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Request IR-1:

Please provide the data represented in the figures on page 88.

Response IR-1:

The 2014 Sustaining Capital Forecast data can be found in Attachment 1, also provided electronically.

The table comparing the IRP long-term sustaining capital assumption to ACE 2016 is based on the following data:

Asset Class	IRP ($)	ACE 2016 ($)
Balance of Plant	9,250,000	8,817,391
Generator	2,750,000	3,744,986
Fuel Systems	2,233,750	6,093,358
Boiler	9,471,250	12,231,919
Turbine	10,925,000	8,740,469
Combustion Turbines	5,500,000	9,477,875
Environment	6,725,000	15,249,678
Cooling Water	425,000	4,146,457
Feedwater/Chemical	1,750,000	1,419,203
Instrumentation/Electrical	2,200,000	3,268,979

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Asset Class	Year	Investment
Boiler	2015	7,808,750
Boiler	2016	9,471,250
Boiler	2017	5,731,875
Boiler	2018	6,575,625
Boiler	2019	6,825,625
Boiler	2020	8,263,125
Boiler	2021	7,606,875
Boiler	2022	10,263,125
Boiler	2023	5,263,125
Boiler	2024	5,263,125
Boiler	2025	5,186,250
Boiler	2026	6,236,250
Boiler	2027	10,186,250
Boiler	2028	5,186,250
Boiler	2029	4,717,500
Boiler	2030	4,248,750
Boiler	2031	6,736,250
Boiler	2032	4,373,875
Boiler	2033	9,171,875
Boiler	2034	3,703,125
Boiler	2035	3,703,125
Boiler	2036	4,753,125
Boiler	2037	3,703,125
Boiler	2038	3,703,125
Boiler	2039	3,703,125
Boiler	2040	3,703,125
New Combustion Turbine 50 MW 1	2035	250,000
New Combustion Turbine 50 MW 1	2036	250,000
New Combustion Turbine 50 MW 1	2037	250,000
New Combustion Turbine 50 MW 1	2038	250,000
New Combustion Turbine 50 MW 1	2039	250,000
New Combustion Turbine 50 MW 2	2039	250,000
Combustion Turbines	2015	3,000,000
Combustion Turbines	2016	3,000,000
Combustion Turbines	2017	3,000,000
Combustion Turbines	2018	3,000,000
Combustion Turbines	2019	3,000,000
Combustion Turbines	2020	3,000,000
Combustion Turbines	2021	3,000,000
Combustion Turbines	2022	3,000,000
Combustion Turbines	2023	3,000,000
Combustion Turbines	2024	3,000,000
Combustion Turbines	2025	3,000,000
Combustion Turbines	2026	3,000,000
Combustion Turbines	2027	3,000,000
Combustion Turbines	2028	3,000,000

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Asset Class	Year	Investment
Combustion Turbines	2029	3,000,000
Combustion Turbines	2030	3,000,000
Combustion Turbines	2031	3,000,000
Combustion Turbines	2032	3,000,000
Combustion Turbines	2033	3,000,000
Combustion Turbines	2034	3,000,000
Combustion Turbines	2035	3,000,000
Combustion Turbines	2036	3,000,000
Combustion Turbines	2037	3,000,000
Combustion Turbines	2038	3,000,000
Combustion Turbines	2039	3,000,000
Combustion Turbines	2040	3,000,000
Cooling Water	2015	1,962,500
Cooling Water	2016	425,000
Cooling Water	2017	553,125
Cooling Water	2018	1,600,000
Cooling Water	2019	3,225,000
Cooling Water	2020	1,525,000
Cooling Water	2021	3,750,000
Cooling Water	2022	512,500
Cooling Water	2023	1,962,500
Cooling Water	2024	6,012,500
Cooling Water	2025	2,431,250
Cooling Water	2026	3,375,000
Cooling Water	2027	493,750
Cooling Water	2028	1,775,000
Cooling Water	2029	3,150,000
Cooling Water	2030	1,275,000
Cooling Water	2032	371,875
Cooling Water	2033	1,462,500
Cooling Water	2034	4,025,000
Cooling Water	2035	1,131,250
Cooling Water	2037	343,750
Cooling Water	2038	1,368,750
Cooling Water	2039	1,525,000
Cooling Water	2040	671,875
Environment & Emissions	2015	6,725,000
Environment & Emissions	2016	6,725,000
Environment & Emissions	2017	10,400,000
Environment & Emissions	2018	7,725,000
Environment & Emissions	2019	6,725,000
Environment & Emissions	2020	6,525,000
Environment & Emissions	2021	3,962,500
Environment & Emissions	2022	3,962,500
Environment & Emissions	2023	3,962,500
Environment & Emissions	2024	3,962,500

Asset Class	Year	Investment
Environment & Emissions	2025	3,887,500
Environment & Emissions	2026	3,887,500
Environment & Emissions	2027	3,887,500
Environment & Emissions	2028	3,887,500
Environment & Emissions	2029	3,587,500
Environment & Emissions	2030	3,287,500
Environment & Emissions	2031	3,287,500
Environment & Emissions	2032	3,212,500
Environment & Emissions	2033	3,212,500
Environment & Emissions	2034	2,875,000
Environment & Emissions	2035	2,875,000
Environment & Emissions	2036	2,875,000
Environment & Emissions	2037	2,875,000
Environment & Emissions	2038	2,875,000
Environment & Emissions	2039	2,875,000
Environment & Emissions	2040	2,875,000
Fuel Systems	2015	2,233,750
Fuel Systems	2016	2,233,750
Fuel Systems	2017	2,205,000
Fuel Systems	2018	2,138,750
Fuel Systems	2019	2,138,750
Fuel Systems	2020	2,006,250
Fuel Systems	2021	2,006,250
Fuel Systems	2022	2,006,250
Fuel Systems	2023	2,006,250
Fuel Systems	2024	2,006,250
Fuel Systems	2025	1,977,500
Fuel Systems	2026	1,977,500
Fuel Systems	2027	1,977,500
Fuel Systems	2028	1,977,500
Fuel Systems	2029	1,778,750
Fuel Systems	2030	1,580,000
Fuel Systems	2031	1,580,000
Fuel Systems	2032	1,551,250
Fuel Systems	2033	1,551,250
Fuel Systems	2034	1,352,500
Fuel Systems	2035	1,352,500
Fuel Systems	2036	1,352,500
Fuel Systems	2037	1,352,500
Fuel Systems	2038	1,352,500
Fuel Systems	2039	1,352,500
Fuel Systems	2040	1,352,500
Feed Water	2015	1,750,000
Feed Water	2016	1,750,000
Feed Water	2017	1,700,000
Feed Water	2018	1,750,000

Asset Class	Year	Investment
Feed Water	2019	1,750,000
Feed Water	2020	1,650,000
Feed Water	2021	1,650,000
Feed Water	2022	1,650,000
Feed Water	2023	1,650,000
Feed Water	2024	1,650,000
Feed Water	2025	1,600,000
Feed Water	2026	1,600,000
Feed Water	2027	1,600,000
Feed Water	2028	1,600,000
Feed Water	2029	1,450,000
Feed Water	2030	1,300,000
Feed Water	2031	1,300,000
Feed Water	2032	1,250,000
Feed Water	2033	1,250,000
Feed Water	2034	1,100,000
Feed Water	2035	1,100,000
Feed Water	2036	1,100,000
Feed Water	2037	1,100,000
Feed Water	2038	1,100,000
Feed Water	2039	1,100,000
Feed Water	2040	1,100,000
Generator	2015	3,950,000
Generator	2016	2,750,000
Generator	2017	1,000,000
Generator	2018	4,000,000
Generator	2020	4,000,000
Generator	2021	5,625,000
Generator	2022	3,100,000
Generator	2025	1,375,000
Generator	2026	300,000
Generator	2027	1,000,000
Generator	2028	500,000
Generator	2030	875,000
Generator	2033	2,000,000
Instrumentation & Electrical	2015	6,800,000
Instrumentation & Electrical	2016	2,200,000
Instrumentation & Electrical	2017	3,900,000
Instrumentation & Electrical	2018	3,500,000
Instrumentation & Electrical	2019	1,500,000
Instrumentation & Electrical	2020	3,350,000
Instrumentation & Electrical	2021	2,500,000
Instrumentation & Electrical	2022	2,100,000
Instrumentation & Electrical	2023	3,350,000
Instrumentation & Electrical	2024	1,000,000
Instrumentation & Electrical	2025	4,350,000

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Asset Class	Year	Investment
Instrumentation & Electrical	2026	1,500,000
Instrumentation & Electrical	2027	1,800,000
Instrumentation & Electrical	2028	3,650,000
Instrumentation & Electrical	2029	1,500,000
Instrumentation & Electrical	2030	3,350,000
Instrumentation & Electrical	2031	2,500,000
Instrumentation & Electrical	2032	1,500,000
Instrumentation & Electrical	2033	2,950,000
Instrumentation & Electrical	2034	1,000,000
Instrumentation & Electrical	2035	3,750,000
Instrumentation & Electrical	2036	1,800,000
Instrumentation & Electrical	2037	300,000
Instrumentation & Electrical	2038	2,250,000
Instrumentation & Electrical	2039	1,500,000
LM 6000	2015	2,500,000
LM 6000	2016	2,500,000
LM 6000	2017	2,500,000
LM 6000	2018	2,500,000
LM 6000	2019	2,500,000
LM 6000	2020	2,500,000
LM 6000	2021	2,500,000
LM 6000	2022	2,500,000
LM 6000	2023	2,500,000
LM 6000	2024	2,500,000
LM 6000	2025	2,500,000
LM 6000	2026	2,500,000
LM 6000	2027	2,500,000
LM 6000	2028	2,500,000
LM 6000	2029	2,500,000
LM 6000	2030	2,500,000
LM 6000	2031	2,500,000
LM 6000	2032	2,500,000
LM 6000	2033	2,500,000
LM 6000	2034	2,500,000
LM 6000	2035	2,500,000
LM 6000	2036	2,500,000
LM 6000	2037	2,500,000
LM 6000	2038	2,500,000
LM 6000	2039	2,500,000
LM 6000	2040	2,500,000
Other	2015	9,250,000
Other	2016	9,250,000
Other	2017	9,000,000
Other	2018	8,750,000
Other	2019	8,750,000
Other	2020	8,250,000

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Asset Class	Year	Investment
Other	2021	8,250,000
Other	2022	8,250,000
Other	2023	8,250,000
Other	2024	8,250,000
Other	2025	8,000,000
Other	2026	8,000,000
Other	2027	8,000,000
Other	2028	8,000,000
Other	2029	7,250,000
Other	2030	6,500,000
Other	2031	6,500,000
Other	2032	6,250,000
Other	2033	6,250,000
Other	2034	5,500,000
Other	2035	5,500,000
Other	2036	5,500,000
Other	2037	5,500,000
Other	2038	5,500,000
Other	2039	5,500,000
Other	2040	5,500,000
Turbine	2015	10,925,000
Turbine	2016	10,925,000
Turbine	2017	6,900,000
Turbine	2018	875,000
Turbine	2019	9,875,000
Turbine	2020	6,825,000
Turbine	2021	9,825,000
Turbine	2022	825,000
Turbine	2023	6,825,000
Turbine	2024	6,825,000
Turbine	2025	10,800,000
Turbine	2026	800,000
Turbine	2027	9,000,000
Turbine	2028	800,000
Turbine	2029	13,725,000
Turbine	2030	650,000
Turbine	2031	650,000
Turbine	2032	625,000
Turbine	2033	6,625,000
Turbine	2034	550,000
Turbine	2035	9,550,000
Turbine	2036	550,000
Turbine	2037	9,550,000
Turbine	2038	550,000
Turbine	2039	550,000
Turbine	2040	550,000

NON-CONFIDENTIAL

Request IR-2:

Please explain whether the ash pond costs discuss at p. 89 are reported as part of "environment" in the stacked bar chart on p. 88, and if not, explain the changes in the environmental category from the IRP to the ACE and explain where the ash-pond costs are reported in the chart.

Response IR-2:

The ash site investment being undertaken in 2016 is included in the Environment category on page 88.

NON-CONFIDENTIAL

Request IR-3:

Please describe the projects in the cooling water category in the stacked bar chart on p. 88, and explain the changes this category from the IRP to the ACE.

Response IR-3:

The projects included in this asset category include investment in cooling water (CW) pumps, screens, condenser and a debris removal system.

The increase in the 2016 ACE Plan compared to the IRP assumption is largely driven by the debris removal system and a cofferdam outer cell refurbishment that was not included in the 2016 forecast as part of the levelized IRP capital forecast.

Request IR-4:

Regarding the comparison of the IRP and ACE generation investments on p. 89:

(a) Please provide the values graphed in this figure and reconcile those values with the costs in the tables on pp. 93–99.

(b) Please explain why the Common costs Lingan, Trenton and Tufts Cove were zero in the IRP and substantial in the ACE plan.

(c) Please explain whether the Common costs for Lingan and Trenton are dominated by the ash ponds for those plants, and if not, please explain the nature of those common costs.

(d) Please explain whether the ACE common costs for Tufts Cove consist primarily of the auxiliary boiler and identify the other costs in this category.

(e) Please identify the portions of the increase in the capital costs from the IRP to ACE for Pt. Aconi and Pt. Tupper that are related to the ash ponds for those plants.

Response IR-4:

(a) Please refer to the following table for the values used in the figure on Page 89. These figures cannot be reconciled to the ranking lists on Pages 93-99 as the table below includes all capital investment in 2016 while the lists on Page 93-99 only include new individual capital projects and exclude routine and carryover projects.

Unit	IRP ($)	ACE 2016 ($)
Gas Turbines	5,500,000	7,891,819
Lingan Common	-	7,406,150
Lingan Unit 1	1,998,750	1,038,765
Lingan Unit 2	666,250	-
Lingan Unit 3	2,815,000	1,791,168
Lingan Unit 4	16,365,000	13,222,797
Pt Aconi	6,390,000	9,926,137
Pt. Tupper	2,740,000	5,894,774
Port Hawkesbury Biomass	1,440,000	1,100,825
Trenton Unit 5	2,905,000	4,565,400
Trenton Unit 6	4,440,000	1,049,971
Trenton Common	-	8,095,959
Tufts Cove Unit 1	530,625	2,532,325
Tufts Cove Unit 2	530,625	1,291,182
Tufts Cove Unit 3	3,061,250	2,534,798
Tufts Cove Unit 6	1,847,500	334,159
Tufts Cove Common	-	4,514,088

(b) Please refer to NSUARB IR-31.

(c) The common costs for Trenton are primarily ash site investment costs in 2016. Lingan common costs are made up of multiple projects focused on assets such as coal handling structures, stack, and buildings. Included in these common categories are projects related to Cooling Water (CW) screens, CW Pumps and coal mills. As the specific units on which these projects will be undertaken are not known at the time of the filing of the ACE Plan, they are classified as common. Based on the age and use of these components, annual refurbishment/replacement of a number of these components is necessary. Which components are in need of refurbishment/replacement is not known until further scoping is completed throughout the year. However, when the work is completed, they are allocated to the applicable unit.

(d) The auxiliary boiler is the main driver of costs in Tufts Cove common, accounting for approximately 2/3 of the costs; however, there are also costs related to asbestos, roofing and chemical assets that are applicable to all Tufts Cove units.

(e) The ash site investment at Pt. Aconi is responsible for $3 million of the $3.5 million increase from IRP to ACE. There is no significant ash site investment at Pt. Tupper in 2016.

CONFIDENTIAL (Attachment Only)

Request IR-5:

Please provide the Plexos model runs that demonstrate that "the optimum size of capacitor bank that would minimize the fuel cost was found to be 100 MVAR" and that "Upgrading to higher than 100 MVAR will not have further significant fuel savings." (CI 46587, p. 619)

Response IR-5:

The results of the Plexos study that demonstrates the optimal size of the capacitor bank to minimize fuel cost is included in Partially Confidential Attachment 1, also provided electronically.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

$000		Cap Bank Additions		
	Base Case	50 Mvar	100 Mvar	150 Mvar
Fuel and Import Power Cost	[redacted]			
Value of cap bank additions	-	1,700	3,400	3,500
Incremental value of 50 to 100 Mvar total	-	-	1,700	
Incremental value of 100 to 150 Mvar total	-	-	-	100

Cap Bank Addition 2016 [+ 50 Mvar]

2016 Base Case

Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Market	NB - exports	-	Revenue	1	2016	[redacted]
System	Market	NB - exports	-	Cost	1	2016	[redacted]
System	Market	NB - imports firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports firm	-	Cost	1	2016	[redacted]
System	Market	NB - imports non firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports non firm	-	Cost	1	2016	[redacted]
Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Region	Nova Scotia	-	Generation Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Generator Start & Shutdown Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Abatement Cost	1	2016	[redacted]
						BASE	
						Total Cost	[redacted]

2016 Cap Bank 50Mvar

Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Market	NB - exports	-	Revenue	1	2016	[redacted]
System	Market	NB - exports	-	Cost	1	2016	[redacted]
System	Market	NB - imports firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports firm	-	Cost	1	2016	[redacted]
System	Market	NB - imports non firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports non firm	-	Cost	1	2016	[redacted]
Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Region	Nova Scotia	-	Generation Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Generator Start & Shutdown Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Abatement Cost	1	2016	[redacted]
						Cap Bank 50Mvar	
						Total Cost	[redacted]
						Value	**$1,742**

Cap Bank Addition 2016 [+ 100 Mvar]

2016 Base Case

Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Market	NB - exports	-	Revenue	1	2016	[redacted]
System	Market	NB - exports	-	Cost	1	2016	[redacted]
System	Market	NB - imports firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports firm	-	Cost	1	2016	[redacted]
System	Market	NB - imports non firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports non firm	-	Cost	1	2016	[redacted]
Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Region	Nova Scotia	-	Generation Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Generator Start & Shutdown Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Abatement Cost	1	2016	[redacted]

BASE	
Total Cost	[redacted]

2016 Cap Bank 100Mvar

Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Market	NB - exports	-	Revenue	1	2016	[redacted]
System	Market	NB - exports	-	Cost	1	2016	[redacted]
System	Market	NB - imports firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports firm	-	Cost	1	2016	[redacted]
System	Market	NB - imports non firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports non firm	-	Cost	1	2016	[redacted]
Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Region	Nova Scotia	-	Generation Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Generator Start & Shutdown Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Abatement Cost	1	2016	[redacted]

Cap Bank 100Mvar	
Total Cost	[redacted]
Value	3,406

Cap Bank Addition (with SVC) 2016 [+ 100 Mvar]

Cap Bank 50Mvar	
Total Cost	[redacted]

Cap Bank 100Mvar	
Total Cost	[redacted]
Value	1,664

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Cap Bank Addition 2016 [+ 150 Mvar]

2016 Bace Case

Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Market	NB - exports	-	Revenue	1	2016	[redacted]
System	Market	NB - exports	-	Cost	1	2016	[redacted]
System	Market	NB - imports firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports firm	-	Cost	1	2016	[redacted]
System	Market	NB - imports non firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports non firm	-	Cost	1	2016	[redacted]
Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Region	Nova Scotia	-	Generation Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Generator Start & Shutdown Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Abatement Cost	1	2016	[redacted]

BASE	
Total Cost	[redacted]

2016 Cap Bank +150Mvar

Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Market	NB - exports	-	Revenue	1	2016	[redacted]
System	Market	NB - exports	-	Cost	1	2016	[redacted]
System	Market	NB - imports firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports firm	-	Cost	1	2016	[redacted]
System	Market	NB - imports non firm	-	Revenue	1	2016	[redacted]
System	Market	NB - imports non firm	-	Cost	1	2016	[redacted]
Parent Name	Collection	Child Name	Category	Property	Band	Datetime	Value
System	Region	Nova Scotia	-	Generation Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Generator Start & Shutdown Cost	1	2016	[redacted]
System	Region	Nova Scotia	-	Abatement Cost	1	2016	[redacted]

7-b Cap Bank +150Mvar	
Total Cost	[redacted]
Value	**3,532**

Cap Bank Addition 2016 [+ 100 Mvar]

Cap Bank +50Mvar	
Total Cost	[redacted]

Cap Bank +100Mvar	
Total Cost	[redacted]
Value	**1,664**

Cap Bank Addition 2016 [+ 150 Mvar]

Cap Bank +50Mvar	
Total Cost	[redacted]

Cap Bank +150Mvar	
Total Cost	[redacted]
Value	**1,791**

7- Cap Bank Addition (with SVC) 2016 [+ 150 Mvar]

Cap Bank 100Mvar	
Total Cost	[redacted]

Cap Bank +150Mvar	
Total Cost	[redacted]
Value	**$126.41**

Request IR-6:

Please explain the relationship among CI 46587 (installation of 50 MVAR capacitors at Sackville and Lakeside), CI 48025 (the capacitor on the upgraded L7018), CI 48024 (addition of capacitor at Sackville) and CI 48023 (addition of capacitor at Lakeside).

(a) Do CI 48023 and 48024 include additional capacitors beyond those in CI 46587?

(b) Do the costs for CI 48023 and 48024 include any costs for the CI 46587 capacitors or their installation?

(c) Can CI 46587 be completed without CI 48023 and 48024? If not, what is the point of requesting approval of CI 46587 without the other two projects?

(d) How did NS Power determine that the set of capacitors to be added in these projects would be effective and cost-effective?

Response IR-6:

CI 46587 was identified as the first phase of reducing the requirement to run Tuft's Cove generation to support steady state voltage levels in the Metro Halifax area. Further study was required to complete system studies and validate the economic benefits to increase the Onslow South transfer level (phase 2) and further reduce the requirement to dispatch Tuft's Cove generation uneconomically for system voltage support. CI 48023 and CI 48025 are part of the other related CIs that will be subsequently submitted for approval as part of phase 2.

(a) Yes.

(b) No.

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(c) Yes.

(d) NS Power utilized the Plexos modeling tool to identify the avoided generation costs associated with reducing the requirement to run Tuft's Cove generation to support system voltage during high system load. The economic analysis model provided in CI 46587 identifies a positive net present value (NPV) due to avoided generation costs resulting from these capital investments.

NON-CONFIDENTIAL

Request IR-7:

Please explain how CI 48022 (Spider Lake Substation Addition) and the L7018 Upgrade to 345kV in CI 48025 are related to CI 46587.

(a) Specifically, do any of these projects require one or both of the other projects?

Response IR-7:

CI 48022 (Spider Lake Substation Addition) and CI 48025 (L-7018 upgrade to 345kV) are also part of the related CIs that have been identified to further reduce the requirement to dispatch Tuft's Cove generation as part of phase 2. Please also refer to CA IR-6.

(a) CI 46587 does not require completion of the referenced projects to deliver the benefits identified in the capital project justification.

Request IR-8:

Comparing the Investment Type Table (Section 1.1 Sustaining Capital, page 8) to the similar table in ACE 2015, there is a cumulative increase of $84.3 million in "Sustaining Capital" for the years 2016–2019. Please explain the changes between the 2015 ACE and 2016 ACE for years 2016-2019.

Response IR-8:

For the description of the change for 2016-2018, please refer to NSUARB IR-10.

2019 has stayed relatively stable from the 2015 ACE Plan to the 2016 ACE Plan.

Request IR-9:

Please explain the large jump in forecasted Generation capital spending in 2018 (Section 1.4 Capital Spending, Total Annual Capital Expenditures by Function, page 16).

Response IR-9:

The increase in forecasted Generation capital spending in 2018 is primarily due to an overhaul of the Wreck Cove generating units, estimated at approximately $60 million. Additionally, a $20 million investment as part of the Mersey Hydro System re-development project is also forecasted to occur in 2018.

Request IR-10:

Section 2.3, Distribution CI# 47124, Automated Metering Infrastructure shows a 2016 ACE budget of $7 million with a project total cost of $100 million.

(a) Please state when NS Power started its AMI program and how much NS Power has invested annually in AMI.

(b) Please describe the technological components of NS Power's AMI program.

(c) Does the AMI program include installation of interval meters, suitable for time-of-use and real-time pricing?

(d) Please provide any overall description of the AMI project that NS Power has prepared.

(e) Please identify any Orders or Decisions that the Board has issued regarding an AMI program.

(f) How many advanced meters have been deployed?

(g) Please provide the percentage of customers with AMI, by class.

Response IR-10:

(a) NS Power has considered an Advanced Metering Infrastructure (AMI) project in the past, but technology maturity and cost were determined to be prohibitive. A pilot project was conducted in 2006 and 2007 under CI 26404 – Automated Meter Reading (AMR). The project was completed in 2007. These meters are still in service today. A subsequent project was initiated under CI 32622 – Automated Metering Infrastructure to Production.

This project was for the purpose of transferring meter readings for billing purposes. The project was completed in 2010. The annual investment in these two projects is tabulated below.

Year	26404-P710 ($)	32622-P786 ($)	Total by Year ($)
2006	214,899		214,899
2007	6,228		6,228
2008	(373)		(373)
2009		45,881	45,881
2010		13,503	13,503
Project Total	**220,755**	**59,384**	**280,140**

NS Power began re-evaluating the AMI opportunity in July 2015. Efforts on the project to date have been limited to draft business case development. No AMI infrastructure has been procured or installed under this project to date.

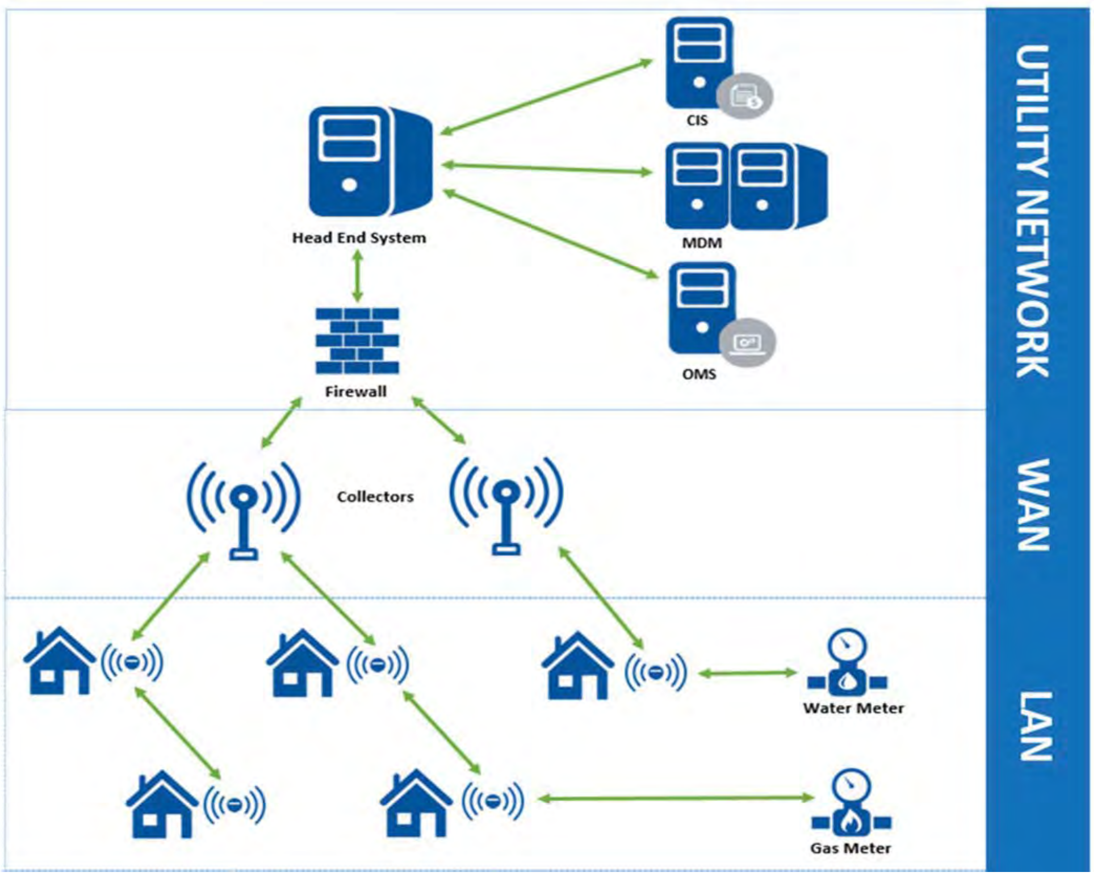
(b) As part of the project evaluation, a variety of AMI technology elements are being considered, but no decisions have been made to date. Typically an AMI system may be comprised of the following components and is shown in the diagram below:

- Measurement Technology (meters) – smart meters with two-way communication capability.

- Communications Technology & Networks – local area network (LAN) and wide area network (WAN) comprised of collectors, repeaters and gateways transports data to and from meters to head end.

- Head End – hardware and software that receives the stream of meter data brought back to the utility through the AMI.

- Meter Data Management System – MDM system performs long term data storage and management for data delivered by AMI systems. This data consists primarily of usage data and events that are imported from the head end. An MDM system will typically import the data, then validate, cleanse and process it before making it available for billing and analysis, or other applications.



(c) NS Power anticipates that an AMI project would include the installation of interval meters.

(d) The scope of the AMI project has not been finalized, and NS Power has not prepared a project description.

(e) Two Way Automated Communication System (TWACS) Automated Metering Infrastructure was installed as a pilot system in the Hubbards Substation in late 2006 under CI 26404 – Automated Meter Reading (AMR) included in the 2006 ACE plan and approved in the 2006 ACE Plan Order dated June 6, 2006 (NSPI-P-128.06). In early 2007, NS Power completed the installation of approximately 400 AMI meters on difficult to access customers in the area. Phase 2 of this project, CI 28400 – AMR Project Phase II, was submitted in the 2007 ACE Plan and was also approved in the 2007 ACE Plan Order dated May 17, 2007 (NSUARB-NSPI-P-128.07), but the project was not initiated.

CI 32622 – Automated Metering Infrastructure to Production was included in the 2009 ACE Plan as a General Plant item to implement the required hardware redundancy and implement business processes to bring the TWACS system to the level of a full production system, and interface it with the Customer Information System (CIS) for the purpose of transferring meter readings for billing purposes. This project was approved with the 2009 ACE plan and the project was put in service in September 2010.

CI 32304 – AMI Hardware & Software Installation was also included in the 2009 ACE plan, but was deferred in both the 2010 and 2011 ACE plans, and was subsequently cancelled in the 2012 ACE Plan. The project was replaced in the 2012 ACE Plan with two new capital items (CI 41766 Commercial AMI Pilot and CI 41845 Residential AMI Pilot) which were included in the subsequent approval portion of the plan. CI 41766 and CI 41845 were noted as deferred from 2012 to 2013 and were also included in the subsequent approval portion of the 2013 ACE plan. These projects were not brought to the Board for approval. A potential strategic investment in AMI of $100 million over 4 years (2016-2019) was noted in the discussions in Section 1.1 and 8.1.4, which has been included in the 2016 ACE plan as CI 47124. CI 47124 supersedes CI 41766 and CI 41845.

(f) No AMI meters have been deployed under CI 47124. Existing advanced meters currently in service include 400 Two Way Automated Communication System (TWACS) meters from the CI 26404 referenced in part (e) and 667 Automated Meter Reading (AMR) meters deployed for load research, commercial and industrial customers.

(g) Please refer to the table below.

Class	Number of AMI/AMR meters
Residential	663
Commercial	231
Industrial	173
Total	**1,067**

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Request IR-11:

Regarding 47124 Automated Metering Infrastructure (p. 29) "2016 investment will include business case preparation and a possible pilot project to best determine the most beneficial path forward in fully implementing Automated Metering Infrastructure. It is planned to be completed over a 3-4 year window."

(a) Please explain what NS Power plans to complete over 34 years: the pilot project, the business plan, or the AMI implementation.

(b) When does NS Power expect to file this project with the Board?

(c) Please describe any stakeholder consultation that NS Power expects to conduct regarding the AMI program.

Response IR-11:

(a) NS Power plans to complete a full AMI implementation over a 3-4 year period, if the business plan indicates this project is an appropriate investment for customers.

(b) NS Power expects to file this project in the third quarter of 2016, if the business plan indicates this project is an appropriate investment for customers.

(c) If the business plan indicates this project is an appropriate investment for customers, NS Power will determine the nature of its stakeholder consultation once the project scope is finalized and CI 47124 is submitted to the Board for approval.

Request IR-12:

Please answer the following questions, referring to Section 2.3, Distribution CI# 47403, Load Research Sample Update – the project is to add 400 interval meters to the existing sample:

(a) **Please explain how NS Power determined that it needed to increase its load-research sample?**

(b) **How many interval meters have been deployed to date by sector?**

(c) **What are the types and associated costs of the interval meters that have been deployed?**

(d) **How large is the current sample by class?**

(e) **How many load-research meters will be added for each class?**

(f) **How is each sampled class disaggregated by strata?**

(g) **When did NS Power first deploy interval meters to for its load research sample?**

(h) **Please describe the status of updating NS Power load data for the cost-of-service study, as undertaken in the COS proceeding.**

Response IR-12:

(a) This project was initiated as a result of the conclusions reached from the review of the Load Research sample. This review was the result of the conclusions of the 2013 Cost of Service (COS) proceeding. NS Power's response to COS Undertaking U-6 states:

> NS Power will undertake to complete a review of the Load Research sample to confirm its accuracy and make any appropriate adjustments. This undertaking will involve the engagement of a statistician, procurement and installation of meters, data collection for one full calendar year and implementation of data into the COS.

On November 28, 2014, NS Power filed a progress update which included a report from Itron Inc., who was engaged by NS Power to recommend a refreshed sample design for Load Research Data Collection. The Itron report outlines a new sample design with new strata boundaries, an increased number of sample points and the introduction of voltage level segregation, which was recommended by Christensen Associates Energy Consulting (CAEC) during the COS proceeding.

(b-c) NS Power has not yet begun deploying new meters to repopulate the load research sample.

(d) The below table summarizes the number of active contributors by rate class in 2014.

Rate Class	Number of Active Meters
Residential	104
Time of Use	30
Small General	21
General Demand	87
Small Industrial	51
Medium Industrial	42

(e) The below table summarizes the number of new meters required by rate class in order to meet the sample design proposed by Itron.

Rate Class	Number of New Meters Required
Residential	96
Time of Use	120
Small General	89
General Demand	35
Small Industrial	35
Medium Industrial	20

(f) Please refer to Attachment 1 for details on how the number of strata per rate class were chosen and the number of meters required per strata for each rate class.

(g) NS Power first deployed interval meters for the purposes of load research in the mid-1990s.

(h) Please refer to part (a). The purpose of this capital item is to purchase the meters necessary to update the load research sample as a result of the conclusions of NS Power's review which was directed by the Board in its 2013 COS Decision.

NS Power is currently developing the scope of this project and determining appropriate solutions. Meters with integrated analogue modems, which are the type of meters currently supporting NS Power's load research sample, were not available from vendors in 2014 and 2015. Meters with cellular technology are being investigated, and an appropriate technological option for this project will be determined.

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Load Research Sample Design

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November 2014

Contents

Overview

Nova Scotia Power (NSP) contracted Itron to update their load research sample. Their initial sample was designed in 1991. The objective of this project was to evaluate sample accuracy for 2013 and to develop new sample designs based on NSP's 2013 customer base. New samples were developed for the following rate classes:

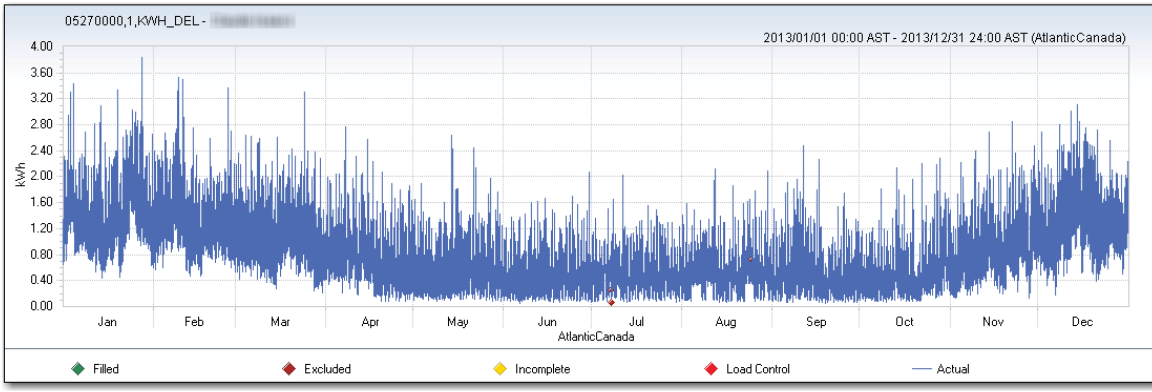
Table 1: NSP Rate Class Descriptions

Rate	Description
Rate 02	Residential Non-Electric Heat
Rate 03	Residential Electric Heat
Rate 06	Residential Time of Day
Rate 10	Commercial Small General
Rate 11	Commercial General Demand
Rate 21	Small Industrial
Rate 22	Medium Industrial

Itron evaluated new load research samples for the secondary and primary distribution customers for Rates 10, 21, and 22. In addition, Itron addressed the impact of potential customer migration from Rate 11 to Rate 10.

Itron's Load Research System (LRS) was used to process NSP's current load research sample, import 2013 customer billing data, and develop 2013 hourly load estimates. New samples were designed using the LRS Sample Design module. LRS includes functionality to import meta data (i.e., characteristics about the customers, including: Service Point ID, address, customer name, etc.) from an MV-90 xi Master File and to import interval data from an MV-90 MDEF (Meter Data Exchange Format) file. Itron populated LRS with meta data and interval data (primarily at the 15-minute frequency) covering the period January 1, 2013 to December 31, 2013 from NSP's current load research sample via these two MV-90 interfaces. Figure 1 shows an example of 15-minute interval data for 2013 from one of the Rate3 (residential electric heat) customers. The data set for the overwhelming majority of sample points was mostly complete, with very few missing observations.

Figure 1: Interval Data for a Residential Electric Heat Sample Point



Current Sample Accuracy

The first task was to develop 2013 class profiles for the current load research sample and evaluate class precision at the time of the winter and summer peaks. The current load research data was expanded to total rate class hourly loads using 2013 monthly customer billing data with the Mean per Unit (*MPU*) expansion method. Figure 2 to Figure 8 shows the resulting profiles.

Figure 2: Residential Non-Electric Heat (Rate 02) Profile

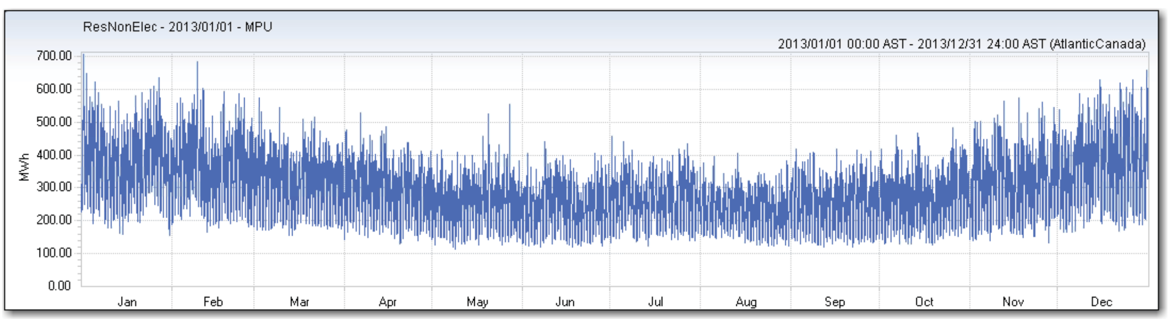


Figure 3: Residential Electric Heat (Rate 03) Profile

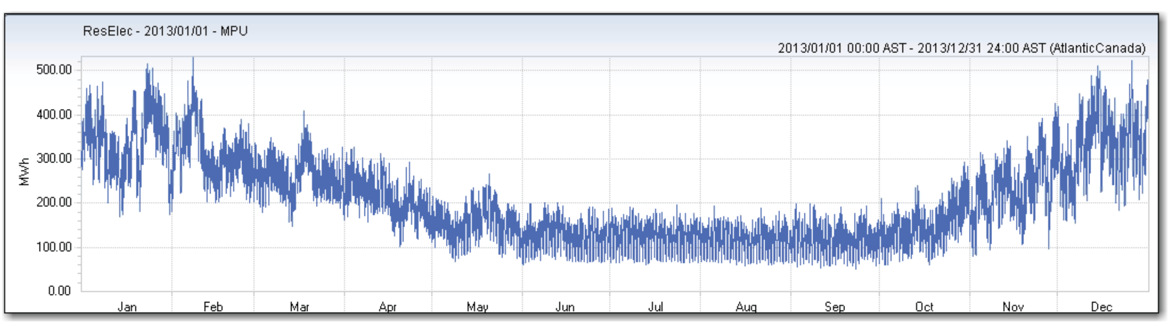


Figure 4: Residential Time of Day (Rate 06) Profile

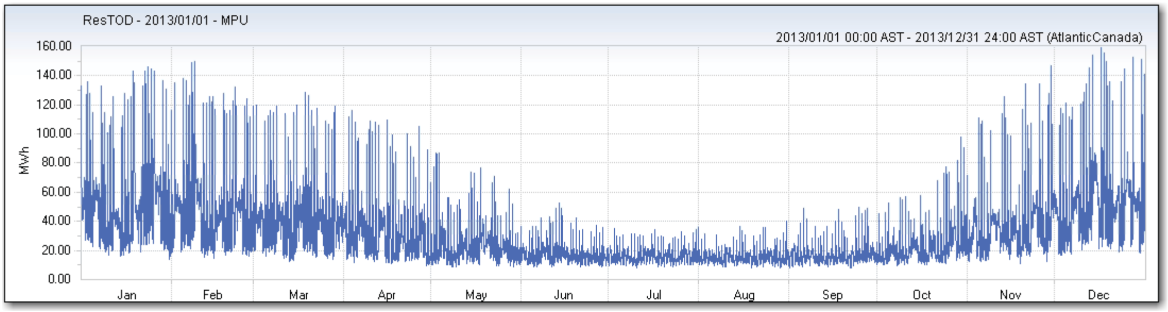


Figure 5: Commercial Small General (Rate 10) Profile

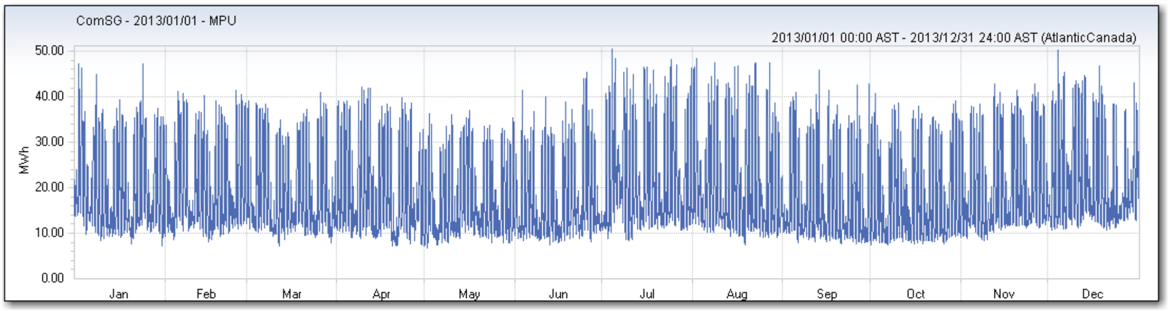


Figure 6: Commercial General Service Demand (Rate 11) Profile

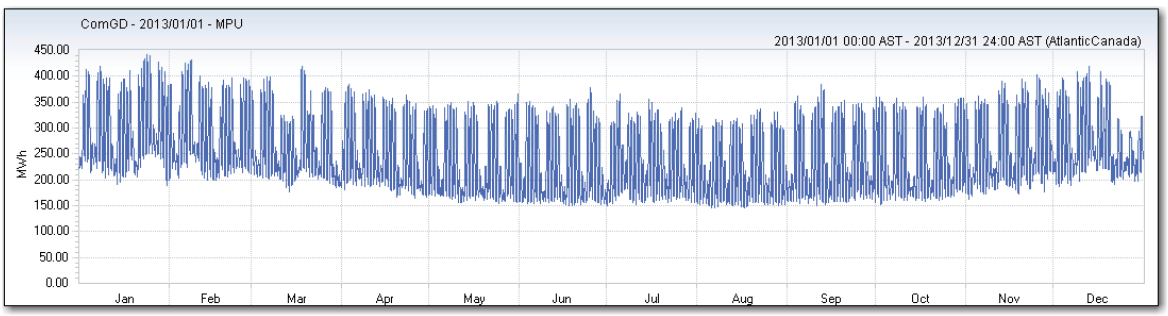


Figure 7: Small Industrial (Rate 21) Profile

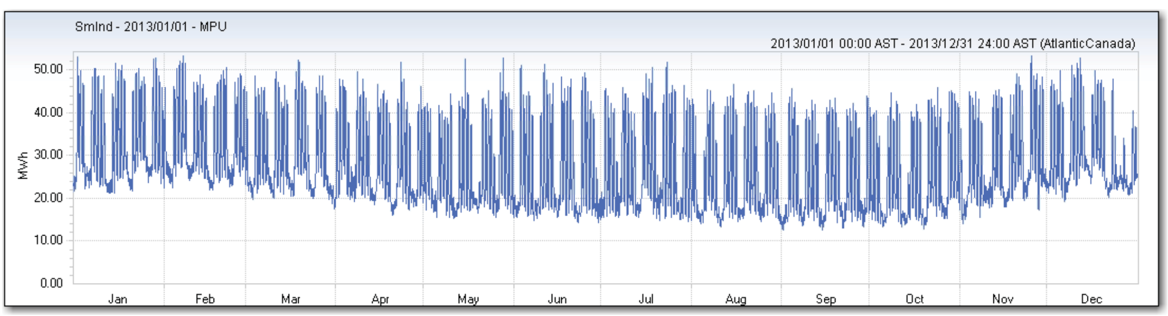
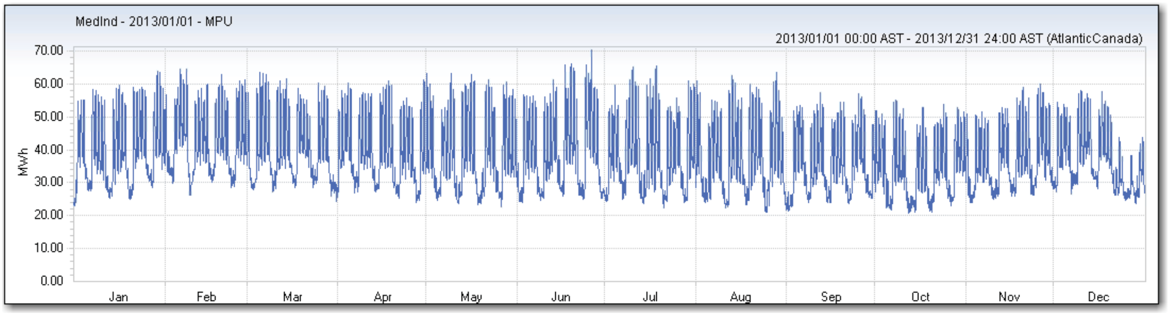


Figure 8: Medium Industrial (Rate 22) Profile



One of the key questions is how accurate are the expanded hourly load profiles. The general approach for assessing profile accuracy is to estimate the precision of the hourly load estimate at the time of the system peak. Precision is a measure of the variance of the expected load at time of peak. The generally accepted design criteria is at the 90% level of statistical confidence and the precision is defined as:

$$RP90\% = \frac{1.65 \times StdErr}{yAvg}$$

Where:

> *yAvg* is the estimated class load at the time of the system peak
> *StdErr* is the calculated standard error around the class peak estimate

As the standard error declines (i.e., less variance around the estimated load at peak), the level of precision increases. The target precision is 10% or lower. At that precision level, we can say that we are 90% confident that the true class coincident peak is within 10% of the estimated class coincident peak demand.

As NSP is a winter-peaking utility, the current sample precision was evaluated for the 2013 winter peak. Coincident peak demand estimates and precision are calculated in LRS reports. The winter peak occurred on January 24 at 7:00 pm. We also calculated the precision for the summer peak. Summer peak occurred on August 28 at 12:00 pm. Table 2 summarizes the resulting winter and summer rate class precision.

Table 2: Estimated Rate Class Precision

ProfileID	Period	Month	Peak Date	Precision
Rate 02	2013 Jan	2013/01	1/24/2013 19:00	19.58%
Rate 02	2013 Aug	2013/08	8/28/2013 12:00	22.81%
Rate 03	2013 Jan	2013/01	1/24/2013 19:00	10.43%
Rate 03	2013 Aug	2013/08	8/28/2013 12:00	20.43%
Rate 06	2013 Jan	2013/01	1/24/2013 19:00	30.34%
Rate 06	2013 Aug	2013/08	8/28/2013 12:00	31.54%
Rate 10	2013 Jan	2013/01	1/24/2013 19:00	37.35%
Rate 10	2013 Aug	2013/08	8/28/2013 12:00	40.56%
Rate 11	2013 Jan	2013/01	1/24/2013 19:00	10.13%
Rate 11	2013 Aug	2013/08	8/28/2013 12:00	14.51%
Rate 21	2013 Jan	2013/01	1/24/2013 19:00	18.55%
Rate 21	2013 Aug	2013/08	8/28/2013 12:00	24.91%
Rate 22	2013 Jan	2013/01	1/24/2013 19:00	12.28%
Rate 22	2013 Aug	2013/08	8/28/2013 12:00	22.84%

The estimated class loads are derived using *Mean per Unit* (*MPU*) expansion. Three of the rate classes, Rate 03, Rate 11, and Rate 22, were very close to meeting the 10% precision target. The other rate classes failed to meet the target precision level largely as a result of the degradation of the initial sample sizes. For Rate 06, another contributing factor has been the changing customer characteristics. Time of Day (TOD) customers are generally larger than in the initial sample design.

Sample Design Summary

The new sample is designed to achieve 10% precision at the 90% confidence level around the 2013 winter peak. The target variable is class demand (kW) at the time of the system peak. Class coincident peak and demand-to-usage ratios are derived from the current load research sample. The population stratification is based on average daily winter use (kWh) over the period January 1, 2013 to March 31, 2013. Population data (customer counts and daily average use) are calculated from 2013 billed sales. The sample design approach is similar to the one used in NSP's current sample design.

Ideally, the entire sample would be replaced by the new sample with newly defined usage strata. Since there are costs associated with deploying meters, we recommend the existing sample be re-stratified (i.e., assign current sample points to the new strata) and additional sample points to be added to the new strata where the existing numbers of sample points fall short of the new target sample size. Over time however, the existing sample customers should be refreshed. Table 3 shows the current level of precision, number of active sample points, proposed sample points, and new sample precision based on the 2013 winter peak.

Table 3: Proposed Load Research Sample

Rate Schedule	Description	Current Winter Pk Precision	Original Sample Size	Current Sample Size	Pct of Original	Proposed Sample Size	Additional Sample Points	New Design Precision
Rate 02	Residential Non-Electric Heat	19.6%	101	52	51.5%	120	68	8.8%
Rate03	Residential Electric Heat	10.4%	90	72	80.0%	80	8	7.1%
Rate 06	Residential TOD	30.3%	40	29	72.5%	150	121	9.8%
Rate 10	Small Commercial	37.4%	45	22	48.9%	110	88	8.8%
Rate 11	Commercial Demand	10.1%	90	89	98.9%	115	26	3.0%
Rate 21	Small Industrial	18.6%	78	48	61.5%	60	12	7.0%
Rate 22	Medium Industrial	12.3%	77	41	53.2%	45	4	8.2%
Total			521	353	67.8%	680	327	

Ultimately, not all the sample meters are likely to have load during all hours and customers are likely to shift across strata over time. To account for potential missing data and customer migration, a slightly higher precision than the 10% precision target was chosen and, in the final design, set a minimum of 20 sample points per stratum.

Methodology

In developing load samples, there are two primary design options. The first is a sample design to support *Mean per Unit* expansion (*MPU*) and the second is to support a *Combined Ratio* (*Ratio*) expansion. Sample size could also be constructed to support *Separate Ratio Expansion*, although it is generally not used as it requires having monthly population consumption data at the strata level on an ongoing basis.

In an *MPU* expansion, each sample point represents a proportion of the population within that stratum. If, for example, the population within a stratum was 10,000 and there were 20 sample points, each sample would represent 500 customers. The population load estimate *YTot* for stratum s would be estimated as:

$$YTot_s = yAvg_s \times N_s$$

Where:

$yAvg_s$ is the sample average (kW) load for stratum *s*
N_s is the total customer count for the stratum *s*

The total class load estimate was derived by adding the sample-expanded loads across the strata. The residential samples were designed for *MPU* expansion. The new Rate 06 sample size is relatively large, as there are many customers with much higher usage than what is reflected in the original sample; the estimated standard error of this rate is consequently quite large, resulting in the need for a large sample to achieve the 10% precision criteria.

While *MPU* and *Ratio* samples were designed for the non-residential rate classes, the proposed non-residential rate class samples are based on *Ratio* sample design. For most non-residential tariffs, the required sample size is significantly smaller using a *Ratio* design. Alternatively, with the current number of sample points, the *Ratio* design provides significantly higher precision.

Ratio expansion takes advantage of the relationship between customer demand (kW) and customer average use (kWh). If the correlation between kW (the target variable) and kWh (the auxiliary variable) is strong, the relationship can be used to design strong load research samples. The ratio of demand to average use (r) is derived from the existing load research data. The ratio is defined as:

$$r_s = \frac{yAvg_s}{xAvg_s}$$

Where:

$yAvg_s$ (kW) is the sample demand estimate for stratum *s*
$xAvg_s$ (kWh) is the sample average use for stratum *s*

The population average demand ($YAvg_s$) for stratum s can then be estimated as:

$$YAvg_s = r_s \times XAvg_s$$

Where:

$XAvg_s$ is the population average use (kWh) in stratum *s*

Total class demand for stratum *s* can be calculated as:

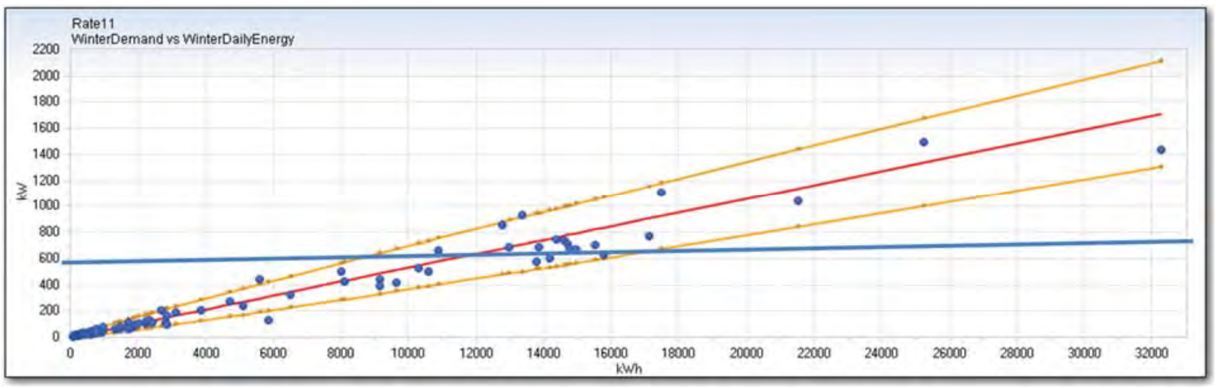
$$YTot_s = YAvg_s \times N_s$$

Where:

N_s is the number of customers in stratum *s*

Most utilities do not maintain monthly rate class sales by strata and use a *Combined Ratio* expansion, in which, *r* is calculated as a weighted average across the sample strata. Total class hourly average demand (*YAvg*) is then calculated as *r* × *XAvg* where *XAvg* is the average monthly usage for the rate class. When there is a strong correlation between customer demand and usage, *Ratio* expansions will result in a smaller variance around the estimated demand and higher sample precision. This is illustrated in the Rate 11 (Commercial General Demand) ratio model shown in Figure 9.

Figure 9: Rate 11 (Commercial General Demand) Ratio Model



The ratio model is estimated using LRS. The model shows the relationship between coincident peak demand (kW) on the Y-axis and daily winter average use (kWh) on the X-axis (red line). The ratio line is similar to a regression model in which peak coincident demand is regressed on daily average winter use. The blue line shows the average coincident peak demand for the sample. The ratio model also provides an estimate of the sample variance that can be used directly in the sample design.

Using an *MPU* expansion, the standard error is calculated around the mean (shown as the horizontal blue line in Figure 9 above). In an *MPU* design, we attempt to reduce the size of the variance by segmenting the population into strata. In a *Ratio* expansion, the variance is calculated around the ratio line; as can be seen in the graph, the variance around the ratio line is significantly smaller than the variance around the average coincident peak.

Sample variance (and the sample size itself) can be reduced by grouping customers by usage level; in general, the variance within a defined stratum (or usage grouping) is smaller than across the entire population. The new sample design was based on customer average daily usage for the 2013 winter (January 1, 2013 to March 31, 2013). Customers were assigned to stratum using the *Dalenious-Hodges* method. *Dalenious-Hodges* method takes into account the number of customers in the rate class and customers usage in determining where to set the strata bounds. This is the most common approach used in load research. Once the breakpoints are determined, the sample size and sample strata allocations were derived using a *Neyman* allocation. A *Neyman* allocation allocates the sample to strata based on the relative share of that stratum's standard deviation to the total sample deviation. *Dalenious-Hodges* determined breakpoints combined with *Neyman* allocation results in an optimal sample design – the smallest sample that achieves the target precision level.

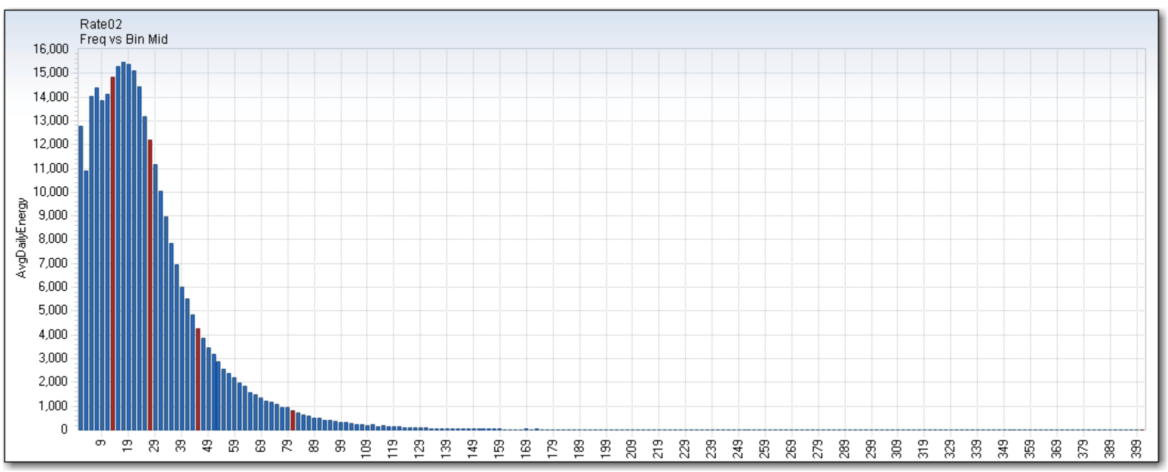
Rate Class Sample Design

Rate 02: Residential Non-Electric Heat

Rate 02 is the NSP residential non-electric heating rate, which includes approximately 300,000 customers. When the sample was initially implemented, there were roughly 240,000 Rate 02 customers. In the original sample design, there were 101 sample points spread evenly across five strata, where the strata are based on daily average winter use. The 2013 winter peak precision for the existing sample is 19.6%. The reason the precision is relatively low (a high percentage) is that only half of the original sample remains.

The new Rate 02 sample is based on an *MPU* design. To improve on sample precision, the Rate 02 customer base was stratified into four strata, where the strata are defined based on customers average daily winter use for January 1, 2013 to March 31, 2013. Stratum breakpoints are derived using the *Dalenious-Hodges* method. Figure 10 shows the breakpoint results. The graph shows the number of customers by usage bin.

Figure 10: Residential Non-Electric Heat (Rate 02) Population Frequency Distribution



We also evaluated five strata breakpoints like that used in the current sample design. We found no significant improvement in overall precision increasing from 4 strata to 5 strata.

From the breakpoint analysis, we calculate population characteristics (the X variables) and estimated load impacts at the time of peak from the sample load research data (the Y variables). These results are for Rate 02 are summarized below in Table 4.

Table 4: Rate 02 Population Characteristics

Stratas	Population	Shr Pop	Xavg	X Std Dev	X CV	Yavg	Y Std Dev	Y CV
0 to 20	137,404	45.7%	14.0	5.2	0.37	1.1	1.1	0.99
20 to 35	89,120	29.6%	25.0	4.8	0.19	1.7	1.0	0.57
35 to 70	60,047	20.0%	51.2	8.7	0.17	3.1	1.0	0.31
70 Plus	14,270	4.7%	86.3	13.2	0.15	6.1	1.8	0.29
All	300,841	100.0%	28.1	20.1	0.71	1.9	1.6	0.83

The population characteristic tables show:

- Population distribution across strata (**Population**)
- Population distribution across strata (**Shr Pop**)
- Average daily use within each strata and for the total rate class (**Xavg**)
- The daily average use standard deviation (**X Std Dev**)
- The coefficient of variation for average daily use (**X CV**)
- The estimated average demand at time of peak (**Yavg**)
- The demand standard deviation at the time of peak (**Y Std Dev**)
- The demand coefficient of variation (**Y CV**)

Table 5 summarizes the resulting *MPU* sample design for a 90% confidence interval.

Table 5: Rate 02 Sample Design

Strata	Population	Shr Pop	n	Precision	Proposed n	Precision	Sample Dist
0 t0 20	137,404	45.7%	40	25.8%	40	25.8%	33.3%
20 to 35	89,120	29.6%	23	19.5%	35	15.8%	29.2%
35 t0 70	60,047	20.0%	15	13.1%	25	10.1%	20.8%
70 plus	14,270	4.7%	6	19.4%	20	10.6%	16.7%
All	300,841	100.0%	84	10.0%	120	8.8%	100.0%

While in theory, 10% precision around the 2013 winter peak requires 84 sample points, we recommend designing for a higher precision level, given the unlikelihood that all the sample points will have available data every hour. A sample size of 120 results in an overall precision of 8.8%. For Rate 02, we recommend a minimum number of meters per stratum of 20; this is similar to the minimum meters per stratum in NSP's original sample design.

To achieve the required sample size cost-effectively, we recommend assigning the existing sample to the new strata and then filling in with additional sample points. Table 6 shows the proposed sample design, the current active sample, and required additional sample points.

Table 6: Rate 02 Sample Allocation

Strata	Proposed	Current	Additional
0 t0 20	40	17	23
20 to 35	35	14	21
35 t0 70	25	13	12
70 plus	20	8	12
All	120	52	68

Rate 03: Residential Electric Heat

The current Rate 03 precision is relatively high. The 2013 winter peak precision is 10.4%; the primary reason is that there are 72 active sample meters from an initial design of 90 load research meters.

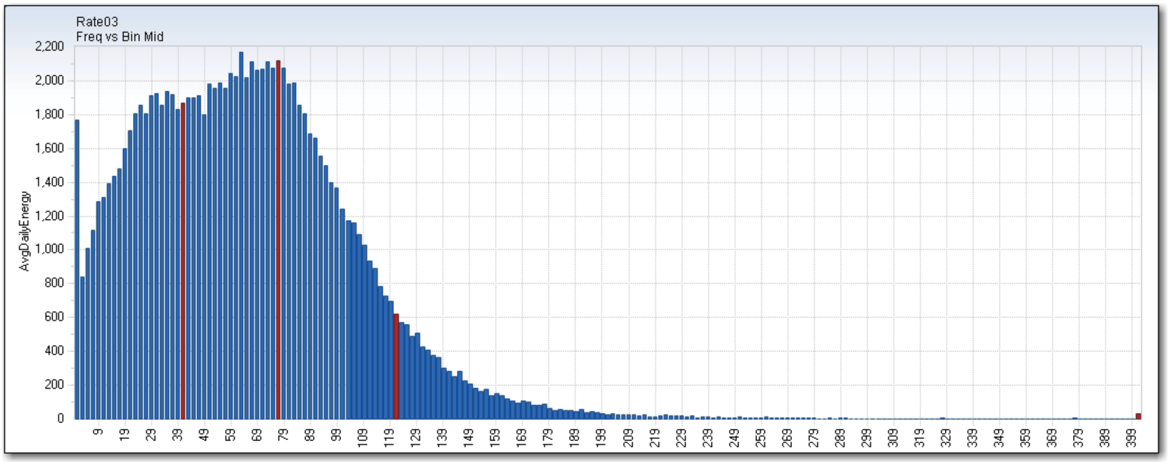
The proposed stratification and population characteristics for Rate 03 are summarized in Table 7.

Table 7: Rate 03 Population Characteristics

Strata	Population	Shr Pop	Xavg	X Std Dev	X CV	Yavg	Y Std Dev	Y CV
0 t0 40	31,146	29.2%	22.4	11.0	0.49	1.6	1.34	0.84
40 to 75	34,927	32.8%	57.9	10.1	0.17	3.7	1.17	0.31
75 t0 120	31,713	29.8%	93.4	12.3	0.13	6.1	2.00	0.33
120 plus	8,725	8.2%	150.2	40.9	0.27	9.6	2.41	0.25
All	106,511	100.0%	65.6	40.4	0.62	4.3	2.87	0.67

The stratification is based on assigning four breakpoints and using the *Dalenious-Hodges* breakpoint method. Figure 11 shows the population frequency distribution.

Figure 11: Rate 03 Population Frequency Distribution



There are approximately 106,500 electric heat customers. The coefficient of variation shows that the relative electric heat usage variation around daily average winter use and peak is lower than non-electric heat. The smaller variance results in a smaller load research sample than that required for non-electric heat. Table 8 shows the Rate 03 proposed sample size with a minimum of 20 sample points assigned to each stratum.

Table 8: Rate 03 Proposed Sample Design

Strata	Population	Shr Pop	Proposed n	Precision	Sample Dist
0 t0 40	31,146	29.2%	20	31.1%	25.0%
40 to 75	34,927	32.8%	20	11.6%	25.0%
75 t0 120	31,713	29.8%	20	12.0%	25.0%
120 plus	8,725	8.2%	20	9.2%	25.0%
All	106,511	100.0%	80	7.1%	100.0%

Once the current Rate 03 is re-stratified, NSP should only have to add a few additional meters largely to satisfy the 20 meter minimum. Table 9 shows the proposed stratification and additional sample points.

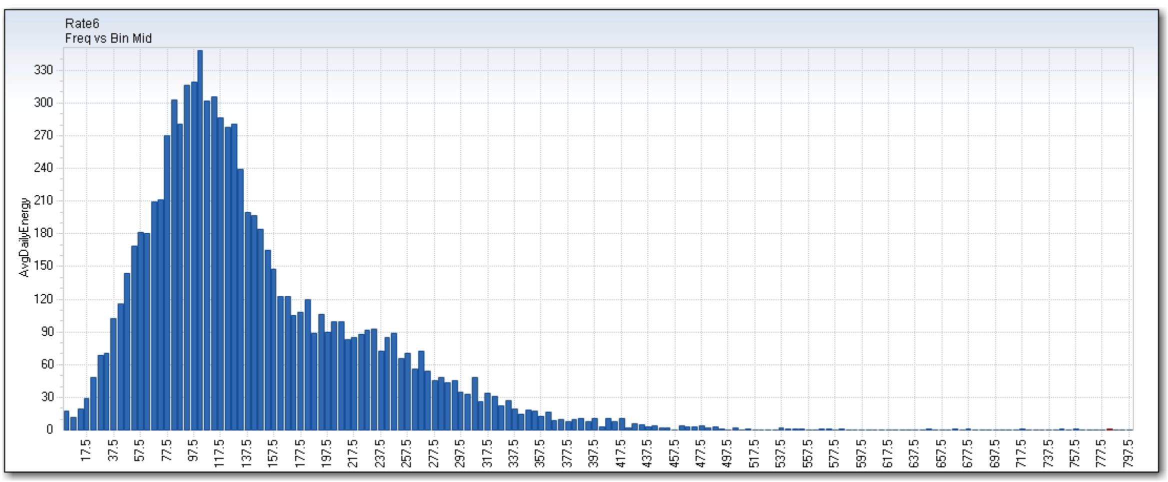
Table 9: Rate 03 Sample Allocation

Strata	Proposed	Current	Additional
0 t0 40	20	13	7
40 to 75	20	20	0
75 t0 120	20	24	0
120 plus	20	15	5
All	80	72	12

Rate 06: Residential Time-of-Day

NSP has approximately 10,000 Rate 06 customers. These customers include some of NSP's largest residential customer users. Rate 06 winter average use (2013) is 143.3 kWh per day. In comparison, Rate 02 average winter use is 28.1 kWh per day and Rate 03 average winter use is 66 kWh per day. The 2013 winter peak precision is relatively low at 30.3%. The primary reason for the poor precision is that there are only 29 contributing load research meters. The population characteristics have also changed significantly since the initial sample was put in place. NSP will need at least 140 load research meters for this rate class. The reason for the relatively large sample size is that the usage and estimated demand variance across Rate 06 is quite large. Further, there are now much larger customers in the population than there were in the original population sample design. Figure 12 shows the population distribution for this rate.

Figure 12: Rate 06 Population Frequency Distribution



Close to 18% of Rate 06 customers use over 6,600 kWh per month during the winter. Rate 06 population characteristics are summarized in Table 10.

Table 10: Rate 06 Population Characteristics

Strata	Population	Shr Pop	Xavg	X Std Dev	X CV	Yavg	Y Std Dev	Y CV
0 to 120	4,302	49.1%	81.1	26.2	0.32	2.8	2.5	0.91
120 to 220	2,920	33.4%	158.8	28.7	0.18	4.6	3.0	0.65
220 Plus	1,533	17.5%	287.7	65.9	0.23	8.6	5.6	0.65
All	8,755	100.0%	143.2					

Demand estimates (*Yavg*) are derived from the existing load research sample. As no current sample points fall in the third stratum, demand is estimated using the demand to use ratio for stratum 2. Table 11 shows the proposed sample design for Rate 06.

Table 11: Rate 06 Sample Design

Stratas	Population	Shr Pop	n	Precision	Proposed n	Precision	Sample Dist
0 to 120	4,302	49.1%	55	20.1%	50	21.1%	33.3%
120 to 220	2,920	33.4%	44	16.0%	50	15.0%	33.3%
220 Plus	1,533	17.5%	43	16.1%	50	14.9%	33.3%
All	8,755	100.0%	142	10.0%	150	9.8%	100.0%

Using an *MPU* expansion, the minimum sample size to achieve a 10% precision level is 142. We recommend using a slightly higher sample of 150 meters to account for likely missing interval data over some of the hours, and the higher level of uncertainty associated with lacking demand data for the 220 Plus stratum. Table 12 shows the additional load research meters required to meet the design sample size once the existing sample is re-stratified.

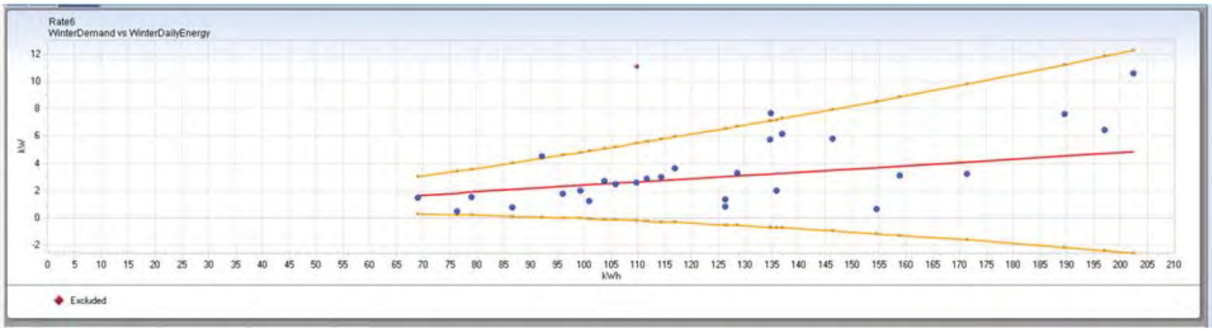
Table 12: Rate 06 Sample Allocation

Stratas	Proposed	Current	Additional
0 to 120	50	15	35
120 to 220	50	14	36
220 Plus	50	0	50
All	150	29	121

We evaluated a *Ratio* expansion design for Rate 06, but the correlation between demand and use is not particularly strong (at least for the current sample). This is illustrated in Figure 13.

A ratio expansion design does not produce a smaller sample because there is a weak relationship between energy and demand.

Figure 13: Rate 06 (Residential TOD) Ratio Model



Rate 10: Small Commercial General Service

There are approximately 20,650 Rate 10 customers with an average daily winter use of 42.2 kWh. Average demand at the time of the 2013 winter peak is estimated to be 2.3 kW.

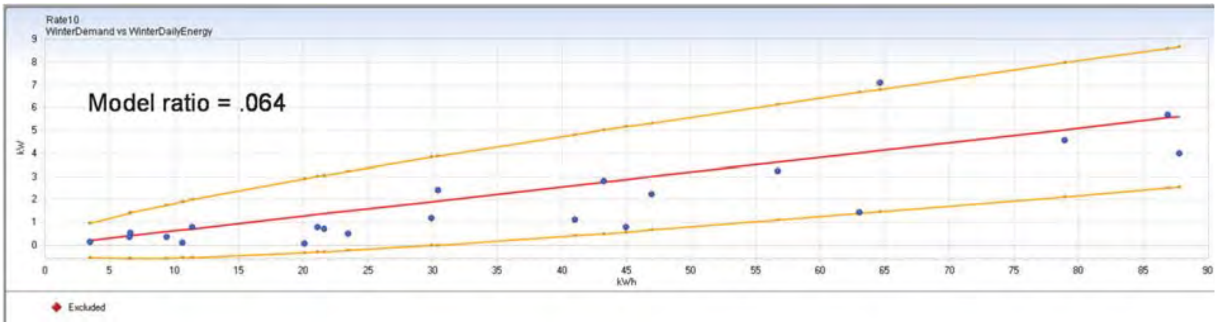
The 2013 winter peak precision is relatively low as there are only 22 active load research meters. The original sample design included 45 meters. Customers are assigned to one of three stratums using *Dalenious-Hodges* breakpoint analysis. Table 13 shows the results for Rate 10.

Table 13: Rate 10 Population Characteristics

Stratas	Population	Shr Pop	Xavg	X Std Dev	X CV	Yavg	Y Std Dev	Y CV
0 t0 35	11,606	56.2%	13.5	10.4	0.77	0.7	0.3	0.53
35 to 96	7,138	34.6%	59.5	16.7	0.28	3.3	2.1	0.63
96 Plus	1,898	9.2%	153.0	130.6	0.85	9.0	5.6	0.63
All	20,642	100.0%	42.2	57.4	1.36	2.3	3.2	1.38

Xavg is the average winter daily use and *Yavg* is the estimated demand at time of peak. Demand estimates for the first two strata are derived from the current load research sample. As the existing load research sample does not include any meters in the highest stratum, coincident demand for this stratum is estimated based on the ratio model results. Figure 14 shows the Rate 10 *Ratio* model.

Figure 14: Rate 10 (Small Commercial GS) Ratio Model



The overall correlation between winter average use and winter coincident peak demand is relatively high with the load research sample showing a 0.83 correlation. The relatively high demand-to-use correlation allows us to develop a sample for Rate 10 using a Ratio design that is smaller than that for an *MPU* expansion. Table 14 shows the resulting sample where sample points are allocated to stratum using a *Neyman* allocation.

Table 14: Rate 10 Sample Design - Ratio Expansion

Stratas	Population	Shr Pop	n	Precision	Proposed n	Precision	Sample Dist
0 to 35	11,606	56.2%	14	29.0%	20	24.3%	18.2%
35 to 96	7,138	34.6%	52	11.1%	52	11.1%	47.3%
96 Plus	1,898	9.2%	38	15.4%	38	15.4%	34.5%
All	20,642	100.0%	104	9.0%	110	8.6%	100.0%

The recommended sample size is 110 meters when a mininum of 20 sampling points are assigned to the first strata. Again, we targeted a 9% precision in the design in order to achieve a 10% precision from actual sample expansions. Further, expected customer migration from Rate 11 to Rate 10 adds to the design uncertainty; the slightly larger sample combined with ratio expansion should help achieve targeted 10% winter peak precision. An *MPU* expansion to achieve the same level of precision requires over 150 load research meters. Table 15 shows the proposed sample, current meters (re-stratified based on 2013 winter average use), and additional required load research meters for Rate 10.

Table 15: Rate 10 Sample Allocation

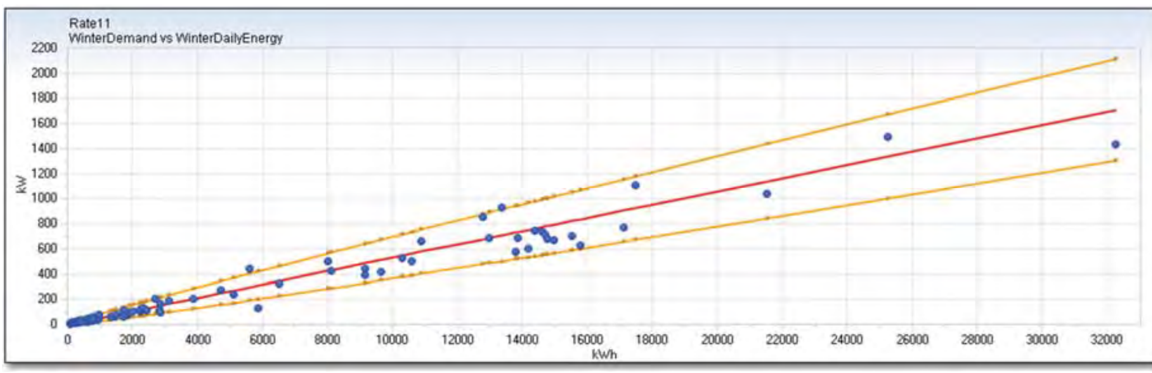
Stratas	Proposed	Current	Additional
0 to 35	20	12	8
35 to 96	52	10	42
96 Plus	38	0	38
All	110	22	88

Rate 11: Commercial General Demand

Rate 11 has approximately 11,300 customers and includes some of NSP's largest customers. In 2013, estimated class winter coincident peak was 441 MW with an estimated precisoin of 10.1%. The relatively high level of precision is a result of the number of sample load research meters. At the time of the winter peak there were 89 active load research meters out of an original sample of 90.

The new sample is designed for *Ratio* expansion as there is a strong correlation between winter average daily use and demand at time of peak. The Rate 11 *Ratio* model (Figure 15) shows this relationship estimated from the current load research sample.

Figure 15: Rate 11 Ratio Model



Given the wide range in winter usage across the rate class, we elected to stratify customers into five usage groups; this is also consistent with the original sample stratification. Figure 16 shows the customer frequency distribution and Table 16 shows the population characteristics for Rate 11.

Figure 16: Rate 11 Customer Frequency Distribution

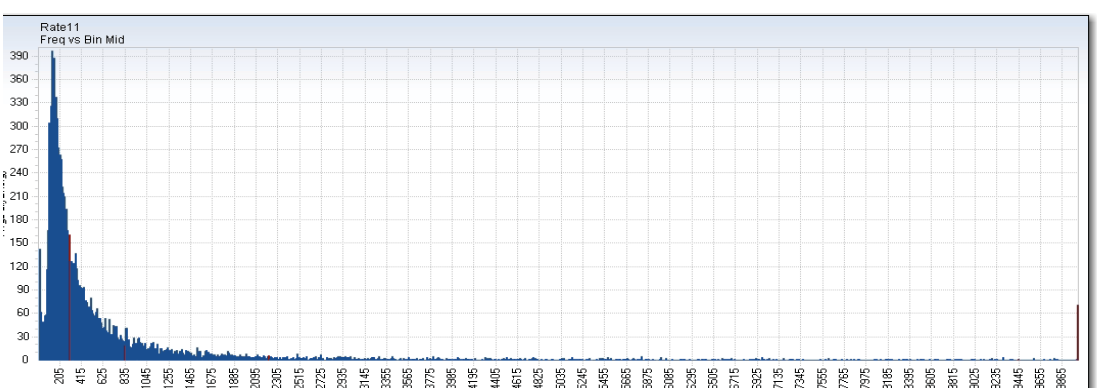


Table 16: Rate 11 Population Characteristics

Strata	Population	Shr Pop	Xavg	X Std Dev	X CV	X Total	Shr X
0 to 240	5,140	45.4%	145.7	53.7	0.37	748,882	10.3%
240 to 585	3,445	30.4%	372.2	97.8	0.26	1,282,186	17.6%
585 to 1,322	1,661	14.7%	858.4	201.7	0.23	1,425,740	19.5%
1,322 to 3,308	726	6.4%	1,965.0	531.1	0.27	1,426,575	19.6%
3,310 to 32,606	354	3.1%	6,810.1	3,549.1	0.52	2,410,770	33.1%
ALL	11,326	100.0%	644.0			7,294,153	100.0%

Strata	Yavg	Y Std Dev	Y CV	Y Total	Shr Y
0 to 240	8.5	3.1	0.37	43,572	10.2%
240 to 585	20.1	5.6	0.28	69,291	16.2%
585 to 1,322	38.4	15.0	0.39	63,745	14.9%
1,322 to 3,308	102.2	35.2	0.34	74,161	17.4%
3,310 to 32,606	497.1	274.4	0.55	175,973	41.2%
ALL	37.7			426,742	100.0%

The customer usage distribution is relatively large with the smallest stratum averaging 145.7 kWh per day to the highest stratum averaging 6,810 kWh per day. The first stratum accounts for over 45% of the customers, but just 10% of winter usage while the highest stratum includes only 354 customers, but accounts for 33.1% of winter usage. Coincident demand estimates (*Yavg* and *YTotal*) are derived from the current load research sample.

Using a *Ratio* expansion design, the current sample size results in a 3.2% precision for the winter peak day (at 90% confidence interval). Our recommendation is to increase the sample size to a minimum of 20 per stratum. The additional meters in the lower stratum will help address potential migration impacts to Rate 10. Table 17 summarizes the sample design results for 90% confidence level for Rate 11.

Table 17: Rate 11 Proposed Sample Design

Strata	Population	Shr Pop	n	Precision	Proposed n	Precision	Sample Dist
0 to 240	5,140	45.4%	12.64	12.1%	20	9.7%	17.4%
240 to 585	3,445	30.4%	16.01	8.8%	20	7.8%	17.4%
585 to 1,322	1,661	14.7%	14.24	7.5%	20	6.2%	17.4%
1,322 to 3,308	726	6.4%	35.18	3.8%	35	3.8%	30.4%
3,310 to 32,606	354	3.1%	10.94	4.6%	20	3.2%	17.4%
All	11,326	100.0%	89.00	3.2%	115	2.8%	100.0%

As the current sample is relatively large, NSP will need to add relatively few new sample metering points. Though again, it is good practice to refresh the existing sample over time. Table 18 shows the additional sample point requirements for Rate 11 after the current sample is re-stratified.

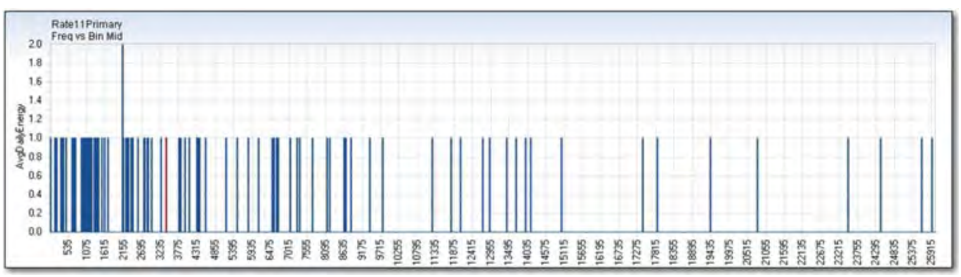
Table 18: Rate 11 Sample Allocation

Strata	Proposed	Current	Additional
0 to 240	20	13	7
240 to 585	20	16	4
585 to 1,322	20	14	6
1,322 to 3,308	35	35	-
3,310 to 32,606	20	11	9
All	115	89	26

Secondary and Primary Sample Design. NSP provides service for Rate 11 customers at secondary and primary voltage levels. As part of the Rate 11 design we evaluated samples for secondary and primary voltage targeting the 10% precision level. For the secondary services the proposed Rate 11 sample is more than adequate to achieve 10% precision; all but 100 Rate 11 customers are served at the secondary voltage level.

There are roughly 100 primary voltage customers with half of these customers falling in the highest Rate 11 usage stratum. Figure 17 shows the distribution of winter average daily use for primary service customers.

Figure 17: Rate 11 Primary Customer Distribution



Using ratio expansion requires roughly 20 primary sample points to meet the 10% precision level. There are currently 13 primary sample points. Adding an additional 7 primary meter sample points as part of the Rate 11 sample selection process should achieve target precision levels, but recognizing that in any given year a few individual customers' operations could result in actual variation that is higher than that of the sample design. Table 19 shows the proposed sample stratification for Rate 11 Primary customers.

Table 19: Proposed Rate 11 Primary Sample

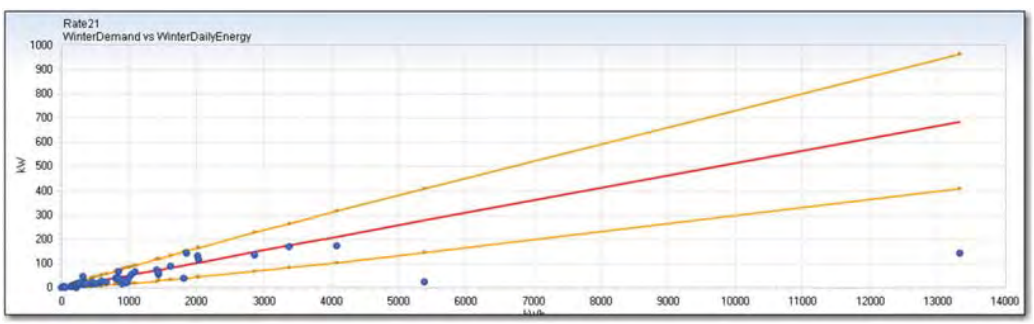
Strata	Proposed	Current	Additional
0 to 3400	5	2	3
3400 Plus	15	11	4
All	20	13	7

Rate 21: Small Industrial Demand

Rate 21 includes approximately 2,100 small industrial demand. The estimated 2013 class peak demand is 70.2 MW and system coincident peak demand is 40.6 MW. The precision on the demand estimates however, are low; the winter coincident demand precision is 18.6% using a *MPU* expansion. The low precision is primarily result of decline in sample size. The original design included a 1,100 Rate 21 customers and a 78 sample points; there are currently 48 Rate 21 sample meters.

Precision can be significantly improved using *Ratio* rather than *MPU* expansion. With *Ratio* expansion, the current sample (allocated across five strata) yields a precision of 7.9%. The reason for the improvement is because of the strong relationship between class demand at peak and average daily winter usage. The Rate 21 *Ratio* model (Figure 18) shows this relationship (the two large, lower outliers are marked off for purpose of estimating the model).

Figure 18: Rate 21 Ratio Model



The customer base is stratified into five usage groups based on each customer's average daily winter use (X). The breakpoints are calculated using *Dalenious-Hodges*. Estimated coincident peak load (*Yavg* and *Y Total*) are derived from the current load research sample. Table 20 summarizes customer characteristics.

Table 20: Rate 21 Customer Characteristics

Strata	Population	Shr Pop	Xavg	X Std Dev	X CV	X Total	Shr X
0 to 115	932	44.2%	41	32.7	0.79	38,500	5.1%
115 to 370	535	25.4%	195	56.0	0.29	104,558	14.0%
370 to 670	311	14.8%	465	102.1	0.22	144,461	19.3%
670 to 1250	203	9.6%	916	158.4	0.17	185,885	24.9%
1250 Plus	127	6.0%	2,161	939.9	0.43	274,475	36.7%
ALL	2,108	100.0%				747,881	100.0%

Strata	Yavg	Y Std Dev	Y CV	Y Total	X/Y Corr
0 to 115	2.1	2.0	0.94	1,959	0.74
115 to 370	11.8	10.5	0.89	6,336	0.63
370 to 670	20.4	4.5	0.22	6,332	0.48
670 to 1250	39.2	15.8	0.40	7,950	0.51
1250 Plus	101.2	52.4	0.52	12,855	0.87
ALL				35,432	0.95

Table 21 shows the sample size and distribution for 9% precision at the 90% confidence interval and the precision with the proposed number of sample points of 58.

Table 21: Rate 21 Proposed Sample

Stratas	Population	Shr Pop	n	Precision	Proposed n	Precision	Sample Dist
0 to 115	932	44.2%	5.1	47.2%	10	33.3%	16.7%
115 to 370	535	25.4%	7.9	30.8%	10	27.5%	16.7%
370 to 670	311	14.8%	8.0	22.3%	10	19.9%	16.7%
670 to 1250	203	9.6%	8.8	20.0%	10	17.8%	16.7%
1250 Plus	127	6.0%	18.3	9.3%	18	9.3%	33.3%
All	2,108	100.0%	48.0	8.8%	58	7.8%	100.0%

Using a *Ratio* expansion, the current sample size (48) gives a 8.8% precision level at the 90% confidence interval. With a minimum of 10 sample points per stratum the overall precision improves to 7.8%.

Table 22 shows the additional sample points required for the proposed sample size after the current sample is re-stratified for Rate 21.

Table 22: Proposed Rate 21 Sample Allocation

Stratas	Proposed	Current	Additional
0 to 115	10	4	6
115 to 370	10	15	-
670 to 1250	10	6	4
670 to 1250	10	11	-
1250 Plus	18	12	6
All	58	48	16

Given the current number of load research meters and re-stratification of these meters, NSP would need to add 16 additional load research meters to this class.

Secondary and Primary Service. There are only 22 Rate 21 customers that take service at the primary voltage level. Fifteen of these customers fall within the two highest strata, and 7 of these customers fall in the two lowest strata. While there are 5 current primary load research meters, the meters provide minimal information on demand characteristics for this class. In estimating a primary ratio 1 of the 5 sample points was marked off as "bad" as it had an average daily winter use of 13,500 kWh, but demand at peak of only 140 kW.

To estimate a sample, for this class we used results of the *Total Class Ratio* model. Sample design results indicated that we would need 13 sample points out of the total 22 primary customers. Given that each of these customers likely has very different business operations, there is no guarantee that even the 13 sample meters would provide actual precision at the 10% precision level. With small population size, the best solution to achieve a high level precision at the voltage level would be to meter all primary service customers.

The proposed total Rate 21 sample is large enough that it should be able to achieve reasonable precision for secondary service delivery.

Rate 22: Medium Industrial Demand

The medium industrial demand rate class includes 190 customers with average daily winter use of 7,244 kWh. Estimated class coincident peak demand in 2013 is 40.6 MW with a maximum class demand in 2013 of 70.2 MW. The winter peak precision estimate is 12.3%; this is based on 44 active sample meters.

The Rate 22 customer base is mapped to one of three stratum based on winter average daily use. Stratum break-points are determined using *Dalenious-Hodges*. The sample is allocated to strata using a *Neyman* allocation. Table 23 shows the results of this analysis.

Table 23: Rate 22 (Medium Industrial Demand) Characteristics

Strata	Pop	Avg X	TotalX	PctN	PctX
0 to 3,940	97	2,171	210,560	51.1%	15%
3,940 to 11,325	61	6,985	426,073	32.1%	31%
11,325 Plus	32	23,116	739,715	16.8%	54%
Total	190	7,244	1,376,348	100.0%	100%

AvgX is the average 2013 winter daily usage. The largest stratum accounts for 54% of class usage with the lowest stratum accounting for 15% of the usage with over 50% of the customers.

Rate 22 customer characteristics have changed significantly since the original design. Table 24 shows the population and usage distribution for the original design.

Table 24: Original Rate 22 Sample Characteristics

Strata	Pop	Avg X	TotalX	PctN	PctX
100 to 3700	104	2,363	245,766.67	77%	41%
3700 to 9500	17	6,457	109,769.63	13%	18%
9500 Plus	14	17,018	238,255.56	10%	40%
Total	135	5,017	593,791.85	100%	100%

Average daily use in Table 24 is derived from the load research sample. The current population estimates (7,244 kWh vs. 5,017 kWh) is significantly higher. There are also twice as many customers in the higher use stratum than in the initial design.

The differences in the population characteristics makes it difficult to use the current load research sample points for deriving load estimates for the new population stratification. Using the current load research sample data points, demand estimates for the new population stratifications are too low. Instead, stratum demand estimates are based on the *Ratio* model for Rate 21. The demand to energy ratio from the Rate 21 model gives a coincident peak demand estimate close to that implied by the current load research sample. The demand variance estimate is based on the current Rate 22 sample.
Table 25 shows the estimated class coincident peak demand for the new stratification.

Table 25: Rate 22 Coincident Peak Demand Estimates

Strata	Pop	Avg Y	Total Y	Std Dev Y	CV
0 to 3,940	97	65	6,318	35	0.54
3,940 to 11,325	61	210	12,783	113	0.54
11,325 Plus	32	693	22,191	409	0.59
Total	190	217	41,292	409	1.88

The proposed sample is based on ratio expansion, 2013 population characteristics, and new stratum winter coincident peak demand estimates for Rate 22 are shown in
Table 26.

Table 26: Rate 22 Proposed Sample Design

Stratas	Population	Shr Pop	n	Precision	Proposed n	Precision	Sample Dist
0 to 3,940	97	51.1%	6.0	30.2%	10	22.9%	22.2%
3,940 to 11,325	61	32.1%	12.1	19.3%	12	19.3%	26.7%
11,325 Plus	32	16.8%	22.9	8.7%	23	8.1%	51.1%
All	190	100.0%	41.0	8.9%	45	8.2%	100.0%

The target precision is 9.0%. Assigning a minimum of 10 sample points to the first stratum results in an estimated precision of 8.2%. Half of the new sample is assigned to the largest stratum as this stratum accounts for over half of the Rate 21 daily usage.

Rate 22 already includes 41 active load research meters. The distribution of these meters after re-stratification is shown in
Table 27.

Table 27: Proposed Sample Stratification

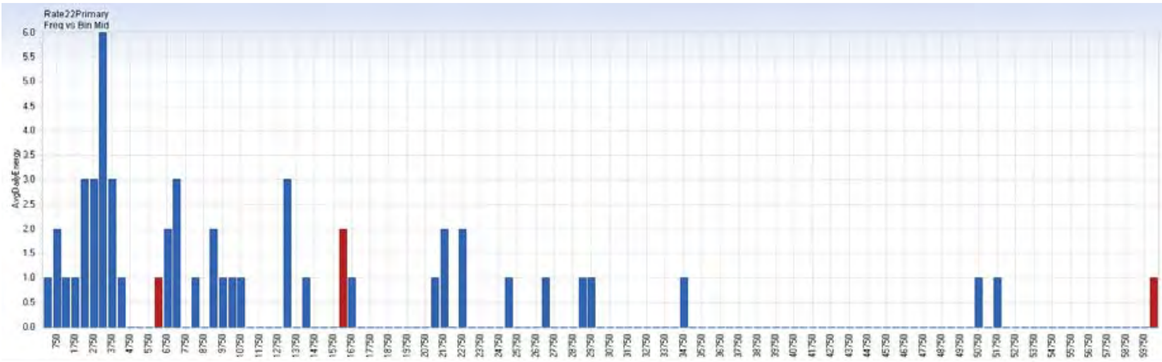
Stratas	Proposed	Current	Additional
0 to 3,940	10	9	1
3,940 to 11,325	12	18	-
11,325 Plus	23	17	6
All	45	44	7

Leveraging off of the existing sample, NSP would not have to add many meters to achieve the target precision. However, given that these sample points were initially placed in very different stratum and over time are likely to have very different load characteristics we would recommend that at that 20% of the current load research sample meters are replaced.

Primary and Secondary Samples. The proposed sample size should achieve close to 10% precision for each of the voltage delivery classes. Sample selection would also have to involve customer voltage service level.

There are 54 primary voltage customers on Rate 22. The distribution of these customers is depicted in Figure 19.

Figure 19: Rate 22 Primary Customer Distribution



The required sample size is relatively large (compared with the population size) as there is large variation in customer usage. NSP would need a sample size of 18 to achieve 9% precision. Currently there are 12 primary load research meters. Table 28 shows the primary sample design where these 12 sample points are re-stratified for Rate 22.

Table 28: Rate 22 Primary Sample Design

Stratas	Proposed	Current	Additional
0 to 3,940	5	1	4
3,940 to 11,325	5	5	-
11,325 Plus	8	6	2
All	18	12	6

Given that these sample points were initially selected for different strata, there is the risk that some of the existing load research meters are no longer representative of the new stratification.

The secondary voltage service customers include most of the Rate 22 customers. Using a *Ratio* design 10% precision can be achieved with roughly 36 sample points for Rate 22, shown in
Table 29.

Table 29: Rate 22 Secondary Sample Design

Stratas	Proposed	Current	Additional
0 to 3,940	10	8	2
3,940 to 11,325	13	13	-
11,325 Plus	13	11	2
All	36	32	4

The 10% precision target should be possible for the total Rate 22 and for secondary and primary customers. In sample selection process, NSP will need to select based on voltage service as well as winter daily usage level.

Impact of Rate Migration

New rules will allow Rate 11 customers (Commercial General Demand) to move to Rate 10 (Commercial General Service). NSP is concerned that future customer migration may impact the precision of the new Rate 10 and Rate 11 load research samples. We believe that this shouldn't be a problem as we are proposing to significantly increase the Rate 10 sample size with a large sample allocation to the highest Rate 10 stratum.

In the new design, there is a fairly large overlap in terms of winter daily usage between the largest Rate 10 and Rate 11. Ninety-nine percent of Rate 10 customers use 200 kWh or less per day while 44% of Rate 11 customers (which includes those customers that would potentially migrate) use less than 200 kWh per day. There is no reason to assume that Rate 11 customers in the first stratum (0 to 296 kWh per day) load characteristics would be significantly different than those customers in the highest Rate 10 stratum (96 kWh and above per day). The large number of sample points in the highest Rate 10 usage stratum (38 sample points) will mitigate any precision issues if using a ratio sample expansion.

Conclusions

Several of the load research samples were able to achieve close to the 10% precision target for the 2013 winter system peak. These are samples where there is not been a significant degradation from the initial sample design. For these samples including Rate 03, Rate 11, Rate 21, and Rate 22, the 10% precision target can be met by re-stratifying the existing sample and adding new meters to fill the missing gaps. To achieve 10% precision for the non-residential rate classes will also require using *Combined Ratio* expansion rather than *MPU* expansion.

Several rate classes will need significantly more load research meters including Rate 02, Rate 06 and Rate 10. The current samples for these classes have the poorest winter peak precision.

Sample precision at the voltage level can be improved significantly where voltage is included in the sample selection process and profiles are generated using ratio expansion.

Ratio Expansion. *Combined Ratio* expansion will result in significantly higher precision for the non-residential rate classes as there is a relatively strong relationship between class coincident peak demand and their usage. *Ratio* expansion scales the sample hourly demand to rate class total demand based on the ratio of total rate class average monthly use to sample average use.

With *Ratio* expansion it's important that the total rate class average use is on the same timing basis as the load research sample average use. In general, this is not the case; load research average use is calculated for the calendar month while total rate class average use is derived from the billing data. Billing data includes usage in the current and prior calendar-months. Using calendar-month load research usage and billing-data based average use will result in poor precision and sometimes unreasonable load profiles.

There are two options for synchronizing load research and total class average use. One option is to assign the load research meters to the meter read schedule and calculate billed-sales average use estimates for the load research sample. Alternatively, billed sales data for the load research sample can be used in the sample expansion. LRS allows for both of these options.

Another approach is to convert the billed sales data to a calendar-month. This is done by estimating a monthly sales model for each rate class and use the model to estimate sales for the calendar-month period.

Maintaining the Load Research Sample. In general, it is a good practice to replace existing meters on a regular basis and to evaluate whether there has been any significant change in the population characteristics over time; this may indicate a need to assess the current sample stratification and sample design.

Load research information that's easily accessible provides a wealth of information. In addition to providing load characteristics for cost of service studies. Load research data can be used to develop strong rate class weather normalization models, track customer usage trends, improve on sales forecasts, and develop class and end-use hourly profiles for evaluating the impact of class and end-use targeted DSM programs on load. A strong load research program is worth the investment.

LRS. The sample design work and assessment of the current load research sample was done using Itron's Load Research System (LRS). LRS works with Itron's MV-90 and is configured to read load research sample data from NSP's MV-90. LRS generates a numerous load research reports and the statistics used in the sample design process. LRS also provides easy access to both individual customer load research data and rate class level profile estimates.

Request IR-13:

Section 4.1 Transmission – Highlights, page 45, please explain:

(a) The driving factors for the $8.2 million increase in carry-over capital spending in ACE 2016 compared to that forecasted in ACE 2015.

(b) The drivers for the $8.8 million increase in routine capital spending in ACE 2016 from the ACE 2015 forecast, to $15.2 million.

Response IR-13:

(a) In the 2015 ACE Plan, the transmission carryover total was $8.2 million. In the 2016 ACE Plan, the carryover total amount is $14.8 million, representing an increase of $6.6 million. The increase is primarily due to two large multi-year projects that were part of the 2015 ACE Plan: CI 44987 – L7003 Lidar Upgrades[1] ($3 million) and CI 46339 – 120H Brushy Hill – SVC Controls Replacement ($3.3 million). The remaining variance is spread amongst multiple projects.

(b) In the 2015 ACE Plan, the transmission routine program was $8.8 million. In the 2016 ACE Plan, the routine program is $15.2 million, representing an increase of $6.4 million. The increase is primarily due to an increased spend in the Transmission Right-of-Way Widening (T010) routine in response to the Post Tropical Storm Arthur proceedings where the report recommended NS Power to "develop a comprehensive plan to manage the 69kV transmission line corridor Rights-of-Way including reclaiming and/or widening."

[1] This project is currently before the Board.

Request IR-14:

Please explain the difference between P061 Transportation Vehicle Replacements, P062 Work Class Replacements and P063 Work Vehicle Replacements, page 73.

Response IR-14:

The difference between each of the above noted vehicle replacement routines is the type of vehicle being replaced under that routine. P061 Transportation Vehicles are for the replacement of Class 0, 1, and 2 vehicles. P062 Work Class Vehicles are for Class 4 and 5 vehicle replacements. P063 Work Vehicles are for the replacement of Class 3 vehicles.

Vehicle Class	Description
Class 0	ATVs, Snowmobiles
Class 1	Cars
Class 2	Pickup Trucks, Vans, SUVs
Class 3	Vehicles over 4,500 kg, such as large trucks, flat deck trucks and services trucks
Class 4	Aerial line trucks
Class 5	Digger trucks

NON-CONFIDENTIAL

Request IR-15:

Please provide the inventory of NS Power's vehicle fleet, by vehicle type and function.

Response IR-15:

Please refer to Attachment 1, also provided electronically.

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Year	Vehicle #	Type	Class	Make	Model
1992	1008	Trailer	0	ATC	HOTLINE
2003	1010	Trailer	0	SPECIALITY STEEL	ATV TRAILER
2007	17001	Trailer	0	DURASTAR	ATV TRAILER
2007	17006	Trailer	0	HOMEMADE	POLE TRAILER
2007	17012	Trailer	0	INTER	CARGO TRAILER
2008	17014	Trailer	0	HOMEMADE	UTILITY TRAILER
2007	17015	Trailer	0	SAUBER	S/REELTRAILER
2007	17016	Trailer	0	SAUBER	S/REELTRAILER
2007	17017	Trailer	0	WEBER	FLATDECK
2008	17101	Car	1	FORD	FOCUS
2008	17102	Car	1	FORD	FOCUS
2008	17103	Car	1	FORD	FOCUS
2008	17104	Car	1	FORD	FOCUS
2008	17202	SUV	2	FORD	ESCAPE 4X4
2008	17203	Pickup	2	FORD	RANGER EXT
2008	17205	Pickup	2	FORD	RANGER EXT
2008	17206	Pickup	2	FORD	RANGER EXT
2008	17207	Van	2	FORD	E350
2008	17209	Pickup	2	FORD	RANGER E4X4
2008	17210	Pickup	2	FORD	RANGER EXT
2008	17211	Pickup	2	FORD	RANGER EXT
2007	17213	Pickup	2	FORD	F150 EXT
2008	17214	Van	2	FORD	E350
2008	17215	Van	2	DODGE	CARAVAN
2008	17218	Van	2	DODGE	CARAVAN
2007	17227	Pickup	2	FORD	F150 EXT
2008	17230	Van	2	FORD	E350
2008	17231	SUV	2	FORD	ESCAPE
2008	17232	Van	2	FORD	E350
2008	17233	Van	2	FORD	E350
2008	17234	Van	2	FORD	E350
2008	17238	Van	2	DODGE	CARAVAN
2008	17253	Pickup	2	FORD	RANGER EXT
2007	17266	Pickup	2	FORD	F150 EXT 4X4
2007	17270	Pickup	2	FORD	F150 EXT-YARD
2007	17273	Pickup	2	FORD	F150 EXT
2008	17276	SUV	2	FORD	ESCAPE 4X4
2008	17298	Pickup	2	FORD	F250 EXT
2008	17300	Service	3	FORD	F550
2008	17301	Service	3	FORD	F550
2008	17901	ATV	9	BOMBARDIER	400 OUTLANDER
2007	17902	ATV	9	HONDA	TRX500FM
2007	17903	ATV	9	HONDA	TRX500FM
2008	17904	ATV	9	HONDA	TRX500FM
2008	17905	ATV	9	HONDA	TRX500FM
2008	18000	Trailer	0	LOADR	BOAT TRAILER
2008	18086	Trailer	0	NETVISION	MOBILE VIDEO
2009	18100	Car	1	FORD	FUSION SEL
2009	18101	Car	1	FORD	FOCUS
2009	18102	Car	1	FORD	FUSION
2008	18200	Pickup	2	FORD	RANGER E4X4
2008	18203	Pickup	2	FORD	F150 EXT
2008	18205	Pickup	2	FORD	F150 EXT 4X4
2009	18206	SUV	2	FORD	ESCAPE
2009	18207	SUV	2	FORD	ESCAPE
2008	18208	Pickup	2	FORD	F150 EXT

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Year	Vehicle #	Type	Class	Make	Model
2008	18209	Pickup	2	FORD	F150 EXT 4X4
2008	18212	Pickup	2	FORD	F150 EXT
2008	18223	Pickup	2	FORD	F150 EXT-YARD
2008	18226	Pickup	2	FORD	F150 EXT 4X4
2008	18229	Van	2	FORD	E350
2008	18231	Pickup	2	FORD	F250 EXT 4X4
2008	18234	Pickup	2	FORD	F150 EXT
2008	18236	Pickup	2	FORD	F150 EXT
2008	18241	Pickup	2	FORD	RANGER E4X4
2008	18243	Pickup	2	FORD	F150 EXT
2008	18244	Pickup	2	FORD	F150 EXT 4X4-YRD
2008	18255	Pickup	2	FORD	F150 EXT 4X4
2008	18256	Pickup	2	FORD	F150 EXT 4X4
2008	18257	Pickup	2	FORD	F150 EXT
2008	18258	Pickup	2	FORD	F150 EXT 4X4
2008	18260	Pickup	2	FORD	F150 EXT
2008	18261	Van	2	FORD	E350
2008	18262	Pickup	2	FORD	RANGER E4X4
2008	18265	Pickup	2	FORD	F150 EXT
2008	18266	Pickup	2	FORD	F150 EXT
2008	18269	Pickup	2	FORD	F250 EXT 4X4
2008	18270	Pickup	2	FORD	F250 EXT 4X4
2008	18271	Pickup	2	FORD	F150 EXT
2008	18272	Pickup	2	FORD	F150 EXT
2008	18273	Pickup	2	FORD	F150 EXT
2008	18274	Pickup	2	FORD	F150 EXT
2008	18276	Pickup	2	FORD	F150 EXT
2008	18277	Pickup	2	FORD	F150 EXT
2008	18291	Pickup	2	FORD	F250
2009	18294	Pickup	2	FORD	F150 EXT 4X4
2008	18300	Service	3	FORD	F550
2008	18301	Service	3	FORD	F550
2008	18400	Aerial	4	FORD	F550
2008	18401	Aerial	4	FORD	F550
2008	18402	Aerial	4	FORD	F550
2008	18403	Aerial	4	FORD	F550
2008	18404	Aerial	4	INTERNATIONAL	4400
2008	18405	Aerial	4	INTERNATIONAL	7400
2008	18406	Aerial	4	INTERNATIONAL	7400
2008	18407	Aerial	4	INTERNATIONAL	7400
2008	18409	Aerial	4	INTERNATIONAL	4400
2009	18410	Aerial	4	INTERNATIONAL	4400
2009	18411	Aerial	4	INTERNATIONAL	4400
2008	18412	Aerial	4	INTERNATIONAL	4400
2008	18413	Aerial	4	INTERNATIONAL	4400
2008	18414	Aerial	4	INTERNATIONAL	4400
2008	18500	Digger	5	INTERNATIONAL	7400
2008	18501	Digger	5	INTERNATIONAL	7400
2008	18502	Digger	5	INTERNATIONAL	7400
2008	18503	Digger	5	INTERNATIONAL	7400
2007	18805	ATV	8	CATERPILLAR	824H
2008	18900	ATV	9	HONDA	TRX500FM
2006	18905	Forklift	9	HYUNDAI	HLF30-5
2004	18920	Forklift	9	HYUNDAI	F30 FORKLIFT
2007	18929	ATV	9	KUBOTA	RTV600
2009	18930	ATV	9	HONDA	TRX500FM

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Year	Vehicle #	Type	Class	Make	Model
2009	18931	ATV	9	HONDA	TRX500FM
2003	1905	ATV	9	BOMBARDIER	TRAXTER
1990	1906	Forklift	9	NISSAN	FORKLIFT
2009	9440	Aerial	4	INTERNATIONAL	4400
2009	9441	Aerial	4	INTERNATIONAL	4400
2009	9442	Aerial	4	INTERNATIONAL	4400
2009	9443	Aerial	4	INTERNATIONAL	4400
2009	9444	Aerial	4	INTERNATIONAL	4400
2009	9445	Aerial	4	INTERNATIONAL	4400
2009	9446	Aerial	4	INTERNATIONAL	4400
2009	9447	Aerial	4	INTERNATIONAL	4400
2009	9448	Aerial	4	INTERNATIONAL	4400
2009	9449	Aerial	4	INTERNATIONAL	4400
2009	9450	Aerial	4	INTERNATIONAL	4400
2009	9451	Aerial	4	INTERNATIONAL	4400
2009	9452	Aerial	4	INTERNATIONAL	4400
2009	9453	Aerial	4	FORD	F550
2009	9454	Aerial	4	FORD	F550
2009	9505	Digger	5	INTERNATIONAL	7400
1995	2000	Trailer	0	SPECIALITY STEEL	UTILITY
2001	2020	Trailer	0	OMALLEY & HUNTER	REEL ARBOUR
1991	2066	Trailer	0	BALCOM	REEL
1993	2072	Trailer	0	NOVA	HEAVY DUTY REEL
1993	2907	Trailer	9	TIMBERLAND	DPT40B
1991	2910	Forklift	9	NISSAN	FORKLIFT F03
1996	3007	Trailer	0	REMEC	SKIDOO TRAILER
1986	3056	Trailer	0	BALCOM	HOTLINE
1991	3075	Trailer	0	BALCOM	ARBOUR
1991	3076	Trailer	0	BALCOM	ARBOUR
1993	3903	Trailer	9	TIMBERLAND	DPT40B
1984	3904	Forklift	9	TOYOTA	2FBCA15
2004	4000	Trailer	0	SAUBER	1520 REEL
2004	4001	Trailer	0	SAUBER	4500 POLE
2004	4002	Trailer	0	SAUBER	4500 POLE
2004	4003	Trailer	0	BLA	ATV TRAILER
2004	4004	Trailer	0	BLA	ATV TRAILER
2004	4203	Pickup	2	FORD	F250 EXT 4X4
2005	4311	Service	3	FORD	F550
2005	4551	Digger	5	INTERNATIONAL	7400
2005	4553	Digger	5	INTERNATIONAL	7400
2005	4556	Digger	5	INTERNATIONAL	7400
2005	4557	Digger	5	INTERNATIONAL	7400
2003	4900	ATV	9	HONDA	TRX400
2003	4908	ATV	9	HONDA	TRX400
2004	4910	ATV	9	HONDA	TRX500
2004	4911	ATV	9	HONDA	TRX500
2001	4920	Forklift	9	LIFTOW	7FGU30
2005	5001	Trailer	0	HOMEMADE	GENERATOR
1992	5002	Trailer	0	NOVA	MEDIUM DUTY POLE
2005	5006	Trailer	0	SAUBER	4500 POLE
2005	5009	Trailer	0	SAUBER	4500 POLE
2005	5010	Trailer	0	SAUBER	1520 REEL
1998	5016	Trailer	0	SAUBER	UTILITY
1999	5020	Trailer	0	TIMBERLAND	REEL RC5
2000	5021	Trailer	0	TIMBERLAND	REEL RC5
1991	5033	Trailer	0	NOVA	MEDIUM DUTY POLE

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Year	Vehicle #	Type	Class	Make	Model
1999	5037	Trailer	0	TIMBERLAND	UTILITY
2000	5039	Trailer	0	OMALLEY & HUNTER	OMH6R
2000	5040	Trailer	0	OMALLEY & HUNTER	OMH15P
1990	5080	Trailer	0	NOVA	PLATFORM
2001	5084	Trailer	0	OMALLEY & HUNTER	OMALLEY & HUNTER REEL
2001	5085	Trailer	0	OMALLEY & HUNTER	OMALLEY & HUNTER REEL
2001	5086	Trailer	0	OMALLEY & HUNTER	OMALLEY & HUNTER REEL
2001	5087	Trailer	0	OMALLEY & HUNTER	OMALLEY & HUNTER REEL
2001	5088	Trailer	0	OMALLEY & HUNTER	OMALLEY & HUNTER REEL
2001	5089	Trailer	0	OMALLEY & HUNTER	OMALLEY & HUNTER REEL
1998	5090	Trailer	0	TIMBERLAND	REEL RC5
1998	5091	Trailer	0	TIMBERLAND	REEL RC5
1998	5092	Trailer	0	TIMBERLAND	REEL RC5
1998	5093	Trailer	0	TIMBERLAND	REEL RC5
2004	5094	Trailer	0	SHORELANDER	BOAT
2003	5096	Trailer	0	HOMEMADE	FLATBED
2001	5097	Trailer	0	OMALLEY & HUNTER	OMALLEY & HUNTER POLE
2001	5098	Trailer	0	OMALLEY & HUNTER	OMALLEY & HUNTER POLE
2001	5099	Trailer	0	OMALLEY & HUNTER	OMALLEY & HUNTER POLE
2005	5201	Pickup	2	FORD	F150 EXT
2005	5208	Pickup	2	FORD	RANGER EXT
2006	5226	Van	2	FORD	E350
2005	5253	Pickup	2	FORD	F150 EXT 4X4
2006	5254	Pickup	2	FORD	F150 EXT 4X4
2006	5279	Pickup	2	FORD	F250 EXT 4X4
2005	5286	Pickup	2	FORD	F150 EXT 4X4
2006	5300	Service	3	FORD	F550
2006	5301	Service	3	FORD	F450 4X4
2006	5302	Service	3	FORD	F450
2006	5303	Service	3	FORD	F550
2006	5304	Service	3	FORD	F550
2006	5411	Aerial	4	INTERNATIONAL	7400
2006	5412	Aerial	4	INTERNATIONAL	7400
2006	5414	Aerial	4	INTERNATIONAL	7400
2006	5419	Aerial	4	INTERNATIONAL	7400
1985	5902	Forklift	9	NISSAN	P4000
1993	5911	Trailer	9	TIMBERLAND	DPT40B
1988	5914	Forklift	9	TOYOTA	425FG25
1998	5918	Forklift	9	TOYOTA	FORKLIFT
2005	5930	ATV	9	ARGO	RESP8X8
1988	6006	Trailer	0	HOMEMADE	UTILITY
1992	6010	Trailer	0	MIL	EDT24
2003	6020	Trailer	0	HOMEMADE	UTILITY
2006	6201	Pickup	2	FORD	F150 EXT 4X4
2006	6214	Van	2	FORD	E350
2007	6215	Pickup	2	FORD	F150 EXT 4X4
2007	6225	Pickup	2	FORD	F150 EXT 4X4
2007	6233	Pickup	2	FORD	RANGER E4X4
2007	6261	Pickup	2	FORD	F250 4X4
2007	6300	Service	3	FORD	F550
2007	6301	Service	3	FORD	F550
2007	6302	Service	3	FORD	F350 4X4
2007	6401	Aerial	4	INTERNATIONAL	7400
2007	6402	Aerial	4	INTERNATIONAL	7400
2007	6403	Aerial	4	INTERNATIONAL	7400
2007	6407	Aerial	4	INTERNATIONAL	4400

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Year	Vehicle #	Type	Class	Make	Model
2007	6411	Aerial	4	INTERNATIONAL	4400
2007	6412	Aerial	4	INTERNATIONAL	4400
2007	6500	Digger	5	INTERNATIONAL	4300
2007	6501	Digger	5	INTERNATIONAL	4400
1986	6602	VACCUM TRU(	6	INTERNATIONAL	VACCUM
1993	6608	Crane	6	INTERNATIONAL	5000
1993	6610	CRANE	6	INTERNATIONAL	5000
1987	6620	Crane	6	GMC	C7D042
1992	6802	LOADER/DOZE	8	CATERPILLAR	824C
1987	6807	LOADER/DOZE	8	MICHIGAN	L90 WHEEL
2001	6810	LOADER/DOZE	8	THOMSON	1153D
1992	6811	LOADER/DOZE	8	MICHIGAN	L120B
1990	6817	LOADER/DOZE	8	MICHIGAN	L90 WHEEL
1987	6820	LOADER/DOZE	8	CATERPILLAR	824C
1989	6822	LOADER/DOZE	8	CATERPILLAR	824C
1993	6824	LOADER/DOZE	8	FORD	4630
2004	6830	LOADER/DOZE	8	CATERPILLAR	216B LOADER
1995	6900	FORKLIFT	9	LIFTOW	026FG30
1982	6901	ATV	9	ALC	ACP80
2002	6904	ATV	9	JDE	GATOR 6X4
1992	6907	CRANE	9	GROVE	AP308
1975	6910	CRANE	9	GROVE	RT49 MOB
1989	6913	LOADER/DOZE	9	CATERPILLAR	V90E
1990	6914	LOADER/DOZE	9	CATERPILLAR	R80 4X4
1993	6915	LOADER/DOZE	9	CATERPILLAR	GPL40
1994	6916	CRANE	9	GROVE	AMZ50G
1990	6917	CRANE	9	GROVE	AP308
1992	6920	Forklift	9	JDE	025FD40
1995	6921	CRANE	9	SHUTTLE	CRANE
1995	6922	PLANT EQUIP	9	SIMON	AT45C
1998	6925	ATV	9	JDE	GATOR 6X4
1988	6926	CRANE	9	GROVE	AP308
1998	6928	ATV	9	JDE	GATOR 6X4
1989	6940	PLANT EQUIP	9	CAN	SWX35A
2001	6942	ATV	9	JDE	GATOR 6X4
1979	6953	CRANE	9	GROVE	24 MOBILE
1998	6960	Forklift	9	TOYOTA	FORKLIFT
2006	6970	ATV	9	HONDA	TRX500
2006	6971	ATV	9	HONDA	TRX500
2007	6974	ATV	9	HONDA	TRX500
1992	7000	Trailer	0	NOVA	MEDIUM POLE
1981	7003	Trailer	0	KEARNEY	HOTLINE
1991	7007	Trailer	0	BALCOM	ARBOUR
1998	7008	Trailer	0	SAUBER	REEL
1991	7010	Trailer	0	BALCOM	ARBOUR
1998	7011	Trailer	0	SAUBER	1521-1R
1998	7020	Trailer	0	KEI	REEL S/L
1993	7030	Trailer	0	BLA	UTILITY
1978	7044	Trailer	0	ABC	HOTLINE
1993	7047	Trailer	0	NOVA	UTILITY
1998	7056	Trailer	0	TIMBERLAND	REEL RC5
1998	7057	Trailer	0	TIMBERLAND	REEL RC5
1989	7067	Trailer	0	BALCOM	MEDIUM DUTY REEL
1992	7086	Trailer	0	NOVA	MEDIUM DUTY POLE
1992	7087	Trailer	0	NOVA	MEDIUM DUTY POLE
1992	7094	Trailer	0	NOVA	REEL

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Year	Vehicle #	Type	Class	Make	Model
1990	7099	Trailer	0	NOVA	PLATFORM
2000	10602	CRANE	6	INTERNATIONAL	4700
1995	7900	Forklift	9	LIFTOW	025FG30
1993	7909	Trailer	9	TIMBERLAND	DPT40B
1988	7950	Forklift	9	TOYOTA	FORKLIFT
1998	7990	Forklift	9	TOYOTA	526FGU30
1985	8015	Trailer	0	HOMEMADE	UTILITY
1993	8042	Trailer	0	ESL	BOAT TRAILER 600
2000	8046	Trailer	0	LOADRITE	14900LRT
2004	8054	ATV	0	SKIDOO	LEGEND GT380
2001	8064	Trailer	0	SKIDOO	TRAILER
1990	8072	Trailer	0	NOVA	PLATFORM
2004	8237	Pickup	2	FORD	F250 4X4
2003	8282	Pickup	2	FORD	F250 4X4
1984	8801	LOADER/DOZE	8	JDE	450D
1981	8802	LOADER/DOZE	8	INTERNATIONAL	784
1978	8811	LOADER/DOZE	8	FORD	A64 LOAD
1978	8812	LOADER/DOZE	8	FORD	BACKHOE
1991	8820	LOADER/DOZE	8	JDE	410D B/H
2002	8904	ATV	9	BOMBARDIER	TRAXTER
1987	8908	WELDER	9	HOMEMADE	WELDER
1988	8909	COMPRESSOR	9	LEROY	Q185 TRAILER
2001	8911	Forklift	9	LIFTOW	427FG2
1994	8914	COMPRESSOR	9	MIL	251D
1986	8918	ATV	9	HONDA	TRX350
1999	8924	GENERATOR	9	SCOTT	5000
1980	8952	COMPRESSOR	9	LEROY	COMPRESS
1987	8980	COMPRESSOR	9	RAN	P250
1990	9900	Forklift	9	TOYOTA	425FG2512721
2004	9901	OIL TANKER	9	TREMCAR	OIL TANKER
1962	9902	MOBILE SUBST	9	CGE	MOBILE
1964	9903	MOBILE SUBST	9	KING	MOBILE
1992	9904	MOBILE SUBST	9	KING	MOBILE
1979	9905	MOBILE SUBST	9	MOL	MOBILE
1991	9906	MOBILE SUBST	9	MOL	MOBILE
2010	19201	SUV	2	FORD	ESCAPE
2010	19203	SUV	2	FORD	ESCAPE
2010	19204	SUV	2	FORD	ESCAPE
2010	19205	Pickup	2	FORD	F150 EXT
2010	19206	Pickup	2	FORD	F150 EXT
2010	19207	SUV	2	FORD	ESCAPE
2010	19208	Pickup	2	FORD	F250 EXT 4X4
2010	19209	Pickup	2	FORD	F150 EXT 4X4
2010	19210	Pickup	2	FORD	F150 EXT 4X4
2010	19211	Pickup	2	FORD	F150 EXT
2010	19212	Pickup	2	FORD	F150 EXT
2010	19214	Van	2	FORD	E350
2010	19215	Pickup	2	FORD	F250 CC 4X4
2010	19219	Pickup	2	FORD	F150 EXT
2010	19243	Pickup	2	FORD	F150 EXT
2010	19244	Pickup	2	FORD	F150 EXT
2010	19245	Pickup	2	FORD	F150 EXT
2010	19246	Pickup	2	FORD	F150 EXT
2010	19248	Pickup	2	FORD	F150 EXT
2008	19918	ATV	9	ARGO	8X8 750
2010	19917	ATV	9	ARGO	8X8 AVENGER 700

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Year	Vehicle #	Type	Class	Make	Model
2010	19249	SUV	2	FORD	ESCAPE 4X4
2010	19000	Trailer	0	HOMEMADE	HEAVY DUTY POLE
2010	19001	ATV	0	SKIDOO	TUNDRA SPT 550
2009	10000	Trailer	0	MISS	UTILITY
2010	10019	Trailer	0	SURE	PLATFORM
2010	10422	Aerial	4	ALTEC	AT37GW
2009	10034	Trailer	0	H & H	PLATFORM
2009	10538	Digger	5	ALTEC	DB37 DIGGER
2010	10001	Trailer	0	GATOR	UTILITY
2011	10400	Aerial	4	INTERNATIONAL	4400
2010	10401	Aerial	4	INTERNATIONAL	7400
2011	10402	Aerial	4	INTERNATIONAL	4400
2010	10403	Aerial	4	INTERNATIONAL	7400
2010	10404	Aerial	4	INTERNATIONAL	7400
2010	10405	Aerial	4	INTERNATIONAL	7400
2011	10406	Aerial	4	INTERNATIONAL	4400
2010	10407	Aerial	4	INTERNATIONAL	7400
2010	10408	Aerial	4	INTERNATIONAL	4400
2010	10409	Aerial	4	INTERNATIONAL	4400
2010	10410	Aerial	4	INTERNATIONAL	4400
2010	10411	Aerial	4	INTERNATIONAL	4400
2011	10412	Aerial	4	INTERNATIONAL	4400
2011	10413	Aerial	4	INTERNATIONAL	4400
2011	10414	Aerial	4	INTERNATIONAL	4400
2010	10415	Aerial	4	INTERNATIONAL	7400
2010	10416	Aerial	4	INTERNATIONAL	7400
2010	10417	Aerial	4	INTERNATIONAL	7400
2010	10418	Aerial	4	INTERNATIONAL	4400
2010	10419	Aerial	4	INTERNATIONAL	4400
2010	10420	Aerial	4	INTERNATIONAL	4400
2010	10522	Digger	5	INTERNATIONAL	7400
2010	10523	Digger	5	INTERNATIONAL	7400
2010	10524	Digger	5	INTERNATIONAL	7400
2010	10525	Digger	5	INTERNATIONAL	7400
2010	10526	Digger	5	INTERNATIONAL	7400
2010	10100	Car	1	FORD	FUSION
2011	10200	SUV	2	FORD	ESCAPE
2011	10201	SUV	2	FORD	ESCAPE
2010	10202	Pickup	2	FORD	F150 EXT
2010	10203	SUV	2	FORD	ESCAPE
2010	10204	SUV	2	FORD	ESCAPE
2010	10205	Pickup	2	FORD	F150 EXT 4X4
2010	10207	SUV	2	FORD	ESCAPE
2010	10210	Pickup	2	FORD	RANGER E4X4
2010	10211	Van	2	FORD	E350
2010	10212	Van	2	FORD	E350
2010	10213	Pickup	2	FORD	RANGER EXT
2010	10214	Pickup	2	FORD	F150 EXT
2010	10215	SUV	2	FORD	ESCAPE 4X4
2010	10216	Van	2	FORD	E350
2010	10217	Pickup	2	FORD	F150 EXT-YRD
2011	10218	Pickup	2	FORD	RANGER EXT
2010	10219	Pickup	2	FORD	F150 EXT
2010	10220	Pickup	2	FORD	RANGER E4X4
2010	10221	Van	2	FORD	E350
2010	10222	Pickup	2	FORD	RANGER E4X4

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Year	Vehicle #	Type	Class	Make	Model
2010	10223	Pickup	2	FORD	F150 EXT 4X4
2010	10224	Pickup	2	FORD	F150 EXT 4X4
2010	10225	Pickup	2	FORD	RANGER EXT
2010	10226	Van	2	FORD	E350
2010	10227	Pickup	2	FORD	F150 EXT 4X4
2010	10228	Pickup	2	FORD	F150 EXT 4X4
2010	10230	Pickup	2	FORD	F150 EXT 4X4
2010	10231	Pickup	2	FORD	F150 EXT 4X4
2010	10232	Pickup	2	FORD	F150 EXT 4X4
2010	10233	Pickup	2	FORD	F150 EXT 4X4
2010	10234	Pickup	2	FORD	F150 EXT
2010	10235	Pickup	2	FORD	F150 EXT 4X4
2011	10236	Pickup	2	FORD	F250
2010	10237	Pickup	2	FORD	F150 EXT 4X4
2010	10238	SUV	2	FORD	ESCAPE 4X4
2010	10239	Pickup	2	FORD	F150 EXT 4X4
2010	10241	Van	2	FORD	E350
2010	10242	SUV	2	FORD	ESCAPE 4X4
2011	10243	Pickup	2	FORD	F250 EXT 4X4
2010	10244	Pickup	2	FORD	F150 EXT 4X4
2010	10245	Pickup	2	FORD	F150 EXT
2010	10246	Pickup	2	FORD	F150 EXT 4X4
2010	10247	Pickup	2	FORD	F150 EXT
2010	10248	Van	2	FORD	E350
2010	10249	Pickup	2	FORD	F150 EXT 4X4
2010	10251	Pickup	2	FORD	F150 EXT
2010	10252	Pickup	2	FORD	F150 4X4
2010	10253	Pickup	2	FORD	F150 EXT 4X4
2010	10254	Pickup	2	FORD	F150 4X4
2011	10255	Pickup	2	FORD	F350 CREW 4X4
2011	10256	Pickup	2	FORD	F250 4X4
2010	10257	Pickup	2	FORD	F150 EXT 4X4
2010	10258	Pickup	2	FORD	F150 EXT 4X4
2010	10259	Pickup	2	FORD	F150 4X4
2010	10260	Pickup	2	FORD	F150 EXT 4X4
2010	10261	Pickup	2	FORD	F150 EXT
2011	10262	Pickup	2	FORD	F250
2010	10263	SUV	2	FORD	ESCAPE 4X4
2011	10264	Pickup	2	FORD	F250 4X4
2007	10265	Pickup	2	FORD	F150 CC 4X4
2011	10266	Van	2	FORD	E350
2010	10421	Aerial	4	FORD	F550
2010	10002	Trailer	0	SAUBER	1520 DBL ARBOUR
2010	10003	Trailer	0	SAUBER	1500 SGL ARBOUR
2010	10004	Trailer	0	SAUBER	4500 POLE
2010	10005	Trailer	0	SAUBER	1500 SGL ARBOUR
2010	10006	Trailer	0	SAUBER	1550 SGL UTILITY
2011	10600	CRANE	6	INTERNATIONAL	4400 16' ALUM
2011	10601	CRANE	6	INTERNATIONAL	4400 21' ALUM
2010	10267	Pickup	2	FORD	F150 EXT 4X4
2011	10300	Service	3	FORD	F550/CRANE
2011	10301	Service	3	FORD	F550
2011	10302	Service	3	FORD	F550
2010	10902	Trailer	0	SATURN	SWITCH TRAILER
2010	10907	Trailer	0	SATURN	SWITCH TRAILER
2010	10007	Trailer	0	LOADRITE	16F1200 BOAT TRAILER

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Year	Vehicle #	Type	Class	Make	Model
2010	10009	Trailer	0	GATOR	ATV TRAILER
2010	10910	Forklift	9	TOYOTA	8FGU30 FORKLIFT
2010	10911	Forklift	9	TOYOTA	8FGU25 FORKLIFT
2011	10270	Pickup	2	FORD	RANGER EXT
2011	10268	SUV	2	FORD	ESCAPE 4X4
2011	10269	SUV	2	FORD	ESCAPE
2010	10011	Trailer	0	GATOR	6X16 UTILITY
2010	10912	ATV	9	KAWASAKI	TERYX 4X4
2011	10272	Pickup	2	FORD	F250
2011	10274	Pickup	2	FORD	F250
2011	10209	Pickup	2	FORD	F250 CC 4X4
2010	10277	Pickup	2	FORD	F150 EXT
2010	10275	Pickup	2	FORD	F150 EXT 4X4
2010	10276	Pickup	2	FORD	F150 EXT 4X4
2010	10012	ATV	0	CATERPILLAR	570 BEARCATERPILLAR
2011	10273	Pickup	2	FORD	F250 4X4
2011	10904	ATV	9	ARGO	750 HD
2011	10901	ATV	9	HONDA	TRX500 PGCTE
2011	10908	ATV	9	HONDA	TRX500 PGCTE
2011	10909	ATV	9	HONDA	TRX500 PGCTE
2010	10013	ATV	0	CATERPILLAR	570 BEARCATERPILLAR
2011	10279	Pickup	2	FORD	RANGER EXT
2010	10913	Forklift	9	TOYOTA	7FGU25
2011	10914	ATV	9	GATOR	TH6X4
2011	10280	SUV	2	FORD	ESCAPE 4X4
2010	11014	Trailer	0	KARAVAN	BOAT TRAILER
2011	10915	ATV	9	KAWASAKI	MULE610 6X4
2011	11015	Trailer	0	EQUESTRIAN	UTILITY
2008	11800	LOADER/DOZE	8	KOMATSU	D155AX-6 DOZER
2011	11200	Pickup	2	FORD	RANGER EXT
2012	11201	SUV	2	FORD	ESCAPE
2011	11202	Pickup	2	FORD	RANGER EXT
2012	11203	SUV	2	FORD	ESCAPE
2011	11204	Pickup	2	FORD	RANGER EXT
2011	11205	Van	2	FORD	E350
2011	11206	Pickup	2	FORD	F150 EXT
2011	11207	Pickup	2	FORD	RANGER EXT
2011	11208	Pickup	2	FORD	RANGER EXT
2012	11209	SUV	2	FORD	ESCAPE
2011	11210	Pickup	2	FORD	F150 EXT 4X4
2011	11211	Pickup	2	FORD	F150 EXT
2011	11212	Pickup	2	FORD	F150 EXT
2011	11213	Pickup	2	FORD	RANGER EXT
2012	11214	SUV	2	FORD	ESCAPE
2011	11215	Pickup	2	FORD	RANGER EXT
2011	11217	Pickup	2	FORD	F150 EXT 4X4
2011	11218	Pickup	2	FORD	F150 EXT
2011	11219	Pickup	2	FORD	F150 EXT
2011	11220	Pickup	2	FORD	F150 EXT
2011	11221	Pickup	2	FORD	F150 EXT
2011	11222	Pickup	2	FORD	F150 EXT 4X4
2011	11223	Pickup	2	FORD	RANGER EXT
2011	11225	Pickup	2	FORD	F150 EXT 4X4
2011	11226	Pickup	2	FORD	F150 EXT 4X4
2011	11227	Pickup	2	FORD	RANGER EXT
2011	11228	Pickup	2	FORD	F150 EXT 4X4

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Year	Vehicle #	Type	Class	Make	Model
2011	11229	Pickup	2	FORD	F150 EXT 4X4
2012	11230	SUV	2	FORD	ESCAPE
2011	11231	Pickup	2	FORD	F150 EXT
2012	11232	SUV	2	FORD	ESCAPE 4X4
2011	11233	Pickup	2	FORD	F150 EXT
2011	11234	Pickup	2	FORD	F150 EXT-YARD
2011	11235	Pickup	2	FORD	F150 EXT 4X4
2012	11236	SUV	2	FORD	ESCAPE 4X4
2011	11237	Pickup	2	FORD	F150 EXT 4X4
2012	11238	SUV	2	FORD	ESCAPE 4X4
2012	11239	SUV	2	FORD	ESCAPE 4X4
2012	11240	SUV	2	FORD	ESCAPE 4X4
2011	11241	Pickup	2	FORD	F150 EXT 4X4
2012	11242	SUV	2	FORD	ESCAPE 4X4
2012	11243	Pickup	2	FORD	F350 EXT4X4 8'
2012	11244	Pickup	2	FORD	F350 EXT4X4 8'
2011	11245	Pickup	2	FORD	F150 EXT 4X4
2011	11246	Pickup	2	FORD	F150 EXT 4X4
2011	11247	Van	2	FORD	E350
2011	11248	Van	2	FORD	E350
2011	11249	Van	2	FORD	E350
2012	11250	Pickup	2	FORD	F350 EXT4X4 8'
2012	11251	Pickup	2	FORD	F350 EXT4X4 8'
2011	11252	Van	2	FORD	E350
2012	11253	SUV	2	FORD	ESCAPE 4X4
2011	11254	Pickup	2	FORD	F150 EXT 4X4
2011	11255	Pickup	2	FORD	F150 EXT 4X4
2011	11256	Pickup	2	FORD	F150 EXT 4X4
2011	11257	Pickup	2	FORD	F150 EXT 4X4
2012	11258	SUV	2	FORD	ESCAPE 4X4
2011	11260	Pickup	2	FORD	F150 EXT 4X4
2012	11262	SUV	2	FORD	ESCAPE 4X4
2012	11263	Pickup	2	FORD	F250 EXT 4X4
2012	11264	SUV	2	FORD	ESCAPE 4X4
2012	11265	SUV	2	FORD	ESCAPE 4X4
2012	11600	Crane	6	INTERNATIONAL	7600
2011	11801	LOADER/DOZE	8	JDE	544K 4WD LOADER
2011	11408	Aerial	4	INTERNATIONAL	4400
2011	11410	Aerial	4	INTERNATIONAL	4400
2011	11413	Aerial	4	INTERNATIONAL	4400
2012	11400	Aerial	4	INTERNATIONAL	4400
2012	11401	Aerial	4	INTERNATIONAL	4400
2012	11402	Aerial	4	INTERNATIONAL	7400
2012	11403	Aerial	4	INTERNATIONAL	4400
2012	11404	Aerial	4	INTERNATIONAL	4400
2012	11405	Aerial	4	INTERNATIONAL	4400
2012	11406	Aerial	4	INTERNATIONAL	4400
2012	11407	Aerial	4	INTERNATIONAL	7400
2012	11409	Aerial	4	INTERNATIONAL	4400
2012	11411	Aerial	4	INTERNATIONAL	4400
2012	11412	Aerial	4	INTERNATIONAL	4400
2012	11500	Digger	5	INTERNATIONAL	4400
2011	11000	Trailer	0	SAUBER	1500 REEL
2011	11001	Trailer	0	SAUBER	1500 REEL
2011	11002	Trailer	0	SAUBER	1500 SGL REEL
2011	11003	Trailer	0	SAUBER	1500

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Year	Vehicle #	Type	Class	Make	Model
2011	11004	Trailer	0	SAUBER	1500
2011	11005	Trailer	0	SAUBER	1500
2011	11006	Trailer	0	SAUBER	1500 ARBOUR
2011	11021	Trailer	0	SAUBER	1555 REEL
2011	11022	Trailer	0	SAUBER	1555 SGL UTILITY
2012	11303	Service	3	TERRASTAR	SFA4X2
2012	11304	Service	3	TERRASTAR	SFA4X2
2011	11916	Forklift	9	CATERPILLAR	2P6000 FORKLIFT
2012	11305	Service	3	TERRASTAR	SFA4X2
2012	11306	Service	3	TERRASTAR	SFA4X2
2011	11109	Car	1	FORD	FOCUS
2012	11917	ATV	9	SUZUKI	750 KINGQUAD ATV
2012	11918	ATV	9	SUZUKI	750 KINGQUAD ATV
2011	11919	ATV	9	SUZUKI	750 KINGQUAD ATV
2011	11920	Forklift	9	CATERPILLAR	P9000 FORKLIFT
2006	11921	Forklift	9	YALE	ERP050 FORKLIFT
2012	11111	Car	1	NISSAN	LEAF SEDAN
2012	11116	Car	1	NISSAN	LEAF SEDAN
2011	11016	Trailer	0	SAUBER	1531 REEL TRAILER
2011	11017	Trailer	0	SAUBER	1531 REEL TRAILER
2011	11018	Trailer	0	SAUBER	1531 REEL TRAILER
2011	11020	Trailer	0	SAUBER	1531 REEL TRAILER
2010	11456	Aerial	4	INTERNATIONAL	7600
2012	11603	Crane	6	INTERNATIONAL	7600
2012	11023	Trailer	0	MAXI	UTILITY TRAILER
2012	11266	Pickup	2	FORD	F250 EXT 4X4
2011	12024	Trailer	0	IDEAL	CARGO TRAILER
2011	11922	LOADER/DOZE	9	KUBOTA	RTV110
2011	12025	Trailer	0	TRANSPORT	XL81 BATTERY TRAILER
2012	12215	Van	2	DODGE	RAM CARGO
2012	12217	Van	2	DODGE	RAM CARGO
2012	12267	Van	2	DODGE	RAM CARGO
2012	12026	Trailer	0	SAUBER	4500 POLE
2012	12923	ATV	9	SUZUKI	750 KING QUAD ATV
2012	12027	ATV	0	RENEGADE	600 ACE SKIDOO
2011	12207	Pickup	2	FORD	RANGER EXT
2013	12292	Pickup	2	FORD	F250 EXT
2011	12214	Pickup	2	FORD	RANGER EXT
2011	12273	Pickup	2	FORD	RANGER EXT
2011	12278	Pickup	2	FORD	RANGER EXT
2011	12219	Pickup	2	FORD	RANGER E4X4
2011	12282	Pickup	2	FORD	RANGER E4X4
2011	12295	Pickup	2	FORD	RANGER E4X4
2011	12284	Pickup	2	FORD	RANGER E4X4
2011	12283	Pickup	2	FORD	RANGER E4X4
2011	12276	Pickup	2	FORD	RANGER E4X4
2011	12226	Pickup	2	FORD	RANGER E4X4
2012	12203	Pickup	2	FORD	F250 CC 4X4
2012	12208	Van	2	FORD	E350
2012	12285	Van	2	FORD	E150 VAN
2012	12286	Van	2	FORD	E150 VAN
2013	12297	Van	2	FORD	E350
2012	12298	Van	2	FORD	E150 VAN
2010	19247	Pickup	2	FORD	F150 EXT-YARD
2012	12202	Pickup	2	FORD	F150 EXT
2012	12205	Pickup	2	FORD	F150 EXT

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Year	Vehicle #	Type	Class	Make	Model
2012	12209	Pickup	2	FORD	F150 EXT
2012	12213	Pickup	2	FORD	F150 EXT
2012	12220	Pickup	2	FORD	F150 EXT
2012	12221	Pickup	2	FORD	F150 EXT
2012	12224	Pickup	2	FORD	F150 EXT
2012	12272	Pickup	2	FORD	F150 EXT
2012	12274	Pickup	2	FORD	F150 EXT
2012	12281	Pickup	2	FORD	F150 EXT
2012	12289	Pickup	2	FORD	F150 EXT
2012	12290	Pickup	2	FORD	F150 EXT
2012	12201	Pickup	2	FORD	F150 EXT 4X4
2012	12210	Pickup	2	FORD	F150 EXT 4X4
2012	12211	Pickup	2	FORD	F150 EXT 4X4
2012	12212	Pickup	2	FORD	F150 EXT 4X4
2012	12216	Pickup	2	FORD	F150 EXT 4X4
2012	12218	Pickup	2	FORD	F150 EXT 4X4
2012	12222	Pickup	2	FORD	F150 EXT 4X4
2012	12223	Pickup	2	FORD	F150 EXT 4X4
2012	12225	Pickup	2	FORD	F150 EXT 4X4
2012	12227	Pickup	2	FORD	F150 EXT 4X4
2012	12269	Pickup	2	FORD	F150 EXT 4X4
2012	12270	Pickup	2	FORD	F150 EXT 4X4
2012	12271	Pickup	2	FORD	F150 EXT 4X4
2012	12275	Pickup	2	FORD	F150 EXT 4X4
2012	12288	Pickup	2	FORD	F150 EXT 4X4
2012	12294	Pickup	2	FORD	F150 EXT 4X4
2012	12299	Pickup	2	FORD	F150 EXT 4X4
2012	12200	Pickup	2	FORD	F350 EXT4X4 8'
2012	12268	Pickup	2	FORD	F350 EXT4X4 8'
2012	12296	Pickup	2	FORD	F250 EXT 4X4
2013	12206	SUV	2	FORD	ESCAPE
2013	12277	SUV	2	FORD	ESCAPE
2013	12280	SUV	2	FORD	ESCAPE
2012	12287	SUV	2	FORD	ESCAPE
2013	12291	SUV	2	FORD	ESCAPE
2013	12293	SUV	2	FORD	ESCAPE
2012	12204	Pickup	2	FORD	F250 4X4
2012	12028	Trailer	0	LOADRITE	BOAT TRAILER
2012	12029	Trailer	0	HOMEMADE	POLE TRAILER
2012	12030	Trailer	0	IDEAL	CARGO TRAILER
2012	12031	Trailer	0	SAUBER	1566
2012	12032	Trailer	0	SAUBER	1555
2012	12033	Trailer	0	SAUBER	1555
2012	12230	SUV	2	FORD	ESCAPE 4X4
2013	12457	Aerial	4	INTERNATIONAL	7600
2013	12458	Aerial	4	INTERNATIONAL	7600
2013	12459	Aerial	4	INTERNATIONAL	7600
2013	12460	Aerial	4	INTERNATIONAL	4400
2013	12461	Aerial	4	INTERNATIONAL	4400
2013	12462	Aerial	4	INTERNATIONAL	4400
2013	12463	Aerial	4	INTERNATIONAL	4400
2013	12464	Aerial	4	INTERNATIONAL	7600
2013	12465	Aerial	4	INTERNATIONAL	4400
2013	12466	Aerial	4	INTERNATIONAL	TERRASTAR
2013	12467	Aerial	4	INTERNATIONAL	4400
2013	12468	Aerial	4	INTERNATIONAL	TERRASTAR

Year	Vehicle #	Type	Class	Make	Model
2013	12469	Aerial	4	INTERNATIONAL	4400
2013	12470	Aerial	4	INTERNATIONAL	7600
2013	12471	Aerial	4	INTERNATIONAL	7600
2013	12558	Digger	5	INTERNATIONAL	4400
2012	12231	Pickup	2	FORD	F250 4X4
2012	12034	Trailer	0	GATOR	16 LOW
2013	13925	ATV	9	POLARIS	RANGER 800XP
2012	13924	Forklift	9	CATERPILLAR	P6000LE
2014	13307	Service	3	FORD	F450 EXT 4X4
2014	13308	Service	3	FORD	F450 EXT 4X4
2014	13472	Aerial	4	INTERNATIONAL	4400
2014	13473	Aerial	4	INTERNATIONAL	4400
2014	13474	Aerial	4	INTERNATIONAL	4400
2014	13475	Aerial	4	INTERNATIONAL	4400
2013	13926	GENERATOR	9	AGB	600L GENERATOR/TRAILER
2011	13200	Pickup	2	FORD	RANGER EXT
2011	13201	Pickup	2	FORD	RANGER EXT
2014	14476	Aerial	4	INTERNATIONAL	7400
2014	14477	Aerial	4	INTERNATIONAL	7400
2014	14478	Aerial	4	INTERNATIONAL	7400
2014	14479	Aerial	4	INTERNATIONAL	7400
2014	14480	Aerial	4	INTERNATIONAL	4400
2014	14487	Aerial	4	INTERNATIONAL	4400
2014	14482	Aerial	4	INTERNATIONAL	4400
2014	14483	Aerial	4	INTERNATIONAL	4400
2014	14484	Aerial	4	INTERNATIONAL	4400
2014	14485	Aerial	4	INTERNATIONAL	4400
2014	14486	Aerial	4	INTERNATIONAL	7400
2014	14559	Digger	5	INTERNATIONAL	7400
2013	13035	Trailer	0	GATOR	UTILITY 16'
2014	13202	Pickup	2	FORD	F150 4X4
2014	13205	Pickup	2	FORD	F150 4X4
2014	13208	Pickup	2	FORD	F150 4X4
2014	13206	SUV	2	FORD	ESCAPE
2014	13207	SUV	2	FORD	ESCAPE
2014	13204	SUV	2	FORD	ESCAPE
2014	13203	SUV	2	FORD	ESCAPE
2014	13927	ATV	9	SUZUKI	750 KING QUAD
2014	13928	ATV	9	SUZUKI	750 KING QUAD
2014	13929	ATV	9	SUZUKI	750 KING QUAD
2014	13931	ATV	9	SUZUKI	750 KING QUAD
2014	13930	ATV	9	SUZUKI	750 KING QUAD
2014	13932	ATV	9	SUZUKI	750 KING QUAD
2014	13210	SUV	2	FORD	ESCAPE
2014	13211	SUV	2	FORD	ESCAPE
2014	13212	SUV	2	FORD	ESCAPE 4X4
2014	13209	Pickup	2	FORD	F250 4X4
2014	14036	Trailer	0	GATOR	16' UTILITY
2014	14037	Trailer	0	GATOR	12' UTILITY
1991	9920	Aerial	9	INTERNATIONAL	SF265
1994	9921	PUMPER TRUC	9	INTERNATIONAL	SF265 TANK/PUMP
1994	9922	Aerial	9	FORD	LGT
2014	14904	Forklift	9	HYSTER	J50XN
2014	14038	Trailer	0	ALC	HIGHC 5X10
2014	ENL200	Pickup	2	FORD	F150 EXT 4X4
2014	ENL202	Pickup	2	FORD	F150 EXT 4X4

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Year	Vehicle #	Type	Class	Make	Model
2014	ENL203	Pickup	2	FORD	F150 EXT 4X4
2014	ENL201	Pickup	2	FORD	F150 EXT 4X4
2014	14933	ATV	9	ARGO	750 HD
2014	ENL204	Pickup	2	FORD	F150 CREWCAB 4X4
2014	ENL205	Pickup	2	FORD	F150 CREWCAB 4X4
2014	ENL206	Pickup	2	FORD	F150 CREWCAB 4X4
2014	ENL207	Pickup	2	FORD	F150 CREWCAB 4X4
2014	ENL208	Pickup	2	FORD	F150 CREWCAB 4X4
2014	ENL209	Pickup	2	FORD	F150 CREWCAB 4X4
2015	14213	SUV	2	FORD	ESCAPE
2014	14214	Pickup	2	FORD	F150 EXT-YARD
2014	14215	Pickup	2	FORD	F150 EXT
2014	14216	Pickup	2	FORD	F150 EXT 4X4
2015	14217	SUV	2	FORD	ESCAPE 4X4
2014	14218	Pickup	2	FORD	F150 EXT 4X4
2015	14219	SUV	2	FORD	ESCAPE
2015	14220	SUV	2	FORD	ESCAPE 4X4
2014	14221	Pickup	2	FORD	F150 EXT 4X4
2015	14222	SUV	2	FORD	ESCAPE
2014	14223	Pickup	2	FORD	F150 EXT
2014	14224	Pickup	2	FORD	F150 EXT 4X4
2015	19239	SUV	2	FORD	ESCAPE 4X4
2015	14226	SUV	2	FORD	ESCAPE
2015	14227	SUV	2	FORD	ESCAPE 4X4
2014	14228	Pickup	2	FORD	F150 EXT
2014	14229	Pickup	2	FORD	F150 EXT-YARD
2014	14230	Pickup	2	FORD	F150 EXT 4X4
2015	14231	SUV	2	FORD	ESCAPE
2014	14232	Pickup	2	FORD	F150 EXT
2014	14233	Pickup	2	FORD	F150 EXT 4X4
2015	14234	SUV	2	FORD	ESCAPE
2014	14235	Pickup	2	FORD	F150 EXT 4X4
2014	14236	Pickup	2	FORD	F150 EXT 4X4
2014	14237	Pickup	2	FORD	F150 EXT 4X4
2015	14238	SUV	2	FORD	ESCAPE
2015	14239	SUV	2	FORD	ESCAPE
2015	14240	SUV	2	FORD	ESCAPE
2014	14241	Pickup	2	FORD	F150 EXT 4X4
2014	14242	Pickup	2	FORD	F150 EXT
2014	14243	Pickup	2	FORD	F150 EXT
2014	14244	Pickup	2	FORD	F150 EXT
2015	14245	Pickup	2	FORD	F250 REG 8'
2014	14246	Pickup	2	FORD	F150 EXT 4X4
2014	14247	Pickup	2	FORD	F150 EXT 4X4
2014	14248	Pickup	2	FORD	F150 EXT 4X4
2014	14249	Pickup	2	FORD	F150 EXT 4X4
2015	14250	SUV	2	FORD	ESCAPE
2015	14251	SUV	2	FORD	ESCAPE
2014	14252	Pickup	2	FORD	F150 EXT
2015	14253	Pickup	2	FORD	F250 EXT 4X4
2014	14039	Trailer	0	DOVETAIL	UTILITY
2014	14934	ATV	9	SUZUKI	KING QUAD L-750
2015	14935A	MOBILE SUBST	9	RACKLEY	MOBILE MP4
2015	14935B	MOBILE SUBST	9	RACKLEY	MOBILE AXLE JEEP
2014	14936	ATV	9	SUZUKI	750 KING QUAD
2013	14040	ATV	0	ARCTIC	CATERPILLAR 570XT

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Year	Vehicle #	Type	Class	Make	Model
2013	14041	ATV	0	ARCTIC	CATERPILLAR 570XT
2015	14042	ATV	0	ARCTIC	CATERPILLAR 5701XTE
2010	14831	ATV	8	CATERPILLAR	336DL EXCAVATOR
2014	14938	Forklift	9	TOYOTA	8FGC70U
2011	14937	Trailer	9	GODWIN	DIESEL PUMP
2014	14939	Forklift	9	HYUNDAI	25L7A LPG CAB
2014	ENL210	Pickup	2	FORD	F150 4X4
2014	ENL211	Pickup	2	FORD	F150 4X4
2014	ENL212	Pickup	2	FORD	F150 4X4
2015	14044	Trailer	0	GATOR	6X12 DUAL AXLE
2015	14043	Trailer	0	GATOR	6X12 S/A AXLE
2014	15045	Trailer	0	USCARGO	6X12 UTILITY
2014	15046	Trailer	0	USCARGO	6.5X12 UTILITY
2010	10916	ATV	9	GATOR	XUV6201
2015	15047	Trailer	0	ATC	RAVEN 8.5
2015	15048	Trailer	0	ATC	RAVEN 7
2011	10603	Dump	6	JDE	250DII WATER
2007	17800	LOADER/DOZE	8	JDE	850J DOZER
2015	15940	LOADER/DOZE	9	KUBOTA	X1100C
2015	15254	Van	2	DODGE	G CARAVAN
2015	15255	Van	2	DODGE	G CARAVAN
2015	15200	Pickup	2	FORD	F150 EXT
2015	15201	Pickup	2	FORD	F150 EXT 4X4
2015	15202	Pickup	2	FORD	F150 EXT 4X4
2015	15203	Pickup	2	FORD	F150 EXT
2015	15204	Pickup	2	FORD	F150 EXT
2016	15205	SUV	2	FORD	ESCAPE 4X4
2016	15206	SUV	2	FORD	ESCAPE 4X4
2015	15207	Pickup	2	FORD	F150 EXT
2015	15208	Pickup	2	FORD	F150 EXT 4X4
2016	15209	SUV	2	FORD	ESCAPE
2016	15210	Pickup	2	FORD	F250 4X4
2015	15211	Service	2	FORD	F150 REG 4X4
2015	15212	Pickup	2	FORD	F150 EXT 4X4
2015	15213	Pickup	2	FORD	F150 EXT 4X4
2015	15214	Pickup	2	FORD	F150 REG 4X4
2016	15215	Pickup	2	FORD	F250
2016	15216	Pickup	2	FORD	F250
2016	15217	SUV	2	FORD	ESCAPE 4X4
2016	15218	SUV	2	FORD	ESCAPE 4X4
2015	15219	Pickup	2	FORD	F150 REG 4X4
2015	15220	Pickup	2	FORD	F150 EXT 4X4
2016	15221	SUV	2	FORD	ESCAPE 4X4
2015	15222	Pickup	2	FORD	F150 REG 4X4
2015	15223	Pickup	2	FORD	F150 REG 4X4
2015	15224	Pickup	2	FORD	F150 REG 4X4
2015	15225	Pickup	2	FORD	F150 REG 4X4
2016	15226	SUV	2	FORD	ESCAPE
2015	15227	Pickup	2	FORD	F150 EXT 4X4
2015	15228	Pickup	2	FORD	F150 EXT
2016	15229	SUV	2	FORD	ESCAPE 4X4
2015	15230	Pickup	2	FORD	F150 EXT
2015	15231	Pickup	2	FORD	F150 EXT 4X4
2015	15232	Pickup	2	FORD	F150 EXT 4X4
2015	15233	Pickup	2	FORD	F150 EXT
2015	15234	Pickup	2	FORD	F150 REG 4X4

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Year	Vehicle #	Type	Class	Make	Model
2015	15235	Pickup	2	FORD	F150 EXT 4X4
2016	15236	SUV	2	FORD	ESCAPE 4X4
2015	15237	Pickup	2	FORD	F150 EXT
2016	15238	SUV	2	FORD	ESCAPE 4X4
2015	15239	Pickup	2	FORD	F150 REG 4X4
2015	15240	Pickup	2	FORD	F150 EXT 4X4
2015	15241	Pickup	2	FORD	F150 EXT 4X4
2015	15242	Pickup	2	FORD	F150 EXT
2015	15243	Pickup	2	FORD	F150 EXT
2016	15244	SUV	2	FORD	ESCAPE 4X4
2015	15245	Pickup	2	FORD	F150 REG 4X4
2015	15246	Pickup	2	FORD	F150 EXT 4X4
2016	15247	Pickup	2	FORD	F250 4X4 8'/PL
2015	15248	Pickup	2	FORD	F150 EXT 4X4
2015	15249	Pickup	2	FORD	F150 EXT 4X4
2015	15560	Digger	5	FREIGHTLINER	FW2
2015	15049	Trailer	0	BROOKS BROS	SRT-SINGLE REEL
2015	15050	Trailer	0	BROOKS BROS	2RT-TWO REEL
2015	15051	Trailer	0	BROOKS BROS	3RT-THREE REEL
2015	15834	LOADER/DOZE	8	CATERPILLAR	226B3N LOADER
2015	15488	Aerial	4	INTERNATIONAL	4400
2015	15489	Aerial	4	INTERNATIONAL	4400
2016	15561	Digger	5	INTERNATIONAL	7400
2016	15562	Digger	5	INTERNATIONAL	4300
2016	15563	Digger	5	INTERNATIONAL	7400
2016	15564	Digger	5	INTERNATIONAL	7400
2016	15490	Aerial	4	INTERNATIONAL	7400
2016	15492	Aerial	4	INTERNATIONAL	7400
2016	15493	Aerial	4	INTERNATIONAL	7400
2016	15494	Aerial	4	INTERNATIONAL	7400
2016	15495	Aerial	4	INTERNATIONAL	7400
2016	15496	Aerial	4	INTERNATIONAL	7400
2016	15497	Aerial	4	INTERNATIONAL	7400
2016	15256	Pickup	2	FORD	F250 EXT
2016	15257	Pickup	2	FORD	F250 EXT
2016	15258	Pickup	2	FORD	F250 EXT
2016	15259	Pickup	2	FORD	F250 EXT
2016	15260	Pickup	2	FORD	F250 EXT
2016	15491	Aerial	4	INTERNATIONAL	7400
2015	15052	Trailer	0	SKIDOO	XT-10 SKIDOO TRAILER
2006	15941	Forklift	9	TOYOTA	7FGU30
2015	15290	Pickup	2	FORD	F150 SUPERCREW
2015	15300	Service	3	DODGE	RAM 5500 CREW
2015	15301	Service	3	DODGE	RAM 3500 CREW
2016	15250	Pickup	2	FORD	F150 4X4
2015	15291	SUV	2	FORD	ESCAPE
2015	15292	SUV	2	FORD	ESCAPE 4X4
2015	15293	SUV	2	FORD	ESCAPE 4X4
2015	15294	SUV	2	FORD	ESCAPE 4X4
2015	15295	SUV	2	FORD	ESCAPE 4X4
2015	15296	SUV	2	FORD	ESCAPE 4X4
2015	15297	SUV	2	FORD	ESCAPE 4X4
2015	14225	SUV	2	FORD	ESCAPE
2015	ENL214	Aerial	2	FORD	F150 4X4

CONFIDENTIAL (Attachment Only)

Request IR-16:

Please provide the derivation of the replacement energy costs used in the EAM spreadsheets, including descriptions of the input assumptions in the Plexos (or other production-costing model) runs.

(a) Please explain how the incremental replacement costs of certain units can be negative.

(b) Please explain why the incremental replacement costs are shown as being the same across steam units in a plant, even where those units have different heat rates.

(c) Please explain why the incremental replacement costs are shown as being identical across the hydro units, even though the operating patterns of those units vary substantially, in terms of daily and monthly patterns.

(d) Please provide NS Power's projection of the cost of replacement energy by hour for the years modeled.

(e) Please provide any data on the monthly, daily and hourly dispatch of each NSP generating unit or purchase in the Plexos (or other production costing model) runs used to develop the projection of the replacement energy cost.

(f) Please provide NS Power's estimate of the cost of replacement energy by hour for 2014 and 2015 (to the latest date available).

(g) Please provide the actual hourly dispatch of each NSP generating unit or purchase for 2014 and 2015 (to the latest date available).

Response IR-16:

Please refer to Partially Confidential Attachment 1, also provided electronically.

(a) The Plexos simulation captures the operation of the NS Power system over an entire year and this includes periods where some generators may be run for reasons such as system stability or minimum up and down times. These periods contribute to the negative calculation of the replacement energy cost, since the calculation does not value the other ancillary services being provided by those generators.

(b) Incremental replacement energy cost for Lingan and Tufts Cove generating stations were reported as station replacement cost since heat rate differences between the four Lingan generating units are small and are dependent on generating unit output. Unit commitment and dispatch decisions are made based on present unit condition and commitment status. These unit commitment and dispatch decisions affect generating unit heat rates, and may produce heat rate order different from the historical. For this reason, Lingan generating units are not differentiated by heat rate.

Tufts Cove units are marginal units when natural gas prices are relatively expensive and are also used for provision of ancillary services. As such, a unit with historically high heat rate, when dispatched at optimal output can have heat rate lower than that of a unit with historically low heat rate dispatched to provide ancillary services. Without the foreknowledge of when the replacement energy will be required for any given generator in the station, and at what unit output level, average replacement costs are a suitable proxy of replacement energy costs for all three units in the station.

(c) Hydro systems replacement energy costs are based on avoided cost of fuel and purchased power. Even though hydro generating units have different capabilities and provide a range of products from energy to ancillary services, replacement energy costs focus on the cost of energy replacement.

(d) Hourly replacement energy costs are not available. Replacement energy costs are calculated as seasonal and annual weighted averages.

(e) Please refer to Partially Confidential Attachment 2, also provided electronically.

(f) Hourly replacement energy costs are not available. Replacement energy costs are calculated as seasonal and annual weighted averages.

(g) The requested analysis was not completed as a part of this Application. Historical hourly system dispatch was not used as an input in producing 2016 replacement energy costs.

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PLEXOS OUTPUT DATA: Energy Output and Average Cost (No PHP)

	2016		2017		2018		2019		2020	
	(GWh)	($/MWh)	(GWh)	($/MWh)	(GWh)	($/MWh)	(GWh)	($/MWh)	(GWh)	($/MWh)
01 - Lingan 1	[redacted]									
02 - Lingan 2										
03 - Lingan 3										
04 - Lingan 4										
05 - Point Aconi										
06 - Point Tupper										
07 - Trenton 5										
08 - Trenton 6										
09 - PHBM										
11 - Tufts Cove 1										
12 - Tufts Cove 2										
13 - Tufts Cove 3										
14 - Tufts Cove 4										
15 - Tufts Cove 5										
16 - Tufts Cove 6										
CT - Burnside 1										
CT - Burnside 2										
CT - Burnside 3										
CT - Burnside 4										
CT - Tusket										
CT - VJ 1										
CT - VJ 2										
Imports from NB										
Surplus Imports from NL										
Hydro										

REPLACEMENT ENERGY COST DERIVATION:

	2016	2017	2018	2019	2020
Weighted average of all averge production costs (<70% CF)	[redacted]				
Weighted average of Tufts Cove 123 average produciton costs					
Weighted average of Tufts Cove 6 average produciton costs					
Weighted average of CT average production cost					
Weighted average of CT average production cost and imports					
Weighted average of TUC steam and Imports					
Weighted average of TUC steam and CTs					
Weighted average of TUC steam, imports, and CTs					

Any coal steam unit produciton can be replaced by any other generating unit production, except by the units that are fully dispatched

Weighted average of all production - Individual coal units average cost

Replacement Energy Cost $/MWh

	2016	2017	2018	2019	2020
Lingan average	[redacted]				
Point Aconi					
Point Tupper					
Trenton 5					
Trenton 6					

Tufts Cove Steam generation can be replaced by weighted average of TUC Steam, Imports and CT generation

	2016	2017	2018	2019	2020
Tufts Cove steam	[redacted]				

Tufts Cove combined cycle generation can be replaced by weighted average of Tufts Cove Steam generation and imports

	2016	2017	2018	2019	2020
Tufts Cove CC	[redacted]				

Combustion Turbine generation can be replaced by equivalent import plus 3% to account for losses from NB border to load center

	2016	2017	2018	2019	2020
Combustion Turbines	[redacted]				

Hydro generation can be replaced by any other dispatchable generator on the system

	2016	2017	2018	2019	2020
Hydro	[redacted]				

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

PLEXOS OUTPUT DATA: Energy Output and Average Cost (No PHP)

	2016		2017		2018		2019		2020	
	(GWh)	($/MWh)	(GWh)	($/MWh)	(GWh)	($/MWh)	(GWh)	($/MWh)	(GWh)	($/MWh)
01 - Lingan 1	241.0	[redacted]	260.4	[redacted]	223.0	[redacted]	208.6	[redacted]	145.4	[redacted]
02 - Lingan 2	300.8		321.4		188.3		0.0		0.0	
03 - Lingan 3	281.8		331.1		324.8		234.4		239.3	
04 - Lingan 4	452.5		436.2		458.8		450.7		436.9	
05 - Point Aconi	567.9		573.8		552.5		550.2		560.6	
06 - Point Tupper	538.0		530.5		500.8		470.9		516.2	
07 - Trenton 5	412.1		370.0		252.8		353.7		333.8	
08 - Trenton 6	523.2		476.9		510.1		473.7		498.0	
09 - PHBM	139.8		139.8		139.8		139.8		139.8	
11 - Tufts Cove 1	12.7		9.3		43.8		42.3		42.7	
12 - Tufts Cove 2	9.9		20.6		21.2		20.5		25.6	
13 - Tufts Cove 3	34.2		49.4		46.6		54.8		61.4	
14 - Tufts Cove 4	33.6		43.0		40.8		45.6		69.0	
15 - Tufts Cove 5	32.2		53.5		43.5		52.9		73.1	
16 - Tufts Cove 6	19.0		27.1		23.6		29.3		41.3	
CT - Burnside 1	0.0		0.5		1.2		0.3		0.4	
CT - Burnside 2	0.2		0.2		1.5		0.7		0.7	
CT - Burnside 3	0.1		0.4		1.6		0.1		0.4	
CT - Burnside 4	0.1		0.5		1.0		0.5		0.6	
CT - Tusket	0.2		0.3		0.8		0.1		0.3	
CT - VJ 1	0.0		0.4		1.1		0.0		0.0	
CT - VJ 2	0.0		0.4		1.1		0.0		0.0	
Imports from NB	2.7		10.0		6.8		3.7		5.4	
Surplus Imports from NL	0.0		0.0		7.7		20.2		34.0	
Hydro	527.2		527.0		526.3		527.2		527.2	

REPLACEMENT ENERGY COST DERIVATION:

	2016	2017	2018	2019	2020
Weighted average of all averge production costs (<70% CF)	[redacted]				
Weighted average of Tufts Cove 123 average produciton costs					
Weighted average of Tufts Cove 6 average produciton costs					
Weighted average of CT average production cost					
Weighted average of CT average production cost and imports					
Weighted average of TUC steam and Imports					
Weighted average of TUC steam and CTs					
Weighted average of TUC steam, imports, and CTs					

Any coal steam unit produciton can be replaced by any other generating unit production, except by the units that are fully dispatched

Weighted average of all production - Individual coal units average cost:

Replacement Energy Cost $/MWh

	2016	2017	2018	2019	2020
Lingan average	[redacted]				
Point Aconi					
Point Tupper					
Trenton 5					
Trenton 6					

Tufts Cove Steam generation can be replaced by weighted average of TUC Steam and CT generation (no imports - transmission)

	2016	2017	2018	2019	2020
Tufts Cove steam	[redacted]				

Tufts Cove combined cycle generation can be replaced by weighted average of Tufts Cove Steam generation and CTs (no imports - transmission)

	2016	2017	2018	2019	2020
Tufts Cove CC	[redacted]				

Combustion Turbine generation can be replaced by equivalent import plus 3% to account for losses from NB border to load center

	2016	2017	2018	2019	2020
Combustion Turbines	[redacted]				

Hydro generation can be replaced by any other dispatchable generator on the system

	2016	2017	2018	2019	2020
Hydro	[redacted]				

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PLEXOS OUTPUT DATA: Energy Output and Average Cost (No PHP)

Any coal steam unit production can be replaced by any other generating unit production, except by the units that are fully dispatched

Weighted average of all production - Individual coal units average cost:

	Replacement Energy Cost $/MWh				
	2016	**2017**	**2018**	**2019**	**2020**
Lingan average	[redacted]				
Point Aconi					
Point Tupper					
Trenton 5					
Trenton 6					

Tufts Cove Steam generation can be replaced by different sources depending on season (see individual tabs)

	2016	**2017**	**2018**	**2019**	**2020**
Tufts Cove steam (1/2/3)	[redacted]				

Tufts Cove combined cycle generation can be replaced by different sources depending on season (see individual tabs)

	2016	**2017**	**2018**	**2019**	**2020**
Tufts Cove CC (4/5/6)	[redacted]				

Combustion Turbine generation can be replaced by equivalent import plus 3% to account for losses from NB border to load center

	2016	**2017**	**2018**	**2019**	**2020**
Combustion Turbines	[redacted]				

Hydro generation can be replaced by any other dispatchable generator on the system

	2016	**2017**	**2018**	**2019**	**2020**
Hydro	[redacted]				

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Annual

Child Name	Property	2016	2017	2018	2019	2020
01 - Lingan 1	Capacity Factor	[redacted]				
02 - Lingan 2	Capacity Factor					
03 - Lingan 3	Capacity Factor					
04 - Lingan 4	Capacity Factor					
05 - Point Aconi	Capacity Factor					
06 - Point Tupper	Capacity Factor					
07 - Trenton 5	Capacity Factor					
08 - Trenton 6	Capacity Factor					
09 - PHBM	Capacity Factor					
11 - Tufts Cove 1	Capacity Factor					
12 - Tufts Cove 2	Capacity Factor					
13 - Tufts Cove 3	Capacity Factor					
14 - Tufts Cove 4	Capacity Factor					
15 - Tufts Cove 5	Capacity Factor					
16 - Tufts Cove 6	Capacity Factor					
CT - Burnside 1	Capacity Factor					
CT - Burnside 2	Capacity Factor					
CT - Burnside 3	Capacity Factor					
CT - Burnside 4	Capacity Factor					
CT - Tusket	Capacity Factor					
CT - VJ 1	Capacity Factor					
CT - VJ 2	Capacity Factor					

Annual Net Capacity Factor
(output GWH / net rating * 8760/1000)

Summer

Child Name	Property	2016	2017	2018	2019	2020
01 - Lingan 1	Capacity Factor	[redacted]				
02 - Lingan 2	Capacity Factor					
03 - Lingan 3	Capacity Factor					
04 - Lingan 4	Capacity Factor					
05 - Point Aconi	Capacity Factor					
06 - Point Tupper	Capacity Factor					
07 - Trenton 5	Capacity Factor					
08 - Trenton 6	Capacity Factor					
09 - PHBM	Capacity Factor					
11 - Tufts Cove 1	Capacity Factor					
12 - Tufts Cove 2	Capacity Factor					
13 - Tufts Cove 3	Capacity Factor					
14 - Tufts Cove 4	Capacity Factor					
15 - Tufts Cove 5	Capacity Factor					
16 - Tufts Cove 6	Capacity Factor					
CT - Burnside 1	Capacity Factor					
CT - Burnside 2	Capacity Factor					
CT - Burnside 3	Capacity Factor					
CT - Burnside 4	Capacity Factor					
CT - Tusket	Capacity Factor					
CT - VJ 1	Capacity Factor					
CT - VJ 2	Capacity Factor					

Winter

Child Name	Property	2016	2017	2018	2019	2020
01 - Lingan 1	Capacity Factor	[redacted]				
02 - Lingan 2	Capacity Factor					
03 - Lingan 3	Capacity Factor					
04 - Lingan 4	Capacity Factor					
05 - Point Aconi	Capacity Factor					
06 - Point Tupper	Capacity Factor					
07 - Trenton 5	Capacity Factor					
08 - Trenton 6	Capacity Factor					
09 - PHBM	Capacity Factor					
11 - Tufts Cove 1	Capacity Factor					
12 - Tufts Cove 2	Capacity Factor					
13 - Tufts Cove 3	Capacity Factor					
14 - Tufts Cove 4	Capacity Factor					
15 - Tufts Cove 5	Capacity Factor					
16 - Tufts Cove 6	Capacity Factor					
CT - Burnside 1	Capacity Factor					
CT - Burnside 2	Capacity Factor					
CT - Burnside 3	Capacity Factor					
CT - Burnside 4	Capacity Factor					
CT - Tusket	Capacity Factor					
CT - VJ 1	Capacity Factor					
CT - VJ 2	Capacity Factor					

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Child Name	Units	January, 2016	February, 2016	March, 2016	April, 2016	May, 2016	June, 2016	July, 2016	August, 2016	September, 2016	October, 2016	November, 2016	December, 2016	January, 2017	February, 2017	March, 2017	April, 2017	May, 2017	June, 2017	July, 2017	August, 2017	September, 2017	October, 2017	November, 2017
01 - Lingan 1	GWh	[redacted]																						
02 - Lingan 2	GWh																							
03 - Lingan 3	GWh																							
04 - Lingan 4	GWh																							
05 - Point Aconi	GWh																							
06 - Point Tupper	GWh																							
07 - Trenton 5	GWh																							
08 - Trenton 6	GWh																							
09 - PHBM	GWh																							
11 - Tufts Cove 1	GWh																							
12 - Tufts Cove 2	GWh																							
13 - Tufts Cove 3	GWh																							
14 - Tufts Cove 4	GWh																							
15 - Tufts Cove 5	GWh																							
16 - Tufts Cove 6	GWh																							
CT - Burnside 1	GWh																							
CT - Burnside 2	GWh																							
CT - Burnside 3	GWh																							
CT - Burnside 4	GWh																							
CT - Tusket	GWh																							
CT - VJ 1	GWh																							
CT - VJ 2	GWh																							
NB Imports	GWh																							
ML Imports	GWh																							
Hydro	GWh																							

		2016		2017		2018		2019		2020	
		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
01 - Lingan 1	GWh	[redacted]									
02 - Lingan 2	GWh										
03 - Lingan 3	GWh										
04 - Lingan 4	GWh										
05 - Point Aconi	GWh										
06 - Point Tupper	GWh										
07 - Trenton 5	GWh										
08 - Trenton 6	GWh										
09 - PHBM	GWh										
11 - Tufts Cove 1	GWh										
12 - Tufts Cove 2	GWh										
13 - Tufts Cove 3	GWh										
14 - Tufts Cove 4	GWh										
15 - Tufts Cove 5	GWh										
16 - Tufts Cove 6	GWh										
CT - Burnside 1	GWh										
CT - Burnside 2	GWh										
CT - Burnside 3	GWh										
CT - Burnside 4	GWh										
CT - Tusket	GWh										
CT - VJ 1	GWh										
CT - VJ 2	GWh										
NB Imports	GWh										
ML Imports	GWh										
Hydro	GWh										

01 - ML Surplus Purchases (Peak)	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
02 - ML Surplus Purchases (Offpeak)	GWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Child Name	December, 2017	January, 2018	February, 2018	March, 2018	April, 2018	May, 2018	June, 2018	July, 2018	August, 2018	September, 2018	October, 2018	November, 2018	December, 2018	January, 2019	February, 2019	March, 2019	April, 2019	May, 2019	June, 2019	July, 2019	August, 2019	September, 2019	October, 2019	November, 2019
01 - Lingan 1	[redacted]																							
02 - Lingan 2																								
03 - Lingan 3																								
04 - Lingan 4																								
05 - Point Aconi																								
06 - Point Tupper																								
07 - Trenton 5																								
08 - Trenton 6																								
09 - PHBM																								
11 - Tufts Cove 1																								
12 - Tufts Cove 2																								
13 - Tufts Cove 3																								
14 - Tufts Cove 4																								
15 - Tufts Cove 5																								
16 - Tufts Cove 6																								
CT - Burnside 1																								
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CT - Burnside 3																								
CT - Burnside 4																								
CT - Tusket																								
CT - VJ 1																								
CT - VJ 2																								
NB Imports																								
ML Imports																								
Hydro																								
01 - Lingan 1																								
02 - Lingan 2																								
03 - Lingan 3																								
04 - Lingan 4																								
05 - Point Aconi																								
06 - Point Tupper																								
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11 - Tufts Cove 1																								
12 - Tufts Cove 2																								
13 - Tufts Cove 3																								
14 - Tufts Cove 4																								
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16 - Tufts Cove 6																								
CT - Burnside 1																								
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CT - Burnside 3																								
CT - Burnside 4																								
CT - Tusket																								
CT - VJ 1																								
CT - VJ 2																								
NB Imports																								
ML Imports																								
Hydro																								
01 - ML Surplus Purchases (Peak)	0.00	0.00	0.00	2.40	0.01	29.13	0.23	2.12	5.93	5.26	36.31	0.66	0.81	5.62	0.63	3.67	1.87	26.63	0.35	4.13	6.89	43.51	54.92	3.13
02 - ML Surplus Purchases (Offpeak)	0.00	0.00	0.00	0.29	39.12	34.03	31.10	44.41	49.52	27.83	49.71	3.51	0.03	0.35	0.07	0.51	39.62	33.68	33.49	43.35	48.90	29.88	47.17	3.70

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Child Name	December, 2019	January, 2020	February, 2020	March, 2020	April, 2020	May, 2020	June, 2020	July, 2020	August, 2020	September, 2020	October, 2020	November, 2020	December, 2020
01 - Lingan 1	[redacted]												
02 - Lingan 2													
03 - Lingan 3													
04 - Lingan 4													
05 - Point Aconi													
06 - Point Tupper													
07 - Trenton 5													
08 - Trenton 6													
09 - PHBM													
11 - Tufts Cove 1													
12 - Tufts Cove 2													
13 - Tufts Cove 3													
14 - Tufts Cove 4													
15 - Tufts Cove 5													
16 - Tufts Cove 6													
CT - Burnside 1													
CT - Burnside 2													
CT - Burnside 3													
CT - Burnside 4													
CT - Tusket													
CT - VJ 1													
CT - VJ 2													
NB Imports													
ML Imports													
Hydro													
01 - Lingan 1													
02 - Lingan 2													
03 - Lingan 3													
04 - Lingan 4													
05 - Point Aconi													
06 - Point Tupper													
07 - Trenton 5													
08 - Trenton 6													
09 - PHBM													
11 - Tufts Cove 1													
12 - Tufts Cove 2													
13 - Tufts Cove 3													
14 - Tufts Cove 4													
15 - Tufts Cove 5													
16 - Tufts Cove 6													
CT - Burnside 1													
CT - Burnside 2													
CT - Burnside 3													
CT - Burnside 4													
CT - Tusket													
CT - VJ 1													
CT - VJ 2													
NB Imports													
ML Imports													
Hydro													
01 - ML Surplus Purchases (Peak)	2.09	7.95	1.00	6.28	4.01	74.58	7.14	18.76	62.49	63.55	66.01	8.53	1.88
02 - ML Surplus Purchases (Offpeak)	0.45	0.60	0.26	1.57	41.12	35.78	31.52	44.16	49.40	30.41	51.36	5.34	0.55

NON-CONFIDENTIAL

Request IR-17:

Please identify any project subject to economic analysis that would be uneconomic if not for the credit for OM&A during construction.

Response IR-17:

NS Power assumes the reference to OM&A refers to AO. If that assumption is correct, then there are no projects included in the 2016 ACE Plan with an economic analysis that would be uneconomic if the credit for administrative overhead were to be removed from the analysis.

Please also refer to NSUARB IR-14.

NON-CONFIDENTIAL

Request IR-18:

For CI 47755, please explain why NS Power conducted an economic analysis, given that "High pressure steam leaking from high-pressure joints is a critical safety issue" (p. 325).

(a) How uneconomic would the High Temperature Fasteners Replacement need to be for NS Power to defer resolution of this safety issue?

(b) Given the long order time reported in the EAM spreadsheet, has NS Power considered the option of keeping replacement fasteners in stock, to speed up replacement on failure?

(i) If not, why not?

(ii) If so, would pre-stocking and replacement on failure be less expensive than replacement of all the fasteners at this outage?

Response IR-18:

Although there are safety aspects related to this project, it is not primarily justified on safety. Pursuant to the description for CI 47755, the justification criteria for this capital work is Thermal Equipment Replacement/Refurbishment. The description also provides that evaluation of LIN4 high temperature fasteners using Original Equipment Manufacturer (OEM) criteria indicates that these fasteners are now at the end of their service life and must be replaced, and that high pressure steam leaking from high-pressure joints may require maintenance outages, costly repairs and a loss of efficiency.

(a) As noted above, this is a project that is based primarily on the replacement of end of life components and the economics of avoided loss of efficiency, that also happens to address potential safety issues.

(b) Steam Turbines and Generators include many major components of significant cost, therefore sustaining inventory for all of these components would be very expensive. Because of this, NS Power has relied on regular maintenance and inspection intervals and, more recently, detailed health assessment from independent experts to plan the timing and scope of Turbine/Generator outages and component replacement. The approach has been effective in mitigating risk and proactively determining the timing of component replacement and refurbishment in order to avoid in-service failures of these components leading to unplanned outages.

Request IR-19:

Please provide NS Power's estimate of the remaining useful life of each steam unit, and any analysis supporting that estimate.

Response IR-19:

Please refer to NSUARB IR-44. The 2014 Integrated Resource Plan, filed with the UARB on October 15, 2014 (M05522) and available on the UARB's website, is the analysis supporting the estimated retirement dates.

Request IR-20:

(a) Please explain how CI 48018, the TUC1 HP/IP Turbine Blading Replacement, can have a useful life of 25 years, when the IRP assumed that Tufts Cove 1 would retire in 2025.

(b) Please explain whether the statement "Tuft's Cove Unit #1 is expected to continue operation well into the future" (p. 345) is consistent with the IRP.

(c) Please list all the generation projects in the 2016 ACE filing that have longer assumed useful lives than the assumed life of the generating unit in the IRP.

Response IR-20:

(a) Typically, blade life is estimated at 25 years. This is consistent with other turbine blade components installed at other generating units. As noted in NSUARB IR-44, Tuft's Cove Unit #1 has a forecasted retirement date of 2025 which would give these particular blades an expected useful life of 10 years. The estimated useful life of these blades should have been listed at 10 years. However, it is still necessary to complete this project to allow for the reliable operation of Tufts Cove Unit #1 for the next ten years. .

In most cases, as in this case, blade replacement is determined based on adequacy for ongoing service. NS Power and independent experts were engaged and determined that replacement is required. Pursuant to the description of CI 48018:

> Replacing this row of blades is required for ongoing reliable operation of Tuft's Cove Unit #1 and will mitigate the risk of an unplanned outage due to blade failure and the associated component damage.

(b) This statement is consistent with the IRP as the forecasted retirement date of Tufts Cove Unit #1 is 2025. This project is required to allow Tufts Cove Unit #1 to reliably and safely operate for those 10 years.

(c) The only other project listed with an Estimate Useful Life of the Asset that is longer than the current expected useful life of the generating unit is CI 47552 TRE5 Boiler Refurbishment. While the estimated useful life of the asset is listed as longer than the expected life of that particular generating unit, the payback period for the capital project is well within the life of the generating unit, making this project the appropriate decision at this time.