MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0500 TRANSMISSION LINES

Subpart 1. **Existing transmission lines**. Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:

A. a map showing the location of each line;
B. the design voltage of each line;
C. the size and type of conductor;
D. the approximate location of d.c. terminals or a.c. substations; and
E. the approximate length of each line in Minnesota.

Subpart 2. **Transmission line additions**. Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

Subpart 3. **Transmission line retirements**. Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts that the utility plans to retire within the next 15 years.

In Use (enter X for selection)	To Be Built (enter X for selection)	To Be Retired (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)
x			230.	954	ACSR	AC	Winger Substation to Wilton Substation		54
x			230.	795	ACSR	AC	Sheyenne Sub to Audubon Substation		42
x			230.	795	ACSR	AC	Audubon Substation to Hubbard Substation		50
x			230.	795	ACSR	AC	Fergus Falls Sub to Wahpeton Substation		28
x			230.	795	ACSR	AC	Fergus Falls Sub to Henning Substation		30
x			230.	954	ACSR	AC	Harvey Substation to Balta Substation		
x			230.	954	ACSR	AC	Balta Substation to Rugby Substation		
x			230.	954	ACSR	AC	Coal Creek Sub to Underwood Substation		
x			230.	954	ACSR	AC	Underwood Sub to Harvey Substation		
x			345.	2-1272	ACSR	AC	Center Sub to Jamestown Substation		
x			230.	954	ACSR	AC	Drayton Substation to Prairie Substation		
x			230.	795	ACSR	AC	Wahpeton Sub to Hankinson Substation		
x			230.	954	ACSR	AC	Browns Valley Sub to Hankinson Sub		
x			230.	1,272	ACSR	AC	Big Stone Substation to Blair Substation		
x			230.	795	ACSR	AC	Hankinson Sub to Forman Substation		
x			230.	795	ACSR	AC	Forman Substation to Oakes Substation		
x			230.	795	ACSR	AC	Oakes Substation to Ellendale Substation		
x			230.	795	ACSR	AC	Pillsbury Substation to Luverne Substation		
x			345.	2-954	ACSS	AC	St. Cloud (Quarry) Sub to Montevideo 345 kV Sub [2]		29
x			230.	795	ACSS	AC	Wilton Sub to Cass Lake Sub [1]		20
x			230.	795	ACSS	AC	Cass Lake Sub to Boswell Sub [1]		50
x			345.	2-954	ACSS	AC	Bison 345 kV Sub to Alexandria Switch Station [2]		98
x			345.	2-954	ACSS	AC	Alexandria Switch St. to St. Cloud (Quarry) Sub [2]		77
x			345.	2-954	ACSS	AC	Cedar Mountain Sub to Helena Switch Sub#1 [3]		72
x			345.	2-954	ACSS	AC	Cedar Mountain Sub to Helena Switch Sub#2 [3]		72
x			345.	795	ACSS	AC	Cedar Mountain Sub to Franklin Sub [3]		4
x			345.	2-954	ACSS	AC	Helena Switch Sub to Chub Lake Sub [3]		20
x			345.	2-954	ACSS	AC	Chub Lake Sub to Hampton Corners Sub [3]		18
x			345.	2-954	ACSS	AC	Lyon County Sub to Hazel Creek Sub [3]		24
x			345.	2-954	ACSS	AC	Hazel Creek Sub to MN Valley Sub [3]		5
x			345.	2-954	ACSS	AC	Brookings County Sub to Lyon County Sub 3		50
x			345.	2-954	ACSS	AC	Lyon County Sub to Cedar Mountain Sub#1 [3]		50
x			345.	2-954	ACSS	AC	Lyon County Sub to Cedar Mountain Sub#2 [3]		50
	x		230.	1,272	ACSR	AC	Big Stone Plant Sub to Big Stone South Sub #1	2017	
	x		230.	1,272	ACSR	AC	Big Stone Plant Sub to Big Stone South Sub #2	2017	
	x		345.	2-954	ACSS	AC	Big Stone South Sub to Ellendale Sub 345 kV[4]	2019	
	x		345.	2-954	ACSS	AC	Big Stone South Sub to Brookings 345 kV[5]	2017	

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0600, item A. 24 - HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:

A table of the demand in megawatts by the hour over a 24-hour period for:

1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest

	DATE	DATE	
	8/14/15	1/5/15	<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	513	755	
0200	493	746	
0300	479	734	
0400	471	732	
0500	473	747	
0600	485	769	
0700	516	817	
0800	607	771	
0900	632	755	
1000	638	754	
1100	678	895	
1200	685	897	
1300	685	873	
1400	692	856	
1500	**710**	837	
1600	716	830	
1700	714	828	
1800	704	**837**	
1900	689	828	
2000	662	790	
2100	633	715	
2200	622	718	
2300	579	794	
2400	541	755	

COMMENTS

SECTION 3

Electric Utility Information Reporting
Forecast Section

Form EN-0005 – 20

7610.0320 FORECAST DOCUMENTATION

7610.0320 FORECAST DOCUMENTATION.

Subpart 1. Forecast methodology. *An applicant may use the forecast methodology that yields the most useful results for its system. However, the applicant shall detail in written form the forecast methodology employed to obtain the forecasts provided under parts 7610.0300 to 7610.0315, including:*

A. the overall methodological framework that is used;

Aggregate econometric models of use-per-customer and number of customers were developed for each customer class, using historical data on monthly sales, customers, economic activity, and weather conditions. Monthly use-per-customer and number of customers (Customer) forecasting models were estimated as a function of these explanatory variables, plus month-specific variables to capture any seasonal patterns that are not related to the other explanatory variables. Monthly sales forecasts were developed by multiplying use-per-customer forecasts by customer forecasts for each customer class. To forecast system peak demand, an econometric model was developed that explains monthly system peak demands as a function of weather, economic conditions, and month-specific variables.

B. the specific analytical techniques that are used, their purpose, and the components of the forecast to which they have been applied;

1. **Econometric Analysis.** Otter Tail Power Company used econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter of the following: Farm, Large Commercial, Other Public Authority, Residential, Small Commercial, Street Lights, and Unclassified.

2. **Judgment.** Judgment is inherent to the development of any forecast. Whenever possible, Otter Tail Power Company tries to use appropriate statistical tests of quantitative models to structure its judgment in the forecasting process.

3. **Loss Factor Methodology.** Loss factors were applied to convert the sales forecasts into system energy requirements.

4. **Peak Demand Forecast.** Econometric analysis was used to produce a total system MW demand forecast for each month of the forecast period.

A MWh sales forecast was developed for each customer class and jurisdiction. Summing the various jurisdictional class forecasts yields the total system sales forecast. A monthly loss factor is applied to convert MWh sales to MWh native energy requirements.

For the sales forecasting models and system demand forecasting model, we used a standard ordinary least squares (OLS) regression model. The purpose of this model is to estimate the relationship between a dependent variable and explanatory variables (*e.g.*, heating degree days, or GDP).

C. the manner in which these specific techniques are related in producing the forecast;

The econometric techniques described in Section B are applied to historical data to produce estimated effects of weather, economic factors, and demographic factors on class usage or system demand. Forecast values for the explanatory values (derived either from Woods and Poole forecasts or based on weather normal conditions) are then inserted into the estimated equations to produce forecast values of class-level sales and system demand.

D. where statistical techniques have been used, the purpose of the technique, typical computations (e.g., computer printouts, formulas used) specifying variables and data, and the results of appropriate statistical tests;

Models used

The basic structure for the use-per-customer models estimates monthly use-per-customer as a function of economic conditions, weather conditions, and month-specific variables. The economic variables that are most often used are Gross Regional Product and Total Personal Income. Weather conditions are represented using monthly heating degree days and cooling degree days. In some cases, indicator variables were included in the equation to account for events in the historical time period.

The basic form of the use-per-customer models is represented by the equation below. In this equation “m2” equals one in February and zero in all other months.

$$\text{Use-per-customer} = a + b_1 * \text{Economic Variable} + b_2 * \text{CDD/day} + b_3 * \text{HDD/day} + b_4 * m2 + \ldots + b_{14} * m12$$

The basic structure for the customer models estimates monthly customers as a function of economic conditions and month-specific variables. The economic variables that are most often used are Number of Households and Total Population. The customer model is shown in the equation below.

$$\text{Customers} = a + b_1 * \text{Economic Variable} + b_2 * \text{CDD/day} + b_3 * \text{HDD/day} + b_4 * m2 + \ldots + b_{14} * m12$$

The system peak demand model uses the equation below.

kW = a + b_1 * Winter * HDD Buildup + b_2 * Summer * Temperature Humidity Index Buildup + b_3 * Swing Month * CDD & HDD Buildup + b_4 * Gross Regional Product + b_5 * m2 + … + b_{15} * m12

The weather buildup variables are constructed as follows: 40/75 * X_t + 20/75 * X_{t-1} + 10/75 * X_{t-2} + 5/75 * X_{t-3}, where X is the weather variable in question, t is the peak day and t-3 is three days prior to the peak day. The CDD & HDD variable used in the swing months (May and September) is constructed by adding the HDD value to three times the CDD value.

The models use information from Woods and Poole Economics, Inc. for its forecasts of economic demographic variables.

The table under Subp. 2 (data base for forecasts) shows the variables that are included in each model. Specifications that included more variables were also tested to determine the final model used.

E. forecast confidence levels or ranges of accuracy for annual peak demand and annual electrical consumption; and

The estimated effect of each variable in the equations above (*e.g.*, the effect of heating degree days on system peak demand) has a standard error associated with it that is used to generate a confidence interval around the forecasted demand value (*e.g.*, there is some probability that the “true” value of the parameter is actually larger than the estimated value, which would imply that the effect of weather on demand would be larger, leading to a higher peak demand for a given assumed weather condition). In calculating the confidence intervals around the demand forecast, the values of the explanatory variables, such as weather, economic growth, and demographics are all maintained at fixed assumed or expected levels. TABLE 1 (below) shows the results of the confidence levels in 5 year increments.

Table 1
Forecast Confidence Levels
2017 Econometric Forecast
Percent Deviation from Base

	Low Scenario		**High Scenario**	
Year	**Peak**	**Sales**	**Peak**	**Sales**
2017	(9.5%)	(6.7%)	9.5%	6.8%
2022	(9.1%)	(6.5%)	9.1%	6.5%
2027	(8.7%)	(6.3%)	8.7%	6.5%
2031	(8.5%)	(7.3%)	8.5%	7.5%

F. a brief analysis of the methodology used, including its strengths and weaknesses, its suitability to the system, cost considerations, data requirements, past accuracy, and any other factors considered significant by the utility.

Methodology As discussed in A the Company uses Econometric models to forecast energy sales requirements and system peak demand. This method is used as it is a standard methodology in the industry and thus facilitates review.

Strengths and Weaknesses As mentioned above, one of the main strengths is the ability of the econometric model to be understood because as mentioned above, the econometric model is an industry standard. The model is reasonably easy to fine tune as it was developed in-house. One of the weaknesses is that the data it uses is not as detailed as the data used in an end-use forecast.

Suitability to the system The econometric methodology is a very good fit to Otter Tail Power Company's system. Serving three states with distinct economic differences, using the econometric model makes it easy to utilize the different economic data for each state and determine whether particular variables are drivers for each state.

Cost Considerations The econometric approach, relative to an end-use model approach, is inexpensive to maintain while being very reliable.

Data Requirements
The forecast utilizes about 20 years of monthly historical energy and demand data along with their corresponding weather and econometric variables. As described in detail in subpart 2, the sources of data for the explanatory variables was Otter Tail Power Company weather monitoring stations for weather data; the Otter Tail Power Company Customer Information System for customer counts; Woods and Poole Economics, Inc for econometric data; and the High Plains Regional Climatic Center for weather data that was not available from Otter Tail Power Company weather monitoring stations.

Past Accuracy
Otter Tail Power Company does what is called a "backcast". This is when the model is used to predict the historical period. If the model predicts backwards well, there is a reasonable confidence that it will predict well in the future. We've looked at the 20 year backcast for the energy and demand forecasts models. The energy model has an Average Absolute Error of 0.3% over the past ten years. The demand model has an Average Absolute Error of 4.1% over the past ten years.

Subp. 2. Data base for forecasts. The utility shall discuss in written form the data base used in arriving at the forecast presented in part 7610.0310, including:

- ***A. a complete list of all data sets used in making the forecast, including a brief description of each data set and an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer); and***

- ***B. a clear identification of any adjustments made to raw data to adapt them for use in forecasts, including the nature of the adjustment, the reason for the adjustment, and the magnitude of the adjustment.***

Sales Forecast

Table 2

		State	CDD65	HDD65	Total Personal Income	Number Of Households	Residential Customer Cour	Gross Regional Product	Farm Employment	Total Employment	Persons Per Household	Farm Earnings	Total Population	Miscellaneous Binaries
Residential	Use Per Customer	MN	X	X										X
		ND	X	X										X
		SD	X	X										X
	Customers	MN	X	X		X								X
		ND				X								X
		SD	X	X										X
Farm	Use Per Customer	MN	X	X								X		X
		ND		X										X
		SD	X	X										X
	Customers	MN							X					X
		ND				X								X
		SD										X		X
Small Commercia	Use Per Customer	MN	X	X										X
		ND	X	X										X
		SD	X	X										X
	Customers	MN					X							X
		ND						X						X
		SD						X						X
Large Commercia	Use Per Customer	MN	X	X										X
		ND	X	X										X
		SD												X
	Customers	MN						X						X
		ND			X									X
		SD								X				X
Other Public Auth	Use Per Customer	MN		X										X
		ND		X										X
		SD		X										X
	Customers	MN												X
		ND												X
		SD												X
Streetlighting	Use Per Customer	MN						X						X
		ND											X	X
		SD												X
	Customers	MN						X						X
		ND											X	X
		SD												X
Unclassified	Use Per Customer	MN		X										X
		ND		X										X
		SD		X										X
	Customers	MN												X
		ND												X
		SD												X

Database: Otter Tail Power Company's Customer Information System (CIS)
Variables Used:
Use-per-customer: kwh sales divided by the number of customers
Customers: number of customers
Description/Source:
KWH and the number of customers were read from SAS CISA data sets. The SAS data sets were created from extracts of the CIS taken the last day of each month. Each record was assigned to one of 40 rate groups within each state based on rate and revenue class combinations. Records were summed to the rate group level within each state. Each rate group was then assigned to one of the 8 classes used in the forecast. The variable *Use-per-customer* was calculated by dividing the monthly KWH by the monthly number of customers.
Adjustments Made:
Each record was checked to be sure it was assigned a rate group. Any record not assigned a rate group had its rate and/or revenue class corrected so a rate group was properly assigned. Monthly group KWH data was graphed and values were checked for errors due to meters not being billed, being billed twice one month, etc. In most cases the data used for corrections was taken from a second CIS download that was run later the following month after billing corrections had been made. In some cases judgment was used.

Database: DEGREE DAYS
Variables Used:
cdd65: average cooling degree days for each month with a 65 degree base
hdd65: average heating degree days for each month with a 65 degree base
Description/Source:
Hourly temperature data was obtained from 14 monitoring stations throughout Minnesota, North Dakota and South Dakota. Scheduled billing cycle start and stop dates were obtained from the Customer Information System (CIS). Daily heating degree days (*hdd*) and cooling degree days (*cdd*) were calculated based on 65 degree base and the rounded average of the twenty-four hourly temperatures. Daily degree days were then averaged and weighted for each state and added to calculate billing month and calendar month heating degree days and cooling degree days. Average monthly *hdd* and *cdd* were calculated over a 20 year period to calculate normal billing month and calendar month *hdd* and *cdd*. Billing month *hdd* and *cdd* were used for the historical period and calendar month *hdd* and *cdd* were used for the forecast period.
Adjustments Made:
Hourly monitoring station temperatures are graphed each month after the data is downloaded. Any missing or obviously bad temperatures are corrected based on temperatures from other nearby monitoring points or by judgment when necessary.

Database: WOODS AND POOLE

Variables Used:

Total Personal Income
Number of Households
Residential Customer Count
Gross Regional Product
Farm Employment
Total Employment
Persons Per Household
Farm Earnings
Total Population

Description/Source:

2015 state profile econometric data for Minnesota, North Dakota and South Dakota was purchased from Woods and Poole Economics, Inc., 4910 Massachusetts Avenue NW Ste 208, Washington, DC 20016-4368 (www.woodsandpoole.com). The 2015 state profile data contains annual historical data for 1969-2014 and annual forecast data for 2015-2050 at the county level.

Adjustments Made:

Otter Tail Power Company does not serve all of the load in the counties within its service territory. This is especially problematic when Otter Tail Power Company does not serve a large city that has a significant impact on the economy of the county. Some examples are Fargo, Moorhead, Grand Forks and Minot. To reflect this, a decision was made to not use econometric data from counties where Otter Tail Power Company served less than 10% of the population of the county. County population data was downloaded from www.census.gov .The percentage of the population served by Otter Tail Power Company in each county was determined by dividing the sum of populations of towns served by Otter Tail Power Company in each county by the population of the county. Counties with a percentage of less than 10% were not included. Town populations were obtained from an internal database of towns served. The data was then summed to the state level and graphed as a reasonability check. Annual Woods and Poole data was converted from annual data to monthly by interpolating between annual values with a flat line.

Demand Forecast

Table 3

Independent Variables Used in the Peak Demand Forecast Model	Monthly Binaries	whdd55buildup	sthibuildup	swcdd65hdd55buildup	Gross Regional Product
System Peak Demand	X	X	X	X	X

Database: Otter Tail Power Company's System Load Data
Variables Used: *System Peak Demand*
Description/Source: Annual hourly system load (MAPP) files and annual hourly net controlled load (NCL) files were obtained from System Operations. System load data was combined with the net controlled load data to give hourly system demands without control.
Adjustments Made: The hourly system load files are graphed and reviewed by System Operations personnel each month.

Database: WOODS AND POOLE
Variables Used: *Gross Regional Product*
Description/Source: 2015 state profile econometric data for Minnesota, North Dakota and South Dakota was purchased from Woods and Poole Economics, Inc., 4910 Massachusetts Avenue NW Ste 208, Washington, DC 20016-4368 (www.woodsandpoole.com). The 2015 state profile data contains annual historical data for 1969-2014 and annual forecast data for 2015-2050 at the county level.
Adjustments Made: Otter Tail Power Company does not serve all of the load in the counties within its service territory. This is especially problematic when Otter Tail Power Company does not serve a large city that has a significant impact on the economy of the county. Some examples are Fargo, Moorhead, Grand Forks and Minot. To reflect this, a decision was made to not use econometric data from counties where Otter Tail Power Company served less than 10% of the population of the county. County population data was downloaded from www.census.gov .The percentage of the population served by Otter Tail Power Company in each county was determined by dividing the sum of populations of towns served by Otter Tail Power Company in each county by the population of the county. Counties with a

percentage of less than 10% were not included. Town populations were obtained from an internal database of towns served. The data was then summed to the state level and graphed as a reasonability check. Annual Woods and Poole data was converted from annual data to monthly by interpolating between annual values with a flat line.

Database: FARGO WEATHER DATA
Variables Used: *sthibuildup*: summer temperature humidity index buildup
Description/Source: Hourly weather data files were obtained from the High Plains Regional Climatic Center (**www.hprcc.unl.edu**). for Fargo, ND. Fargo is used as a proxy for the system average weather data (other than temperatures which come from Otter Tail Power Company division weather stations). The hourly temperature humidity index (*thi*) was calculated from the hourly dry bulb temperatures and the hourly relative humidity (*thi*=*db*-(.55-.55**rh*/100)*(*db*-58)). The average daily temperature humidity index (*thi*) was calculated from the hourly values. The variable *thibuildup* was calculated from *thi* for the day of monthly system peak and *thi* from the previous three days so that each previous day has half the influence of following day ((40/75)**thi*+(20/75)**lag1thi*+(10/75)**lag2thi*+(5/75)* *lag3thi*). The variable *sthibuildup* has the value of *thibuildup* for the months of June, July and August and zero for all other months. The forecast period *sthibuildup* variable was calculated by determining the value of *thi* for each monthly system peak day and the three days previous to the peak for the last 20 years.
Adjustments Made: High Plains Climatic Center data was used rather than NOAA data because the High Plains Climatic Center data has been reviewed and edited where necessary and the NOAA data has not.

Database: DEGREE DAYS
Variables Used:
Whdd65buildup: winter heating degree day buildup
swcdd65hdd65buildup: swing month cooling and heating degree day buildup
Description/Source: Average hourly temperature data was obtained by averaging hourly temperatures across 14 monitoring stations throughout Minnesota, North Dakota and South Dakota. Daily heating degree days (*hdd*) and cooling degree days (*cdd*) were calculated based on a 65 degree base and the rounded average of the twenty-four hourly temperatures. The variables *hddbuildup* and *cddbuildup* were calculated from the degree days for the day of monthly system peak and the degree days from the previous three days so that each previous day has half the influence of following day (for example, (40/75)**hdd*+(20/75)**lag1hdd*+(10/75)**lag2hdd*+(5/75)* *lag3hdd*). The variable *whdd65buildup* has the value of *hddbuildup* for the months of January, February, March, April, October, November and December and zero for all other months. The variable *cddhdd* was calculated by adding 3 times *cdd* to1 times *hdd* (3**cdd*+1**hdd*). The variable *swcdd65hdd65buildup* has the value *cddhdd* for the months of May and September and zero for all other months. Forecast period *whdd65buildup* and *swcdd65hdd65builup* variables were calculated by determining

the value of *hdd* and *cdd* for each monthly system peak day and the three days previous to the peak for the last 20 years.

Adjustments Made: Hourly monitoring station temperatures are graphed each month after the data is downloaded. Any missing or obviously bad temperatures are corrected based on temperatures from other nearby monitoring points or by judgment when necessary.

Subp. 3. Discussion. The utility shall discuss in writing each essential assumption made in preparing the forecasts, including the need for the assumption, the nature of the assumption, and the sensitivity of forecast results to variations in the essential assumptions.

Some assumptions should be listed individually for emphasis.

1). No load management:

Need: Load management is used at Otter Tail Power during peak conditions, summer, and winter. The use of the control is not always predictable. To build a forecast to match a load subject to load management is not practical.

Assumption: The forecast is made to match uncontrolled load. Therefore, to match forecast to load, the observed load must have the estimated load management added. This simplifies the process of reconciling the forecast.

Sensitivity: There is nothing to test.

2). Woods and Poole Economics, Inc.

Need: Economic forecasts are needed to provide projections of population and employment. The forecasts must be consistent among county, state, and national projections, so the forecasts need to be from similar sources or be based on similar assumptions. For this reason, these elements of the forecast are taken from a single source.

Assumption: Woods and Poole data provides a consistent scenario of the future that connects national, state and county projections. Population and employment follow this story of the future economy.

Sensitivity: No consistent alternatives are provided.

See also the above discussions and the discussion below regarding subject of assumption.

Subp. 4. Subject of assumption. The utility shall discuss the assumptions made regarding the availability of alternative sources of energy, the expected conversion from other fuels to electricity or vice versa, future prices of electricity for customers in the utility's system and the effect that such price changes will likely have on the utility's system demand, the assumptions made in arriving at

any data requested in part 7610.0310 that is not available historically or not generated by the utility in preparing its own internal forecast, the effect of existing energy conservation programs under federal or state legislation on long term electrical demand, the projected effect of new conservation programs that the utility deems likely to occur through future state and federal legislation on long term electrical demand, and any other factor considered by the utility in preparing the forecast. In addition the utility shall state what assumptions were made, if any, regarding current and anticipated saturation levels of major electric appliances and electric space heating within the utility's service area. If a utility makes no assumptions in preparing its forecast with regard to current and anticipated saturation levels of major electrical appliances and electric space heating it shall simply state this in its discussion of assumptions.

Otter Tail Power Company's forecast assumes availability of alternative sources of energy will continue in similar patterns as have been historically.

Otter Tail Power Company did not assume any changes in the availability of alternative sources of energy, the expected conversions from other fuels to electricity or vice versa, future prices of electricity for customers in the utility's system and the effect that such price changes will have on the utility's system demand. The current forecast by default assumes any prices changes would be in small increments that demand is not noticeably impacted. While price changes due to rate cases are not necessarily smooth in the short-term (reality), for the purposes of the long-term forecast any price changes smooth out over time. This reality is due to the long-term planning process. The utility itself and regulatory bodies are involved in the IRP process in part to avoid situations that create large price increases.

Otter Tail Power Company's forecast does not make any explicit assumptions about current and anticipated saturation levels of major electric appliances and electric space heating within the utility's service area.

Subp. 5. Coordination of forecasts with other systems.
The utility shall provide in writing:

A. ***a description of the extent to which the utility coordinates its load forecasts with those of other systems, such as neighboring systems, associate systems in a power pool, or coordinating organizations; and***
B. ***a description of the manner in which such forecasts are coordinated, and any problems experienced in efforts to coordinate load forecasts.***

Otter Tail Power Company does not coordinate its long-term load forecasts with those of other systems.

STAT AUTH: MS s 216C.10
HIST: L 1987 c 312 art 1 s 9; 16 SR 1400

Appendix C
TAB

Appendix C: Existing Resources

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Existing Resources

Otter Tail Power Company has a variety of existing resources available to meet the energy needs of its customers, both reliably and economically. These resources consist of existing generating facilities, the radio load management system, the Midcontinent ISO, purchases from other utilities, customer owned generation, the transmission and distribution network, and current Company sponsored conservation programs.

Figure 1-1 shows the composition of the 2016 Planning Year capacity by fuel source for the Company.

Figure 1-1: 2016 Planning Year Accredited Capacity Resources Fuel Source Percent of Total = 766.5 MW

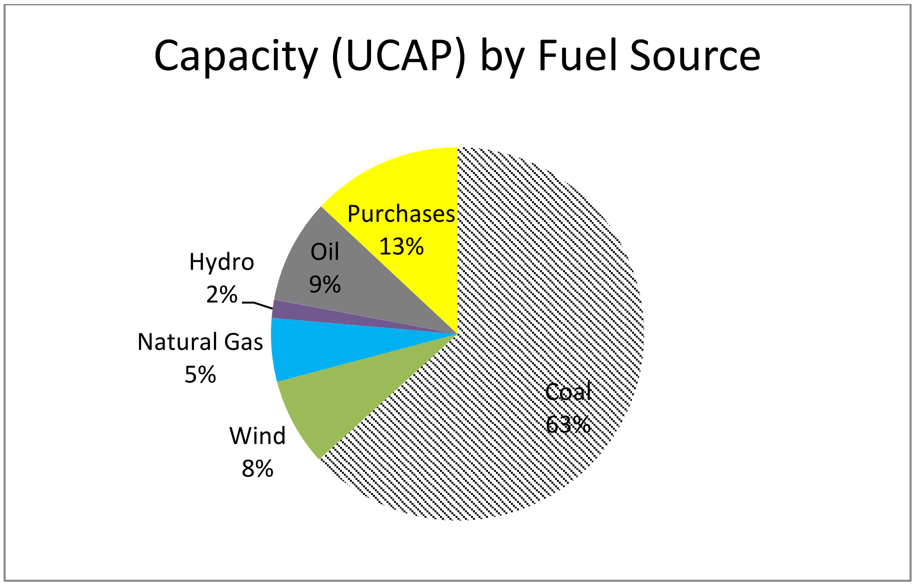

Table 1-1 shows a listing of the Company’s resources and their capacity ratings for the 2016 Planning Year. The capacity ratings data provided is based on current Midcontinent ISO ratings under Module E’s resource adequacy requirements in effect for the Planning Year June 1, 2016 through May 31, 2017.

Table 1-1: 2016 Company Capacity Resources

Capacity - Owned Resources	ICAP (MW)	UCAP (MW)
COAL		
Big Stone Plant	255.8	236.5
Coyote	149.8	112.5
Hoot Lake #2	58.7	55.2
Hoot Lake #3	81.4	80.8
GAS CT		
Solway 1	42.5	42.2
WIND		
Ashtabula	48.0	11.5
Luverne	49.5	13.5
Langdon	40.5	9.5
HYDRO		
Bemidji Hydro	-	-
Bemidji Hydro 2	-	-
Dayton Hollow Hydro 1	0.5	0.5
Dayton Hollow Hydro 2	0.5	0.5
Hoot Lake Hydro	0.5	0.5
Pisgah Hydro	0.6	0.6
Taplin Gorge Hydro	0.4	0.4
Wright Hydro	-	-
OIL		
Lake Preston	20.4	20.4
Jamestown 1	20.7	20.2
Jamestown 2	21.1	21.1
Big Stone Diesel	1.1	1.0
Fergus Control Center	1.8	1.6
Hoot Lake Diesel 2A	0.3	0.3
Hoot Lake Diesel 3A	0.2	0.2
Solway IC	-	-
Total Owned:	794.3	629.0

Capacity - Purchased Resources	ICAP (MW)	UCAP (MW)
WIND		
Edgeley (ND Wind II)	21.0	3.6
Langdon	19.5	4.7
Ashtabula III	62.4	15.4
Customer Owned Diesel	4.5	4.1
Short Term Capacity contracts	85.0	85.0
Total Purchased:	192.4	112.8

1.1 Hydroelectric Facilities

Otter Tail Power Company has 6 units located at five dams on the Otter Tail River near Fergus Falls, MN and 2 units located at a dam on the outlet of Lake Bemidji at Bemidji, MN. These hydro units were constructed in the early 1900's and were the backbone of the generating resources for Otter Tail for many years in the early days of the Company. The total capability of all of the hydro units is about 3.7 MW.

The hydro units located on the Otter Tail River are under FERC jurisdiction and were licensed for the first time in 1991. All of these units were built prior to licensing requirements. The units are predominantly operated in run of river mode without pondage capability except for Hoot Lake and Wright Lake behind the Hoot Lake Hydro. Prior to the FERC licensing, there was a small amount of pondage and cycling capability with these units that increased the amount of energy obtained from the water flow. The FERC license required a change to strict run of river operation.

All of the hydro units in run of river mode have had updated reservoir level monitoring systems installed to aid in complying with the operating requirements of the FERC license. Automatic level control systems have also been installed at a number of the units to control the reservoir level using the signal from the reservoir level monitoring system. Significant other equipment upgrades were completed in the past 15 years, to upgrade electrical control and protection equipment.

The FERC re-licensing process is approximately 5 years and OTP has been preparing for submission for license renewal. This submission known as the Notice of Intent (NOI) and Project Application Document (PAD) is being prepared and the process through FERC will begin officially in the summer of 2016.

Bemidji Hydro
The Bemidji Hydro units were built in 1907. These units were authorized by Congress and are not subject to FERC jurisdiction. Otter Tail acquired ownership of these units in the 1940's. The Unit #1 generator stator and rotor field was rewound in 2008.

Dayton Hollow Hydro
Dayton Hollow Dam was built in 1909 with two generators installed. A third generator was added in 1917. One of the original generators was retired and removed in 1964. The Unit #2 turbine and generator were refurbished in 2006 and the turbine also had a major repair in 2008 – 2009. Annual generation from the Dayton Hollow units is about 5,000 – 7,000 MWh.

Hoot Lake Hydro
The Hoot Lake Hydro was built in 1914. The hydro originally had two units, but one unit was retired with the addition of the Hoot Lake #3 steam unit in 1964. The Hoot Lake Hydro is part of a system that was developed to make further use of the Otter Tail River. Diversion Dam was built on the Otter Tail River and part of the water from the river is diverted through an underground tunnel to Hoot Lake that flows into Wright Lake. The two lakes were created from the diverted water. The water from Wright Lake flows through the Hoot Lake structure, and is used in the hydro unit and for cooling water for the Hoot Lake steam units. The arrangement allows the cooling water for the steam plant to be gravity fed, rather than

pumped, through the plant and improves the efficiency of the units. Hoot Lake Hydro has been generating about 3,000 - 4,000 MWh annually. The City of Fergus Falls also makes use of the Diversion Dam system as water supply for the city.

Pisgah Hydro
Pisgah Hydro was built in 1918. The generator stator and rotor was rewound in 2001. The turbine was rebuilt in 2005. This unit provides about 3,500 – 4,500 MWh during normal years.

Taplin Gorge (Friberg) Hydro
Taplin Gorge, also known as Friberg, was constructed in 1925. The structure is well known in the Fergus Falls area because the powerhouse is a replica of the tomb of the former Italian ruler, Theodoric. The generator was rewound in 1999. Annual generation is in the 3,000 – 4,200 MWh range.

Wright (Central) Hydro
Wright Dam (also called Central) is located in downtown Fergus Falls, and has been the location of a dam since the 1880's. It originally provided power via drive belts to industries located nearby. The current structure was built in 1922. The turbine was rebuilt and the generator cleaned and rewedged in 2002 – 2003. Annual generation is in the range of 2,000 – 3,000 MWh.

1.2 Peaking Facilities

Otter Tail Power Company has a number of peaking units on the system. Some are internal combustion units, but most of the capacity is comprised of combustion turbines. Other than Solway, Otter Tail's peaking units operate on a very limited basis annually, either for emergency or extreme peak times, or for testing purposes. Solway is frequently dispatched by the MISO centralized market.

In the summer of 2001, an inlet fogging system was added to each of the three GE Frame 5 peaking units. The inlet fogging system is to be used during the summer months to increase the output of the turbines during the hotter weather conditions by lowering the temperature of the incoming air. Combustion turbine output is impacted by air density, so the denser cooler air allows for higher output capability.

Jamestown Combustion Turbines
Otter Tail has two fuel oil-fired combustion turbines located at Jamestown, ND. These units are of 1976 and 1978 vintage. These units are operated for emergency, peaking, and testing situations, as well as for economy during periods when market prices support it. The Frame 5 units at Jamestown operate a very limited number of hours during the year.

Lake Preston Combustion Turbine
Lake Preston is a third combustion unit, identical to the Jamestown units, located at Lake Preston, SD. This unit was installed in 1978. This unit is also fired with fuel oil and has limited operation. The unit usually operates for emergencies, peak loads, and testing, but is also used for area voltage support under certain transmission line switching and outage scenarios. The Frame 5 unit at Lake Preston operates a very limited number of hours during the year.

Solway Combustion Turbine Plant
Otter Tail brought on-line a General Electric LM6000 dual-fuel combustion turbine just prior to the 2003 summer season. The unit includes inlet chilling to improve the summer rating and efficiency, as well as water injection for NOX control and increased output. Interruptible natural gas is the primary fuel with fuel oil as the back-up fuel supply. The combustion turbine also includes a clutch to allow synchronous condensing service to support the transmission system. The LM6000 is an aeroderivative machine, powered by a Boeing 747 engine.

Hoot Lake Diesels
These diesels were installed as emergency units in case of a blackout, to provide lighting and minimum service to the plants. They are capable of synchronizing with the system and are accredited. Typically these units have only operated for extreme emergency and testing purposes.

Big Stone Diesel
The Big Stone Plant has an internal combustion emergency diesel unit. This unit operates only for extreme emergency or testing purposes, but can synchronize with the system and is submitted as a capacity resource. The unit was installed in 1975 with the construction of the Big Stone Plant.

Fergus Control Center Diesel
A 2,000 kW diesel unit was installed at Otter Tail's System Control Center to serve as a standby generator for the facility, in accordance with NERC reliability criteria. The System Control Center was added to an existing Company building that contains the main business computers for Otter Tail. The system is staffed 24 hours per day and must have firm electric service to keep the System Control Center in operation during outages. The standby generator will supply emergency power, when required, to the total System Control Center and to the computer facilities.

New EPA Emission Standards for Stationary Engines
On March 3, 2010 the U.S. Environmental Protection Agency issued new national emission standards for hazardous air pollutants for existing stationary compression ignition reciprocating internal combustion engines. The new standards include emissions limitations, operating limitations, maintenance requirements, performance tests, recordkeeping requirements, and reporting requirements. By May 1, 2016 all of Otter Tail's engines affected by the RICE Rule will be considered emergency or blackstart in nature and therefore exempt from emissions limitations and performance tests. Only minimal efforts will be needed to comply with the rule.

1.3 Baseload Resources

Otter Tail Power has partial or full ownership of four coal-fired generators located at three plants. Until 1988 Otter Tail's coal-fired units had burned primarily North Dakota lignite. Some early units, long since retired, had used eastern coals, but lignite had been the fuel of choice for many years. Following a fuel switch in 1988 at Hoot Lake Plant and in 1995 at Big Stone Plant to low-sulfur western sub-bituminous coal, Coyote is the only plant still burning lignite coal. The coal-fired units also use fuel oil for startup, and flame stabilization at times. The use of fuels at each facility is discussed in the following sections.

Otter Tail is always reviewing opportunities to improve the efficiency and operation of its units. The improvements and conservation efforts within the generating stations have helped Otter Tail maintain some of the lowest system heat rates in its history.

Hoot Lake Plant
The Hoot Lake Plant, consisting of unit #2 and unit #3, is located in Fergus Falls, MN. Hoot Lake #1 generator, built in 1948 with a nameplate rating of 7,500 kW, was retired at the end of 2005.

Hoot Lake #2, was built in 1959 with a nameplate rating of 53,500 kW. The #2 unit is designed as a base load unit, saw intermediate service during the 1980’s and 1990’s, and is now available to the MISO market, but recently the market energy costs have been low enough that Unit #2 has been mainly operated in the winter, partly as a source of building heat for both units. The unit is equipped with an electrostatic precipitator for particulate removal and over-fire air and low-NO_x burners for NO_x emissions reduction.

Hoot Lake #3 is a 75,000 kW nameplate unit that was added in 1964. The unit is also equipped with an electrostatic precipitator for particulate removal and over-fire air and low NO_x burners for NO_x emissions reduction. Hoot Lake #3 was designed for base load duty, but saw mostly intermittent use during the 1980's and 1990’s. Due to recent low MISO market prices, HLP #3 has had only limited operation year round and is now typically run for needed environmental testing and as MISO calls for the unit.

Both Hoot Lake #2 and #3 were upgraded to meet the MATS rule in 2015. These upgrades included new electrostatic precipitator components, as well as activated carbon injection.. As was directed in the Baseload Diversification study completed in 2013, Otter Tail is planning for the retirement of these units in May 2021 (MISO planning year 2020).

Big Stone Plant
The Big Stone Plant, of which Otter Tail owns 53.9 percent, became commercial on May 1, 1975. Improvements have come about as the result of conservation, operational efforts, and equipment updates within the plant. The current output rating for the Big Stone Plant is 475,000 kw (total plant).

The switch to sub-bituminous coal in late 1995 helped to reduce the plant net heat rate. Other efficiency improvements, and the installation of a new low-pressure rotor in 1996, have also helped to lower the heat rate level at Big Stone Plant. A new high-pressure/intermediate pressure rotor was installed in 2005 and improved efficiency by about 2 percent.

The POET Bio-refining ethanol plant (formerly Northern Lights Ethanol) is located on the Big Stone Plant site. Big Stone Plant supplies steam for ethanol production. The steam is extracted part of the way through the electrical production process, so by serving the ethanol plant, Big Stone is truly a cogeneration plant involving the sequential use of the energy for two different purposes. The cogeneration operation does not impact the plant's ability to generate electricity.

In 2015, the largest capital project in Otter Tail Power history was undertaken as the AQCS project was installed at Big Stone Plant to meet the regional haze rule requirements. The AQCS project was a project to install controls for NOx (SCR and SOFA), SO2 (circulating dry fluidized bed scrubber), particulate (baghouse) and Hg control (activated carbon injection to meet MATS rule). The original budget for the AQCS project was $491 million, and through efforts related to project team management and overall project timing, the final cost of the project was about $367 million.

Coyote Station

The Coyote Station, located near Beulah, ND is a lignite-fired mine mouth facility. Otter Tail owns 35 percent of this unit. The Coyote Station was declared commercial on May 1, 1981 and is equipped with a flue gas desulfurization unit and a baghouse. Otter Tail became the operating agent of the facility on July 1, 1998. The other co-owners of this facility are Northern Municipal Power Agency, Montana-Dakota Utilities, and Northwestern Public Service. Minnkota Power Cooperative acts as the agent for Northern Municipal Power Agency.

The Coyote Station is a sister unit to Big Stone, but six years newer. The Coyote Station approved outlet rating is limited to 427,000 kW due to transmission limitations. The facility also has two emergency diesel generators that are not accredited in Midcontinent ISO due to the transmission limitations.

Coyote completed a high-pressure/intermediate pressure rotor replacement in 2009 that resulted in about a 2 percent increase in efficiency. It also increased the UCAP rating of the plant by about 6,000 kW.

Coyote completed the installation of activated carbon injection for Hg control in 2015 as well as a SOFA (separated over-fire air) system for NOx reduction during 2016.

Additionally, the Owners of the Coyote station have entered into a 25 year lignite supply agreement with Coyote Creek Mining Company to begin supplying the Coyote Station with lignite from a new, efficient mine. Supply of lignite coal from CCMC begins approximately June 1, 2016 at the completion of an outage.

1.4 Demand Resources

Otter Tail Power Company has two demand resources registered under Module E with Midcontinent ISO. Both resources are load modifying resources ("LMR") that are netted from the demand forecast and available to Midcontinent ISO in emergency events. These resources are obligated to provide sustained load reduction for up to 4 hours at a time and be available five times a year to Midcontinent ISO in the event of an emergency. This obligation does not preclude the Company from relying on these resources to control for capacity events or economic reasons outside of a Midcontinent ISO emergency event.

Direct Load Control – The Radio Load Management System
The first resource, "Direct Load Control" represents the Company's extensive radio load management system that is used to control customer load during economic or capacity events. This resource was accredited at 18 MW for Midcontinent ISO planning year 2015/2016 based on summer capability but has proven capability as high as 130 MW during the winter months. Otter Tail has approximately 129,800 customers and approximately 42,000 of those customers have some type of load control. The level of control that is available can vary with temperature, customer behavior, and load control responsiveness. For example, more load control is available during extremely cold temperatures in the winter than during moderate temperatures and customers with dual-fuel load may choose to switch to an alternate fuel, particularly during a period of lower prices.

Winter season manageable loads are in several categories and can reach as high as 130 MW. These manageable loads include water heaters, thermal storage, residential demand controllers, commercial time of use rates, small dual fuel heating systems, and large dual fuel (industrial and bulk interruptible loads). The radio load management system also has the capability of interrupting as much as 15 MW of summer peak load in the months of June through September. These summer loads consists primarily of water heaters, irrigation, the large dual fuel industrials and air conditioning. Otter Tail continues to add customers to the newest program that allows cycling control of residential and commercial central air conditioning (15 minutes on, 15 minutes off).

Although measurement data shows the load management system as able to achieve higher levels than the level accredited, those higher levels related to peak control levels during a minimum number of hours and were impacted by weather and load diversity. Those higher levels do not represent the typical levels of control that Otter Tail is confident can be sustained. The measurement and verification requirements for continued accreditation and the risk of potential penalties were also significant factors in the lower accreditation level registered by the Company.

Firm Service Level – Customer Contracts
The second demand resource registered with Midcontinent ISO is a "Firm Service Level" resource that represents Otter Tail's contract with a large industrial customer to shed load to a firm service level in the event of a capacity event. This resource was certified at 14.3 MW for Midcontinent ISO planning year 2016/2017. Unlike the "Direct Load Control" resource that reduces load when called upon by our load management system, this resource must demonstrate that it did not exceed the registered load level during a capacity event.

1.5 Transactions

- A capacity-only contract with Great River Energy for 50 MW capacity in 2014 and increases to 100 MW from January 2015 through May 31, 2017.
- A capacity-only contract with Great River Energy that begins with 25 MW on June 1, 2017 through May 31, 2019 and increases to 50 MW for June 2019 through May 31, 2021.
- A capacity-only contract with Great River Energy for 55 MW that begins on June 1, 2017 and goes through May 31, 2019.
- An energy-only contract with Xcel Energy for 50 MW on-peak 5 X 16 energy for calendar years 2016-2020.

Otter Tail has a number of large commercial customers that are shared loads with local rural electric cooperatives. These loads are in areas that may be in one utility's service territory, but are located where the other utility already had the necessary facilities to handle the load. In order to reduce costs and avoid duplication of facilities, these loads have been shared. In the accounting process, these loads are usually served as if they are Otter Tail customers, and then 50 percent of the energy is purchased wholesale from the other utility at the retail rate used to serve the customer. All of the retail energy shows up as Otter Tail energy with a 50 percent wholesale energy purchase, even though Otter Tail only served half of the load.

WAPA Allocation to Native American Tribes

The Western Area Power Administration ("WAPA") is a federal Power Marketing Agency that provides capacity and energy from hydroelectric facilities located on the Missouri River to preference customers. Otter Tail does not qualify as a preference customer. Native American tribes are preference customers eligible to receive the federal power. The tribes, however, are not utilities in the same manner as typical WAPA preference customers such as municipals and rural electric cooperatives. The tribal lands are typically served by a combination of existing utilities.

In order to facilitate the delivery of the electricity to the tribes, or the economic benefits of the low-cost federal electricity, WAPA developed a process in which the electricity is delivered to the utilities providing electric service on tribal lands. Each tribe has the right to determine which tribal entities receive the benefits. For the customers designated by the tribe as receiving the benefits, WAPA delivers the electricity to Otter Tail at the WAPA rate, and then Otter Tail provides a bill credit to the customer. The bill credit is essentially equal to the difference in cost between the WAPA power and the embedded Otter Tail cost of generation, less expenses to administer the program. Otter Tail has filed the appropriate information with and received approval from the state regulatory commissions in the states involved.

Otter Tail has five tribes that receive the benefits of the WAPA power. The current capacity amount varies monthly from a low of 4.3 MW to a high of 5.6 MW, with annual energy of 32,158,236 kWh. Otter Tail also receives the load based reserve margin benefit with the capacity. Because the tribes have the right to change who receives the benefit and such changes may move benefits from tribal customers served by Otter Tail to tribal customers served by another utility, the amount of capacity and energy received for the tribal loads may vary over time. The current amount of tribal allocation that is received through Otter Tail is included in all analysis scenarios. None of the WAPA power qualifies for compliance with the Minnesota Renewable Energy Objective, as all of the WAPA hydroelectric facilities are greater than 100 MW when considering all units at a specific location.

Customer Owned Generation

Otter Tail has worked with several customers who desired to install small diesel generators for back-up emergency power. These units are owned by the customers and capable of being interconnected to Otter Tail's system. The capacity from these units is purchased by Otter Tail and submitted as behind the meter capacity resources registered with Midcontinent ISO. Currently the NDC rating of these units is 4,500 kW in total and the UCAP rating is 4,100 kW in total.

On March 3, 2010 the U.S. Environmental Protection Agency issued new national emission standards for hazardous air pollutants for existing stationary compression ignition reciprocating internal combustion engines. The new standards include emissions limitations, operating limitations, maintenance requirements, performance tests, recordkeeping requirements, and reporting requirements. By May 1, 2016 all of Otter Tail's engines affected by the RICE Rule will be considered emergency or blackstart in nature and therefore exempt from emissions limitations and performance tests. Only minimal efforts will be needed to comply with the rule.

Otter Tail also has power purchase agreements with several wind generation facilities as described in the following section.

1.6 Wind Generation Resources

Otter Tail has more than 246 MW of wind generation on the system, including utility owned and contracted wind generation. The Company owns 138 MW of wind generation. This wind generation accounted for 18% of the Company's energy needs in 2015.

Langdon Wind Energy Center
Otter Tail owns 40.5 MW of wind generation located south of Langdon, ND consisting of 27 1.5MW GE wind turbines. This facility began operation in January 2008.

Ashtabula Wind Energy Center
Otter Tail owns 48.0 MW of wind generation located in Barnes County, ND consisting of 32 1.5MW GE wind turbines. This facility began operation in November 2008.

Luverne Wind Energy Center
Otter Tail owns 49.5 MW of wind generation located in Steele County, ND consisting of 33 1.5MW GE wind turbines. This facility began operation in September 2009.

Approximately 108 MW of wind generation is purchased by Otter Tail from customers or other entities and is identified in Table 1-2. Customer owned units do not have the ownership name included to protect customer information. Often generation from smaller, customer owned units is used to serve the customer and only the surplus generation is sold to Otter Tail.

Table 1-2: Contracted Wind Generation Facilities

Name and Owner	State	kW Rating
FPL Energy ND Wind II - NextEra	ND	21,000
Hendricks Wind I	MN	900
Borderline Wind	MN	900
Dakota Wind Exchange	SD	90
Langdon Wind Energy Center – NextEra	ND	19,500
Ashtabula III – NextEra	ND	62,400
Various Small Wind Producers	ND	3,234
Various Small Wind Producers	MN	2,200
Various Small Wind Producers	SD	8

As shown in Table 1-2, Otter Tail has contracts for roughly 110 MW of wind generation. Often generation from smaller, customer owned units is used to serve the customer and only the surplus generation is sold to Otter Tail.

1.7 Energy Efficiency Programs

Otter Tail Power Company operates a number of Demand-Side Management Programs in its service territory. In Minnesota, some of these projects are part of the Company's Conservation Improvement Program ("CIP") filing, Docket No. E017/CIP-13-277. The Company also operates an energy efficiency program in South Dakota. The Company's MN and SD energy efficiency results have been on target with the energy efficiency goals in historical integrated resource plan filings.

Otter Tail's 2014-2016 CIP triennial, filed on June 1, 2013, supports energy efficiency objectives in the Company's 2014-2028 Integrated Resource Plan, Docket No. E017/RP-13-961 and in the proposed 2017-2031 resource plan. Due to timing and baseline year differences, the annual energy savings resource plan objective of 1.5 percent energy savings will not exactly match the annual energy savings goal in the 2014-2016 CIP triennial plan, which slightly exceeds 1.5 percent annual energy savings. Table 1-3 reflects approved annual energy and demand savings goals for Minnesota's CIP 2014-2016. For 2014 and 2015, Otter Tail's CIP results have met the annual energy and demand savings goals.

Table 1-3: Planned MN Energy Efficiency Goals

Year	Annual MW Savings Goal (Summer)	Annual MWH Savings Goal
2014	8.4	31,405,290
2015	8.4	31,762,333
2016	8.6	32,476,419

The 2014-2016 Plan builds upon lessons learned from more than two decades of offering energy efficiency programs. The entire portfolio can be reviewed in Docket No. E017/CIP-13-277. On June 1, 2016, Otter Tail will file its 2017-2019 CIP triennial plan with the Minnesota Department of Commerce. This proposed plan will target annual energy saving achievements of 1.5 percent, similar to the 2014-2016 CIP triennial.

1.8 Midcontinent Independent Transmission System Operator ("Midcontinent ISO")

Otter Tail continues to play an active role in the regional transmission planning efforts. While Otter Tail still leads and conducts studies to ensure the adequacy of the transmission system to serve its customers, all transmission planning activities related to regional transmission are coordinated with the Midcontinent ISO and the surrounding non-Midcontinent ISO transmission owners.

Transmission planning occurs through the course of performing transmission studies at several different levels, from individual utility plans, to joint utility plans with utility neighbors, to broad regional studies. Regardless of the type of studies, the forum for which these studies are discussed is through a regional transmission planning process. Otter Tail actively participates in several Midcontinent ISO study groups, such as which is the West Subregional Planning Meetings (SPM) and the Western Technical Studies Task Team ("WTSTT"). These groups provide forums for regional transmission planners to discuss the needs and projects related to the transmission system in the Otter Tail and surrounding area that are within the western footprint of the Midcontinent ISO region.

Otter Tail closely coordinates its transmission planning efforts with the Midcontinent ISO. For transmission planning purposes, Midcontinent ISO performs three primary functions. The first two are federally mandated processes established by FERC, generator interconnection and delivery service, and the third process is related to expansion planning.

Midcontinent ISO administers and processes requests to use the transmission system of the Midcontinent ISO transmission owners. Midcontinent ISO has established procedures for processing generation interconnection and delivery service transmission requests of generators and market participants. Through this FERC mandated process, Midcontinent ISO offers the area utilities opportunities to participate in "ad-hoc" study groups to provide input and review of the technical studies completed for generation interconnection or delivery service. In addition to these FERC mandated requirements, Midcontinent ISO also performs expansion planning studies on an annual basis. These expansion planning studies are referred to as the Midcontinent ISO Transmission Expansion Plan ("MTEP") and focuses on a variety of studies, from reliability assessments to targeted studies focused on a particular issue or item. Otter Tail's transmission system falls within the Midcontinent ISO West region. Through the MTEP process, Midcontinent ISO completes a reliability analysis assessing the transmission system performance against the regional reliability criteria. Otter Tail also participates in the MN TACT (Minnesota Transmission Assessment Compliance Team) group which also performs a reliability assessment of the western transmission system. In the event that standards are not met, additional analysis is completed to find mitigation to a particular system issue. Otter Tail actively participates in the MTEP, MN TACT, generator interconnection, and delivery service efforts by attending meetings, reviewing study results and providing input into the study process.

Midcontinent ISO has also sponsored targeted studies in the region as part of the MTEP process. Otter Tail actively participates in many of these targeted studies, including the Northern Area Study (NAS), Market Efficiency Projects ("MEP"), Manitoba Hydro Wind Synergy Study ("MWHSS"), as well as other targeted studies. Through these various study efforts, Otter Tail attends meetings, reviews study results and provides input into the study processes.

In addition to the specific study opportunities, the Midcontinent ISO conducts meetings of several stakeholder groups, which include the Planning Subcommittee ("PSC"), the Planning Advisory Committee ("PAC"), the Regional Economic and Criteria Benefits Task Force ("RECB TF"), the Interconnection Process Task Force ("IPTF"), among several others. These meetings are attended by various representatives of the different stakeholder groups at Midcontinent ISO. These meetings act as a forum between Midcontinent ISO staff and the stakeholders to provide input into the processes of the

Midcontinent ISO. Otter Tail regularly attends several of these meetings to stay engaged within the Midcontinent ISO transmission planning process as well as provide input and feedback to the Midcontinent ISO.

Otter Tail has been an active participant in the CapX 2020 effort. The CapX 2020 sponsoring companies embarked on a transmission study developing a long-term transmission plan to ensure reliable service to customer loads in the year 2020. The CapX 2020 utilities are currently engaged in construction and operation of what is termed as the "Group 1" projects, which include three 345 kV projects and one 230 kV project within Minnesota. The efforts of the CapX 2020 studies have been closely coordinated with the Midcontinent ISO planning process.

In addition to these previously mentioned planning-related activities, Otter Tail is also monitoring other regional transmission development initiatives, such as the Clean Line HVDC projects, and the Eastern Interconnection Planning Collaborative ("EIPC"). Otter Tail is a regular participant in meetings and conference calls related to these study initiatives.

All of these transmission planning activities are then combined into, and are consistent with, the MN state transmission planning process.

Transmission Interconnections
On May 9, 2002, the Commission gave conditional authority to Otter Tail to transfer operating control of certain transmission facilities to the Midcontinent ISO. Since joining Midcontinent ISO and transferring operational control of its high voltage transmission facilities to Midcontinent ISO, Otter Tail has seen positive benefits in this relationship regarding the generator interconnection processes.

Since Otter Tail joined Midcontinent ISO, several generators have successfully interconnected to the Otter Tail electric system under Midcontinent ISO's generator interconnection procedures. Under Midcontinent ISO's Open Access Transmission and Energy Markets Tariff ("TEMT"), all generator interconnection requests (regardless of generator size or interconnecting voltage level) are required to abide by the Midcontinent ISO generator interconnection process if the generator intends on engaging in wholesale transactions. The Midcontinent ISO, as an independent system operator, ensures comparable treatment for all customers and it is staffed to provide and administer this service. Otter Tail receives value and efficiencies from the Midcontinent ISO process given that Midcontinent ISO is staffed to administer its procedures and, as an independent organization, ensures comparable treatment to all parties involved. Additionally, Otter Tail stays actively engaged in several Midcontinent ISO studies and provides information regarding the transmission system when reviewing study results and giving direction for future studies. This is an efficient process and a benefit to all parties since Otter Tail has ultimate knowledge and familiarity with its system and most efficiently and effectively provides this service. Project coordination, administration, and filing requirements fall upon Midcontinent ISO, thus freeing up Otter Tail's resources to focus on its key priority of providing clean, efficient, and low cost energy to its customers.

Locational Marginal Pricing (LMP) Energy Market and Ancillary Services Market (ASM)
The Midcontinent ISO Locational Marginal Pricing ("LMP") energy market was introduced on April 1, 2005. The Midcontinent ISO subsequently introduced the Ancillary Services Market ("ASM") on January 6, 2009. Both market introductions went well, but utility operations and market functions have changed significantly.

Many of the key preparations and day-to-day activities since commencement of the markets include:

- Development of software interfaces and procuring or developing new software systems.
- Training of employees.
- Developing after-the-fact data flows to ensure a seamless transition in the accounting and regulatory areas.
- Active involvement in filings related to the Energy Market at the Federal Energy Regulatory Commission ("FERC") and state commissions. This includes settlement proceedings for the non-Midcontinent ISO Load Serving Entities located within the Otter Tail Power Company Control Area.

- Nominating and receiving Auction Revenue Rights (“ARRs”) and Financial Transmission Rights (“FTR”) allocations to safeguard Otter Tail’s native load.
- Developing business practices, strategies and risk management policies to accommodate an LMP and ASM Market.
- Actively participating in the numerous Midcontinent ISO committees seeking to ensure that Otter Tail’s best interests and the interests of its customers were not adversely impacted by decisions and policies resulting out of these committees.

Market operations continue to go smoothly, and the company is generally pleased with the transition to the centralized energy and ancillary services markets.

Midcontinent ISO Resource Adequacy (Module E)
Otter Tail’s reserve requirements are established by Midcontinent ISO under Module E of the Midcontinent ISO Tariff. For planning year 2016 (June 2016 – May 2017) the Midcontinent ISO reserve margin requirement is 7.6 percent.

MISO currently operates in an annual construct with a system wide coincident peak occurring in the summer months. The Company’s coincident peak demand diversity factor is approximately 8 percent of its non-coincident peak demand. For modeling purposes, Otter Tail used a zero cost capacity transaction within Strategist to reflect the impact of the coincident peak demand on reserve requirements.

MISO is discussing with stakeholder the possibility of moving to a two season capacity construct starting in planning year 2018. Upon initial review, the Company does not see this being a concern from a capacity perspective. Although the Company has a winter peak of roughly 100 MWs higher than its summer peak, there will also be an additional 100 MWs of winter demand response resources available to offset the increase in peak load.

Resource accreditations change annually and are based on summer ratings. Ratings for non-wind generators are based on historic generator availability data or, if that is unavailable, class averages are used.

Wind generation is accredited based on unit specific historical capacity factors. Accreditation for the 2016 planning year for the Company’s wind farms varied from 27 percent at the Luverne Wind Farm to 17 percent at the Edgeley Wind Farm.

Otter Tail has successfully registered the load management system and retail firm service level contracts under Module E as Demand Resources. The accredited capability of these resources is subtracted from the Company's forecast demand prior to calculation of the planning reserve margin. Otter Tail's accredited Demand Resources for planning year 2016 totaled 32.3 MW. This accreditation is based on its summer capability which is when Midcontinent ISO experiences its annual peak demand.

1.9 Transmission Facilities

Otter Tail serves many very small communities located in a geographical area about the size of the State of Wisconsin. The characteristics of the customer loads and locations have required an extensive transmission system. When compared to many investor-owned utilities, Otter Tail's customer count per mile of transmission facilities is quite small. To minimize cost, Otter Tail has become party to several integrated transmission agreements. The Company participates in many shared networks with other investor owned utilities, municipals, G & T cooperatives, and rural electric cooperatives. In many cases, a 41.6 kV or 69 kV transmission line will serve an equal number of non-Otter Tail and Otter Tail distribution substations.

These agreements have resulted in over 200 points of interconnection with other utilities. Such a network adds to the complexity of operating the electrical system, but also adds the capability for the facilities of one utility to provide either full time or emergency service to another utility. The ultimate result is reduced cost and increased reliability for the customer. Table 1-4 lists the mileage of various voltage classes of transmission lines. All of these lines are overhead lines except for less than one mile of underground cable in the 41.6 kV class.

Table 1-4: Circuit Miles of Transmission by Voltage

Voltage (kilovolts)	Circuit length
345 kV	*657 miles
230 kV	*491 miles
115 kV	*876 miles
69 kV	209 miles
41.6 kV	3763 miles

**Mileage includes Otter Tail Power Company joint ownership in CapX2020 transmission projects. See CapX2020.com for more information.*

Appendix D
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Appendix D: Potential Resources

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Potential Resources

This appendix provides a description of the resources that were evaluated in the development of the 2016 Integrated Resource Plan by Otter Tail. The development of the resource plan focused on the evaluation of resources that are available to the Company, taking into account a number of factors. These factors include available size increments of the technology, the maturity and commercial availability of the technology, the availability of interested co-owners of large facilities, operational parameters, and available data.

As the Strategist model evaluates each year's resource alternatives, it is able to save a finite number of feasible combinations of solutions, called "states." These states are carried forward as starting points to the following year's evaluation of resource alternatives. The model ranks all states by cost and discards those states that rank higher than a prescribed saved states limit. For example, if the saved states limit is 2000, any plan that ranks 2001 or higher based on cost is discarded. It is possible that a feasible state discarded early in the study period could be the least cost solution over the study period. To minimize the potential error of discarding the true least cost plan, it is prudent to minimize the number of alternatives made available to the model. This effort helps to minimize the number of feasible combinations of alternatives and in turn minimizes the likelihood that the model will discard the least-cost plan. Narrowing the number of alternatives for evaluation also shortens the model run-time, allows the model to be more user-friendly for evaluation of various futures, and provides greater opportunity for verification and validation of model performance. The Company aimed to adequately represent every resource type in the mix of alternatives made available to the model while reducing redundancy as much as possible.

Specific cost and performance data used for the computer modeling came from a variety of sources and is provided in detail in Appendix F: Assumptions for Strategist Modeling Scenarios.

1 Supply-Side Generation

A discussion of each of the coal- and gas-fired technologies and other supply-side technologies is included in the following pages. The technologies are grouped into the following two categories

<u>Generation Alternatives in the Model</u>

- Combined Cycle Gas Turbine ("CCGT")
- Simple Cycle Combustion Turbine
- Wind
- Solar Photovoltaic

Pre-screened Generation Alternatives Not in the Model

- Nuclear
- Pulverized Coal - Subcritical
- Atmospheric Circulating Fluidized Bed Coal (“ACFB”)
- Pulverized Coal – Supercritical and Ultra-supercritical (green field site)
- Supercritical Coal, using a brown field site
- Integrated Gasification Combined Cycle (“IGCC”)
- Reciprocating Engine Plants
- Phosphoric Acid Fuel Cell (“PAFC”)
- Hydro (owned projects)
- Heat Recovery
- Energy Storage
- Anaerobic Digestion
- Landfill Gas
- Microturbines
- Biomass
- Geothermal

Whether a technology was pre-screened or included in the model for capacity expansion evaluation is indicated in the text. The effort on screening resources was necessary to develop a useful modeling tool that was practical in terms of run-time while simultaneously comprehensive in evaluating the forward-looking resource mix. It is important to note that any resource used as a potential future addition in the Strategist model was intended to be generic and representative of the Company’s needs. In no way do the alternatives selected for modeling purposes exclude future consideration of competing options in similar generation categories.

1.1 Technology options included in the model

Simple Cycle Combustion Turbine - Large
The model was given the preferred combustion turbine option.. This is a heavy-duty frame unit with an ISO rating of about 248 MW. The heavy-duty frame units are characterized by a lower capital cost per kW and lower maintenance cost,.

Aeroderivative Simple Cycle Combustion Turbine – Small
The 49 MW ISO-rated alternative is based on the existing GELM6000 aeroderivative technology that Otter Tail currently owns and operates at Solway, MN. As the name implies, aero derivative electric generation units were derived from gas turbine development for the aircraft industry. The traits of aeroderivative units compared to the frame-style gas turbines are typically, faster starts, higher efficiency, smaller overall size, and higher capital cost in $/kw. However, frame CT technology has advanced and it should be noted that starts times and efficiency have dropped in recent years, as now some frame CT suppliers are offering units that can meet the 10 minute start time that was the hallmark of aero derivative units in the past.

Combined Cycle Gas Turbine ("CCGT")
The basic principle of the Combined Cycle Gas Turbine is to use a gaseous fuel such as natural gas, or a liquid fuel such as no. 2 fuel oil, to produce power in a gas turbine and to use the hot exhaust gases from the gas turbine to produce steam in a Heat Recovery Steam Generator ("HRSG"). The steam would be used to generate electric power with a steam driven turbine-generator set. Typical CCGT units operate with natural gas as the operating fuel, but often dual-fuel capability with oil as a backup is used to increase the availability of the generation when natural gas supplies are curtailed. The model was given the option of a 311 MW combined cycle alternative during the study period.

Wind Generation
Wind generation was made available to the model in 100 MW blocks throughout the study period modeled as a purchased power transaction.

Solar Generation
Solar generation was made available to the model in 30 MW blocks throughout the study period modeled as a purchased power transaction.

1.2 Technology options not allowed in the model

Nuclear
Electricity from a nuclear power plant remains a very clean and safe form of electrical generation in the United States and the world. In 1994, the Minnesota Legislature passed a law that created a moratorium on the construction of new nuclear generation facilities in Minnesota (216B.243, subd. 3b). Nuclear energy was not considered as a resource alternative because of the law listed above, and what appear to be very high costs related to siting, permitting, and construction. Additionally, the Company is not aware of any nuclear project under development soliciting joint ownership. Due to the factors listed above, the addition of nuclear generation was not included in the model.

Carbon Capture and Sequestration (CCS)
There is significant research being conducted on the possibility of developing technologies and regulations around the concept of capturing carbon dioxide from electric generating units using fossil fuels. While there is much information in the public domain about development work, demonstration projects, and future-looking analysis for resource planning purposes, it is the position of Otter Tail that CCS is not commercially available and will not be considered a likely technology to employ within the current planning period. If regulations or successful demonstration projects develop into full-scale projects which can be offered with commercial and performance guarantees, the Company will reconsider this position.

Pulverized Coal - Subcritical
Pulverized coal boiler technology is a mature and reliable energy producing technology around the world. The operating pressure of conventional coal-fired power plants can be classified as sub-critical and super-critical. Sub-critical and super-critical technologies refer to the state of the water that is used in the steam generation process. The critical point of water is 3208.2 psia and 705.47° F. At this critical point, there is

no difference in the density of water and steam. At pressures of about 3208.2 psia, heat addition no longer results in the typical boiling process in which there is an exact division between steam and water. The fluid becomes a composite mixture throughout the heating process. A sub-critical pulverized coal unit was eliminated from consideration as an option because of higher emissions and a less efficient heat rate.

Pulverized Coal – Supercritical and Ultra-Supercritical
The current Minnesota Next Generation Act of 2007 eliminates any reasonable chance of construction of coal-fired generation for Minnesota and was not made available to the model. Super-critical pulverized coal units have been part of the U.S. power generation mix since the mid-1950's. Since the 1980's, the development of high strength materials and Distributed Control Systems (DCS) have helped to make supercritical units easier to control and operate. Supercritical units typically operate at 3500 psig and up to 1050° F or 1080° F. at the steam turbine inlet. In addition, while there is no current technical definition of an ultra-supercritical unit, it seems to be generally accepted that units designed to operate at 1100° F or higher are ultra-supercritical. There is currently at least one new unit that is being constructed in the United States where the design steam temperatures are above 1100° F. Heat rates for supercritical or ultra-supercritical units can be lower than 9,000 btu/kWh. If the average heat rate of the current coal fleet is 11,500 btu/kWh, use of a modern supercritical or ultra-supercritical unit would result in over 20% less coal being burned per MWh or 20% less CO_2 emissions per MWh.

Atmospheric Circulating Fluidized Bed Coal ("ACFB")
The consideration of a baseload coal-fired unit at the Big Stone Plant ("BSP") site included evaluation of a large ACFB facility. The combustion within a fluidized bed boiler occurs in a suspended bed of solid particles in the lower section of the boiler. Combustion within the bed occurs at a slower rate and lower temperature than a conventional pulverized coal-fired boiler. Deviations in fuel type, size, or Btu content have minimal effect on the furnace performance characteristics. The bed allows for re-injection of a sorbent, such as fly ash or limestone, to reduce SO_2 emissions. This type of operation requires approximately 1.5 times the quantity of limestone to achieve a reduction in SO_2 similar to that of a wet limestone scrubber.

One of the benefits of an ACFB facility would have been an increased ability to use biomass fuels. The BSP unit already has an alternative fuels handling facility and the capability to burn alternate fuels. There has been difficulty in expanding the use of biomass fuels at BSP due to cost and availability. The benefit of being able to use biomass fuels was outweighed by a number of other factors, and a large fluidized bed unit was eliminated from consideration. The Minnesota Next Generation Energy Act of 2007 requires new coal-based generation to offset CO2 emissions. Any ACFB alternative would require CCS to be installed in order to serve load in Minnesota. Otter Tail Power's view of CCS is that it is a promising technology but not currently commercial.

Integrated Gasification Combined Cycle ("IGCC")
IGCC technology produces a low energy value syngas from coal or solid waste, for firing in a conventional combined cycle plant. The gasification process in itself is a proven technology having been previously used extensively for production of chemical products such as ammonia for use in fertilizer. The U.S. Department of Energy (DOE) has jointly funded several power plant facilities through the U.S. The majority of the DOE test facilities use entrained flow gasification design with coal as feedstock. In that process, coal is fed in conjunction with water and oxygen from an air separation unit, into the gasifier at around 450 psig where the partial oxidation of the coal occurs. The raw syngas produced by the

reaction in the gasifier exists at around 2400° F. and is then cooled to less than 400° F. in a gas cooler, which produces additional steam for both the steam turbine and the gasification process. Particulate, ammonia (NH_3), hydrogen chloride, and sulfur are then removed from the raw syngas stream. The cooled and treated syngas then feeds into a modified combustion chamber of a gas turbine specifically designed to accept the low calorific value syngas. Exhaust heat from the gas turbine then generates steam in a HRSG which in turn powers a steam turbine.

It is recognized that IGCC, in theory, shows potential to become a reliable, low emission source of electrical energy in the future that more easily adapts to the potential of CCS. Compared to supercritical pulverized coal, IGCC projects appear to have higher upfront capital costs, variable O&M, and fixed O&M. The Minnesota Next Generation Energy Act of 2007 requires new coal-based generation to offset CO2 emissions. Any IGCC alternative would require CCS to be installed. Otter Tail Power's view of CCS is that it is a promising technology but appear to not be economically viable today.. Based on all of these considerations, Otter Tail did not include IGCC as an option in the planning model.

Reciprocating Engine Plants

Large-scale reciprocating engine power plants have begun to gain in popularity in some areas of the country in recent years. A reciprocating engine plant is constructed of incrementally sized engines (2 MW – 16 MW each). Most large-scale reciprocating engine plants are fueled with natural gas only. However, some systems may be dual fuel (natural gas and fuel oil). Typically speaking, the construction costs of a reciprocating engine plant are more expensive than a simple cycle combustion turbine (perhaps 10% – 20% higher). However, on a unit to unit comparison, the reciprocating engine is more efficient than a typical aeroderivative combustion turbine. If you consider partial load operation, the overall fuel savings can be considerable. Some energy providers have viewed the installation of reciprocating engine plants as a good fit to a region with high wind or other intermittent energy resources. A generation resource that is capable of high efficiency through a wide range of output may become attractive enough to overcome initial higher installation costs. Through the prescreening process, reciprocating engines were excluded from the alternatives made available to Strategist, largely due to the higher O&M and capital costs.

Phosphoric Acid Fuel Cell ("PAFC")

The model evaluation excluded the option to select fuel cells due to the resource's higher costs compared to other units of similar technology. Fuel cells function by converting hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cells can sustain high efficiency operation even under partial load conditions and they have a rapid response to load changes. The construction of fuel cells is inherently modular, making it easy to size facilities according to power requirements. One of the most significant benefits to fuel cells is the lack of emissions. The only significant emissions are water and carbon dioxide.

Hydro

For past resource plan filings Otter Tail has reviewed the potential for cost-effective small hydro development within its service territory. A Minnesota Department of Natural Resources (DNR) survey of potential sites within the state served as a basis for that review. The DNR conclusion was that the existing economic sites had already been developed. For that reason, Otter Tail did not include any potential development of small hydro within the model.

Even if potential sites existed within the Company's service territory, it is unlikely that they would be economic for development if the sites were under FERC jurisdiction. If a waterway has a designation as a navigable stream, then it falls under FERC jurisdiction. Otter Tail's small hydros on the Otter Tail River near Fergus Falls were all built prior to FERC licensing requirements. The Otter Tail River was designated as a navigable stream because in the 1800's it was used for transportation and to float logs to the sawmill. In the late 1980's and early 1990's, Otter Tail was ordered to obtain FERC licensing on these units. The licensing process took several years and cost about $400/kW, for existing units. The licensing cost for developing a new site is likely to be so high as to make the process uneconomic.

Energy Storage

Promising new technologies are being developed, tested, and demonstrated in the field of energy storage. These technologies include battery storage, compressed air energy storage, and proven pumped hydro storage. As the overall percentage of intermittent renewable resources connected to the electrical supply system increases, the focus on energy storage technologies will increase.

Anaerobic Digestion
Previous study work within Otter Tail concluded the amount of potential generation from anaerobic digestion within Otter Tail's system may result in minimal (less than 5 MW) opportunity and too small to be of consequence to this resource plan filing. Anaerobic digestion was not included as a generation option within the model.

Landfill Gas
According to an EPRI report completed in the late 1990's, the Otter Tail Service territory does not include any landfills of sufficient size to support a landfill gas generating facility. The only two landfills in the area that were identified as having sufficient size are located at Fargo and Grand Forks, both served by another utility. Fargo now has a unit installed. Each of those landfills was identified as having the potential to support two 2 MW generators. Landfill gas was not included as an option within the model.

Microturbines
Microturbines are miniature combustion turbines, similar in concept to the large combustion turbines used in conventional utility power plants. Whereas large combustion turbines range from 20,000 to over 330,000 kW, microturbines fit into the 25 to 400 kW range. The waste heat from the turbine exhaust can be collected to supply a useful thermal load, which improves the overall cycle efficiency and the economics. However, the capital costs are still higher than the cost of a standard utility size combustion turbine and the efficiencies are much worse. At this point in time, potential economic applications are somewhat limited. The model did not include consideration of microturbines due to their small size, limited application at this time, and high cost.

Biomass
Since the early 1990's Otter Tail has made an effort to use renewable fuels in its existing coal-fired plants. The Big Stone Plant has burned a number of renewable and alternate fuels over the years and has an alternative fuels handling facility to aid in blending such fuels in with coal. Some of the renewable fuels that have been tried or researched over the years include spoiled or research corn seed, wood waste in various types, soybeans, sunflower hulls, and similar agricultural wastes. Some of these materials caused significant problems in test burns by either plugging fuel handling systems (bark wood waste) or plugging boilers (soybeans). Sunflower hulls and soybeans have proven to be problematic due to their high content of potassium. As of January 1, 2010, Big Stone Plant has stopped the alternative fuel program. The primary reasons were the limited availability of fuel and the high cost of maintenance of the handling facilities.

Otter Tail did not include any other additional biomass alternatives in the model. As the cost of fossil fuels increases, other markets develop for biomass fuels such as wood waste. In many cases, the wood products companies that create the waste use it as fuel in their own process. Otter Tail has worked with customers on potential wood waste-fired biomass facility investigations. The fuel supply is limited and the costs of such facilities are high. The development potential of these facilities is limited and very site specific. To date, Otter Tail has not found other opportunities for development of such facilities with costs being close to economic.

Geothermal

Otter Tail has worked with the Geology Dept. at the University of North Dakota on investigating the potential for geothermal energy. Western North Dakota has geothermal resources in temperature ranges that would be suitable for binary cycle geothermal technologies. A binary cycle facility typically pumps natural water or brine from underground that has been heated by the earth to moderate temperature ranges of 200° F. - 500° F. The heat in the fluid is transferred to another working fluid such as iso-pentane which is used in place of water in a normal vaporization/condensation cycle. The brine is then reinjected back into the earth. The extraction and reinjection wells are typically from 1,000 – 3,000 feet deep and require significant horsepower to extract the fluid and then reinject it. The resources in western North Dakota are located much too deep to be economic for binary cycle operation, typically in the 10,000 – 12,000 foot range. Otter Tail did not include any geothermal options as potential generating resources in the model.

Otter Tail does have geothermal heat pumps as programs within its CIP process.

2 Demand Side Resources

Following is a description and comment on each of the demand response and energy efficiency resources used in this resource plan.

- **1.5 percent CIP** – The model uses annual energy efficiency and conservation alternative for Minnesota load that is 1.5 percent of average retail sales for the prior three years. By 2031, summer peak demand impacts from energy efficiency and conservation are expected to be 133.1 MW, not including the reserve margin savings. Additional sensitivities were modeled to assess the impacts of increasing the energy efficiency goals from 1.6 percent to 2.0 percent in 0.1 percent increments as ordered by the Commission.

- **Demand Response –** Demand response includes both load management capability and customer contracts that allow load shedding to a firm service level. In the preferred plan, demand response capability started at 33 MWs in 2017 and increased to 41 MW of summer season capability by 2031.

Appendix E
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Appendix E: Assessment of Federal and State Environmental Regulations

Assessment of Federal and State Environmental Regulations

I. GREENHOUSE GAS REGULATION

In 2009 EPA began addressing greenhouse gas ("GHG") emissions using the Clean Air Act ("CAA"). The first step in the EPA rulemaking process was the publication of an endangerment finding in the Federal Register on December 15, 2009. The EPA found that carbon dioxide ("CO_2") and five other GHGs – methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride – threatened public health and welfare. These findings did not themselves impose any requirements to control GHG emissions, but they were a prerequisite to finalizing GHG standards for vehicles. Since the motor vehicle standard regulated GHG emissions for the first time under the CAA, GHG emissions are therefore included in the pollutants subject to the requirements of the New Source Review program of the CAA.

Additionally, on June 25, 2013 President Obama issued a memorandum directing the EPA to implement carbon pollution standards for new power plants, and to implement carbon pollution standards, regulations, or guidelines for modified, reconstructed, and existing power plants.

A. Existing Source Guidelines

1. <u>Background</u>

The EPA is developing GHG performance standards for existing sources under CAA Section 111(d), through a rule termed the Clean Power Plan ("CPP"). Under Section 111(d), the EPA promulgates emission guidelines, and the states are then given a period of time to develop plans to implement the standard. The EPA reviews each state-developed standard and then approves it if the state's plan comports with the federal emission guidelines; if the state does not submit a plan or the EPA finds that the plan is inadequate, the EPA will prescribe a plan for that state.

A "standard of performance," is defined as:

> …a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the [EPA] Administrator determines has been adequately demonstrated.

Additionally, for existing sources, Section 111(d) requires the EPA to consider, "among other factors, remaining useful lives of the sources in the category of sources to which such standard applies."

2. Proposed Rule

On June 2, EPA signed the proposed CPP that provided state-specific rate-based goals for CO_2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the goals. An interim goal was proposed to be achieved on average over the ten year period of 2020-2029, and a final goal in 2030 and each year thereafter. Nationwide, CO_2 emissions were projected to decrease 30 percent from 2005 levels by 2030 as a result of the rule.

To determine the goals, EPA used 2012 net generation data and CO_2 mass emissions to calculate a 2012 average CO_2 emission rate by state. Then it determined a best system of emissions reduction ("BSER") based on four building blocks applied on an individual state-by-state basis:

1. Achieving plant efficiencies that would average a 6 percent reduction in CO_2 intensity across the fleet of coal-fired power plants.
2. Dispatching natural gas combined cycle ("NGCC") units in each state at a 70 percent capacity factor. Coal-fired generation would be reduced within a state as needed to offset the increased generation from natural gas.
3. Setting renewable energy standards for each state and preserving nuclear energy generation.
4. Using demand-side energy efficiency to save up to 1.5 percent energy a year.

Specific to OTP, EPA's proposed formula created substantially different CO_2 rate targets for North Dakota, South Dakota, and Minnesota, primarily due to the EPA's second building block that envisioned re-dispatching NGCC units to a 70% capacity factor. EPA did not specifically propose equivalent mass-based goals, but did offer an "illustrative" calculation for translating the rate targets into mass targets.

The rate targets that were proposed along with the "illustrative" mass targets for each of OTP's states are shown below.

Table E1: Proposed CPP Rule Targets

State	Rate Targets		"Illustrative" Mass Targets[1]	
	Interim Years 2020-2029 CO_2 Goal (lb/MWh)	Final Year 2030 CO_2 Goal (lb/MWh)	Interim Years 2020-2029 CO_2 Goal (Million Tons)	Final Year 2030 CO_2 Goal (Tons)
MN	911	873	16,651,803	15,954,473

[1] The illustrative approach represented is for existing units only. EPA also included an illustrative approach that would include new units.

ND	1,817	1,783	30,398,748	29,838,327
SD	800	741	1,907,799	1,766,176

OTP was actively engaged with numerous stakeholders during the proposed rule comment period, and we submitted extensive comments to EPA on November 25, 2014. Legal arguments aside, our primary concern with the proposed rule was the miscalculation of the target specific to South Dakota due to the use of 2012 data to calculate the state's target. South Dakota had unique circumstances in 2012 surrounding hydropower generation, and additionally the state's only NGCC plant was under construction for most of the year.

3. Final Rule

On October 23, 2015 the EPA published the final CPP. Under this plan, CO_2 reductions are phased in over a 2022-2029 interim period (a two-year delay to the start of the program as compared to the proposed rule), with final targets achieved by 2030. If the CPP is ultimately implemented, EPA projects that the power sector will have reduced CO_2 emissions 32 percent from 2005 levels by 2030.

The EPA's best system of emission-reduction, on which state goals were computed, was based on three building blocks in the final rule:

1. Heat rate improvements at each coal plant,
2. Increased reliance on natural gas combined cycle units, and
3. Increased deployment of renewable energy above 2012 levels.

Notably, these blocks were applied across three grid interconnections – Eastern, Western, and ERCOT – instead of on a state-by-state basis as compared to the proposed rule. EPA chose the least stringent (i.e., the highest) fossil steam rate and NGCC emission rate among the three regions to establish national uniform source-category emission performance rates. These national uniform rates standards were 1,305 pounds of CO_2 per net megawatt hour for coal plants and 771 pounds of CO_2 per net megawatt hour for NGCC.

After determining the national uniform BSER, state specific goals are determined in terms of rate as the weighted average of the 2012 statewide mix of coal and natural gas combined cycle generation. Finally, an equivalent mass-based state target was computed.

Thus, the final rule outlined two approaches for each state to choose between to implement the CPP:

1. A rate-based goal measured in pounds of CO_2 emitted per MWH generated (intensity)
2. A mass-based goal measured in total short tons of CO_2 produced

Due to EPA's re-designed calculation methodology, a narrower range of rate-based goals were created for each state as compared to the proposed rule. The rate-based and mass-based targets that were finalized for each of OTP's states are shown below.

Table E2: Final CPP Rule Targets

State	Rate Targets		Mass Targets[2]	
	Interim Years 2020-2029 CO_2 Goal (lb/MWh)	Final Year 2030 CO_2 Goal (lb/MWh)	Interim Years 2020-2029 CO_2 Goal (Million Tons)	Final Year 2030 CO_2 Goal (Tons)
MN	1,414	1,213	25,433,592	22,678,368
ND	1,534	1,305	23,632,821	20,883,232
SD	1,352	1,167	3,948,950	3,539,481

Assessing the change in rate targets from the proposed rule to the final rule is not obvious due to a significant change in the formula that eliminated pre-2013 renewable energy from being eligible as a compliance measure. For example, even though South Dakota's Year 2030 goal changed from 741 lbs CO_2/MWh to 1,167 lbs CO_2/MWh, the target actually became more stringent to achieve.[3] Therefore, it is more applicable to compare the "illustrative" mass targets presented in the proposed rule to the final rule mass targets. On that mass target basis, the final rule targets became more stringent for North Dakota, and less stringent for Minnesota and South Dakota.

Specific to OTP, the impact of the final rule – if ultimately implemented pending the outcome litigation – is highly variable depending on the plan design choices made by the three state agencies that regulate our affected units. High level observations for each state include:

- For MN, due to the planned retirement of Hoot Lake Plant, we do not have any direct compliance concerns within the state. However, under a mass-based plan, a key issue for our customers is the continued allocation of allowances to retiring units.
- For SD, the final rule appropriately made corrections surrounding the treatment of hydropower within the state and assigned the one existing NGCC plant in SD as being "under construction". These corrections were more impactful to the mass-based target than the rate-based target, and therefore OTP and the Big Stone co-owners have been

[2] The mass targets represented are for existing units only. EPA also finalized mass targets that would include new units.
[3] The proposed rule 2012 baseline for SD presented by EPA was 1,135 lbs CO2 per MWh, resulting in a 35% reduction to meet the year 2030 target. The final rule 2012 baseline presented by EPA was 2,229 lbs CO2 per MW, resulting in a 48% reduction needed to meet the year 2030 target.

advocating for a mass-based plan in SD if the rule is upheld. However, there would still be key uncertainties regarding allowance allocation methodologies that would need to be addressed within the state plan.

- Both ND rate and mass targets in the final rule became substantially more stringent in the final rule. In absence of further changes to the rule, a trading-ready approach that facilitates nationwide compliance mechanisms as a means of providing the greatest compliance flexibility, economic efficiencies, and market liquidity will be critical.

Regarding future resource additions, OTP's preferred resource plan is an excellent fit with the final CPP. The addition of wind, solar, and continued energy conservation measures would be eligible to generate compliance credits under a rate-based plan. Under a mass-based plan, these same measures, along with retirement of Hoot Lake Plant, would reduce our total tons of carbon emissions. Additionally, simple-cycle CT's are not considered affected sources by the CPP and are therefore excluded from regulation.

4. Litigation Status

A number of states, utilities, and trade groups have filed petitions for review with the D.C. Circuit seeking to overturn the rule, and also moved to stay the rule. On January 14, 2016 the D.C. Circuit denied the stay motions, but expedited briefing such that oral argument would occur in June 2016 before a three-judge panel. Numerous petitioners then sought an emergency stay in the U.S. Supreme Court. On February 9, 2016 the U.S. Supreme Court granted a stay of the CPP pending disposition of the petitions for review in the D.C. Circuit and disposition of a petition for a writ of certiorari seeking review by the U.S. Supreme Court, if such a writ is sought. On May 16, 2016, the D.C. Circuit issued an order on the court's own motion that rescheduled oral argument to be held before an en banc (full) court on September 27, 2016. If, and when, review will occur at the U.S. Supreme Court is not known at this time.

B. New Source Performance Standards

On October 23, 2015 the EPA published final New Source Performance Standards ("NSPS") under section 111(b) of the CAA that requires certain new units (as well as modified and reconstructed units) to meet CO_2 emission standards. New natural gas combustion turbines are required to meet a standard of 1,000 lbs of CO_2 per gross megawatt hour averaged over a 12-month period if they meet the definition of a baseload unit. New natural gas combined cycle units are anticipated to fit into this category. Simple cycle combustion turbines are regulated in a non-baseload category that is required to meet a heat input based standard that can be met by primarily burning clean fuels such as natural gas. The simple-cycle CT that is planned to be added as part of this resource plan would meet the NSPS by using natural gas as the primary fuel and limiting the use, if any, of distillate oil to a secondary fuel.

C. New Source Review

Under the New Source Review Program, the Prevention of Significant Deterioration ("PSD") program applies to areas of the country that attain (or are unclassifiable) the National Ambient Air Quality Standards ("NAAQS"), such as the areas in which Otter Tail's facilities are located. PSD review requires persons constructing new major air pollution sources or implementing significant modifications to existing air pollution sources that constitute a significant net emissions increase to obtain a permit prior to such construction or modification. In order to obtain a PSD permit, the owner or operator of an affected facility must undergo a review which requires the identification and implementation of best-available control technology ("BACT") for the regulated air pollutants for which there is a significant net emissions increase, and an analysis of the ambient air quality impacts of the facility.

In June of 2010, EPA issued a final "tailoring rule" that phases in application of this program to GHG emission sources, including power plants. This program applies to existing sources if there is a physical change or change in the method of operation of the facility that results in a significant net emissions increase. As a result, PSD does not apply on a set timeline as is the case with other regulatory programs, but is triggered depending on what activities take place at a major source.

In June 2012 the United States Court of Appeals for the D.C. Circuit upheld most of the EPA's rules regarding the regulation of GHGs under the CAA, including the tailoring rule. However, in October 2013 the U.S. Supreme Court granted a petition for a writ of certiorari to review the question of whether the regulation of new motor vehicle GHG emissions does in fact automatically trigger PSD and Title V regulation of GHGs for stationary sources. On June 23, 2014 the U.S. Supreme Court issued its decision that, in summary, held the EPA exceeded its statutory authority and may not require a PSD or Title V permit based solely on GHG emissions. However, the U.S. Supreme Court also said the EPA could continue to require that PSD permits for sources otherwise subject to PSD based on emissions of conventional pollutants, contain limitations on GHG emissions based on the application of BACT. EPA is now in the process of determining the minimum GHG threshold to regulate for sources that are subject to PSD permitting for conventional pollutants.

OTP anticipates that our planned addition of a simple-cycle CT will not trigger the PSD thresholds for conventional pollutants (or enforceable operating limits would be accepted to maintain emissions below these thresholds), such that a significant net emissions increase would not occur. Moreover, Otter Tail's existing facilities are not contemplating any changes that would result in a significant net emissions increase.

II. CRITERIA AIR POLLUTANTS

The CAA requires EPA to set standards for six common air pollutants known as "criteria" pollutants. The criteria pollutants are: nitrogen oxides ("NO_X"), sulfur dioxide ("SO_2"), particulate matter ("PM"), ozone, carbon monoxide and lead. These emissions are sometimes regulated under CAA programs when they are a precursor to other types of air pollution. NO_X, for example, is regulated because it is a precursor to fine particle formation, ozone formation, acid deposition and regional haze. Similarly, SO_2 is a precursor to fine particle formation, acid deposition and regional haze. Particulate matter is a precursor to regional haze. This section describes the effect of anticipated regulations to limit criteria pollutant emissions from power plants, with a specific focus on OTP's generating facilities.

A. Acid Deposition and National Ambient Air Quality Standards

Acid Deposition

The Acid Rain Program ("ARP") was created under Title IV of the 1990 amendments to the CAA. Under the ARP, emissions of SO_2 and NO_X from the electric utility industry have been reduced substantially.

1. ARP SO_2 Program

The SO_2 program sets a permanent cap on the total amount of SO_2 that may be emitted by electric generating units greater than 25 megawatts in the contiguous United States. The program was phased in, with the final 2010 SO_2 cap set at 8.95 million tons, which represents a level of about one-half of the emissions from the power sector in 1980.

Under this program, EPA allocates allowances to each source for use in or after a specified year. Each allowance permits a unit to emit 1 ton of SO_2. At the end of the year, if a source's emissions are less than its annual allowance allocation, it can bank the extra allowances forward for use in future years. If a source's annual emissions are more than its annual allocation, the source can then either use banked allowances from previous years, transfer allowances from another facility, or purchase allowances on the open market.

Otter Tail's compliance strategy has always been, and continues to be, to work within our free allowance allocation and use banked allowances when necessary to avoid having to purchase allowances on the open market.

2. ARP NO_X Program

Title IV requires NO_X emission reductions for certain coal-fired electric generating units ("EGUs") by limiting the NO_X emission rate (expressed in lb/mmBtu) in lieu of having an emissions allowance trading program. Congress applied these rate-based emission limits based on a unit's boiler type. The goal of the program is to limit NO_X emission levels from the affected coal-fired boilers so that their emissions are at least two million tons less than the projected level for the year 2000 without implementation of Title IV. Otter Tail has maintained compliance with the Title IV NO_X emission rates by installing low NO_X burners on both Hoot Lake Plant Unit 2 and Unit 3 and an over-fire air system at Big Stone Plant. Coyote Station did not require any changes in order to meet the NO_X emission requirements.

National Ambient Air Quality Standards

The CAA requires EPA to set two types of NAAQS. Primary standards provide public health protection, while secondary standards provide public welfare protection.

In general, compliance with NAAQS is achieved through development of State Implementation Plans ("SIPs") that limit emissions from sources located in areas designated as non-attainment.

To help states attain the NAAQS in local areas, the EPA evaluates whether certain regional or nationally applicable emission limitations should be put into place in order to assist the states in attaining the NAAQS, or states may petition EPA to impose reductions in upwind states. Additionally, federal regulations require that any permit issued under the PSD provisions of the CAA must contain a demonstration of source compliance with the NAAQS.

1. NO_2 and SO_2 NAAQS

In 2010, the EPA promulgated new NAAQS for nitrogen dioxide ("NO_2") and SO_2 averaged over one hour.

For the 2010 NO_2 NAAQS, the States of Minnesota, North Dakota, and South Dakota recommended that their entire states be designated as attainment based on multiple years of air sampling data. The EPA reviewed the recommendations, and on January 20, 2012 EPA determined that no area in the United States is violating the 2010 NO_2 NAAQS. Therefore, EPA designated all areas of the country as "unclassifiable/attainment". EPA and the states are now in the process of expanding the NO_2 monitoring network. Based on population, the Minneapolis-St. Paul-Bloomington Core Based Statistical Area is the only area in North Dakota, South Dakota, and Minnesota that requires additional near-road monitoring. EPA plans to re-designate areas in the future based on the new monitoring data.

For $SO_{2,}$ Minnesota, North Dakota, and South Dakota have no monitored violations of the 2010 NAAQS; however per a March 2, 2015 consent decree EPA is proceeding with two different rounds of designations. In the first round of designations, by July 2, 2016 EPA will promulgate SO_2 designations for areas that either 1) have newly monitored violations of the 2010 SO_2 standard, and 2) areas that contain any stationary source that emitted more than 16,000 tons of SO_2 in 2012 or emitted more than 2,600 tons of SO_2 and had an emission rate of at least 0.45

lb/mmbtu in 2012. Based on those criteria, the areas surrounding Big Stone Plant and Coyote Station are subject to this first round of designations. On February 16, 2016, EPA notified the State of North Dakota that based on modeling data, EPA intends to designate the area surrounding Coyote Station in Central Mercer County as “unclassifiable/attainment”. Also on February 16, 2016, EPA notified the State of South Dakota that EPA intends to designate the area surrounding Big Stone Plant in Grant County as “unclassifiable”.

In the second round of SO_2 designations, air agencies are required to characterize air quality around sources that have actual SO_2 emissions of 2,000 tons or greater. Based on 2014 emissions, this round of designations will apply to the area surrounding Hoot Lake Plant. By July 1, 2016, the State of Minnesota will have to identify whether ambient monitoring or air quality modeling will be used to characterize air quality. For source areas that are evaluated through air quality modeling, the analysis must be submitted by January 13, 2017. For source areas that are evaluated through ambient monitoring, the required monitors must be operational by January 1, 2017.

2. Ozone and PM NAAQS

In the electric power industry, the rule currently being used to assist with attainment of the NAAQS for ozone and particulate matter from regional sources is EPA’s Cross-State Air Pollution Rule (“CSAPR”) that went into effect on January 1, 2015. CSAPR requires SO_2 and NO_x emission reductions from fossil fuel-fired power plants located in the eastern portion of the United States. The Rule establishes two new types of SO_2 allowances (Group 1 and Group 2) and two new types of NO_X allowances (Annual and Ozone). Minnesota is classified as a Group 2 SO_2 state (along with six other states - Alabama, Georgia, Kansas, Nebraska, South Carolina and Texas) and an Annual NO_X state (along with 22 other states). South Dakota and North Dakota are not included in CSAPR.

Similar to the Acid Rain Program, under CSAPR, EPA allocates allowances to each source for use in or after a specified year. At the end of the year, if a source’s emissions are less than its annual allowance allocation, it can bank the extra allowances forward for use in future years. If a source’s annual emissions are more than its annual allocation, the source can then either use banked allowances from previous years, transfer allowances from another facility, or purchase allowances on the open market. However, a Group 2 SO_2 unit can only use Group 2 SO_2 allowances. Hoot Lake Plant currently receives 1,255 SO_2 allowances and 874 NO_X allowances each year.

Since South Dakota and North Dakota are not included in CSAPR, we are not able to transfer any allowances from those facilities. However, Hoot Lake Plant’s expected 2016 emissions will be below our CSAPR allocations, meaning we anticipate being able to comply with CSAPR in 2016 without purchasing allowances in the open market.

On December 3, 2015 the EPA proposed an update to CSAPR; however the proposed update does not apply to Minnesota, North Dakota and South Dakota.

On October 1, 2015 the EPA announced that it has tightened the primary and secondary NAAQS for ozone from 75 parts per billion (ppb) to 70 ppb. The EPA plans to use 2014-2016 air quality data to make final determinations of whether areas are in attainment with the new standard by October 1, 2017. It appears that the states in which OTP operates will not have any nonattainment areas at the 70 ppb level. Nonattainment areas are required to meet the standard in the 2020 to 2037 timeframe, with deadlines depending on the severity of an area's ozone problem. During the fourth quarter of 2015 several parties filed petitions for review in the D.C. Circuit challenging the rule and that litigation is now pending.

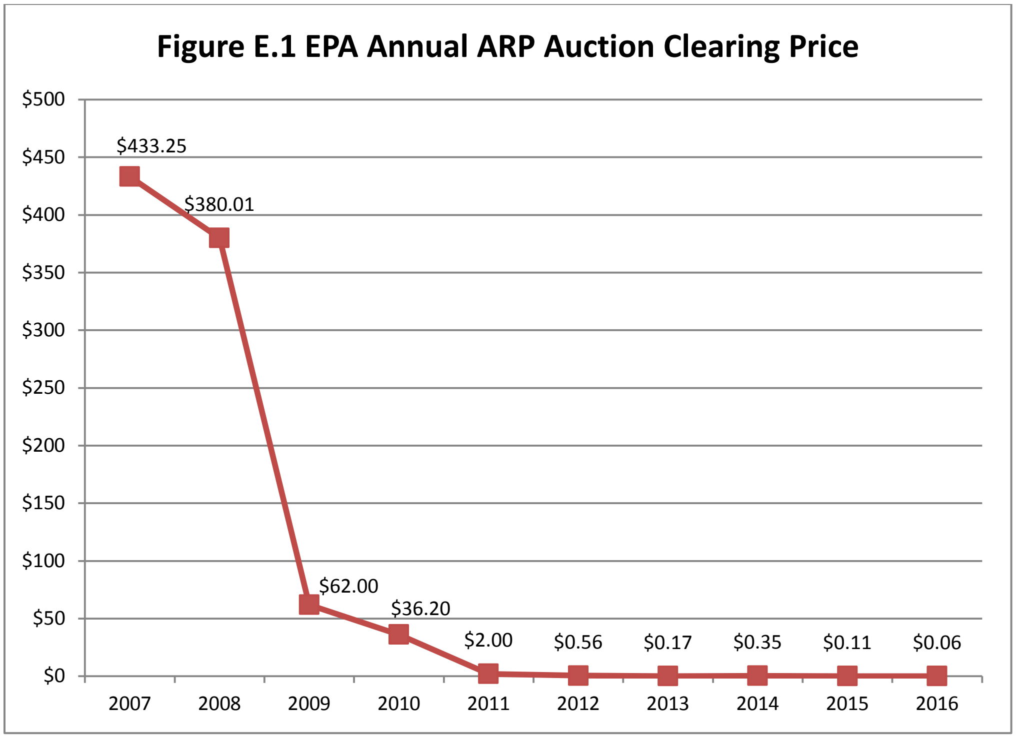
Market Cost of Allowances

As described for the ARP and CSAPR, if a source's annual emissions are more than its annual allocation, the source can either use banked allowances from previous years, transfer allowances from another facility, or purchase allowances on the open market.

Specific to the ARP, over time at a national level sources have made significant reductions in SO_2 emissions, resulting in annual emissions far below the SO_2 cap. According to EPA's most recent ARP Progress Report, in 2013 units in the ARP emitted 3.2 million tons, well below the statutory cap of 8.95 million tons[4]. ARP sources reduced emissions by 12.5 million tons (80 percent) from 1990 levels and 14.1 million tons (81 percent) from 1980 levels.[5]

As a result of these reductions, the market price of ARP SO_2 allowances has decreased significantly. The below figure shows the clearing price (the clearing price is the lowest price at which a successful bid was made) for the annual EPA allowance auction for the previous ten years. As shown, the 2016 clearing price was $0.06.

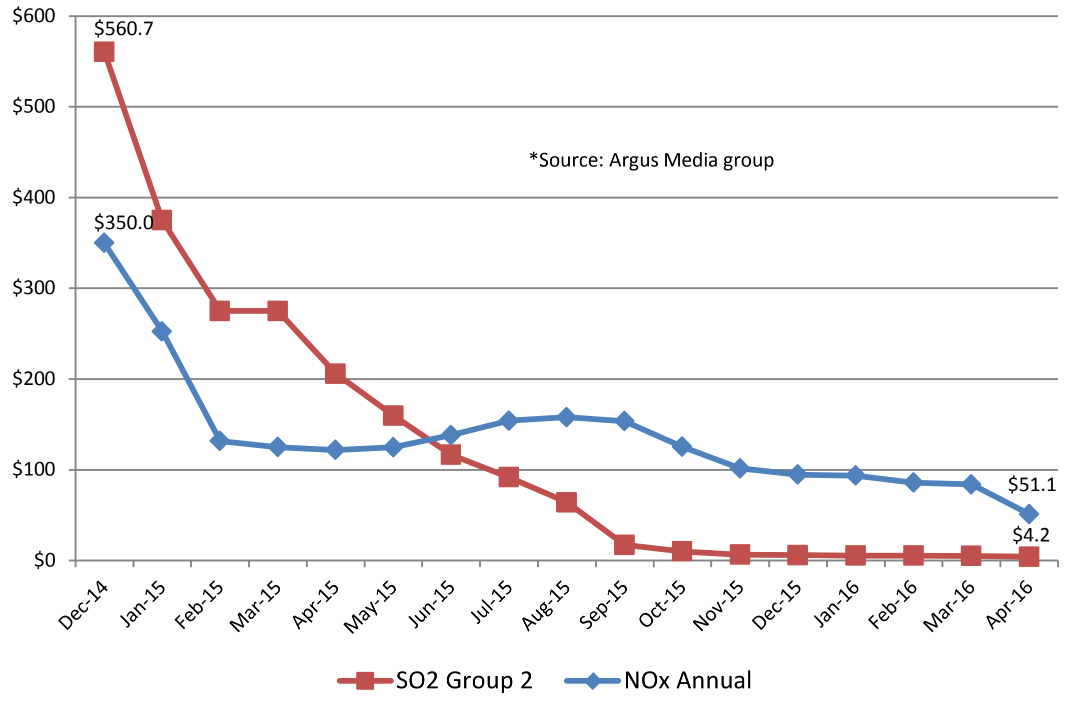
[4] https://www3.epa.gov/airmarkets/progress/reports/pdfs/2013_full_report.pdf, Page 11.
[5] Ibid.



Although CSAPR has been in effect for less than two years, allowance prices for Group 2 SO2 and Annual NOx have similarly followed a declining trend. Figure E.2 shows Argus Media Air Daily Indexes from December 2014 through April 2016[6].

[6] Argus Media, Argus Air Daily, and Argus index names are trademarks of Argus Media Limited. Data is presented by permission.

Figure E.2 Air Daily Indexes for SO2 Group 2 and NOx Annual Allowances*



B. Regional Haze Program

EPA promulgated the Regional Haze Rule ("RHR") in 1999 to address visibility impairment in Class I areas. Class I areas include 156 national parks and wilderness areas, including the Boundary Waters Canoe Area Wilderness and Voyager's National Park in Minnesota. States were required to submit SIPs detailing their strategy to reduce haze, and to set reasonable progress goals that meet the goal of no man-made visibility impairment in Class I areas by 2064. The first regional progress goals must be established for the planning period 2008 to 2018.

Included in the RHR is a provision that sources built between August 7, 1962 and August 7, 1977, and that are found to contribute to visibility impairment in Class I areas, must install best available retrofit technology ("BART"). Hoot Lake Plant Unit 3 and Big Stone Plant were built within the 1962 – 1977 timeframe, and therefore were required to be evaluated whether or not they contribute to visibility impairment in Class I areas.

In March 2006 the MPCA conducted source-specific dispersion modeling of all BART-eligible Minnesota sources to determine if they contribute to Class I area visibility impairment. The MPCA's dispersion modeling determined that Hoot Lake Plant Unit 3 did not significantly contribute to visibility impairment, and is thus not subject to BART. The MPCA submitted a Regional Haze SIP to EPA for approval on December 30, 2009, which included the findings on

Hoot Lake Plant. EPA published final approval of the Minnesota SIP on June 12, 2012[7]; therefore, at this time Hoot Lake Unit 3 does not need to take any further action.

Using air dispersion modeling, Big Stone Plant was found to contribute to visibility impairment at the Badlands National Park in South Dakota, Theodore Roosevelt National Park in North Dakota, Isle Royale National Park in Michigan, and Voyagers National Park and the Boundary Waters Canoe Area in Minnesota. Consequently, Big Stone Plant was required to install and operate BART. The South Dakota Department of Environment and Natural Resources ("DENR") determined that BART constitutes selective catalytic reduction in conjunction with separated over-fire air for control of nitrogen oxides, a scrubber for reducing SO_2, and a baghouse to control particulate matter. EPA's final approval of the SD Regional Haze SIP, including the BART requirements for Big Stone Plant, was published in the Federal Register on April 26, 2012. The equipment began commercial operation on December 29, 2015.

For Coyote Station, although the unit was not BART eligible, the North Dakota Regional Haze State Implementation Plan required that Coyote Station reduce its NOx emissions as part of the State's long term strategy. To satisfy the SIP, separated overfire air equipment must be installed at Coyote by July 1, 2018. This equipment was installed during a Spring 2016 outage.

Going forward, states are required by 40 CFR 51.308(g) to submit five-year periodic reports evaluating progress towards the goals established for each mandatory Class I area. Based on the findings of the five-year periodic progress report, a state must make a determination of adequacy of the existing SIP and take action if the strategies are found to be inadequate. The first five-year progress reports submitted by Minnesota, North Dakota, and South Dakota all identified that their Regional Haze SIPs were adequate, and that no revisions are necessary achieve the 2018 reasonable progress goals.

In addition, states are currently required by 40 CFR 51.308(f) to revise their regional haze implementation plan and submit a plan revision to EPA by July 31, 2018, and every 10 years thereafter. However, on April 25, 2016 EPA signed a proposed rule to delay the July 31, 2018 submittal date by three years, such that a revision would not be due until July 31, 2021. The revised plan will be required to address current visibility conditions, effectiveness of the long-term strategy, and affirm or revise reasonable progress goals for Class I areas.

At this time it is highly uncertain how future regional haze SIP revisions could affect Otter Tail's facilities, but post-2021 Otter Tail believes the rule could possibly require additional NO_X and SO_2 reductions at Coyote Station

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[7] Note that within the June 12, 2012 approval EPA deferred action on the MN Regional Haze SIP for taconite facilities and Xcel Energy's Sherburne County facility until a later time

III. HAZARDOUS AIR POLLUTANTS

A. Mercury and Other Hazardous Air Pollutant Emissions Rulemaking

The 1990 Amendments to the CAA required EPA to study the effects of emissions of listed hazardous air pollutants ("HAPs") by electric steam generating plants. On March 16, 2011, EPA proposed Section 112 air toxics standards for all coal- and oil-fired EGUs that reflect the application of the maximum achievable control technology consistent with the requirements of the CAA. EPA signed a final rulemaking, termed the mercury and air toxics standards (MATS) rule, on December 16, 2011, which was subsequently published in the Federal Register on February 16, 2012.

Power plants had three years and sixty days from the date of publication (April 16, 2015) to comply with MATS, although EPA encouraged state permitting authorities to broadly grant a one-year compliance extension to plants that need additional time to install controls. The EPA is also providing a pathway for reliability critical units to obtain an additional year to achieve compliance; however, the EPA believes there will be few situations in which this pathway is needed.

Hoot Lake Plant is meeting MATS through an upgrade of the Unit 2 and Unit 3 electrostatic precipitators to reduce particulate matter, and activated carbon injection to reduce mercury emission. Coyote Station is meeting MATS by utilizing its existing spray dryer and fabric filter, and by installing activated carbon injection. Finally, Big Stone Plant is meeting MATS through the installation activated carbon injection in conjunction with the pollution control equipment required by the Regional Haze Rule. Due to the extensive nature of the Big Stone Plant equipment, on August 27, 2013, the plant was granted a one year extension (until April 16, 2016) by the South Dakota Department of Environment and Natural Resources to comply with MATS. Emissions monitoring equipment and stack testing is being utilized to verify compliance with the standards at each facility.

On June 29, 2015 the U.S. Supreme Court held that EPA must consider cost, including cost of compliance, before deciding whether regulation of mercury emissions is appropriate and necessary. The MATS rule, however, remained in effect while the case was remanded to the D.C. Circuit for further proceedings. On December 15, 2015, the D.C. Circuit ordered that the MATS rule be remanded to EPA without vacating the rule. In its order, the D.C. Circuit noted that EPA has represented they are on track to issue a final finding that addresses the costs of the MATS rule in April 2016. On April 25, 2016, EPA issued a final supplemental finding that concludes that a consideration of cost does not change their determination that regulation of HAPs from coal and oil-fired EGUs is appropriate and necessary. Therefore, at this time, facilities will have to continue to comply with all applicable MATS requirements.

B. Minnesota TMDL

The federal Clean Water Act requires each state to evaluate its water bodies and determine whether they meet water-quality standards. For mercury, these standards define how much mercury can be in the water and in fish. Water bodies that do not meet water-quality standards are added to a list of water bodies referred to as the Impaired Waters List. About two-thirds of the water impairments on Minnesota's 2004 Impaired Water List were due to mercury.

To address impaired waters, states are required to evaluate the sources of pollution, the reduction in the pollutant needed to meet water-quality standards, and allowable levels of future pollution. This evaluation, typically done for each water body or watershed, is called a Total Maximum Daily Load, or TMDL. Because the source of essentially all mercury to Minnesota waters is the atmosphere, the Minnesota Pollution Control Agency (MPCA) prepared a statewide mercury TMDL. This TMDL established an annual mercury air emission target of 789 pounds, and was approved by the MPCA Board in December 2006 and by the EPA in March 2007. Additionally, MPCA analyzes and assesses new fish tissue mercury concentration data every 2 years and revises the waterbodies included on the Impaired Water List. The most recent revision that has been approved by EPA was submitted by the MPCA on April 15, 2014.

To achieve the goals of the TMDL, a stakeholder process was convened to develop specific recommendations. The stakeholders identified sector-specific strategies to meet the TMDL targets by 2025, and one of the sector-specific strategies includes reducing mercury emissions from Minnesota coal-fired generation.

Specific to Hoot Lake Plant Units 2 and 3, according to Minnesota Administrative Rule 7011.0561, by January 1, 2025 owners or operators of a coal fired EGU with a nameplate capacity less than 100 MW must either: (1) control mercury such that at least 70 percent of the mercury present in the fuel is captured and not emitted, or (2) demonstrate that the unit emits no more than 2.3 pounds of mercury per Tbtu of heat input. Since this timeframe is beyond the compliance of the timeframe of the more stringent MATS rule, compliance with the TMDL target for Hoot Lake Plant Units 2 and 3 is being met through compliance with MATS.

IV. COAL COMBUSTION RESIDUALS REGULATION

On December 19, 2014 EPA signed a final rule to further regulate coal combustion residuals (CCR) as non-hazardous waste under subtitle D of the Resource Conservation and Recovery Act (RCRA). EPA had been considering a more stringent subtitle C designation that would have regulated CCRs similar to a hazardous waste.

The final subtitle D rule will require OTP to meet several new requirements, including installing additional groundwater monitoring wells, publish data on our CCR units on a website, conduct structural integrity assessments, determine compliance with location restrictions, and develop and implement plans for fugitive dust, hydrologic capacity, run-on & run-off control, and closure & post-closure care. The groundwater background monitoring program must be completed by October 19, 2017, while the location restriction determination is due by October 19, 2018. Existing landfill cells can continue to operate as designed, but future expansions will require composite liner and leachate collection systems. EPA is also leaving the door open to a future evaluation of CCRs as hazardous waste.

The Hoot Lake Plant operates a dry ash disposal site that is regulated, permitted and inspected by the MPCA. The existing operating site is lined with a synthetic liner and it has a leachate collection system. Future portions of the designated disposal areas will be covered with a synthetic cover and an engineered soil cover. The site has a groundwater monitoring system and annual reports have been provided to the MPCA.

Big Stone Plant operates a dry disposal site that is regulated, permitted and inspected by the South Dakota DENR. The site is underlain with native clay, and each portion of the designated disposal area is covered with clay and topsoil once it is filled to capacity. Monitoring of groundwater is ongoing and annual reports are provided to the DENR. Big Stone Plant also operates an impoundment to temporarily handle boiler slag that is sluiced to the impoundment. Boiler slag is either dry disposed in the permanent disposal site or beneficially reused, commonly as a blasting media, shingle grit, and in traction control on icy roads.

Coyote Station has one active dry disposal site that is regulated, permitted and inspected by the North Dakota Department of Health ("DOH"). The site has an engineered clay liner for acceptance of flue gas desulfurization product and boiler slag. The site has a groundwater monitoring system and annual reports have been provided to the DOH. Coyote Station also operates three impoundments to dewater and temporarily handle boiler slag that is sluiced to the impoundments. Similar to Big Stone, the slag at Coyote Station is often beneficially reused.

Since OTP has not yet completed its actions to determine whether or not the existing surface impoundments will need to be closed or retrofitted with liners, the cost impact of the rule will not be known until those actions are complete.

V. WATER REGULATION

A. 316(b)

Section 316(b) of the Clean Water Act ("CWA") requires facilities with cooling water intake structures to ensure that the location, design, construction and capacity of the structures reflect the best technology available to minimize harmful impacts on the environment. EPA first promulgated regulations to implement section 316(b) in 1976. In 1977 the U.S. Court of Appeals for the Fourth Circuit remanded these regulations to EPA, which withdrew them and left in place a provision that directed permitting authorities to determine best technology available for each facility on a case-by-case basis. After numerous years of proceedings, on May 9, 2014, EPA signed the final rule setting national standards for cooling water intake structures at existing facilities with National Pollutant Discharge Elimination System ("NPDES") permits that withdraw at least 2 million gallons of water per day (MGD) and use at least 25% of that water for cooling purposes.

Under the final rule, all affected facilities will need to comply with one of seven Best Technology Available ("BTA") alternatives for reducing impingement, while site-specific BTA for reducing entrainment will be up to the states. However, in addition to the seven BTA options for impingement, another option identified as "*de minimus*" impingement is provided in the rule. In this option, facilities with very low levels of impingement are not required to use any additional impingement controls. In any case, new requirements will be incorporated into NPDES permits to achieve 316(b) compliance "as soon as practicable according to the schedule of requirements set by the Director."

Hoot Lake Plant uses once-through cooling except during periods of low water availability and during periods when the water discharge permit require use of the plant cooling towers. The impact of the Hoot Lake Plant intake structure has been extensively evaluated in two separate studies (conducted in 1976 and 2005), both of which showed minimal impact, and in fact in December 1977 the MPCA, the Minnesota Department of Natural Resources, and EPA concluded that Hoot Lake Plant's intake structure creates a negligible impact in the aquatic ecosystem and was therefore in compliance with Section 316(b). Any future additional requirements will be ultimately determined by the State of Minnesota; however, the impact to Hoot Lake Plant is anticipated to be minimal due to the low levels of impingement demonstrated by previous studies and due to the plant planning to retire in 2021.

Both Big Stone Plant and Coyote Station use closed cycle cooling, and thus it is anticipated that those facilities will not be significantly impacted by the 316(b) rule.

B. Effluent Limit Guidelines

The Clean Water Act establishes a structure for regulating discharges of pollutants to surface waters of the United States. As part of the implementation, EPA issues effluent limit guidelines ("ELG") for industrial dischargers. EPA first issued ELG for steam electric power plants in 1974, with subsequent revisions in 1977 and 1982. EPA announced its decision to proceed with further possible revisions on September 15, 2009, and published a proposed rulemaking on June 7, 2013. On November 3, 2015 the EPA published the final rule that sets technology-basd effluent limitations on certain types of discharges. Generally, the final rule establishes "no discharge" requirements for waste water discharge streams from wet flue gas desulfurization, fly ash transport, and bottom ash transport.

Effluent limits specific to Hoot Lake Plant and Coyote Station are incorporated into their NPDES permits. Big Stone Plant is a zero discharge facility and therefore does not have a NPDES permit. Hoot Lake Plant's and Coyote Station's permit limits are based on a combination of state water quality standards, the Federal ELG, and best professional judgment. Hoot Lake Plant is permitted for several effluent discharges, including once-through cooling water, coal pile runoff and metal cleaning wastes, and other low-volume waste sources such as floor drains and boiler blowdown. Hoot Lake Plant does not use water to transport either fly ash or bottom ash. Coyote Station's primary effluent discharge is cooling tower blowdown while Big Stone Plant is a zero discharge facility. Although Coyote Station and Big Stone Plant use water to sluice boiler slag to internal ponds, this water is used in a closed loop manner and is not discharged. Thus the "no discharge" requirement is being met, and therefore OTP anticipates minimal impact from the rule.

SUMMARY

Environmental Regulatory Assessment Summary

Legend: Air related | Solid Waste related | Water related

Rule	Status	Anticipated Hoot Lake Plant Impact	Anticipated Big Stone Plant Impact	Anticipated Coyote Station Impact	Anticipated Compliance Timeframe
Greenhouse Gas Regulation – 111(d)	Stayed	None; HLP is planned to retire prior to compliance	Unknown; if upheld, OTP will advocate for a mass-based trading ready plan	Unknown; if upheld, OTP will advocate for a trading ready plan	Unknown
Greenhouse Gas Regulation – NSPS	Final	N/A – Applicable to New Plants Only. A new simple-cycle CT will meet the NSPS through the use of clean fuels.	N/A – Applicable to New Plants Only	N/A – Applicable to New Plants Only	New plants
Greenhouse Gas Regulation – Tailoring Rule	Final	PSD Review for projects that result in a significant net CO_2 increase – No PSD Projects planned at HLP. A new simple-cycle CT will likely accept operating limits to not trigger PSD.	No PSD projects planned	No PSD projects planned	As occur (none planned)
Acid Rain Program	Final	Maintain banked allowances (SO2); Operate existing low NOx burners	Maintain banked allowances (SO2); Operate existing SCR and overfire air	Maintain banked allowances (SO2)	Ongoing
2010 NO2 and SO2 NAAQS	Final	SO2 modeling to be conducted during 2016.	Low impact due to installation of SO2 scrubber. Modeling submitted to EPA demonstrates compliance.	Low impact anticipated; based on SO2 modeling, EPA has proposed to classify the area around Coyote as attainment/unclassifiable.	Ongoing
Cross-State Air Pollution Rule	Final	Possible SO2 allowance purchases dependent on HLP operation. No purchases anticipated during 2016.	None -- Rule does not apply to SD	None -- Rule does not apply to ND	2015
Regional Haze Program – Best Available Retrofit Technology	Final	None – HLP2 not BART eligible and HLP3 deemed not subject to BART	Selective Catalytic Reduction and separated overfire air for NOx, scrubber for SO2, and baghouse for PM	Separated overfire air for NOx to satisfy ND's reasonable progress goals	2015-2016
Regional Haze Program – SIP Revisions	Proposed. SIP due by July 31, 2021	None; HLP is planned to retire prior to compliance	None	Possible SO2 and NOx reductions	Post 2020
Mercury and other Hazardous Air Pollutants (MATS)	Final	Upgraded electrostatic precipitators for PM, installed activated carbon injection for Hg	Installed BART equipment plus activated carbon injection	Installed activated carbon injection	April 2015 (HLP and Coy) April 2016 (BSP)

Table Continued on Next Page

Minnesota TMDL	Final	Compliance achieved through MATS	N/A	N/A	2025 (already compliant)
Coal Combustion Residuals	Final	Install additional groundwater monitoring and develop several new plans. HLP already manages an active dry ash disposal site with a synthetic liner and leachate collection, and does not operate any surface impoundments.	Install additional groundwater monitoring and develop several new plans. BSP manages an active dry ash disposal site, but future disposal site sequences will require a synthetic liner and leachate collection, and the boiler slag impoundment will need to be evaluated for closure or retrofit.	Install additional groundwater monitoring and develop several new plans. Coyote manages an active dry ash disposal site, but future disposal site sequences will require a synthetic liner and leachate collection, and the boiler slag impoundments will need to be evaluated for closure or retrofit.	Install GW monitoring network by October 2017 Future actions dependent on outcome of monitoring and studies
Clean Water Act Section 316(b)	Final	To Be Determined – compliance timeframe coincides with planned Hoot Lake Plant retirement	Big Stone uses cooling ponds that qualify as closed cycle cooling	Coyote Station uses a cooling tower that qualifies as closed cycle cooling	TBD
Effluent Guidelines	Final	Low impact; HLP does not use any fly ash or bottom ash transport water.	Low impact; Big Stone does not discharge boiler slag transport water to waters of the United States.	Low impact; Coyote does not discharge boiler slag transport water to waters of the United States.	Ongoing

Appendix F
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Appendix F: Strategist Modeling Assumptions
PUBLIC DOCUMENT –NOT PUBLIC DATA
HAS BEEN EXCISED

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List of Figures

1 Sensitivities Evaluated

Figure 1 shows a grid of sensitivities evaluated in this resource plan. Otter Tail evaluated 58 sensitivities. Thirty-one sensitivities have externality values applied over the study period. Twenty-seven sensitivities do not have the externality values applied.

Figure 1: Sensitivities Evaluated

	Externality values applied	Zero Externalities
0 Base		
1 OTP Preferred Plan		
2 Wind -$5/MWh		
3 Wind +$5/MWh		
4 (CEO) Solar Declining price		
5 Solar -$10/MWh		
6 Solar +$10/MWh		
7 -50% NaturalGas price		
8 -25% NaturalGas price		
9 +25% NaturalGas price		
10 +50% NaturalGas price		
11 +100% NaturalGas price		
12 Low Coal price		
13 High Coal price		
14 Low LoadGrowth		
15 High LoadGrowth		
16 Low Energy Market Price		
17 High Energy Market Price		
18 Limit Market Energy Purchases		
19 Low Externality		
20 High Externality		
21 (CEO) $59/ton CO2		
22 MN CO2 reduction Goal		
23 BAU MN Energy Efficiency		
24 1.6% MN Energy Efficiency		
25 1.7% MN Energy Efficiency		
26 1.8% MN Energy Efficiency		
27 1.9% MN Energy Efficiency		
28 2.0% MN Energy Efficiency		
29 (CEO) 1.0% ND Energy Efficiency		
30 Retire Peakers		

2 Wind Energy Assumptions

Figure 2 shows the wind energy assumptions used in the 2016 resource plan. Otter Tail evaluated wind energy resource alternatives as purchased power agreements (PPA) with a 20 year term and fixed pricing over that term. Wind integration costs are included in the fixed price assumptions.

In December 2015 legislation was enacted that extended the availability of production tax credits (PTC) associated with wind energy through 2019. The legislation also included a phase-out of the tax incentive.

The wind energy price assumptions incorporate the phasing out of the PTCs from 100 percent for projects that have started construction in 2016, to 40 percent for projects that have started construction in 2019. For projects that start construction after 2019, there are no PTCs assumed.

Wind project sizes are assumed to be 100 MW in size with a 40 percent net capacity factor and an accredited capacity of 15.6 percent (15.6 MW). Wind projects are made available for selection in the years 2018, 2020, 2022, 2023, 2025 and 2027. The low and high wind price sensitivities are #2 and #3 respectively.

Figure 2: Wind Energy Assumptions

Strategist Name	Construction Start	COD by end of	First Full Year of Operations	PTC	Fixed Price ($/MWh) Low	Fixed Price ($/MWh) Base	Fixed Price ($/MWh) High	NCF	Nameplate Capacity (MW)	Accredited Capacity (15.6% of Nameplate) (MW)	Year that one Superflous unit available
W16	2016	2020	2021	100%	$25.00	$30.00	$35.00	40%	100	15.60	2018, 2020
W17	2017	2021	2022	80%	$29.00	$34.00	$39.00	40%	100	15.60	2022
W18	2018	2022	2023	60%	$34.00	$39.00	$44.00	40%	100	15.60	2023
W19	2019	2023	2024	40%	$39.00	$44.00	$49.00	40%	100	15.60	
W20	2020	2024	2025	0%	$48.00	$53.00	$58.00	40%	100	15.60	2025
W23	2023	2027	2028	0%	$51.24	$56.24	$61.24	40%	100	15.60	2027
W26	2026	2030	2031	0%	$54.69	$59.69	$64.69	40%	100	15.60	

3 Solar Energy Assumptions

Figure 3 shows the solar energy assumptions used in the 2016 resource plan. Otter Tail evaluated solar energy resource alternatives as purchased power agreements (PPA) with a 20 year term and fixed pricing over that term. Solar integration costs are included in the fixed price assumptions.

Similar to wind, the December 2015 legislation that was enacted extended the availability of investment tax credits (ITC). Solar projects that start construction by 2019 are eligible for the 30 percent ITC. The legislation includes a step-down provision of the ITC to the 10 percent level for projects that start construction after 2021.

Solar project sizes are assumed to be 30 MW in size with 15 percent net capacity factor and an accredited capacity of 50 percent (15 MW). Solar projects are made available for selection in the years 2020, 2022-2025, and 2028. Sensitivity #4 contains a declining price until the year 2020. The low and high solar price sensitivities are #5 and #6 respectively.

Figure 3: Solar Energy Assumptions

Strategist Name	Construction Start	COD by end of	First Full Year of Operations	ITC	Price ($/MWh) Declining	Fixed Price ($/MWh) Low	Fixed Price ($/MWh) Base	Fixed Price ($/MWh) High	NCF	Nameplate Capacity (MW)	Accredited Capacity (50% of Nameplate) (MW)	Year that one Superflous unit available
S19	2016	2018	2019	30%	$80.00	$70.00	$80.00	$90.00	15%	30	15.00	
S19	2017	2019	2020	30%	$70.00	$70.00	$80.00	$90.00	15%	30	15.00	2020
S19	2018	2020	2021	30%	$62.00	$70.00	$80.00	$90.00	15%	30	15.00	
S19	2019	2021	2022	30%	$55.00	$70.00	$80.00	$90.00	15%	30	15.00	2022
S20	2020	2022	2023	26%	$48.00	$75.00	$85.00	$95.00	15%	30	15.00	
S21	2021	2023	2024	22%	$48.00	$80.00	$90.00	$100.00	15%	30	15.00	2024
S22	2022	2024	2025	10%	$48.00	$94.00	$104.00	$114.00	15%	30	15.00	
S22	2025	2027	2028	10%	$48.00	$94.00	$104.00	$114.00	15%	30	15.00	2026, 2028

4 Natural Gas Fuel Price Assumptions

Figure 4 shows the forecasted monthly natural gas fuel prices used in the 2016 resource plan. Otter Tail used the Wood Mackenzie January 2016 North American Power Service for determining the natural gas fuel prices used in the resource plan. Otter Tail evaluated natural gas prices at +/- 25percent of the base case and +/- 50 percent of the base case and at +100 percent of the base case. The natural gas price sensitivities are #7-11.

Figure 4: Natural Gas Fuel Price Assumptions

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5 Coal Price Assumptions

Otter Tail's coal price forecasts for its three coal-fired thermal units are developed using existing coal and freight contracts. For modeling purposes in this resource plan coal fuel prices are broken into two portions: fixed fuel costs and variable fuel costs. The fixed fuel costs modeled for Hoot Lake and Big Stone reflect the rail car lease costs**[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**(OTP portion) annually. The fixed fuel costs modeled for Coyote station are modeled at **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** (OTP portion) annually and represent the non-variable portion of the fuel supply agreement.

The variable cost portion of fuel costs are shown in Figure 5 (Big Stone plant), Figure 6 (Coyote station), and Figure 7 (Hoot Lake plant). Otter Tail evaluated coal price at +/- 25% of the base case. The coal price sensitivities are #12 and #13.

Figure 5: Big Stone Plant Coal Price Assumptions

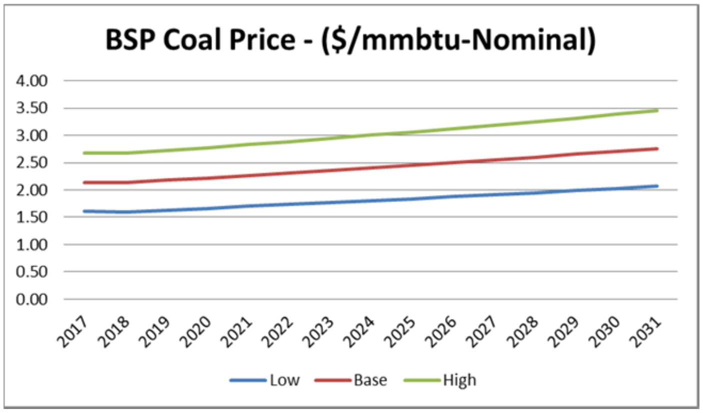


Figure 6: Coyote Station Coal Price Assumptions

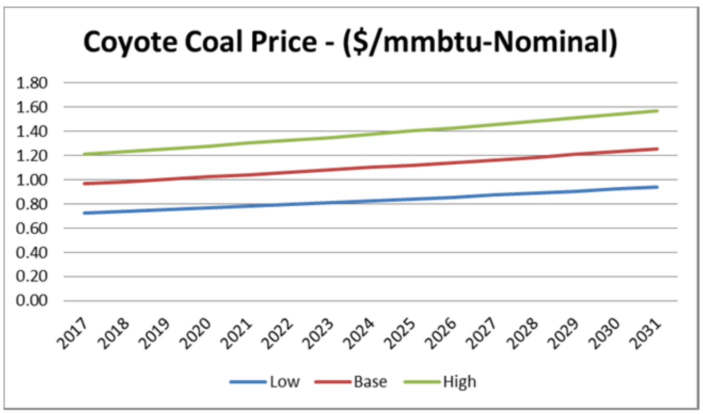
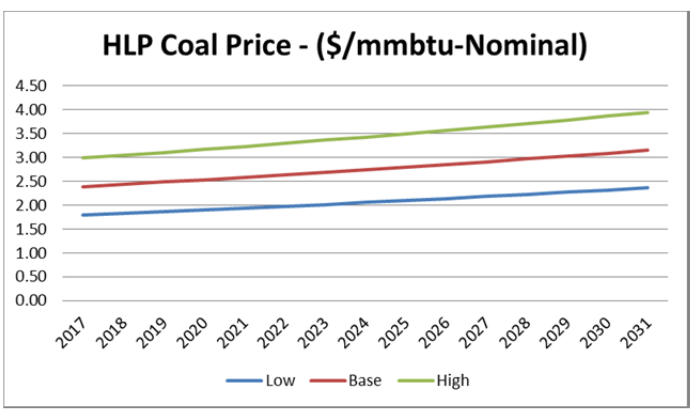


Figure 7: Hoot Lake Plant Coal Price Assumptions

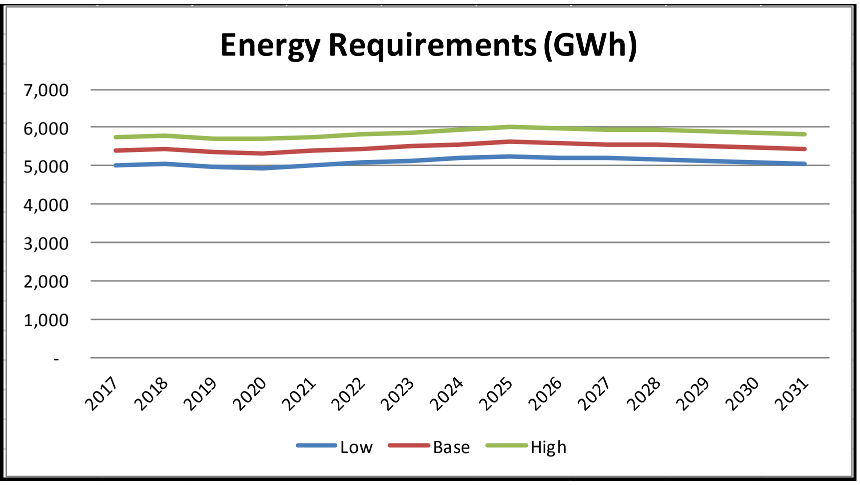


6 Load Growth Assumptions

Figure 8 shows the energy requirement assumptions used in the 2016 resource plan. The load growth sensitivities are #14 and #15.

Figure 8: Load Growth Assumptions

Year	Low	Base	High
2017	5,030	5,392	5,762
2018	5,066	5,431	5,802
2019	4,980	5,346	5,719
2020	4,952	5,320	5,694
2021	5,014	5,383	5,759
2022	5,075	5,445	5,823
2023	5,131	5,503	5,882
2024	5,189	5,562	5,943
2025	5,251	5,626	6,008
2026	5,222	5,598	5,981
2027	5,192	5,569	5,954
2028	5,161	5,540	5,926
2029	5,130	5,510	5,897
2030	5,098	5,479	5,867
2031	5,065	5,447	5,837

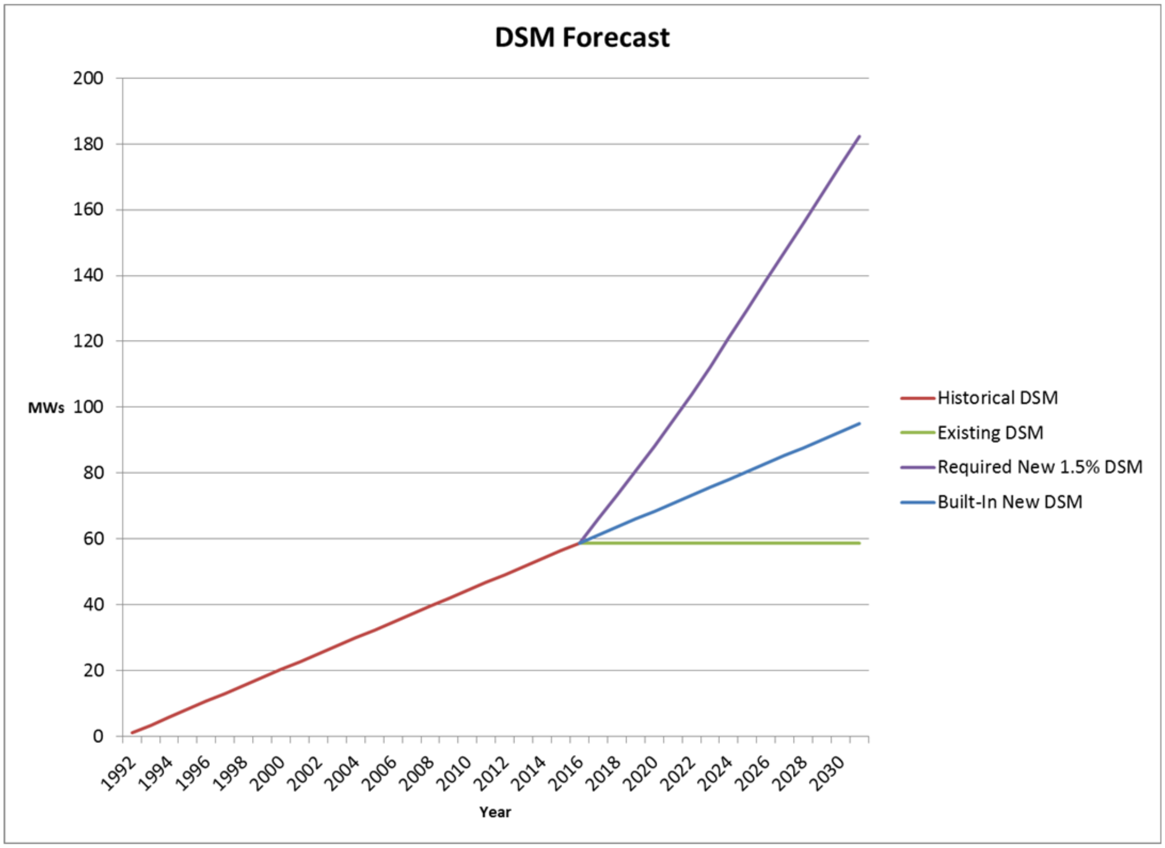


7 Energy Efficiency Assumed in Forecast

Otter Tail has been actively incorporating energy efficiency and Demand Side Management (DSM) programs in Minnesota since 1992. It can be assumed that as time goes on and energy efficiency programs grow, a portion of future energy efficiency will be included in the energy and demand forecasts. This conclusion was reached based on the fact that our historical load growth has been incrementally lowered by the existing energy efficiency programs which will translate to a lower future load growth through the forecasting process. In other words, the forecast assumes additional new energy efficiency to maintain the reduced load growth rates caused by the historical energy efficiency programs.

Figure 9 shows the amount of existing DSM for each historical year, and the assumed amount of included DSM in the future years required to maintain a similar load reduction.

Figure 9: DSM Assumptions



The gap between the green and blue lines is the assumed new DSM that is "built-in" to the forecast. The values for each year are listed in Figure 10.

Figure 10: Built-In DSM/EE

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Built-in DSM (MWs)	3.5	5.9	8.3	10.7	13.1	15.5	17.9	20.3	22.7	25.1	27.5	29.9	32.3	34.8	37.2
Built-in EE (GWHs)	11.9	23.5	35.2	46.8	58.4	70.1	81.7	93.4	105.0	116.6	128.3	139.9	151.6	163.2	174.9

8 Market Energy Price Assumptions

Otter Tail used the Wood Mackenzie January 2016 North American Power Service as the basis for the market energy prices used in the 2016 resource plan. Otter Tail applied the Wood Mackenzie forecasted monthly average energy price to an hourly day-ahead (DA) load zone price profile to reflect the hourly variability/volatility of the energy market. Otter Tail evaluated market energy at +/- 25% of the base case. Figure 11 shows the market energy price basis for the assumptions used in the 2016 resource plan. Figure 11 shows the market capacity price basis for the assumptions used in the 2013 resource plan. The market price sensitivities are #16 and #17.

Figure 11: Market Energy Price Assumptions

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9 Externality Price Assumptions

Figure 12 shows the externality price assumptions used in the 2016 resource plan. The values are from the *Notice of Revised Updated Environmental Externality Values* as issued by the Minnesota Public Utilities Commission on May 27, 2015 and escalated at 2 percent. Hoot Lake, Solway, and market purchases use the "Rural" values. Big Stone plant and the proposed combustion turbine use the "within 200 miles of Minnesota" values. Coyote Station does not have the externality values applied to it since it is over 200 miles from Minnesota, except for CO2 starting in 2022. The base case with externalities uses the mid-point values. The low and high externality price sensitivities are #19 and #20 respectively. Sensitivity #21 used CO2 values that started at $59/ton starting in 2017 and increased by $1/ton until 2022 where the mid-point range on CO2 resumed for the rest of the study period. Otter Tail did not apply any externality/allowance price to SO_2 emissions.

Figure 12: Externality Price ($/ton)

	Rural Externality values (used for HLP, Solway, Market Purchases)			Within 200 milies of MN (used for BSP, new CT)			Beyond 200 milies of MN (used for Coyote)		
	Low	Mid	High	Low	Mid	High	Low	Mid	High
SO2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM10	820.39	1034.25	1248.10	820.39	1034.25	1248.10	0.00	0.00	0.00
CO	0.30	0.45	0.60	0.30	0.45	0.60	0.00	0.00	0.00
NOX	26.28	87.59	148.90	26.28	87.59	148.90	0.00	0.00	0.00
Pb	586.83	620.40	653.97	586.83	620.40	653.97	0.00	0.00	0.00
CO2 (before 2022)	0.44	2.49	4.53	0.00	0.00	0.00	0.00	0.00	0.00
CO2 (starting 2022)	9.00	21.50	34.00	9.00	21.50	34.00	9.00	21.50	34.00

10 New Thermal Alternative Assumptions

Figure 13 shows key assumptions used for new thermal alternatives in the 2016 resource plan.

Figure 13: New Thermal Alternatives

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11 Existing Unit Input Assumptions

Figure 14 shows key input assumptions used for existing baseload units. Figure 15 shows key input assumptions used for existing peaking units. Figure 15 shows key input assumptions used for existing wind purchased power agreements. Figure 17 shows key assumptions used for Otter Tail-owned wind generation that is modeled as transactions in Strategist.

Figure 14: Existing Baseload Unit Assumptions

Existing Baseload Units				
Name	Big Stone	Coyote	Hoot Lake #2	Hoot Lake #3
Fuel	sub-bituminous coal	lignite coal	sub-bituminous coal	sub-bituminous coal
Retirement Date	Jun-2046	Jun-2041	Jun-2021	Jun-2021
Nameplate Capacity(MW)	255.8	149.8	58.7	81.4
Accredited Capacity(MW)	238.8	131	56.6	79.8
Heat Rate at Minimum (Btu/kwh)	11,650	12,310	11,620	11,345
Heat Rate at Maximum (Btu/kwh)	10,450	10,900	11,482	11,755
O&M Escalation	2%	2%	2%	2%
Fixed O&M (2017$/kw-yr)	$ 10.61	$ 11.44	$ 31.06	$ 30.89
Variable O&M (2017$/MWh)	$ 1.44	$ 1.73	$ 0.44	$ 0.86

Figure 15: Existing Peaking Unit Assumptions

Existing Peaking Units				
Name	Solway	Lake Preston	Jamestown 1	Jamestown 2
Fuel	natural gas	fuel oil	fuel oil	fuel oil
Retirement Date	Jun-2038	Jun-2033	Jun-2033	Jun-2033
Nameplate Capacity(MW)	42.5	20.4	20.7	21.1
Accredited Capacity(MW)	41.2	17	19.3	16.2
Heat Rate at Minimum (Btu/kwh)	11,450	16,320	18,480	18,480
Heat Rate at Maximum (Btu/kwh)	9,600	13,000	13,000	13,000
O&M Escalation	2%	2%	2%	2%
Fixed O&M (2017$/kw-yr)	$ 17.76	$ 6.86	$ 6.28	$ 6.16
Variable O&M (2017$/MWh)	$ 4.09	$ 5.79	$ 5.79	$ 5.79

Figure 16: Existing Wind Energy Transaction Assumptions

Existing Wind Purchased Power Transactions				
Name	(Edgeley)	Langdon PPA	Ashtabula III	Small DG
Transaction End Date	11/31/2028	Nov-2032	Sep-2038	Dec-2033
Nameplate Capacity(MW)	21	19.5	62.4	NA
Accredited Capacity(MW)	3.6	4.7	15.4	NA
Net Capacity Factor	30%	43%	42%	NA

Figure 17: Existing Otter Tail-Owned Wind Assumptions

Existing Otter Tail-Owned Wind (Modeled as Transactions in Strategist)			
Name	Langdon	Ashtabula	Luverne
Transaction End Date	Dec-2032	Dec-2033	Dec-2034
Nameplate Capacity(MW)	40.5	48	49.5
Accredited Capacity(MW)	9.5	11.5	13.5
Net Capacity Factor	41%	37%	40%

12 Other Assumptions

General Inflation Rate – 2%
Capital Cost Escalation Rate – 3%
Long Term Debt Rate – 5.51%
Discount Rate – 8.61%
Composite Tax Rate – 39.1%

Appendix G
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Appendix G: Otter Tail's REO/RES Compliance Strategy

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REO/RES Compliance Strategy

This document identifies and discusses the renewable energy requirements of the three states in which Otter Tail Power Company operates. The Company has developed significant wind generation resources, which when included with other renewable energy resources comprise a substantial percentage of the Company's total energy resources.

Renewable energy used for compliance with state requirements must be tracked through the Midwest Renewable Energy Tracking System ("M-RETS") through the use of renewable energy credits. The discussion leads to a strategy for managing the renewable energy credits to the benefit of customers and Otter Tail while simultaneously complying with renewable energy requirements.

1 Jurisdictional Requirements

Otter Tail serves retail load in Minnesota, North Dakota, and South Dakota. All three state jurisdictions have a renewable energy objective ("REO") or renewable energy standard ("RES"). Discussion of compliance efforts with any single jurisdiction also requires a discussion of the other two jurisdictions so that a complete understanding of the Company's compliance efforts can be obtained. Table I describes the requirements in each of the state jurisdictions. Additional detail regarding the state rules follows.

Table I
Jurisdictional REO/RES Requirements

	Minnesota	**North Dakota**	**South Dakota**
REO	2007-2009 1% 2010-2011 7% *(as percentage of retail sales after conservation)*	Prior to 2015 0% 2015 10% *(as percentage of retail sales with an adjustment for hydro energy that cannot be counted toward compliance)*	Prior to 2015 0% 2015 and on 10% *(as percentage of retail sales with an adjustment for hydro energy that cannot be counted toward compliance)*
RES[1]	2012-2015 12% 2016-2019 17% 2020-2024 21.5% (1.5% solar) 2025 and on 26.5% (1.5% solar)	N/A	N/A

[1] These MN REO and RES requirements only apply to utilities without nuclear generating assets. Utilities with nuclear generating assets have a more aggressive standard as detailed in Minn. Stat. §216B.1691.

Minnesota
Eligible energy technologies for compliance include solar, wind, hydroelectric with a capacity of less than 100 MW, hydrogen,[2] or biomass. Biomass includes landfill gas, anaerobic digestion, and mixed municipal solid waste or refuse-derived-fuel from mixed municipal solid waste as a primary fuel. Electricity generated by the combustion of biomass through co-firing with other fuels can be used for compliance, up to the percentage amount of biomass fuel relative to total fuel, only if the generating facility was constructed in compliance with new source performance standards promulgated under the federal Clean Air Act or if the facility employs the maximum achievable or best available control technology (MACT or BACT) for that type of facility.

The Minnesota PUC has ruled that RECs will have a shelf life for compliance with the REO/RES requirements of the year in which they are created plus four more calendar years. The PUC has also ruled that kWh sold under green pricing programs do not count toward REO/RES requirements.

North Dakota
The state REO is 10 percent of retail sales in 2015, and includes both renewable energy and recycled energy. The calculation contains a provision to reduce the amount of retail sales by any hydroelectric energy that cannot be counted toward the REO.[3] Renewable electricity and recycled energy includes electricity generated from solar, wind, biomass,[4] geothermal, hydrogen,[5] hydroelectric (must be from a facility with an in-service date of no earlier than January 1, 2007 or from efficiency improvements to a hydroelectric facility existing as of August 1, 2007), and recycled energy systems producing electricity from currently unused waste heat resulting from combustion or other processes and which do not use an additional combustion process for the electricity. Recycled energy does not include any system whose primary purpose is the generation of electricity.

The North Dakota PSC has not made a determination of the shelf life of RECs for compliance purposes. The PSC has not ruled in any manner on whether kWh sold under green pricing programs count toward REO compliance. Until such a determination is made it is being assumed that North Dakota green pricing electricity will count toward the REO as long as the source of the electricity is a qualifying technology.

South Dakota
The state REO is 10 percent of retail sales which started in year 2015, and includes both renewable energy and recycled energy. The legislation is very similar to the North Dakota requirements. The calculation contains a provision to reduce the amount of retail sales by any hydroelectric energy from a facility with an in-service date prior to July 1, 2008.[6] Renewable electricity and recycled energy include electricity generated from solar, wind, biomass,[7] geothermal, hydrogen,[8] hydroelectric (statutes seem to imply it must be from a facility with an in-service date of no earlier than July 1, 2008), and recycled energy systems producing electricity from currently unused waste heat resulting from combustion or other processes which do not use an additional combustion process to produce the electricity. Recycled energy does not include any system whose primary purpose is the generation of electricity.

[2] After January 1, 2010 the hydrogen must be generated from the other eligible energy technologies listed.
[3] North Dakota Century Code §49-02-30.
[4] Including agricultural crops and wastes and residues, wood and wood wastes and residues, animal wastes, and landfill gas.
[5] Provided that the hydrogen is generated from a source listed in this section of North Dakota Century Code §49-02-25.
[6] South Dakota Codified Laws §49-34A-103.
[7] Includes agricultural crops and wastes and residues, wood and wood wastes and residues, animal and other degradable organic wastes, and landfill gas.
[8] Provided that the hydrogen is generated from a source listed in this section of South Dakota Codified Laws §49-34A-94.

The South Dakota PUC has not made a determination of the shelf life of RECs for REO compliance. The PUC has not ruled in any manner whether kWh sold under a green pricing program count toward REO compliance. Until the PUC makes a determination it is assumed that green pricing electricity does count toward the REO as long as the source of the electricity is a qualifying technology.

2 Midwest Renewable Energy Tracking System

Otter Tail has registered renewable energy resources within the Midwest Renewable Energy Tracking System (“M-RETS"). There are small customer-owned units, generally less than 50 kW each, which the Company has not registered. These customers self-serve a portion of their own load with Otter Tail receiving the remaining surplus energy. Otter Tail does pay the cost, both initial and annual fees, to register a facility in M-RETS.

Otter Tail has developed an account structure within M-RETS to help segregate RECs by type and usage. For customer-owned facilities that self-serve customer load, all of the generation is reported within M-RETS. Otter Tail then transfers RECs associated with the energy used to self-serve load into an account in the customer’s name, for their use as they deem appropriate. The RECs associated with energy purchased by Otter Tail will remain in the Company account.

The Otter Tail M-RETS accounts include a retirement account by state jurisdiction by year. Thus it will be easy to verify the amount of RECs retired annually for compliance with each state’s requirements. RECs associated with Tail*Winds*, the Company’s green pricing program, are retired into separate state jurisdiction accounts to ensure proper accounting for the green pricing tracker balance.

Retired RECs are tracked on a calendar year basis. The M-RETS system became operational in the last half of 2007. While Otter Tail began recording renewable energy within M-RETS late in 2007, the Company began full use of the M-RETS system for reporting compliance verification beginning with the first full calendar year commencing January 1, 2008.

Renewable energy used for REO-RES compliance must be tracked through M-RETS. The states are relying on the system to verify and track renewable energy to ensure that the renewable energy is not double counted and that a company’s actual compliance performance can be readily tracked.

3 Jurisdictional Ownership of RECs

Retail customers pay for resources through the ratemaking cost allocation process. All existing generating resources are used to serve all customers, so the customers in each jurisdiction are paying a portion of the cost of each resource. The Company allocates the RECs to each jurisdiction based on a load/ratio share in the month the RECs are generated.

4 Allowance Banking

Otter Tail can and should bank some allowances for future use. There are several reasons for maintaining a bank balance of RECs including:

- Provide a compliance safety margin for years in which renewable energy generation may be lower than expected.
- Provide a construction safety margin in case planned future renewable energy resources are delayed or canceled.

- Provide a supplemental balance to be used in those years when there is a step increase in the REO-RES compliance levels.
- Provide a reserve for the time when Otter Tail may become deficit for its REO/RES compliance needs.

A number of RECs should be banked, only as long as Otter Tail has surplus RECs to bank for contingencies and future use. Once a jurisdiction is required to purchase RECs for REO/RES compliance, it does not make sense to purchase RECs simply to maintain a bank balance, unless it is expected that RECs will not be available for purchase in the future or if a particularly economic REC purchase opportunity arises.

While the prior discussion identifies the various purposes for banking RECs, the current Otter Tail situation becomes very simple. All RECs in the Minnesota jurisdiction that qualify for compliance in Minnesota should be banked as long as there isn't a risk of those RECs exceeding the allowable shelf life for MN compliance.

In all cases, the oldest RECs possible should be used for compliance as newer RECs will tend to have a higher value and a longer remaining shelf life for MN compliance.

In summary:

- All MN jurisdiction RECs eligible for MN compliance should be banked.
- Wherever possible, non-eligible jurisdictional RECs should be swapped between MN and the Dakotas to make optimum use of these RECs (which are all non-wind), for compliance purposes.
- Sell all surplus Dakotas jurisdiction RECs.

5 RES/SES Rate Impacts

As ordered by the Minnesota Commission, each utility that files a Resource Plan must calculate the cost of complying with Minn. Stat. §216B.1691. Utilities are required to do the following:

- Analyze costs for the period 2005 until the last reported year.
- Analyze costs from the year following the last reported year, and for the following 15 years.
- Include all facilities used to comply with the Renewable Energy Standard and the Solar Energy Standard, regardless of when the facilities were constructed.
- Calculate direct costs to include payments under power purchase agreements and revenue requirements associated with utility-owned renewable energy projects.
- Provide a narrative discussion about the impact that adding generators powered by renewable sources may have on the utilities indirect costs, such as the cost for ancillary services and base load cycling.
- Include transmission improvement costs.
- Calculate Energy and Capacity savings arising from avoiding costs that the utility would have incurred directly in the absence of the RES and SES.
- Calculate past and future emission compliance savings arising from avoiding costs that the utility would have incurred indirectly in the absence of the RES and SES.
- Report estimated annualized and estimated levelized costs.
- Calculate the costs of complying with the RES and SES separately.
- Calculate the ultimate rate impact of Minn. Stat. §216B.1691 to reflect the fact that renewable energy comprises only a fraction of a utility's total energy costs, and consequently most of a utility's energy costs are unaffected by the RES and SES.

Past RES Rate Impacts

RES Generation	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total RES Generation (GWh)	95.4	79.3	83.2	307.3	648.1	735.6	818	750	658	902.5	839.3
RES Generation Costs											
PPA + Owned Generation Costs (millions)	$2.6	$2.2	$2.3	$13.0	$20.7	$28.4	$26.9	$27.3	$27.2	$31.3	$31.0
RES Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total RES Costs (millions)	$2.6	$2.2	$2.3	$13.0	$20.7	$28.4	$26.9	$27.3	$27.2	$31.3	$31.0
RES Costs ($/MWh)	$27.25	$27.74	$27.64	$42.30	$31.94	$38.61	$32.89	$36.40	$41.34	$34.68	$36.94
Avoided Costs Due to RES											
Avoided Energy Costs (millions)	$4.5	$3.5	$4.3	$14.8	$16.3	$20.6	$20.3	$16.0	$18.6	$30.9	$18.4
Avoided Capactiy Costs (millions)	$0.4	$0.2	$0.3	$1.0	$1.4	$0.5	$0.4	$0.4	$1.1	$0.5	$0.8
Avoided Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Avoided Costs (millions)	$4.9	$3.7	$4.6	$15.8	$17.7	$21.1	$20.7	$16.4	$19.7	$31.5	$19.3
Total Avoided Costs ($/MWh)	$51.68	$47.13	$55.33	$51.42	$27.27	$28.65	$25.24	$21.85	$29.95	$34.87	$22.95
Total RES Premium/Discount (millions)	($2.3)	($1.5)	($2.3)	($2.8)	$3.0	$7.3	$6.2	$10.9	$7.5	($0.2)	$11.7
Total RES Premium/Discount ($/MWh)	($24.43)	($19.39)	($27.69)	($9.12)	$4.67	$9.96	$7.64	$14.55	$11.39	($0.19)	$13.99
Annualized RES Rate Impacts											
Total Company Sales (GWh)	3903	3988	4118	4215	4248	4284	4303	4216	4449	4684	4597
Rate Impact ($/MWh)	($0.60)	($0.39)	($0.56)	($0.66)	$0.71	$1.71	$1.45	$2.59	$1.68	($0.04)	$2.55
Rate impact (¢/kWh)	(0.06)	(0.04)	(0.06)	(0.07)	0.07	0.17	0.15	0.26	0.17	(0.00)	0.26

Past SES Rate Impacts

SES Generation	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total SES Generation (GWh)	-	-	-	-	-	-	-	-	-	-	-
SES Generation Costs											
PPA + Owned Generation Costs (millions)	-	-	-	-	-	-	-	-	-	-	-
SES Transmission Costs (millions)	-	-	-	-	-	-	-	-	-	-	-
Total SES Costs (millions)	-	-	-	-	-	-	-	-	-	-	-
SES Costs ($/MWh)	-	-	-	-	-	-	-	-	-	-	-
Avoided Costs Due to SES											
Avoided Energy Costs (millions)	-	-	-	-	-	-	-	-	-	-	-
Avoided Capactiy Costs (millions)	-	-	-	-	-	-	-	-	-	-	-
Avoided Transmission Costs (millions)	-	-	-	-	-	-	-	-	-	-	-
Avoided Emission Costs (millions)	-	-	-	-	-	-	-	-	-	-	-
Total Avoided Costs (millions)	-	-	-	-	-	-	-	-	-	-	-
Total Avoided Costs ($MWh)	-	-	-	-	-	-	-	-	-	-	-
Total SES Premium/Discount (millions)	-	-	-	-	-	-	-	-	-	-	-
Total SES Premium/Discount ($/MWh)	-	-	-	-	-	-	-	-	-	-	-
Annualized SES Rate Impacts											
Total Company Sales (GWh)	-	-	-	-	-	-	-	-	-	-	-
Rate Impact ($/MWh)	-	-	-	-	-	-	-	-	-	-	-
Rate impact (¢/kWh)	-	-	-	-	-	-	-	-	-	-	-

Future RES Rate Impacts

RES Generation	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total RES Generation (GWh)	871	871	1223	1223	1580	1575	1575	1576	1580	1576	1575	1575	1576	1520	1520	1520
RES Generation Costs																
PPA + Owned Generation Costs (millions)	$15.0	$15.0	$25.8	$26.0	$36.9	$37.0	$37.2	$37.4	$37.8	$37.9	$38.1	$38.4	$38.6	$37.2	$37.5	$37.8
RES Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total RES Costs (millions)	$15.0	$15.0	$25.8	$26.0	$36.9	$37.0	$37.2	$37.4	$37.8	$37.9	$38.1	$38.4	$38.6	$37.2	$37.5	$37.8
RES Costs ($/MWh)	$17.20	$17.20	$21.05	$21.23	$23.32	$23.46	$23.61	$23.75	$23.91	$24.05	$24.21	$24.37	$24.51	$24.50	$24.67	$24.85
Avoided Costs Due to RES																
Avoided Energy Costs (millions)	$24.4	$26.1	$34.2	$34.0	$44.4	$45.0	$47.6	$51.1	$53.6	$56.3	$58.5	$60.0	$61.7	$64.8	$70.0	$73.8
Avoided Capactiy Costs (millions)	$0.2	$0.2	$2.3	$6.2	$7.4	$7.5	$7.6	$7.7	$7.8	$7.8	$7.9	$8.1	$8.2	$8.0	$8.2	$8.3
Avoided Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Avoided Costs (millions)	$24.6	$26.4	$36.5	$40.2	$51.8	$52.5	$55.2	$58.8	$61.4	$64.2	$66.5	$68.0	$69.9	$72.9	$78.2	$82.1
Total Avoided Costs ($/MWh)	$28.25	$30.27	$29.85	$32.87	$32.78	$33.33	$35.05	$37.31	$38.83	$40.73	$42.21	$43.18	$44.35	$47.95	$51.44	$54.00
Total RES Premium/Discount (millions)	($9.6)	($11.4)	($10.8)	($14.2)	($15.0)	($15.5)	($18.0)	($21.4)	($23.6)	($26.3)	($28.4)	($29.6)	($31.3)	($35.6)	($40.7)	($44.3)
Total RES Premium/Discount ($/MWh)	($11.06)	($13.07)	($8.79)	($11.65)	($9.46)	($9.86)	($11.44)	($13.56)	($14.93)	($16.68)	($18.00)	($18.82)	($19.84)	($23.45)	($26.76)	($29.15)
Annualized RES Rate Impacts																
Total Company Sales (GWh)	5392	5392	5431	5346	5320	5383	5445	5503	5562	5626	5598	5569	5540	5510	5479	5447
Rate Impact ($/MWh)	($1.79)	($2.11)	($1.98)	($2.66)	($2.81)	($2.89)	($3.31)	($3.88)	($4.24)	($4.67)	($5.07)	($5.32)	($5.64)	($6.47)	($7.42)	($8.14)
Rate impact (¢/kWh)	(0.18)	(0.21)	(0.20)	(0.27)	(0.28)	(0.29)	(0.33)	(0.39)	(0.42)	(0.47)	(0.51)	(0.53)	(0.56)	(0.65)	(0.74)	(0.81)

Future SES Impacts

SES Generation	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total SES Generation (GWh)	0	0	0	0	39.1	39	39	39	39.1	39	39	39	39.1	39	39	39
SES Generation Costs																
PPA + Owned Generation Costs (millions)	$0.0	$0.0	$0.0	$0.0	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1
SES Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total SES Costs (millions)	$0.0	$0.0	$0.0	$0.0	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1	$3.1
SES Costs ($/MWh)	$0.00	$0.00	$0.00	$0.00	$80.05	$80.00	$80.00	$80.00	$80.05	$80.00	$80.00	$80.00	$80.05	$80.00	$80.26	$80.00
Avoided Costs Due to SES																
Avoided Energy Costs (millions)	$0.0	$0.0	$0.0	$0.0	$1.1	$1.1	$1.2	$1.3	$1.3	$1.4	$1.4	$1.5	$1.5	$1.7	$1.8	$1.9
Avoided Capactiy Costs (millions)	$0.0	$0.0	$0.0	$1.0	$1.2	$1.2	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3	$1.4	$1.4	$1.4	$1.4
Avoided Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Avoided Costs (millions)	$0.0	$0.0	$0.0	$1.0	$2.3	$2.4	$2.4	$2.5	$2.6	$2.7	$2.8	$2.8	$2.9	$3.1	$3.2	$3.3
Total Avoided Costs ($/MWh)	$0.00	$0.00	$0.00	$0.00	$59.63	$60.58	$62.70	$65.27	$67.09	$69.24	$71.10	$72.57	$74.10	$78.41	$82.39	$85.36
Total SES Premium/Discount (millions)	$0.0	$0.0	$0.0	($1.0)	$0.8	$0.8	$0.7	$0.6	$0.5	$0.4	$0.3	$0.3	$0.2	$0.1	($0.1)	($0.2)
Total SES Premium/Discount ($/MWh)	$0.00	$0.00	$0.00	$0.00	$20.43	$19.42	$17.30	$14.73	$12.96	$10.76	$8.90	$7.43	$5.95	$1.59	($2.13)	($5.36)
Annualized RES Rate Impacts																
Total Company Sales (GWh)	5392	5392	5431	5346	5320	5383	5445	5503	5562	5626	5598	5569	5540	5510	5479	5447
Rate Impact ($/MWh)	$0.00	$0.00	$0.00	($0.19)	$0.15	$0.14	$0.12	$0.10	$0.09	$0.07	$0.06	$0.05	$0.04	$0.01	($0.02)	($0.04)
Rate impact (¢/kWh)	0.00	0.00	0.00	(0.02)	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	(0.00)	(0.00)

Levelized RES Rate Impacts

Levelized RES Generation	Historic	Future
Total RES Generation (GWh)	538	1434

Levelized RES Generation Costs		
PPA + Owned Generation Costs (millions)	$28.5	$18.0
RES Transmission Costs (millions)	$0.0	$0.0
Total RES Costs (millions)	$28.5	$18.0
RES Costs ($/MWh)	$52.93	$12.59

Levelized Avoided Costs Due to RES		
Avoided Energy Costs (millions)	$23.3	$26.4
Avoided Capactiy Costs (millions)	$1.1	$3.3
Avoided Transmission Costs (millions)	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0
Total Avoided Costs (millions)	$24.4	$29.7
Total Avoided Costs ($/MWh)	$45.35	$20.70

Total RES Premium/Discount (millions)	$4.1	($11.6)
Total RES Premium/Discount ($/MWh)	$7.58	($8.11)

Levelized RES Rate Impacts		
Total Company Sales (GWh)	4273	5471
Rate Impact ($/MWh)	$0.95	($2.12)
Rate impact (¢/kWh)	0.10	(0.21)

Levelized SES Rate Impacts

Levelized SES Generation	Historic	Future
Total SES Generation (GWh)	-	39

Levelized SES Generation Costs		
PPA + Owned Generation Costs (millions)	-	$1.4
SES Transmission Costs (millions)	-	$0.0
Total SES Costs (millions)	-	$1.4
SES Costs ($/MWh)	-	$36.36

Levelized Avoided Costs Due to SES		
Avoided Energy Costs (millions)	-	$0.6
Avoided Capactiy Costs (millions)	-	$0.7
Avoided Transmission Costs (millions)	-	$0.0
Avoided Emission Costs (millions)	-	$0.0
Total Avoided Costs (millions)	-	$1.3
Total Avoided Costs ($/MWh)	-	$32.78

Total SES Premium/Discount (millions)	-	$0.1
Total SES Premium/Discount ($/MWh)	-	$3.58

Levelized SES Rate Impacts		
Total Company Sales (GWh)	-	5471
Rate Impact ($/MWh)	-	$0.03
Rate impact (¢/kWh)	-	0.00

Indirect Costs

As a member of the Midcontinent ISO, Otter Tail is required to offer its generation units into the day-ahead energy market. Recently energy prices have been very low due to the addition of renewable resources as well as low fuel costs for existing thermal units. Up until this point in time, Otter Tail has offered in its co-owned baseload thermal units as “must-run” units to prevent them from cycling on and off with fluctuating energy prices. This means that if the day-ahead price of energy dips below the cost of the unit, the unit will still clear at minimums in order to keep the unit online. Because these units stay online regardless of energy prices, there is no increase in cycling charges. Otter Tail does have one solely owned coal plant with higher costs than the jointly owned units. This unit is offered into the market economically meaning the day-ahead energy price has to be higher than the unit’s cost for long enough to justify bringing the unit online. As a result, it could be argued that this unit cycles more because of the additional renewable resources on the system.

In terms of ancillary services, Otter Tail has not identified any impacts which can be attributed to the implementation of the RES requirements so far. That being said, as the amount of renewable resources increases, so does the need for ancillary services. Eventually there will be a tipping point where the amount of renewable resources increases and the amount of available spinning reserves decreases to a level which causes the cost of ancillary services to rise.

Avoided Permitting and Emission Cost Impacts

All historical avoided permitting and emission costs are factored in when calculating the avoided energy and capacity costs. For the future avoided CO_2 costs, Otter Tail used the Commission approved value of $21.50/ton CO_2 penalty starting in 2022.

Transmission Costs

For the purpose of simplifying our modeling, all transmission costs for future RES/SES projects are built into the project energy price. It is also assumed that all avoided energy and capacity costs (both past and future) will be purchased from the market resulting in no added transmission costs.

6 Summary

The following strategy is being used to optimize the usage of RECs:

- Otter Tail allocates RECs from resources used to serve all customers based on a monthly energy allocation.
- Otter Tail banks all MN jurisdiction RECs which are eligible for MN compliance to be used for current and future REO/RES compliance.
- Otter Tail swaps MN jurisdiction RECs which cannot be used for MN compliance but can be used for Dakotas compliance for Dakotas jurisdiction RECs which cannot be used for ND or SD compliance but can be used for MN compliance. Equivalent monetary value will be maintained for all swaps.
- Otter Tail expects to transfer enough Dakotas RECs to Minnesota, as necessary, to maintain a bank balance for MN REO/RES compliance, but without risking shelf life expiration of RECs for compliance purposes.
- Otter Tail sells the surplus ND and SD allocated RECs.
- Otter Tail evaluates opportunities to purchase/use lower value RECs for compliance and banking, while selling higher value RECs. All benefits and costs flow to customers.
- When possible, sell higher value MN RECs and acquire older and lower value Dakotas RECs for compliance in MN. MN REC sales revenues, net of replacement purchase costs, will be treated in accordance with MN Commission Orders. Dakotas REC revenues from sales to the MN jurisdiction will be treated in accordance with the Commission Orders in those two states.
- The oldest RECs possible should be used for compliance or for sales in order to keep the REC inventory as fresh as possible and at as high a value as possible.
- Seek opportunities to sell wind generation energy either with or without RECs if lower cost replacement energy purchases can be made to reduce energy costs.

Appendix H
TAB

Appendix H: Update on C-BED Projects

Update on C-BED Projects

Minnesota Stat. §216B.1612 requires utilities submitting resource plans under Minnesota Stat. §216B.2422 to include a description of its efforts to purchase energy from Community Based Energy Development ("C-BED"), including a list of projects under contract and the amount of C-BED energy purchased.

Otter Tail has one project currently under a C-BED PPA that began in 2011. The PPA is with the University of Minnesota-Morris for the net generation from a 1,650 kw wind facility. The net energy purchased from the project in 2015 was 4,916 MWh.

The Company has numerous C-BED eligible projects that have chosen not to use a C-BED PPA. There are several primary reasons that project developers have chosen not to use the C-BED tariff. Minnesota Stat. §216B.1612, subd. 3 requires a 20-year life of the PPA. Most small developers do not like the risks associated with a long-term firm obligation to supply, as this requirement is viewed as placing them at some future risks should there be significant project difficulties due to mechanical failure. The same subdivision also requires sufficient security to guarantee performance over the life of the project, which increases cost and complexity for the developer. Finally, many project owners choose to use some of the generation to serve their native load on-site and these situations make it more difficult to establish pricing to ensure the higher upfront cost in the C-BED PPA is offset by the lower long-term cost in the PPA.

It is difficult for C-BED projects based in Minnesota to compete economically with other wind generation projects available to the Company. The federal Production Tax Credit ("PTC") currently reduces the cost of wind generation by about 33 percent. Many of the entities eligible for C-BED are tax exempt entities and therefore do not benefit from the federal PTC.

The Company continues to evaluate C-BED projects. However, C-BED proposals have had a significant price premium compared to other alternatives. As a result, Otter Tail has not added a C-BED project to its portfolio since 2011.

Appendix I
TAB

Appendix I: Integrated Resource Plan

Sensitivity Summary

Appendix I - 2016 Integrated Resource Plan Sensitivity Summary

With CO2 Tax/Externalities

Run Number	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Sensitivity:	**Base -with externalities**	**OTP Preferred Plan**	**Wind -$5/MWh**	**Wind +$5/MWh**	**(CEO)Solar Declining price**	**Solar -$10/MWh**	**Solar +$10/MWh**	**-50% Natural Gas price**	**-25% Natural Gas price**	**+25% Natural Gas price**	**+50% Natural Gas price**	**+100% Natural Gas price**	**Low Coal price**	**High Coal price**	**Low Load Growth**	**High Load Growth**
Mkt Forecast Basis	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016
CO2 Tax/ton(Start Yr)	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**
Assumption Sensitivity	**N/A**	**N/A**	**-$5/MWh**	**+$5/MWh**	**Declining**	**-$10/MWh**	**+$10/MWh**	**-50%**	**-25%**	**+25%**	**+50%**	**+100%**	**-25%**	**25%**		
Plan Year																
2017																
2018	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)
2019																
2020	Wind(100) SLR(30) *	Wind(100) SLR(30) *	Wind(100)	Wind(100)	Wind(100) SLR(30)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)
2021	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)
2022	Wind(100)		Wind(100)	Wind(100)	Wind(100) SLR(30)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100) SC(48)
2023	Wind(100)		Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)
2024					SLR(30)											
2025			Wind(100)													
2026					SLR(30)											
2027																
2028					SLR(30)											
2029																
2030					SLR(30)											
2031																
Present Value of Societal Costs (2017$) ($000)	$3,093,438	$3,165,077	$3,025,662	$3,144,743	$3,066,290	$3,086,140	$3,086,140	$2,948,721	$3,051,842	$3,099,543	$3,109,224	$3,124,339	$2,928,015	$3,236,331	$2,885,171	$3,353,757
Difference from Base	0.00%	2.32%	-2.19%	1.66%	-0.88%	-0.24%	-0.24%	-4.68%	-1.34%	0.20%	0.51%	1.00%	-5.35%	4.62%	-6.73%	8.42%

Without CO2 Tax/Externalities

Run Number	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Sensitivity:	**Base - Zero Externalities**	**OTP Preferred Plan**	**Wind -$5/MWh**	**Wind +$5/MWh**	**(CEO)Solar Declining price**	**Solar -$10/MWh**	**Solar +$10/MWh**	**-50% Natural Gas price**	**-25% Natural Gas price**	**+25% Natural Gas price**	**+50% Natural Gas price**	**+100% Natural Gas price**	**Low Coal price**	**High Coal price**	**Low Load Growth**	**High Load Growth**
2017																
2018	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)
2019																
2020	Wind(100)	Wind(100) SLR(30)*	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100) SLR(30)
2021	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)
2022			Wind(100)								Wind(100)	Wind(100)		Wind(100)		Wind(100) SLR(30)
2023																
2024					SLR(30)											
2025																
2026					SLR(30)											
2027																
2028					SLR(30)											
2029																
2030					SLR(30)											
2031																
Present Value of Utility Costs (2017$) ($000)	$2,408,720	$2,419,233	$2,364,089	$2,442,806	$2,405,343	$2,408,720	$2,408,720	$2,321,506	$2,377,042	$2,432,903	$2,450,441	$2,476,486	$2,239,088	$2,570,565	$2,250,380	$2,613,568
Difference from Base	0.00%	0.44%	-1.85%	1.42%	-0.14%	0.00%	0.00%	-3.62%	-1.32%	1.00%	1.73%	2.81%	-7.04%	6.72%	-6.57%	8.50%

SC(48) - generic 48 MW nameplate capacity aeroderivitive type simple cycle unit
SC(248) - 248 MW nameplate capacity frame type simple cycle unit
Wind (100) - Generic 100 MW nameplate capacity wind resource
SLR (30) - Generic 30 MW nameplate capacity solar photovoltaic resource
* - Resource was forced into the plan

With CO2 Tax/Externalities

Run Number	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Sensitivity:	**Low Energy Market Price**	**High Energy Market Price**	**Limit Market Energy Purchases**	**Low Externality**	**High Externality**	**(CEO) $59/ton CO2**	**MN CO2 reduction Goal**	**BAU MN Energy Efficiency**	**1.6% MN Energy Efficiency**	**1.7% MN Energy Efficiency**	**1.8% MN Energy Efficiency**	**1.9% MN Energy Efficiency**	**2.0% MN Energy Efficiency**	**(CEO) 1.0% ND Energy Efficiency**	**Retire Peakers**
Mkt Forecast Basis	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016	WM Jan 2016
CO2 Tax/ton(Start Yr)	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$9.00 (2022)**	**$34.00 (2022)**	**$59.00 (2017)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**	**$21.50 (2022)**
Assumption Sensitivity	**-25%**	**+25%**		**$9.00/Ton**	**$34.00/Ton**	**$21.50 (2022)**	**NA**	**BAU**	**1.60%**	**1.70%**	**1.80%**	**1.90%**	**2.00%**	**1.00%**	**2023**
Plan Year															
2017															
2018	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)
2019															
2020	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)
			SLR(30)				SLR(30) *	SLR(30) *	SLR(30) *	SLR(30) *	SLR(30) *	SLR(30) *	SLR(30) *	SLR(30) *	SLR(30) *
2021	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)
2022	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)
			SLR(30)												SLR(30)
2023	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)
2024			SLR(30)												
2025			Wind(100)		Wind(100)										
2026															
2027					Wind(100)										
2028															
2029															
2030															
2031															
Present Value of Societal Costs (2017$) ($000)	$2,971,507	$3,152,240	$3,293,122	$2,691,726	$3,456,571	$3,275,767	$3,093,438	$3,061,343	$3,088,948	$3,089,786	$3,092,405	$3,104,475	$3,099,478	$3,006,444	$3,129,537
Difference from Base	-3.94%	1.90%	6.46%	-12.99%	11.74%	5.89%	0.00%	-1.04%	-0.15%	-0.12%	-0.03%	0.36%	0.20%	-2.81%	1.17%

Without CO2 Tax/Externalities

Sensitivity:	**Low Energy Market Price**	**High Energy Market Price**	**Limit Market Energy Purchases**					**BAU MN Energy Efficiency**	**1.6% MN Energy Efficiency**	**1.7% MN Energy Efficiency**	**1.8% MN Energy Efficiency**	**1.9% MN Energy Efficiency**	**2.0% MN Energy Efficiency**	**(CEO) 1.0% ND Energy Efficiency**	**Retire Peakers**
2017															
2018		Wind(100)	Wind(100)					Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)
2019															
2020	Wind(100)	Wind(100)	Wind(100)					Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)	Wind(100)
			SLR(30)												
2021	SC(248)	SC(248)	SC(248)					SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)	SC(248)
2022		Wind(100)	Wind(100)					Wind(100)							Wind(100)
			SLR(30)												
2023															
2024			SLR(30)												
2025															
2026															
2027															
2028															
2029															
2030															
2031															
Present Value of Utility Costs (2017$) ($000)	$2,279,706	$2,490,509	$2,644,439					$2,367,729	$2,408,368	$2,413,544	$2,419,800	$2,436,096	$2,435,151	$2,350,109	$2,467,841
Difference from Base	-5.36%	3.40%	9.79%					-1.70%	-0.01%	0.20%	0.46%	1.14%	1.10%	-2.43%	2.45%

Appendix J
TAB

Appendix J: Navigant DSM Potential Study Final Report – March 15

NAVIGANT

Electric Demand Side Management (DSM) Market Potential Study

Prepared for:
Otter Tail Power Company

OTTER TAIL POWER COMPANY

Final Report

Submitted by:
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March 15, 2016

NAVIGANT

Table of Contents

1. Executive Summary

This report presents the results of a 2015 study of the energy efficiency potential for Otter Tail Power Company's Minnesota service area. The goal of the project was to estimate both energy efficiency market potential and also the potential for direct load control measures, in support of Otter Tail Power's (OTP's) strategic resource and Conservation Improvement Program (CIP) planning. The study approach to estimating energy conservation potential relied on four key data inputs:

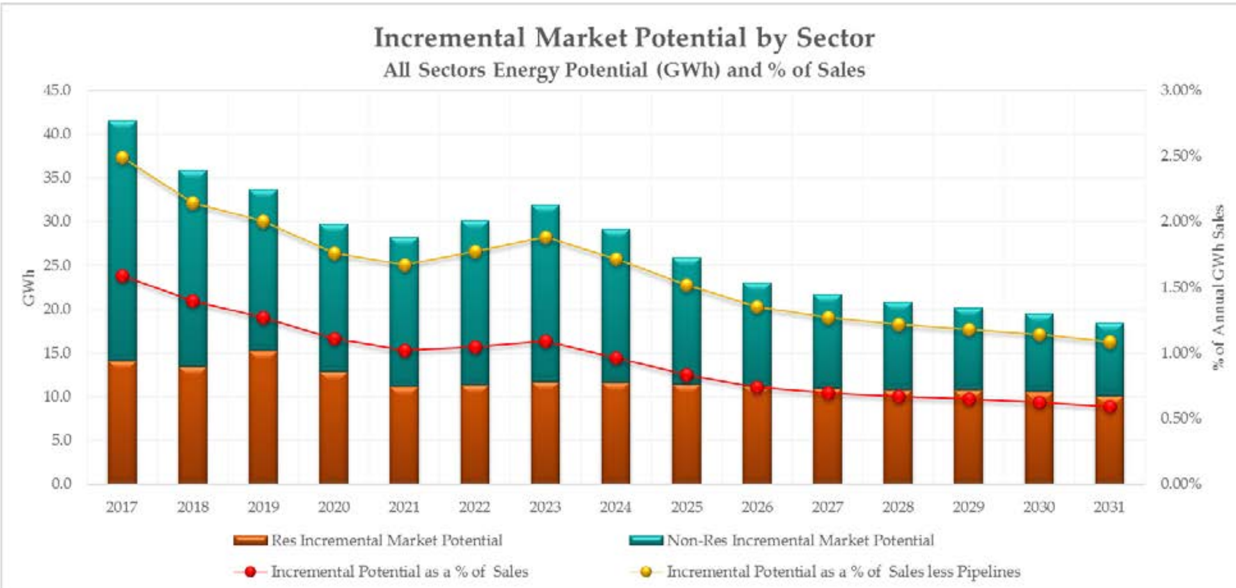
1. The current saturations of electric energy efficiency measures in statistically representative samples of OTP's residential and commercial/industrial facilities
2. Energy efficiency measures' energy and demand savings, costs and lifetimes, from the Minnesota Statewide Technical Reference Manual (TRM), plus additional measures provided in OTP's TRM
3. The actual energy savings achieved by best practice energy efficiency programs in the Midwest and across North America
4. The actual energy savings achieved by existing OTP energy efficiency programs in Minnesota

The Electricity Resource Assessment Model (ELRAM), developed by Navigant Consulting, Inc. (Navigant), utilized these inputs to prepare the following types of DSM potential results: technical and economic electric energy efficiency potential, and market-achievable DSM potential for an expected base case, and six scenarios. These additional six scenarios reach DSM goals of 1.5% to 2.0% of utility sales in 0.1% increments.

1.1 DSM Potentials Results

Navigant began with a base case model run showing the results of "business as usual," where the modeling team made no adjustments to current incentive levels or program administrative costs. The left axis of Figure E–1 illustrates the base scenario incremental market potential (GWh) and the right axis presents the base scenario incremental market energy potential expressed as a percent of total OTP forecasted sales. There are two representations of the percent of sales values in this figure. The first is a percent of all sales and the second percent of all sales less pipeline sales. The two representations illustrate the effect of the large share of pipeline sales to total sales for OTP. Over the forecast period, pipeline sales represent between 35-45% of total sales, depending on the year. However, the pipeline companies have informed OTP the pumps currently used by the pipelines are already high performance pumps and offer no current DSM potential. When considering goals expressed as percent of sales, Navigant suggests that it may be more appropriate for OTP to express their DSM goals as percent of sales less pipeline sales.

Figure E–1. Base Case Incremental Market Energy Potential by Sector (GWh) and Percent of Sales



Source: Navigant 2015

Table E–1 provides the values represented in Figure E–1. For the base case, energy potential as expressed as a percent of total sales is 1.59% in 2017 and falls to 0.59% by 2031. When expressed as a percent of sales less pipeline sales, the values are 2.49% in 2017 falling to 1.08% by 2031. However in the latter scenarios, the incremental market potential as expressed as a percent of sales remains at or above the 1.5% goal though 2031.

Incremental market potential decreases each year in the base case scenario due to incentive levels remaining constant, the impacts of codes and standards reducing programmatic opportunities, and certain measures beginning to reach saturation levels by the end of the forecast period. At the sector level, the residential share of incremental market potential in 2017 is about 34% of the total incremental market potential. By 2031, the residential share increases to about 55%.

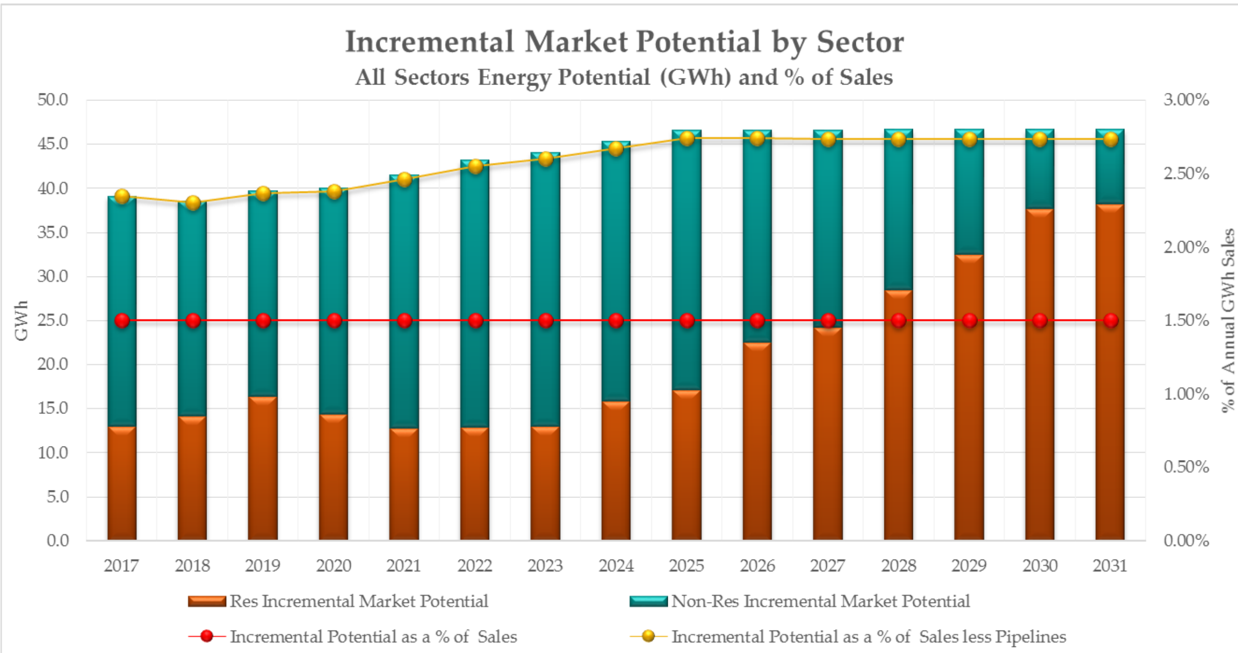
Table E–1. Base Case Incremental Market Energy Potential by Sector (GWh) and Percent of Sales

All Sectors (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Incremental Market Potential	41.5	35.9	33.6	29.7	28.2	30.1	32.0	29.2	25.9	23.0	21.7	20.8	20.2	19.5	18.5
Res Incremental Market Potential	14.1	13.5	15.3	12.9	11.1	11.3	11.7	11.6	11.4	11.2	11.0	10.8	10.7	10.6	10.1
Non-Res Incremental Market Potential	27.4	22.4	18.4	16.8	17.1	18.8	20.3	17.5	14.4	11.8	10.7	10.0	9.4	8.9	8.4
Incremental Potential as % of Sales	1.59%	1.40%	1.27%	1.11%	1.02%	1.04%	1.09%	0.97%	0.83%	0.74%	0.70%	0.67%	0.65%	0.63%	0.59%
Incremental Potential as % of Sales less Pipeline	2.49%	2.14%	2.00%	1.76%	1.67%	1.78%	1.89%	1.72%	1.52%	1.35%	1.27%	1.22%	1.18%	1.14%	1.08%

Source: Navigant 2015

OTP's currently DSM goal is 1.5% percent of *total* sales. Navigant modeled the 1.5% scenario to meet this goal through 2031, by increasing incentive and administrative costs, and enlarging program budgets. Figure E–2 shows the results of the 1.5% scenario. The flat red line illustrates OTP meeting the 1.5% goal each year of the forecast. The yellow line represents what the percentage would be if calculated against total sales less pipeline sales. On average, the yellow line is nearly a full percentage point higher.

Figure E–2. 1.5% Scenario Incremental Market Energy Potential by Sector (GWh) and % of Sales



Source: Navigant 2015

Table E–2 provides the values represented in Figure E–2. The modeling team increased incentive, administrative, and budget levels each year to meet the 1.5% goal. When expressed as a percent of sales less pipeline sales, the values are 2.35% in 2017 increasing to 2.74% by 2031.

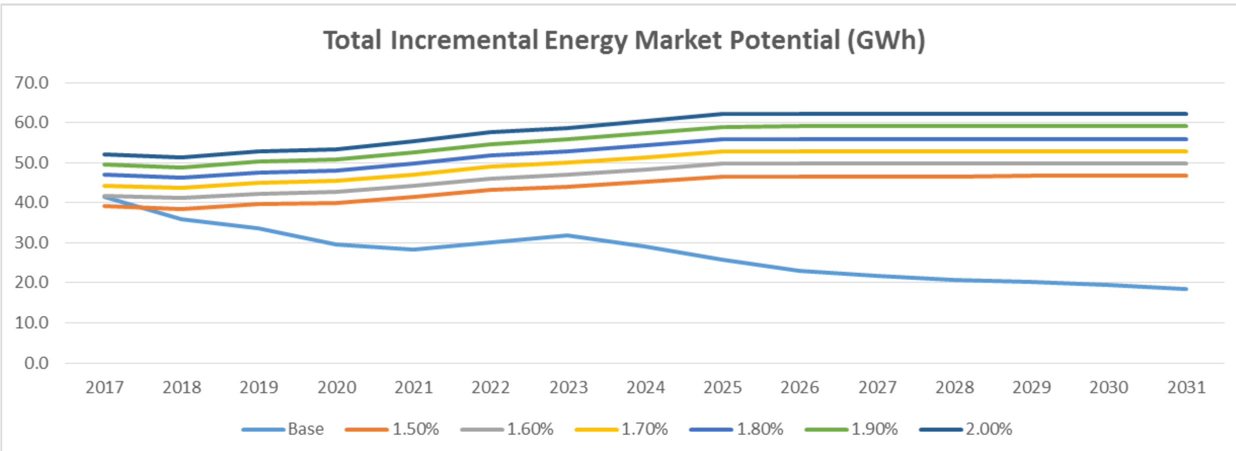
Table E–2. 1.5% Scenario Incremental Market Energy Potential by Sector (GWh) and % of Sales

All Sectors (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Incremental Market Potential	39.1	38.6	39.7	40.1	41.5	43.2	44.1	45.4	46.6	46.6	46.7	46.7	46.7	46.7	46.7
Res Incremental Market Potential	13.0	14.1	16.4	14.4	12.8	12.9	13.0	15.9	17.1	22.5	24.3	28.5	32.5	37.7	38.3
Non-Res Incremental Market Potential	26.1	24.4	23.3	25.7	28.7	30.3	31.1	29.5	29.5	24.1	22.4	18.1	14.2	9.0	8.4
Incremental Potential as a % of Sales	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Incremental Potential as a % of Sales less Pipelines	2.35%	2.31%	2.37%	2.38%	2.46%	2.55%	2.60%	2.67%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%

Source: Navigant 2015

OTP also requested modeling scenarios stepping up to 2.0% of sales, in 0.1% increments. The following figures and tables summarize the potential savings and administrator costs for each of these incremental scenarios.

Figure E–3. Incremental Market Potential by Scenario (GWh)



Source: Navigant 2015

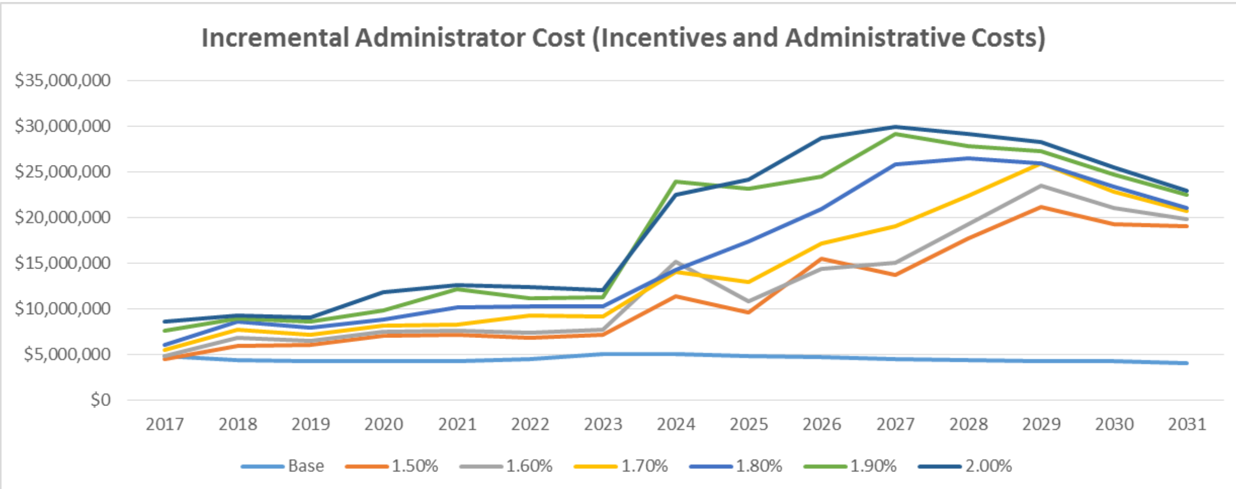
Table E–3. Incremental Market Potential by Scenario (GWh)

All Sectors (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Base	41.5	35.9	33.6	29.7	28.2	30.1	32.0	29.2	25.9	23.0	21.7	20.8	20.2	19.5	18.5
1.50%	39.1	38.6	39.7	40.1	41.5	43.2	44.1	45.4	46.6	46.6	46.7	46.7	46.7	46.7	46.7
1.60%	41.7	41.1	42.3	42.7	44.3	46.1	47.0	48.4	49.7	49.7	49.8	49.8	49.8	49.8	49.8
1.70%	44.3	43.7	45.0	45.4	47.1	49.0	50.0	51.4	52.8	52.9	52.9	52.9	52.9	52.9	52.9
1.80%	46.9	46.3	47.6	48.1	49.9	51.8	52.9	54.4	55.9	56.0	56.0	56.0	56.0	56.0	56.0
1.90%	49.5	48.8	50.3	50.8	52.7	54.7	55.9	57.5	59.0	59.1	59.1	59.1	59.1	59.1	59.2
2.00%	52.2	51.4	52.9	53.4	55.4	57.6	58.8	60.5	62.1	62.2	62.2	62.2	62.2	62.2	62.2

Source: Navigant 2015

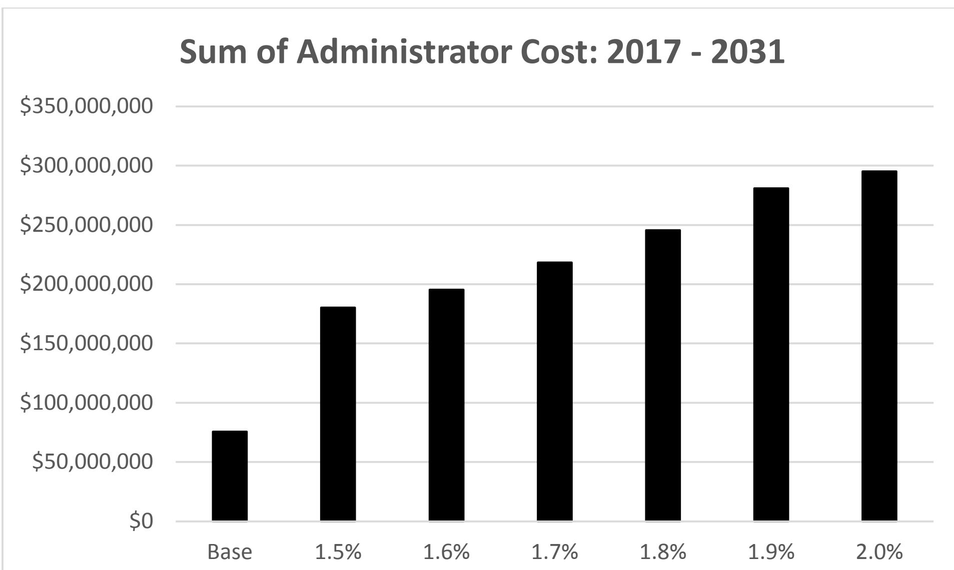
Figure E–4 illustrates what the incremental cost impacts would be to achieve each of these incremental scenarios. Figure E–5 illustrates the cumulative administrator cost by scenario over the 2017 through 2031 time period. The administrator cost is the sum of administrative cost and incentive cost. The base scenario is the "business as usual" scenario where incentives and administrator costs remain as they are currently. All costs are expressed in 2015 real $s.

Figure E–4. Incremental Administrator Cost by Scenario



Source: Navigant 2015

Figure E–5. Cumulative Administrator Cost by Scenario (2017-2031)



Source: Navigant 2015

Table E-4 displays the values illustrated in Figure E–4 and Figure E–5. The 2.0% of sales scenario proves to be especially costly over the entire forecast horizon. The cumulative administrator cost over the period 2017 through 2031 for the 2.0% scenario is 164% greater than the 1.5% scenario and 390% greater than the base scenario. In contrast, the cumulative of incremental energy savings over this time frame for the 2% scenario is 130% greater than the 1.5% scenario and 197% of the base scenario. The cost/kWh is $0.156 for the base case; rises rapidly to $0.246 for the 1.5% scenario and increases with each succeeding scenario to $0.310 for the 2% scenario.

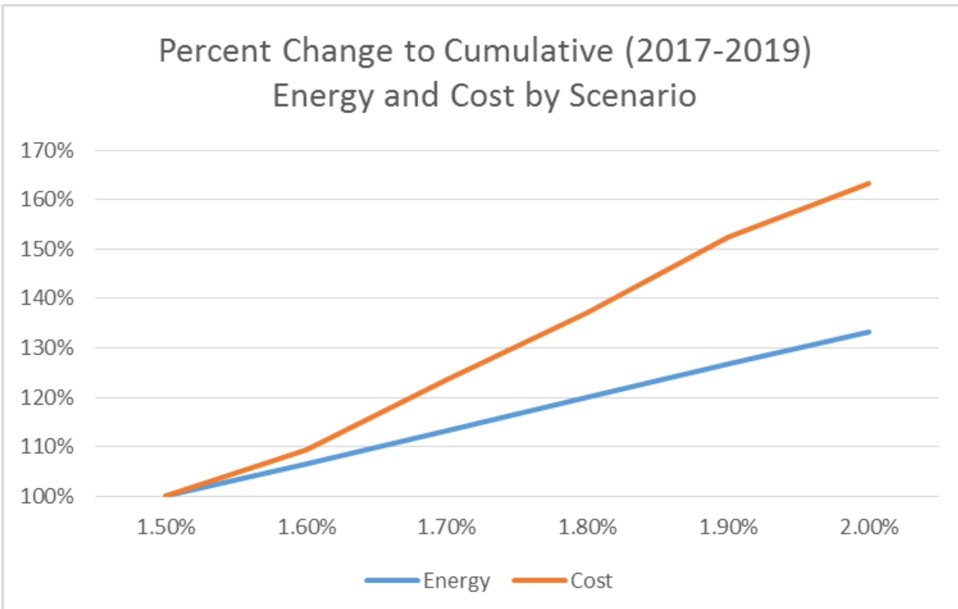
Table E–4. Incremental and Total Administrator Cost by Scenario ($ and $/kWh)

Scenario	2017	2018	2019	2020	2021	2022	2023	ta2024	2025	2026	2027	2028	2029	2030	2031	Sum 2017 - 2031	Cost/kWh
Base	$4,761,274	$4,374,874	$4,278,151	$4,285,840	$4,268,492	$4,442,193	$5,057,158	$5,024,716	$4,840,897	$4,629,534	$4,478,431	$4,321,669	$4,289,326	$4,194,358	$4,036,577	$75,739,689	$0.156
1.50%	$4,499,070	$5,917,208	$6,003,134	$7,047,286	$7,140,769	$6,849,860	$7,184,140	$11,380,896	$9,571,697	$15,496,337	$13,662,661	$17,719,670	$21,175,541	$19,314,517	$19,000,258	$180,419,244	$0.246
1.60%	$4,787,637	$6,757,604	$6,427,051	$7,467,927	$7,534,130	$7,309,285	$7,637,643	$15,194,437	$10,775,775	$14,346,252	$15,084,705	$19,305,333	$23,518,666	$21,024,096	$19,800,893	$195,427,633	$0.252
1.70%	$5,492,949	$7,632,083	$7,180,661	$8,107,110	$8,214,340	$9,259,974	$9,182,642	$14,084,478	$12,870,299	$17,124,692	$19,085,695	$22,377,074	$25,947,081	$22,781,601	$20,690,322	$218,487,202	$0.266
1.80%	$6,024,611	$8,604,338	$7,869,206	$8,846,779	$10,156,474	$10,218,799	$10,242,819	$14,218,632	$17,352,883	$20,905,403	$25,835,194	$26,507,041	$25,934,898	$23,342,555	$21,026,731	$245,542,564	$0.284
1.90%	$7,534,509	$8,889,266	$8,600,915	$9,852,154	$12,092,584	$11,144,072	$11,278,568	$23,925,301	$23,113,305	$24,464,693	$29,194,405	$27,892,936	$27,252,619	$24,674,495	$22,550,404	$280,916,423	$0.309
2.00%	$8,538,390	$9,241,626	$9,051,460	$11,837,981	$12,568,061	$12,362,158	$12,035,624	$22,457,681	$24,141,109	$28,756,101	$29,909,055	$29,227,766	$28,265,068	$25,505,330	$22,957,481	$295,311,092	$0.310

Source: Navigant 2015

Focusing on the near term (2017-2019), Figure E–6 illustrates the percentage change in cumulative energy savings potential and cost by scenario. The cumulative additional administrator cost over the three years of the 2.0% scenario is $10.4 million more than the 1.5% scenario and $13.4 million more than the base "business as usual" scenario.

Figure E–6. Percent Change to Cumulative (2017-2019) Energy and Cost by Scenario



Source: Navigant 2015

1.2 Direct Load Control Results

OTP has a number of direct load control programs. Some designed to reduce summer peak demand, others winter peak demand, and there are strategies within programs designed to reduce both summer and winter peak demand or provide load shifting. The primary incentive to participate in these programs are special controlled service rates that are about 30-50 percent less than OTP standard rates. The following are programs and strategies offered through OTP. Several of the programs provide both summer and winter load control. Those that provide both summer and winter control (such as heat pumps) are included in the separate summer and winter categories.

- Summer Load - Air Conditioning Control - Res
- Summer Load - Air Conditioning Control - Com
- Summer Load - Water Heat Control - Com
- Summer Load - Water Heat Control - Res
- Summer Load - Residential Demand Control
- Winter Load - Residential Demand Control
- Winter Load - Deferred Load - Res

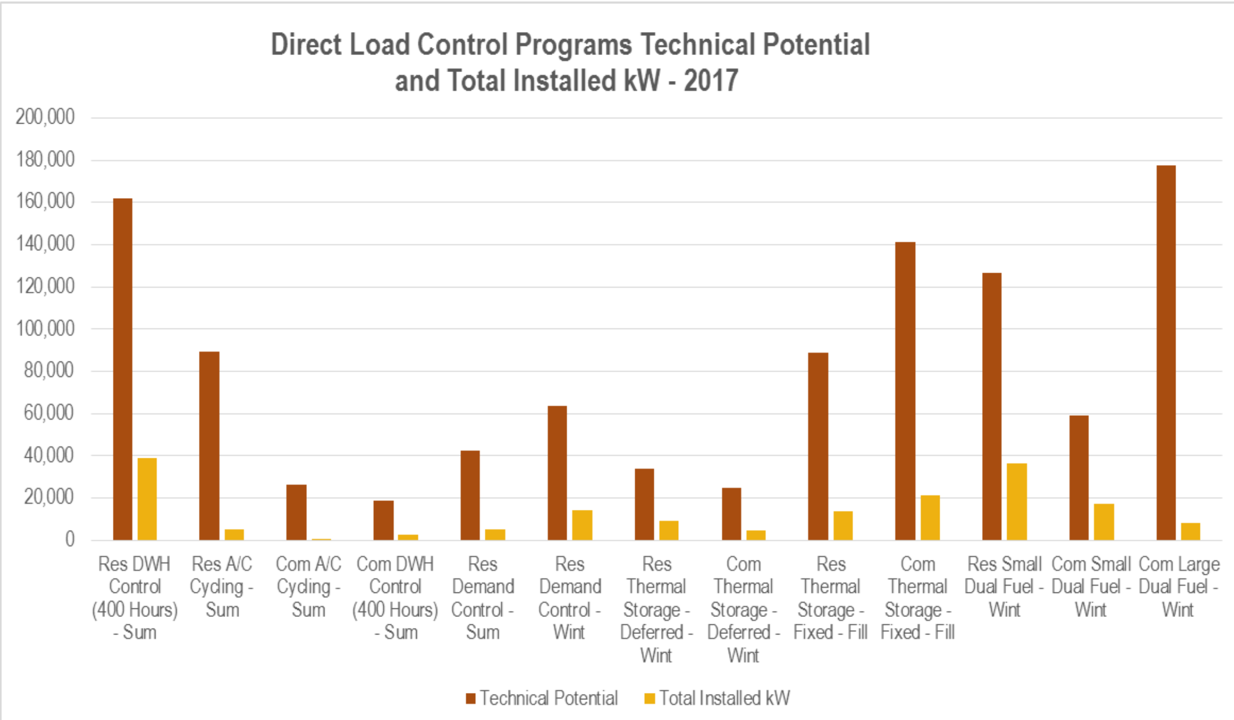
- Winter Load - Deferred Load - Com
- Winter Load - Fixed Time of Delivery - Res
- Winter Load - Fixed Time of Delivery - Com
- Winter Load - Small Dual Fuel - Res
- Winter Load - Small Dual Fuel – Com
- Winter Load - Large Dual Fuel – Com

1.2.1 Technical and Economic Potential

Technical and economic potential are the same size as all of the load control programs have a TRC of at least 1.0. Figure E-7 illustrates the technical/economic potential and total installed kW for controlled loads by program in 2017. On average, the OTP direct load control programs installed kW is about 17% of technical potential. The highest percentage at 29% of technical potential is the commercial sector small dual fuel program. The lowest percentage at 2% of technical potential is the commercial sector A/C cycling program.

The commercial sector large dual fuel program provides the most technical/economic potential at 177.7 MW but control of residential water heaters provides the greatest amount of installed kW at 38.9 MW by 2017. The smallest amount of technical/economic potential at 18.6 MW is provided by the control of commercial sector water heaters and the smallest amount of installed kW at 0.5 MW is from the commercial sector A/C cycling program in 2017.

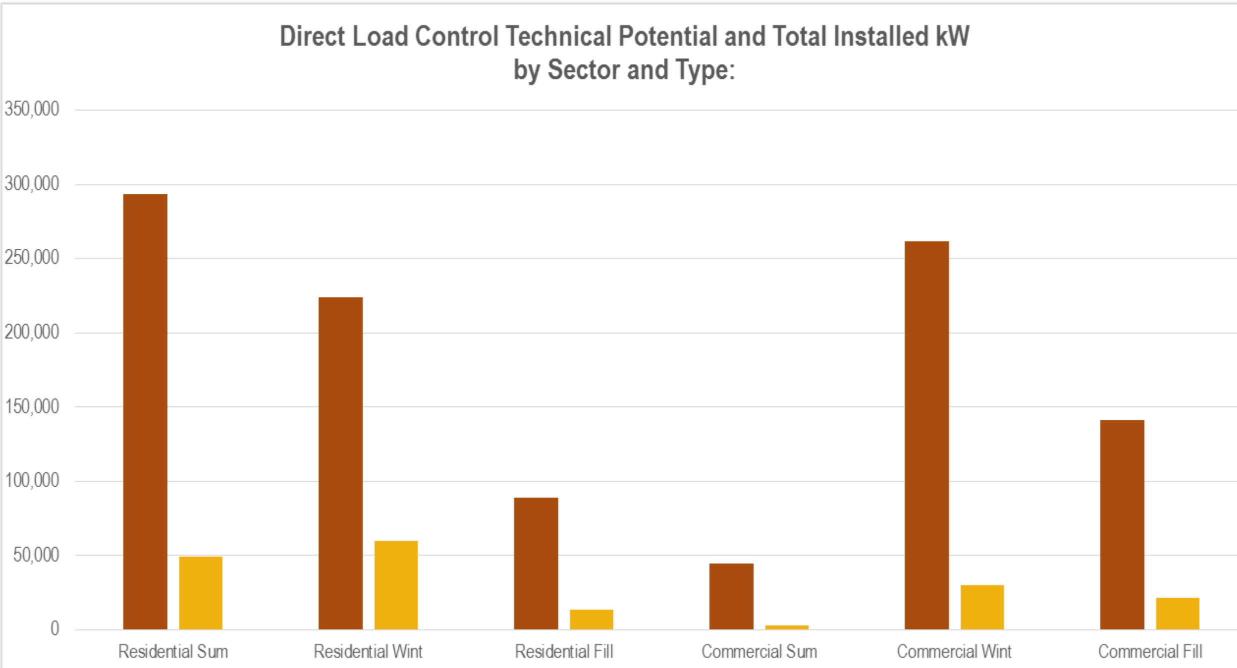
Figure E–7. Installed kW and Technical/Economic Potential for Direct Load Control Programs in 2017



Source: Navigant 2015

Figure E-8 illustrates the 2017 technical/economic and total installed kW for controlled loads by type of program in 2017. The greatest technical/economic potential is from residential summer controlled loads. The largest amount of installed kW is from residential winter controlled loads.

Figure E–8. Installed kW Technical/Economic Potential for Direct Load Control Programs by Sector and Type in 2017



Source: Navigant 2015

1.2.2 Controlled Load Base Results

Figure E-9 illustrates the projected incremental load reduction installed capacity in the years 2017, 2018, and 2019 from residential sector direct load control programs. Included in the figure are projected load reductions for summer load reduction and winter load reduction. Each bar represents an incremental addition to the installed kW by program. For example, for residential A/C cycling, in 2017, the incremental addition to installed kW is 443 kW, followed in 2018 by an additional 472 kW, and in 2019 494 kW. The residential dual fuel program, which provides winter load reduction, provides the largest amount of load reduction installed capacity. A/C cycling provides the second largest amount of load reduction installed capacity with its capacity available in the summer.

Figure E-10 illustrates the projected incremental load reduction installed capacity in the years 2017, 2018, and 2019 from non-residential sector direct load control programs. The non-residential large and small dual fuel programs provide the largest amount of load reduction installed capacity. Each of these programs provides winter peak load reduction potential. A/C cycling provides the largest summer load reduction installed capacity potential.

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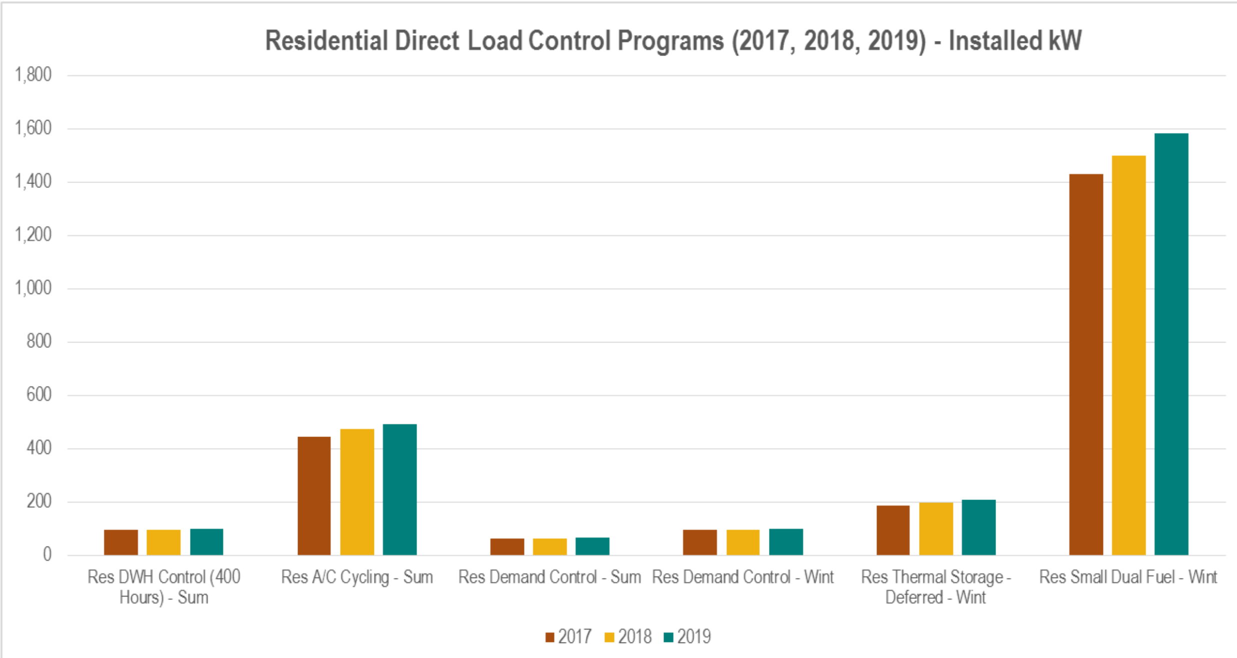
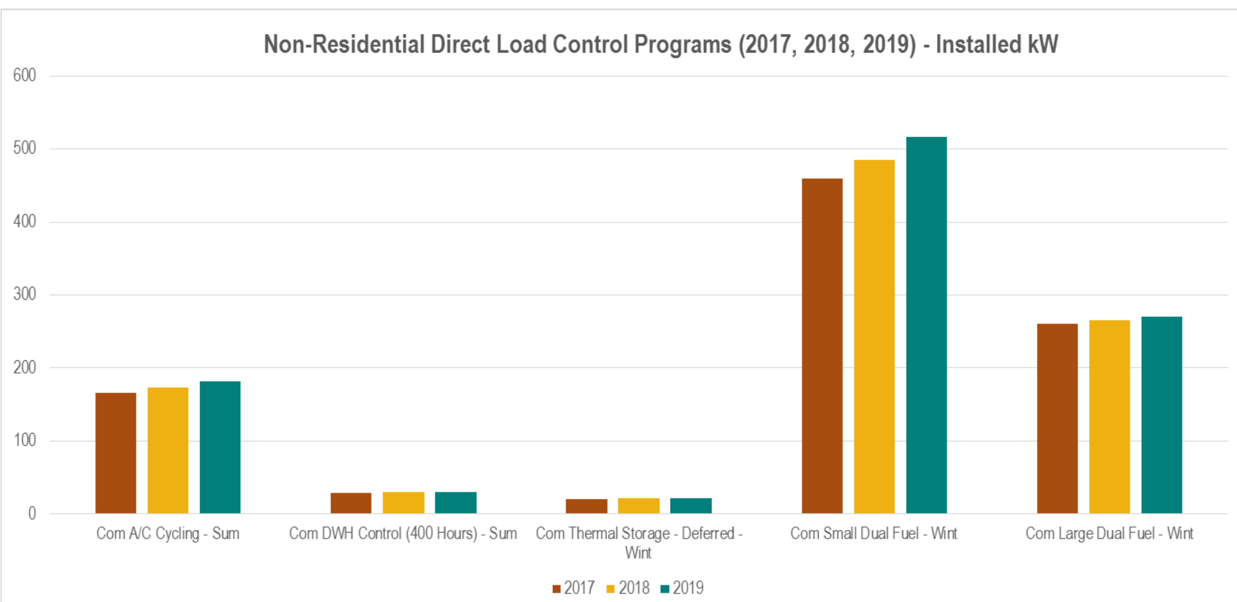
Figure E–9. Residential Direct Load Control Programs (kW Installed)



Source: Navigant 2015

Figure E–10. Non-Residential Direct Load Control Programs (kW Installed)



Source: Navigant 2015

1.2.3 Controlled Load Scenario Results for a 5% Increase and a 10% Increase in Controlled Loads

In addition to the base case, which models the market potential for controlled loads in a "business as usual" condition, Navigant also developed two additional scenarios; one for achieving 5% more and the other 10% more incremental installed controlled load market potential compared to the base scenario. The primary purpose of this exercise is to estimate the additional costs for achieving these high levels of controlled loads. To achieve these goals, the modeling team increased incentives, administrative costs, and program budgets.

The administrator cost (combined administrative and incentive cost) for each scenario is provided in Figure E-11. Table E-5 provides the data illustrated in the Figure. On average, the cost for the 5% scenario is 6.5% greater than the base scenario and for the 10% scenario, 14.1% more than the base scenario. These costs are relatively close to the incremental increases in installed capacity.

Figure E–11. Administrator (Administrative & Incentive) Cost by Scenario

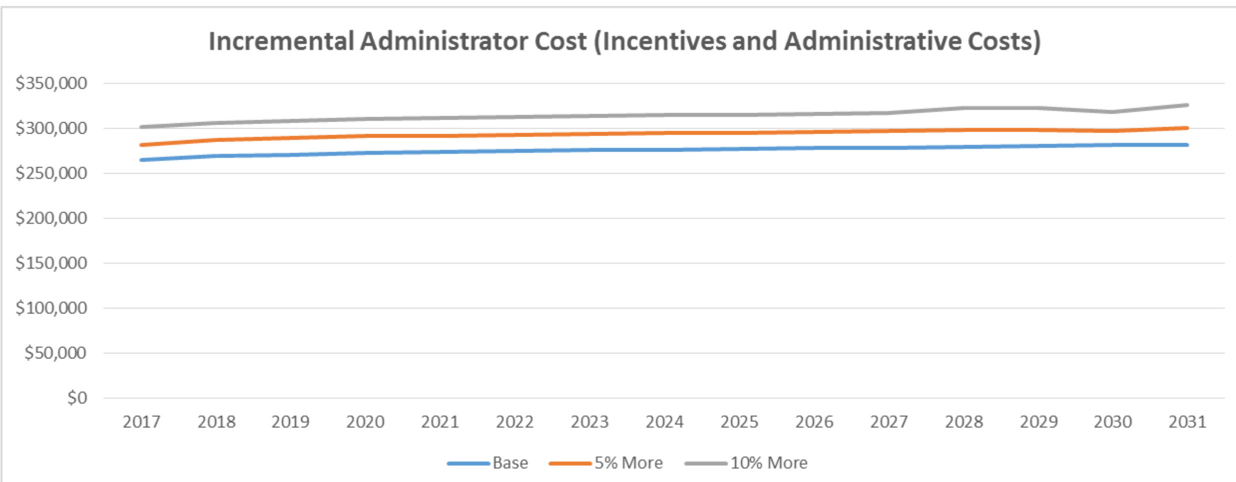


Table E–5. Administrator (Administrative & Incentive) Cost by Scenario

Cost	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Base	$264,566	$269,001	$271,126	$272,984	$273,944	$275,121	$275,818	$276,769	$277,443	$278,311	$279,000	$279,829	$280,546	$281,359	$282,102
5% More	$281,941	$287,092	$289,588	$291,291	$292,042	$293,302	$293,948	$294,960	$295,631	$296,592	$297,285	$298,209	$298,936	$296,863	$300,999
10% More	$302,093	$306,208	$308,673	$310,589	$311,687	$313,040	$313,777	$314,950	$315,622	$316,727	$317,400	$323,090	$323,391	$318,529	$326,418
Cost Increase	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
5% More	6.6%	6.7%	6.8%	6.7%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	5.5%	6.7%
10% More	14.2%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	15.5%	15.3%	13.2%	15.7%

1.3 Findings and Recommendations

This study was conducted to assist Otter Tail Power Company to comply with a 2015 Minnesota Public Utilities Commission order to investigate whether exceeding the 1.5% energy savings requirements in Minnesota would be cost effective. This section summarizes the most important findings and recommendations from this study.

1.3.1 DSM Program Benchmarking

Finding 1. Navigant conducted a DSM benchmarking study which compares Otter Tail's 2013 program results to a group of 14 primarily Midwestern utilities, including the three other electric investor owned utilities (IOUs) in Minnesota. For this group of utilities, Otter Tail's normalized energy savings were the highest, at 1.6% of baseline sales.

Finding 2. Otter Tail's normalized DSM spending was the second largest for this group of utilities at 3.3% of the overall revenues. Otter Tail's normalized costs of conserved energy was 14 cents per first year kWh saved, the median for this group of utilities in 2013.

Finding 3. Navigant found that there were a small number of programs that some of the high performing utilities were conducting that Otter Tail Power was not currently conducting. These included a program targeted towards small business customers that offer larger rebates than the regular commercial EE programs. These programs tend to get most of their energy savings from lighting EE measures.

Recommendation 1. Navigant recommends that Otter Tail conduct DSM benchmarking analyses periodically so that they are aware of how their program savings and costs compare to other Midwestern utilities, and to keep abreast of the latest program offerings.

1.3.2 Baseline Study

Finding 4. Navigant conducted on-site surveys with random samples of 36 residential and 36 commercial and industrial customers. For residential customers, Navigant found that the two most prevalent metrics for customers to make decisions about installing EE measures were lowest first costs, which was reported by 44% of the customers surveyed, and simple payback, which was reported by 33% of the customers surveyed.

Finding 5. For commercial and industrial customers, Navigant found that the two most prevalent metrics for customers to make decisions about installing EE measures were lowest first costs, which was reported by 42% of the customers surveyed, and simple payback, which was reported by 39% of the customers surveyed.

Finding 6. Navigant found that customer awareness of most Otter Tail DSM programs was less than 50%, although customer interest in several Otter Tail DSM program was greater than 50%.

Recommendation 2. Navigant recommends that Otter Tail conduct telephone and/or online surveys with larger samples of residential, commercial, and industrial customers to determine which market segments are most and least aware of and interested in Otter Tail's DSM programs. This information would be useful to help guide Otter Tail's DSM program marketing efforts.

1.3.3 DSM Potential Results

Finding 7. Over the 15 year forecast period (2017-2031), the base case or business as usual energy efficiency (EE) scenario continues Otter Tail's historical spending of about $5 million per year on average in real dollars. Energy savings from this base case scenario decrease from about 40 GWh (about 1.6% of baseline sales) per year in 2017 to about 20 GWh per year (about 0.6% of baseline sales) in 2031, primarily due to increased energy efficiency codes and standards, and the increasing saturations of EE measures over time. This scenario costs about 15.6 cents per first year kWh saved.

Finding 8. Over the 15 year forecast period (2017-2031), the scenario that conserves 1.5% of baseline sales per year is projected to cost about $180 million in real dollars, about 2.4 times the cost of the base case scenario. This amounts to about 24.6 cents per first year kWh saved.

Finding 9. Navigant developed five additional scenarios that conserve between 1.6% of baseline sales and 2.0% of baseline sales. These scenarios cost between $195 million and $295 million in real dollars over the forecast period, which amounts to between 25.2 cents per kWh saved and 31 cents per kWh saved.

Recommendation 3. The optimal DSM scenario from an economic perspective should be determined based on Otter Tail's integrated resource planning (IRP) analysis. The scenario that produces the lowest present value of revenue requirements including environmental externalities should be selected based on Otter Tail's IRP analysis.

2. Introduction

Demand Side Management (DSM) is the planning and implementation of programs and services that help and encourage customers to use electricity as efficiently as possible. DSM represents an important resource for Otter Tail Power as fuel and commodity prices become more volatile and greenhouse gas regulation evolves. Estimates of DSM potential are a key input to the integrated resource planning process, which considers the load forecast and both supply- and demand-side resources, and also the Conservation Improvement Program (CIP) process. This study presents the results of an analysis of the DSM potential in Otter Tail Power's Minnesota service area, conducted by Navigant Consulting, Inc.

2.1 Overview of Otter Tail Power's Electricity Market

Otter Tail Power (OTP) is a mid-sized utility in Minnesota, with about 50,000 residential/farm customers and over 10,000 commercial and industrial customers. Total peak demand in 2015, including pipelines, is about 1,050 MW. Overall, the forecasted demand including pipelines in Minnesota exceeds 1,400 MW by 2031. Annual energy sales in Minnesota, including pipelines, in 2015 are 2,445 GWh/year including losses. Projected energy sales including pipelines reach 3,112 GWh/year by 2031.

In 2014, Otter Tail Power spent about $4.7 million on CIP programs to achieve total annual electricity savings of about 34 GWh.

2.2 Study Goals and Approach

The overall goals of this DSM potential study are to assess the technical, economic, and achievable potential for the residential and commercial/industrial sectors for the timeframe of 2017-2031. Navigant also identifies OTP's costs under a base case model run, and six additional scenarios cases designed to reach DSM goals of 1.5% to 2.0% of utility sales in 0.1% increments.

OTP tasked Navigant with estimating the DSM potential across the Minnesota service territory by:

- Conducting primary field data collection from a representative sample of OTP customers, both residential and C&I
- Conducting a DSM benchmarking and best practices analysis to guide the potentials estimation
- Utilizing targeted electric energy efficiency measures from the Minnesota TRM, supplemented by additional measures in which OTP is interested in assessing
- Conducting benefit-cost analysis of the selected measures
- Estimating electricity DSM potentials
- Assessing direct load control measures

2.3 Organization of Report

Chapter 3 summarizes the study methodology. Chapter 4 discusses the sampling methods used to select the sampled sites for the on-site survey. Chapter 5 reviews the measures utilized in the study. Chapter 6 provides discussion of benchmarking and best practice results. Chapter 7 presents the DSM potential analysis methodology and results.

3. Methodology

The study method combined primary data collection with best-practice benchmarking to analyze a selected set of key energy efficiency and direct load control measures from the 2014 Minnesota Statewide Technical Reference Manual (MN TRM), plus a supplemental set of measures from OTP's own TRM. [1]

The modeling team utilized the Electric Resource Assessment Model (ELRAM) developed by Navigant Consulting to estimate the DSM Potential estimates. The model is a stock/flow Excel spreadsheet model based on the integration of energy efficiency measure impacts and costs, utility customer characteristics, utility load forecasts, and utility avoided costs and rate schedules. ELRAM utilizes Excel as the modeling platform due to the transparency in the DSM potential estimation process, and because of the ubiquitous knowledge of the platform in general. Excel also allows the team to customize ELRAM to accommodate the client's unique set of input characteristics and utility data.

The model utilizes a "bottom-up" approach, beginning with study area building stocks, equipment saturation estimates, forecasts of building stock decay and new construction, energy efficiency technology data, past energy efficiency program accomplishments, and decision maker variables that influence the program scenarios. The study approach to estimating OTP energy conservation potential relied on four key data inputs:

1. The current saturations of electric energy efficiency measures in statistically representative samples of OTP residential and commercial/industrial facilities
2. Information on energy efficiency measures' energy and demand savings, costs and lifetimes, from the MN TRM, along with a supplemental set of measures from OTP's TRM
3. Information from OTP on the characteristics of their direct load control strategies
4. Actual energy savings achieved by OTP programs in 2014 for use in calibrating market potential results

The model utilizes these inputs to develop estimates of technical, economic, and market potential. Figure 1 illustrates these types of energy conservation potential, as defined below:

Technical Potential. ELRAM calculates technical potential as the product of a measure's savings per unit, the quantity of applicable units in each facility, and the number of facilities in a utility's service area. This potential savings assessment includes measures that may not be cost-effective, and therefore provides an upper bound of efficiency potential regardless of cost or market penetration. For measures considered to replace inefficient measures on burnout (ROB), the quantity of applicable units per year is limited to the number that need to be replaced, which is determined by measure life. As time passes, this potential population grows until meeting the full measure life. For non-ROB measures all baseline units are available.

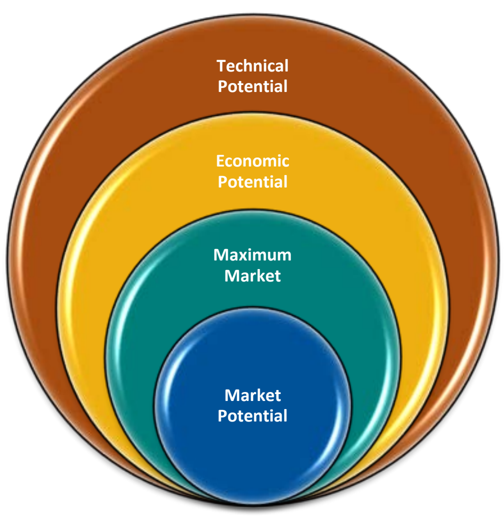
[1] Navigant used the 2014 MN TRM as the 2015 version was incomplete at the time of this potential study.

Economic Potential. ELRAM estimates economic potential as the amount of technical potential that is cost-effective, as defined in this case by the results of the Total Resource Cost (TRC) test. The TRC test is a cost-benefit analysis of relevant energy efficiency measures, excluding market barriers such as lack of consumer knowledge. Benefits include the avoided costs of generation, transmission and distribution investments, avoided fuel costs, and other benefits that may accrue to participants and/or to the utility. Costs vary by economic test but may include incremental technology cost, incentives, administrative costs, and/or lost revenue. The economic screen is set to 1.0 to determine Economic Potential. ELRAM treats ROB measures the same as with technical potential

Maximum Market Potential. ELRAM screens the amount of economic potential that utility programs *could* capture over the forecast period. The measure level economic screening value for maximum market potential can be set to less than 1.0, but results at the program level must have an overall economic screen of 1.0 or better. This allows the program to include a mix of measures above and below the 1.0 screening threshold. For OTP, the economic screen for market potential is set to 0.75. This adjustment factor can vary by program. In addition to the economic screening value, maximum market potential includes the effects of decision maker awareness of each measure and if aware, their willingness to install the measure.

Market Potential. ELRAM uses a fourth step for calculating achievable energy savings at the market level using simple payback elasticity. The achievable market potential uses the remaining maximum market potential at the measure level available each year and applies a decision maker simple payback elasticity coefficient to identify yearly savings available in the marketplace. The model calculates this payback elasticity based on historical program achievements and the identified incentive levels by measure. This step provides realistic forecasts of market potential given incentive and program budget levels, which can change over the forecast period.

Figure 1. Diagram of Types of Energy Efficiency Potential



Source: Navigant 2015

Navigant calculated seven market potential scenarios: one base case scenario and six goal scenarios ranging from 1.5% of sales to 2.0% of utility sales in 0.1% increments. The modeling team achieved each of these market potential estimates by adjusting both incentive levels and overall program budgets.

3.1 Approach to Estimating DSM Potential

ELRAM utilizes "Measure Payback Response Curves" to calculate market potential by year. The method for creating these curves comes from the methodology used for the Bass Diffusion Model developed by Dr. Frank Bass. The Bass Diffusion Model describes the process of the adoption of products as an interaction between users and potential users.

The decision maker function estimates a measure's elasticity response to first cost measure payback calculated in the base calibration year. This base year uses measure-level utility program achievements and first cost measure payback. First cost measure payback does not include any savings from extended measure life of changes in maintenance costs. Utilizing this elasticity based decision process allows the model to create scenario options based on changes to measure level incentives. In addition, ELRAM includes other input variable flexibilities to allow for a number of different scenario considerations including program budget levels and program promotion costs.

3.2 Model Structure and Flow

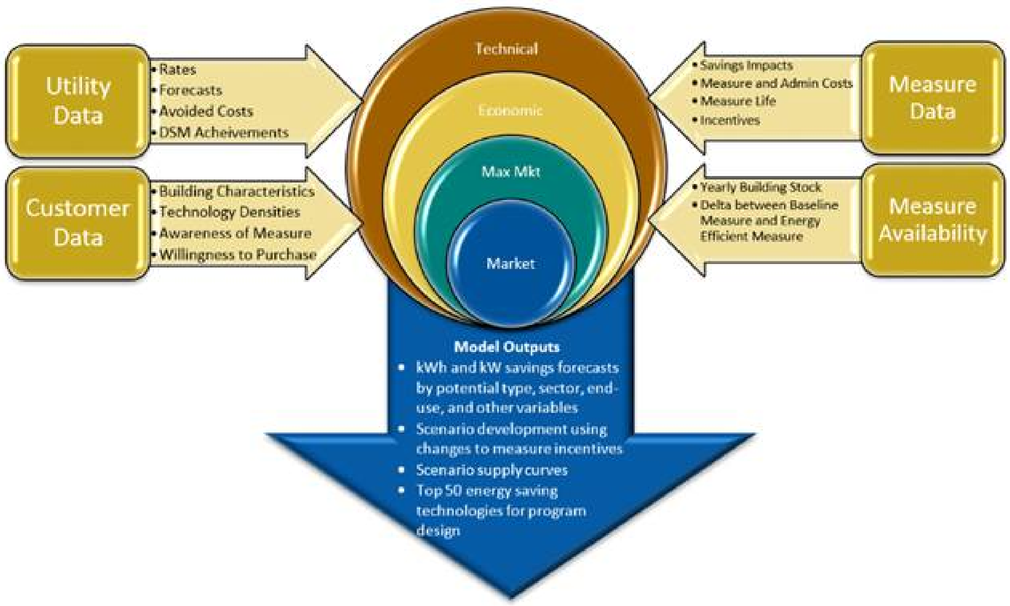
ELRAM includes nearly 40 distinct worksheets including input, calculation, and output pages, as well as a Scenario Dashboard that offers modelers a quick way to interact with the model and produce different scenario runs. The variables available on the dashboard include:

- Economic test screens
- Beyond first measure life considerations
- Fiscal variables including:
    - Incentive level
    - Administrative costs
    - Program budget limitations

There is also an "output viewer" connected to the results of the model which allows OTP to view potential savings estimates in a variety of ways. Navigant will provide these tools to OTP at the conclusion of the study.

Figure 2 provides a general overview of the data flow through the ELRAM model. The model structure can vary from client to client depending on available data and output needs.

Figure 2. ELRAM Data Flow Overview



Successful potential savings forecasts rely on high quality and accurate data inputs into ELRAM. These inputs fall into four categories including:

- **Utility Data.** Navigant worked closely with OTP to gather all utility specific data such as avoided costs, energy (kWh) and demand (kW) forecast estimates, past program savings achievements for use in calibrating ELRAM, customer rate classes, and discount rates.
- **Customer Data.** Navigant conducted onsite audits of a sample of residential and non-residential buildings across OTP's service territory.[2] These audits provided data on end-use saturations and technology densities, as well as customer awareness and willingness values.
- **Measure Data.** The Navigant modeling team reviewed the MN TRM, and OTP's supplemental TRM to characterize the measures included in this study. These characteristics include costs, energy and demand use impacts, and measure life for both baseline and energy efficient technologies.[3]
- **Measure Availability.** ELRAM uses building stock inputs along with the availability of technology density each year to estimate potential energy savings throughout the forecast period.

The outputs from ELRAM accomplish multiple objectives, including:

[2] See the Baseline Building Characteristics section for more on the onsite audit methodology.
[3] See the DSM Measure Characteristics section for more on measure level variables used in ELRAM.

- Determining the total technical, economic, and market potential of energy savings available over the forecast period, both annually and cumulatively; the model calculates these potential estimates at the sector, building type, program type, and end-use classification levels
- Providing guidance for a utility's next energy efficiency goals at an aggregate level, as well as at the measure category level, where appropriate; ELRAM calibrates calculations to past utility achievement levels to ensure continuity with past utility efforts
- Identifying cost-effectiveness using multiple cost effectiveness tests
- Identifying specific costs and benefits, including administrative, incentive, and technology costs, along with avoided cost and reductions in other resource requirement benefits (such as water use reduction)

The DSM Potentials Results section provides the full set of ELRAM outputs OTP requested for this potential study.

4. Baseline Building Characteristics

Navigant conducted onsite-visits of a targeted representative sample of OTP's Conservation Improvement Program (CIP)-eligible residential and non-residential customers in an effort to collect building characteristic data for input into ELRAM. The model uses a number of key inputs including—among others—saturations of electric versus gas space heat and water heat, the density of inefficient technologies, and the density of existing energy efficient technologies. To obtain these building characteristics and create the model "baseline," Navigant performed on-site surveys for a statistically significant number of OTP residential (36), and non-residential sectors (36) at a confidence of 90 percent and +/- 15 percent margin of error for each sector. This section provides the steps Navigant took to create a representative sample of OTP buildings, gather the building characteristic data onsite, and ensure all onsite data flowing into ELRAM was quality controlled and accurate.

4.1 Stratified Ratio Estimation

Navigant used a "stratified ratio estimation" method—which combines a stratified sample design with a ratio estimator—to achieve a sample of residential and non-residential buildings at a 90/15 confidence and precision (CP). Both the stratification and the ratio estimation steps take advantage of supporting information available for each project in the population. For OTP customer accounts, the supporting information Navigant used is energy use per account.

The customer population data provided by OTP contains a large number of accounts with low energy use and a small number of accounts with high energy use. This disproportion causes simple random sampling methods impractical or inaccurate. Navigant mitigates this issue by using the energy use per account as a stratification variable. Stratifying by the energy use generally reduces the coefficient of variation of actual savings in each stratum thereby improving the statistical precision. The sampling fraction also varies from stratum to stratum to further improve the statistical precision. In particular, accounts with small energy use represent a relatively small sample of their total accounts, but the sample will include a higher proportion of the projects with larger levels of energy use. For OTP, a large percentage of the very highest energy using customers are included in the sample.

4.2 Treatment of Customer Dataset

Navigant utilized the OTP customer dataset to create a master population dataset drawing the final samples taking the following steps:

- Segmenting the dataset into residential and non-residential accounts
- Removing all "0" and negative value accounts
- Identifying all unique "DIV-ACCTNO" numbers
- Aggregating—when appropriate—all meters associated with each "DIV-ACCTNO"

4.3 Residential Sample Draw

There were 51,427 non-zero residential meters within the original OTP customer dataset. Of these, there were 38,536 unique meters split into two revenue classes. These 38,536 unique meters were rank ordered by kWh sales and Navigant employed the stratified ratio sampling technique utilizing three sales-based strata. Setting the statistical validity at 90% confidence and +/- 15% precision, the final sample consisted of 36 homes; 12 from each stratum. In addition to including 12 homes from each stratum, consideration was also made to maintain the split of the two revenue classes (class 1 = electric space heat and class 2 = non-electric space heat) within each stratum. This split varied by stratum:

- Stratum 1 (high energy users) – 30% Class 1
- Stratum 2 (medium energy users) – 19% Class 1
- Stratum 3 (lower energy users) – 9% Class 1

4.4 Non-Residential Sample Draw

Navigant further defined the non-residential population master dataset by:

- Translating the NAICS to commercial building types and industrial classifications
- Removing Pipeline, Mining, and Utility Generation & Transmission from the population
- Identifying the commercial building types with the most sales
- Identifying four commercial sector sampling segments based on sales and one industrial segment
- Placing all of the accounts into one of these five sampling segments, including:
    - COM-Education
    - COM-Health
    - COM-Grocery
    - COM-Other
    - IND
- Aggregating all the meters associated with each "DIV-ACCTNO"
- Ranking all C&I accounts by annual kWh within each sampling segment
- Setting the statistical validity at 90% confidence and +/- 15% precision for the entire non-residential sector
- Setting the statistical validity at 80% confidence and +/- 25% precision within each of the five building type segments
- Applying an annual kWh sales stratification variable with two stratum per segment

Based on these steps and assumptions, the final sample draw was seven per stratum for a total of 35 sites in the non-residential sector, however the team actually visited 36 sites.

4.5 Fieldwork Activities

Navigant used the sample of representative residential and non-residential customers to conduct field visits and complete the Building Energy Characteristics Onsite Survey Form (onsite survey) at each visited site. This onsite survey characterizes all of the energy using technologies at a site for use in the ELRAM model. The field survey work comprised of recruiting and scheduling customers, conducting the onsite surveys, uploading the surveys to the quality control team, and delivering a gift card incentive to participating customers. Navigant performed these tasks from May through August, 2015, with the residential on-site surveys performed from mid-June through early July and the non-residential surveys performed in July. The fieldwork team comprised of two primary surveyors, a qualified recruiter, and an assistant available for data enumeration for many of the larger surveys.

The activities began with sector-specific recruiting letters sent to the pool of prospective residential and non-residential candidates under OTP letterhead and signed by OTP's project manager. The study offered a $100 gift card as a participation incentive. The team sent the residential letter in two geo-sorted waves to help minimize surveyor travel, as this sector has a greater "spread" across the OTP service area than the non-residential sector. A couple of days after sending the recruitment letter, Navigant staff followed up with a direct telephone call to prospects in the survey pool, to gauge participation interest and to schedule the onsite visits. Scheduling visits typically took only one or two contact phone calls. Many OTP customers took it upon themselves to contact Navigant and volunteer participation. Overall, the study achieved a high response rate—more than 90% of those contacted, participated (see Table 1 and Table 2).[4] Navigant's recruiting/scheduling staff tracked progress each day to manage stratum quotas and ensure timely delivery of the incentive gift cards. This study's recruiting and scheduling process proved to be one of the most successful efforts Navigant has undertaken to date.

Table 1. Residential Survey Sample Results

Scheduled Quotas									
Stratum Type - Revenue Class	Total Available	Maximum Needed	Scheduled	Visit Done	Remaining Needed	Passed	In Progress	Never Called	Scheduled or Visit Done
Strata #1 - 1	21	3	0	3	0	2	4	12	3
Strata #2 - 1	13	1	0	1	0	0	0	12	1
Strata #3 - 1	26	1	0	1	0	4	11	10	1
Strata #1 - 2	49	9	0	9	0	2	24	14	9
Strata #2 - 2	56	11	0	11	0	13	32	0	11
Strata #3 - 2	63	11	0	11	0	6	32	14	11
Totals	228	36	0	36	0	27	103	62	36

Source: Navigant 2015

[4] The C&I sample achieved one more site visit than the sample quota called for due to the project policy of surveying all customers scheduled. This stratum ended up with one more site scheduled than required.

Table 2. Commercial & Industrial Survey Sample Results

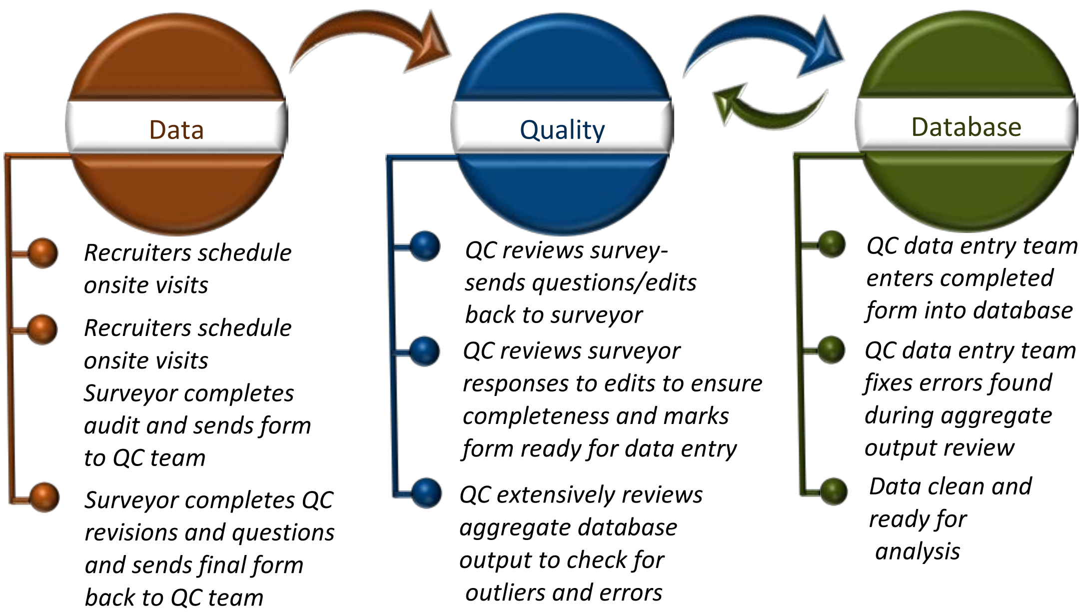
Scheduled Quotas									
Stratum Type	Total Available	Maximum Needed	Scheduled	Visit Done	Remaining Needed	Passed	In Progress	Never Called	Scheduled or Visit Done
Strata #1 - Education	28	4	0	4	0	0	5	19	4
Strata #2 - Education	31	3	0	4	-1	0	5	22	4
Strata #1 - Grocery	28	3	0	3	0	1	1	23	3
Strata #2 - Grocery	28	4	0	4	0	0	3	21	4
Strata #1 - Health	29	4	0	4	0	1	2	22	4
Strata #2 - Health	29	3	0	3	0	1	6	19	3
Strata #1 - Industrial	29	3	0	3	0	1	6	19	3
Strata #2 - Industrial	29	4	0	4	0	1	11	13	4
Strata #1 - Other	29	4	0	4	0	0	0	25	4
Strata #2 - Other	31	3	0	3	0	1	1	26	3
Totals	291	35	0	36	-1	6	40	209	36

Source: Navigant 2015

The time to complete residential surveys was typically about 2 hours, while non-residential surveys varied from 2 hours to a full day. The largest sites required both surveyors onsite to complete the onsite survey in a single day. Each surveyor displayed clear badge identification and carried credentials to validate identity with OTP and the project. Only one customer complained that the survey took longer to complete than expected. At the end of each survey, the customer received a “FAQ” sheet regarding the project and included contact information should they wish to discuss any aspects of the study with OTP or Navigant. The field staff also sent out the gift cards typically one business day after completion of the survey.

The field staff then uploaded the completed onsite surveys onto Navigant's data storage site and alerted the quality control (QC) team. The QC team reviewed the onsite surveys for quality and engaged in back-and-forth communication with field staff to answer any questions. Figure 3 shows the entire onsite data gathering process flow and QC check.

Figure 3. Data Collection and Quality Control Process Flow



Source: Navigant 2015

4.6 Building Characteristic Data Analysis

Navigant utilized the data collected onsite to develop density values for each measure included in ELRAM, as well as for saturation estimates of baseline and efficient measures. A "density value" includes the number of measures or technology units per a common scaling metric. The residential common scaling metric is per home, while the typical non-residential common scaling metric is per 1,000 square feet of building floor area. The model requires three relevant density values, all derived from the onsite surveys: the baseline density, efficient density, and the total maximum density. The total maximum density is the total number of units installed within a home or per 1,000 square feet of non-residential floor space. For example, in the context of residential lighting, the total number of light bulb sockets in a home would be the total maximum density for screw-in lighting measures such as CFLs and LEDs. The baseline and efficient densities are the saturation of the baseline and efficient technologies.[5] Continuing the residential lighting example, the base density for a CFL lighting measure would be the average number of incandescent bulbs per home and the efficient density would be the number of efficient bulbs already installed.

[5] See the DSM Measure Characteristics section for more on the baseline and efficient technologies included in this study.

Table 3 provides the specific variables included in the onsite survey used to inform the densities for each of the technologies included in this study.

Table 3. Residential On-Site Survey Variables Used in Measure Characterization

Residential End-Use	Survey Variables
All End-Uses	% of homes with electric space heat % of homes with electric hot water
Appliances and Plug Loads	Clothes Washer Count and % Energy Star Dishwasher Count and % Energy Star Refrigerator Count and % Energy Star Freezer Count and % Energy Star
Domestic Hot Water	Electric Water Heater Count Heat Pump Water Heater Count % of WH with low Set Point (<120F) % of WH with Jacket Insulation % of WH with Pipe Insulation Faucet Count and % with Aerators Showerhead Count and % Low Flow
HVAC	Total Cooling Capacity in Tons by SEER Level *(Central AC, ASHP, and Room AC)* Geothermal Heat Pump Count Furnace Count and % with ECM motor Dehumidifier Count and % Energy Star Ceiling Fan Count and % Energy Star % of Homes reporting HVAC Tune-ups % of Homes Participating in AC Cycling Program
Envelope	% of Homes with Electric Space Heat % of Homes with Wall Insulation % of Homes with Roof Insulation % of Homes with Poor Weather Stripping
Lighting	Total Screw-in Sockets per Home *% Incandescent, CFL and LED* Total Hardwired Fixtures per Home *% Incandescent, CFL and LED* Torchiere Count per home

Source: Navigant 2015

Table 4. C&I On-Site Survey Variables Used in Measure Characterization

C&I End-Use	Survey Variables
All End-Uses	% of floor area with electric space heat % of floor area with electric hot water
Plug Loads	Desktop Computer and Server Counts and % High Efficiency Vending Machine Count and % with Auto Shutoff
Cooking	Combination Oven (Elec) Count Convection Oven (Elec) Count Electric Griddle Count Oven and Range (Elec) Count Electric Steamer Count
Domestic Hot Water	Electric Water Heater Count and % HE Heat Pump Water Heater Count Faucet Count and % with Aerators Pre-Rinse Sprayers Count and % Low Flow
HVAC	Average Cooling Capacity in Tons by SEER Level per 1,000 sq. ft. *(Broken out by Central AC, ASHP and PTAC)* Geothermal Heat Pump Count % of AC Units with Economizer Count of HVAC Fans Average Chiller Tonnage % of Floor Area Participating in AC Cycling Program
Motors	Average Total HP of All Motors % with VSD
Lighting	Total Screw-in Sockets per 1,000 sq. ft. *% Incandescent, CFL and LED (Indoor and Outdoor)* Total Hardwired Fixtures per 1,000 sq. ft. *% Incandescent, CFL and LED (Indoor)* Total Linear Fluorescent Fixtures per 1,000 sq. ft. *% T12, T8, Low Wattage T8, T5, and LED (Indoor)* Total HID Fixtures per 1,000 sq. ft. *(Indoor and Outdoor)* Total Outdoor LED Fixtures per 1,000 sq. ft. % of Lighting Load Connected to Occupancy Sensors Total Exit Signs per 1,000 sq. ft. *% Incandescent, CFL and LED/LEC*
Refrigeration	Walk-in Cooler Count and % with ECM Display Case Count and % with ECM Display Case Number of Doors and % with ASH Controls Refrigerator and Freezer Counts and % with Glass Doors Display Case Lighting Lamp Total and % LED
Compressed Air	Air Compressor Count Air Compressor Total HP per 1,000 sq. ft. % of HP with VSD

Source: Navigant 2015

4.7 Decision Maker Surveys

Navigant also conducted a decision maker survey as part of the onsite survey effort. The decision maker survey probed customer understanding regarding:

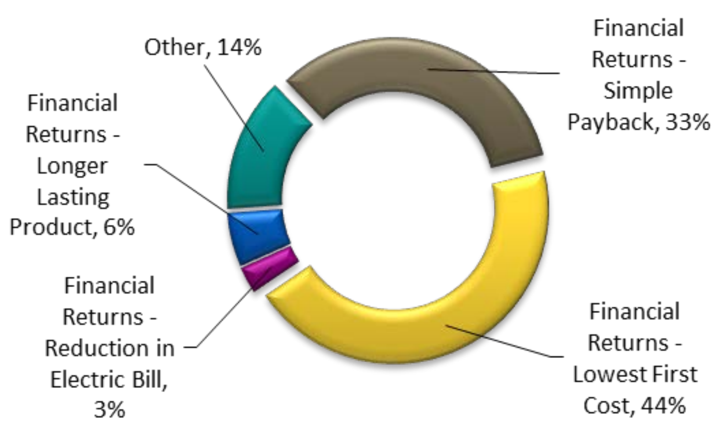
- Decisions about purchasing energy efficient technologies including, awareness of the efficient technology, barriers to installing the efficient technology, and motivations for purchasing the efficient technologies
- Awareness of OTP offered incentive programs and their willingness to participate in these programs

The following sections provide the results of the decision maker surveys for the residential and non-residential sectors.

4.7.1 Residential Results

Figure 4 shows the results of the residential purchasing decisions regarding energy efficient technologies. As illustrated, 86 percent of customers have financial considerations in mind when choosing efficient technologies. The "other" 14 percent of participants mentioned such things as being resistant to change, having a lack of interest in energy efficiency, and valuing comfort over efficiency.

Figure 4: Residential Purchasing Decisions around Energy Efficiency

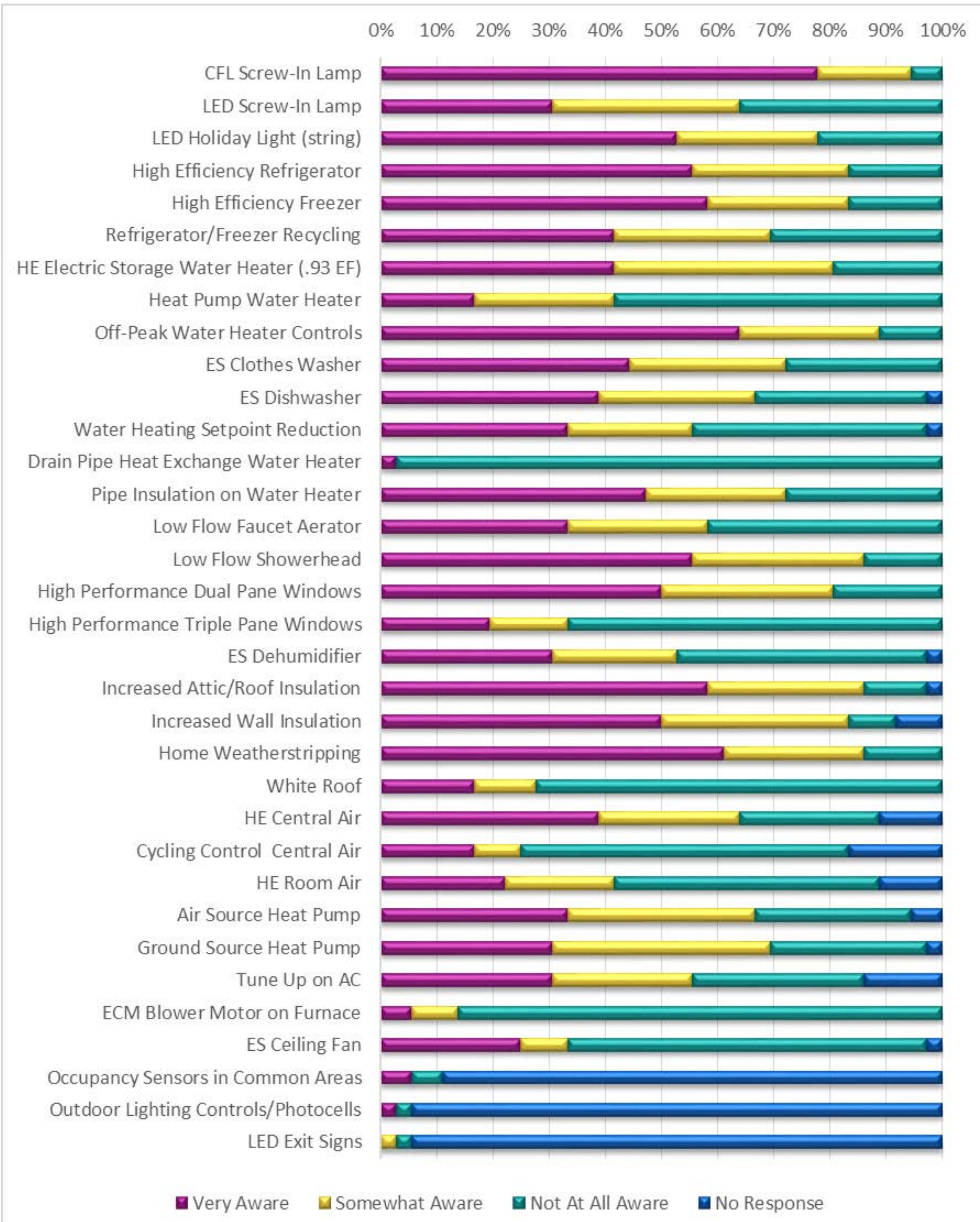


Source: Navigant 2015

Navigant also asked customers about their awareness in general of many energy efficient technologies. Obviously, a major barrier to improving energy efficiency is ensuring customers are aware that a better option exists.

Figure 5 shows the results of customer awareness as a percentage of the 36 participants. The responses ranged from Very Aware of a technology, to Not At All Aware.

Figure 5: Customer Awareness of Energy Efficient Measures – Residential



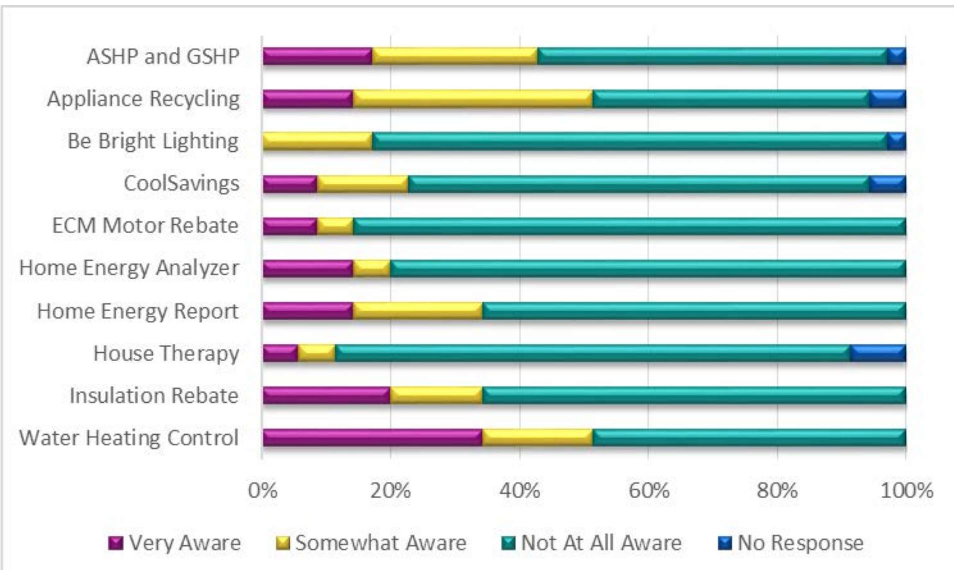
Source: Navigant 2015

The decision maker survey also included questions probing customer *awareness of* and *interest in* OTP's portfolio of efficiency programs. The program offerings at the time of the survey included:

- Air Source Heat Pump Upgrades
- Appliance Recycling
- Be Bright Lighting
- CoolSavings
- ECM Motor Rebate
- Home Energy Analyzer
- Home Energy Report
- House Therapy
- Insulation Rebate
- Water Heating Control

Figure 6 shows the customer awareness of each program as a percentage of the 36 surveyed customers.

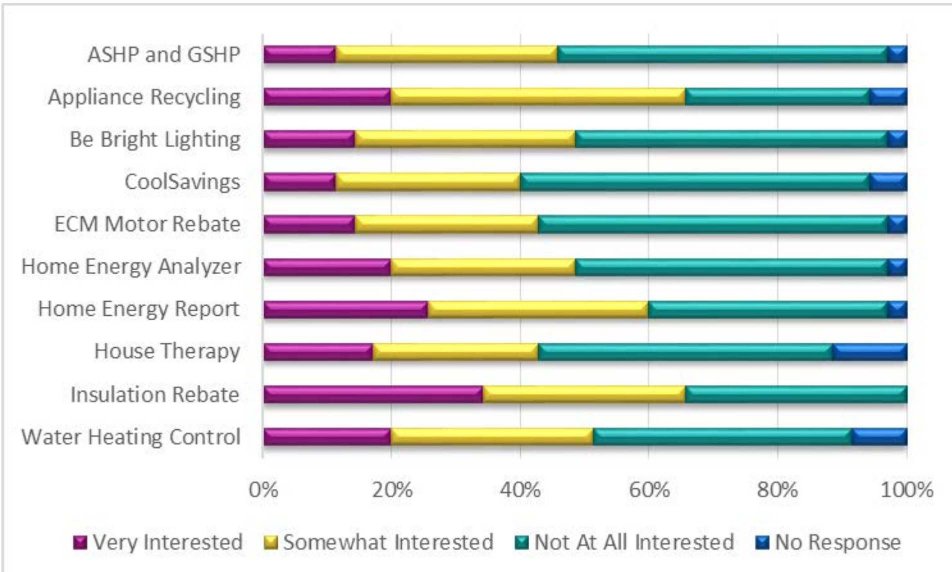
Figure 6: Customer Awareness of OTP Programs – Residential



Source: Navigant 2015

Navigant also asked customers if they had any interest in participating in OTP efficiency programs going forward. Figure 7 shows these results as a percent of the 36 surveyed customers.

Figure 7: Customer Interest in OTP Programs – Residential

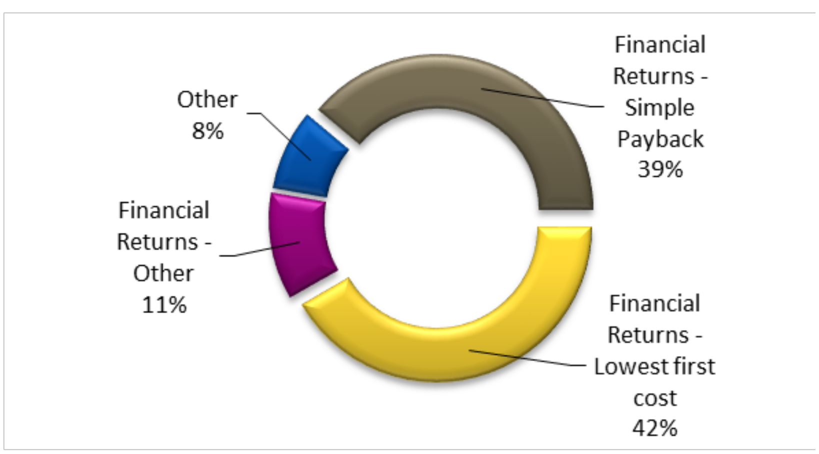


Source: Navigant 2015

4.7.2 Non-Residential Results

Figure 8 provides the purchasing decision results for the non-residential sector. Similar to the residential sector, the vast majority of respondents (92%) mentioned financial considerations as the primary driver for purchasing efficient technologies. The "other" 8 percent said that efficiency and conservation alone were enough to convince them to pursue energy efficiency.

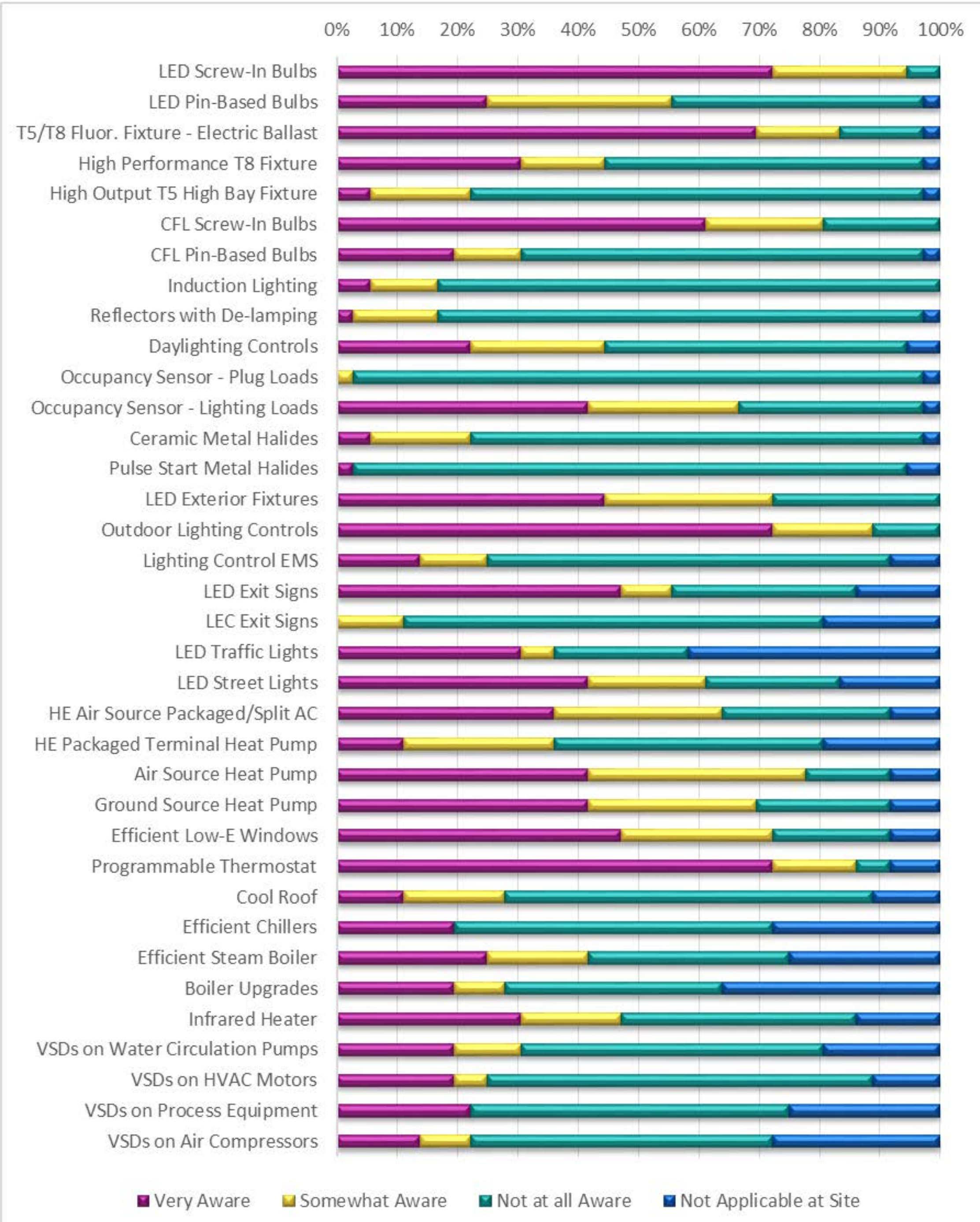
Figure 8: Non-Residential Purchasing Decisions around Energy Efficiency



Source: Navigant 2015

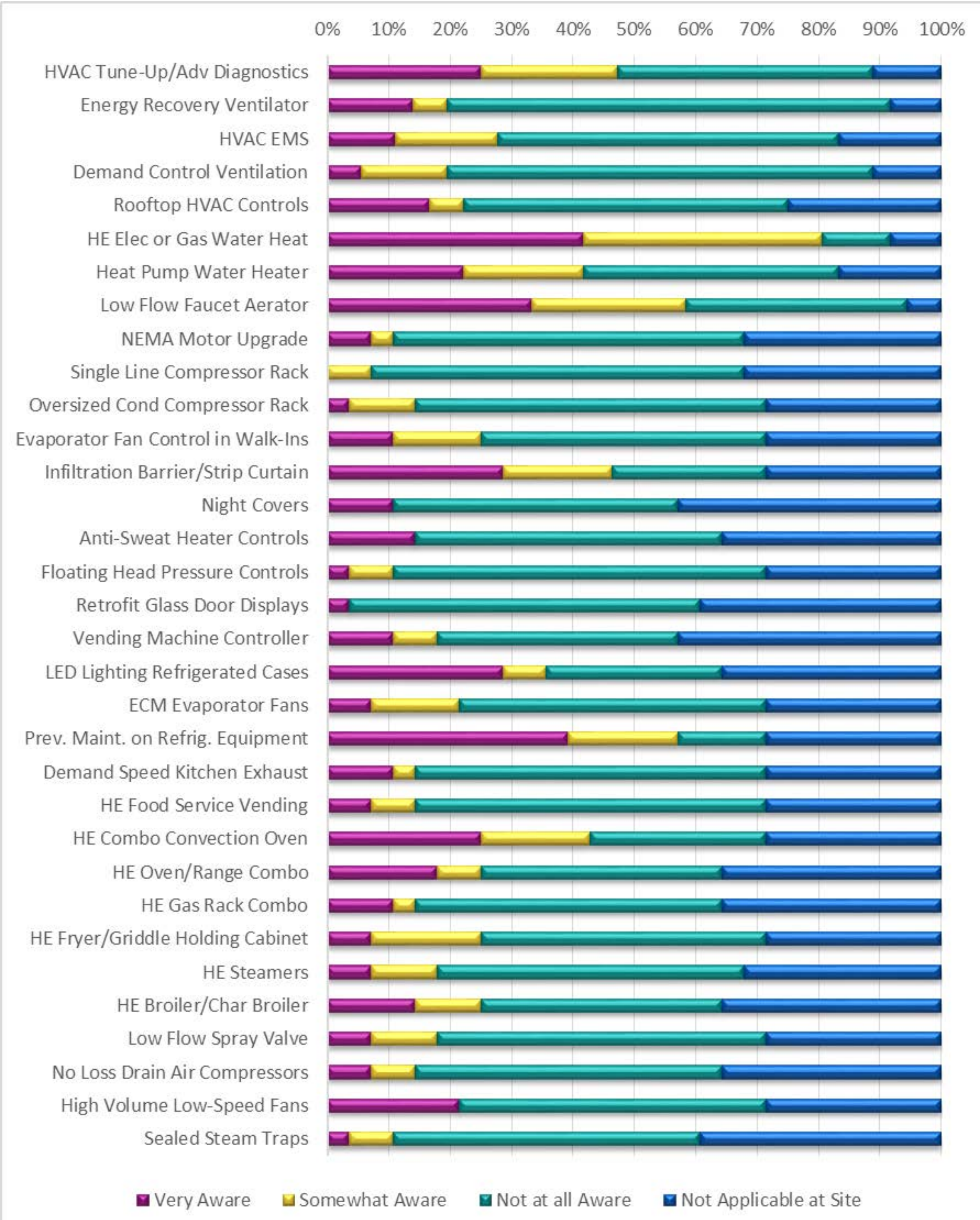
Figure 9 and Figure 10 show the customer awareness results for a list of technologies installed in the non-residential sector. The scale ranges from "very aware" to "not at all aware".

Figure 9: Customer Awareness of Energy Efficient Measures – Non-Residential (1)



Source: Navigant 2015

Figure 10: Customer Awareness of Energy Efficient Measures – Non-Residential (2)



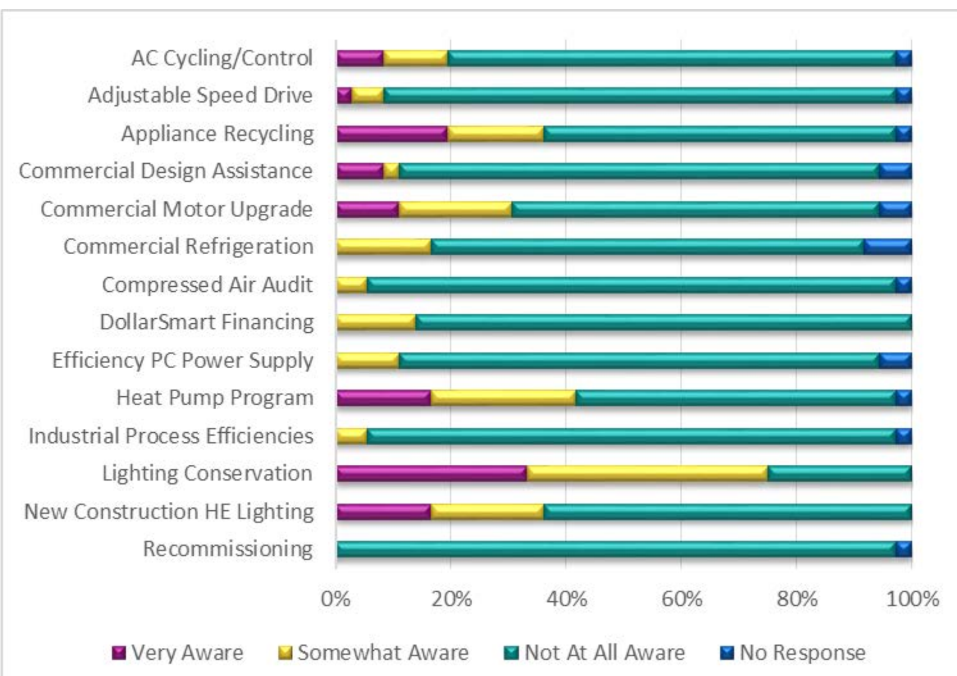
Source: Navigant 2015

Navigant also probed participants as to their awareness and interest in OTP's portfolio of non-residential programs. The programs offered at the time of the survey included:

- AC Cycling and Control
- Adjustable Speed Drive
- Appliance Recycling
- Commercial Design Assistance
- Commercial Motor Upgrade
- Commercial Refrigeration
- Compressed Air Audit
- DollarSmart Financing
- Efficiency PC Power Supply
- Heat Pump Program
- Industrial Process Efficiencies
- Lighting Conservation
- New Construction HE Lighting
- Recommissioning

Figure 11 shows the customer awareness levels for each program as a percentage of the 36 surveyed non-residential customers.

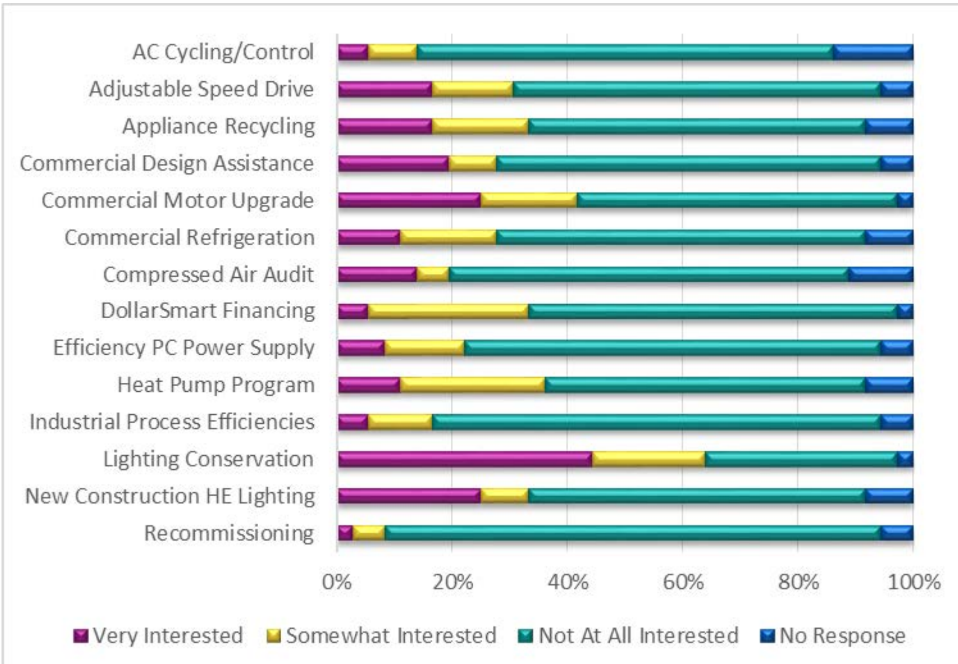
Figure 11: Customer Awareness of OTP Programs – Non-Residential



Source: Navigant 2015

Navigant also asked customers if they had any interest in participating in OTP efficiency programs going forward. Figure 12 shows these results as a percent of the 36 surveyed non-residential customers.

Figure 12: Customer Interest in OTP Programs – Non-Residential



Source: Navigant 2015

5. DSM Measure Characteristics

Navigant's ELRAM model calculates potential energy savings at the measure level and is therefore heavily reliant on high quality and detailed measure characteristics. The modeling team created the Measure Input Characterization Sheet (MICS) including measure costs, savings impacts, measure life, incentive levels, and a host of other variables. The team characterized all of the variables included in the MICS for list of measures assembled by both Navigant and OTP.

5.1 DSM Measure List

Navigant relied on the 2014 Minnesota statewide Technical Reference Manual (TRM) and OTP's supplemental TRM for the list of measures to include in the 2015 study. The team did not use the 2015 MN TRM as it was not complete at the time of this study. Navigant collaborated with OTP during the creation of the measure list to ensure it included all measures that were of interest to OTP, including direct load control measures which informed that portion of the study. As with other statewide TRMs which include deemed savings values, the Minnesota TRM includes measure detail for several different building types and climate zones. This provides program planners with consistent savings information and aids in program design.

5.2 Measure Characteristics

The Navigant modeling team again relied on the MN TRM and OTP TRM to characterize the energy savings and costs for the measures included in the DSM measure list. ELRAM requires over 80 specific characteristics per measure including, energy savings impacts and costs for the baseline, code minimum, and efficient technologies, incentive amounts, measure life, associated program types, densities, willingness and awareness, and externality impacts. The team used existing sources—compiled over past potential and other studies—to complete all of these characteristics and created the MICS workbook to flow directly into the ELRAM model.

6. Benchmarking and Best Practice

Navigant conducted a benchmarking assessment of utilities in the Midwest and neighboring states to ensure that 1) the DSM potential estimates developed for this study are reasonable and appropriate, and 2) to identify the best practices regarding DSM programs used by utilities other than OTP. The benchmarking analysis compares detailed program results by customer sector in these states utilizing 2013 DSM program results, to identify common best practices of top program performers. Navigant provided the results from this benchmarking effort to OTP in August, 2015 as a PowerPoint presentation.

6.1 Organizations Reviewed

Navigant collected data on DSM program results for 15 investor-owned utilities (IOUs) in the Midwest or neighboring states (Table 5), chosen for their geographic proximity to OTP's service territory.

Table 5. Benchmarked Utilities

State	Organization
MN	Otter Tail Power
	Interstate Power & Light
	MN Power
	Xcel Energy
CO	Black Hills
IA	Interstate Power & Light
	MidAmerican
IL	Ameren IL
	ComEd IL
MI	Consumers Energy
	DTE Energy
MT	Northwestern Energy
OH	AEP Ohio
	Dayton P&L
SD	Black Hills

Source: Navigant 2015

6.2 Methodology

The team gathered and prepared the benchmarking data for each organization as follows:

- Review of utility annual reports—collected through E Source and supplemented by targeted email—for DSM program spending and savings results
- Collection of baseline sales and revenue from FERC Form 861 www.eia.doe.gov
- Retail revenue data for utilities in IL and OH specify EIA statistics for both energy and delivery. However, utilities did not report all delivery revenue so Navigant calculated a ratio using the provided energy $/kWh revenue data (revenue ÷ retail kWh sales), and applied it to the delivery's retail kWh sales volume to estimate the missing delivery revenue.
- Normalization of DSM savings and spending for same program year, baseline sales, and baseline revenue
- Inclusion of OTP (MN)'s large C&I customers' retail kWh sales and revenue as they are not technically opt out customers

Benchmarking comparisons can identify best practice programs and common best practice techniques among the top performers. However, Navigant stresses several caveats when reviewing benchmarking results, including:

- Variations in program offerings and reporting practices across DSM portfolios precludes a strict apples-to-apples comparison of all programs
- Accounting differences between program administrators including variations in aggregating and allocating costs

Benchmarking is useful however, for identifying organizations and programs to analyze more closely; as close analysis provides better understanding of program practices and informs cost-effective program design. Benchmarking is not a substitute for a process evaluation—it shows what utilities are achieving in terms of energy and demand savings and what they're spending on programs to achieve these savings, but does not attempt to derive meanings or conclusions from this data.

6.3 Residential Benchmarking Results

Table 6 provides overall results for OTP residential programs compared to the benchmark utilities. OTP's residential DSM spending (as a percentage of residential revenue) is above the median of the group while their residential energy savings (as a percentage of residential sales) is below the median of the group.

Table 6. Residential Benchmarking Results

	Spending as % of Revenue	Energy Savings as % of Sales	Summer Peak Demand Savings as % of Peak Demand	Cost of First Year Savings	
				$/kWh	$/kW
All Benchmarked Median	2.3%	1.6%	1.2%	$0.14	$864
OTP (MN)	2.4%	1.1%	1.1%	$0.18	$532

Source: Navigant 2015

Navigant interviewed program evaluators for the following residential programs to better understand the 2013 residential program performance:

- Residential ENERGY STAR Lighting Program – ComEd
- Home Energy Reports – ComEd
- Efficient Products Program – AEP OH
- Home Energy Reports – AEP OH

6.3.1 ComEd (IL)'s Residential ENERGY STAR Lighting Program

The ComEd program achieved 421 GWh savings (1.53% of residential sales) at $0.05/kWh in 2013. OTP's lighting program achieved 0.39% residential energy savings as % of sales at $0.04/kWh. The majority of the program's savings (82%) were from standard CFLs.

- Key Best Practices
  - The program offers large incentives for standard and specialized CFLs in 2013
  - The implementer maintains a good relationship with retail trade allies by continuing an active presence in participating stores
- Supporting Practices
  - The utility maintains a good relationship with the implementer through biweekly status calls to keep program on track
- Future Practices
  - Program plans to incentivize LEDs moving forward
  - Program plans to discontinue incentives for specialty CFLs
- Favorable Conditions

- Upstream program had 17 retailers (1,250 retail outlets) participate in 2013
- Program has massive reach (around 12 million bulbs sold a year)

6.3.2 ComEd (IL)'s Home Energy Reports (HERs) Program

The ComEd HERs program achieved 129.1 GWh savings (0.47% of sales) at $0.01/kWh in 2013. OTP (MN)'s Behavioral program achieved 0.40% residential energy savings as % of residential sales at $0.15/kWh.

- Key Best Practices
  - The program developed marketing methods targeted at specific customer segments
  - The program added more customer waves—the addition of a sixth wave in June 2013 targeting 100,000 customers, increased program participation to about 447,000 customers
  - The utility holds bi-weekly status calls with the implementation contractor to stay on target
- Supporting Practices
  - Opower has implemented this program for the past five years
  - ComEd has recently started taking a more active role in the HER program
- Favorable Conditions
  - Longevity of program and ComEd's large customer base help production and ability to achieve participation targets

6.3.3 AEP Ohio's Residential Efficient Products Program

This AEP Ohio program achieved 203 GWh savings (1.40% of residential sales) at $0.06/kWh in 2013. This included both lighting and appliance measures. Lighting measures accounted for 96% of the program's total savings. OTP's lighting program achieved 0.39% residential energy savings as % of sales at $0.04/kWh. This is an upstream program with the majority of the program's lighting savings (96%) were from CFLs (about 2% came from LEDs).

- Key Best Practices
  - The implementation contractor maintains strong relationships with manufacturers and retailers by:
    - Handling all marketing materials and promotional activities, training retail staff, and visiting stores regularly to confirm proper labeling and marketing of qualified products
    - Maintaining an overall active presence in participating stores
  - The utility holds bi-weekly status calls with the implementation contractor to stay on target
- Supporting Practices

- The program added the Dollar Store as a participating retailer
- The program offers both markdown and coupon components for lighting measures
- The program provides CFL giveaways through food banks and to customers who submit an appliance rebate
- The program expanded the selection of general purpose LEDs in 2013

- Future Practices
  - The Ohio TRM plans to improve savings calculation methods which may generate better CFL savings

6.3.4 AEP Ohio's Home Energy Reports (HERs) Program

The AEP Ohio HERs program achieved 62 GWh savings (0.43% of residential sales) at $0.04/kWh in 2013. OTP (MN)'s Behavioral program achieved 0.40% residential energy savings as % of residential sales at $0.15/kWh.

- Supporting Practices
  - Opower has implemented this program for the past three years
  - The utility holds bi-weekly status calls with the implementation contractor to stay on target
  - The program added around 125,000 participants in the spring of 2013 bringing the total to about 307,000 participants
- Future Practices
  - The utility looks to increase activity and involvement with the Opower run program
  - The program plans to use bill inserts as a means to find more participants
  - The program may update the format of the reports to help keep existing customers engaged

6.4 Commercial & Industrial Benchmarking Results

Table 7 provides overall results for OTP commercial & industrial (C&I) programs compared to the benchmark utilities. OTP's C&I DSM spending (as a percentage of C&I revenue) is the second highest among the group while their C&I energy savings (as a percentage of C&I sales) is the highest among the group.

Table 7. Commercial & Industrial Benchmarking Results

	Spending as % of Revenue	Energy Savings as % of Sales	Summer Peak Demand Savings as % of Peak Demand	Cost of First Year Savings	
				$/kWh	$/kW
All Benchmarked Median	1.8%	1.0%	0.9%	$0.14	$761
OTP (MN)	3.8%	1.8%	0.9%	$0.14	$745

Source: Navigant 2015

To better understand the 2013 C&I performance of the utilities, Navigant completed interviews with the evaluation staff responsible for evaluating the following C&I programs:

- Business Instant Lighting Discount Program – ComEd
- Small Business Direct Install Program – Consumers Energy

6.4.1 Consumers Energy's Small Business Direct Install (SBDI) Program

The Consumers Energy SBDI program achieved about 91 GWh savings (0.38% of C&I sales) at $0.11/kWh in 2013. OTP did not offer a SBDI program in 2013.

- Key Best Practices
  - The utility offers a Small Business Solutions Core program along with multiple targeted initiatives:
    - The Small Business Solutions Core program is designed to promote energy savings through the installation of common lighting and refrigeration measures. Lighting measures (such as conversion of incandescent and standard T12 fluorescent to T8 or T5 fluorescent lighting, CFLs, high-bay fluorescent lighting, occupancy sensors, LEDs, and LED exit sign retrofit kits) were responsible for more than 75% of program savings with the remaining savings attributed to refrigeration measures (anti-sweat heater controls and ECM motors).
    - Targeted initiatives include 1) Thermostat Initiative (targeting small businesses specifically to install thermostats and other low cost measures), 2) Hospitality Initiative (designed to introduce energy efficiency to hospitality segment – modeled after the thermostat initiative but provided LEDs to this segment) and 3) Nonprofit Initiative (new in 2013 and offered LEDs, faucet aerators, pre-rinse sprayers, programmable thermostats and vending misers to the nonprofit sector).

        - CFL Drop Initiative where the program's implementation contractor delivers boxes of CFLs to small businesses located in the utilities' electric and combination territories.

- Supporting Practices
    - To encourage participation, the utility set measure incentives to up to 100% of installed measure cost, with a cap of $7,500 per participating customer
    - Customers who participated in the one of the other initiatives received free direct installation of measures
    - Designed as a "lever program," administrators can scale back or ramped up the program depending on overall portfolio performance

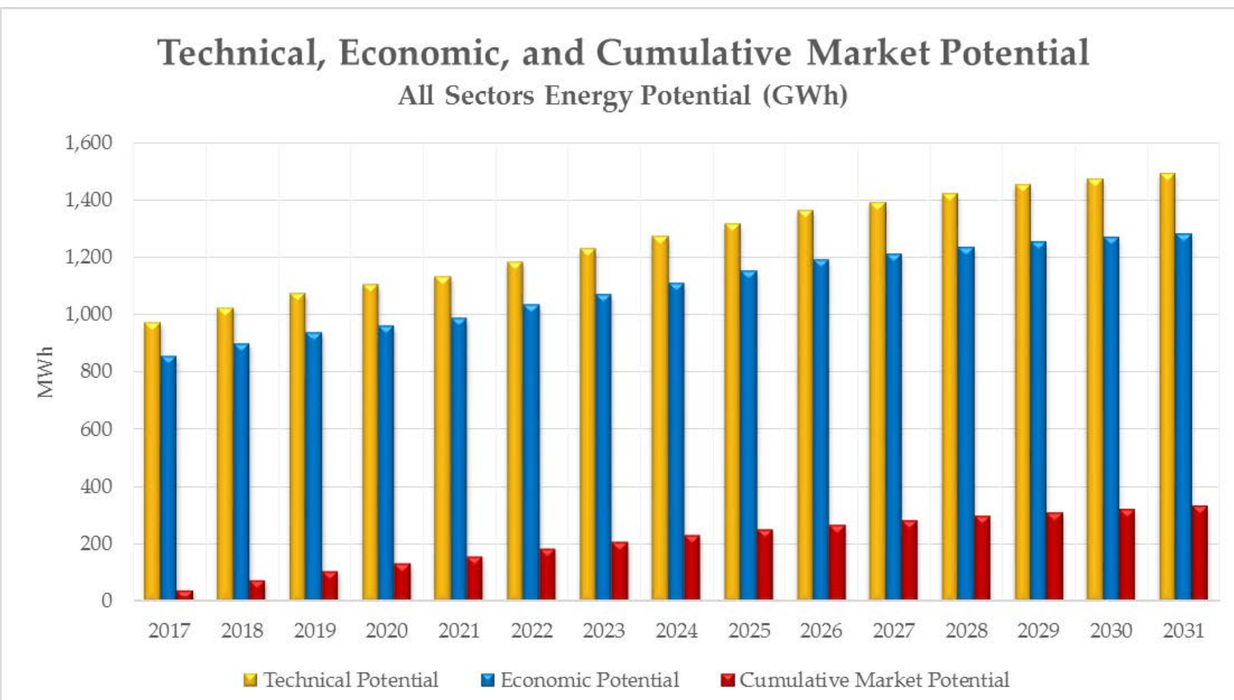
7. DSM Potentials Results

Navigant used the ELRAM potential model to estimate a total of seven market potential scenarios: a base case and six additional scenarios designed to reach DSM goals of 1.5% to 2.0% of utility sales in 0.1% increments. The base case models potential energy savings estimates using a "business as usual" approach, with no changes to current incentive levels or program administrative costs. The additional scenarios with specific savings goals in mind, do adjust incentive levels, administrative costs, and program budgets.

7.1 Base Case Potential

Figure 13 presents the technical, economic, and cumulative energy potential and Figure 14 the demand potential for the base, "business as usual" case. Table 8 and Table 9 provide this same information in tabular form and also include this data by sector. Cumulative market potential looks small and is somewhat ambiguous in comparison to technical and economic potential because cumulative market potential does not start cumulating until 2017 It does not include any of the OTP DSM program achievements from earlier years.

Figure 13. Base Case Technical, Economic, and Cumulative Market Energy Potential (GWh)

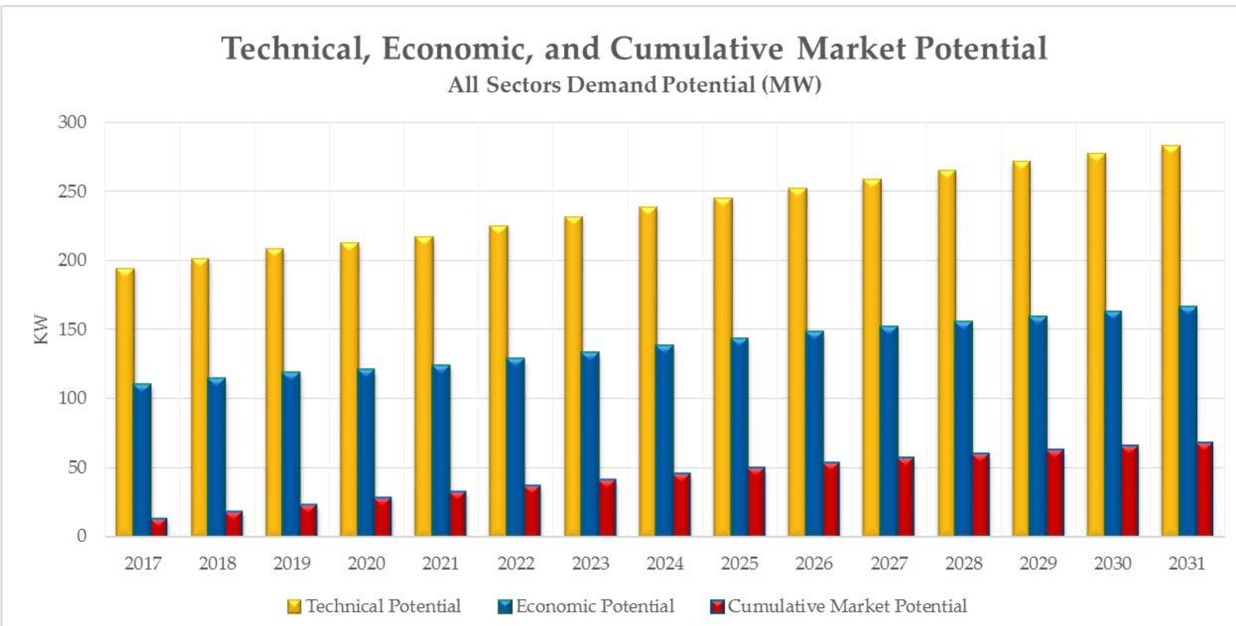


Source: Navigant 2015

Both technical and economic potential grow over the forecast period because of utility growth but more importantly because of the treatment of replace on burnout (ROB) measures. The technical and economic potential from ROB measures is not included until after measure life is achieved. For example, a ROB measure with a 10 year measure life would be included 1/10th summed at a time until the model reaches a full 10 years. Technical potential grows from 975 GWh and 194 MW in 2017 to 1,494 GWh and 283 MW by 2031. Economic potential is about 90% of technical potential. Cumulative market potential cumulates from the 2017 incremental savings value of 41 GWh and 12 MW in 2017 to 332 GWh and 67 MW by 2031.

In the beginning of the forecast period, about 65% of cumulative market potential energy and 50% of cumulative demand potential comes from the non-residential sector. By 2031, these shares stay about the same.

Figure 14. Base Case Technical, Economic, and Cumulative Market Demand Potential (MW)



Source: Navigant 2015

Cumulative potential does not represent the running sum of incremental potential. The accumulation, persistence, and decay of cumulative potential is a four step process.

- *Step 1 - Accumulation*: A running summation of the Incremental Potential for the duration of measure life.
- *Step 2 - End of Life Savings Adjustment:* Once a measure reaches the end of its useful life, remove savings from the initial measure lifetime.
- *Step 3 - Re-Engagement:* A share of the population is assumed to "re-engage" and continue with the equivalent or better energy efficiency measure to replace the measure that has reached "end of life" (decayed savings). The savings associated with this continued engagement is added back to cumulative potential until the end of its next measure life.
- *Step 4 - Adjust for Dual Baseline Measures:* For early retirement (dual baseline) measures, once the remaining life of the baseline technology is reached, energy savings decrease. This step adjusts cumulative potential for this decrease.

Table 8. Base Case Technical, Economic, and Cumulative Market Energy Potential by Sector (GWh)

All Sectors (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	975	1,027	1,076	1,108	1,137	1,187	1,231	1,277	1,320	1,366	1,395	1,426	1,454	1,475	1,494
Economic Potential	859	901	940	964	981	1,036	1,073	1,112	1,155	1,192	1,214	1,237	1,259	1,272	1,283
Cumulative Market Potential	41	75	106	133	159	183	210	232	252	268	284	298	311	322	332
Residential (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	447	487	525	550	572	611	649	688	725	766	792	819	845	863	879
Economic Potential	344	376	404	421	433	466	496	528	566	598	617	636	655	665	674
Cumulative Market Potential	14	25	38	49	58	63	70	77	86	93	101	106	112	116	121
Non- Residential (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	528	539	551	558	565	575	582	589	595	600	603	606	610	613	615
Economic Potential	515	525	535	543	549	570	577	584	590	594	598	601	604	607	610
Cumulative Market Potential	27	50	68	84	101	120	140	154	166	175	183	191	199	205	212

Source: Navigant 2015

Table 9. Base Case Technical, Economic, and Cumulative Market Demand Potential by Sector (MW)

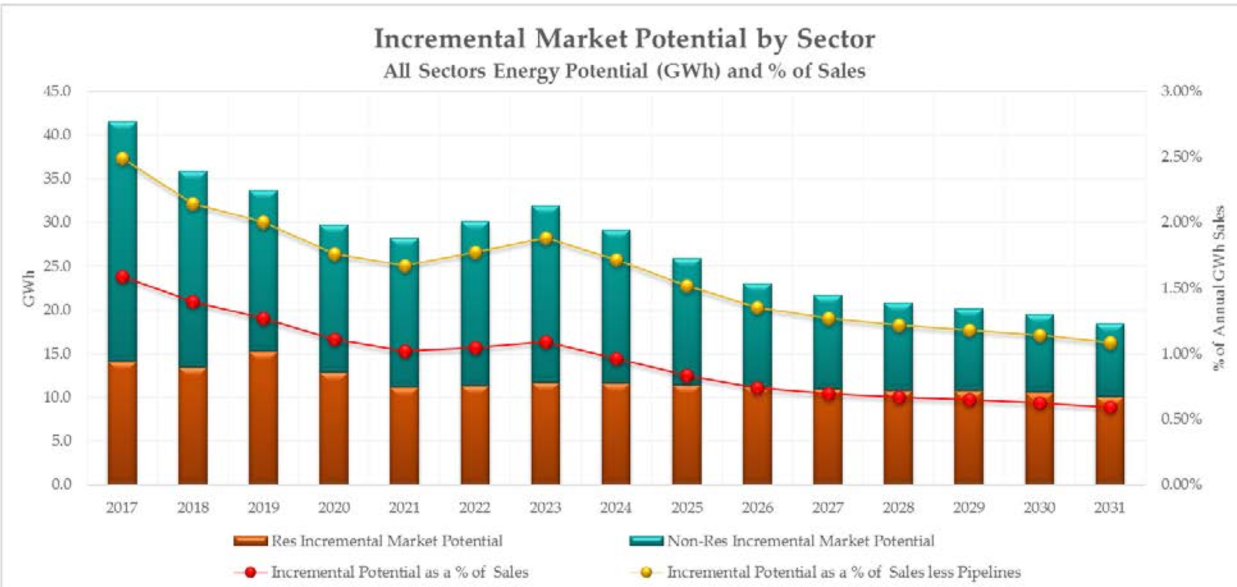
ALL Sectors (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	194	201	208	213	217	224	231	239	245	252	258	265	271	277	283
Economic Potential	109	114	118	121	122	128	133	138	143	147	151	155	159	162	166
Cumulative Market Potential	12	18	23	28	32	36	41	45	49	53	56	59	62	65	67
Res (MW)															
Technical Potential	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Economic Potential	111	117	122	126	129	135	140	146	151	157	162	168	174	179	184
Cumulative Market Potential	40	43	46	47	48	51	54	58	62	65	68	71	74	77	80
Non-Res (MW)	6	8	11	12	14	15	16	17	19	20	22	23	24	25	25
Technical Potential															
Economic Potential	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cumulative Market Potential	82	84	86	87	88	90	91	93	94	95	96	97	98	98	99

Source: Navigant 2015

7.1.1 Base Case Incremental Market Potential

Navigant began with a base case model run showing the results of "business as usual," where the modeling team made no adjustments to current incentive levels or program administrative costs. The left axis of Figure 15 illustrates the base scenario incremental market potential (GWh) and the right axis presents the base scenario incremental market energy potential expressed as a percent of total OTP forecasted sales. There are two representations of the percent of sales values in this figure. The first is a percent of all sales and the second percent of all sales less pipeline sales. The two representations illustrate the effect of the large share of pipeline sales to total sales for OTP. Over the forecast period, pipeline sales represent between 35-45% of total sales, depending on the year. However, the pipeline companies have informed OTP the pumps currently used by the pipelines are already high performance pumps and offer no current DSM potential. When considering goals expressed as percent of sales, Navigant suggests that it may be more appropriate for OTP to express their DSM goals as percent of sales less pipeline sales.

Figure 15. Base Case Incremental Market Energy Potential by Sector (GWh) and Percent of Sales



Source: Navigant 2015

Table 10 provides the values represented in Figure 15. For the base case, energy potential as expressed as a percent of total sales is 1.59% in 2017 and falls to 0.59% by 2031. When expressed as a percent of sales less pipeline sales, the values are 2.49% in 2017 falling to 1.08% by 2031. However in the latter scenarios, the incremental market potential as expressed as a percent of sales remains at or above the 1.5% goal through 2031.

Incremental market potential decreases each year in the base case scenario due to incentive levels remaining constant, the impacts of codes and standards reducing programmatic opportunities, and certain measures beginning to reach saturation levels by the end of the forecast period. At the sector level, the residential share of incremental market potential in 2017 is about 34% of the total incremental market potential. By 2031, the residential share increases to about 55%.

Table 10. Base Case Incremental Market Energy Potential by Sector (GWh) and Percent of Sales

All Sectors (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Incremental Market Potential	41.5	35.9	33.6	29.7	28.2	30.1	32.0	29.2	25.9	23.0	21.7	20.8	20.2	19.5	18.5
Res Incremental Market Potential	14.1	13.5	15.3	12.9	11.1	11.3	11.7	11.6	11.4	11.2	11.0	10.8	10.7	10.6	10.1
Non-Res Incremental Market Potential	27.4	22.4	18.4	16.8	17.1	18.8	20.3	17.5	14.4	11.8	10.7	10.0	9.4	8.9	8.4
Incremental Potential as % of Sales	1.59%	1.40%	1.27%	1.11%	1.02%	1.04%	1.09%	0.97%	0.83%	0.74%	0.70%	0.67%	0.65%	0.63%	0.59%
Incremental Potential as % of Sales less Pipeline	2.49%	2.14%	2.00%	1.76%	1.67%	1.78%	1.89%	1.72%	1.52%	1.35%	1.27%	1.22%	1.18%	1.14%	1.08%

Source: Navigant 2015

7.1.2 Base Case Conservation Supply Curves and Top Fifty Measures

Figure 16 illustrates the 2017 energy DSM potential supply curve. The curve is expressed in terms of levelized cost per kWh saved. The levelized cost formula is:

Levelized cost = capital recovery factor * incremental measure cost / annual kWh savings

Where:
Capital Recovery Factor = utility discount rate / (1-(1+utility discount rate)^-measure life

The distribution of savings by percentage category groups include:

- 25% of potential savings cost a levelized 1.1 cents/kWh or less
- 50% of potential 2.7 cents/kWh or less
- 75% of potential 4.7 cents/kWh or less
- 90% of the potential costs 7.7 cents/kWh or less

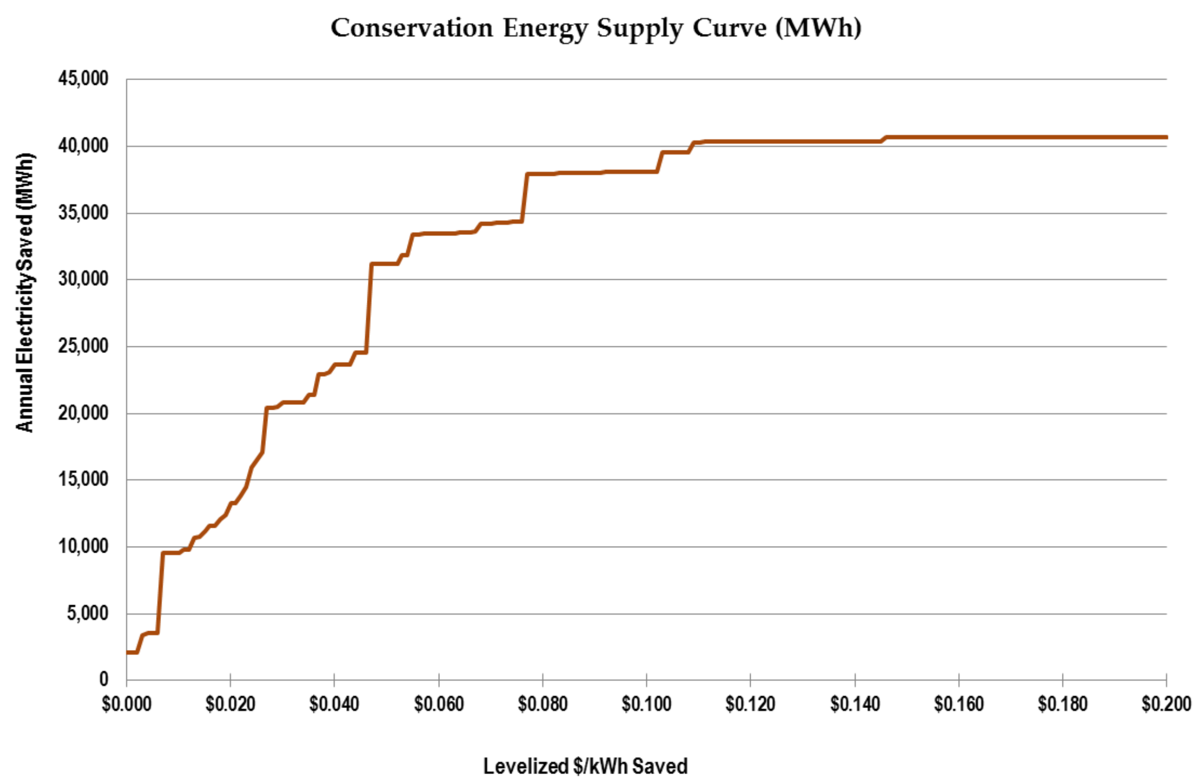
Table 11 lists the top 50 measures in terms of potential energy savings for the year 2017. VSDs on non-HVAC motors in the commercial sector provides the most savings, representing 12.9% of the total potential savings in 2017. Measures with the designation "New Measure" at the beginning of the measure name are measures currently not in the OTP portfolio.

The top six measures account for nearly 50% of the total 2017 potential savings. These top six measures are:

- Commercial - VSD on Non HVAC Motors
- Commercial - Occupancy Sensors
- Commercial - Custom
- Res-Exist - CFL Screw-In Lamp - Low (13w average)

- Res-Exist - Residential Behavior Programs
- Res-Exist - LED Screw-In Lamp - Low (9w avg)

Figure 16. Base Case DSM Energy Supply Curve for 2017



Source: Navigant 2015

Table 11. Base Case Top Fifty Measures in Terms of Energy Savings in 2017

Rank	Top Fifty Measures - 2017	2017 - Energy Savings (MWh)	2017 - Demand Savings (KW)	Energy % of Total	Demand % of Total
1	Commercial - VSD on Non HVAC Motors	5,572	1,078.3	13.4%	10.4%
2	Commercial - Occupancy Sensors	4,908	187.4	11.8%	1.8%
3	Commercial - Custom	3,515	1,033.9	8.5%	10.0%
4	Res-Exist - CFL Screw-In Lamp - Low (13w avg)	2,893	441.9	7.0%	4.3%
5	Res-Exist - Residential Behavior Programs	2,086	1,169.4	5.0%	11.3%
6	Res-Exist - LED Screw-In Lamp - Low (9w avg)	1,500	222.3	3.6%	2.1%
7	Commercial - Commercial Design Assistance (COM NC)	1,495	314.7	3.6%	3.0%
8	Res-Exist - Geothermal Heat Pump	1,399	33.8	3.4%	0.3%
9	Commercial - T8 Delamping	1,315	153.8	3.2%	1.5%
10	Industrial - VSD on Non HVAC Motors	756	146.3	1.8%	1.4%

Rank	Top Fifty Measures - 2017	2017 - Energy Savings (MWh)	2017 - Demand Savings (KW)	Energy % of Total	Demand % of Total
11	New Measure - Res-Exist - ENERGY STAR Clothes Washer (2.07 MEF)	706	89.7	1.7%	0.9%
12	Res-Exist - CFL Screw-In Lamp - High (23w avg)	690	105.3	1.7%	1.0%
13	Industrial - Occupancy Sensors	668	25.5	1.6%	0.2%
14	Res-Exist - High Efficiency ASHP SEER 18	617	188.0	1.5%	1.8%
15	Res-Exist - ENERGY STAR Ceiling Fan/Light	595	45.8	1.4%	0.4%
16	Commercial - ASHP SEER 18	595	24.4	1.4%	0.2%
17	Commercial - NEMA Premium Efficiency Motors	576	111.5	1.4%	1.1%
18	New Measure - Res-Exist - Drainpipe Heat Exchanger on Electric Storage Water Heater	560	63.9	1.4%	0.6%
19	Res-Exist - High Efficiency ASHP SEER 15	548	167.0	1.3%	1.6%
20	Industrial - Custom	544	82.7	1.3%	0.8%
21	Commercial - Geothermal HP (replacing Elec Res Heat)	543	14.0	1.3%	0.1%
22	Commercial - ASHP SEER 15	516	13.6	1.2%	0.1%
23	Commercial - T8 4-Ft Fixture	480	39.9	1.2%	0.4%
24	Commercial - LED Screw-In Lamp (14W Avg)	468	63.9	1.1%	0.6%
25	Commercial - Retrocomissioning	458	7.9	1.1%	0.1%
26	Commercial - T8 Standard Lamp to Low Wattage Retrofit	347	7.7	0.8%	0.1%
27	Res-Exist - Freezer Recycling	336	40.8	0.8%	0.4%
28	Res-Exist - LED Screw-In Lamp - High (18w avg)	317	47.3	0.8%	0.5%
29	Commercial - Exterior Screw-In LED (14 W)	307	62.7	0.7%	0.6%
30	Res-Exist - Home Transformer Package (multi-water measures, 2 CFLs, 2 LEDs, block heater)	243	7.2	0.6%	0.1%
31	Res-Exist - Refrigerator Recycling	236	35.5	0.6%	0.3%
32	Commercial - VSD on HVAC Pumps <=10 HP	236	26.9	0.6%	0.3%
33	Commercial - Anti-Sweat Heat (ASH) Controls	227	12.7	0.5%	0.1%
34	Commercial - High Evaporator Temp Cases	222	6.8	0.5%	0.1%
35	Commercial - Preventative Refrigeration Maintenance (all store size)	200	41.8	0.5%	0.4%
36	Commercial - Exterior Canopy/Area Lights Retrofit with LEDs	195	39.7	0.5%	0.4%
37	Commercial - Outdoor Air Cooling (Natural Air)	187	5.5	0.5%	0.1%
38	Commercial - Parallel Rack Compressor Retrofit	187	23.3	0.4%	0.2%
39	Industrial - T8 Delamping	178	20.9	0.4%	0.2%
40	Commercial - VSD on HVAC Fans <=10 HP	165	18.9	0.4%	0.2%
41	Commercial - LED Display Case Lighting	163	32.4	0.4%	0.3%
42	Res-Low Income - Home Therapy (Low Income)	142	17.7	0.3%	0.2%
43	Res-Exist - Wall insulation	141	0.0	0.3%	0.0%
44	Commercial - LED Linear Replacement Lamp	135	1.0	0.3%	0.0%
45	Res-Exist - School Kit	133	9.7	0.3%	0.1%
46	Res-Exist - DWH Control (400 Hours)	132	3,111.0	0.3%	30.0%

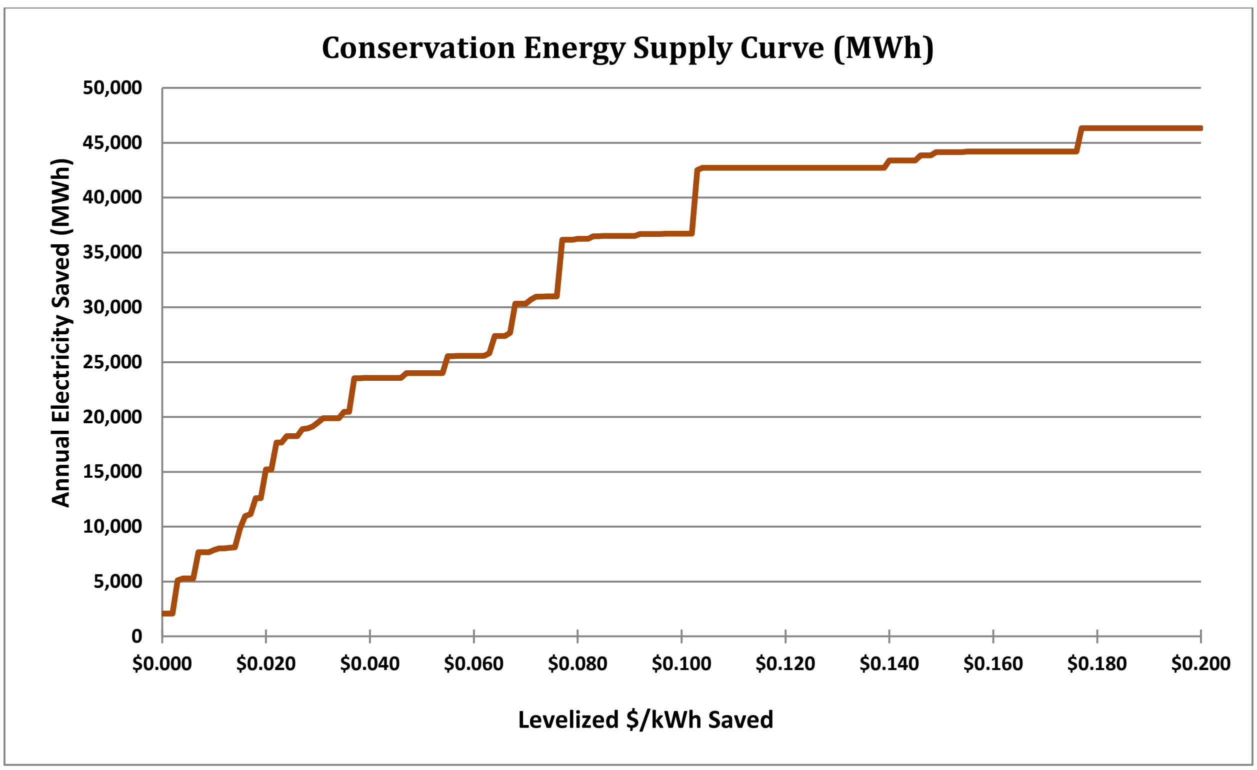
Rank	Top Fifty Measures - 2017	2017 - Energy Savings (MWh)	2017 - Demand Savings (KW)	Energy % of Total	Demand % of Total
47	Res-Exist - High Efficiency ASHP (replacing Elec Resis Heat)	129	1.8	0.3%	0.0%
48	Res-Exist - ECM Blower Motor	120	11.0	0.3%	0.1%
49	Commercial - CFL Screw-In Lamp (23W Avg)	118	15.2	0.3%	0.1%
50	Commercial - Solid State Controller	118	14.7	0.3%	0.1%

Source: Navigant 2015

As shown in Figure 17, the shape of the supply curve flattens somewhat in 2031 with the potential savings becoming more costly. The distribution of savings by percentage category groups changed from 2017 to 2031 as follows:

- 25% of potential savings cost a levelized 1.1 cents/kWh or less in 2017 and 1.8 cents/kWh in 2031
- 50% of potential 2.7 cents/kWh or less in 2017 and 3.7 cents/kWh in 2031
- 75% of potential 4.7 cents/kWh or less in 2017 and 7.7 cents/kWh in 2031
- 90% of the potential costs 7.7 cents/kWh or less in 2017 and 10.3 cents/kWh in 2031

Figure 17. Base Case DSM Energy Supply Curve for 2031



Source: Navigant 2015

Table 12 lists the top 50 measures in terms of potential energy savings for the year 2031. The geothermal heat pump measure in the residential sector is now the new measure that provides the most savings, representing 12.4% of the total potential savings in 2031. Measures with the designation "New Measure" at the beginning of the measure name are measures currently not in the OTP portfolio.

The top six measures now account for 60.9% of the total 2031 potential. The 2031 top six measures are:

- Commercial - Custom
- Res-Exist - Geothermal Heat Pump
- Res-Exist - Residential Behavior Programs
- Commercial - Commercial Design Assistance (COM NC)
- Commercial - Retrocomissioning
- New Measure - Res-Exist - Drainpipe Heat Exchanger on Electric Storage Water Heater

Table 12. Base Case Top Fifty Measures in Terms of Energy Savings in 2031

Rank	Top Fifty Measures - 2031	2031 - Energy Savings (MWh)	2031 - Demand Savings (KW)	Energy % of Total	Demand % of Total
1	Commercial - Custom	4,194	1,233.4	22.7%	14.4%
2	Res-Exist - Geothermal Heat Pump	2,429	58.8	13.2%	0.7%
3	Res-Exist - Residential Behavior Programs	2,086	1,169.4	11.3%	13.7%
4	Commercial - Commercial Design Assistance (COM NC)	1,301	273.9	7.1%	3.2%
5	Commercial - Retrocomissioning	631	10.9	3.4%	0.1%
6	New Measure - Res-Exist - Drainpipe Heat Exchanger on Electric Storage Water Heater	598	68.2	3.2%	0.8%
7	Res-Exist - High Efficiency ASHP SEER 18	585	178.3	3.2%	2.1%
8	New Measure - Res-Exist - ENERGY STAR Clothes Washer (2.07 MEF)	576	73.2	3.1%	0.9%
9	Commercial - Geothermal HP (replacing Elec Res Heat)	528	13.6	2.9%	0.2%
10	New Measure - Res-Exist - Solar Space Heating (Displacing Electricity)	525	59.9	2.8%	0.7%
11	Res-Exist - High Efficiency ASHP SEER 15	516	157.4	2.8%	1.8%
12	Commercial - T8 Standard Lamp to Low Wattage Retrofit	403	9.0	2.2%	0.1%
13	Res-Exist - Home Transformer Package (multi-water measures, 2 CFLs, 2 LEDs, block heater)	287	8.5	1.6%	0.1%
14	Res-New - High Efficiency ASHP SEER 18 - NC	226	68.8	1.2%	0.8%
15	Res-Exist - Wall insulation	186	0.0	1.0%	0.0%
16	Res-Exist - High Efficiency ASHP (replacing Elec Resis Heat)	184	2.6	1.0%	0.0%
17	Res-Exist - DWH Control (400 Hours)	174	4,104.9	0.9%	48.0%
18	New Measure - Res-Exist - HE Electric Storage Water Heater (.95 EF)	174	19.8	0.9%	0.2%
19	Commercial - Exterior Canopy/Area Lights Retrofit with LEDs	172	35.1	0.9%	0.4%
20	Res-Exist - ECM Blower Motor	166	15.2	0.9%	0.2%

Rank	Top Fifty Measures - 2031	2031 - Energy Savings (MWh)	2031 - Demand Savings (KW)	Energy % of Total	Demand % of Total
21	Industrial - Custom	161	24.5	0.9%	0.3%
22	Res-Exist - Freezer Recycling	155	18.8	0.8%	0.2%
23	Commercial - LED Linear Replacement Lamp	155	1.1	0.8%	0.0%
24	Res-Exist - LED Screw-In Lamp - Low (9w avg)	142	21.0	0.8%	0.2%
25	Res-Low Income - Home Therapy (Low Income)	142	17.7	0.8%	0.2%
26	Res-Exist - Refrigerator Recycling	108	16.2	0.6%	0.2%
27	Res-Exist - School Kit	103	7.5	0.6%	0.1%
28	New Measure - Commercial - Large High Volume Low Speed Ventilation Fans	83	16.8	0.4%	0.2%
29	New Measure - Res-Exist - High Efficiency Central AC System SEER 21	70	164.3	0.4%	1.9%
30	Res-New - High Efficiency ASHP SEER 15 - NC	68	20.6	0.4%	0.2%
31	New Measure - Res-New - Solar Space Heating (Displacing Electricity)	67	7.7	0.4%	0.1%
32	Commercial - Occupancy Sensors - NC	66	1.1	0.4%	0.0%
33	Commercial - ENERGY STAR Freezer w/ Glass Door	58	6.0	0.3%	0.1%
34	Industrial - Retrocomissioning	56	1.1	0.3%	0.0%
35	New Measure - Res-Exist - High Efficiency Central AC System SEER 18	55	128.5	0.3%	1.5%
36	Industrial - T8 Standard Lamp to Low Wattage Retrofit	55	1.2	0.3%	0.0%
37	Res-Exist - Attic insulation	54	0.0	0.3%	0.0%
38	Commercial - Exterior Wall Pack Retrofit with LEDs	49	10.1	0.3%	0.1%
39	New Measure - Res-Exist - LED Holiday Lights	47	0.0	0.3%	0.0%
40	Res-New - ENERGY STAR CFL Torchiere - NC	47	4.2	0.3%	0.0%
41	Res-Exist - LED Screw-In Lamp - High (18w avg)	45	6.7	0.2%	0.1%
42	New Measure - Res-Exist - High Efficiency Room AC (1 Ton; 11 EER Avg)	44	101.1	0.2%	1.2%
43	Res-Exist - LED Screw-In Lamp - CFL Base - Low (9w avg)	33	3.3	0.2%	0.0%
44	Res-New - LED Screw-In Lamp - CFL Base - Low (9w avg) - NC	31	3.1	0.2%	0.0%
45	New Measure - Commercial - Vending Machine Automatic Shutoff Control	29	0.9	0.2%	0.0%
46	Commercial - Desktop: ES 5 + 20%	27	6.4	0.1%	0.1%
47	Res-Exist - ENERGY STAR CFL Torchiere	27	2.5	0.1%	0.0%
48	Industrial - NEMA Premium Efficiency Motors	26	5.0	0.1%	0.1%
49	Res-Exist - LED Screw-In Lamp - CFL Base - High (18w avg)	26	2.6	0.1%	0.0%
50	Industrial - Exterior Canopy/Area Lights Retrofit with LEDs	23	4.8	0.1%	0.1%

Source: Navigant 2015

7.1.3 Base Case Program Costs

Table 13 provides a summary of base case model results for the planning years of 2017, 2018, and 2019. Included in the table is year by year information for the residential, non-residential and sector totals on:

- Incremental and cumulative energy and demand potential savings
- Incremental energy savings as a percent of sales; both with and without pipeline sales
- Incremental administrative and incentive costs
- Other program related costs (based on 2015 values)

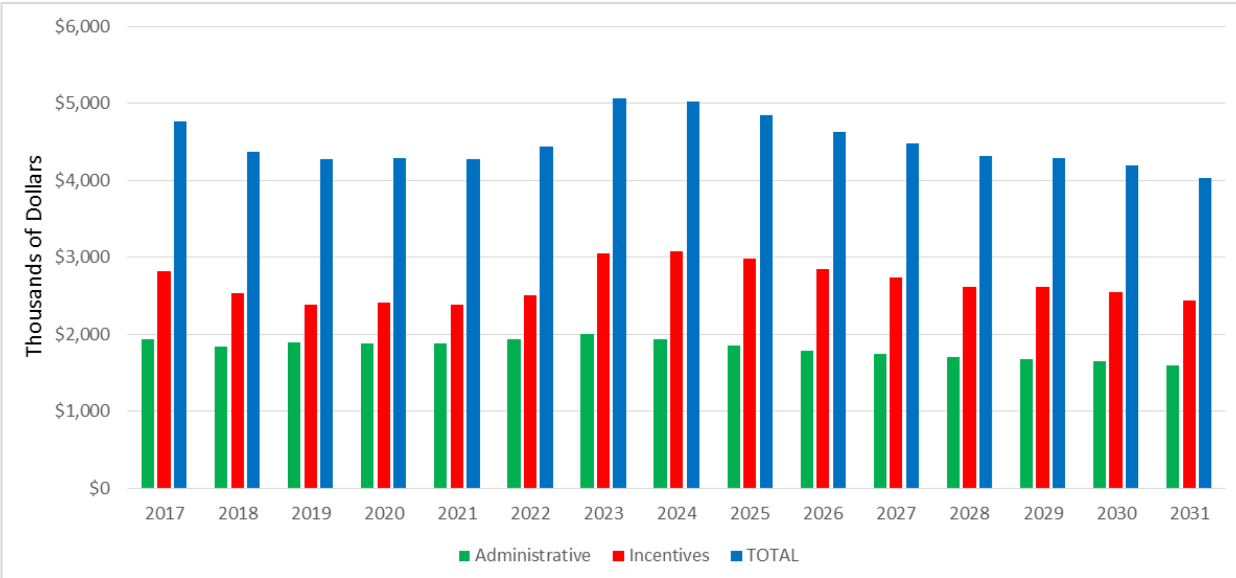
Table 13. Base Case Total DSM Savings and Costs for 2017, 2018, and 2019

Total DSM Savings and Costs (Net at Meter) - All Sectors											
Year	Energy Savings (GWh)		Peak Demand Savings (MW)		Energy Savings As a % of Sales		Program Administrator Costs (million $)				
	Incremental	Cumulative	Incremental	Cumulative	Incremental Potential as % of Sales	Incremental Potential as % of Sales Less Pipeline	Incremental Admin Costs	Incremental Incentive Cost	Other Sector Based (based on 2015)	Other Non-Sector Based (based on 2015)	Total
2017	41.5	41.5	12.4	12.4	1.59%	2.49%	$1.9	$2.8	$0.4	$0.8	$5.1
2018	35.9	75.1	11.8	17.8	1.40%	2.14%	$1.9	$2.5	$0.4	$0.8	$4.8
2019	33.6	106.3	11.8	22.9	1.27%	2.00%	$1.9	$2.4	$0.4	$0.8	$4.7
Total DSM Savings and Costs (Net at Meter) - Residential Sector (Includes Low Income)											
2017	14.1	14.1	6.3	6.3			$1.0	$1.0	$0.2		$2.2
2018	13.5	25.3	6.3	8.3			$1.0	$1.0	$0.2		$2.2
2019	15.3	38.4	6.6	10.5			$1.0	$1.2	$0.2		$2.4
Total DSM Savings and Costs (Net at Meter) - Commercial / Industrial Sector											
2017	27.4	27.4	6.1	6.1			$1.0	$1.9	$0.1		$3.0
2018	22.4	49.8	5.5	9.4			$0.9	$1.5	$0.1		$2.5
2019	18.4	67.9	5.1	12.4			$0.9	$1.2	$0.1		$2.2

Source: Navigant 2015

Figure 18 and Table 14 provide estimates of administrative and incentive costs by year over the forecast horizon of 2017 through 2031. All costs are expressed in 2015 real $s.

Figure 18. Base Case DSM Program Incentive and Administrative Costs (Dollars)



Source: Navigant 2015

Total expenditures decline over the forecast period, but not as rapidly as the decline in program savings, as shown in Table 14. Administrative costs are about 40-45% of total program costs.

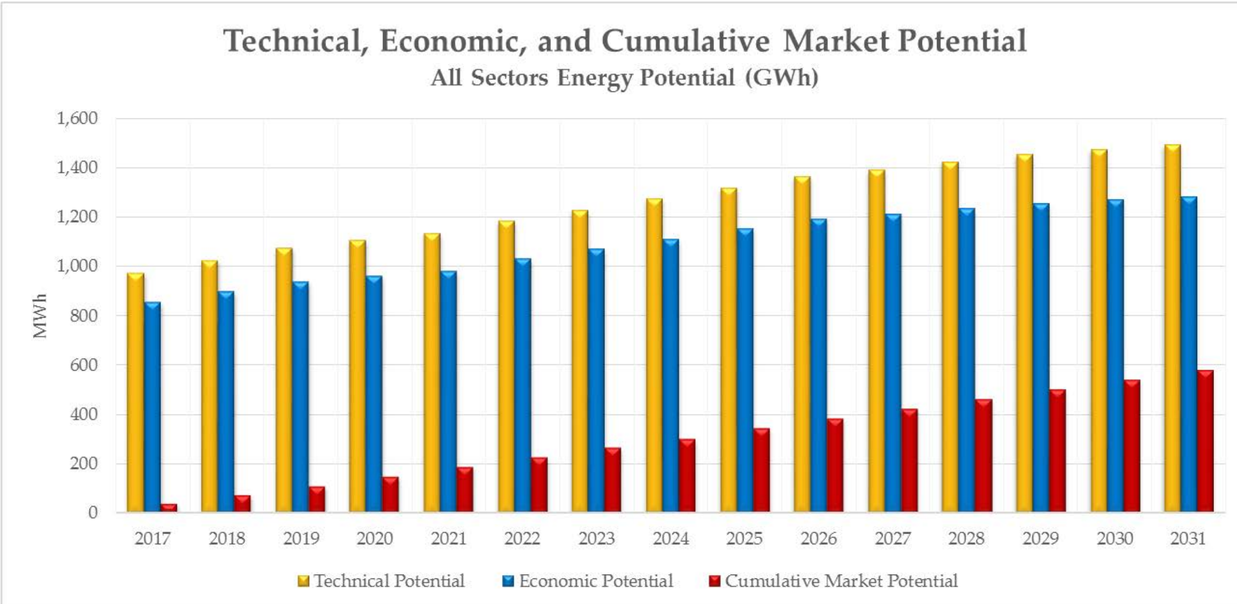
Table 14. Base Case Program Incentive and Administrative Costs (Thousands $) Source: Navigant 2015

Cost Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Administrative	$1,938	$1,846	$1,891	$1,878	$1,878	$1,938	$2,006	$1,940	$1,856	$1,782	$1,745	$1,706	$1,679	$1,645	$1,594
Incentives	$2,823	$2,529	$2,387	$2,408	$2,391	$2,505	$3,052	$3,085	$2,985	$2,848	$2,734	$2,615	$2,611	$2,550	$2,442
TOTAL	$4,761	$4,375	$4,278	$4,286	$4,268	$4,442	$5,057	$5,025	$4,841	$4,630	$4,478	$4,322	$4,289	$4,194	$4,037

7.2 Scenario 1.5% of Sales

The 1.5% scenario includes pipeline sales over the entire forecast period of 2017 through 2031. To achieve these goals, the modeling team increased incentive and administrative costs and enlarged budgets. Figure 19 presents the technical, economic, and cumulative energy potential and Figure 20 the demand potential for the 1.5% of sales scenario. Table 15 and Table 16 provide a breakdown of this same information in tabular form as well as by sector. As noted in the base case discussion, cumulative market potential looks small in comparison to technical and economic potential because cumulative market potential does not start cumulating until 2017. It does not include any of the OTP DSM program achievements from earlier years.

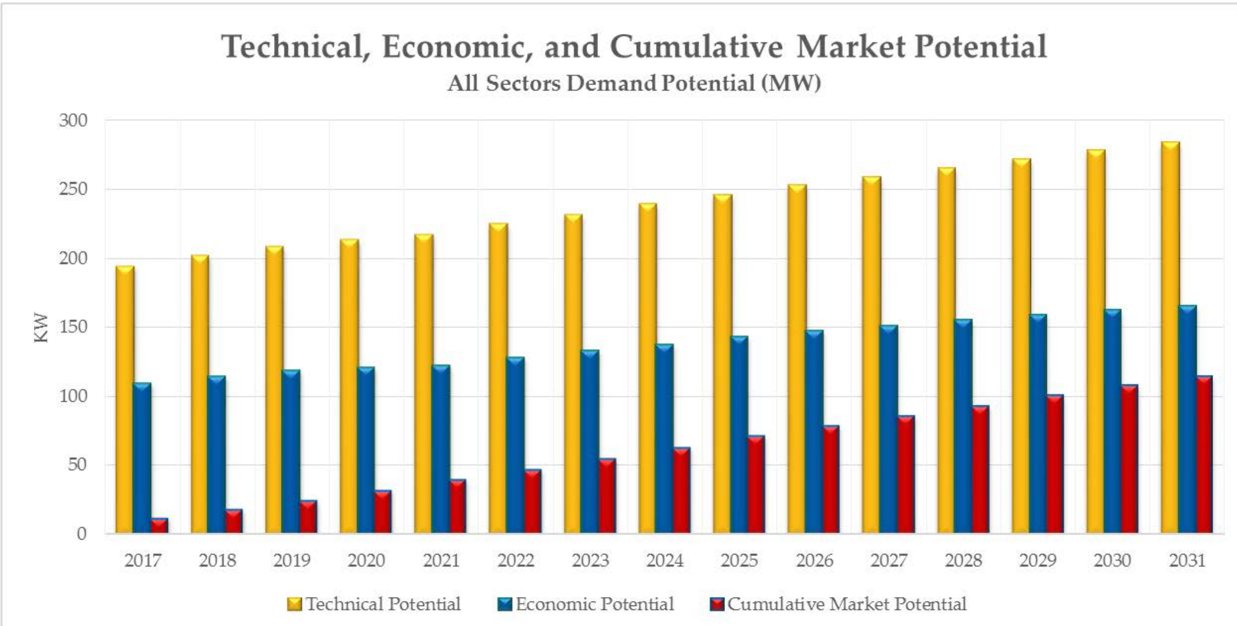
Figure 19. 1.5% Scenario Technical, Economic, and Cumulative Market Energy Potential (GWh)



Source: Navigant 2015

Under this 1.5% of sales scenario, cumulative market potential cumulates from the 2017 incremental savings value of 39 GWh and 12 MW in 2017 to 579 GWh and 115 MW by 2031. Similar to the base scenario, about 67% of cumulative market potential energy and 50% of cumulative demand potential in 2017 comes from the non-residential sector. By 2031, the share for non-residential energy falls to 55% (same as the base scenario) and the share of demand is 51% (50% for the base scenario). The lower energy and demand 2031 shares from the non-residential sector in this scenario is from a change of available measures by 2031 between the two scenarios. Several measures, such as the "Custom" measure are approaching measure saturation by 2031 due to the higher incentives and increased budgets.

Figure 20. 1.5% Scenario Technical, Economic, and Cumulative Market Demand Potential (MW)



Source: Navigant 2015

Table 15. 1.5% Scenario Technical, Economic, and Cumulative Market Energy Potential by Sector (GWh)

All Sectors (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	975	1,027	1,076	1,108	1,137	1,187	1,231	1,277	1,320	1,366	1,395	1,426	1,454	1,475	1,494
Economic Potential	859	901	940	964	981	1,036	1,073	1,112	1,155	1,192	1,214	1,237	1,259	1,272	1,283
Cumulative Market Potential	39	75	113	150	189	227	266	303	344	384	424	464	503	541	579
Residential (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	447	487	525	550	572	611	649	688	725	766	792	819	845	863	879
Economic Potential	344	376	404	421	433	466	496	528	566	598	617	636	655	665	674
Cumulative Market Potential	13	25	39	51	62	69	77	88	102	121	142	166	193	224	257
Non- Residential (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	528	539	551	558	565	575	582	589	595	600	603	606	610	613	615
Economic Potential	515	525	535	543	549	570	577	584	590	594	598	601	604	607	610
Cumulative Market Potential	26	51	74	99	127	158	189	215	242	262	282	298	310	316	322

Source: Navigant 2015

Table 16. 1.5% Scenario Technical, Economic, and Cumulative Market Demand Potential by Sector (MW)

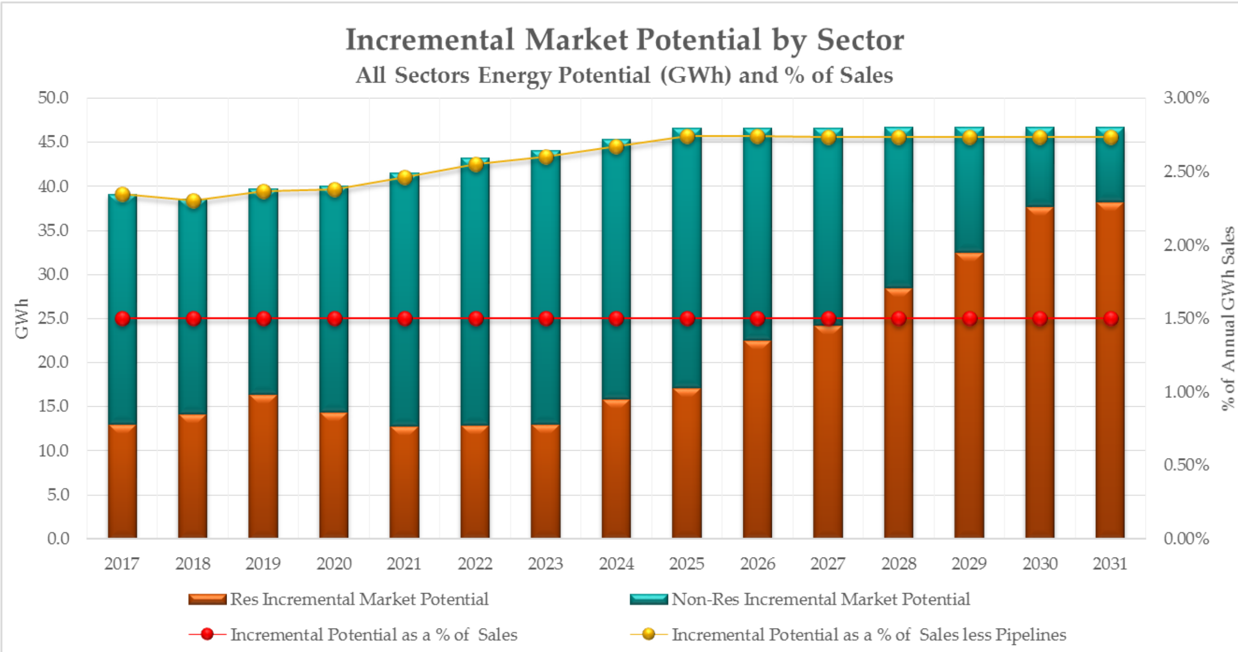
ALL Sectors (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	194	201	208	213	217	224	231	239	245	252	258	265	271	277	283
Economic Potential	109	114	118	121	122	128	133	138	143	147	151	155	159	162	166
Cumulative Market Potential	12	18	24	32	39	47	55	63	71	79	86	93	101	108	115
Res (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	111	117	122	126	129	135	140	146	151	157	162	168	174	179	184
Economic Potential	40	43	46	47	48	51	54	58	62	65	68	71	74	77	80
Cumulative Market Potential	6	8	11	13	15	16	18	20	23	28	32	38	44	51	56
Non-Res (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	82	84	86	87	88	90	91	93	94	95	96	97	98	98	99
Economic Potential	69	71	73	74	75	77	79	80	81	82	83	84	85	85	86
Cumulative Market Potential	6	10	14	19	24	31	37	42	48	51	53	55	56	57	58

Source: Navigant 2015

7.2.1 Scenario 1.5% of Sales Incremental Market Potential

Figure 21 shows the results of the incremental market potential, with the left axis as incremental market potential (GWh) and the right axis as the incremental market potential expressed as a percent of sales. There are two representations of the percent of sales values. The first is a percent of all sales and the second percent of all sales less pipeline sales. Navigant provided the two representations the large share of pipeline sales to total sales ratio in OTP's territory. When considering goals expressed as percent of sales, it may be more appropriate for OTP to have these goals expressed as percent of sales less pipeline sales. The flat red line in Figure 21 illustrates OTP meeting the 1.5% goal each year of the forecast. The yellow line represents what the percentage would be if calculated against total sales less pipeline sales. On average, the yellow line is nearly a full percentage point higher.

Figure 21. 1.5% Scenario Incremental Market Energy Potential by Sector (GWh) and Percent of Sales



Source: Navigant 2015

Table 17 provides the values represented in Figure 21. The modeling team increased incentive, administrative, and budget levels to meet the 1.5% of total sales goal for each year of the forecast. When expressed as a percent of sales less pipeline sales, the values are 2.35% in 2017 increasing to 2.74% by 2031.

At the sector level, the residential share of incremental market potential in 2017 is about 33% of the total incremental market potential. By 2031, the residential share increases to about 82%. This is a higher residential share than found in the base scenario.

Table 17. 1.5% Scenario Incremental Market Energy Potential by Sector (GWh) and Percent of Sales

All Sectors (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Incremental Market Potential	39.1	38.6	39.7	40.1	41.5	43.2	44.1	45.4	46.6	46.6	46.7	46.7	46.7	46.7	46.7
Res Incremental Market Potential	13.0	14.1	16.4	14.4	12.8	12.9	13.0	15.9	17.1	22.5	24.3	28.5	32.5	37.7	38.3
Non-Res Incremental Market Potential	26.1	24.4	23.3	25.7	28.7	30.3	31.1	29.5	29.5	24.1	22.4	18.1	14.2	9.0	8.4
Incremental Potential as a % of Sales	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Incremental Potential as a % of Sales less Pipelines	2.35%	2.31%	2.37%	2.38%	2.46%	2.55%	2.60%	2.67%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%

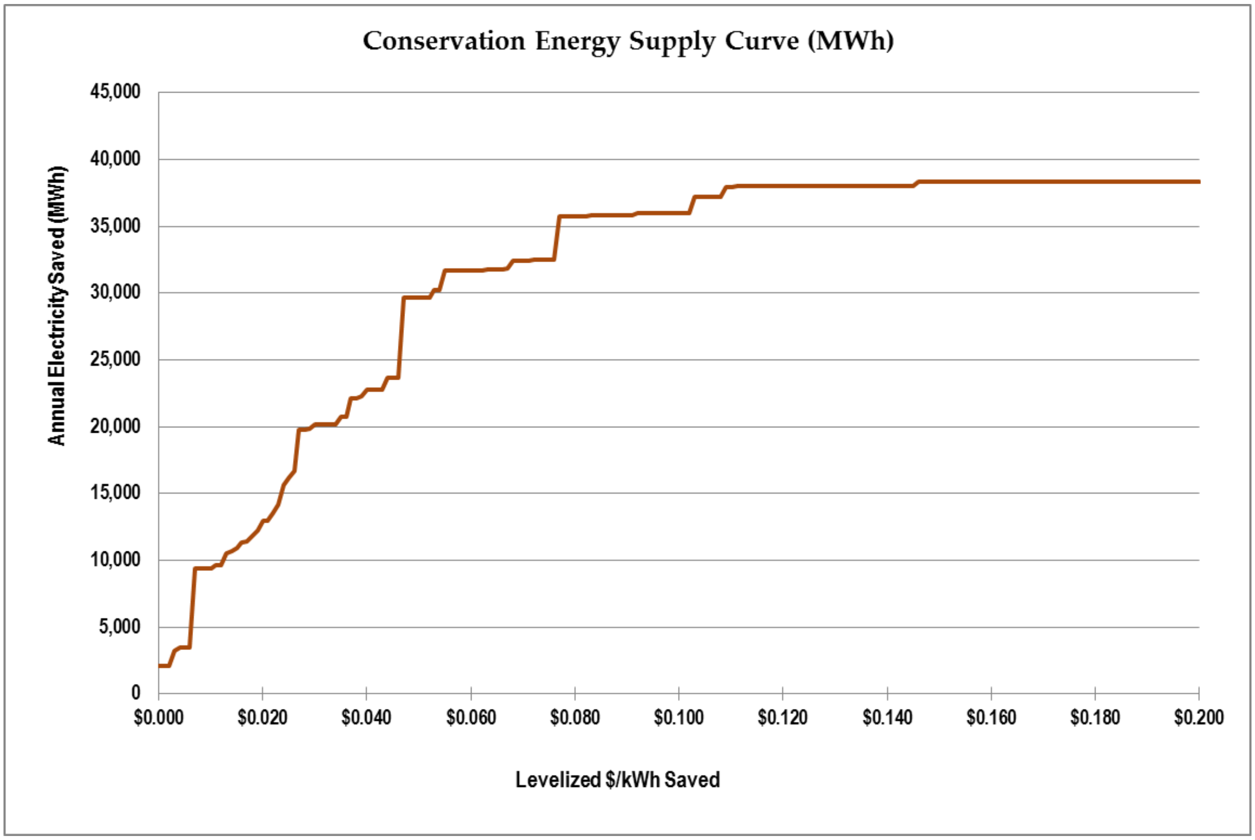
Source: Navigant 2015

7.2.2 Scenario 1.5% of Sales Conservation Supply Curves and Top Fifty Measures

Figure 22 illustrates the 2017 energy DSM potential supply curve. The distribution of savings by percentage category groups include:

- 25% of potential savings cost a levelized 1.1 cents/kWh or less
- 50% of potential 2.7 cents/kWh or less
- 75% of potential 4.7 cents/kWh or less
- 90% of the potential costs 7.7 cents/kWh or less

Figure 22. 1.5% Scenario DSM Energy Supply Curve for 2017



Source: Navigant 2015

Table 18 lists the top 50 measures in terms of potential energy savings for the year 2017. VSDs on non HVAC motors in the commercial sector provides the most savings, representing 12.9% of the total potential savings in 2017. Measures with the designation "New Measure" at the beginning of the measure name are measures currently not in the OTP portfolio.

The top six measures account for 49% of the total 2017 potential savings and include:

- Commercial - VSD on Non HVAC Motors

- Commercial - Occupancy Sensors
- Commercial - Custom
- Res-Exist - CFL Screw-In Lamp - Low (13w avg)
- Res-Exist - Residential Behavior Programs
- Res-Exist - LED Screw-In Lamp - Low (9w avg)

Table 18. 1.5% Scenario Top Fifty Measures in Terms of Energy Savings in 2017

Rank	Top Fifty Measures - 2017	2017 - Energy Savings (MWh)	2017 - Demand Savings (KW)	Energy % of Total	Demand % of Total
1	Commercial - VSD on Non HVAC Motors	5,042	975.6	12.9%	9.8%
2	Commercial - Occupancy Sensors	4,908	187.4	12.5%	1.9%
3	Commercial - Custom	3,180	935.4	8.1%	9.4%
4	Res-Exist - CFL Screw-In Lamp - Low (13w avg)	2,617	399.8	6.7%	4.0%
5	Res-Exist - Residential Behavior Programs	2,086	1,169.4	5.3%	11.8%
6	Res-Exist - LED Screw-In Lamp - Low (9w avg)	1,357	201.1	3.5%	2.0%
7	Commercial - Commercial Design Assistance (COM NC)	1,353	284.7	3.5%	2.9%
8	Commercial - T8 Delamping	1,315	153.8	3.4%	1.5%
9	Res-Exist - Geothermal Heat Pump	1,265	30.6	3.2%	0.3%
10	Industrial - VSD on Non HVAC Motors	684	132.3	1.7%	1.3%
11	Industrial - Occupancy Sensors	668	25.5	1.7%	0.3%
12	New Measure - Res-Exist - ENERGY STAR Clothes Washer (2.07 MEF)	639	81.2	1.6%	0.8%
13	Res-Exist - CFL Screw-In Lamp - High (23w avg)	624	95.3	1.6%	1.0%
14	Commercial - ASHP SEER 18	595	24.4	1.5%	0.2%
15	Commercial - NEMA Premium Efficiency Motors	576	111.5	1.5%	1.1%
16	Res-Exist - High Efficiency ASHP SEER 18	558	170.1	1.4%	1.7%
17	Res-Exist - ENERGY STAR Ceiling Fan/Light	538	41.4	1.4%	0.4%
18	Commercial - ASHP SEER 15	516	13.6	1.3%	0.1%
19	New Measure - Res-Exist - Drainpipe Heat Exchanger on Electric Storage Water Heater	507	57.8	1.3%	0.6%
20	Res-Exist - High Efficiency ASHP SEER 15	495	151.0	1.3%	1.5%
21	Industrial - Custom	492	74.8	1.3%	0.8%
22	Commercial - Geothermal HP (replacing Elec Res Heat)	491	12.6	1.3%	0.1%
23	Commercial - T8 4-Ft Fixture	480	39.9	1.2%	0.4%
24	Commercial - LED Screw-In Lamp (14W Avg)	468	63.9	1.2%	0.6%
25	Commercial - Retrocomissioning	458	7.9	1.2%	0.1%
26	Commercial - T8 Standard Lamp to Low Wattage Retrofit	347	7.7	0.9%	0.1%
27	Commercial - Exterior Screw-In LED (14 W)	307	62.7	0.8%	0.6%
28	Res-Exist - Freezer Recycling	304	36.9	0.8%	0.4%

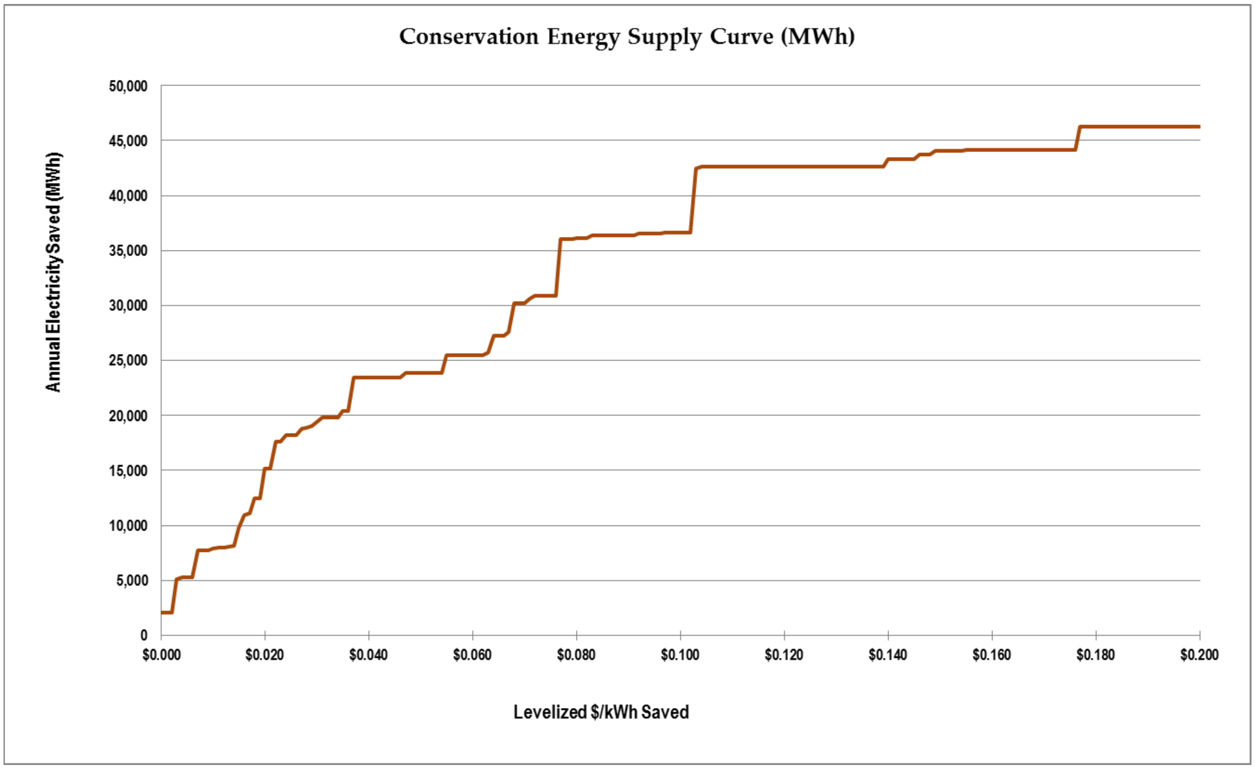
Rank	Top Fifty Measures - 2017	2017 - Energy Savings (MWh)	2017 - Demand Savings (KW)	Energy % of Total	Demand % of Total
29	Res-Exist - LED Screw-In Lamp - High (18w avg)	287	42.8	0.7%	0.4%
30	Commercial - Anti-Sweat Heat (ASH) Controls	227	12.7	0.6%	0.1%
31	Commercial - High Evaporator Temp Cases	222	6.8	0.6%	0.1%
32	Res-Exist - Home Transformer Package (multi-water measures, 2 CFLs, 2 LEDs, block heater)	220	6.5	0.6%	0.1%
33	Res-Exist - Refrigerator Recycling	214	32.2	0.5%	0.3%
34	Commercial - VSD on HVAC Pumps <=10 HP	213	24.3	0.5%	0.2%
35	Commercial - Preventative Refrigeration Maintenance (all store size)	200	41.8	0.5%	0.4%
36	Commercial - Exterior Canopy/Area Lights Retrofit with LEDs	195	39.7	0.5%	0.4%
37	Commercial - Outdoor Air Cooling (Natural Air)	187	5.5	0.5%	0.1%
38	Commercial - Parallel Rack Compressor Retrofit	187	23.3	0.5%	0.2%
39	Industrial - T8 Delamping	178	20.9	0.5%	0.2%
40	Commercial - LED Display Case Lighting	163	32.4	0.4%	0.3%
41	Commercial - VSD on HVAC Fans <=10 HP	150	17.1	0.4%	0.2%
42	Res-Low Income - Home Therapy (Low Income)	142	17.7	0.4%	0.2%
43	Commercial - LED Linear Replacement Lamp	135	1.0	0.3%	0.0%
44	Res-Exist - DWH Control (400 Hours)	132	3,111.0	0.3%	31.3%
45	Res-Exist - Wall insulation	127	0.0	0.3%	0.0%
46	Res-Exist - School Kit	120	8.7	0.3%	0.1%
47	Commercial - CFL Screw-In Lamp (23W Avg)	118	15.2	0.3%	0.2%
48	Commercial - Solid State Controller	118	14.7	0.3%	0.1%
49	Res-Exist - High Efficiency ASHP (replacing Elec Resis Heat)	116	1.6	0.3%	0.0%
50	Commercial - Exit Sign Retrofit with LED	116	13.2	0.3%	0.1%

Source: Navigant 2015

Figure 23 shows the shape of the supply curve flattening out somewhat in 2031 with the potential savings becoming more costly. The distribution of savings by percentage category groups changed from 2017 to 2031 as follows:

- 25% of potential savings cost a levelized 1.1 cents/kWh or less in 2017 and 1.8 cents/kWh in 2031
- 50% of potential 2.7 cents/kWh or less in 2017 and 3.7 cents/kWh in 2031
- 75% of potential 4.7 cents/kWh or less in 2017 and 7.7 cents/kWh in 2031
- 90% of the potential costs 7.7 cents/kWh or less in 2017 and 10.3 cents/kWh in 2031

Figure 23. 1.5% Scenario DSM Energy Supply Curve for 2031



Source: Navigant 2015

Table 19 lists the top 50 measures in terms of potential energy savings for the year 2031. The top six list changed from both the 2017 list as well as the 2031 list from the base scenario. Several measures are near measure saturation by 2031 due to the higher incentives and increased budgets. The residential geothermal heat pump measure is now the measure that provides the most savings, representing 12.5% of the total potential savings in 2031. Measures with the designation “New Measure” at the beginning of the measure name are measures currently not in the OTP portfolio.

The top six measures now account for 47.8% of the total 2031 potential savings, and include:

- Res-Exist - Geothermal Heat Pump
- Res-New - High Efficiency ASHP SEER 18 - NC
- Commercial - Commercial Design Assistance (COM NC)
- Res-Exist - ENERGY STAR Clothes Washer (2.07 MEF)
- Res-Exist - High Efficiency ASHP (replacing Elec Resist Heat)
- Res-Exist - Drainpipe Heat Exchanger on Electric Storage Water Heater

Table 19. 1.5% Scenario Top Fifty Measures in Terms of Energy Savings in 2031

Rank	Top Fifty Measures - 2031	2031 - Energy Savings (MWh)	2031 - Demand Savings (KW)	Energy % of Total	Demand % of Total
1	Res-Exist - Geothermal Heat Pump	5,812	140.6	12.5%	1.1%
2	Res-New - High Efficiency ASHP SEER 18 - NC	5,162	1,573.6	11.1%	12.2%
3	Commercial - Commercial Design Assistance (COM NC)	3,061	644.3	6.6%	5.0%
4	New Measure - Res-Exist - ENERGY STAR Clothes Washer (2.07 MEF)	3,034	385.6	6.5%	3.0%
5	Res-Exist - High Efficiency ASHP (replacing Elec Resis Heat)	2,633	36.9	5.6%	0.3%
6	New Measure - Res-Exist - Drainpipe Heat Exchanger on Electric Storage Water Heater	2,625	299.4	5.6%	2.3%
7	Res-Exist - Home Transformer Package (multi-water measures, 2 CFLs, 2 LEDs, block heater)	2,382	70.3	5.1%	0.5%
8	New Measure - Res-Exist - Solar Space Heating (Displacing Electricity)	2,111	240.9	4.5%	1.9%
9	Res-Exist - Residential Behavior Progams	2,086	1,169.4	4.5%	9.0%
10	Res-Exist - Freezer Recycling	1,594	193.3	3.4%	1.5%
11	Res-New - High Efficiency ASHP SEER 15 - NC	1,549	472.1	3.3%	3.6%
12	Res-Exist - LED Screw-In Lamp - Low (9w avg)	1,533	227.3	3.3%	1.8%
13	Res-Exist - Refrigerator Recycling	1,362	204.7	2.9%	1.6%
14	Res-Exist - Wall insulation	1,315	0.0	2.8%	0.0%
15	Commercial - T8 Standard Lamp to Low Wattage Retrofit	987	22.0	2.1%	0.2%
16	Res-Exist - School Kit	807	58.8	1.7%	0.5%
17	New Measure - Res-Exist - HE Electric Storage Water Heater (.95 EF)	676	77.1	1.4%	0.6%
18	Commercial - Retrocomissioning	571	9.9	1.2%	0.1%
19	Commercial - Exterior Canopy/Area Lights Retrofit with LEDs	426	86.9	0.9%	0.7%
20	Res-Exist - LED Screw-In Lamp - High (18w avg)	417	62.2	0.9%	0.5%
21	Res-Exist - ECM Blower Motor	401	36.6	0.9%	0.3%
22	New Measure - Commercial - Large High Volume Low Speed Ventilation Fans	395	80.1	0.8%	0.6%
23	Commercial - LED Linear Replacement Lamp	394	2.8	0.8%	0.0%
24	Res-Exist - Attic insulation	380	0.0	0.8%	0.0%
25	New Measure - Res-Exist - High Efficiency Central AC System SEER 21	310	725.6	0.7%	5.6%
26	New Measure - Res-New - Solar Space Heating (Displacing Electricity)	297	33.9	0.6%	0.3%
27	New Measure - Res-Exist - High Efficiency Central AC System SEER 18	242	567.9	0.5%	4.4%
28	New Measure - Res-Exist - LED Holiday Lights	225	0.0	0.5%	0.0%
29	New Measure - Res-Exist - High Efficiency Room AC (1 Ton; 11 EER Avg)	196	452.2	0.4%	3.5%

Rank	Top Fifty Measures - 2031	2031 - Energy Savings (MWh)	2031 - Demand Savings (KW)	Energy % of Total	Demand % of Total
30	Res-Exist - DWH Control (400 Hours)	174	4,104.9	0.4%	31.7%
31	Commercial - GSHP Units (open loop) EER 20.1	164	9.0	0.4%	0.1%
32	Commercial - GSHP Units (closed loop) EER 17.1	163	10.1	0.4%	0.1%
33	Commercial - Desktop: ES 5 + 20%	161	37.6	0.3%	0.3%
34	New Measure - Commercial - Vending Machine Automatic Shutoff Control	159	4.9	0.3%	0.0%
35	Commercial - Occupancy Sensors - NC	155	2.6	0.3%	0.0%
36	Res-Low Income - Home Therapy (Low Income)	142	17.7	0.3%	0.1%
37	Commercial - ENERGY STAR Freezer w/ Glass Door	139	14.3	0.3%	0.1%
38	Industrial - T8 Standard Lamp to Low Wattage Retrofit	134	3.0	0.3%	0.0%
39	Commercial - Exterior Wall Pack Retrofit with LEDs	122	24.9	0.3%	0.2%
40	Commercial - Desktop: ES 5 (w/ 80 Plus)	118	27.6	0.3%	0.2%
41	Res-New - ENERGY STAR CFL Torchiere - NC	110	10.0	0.2%	0.1%
42	Industrial - Server ES 1	108	25.1	0.2%	0.2%
43	New Measure - Res-Exist - High Efficiency Central AC System SEER 15	100	234.8	0.2%	1.8%
44	New Measure - Commercial - HVAC System with Economizer	100	11.4	0.2%	0.1%
45	Commercial - Desktop: ES 5	99	23.0	0.2%	0.2%
46	New Measure - Res-Exist - High Efficiency Refrigerator	96	11.0	0.2%	0.1%
47	Res-Exist - LED Screw-In Lamp - CFL Base - Low (9w avg)	88	8.9	0.2%	0.1%
48	New Measure - Res-New - High Efficiency Refrigerator - NC	87	9.9	0.2%	0.1%
49	Res-New - LED Screw-In Lamp - CFL Base - Low (9w avg) - NC	73	7.4	0.2%	0.1%
50	Res-Exist - LED Screw-In Lamp - CFL Base - High (18w avg)	69	7.0	0.1%	0.1%

Source: Navigant 2015

7.2.3 Scenario 1.5% of Sales Program Costs

Table 20 provides a summary of base case model results for the planning years of 2017, 2018, and 2019. Included in the table is year by year information for the residential, non-residential and sector totals on:

- Incremental and cumulative energy and demand potential savings
- Incremental energy savings as a percent of sales; both with and without pipeline sales
- Incremental administrative and incentive costs
- Other program related costs (based on 2015 values)

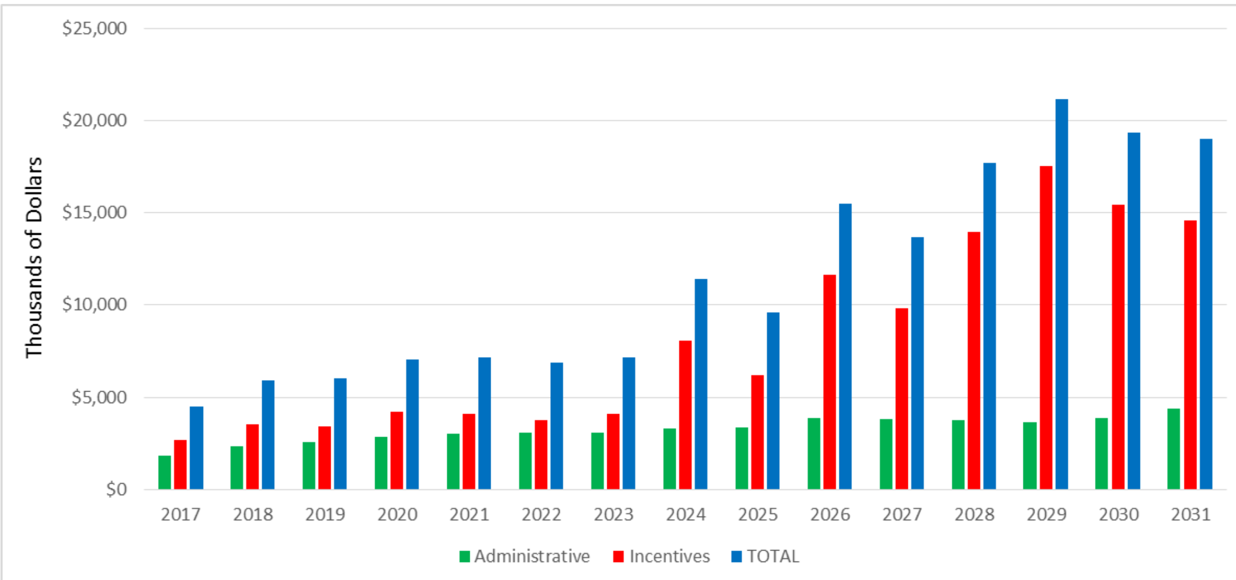
Table 20. 1.5% Scenario Total DSM Savings and Costs for 2017, 2018, and 2019

Year	Energy Savings (GWh)		Peak Demand Savings (MW)		Energy Savings As a % of Sales		Program Administrator Costs (million $)				
	Incremental	Cumulative	Incremental	Cumulative	Incremental Potential as % of Sales	Incremental Potential as % of Sales Less Pipeline	Incremental Admin Costs	Incremental Incentive Cost	Other Sector Based (based on 2015)	Other Non-Sector Based (based on 2015)	Total
Total DSM Savings and Costs (Net at Meter) - All Sectors											
2017	39.1	39.1	11.9	11.9	1.50%	2.35%	$1.8	$2.7	$0.4	$0.8	$4.9
2018	38.6	75.5	12.4	17.9	1.50%	2.31%	$2.4	$3.5	$0.4	$0.8	$6.3
2019	39.7	112.7	13.1	24.4	1.50%	2.37%	$2.6	$3.4	$0.4	$0.8	$6.4
Total DSM Savings and Costs (Net at Meter) - Residential Sector (Includes Low Income)											
2017	13.0	13.0	6.1	6.1			$0.9	$0.9	$0.2		$2.1
2018	14.1	24.9	6.4	8.2			$1.2	$1.4	$0.2		$2.8
2019	16.4	39.1	6.9	10.7			$1.3	$1.5	$0.2		$3.0
Total DSM Savings and Costs (Net at Meter) - Commercial / Industrial Sector											
2017	26.1	26.1	5.8	5.8			$0.9	$1.8	$0.1		$2.8
2018	24.4	50.6	6.0	9.7			$1.2	$2.2	$0.1		$3.5
2019	23.3	73.6	6.2	13.7			$1.3	$1.9	$0.1		$3.4

Source: Navigant 2015

Figure 24 and Table 21 provide estimates of administrative and incentive costs by year over the forecast horizon of 2017 through 2031. All costs are expressed in 2015 real $s.

Figure 24. 1.5% Scenario DSM Program Incentive and Administrative Costs (Thousands of Dollars)



Source: Navigant 2015

Total expenditures increase over the forecast period, reflecting the additional program budgets needed to meet the 1.5% of sales goals. The growth in costs is more rapid than the energy savings, as shown in Figure 24. Administrative costs are about 20-45% of total program costs, depending on the year.

Table 21. 1.5% Scenario Program Incentive and Administrative Costs ($ Thousands)

Cost Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Administrative	$1,835	$2,368	$2,571	$2,832	$3,016	$3,065	$3,073	$3,331	$3,359	$3,881	$3,831	$3,758	$3,665	$3,871	$4,403
Incentives	$2,664	$3,549	$3,432	$4,216	$4,124	$3,785	$4,111	$8,050	$6,212	$11,615	$9,832	$13,961	$17,510	$15,443	$14,597
TOTAL	$4,499	$5,917	$6,003	$7,047	$7,141	$6,850	$7,184	$11,381	$9,572	$15,496	$13,663	$17,720	$21,176	$19,315	$19,000

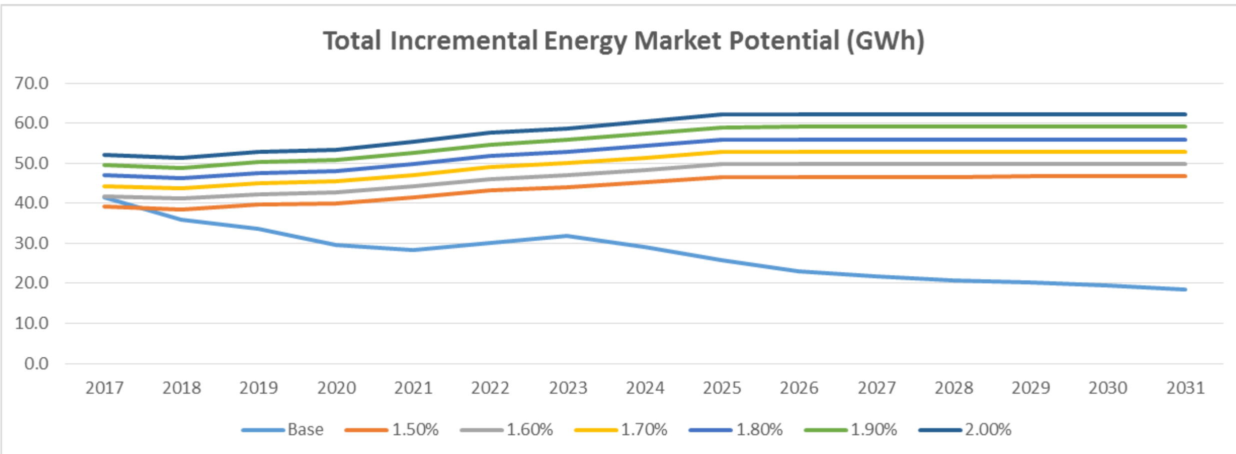
Source: Navigant 2015

7.3 Total Potential – Remaining Scenarios up to 2% of Sales

OTP requested modeling scenarios beyond the 1.5% of sales goal to understand if such were achievable, and at what cost. Navigant created scenarios at 0.1% increments starting at 1.6% up through 2.0% over the forecast period. The modeling team increased incentives, administrative costs, and program budgets to meet each scenario goal.

Figure 25 illustrates the annual incremental market potential by scenario and year. Table 22 provides the values illustrated in Figure 25. All the scenarios diverge quickly from the base "business as usual" scenario indicating that OTP would need to rapidly increase funds to achieve the higher scenario levels.

Figure 25. Incremental Market Potential by Scenario (GWh)



Source: Navigant 2015

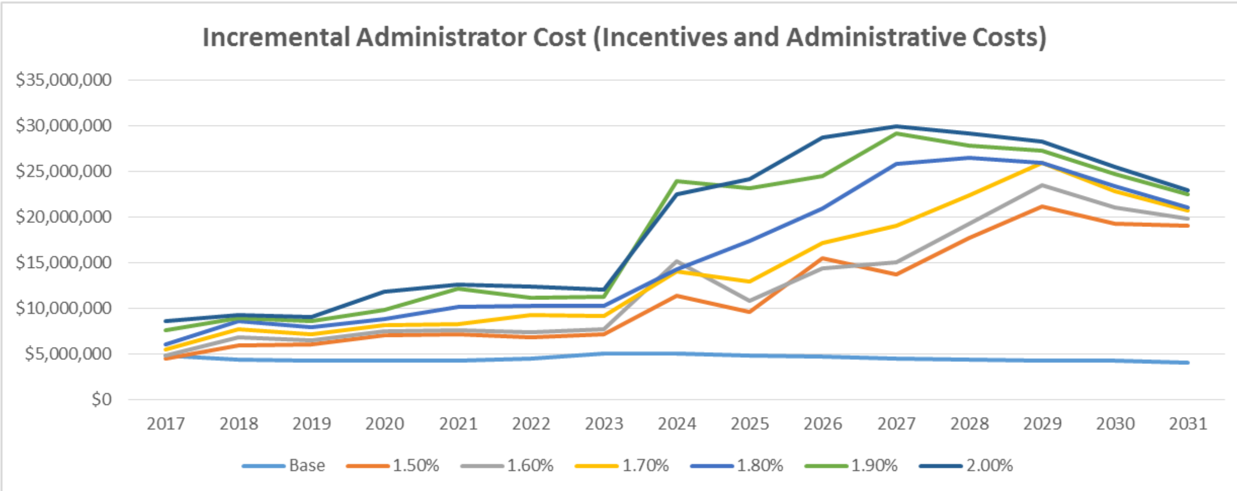
Table 22. Incremental Market Potential by Scenario (GWh)

All Sectors (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Base	41.5	35.9	33.6	29.7	28.2	30.1	32.0	29.2	25.9	23.0	21.7	20.8	20.2	19.5	18.5
1.50%	39.1	38.6	39.7	40.1	41.5	43.2	44.1	45.4	46.6	46.6	46.7	46.7	46.7	46.7	46.7
1.60%	41.7	41.1	42.3	42.7	44.3	46.1	47.0	48.4	49.7	49.7	49.8	49.8	49.8	49.8	49.8
1.70%	44.3	43.7	45.0	45.4	47.1	49.0	50.0	51.4	52.8	52.9	52.9	52.9	52.9	52.9	52.9
1.80%	46.9	46.3	47.6	48.1	49.9	51.8	52.9	54.4	55.9	56.0	56.0	56.0	56.0	56.0	56.0
1.90%	49.5	48.8	50.3	50.8	52.7	54.7	55.9	57.5	59.0	59.1	59.1	59.1	59.1	59.1	59.2
2.00%	52.2	51.4	52.9	53.4	55.4	57.6	58.8	60.5	62.1	62.2	62.2	62.2	62.2	62.2	62.2

Source: Navigant 2015

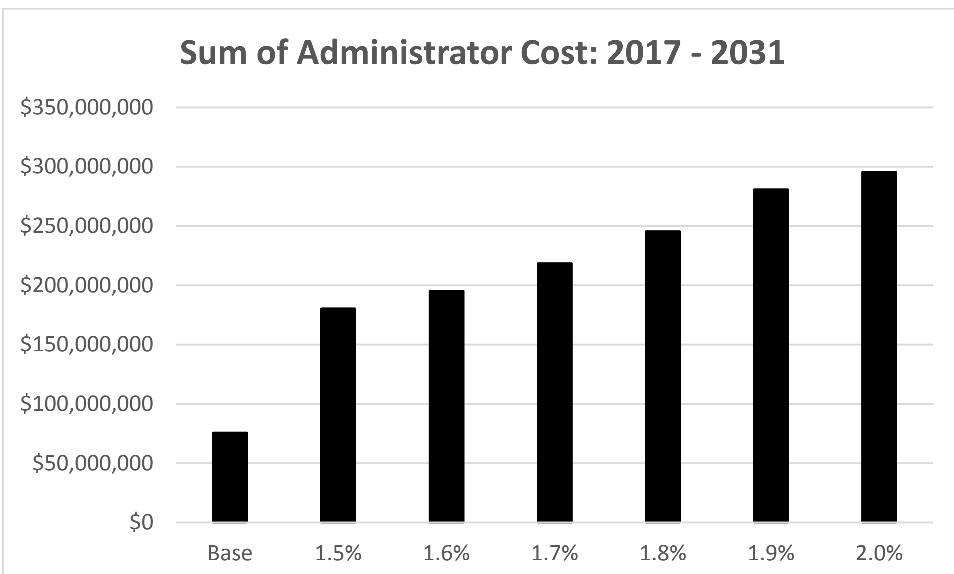
Figure 26 illustrates what the incremental cost impacts would be to achieve each of the scenario levels. Figure 27 5 illustrates the cumulative administrator cost by scenario over the 2017 through 2031 time period. The administrator cost is the sum of administrative cost and incentive cost. The base scenario is the "business as usual" scenario where incentives and administrator costs remain as they are currently. All costs are expressed in 2015 real $s.

Figure 26. Incremental Administrator Cost by Scenario



Source: Navigant 2015

Figure 27. Cumulative Administrator Cost by Scenario (2017-2031)



Source: Navigant 2015

Table 23 displays the values illustrated in Figure 26 and Figure 27. The 2.0% of sales scenario proves to be especially costly over the entire forecast horizon. The cumulative administrator cost over the period 2017 through 2031 for the 2.0% scenario is 164% greater than the 1.5% scenario and 390% greater than the base scenario. In contrast, the cumulative of incremental energy savings over this time frame for the 2% scenario is 130% greater than the 1.5% scenario and 197% of the base scenario. The cost/kWh is $0.156 for the base case; rises rapidly to $0.246 for the 1.5% scenario and increases with each succeeding scenario to $0.310 for the 2% scenario.

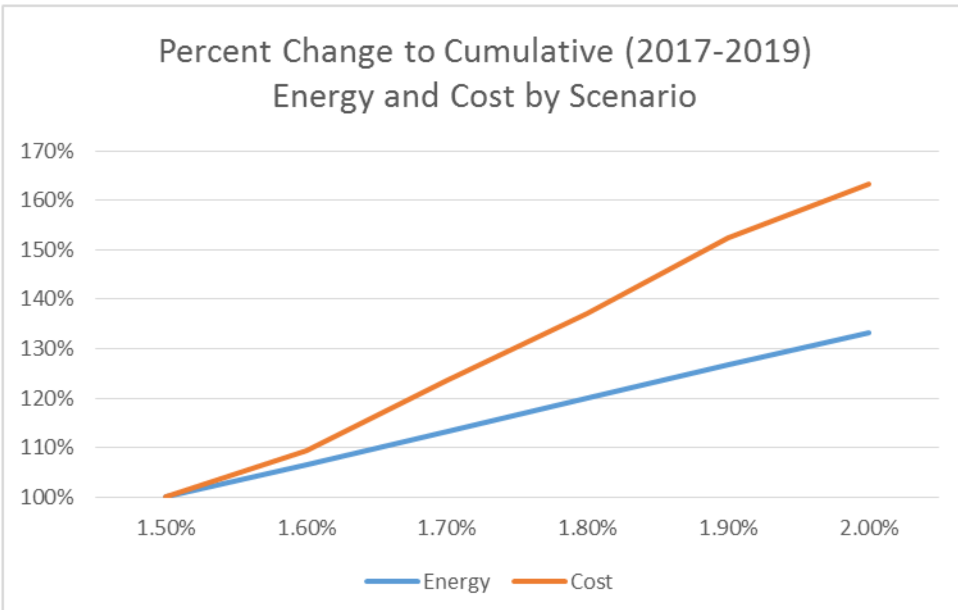
Table 23. Incremental and Total Administrator Cost by Scenario ($ and $/kWh)

Scenario	2017	2018	2019	2020	2021	2022	2023	ta2024	2025	2026	2027	2028	2029	2030	2031	Sum 2017 - 2031	Cost/kWh
Base	$4,761,274	$4,374,874	$4,278,151	$4,285,840	$4,268,492	$4,442,193	$5,057,158	$5,024,716	$4,840,897	$4,629,534	$4,478,431	$4,321,669	$4,289,326	$4,194,358	$4,036,577	$75,739,689	$0.156
1.50%	$4,499,070	$5,917,208	$6,003,134	$7,047,286	$7,140,769	$6,849,860	$7,184,140	$11,380,896	$9,571,697	$15,496,337	$13,662,661	$17,719,670	$21,175,541	$19,314,517	$19,000,258	$180,419,244	$0.246
1.60%	$4,787,637	$6,757,604	$6,427,051	$7,467,927	$7,534,130	$7,309,285	$7,637,643	$15,194,437	$10,775,775	$14,346,252	$15,084,705	$19,305,333	$23,518,666	$21,024,096	$19,800,893	$195,427,633	$0.252
1.70%	$5,492,949	$7,632,083	$7,180,661	$8,107,110	$8,214,340	$9,259,974	$9,182,642	$14,084,478	$12,870,299	$17,124,692	$19,085,695	$22,377,074	$25,947,081	$22,781,601	$20,690,322	$218,487,202	$0.266
1.80%	$6,024,611	$8,604,338	$7,869,206	$8,846,779	$10,156,474	$10,218,799	$10,242,819	$14,218,632	$17,352,883	$20,905,403	$25,835,194	$26,507,041	$25,934,898	$23,342,555	$21,026,731	$245,542,564	$0.284
1.90%	$7,534,509	$8,889,266	$8,600,915	$9,852,154	$12,092,584	$11,144,072	$11,278,568	$23,925,301	$23,113,305	$24,464,693	$29,194,405	$27,892,936	$27,252,619	$24,674,495	$22,550,404	$280,916,423	$0.309
2.00%	$8,538,390	$9,241,626	$9,051,460	$11,837,981	$12,568,061	$12,362,158	$12,035,624	$22,457,681	$24,141,109	$28,756,101	$29,909,055	$29,227,766	$28,265,068	$25,505,330	$22,957,481	$295,311,092	$0.310

Source: Navigant 2015

Focusing on the near term (2017-2019), Figure 28 illustrates the percentage change in cumulative energy savings potential and cost by scenario. The cumulative additional administrator cost over the three years of the 2.0% scenario is $10.4 million more than the 1.5% scenario and $13.4 million more than the base "business as usual" scenario.

Figure 28. Percent Change to Cumulative (2017-2019) Energy and Cost by Scenario



Source: Navigant 2015

7.4 Direct Load Control

OTP has a number of direct load control programs. Some designed to reduce summer peak demand, others winter peak demand, and there are strategies within programs designed to reduce both summer and winter peak demand or provide load shifting. The primary incentive to participate in these programs are special controlled service rates that are about 30-50 percent less than OTP standard rates. The following are programs and strategies offered through OTP. Several of the programs provide both summer and winter load control. Those that provide both summer and winter control (such as heat pumps) are included in the separate summer and winter categories.

- Summer Load - Air Conditioning Control - Res
- Summer Load - Air Conditioning Control - Com
- Summer Load - Water Heat Control - Com
- Summer Load - Water Heat Control - Res
- Summer Load - Residential Demand Control
- Winter Load - Residential Demand Control

- Winter Load - Deferred Load - Res
- Winter Load - Deferred Load - Com
- Winter Load - Fixed Time of Delivery - Res
- Winter Load - Fixed Time of Delivery - Com
- Winter Load - Small Dual Fuel - Res
- Winter Load - Small Dual Fuel - Com
- Winter Load - Large Dual Fuel - Com

7.4.1 Program Descriptions

7.4.1.1 CoolSavings Air Conditioning Control

This program is open to all customers with central air conditioning. In this program, OTP cycles the participant's air conditioner on and off every 15 minutes during summer peak conditions. Participants receive a $7 credit on their electric bill each month from June through September. There is no cost to participate. OTP installs a radio receiver, allowing them to cycle the cooling system. Commercial customers in MN may qualify to receive a $5 per ton credit on their electric bill each month from June through September.

7.4.1.2 Residential Demand Control

Residential demand control (RDC) provides participants a rate that's about 25 percent lower than the standard electricity rates. Customers who have RDC units installed in their homes typically save about $300 a year on their energy costs. RDC works best if a participant uses electricity for all or part of their home-heating needs or if the participant has higher-than-average electricity use. Under the program, OTP will on occasional control operation of certain appliances. To participate, all electric load in the home is available for control down to the demand limit preset by the customer. Load is available for control during the winter season only. Water heating loads are controlled throughout the year.

7.4.1.3 Deferred Load

The Deferred Load rate saves participants up to 30 percent when compared to the standard electric rates. This special rate is open to both residential and non-residential customers. It works with thermal-storage technologies, including:

- Underfloor heating
- Central-storage furnaces
- Room units
- Thermal-storage cooling

These technologies charge during off-peak hours to keep the building warm (or cool) during energy control periods. Radio signals control service during peak and emergency conditions.

Additionally, cycled energy control is available during the summer season (June through September). That means that an air-source heat pump installed on this rate are available for cycling 15 minutes on, 15 minutes off, during peak periods.

7.4.1.4 Fixed Time of Delivery (TOD)

With the Fixed Time of Delivery Rate, OTP delivers electricity between 10 p.m. and 6 a.m. when demand on the system is low, to recharge thermal-storage heating or cooling systems. The energy stored at night is released throughout the day to keep the home or business warm or cool. This rate is less than half the standard price for electricity.

Thermal-storage heating systems include:

- Underfloor heat storage
- Central storage furnaces
- Room-sized units

Thermal-storage cooling system technologies can be installed in buildings to meet summer cooling needs.

7.4.1.5 Small and Large Dual Fuel

In a dual-fuel system electricity is the primary heating fuel during normal off-peak conditions. A non-electric backup system supplies heat during energy control. OTP sends radio signals to switch from one fuel to the other automatically. OTP supplies and installs the necessary meter and radio controls. Dual fuel options include:

- Plenum heaters - installed where the existing furnace and the ductwork system meet. Air warms as it flows over heating elements inside the plenum.
- Air-source heat pumps - under the dual fuel rates, the units are cycled on and off in 15-minute increments, but only during peak summer control periods.
- Fossil fuel/electric boilers - heats water distributed to radiators, hydronic baseboards, or in-floor hydronic heating system.
- For areas that aren't well heated, supplemental electric heat installed as part of a dual-fuel system can help keep every room comfortable.
    - Electric baseboard – units are installed near the floor
    - Cove heat - radiant heaters are installed near the ceiling.
    - Ceiling panels - radiant panels embedded with heating cables installed in the ceiling.

7.4.1.6 Water Heater Control

This program is open to all customers with electric water heaters. The Controlled Service Water Heating rate is about 25 percent less than our standard price for electricity. Water heater control can also occur under a number of different programs when the customer also has a heating system that is subject to control such as:

- Deferred Load
- RDC
- Dual Fuel

7.4.2 Methodology

The method used to estimate future load reduction installed capacity for the load control programs utilized the same decision maker logic used for the DSM programs. What is forecast by ELRAM are the new additions to the load control programs and their cost.

The decision maker logic is based on payback diffusion curves. However, the payback diffusion curve logic is modeled using energy and not demand capacity. This required that the load control capacities be tied to an artificial energy savings value. The demand capacity per application utilized the model's energy/demand ratios. The ratios were set so that each application provides all of the kW capacity expected, but only 1 kWh of savings.

7.4.3 Technical and Economic Potential

Technical and economic potential are the same amount as all of the load control programs have a TRC of at least 1.0. Figure 29 illustrates the technical/economic potential and total installed kW for controlled loads by program in 2017. On average, the OTP direct load control programs installed kW is about 17% of technical potential. The highest percentage at 29% of technical potential is the commercial sector small dual fuel program. The lowest percentage at 2% of technical potential is the commercial sector A/C cycling program.

The commercial sector large dual fuel program provides the most technical/economic potential at 177.7 MW but control of residential water heaters provides the greatest amount of installed kW at 38.9 MW by 2017. The smallest amount of technical/economic potential at 18.6 MW is provided by the control of commercial sector water heaters and the smallest amount of installed kW at 0.5 MW is from the commercial sector A/C cycling program in 2017.

Table 24 provides the technical/economic program potential data by year. Table 25 provides the total installed kW by program by year.

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Figure 29. Installed kW and Technical/Economic Potential for Direct Load Control Programs in 2017

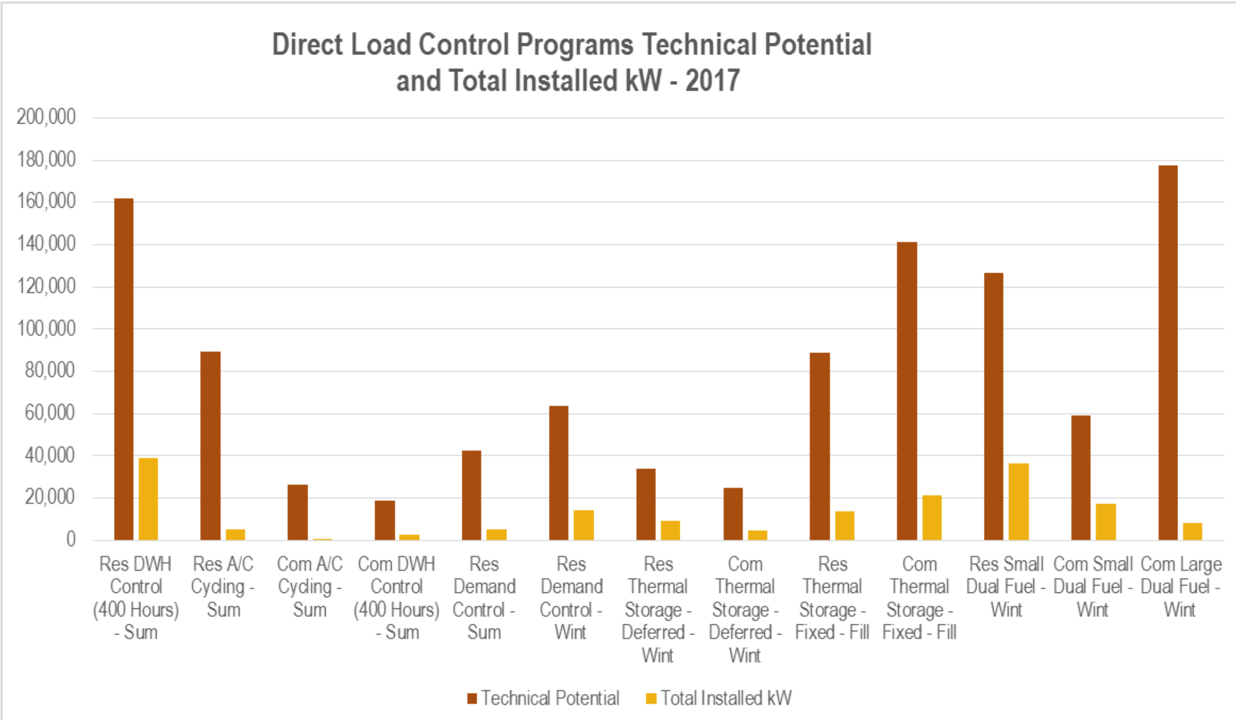


Table 24. Installed kW Technical/Economic Potential for Direct Load Control Programs

Program	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Res DWH Control (400 Hours) - Sum	162,104	162,885	163,576	164,226	164,808	165,150	165,324	165,391	165,391	165,391	165,391	165,391	165,391	165,391	165,391
Res A/C Cycling - Sum	89,216	89,645	90,026	90,384	90,704	90,892	90,988	91,025	91,025	91,025	91,025	91,025	91,025	91,025	91,025
Com A/C Cycling - Sum	26,103	26,184	26,261	26,337	26,411	26,475	26,532	26,586	26,636	26,683	26,727	26,770	26,808	26,842	26,874
Com DWH Control (400 Hours) - Sum	18,563	18,620	18,675	18,729	18,781	18,827	18,868	18,906	18,941	18,975	19,007	19,037	19,064	19,088	19,111
Res Demand Control - Sum	42,245	42,203	42,160	42,118	42,076	42,034	41,992	41,950	41,908	41,866	41,824	41,783	41,741	41,699	41,657
Res Demand Control - Wint	63,367	63,304	63,241	63,177	63,114	63,051	62,988	62,925	62,862	62,799	62,737	62,674	62,611	62,549	62,486
Res Thermal Storage - Deferred - Wint	33,928	33,894	33,860	33,826	33,792	33,759	33,725	33,691	33,657	33,624	33,590	33,557	33,523	33,490	33,456
Com Thermal Storage - Deferred - Wint	24,685	24,761	24,834	24,906	24,975	25,036	25,090	25,141	25,188	25,232	25,275	25,315	25,351	25,383	25,413
Res Thermal Storage - Fixed - Fill	88,714	88,626	88,537	88,448	88,360	88,272	88,183	88,095	88,007	87,919	87,831	87,743	87,656	87,568	87,480
Com Thermal Storage - Fixed - Fill	140,957	141,392	141,809	142,220	142,618	142,964	143,275	143,562	143,832	144,086	144,328	144,555	144,761	144,949	145,120
Res Small Dual Fuel - Wint	126,735	126,608	126,481	126,355	126,229	126,102	125,976	125,850	125,724	125,599	125,473	125,348	125,222	125,097	124,972
Com Small Dual Fuel - Wint	59,243	59,425	59,601	59,774	59,941	60,086	60,217	60,338	60,451	60,558	60,659	60,755	60,842	60,920	60,992
Com Large Dual Fuel - Wint	177,728	178,276	178,802	179,321	179,822	180,259	180,650	181,013	181,354	181,673	181,978	182,265	182,525	182,761	182,977

Table 25. Total Installed kW Forecast by Program and Year

Program	Total Installed kW 2017	Total Installed kW 2018	Total Installed kW 2019	Total Installed kW 2020	Total Installed kW 2021	Total Installed kW 2022	Total Installed kW 2023	Total Installed kW 2024	Total Installed kW 2025	Total Installed kW 2026	Total Installed kW 2027	Total Installed kW 2028	Total Installed kW 2029	Total Installed kW 2030	Total Installed kW 2031
Res DWH Control (400 Hours) - Sum	38,935	39,030	39,128	39,227	39,329	39,432	39,537	39,645	39,755	39,867	39,981	40,097	40,216	40,337	40,461
Res A/C Cycling - Sum	5,288	5,759	6,253	6,744	7,239	7,733	8,228	8,724	9,219	9,714	10,210	10,705	11,201	11,696	12,191
Com A/C Cycling - Sum	532	705	887	1,068	1,250	1,432	1,615	1,798	1,982	2,165	2,350	2,534	2,719	2,903	3,089
Com DWH Control (400 Hours) - Sum	2,389	2,419	2,450	2,481	2,513	2,545	2,578	2,612	2,646	2,681	2,717	2,753	2,791	2,829	2,867
Res Demand Control - Sum	5,004	5,067	5,132	5,198	5,266	5,335	5,405	5,477	5,550	5,625	5,701	5,778	5,858	5,938	6,021
Res Demand Control - Wint	14,345	14,441	14,538	14,638	14,739	14,842	14,948	15,055	15,165	15,277	15,391	15,508	15,626	15,748	15,871
Res Thermal Storage - Deferred - Wint	9,023	9,219	9,428	9,638	9,848	10,058	10,267	10,476	10,685	10,893	11,102	11,309	11,517	11,724	11,931
Com Thermal Storage - Deferred - Wint	4,701	4,722	4,744	4,766	4,789	4,812	4,835	4,859	4,883	4,908	4,934	4,959	4,986	5,013	5,040
Res Thermal Storage - Fixed - Fill	13,668	14,006	14,345	14,687	15,026	15,366	15,704	16,044	16,381	16,720	17,057	17,394	17,730	18,067	18,402
Com Thermal Storage - Fixed - Fill	21,445	21,999	22,560	23,127	23,692	24,262	24,831	25,403	25,975	26,549	27,123	27,699	28,276	28,853	29,432
Res Small Dual Fuel - Wint	36,240	37,739	39,321	40,954	42,615	44,291	45,973	47,658	49,344	51,029	52,712	54,394	56,073	57,750	59,425
Com Small Dual Fuel - Wint	16,995	17,479	17,995	18,527	19,066	19,609	20,153	20,700	21,249	21,798	22,350	22,902	23,456	24,010	24,566
Com Large Dual Fuel - Wint	8,365	8,630	8,901	9,177	9,459	9,746	10,039	10,337	10,642	10,953	11,270	11,593	11,923	12,260	12,603

Figure 30 illustrates the 2017 technical/economic and total installed kW for controlled loads by type of program in 2017. The greatest technical/economic potential is from residential summer controlled loads. The largest amount of installed kW is from residential winter controlled loads. Table 26 provides the data for this figure as well as for the years through 2031.

Figure 30. Installed kW Technical/Economic Potential for Direct Load Control Programs by Sector and Type in 2017

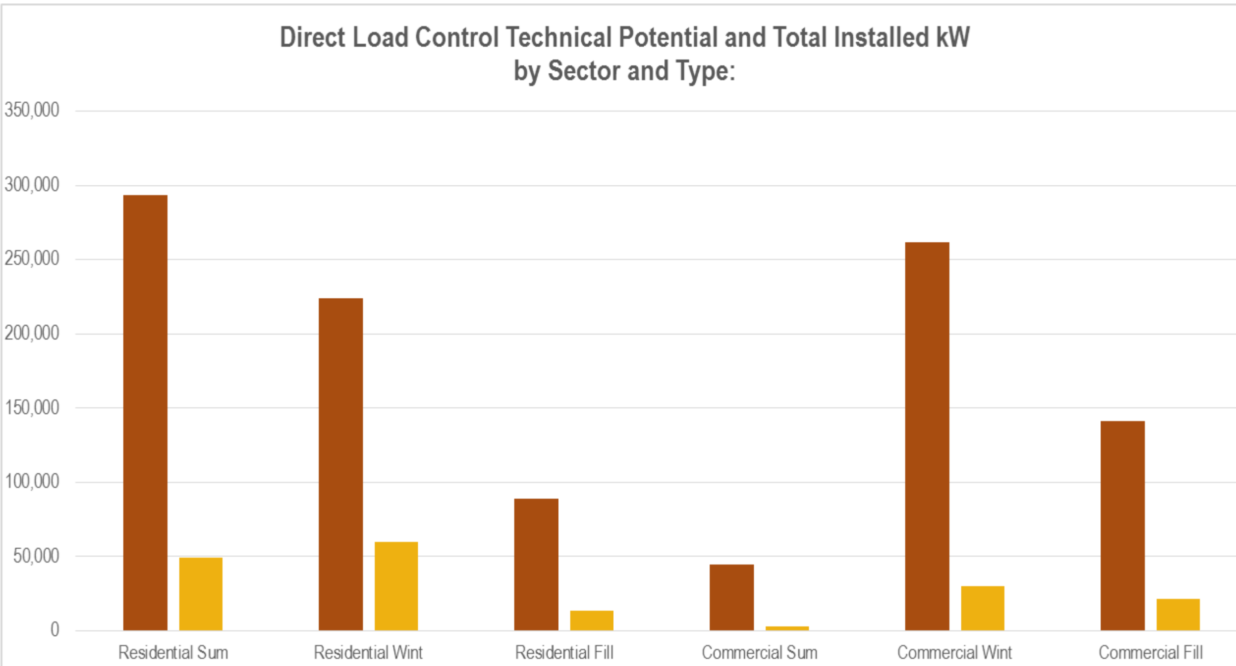


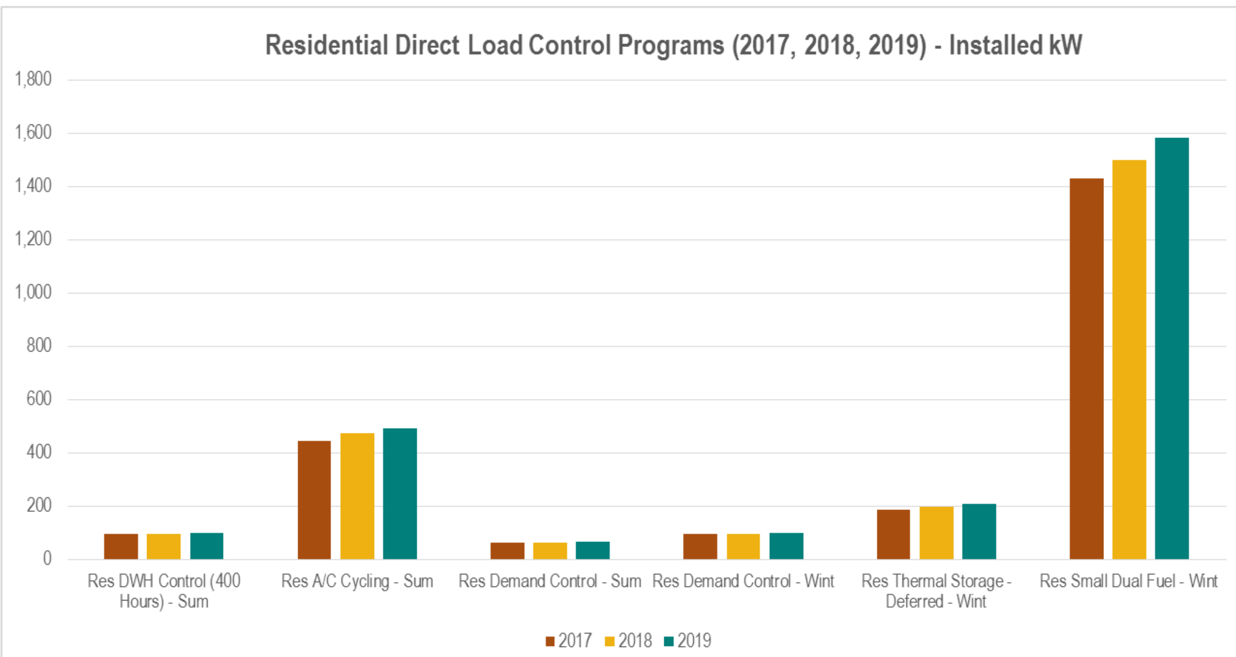
Table 26. Installed kW Technical/Economic Potential for Direct Load Control Programs by Sector and Type

Technical Potential	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential Sum	293,564	294,733	295,762	296,729	297,588	298,077	298,305	298,367	298,325	298,283	298,241	298,199	298,157	298,116	298,074
Residential Wint	224,030	223,806	223,582	223,359	223,135	222,912	222,689	222,466	222,244	222,022	221,800	221,578	221,356	221,135	220,914
Residential Fill	88,714	88,626	88,537	88,448	88,360	88,272	88,183	88,095	88,007	87,919	87,831	87,743	87,656	87,568	87,480
Commercial Sum	44,666	44,804	44,936	45,066	45,192	45,302	45,400	45,491	45,577	45,657	45,734	45,806	45,871	45,931	45,985
Commercial Wint	261,656	262,462	263,237	264,000	264,739	265,381	265,957	266,491	266,993	267,464	267,912	268,335	268,717	269,065	269,382
Commercial Fill	140,957	141,392	141,809	142,220	142,618	142,964	143,275	143,562	143,832	144,086	144,328	144,555	144,761	144,949	145,120
Total	1,053,588	1,055,821	1,057,863	1,059,822	1,061,632	1,062,908	1,063,810	1,064,473	1,064,978	1,065,431	1,065,845	1,066,217	1,066,519	1,066,762	1,066,955
Installed kW	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Residential Sum	49,226	49,857	50,513	51,169	51,833	52,500	53,171	53,846	54,524	55,206	55,891	56,581	57,274	57,971	58,673
Residential Wint	59,609	61,399	63,287	65,230	67,202	69,191	71,188	73,190	75,194	77,199	79,205	81,211	83,217	85,222	87,228
Residential Fill	13,668	14,006	14,345	14,687	15,026	15,366	15,704	16,044	16,381	16,720	17,057	17,394	17,730	18,067	18,402
Commercial Sum	2,922	3,124	3,336	3,549	3,763	3,977	4,193	4,410	4,628	4,847	5,067	5,287	5,509	5,732	5,956
Commercial Wint	30,061	30,832	31,640	32,470	33,313	34,166	35,027	35,897	36,774	37,660	38,553	39,455	40,365	41,283	42,210
Commercial Fill	21,445	21,999	22,560	23,127	23,692	24,262	24,831	25,403	25,975	26,549	27,123	27,699	28,276	28,853	29,432
Total	**176,930**	**181,218**	**185,682**	**190,232**	**194,829**	**199,462**	**204,115**	**208,788**	**213,476**	**218,180**	**222,896**	**227,627**	**232,371**	**237,129**	**241,900**

7.4.4 Controlled Load Base Results

Figure 31 illustrates the projected incremental load reduction installed capacity in the years 2017, 2018, and 2019 from residential sector direct load control programs. Included in the figure are projected load reductions for summer load reduction and winter load reduction. Each bar represents an incremental addition to the installed kW by program. For example, for residential A/C cycling, in 2017, the incremental addition to installed kW is 443 kW, followed in 2018 by an additional 472 kW, and in 2019 494 kW. The residential dual fuel program, which provides winter load reduction, provides the largest amount of load reduction installed capacity. A/C cycling provides the second largest amount of load reduction installed capacity with its capacity available in the summer. The data for this figure is included in Table 27.

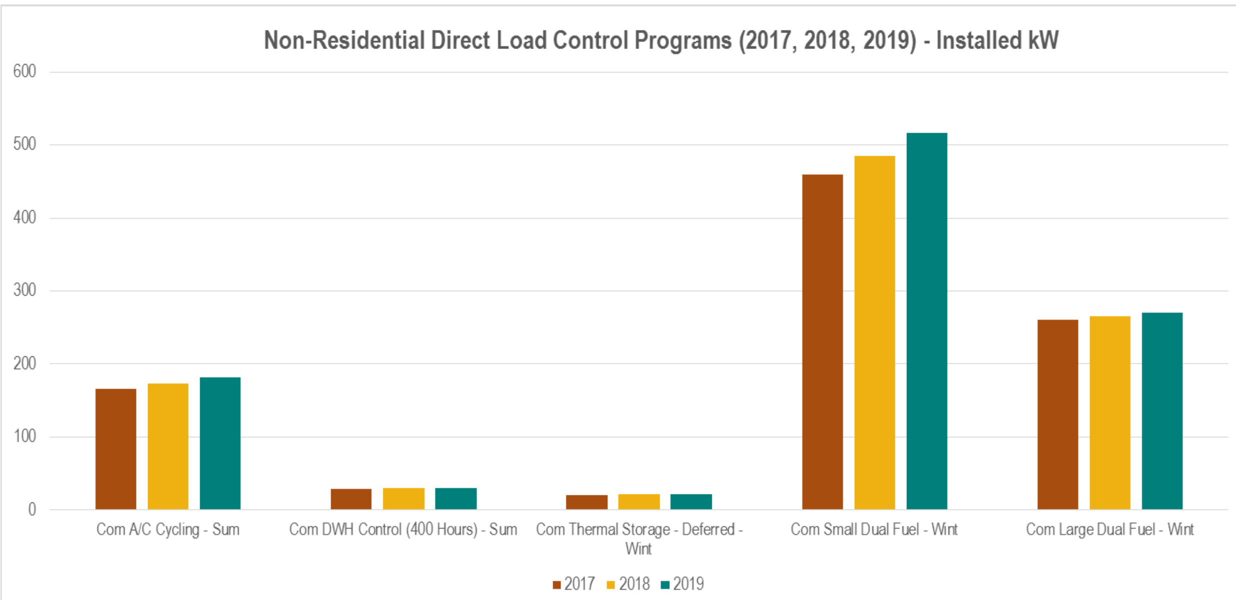
Figure 31. Residential Direct Load Control Programs (kW Installed)



Source: Navigant 2015

Figure 32 illustrates the projected incremental load reduction installed capacity in the years 2017, 2018, and 2019 from non-residential sector direct load control programs. The non-residential large and small dual fuel programs provide the largest amount of load reduction installed capacity. Each of these programs provides winter peak load reduction potential. A/C cycling provides the largest summer load reduction installed capacity potential.

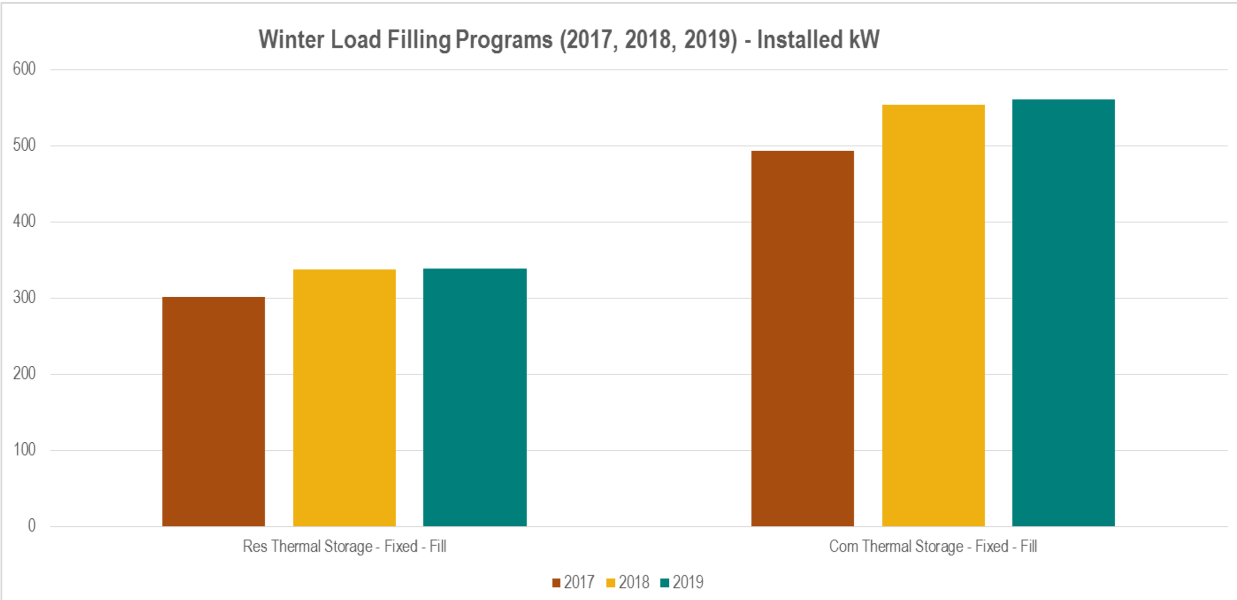
Figure 32. Non-Residential Direct Load Control Programs (kW Installed)



Source: Navigant 2015

Figure 33 illustrates the projected incremental load reduction installed capacity amounts in the years 2017, 2018, and 2019 from the residential and commercial winter load filling programs.

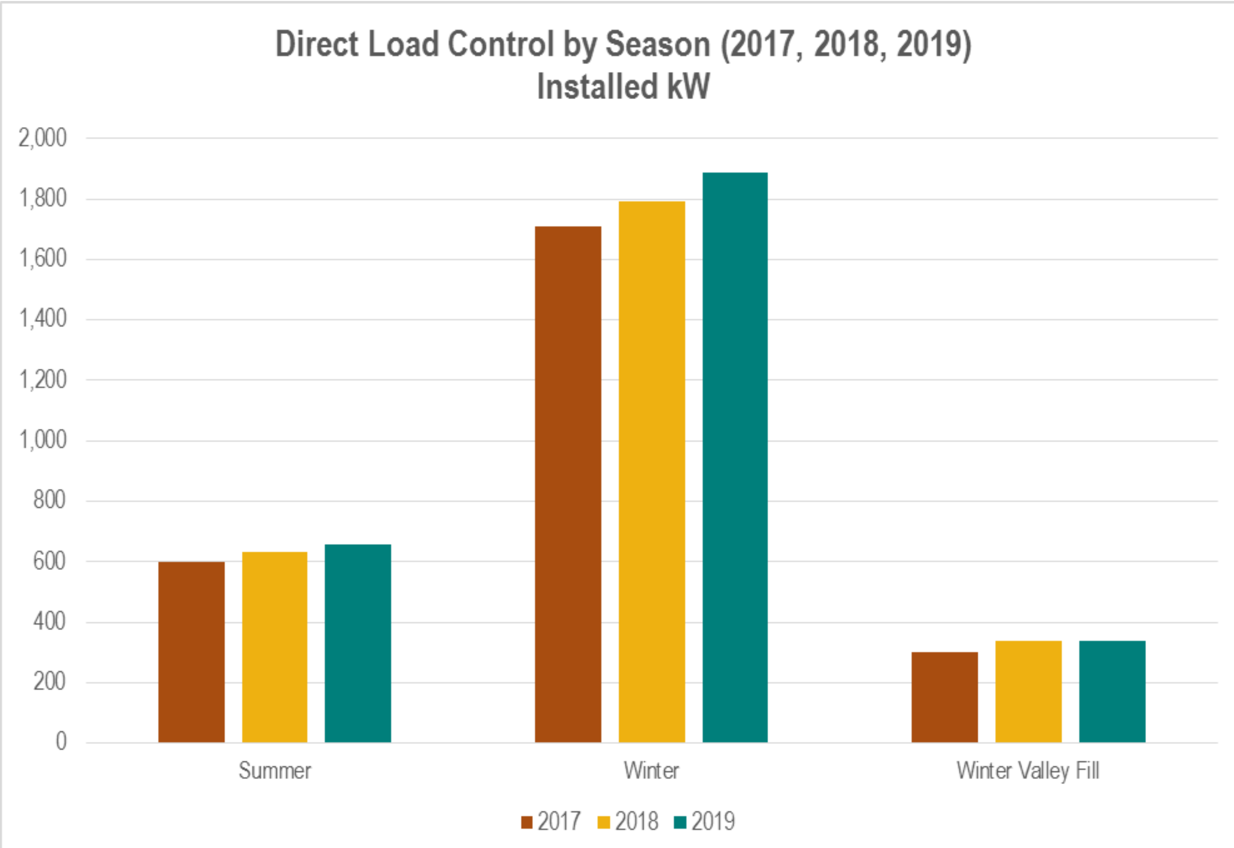
Figure 33. Winter Load Filling Programs (kW Installed)



Source: Navigant 2015

Figure 34 illustrates the projected incremental load reduction installed capacity amounts in the years 2017, 2018, and 2019 by season and type from the load reduction or valley filling programs. The winter load reduction installed capacity is just over three times larger than the summer load reduction installed capacity.

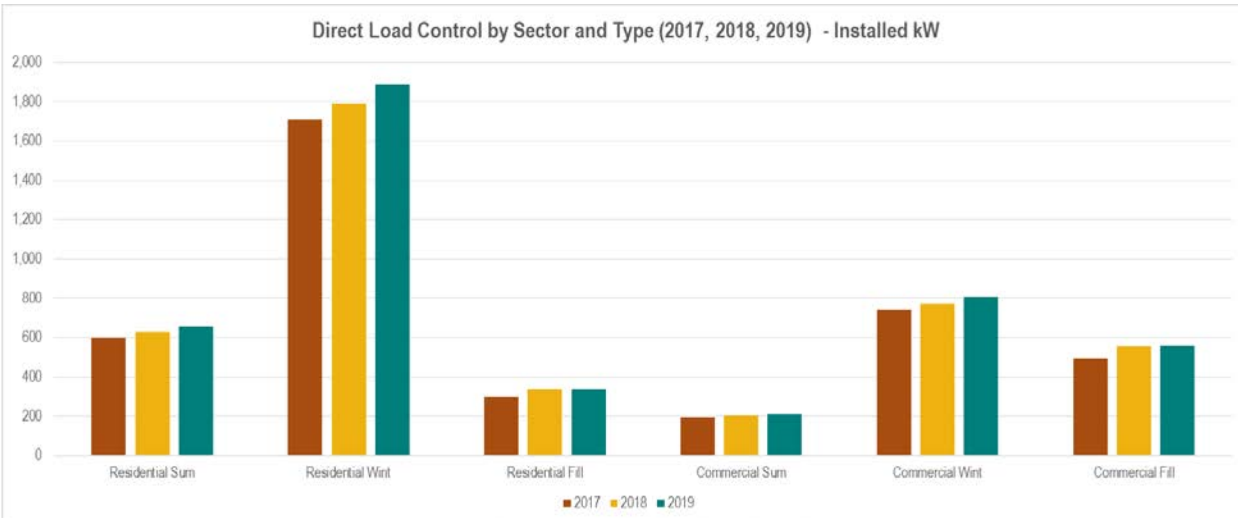
Figure 34. Direct Load Control Programs by Season (kW Installed)



Source: Navigant 2015

Figure 35 illustrates the projected incremental total kW load reduction installed capacity in the years 2017, 2018, and 2019 by sector from the load reduction and valley filling programs. The residential sector winter load reduction programs offer the greatest amount of installed capacity potential.

Figure 35. Direct Load Control Programs by Sector and Type (kW Installed)



Source: Navigant 2015

Table 27 provides the values illustrated in Figures 29 -33. In addition, the table provides the estimates of installed capacity load reduction or shift by program through the year 2031.

Table 27. Direct Load Control Programs (kW Installed)

Program	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Res DWH Control (400 Hours) - Sum	94	96	97	99	101	103	105	108	110	112	114	116	119	121	124
Res A/C Cycling - Sum	443	472	494	491	495	494	495	495	495	495	495	495	495	495	495
Com A/C Cycling - Sum	166	173	181	181	182	182	183	183	183	184	184	184	185	185	185
Com DWH Control (400 Hours) - Sum	29	30	31	31	32	32	33	34	34	35	36	36	37	38	39
Res Demand Control - Sum	62	64	65	66	68	69	70	72	73	75	76	78	79	81	82
Res Demand Control - Wint	94	96	97	99	101	103	105	108	110	112	114	116	119	121	124
Res Thermal Storage - Deferred - Wint	187	196	208	210	210	210	209	209	209	208	208	208	208	207	207
Com Thermal Storage - Deferred - Wint	21	21	22	22	23	23	23	24	24	25	25	26	26	27	27
Res Thermal Storage - Fixed - Fill	302	338	339	342	339	340	338	339	338	338	337	337	336	336	336
Com Thermal Storage - Fixed - Fill	494	554	561	567	566	569	569	572	572	574	574	576	577	578	578
Res Small Dual Fuel - Wint	1,430	1,499	1,582	1,633	1,661	1,675	1,682	1,685	1,686	1,685	1,683	1,681	1,679	1,677	1,675
Com Small Dual Fuel - Wint	459	485	516	532	539	542	545	547	548	550	551	552	554	555	556
Com Large Dual Fuel - Wint	260	265	271	276	282	287	293	299	305	311	317	323	330	336	343

Source: Navigant 2015

Table 28 provides the estimates of incremental cost by program for each forecasting year.

Table 28. Direct Load Control Program Costs ($)

Program	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Res DWH Control (400 Hours) - Sum	$7,607	$7,760	$7,915	$8,073	$8,234	$8,399	$8,567	$8,739	$8,913	$9,092	$9,273	$9,459	$9,648	$9,841	$10,038
Res A/C Cycling - Sum	$23,645	$25,182	$26,340	$26,193	$26,409	$26,391	$26,443	$26,434	$26,439	$26,437	$26,438	$26,437	$26,437	$26,437	$26,437
Com A/C Cycling - Sum	$8,898	$9,263	$9,720	$9,722	$9,755	$9,776	$9,798	$9,817	$9,835	$9,852	$9,869	$9,884	$9,898	$9,911	$9,922
Com DWH Control (400 Hours) - Sum	$2,383	$2,431	$2,480	$2,529	$2,580	$2,631	$2,684	$2,738	$2,793	$2,848	$2,905	$2,963	$3,023	$3,083	$3,145
Res Demand Control - Sum	$4,528	$4,619	$4,711	$4,805	$4,902	$5,000	$5,100	$5,202	$5,306	$5,412	$5,520	$5,630	$5,743	$5,858	$5,975
Res Demand Control - Wint	$6,792	$6,928	$7,066	$7,208	$7,352	$7,499	$7,649	$7,802	$7,958	$8,117	$8,279	$8,445	$8,614	$8,786	$8,962
Res Thermal Storage - Deferred - Wint	$31,803	$33,261	$35,341	$35,664	$35,627	$35,576	$35,526	$35,475	$35,425	$35,375	$35,324	$35,274	$35,224	$35,174	$35,124
Com Thermal Storage - Deferred - Wint	$3,530	$3,601	$3,673	$3,747	$3,822	$3,898	$3,976	$4,055	$4,137	$4,219	$4,304	$4,390	$4,478	$4,567	$4,658
Res Thermal Storage - Fixed - Fill	$22,452	$25,133	$25,223	$25,432	$25,202	$25,337	$25,169	$25,254	$25,127	$25,177	$25,080	$25,105	$25,029	$25,037	$24,975
Com Thermal Storage - Fixed - Fill	$36,748	$41,261	$41,762	$42,171	$42,101	$42,375	$42,355	$42,552	$42,568	$42,716	$42,752	$42,868	$42,907	$42,995	$43,034
Res Small Dual Fuel - Wint	$63,043	$66,080	$69,740	$72,018	$73,240	$73,873	$74,178	$74,301	$74,322	$74,287	$74,221	$74,136	$74,042	$73,943	$73,841
Com Small Dual Fuel - Wint	$20,257	$21,364	$22,762	$23,452	$23,757	$23,918	$24,023	$24,105	$24,177	$24,242	$24,303	$24,360	$24,412	$24,460	$24,504
Com Large Dual Fuel - Wint	$7,527	$7,678	$7,831	$7,988	$8,148	$8,311	$8,477	$8,646	$8,819	$8,996	$9,176	$9,359	$9,546	$9,737	$9,932

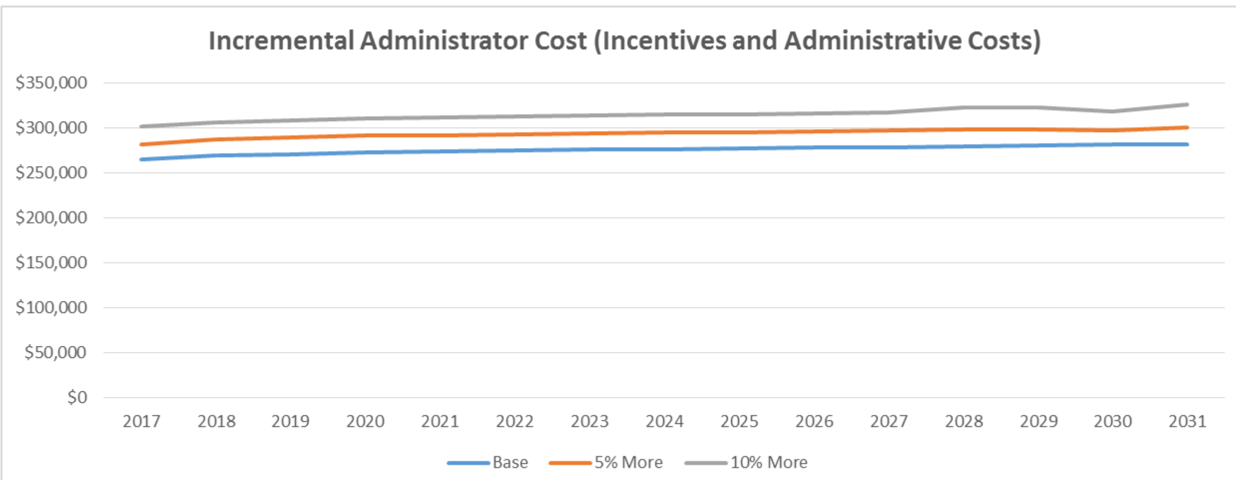
Source: Navigant 2015

7.4.5 Controlled Load Scenario Results for a 5% Increase and a 10% Increase in Controlled Loads

In addition to the base case, which models the market potential for controlled loads in a "business as usual" condition, Navigant also developed two additional scenarios; one for achieving 5% more and the other 10% more incremental installed controlled load market potential compared to the base scenario. The primary purpose of this exercise is to estimate the additional costs for achieving these high levels of controlled loads. To achieve these goals, the modeling team increased incentives, administrative costs, and program budgets.

The administrator cost (combined administrative and incentive cost) for each scenario is provided in Figure 36. Table 29 provides the data illustrated in the Figure. On average, the cost for the 5% scenario is 6.5% greater than the base scenario and for the 10% scenario, 14.1% more than the base scenario. These costs are relatively close to the incremental increases in installed capacity.

Figure 36. Administrator (Administrative & Incentive) Cost by Scenario



Source: Navigant 2015

Table 29. Administrator (Administrative & Incentive) Cost by Scenario

Cost	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Base	$264,566	$269,001	$271,126	$272,984	$273,944	$275,121	$275,818	$276,769	$277,443	$278,311	$279,000	$279,829	$280,546	$281,359	$282,102
5% More	$281,941	$287,092	$289,588	$291,291	$292,042	$293,302	$293,948	$294,960	$295,631	$296,592	$297,285	$298,209	$298,936	$296,863	$300,999
10% More	$302,093	$306,208	$308,673	$310,589	$311,687	$313,040	$313,777	$314,950	$315,622	$316,727	$317,400	$323,090	$323,391	$318,529	$326,418
Cost Increase	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
5% More	6.6%	6.7%	6.8%	6.7%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	5.5%	6.7%
10% More	14.2%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	13.8%	15.5%	15.3%	13.2%	15.7%

Source: Navigant 2015

Appendix K
TAB

Appendix K: Distributed Renewable Generation

Distributed Renewable Generation

Existing Distributed Renewable Generation Projects

Otter Tail currently has 40 interconnected facilities with over 5.6 MW of installed nameplate capacity of distributed renewable generation (DG) on its system. The majority of these facilities are customer owned units that are utilizing the small power producer tariffs that exist in all three jurisdictions that Otter Tail operates.

New Distributed Renewable Generation Projects

Otter Tail expects new small customer owned DG facilities to continue to grow over time. Otter Tail does not expect that the increase in distributed generation facilities on its system will have an impact on the current preferred resource plan.

In order for DG facilities to have an impact on Otter Tail's resource plan, the facilities will need to be competitive with other generation facilities available to Otter Tail including the cost of capacity and energy in the Midcontinent ISO market. That is a difficult hurdle in today's energy market.

Wholesale energy prices remain low following the economic recession, the increasing penetration of wind generation, and continuing low natural gas prices. Annual average Locational Marginal Prices ("LMP") at the OTP.OTP load zone in the day-ahead market remain low:

2010: $28.00/MWh
2011: $24.80/MWh
2012: $23.84/MWh
2013: $28.23/MWh
2014: $34.27/MWh
2015: $21.97/MWh
2016 (YTD April 25): $18.26/MWh

While it can be argued that there are transmission and distribution loss savings to be realized, the magnitude of those savings will not come close to offsetting the additional cost of the energy.

Otter Tail will continue to analyze renewable distributed generation projects that are submitted for consideration. However, with its RES/REO obligations met in all three states, Otter Tail will only consider projects that are competitive with the Midcontinent ISO energy market or are needed to meet renewable objectives or the solar mandate in the service territory that it serves.

In order to keep customers bills as low as possible, it is prudent for Otter Tail to enter into only projects that are cost competitive with the Midcontinent ISO market.

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