Minnesota Department of Commerce Demand Response Impact Study

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Executive Summary

Demand response events are used by utilities to reduce system-wide demand on peak load days, typically summer weekday afternoons. There are many ways to reduce this peak demand by controlling equipment at customer facilities. These methods include cycling air conditioners, disabling water heaters, utilizing thermal energy storage, and simply curtailing service to customers with backup capacity. Many of these methods move the customer's equipment away from its standard operating set points during the demand response event, leading to snapback. Snapback is the increase in energy and demand in the hours immediately following a demand response event.

This study investigated these methods of demand response in order to determine their net energy and demand impacts, including snapback effects. The study utilized three methods of investigation: research on previous studies related to demand response, gathering and analyzing aggregate system load and demand response data from two large Minnesota utilities during demand control days, and using energy modeling to analyze various demand response controls applied to typical residential and small commercial buildings. The analysis in this study focused entirely on facilities and utilities located in Minnesota and used Minneapolis weather data. It found consistency between the actual utility data for demand response events, published research from other states, and modeling results.

The technologies used for demand response that exhibit snapback are: air conditioner cycling, water heater curtailment, and electric heating cycling. Other technologies that are often used do not have snapback effects due to the nature of their operations. These include ice storage, electric heating thermal storage, and on-site generation.

The results of this analysis produced deemed energy and demand savings values for: demand response and snapback for entire utilities, residential air conditioner cycling, water heater curtailment (in both winter and summer peaks), electric heat cycling, and electric heating thermal storage, as well as commercial packaged rooftop unit ice storage. These deemed savings values are intended to be used as estimates for utilities to determine the energy and demand impacts of demand response technologies.

The results of this study show that although most demand response events produce significant snapback, there is still a net energy savings. The snapback and normalized energy savings results are shown for each utility in Table 1. The source and customer energy savings per demand response event have been

normalized by load relief and load control capacity to make the results more meaningful to other utilities.

TABLE 1 - UTILITY DEMAND RESPONSE ANALYSIS RESULTS

	Utility Name	
Value	Xcel Energy	Great River Energy
Snapback as a Percentage of Source Energy Savings	1.3%	6.9%
Source Net Energy Savings/Load Relief [MMBTU/MW]	103	106
Customer Net Energy Savings/Load Control Capacity [MWh/MW]	3.7	2.85

Introduction

The first intent of this study is to identify, characterize, and quantify the energy impacts of demand response events in Minnesota using aggregated data from two utilities. The second intent is to study, using energy modeling, the effects of air conditioner and electric heat cycling, domestic water heater curtailment, and electric thermal storage on single-family homes and ice storage on small commercial buildings. In order to meet electric demand on peak days (days where the electric system demand is at its highest, approaching the limits of the generating capacity of the grid), utilities initiate demand response events to temporarily interrupt service to customers who have volunteered to participate in the interruptible program. This reduces the system demand enough to prevent the utility from using its reserve capacity and/or starting up low-efficiency peaking power plants. These temporary service interruptions, or demand response events, can last anywhere from a few minutes to 12 hours, depending on system loads. For industrial customers, these interruptions often involve complete cessation of electrical service. For commercial and residential customers, they typically involve only cycling of primary cooling equipment, since this equipment is the primary demand driver on peak days, which usually occur in the summer months when the outdoor air temperature is high.

The most common cycling scheme is a 50% cycling control [1] [2] [3] [4] (also called direct load control or DLC), where the air conditioning units being controlled will be allowed to operate 50% of the time and forced off 50% of the time during the event, usually in 15-minute increments. Other methods of control include programmable communicating thermostat set up (also known as PCT), where the utility increases the cooling set point temperature of a building during an event to reduce the air conditioner operation and complete shut off of all air conditioning equipment. These same methods can also be applied to electric heating equipment. Domestic water heaters are almost always controlled using direct load control with curtailment (the heater is turned off completely during the event and the building must run off the stored heat in the tank).

Residential buildings will often encounter an increase in energy consumption and demand in the hours following a demand response event. This is called the “snapback” effect. This occurs because the space temperature in a home drifts up during a demand response event and once the event ends, the air conditioning system will try to return the space temperature back to its original set point. On a very warm day, the interior temperature could drift significantly from the set point and require significant cooling to return to the set point, leading to higher energy use than if the set point had been maintained during the event. Snapback effects also occur with heating and domestic hot water control. This study investigates snapback effects and includes them in the net demand response event energy savings.

The utility-wide effects of demand response were analyzed using data from two large Minnesota utilities, Xcel Energy[1] and Great River Energy Cooperative. The data provided consists of hourly demand (in megawatts) for each of the days in a given year that had a demand response event. This data also included the results of each utility's regression modeling of the system demand in the absence of demand response to determine an estimate of the amount of load relief created by the demand response event.

To further understand the effects of demand response on the residential sector, an energy model of three sizes of typical single-family homes were used to determine the energy impacts of demand response on a single home. The air conditioner was cycled (50% of the event time, every 15 minutes) during a simulated demand response event lasting seven hours, from 1 pm to 8 pm, and the resulting energy impacts (before, during, and after the event) were recorded when compared to a simulation with no demand response event. A similar method was used to evaluate the impacts of disabling domestic water heaters in homes during a demand response event in both winter and summer peak periods. The use of electric thermal storage systems (or ETS) were analyzed and modeled as well, although the effects of these off-peak heating devices could not be integrated with an energy simulator and had to be modeled more simplistically. Additionally, an energy simulation was performed on several typical small commercial facilities to determine the net energy and demand impacts of thermal storage devices, namely ice storage, when demand response events are encountered, as well as their annual energy impacts.

[1] Note from Xcel regarding this data: While Xcel Energy is happy to provide this data and analysis for our demand control in 2007, it is important to recognize that the electricity market has changed significantly for us since that time and data from more recent years would not have the same patterns or results. The recent recession decreased our electric loads, for both demand and energy sales to the extent that we've not used demand reduction programs in recent years. Our supplies have been sufficient for peak demand periods to allow customers to continue to operate without curtailment events. This study is significant and important for us to consider however as the electricity market rebounds and we again need demand response programs.

Previous Research on Demand Response Impacts

Several government entities, primarily in California, have previously studied demand response impacts. One prominent study [5] was completed in 2011 by the California Energy Commission (CEC) and involved the three investor-owned utilities in California. The study detailed the ex post load impact of aggregator demand response programs for these utilities. This study quantified the energy and demand savings for each utility's demand response programs. It is of note that the study did not combine results across utilities, "due to underlying differences in the number and timing of event days, the industry mix that is participating in each jurisdiction and other factors such as partial dispatch of resources." This study did not address so-called "snapback", or post-demand response event increases in demand and energy consumption due to increased HVAC loading, despite the fact that snapback (also called rebound) effects were evident in the data and charts provided in the study.

A Pacific Gas & Electric study [6] in 2008 focused on residential air conditioner demand response impacts using either programmable communicating thermostats (PCTs) or direct control switches on the air conditioning system. This study did quantify both demand response savings and snapback on a per-customer basis. It used a cooling load baseline model based on a regression analysis of air conditioning kW versus outdoor air temperature to determine what the hourly kW would have been if no demand response event had been triggered. The limitations of this study are that it only examined 578 homes and there were no actual control events during 2008, only a system test. Additionally, there were 18 tests on the sample homes without the control homes, and only a peak snapback effect from the data set, not an aggregate or average effect, was produced. The peak demand reduction was 0.86 kW per device with a peak snapback effect of 0.46 kW. This study also noted that higher snapback impacts occurred the day after the demand response event. A 2009 impact evaluation of the demand control program for Xcel Energy in Minnesota showed 1.93 kWh saved per customer per event for air conditioner DLC, with 1.07 kW of net load relief for the system per customer per event.

Lawrence Berkeley Laboratory conducted an extensive study [4] of DLC for air conditioners and water heaters in the PJM grid area (East Coast) to determine deemed savings values. They produced tables that demonstrate the deemed kW savings at 5 pm for air conditioners based on weather conditions, cycling scheme, and typical air conditioner size (in kW). Similarly, they developed tables for domestic water heaters, where the kW demand reduction is based on the season, day of the week, and hour of the day. The values of water heater demand savings range from 0.12 kW to 0.84 kW. The air conditioner savings range from 0.01 kW to 3.03 kW, with a heavy dependence on outdoor air conditions and % cycling. At 50% cycling and a weighted temperature and humidity index of 84°F, the tables predict 0.8 kW.

Two studies [7] [8] focused on using energy modeling software to model demand response events and compared the energy modeling results to metered energy use on the modeled buildings to determine the accuracy of these models. Both of these studies showed that energy models can produce a reasonably accurate depiction of the energy and demand impacts of demand response events on commercial and residential facilities. This report will utilize this fact to justify the use of energy modeling software to model demand response event effects in a typical home and small commercial facility.

Electric thermal storage (ETS) and domestic water heater control have also been studied for demand response impacts. A Bonneville Power Administration's study [9] showed the energy impacts for both winter domestic hot water and electric heating (thermostat control) control and summer air conditioning and domestic hot water (DHW) control. In the sample studied, the average winter demand savings during demand response events was 1.65 kW/participant, while the summer demand savings was 0.65 kW/participant. The summer data also showed that domestic hot water heater control alone produced 0.26 kW/participant in demand savings. This report also shows significant snapback after each event, though it is not addressed in detail and is not quantified generally, only on an individual event basis for each of the events of the year studied. This study included both electric resistance heating and heat pumps in its heating analysis, but did not separate the two. The method of heating control was thermostat set back. Off-peak electric thermal storage was not considered. Water heater control was not separated from heating control in the winter event data.

ETS involves using, most commonly, ceramic bricks in an insulated container with integrated electric heating coils to store large quantities of heat during off-peak hours when electric rates are low and then discharging the stored heat, usually with the aid of a fan, during on-peak hours. Researchers at Argonne National Laboratory [10] studied off-peak ETS and its potential in the early 1980s. This included a study of ETS systems installed in 45 homes in Vermont, along with control homes for comparison. The study concluded that room ETS units had a societal benefit-cost ratio of 3.4 and central units had a ratio of 5.6. These same researchers developed performance curves, sizing guidelines, and other information related to ETS systems that were used in ASHRAE handbooks [11].

The East Kentucky Power Cooperative's latest integrated resource plan [12] shows a societal benefit-cost ratio of 2.63 for ETS systems and a combined benefit-cost ratio of 1.67. Furthermore, the plan shows 2012 program participants (70) saving 0.4 MW of winter peak demand, for an average of 5.7 kW/participant and an *increase* in energy by 8 MWh, or 114 kWh/participant. This plan also has 6,500 participants saving 301 MWh of energy, 2 MW of peak winter demand, and 8.4 MW of summer peak demand in 2012 for water heater and air conditioner direct load control. This leads to 46 kWh of energy savings, 0.31 kW of winter demand savings, and 1.29 kW of summer demand savings per participant. Since the winter demand savings here is for domestic hot water only, this matches well with the 0.26 kW/participant seen in the Bonneville data.

Thermal energy storage encompasses all forms of storing thermal energy (heating or cooling potential) for use at a later time, when it is more advantageous or cost-effective. Ice storage is a common form of thermal energy storage used to reduce on-peak cooling energy consumption. On-peak energy (typically 1 pm - 8 pm on hot, summer weekdays) is the most expensive energy and almost always coincides with peak cooling loads. Therefore, shifting cooling loads to off peak hours is very desirable. Ice storage allows for this shift by using cooling equipment to freeze a large volume of water overnight, when energy is inexpensive, available cooling capacity is large, and outdoor temperatures are low. This large block of ice is then used during peak hours to provide cooling, bypassing or assisting the chiller or packaged unit's compressor.

Ice storage in large commercial buildings using chilled water and chillers has been studied extensively, as evidenced by its inclusion in most popular energy modeling programs, such as eQuest [13] and EnergyPlus [14]. However, chilled water systems represent a minority [15] of the air conditioning units in the U.S., especially in small commercial buildings. The Department of Energy [15] uses packaged single zone systems as benchmark HVAC equipment in 9 out of 15 commercial building types (for buildings built after 1980) and in 10 out of 15 building types for older buildings. Packaged units provide cooling to 44% [16] of all commercial buildings with cooling, while central chillers provide cooling to only 3%.

Very little information exists about ice storage on these packaged systems. The largest source of information and equipment in this sector is Ice Energy. Ice Energy manufactures the Ice Bear system, which provides about 30 ton-hours [17] of ice storage for each unit and can be retrofit to existing rooftop units (RTU) by running refrigerant lines from the Ice Bear to the RTU and installing an additional evaporator coil in the RTU to transfer heat to and from the Ice Bear unit. Ice Energy performed a pilot study in Anaheim, California on a fire station [18]. The results show significant peak demand savings, but are inconclusive about the annual energy impacts of the Ice Bear units. Another report [19] issued by engineers at Ice Energy for ASHRAE concludes that the Ice Energy systems are "energy neutral or better." This report includes an evaluation of the Ice Bear technology for application in small commercial buildings for demand reduction. The net energy impacts will also be investigated in this study. The Ice Bear unit will be the focus of the ice storage analysis since, as mentioned above, packaged rooftop units represent the largest opportunity and impact the largest number of customers.

Minnesota Utility Demand Response Data

Two large Minnesota utilities, one investor-owned (Xcel Energy) and one cooperative (Great River Energy), provided system load data for a total of 29 demand response events. The Xcel Energy data (8 events) was from 2007, while the Great River Energy data (21 events) was from 2011. This data shows both measured system load and the load reduction produced by the demand response compared to a regression-based predicted baseline load (developed by each utility). This data includes hourly demand for all 24 hours of each event day. The data was aggregated into one typical system load for each utility by averaging the system load each hour across all of the days with demand response events. Table 1 shows the data for Xcel Energy.

TABLE 2 – XCEL ENERGY HOURLY LOADS ON DEMAND RESPONSE EVENT DAYS

	Hourly Loads (MW)								
Hour	6/26/2007	7/24/2007	7/25/2007	7/26/2007	7/30/2007	7/31/2007	8/1/2007	9/5/2007	AVG
1	6,081	5,955	6,208	6,613	5,452	6,130	6,146	5,882	6,058
2	5,777	5,620	5,846	6,221	5,185	5,863	5,770	5,597	5,735
3	5,564	5,391	5,589	5,970	5,015	5,595	5,550	5,306	5,498
4	5,440	5,289	5,474	5,786	4,938	5,460	5,429	5,236	5,382
5	5,475	5,376	5,512	5,800	4,984	5,455	5,435	5,279	5,415
6	5,777	5,662	5,797	6,048	5,306	5,765	5,744	5,638	5,717
7	6,401	6,169	6,312	6,572	5,714	6,192	6,206	6,280	6,231
8	7,070	6,756	6,897	7,141	6,351	6,780	6,794	6,690	6,810
9	7,632	7,256	7,430	7,650	6,833	7,328	7,295	7,042	7,308
10	8,090	7,647	7,882	8,065	7,205	7,718	7,725	7,448	7,723
11	8,418	8,109	8,278	8,488	7,670	8,094	8,126	7,893	8,135
12	8,624	8,395	8,595	8,716	7,996	8,248	8,408	8,247	8,404
13	8,713	8,542	8,697	8,802	8,214	8,234	8,446	8,526	8,522
14	8,724	8,663	8,656	8,803	8,389	8,252	8,530	8,636	8,582
15	8,633	8,662	8,786	8,715	8,434	8,283	8,541	8,558	8,577
16	8,372	8,650	8,788	8,340	8,485	8,366	8,646	8,534	8,523
17	8,395	8,570	8,771	8,246	8,560	8,375	8,645	8,555	8,515
18	8,425	8,464	8,618	8,166	8,585	8,449	8,612	8,517	8,480
19	8,305	8,382	8,633	7,864	8,614	8,542	8,533	8,526	8,425
20	8,110	8,224	8,647	7,668	8,422	8,385	8,332	8,307	8,262
21	7,761	8,074	8,481	7,422	8,192	8,145	8,136	8,287	8,062
22	7,556	7,982	8,423	7,338	8,031	7,994	7,944	7,827	7,887
23	7,021	7,368	7,830	6,870	7,380	7,340	7,356	7,124	7,286
24	6,279	6,749	7,148	6,307	6,704	6,627	6,704	6,475	6,624

The average for each hour is simply the mean value for each of the columns in its row. Great River Energy's data involves 21 events, and is not shown here for brevity. To determine the system level snapback and demand reduction, an average megawatts saved (or increased, for snapback) per hour value was determined for each hour. Using the hourly load relief data provided by the utilities along with a control history, it was discovered that the average demand response event lasts between 7 and 8 hours. For Xcel Energy, the events centered around the time period of 11 am to 7 pm, with some starting later or ending earlier, but all falling within this time period. This time period was selected to develop the aggregate load reduction profile for Xcel Energy. Great River Energy's events occurred at a later time, 3 pm to 10 pm. The hourly load relief data (Table 2) for Xcel Energy shows the amount of load relief (or snapback) for each hour of the day during a demand response event day.

TABLE 3 - HOURLY LOAD RELIEF FOR XCEL ENERGY

	Hourly Load Relief (MW)						Control Period	
Hour	6/26/2007	7/24/2007	7/25/2007	7/26/2007	7/30/2007	7/31/2007	8/1/2007	9/5/2007
1	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0
8	2	10	11	18	-8	-9	2	15
9	-8	-7	-9	23	7	-14	9	16
10	-17	3	-14	5	16	5	-5	-8
11	11	-17	-5	10	-7	74	5	-15
12	82	-23	23	94	-25	185	44	2
13	220	16	101	277	-20	380	151	9
14	358	74	292	489	13	561	333	132
15	467	186	413	642	133	690	416	263
16	609	230	462	741	172	663	402	351
17	596	225	443	551	167	637	389	342
18	375	151	417	247	109	441	284	278
19	197	66	271	202	4	209	115	82
20	56	-12	93	91	-14	29	14	0
21	19	-18	5	105	-21	-25	9	10
22	38	15	-36	30	1	-15	4	21
23	8	13	-19	19	-12	-21	-16	-12
24	9	-19	-26	17	-26	-24	-19	-16

Table 3 shows the modified version of this data after irrelevant pre-event hours and post-event hours that show no snapback (since the goal was to characterize events with snapback effects) are removed for each event day. This data was then used to produce an average megawatt saved per hour for the time period of 11 am to 7 pm. The resulting profile shows the aggregated load reduction and snapback per event for each hour. This profile was then applied to the average system load profile for each utility to develop the deemed savings per demand response event. The next section of this report details the process of determining the deemed savings from these profiles.

It should be noted here that Great River Energy's data was noticeably different from Xcel Energy's data. Snapback effects were only apparent for one hour after each event and there was much more variability in the start and end times of each event. The pre-event and event load relief values were aggregated as before, but the snapback effects were calculated by averaging the snapback for each event day, and then this average snapback value was applied to the hour immediately after the aggregated demand response event schedule (3 pm to 10 pm).

TABLE 4 – XCEL ENERGY LOAD RELIEF (ADJUSTED)

Hour	Load Relief (MW)								Time Period
1	0	0	0	0	0	0	0	0	Pre-Event
2	0	0	0	0	0	0	0	0	Pre-Event
3	0	0	0	0	0	0	0	0	Pre-Event
4	0	0	0	0	0	0	0	0	Pre-Event
5	0	0	0	0	0	0	0	0	Pre-Event
6	0	0	0	0	0	0	0	0	Pre-Event
7	0	0	0	0	0	0	0	0	Pre-Event
8	0	0	0	0	0	0	0	0	Pre-Event
9	0	0	0	0	0	0	0	0	Pre-Event
10	0	0	0	0	0	0	0	0	Pre-Event
11	11	0	0	10	0	74	0	0	DR Event
12	82	0	23	94	0	185	44	0	DR Event
13	220	16	101	277	0	380	151	9	DR Event
14	358	74	292	489	13	561	333	132	DR Event
15	467	186	413	642	133	690	416	263	DR Event
16	609	230	462	741	172	663	402	351	DR Event
17	596	225	443	551	167	637	389	342	DR Event
18	375	151	417	247	109	441	284	278	DR Event
19	197	66	271	202	0	209	115	0	DR Event
20	0	-12	0	0	-14	0	0	0	Snapback
21	0	-18	0	0	-21	-25	0	0	Snapback
22	0	0	-36	0	0	-15	0	0	Snapback
23	0	0	-19	0	-12	-21	-16	-12	Snapback
24	0	-19	-26	0	-26	-24	-19	-16	Snapback

Information on generator heat rates and efficiencies and generation types and capacities were collected using the U.S. Energy Information Agency's reports [20] [21] [22] [23] [24]. This information was used to determine the source energy saved during a demand response event by loading the generators up with the system load at each hour, starting with the base load generators and ending with the peak generators (gas turbines). Each utility has a unique mixture of generator types and heat rates and a resulting difference in source energy efficiency. These efficiencies were applied to the energy saved or consumed during and after the aggregate demand response event to determine the source energy impacts of each event. Transmission and distribution losses were included as well and were based off of each utility's publicly filed transmission and distribution loss factors for residential and non-residential customers [25] [26] [27]. These loss factors are shown in Table 4 for each utility. The final row of the table is the weighted average of the residential and non-residential values, based on the proportion of the total demand reduction capacity participating in the utility's demand reduction program for each customer type. For example, according to the U.S. EIA [20] [21], Xcel Energy had 923 MW of program participation in 2007, with 372 MW from residential customers. This proportion was used to weight the transmission and distribution loss factors.

TABLE 5 - TRANSMISSION AND DISTRIBUTION LOSSES

Transmission and Distribution Loss Factors

	Xcel Energy (2007 values)		Great River Energy (2011 values)	
	kW	kWh	kW	kWh
Residential	8%	8%	4.7%	4.7%
Non-Residential	6%	6%	4.7%	4.7%
Weighted Avg	6.8%	6.8%	4.7%	4.7%

Aggregate Demand Response Analysis

The data provided by the utilities was used to develop a deemed savings for each demand response event for each utility. The two utilities were kept separate for the same reasons cited in the Pacific Gas & Electric study. The average demand and snapback were calculated for each hour of the day for the provided event days for each utility. Table 5 shows the Xcel Energy and Great River Energy typical daily load curves on peak days and the adjusted load curves for demand response and snapback. These profiles were developed as described in the previous section.

TABLE 6 - SYSTEM LOAD PROFILES

	Xcel Energy System Loads			Great River Energy System Loads		
Hour	Typical Profile (Baseline),in MW	Actual Profile (DR), in MW	Reduction (MW)	Typical Profile (Baseline),in MW	Actual Profile (DR), in MW	Reduction (MW)
1	6058	6058	0	1528	1528	0
2	5735	5735	0	1370	1370	0
3	5498	5498	0	1283	1283	0
4	5382	5382	0	1238	1238	0
5	5415	5415	0	1235	1235	0
6	5717	5717	0	1297	1297	0
7	6231	6231	0	1430	1430	0
8	6810	6810	0	1560	1560	0
9	7308	7308	0	1662	1662	0
10	7723	7723	0	1752	1752	0
11	8135	8135	0	1832	1832	0
12	8457	8404	53	2006	1902	105
13	8666	8522	144	2075	1933	142
14	8863	8582	282	2114	1950	164
15	8978	8577	401	2061	1956	105
16	8977	8523	454	2105	1962	142
17	8933	8515	419	2139	1975	164
18	8767	8480	288	2186	2001	184
19	8557	8425	133	2180	1999	181
20	8259	8262	-3	2128	1963	165
21	8054	8062	-8	2080	1979	100
22	7881	7887	-6	2036	1982	54
23	7276	7286	-10	1842	1855	-13
24	6608	6624	-16	1712	1712	0

To determine the peak generator MW savings for each demand response event, the peak load reduction for each utility was divided by the last generator efficiency. The last generator efficiency was computed by collecting heat rate (fuel efficiency) data from the Energy Information Administration [23] [24] on the generators for each utility and averaging the heat rates for each type of generator: small coal, medium coal, large coal, nuclear, gas turbine, refuse, gas turbine combined cycle, wind, and grid purchased. The average heat rate for each generator type was then converted to an efficiency (%) by taking the conversion factor 3,413 BTU/kWh and dividing by the heat rate (in BTU/kWh).

$$Efficiency = \frac{3{,}412\ BTU/kWh}{Generator\ Heat\ Rate\ \left[\frac{BTU\ input}{kWh\ output}\right]}$$

As anticipated, the gas turbine "peaking" plants had the lowest average thermal efficiency. As the least efficient generators, these were assumed to be the last generators to come online. Therefore, any peak demand savings resulting from demand response should be applied to the gas turbine capacity first, since they would be the first generators to be taken offline in a demand response event, as they are the most expensive to operate based on fuel efficiency. Therefore, demand savings at the source up to the total gas turbine capacity was calculated based on the average efficiency of each utility's gas turbine generators.

The source energy per demand event was computed by taking the peak load relief in MW, accounting for transmission and distribution losses and the average gas turbine generator efficiency, applying unit conversions, and using a one-hour time step. The final value was produced in MMBTU/demand response event hour, where MMBTU is one million BTU (British thermal units) of source energy. The average number of hours per event was determined based on the event history provided by each utility. Xcel Energy had an average of 7.625 hours/event, while Great River Energy had an average of 7.33 hours. From this information, a gross source energy savings per demand response event (in MMBTU) was computed by multiplying the MMBTU/hour by the average number of hours per event.

$$Source\ Energy\ \left[\frac{MMBTU}{h}\right] = \frac{Peak\ Load\ Relief\ [MW]}{(1 - Trans.\&\ Dist.Losses\ (\%)) \times (GT\ Gen.Eff.)} \times \frac{3{,}412{,}000\ [BTU]}{1\ [MWh]} \times \frac{1\ [MMBTU]}{1000000\ [BTU]}$$

The net source energy savings per event included the effects of snapback and subtracted the snapback source energy increase from the gross source energy savings.

$$\begin{aligned} Net\ Source\ Energy\ Savings\ [MMBTU] \\ &= Gross\ Source\ Energy\ Savings\ [MMBTU] \\ &- Snapback\ Source\ Energy\ Increase\ [MMBTU] \end{aligned}$$

The snapback energy increase was determined in a similar fashion as the gross savings. For each hour of snapback after the aggregate demand response event for each utility, the snapback MW from the load profile was multiplied by 1 hour, converted to BTU, and then divided by the last generator efficiency and transmission and distribution losses, before being converted to MMBTU. The net MMBTU source energy savings per demand response event was then computed by subtracting the sum of the source energy increase for each snapback hour from the gross savings value computed earlier.

$$Snapback\ Source\ Energy\ Increase\ = \sum_{h=1}^{End\ of\ Snapback} Source\ Energy\ Increase\ \ Per\ Hour$$

In order to make this value more universal, the MMBTU source energy savings were also divided by the MW participating in the demand response program to determine an MMBTU/MW participating deemed savings value.

$$\frac{MMBTU}{MW} = \frac{Net\ Source\ Energy\ Savings\ [MMBTU]}{Controlled\ Load\ Participating\ in\ Program\ [MW]}$$

An alterative presentation of the deemed savings per event was calculated to provide another tool for utilities to evaluate the impacts of demand response events. This value, the MWh saved/MW participating, provides a measure of the customer energy saved in relation to the load relief capacity participating in the demand response program. To compute this value, the customer MWh/h saved in the peak hour of the demand response was multiplied by the average length of the event, then the sum of the snapback energy increase (in MWh) after the event was subtracted, and finally, this value was divided by the total MW participating in the demand response program for each utility. This value can then be used by utilities moving forward to calculate the net energy impacts of demand response events. Since this value is based on the MW participating in the program, it can be scaled for each utility based on the program participation. All of the deemed savings values can be seen in Table 6 in the Results section.

$$\frac{MWh}{MW} = \frac{Cust.Energy\ Saved\ [MWh/h] \times Avg.Event\ Length\ [h] - Snapback\ Energy\ [MWh]}{Customer\ Load\ Participating\ in\ the\ Program\ [MW]}$$

Demand Response Energy Modeling

Residential Model Assumptions

To better evaluate the demand response impacts on residential buildings, an energy model was created in BEopt [28] and EnergyPlus [14] energy modeling software to simulate demand response events and monitor the impacts on an hourly basis before, during, and after the event. The parameters of the model were developed by using typical existing housing information from a previous Minnesota Department of Commerce study [29] on geothermal heating and cooling and from U.S. Census data [30] for the Minneapolis/St.Paul metropolitan area. An existing small house, existing large house, and an existing median (median Census Twin Cities house) house were used. Table 6 shows the characteristics from the geothermal study and those used in this study. Because NREL's BEopt software only allows a discrete set of input values, the values closest to those from the geothermal study were selected. The large house model used four bedrooms and three bathrooms. The small house model used two bedrooms and two bathrooms. The median house used three bedrooms and two bathrooms.

TABLE 7 - RESIDENTIAL MODELING PARAMETERS

	Small Residential - Geothermal	Large Residential - Geothermal	Small Residential - BEopt	Large Residential - BEopt	Median Residential - BEopt
Building Size (sq. ft.)	1,216	2,520	1,230	2,520	2,169
Number of floors	1	2	1	2	2
Aspect Ratio	1.20	1.60	1.20	1.60	1.60
Floor to Floor Height (ft)	10	10	10	10	10
Plenum Height (ft)	N/A	N/A	N/A	N/A	N/A
Zones per Floor	1	1	1	1	1
Perimeter Zone Depth (ft)	N/A	N/A	N/A	N/A	N/A
Glazing Fraction	0.11	0.11	0.15	0.15	0.15
Occupancy (ft^2/person)	405	504	N/A	N/A	N/A
Ventilation (cfm/person)	0.00	0.00	0	0	0
Lighting (W/ft^2)	0.7	0.7	Benchmark	Benchmark	Benchmark
Plug Loads (W/ft^2)	1.1	1.1	Benchmark	Benchmark	Benchmark
Construction Type	Wood Frame	Wood Frame	Wood Frame	Wood Frame	Wood Frame
Roof Insulation R-Value	25	25	25	25	25
Wall Insulation R-Value (ASHRAE Zone 6)	11	11	11	11	11
Glazing SHGC (ASHRAE Zone 6)	0.73	0.73	0.73	0.73	0.73
Glazing SHGC (North) (ASHRAE Zone 6)	0.73	0.73	0.73	0.73	0.73
Glazing U-Value	1.1	1.1	1.1	1.1	1.1
Glazing U-Value (North)	1.1	1.1	1.1	1.1	1.1
Infiltration	0.9	0.9	0.9	0.9	0.9
System Type	Split	Split	Split	Split	Split
Fan Control	CV	CV	CV	CV	CV
Baseline Cooling Type	DX	DX	DX	DX	DX
Baseline Heating Type	F	F	F	F	F
Baseline Cooling EER	13 SEER	13 SEER	13 SEER	13 SEER	13 SEER
Baseline Heating Eff	80%	80%	80%	80%	80%

The BEopt software was selected because it is designed to model residential buildings and makes it easy to generate input files for EnergyPlus, which is the software that performs the necessary calculations based on the detailed input information from BEopt. A demand response event was simulated on July 15 and the air conditioning was cycled every 15 minutes during the event, which lasted for 7 hours, from 1 pm to 8 pm. A domestic water heater demand response event was also simulated on these homes on both winter (January 28) and summer peak days. The winter demand event occurred from 4 pm to 7 pm. Minneapolis TMY2 weather data was used in all of the simulations. The summer event schedule was selected based on the data provided by the two utilities in this study, which showed that 1 pm to 8 pm was the most common control period. The winter event schedule was selected based on the fact that Xcel

Energy triggers events on winter afternoons [31] and Great River Energy's website [3] shows that their winter loads peak in the late afternoon and early evening hours. Although there are a variety of control methods, 50% cycling of air conditioners was used in this model because it is the most commonly used [3] [31] scheme in Minnesota. Load curtailment during the event was used for domestic water heaters, since that is the most common form of control for those systems, according to the websites of both of the utilities [3] [31]. July 15 was selected as the summer peak day because the TMY2 weather data showed that the outdoor air temperature was near the annual peak and the following day had a nearly identical temperature profile in order to properly evaluate snapback effects that may linger into the next day after a demand response event. January 28th was selected for the winter event because it was one of the coldest days in the TMY2 weather data and the following day's temperature profile was very similar.

The BEopt and EnergyPlus software was used to size the heating and air conditioning systems for each example home. When a parameter was not defined in the geothermal study, the default value from BEopt was used, as NREL (National Renewable Energy Laboratory) developed the default values to represent a typical U.S. home. The following assumptions were made in developing the model: neighboring houses (one to the east and one to the west) were identical in size and shape and spaced 20 feet apart, the home is oriented north, the heating set point is 68°F, the cooling set point is 76°F, the humidity set point is 60%, miscellaneous gas, hot water, and electrical loads are set at the Building America Benchmark [32] values, natural ventilation is also set to the benchmark value, the building slab is uninsulated, the floor is 20% exposed, the drywall is ½-inch, the windows occupy 15% of the wall area, interior shading values from the Building America Benchmark, two-foot eaves, spot ventilation only, standard efficiency electric appliances (including a top-freezer refrigerator), Building America Benchmark lighting, typical, uninsulated ducts, Building America Benchmark ceiling fans, uninsulated copper hot water piping, and no dehumidifier.

In addition to water heating and air conditioning, electric heating cycling was also modeled on the example houses. The electric resistance furnace of the example houses was cycled in 15-minute increments during the winter demand event from 1 pm to 8 pm. This is one method of reducing heating energy consumption in homes with electric heat. Another method that was analyzed in this report, although it could not be integrated into BEopt due to technical limitations, was electric thermal storage (ETS). A whole-house ETS system was sized and modeled for the median example home in this report.

Small Commercial Ice Storage Model Assumptions

A small commercial building model was developed to determine the effects of thermal storage (ice storage) on cooling and fan energy and demand. Just as with the residential models, the existing small commercial building model from the previous geothermal study [29] was used as a basis for the model in this study. Table 7 compares the geothermal study small commercial building with the models (three different sizes) used in this study. The three different building sizes were selected carefully in order to model the desired rooftop unit cooling capacities. The modeled ice storage units are only available in 5-ton sizes, so each building size needed to require cooling in a multiple of 5 tons. Therefore, the 2,000 square foot building could be served by one 5-ton unit, the 4,000 square foot building could be served by two units (10 tons) and the 8,000 square foot building could be served by four units (20 tons).

eQuest was selected to perform the energy modeling for this technology because it is a more capable software for commercial building modeling than BEopt and is more user-friendly than EnergyPlus. Where values from the geothermal study were not available or undefined, the eQuest defaults were used based on a "two-story office" building type (the buildings were actually modeled as one-story, however) and eQuest's auto-sizing of the supply fan and cooling equipment was disabled to allow for consistent equipment sizes for all schedules. The building operation hours were varied for each building size to account for the effects of building schedule on the cooling loads, equipment runtimes, and energy use. Four different schedules were modeled. These schedules are shown in Table 8. These schedules were selected because they represent common small commercial building uses: a simple office schedule, an extended office schedule, a retail schedule, and a 24-hour facility. The eQuest model runs were used to determine the baseline cooling and fan energy use, when no ice storage is in use. eQuest does not permit modeling ice storage for packaged single zone air conditioning units, so a spreadsheet model was created to model the proposed system operation with ice storage.

TABLE 8 - SMALL COMMERCIAL BUILDING MODELS

	Small Office - Geothermal Study	2000 SF Office	4000 SF Office	8000 SF Office
Building Size (sq. ft.)	13,000	2,000	4,000	8,000
Number of floors	1	1	1.0	1
Aspect Ratio	1.2	1.2	1.2	1.2
Floor to Floor Height (ft)	13	13	13	13
Plenum Height (ft)	4	4	4	4
Zones per Floor	5	1	1	1
Perimeter Zone Depth (ft)	15	N/A	N/A	N/A
Glazing Fraction	0.41	0.41	0.41	0.41
Occupancy (ft^2/person)	275	275	275	275
Ventilation (cfm/person)	17	17	17	17
Lighting (W/ft^2)	1.57	1.57	1.57	1.6
Plug Loads (W/ft^2)	1.3	1.3	1.3	1.3
Construction Type	Steel Frame	Steel Frame	Steel Frame	Steel Frame
Roof Insulation R-Value	8.8	9	9	9
Wall Insulation R-Value (ASHRAE Zone 6)	2.1	2.0	2.0	2.0
Glazing SHGC (ASHRAE Zone 6)	0.52	0.52	0.52	0.52
Glazing U-Value	0.9	0.9	0.9	0.9
Glazing U-Value (North)	0.9	0.9	0.9	0.9
Infiltration	0.5	0.5	0.5	0.5
System Type	PVAV	PSZ	PSZ	PSZ
Fan Control	VAV	CV	CV	CV
Baseline Cooling Type	DX	DX	DX	DX
Baseline Heating Type	F	F	F	F
Baseline Cooling EER	9.8	9.8	9.8	9.8
Baseline Heating Eff	80%	80%	80%	80%
DHW efficiency	0.62	0.62	0.62	0.62
Fan Power	1.7 hp/1000 CFM	Auto-sized	Auto-sized	Auto-sized

TABLE 9 - SMALL COMMERCIAL BUILDING SCHEDULES

Schedule Name	Days of the Week			
	M-F	Sat.	Sun.	Holidays
Simple Office	8 am - 5 pm	Closed	Closed	Closed
Extended Office	8 am - 8 pm	8 am - 3 pm	Closed	Closed
Retail	8 am - 9 pm	8 am - 9 pm	10 am - 6 pm	Closed
24 hour	12 am - 12 am	12 am - 12 am	12 am - 12 am	12 am - 12 am

Ice Energy produces the Ice Bear 30, which is an ice storage system designed for packaged rooftop cooling units. It stores 30 tons-hours [17] of cooling energy, which is enough to replace a 5-ton rooftop unit for six hours. Each unit has its own compressor and can freeze up to 480 gallons of water. When the additional evaporator coil is installed in the rooftop unit to transfer heat between the existing RTU and the Ice Bear unit, additional static pressure is placed on the existing supply fan. This increases the energy consumption of the supply fan. This is counter-acted to some degree by the increased energy efficiency of the Ice Bear's compressor operating at cooler night time conditions over the rooftop unit's compressor operating in hot afternoon hours. This effect is tempered by the fact that the suction temperature required to make ice (often around 25°F) is much lower than required for space cooling (45°F), so the compressor lift and energy required is almost unchanged.

Table 9 and Table 10 show performance data from Ice Energy about the Ice Bear 30 units. The data from Table 10 was used to determine the minimum, maximum, and average static pressure increases caused by the addition of the ice storage evaporator coil. The three static pressure penalties were applied to each building model to demonstrate the range of energy and demand impacts related to these values. The data from Table 9 was used to develop performance curves of the Ice Bear units. These figures (Figure 1 and Figure 2) establish curve fits to data from the table and show the relationships between the Ice Bear's average power (kW) and the outdoor air temperature and between the unit's charging time (in hours), thermal storage (in ton-hours), and outdoor air temperature. Specifically, Figure 1 shows the relationship between power and outdoor air temperature, while Figure 2 shows the relationship between charging time per ton-hour of storage and outdoor air temperature. The charging time per ton-hour of storage is the slope of a linear fit of ice charge time and thermal storage data at various temperatures.

TABLE 10 - ICE MAKE CAPACITY & POWER AT AMBIENT TEMPERATURE FOR ICE BEAR 30

		Outdoor Temperature (°F)									
		55°		65°		75°		85°		95°	
		Capacity Stored (T-hrs)	Energy Consumed (kW-hr)	Capacity Stored (T-hrs)	Energy Consumed (kW-hr)	Capacity Stored (T-hrs)	Energy Consumed (kW-hr)	Capacity Stored (T-hrs)	Energy Consumed (kW-hr)	Capacity Stored (T-hrs)	Energy Consumed (kW-hr)
Time (hrs)	1	3.61	2.88	3.49	3.19	3.33	3.53	3.08	3.96	2.80	4.40
	2	7.15	5.72	6.76	6.33	6.47	7.00	6.00	7.84	5.46	8.70
	3	10.61	8.54	10.01	9.46	9.56	10.47	8.88	11.70	8.07	12.99
	4	14.03	11.35	13.22	12.59	12.62	13.94	11.71	15.55	10.66	17.27
	5	17.4	14.16	16.41	15.71	15.64	17.41	14.52	19.40	13.23	21.55
	6	20.77	16.97	19.59	18.83	18.66	20.87	17.32	23.24	15.79	25.83
	7	24.12	19.77	22.74	21.94	21.66	24.32	20.10	27.08	18.35	30.10
	8	27.46	22.57	25.89	25.04	24.64	27.78	22.88	30.92	20.89	34.37
	9	30.75	25.36	29.01	28.13	27.60	31.24	25.63	34.76	23.43	38.63
	10	31.57	26.06	31.57	30.71	30.52	34.70	28.38	38.59	25.95	42.89
	11					31.57	35.95	31.09	42.42	28.46	47.15
	12							31.57	43.11	30.94	51.40
	13									31.57	52.50
Actual Make Time (hrs)			9.24		9.84		10.36		11.17		12.25
Typical Demand (kW)			2.82		3.12		3.47		3.86		4.28

TABLE 11 - PERFORMANCE SUMMARY FOR ICE-READY ROOFTOP UNITS

Ice-Coil P/N	Unit		Tested Configuration with Ice Bear 30 Unit	Heat Transfer Capacity at 75° F		Additional Static Pressure Required at 400 scfm/ton (in. H_2O)
	RTU Model	Description		Ice-Coil (Btu/hr)	Ice + DX (Btu/hr)	
1861 (CA)	48TFF006	5-ton SE Carrier R-22 Gas Pack	Displaced 5T with ice storage	71,500	N/A	0.28
1861 (CA)	48TCEA06	5-ton HE Carrier R-410A Gas Pack	Displaced 5T with ice storage	60,800	N/A	0.3
2203 (CJ)	48PGDC06	5-ton UHE Carrier R-410A Gas Pack	Displaced 5T with ice storage	59,900	N/A	0.28
2501 (CK)	50HJQ006	5-ton HE Carrier R-22 Heat Pump	Displaced 5T with ice storage	61,000	N/A	0.15
2364 (TA)	WSC060E	5-ton SE Trane R-410A Heat Pump	Displaced 5T with ice storage	63,500	N/A	0.1
2364 (TE)	YSC092A	7.5-ton SE Trane R-22 Gas Pack	Displaced 4.5T with ice storage & DX	N/A	100,200	0.15
2205 (CE)	48PGD012	10-ton UHE Carrier R-410A Gas Pack	Displaced 5T with ice storage & DX	67,500	126,100	0.1
2527 (LA)	LGA120H4B	10-ton HE Lennox R-410A Gas Pack	Displaced 10T with dual Ice Bear 30 units	120,400	N/A	0.1
			Displaced 5T with ice storage & DX	58,600	127,200	0.1
2578 (YA)	ZH120N15N2	10-ton SE York R-410A Gas Pack	Displaced 10T with dual Ice Bear 30 units	120,300	N/A	0.15
			Displaced 5T with ice storage & DX	N/A	139,400	0.15
2463 (CF)	48TMF012	10-ton SE Carrier R-22 Gas Pack	Displaced 10T with dual Ice Bear 30 units	129,600	N/A	0.26
			Displaced 5T with ice storage & DX	70,000	135,100	0.26

FIGURE 1 - AVERAGE CHARGING POWER VERSUS OUTDOOR AIR TEMPERATURE

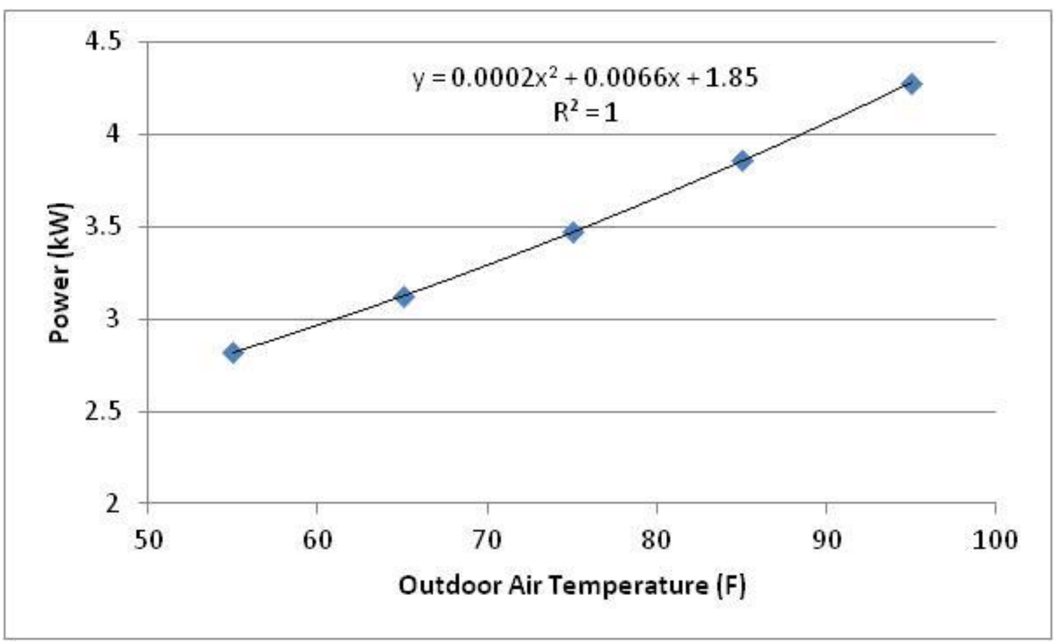
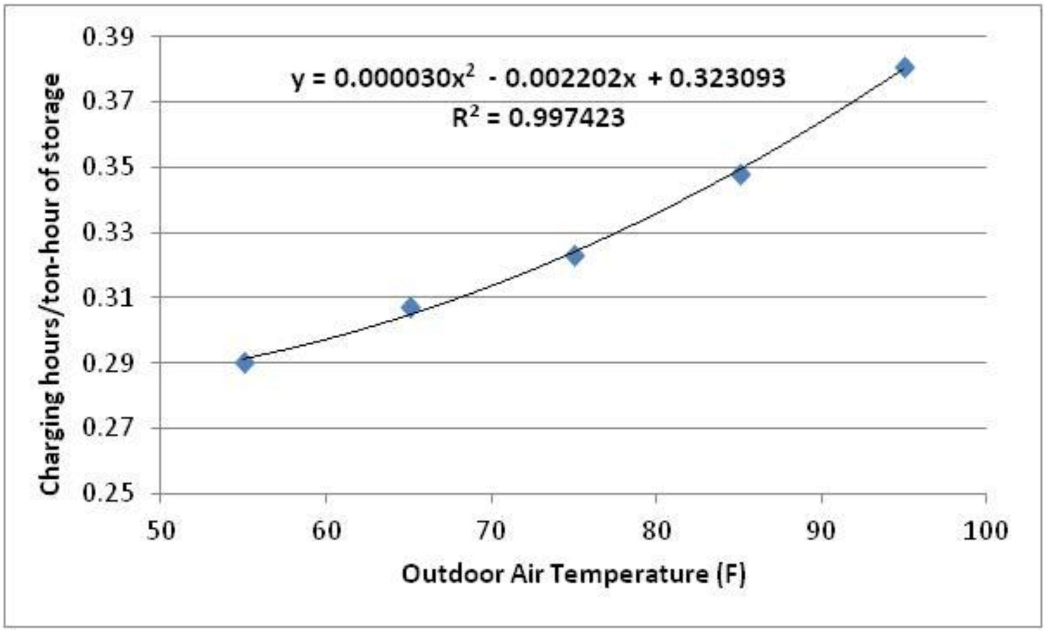


FIGURE 2 - CHARGING HOURS REQUIRED PER TON-HOUR OF STORAGE VERSUS OUTDOOR AIR TEMPERATURE



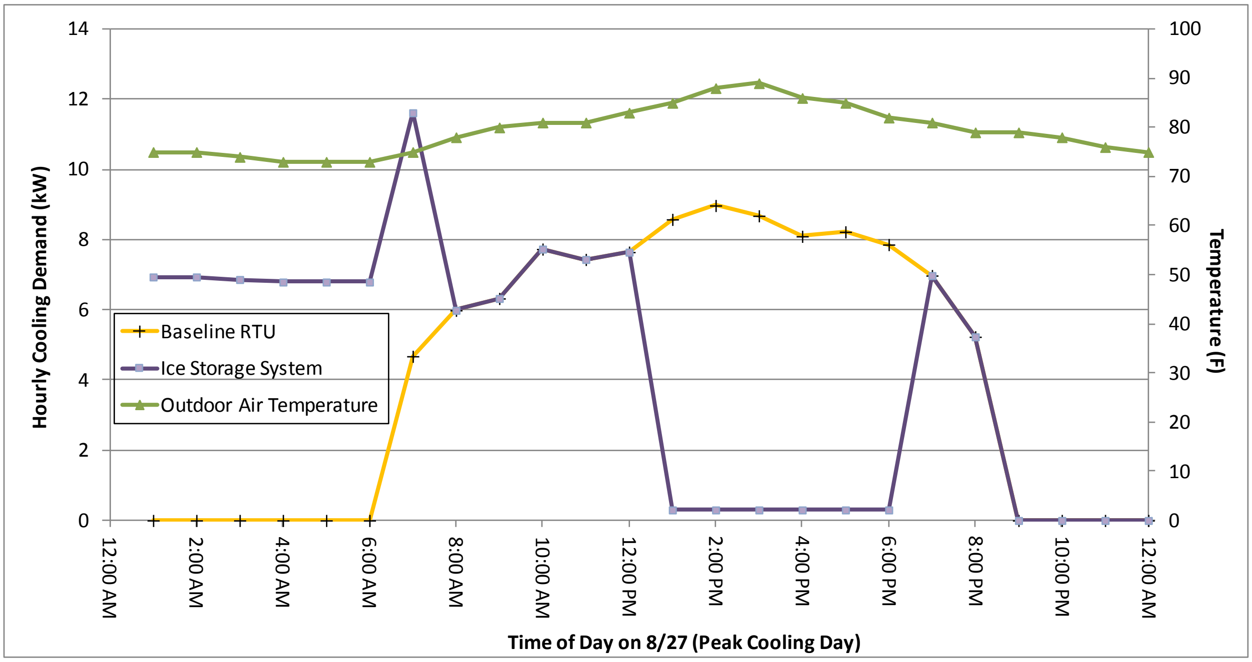
These relationships were utilized when the ice storage units were in charging mode, which was set to occur as needed from 12 am to 12 pm to meet afternoon cooling loads occurring from 1 pm to 7 pm. The charging time was calculated to determine the length of time needed to store enough thermal energy to meet that day's afternoon cooling loads completely. While the ice storage unit was charging, all cooling loads were assigned to the existing rooftop unit, using the values from the baseline energy model. The baseline values were also used for all hours between charging and discharging.

Table 11 shows a typical charging and discharging schedule for a non-peak summer day. This schedule changes as the daily cooling load varies from day to day, since the charge time varies. During discharge, the spreadsheet model assumes that only the small refrigerant circulation pump (300 watts) and the supply fan are operating. The discharge period runs from 1 pm to 7 pm everyday, as needed to meet cooling loads. The fan energy and run time from the baseline eQuest energy model is used for the proposed condition, except that the additional static pressure from the ice storage evaporator is accounted for by increasing the brake horsepower of the fan according to a typical fan performance curve [33]. As described above, three different static pressures were modeled, corresponding to the range of static pressure increases seen in Ice Energy's performance testing. Figure 3 shows a typical daily load and temperature profile for a baseline rooftop unit and an ice storage system. This data is for a peak summer day for a 4,000 square-foot building with an extended office schedule.

TABLE 12 - ICE STORAGE CHARGING SCHEDULE

Hour	System State
1:00 AM	charging
2:00 AM	charging
3:00 AM	charging
4:00 AM	charging
5:00 AM	charging
6:00 AM	charging
7:00 AM	charging
8:00 AM	RTU
9:00 AM	RTU
10:00 AM	RTU
11:00 AM	RTU
12:00 PM	RTU
1:00 PM	discharging
2:00 PM	discharging
3:00 PM	discharging
4:00 PM	discharging
5:00 PM	discharging
6:00 PM	discharging
7:00 PM	RTU
8:00 PM	RTU
9:00 PM	RTU
10:00 PM	RTU
11:00 PM	RTU
12:00 AM	RTU

FIGURE 3 - DAILY LOAD PROFILE FOR SMALL COMMERCIAL BUILDING



Residential Electric Thermal Storage Model Assumptions

Electric thermal storage systems were modeled by replicating information from ASHRAE [11] and from an ETS manufacturer [34] and by utilizing the results from the residential energy modeling described above. The electric heating cycling model was used to determine the peak electric heating demand for the median home. The manufacturer information provided the peak charging demand for each ETS unit sized to meet the daytime heating loads of the median house. The ETS units each have small circulation fans that consume a small amount of power, but the existing electric furnace also has a circulation fan, so this effect is minimized. The modeling results show no appreciable increase in fan energy with the ETS.

The demand impact during peak hours was computed as the entire electric heating demand (fan energy was excluded) during those hours when the ETS units would be operating. In other words, during peak hours the proposed ETS system uses no power for heating (only for circulation) whereas the existing furnace uses a maximum of 27 kW during these hours on the coldest day of the year, which was January 30th in the simulations. This results in 27 kW of peak demand savings with an ETS system.

In order to store enough thermal energy overnight for the next day's peak heating loads, several ETS units are needed, since room units are commonly used and they can only handle the loads in a single room of a house. The "warm room" concept [35] is often used, which involves placing one or more ETS units in a single room of a house, often a living room, and then relying on circulation and conduction to transfer this heat to the other rooms. This keeps the other rooms warmer than they would be with no heat source, but cooler than most would find comfortable. This makes the most sense when the home will be unoccupied during the day or a single room will be occupied primarily. Due to the modeling complexities of the warm room concept, it could not be modeled for this study. Instead, a whole house concept where ETS units are distributed throughout the home to maintain the same daytime temperature in all spaces (68°F) was used. This method ensures that there will be no snapback after the ETS units have fully discharged their heat and the furnace re-assumes control of the house.

Charging times were determined primarily by utility program guidelines. Xcel Energy uses a charging time period of 10 pm to 6:30 am [36] in its off-peak heating program. Any electric heating occurring outside of this window incurs a significant cost penalty. Therefore, the ETS system was modeled such that all charging occurs during this time window and the ETS units are discharging during the remaining hours of the day. The ASHRAE model of room ETS units [11], shown in Figure 4, demonstrates how each unit's heat output decreases over time during discharging. These curves come from previous work by Hersh et al. [37] and the four curves represent different discharge modes (static, two different mixtures of static and dynamic, and dynamic). To ensure that sufficient heat is provided to meet the home's heating loads at the end of the discharging period, the unit must be over-sized. ASHRAE recommends sizing each unit according to Figure 5, based on available charging time. This sizing multiplier is used to size the unit by multiplying it by the peak heating demand. This determines the size of the unit or units required, in kW.

FIGURE 4 - TYPICAL STORAGE HEATER PERFORMANCE CHARACTERISTICS

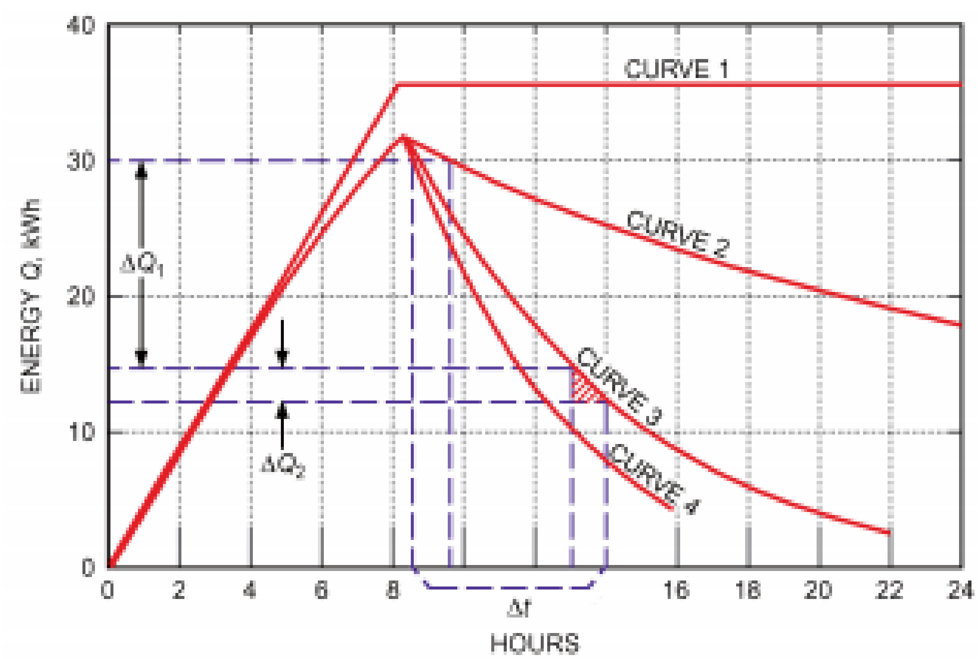
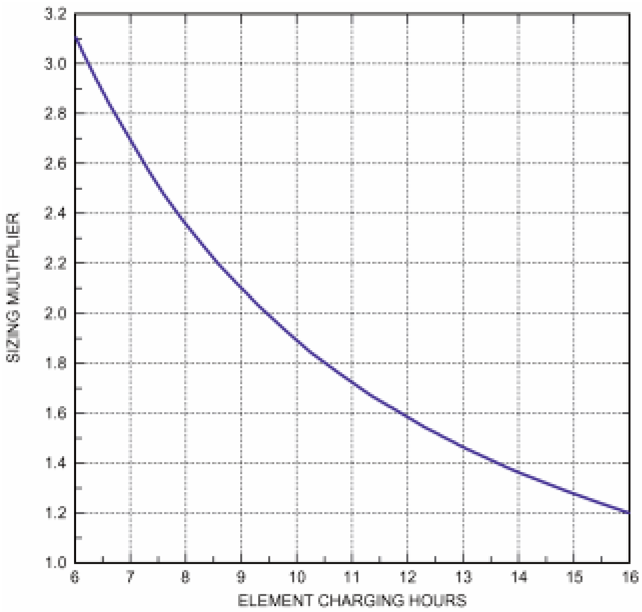


FIGURE 5 - REPRESENTATIVE SIZING FACTOR SELECTION GRAPH FOR RESIDENTIAL STORAGE HEATERS



Using these sizing guidelines, ETS units were selected for the median Twin Cities house. Units capable of 60 kW, combined, were needed for this house. To achieve this output in a commercially-available ETS unit, two Steffes 4130 [34] whole-house ETS units were selected for use in this study. The total daytime (7 am to 10 pm) heating load from the energy model was 319 kWh. The Steffes 4130 units store 180 kWh of thermal energy each, for a total of 360 kWh. Therefore there is some excess capacity, which is desirable. The charging power for each unit is 28.8 kW. These two units would need to charge about 6 hours on January 30th to meet the day's heating loads. After they are charged with enough energy for the day, they enter a "holding" mode while they wait for the peak period to begin. During this holding period, the existing furnace (or baseboard heating) continues to meet the home's loads. The charging profile for this system on January 30th is shown in Table 12. This shows how the off-peak demand increases significantly (by 57.6 kW) while the on-peak demand decreases by about 27 kW. If the utility's winter peak occurs in the late afternoon, the peak demand savings is closer to 18.3 kW.

TABLE 13 - ETS DEMAND PROFILE FOR MEDIAN HOUSE

Median House				
		Demand (kW)		
Date	Time	No ETS	ETS	ETS mode
1/30	12:00 AM	23.5	81.1	Charging
1/30	1:00 AM	24.0	81.6	Charging
1/30	2:00 AM	24.6	82.2	Charging
1/30	3:00 AM	24.9	82.5	Charging
1/30	4:00 AM	25.6	56.9	Charging
1/30	5:00 AM	25.7	25.7	Holding
1/30	6:00 AM	27.1	27.1	Holding

1/30	7:00 AM	27.3	0.0	Discharging
1/30	8:00 AM	24.7	0.0	Discharging
1/30	9:00 AM	22.6	0.0	Discharging
1/30	10:00 AM	22.0	0.0	Discharging
1/30	11:00 AM	20.3	0.0	Discharging
1/30	12:00 PM	18.6	0.0	Discharging
1/30	1:00 PM	16.9	0.0	Discharging
1/30	2:00 PM	15.4	0.0	Discharging
1/30	3:00 PM	15.8	0.0	Discharging
1/30	4:00 PM	16.5	0.0	Discharging
1/30	5:00 PM	18.7	0.0	Discharging
1/30	6:00 PM	18.7	0.0	Discharging
1/30	7:00 PM	19.3	0.0	Discharging
1/30	8:00 PM	20.2	0.0	Discharging
1/30	9:00 PM	20.9	0.0	Discharging
1/30	10:00 PM	21.4	0.0	Discharging
1/30	11:00 PM	21.6	79.2	Charging

In the "Previous Research on Demand Response Impacts" section, demand savings for ETS installations in Kentucky averaged 5.7 kW, which is a significant reduction from the 27 kW shown here, or even the afternoon (4 pm - 7 pm average) demand savings of 18.3 kW. There are a number of explanations for this discrepancy. First, the analysis shown here assumes that the ETS system will be able to completely meet all of the home's heating loads during peak (discharging) hours. The homes in the Kentucky study may use ETS units to handle part of the home's load, while still using other electric heat sources to meet the remaining load. This would reduce the peak demand savings of the ETS. Also, some of the homes in the program may have an alternate heat source (wood, propane, etc.) and use electric heating and ETS only for certain spaces within the home not served by those other heat sources. This too would reduce the demand savings. Finally, Kentucky's climate is significantly warmer than Minnesota's and this would lead to smaller heating loads, smaller peak demand for electric heating, and smaller demand savings with ETS. The Kentucky report did not describe their ETS program in enough detail to fully determine the source of the demand savings discrepancy.

Results

System-level Impact Results

After analyzing the aggregate utility data and the energy modeling results, deemed savings models for demand response events were developed. Table 6 shows the deemed savings values described in the Aggregate Demand Response Analysis section for the system-level demand response analysis of the two utilities. Note that these values were derived for summer demand response events only. There was no data provided to evaluate winter events.

TABLE 14 - DEEMED SAVINGS FOR SYSTEM-LEVEL DEMAND RESPONSE EVENTS

Utility	Description	Deemed Savings Value	
Xcel Energy	Load Relief for Event	454	MW
Xcel Energy	Net Source Savings for Event	46,659	MMBTU
Xcel Energy	Net Source Savings for Event/MW Control Capacity	50.55	MMBTU/MW
Xcel Energy	Net MWh/MW Load Control Capacity	3.70	MWh/MW
Great River	Load Relief for Event	184	MW
Great River	Net Source Savings for Event	19,507	MMBTU
Great River	Net Source Savings for Event/MW Control Capacity	41.50	MMBTU/MW
Great River	Net MWh/MW Load Control Capacity	2.85	MWh/MW

The contrast between the two utilities and their unique customer bases and generation capacity is clear in these deemed savings values. Xcel Energy has more energy savings, both at the customer and at the source on a MWh/MW basis. This is likely due to the inclusion of commercial and industrial loads in Xcel Energy's program because these loads tend not to produce snapback effects, but do produce significant load relief (see Table 14 in the appendix). It is hypothesized here that the commercial and industrial customers do not show snapback effects for two reasons: large commercial and industrial facilities often have backup generation capacity so their operations are not interrupted during a demand response event and small commercial buildings, like offices, may enter an unoccupied mode of operation after a demand response event (which is often several hours after normal business hours), reducing the need for cooling and/or lighting.

These results also show that there is significant energy savings associated with demand response events. Although there are snapback effects that reduce the energy savings, each event saves far more energy than it loses to snapback. The source energy savings, as discussed earlier, are based on the efficiency of gas turbine generators, as it was assumed that these would be the last units to be utilized and the first to be shut off when demand relief occurs. Therefore, each utility can use and customize the deemed savings template by entering the following information: their aggregate load profile for a typical demand response day, the load relief values during each event, the snapback values experienced after an event, the average thermal efficiency of the utility's gas turbine generators (or another type if the utility does not use gas turbines to handle peak loads), the transmission and distribution losses, and the MW of customer participation in the load reduction program. However, the deemed savings values shown here can also be used directly by matching the utility in question with one of the two utilities used in this study (whichever utility is closer in customer base and size) and applying the correct savings values. Only the two normalized savings values should be used, since the other values are specific to Xcel Energy and Great River Energy in the given years.

Individual Residential Impact Results

In order to better understand what comprises the system energy savings shown in Table 7, energy modeling of individual demand response controls was performed, as described in the previous section. The resulting energy and demand savings and snapback magnitudes for all of the modeled controls are shown in Table 14 for the median house, since that is the house to be used for deemed savings. The median house is the best representation of the typical Minnesota home. These modeling results show that four out of five of these demand controls result in net energy savings, despite significant amounts of snapback after the event. Note that the kWh savings values already include snapback and are net energy savings. Table 18 and Table 19 in the appendix show the results for all three home sizes.

The electric thermal storage system yields no energy savings or energy penalty since electric resistance heating has the same energy efficiency regardless of the outdoor air conditions, unlike cooling equipment. Also, there is no snapback because space temperatures are maintained throughout the demand response event. There are significant demand savings possible with this technology as well as customer energy cost savings using off-peak energy rates. These results are estimates for deemed energy and demand savings for individual homes per demand response event for these five demand controls. It should be noted that the values here for air conditioner cycling and domestic hot water (DHW) curtailment fall within the ranges noted in the "Previous Research on Demand Response Impacts" section, although the cooling savings are on the lower end of these ranges. The cooling discrepancy can likely be explained by Minnesota's cool climate, since many of the studies come from warmer climates. Additionally, the sizes of homes participating in the study can have a significant impact on the energy and demand savings and may differ from the median home used in this study.

TABLE 15 - ENERGY MODELING RESULTS FOR MEDIAN HOUSE

	Median Twin Cities Metro House (2,169 sq. ft.)			
	Net kWh Savings	Net kW Savings	Snapback kWh	Snapback Peak kW
A/C Cycling	0.712	0.205	0.721	0.336
Elec. Heat Cycling	7.381	3.099	14.311	5.514
DHW Curtail Summer	0.405	0.445	2.713	2.713
DHW Curtail Winter	0.098	0.731	2.095	2.095
Electric Thermal Storage	0.0	27.0	0.0	0.0

Individual Small Commercial Ice Storage Impact Results

The small commercial building analysis was completed by computing and tabulating the total cooling and fan energy for both the baseline and proposed systems for the two smaller building sizes for all schedules, while the largest building was only modeled for the simple office schedule to determine the relationship between building size and energy and demand to validate the trends seen in the two smaller buildings. In all cases, there was a net energy increase and a significant peak demand savings. The energy increase ranges from 295 kWh to 2,565 kWh and the demand savings range from 3.9 kW to 18.2 kW. Table 15 in the appendix shows all of the ice storage modeling results.

To determine deemed savings models from these results, regression analysis was performed. The demand savings was found to vary little with the schedule, so the demand savings were plotted with respect to cooling capacity (tons) for all three buildings using the average static pressure penalty of 0.183 inches of water. The resulting linear model is shown in Figure 3 in the appendix. The slope and intercept are shown on the graph, along with the correlation coefficient. The resulting equation can be used to determine the deemed demand savings for these packaged rooftop unit ice storage units based on the cooling capacity of the rooftop units:

$$Demand\ savings\ (kW) = 0.9393 \times tons - 0.5943$$

The energy increase is dependent on both cooling capacity and hours of operation, so a two-independent-variable regression was performed using data analysis software to determine the best fit model to the data. Figure 4 in the appendix shows the three-dimensional graph of the resulting model. The resulting deemed energy increase model is:

$$kWh = -82.454 \times tons - 1.0166 \times hours\ of\ operation\ per\ week - \frac{58{,}368}{tons^4}$$

This equation computes the energy increase in kWh that a facility would experience over the course of a year by installing the Ice Bear system. The resulting value is negative because it is treated as negative energy savings over baseline, since the proposed case uses more energy than the baseline. In order to determine deemed demand and energy savings for small commercial buildings with packaged, single-zone, constant volume air-conditioning units, the cooling capacity and building hours of operation should be collected and input into the energy and demand models. It should be noted that these models do not produce meaningful results below five tons of cooling capacity, as they were not fit to data in that range.

Conclusions

Demand response offers utilities two benefits: reduced peak generation load and, according to this report, net energy savings. Regardless of the type of demand response, there is net energy savings, with the exceptions of electric thermal storage, which is energy neutral, and ice storage, which results in increased energy use. Each utility will see a similar load profile on load control days with a nearly flat profile during the afternoon peak when the load is being controlled and a sharp increase immediately after the event, followed by a decrease down to nighttime minimum loads. The size and impact of the snapback after an event will depend on the types of customers served by the utility. The larger the portion of a utility's customers that are residential, the larger the snapback after an event will be. It is important to keep in mind that even 100%-residential utilities will see a net energy savings with demand response, but the savings will be less than utilities with more commercial and industrial customers.

Demand response events produce both end-user and source energy savings. This report analyzed actual utility system-wide load profiles to determine large-scale impacts of demand response. Two different utility types were analyzed to provide a more comprehensive view. Utilities or other parties wishing to utilize the results of this study should compare their particular utility and its customer base to the two studied here, and use the deemed savings values that correspond to the utility that best matches their own. If the utility is a cooperative and/or serves more rural areas with primarily light industrial, commercial, and a large portion of residential customers, then Great River Energy's system-wide deemed savings values from Table 13 should be used. If the utility is a larger utility that serves a suburban and/or urban area with a large portion of commercial and industrial customers (in terms of demand), then Xcel Energy's values should be used.

To evaluate the energy and demand impacts of individual demand response technologies and control methods, this study modeled a typical Minnesota home and small business using energy modeling software, and analyzed the energy impacts of these demand controls: air conditioner cycling, electric heat cycling, domestic water heater curtailment, ice storage, and electric thermal storage. The analysis developed deemed savings values that utilities and other parties can use to quantify the energy and demand impacts of each of these technologies. Since these deemed values are based on typical buildings, they will over-estimate savings for some and under-estimate the savings on others, but, on average, they should be reasonable. Although the residential results presented above are for the median-sized home only, results for the small and large homes are available in the appendix. These results, combined with the results for the median home, produce a trend that shows that energy savings, demand savings, and snapback all correlate directly with home size. Larger homes produce larger values of savings and snapback.

Ice storage is a viable demand response strategy for small commercial customers with rooftop units. It offers significant peak demand savings at the expense of increased off-peak energy consumption. Because peak energy is much more expensive than off-peak energy, this trade-off is favorable. Ice storage, like electric thermal storage, maintains a constant space temperature in the building, so an added bonus is that there is no snapback after a demand response event. Ice storage will flatten a facility's load profile on summer days. Based on the small number of manufacturers currently offering ice storage for packaged rooftop units, it appears that there is significant opportunity for utilities to install ice storage systems in their customers' buildings as a controllable load resource that is reliable and does not impact occupant comfort, unlike cycling or set back controls. This represents an emerging potential for demand reduction, as long as the energy penalty is understood. It should be noted that costs and return-on-investment were not considered in this study.

Demand response is an important aspect of any utility's demand-side management plan as it offers a cost-effective way to minimize peak demand, reducing the need for additional spinning generation capacity. Most demand response involves snapback after the event, when demand sharply rises for a short time as customers return to normal operation. This snapback cannot be easily eliminated, but its existence should not be a significant concern for utilities, since the net impact of each demand response event is energy and demand savings. All of the methods of control modeled in this study are viable and worth studying. Many of them are tailored to specific customer types or equipment, so their applications are sometimes limited. In spite of that, their combined demand savings potential, along with their not insignificant energy savings potential, make them an important resource for every utility.

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Appendix

TABLE 16 - ICE STORAGE MODELING RESULTS, STATIC PRESSURE (SP) IN INCHES OF WATER

Building Description	SP Increase	kWh Savings	kW Savings
4000 sq ft 10-ton PSZ RTU 8am-5pm M-F fan cycling at min OA during unocc, 6 deg set up (76,82)	0.1	-482	9.1
	0.183	-889	9.1
	0.26	-1297	9.0
4000 sq ft 10-ton PSZ RTU 8am-8pm M-F, 8 am to 3 pm Sat fan cycling at min OA during unocc, 6 deg set up (76,82)	0.1	-454	8.6
	0.183	-893	8.6
	0.26	-1332	8.5
4000 sq ft 10-ton PSZ RTU 8am-9pm M-Sat, 10 am to 6 pm Sun fan cycling at min OA during unocc, 6 deg set up (76,82) (retail schedule)	0.1	-442	8.6
	0.183	-913	8.6
	0.26	-1384	8.5
4000 sq ft 10-ton PSZ RTU 24/7 operation (including holidays)	0.1	-421	9.0
	0.183	-1010	9.0
	0.26	-1599	8.9
2000 sq ft 5-ton PSZ RTU 8am-5pm M-F fan cycling at min OA during unocc, 6 deg set up (76,82)	0.1	-340	4.2
	0.183	-573	4.1
	0.26	-854	4.1
2000 sq ft 5-ton PSZ RTU 8am-8pm M-F, 8 am to 3 pm Sat fan cycling at min OA during unocc, 6 deg set up (76,82)	0.1	-295	4.2
	0.183	-554	4.1
	0.26	-864	4.1
2000 sq ft 5-ton PSZ RTU 8am-9pm M-Sat, 10 am to 6 pm Sun fan cycling at min OA during unocc, 6 deg set up (76,82) (retail schedule)	0.1	-333	4.0
	0.183	-599	3.9
	0.26	-919	3.9
2000 sq ft 5-ton PSZ RTU 24/7 operation (including holidays)	0.1	-344	4.3
	0.183	-671	4.2
	0.26	-1062	4.2
8000 sq ft 20-ton PSZ RTU 8 am to 5 pm M-F, fan cycling at min OA during unocc, 6 deg set up (76,82)	0.1	-814	18.2
	0.183	-1690	18.2
	0.26	-2566	18.2

FIGURE 6 - PEAK DEMAND SAVINGS VERSUS COOLING CAPACITY

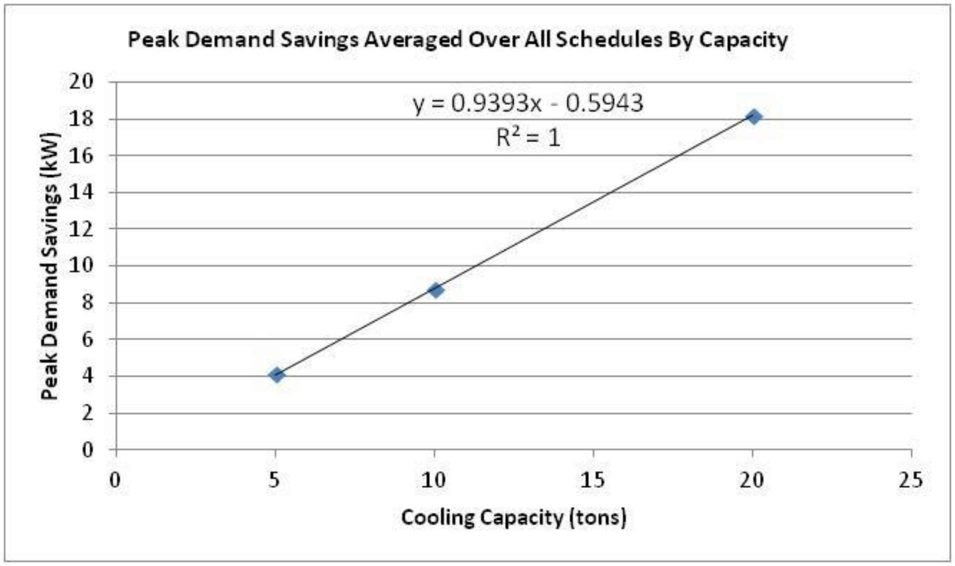

FIGURE 7 - SURFACE FIT OF COOLING CAPACITY, SCHEDULE, AND ENERGY SAVINGS

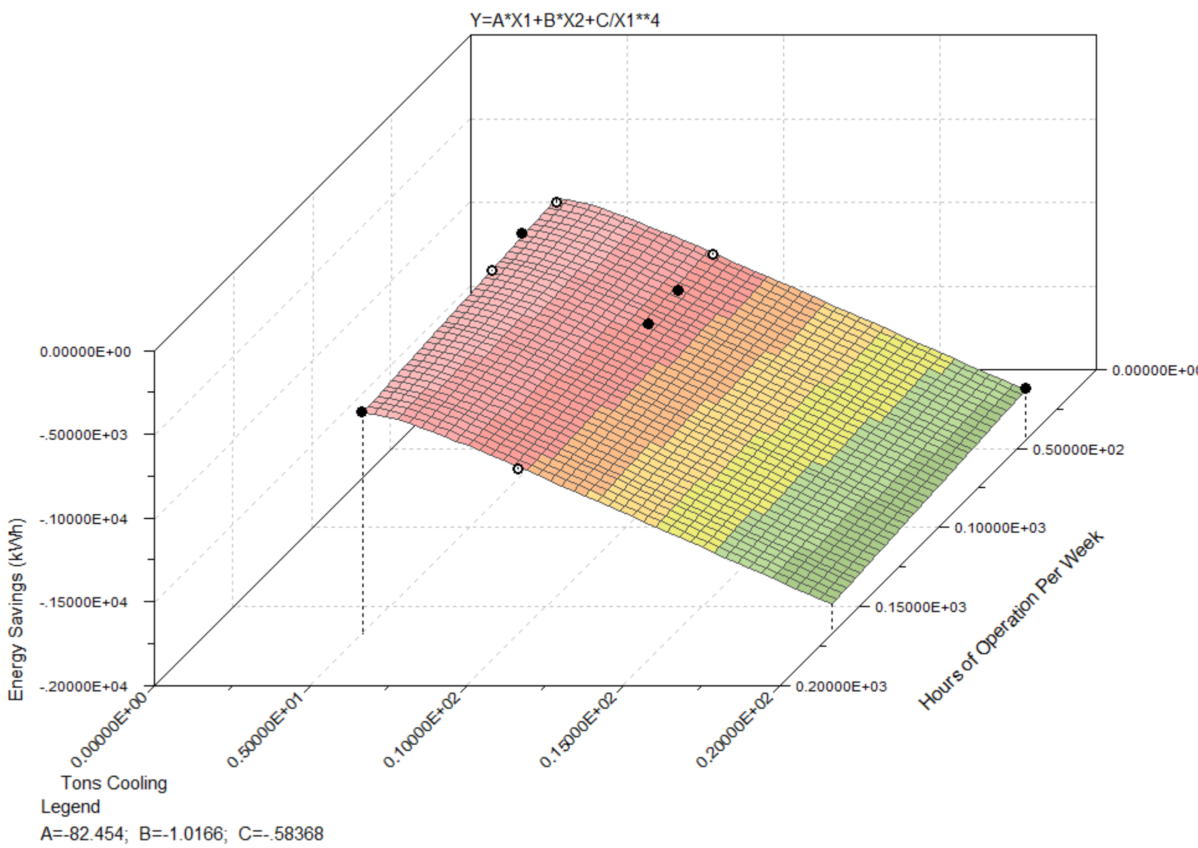

TABLE 17 – XCEL ENERGY DEMAND RESPONSE EVENTS BY CUSTOMER TYPE

		Demand Response Events for Xcel Energy in 2007 by Customer Segment								
Segment		6/26/2007	7/24/2007	7/25/2007	7/26/2007	7/30/2007	7/31/2007	8/1/2007	9/5/2007	**Totals**
C&I	MWh	1854.4	657.6	1657.6	2224.0	469.1	2828.6	1694.0	1176.7	12562.0
C&I	Snapback MWh	0.0	0.0	0.0	0.0	-39.2	0.0	0.0	0.0	-39.2
C&I	% Snapback	0%	0%	0%	0%	-8%	0%	0%	0%	0%
Res	MWh	276.7	149.3	288.2	266.6	39.8	233.6	0.0	134.8	1389.0
Res	Snapback MWh	-80.5	-28.9	-57.6	-52.6	-17.7	-51.9	0.0	-60.1	-349.3
Res	% Snapback	-29%	-19%	-20%	-20%	-44%	-22%	0%	-45%	-25%

TABLE 18 - RESIDENTIAL MODELING RESULTS - ENERGY

	Small House				Large House				Median House			
	kWh no DR	kWh DR	Net kWh Savings	Snapback kWh	kWh no DR	kWh DR	Net kWh Savings	Snapback kWh	kWh no DR	kWh DR	Net kWh Savings	Snapback kWh
A/C Cycling	8.0	7.6	0.4	0.2	16.5	15.9	0.7	0.8	13.8	13.1	0.7	0.7
Elec. Heat Cycling	208.4	203.8	4.5	8.0	398.2	389.3	8.9	17.3	326.3	318.9	7.4	14.3
DHW Curtailment Summer	3.1	2.7	0.4	2.3	4.2	3.9	0.4	3.2	4.1	3.7	0.4	2.7
DHW Curtailment Winter	3.3	3.2	0.1	1.7	4.5	4.5	0.1	2.5	3.9	3.8	0.1	2.1

TABLE 19 - RESIDENTIAL MODELING RESULTS - DEMAND

	Small House		Large House		Median House	
	Peak kW Savings	Peak Snapback kW	Peak kW Savings	Peak Snapback kW	Peak kW Savings	Peak Snapback kW
A/C Cycling	0.153	0.123	0.330	0.390	0.205	0.336
Elec. Heat Cycling	2.455	3.107	4.843	6.719	3.099	5.514
DHW Curtailment Summer	0.506	2.262	0.696	3.227	0.445	2.713
DHW Curtailment Winter	0.732	1.749	1.012	2.454	0.731	2.095