expert system—sophisticated software that will manage all the necessary transactions in line with the consumer's desired profile. Just as consumers don't need to know the details of packet-switching in order to send a text or post on Facebook, consumer access to the transactive energy market will be enabled by software that hides the messy details and simplifies the choices.

What will this mean to the average consumer? For starters, "average" will become much less meaningful. Each consumer will have the choice of how fully to participate in the new electric grid and will be able to select among many individualized profiles. Consumers might self-generate in part, buy only renewable energy, offer demand response, plug into a micro grid, time shift usage, or offer local storage to the rest of the grid. The uptake of these new technological choices will probably follow the customary "S-curve" of adoption. Early adopters will emerge, followed in time by most of the consumer base.

How rapidly these changes happen will depend in large part on how today's electric utilities are allowed by regulators to evolve. The way we regulate electric utilities hasn't changed much in five decades. Utilities will need much more flexibility than traditional regulation affords today. That means that the focus of regulation should accommodate the far more complex grid—and its opportunities—that will entice competitors at every turn.

Regulators need to turn to incentive regulation—an approach that rewards utilities for achieving desirable policy goals, or penalizes them for failing to do so. This approach will provide adequate or even increased earnings, while encouraging utilities to embrace and excel in fundamentally new roles—providing *energy services* and being the "orchestra conductor" for all the instruments in the new electric grid.

To some readers, this may be an unsatisfying vision. It predicts profound changes for consumer electric service, but offers few details or assurances. It projects a future by analogy to other sectors of the economy that have been transformed by information technology. But in 1980 few could foresee the profound changes the Internet would bring to so many aspects of our lives today.

Predictable or not, the Internet of Things is coming to electricity.

"We are putting pieces of the energy puzzle back together and providing innovative customer solutions–redefining customer expectations in the energy space much like Uber did for the taxi industry."

–MARY ANNE BRELINSKY

Putting the Energy Puzzle Pieces Back Together

MARY ANNE BRELINSKY
President, EDF Energy Services

I was standing in my parents' kitchen over the holidays and my youngest son, Noah, asked me, "Mommy, is Grandma afraid she's going to lose her phone?" I gave him a quizzical look and replied, "No, I don't think so. Why?" My bright, inquisitive child asked, "Well, why does she have it tied to the wall?"

It is easy to forget that this generation of Millennials has never had to untangle the long curly phone cord tied to the wall, hold a tape recorder next to the radio to record their favorite Cindy Lauper song, or drive to Blockbuster to rent a movie. Uber is yet another example of the same evolution and the continuing change in paradigms. Uber has forever changed the way we get from point A to point B. Uber has single-handedly turned the taxi industry on its head—no small feat, given the industry has employed the same basic business model since horse-drawn for-hire carriages began operating in Paris in the early 17th century. Since the introduction of Uber in NYC, the value of a single taxi medallion has gone from a high of $1.3 million to a mere $650,000.

Technology advancement is happening at an ever-increasing pace. Imagine if Alexander Graham Bell was alive today and you handed him a cell phone. He would have no idea what it was or how it worked. The technology in our phone looks and functions nothing like the old-school rotary phone of my childhood.

But if you dropped Thomas Edison in the middle of a switchyard next to a power plant, he could follow the turbines in the electric generator and the transmission and distribution lines and find the light bulb at the end of the line. We haven't experienced a revolutionary change in our electric industry in several generations. Yes, the industry has added renewable resources to the generation stack, provided demand response opportunities for industrial and residential customers, and developed innovative products that allow customers to tailor their energy procurement strategies. That said, our industry hasn't experienced true transformational disruption, but it will.

As an industry, are we laser-focused on these real challenges? Are we pushing our teams outside their comfort zones and traditional paradigms and forcing transformation through technology like others have done? How do we put ourselves in the driver's seat rather than continuing to wait for the taxi?

In the 1990s, our industry in the U.S. was partially unbundled and deregulated. The generators were separated from the traders, and the wholesale traders were separated from the retailers. Competition drove efficiency in these segments, which helped drive down prices to the consumers. But competition and unbundling came with an unintended consequence: those companies could no longer provide robust solutions across the entire energy value chain. I believe that transformational disruption for our industry is in how we put the pieces of the energy puzzle back together.

Putting the Energy Value Chain Pieces Back Together

At EDF, we have been experimenting with putting the energy value chain pieces back together using technology and offering unique products. We are knocking down the walls between our retail business teams and the wholesale markets that support them. Our EDF Energy Services customer business works collaboratively with EDF Trading to provide our commercial and industrial customers access to wholesale markets, while also providing expert retail service. Sometimes that means providing integrated products that combine renewable generation, load shifting, and price alerts in a single, integrated offering. We are putting pieces of the energy puzzle back together and providing innovative customer solutions—redefining customer expectations in the energy space much like Uber did for the taxi industry.

By employing both our Retail business and our Generation Services business in a single organization, we've created a unique, integrated corporate structure. This incents our people to work together to foster creative customer solutions. I realized the power of this structure a few years ago when one of our global industrial customers asked us to find a wind generator to supply a large manufacturing facility. This particular customer wanted a "green" energy retail supply deal with EDF and they wanted that "greenness" to be steel in the ground, not just paper certificates. This customer also wanted its logo painted on the wind turbine and photos for its annual report. We approached one of our wind generator clients whose response was, "If they give me a reasonable price for the energy they can paint anything they want on the turbine." When you walk into the lobby of this customer today, a photo of the logo-decorated wind farm with longhorn cattle grazing nearby is front and center.

In addition to integrated products, speed is also becoming more important to consumers. At EDF Energy Services, we are taking "big data" and turning it into information that our customers can use to make energy consumption decisions in real time. Our customers need information at a faster and faster rate. Turning energy data streams into information that our customers can use to run their businesses is our primary objective. For example, we've developed an iPhone app that allows customers to monitor their power stations from their phone; it displays current wind speeds and weather near their facilities, and allows retail customers to see their power and gas consumption alongside the appropriate real-time energy prices. Customers who have facilities in multiple locations can use this information to shift consumption from their facilities in areas with high prices to facilities in areas with lower prices. Yes, we have an app for that!

As an industry, we've spent billions installing smart meters. We should take advantage of that and make flexible, real-time pricing available on a wide scale. It would make us all as consumers of energy much more aware of how and when to use energy and get more efficient results in the process.

On a more personal note, my home electricity bill is indexed to the spot market. The price I pay for electricity at my home in Houston changes every 15 minutes. I have saved money for more than ten years paying spot-index prices for electricity, but that's not why I do it. I want to ride the wave of energy innovation. I have a smart meter. I have a smart thermostat. The cost of electricity at 4:00 p.m. on a hot afternoon in Texas is not the same price as it is on a mild Saturday morning. Over the last ten years, there have been brief periods of very high prices. On one occasion when my electricity price increased to more than $1,000 per MWh, I called home and asked my husband to go out to the garage and unplug the beer fridge. You would have thought I asked him to fly to the moon. At that moment, I'm sure he wished I was like the taxicab, but I really like being more like Uber.

"How can utilities add a new layer on top of their existing services–something to make customers happy and broaden the customer relationship? The answer is personalization."

–TONY FADELL

Making Energy Personal

TONY FADELL
Founder and CEO, Nest Labs

Keeping energy flowing safely and reliably into homes and businesses is challenging and complicated. But, for most utilities, the relationship with customers is—at a high level—pretty simple: The utility brings energy to a customer's home—the customer uses a certain amount of that energy, and the utility sends a bill for the amount used. It's straightforward, and it's worked the same way for a really long time.

It's also very limiting.

Say a utility wants to build a better relationship with customers and set itself apart. If the only interaction with those customers is the product they're being sold (which they don't really think about unless the power is out) and the bill they receive (which they don't really like because it costs them money), then the utility doesn't have many options. And that's especially problematic when utilities want customers to do something different—like using less energy on a hot summer day or engaging around other energy programs and services.

So how do we fix that? How can utilities add a new layer on top of their existing services—something to make customers happy and broaden the customer relationship?

The answer is personalization.

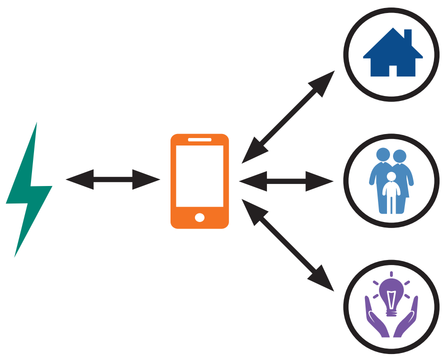
When we launched Nest four years ago, we wanted to take the technology inside our smartphones and put it inside the devices in our homes that have looked and functioned the same way for decades. We wanted to give people greater control over their energy use; the safety of their families; the security of their homes.

That's how the Nest Learning Thermostat was born.

Instead of asking people to set their own energy usage schedules (which most people never do) we designed a thermostat that learned home consumption patterns and programmed itself. And it worked. This year, independent studies proved that, on average, the Nest Learning Thermostat saved

U.S. customers about 10–12 percent on their heating bills and about 15 percent on their air-conditioning (A/C) bills.

So what does this mean for utilities? First, it proves that utilities can use personalized technology to give their customers an experience they really want and begin to build a better, stronger relationship.



Technology Enables Energy Personalization

For years, most people didn't give their thermostat a second (or first) thought. When their HVAC system broke, they had the repairman install a new one.

Today, that's changed. People don't just buy our thermostats when their old ones break. They get excited about them, give them as gifts, perform the installation themselves, and check on them through a mobile app multiple times a week. And, every month we send a Home Report with data about how much energy they used.

For a utility, that opens up a whole world of possibilities. All of a sudden, customers don't just see the utility as the entity that sends them a bill at the end of the month. Instead, the utility is providing a product that knows them; responds to them; and stays connected to them no matter where they go. The utility's brand gets stronger, and the relationship with customers goes from a transactional one to something much more meaningful.

So that's the first way personalized technology can help a utility build a better relationship with customers: by creating a great experience. The second way is by using technology as an incentive to transform how and when customers use energy.

Two years after we launched the Nest Learning Thermostat, we announced an opt-in program for our customers called Rush Hour Rewards (RHR). RHR helps people earn money or credits from their energy providers by using less energy when everyone else is using more. Unlike traditional demand response programs that are one-size-fits-all, RHR takes into account when people are home or away, their preferred temperatures, the "profile" of the home (large/small, how quickly it loses cooling), and only deploys to homes that can help reduce A/C use during peak periods. Most important, RHR customers are always in control of the temperature to ensure their comfort.

To date, Rush Hour Rewards has helped achieve an average of 55 percent energy reduction in residential air conditioning loads during peak periods. And while customers can adjust the temperature at any time, just 14 percent of RHR participants changed the temperature during an event.

For utilities, this is an example of a potential game-changer. It's easy to imagine a future where technology takes complex and difficult energy programs and makes it easy for every consumer to understand and participate in them.

That's why personalization is so important—and why it holds so much promise. Today, we're seeing the first glimpses of how personalized technology can give customers and utilities more control and help them build a better relationship over time.

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The next decade will bring even more examples like this, with utilities and technology companies working to make tools that people actually use and love. And together, those tools will make a huge difference.

"We now need policy makers to take the lead in charting the path forward to accelerate our electricity and environmental future by defining the framework and incentives to make this vision a reality."

–PETER KIND

Residential Electricity Service in 2025

PETER KIND
Executive Director, Energy Infrastructure Advocates LLC

With a push from innovative approaches to regulation and reliance on realized and future advances in technology—smartphones, remote sensors, renewables, storage, and much more—electricity service in 2025 can be cleaner and more omnipresent than it is today. Customers' reliance on their smartphones is but one portal to achieving a deeper penetration of electricity throughout the economy, including the transportation sector.

But to make this vision a reality, policy makers—legislators, energy regulators, and perhaps other stakeholders—must provide an appropriate framework, including standards, incentives, and accountability to promote and produce the desired behaviors.

Few will argue with the benefits that customers, our economy, and society overall can realize from an enhanced commitment to efficient energy consumption, deployment of cost-effective clean energy resources (CERs), optimization of capital deployment, and a reduced carbon footprint.

But we must not get ahead of ourselves. To bring these benefits to fruition we should bring all the players along, beginning with the public: that is, customers. How do we reach customers, who are distracted by countless other concerns, with something they take for granted—their electricity service? There is no easy answer to that, but appearances before civic, neighborhood, and business groups by both utility and regulatory officials to discuss topics of interest would be one opportunity. For example: utility and regulator readiness to speak after severe weather or other significant events could offer an important opportunity to gain credibility with such groups.

In any case, studies suggest that energy efficiency and CER adoption levels are still much lower than they should be, while the opportunity to increase adoption, based on available technologies, is great. Enhancements in internet and smartphone technology can also improve how we educate our constituents about available opportunities.

My vision for future electric services is premised largely on broadened smartphone applications ("apps") and remote wireless sensors. While some utilities have introduced app-based efficiency tools, they are still in their infancy and have not yet been deployed at scale. In the future I envision, these energy saving enabling tools will:

- Allow customers to remotely control and program their lighting, appliances, heating and air conditioning;
- Connect customers to opportunities to participate in CERs, including community and distributed PV, storage, and demand response;
- Allow utilities to cycle their customers' air conditioners and chip-enabled appliances during peak periods to save their customers money and reduce the need for new energy resources that would otherwise be required; and
- Allow electric vehicles to be charged and discharged at optimal times to enhance customer economic value.

Smart meters and energy billing apps can also provide customers with actionable information about their usage, how it compares with similarly situated neighbors, and potential energy saving opportunities. Providing customers appropriate education and financial incentives will be key to achieving significant customer acceptance and adoption.

How do we encourage this vision and accelerate the pathway to a clean, efficient, and more profitable energy future?

Educating customers about opportunities that exist must be a priority. Utilities have access to dwelling size and age and energy usage. They can make it easy and profitable for customers to learn about and adopt energy savings tools. A commitment to outreach and education will drive increased demand for efficiency technologies and practices.

Utilities, empowered by clear regulatory policy, should take the lead in educating customers on opportunities to save. For the most part, customers trust their utility. But, for utilities to be trusted advisors to their customers, they must be indifferent to customers' preferences for specific technologies, vendors, or services.

Why aren't distribution utilities rushing in to assume this advisor role today? It's complicated, but generally utilities lack regulatory incentives to benefit from selling less electricity and deploying fewer resources. While many jurisdictions offer programs to compensate utilities for sales lost to efficiency—through decoupling and performance incentives—these are not sufficient to induce utilities to wholeheartedly promote more efficient outcomes. Today's regulatory frameworks are weak band-aids, not transformational.

For utilities to adopt a business model that places a premium on energy efficiency and making this energy and economic transition a reality, we need transformational reform.

In this "reformed" industry model, utilities would be incented to earn profits—in addition to a nominal return on invested capital—by providing customers valued advice, services, and efficiency measures. Of course, utilities that take on this challenge must be accountable for achieving the objectives and metrics adopted by policy makers.

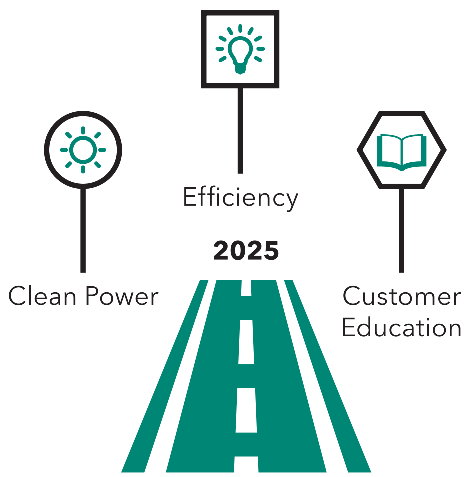
In addition to this regulatory reform, policy makers must set forth new standards for buildings, appliances, and energy consuming equipment that encourages both efficient use of energy and interconnection with today's energy management tools, smartphones, smartphone apps, and home energy management technologies.

We now need policy makers to take the lead in charting the path forward to accelerate our electricity and environmental future by defining the framework and incentives to make this vision a reality.

With policy makers' leadership:

- Customers will have new tools to control their energy use, manage their energy costs, and improve their carbon footprint;
- Utilities will be re-energized by this new model and approach—doing well for their investors and enhancing customer value;
- Technology providers will benefit from broader market opportunities and distribution channels for their offerings.

If policy makers will chart a pathway forward, our entire society will benefit—customers, technology providers, utilities and their investors, and the global economy and environment. There's no time to waste. Seize the day!



Charting the Path Forward

"Cloud software can help utilities deliver personalized digital experiences at every customer touchpoint—from the day a family moves into a new home through every bill, outage, or change they experience."

–ALEX LASKEY

Unlocking Value Through Customer Engagement

ALEX LASKEY
President and Founder, Opower

The world is embarking on a new chapter in energy use, generation, and distribution. In the United States and Europe, utilities and retailers are watching energy demand level off for the first time in history. Globally, new technologies and regulatory approaches are giving consumers more control over their energy use.

In the 20th century, the goal was to bring electricity to people. The advent of cheap, abundant energy sparked revolutions in science and technology, and utility companies focused on growing their generation fleets to meet the mushrooming demand for power. Today in the 21st century, utilities face new challenges, as electricity demand stagnates. Rising consumer expectations for new service offerings and competition from distributed generation are forcing a transformation of the industry.

No companies are better positioned than utilities to lead the way forward. Electric utilities have accumulated more than a century of experience and developed valuable customer loyalty. Research by Accenture shows that consumers trust their utilities to deliver helpful energy advice more than any other service provider.[1] Now utilities and others they may work with must deepen these relationships and provide valuable *individualized services* to residents and business owners.

Globally, energy providers spend $30 billion a year on customer service, with the largest of that expenditure going toward billing and call center operations. Despite this massive investment, research shows that interactions between utilities and their customers lag behind most other consumer-facing industries.[2] Companies in the banking, retail, and transportation sectors have made dramatic improvements to the customers' experience, leaving the energy industry with a challenge just to catch up.

Surveys and data make it clear what customers want: lower bills, more ways to save, and personalized energy service options. With the growth of smart meter infrastructure, utilities are managing more customer data than ever. Their first impulse is often simply to report this data back to customers online, but the great majority of customers want utilities to give them simple, easily accessible, actionable advice—not data.[3]

With the help of companies like Opower, utilities are using cloud software to increase customer satisfaction while lowering their overall service costs. Focusing perceptively on the experience customers want, energy providers can forge new business models that position them to lead in the new energy economy.

Personalizing Offers to Households

Thanks to the growth of smart meter deployment, energy usage data from households and businesses have become increasingly available to utilities. Behavioral demand-side management technologies—including Opower's "Behavioral Energy Efficiency" and "Behavioral Demand Response" solutions—can play a significant role, as utilities look to reduce costs while improving the customer experience.

Utilities also realize that they need to accelerate the digitization of their customer service. Cloud software can help utilities deliver personalized digital experiences at every customer touchpoint—from the day a family moves into a new home through every bill, outage, or change they experience.

NEW TOOLS FOR ENGAGING CUSTOMERS

Already, many utilities are meeting rising customer expectations with innovative technologies. In regulated and competitive electricity markets, technology companies like Opower are giving utilities and energy providers the tools they need to unlock strategic business value from improved customer engagement.

Puget Sound Energy (PSE) first partnered with Opower to engage its customers through Home Energy Reports (HERs), which provide customers with insights about their energy use and tips to help them save. PSE saw significant results from its HER deployment; it was able to meet its energy efficiency targets while adding a new, high-quality touch point with its customers. That success led PSE to be the first utility to launch Opower's Bill Advisor solution, which provides customers with proactive alerts about their usage, intuitive self-service tools, and integrated call center software.

Billing issues are the number one driver of customer calls to utility call centers. Fully 80 percent of customers say they want advance notification if they are on track for a large bill.[4] PSE now directly addresses these concerns through its deployment of Bill Advisor.

Technologies that manage ways of meeting heightened customer expectations can also address the increasing number of customers who want access to distributed energy resources (DERs). This is a boon for solar companies, but customers may also benefit from expanded options when considering whether and how to go solar. This also offers a valuable opening for utilities seeking to advise their customers' energy purchases.

Con Edison, the utility that serves New York City and Westchester County, N.Y., is striving to position itself as a trusted energy adviser to its customers. To guide the conversation around DERs and accelerate uptake, the utility is partnering with Opower to deliver personalized offers to households that are most likely to take advantage of new programs, products, and services—from self-generation technology to smart thermostats.

This strategy represents a win-win-win. Customers benefit from helpful, trustworthy advice about what products are right for their homes; DER providers get an opportunity to expand their customer base; and Con Edison is able to earn new revenue with a new platform to market targeted products and services. And all of this benefits the environment by promoting energy efficiency and clean forms of generation.

As energy providers look to evolve their business models and take a leadership role in the industry's transformation, Con Edison is demonstrating how a strategic, customer-focused approach can bring value both to their business as well as to the customers they serve.

1. Accenture Energy Consumer Services, THE NEW ENERGY CONSUMER: UNLEASHING BUSINESS VALUE IN A DIGITAL WORLD 2015, *available at* https://resapps.accenture.com/newenergyconsumer/unleashing-business-value-main.html.
2. 5 Universal Truths About Energy Consumers, https://opower.com/fivetruths/index.html.
3. *Id.*
4. Opower, MOMENTS THAT MATTER: A CUSTOMER-CENTRIC APPROACH TO EXPERIENCE MANAGEMENT 2015, http://www2.opower.com/moments-that-matter-whitepaper.

"I think of the evolution now underway as a movement from the utility as an infrastructure and commodity provider to being an essential infrastructure and service provider."

–BOB ROWE

Conclusion

BOB ROWE
President and CEO, NorthWestern Energy

The Institute for Electric Innovation and the Edison Electric Institute perform a great service by keeping us informed about and focused on the exciting changes in how energy is produced, distributed, and used. As you've read throughout *Key Trends Driving Change in the Electric Power Industry*, these changes are happening quickly, with common elements, but in each instance on a timeline and with approaches tailored to local requirements and expectations.

This timely volume has focused on:

- **The rapid transition to clean energy.** This is remarkable given the complexity of the supply system and its capital intensity. Most of this transformation has been industry-led, as part of thoughtful supply planning, and in response to economic signals and customer interests.
- **The evolution of the grid to be more digital, flexible, reliable and resilient.** It's never quite been true that "Edison would recognize today's grid," and I've never heard a system engineer utter that canard. Companies across the country are investing in grid modernization in ways that balance near-term price impacts with long-term system and customer benefits.
- **Increasingly individualized services.** While most customers continue to expect a foundation of reliable, safe, and affordable service, increasing numbers also demand especially high levels of service quality (e.g., stable frequency or voltage), exceptionally high reliability, or an especially low carbon energy source. Notably, some customers even want a high degree of engagement with production, distribution, and use of their energy.

My company, NorthWestern Energy, is an electric and natural gas provider in Montana and South Dakota, also with natural gas service in Nebraska, and electric service in Yellowstone Park, Wyoming. We're making progress on each of these fronts in ways that make the most sense for our customers and our region. Our Montana electric supply portfolio is now, by nameplate, almost 70-percent carbon free (hydro-based, with wind), but with a diverse set of assets that complement one another.

Given our largely carbon free supply portfolio, we are very concerned about policies that mandate specific supply choices that do not meet our portfolio needs and eventually drive up costs to customers.

We've also been engaging with our stakeholders to plan for the network's future. Building on success with our ongoing Distribution System Infrastructure Plan, we've now launched an Infrastructure Stakeholder Group that will help us take an end-to-end look at our gas and electric transmission, substation, and distribution systems—including the value proposition—and customer expectations for even more technology deployment. We will also benefit from our participation in the Pacific Northwest Smart Grid Pilot, results from which will inform our planning and investment over the next decade.

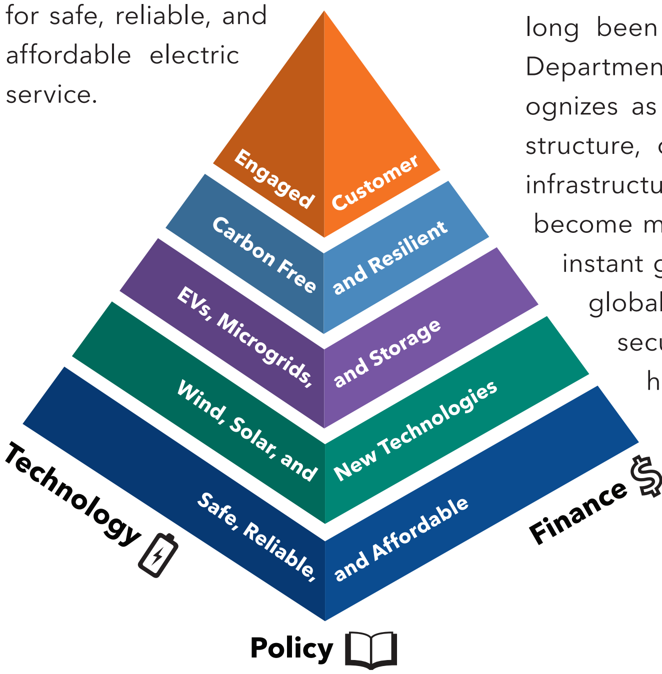
Simultaneously, we've launched a Community Sustainable Energy Work Group. This stakeholder group is facilitated by the Solar Electric Power Association and includes, among others, parties with whom we do not always agree on subjects such as expansion of current net metering programs or implementation of the EPA's Clean Power Plan. We're asking this group to help us design specific projects, for which we have set aside capital, that will help us understand how distributed technology, including solar and storage, may fit with our system and respond to specific customer expectations. A related project involves the use of solar, storage, and controls on exposed rural radials to enhance reliability. With a large, rugged, dispersed system—in many areas characterized by miles of line per customer rather than customers per miles of line—we are interested to see what applications may become cost-effective over time.

Also, while many companies are closing local customer offices, we are reopening local customer offices and providing our employees access to more tools, information, and mobility in the field. We want to be there for our customers in the ways that are most valuable to them, including face-to-face.

As Tom Fanning describes in his essay, the modern supply planning process, which has been a great success over recent decades, has worked well to achieve long-term, least-cost, least-risk supply choices and increasingly clean electricity. That continues to provide a foundation for good decision making. The Southern Company, Xcel Energy, Southern California Edison, and many other electric utilities are in the process of transforming their supply portfolios.

Current planning regimes may be less satisfactory in meeting the more specific expectations of some customers for specific attributes, or to meet emerging policy goals. Xcel Energy's Frank Prager highlights innovations in a number of states, including Minnesota's "e21" project, which addresses multiple goals and processes and the potential benefits of a collaborative approach to achieving regulatory reform.

In a sense, Abraham Maslow's "hierarchy of needs" describes how our energy supply planning processes to-date have allowed us—and challenged us—to meet our customers' changing needs for more sustainable energy and greater resiliency, for example, while still meeting customers' basic needs for safe, reliable, and affordable electric service.



Key Drivers of Change: Technology, Policy, and Finance

Both customer advocates and utility companies want to protect customers who simply expect safe, reliable, and affordable service, while also working with customers who have more specific goals. Our ability to meet both basic and evolving customer expectations depends on

- *Technology*—what can be done?
- *Policy*—what either is required to be done or is permitted to be done?
- *Finance*—what will debt and equity investors support being done?

MEETING COMPLEX CUSTOMER EXPECTATIONS

Electric and natural gas utilities have long been the trustees of what the Department of Homeland Security recognizes as a uniquely essential infrastructure, on which all other critical infrastructures depend. That role has become more important in an age of instant global communications and global risks, including physical security, cyber security, and heightened preparation for extreme weather events.

In California, Southern California Edison's Pedro Pizarro is helping lead one of the most dramatic and complex transitions in the industry, while fulfilling multiple, important commitments. Pedro speaks for the industry when he says this requires us "to implement this transition thoughtfully, engaging with our customers at the forefront of technology adoption, while continuing to control costs."

As the articles in this volume make clear, infrastructure now includes hardware and software, and assets with very different characteristics, operating together in complex ways. Nancy Pfund and Mark Perutz describe a technology-driven evolution to a flexible, web-like network. This infrastructure enables and requires new ways to manage and use unprecedented volumes of data, converting noise to useable information.

C3's Tom Siebel describes an ecosystem of addressable devices generating data, which enable utilities to tackle multiple subjects involving asset management and predictive maintenance, reliability, and revenue assurance.

Oracle's Rodger Smith describes how the industry is at the leading edge of power grids that can readily accommodate distributed generation of all types and how the utility of the future will be the platform for delivering new processes and programs, integrating data and analytics to manage the grid.

The evolution has also enabled new ways of meeting customer expectations for a range of energy services, including—but also well beyond—the efficient delivery of electrons and molecules. Opower's Alex Laskey explains how utilities can meet rising customer expectations, offer more personalized services, and ultimately function as "trusted energy advisors."

Service both more automated and more personalized will increasingly be expected by Ron Binz's "digital natives," who have lived their entire lives with technologies that were commercialized only when the Boomers were buying their mini-vans. The "natives" are comfortable with complexity and want to participate in decisions—and the natives are impatient.

I think of the evolution now underway as a movement from the utility as an infrastructure and commodity provider to being an essential infrastructure and service provider. Serving as "trusted energy advisors" fits perfectly with the infrastructure and service model. Sunpower's Tom Werner also emphasizes the value of partnerships, including some very non-traditional partnerships among utilities and a whole range of entities relatively new to the space, including some of the authors who contributed to this volume.

Peter Kind says utilities can serve as customers' trusted advisors if regulation can be modernized so that utilities are compensated for meeting policy goals, like helping customers achieve cost-effective energy efficiency, rather than solely from earning based on their capital investment. Then, he says, utilities will be able to use all the tools of modern technology to achieve the most desirable goals for customers.

One of those technology tools could benefit utilities as well as customers, says Tony Fadell, as the NEST Learning Thermostat and its opt-in Rush Hour Rewards (RHR) program offer opportunities for both peak-period capacity savings for the utility and money savings for the customer. Perhaps more important, a personalized technology like the NEST Thermostat can help utilities give their customers an experience they want, even if they didn't know they wanted it, and begin to build a better, stronger relationship.

Mary Anne Brelinsky reports that her company, EDF Energy Services, is experimenting with putting the energy value chain pieces back together—using its retail business teams, its trading operation, and wholesale markets—to provide commercial and industrial customers the solutions they desire.

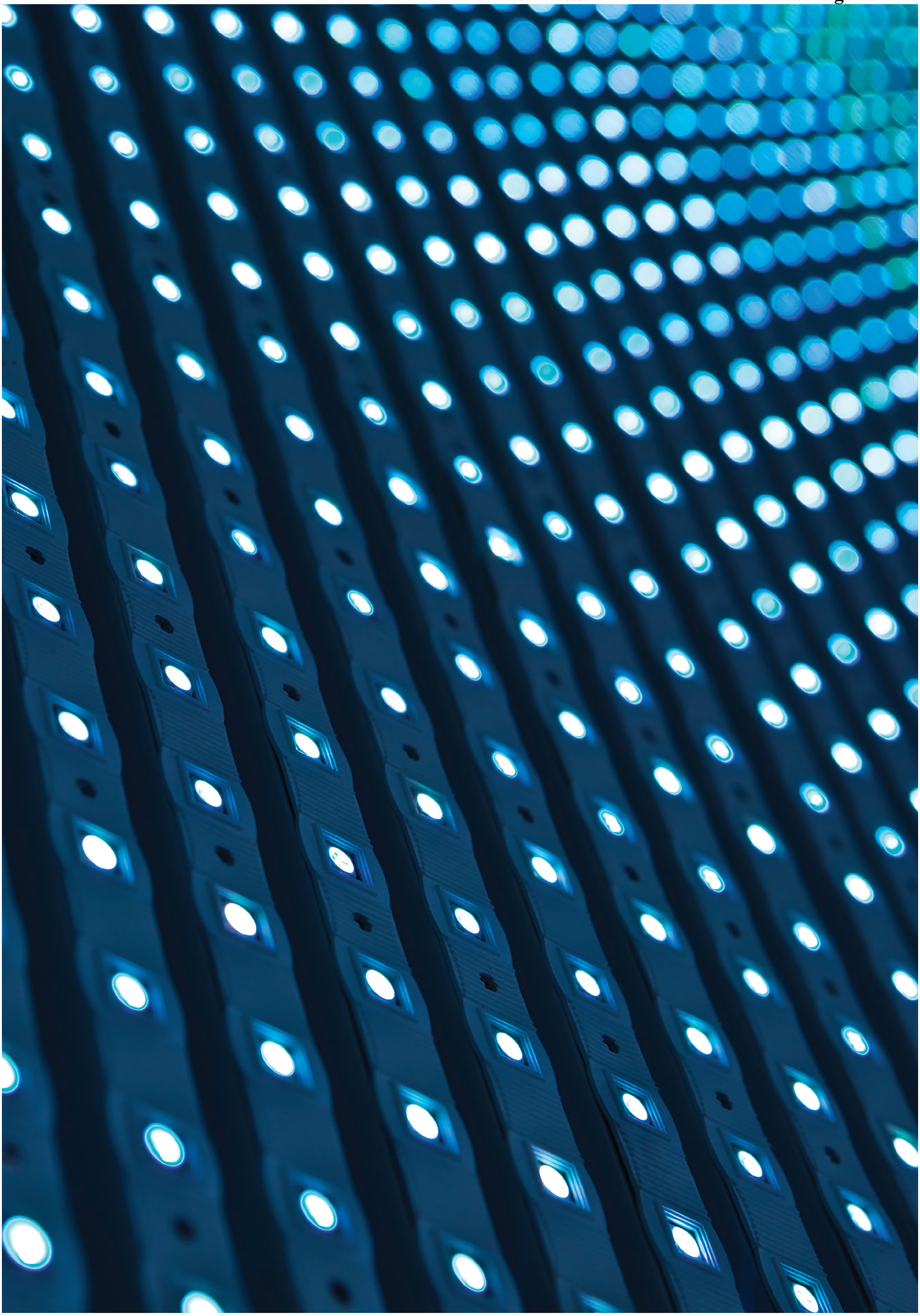
Scott Lang describes an exciting new area for collaboration, going beyond the smart grid to the smart city, in which Silver Spring Networks is much involved. Smart city projects range in both size and scope. As Scott states, the only limit is imagination.

Moving relatively toward a services model rather than a throughput model does require those of us in the industry to "think differently" about how we do our work and engage with our customers. Technology innovation also requires business innovation. Because we—as electric and natural gas utilities—are trustees of essential infrastructure and service, the business model must be sustainable as well as nimble and efficient. It must be able to earn the support of long-term investors, because the capital requirements are both large and ongoing.

Finally, both technology and business innovation require policy makers to support the transition, including modified cost recovery and pricing mechanisms, and also less litigious and more collaborative ways to make decisions and provide guidance. Ron Binz asserts that regulation has changed little in decades, and that utilities must "be allowed to evolve" by regulators. Frank Prager says that collaboration, good public policy, and appropriate regulatory policies are critical for the successful transformation of the power sector. For all of us—policy makers and regulators, electric service providers, technology partners, and investors—to meet policy goals and especially customer expectations, that kind of alignment will be necessary.

* * * * *

The path to the future is never quite clear. As we identify the challenges we face and pursue solutions, it becomes clearer with every step we take. The customers we serve are counting on us to take those steps.



About the Institute for Electric Innovation

The Edison Foundation Institute for Electric Innovation focuses on advancing the adoption and application of new technologies that will strengthen and transform the power grid. IEI's members are the investor-owned electric utilities that represent about 70 percent of the US electric power industry. The membership is committed to an affordable, reliable, secure, and clean energy future.

IEI promotes the sharing of information, ideas, and experiences among regulators, policy makers, technology companies, thought leaders, and the electric power industry. IEI also identifies policies that support the business case for the adoption of cost-effective technologies.

IEI is governed by a Management Committee of electric industry Chief Executive Officers. In addition, IEI has a Strategy Committee made up of senior electric industry executives and more than 30 smart grid technology company partners.

About the Edison Foundation

The Edison Foundation is a 501(c)(3) charitable organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide. Furthering Thomas Alva Edison's spirit of invention, the Foundation works to encourage a greater understanding of the production, delivery, and use of electric power to foster economic progress; to ensure a safe and clean environment; and to improve the quality of life for all people. The Edison Foundation provides knowledge, insight, and leadership to achieve its goals through research, conferences, grants, and other outreach activities.

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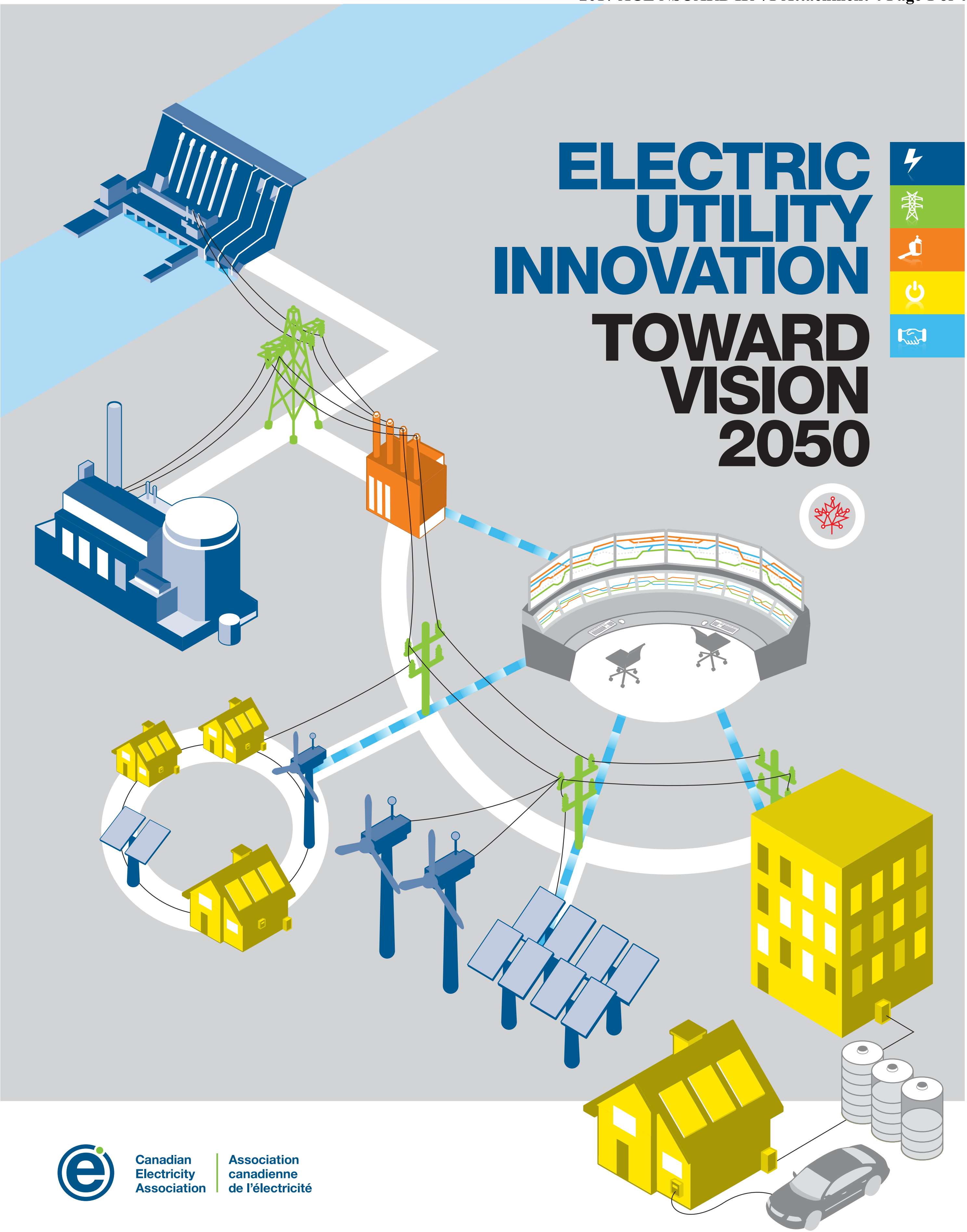
ELECTRIC UTILITY INNOVATION

TOWARD VISION 2050



Canadian Electricity Association | Association canadienne de l'électricité

WHY NEW IDEAS ARE NEEDED IN CANADA'S ELECTRICITY SECTOR— AND WHY THE TIME TO PURSUE THEM IS NOW

Recommended citation: Canadian Electricity Association, *Electric Utility Innovation: Toward Vision 2050,* 2015.

Ce document est aussi disponible en français sur le site Internet de l'ACÉ à l'adresse www.electricite.ca.

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Canadian Electricity Association | Association canadienne de l'électricité

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1 EXECUTIVE SUMMARY

AltaLink's Bowmanton to Whitla Transmission Project—a 240 kV transmission line from east of Medicine Hat to South of Whitla—was built on screw pile foundations. *Photo courtesy of AltaLink.*

ACROSS CANADA, THE ROLE OF ELECTRIC UTILITIES IS CHANGING. IT'S NO LONGER ENOUGH TO SIMPLY DELIVER ELECTRICITY AS A COMMODITY.

Today, utilities are being asked to provide a broad range of *energy services* through a data-driven, customer-centric system operations platform capable of managing responsive loads, electric vehicles, storage devices and distributed generation.

Utilities are expected to meet this expanded mandate in a way that encourages environmental, social and economic sustainability. Doing so will require a degree of technological innovation that goes beyond incremental productivity improvements. With funding and support from policymakers, regulators, and private industry, the electricity sector must develop, test and deploy new ideas, devices and processes that will meet the shifting needs and expectations of tomorrow's customers.

Why Innovation is Needed *Now*

Canada's electricity sector is at a critical inflection point. With much of the country's electricity infrastructure nearing the end of its life expectancy, investing in grid renewal and modernization today will be essential to ensuring a reliable, cost-effective and sustainable power supply tomorrow. The costs of doing so will be high—at least $350 billion in capital investments over the next 20 years—but will be necessary to address the deteriorating condition of utility assets.

This unprecedented need for infrastructure investment is driving up electricity rates, with the average retail electricity price expected to be approximately 20 per cent higher in 2035 compared to 2013. Only through a systematic approach to innovation will it be possible to both pilot new technologies to meet rapidly shifting demand and find new efficiencies to mitigate the impact of rising rates.

The Drivers of Innovation

The motivating drivers for grid modernization in Canada reflect society's changing expectations of utility providers with regard to economic, environmental and social sustainability. Four key drivers are currently guiding the service-related decisions being made by utilities: reducing greenhouse gas emissions; increasing system resiliency to climate change and extreme weather events; empowering customers to play a more central role in shaping the electricity system; and containing costs to be able to do more with less.

Key Technology Areas to Focus On

With a once-in-a-generation investment cycle peak comes the opportunity to develop, test and deploy a wide range of leading-edge grid modernization technologies. From the perspective of the Canadian Electricity Association (CEA), five technology areas currently being explored by Canada's utilities show the most promise for shaping the functionality of tomorrow's electricity system: demand response; the facilitation of distributed generation; the facilitation of electric vehicles; the optimization of asset use; and fault detection and mitigation. As a result, these areas should receive immediate support in the form of pilot project funding.

Customer conserves electricity by turning off the lights. *Photo courtesy of BC Hydro and Power Authority.*

RECOMMENDED ACTIONS

TAKING INTO ACCOUNT THE KEY DRIVERS AND TECHNOLOGY AREAS INFLUENCING THE GRID MODERNIZATION OPPORTUNITY IN CANADA, CEA PUTS FORWARD THE FOLLOWING RECOMMENDED ACTIONS THAT CAN BE TAKEN TODAY TO ENSURE UTILITIES HAVE THE MANDATE AND MEANS TO CONTINUE TO INVEST IN INNOVATION GOING FORWARD:

- **Align priorities and goals**
  Through national organizations and strategic forums, provincial regulators, policymakers and utilities can develop common priorities and goals related to the transformation of Canada's electricity infrastructure.

- **Track grid modernization indicators at a national level**
  A national approach to tracking key indicators related to grid modernization benefits and implementation is needed to proactively identify areas that will require near-term technical and regulatory solutions.

- **Look internationally**
  By participating in the International Energy Agency's International Smart Grid Action Network (ISGAN) and other multi-national forums, Canada has the opportunity to learn from other countries also aggressively pursuing electricity innovation.

- **Pool innovation funding to mitigate risk and share rewards**
  Utilities should hold a broad portfolio of innovation projects. Funding for those projects that support provincial or national policy objectives should be fully or partially matched by public funds through organizations such as Sustainable Development Technology Canada.

- **Share lessons learned**
  All stakeholders involved in grid modernization, including regulators, policymakers, utilities and customers, benefit from the sharing of lessons learned emerging from both successful and failed demonstration projects.

- **Lock in knowledge by developing codes and standards**
  As technologies develop and lessons learned are distilled, knowledge should be formalized into codes and standards that guide utility technical planning and operating practices.

- **Keep customers informed and engaged**
  Grid modernization is focused on protecting and improving the value of electricity service—and it will be critical to communicate this to customers early and often. Going forward, utilities, policymakers and regulators will have to broaden the conversation to engage the public in new ways.

2 INTRODUCTION

MOVING TOWARD A MORE SUSTAINABLE MODEL OF ELECTRICITY DISTRIBUTION WILL REQUIRE EXPERIMENTATION AND INNOVATION

Transmission Lines and the skyline. *Photo courtesy of Nalcor Energy.*

TRADITIONALLY, THE UTILITY MANDATE HAS BEEN TO GENERATE, TRANSMIT AND DISTRIBUTE ELECTRICAL ENERGY IN A SAFE, RELIABLE, AND COST-EFFECTIVE WAY.

Equipment exceeding its expected useful life was typically replaced "like for like," with the suppliers of that equipment focused on incremental improvements to the functionality, longevity or safety of their products. Utility managers, meanwhile, focused primarily on continuous productivity improvement: performing routine electric utility tasks safer, faster and cheaper.

But that mandate is rapidly evolving and with it the very notion of what an electricity distribution utility should be. The modern utility is no longer simply the provider of "poles and wires" and on-demand commodity delivery. It is instead a data-driven, customer-centric system operations platform capable of managing responsive loads, electric vehicles, storage devices and distributed generation in real time.

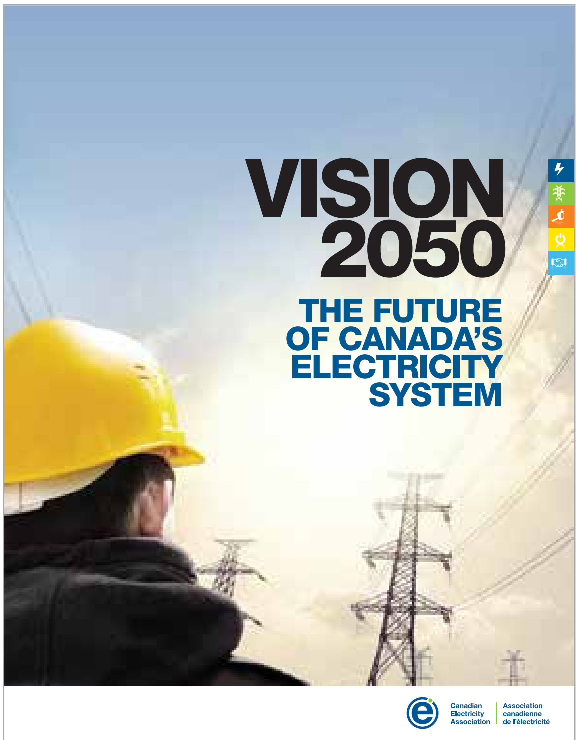
Behind this transformation is a commitment to *sustainable development*, which CEA defines as: pursuing progressive business strategies and activities that meet the needs of the present, while enhancing the environmental, social and economic resources that will be needed in the future.

Moving toward a more sustainable model of electricity distribution will require experimentation and innovation that goes beyond incremental productivity improvements. With the support of policymakers, regulators and private industry, it is imperative that the electricity sector begins to develop, test and deploy new ideas, devices and processes that will meet the needs and expectations of tomorrow's customers.

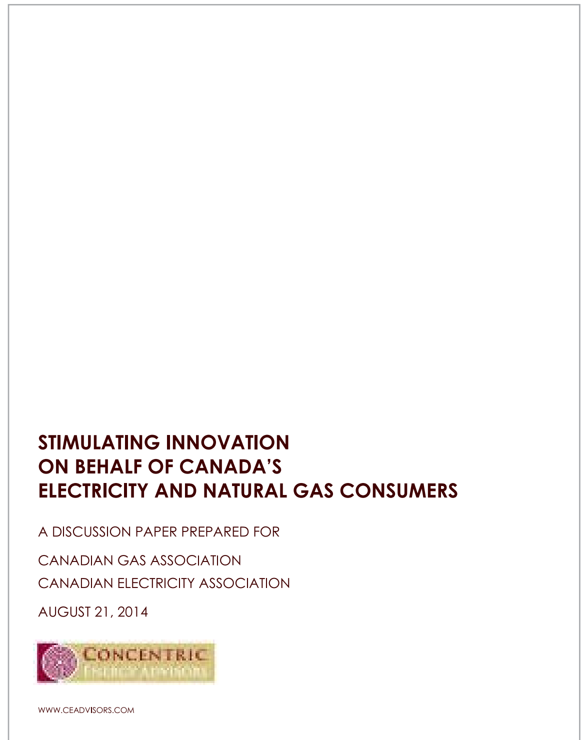
Advancing the Innovation Agenda

This policy paper is intended to give regulators, policymakers and other key stakeholders the necessary information and context to support the electricity innovation agenda.

First, the paper examines the current drivers of Canadian electric utility innovation, showing why the sector is at a critical inflection point. It then reviews the key technology areas that are shaping the functionality of tomorrow's electricity system (and therefore represent considerable opportunities for innovation): demand response; facilitation of distributed generation; facilitation of electric vehicles; optimization of asset use; and fault detection and mitigation. Finally, the paper offers seven recommendations that will help regulators, policymakers and utilities continue to push the innovation agenda forward.



CEA's *Vision 2050: The Future of Canada's Electricity System* cover.


STIMULATING INNOVATION
ON BEHALF OF CANADA'S
ELECTRICITY AND NATURAL GAS CONSUMERS

A DISCUSSION PAPER PREPARED FOR

CANADIAN GAS ASSOCIATION
CANADIAN ELECTRICITY ASSOCIATION

AUGUST 21, 2014

CONCENTRIC ENERGY ADVISORS

WWW.CEADVISORS.COM

Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers cover.

While this paper draws on numerous sources for information and inspiration, it attempts to build on the framework established by two papers in particular.

The first is CEA's *Vision 2050: The Future of Canada's Electricity System*.[1] Published in March 2014, it maps out a vision for the future of electricity in Canada—and offers ideas on how to achieve that vision. Specifically, *Vision 2050* recommends the acceleration of electric utility innovation through active support from policymakers and regulators combined with prudent investment decisions made by utilities that focus on key principles such as reliability, equity, integration, efficiency, and growth.

The second is *Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers*.[2] Published in August 2014 by Concentric Energy Advisors for CEA and the Canadian Gas Association, this paper proposes a gold standard model that Canadian utilities and regulators can adopt to promote and fund innovation. It puts forward recommended guidelines related to funding levels, regulatory oversight, program management and opportunities for collaboration. Informed by global practices, the paper's recommendations are backed by examples of successful innovation approaches already in place across Canada, the United States, and Europe.

With this paper, CEA adds to the innovation conversation with an overview of the specific areas that require action today, as well as a series of recommendations that will help ensure the full value of any innovation investments made in Canada's electricity sector is realized.

1 Canadian Electricity Association. "Vision 2050: The Future of Canada's Electricity System," 2014. Available from http://powerforthefuture.ca/wp-content/uploads/2014/04/Vision2050.pdf.

2 Stephen Caldwell, Robert Yardley, Jr, and James Coyne, 2014. "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers." Available from http://www.electricity.ca/media/ReportsPublications/StimulatingInnovation2014.pdf.

SaskPower lineman looks at plans at a substation. *Photo courtesy of SaskPower.*

Power line technician ensure power reliability.
Photo courtesy of Maritime Electric Company Limited.

WITH THIS PAPER, CEA ADDS TO THE INNOVATION CONVERSATION WITH AN OVERVIEW OF THE SPECIFIC AREAS THAT REQUIRE ACTION TODAY, AS WELL AS A SERIES OF RECOMMENDATIONS THAT WILL HELP ENSURE THE FULL VALUE OF ANY INNOVATION INVESTMENTS MADE IN CANADA'S ELECTRICITY SECTOR IS REALIZED.

3 ECONOMIC PRESSURE AND AGING INFRASTRUCTURE

WHY INNOVATION IS NEEDED NOW

Power line technician, Jessica Hadfield safely repairing a line. *Photo courtesy of Manitoba Hydro.*

TWO DOMINANT THEMES ARE RE-SHAPING THE LANDSCAPE IN WHICH CANADIAN ELECTRICITY UTILITIES OPERATE: THE UNPRECEDENTED INFRASTRUCTURE INVESTMENT THAT WILL BE REQUIRED OVER THE NEXT 20 YEARS TO MAINTAIN AND EXPAND THE ELECTRICITY NETWORK, AND THE ACCELERATED PACE OF CHANGE RELATED TO SUSTAINABILITY AND SERVICE EXPECTATIONS.

The need for massive infrastructure investment is driving up electricity rates across Canada. This has led to pressure from regulators, politicians, and consumer groups to find efficiencies and manage costs in the short term. The productivity imperative often seems incompatible with developing and piloting new processes and technologies to keep up with the ever increasing pace of change. In other words, to spend both time and money on innovations that, while fruitful over the longer term, rarely deliver same-year payback.

Utilities are finding ways to address both through a commitment to individual and collaborative innovation. As pressures build to cut costs now, a more systematic, structured approach to innovation will be required if the electricity sector is to successfully bridge the gap between productivity today versus innovation for the future.

Slowed Economic Growth

The cost pressures facing Canada's electricity utilities are exacerbated by a macroeconomic landscape that is markedly different than it was during the last major infrastructure investment campaign about 40 years ago. At that time, the country's real GDP was growing by about five per cent per year[3]. As industrial, commercial and residential customers adopted a broad range of new electric-powered appliances, utility sales increased by five to 11 per cent each year between 1965 and 1974—for a cumulative increase of 94 per cent over the 10 year period.[4]

Comparing the economic boom of the 1970s to today's low-growth reality is sobering. The National Energy Board predicts that Canada's real GDP will grow at an average rate of just two per cent per year until 2035.[5] Growth in electricity generation capacity over that same period will remain relatively flat at about one per cent per year, primarily due to efforts to reduce the energy intensity of the Canadian economy.[6]

3 Statistics Canada. Table 380-0501 – "Gross domestic product (GDP), expenditure-based, 1968 System of National Accounts (SNA), quarterly (dollars)." From CANSIM database accessed: 2014-12-22.

4 Statistics Canada. "Series Q92-96 – Production and trade in electrical energy, 1919 to 1975, CVS document." From StatsCan website http://www5.statcan.gc.ca/access_acces/archive.action?l=eng&loc=Q92_96-eng.csv.

5 National Energy Board, 2013. "Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035." Available from https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/2013nrgftr-eng.pdf.

6 Ibid, 63.

Canada's Infrastructure Deficit

Much of Canada's generation, transmission and distribution infrastructure is nearing the end of its life expectancy. Toronto Hydro Corporation, for example, estimates that approximately one-third of its electricity distribution assets are currently past their expected useful life.[7] Similarly, BC Hydro and Power Authority (BC Hydro) acknowledges that many assets were built before 1970 and their aging and deteriorating state must be addressed.[8]

It is clear that investing in infrastructure renewal and modernization will be essential to ensuring a reliable, cost-effective and sustainable supply of electricity. It will also be essential for preparing Canada's electricity system for the year 2050 and a world of engaged customers, variable energy resources, electric vehicles, energy storage, advanced asset analytics and responsive outage management systems.

Getting there, however, will require utilities to carefully evaluate the most efficient path forward. Which assets should be replaced "like for like" with more of the same? Which should be replaced with something new? And which may not need to be replaced at all?

Regardless of the approach taken, the cost to maintain and modernize Canada's grid will be high. According to a 2012 Conference Board of Canada (CBoC) report, renewing Canada's electricity infrastructure will cost nearly $350 billion over the next 20 years. And this is likely to be the lower bound: the CBoC notes, for example, that "transmission investments identified in [the] report are likely to be underestimated."[9] Given that caveat, the Canadian electricity sector is likely facing a period of sustained capital investment of about $20 billion per year for 20 years—for a total required investment of approximately $400 billion.

Capital expenditures on new and refurbished infrastructure are increasing each year as utilities begin to chip away at this infrastructure deficit. Among CEA Corporate Utility Members, transmission and distribution infrastructure spending increased from $5.6 billion in 2011 to $7.6 billion in 2012 and then to $9.0 billion in 2013, a three-year increase of 61 per cent.[10] Including generating assets, total infrastructure investment rose to $14 billion in 2013, an increase of 17.7 per cent over 2012.[11]

Fortunately, the investments being made by utilities across Canada are providing a much needed short-term boost to the economy through economic stimulus and job creation. Working from its anticipated infrastructure spend of $350 billion, the CBoC estimates that these investments will contribute $10.9 billion to Canada's real GDP—as well as an average of 156,000 jobs—every year.[12]

THE CANADIAN ELECTRICITY SECTOR IS LIKELY FACING A PERIOD OF SUSTAINED CAPITAL INVESTMENT OF ABOUT $20 BILLION PER YEAR FOR 20 YEARS—FOR A TOTAL REQUIRED INVESTMENT OF APPROXIMATELY $400 BILLION.

7 Toronto Hydro Corporation, 2013. "2012 Annual Report: The Measure of Our Commitment, 2013." Available from https://www.torontohydro.com/sites/corporate/InvestorRelations/FinancialReports/Documents/Financial%20Reports/2012%20Interactive/pdf/TOHY%202012AR_eReport.pdf.

8 BC Hydro and Power Authority, 2013. "Annual Report 2012" Available from http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/annual_report/2012_BCH_AnnualReport.pdf.

9 Len Coad, Todd A. Crawford and Alicia Macdonald, 2012. "Shedding Light on the Economic Impact of Investing in Electricity Infrastructure." Conference Board of Canada, available from http://www.conferenceboard.ca/e-library/abstract.aspx?DID=4673.

10 Canadian Electricity Association, 2014. "2014 Sustainable Electricity Annual Report: Engaged for a Sustainable Future." Available from http://sustainableelectricity.ca/wp-content/uploads/2014/09/EngagedforaSustainableFuture2014.pdf.

11 Ibid.

12 Len Coad, Todd A. Crawford and Alicia Macdonald, 2012. "Shedding Light on the Economic Impact of Investing in Electricity Infrastructure." Conference Board of Canada, available from http://www.conferenceboard.ca/e-library/abstract.aspx?DID=4673.

Rising Electricity Rates

Infrastructure investments bring about a number of economic benefits, but they can also cause electricity rates to rise for all Canadians. This is nothing new: even in the booming economy of the 1970s, BC Hydro's last major cycle of infrastructure investment led to a 113 per cent cumulative bill increase from 1973 to 1982.[13] While energy efficiency and conservation programs have helped soften the bottom-line impact to customers, rate increases are inevitable.

What kind of rate increases should Canadians expect in the coming years? In its report titled *Canada's Energy Future 2013*, the National Energy Board projects that the average retail electricity price (including residential, commercial and industrial prices) will be approximately 20 per cent higher in 2035 compared to 2013.[14] The Government of Ontario's Long Term Energy Plan, predicts that rates will increase by 2.8 per cent annually over the next 20 years—resulting in a 42 per cent increase by 2018 and a 68 per cent increase by 2032.[15] (It should be noted that these numbers are actually *lower* than the province's 2010 projections, which forecasted an increase of 3.5 per cent per year until 2030; this decrease is largely due to the success of Ontario's aggressive conservation targets.)[16]

In British Columbia, the cumulative rate increase has been capped by the provincial government at 28 per cent from 2014 to 2019[17]. Beyond that, increases will be determined by the BC Utilities Commission; however, it is expected that investments in BC Hydro's Power Smart Program, lower operating costs and a reduced dividend paid to the province will lead to more modest increases beyond 2019. While not all provinces publish long-term rate forecasts, most jurisdictions will follow the national rate increase trend-line.

CEA'S WWW.POWERFORTHEFUTURE.CA WEBSITE PROVIDES A FOUNDATIONAL RESOURCE FOR STARTING THIS CONVERSATION WITH ELECTRICITY CUSTOMERS ACROSS CANADA.

Besides drastically increasing debt, utilities have three broad ways to mitigate the rate impacts resulting from increased capital and operational costs. The first is to increase sales volume for traditional end-uses so they can spread fixed network costs over a greater volume of kilowatt-hours sold. This is an unlikely proposition given the current economic conditions and the ongoing push for energy conservation.

The second option is to change the *perceived* value of electricity service by explaining the need for infrastructure investments to customers directly. If the messages gain traction, it will soften the impact of rising rates because customers will understand why they are necessary.

The third option is to improve the *actual* (rather than perceived) value of electricity service delivered to customers by providing a platform that seamlessly integrates new end-use applications and responds instantly to individual preference. From an operations perspective this is the preferred option—and it is also the option that will require the greatest focus on new innovation to make feasible.

13 Bill Bennett, "10 Year Plan for BC Hydro," Presentation by the Minister of Energy and Mines, November 26, 2013. http://www.newsroom.gov.bc.ca/downloads/Presentation.pdf.

14 National Energy Board, 2013. "Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035." Available from https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/2013nrgftr-eng.pdf.

15 Ontario Ministry of Energy, 2013. "Achieving Balance: Ontario's Long Term Energy Plan." Available from http://powerauthority.on.ca/sites/default/files/planning/LTEP_2013_English_WEB.pdf.

16 Ontario Ministry of Energy, 2010. "Building Our Clean Energy Future: Ontario's Long Term Energy Plan," Available from http://www.powerauthority.on.ca/sites/default/files/page/MEI_LTEP_en_0.pdf.

17 "10 Year Plan Means Predictable Rates as BC Hydro Invests in System." BC Government news release on November 26, 2013 on the BC Government website http://www2.news.gov.bc.ca/news_releases_2013-2017/2013MEM0023-001774.pdf.

4 WHAT'S DRIVING UTILITIES TO INNOVATE?

UTILITIES ARE REACTING TO AND ADAPTING TO A CHANGING ELECTRICITY CLIMATE

TO UNDERSTAND THE PUSH FOR (AND URGENCY OF) GRID MODERNIZATION IN CANADA, IT IS USEFUL TO CONSIDER TWO TYPES OF DRIVERS: MOTIVATING DRIVERS AND ENABLING DRIVERS.

Motivating drivers reflect society's changing expectations of what Canada's electricity sector should deliver in terms of economic, environmental and social sustainability; and

Enabling drivers are the market and technological forces that, if harnessed properly, will allow utilities to deliver on their evolving mandate.

This section focuses on the following motivating drivers that are currently guiding the service decisions being made by utilities across Canada (and in later sections, the technological opportunities available to address them):

- Reducing greenhouse gas emissions;
- Increasing resiliency;
- Empowering customers; and
- Containing costs.

For additional context, this section also touches on one of the major enabling drivers that will allow utilities to better meet increased expectations and realize CEA's *Vision 2050*: the emergence of Big Data.

Reducing Greenhouse Gas Emissions

Canada boasts one of the greenest electricity systems in the world, with about 80 per cent of the electricity generated coming from sources that do not emit greenhouse gases. In 2013, hydro dams accounted for 63.4 per cent of electricity generation in Canada, followed by fossil fuels (19.2 per cent), nuclear (15.9 per cent), wind (1.5 per cent) and solar (0.04 per cent).[18]

The electricity sector is the only major industrial sector in Canada expected to reduce total greenhouse gas emissions by 2020; relative to 2005 levels, it is expected to cut its emissions by 25 per cent.[19] Real progress is being made: from 2012 to 2013, CEA Corporate Utility Members lowered CO2eq emissions by 3.6 per cent, bringing the total decrease to an impressive 16.6 per cent drop from 2009 levels.[20] CEA's 2014 Sustainable Electricity™ annual report credits this to reduced coal use and the increased integration of renewable and distributed generation.

Still, there is continued pressure to decarbonize Canada's economy. Distributed generation comprises one element of a broader strategy to do so affordably.

18 Statistics Canada. Table 127-0007 – Electric power generation, by class of electricity producer, annual (megawatt hour)." From CANSIM (database) accessed: 2014-12-22.

19 National Round Table on the Environment and the Economy, 2012. "Reality Check: The State of Climate Progress in Canada." Available from http://publications.gc.ca/collections/collection_2012/trnee-nrtee/En134-57-2012-eng.pdf.

20 Canadian Electricity Association, 2014. "Sustainable Electricity Annual Report: Engaged for a Sustainable Future, 2014." Available from http://sustainableelectricity.ca/wp-content/uploads/2014/09/EngagedforaSustainableFuture2014.pdf.

An Emergency Management exercises was held at our System Control Center.
Photo courtesy of Newfoundland Power Inc.

Storm related damage caused by freezing rain in Newfoundland.
Photo courtesy of Newfoundland Power Inc.

Increasing Resiliency

In the past two years, many utilities have experienced severe weather events that have impacted their ability to deliver power. One example of such an event was the Toronto ice storm of December 2013, which left nearly 300,000 customers in the dark over the holiday season. Climate change (and the increasing severity and frequency of extreme weather events that come with it) will continue to have a profound impact on the reliability of Canada's electricity generation, transmission and distribution system. To combat this challenge utilities must make appropriate investment decisions now to increase the resiliency of the power grid.

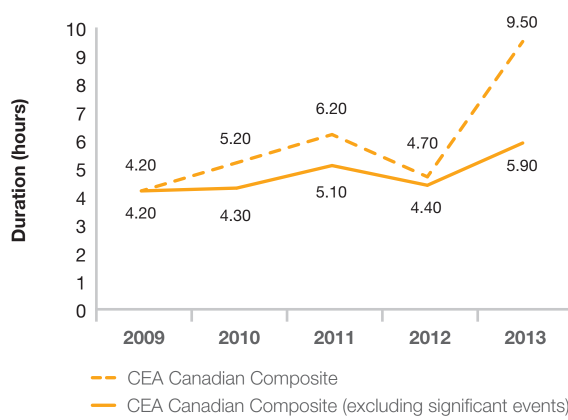
An AltaLink transmission line in Canmore, Alberta during the 2013 flood.
Photo courtesy of AltaLink.

Storm Response

According to the Insurance Bureau of Canada, insurance payouts due to property damage caused by severe weather have doubled every five to 10 years since the 1980s.[21] When property is damaged, electricity infrastructure is likely to be damaged as well. **Figure 1,** right, illustrates how electricity reliability has been affected in recent years by severe weather events.

Public perception is that utilities should be doing more to protect customers from prolonged outages and the expectation is that they will take proactive steps to do so. Improving grid resiliency is just one aspect of a broader push to continuously improve the reliability and quality of electric power service, and this mandate must be delivered with performance and cost finely balanced.

Figure 1. Increases in the System Average Interruption Duration Index (SAIDI) caused by severe weather



21 Insurance Bureau of Canada, 2012. "Telling the Weather Story." Available from http://assets.ibc.ca/Documents/Studies/McBean_Report.pdf.

Manitoba Hydro crews install new equipment in a vault beneath Graham Avenue in downtown Winnipeg as part of the utility's infrastructure renewal efforts.
Photo courtesy of Manitoba Hydro.

For example, while utilities can engineer a distribution system that would deliver very high levels of reliability in the face of ice storms and hurricanes, it would come at a very high cost, especially if such hardening included undergrounding a significant percentage of the distribution system.[22]

As a case in point, Finland has recently set time limits for the longest allowed interruptions due to storms or snow—six hours in cities and 36 hours in all other areas—that must be met by the end of 2028. If the time limits are exceeded, compensation will be paid directly to the customer, up to a maximum of €2,000 per year.[23] The Finnish government expects this policy will encourage greater use of underground cables, and has acknowledged and accepted the associated costs, which are forecast to be significant.

Climate Adaptation

According to Natural Resources Canada, adaptation to climate change can either be reactive (i.e., occurring in response to observed impacts) or anticipatory (i.e., occurring before the impacts of climate change are observed)—and in most circumstances, anticipatory adaptations will result in lower long-term costs and be more effective than reactive ones.[24] Utilities must therefore be given the licence to test anticipatory solutions today.

The challenge will be in understanding appropriate regional system design requirements. Overbuilding leads to charges of the utility investing in "gold-plated" systems simply to maximize its capital expenditures; underbuilding leaves society as a whole vulnerable to severe weather and climate variability. Finding the right balance will require the completion of climate modelling and system vulnerability analyses. Proposed grid-hardening solutions should be tested on a small scale before being rolled out across a full service territory.

22 William P. Zaraka, Philip Q Hanser, and Kent Diep. "Rates, Reliability and Region: Customer Satisfaction and Electric Utilities." Public Utilities Fortnightly, Jan. 2013. Available from http://www.brattle.com/system/publications/pdfs/000/003/981/original/Rates_Reliability_and_Region_Zarakas_Hanser_Diep_PUF_Jan_2013.pdf?1379360894.

23 International Energy Agency, 2013. "Energy Policy Highlights, 2013." Available from http://www.iea.org/publications/freepublications/publication/energy_policy_highlights_2013.pdf.

24 Natural Resources Canada, 2010. "Adapting to Climate Change: An Introduction for Canadian Municipalities." Available from http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/earthsciences/pdf/mun/pdf/mun_e.pdf.

TODAY'S CUSTOMERS, WHO ARE MORE ENGAGED THAN EVER BEFORE, EXPECT A NEW KIND OF RELATIONSHIP WITH THEIR UTILITY.

Empowering Customers

Over the 100-year history of the electric utility in Canada, the successful customer relationship has been characterized by a minimum of contact. Traditional mechanical meters are read six times per year and bills are mailed out shortly thereafter. Customers pick up the phone to call their utility rarely, usually to dispute a bill, report an outage, or arrange a connection or disconnection of service.

In the digital age, where information is abundant and cheap, this model has quickly become outdated. Today's customers, who are more engaged than ever before, expect a new kind of relationship with their utility.

CEA's *Vision 2050* notes that "changing technologies have shifted the role of the customer, increasing the impact of consumers in shaping the electricity system. Fortunately, the same technologies that give the customer a more central role also create opportunities to better manage the new complexities as the system evolves. Customization to meet consumer need will become a key attribute of our electricity system, allowing for efficiencies from production to end use."[25]

In addition to giving utilities new tools to drive grid-side efficiencies, empowering the customer also helps to:

- Contain costs on the grid side, reducing the magnitude of required rate increases;
- Provide customers with the tools to better control their own costs (i.e., conservation, off-peak usage);
- Increase their value through better customer service or the development of new services; and
- Open a two-way dialogue through which utilities can communicate the benefits of technology changes and consumers can communicate their service preferences.

Customer empowerment can yield great benefits to electric utilities if done well, or result in an erosion of public support if done poorly. Either way, it remains a significant driver of utility evolution.

CUSTOMIZATION TO MEET CONSUMER NEED WILL BECOME A KEY ATTRIBUTE OF OUR ELECTRICITY SYSTEM, ALLOWING FOR EFFICIENCIES FROM PRODUCTION TO END USE.

25 Canadian Electricity Association, 2014. "Vision 2050: The Future of Canada's Electricity System." Available from http://powerforthefuture.ca/wp-content/uploads/2014/04/Vision2050.pdf.

Containing Costs

As noted earlier in this paper, the increased investment required to address Canada's infrastructure deficit will also result in rate hikes for utility customers. Yet that doesn't change the fact that Canadian utilities are under continuous pressure to maintain competitive rates and maximize productivity while maintaining the highest possible level of service. Accordingly, utilities are always looking to do more with less.

Grid modernization can help. According to a 2012 Ernst & Young (EY) report (which itself builds on the framework that emerged from the United Kingdom's Smart Grid Forum, an initiative co-created by Britain's national electricity regulator and the Department of Energy and Climate Change), the baseline distribution network infrastructure investment requirement in the UK is about £46 billion by 2050.[26] However, if British distribution utilities embrace smart grid technologies, the required investment may be as little as £27 billion, a total savings of £19 billion.[27]

While it acknowledges EY's work, the UK Department of Energy and Climate Change notes in a 2014 report that while smart grids do not remove the need for conventional reinforcement of networks, they can minimize or defer the need for infrastructure investment by helping utilities reduce costs and incorporate low-carbon technologies at a faster rate.[28]

To put this into a Canadian context, Gaëtan Thomas, President and Chief Executive Officer of New Brunswick Power Holding Corporation, made the business case for his company's pursuit of grid modernization as follows: "By engaging our customers, we can avoid more than $1.3 billion net present value over 25 years on our system by deferring the requirement for new generation or refurbishment by seven to 10 years."[29]

Toronto Hydro Corporation has converted 99.7 per cent of its meter population to Smart or Interval Meters. *Photo courtesy of Toronto Hydro Corporation.*

26 Ernst & Young, 2012. "Great Britain: Unlocking the Potential of the Smart Grid." Available from http://www.ey.com/Publication/vwLUAssets/EY_-_Great_Britain_-_unlocking_the_potential_of_smart_grid/$FILE/EY-Plug-In-Great-Britain-unlocking-the-potential-of-smart-grid-v1.pdf.

27 Ibid.

28 UK Department of Energy and Climate Change, 2014. "Smart Grid Vision and Routemap." Available from https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/285417/Smart_Grid_Vision_and_RoutemapFINAL.pdf.

29 Junior Isles, "Special Project Supplement: Realising a smart vision." Dec. 2013. Available from http://www.anderson.ucla.edu/rosenfeld-library/citing-business-sources#journals.

The Emergence of Big Data

Utilities are reacting to and benefiting from the same technological advances that have affected every other sector of the Canadian economy. Health care, media, retail and countless other sectors have been transformed by the falling costs of collecting, storing and sharing data. Utilities are simply riding the same wave of automation—and Big Data underpins the opportunity to move beyond the traditional ways of delivering electricity and toward CEA's *Vision 2050*.

The Utility Analytics Institute has predicted that spending on Big Data software, hardware and services by North American utilities will increase to about $2 billion in 2016, up from $1.3 billion in 2013[30] and $511 million in 2011.[31] At the same time, data-related costs are continuously decreasing. Over the past 30 years, the cost to store data has been cut in half every 14 months or so. In 1995, storing a gigabyte of data cost about $11,200; by 2000 it was $11 and today costs a mere three cents.[32]

Affordable data storage is critical to grid modernization. Smart meters provide a good example to highlight why this is.

According to the Canadian Electricity and Gas Inspection Regulations, utilities are required to keep "for each billing period, the metering information used by the owner in establishing a charge […] for a period of at least 12 months after the date the meter ceased to be used."[33]

Individual electricity meters typically have an expected useful life of about 30 years. Even for large utilities, storing bi-monthly meter reads logged with pencil on paper has never required more than a few large filing cabinets as each meter has a maximum of 180 reads over the course of its life. Contrast that with the current practice in Ontario, which captures and stores five-minute interval demand data for any customer who is forecast by the distributor to have a monthly average

Toronto Power line technician Pete Patton installs an automated meter.
Photo courtesy of FortisAlberta Inc.

peak demand of more than 50 kilowatts during a calendar year. That works out to 105,120 records per year—and 3,153,600 records over the 30-year life of the meter.

Fortunately, the falling costs of data storage have made the transition to real-time data collection economically feasible, but it is not the end of the story. As information technology systems evolve, old data must be pulled along with it in a way that maintains accuracy and protects security and privacy. The need to protect the integrity of historical data will be one area that will require continuous attention and innovation over the long term.

CEA is confident that the grid operators of 2050 will look back and be amazed that meter reads were performed once every other month *in person*! Also, outages were not known by the utility until customers called in to complain about a lack of power. Advanced metering infrastructure, workforce management, distribution automation, smart homes… Big Data is the tool that enables it all. The next step, of course, is to turn cheap data into valuable information that grid operators and customers can use to make better decisions—and that requires ongoing innovation.

30 Jonathan Berr, "Utility Grid Barons Warm to Big Data's Power," *CNBC*, July 14, 2014. http://www.cnbc.com/id/101823030#.

31 Utility Analytics Institute, "Annual Market Outlook and Forecast: Summary Report, 2012." Available from http://www.energycentral.com/marketing/UAI/2011_UAI_Market_Report_Summary.pdf.

32 Statistic Brain, 2013. "Average Cost of Hard Drive Storage." Available from http://www.statisticbrain.com/average-cost-of-hard-drive-storage.

33 Electricity and Gas Inspections Regulations, SOR/86-131. Available from http://laws-lois.justice.gc.ca/eng/regulations/SOR-86-131.

5 OPPORTUNITIES FOR INNOVATION: KEY TECHNOLOGY AREAS REQUIRING IMMEDIATE SUPPORT

INVESTMENT IN LEADING-EDGE TECHNOLOGIES WILL IMPROVE OPERATIONAL EFFICIENCY AND REDUCE COSTS

EACH PROVINCE AND TERRITORY WEIGHS MOTIVATING AND ENABLING DRIVERS DIFFERENTLY, BASED ON FACTORS SUCH AS THEIR EXISTING INFRASTRUCTURE, NATURAL RESOURCE AVAILABILITY, POLITICAL PRIORITIES AND CUSTOMER PREFERENCES.

There is no one-size-fits-all model for grid modernization. There are, however, some common technological capabilities that can be funded and supported that will help utilities deliver on their expanding mandate.

CEA supports innovation opportunities and technology demonstration projects across three categories:

- Investigating the application of new technologies;
- Developing new methods, procedures or products to carry out work more efficiently or safely; or
- Gaining specific knowledge about the evolving utility environment to enhance design, operations or customer programs.

In practical terms, the interest is in leading-edge technologies that will improve operational efficiency and reduce the cost to transmit electricity: distribution management systems; smart meters; automated switches, transformers and substations; and integrated systems for handling outage management, asset management, geographic information and customer support.

This section takes a closer look at the most promising technology areas currently being explored by Canadian utilities that require immediate support in the form of pilot project funding.

Toronto Hydro's community energy storage system was developed with a lithium-ion battery solution used for distribution grid applications. It consists of batteries, controls, and communication systems that interface with the grid and was made possible through funding in innovation.
Photo courtesy of Toronto Hydro Corporation.

Demand Response

In the traditional grid context, generation follows load, meaning that as electricity usage increases in a given service territory, power plants are brought online to meet the demand and maintain system balance. Grid modernization provides utilities with the data and controls necessary to allow, and even prompt, load to respond to supply conditions or other signals such as power quality deterioration.

In early demonstrations, demand response initiatives have largely focused on peak shaving, which involves shifting energy demand from one time period to another to smooth consumption patterns. However, increasing attention is being given to shorter timescale applications like frequency regulation, which provide the flexibility to better integrate intermittent renewable energy resources and can also serve as a short-term contingency to mitigate unscheduled loss of supply.

Worldwide revenue from residential demand response is expected to grow from $322 million in 2014 to $2.3 billion in 2023.[34] In line with those estimates, Ontario is aiming to use demand response to meet 10 per cent of its peak demand by 2025, equivalent to approximately 2,400 megawatts under forecast conditions.

A December 2013 report from the U.S. Department of Energy's National Renewable Energy Laboratory found that a modest demand response resource of 45.4 megawatts added to a testing scenario could provide up to 113 megawatts of capacity (roughly two per cent of peak load) and shift 135 gigawatt-hours of energy. It can also meet about 33 per cent of the need for frequency regulation, 19 per cent of spinning contingency reserve and 85 per cent of flexibility reserve.[35] Without getting into the details on each of these, suffice it to say that this translates into better grid performance and can significantly reduce necessary infrastructure investment.

In the United States, demand response is currently being challenged by some traditional wholesale generators who feel that paying customers to curtail demand, thus getting paid for negative watts or "negawatts", will ultimately undermine the energy market and starve out traditional utilities.

Table 1. The Impact of Motivating Drivers on Demand Response

Driver	Challenge/Opportunity
Reduce emissions	Most peaker plants burn natural gas to generate electricity, because of the fast ramp rate. Demand response can help alleviate the need for these plants.
Increase resiliency	Demand response reduces pressure on the system during times of peak demand and can provide short-term cover for emergency downtime at traditional power plants.
Empower customers	Demand response is a tool for utility operators to control electricity consumption at times of peak demand; it also includes efforts by customers to respond to real-time price signals. By shifting to off-peak consumption, customers can reduce their bills.
Contain costs	Demand response can help avoid expensive upstream solutions to a "peaky" system, while extending the life of downstream assets by alleviating system congestion.

34 Navigant Research, 2014. "Residential Demand Response." Available from http://www.navigantresearch.com/research/residential-demand-response.

35 National Renewable Energy Laboratory, 2013. "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model." Available from http://www.nrel.gov/docs/fy14osti/58492.pdf.

CEA takes a more favourable view. Used properly, demand response replaces only the most marginal, highest cost peaker plants (i.e., plants that run only during times of high demand). That said, market mechanisms must be developed that reward demand response without unduly punishing incumbent utilities. A failure to provide a fair rate of return on capital investments may lead to an underinvestment in generating assets moving forward, which will undermine the long-term sustainability of Canada's electricity system.

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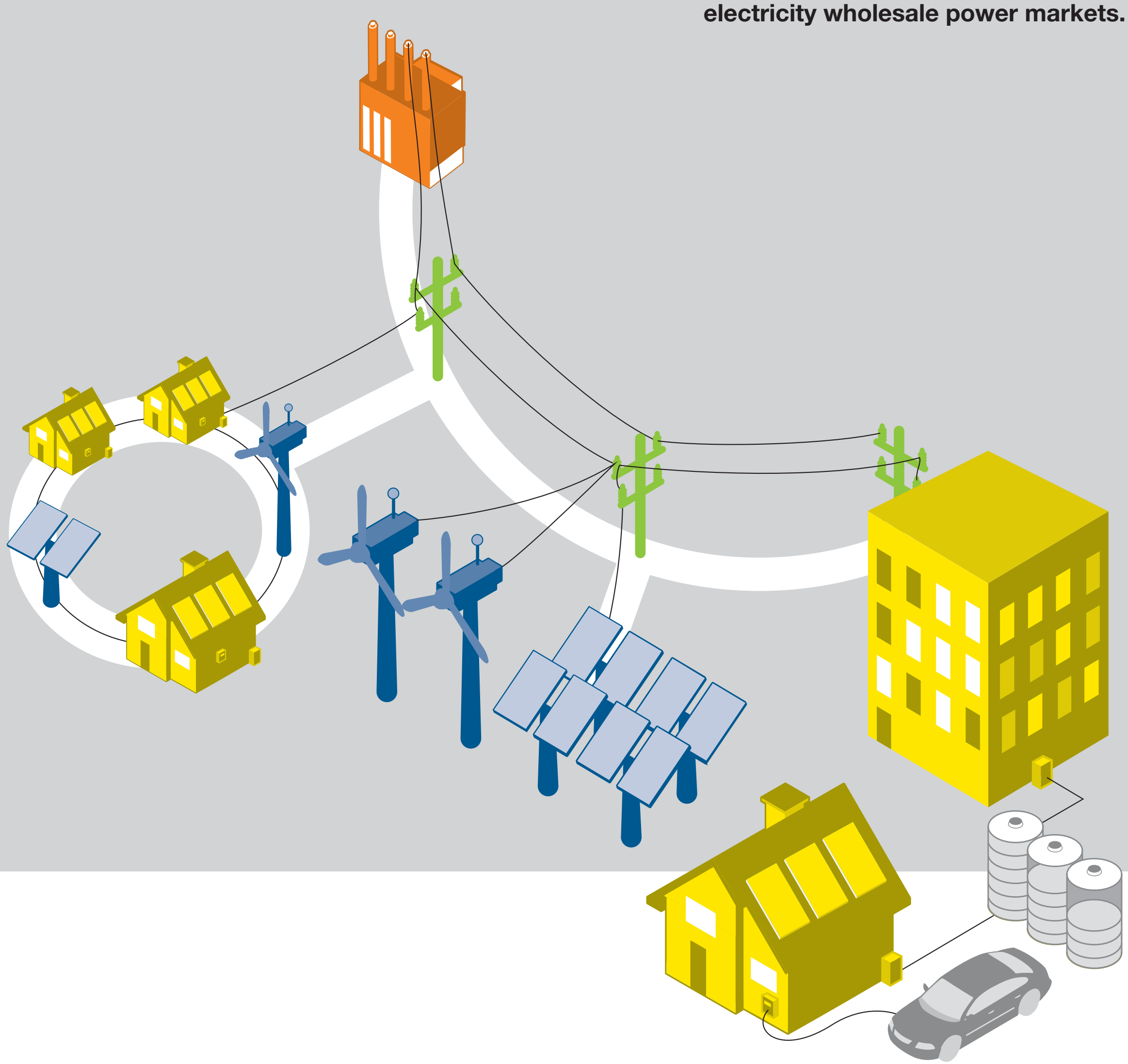
INNOVATION OPPORTUNITIES: DEMAND RESPONSE

- **Better integrate demand response into network management, including increasing the granularity of control to enable targeted demand response at specific substations or even specific feeders.**
- **Develop the tools and information exchanges that will allow customers to respond to price signals from behind the meter.**
- **Design and test incentive programs that lead to the uptake of grid-side demand response programs.**
- **Evaluate various pricing signals to determine what leads customers to curtail electricity usage during times of peak demand.**
- **Develop and pilot market mechanisms to integrate demand response resources into electricity wholesale power markets.**



Facilitation of Distributed Generation

While renewable electricity generation will continue to grow, it is unclear whether its pace of growth will accelerate or remain relatively modest. Despite this uncertainty, there are clear signals that distributed generation is not a passing trend.

Currently, 1,200 megawatts of solar capacity is connected to Canadian electricity grids—and that amount is growing rapidly each year, increasing by 58 per cent in 2013 alone.[36] The increased solar capacity is being driven by feed-in-tariff contracts, renewable energy standards, environmentally conscious energy consumers and falling costs. According to Natural Resources Canada and the Canadian Solar Industries Association, photovoltaic module prices have declined from $10.70 per watt in 2000 to $0.95 per watt in 2013, falling 17 per cent in 2013 alone.[37]

The wind farm in Prince Township, Ontario is the third largest in Canada.
Photo courtesy of Brookfield Renewable Energy Group.

Canada's wind capacity, meanwhile, is now more than 8,500 megawatts—and it also continues to grow at a rapid pace and in line with international trends. According to the Canadian Wind Energy Association, global wind energy capacity grew by 19 per cent in 2012, with the wind industry installing a record level of 44,711 megawatts of new power.[38] The National Energy Board projects Canadian wind capacity to grow to 16,000 megawatts by 2035, with the largest capacity additions expected to occur in Quebec, Ontario, Alberta, and British Columbia.[39]

Of course, Canadian renewable energy development is not limited to solar and wind: project proponents are adding innovative approaches such as small-scale hydro, biomass, geothermal and marine power to Canada's distributed energy resource portfolio. Taken together, Canada had more than 7,000 megawatts of renewable energy capacity in 2012, accounting for 5.5 per cent of the country's total capacity.[40] As the portfolio expands, distribution utilities will need to develop advanced processes and tools to integrate a greater volume of renewable resources without undermining service reliability.

Germany is widely seen as a world leader in distributed generation; however, the rapid growth of distributed generation in that country has resulted in a situation where policymakers and utilities have had to change interconnection rules, grid expansion plans, connectivity requirements, and wind and solar incentives to better integrate distributed resources.[41] As distributed generation expands in Canada, province-specific solutions to each of these issues will need to be developed, tested and deployed.

36 Y. Poissant and P. Luukkonen, (2013) "National Survey Report of PV Power Applications in Canada, 2014." Prepared by the Canadian Solar Industry Association and Natural Resources Canada, 2013.

37 Ibid.

38 Canadian Wind Energy Association, "Wind Facts". Web. 22 December 2014.

39 National Energy Board, 2013. "Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035." Available from https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/2013nrgftr-eng.pdf.

40 Ibid.

41 Electric Power Research Institute, 2013. "The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources." Available from http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733.

Table 2. The Impact of Motivating Drivers on the Facilitation of Distributed Generation

Driver	Challenge/Opportunity
Reduce emissions	While 80 per cent of Canada's electricity supply comes from non-GHG-emitting sources, there remains an opportunity for distributed renewables to replace retiring coal plants or natural gas peaker plants.[42] There may also be increased export opportunities for renewable energy produced in Canada as environmental regulations tighten in the U.S.
Increase resiliency	If not managed effectively, distributed generation can actually undermine grid reliability and resiliency.
Empower customers	In the U.S., more than 500,000 residential and commercial customers have installed rooftop or ground-mounted solar panels.[43] The market has begun to "pull" toward distributed generation.
Contain costs	At this point, distributed generation is driven more by emissions reductions and customer empowerment than it is by cost reductions for either grid operators or consumers. As distributed generation proliferates, owners who want to maintain a connection to the grid will have to pay their fair share of the fixed infrastructure costs.

Completed in 2010, the Digby Neck Wind Farm supplies up to 10,000 homes.
Photo courtesy of Nova Scotia Power Inc.

42 Statistics Canada, Electric Power and Generation – Annual (CANSIM 127-0007), 2013.

43 Solar Energy Industries Association, 2014. "Solar Market Insight Report 2014 Q2." Available from http://www.seia.org/research-resources/solar-market-insight-report-2014-q2.

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INNOVATION OPPORTUNITIES: FACILITATION OF DISTRIBUTED GENERATION

- **Develop tools to better integrate distributed generation, including better forecasting methods, more granular feeder operations assessments, and more robust aggregate system impact modelling and controls.**
- **Further explore the complementary value of energy storage or demand response to distributed generation.**
- **Implement market and tariff mechanisms that adequately value a "backup" grid connection.**
- **Establish dispatch controls and "anti-islanding" protection schemes to prevent distributed generation from continuing to supply electricity to a location when power lines are down, thereby reducing risk to utility workers and guaranteeing a high quality of electricity.**

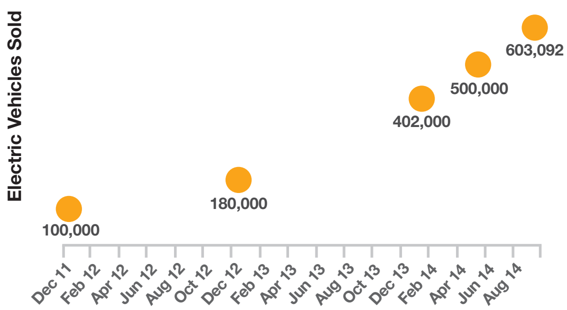
Capital Power Corporation's 105 megawatt Port Dover and Nanticoke Wind project is located in Haldimand and Norfolk Counties, Ontario. The project, which began commercial operations in November 2013, features 58 Vestas V-90 turbines. *Photo courtesy of Capital Power Corporation.*

Facilitation of Electric Vehicles

The transportation sector accounted for almost one-quarter of Canada's total greenhouse gas emissions in 2012.[44] While vehicle emission standards will help bring this number down in the near term, electrifying Canada's light vehicle fleet is the most promising way to drastically reduce the sector's emissions by 2050.

As of early 2015, approximately 10,000 highway-capable plug-in electric vehicles will have been sold in Canada. While this is a long way from having an electric vehicle in every driveway, global sales have now increased to more than 600,000 light duty vehicles over the past 10 years—with the adoption of electric vehicles continuing to accelerate each year (see **Figure 2**).

Figure 2. Total Global Electric Vehicle Sales



Source: http://www.hybridcars.com/global-plug-in-car-sales-now-over-600000

Horizon Utilities' electric vehicle charging station.
Photo courtesy of Horizon Utilities Corporation.

44 Environment Canada, 2014. "Canada's Emission Trends." Available from http://ec.gc.ca/Publications/E998D465-B89F-4E0F-8327-01D5B0D66885/ETR_E-2014.pdf.

Table 3. The Impact of Motivating Drivers on the Facilitation of Electric Vehicles

Driver	Challenge/Opportunity
Reduce emissions	While total emission reductions are ultimately dependent on the supply mix of the electricity used to fuel the vehicle, Canada's electricity mix offers a world-leading opportunity to harness the environmental benefits of switching to electric vehicles.
Increase resiliency	At their current adoption rate, electric vehicles are of no real concern to grid operators. However, if the adoption rate changes significantly over a short period of time, some feeders could be affected. Over the longer term, vehicle-to-grid and vehicle-to-home applications could contribute positively to grid resiliency.
Empower customers	Utilities will not be a roadblock to the adoption of electric vehicles; however, utilities are also not in the best position to directly encourage EV adoption.
Contain costs	Electric vehicles are unlikely to mitigate infrastructure investment needs; however, they do represent a potentially significant new load centre that can help to defray rate impacts.

Horizon Utilities' staff and electric vehicle.
Photo courtesy of Horizon Utilities Corporation.

INNOVATION OPPORTUNITIES: FACILITATION OF ELECTRIC VEHICLES

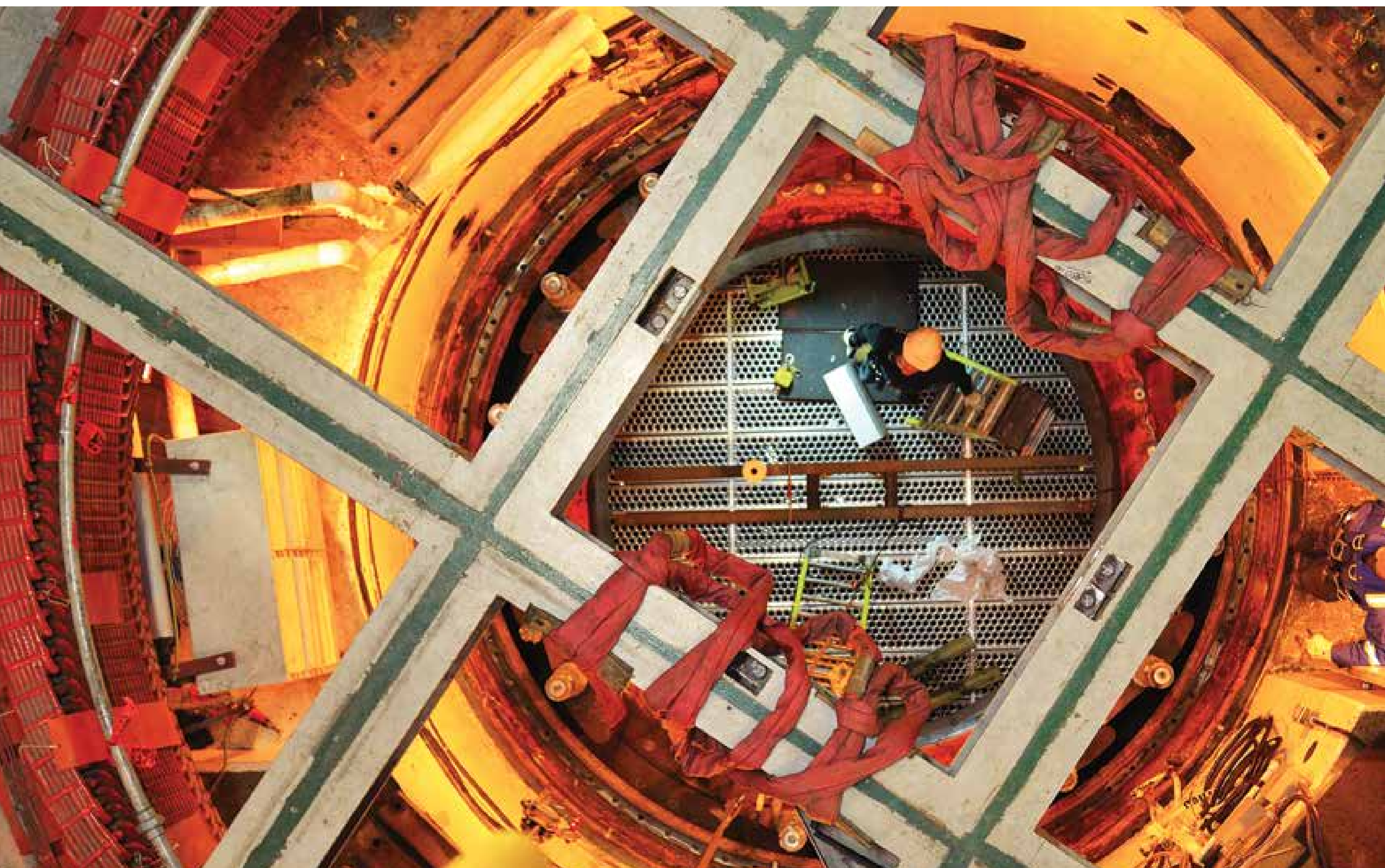
- Explore the feasibility of vehicle-to-grid and vehicle-to-home applications.
- Develop programming that educates customers about the environmental and operational cost advantages of electric vehicles.
- Establish vehicle-charging models that value the natural coordinating role of the distribution utility.
- Build operational tools that allow utilities to predict, evaluate and control charging patterns.
- Develop programs that support the use of electric vehicles in commercial vehicle fleet.

Electric vehicle Direct Current fast charging demonstration by BC Hydro. *Photo courtesy of BC Hydro and Power Authority.*

Optimization of Asset Use

Over the next 20 years across Canada, a significant proportion of the following network components will reach or exceed their anticipated end of life. This includes distribution stations, underground cables, manholes, duct lines, padmount transformers, wood poles, overhead conductors, overhead transformers and streetlight standards. Fortunately, Big Data and grid modernization tools such as sensors, integrated distribution communications systems, advanced analytics software and new diagnostic tests allow for increasingly targeted operations and asset management programs, helping utilities maximize asset performance, proactively maintain equipment and optimize replacement strategies.

Advanced monitoring, for example, enables more timely maintenance; more efficient matching of supply and demand from various economic, operational and environmental perspectives; and overload detection of transformers and conductors—all of which help utilities to reduce energy losses, improve dispatch, enhance stability and extend the lifespan of their assets.



A 10-year maintenance of one of our Whitehorse hydro units. *Photo courtesy of Jim Petelski/Yukon Energy Corporation*.

Table 4. The Impact of Motivating Drivers on the Optimization of Asset Uses

Driver	Challenge/Opportunity
Reduce emissions	Optimization of network assets will allow grid operators to integrate an increasing amount of distributed generation without safety or reliability concerns.
Increase resiliency	Maintaining asset health is critical to ensuring Canada's electricity grid continues to operate to a high standard of reliability.
Empower customers	Optimization of asset use is principally focused on grid-side operations.
Contain costs	Optimizing asset monitoring and usage can significantly extend asset lifespan; this results in lower rates to customers than would be the case under age-based asset replacement programs.

IO INNOVATION OPPORTUNITIES: OPTIMIZATION OF ASSET USE

- **Improve peak load management and energy efficiency through the use of overload detection, phase balancing and volt/VAR control (i.e., managing active power load through voltage controls at the substation level and volt-ampere-reactive [VAR] power load through capacitors at the grid level).**
- **Strengthen distribution system management capabilities such as state estimation, safety management, volt/VAR control, and load forecasting and balancing.**
- **Improve asset health data collection and assessment/ prioritization algorithms.**

Worker makes repairs in residential community. *Photo courtesy of FortisAlberta Inc.*

Fault Detection and Mitigation

While supervisory control and data acquisition (SCADA) and other energy management systems have long been used to monitor transmission systems, visibility into the distribution system has been limited. In fact, many utility customers would probably be surprised to learn of the limited information historically available to grid operators, especially at the distribution level.

As an example, when a blackout occurred customer calls were mapped to define the geographic area affected. This, in turn, allowed utility engineers to determine the lines, transformers and switches involved and what must be done to restore service. On many occasions, a utility's customer care representative would actually ask callers to step outside to visually assess the extent of the power loss in their neighbourhood. It is a testament to the high levels of reliability enjoyed by Canada's electric utility customers that most have never experienced this; however, it is also evidence of an antiquated system.

The end goal is to implement full fault location with isolation and restoration capabilities; however, this will require tying together numerous utility systems—outage management, advanced metering, distribution management, geographical information—and hardening the system so it can withstand more severe weather events.

Fault detection and automated restoration technologies are being developed and are currently being integrated with utility outage management systems; however, they must be piloted by utilities so the potential value of deployment across a full service territory may be assessed.

While storm activity continues to be the biggest threat to service continuity, cyber security threats are on the rise as well. While hackers have traditionally targeted electricity generation and transmission, an automated distribution grid is both a means for grid operators to fix problems and hackers to cause them.

Table 5. The Impact of Motivating Drivers on Fault Detection and Mitigation

Driver	Challenge/Opportunity
Reduce emissions	This driver does not apply in any meaningful way to fault detection and mitigation.
Increase resiliency	While asset optimization will prepare utilities to face extreme weather events, fault detection and mitigation will speed recovery. Resiliency is at this heart of this capability.
Empower customers	Fault detection empowers customers by detecting problems *before* they need to pick up the phone and report them to their utility.
Contain costs	Debate continues as to how much utilities should spend to prepare for extreme weather events. Customers are asked to invest in grid infrastructure as insurance against the significant economic impacts resulting from extended power loss.

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INNOVATION OPPORTUNITIES:
FAULT DETECTION AND MITIGATION

- Explore ways to better handle call volumes and website traffic during an outage event.
- Improve estimated time to restoration models to better inform customers about outage management and response.
- Improve systems tied to restoration efforts, including field communications, outage management, interactive voice response, SCADA, geographic information systems and distribution automation.

Other Promising Technology Areas

While not as fully featured as the other technology areas discussed in this section, other promising opportunities for innovation include the following:

A view of the interior of BC Hydro and Power Authority's Field energy storage facility.
Photo courtesy of BC Hydro and Power Authority.

A view of the exterior of BC Hydro and Power Authority's Field energy storage facility.
Photo courtesy of BC Hydro and Power Authority.

Storage

Downstream electrical energy storage has often been referred to as the "holy grail" of grid modernization—and for good reason. Energy storage promises to simplify the integration of distributed generation and electric vehicles, mitigate the need for demand response (although overall conservation will remain important), limit periods of asset overload, and keep the lights on when the bulk power system fails. The challenge so far has been to do any of these things economically.

A number of Canadian pilot projects are currently exploring energy storage applications. CanmetENERGY, a department of Natural Resources Canada, has tracked more than $70 million worth of storage projects across the country that are funded in part or in full by various federal and provincial funds.[45] According to CanmetENERGY researchers, the integration of distributed generation, storage and reactive sources that can compensate for fluctuating generation and consumption demand will help produce more robust, cost-saving electricity networks.

While these initial pilot projects are important, now is the time to push energy storage innovation into overdrive across Canada. According to the Brattle Group, the cost of installed electricity storage, which is currently $700–$3,000 per kilowatt-hour, is expected to decline to less than half of that over the next three years.[46] Navigant Research, meanwhile, forecasts that the annual revenue of cell sales for advanced batteries for utility-scale storage applications will grow from $221.8 million in 2014 to $17.8 billion in 2023.[47]

Given these numbers, it is imperative that Canada's electricity utilities and regulators start taking a closer look at the value of specific storage applications in Canada.

45 Natural Resources Canada, 2014. "CanmetENERGY Research Brief: Integrating Electricity Storage Into Smart Grid." Available from http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/files/pubs/2014-106_EN.pdf.

46 Judy Chang, Johannes Pfiefenberger, Kathleeen Spees, Matthew Davis, Ioanna Karkatsouli, Lauren Regan, James Marshal, 2014. "The Value of Distributed Electricity in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments." Prepared for Brattle Group, available from http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf.

47 Navigant Research, December 22, 2014. "Advanced Batteries for Utility-Scale Energy Storage." Navigant Research website, available from http://www.navigantresearch.com/research/advanced-batteries-for-utility-scale-energy-storage.

Unmanned Aerial Vehicles

CEA Corporate Utility Members are increasingly interested in using unmanned aerial vehicles (UAVs), or drones, to monitor their assets. Advanced applications allow utilities to map terrain and form an accurate 3D model of the components of their power network and also any surrounding buildings, landscapes and vegetation. Currently, this work is performed predominantly by full-size manned helicopters; UAVs are being touted as a low-cost, safer alternative.

Examples of how UAVs are currently being used by electric utilities include:

- **SaskPower** is testing a $23,000 UAV to survey substations and other assets.[48] Capable of flying for about 25 minutes with a maximum flight path of 1.6 kilometres, the UAV provides SaskPower with visual access to the tops of transformers without having to de-energize them; can fly within six feet of transmission lines, which is close enough for photos to show loose pins and missing bolts; and provides aerial photos during flooding events when some assets may be unreachable by ground travel.
- **San Diego Gas & Electric** was approved by the U.S. Federal Aviation Authority in July 2014 to use UAVs for research, testing and training flights in sparsely populated areas of their service territory.[49] This was the first such approval in the U.S.
- **Iberdola** (Spain) plans to use UAVs to monitor power lines and distributed generation assets such as wind turbines.[50]

Induction Charging

The transformation of the electricity system is often likened to the one experienced by the telecommunications industry, which saw a move from landline telephone systems to cell phones and smart phones. However, while the management of the electricity system and the technologies being powered might change, the physical characteristics of moving power remains the same. Utilities will continue to push electrons through conductive wires from the transmission system into the distribution system.

Induction is the one mainstream technology that can turn this model on its head. Also known as wireless power, induction is the equivalent of replacing the wired Ethernet cable with Wi-Fi— and may eventually allow customers to access electricity "on the go." The current technology is not quite there yet, though. A mobile device charged by induction needs to sit on an induction pad and cannot be used during the charge. Also, charging a device in this way is less efficient than charging by cable, requiring more energy and a longer charge time.

While induction charging is still in its early days, in an increasingly wireless world, it is an area that utilities and regulators simply cannot afford to ignore. Of particular interest is the fact that the market for wireless charging is set to explode over the next few years: revenues from shipments of induction power transmitters and receivers are expected to expand to $8.5 billion in 2018, up from just $216 million in 2013.[51]

48 Mark Melnychuk, "SaskPower Sends in the Drone," Leader-Post, October 15, 2014, available from http://www.leaderpost.com/technology/SaskPower+sends+drone+Video/10289435/story.html.

49 Jeff St. John, "Are Flying Robots the Next Smart Grid Technology Ready to Take Off?" Greentech Media, July 23, 2014, available from http://www.greentechmedia.com/articles/read/flying-robots-for-the-smart-grid.

50 "Iberdola to Use UAVs for Power Lines Monitoring," sUAS News, June 13, 2013. available from http://www.suasnews.com/2013/06/23318/iberdrola-to-use-uavs-for-power-lines-monitoring.

51 Ryan Sanderson, "Wireless Power Report, 2014." IHS Technology. Available from https://technology.ihs.com/438315/wireless-power-2014.

6 APPROACHES FOR FUNDING INNOVATION

REMOVING BARRIERS TO INNOVATION

Employees share their knowledge. *Photo courtesy of Newfoundland Power Inc.*

OVER THE PAST 20 YEARS, CANADA'S ELECTRIC UTILITIES HAVE LARGELY DIVESTED THEMSELVES OF THEIR IN-HOUSE RESEARCH AND DEVELOPMENT (R&D) ARMS. (THERE ARE A FEW EXCEPTIONS, INCLUDING HYDRO-QUÉBEC'S IREQ AND BC HYDRO AND POWER AUTHORITY'S POWERTECH LABS.)

Instead, new technologies are developed by equipment vendors, which are then incorporated into a system managed by utility operators and asset managers. Utilities look to the vendor community for early-stage technological innovation, and then provide controlled grid access to the vendors so their applications can be tested in a real-world environment. Through this relationship, utilities can still help shape the final product to fit a specific need.

Sticking with proven technologies may be the easiest way for Canadian utilities to keep the lights on, but in this new world of grid modernization and increasing customer expectations, "first movers" are required—and they must be incentivized to take on the risk of new technology development, testing and integration.

Collaboration Ecosystems

When done well, collaboration significantly reduces the barriers to innovation. Equipment manufacturers provide the technology, utilities provide the living lab to test the technology, and government partners provide the funding and guidance needed to build a consortium of industry experts to direct the technology's implementation. This kind of collaboration "ecosystem" brings together the broad-based expertise and oversight necessary to ensure project success.

A collaborative approach to innovation sufficiently addresses the lack of in-house R&D capacity as well as the grid access needs of technology developers. It also pools financial and knowledge resources to minimize project risk and spread costs between businesses (both competitive and regulated) and public policy priorities.

The Concentric Model

In August 2014, Concentric Energy Advisors published a discussion paper at the behest of CEA and the Canadian Gas Association.[52] The paper lays out the "gold standard" model for collaborative innovation, which features the following key characteristics:

- **Funding** – The Concentric Model calls for an initial funding level of \$3–\$5 per customer per year—that is, it is fully ratepayer-funded—with funding authorized for a period of at least three years. Cost recovery is achieved through a dedicated reconciling mechanism (e.g., a variance account).
- **Regulatory oversight and program management** – The majority share of the funding should be spent on collaborative projects, with the minority share spent on internal, utility-specific efforts. Multi-year innovation investment plans need to be subject to regulatory approval and formal stakeholder review, and regulatory guidance should be provided with regard to the criteria used to build the business case justifying innovation activities.
- **Collaborative, innovation-focused entities for gas and electric industries** – A clearinghouse for the key findings and lessons learned emerging out of R&D projects (both successful and unsuccessful) should be established. Regulators and public-interest stakeholders should serve on utilities' Boards of Directors or Advisory Councils to provide substantive direction and oversight.

CEA's mid- to long-term vision is a pooled fund for collaborative innovation demonstration projects. To achieve this vision, however, there will need to be greater alignment between the values and objectives of customers, regulators, policymakers, private industry and regulated utilities. The industry can get started on this today.

52 Stephen Caldwell, Robert Yardley, Jr, and James Coyne. "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers, 2014." Available from http://www.electricity.ca/media/ReportsPublications/StimulatingInnovation2014.pdf.

7 RECOMMENDED ACTIONS

ADVANCING THE ELECTRICITY INNOVATION AGENDA IN CANADA

Wind turbines dot the prairie landscape south of Winnipeg. *Photo courtesy of Manitoba Hydro.*

GIVEN THE KEY DRIVERS AND PROMISING TECHNOLOGY AREAS DISCUSSED THROUGHOUT THIS PAPER, CEA PUTS FORWARD FOR CONSIDERATION THE FOLLOWING SEVEN ACTIONS THAT CAN BE TAKEN TODAY TO ENSURE UTILITIES HAVE THE MANDATE AND MEANS TO INVEST IN INNOVATION MOVING FORWARD.

Align Priorities and Goals

While the various drivers and capabilities propelling grid modernization weigh more heavily in some provinces than others, overall there is sufficient commonality that national collaboration is valuable. When it comes to innovation, no one province or country should go it alone.

Provincial regulators can express common priorities and goals through the Canadian Association of Members of Public Utility Tribunals (CAMPUT), and policymakers can do the same through the Council of the Federation's work towards a National Energy Strategy. In both of these forums, CEA hopes participants will advocate for the need to transform Canada's electricity infrastructure, markets and technologies through a long-term, sustained commitment to innovation.

Track Grid Modernization Indicators at a National Level

To support the alignment of key priorities, Canada must have a national approach to tracking key grid modernization indicators such as the amount of distributed generation connected, the number of electric vehicles sold, the number of smart meters in service, and the number of customers engaged in demand response programs. This data will help proactively identify areas that will require technical and regulatory solutions.

CEA has entered into discussions with Natural Resources Canada's CanmetENERGY clean energy research program about conducting a regular smart grid metrics survey for Canadian utilities. Such a project would:

- Create a "dashboard" of national smart grid data;
- Enable data-backed insights and best practices to emerge;
- Inform R&D and demonstration funding; and,
- Provide a useful public reference for discussions with regulators and the public.

CEA and CanmetENERGY continue to explore this initiative, working toward an initial report in late 2015.

Look internationally

Similar to the need to aggregate regional priorities into a national grid modernization program, Canada has the opportunity to learn from other countries that are aggressively pursuing innovation, spurred on by their own domestic drivers (in many cases, emissions reduction commitments, energy security concerns and cost containment).

Through the International Energy Agency's International Smart Grid Action Network (ISGAN), Canadian regulators, policymakers and utilities have access to the metrics that can serve as signposts of global trends. Canadian participation in the ISGAN program is managed through the CanmetENERGY program; support for these activities should remain strong moving forward.

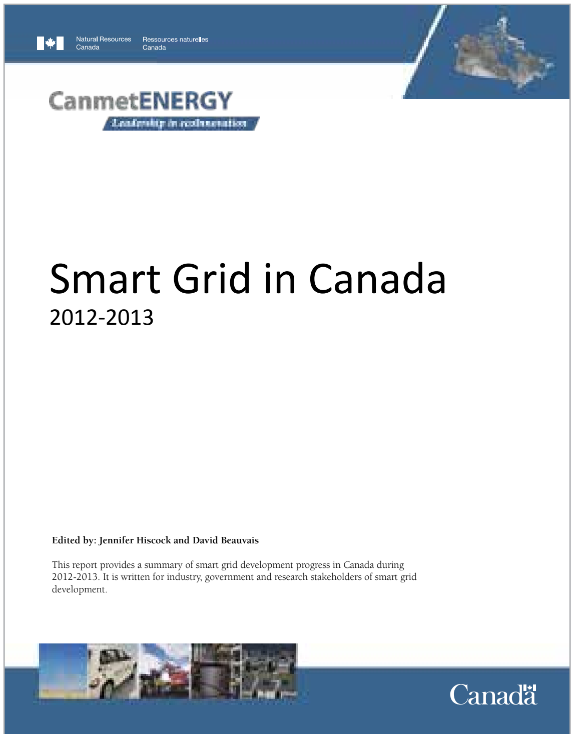
Pool Innovation Funding to Mitigate Risk and Spread Out Rewards

Utilities should maintain a balanced innovation portfolio, which includes funding for projects that address utility-specific needs, enable provincial priorities and/or support a common national vision. To mitigate risk, innovation funding for projects that support provincial or national policy objectives should be fully or partially matched by public funds, largely due to the fact that the benefits resulting from such projects will be more broadly applicable than those of a small-scale, utility-specific demonstration project.

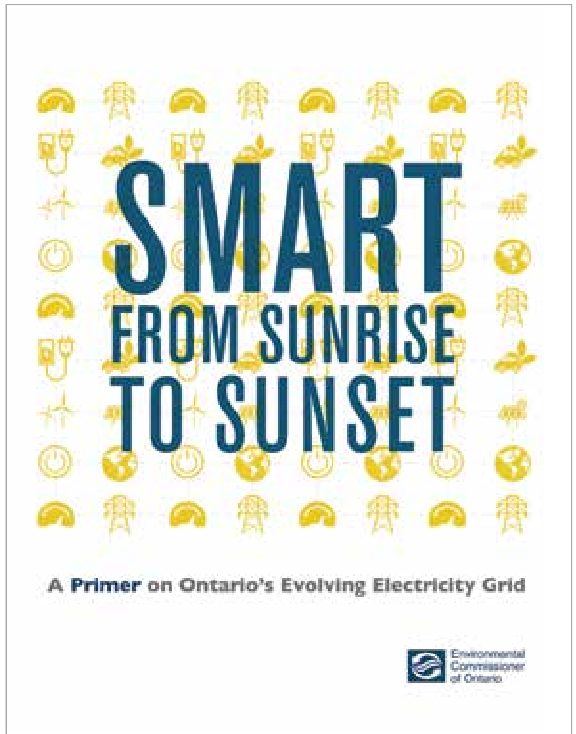
Share Lessons Learned

Whether funding is pooled or individual utilities take on individual projects, all stakeholders (including regulators, policymakers, utilities and customers) benefit from the key learnings from both successful and failed demonstration projects.

CEA contributes to Natural Resources Canada's regularly updated *Smart Grid in Canada* report, which does a good job of collecting information on existing smart grid projects and initiatives. More must be done to identify key learnings and share them broadly. CEA is open to further discussions on how this can best be facilitated.



Smart Grid in Canada report cover, used with permission.



Smart from Sunrise to Sunset: A Primer on Ontario's Evolving Electricity Grid cover, used with permission.

Lock in Knowledge by Developing Codes and Standards

As technologies develop, demonstration projects move forward and lessons learned are distilled, knowledge gained should be formalized into codes and standards that guide utility technical planning, operating practices and work methods.

Participation in standards development requires two increasingly scarce resources: staff time and travel budgets. It is critical, however, that utilities continue to support the development and maintenance of Canada's system of codes and standards, in partnership with the Standards Council of Canada and the relevant standards development organizations.

Keep Customers Informed and Engaged

Whether a specific technology, process or program targets reliability, safety, environmental sustainability or cost control, at its core, grid modernization is about protecting and improving the value of electricity service. It is critical to communicate this to customers early and often.

The Environmental Commissioner of Ontario (ECO) has produced a customer-friendly report titled *Smart from Sunrise to Sunset: A Primer on Ontario's Evolving Electricity Grid*, which is intended to help policymakers and the public alike become more familiar with the concept and potential of the smart grid.[53] CEA fully supports public-facing efforts such as this, and applauds the ECO for taking the initiative to drive the dialogue forward in the public sphere.

53 Environmental Commissioner of Ontario. 2014. "Smart from Sunrise to Sunset: A Primer on Ontario's Evolving Electricity Grid." Available from http://www.eco.on.ca/uploads/Reports%20-%20Background,%20Discussion,%20Roundtable/2014%20Smart%20Grid%20Primer.pdf.

8 CONCLUSION

BC Hydro power line technicians work to ensure power. *Photo courtesy of BC Hydro and Power Authority.*

IN THE FACE OF DETERIORATING INFRASTRUCTURE AND INCREASING CUSTOMER EXPECTATIONS, INNOVATION IS CLEARLY NEEDED IF THE ELECTRICITY SECTOR IS TO ENSURE A RELIABLE SUPPLY OF POWER, CONTAIN COSTS AND REDUCE THE ENVIRONMENTAL IMPACT OF ITS OPERATIONS.

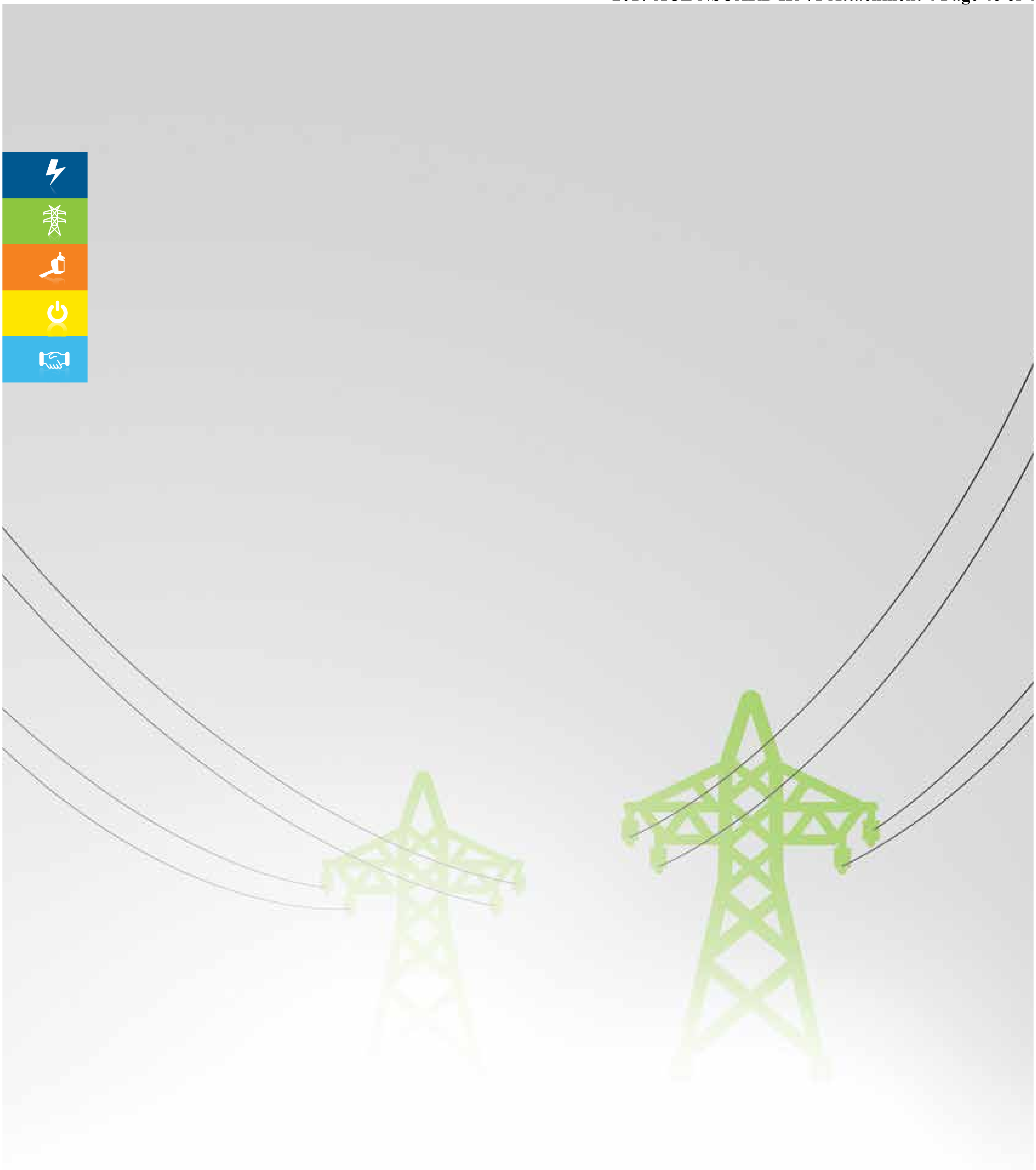
Fortunately, a number of promising technologies have emerged that will help utilities meet these goals and more—and the time to pursue those opportunities is now.

Policymakers and funding agencies should use this paper to inform funding decisions for new pilot projects, allowing them to focus their investments on the top priority areas identified by Canada's electricity sector: demand response; distributed generation; electric vehicles; asset optimization; and fault detection and mitigation.

Utilities can use this paper in a similar way as they continue to explore new technologies, systems and processes to prepare their networks for 2050 and beyond. Of course, there needs to be a recognition that such a focus on innovation, the kind that will help transform utilities from traditional commodity providers to suppliers of a diverse range of energy services, will require a much more customer-centric, agile and risk-adverse mindset, along with a re-invented organizational structure to match. While it is a vastly different culture than the one required for their day-to-day operations, utilities will not (and should not) be deterred from pursuing innovation. In fact, the sector has already shown that it is clearly committed to innovation—and for any utility with a promising pilot project applicable to any of the priority areas outlined in this paper, the Canadian Electricity Association is willing to provide the necessary support in making connections to industry to help them get it off the ground.

GRID MODERNIZATION GOES WELL BEYOND TECHNOLOGICAL IMPROVEMENTS; IT'S ABOUT TRANSFORMING THE ELECTRIC ECOSYSTEM AS A WHOLE.

In the end, grid modernization goes well beyond technological improvements; it's about transforming the electric ecosystem as a whole. As such, *collaboration* will be the most important factor in realizing *Vision 2050*. Every stakeholder has a part to play—utilities, customers, suppliers, regulators, policymakers—and it will be critical that they all work together to fully determine the future of Canada's electricity sector.



www.electricity.ca
www.vision2050.ca
@CDNelectricity

Canadian Electricity Association
Association canadienne de l'électricité

Request IR-72:

With reference to NSPI's approach towards capital investment in IT, noted on pages 14 and 15 of the Application:

(a) Please provide a copy of a report or study that discusses changes in NSPI's approach to managing IT.

(b) In its discussion, NSPI notes software vendors are increasing the frequency of patches and releases. At the same time, it appears the proposed investments in IT lead towards the "more regular, incremental IT upgrades". Does NSPI have any concerns regarding the rising costs for software maintenance/updates, and if so, what measures are being implemented, or will be implemented, to constrain these costs?

Response IR-72:

(a) Please refer to NSUARB IR-71.

(b) The software upgrades being implemented by the Company are necessary to maintain the required level of accessibility, integrity and confidentiality of customer, employee, financial and operational information. NS Power plans to manage the impact of the cost of these software upgrades in the following ways:

(1) Reducing (by standardizing and consolidating) the number of applications that require upgrading;

(2) Standardizing technical infrastructure that supports the applications;

(3) Leveraging mechanized tools to more cost effectively test and implement changes; and

(4) Working with vendors to prepare and execute the changes as regular planned work.

Request IR-73:

For each of the IT projects included in the 2017 ACE Plan submission, please identify the estimated costs related to NSPI's labour, and the costs related to services by external consultants.

Response IR-73:

CI#	Project #	Project Long Title	Internal Labour ($)	External Consultants ($)
44671	P981	IT - Enterprise Resource Planning (ERP)	13,868,000	45,541,273
47477	P967	IT - Next Generation Firewall	125,154	1,394,044
49043		IT Contact Centre Telephony Infrastructure	204,050	1,143,705
48254		IT - Outage Communication Tech Cap Improvement	159,342	932,792
29114	P031	IT - NSPI Infrastructure Routine	86,400	0
46073		IT - Lotus Notes/Oracle Applications Replacement	17,262	787,474
48635	P987	IT - Security Enhancements - Endpoint Data Encryption and Malware Protection	5,217	574,278
49861		IT - PI System Upgrade	101,277	269,117
46365	P108	Maximo Enhancements for Substation Field Mobility	82,821	60,000

The IT projects listed above have either been submitted for approval separately or are in the 2017 ACE Plan, or are carryover projects in the 2017 ACE Plan. This information is not available for IT items included in the Subsequent Submittal list, as there is not a detailed estimate for those projects at this time.

Request IR-74:

With reference to IT services the CGI Group Inc. ("CGI") provides to NSPI, please provide an overview of these services, and describe the role of CGI in NSPI's IT projects included in the 2017 ACE Plan.

Response IR-74:

CGI provides the following services to NS Power:

- System Management Services – Responsible for all aspects of operating, management, monitoring, maintenance and support of servers and related components of NS Power's systems.

- Helpdesk services – Provide NS Power employees with incident resolution and fulfillment of standard technology requests.

- Deskside support – Responsible to provide support on desktop and laptop, hardware and software elements including acquisition, configuration, deployment, LAN access, on-going support and upgrades.

- Technical Support Services – Provide all services necessary for installing and integrating system related software in the current environments and provide on-going technical related support.

- Network Services – Provide the Local area network (LAN) services and the Wide Area Network (WAN) links required to run the business.

- Messaging services – Provide all aspects of operations, monitoring, management and maintenance of all messaging services.

- The services include the on-going administration and supervision of associated maintenance contracts where applicable.

CGI's role in NS Power's IT Projects included in the 2017 ACE Plan will be primarily focused on receiving, configuring, commissioning and operating servers and computers, but could include any of the services listed above.

Request IR-75:

With respect to GP01 (CI 49861 – IT - PI System Upgrade):

(a) Please explain the decisions to select OSIsoft as a software provider and ADM Systems Engineering LTD. as a consultant.

(b) Please provide a quotation and/or other supporting cost details associated with the cost for "Technical PM Lead" in the amount of $100,000.

(c) What does the estimated cost of $70,000 for computer hardware include?

(d) Please confirm whether the PI system project relates to the Enterprise Resource Planning system application, and if so, please advise why it is filed as a separate CI.

Response IR-75:

(a) The PI system is a proprietary system supplied by OSISoft with only two (2) other direct competitors. There are many linkages to this system across the business, from custom interfaces developed for and by individual users, to high-level monitoring programs such as PdP (predictive pattern recognition). Changing to a new software product with similar capabilities would require significant effort to re-create these linkages, as well as re-training of personnel to utilize the new software. This option is an upgrade as opposed to a replacement.

ADM Systems Engineering Ltd. is a Dartmouth-based engineering company whose primary business is PI software installation, upgrades and consulting for large industrial customers. They are a certified OSISoft partner, and capable of providing the expertise available directly through OSISoft (based in Montreal), while being located locally which both optimizes communication and responsiveness, and minimizes travel costs. Commitment to ADM or any other provider will follow standard procurement processes.

(b) The policy of NS Power's Information Technology (IT) department is to ensure significant upgrade projects have consistent and effective oversight in the form of a Technical PM Lead. This role ensures the goals of the project are met, while working to maintain schedule and budget. The estimate is based on the range of rates available through an existing MSA (Master Service Agreement), and an estimate of approximately 50% of a Project Manager's time for twelve (12) months (expected duration of project execution).

(c) The estimated cost of $70,000 for computer hardware includes the following:

- Two (2) production servers to ensure high availability
- One (1) test server
- One (1) development server with the operating systems installed

(d) The PI Upgrade project is not related to the Enterprise Resource Planning system application. PI is a data historian application system for operating data.

Request IR-76:

With respect to GP02 (CI 46572 – 2017 RTU Replacement Program), please list the locations where these new Remote Terminal Units will be deployed.

Response IR-76:

The scope of work for CI 46572 is for the replacement of four RTUs. NS Power plans to deploy new replacement Remote Terminal Units at 129H Kearney Lake, 43V Canaan Road, 50W Milton and 91H Tufts Cove CT.

Request IR-77:

With respect to GP03 (CI 48774 – HYD Milton Shop HVAC Upgrade):

(a) Has NSPI determined whether any other similar facilities require upgrading in the same manner as the Milton Hydro Maintenance shop? If yes, please advise how NSPI proposes to address them.

(b) Please explain why it is estimated to be 20% more costly to go with a single large HVAC unit supplying multiple zones.

Response IR-77:

(a) NS Power does not have other facilities that require upgrading in the same manner as the Milton Hydro Maintenance Shop.

(b) Each zone has its own requirements and constraints, which make a single unit operation complex and expensive. The more cost effective option was to specify equipment to handle the requirements each specific zone. The 20% estimate was based on the third party consultant report, which is included as Attachment 1 as part of the capital project filing within the 2017 ACE Plan.

Request IR-78:

With respect to GP04 (CI 50071 – T&D Inspection Application Upgrade Phase 1), please provide the scope of work for Phase 1 and Phase 2 of this project.

Response IR-78:

Phase 1 includes the transition from ArcGIS Mobile (an approaching end-of-life application) to ArcGIS Collector to support the transmission and distribution inspection programs. Collector will be used for the development of the new detailed distribution feeder inspection tools, underground device inspection tools and Polychlorinated Biphenyl (PCB) potential device inspection tools. The existing transmission and distribution inspection programs, currently under the ArcGIS Mobile application, will be transitioned to the ArcGIS Collector application

The scope of Phase 2 will be finalised in 2017 for expected submission in the 2018 ACE Plan. Preliminary scope includes new inspection tools for transmission clearances and reactive work.

Request IR-79:

With respect to GP06 (CI 49902 – 2017 Telecom Building Replacement – Wittenburg):

(a) Please advise the number of radio site buildings which have been replaced to date.

(b) Please advise the number of radio site buildings remaining to be replaced.

(c) Please indicate when all replacements are anticipated to be completed.

Response IR-79:

(a) Two radio site buildings replacements have been completed to date (CI 43174 – Horton Lake and CI 44972 – Mt. Pleasant) and one building replacement is currently in progress at Maple Ridge (CI 46306).

(b) In addition to the CI 49902 radio site building replacement (Wittenburg), there are four buildings remaining to be replaced. These buildings are located in Onslow, Sackville, Great Hill, and Wreck Cove.

(c) All radio site building replacements are anticipated to be completed by 2022.