COMMONWEALTH EDISON COMPANY

Load Forecast for Five-Year Planning Period
June 2013 – May 2018

July 16, 2012

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I. INTRODUCTION AND SUMMARY

The Public Utilities Act ("PUA") provides that beginning in 2008 electric utilities in Illinois shall provide a range of load forecasts to the Illinois Power Agency ("IPA") by July 15th of each year. The PUA further provides that these load forecasts shall cover the 5-year planning period for the next procurement plan and shall include hourly data representing high-load, low-load and expected-load scenarios for the load of eligible retail customers ("Eligible Retail Customers"). The electric utility is also to provide supporting data and assumptions (220 ILCS 5/16-111.5(d)(2)). This document presents Commonwealth Edison Company's ("ComEd") load forecast for the planning period of June 2013 through May 2018. ComEd will provide the supporting data and assumptions in a separate package of materials.

ComEd's 5-year hourly load forecast ("Forecast") is based on the PUA's definition of Eligible Retail Customers. Eligible Retail Customers include residential and non-residential customers who purchase power and energy from ComEd under fixed-price bundled service ("Blended Service") tariffs, other than those customers whose service has been declared competitive. Because service to certain classes of customers has been declared competitive either by statute or by the Illinois Commerce Commission ("ICC"), only residential and non-residential customers below 100 kW in size are eligible for Blended Service.[1]

The Forecast includes the effects of energy efficiency, demand response and renewable energy resources programs. The Forecast anticipates that these programs will be observed in full compliance with the PUA's requirements, subject to the defined rate impact test.

II. LOAD FORECAST

A. Purpose and Summary

This section of the Forecast provides forecasted energy usage for the Eligible Retail Customers within ComEd's service territory for the 5-year procurement planning period beginning on June 1, 2013. In accordance with Section 16-111.5(b) of the PUA, the Forecast includes a multi-year historical analysis of hourly loads, a review of switching trends and competitive retail market development, a discussion of known and projected changes to future loads and growth forecasts by customer classes. The Forecast also addresses the impacts of demand response and energy efficiency programs on the forecast. Lastly, this Forecast discusses any supply side needs that are projected to be offset by the purchase of renewable energy resources.

[1] There is one exception to this statement. The common area accounts for the condominium associations are exempted from this competitive declaration (see Section 16-103.1 of the PUA).

B. Development of the Five-Year Load Forecast (June 1, 2013 – May 31, 2018)

The hourly load analysis provides the means to determine the on-peak and off-peak quantities needed in the procurement process. In presenting the Forecast, this document focuses on average usage or load during the 12 monthly on-peak and off-peak periods during a year. For the purposes of this Forecast, the definitions of the on-peak and off-peak periods are consistent with those commonly used in the wholesale power markets, and on trading platforms such as the New York Mercantile Exchange ("NYMEX") and the Intercontinental Exchange, Inc. ("ICE"). The on-peak period consists of the week day period from 6 a.m. to 10 p.m. CPT excluding NERC holidays (this is referred to as the 5X16 peak period). The off-peak period consists of all other hours (this is referred to as the off-peak "wrap" period). The Forecast therefore has been summarized as load requirements using the 24 different time periods covered by these standard products. This is the same approach that was presented in past forecasts and approved by the ICC. The hourly load data is being supplied with the supporting data and assumptions materials.

1. Hourly Load Analysis

a. Multi-year historical analysis of hourly load

The 2012 multi-year historical analysis of hourly load is very similar to the approach used in the 2011 procurement filing. Essentially, the hourly models that were developed last year were updated with another year of customer data and reviewed for fit. The results this year are similar to the previous filing.

The 2012 multi-year historical analysis of load during the 24 monthly on-peak and off-peak periods is based on hourly profile data for the period from January 2004 to December 2011. The profiles are based on statistically significant samples from ComEd's residential customer population along with customers applicable to the non-residential watt-hour and 0 to 100 kW delivery classes. These samples provide the only basis for an analysis of actual historical hourly usage of Eligible Retail Customers because the standard meters currently used for these customers do not record usage on an hourly basis. As discussed in greater detail below, the profiles show clear and stable weather-related usage patterns that are indicative of how residential and the small non-residential customers use electricity. Thus, the customer load profiles provide reliable information on the historical hourly usage of customers.

Using the hourly load profiles and actual customer aggregate usage, Table II-1 depicts the historical on-peak and off-peak hourly usage of the major customer groups within the Eligible Retail Customers for the period from January 2009 to December 2011.

Table II-1

Load Forecast Table (Historical Detail 2009-2011)

ComEd Historical Actual Usage

Historical Energy Usage in MWh for Eligible Retail Customers (Line Loss Adjusted)

		Residential Load		Watthour		Small Load (0 to 100kW)		Street Lighting Load		Total Load (MWh)	
Year	Month	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2009	1	1,457,595	1,620,040	32,711	28,467	456,843	398,061	1,776	3,985	1,948,926	2,050,553
2009	2	1,283,975	1,299,737	30,536	23,728	445,544	347,452	1,511	3,561	1,761,565	1,674,478
2009	3	1,046,850	1,098,294	27,024	21,590	402,786	313,589	1,491	4,207	1,478,151	1,437,679
2009	4	992,489	943,062	24,850	17,767	392,072	279,008	1,165	4,379	1,410,576	1,244,217
2009	5	906,711	1,072,505	23,205	20,883	387,856	334,825	822	4,809	1,318,595	1,433,023
2009	6	1,355,202	1,195,758	24,426	16,273	432,494	295,880	716	4,499	1,812,839	1,512,411
2009	7	1,388,217	1,184,043	27,392	18,030	479,595	314,531	749	4,530	1,895,952	1,521,134
2009	8	1,435,413	1,474,624	26,223	20,498	445,149	353,246	931	4,568	1,907,716	1,852,936
2009	9	1,070,334	1,053,646	23,477	17,827	410,966	303,821	1,194	4,095	1,505,972	1,379,389
2009	10	1,035,954	1,030,812	23,691	18,380	374,658	279,925	1,574	4,063	1,435,876	1,333,179
2009	11	1,050,767	1,162,536	24,791	20,983	347,561	296,046	1,757	3,987	1,424,876	1,483,552
2009	12	1,438,365	1,407,180	28,993	22,673	423,983	338,741	2,027	3,867	1,893,367	1,772,461
Totals		**14,461,872**	**14,542,239**	**317,318**	**247,099**	**4,999,506**	**3,855,124**	**15,714**	**50,549**	**19,794,410**	**18,695,010**
2010	1	1,404,757	1,717,737	31,413	29,865	394,710	379,688	1,788	3,991	1,832,667	2,131,281
2010	2	1,286,133	1,277,782	29,465	23,330	372,304	295,291	1,619	3,809	1,689,522	1,600,212
2010	3	963,208	913,012	25,448	18,550	373,592	269,198	1,490	4,225	1,363,739	1,204,986
2010	4	946,120	885,498	23,413	16,808	367,770	259,600	1,134	4,203	1,338,438	1,166,109
2010	5	1,031,288	1,213,285	23,074	20,893	369,598	334,528	868	5,285	1,424,828	1,573,992
2010	6	1,576,774	1,388,093	25,980	17,951	448,417	309,681	193	1,043	2,051,363	1,716,769
2010	7	2,129,095	2,108,142	30,188	22,581	472,460	380,518	456	2,342	2,632,199	2,513,583
2010	8	1,969,934	1,818,869	29,621	20,526	470,662	353,644	391	1,730	2,470,608	2,194,769
2010	9	1,114,031	1,041,725	22,093	16,078	374,281	273,692	550	1,792	1,510,955	1,333,287
2010	10	888,085	960,659	20,918	17,188	316,503	260,706	776	1,918	1,226,282	1,240,471
2010	11	1,049,053	1,098,253	26,069	20,560	359,348	285,012	900	1,965	1,435,369	1,405,790
2010	12	1,528,240	1,418,867	29,071	20,653	363,802	273,574	893	1,643	1,922,006	1,714,736
Totals		**15,886,718**	**15,841,923**	**316,753**	**244,983**	**4,683,448**	**3,675,132**	**11,057**	**33,947**	**20,897,976**	**19,795,985**
2011	1	1,368,678	1,521,717	27,834	23,594	368,850	325,727	785	1,716	1,766,147	1,872,754
2011	2	1,206,062	1,186,929	25,623	20,068	347,348	280,764	774	1,749	1,579,807	1,489,511
2011	3	1,159,167	1,136,895	24,281	17,635	347,838	255,457	709	1,949	1,531,996	1,411,935
2011	4	969,437	983,804	21,379	16,775	308,747	248,293	556	1,937	1,300,120	1,250,809
2011	5	1,019,568	1,094,005	21,641	16,868	322,611	259,005	389	2,140	1,364,208	1,372,018
2011	6	1,470,860	1,238,235	22,653	14,935	372,637	254,261	324	1,938	1,866,474	1,509,369
2011	7	1,975,570	2,222,529	21,480	17,785	377,078	340,216	375	2,009	2,374,503	2,582,539
2011	8	1,735,218	1,390,515	25,114	15,491	409,079	276,763	368	1,810	2,169,779	1,684,580
2011	9	1,099,125	1,079,116	16,169	11,730	268,504	206,113	578	1,861	1,384,376	1,298,820
2011	10	889,369	960,021	18,227	14,295	270,184	219,439	751	1,867	1,178,532	1,195,622
2011	11	1,006,338	1,012,818	19,001	14,450	273,852	215,951	770	1,689	1,299,960	1,244,908
2011	12	1,124,395	1,250,986	21,493	17,811	290,015	251,954	947	1,744	1,436,850	1,522,495
Totals		**15,023,788**	**15,077,571**	**264,895**	**201,438**	**3,956,742**	**3,133,942**	**7,327**	**22,410**	**19,252,752**	**18,435,361**

Table II-2 carries forward the total load in MWh from Table II-1 and then provides the average load for each period in MW, which is useful in determining the required volume of standard wholesale energy products.

Table II-2

Load Forecast Table (Historical Summary 2009-2011)

ComEd Historical Actual Usage
Historical Energy Usage for Eligible Retail Customers
(Line Loss Adjusted)

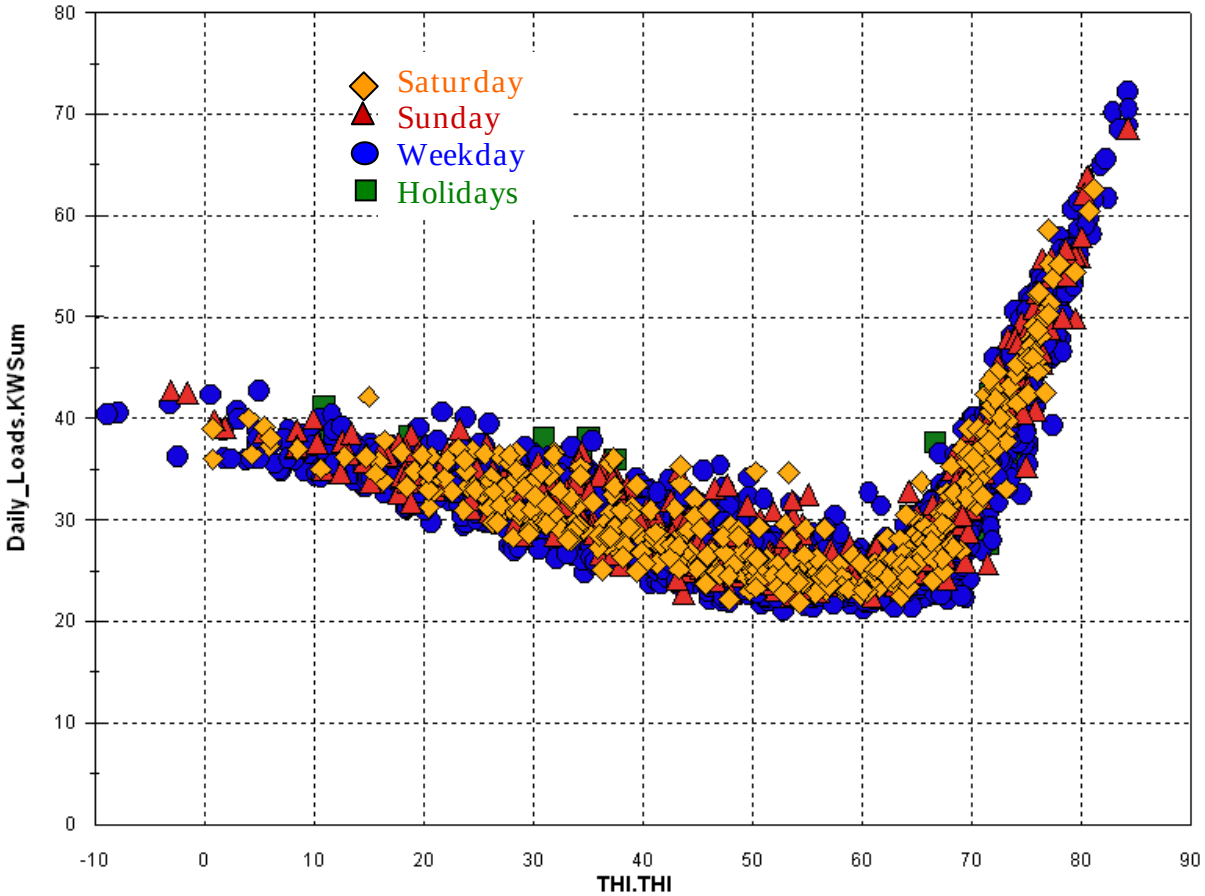
Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2009	1	1,948,926	2,050,553	5,800	5,026
2009	2	1,761,565	1,674,478	5,505	4,757
2009	3	1,478,151	1,437,679	4,199	3,668
2009	4	1,410,576	1,244,217	4,007	3,381
2009	5	1,318,595	1,433,023	4,121	3,380
2009	6	1,812,839	1,512,411	5,150	4,110
2009	7	1,895,952	1,521,134	5,152	4,046
2009	8	1,907,716	1,852,936	5,678	4,542
2009	9	1,505,972	1,379,389	4,482	3,592
2009	10	1,435,876	1,333,179	4,079	3,401
2009	11	1,424,876	1,483,552	4,453	3,709
2009	12	1,893,367	1,772,461	5,379	4,522
Totals		**19,794,410**	**18,695,010**		
2010	1	1,832,667	2,131,281	5,727	5,027
2010	2	1,689,522	1,600,212	5,280	4,546
2010	3	1,363,739	1,204,986	3,706	3,205
2010	4	1,338,438	1,166,109	3,802	3,169
2010	5	1,424,828	1,573,992	4,453	3,712
2010	6	2,051,363	1,716,769	5,828	4,665
2010	7	2,632,199	2,513,583	7,834	6,161
2010	8	2,470,608	2,194,769	7,019	5,599
2010	9	1,510,955	1,333,287	4,497	3,472
2010	10	1,226,282	1,240,471	3,650	3,040
2010	11	1,435,369	1,405,790	4,272	3,661
2010	12	1,922,006	1,714,736	5,223	4,560
Totals		**20,897,976**	**19,795,985**		
2011	1	1,766,147	1,872,754	5,256	4,590
2011	2	1,579,807	1,489,511	4,937	4,232
2011	3	1,531,996	1,411,935	4,163	3,755
2011	4	1,300,120	1,250,809	3,869	3,257
2011	5	1,364,208	1,372,018	4,060	3,363
2011	6	1,866,474	1,509,369	5,302	4,102
2011	7	2,374,503	2,582,539	7,420	6,091
2011	8	2,169,779	1,684,580	5,896	4,480
2011	9	1,384,376	1,298,820	4,120	3,382
2011	10	1,178,532	1,195,622	3,508	2,930
2011	11	1,299,960	1,244,908	3,869	3,242
2011	12	1,436,850	1,522,495	4,276	3,732
Totals		**19,252,752**	**18,435,361**		

ComEd analyzed the hourly load profiles for all the major customer groups within the Eligible Retail Customers. As a result of that analysis, ComEd developed hourly load models for those major customer groups that determined the average percentage of monthly usage that each customer group used in each hour of that month. Those hourly models were then used to develop the monthly on-peak and off-peak usage percentages for the planning periods. These percentages were applied to ComEd's forecasted monthly usage to obtain the forecasted procurement quantities. In the following section, the hourly analysis of the residential single-family non-space heating customer segment is described. This class represents approximately half of the annual usage of the Eligible Retail Customer segment and provides a good example of how the hourly load profile data were analyzed and modeled.

(i) Residential Single-Family Hourly Load Profile Analysis

One of the most significant, and easily understood, determinants of residential energy usage is weather. The "scatter plot" shown below (Chart II-1) demonstrates the significant relationship that exists between weather and usage for the single-family non-space heating residential customer segment.

Chart II-1
Single Family Non-Space Heating Daily Usage vs. Temperature/Humidity



A scatter plot shows the relationship between two variables. Each point represents a single observation (a day in this case). In this chart, the values shown on the vertical or Y-axis are daily usage per customer ("UPC"). The values shown on the horizontal or X-axis are the daily average temperature-humidity index ("THI"). The graph shows daily UPC based on observations from January 2004 to December 2011 and the average THI on those days. THI, rather than temperature alone, is used because residential usage is sensitive to humidity. Different geometric shapes are used to distinguish points representing weekdays from those depicting Saturday, Sunday or holiday usage.

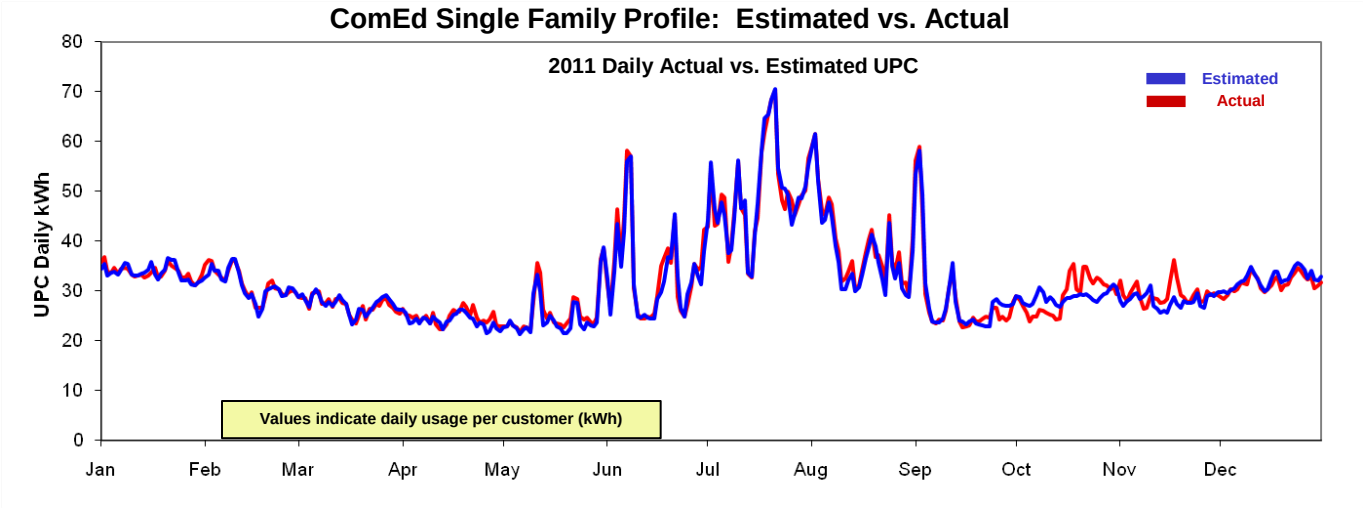
The scatter plot is very useful in understanding the relationship between customer usage and weather. If there were no relationship between usage and weather, then the graph would not display a clear pattern. However, it is apparent that there is a clear pattern. The right side of the graph at the high end of the horizontal axis shows the days on which THI was the highest. The points at that end of graph indicate that the highest UPC occurred when THI levels were at their peak -- 80 plus degrees. Moving to the left, the points show UPC declining rapidly as the THI decreases until the 60 degree level is reached at which a base usage appears. From that base level, UPC gradually increases as colder temperatures are experienced.

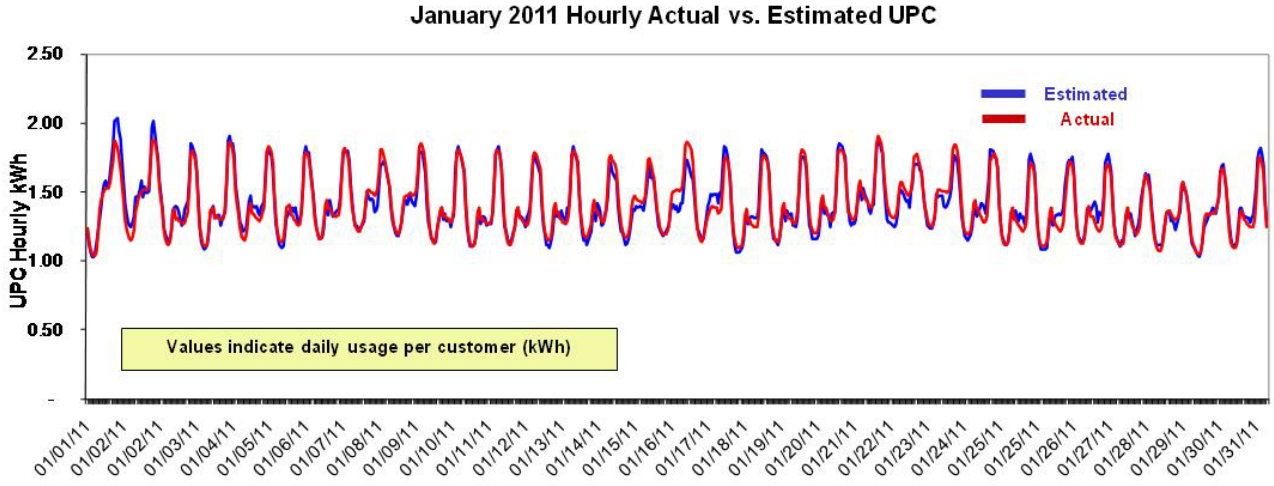
Hourly models were developed to account for the strong weather relationship shown in the graph and to account for numerous other factors that influence residential usage. The models explicitly account for the differing effects of energy use at various temperatures. Variables are included to allow for seasonal usage patterns in water heating, refrigeration and other seasonal uses. Weekend and holiday variables are included to allow for behavioral differences on those days relative to weekdays. The amount of daylight on each day is included to account for seasonal differences in lighting loads. Weather variables for prior days are included in the model to account for the dynamic effects of temperature buildup. The full list of variables included in the residential single-family model is shown in Appendix A-1.

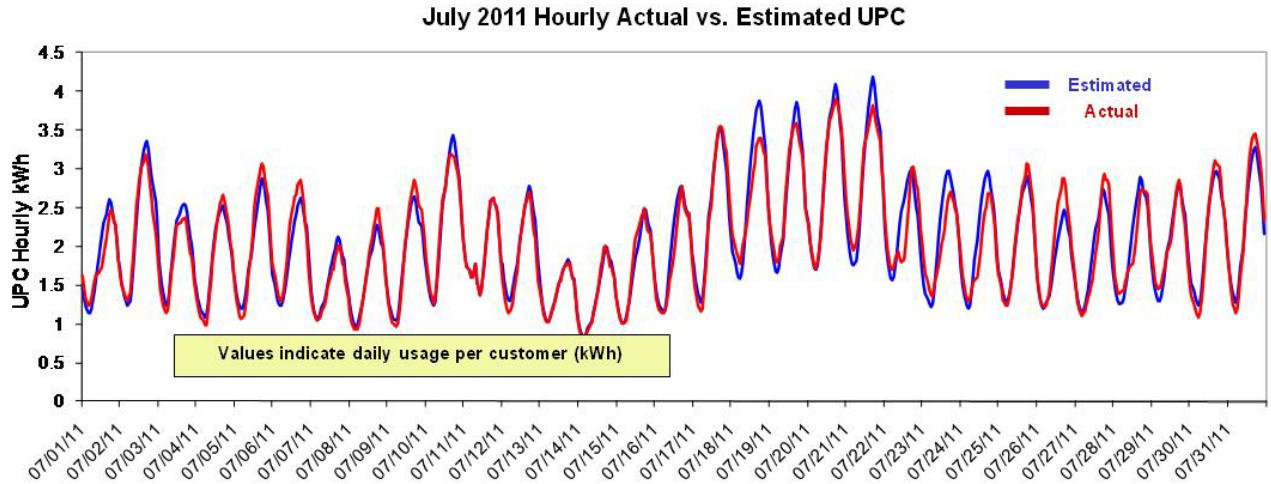
One way to visualize the model's performance is to look at plots of actual and estimated[2] values for the historical estimation period. The following chart demonstrates the performance of the model over the one-year period from January 2011 through December 2011 at the daily level and zooms in to show the hourly performance in January and July of 2011.

[2] The estimated data in Chart II-2 is based on the actual weather experienced over the relevant period.

Chart II-2
ComEd Single Family Profile: Estimated vs. Actual







In all of the graphs above in Chart II-2, the red line indicates the "actual" load data and the blue line indicates the model's estimated values, adjusted for actual weather. It is important to understand that the actual load data itself is an estimate based on a statistical sample of single family residential customers, and minor variations do occur in the sample. Despite these variations, the charts demonstrate that the model's estimated usage is extremely close to the actual usage. The close alignment of the estimated and actual lines on the charts demonstrates that the model is very effective in estimating variations in electrical usage patterns that are significantly influenced by weather conditions.

b. Switching Trends and Competitive Retail Market Analysis

In determining the expected load requirements for which standard wholesale products will be procured, it is important to provide the best possible estimate of the number of Eligible Retail Customers that are likely to be served by Retail Electric Suppliers ("RES"). That issue is considered in the following discussion, which reviews retail development in ComEd's service territory, the entry of RES, the rate of customer switching in the past, future trends affecting customer choice and ComEd's 5-year forecast of the percentage of load from various customer segments that will continue to be served with supply procured by ComEd.

(i) Introduction and Brief Overview of Retail Development

ComEd's service territory is an extremely robust retail market, which is demonstrated in several ways:

1. Residential RES service is approximately 13% of ComEd's total residential service as of May 2012 and this represents approximately 445,000 residential customers. In comparison, only 1% of ComEd's residential usage was taking RES service in May 2011. Thus, residential RES service has been growing at approximately 1% per month in the past year with no indications of slowing down.

2. Municipal Aggregation ("Muni Agg") is growing quickly. Approximately 170 communities (and one county) within ComEd's service territory passed Muni Agg referendums in March 2012[3]. These government entities represent approximately one million residential customers, which is equivalent to approximately 30% of ComEd's total number of residential customers. Additional information related to these government entities can be found at the following website (www.icc.illinois.gov/ORMD/Municipalaggregation.aspx).

3. The current number of active RES has more than doubled since January 2009 and the number of RES approved to serve residential customers has doubled in the past year alone.

[3] This is in addition to the approximately 20 municipalities that passed referendums in March 2011.

4. Almost 90% of ComEd's entire non-residential usage is either supplied through RES or Hourly service as of May 2012. There is no doubt that customer choice is alive and well within the non-residential segment. Plus, there are over 40 RES that are serving the needs of these non-residential customers.

In addition, this already robust retail market continues to evolve. The residential retail market has greatly expanded in the past 18 months and more developments are possible. RES and numerous consultants are continuing to seek customers and educate consumers. As in any competitive market place new developments should be expected – although the exact form of those developments is uncertain.

In summary, retail choice is very active within the ComEd service territory and continuing to develop. A healthy retail market is anticipated for the forecast period.

(ii) RES Development

There continues to be growth in the number of RESs within the ComEd service territory. This growth is shown in the table below:

Table II-3
RES Development in the ComEd Service Territory

RES Category	January 2009	May 2010	May 2011	May 2012
Number of Active RESs[4]	22	26	31	48
Number of RESs approved to serve Residential customers	6	9	16	32
Number of entities in the RES certification process as of May 2012	N.A.	N.A.	N.A.	8

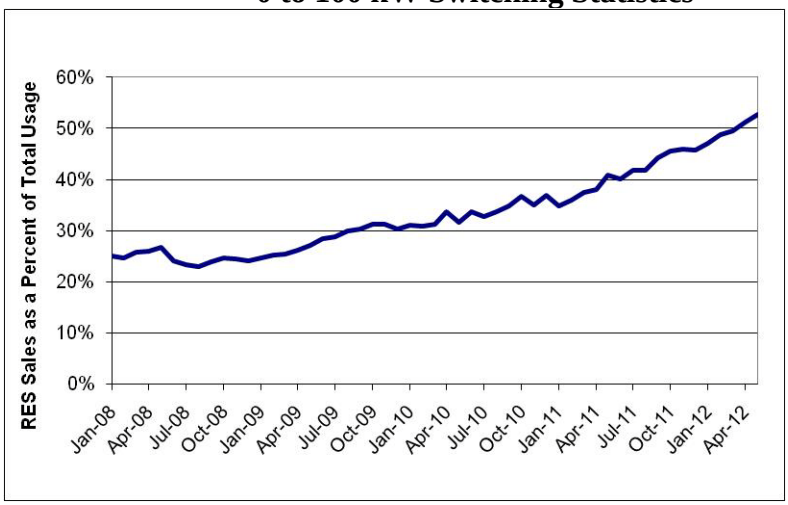
From January 2009 to May 2012 there has been a 118% increase in the number of active RES in the ComEd service territory. Further, RES growth continues with several RES in the certification process. The increase in RES approved to serve residential customers is even more remarkable. The number of RES approved to serve residential customers has doubled in the past year. This growth in the number of RES along with more being eligible to serve residential customers is a positive sign for the retail market.

[4] An "Active RES" is defined as an ICC-approved RES that has passed ComEd's certification process.

(iii) Future Trends

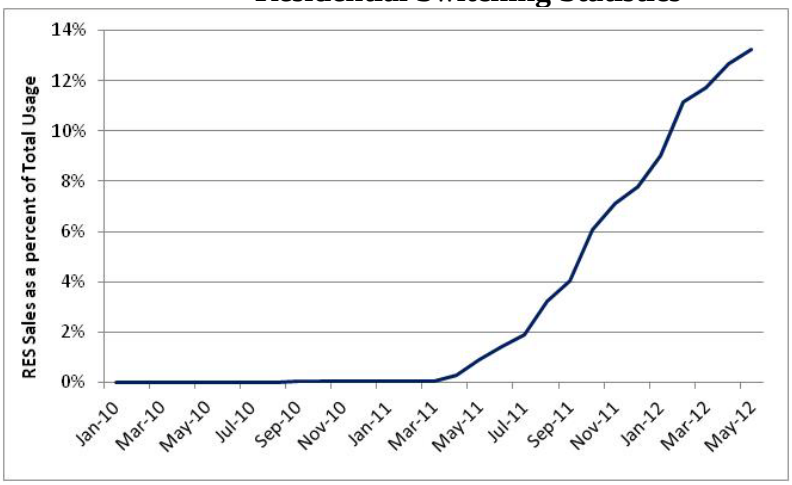
The future trends are very positive for the retail markets for several reasons. First, usage by RES customers in the 0 to 100 kW class have not only grown over time, but the rate of growth has increased in the last few years. Chart II-3 contains the monthly percentage of usage by RES customers from January 2007 through May 2012. While usage related to RES customers has been growing over time within the 0 to 100 kW delivery class, it has doubled in percentage terms from 26% as of April 2009 to 53% by May 2012.

Chart II-3
0 to 100 kW Switching Statistics



Second, the retail market for residential customers is a new market that the RES have entered into during the past 18 months in a rapid fashion. Chart II-4 contains the monthly percentage of usage by RES customers from January 2010 to May 2012. In just over 12 months residential RES usage has increased from being essentially non-existent to approximately 13% of total residential usage.

Chart II-4
Residential Switching Statistics



Third, Muni Agg has firmly taken hold in the ComEd service territory. As previously noted, approximately 170 government entities passed a Muni Agg referendum in March 2012. These communities represent approximately one million residential customers and are now in various stages of reacting to those referendums. As of early July 2012 ComEd had sent account number information to 57 communities totaling approximately 340,000 accounts. In turn, this information will be used by the RES to enroll these customers for RES service. Clearly, a meaningful amount of Muni Agg is currently under way.

For these reasons we expect retail markets to continue to expand during the Forecast period.

(iv) Forecasted Retail Usage

The forecast percentages of Blended Service usage are shown below, along with some historical perspective.

Table II-4
Percentage of Blended Service Usage

Month	Residential	Watthour	0-100 kW
Jun-04	100.0%	99.4%	87.8%
Jul-05	100.0%	99.4%	87.3%
Jul-06	100.0%	99.6%	90.7%
Jul-07	100.0%	97.4%	76.5%
Jun-08	99.9%	98.0%	75.2%
May-09	99.8%	98.0%	72.1%
Jun-10	99.9%	95.0%	65.8%
Jun-11	98.3%	92.3%	57.3%
Jun-12	84.4%	71.5%	44.9%
Jun-13	30.0%	25.3%	25.9%
Jun-14	27.4%	20.1%	19.3%
Jun-15	26.0%	17.7%	15.9%
Jun-16	25.1%	16.4%	14.2%
Jun-17	24.6%	15.7%	13.0%
Jun-18	24.1%	14.9%	11.9%

The main drivers of this forecast are:

1. Increases in Residential RES service is expected for several reasons. First, the Muni Agg associated with the approximately 170 Muni Agg communities is expected to be completed by the end of 2012. We anticipate the residential electric space-heating customers to also take RES service within these approximately 170 communities. Second, non-Muni Agg switching has been occurring at slightly over one percent per month for the non-space-heating customers and that trend is expected to continue for some time. Third, the potential for an additional round of Muni Agg is possible in November 2012. There is a great deal of uncertainty associated with any Muni Agg

referendums for November 2012 because the government entities have until late August to file their proposed November 2012 referendums. ComEd proposes to provide an updated switching forecast in November 2012 (which essentially has been the past practice) to reflect any November 2012 referendum results. In the meantime, based on recent events and public comments, the forecast assumes that load equivalent to that of the City of Chicago will pass Muni Agg referendums in November 2012 and begin taking RES service in early 2013.

2. The Blended Service supply cost is expected to be marginally higher than RES prices beginning in June 2013. This reflects a combination of three-year old contracts within the portfolio, the long-term renewable energy contracts signed in 2010 and the recent Rate Stability procurement, which covered a 4 ½ year period. These contracts should create a small amount of expected "headroom" between Blended Service and RES prices in June 2013. Thus, a continued movement of customers to RES service is expected after June 2013, but at a slower pace than in past years. Further, no additional Muni Agg is expected other than the potential for a November 2012 referendum because of the small expected headroom going forward.

3. The 0 to 100 kW customer class is expected to continue to migrate to RES service as Rider PORCB has enhanced RES' ability to serve the smaller customers within this customer class.

The effects of those drivers by customer group are as follows:

1. The Blended Service portion of the 0 to 100 kW customer class is expected to decline from 44.8% (May 2012) to approximately 19.3% by June 2014. This reflects a combination of Muni Agg developments and the enhanced ability of RES to serve the smaller customers within this customer class.

2. The Blended Service portion of the Watthour customer class is expected to decline from 76.8% (May 2012) to approximately 20.1% by June 2014. This is mostly the result of the Muni Agg assumptions in the forecast.

3. The Blended Service portion of the Residential customer class is expected to decline from 86.3% (May 2012) to approximately 27.4% by June 2014. This decline results from a combination of Muni Agg and non-Muni Agg activities.

By June 2014 Blended Service is expected to be less than one-third of the usage by customers in the Eligible Retail Customer customer classes; specifically 25.9%.

c. Known or Projected Changes to Future Load

Typically, when ComEd forecasts future loads, it considers whether there are any known major customer decisions, such as the relocation of part or all of a business that would impact load. For the Eligible Retail Customers, other than the factors we have discussed elsewhere, e.g. switching, energy efficiency measures, growth, etc., there is only one known or projected change that ComEd is aware of that is different from past conditions and could affect future loads for this group of customers. This is the residential real-time pricing program ("RRTP").

In compliance with Section 16-107(b-5) of the PUA, ComEd received ICC approval to implement an RRTP program for a four-year period,[5] and, more recently, to continue the program for another three to five years.[6] ComEd plans to expand marketing to residential customers related to RRTP. As a result, approximately 7,500 additional customers per year are expected to migrate to RRTP service over the next five years because of those marketing programs. This forecasted increase is reasonable as ComEd has worked to reduce the marketing and acquisition costs for RRTP customers. The expected target of 50,000 RRTP customers by the end of 2017 is a small percent of the existing 3.4 million residential customers.

d. Growth Forecast by Customer Class

(i) Introduction

This section describes ComEd's growth forecast by customer class for the 5-year procurement planning period beginning on June 1, 2013. Section II(B)(1) discussed the hourly customer load profiles used by ComEd to develop models to present the historical load analysis required by the PUA and to predict UPC, or usage per customer. As indicated in this section, in arriving at a growth forecast by customer class, there are additional models beyond those customer-level hourly models that are used to forecast future customer class usage. These other models play an important role in determining expected load during the 5-year planning period among the Eligible Retail Customer groups.

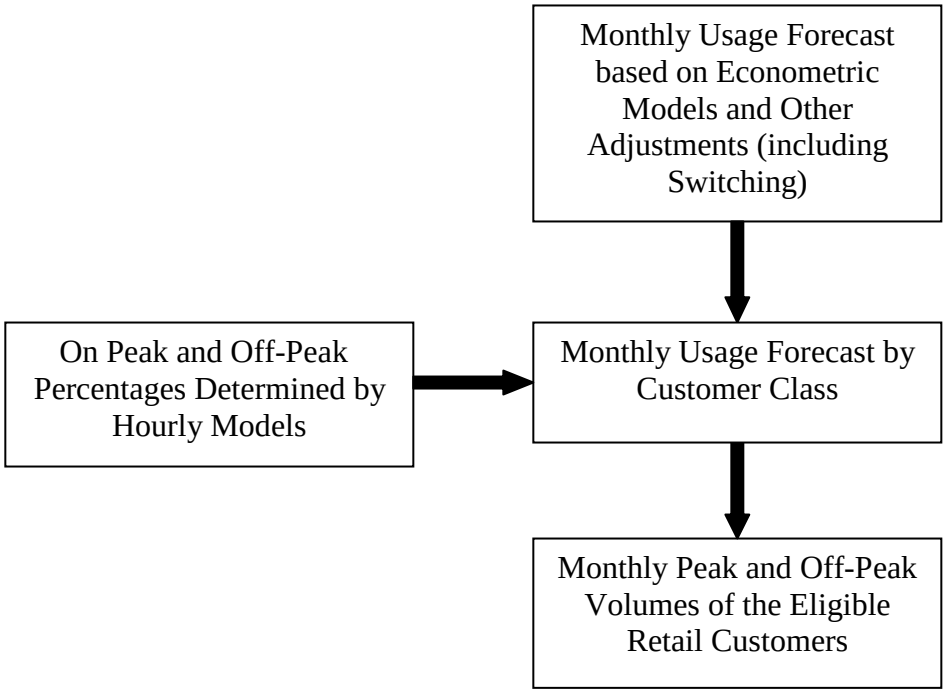
The following chart illustrates the steps in the ComEd load forecasting process.

Chart II-5

[5] See ICC Order of December 20, 2006, in Docket No. 06-0617.

[6] See ICC Order of May 29, 2012 in Docket No. 11-0546.

ComEd Energy Usage Forecast Process



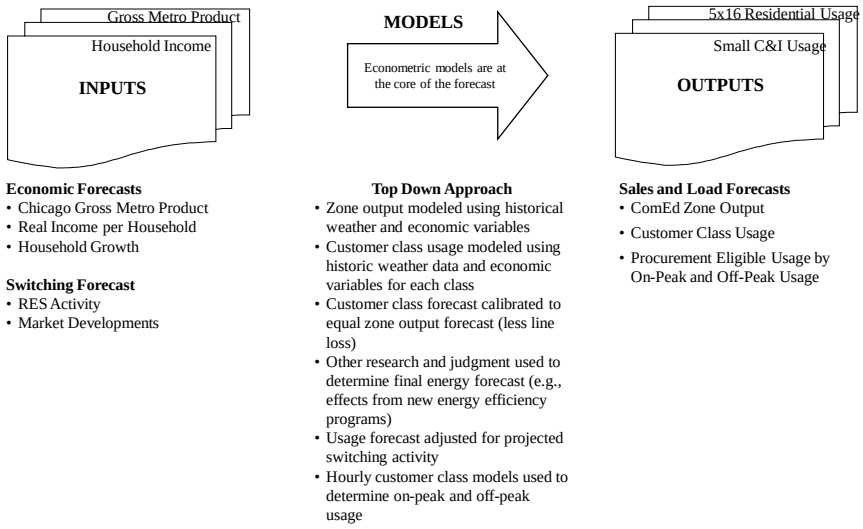
The forecasting process is model based subject to adjustments and judgment. A suite of econometric models is used to produce monthly usage forecasts for ComEd's revenue customer classes. The two major customer classes applicable to this Forecast are Residential and Small C&I. That monthly forecast is adjusted for other considerations (e.g., switching activity) and allocated to more granular delivery service classes (e.g., the residential customer class is composed of four delivery services classes). The forecast usage is combined with the input from the hourly models to obtain on-peak and off-peak quantities for each month and delivery service class.

The econometric modeling portion of the process is described in the following chart:

Chart

II-6

Econometric Modeling Process



As the chart indicates, ComEd's forecasts of usage for its service territory are based on a "top-down" approach. The top-down approach provides a forecast of total usage for the entire service territory and allocates the usage to various customer classes using the models specific to each class. The "zone" forecast model takes into account a number of economic variables that affect electric energy use. For example, the gross metropolitan product ("GMP") for the Chicago and Rockford areas is a good measure of economic activity in ComEd's service territory. As GMP (which is expressed in billions of dollars) increases, use of electric energy rises as well. Section II (B)(1) describes the significant relationship between weather and energy usage, and the zone model contains sophisticated variables to reflect the effects of temperature and humidity, as well as seasonal usage patterns and other factors. The economic assumptions are contained in Table II-6.

Table II-6

Chicago Area Economic Forecasts - Global Insight (February12)

Economic Variables	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Gross Metro Product (Billions)	$ 455	$ 464	$ 472	$ 480	$ 490	$ 507	$ 523	$ 536	$ 548	$ 559
Real Disposable Income (Millions)	$329,915	$333,154	$336,085	$338,926	$342,567	$350,912	$359,132	$367,787	$375,640	$383,976
# of Households (Thousands)	3,320	3,320	3,314	3,324	3,346	3,370	3,395	3,417	3,431	3,442
Real Income/HH	$ 99,375	$100,336	$101,426	$101,954	$102,372	$104,116	$105,779	$107,626	$109,473	$111,569
Total Employment (Thousands)	4,160	4,118	4,149	4,198	4,262	4,333	4,412	4,476	4,522	4,556
Non-Manufacturing	3,753	3,724	3,748	3,787	3,842	3,905	3,975	4,036	4,082	4,118
Manufacturing	406	394	401	410	420	428	437	440	440	438
Housing Starts	5,501	5,397	6,982	10,753	13,856	18,770	22,694	23,687	24,274	27,061
U.S. GDP	12,703	13,088	13,313	13,597	13,908	14,369	14,825	15,232	15,623	16,004

Growth Rate	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Gross Metro Product	(3.2%)	1.9%	1.8%	1.6%	2.1%	3.4%	3.2%	2.4%	2.3%	2.1%
Real Disposable Income	(3.6%)	1.0%	0.9%	0.8%	1.1%	2.4%	2.3%	2.4%	2.1%	2.2%
# of Households	(0.1%)	0.0%	(0.2%)	0.3%	0.7%	0.7%	0.7%	0.7%	0.4%	0.3%
Real Income/HH	(3.5%)	1.0%	1.1%	0.5%	0.4%	1.7%	1.6%	1.7%	1.7%	1.9%
Total Employment	(5.3%)	(1.0%)	0.7%	1.2%	1.5%	1.7%	1.8%	1.5%	1.0%	0.8%
Non-Manufacturing	(4.6%)	(0.8%)	0.6%	1.0%	1.4%	1.6%	1.8%	1.5%	1.1%	0.9%
Manufacturing	(11.8%)	(3.1%)	1.7%	2.4%	2.4%	1.8%	2.2%	0.7%	(0.1%)	(0.4%)
Housing Starts	(61.7%)	(1.9%)	29.4%	54.0%	28.9%	35.5%	20.9%	4.4%	2.5%	11.5%
U.S. GDP	(3.5%)	3.0%	1.7%	2.1%	2.3%	3.3%	3.2%	2.7%	2.6%	2.4%

Source: Global Insight

All of the variables used in each of the models in the forecasting process are identified in Appendix A-4.[7]

The remainder of this section will provide a brief description of the models, starting with the ComEd's Monthly Zone energy usage model ("Monthly Zone Model") and proceeding to the three customer-level models for Monthly Residential bill-cycle energy usage ("Monthly Residential Model"), Monthly Small C&I bill-cycle energy usage ("Monthly Small C&I Model") and Monthly Street Lighting bill-cycle energy usage (Monthly Street Lighting Model").

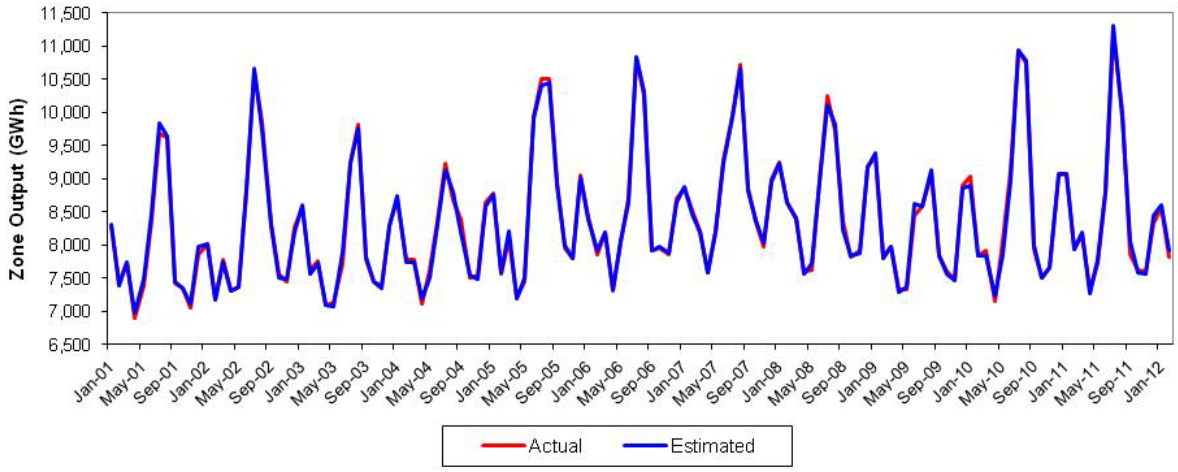
(ii) ComEd Monthly Zone Model

The Monthly Zone Model forecasts energy usage in gigawatt hours (GWh) for the entire ComEd service territory. The following chart shows the performance of the ComEd Monthly Zone Model by comparing actual zone output to the estimates[8] from that model for each calendar month from January 2001 through February 2012.

[7] Technical information about the model coefficients and regression statistics are included in Appendix A-2 and A-3.

[8] Once again, for purposes of this Forecast, the estimates used in Charts II-7, II-8 and II-9 are based on actual weather.

Chart II-7
ComEd Monthly Zone Model: Estimated vs. Actual

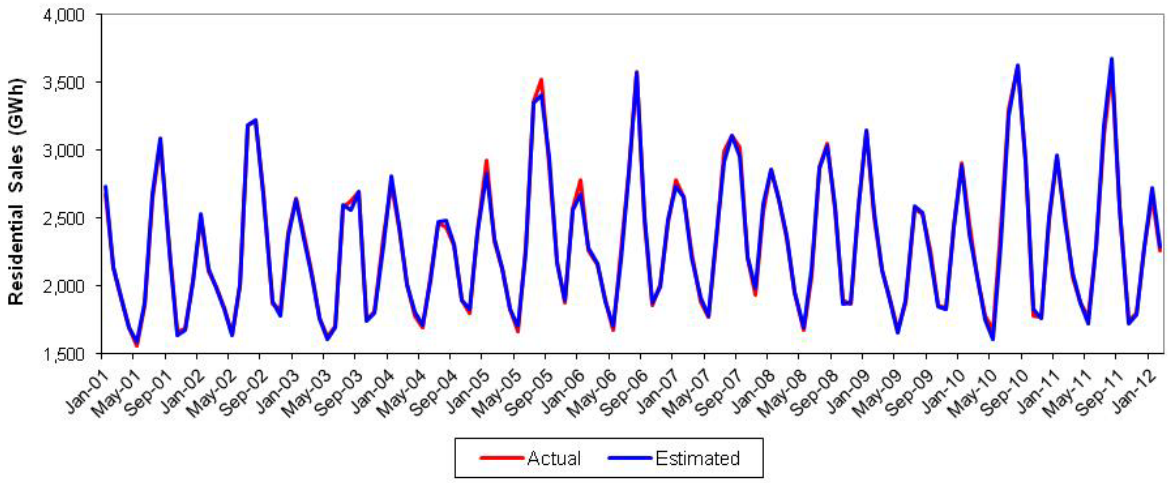


As with customer-level models discussed in Section II(B)(i)(a), the Monthly Zone Model is highly useful in understanding energy usage. The graph line depicting the model's estimated usage (based on actual weather) and the line showing actual usage for the period are nearly identical.

(iii) ComEd Monthly Residential Model

The Monthly Residential Model forecasts monthly residential bill-cycle usage expressed in kWh per customer per day. The Monthly Residential Model is also very useful in understanding energy usage for this customer segment. The following chart compares the monthly energy usage for residential customers estimated by the Monthly Residential Model to the actual residential usage for the time period of January 2001 to February 2012. The graph line depicting the model's estimated usage and the line with actual usage for the period are highly correlated.

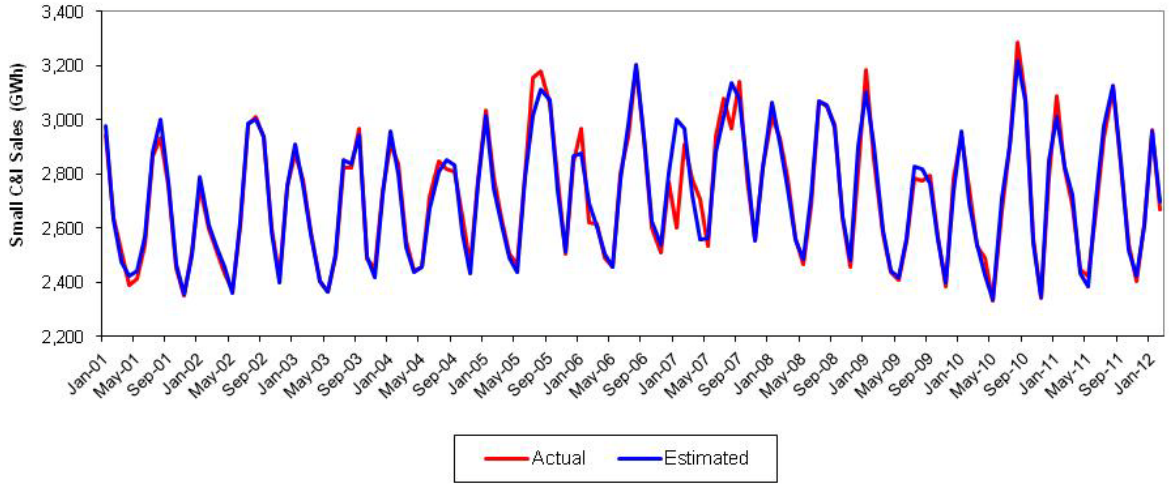
Chart II-8
ComEd Monthly Residential Model: Estimated vs. Actual



(iv) ComEd Monthly Small C&I Model

The Monthly Small C&I Model forecasts monthly Small C&I bill-cycle usage. Chart II-9 shows an estimated versus actual comparison demonstrating the model's effectiveness.

Chart II-9
ComEd Monthly Small C&I Model: Estimated vs. Actual



(v) ComEd Monthly Street Light Model

The Monthly Street Lighting Model forecasts monthly bill-cycle usage related to street lighting. This final model estimates use per day in GWh.

(vi) Growth Forecast

ComEd's historical and forecasted weather-adjusted energy usage for the Residential and Small C&I customer classes are shown in Table II-7.

Table II-7

ComEd Weather Adjusted Annual Energy Usage				
	Residential		Small C&I	
Year	Usage (GWh)	Percent Growth	Usage (GWh)	Percent Growth
2004	27,905		32,733	
2005	28,290	1.4%	33,057	1.0%
2006	28,516	0.8%	32,958	(0.3%)
2007	28,459	(0.2%)	33,508	1.7%
2008	28,599	0.5%	33,391	(0.3%)
2009	28,202	(1.4%)	32,644	(2.2%)
2010	27,865	(1.2%)	32,445	(0.6%)
2011	27,514	(1.3%)	32,182	(0.8%)
2012	27,272	(0.9%)	32,184	0.0%
2013	27,266	(0.0%)	32,325	0.4%
2014	27,395	0.5%	32,544	0.7%
2015	27,564	0.6%	32,833	0.9%
2016	27,918	1.3%	33,125	1.8%
2017	28,056	0.5%	33,107	0.8%
2018	28,293	0.8%	33,125	(0.0%)

Residential customer class usage declined by an average of 0.5% per year from 2005 to 2011. This decline is attributed to a combination of the 2009 recession and the growing energy efficiency programs. As noted last year, the year 2009 was the first time since 1954 (which is the extent of our records) that ComEd experienced a decline in the average number of residential customers from the prior year. In addition, the implementation of energy efficiency programs has worked to reduce residential usage. Looking forward, the growth is forecasted to be slightly positive at 0.3% per year from 2011 to 2017 as the economy picks up steam. However, residential usage does not exceed the usage levels of 2008 in the Forecast period. In a similar manner, Small C&I usage declined 0.4% per year from 2005 to 2011. Small C&I is ComEd's revenue class related to commercial and industrial customers below 1,000 kW in size. Again, a significant decline in Small C&I usage was experienced in 2009 because of the recession. The forecasted growth rate from 2011 to 2017 is also a small 0.5% per year. Small C&I usage does not exceed 2007 levels during the Forecast period.

2. Impact of Demand Side and Energy Efficiency Initiatives

The PUA sets out annual targets for the implementation of cost-effective demand side and energy efficiency measures. The most recent, ICC-approved energy efficiency and demand response plan covered the planning years ("Planning Year")[9] 2011-2013 ("2011-2013 EE/DR Plan").[10] ComEd believes these statutory targets are achievable and plans to meet them in Planning Year 2012. For Planning Year 2013, ComEd agreed to an overall portfolio target of 1.0% pursuant to a settlement agreement with intervening parties. This target is lower than the 1.4% statutory target, and reflects the impacts of spending screen limitations imposed by the PUA.[11]

The demand-side and energy efficiency plans for subsequent years have not yet been developed by ComEd or approved by the ICC. While Planning Year targets have not been established for Planning Years 2014-2017, it is expected that spending screen limits will similarly affect the total amounts of energy efficiency that can be achieved as the screens limited the amount for Planning Year 2013.

a. Impact of demand response programs, current and projected

(i) Background

ComEd is a strong supporter of the use of demand response to actively manage peak demands. Use of demand response resources grew in the mid to late 1990s, and ComEd has maintained a large portfolio of demand response resources, with participation from residential, commercial, and industrial customers. ComEd is leader in the development and management of demand response resources, and will increase participation in appropriate programs to meet the requirements of the PUA.

The 2012 portfolio of ComEd programs includes the following:

- **Direct Load Control ("DLC"):** ComEd's residential central air conditioning cycling program is a DLC program with over 73,000 customers with a load reduction potential of 112 MW (ComEd Rider AC).

- **Voluntary Load Reduction ("VLR") Program:** VLR is an energy-based demand response program, providing compensation based on the value of energy as determined by the real-time hourly market run by PJM. This program also provides for transmission and distribution ("T&D") compensation, based on the local conditions of the T&D network. This portion of the portfolio has roughly 1,225 MW of potential load reduction (ComEd Rider VLR).

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[9] A Planning Year runs from June 1 of one year through May 31 of the next year.

[10] See Order of December 21, 2010 in Docket No. 10-0570.

[11] Order, p. 18.

- **Capacity-based Load Response (Rider CLR) – Suspended June 2012:** As a result of PJM terminating the Interruptible Load for Reliability (ILR) program, which is the basis of ComEd's Capacity-based Load Response (CLR) Program, ComEd will not be offering the Capacity-based Load Response Program to its business customers during the 2012/13 Delivery Year which begins June 1, 2012 and extends through May 31, 2013.

- **Residential Real-Time Pricing (RRTP) Program:** All of ComEd's residential customers have an option to elect an hourly, wholesale market-based rate. The program uses ComEd's Rate BESH to determine the monthly electricity bills for each RRTP participant. This program has roughly 5 MW of price response potential.

(ii) Legislative Requirement

Section 8-103(c) of the PUA establishes a goal to implement demand response measures, providing that:

> (c) Electric utilities shall implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Section 16-111.5 of this Act, and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive. This requirement commences June 1, 2008 and continues for 10 years.

Section 1-10 of the Illinois Power Agency Act defines demand response as "measures that decrease peak demand or shifts demand from peak to off-peak periods."

Table II-8 shows the estimated annual MWs of demand response measures that will need to be implemented over the Five-year Forecast period to meet the goals set forth in the PUA:

Table II-8
Estimated Annual Level of Demand Response Measures

Planning Year	Peak Load at Meter (Prior Year) (MW)	Annual Goal (0.1%) (MW)	Cumulative Goal (MW)
2012	8,795	10.7	54.0
2013	3,193	10.8	64.8
2014	2,834	2.8	67.6
2015	2,675	2.7	70.3
2016	2,603	2.6	72.9
2017	2,563	2.6	75.5

The Planning Year goals in 2012 and 2013 are 10.7 MW and 10.8 MW, respectively, and are from ComEd's 2011 – 2013 EE/DR Plan (page 8). In subsequent years, it is assumed ComEd will meet the statutory goals.

(iii) Implementation of Demand Response Measures

In the 2011-2013 EE/DR Plan, ComEd demonstrated that the demand response targets mandated by the PUA are satisfied by the demand reductions achieved from the implementation of energy efficiency measures. As such, no additional demand response acquisition is provided in that plan. Existing demand response participant levels from the first three-year plan will continue to be funded. Further details are provided in the 2011-2013 EE/DR Plan.[12]

(iv) Impact of Demand Response Programs

Demand response programs do not impact ComEd's load forecasts. Load forecasts are made on a weather normalized, unrestricted basis. Since demand response measures are called on days when the temperature is hotter than "normal", the avoided capacity and energy associated with these resources is incremental to the weather normal forecast, and thus is not factored into the load forecasts. In fact, when developing forecasts, any impact on energy usage from actually implementing a demand response measure in a prior year is added back into that prior year's usage data and then weather normalized before being used to assist in the forecasting process. This assures that the forecast represents a complete picture of the unrestricted demands on the system.

b. Impact of Energy Efficiency Programs

The PUA has a number of provisions regarding various types of energy efficiency programs. This section discusses the impact of each on these programs on the Forecast.

(i) Section 8-103 Energy Efficiency Measures

Section 8-103 of the PUA requires ComEd to implement cost-effective energy efficiency measures beginning June 1st, 2008. This provision provides annual kWh targets based on a projection of the upcoming years' energy usage for all delivery service customers. Additionally, there is a spending cap that limits the amount of expenditures on energy efficiency measures in any year.

[12] See p. 8.

(A) kWh Targets

The kWh target for energy efficiency is based on a projection of the amount of energy to be delivered by ComEd to all of its delivery service customers in the upcoming Planning Year. This percentage increases annually through the year 2015, subject to specified rate impact criteria. The table below shows the target percentages.

Table II-9
Target Incremental Percentages to Meet Energy Efficiency Goals

Year	Annual Percent Reduction in Energy Delivered
2008	0.2%
2009	0.4%
2010	0.6%
2011	0.8%
2012	1.0%
2013	1.4%
2014	1.8%
2015 and each year thereafter	2.0%

(B) Projected Overall Goals

The annual energy efficiency goals were determined based on the kWh targets and the rate impact criteria. As noted above, ComEd's 2011-2013 EE/DR Plan was approved in late 2010. For 2013, the ICC approved an agreed upon 1% reduction instead of the statutory target of 1.4% due to the impacts of the spending screen limitations in the PUA.[13] There is as of yet no ICC-approved plan for Planning Years 2014 – 2016. However, for the purposes of this Forecast ComEd assumes that the spending screen will similarly limit the annual percent reduction to approximately 1%. Also, for purposes of this Forecast only,[14] the allocation of the energy (kWh) targets to the various customer classes (as shown in Table II-7) was based on several years of historical data and judgment.

The above percentages represent the incremental goal to be achieved by the end of each Planning Year for all delivery services customers. Since the various energy efficiency measures will be implemented and phased in over the course of each Planning Year and since Eligible Retail Customers are only a subset of delivery services customers, the actual amount of

[13] See Order of December 21, 2010 in Docket No. 10-0570, p. 18.

[14] The PUA does not prescribe how the kWh targets are to be apportioned among the customer classes, and the energy efficiency plan did not set goals on a customer class basis.

GWh for Eligible Retail Customers that is impacted in each Planning Year will be somewhat less (as shown in Table II-10, below).

(C) Impact on Forecasts

Energy efficiency measures directly impact the amount of energy used by customers throughout the year. As such, they will directly impact the forecasts of future load. The following chart depicts the cumulative impacts of these measures on the Forecast:

Table II-10
Cumulative Impacts of EE on Load Forecast by Customer Type[15]

Planning Year	Residential Allocation (GWh)	Watt-Hour Allocation (GWh)	0-100 kW Allocation (GWh)
2013	374	2	46
2014	426	3	54
2015	475	4	62
2016	520	4	67
2017	572	4	70

(ii) Energy Efficiency Building Codes and Appliance Standards

Section 16-111.5B(a)(1) of the PUA requires procurement plans to include a discussion of the impact of energy efficiency building codes and appliance standards on the Forecast. This section describes how building codes and appliance standards are considered in and impact the Forecast.

The load forecasting models and process described herein takes into account all current and projected building codes and appliance standards. This is accomplished by making energy efficiency adjustments to the forecast beyond what is entailed in the mandated energy efficiency adjustments described herein. Also, the econometric models use actual historical usage data and that data, in turn, reflects the changes to these standards over time.

To demonstrate the impact of these codes and standards on the ComEd Forecast, ComEd conducted an analysis using its Statistical Adjusted End-Use (SAE) models and performing a simulation using different energy efficiency assumptions. The SAE models are econometric models that along with inputs related to economics and weather also include attributes related to end-use applications. For example, there are assumptions pertaining to dishwater appliance energy efficiency standards and saturation that feed into this model based on the U.S. Energy Information Agency regional data and prior ComEd end-use surveys.

[15] These amounts are cumulative from 2008, when the statutory program began.

Since future energy efficiency standards are already reflected in the Forecast, ComEd conducted the simulation by projected energy under 2007 energy efficiency assumptions and comparing the results to projections using current energy efficiency assumptions. Simply put, ComEd uses the current SAE model, but input energy efficiency standards reflecting 2007 assumptions for the following end-uses:

Residential Customers	Small C&I Customers
1 Heating	**1** Heating
2 Cooling	**2** Cooling
3 Electric water-heating	**3** Ventilation
4 Electric cooking	**4** Electric Water Heating
5 First refrigerator	**5** Refrigeration
6 Second refrigerator	**6** Cooking
7 Freezer	**7** Office
8 Dishwasher	**8** Miscellaneous
9 Clothes Washer	
10 Electric Dryer	
11 Television	
12 Miscellaneous	

The results of this simulation are shown in Appendix D. The results show that the projected energy usage for 2013 – 2017 in the residential class based on current appliance standards is 0.1% lower than the projected energy usage using 2007 appliance standards. In other words, the changes in appliance standards are not creating a large change in residential usage during the forecast period. For Small C&I the equivalent percent change was also 0.1%.

The results for the building codes similarly show a small reduction of 0.03% for residential. A similar simulation is not possible for Small C&I. Nonetheless, the change to the overall Forecast from the building codes is likely very little given that the below 100 kW usage is approximately 17% of the quantities being procured in the forecast time period.

(iii) Section 16-111.5B Energy Efficiency Procurement

Section 16-111.5B of the PUA requires procurement plans to include an assessment of opportunities to expand the section 8-103 energy efficiency measures or to implement additional cost-effective energy efficiency measures. This assessment is to include a wide range of information for consideration by the IPA and the ICC. This section provides that information.

One issue that has arisen in the implementation of this program is determining to whom these programs may be offered. The PUA provides that the programs would be offered to Eligible Retail Customers. By definition, this group is limited to customers who actually take fixed price bundled service from ComEd. However, the PUA does not specify the period of time that should be considered for determining which customers qualify as Eligible Retail Customers.

This is important because each of these programs is offered over a relatively long period of time and the cost and energy savings analyses consider a multi-year period. Moreover, it is simply not practical, or even possible, to limit the offering of some of the programs to certain customers. Some programs, such as the light bulb program, are mass marketed to all customers. Given the nature of the programs and the multi-year period required to offer and analyze these programs, it is more appropriate to consider the group of customers who qualify over a longer period of time. Over such a reasonable period, all residential and Small C&I would be eligible to take energy from ComEd under fixed price bundled service. Therefore, ComEd believes this is the appropriate group of customers to whom these programs should be offered.[16] However, in recognition of the uncertainty surrounding this issue, ComEd is providing information assuming both that the programs are offered to the broader set of Eligible Retail Customers or to only those customers who are currently taking fixed price bundled service from ComEd.

(A) Energy Efficiency Potential Study

Section 16-111.5B(a)(3)(A) requires the inclusion of a comprehensive energy efficiency potential study for the utility's service territory that was completed within the past 3 years. Such a study is attached to this Forecast as Appendix C-1. The study identifies technical, economic and achievable energy efficiency potential. Technical potential assumes that all energy efficiency measures are implemented by all of ComEd's customers, irrespective of cost or other barriers. Economic potential screens the technical potential to include only those measures that pass the statutory Total Resource Cost ("TRC") test. Achievable potential further filters these measures to reflect a variety of non-cost, or market barriers, that cause customers to not implement energy-saving measures.

This study was completed in 2009 and as such used the higher avoided energy costs in effect at that time to determine economic potential. This may have the effect of overstating economic potential when considered against the backdrop of current energy supply prices.

(B) Identification of New or Expanded Measures

Section 16-111.5B(a)(3)(C)[17] requires the listing of new or expanded cost-effective energy efficiency programs or measures that could be offered to eligible retail customers. Such a listing is provided in Appendix C-2 - Energy Efficiency Analysis Summary. The programs or vendor names are listed in column A of Appendix C-2, with a short description of the program modification or concept in column J.

(C) Cost Analysis

Section 16-111.5B(a)(3)(D) requires an analysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service. Such an analysis is included in Appendix C-2. "Cost-effective", as used in

[16] SB3811, which passed both houses of the Illinois General Assembly on May 30, 2012, amends the PUA to make this clear.

[17] Section 16-111.5B(a)(3)(B) does not require the inclusion of any additional information until 2014.

Section 16-111.5B, has the same meaning as set forth in Section 8-103(a) of the PUA.[18] As defined in that section, "cost-effective" is determined using the Total Resource Cost ("TRC") test, with a TRC result greater than 1.0 being considered cost-effective. In addition, ComEd conducted an analysis of each program to show that the programs would each lead to a reduction in the overall cost of electric service. ComEd used the Utility Cost Test ("UCT"), as defined by the California Standard Practice Manual[19]. The UCT compares the avoided costs realized by implementing energy efficient measures to the utility's costs to acquire those measures. Since the language in 16-111.5B(a)(3)(D) does not address the time value of money, ComEd has adopted a position preferred by the Stakeholder Advisory Group which adopts a discount rate of zero for this test only. The TRC and UCT results are listed in columns G and H of Appendix C-2.

In addition, Column I shows the Cost to Conserve Energy ("CCE"), which is expressed in dollars per lifetime kWh saved. The CCE allocates the total cost of each program to the lifetime energy savings associated with that program, and it provides a useful comparison between the cost of saving a kWh of energy to supply alternatives.

(D) Comparison to Cost of Comparable Supply

Section 16-111.5B(a)(3)(E) requires an analysis of how the cost of procuring additional energy efficiency measures compares over the life of the measures to the cost of comparable supply. This analysis is provided in Appendix C-2. Column I in that appendix shows the Cost to Conserve Energy ("CCE"), which is expressed in dollars per lifetime kWh saved. The CCE is determined by dividing the total cost of each program by the lifetime energy savings associated with that program. It provides a useful comparison between the cost of saving a kWh of energy to supply alternatives.

(E) Energy Savings Goal[20]

Section 16-111.5B(a)(3)(F) requires the determination of energy savings goal for each of the measure to be implemented. Appendix C-3 shows the amount of energy that each of the new or expanded cost-effective energy efficiency programs or measure is expected to save each month over the five-year Forecast period.[21] Appendix C-2, Columns D and E show the annualized MWh savings at the busbar and the meter, respectively, for each of the measures.

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[18] See section 16-111.5B(b)

[19] http://www.calmac.org/events/SPM_9_20_02.pdf; Referred to as the Program Administrator Cost ("PAC") test in California

[20] SB3811, which has passed both houses and is sitting on the Governor's desk, revises Section 16-111.5B(a)(3) to add subsection (G) which requires an estimated amount that each new measure may reduce the need to procure supply. That information is also provided in Appendix C-3.

[21] Pages 1 and 2 of Appendix C-3 show the energy savings goal associated with the usage of all residential and Small C&I customers who are eligible to receive fixed-price bundled service from ComEd. Pages 3 and 4 show the energy savings goal associated with the usage of the actual Eligible Retail Customers.

C. Impact of Renewable Energy Resources

Section 1-75(c) of the IPA Act (20 ILCS 3855/1-75(c)) establishes the following goals and cost thresholds for cost effective renewable energy resources:

Table II-11
Renewable Energy Resource Requirements

Delivery Period	Minimum Percentage	Maximum Cost
2013-2014	8% of June 1, 2011 through May 31, 2012 Eligible Retail Customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011.
2014-2015	9% of June 1, 2012 through May 31, 2013 Eligible Retail Customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011.
2015-2016	10% of June 1, 2013 through May 31, 2014 Eligible Retail Customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011.
2016-2017	11.5% of June 1, 2014 through May 31, 2015 Eligible Retail Customer Load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011.
2017-2018	13% of June 1, 2015 through May 31, 2016 Eligible Retail Customer Load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011.

Based on the above, Table II-12 shows the amount of renewable energy resources that need to be procured for Planning Year 2013, while Table II-13 shows the maximum amount, i.e., the budget amount, that may be spent acquiring such resources:

Table II-12

Targeted Renewable Energy Resources

Planning Year	Reference Year	Reference Year Delivered Volume (MWH)	Planning Year RPS Target (%)	Planning Year RPS Target (RECs)
2013-14	2011-12	32,536,744	8.0%	2,602,940
2014-15	2012-13	18,971,928	9.0%	1,707,474
2015-16	2013-14	11,039,852	10.0%	1,103,985
2016-17	2014-15	10,036,819	11.5%	1,154,234
2017-18	2015-16	9,500,479	13.0%	1,235,062

Table II-13

Renewable Energy Resources Budgets

Planning Year	Planning Year Delivered Volume (MWH)	RPS 2.015% Cost Cap ($/MWH)	Planning Year RPS Budget ($)
2013-14	11,039,852	1.8917	20,884,088
2014-15	10,036,819	1.8917	18,986,650
2015-16	9,500,479	1.8917	17,972,057
2016-17	9,208,355	1.8917	17,419,445
2017-18	8,993,229	1.8917	17,012,491

Pursuant to previous Commission orders, ComEd currently has existing contracts to procure renewable energy resources that will be in effect over the period covered by the Forecast. In Docket No. 09-0373, the Commission directed ComEd to procure up to 1,400,000 MWhs of renewable energy resources each year for twenty years pursuant to long-term contracts ("LT Renewables"). In Docket No. 11-0660, the Commission directed ComEd to procure the statutorily-prescribed amount[22] of RECs over the period June 1, 2013 through December 31, 2017 ("Rate Stability RECs").

Based upon the Expected Load Forecast, the cost for RECs under existing long-term contracts will exceed the budget and result in rates for Eligible Retail Customers increasing by an amount greater than 2.015% in Planning Year 2013[23]. As a result, no additional RECs for Planning Year 2013 may be purchased[24]. In addition, purchases of RECs under existing

[22] See Section 16-111.5(k-5) of the PUA.

[23] See Appendix E.

[24] In fact, Appendix E shows that the purchases of renewables under the existing long-term contracts are forecasted to exceed the budget in each of the next five Planning Years, i.e. 2013-2017.

contracts will need to be reduced. The LT Renewables contracts contain a provision that allow the quantities to be procured to be reduced in order to ensure that the statutory cost cap is not exceeded[25]. The LT Renewables contracts are the only contracts that permit such a reduction to occur.

Given the rapid changes in customer switching, including switching due to Muni Agg, the Expected Load Forecast will undoubtedly change when ComEd submits its updated forecasts in November. In addition, the Expected Load Forecast does not include the impact on the load of the Eligible Retail Customers that would result from the procurement of the additional energy efficiency measures that are discussed in section II(B)(2)(b)(iii) of this Forecast. That impact can be provided with the updated Forecast after the IPA has indicated which, if any, of the additional measures it recommends be procured. Therefore, the IPA's procurement plan should provide that the procurement of renewables under the LT Renewables contracts should be reduced by sufficient quantities so as not to exceed, on an actual basis, the 2.015% statutory cap.

In accordance with Section 1-75(c)(5) of the IPA Act, ComEd has been collecting Alternative Compliance Payments ("ACP") from its Hourly Service Customers. Beginning in 2011, ComEd must include in its Forecast the amount of ACP that is collected in the prior year ending May 31. The IPA is then to increase its spending for renewable energy resources for the next Planning Year by the amount collected. For the period June, 1, 2010 through May 31, 2011 ComEd collected $1,499,113 in ACP. While ComEd reported this amount in its 2011 Forecast, it was not expended by the IPA in the regular REC 2012 procurement. For the period June 1, 2011 through May 31, 2012 ComEd collected $284,847 in ACP.

3. Five-Year Monthly Load Forecast

[25] See Par. D of the Confirmation, (http://www.comed-energyrfp.com/2010-RFP/docs/lt/8Sample_Confirmation_Final_11-08-2010.pdf).

Based on all of the factors discussed in this section, ComEd has developed the following forecast of projected energy usage to Eligible Retail Customers for the period from June 1, 2013 through May 31, 2014:

Table II-14

ComEd Procurement Period Load Forecast (Expected Load) Projected Energy Usage and Average Demand For Eligible Retail Customers (Weather Normal, Line Loss and DSM Adjusted)					
Year	**Month**	**Total Load (MWh)**		**Average Load (MW)**	
		On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**
2013	6	559,748	562,252	1,749	1,406
2013	7	718,755	636,125	2,042	1,623
2013	8	661,608	587,794	1,880	1,499
2013	9	449,784	455,422	1,406	1,139
2013	10	456,591	381,859	1,241	1,016
2013	11	436,348	463,447	1,364	1,159
2013	12	532,875	559,674	1,586	1,372
2014	1	561,025	545,218	1,594	1,391
2014	2	463,864	449,545	1,450	1,277
2014	3	431,591	458,550	1,284	1,124
2014	4	398,997	354,411	1,134	963
2014	5	385,325	391,797	1,147	960
Totals		**6,056,511**	**5,846,094**		

The forecast set forth above shows ComEd's expected load for the 2013 Planning Year.[26] The PUA requires that the forecast cover a 5-year planning period. The forecast for ComEd's expected load for the 5-year planning period is set forth in Appendix B-1. The PUA also requires ComEd to provide low-load and high-load scenarios. That information for the 2013 Planning Year is set forth in Tables II-17 and II-18. The low-load and high-load scenarios for the 5-year planning period are set forth in Appendix B-2 and Appendix B-3, respectively. In all of the forecasted usage tables, "line loss" refers only to distribution losses.

Table II-15

[26] The forecasts in Tables II-13, 14 and 15 and in Appendices B-1, 2 and 3 do not include the impact of the new Section 16-111.5 energy efficiency procurement. The impact on the Forecast of those measures is depicted in Appendix C-4.

ComEd Procurement Period Load Forecast (Low Load) Projected Energy Usage and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	**Month**	**Total Load (MWh)**		**Average Load (MW)**	
		On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**
2013	6	450,489	487,388	1,408	1,218
2013	7	547,914	519,411	1,557	1,325
2013	8	489,957	452,397	1,392	1,154
2013	9	398,545	404,497	1,245	1,011
2013	10	386,303	318,753	1,050	848
2013	11	364,113	379,365	1,138	948
2013	12	442,905	469,109	1,318	1,150
2014	1	471,232	451,124	1,339	1,151
2014	2	366,475	361,214	1,145	1,026
2014	3	324,060	346,121	964	848
2014	4	297,357	269,935	845	734
2014	5	285,255	288,253	849	707
Totals		**4,824,605**	**4,747,567**		

Table II-16

ComEd Procurement Period Load Forecast (High Load) Projected Energy Usage and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	**Month**	**Total Load (MWh)**		**Average Load (MW)**	
		On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**
2013	6	952,298	949,793	2,976	2,374
2013	7	1,258,538	1,163,095	3,575	2,967
2013	8	1,346,737	1,205,062	3,826	3,074
2013	9	707,370	708,059	2,211	1,770
2013	10	723,486	610,934	1,966	1,625
2013	11	742,133	800,401	2,319	2,001
2013	12	874,236	919,245	2,602	2,253
2014	1	906,729	881,295	2,576	2,248
2014	2	792,387	753,262	2,476	2,140
2014	3	700,112	764,022	2,084	1,873
2014	4	672,192	601,525	1,910	1,635
2014	5	605,603	623,428	1,802	1,528
Totals		**10,281,821**	**9,980,121**		

The low-load and the high-load scenarios are based upon a change to three of the main variables impacting load: weather, switching and load growth.

The Low-Load Forecast assumes that the summer weather is cooler than normal, that load growth occurs at a rate 2% less than the Expected Load Forecast and that a greater number of customers opt for RES service relative to the Expected Load Forecast shown in Table II-13. In this scenario an additional ten percent of the Blended Service usage as of April 2013 switches to RES service pursuant to a November 2012 Muni Agg referendum; plus, the non-Muni Agg switching rate continues at the past trend until 2015. The percentage of Eligible Retail Customers taking Blended Service in this switching scenario is 19.8% (based on usage) as of June 2014 compared to 25.9% in the Expected Load Forecast.

The High-Load Forecast assumes that the summer weather is hotter than normal, that load growth occurs at a rate 2% more than is expected, and that fewer customers opt for RES service. First, this scenario assumes that there is no additional switching due to a November 2012 Muni Agg referendum. Second, the switching rate in 2013 is reduced by approximately 0.5% to 1.0% per month. The percentage of Eligible Retail Customers taking Blended Service in this switching scenario is 41.0% as of June 2014 compared to 25.9% in the Expected Load Forecast.

The +/- 2% load growth assumption in both scenarios reflects, in part, the current economic uncertainty. That uncertainty is described by Global Insight in its U.S. Executive Summary dated June 2012:

> "Europe Derails the Recovery" Scenario: In the pessimistic scenario, the European debt crisis goes from bad to worse and derails the US recovery. With financial markets in panic, access to credit become very difficult and the private sector retrenches sharply. A weak labor market, still-high debt, and depressed incomes also weigh heavily on the housing market. Foreclosures and weak fundamentals push prices down and constrain any type of housing recovery.
>
> "Recovery Reignites" Scenario: In the optimistic scenario, recent fears of another slowdown evaporate quickly, as the soft patch proves to be solely a payback for warm winter weather. The unemployment rate drops to 7.5% by the fourth quarter of 2012, a level it does not reach until late-2014 in the baseline. In short, the optimistic alternative sees the US economy picking up quickly as impressive payroll growth, more optimistic consumers and stronger signs of life in the housing market, as well as better foreign growth, paint a brighter growth picture than depicted in the baseline.

ComEd's intention is to keep the IPA informed of significant changes in its forecast during the procurement proceeding.

III. CONCLUSION

For all of the reasons described here, ComEd believes that its Forecast for the period June 1, 2013 through May 31, 2018 is consistent with the requirements of the PUA and provides an appropriate approach to develop the procurement plan to acquire supply for the Eligible Retail Customers.

Appendices

A. Load Forecast Models

1. Residential Single Family Model (Hour 16)
2. ComEd Model Coefficients
3. ComEd Model Regression Statistics
4. Detailed Description of Variables Used In Forecast Models

B. Five-Year Load Forecast

1. Expected load
2. Low Load
3. High Load

C. Energy Efficiency

1. Potential Study
2. Analysis Summary
3. Monthly Savings Curve

D. Building codes and Appliance Standards

E. Renewables

Appendix A-1

Residential Single Family Model (Hour 16)			
Variable	**Coefficient**	**T-Stat**	**Notes**
CONSTANT	1.843	17.298	Constant term
Monday Binary	-0.094	-8.308	
Tuesday Binary	-0.113	-10.015	
Wednesday Binary	-0.129	-11.487	
Thursday Binary	-0.138	-12.223	
Friday Binary	-0.122	-10.776	
Saturday Binary	-0.029	-3.149	
MLK Binary	0.031	0.646	Martin Luther King's Day
PresDay Binary	0.078	1.623	President's Day
GoodFri Binary	0.032	0.663	Good Friday
MemDay Binary	0.119	2.385	Memorial Day
July4th Binary	0.004	0.076	July 4th.
LaborDay Binary	0.166	3.370	Labor Day
Thanks Binary	0.135	2.668	Thanksgiving Day
FriAThanks Binary	0.045	0.900	Friday after Thanksgiving Day
XMasWkB4 Binary	0.136	2.597	Week before Christmas
XMasEve Binary	0.376	5.435	Christmas Eve
XMasDay Binary	0.246	3.621	Christmas Day
XMasWk Binary	0.112	1.822	Christmas Week
NYEve Binary	0.141	1.927	New Year's Eve Day
NYDay Binary	0.166	2.778	New Year's Day
XMasLights Binary	0.0000	0.211	Christmas Lights
DLSav Binary	-0.475	-5.652	Day-Light Sayings
Sun.FracDark6	0.365	5.430	Fraction of hour 6 am that is dark
Sun.FracDark7	0.235	4.770	Fraction of hour 7 am that is dark
Sun.FracDark8	0.327	4.712	Fraction of hour ending 8 am that is dark
Sun.FracDark17	0.088	1.734	Fraction of hour ending 5 pm that is dark
Sun.FracDark18	-0.183	-3.147	Fraction of hour ending 6 pm that is dark
Sun.FracDark19	-0.217	-4.356	Fraction of hour ending 7 pm that is dark
Sun.FracDark20	-0.285	-5.290	Fraction of hour ending 8 pm that is dark
Sun.FracDark21	-0.608	-6.934	Fraction of hour ending 9 pm that is dark
Binary Feb	-0.046	-1.041	
Binary Mar	0.018	0.382	
Binary Apr	-0.007	-0.132	
Binary May	0.041	0.713	
Binary Jun	0.148	2.481	
Binary Jul	0.243	4.157	
Binary Aug	0.261	5.010	
Binary Sep	0.205	4.152	

Binary Oct	0.173	3.342	
Binary Nov	0.061	1.339	
Binary Dec	0.093	2.113	
Usage Trend	-0.012	-2.647	
Fall HDD Spline	0.006	3.023	HDD Spline for September and October
November HDD Spline	0.005	4.305	HDD Spline for November
December HDD Spline	0.004	4.381	HDD Spline for December
January HDD Spline	0.007	7.131	HDD Spline for January
February HDD Spline	0.008	7.846	HDD Spline for February
March HDD Spline	0.005	4.562	HDD Spline for March
Spring HDD Spline	0.008	5.979	HDD Spline for April and May
Day lag of HDD Spline	-0.001	-1.127	
Two day lag of HDD Spline	0.0000	0.579	
Weekend HDD Spline	0.000	1.003	
Trend HDD Spline	0.000	3.021	
April THI Spline	0.047	2.468	THI (Temperature Humidity Index) Spline for April
May THI Spline	0.155	28.983	THI (Temperature Humidity Index) Spline for May
June THI Spline	0.162	50.101	THI (Temperature Humidity Index) Spline for June
July THI Spline	0.152	44.815	THI (Temperature Humidity Index) Spline for July
August THI Spline	0.163	46.474	THI (Temperature Humidity Index) Spline for August
September THI Spline	0.183	42.043	THI (Temperature Humidity Index) Spline for September
October THI Spline	0.168	20.902	THI (Temperature Humidity Index) Spline for October
Day lag of THI Spline	0.013	5.659	
Two day lag of THI Spline	0.012	6.342	
Weekend THI Spline	0.009	4.158	
THI Spline for Trend	0	0.731	
2007 Plus Dummy	0.062	5.01	An End Shift to describe usage for 2007 and beyond
2009 Plus Dummy	-0.034	-3.141	An End Shift to describe usage for 2009 and beyond
2010 Plus Dummy	-0.013	-1.218	An End Shift to describe usage for 2010 and beyond
Sept-Nov 2011 Dummy	0.246	11.289	
July 2011 Storm Dummy	-0.766	-5.666	
2006 Plus THI Shift	-0.011	-3.952	THI Shift variable is a weather variable akin to the THI Trend variable.

The coefficients provide the effect that each variable has on the hourly usage for a single hour (Hour 16 which includes the load from 3 p.m. to 4 p.m. in the afternoon). The "T-Stat" provides the statistical significance of the variable, with a value generally greater than +/- two (2) indicating that the coefficient is significantly different from zero. The hourly model for Hour 16 has an adjusted R-squared of 0.94, which means that 94% of the variance in the hourly data is being explained by the model.

At the daily level, the mean average percent error ("MAPE") for the summation of the hourly models is 3.4%. The 3.4% daily MAPE means that the average percentage difference on a daily basis between the usage predicted by the model and the actual usage for that period was very small. In other words, the model can explain usage with almost a 97% accuracy rate. Such a high accuracy rate is particularly noteworthy because the model is dealing with very short time frames in which many factors may come into play. The high accuracy rate, the low MAPE and the high R-squared indicate that the model captures the vast majority of factors that affect electrical usage.

Appendix A-2

ComEd Model Coefficients

ComEd Zone Model			
Variable	Coefficient	StdErr	T-Stat
CONST	-879.995	636.09	-1.383
CalVars.Jan	-108.813	26.774	-4.064
CalVars.Feb	-87.72	61.582	-1.424
CalVars.Mar	-300.758	38.502	-7.811
CalVars.Apr	-438.631	55.79	-7.862
CalVars.May	-433.306	66.256	-6.54
CalVars.Jun	-193.239	69.107	-2.796
CalVars.Jul	-196.763	80.425	-2.447
CalVars.Aug	-26.828	74.812	-0.359
CalVars.Sep	-102.083	63.973	-1.596
CalVars.Oct	-258.675	54.069	-4.784
CalVars.Nov	-115.287	46.874	-2.46
CalVars.Yr05Plus	129.182	38.537	3.352
CalVars.Yr07Plus	-74.32	32.339	-2.298
CalVars.Yr10Plus	-96.723	30.522	-3.169
CalHDD.HDDSpline	1.889	0.089	21.111
CalHDD.HDDSplineTrend	0.057	0.012	4.891
CalCDD.SpringTDD	12.265	1.069	11.471
CalCDD.SummerTDD	13.446	0.354	37.931
CalCDD.FallTDD	13.552	1.823	7.434
CalCDD.TDDTrend	0.164	0.058	2.83
CalCDD.Yr06Plus_TDDShift	-0.927	0.41	-2.259
Monthly.EconIndex4	4.412	0.332	13.305
AR(1)	0.427	0.087	4.9

Residential Customer Class Model			
Variable	Coefficient	StdErr	T-Stat
Monthly.Jan	10.33	2.956	3.494
Monthly.Feb	8.693	2.937	2.96
Monthly.Mar	7.9	2.926	2.7
Monthly.Apr	7.053	2.919	2.417
Monthly.May	6.624	2.926	2.264
Monthly.Jun	7.113	2.929	2.428
Monthly.Jul	8.792	2.979	2.951
Monthly.Aug	8.903	3.002	2.966
Monthly.Sep	8.351	2.963	2.819
Monthly.Oct	7.63	2.926	2.608
Monthly.Nov	7.883	2.919	2.701
Monthly.Dec	9.313	2.944	3.163
Monthly.Yr2004Plus	0.498	0.179	2.773
Monthly.July07Plus	-0.444	0.154	-2.883
Monthly.Yr2010Plus	-0.604	0.164	-3.683
CycVars.IncPerHH	0.099	0.03	3.334
CycWthrT.ResHDD	0.206	0.013	15.69
CycWthrT.ResHDDTrend	0.004	0.001	3.594
CycWthrT.ResCDD_Spring	1.44	0.35	4.113
CycWthrT.ResCDD_Jun	2.129	0.15	14.24
CycWthrT.ResCDD_Jul	2.227	0.077	29
CycWthrT.ResCDD_Aug	2.315	0.063	37.03
CycWthrT.ResCDD_Sep	2.427	0.114	21.26
CycWthrT.ResCDD_Fall	2.394	0.174	13.77
CycWthrT.ResCDDTrend	0.04	0.009	4.473
CycWthrT.Yr06Plus_ResCDDShift	-0.232	0.06	-3.845
XVars.NewMonthlyBill	-0.031	0.015	-2.09
AR(1)	0.347	0.095	3.632

Small C&I Customer Class Model			
Variable	Coefficient	StdErr	T-Stat
Monthly.Jan	-34.95	14.626	-2.39
Monthly.Feb	-31.922	14.62	-2.184
Monthly.Mar	-32.844	14.606	-2.249
Monthly.Apr	-33.912	14.616	-2.32
Monthly.May	-34.696	14.615	-2.374
Monthly.Jun	-35.074	14.555	-2.41
Monthly.Jul	-35.03	14.482	-2.419
Monthly.Aug	-32.112	14.465	-2.22
Monthly.Sep	-31.892	14.501	-2.199
Monthly.Oct	-31.189	14.556	-2.143
Monthly.Nov	-33.361	14.603	-2.285
Monthly.Dec	-35.203	14.626	-2.407
Monthly.July07Plus	-1.83	0.59	-3.104
Monthly.Yr2010Plus	-1.582	0.678	-2.332
CycWthrT.SCI_HDD	0.431	0.044	9.69
CycWthrT.SCI_HDDTrend	0.017	0.005	3.595
CycWthrT.SCI_CDD	1.944	0.126	15.485
CycWthrT.SCI_CDDTrend	0.02	0.011	1.792
CycVars.ResCust	0.022	0.004	5.744
XVars.Emp_NonManuf	0.01	0.003	3.42
SCI.DelayedBill2	-0.024	0.003	-7.996
AR(1)	0.434	0.086	5.067

StreetLighting Class Model			
Variable	Coefficient	StdErr	T-Stat
Monthly.Jan	-4.754	0.45	-10.55
Monthly.Feb	-4.75	0.45	-10.56
Monthly.Mar	-5.001	0.449	-11.15
Monthly.Apr	-5.086	0.45	-11.3
Monthly.May	-5.212	0.45	-11.57
Monthly.Jun	-5.219	0.45	-11.61
Monthly.Jul	-5.234	0.45	-11.63
Monthly.Aug	-5.159	0.449	-11.48
Monthly.Sep	-5.046	0.45	-11.22
Monthly.Oct	-4.964	0.449	-11.06
Monthly.Nov	-4.831	0.449	-10.76
Monthly.Dec	-4.754	0.45	-10.57
CycVars.ResCust	0.002	0	15.12
Monthly.Oct09Plus	0.068	0.023	2.988
AR(1)	0.255	0.092	2.773

Appendix A-3

ComEd Model Regression Statistics

Regression Statistics	ZONE	Residential	Small C&I	StreetLighting
Iterations	14	16	18	10
Adjusted Observations	145	142	140	122
Deg. of Freedom for Error	121	114	118	107
R-Squared	0.995	0.995	0.973	0.936
Adjusted R-Squared	0.994	0.994	0.969	0.928
AIC	8.755	-1.868	0.495	-5.193
BIC	9.247	-1.286	0.957	-4.848
Log-Likelihood	-816.46	-40.83	-211.29	158.64
Model Sum of Squares	132,353,701.46	2,836.34	6,157.30	7.74
Sum of Squared Errors	660,248.39	14.78	167.71	0.53
Mean Squared Error	5,456.60	0.13	1.42	0
Std. Error of Regression	73.87	0.36	1.19	0.07
Mean Abs. Dev. (MAD)	50.45	0.24	0.85	0.05
Mean Abs. % Err. (MAPE)	0.60%	1.08%	0.95%	2.76%
Durbin-Watson Statistic	2.129	1.979	2.066	1.888
Ljung-Box Statistic	20.52	29.36	25.57	27.41
Prob (Ljung-Box)	0.6667	0.2069	0.3751	0.2858
Prob (Jarque-Bera)	0.0141	0	0.8843	0.0177

Appendix A-4
Detailed Description Of Variables
Used In Forecast Models

The econometric models are statistical multi-variant regressions that determine the correlation between electrical usage (dependent variable) and weather, economic and monthly factors (independent variables). Consistent with its recent delivery services rate case filing, ComEd's weather normals are based on the 30-year time period of 1981 to 2010. The following models are used in producing the energy usage forecast (GWh) for the eligible customers:

Monthly Zone energy usage for the ComEd zone
Monthly Residential bill-cycle energy usage
Monthly Small C&I bill-cycle energy usage
Monthly Street Lighting bill-cycle energy usage

ComEd's Load Forecasting group with the input of industry experts developed the models. The following sections describe each model and its specifications. Appendices A-2 and A-3 contain the coefficients and other regression statistics for the models.

ComEd's Monthly Zone Model

The dependent variable in the Monthly Zone Model is monthly zone energy usage for the ComEd service territory. The monthly zone usage is in GWh units. The performance of the model is shown in the Chart II-7 in Section II B 1 d (ii) (estimated[27] vs. actual) for the January 2001 to February 2012 time period.

The independent variables within the model are:

- The monthly binary variables reflect monthly usage patterns. Customer electrical usage is a function of other items besides cooling and heating (e.g., lighting). This other usage is not constant per month and the monthly binary variables are used to account for this variability. December is excluded from the monthly binaries, as the constant term establishes December as the base from which the monthly binary variables are adjusted.

- The EconIndex4 variable is a composite economic variable that weights the contributions of GMP, total number of residential customers, and non-manufacturing employment in the ComEd service territory. GMP is the gross metropolitan product for the Chicago metropolitan area and also includes Rockford. This variable measures economic activity for the ComEd service territory. The GMP is adjusted for inflation and is obtained from Global Insight.

[27] As noted in the body of the Forecast, the estimated data used in Charts II-7, II-8 and II-9 is based on actual weather

Further, the variable is adjusted for the number of weekends (and holidays) and weekdays within a calendar month because overall energy usage for a given month is a function of those daily influences. The variable's units are billions of dollars. The residential customer's component is the total number of residential customers within the ComEd service territory. This economic variable reflects the effect of a growing customer base on energy usage and is driven by household formations. This variable is also adjusted for the number of weekends, holidays and weekdays within a calendar month. The non-manufacturing employment is defined below in the Small C&I model. The three economic variables are weighted based on an exponential formula with each of the economic variable roughly receiving a one-third weighting.

- The temperature and humidity degree day ("TDD") variables are weather variables designed to capture the effect on usage from cooling equipment. The TDD variable is similar in design to a cooling degree day ("CDD") variable. A CDD weather variable is often used in energy models. The standard CDD measures the difference in the average daily temperature above a specific threshold (typically 65 degrees as that is a common point at which cooling activity begins). The TDD variable provides several enhancements to the typical CDD variable as delineated below:

  The average daily temperature is the 24-hour average instead of the average of the maximum and minimum temperatures for the day. This captures frontal movements within the day.

  Humidity is included in the TDD variable as humidity does influence electrical usage.

  The TDD variable uses multiple degree bases instead of just a 65 degree-base. This captures the change in the rate at which customers use electricity at different temperature levels.

  The TDD variable is interacted with seasonal binary variables (i.e., Spring, Summer and Fall) to reflect the seasonal usage pattern related to cooling equipment.

  The TDD variable is in degree-day units.

  The TDD trend variable is a weather variable that captures the changing relationship of cooling equipment over time. Simply put, the effect of a TDD changes over time as customers' usage patterns change over time. For example, as homes have become larger over time the amount of cooling load associated with a change in temperature will also change.

  The TDD trend variable essentially captures the growing influence of cooling equipment over time within the service territory. The TDD trend

variable is designed to capture this changing relationship by interacting the TDD variable with a linear time series variable. The TDD trend variable is in degree-day units.

The TDD shift variable is a weather variable akin to the TDD trend variable. This variable is interacted with a binary variable for all years greater than or equal to 2006. The negative sign in the variable's coefficient acknowledges the reduction in cooling effect over the past few years compared to years prior to 2006.

- The HDD Spline variable is a weather variable that measures the relationship on electrical usage from space heating equipment (e.g., natural gas furnace fans and electrical space-heating equipment). The HDD Spline variable is similar in concept to the industry-standard heating degree day ("HDD") weather variable. The HDD Spline provides a couple of enhancements to the HDD weather variable:

  The average daily temperature is the 24-hour average instead of the average of the maximum and minimum temperatures for the day. This captures frontal movements within the day.

  The HDD Spline uses multiple degree bases instead of just a 65 degree-base. This captures the change in the rate at which customers use electricity at different temperature levels.

  The HDD Spline variable is in degree-day units.

  The HDD Spline trend variable is a weather variable that reflects the changing relationship of heating equipment over time. This variable is conceptually similar to the TDD trend variable. The HDD spline variable is in degree-day units.

- The Year 2005, 2007 and 2010 Shift Plus variables are binary variables designed to capture very recent usage activity within the model. For example, the 2005 Shift Plus variable is a binary variable with the unit one for all months beginning with January 2005 and thereafter. By forcing all of the residuals to sum to zero for the months January 2005 to present, the variable is causing the model to be closely aligned with recent usage activity. This variable is useful for forecasting purposes as it ensures that the forecasted usage is also closely aligned with the most recent pattern of electrical usage.

The coefficient values and the standard measurements of significance within the model (e.g., t-stats) and the overall model performance (e.g., R-squared and MAPE) are contained in Appendices A-2 and A-3. Chart II-7 contains a plot of the model's estimated

monthly usage vs. actual monthly usage from January 2001 to February 2012. The two curves are tightly aligned, which speaks to the accuracy of the model.

ComEd Residential Model

The dependent variable in the Residential Model is residential use per customer per day and the units are kWh per customer per day. Chart II-8 shows the model's performance (estimated vs. actual monthly usage for the January 2001 to February 2012 time period), which reflects a close fit.

The independent variables are noted below. (Because many of the variables follow the same purpose and logic as in the Monthly Zone model, please see the Monthly Zone Model description for additional information.)

- The monthly binary variables reflect monthly usage patterns.
- The Real Income per Household variable is the disposable personal income for the Chicago metropolitan area and Rockford (adjusted for inflation) divided by the number of households for the same area. The data is obtained from Global Insight. This variable captures the rising household incomes within ComEd's service territory and the correlation it has with consumer purchases of electronic equipment and housing stock. The variable is in dollars per household units.
- The Monthly Bill variable is a typical monthly residential electricity bill assuming historical tariff charges and weather normal customer usage for the year 2002 (adjusted for inflation). Specifically, the historical tariff charges for a single-family and multi-family (both non-space heat) were multiplied by the weather adjusted billing units from the year 2002 for both residential groups. The monthly bills for both residential groups were weighted, based on energy usage, to form a single monthly bill. The monthly bill was also adjusted for the Chicago CPI-U. This variable reflects the influence of electricity charges/prices over time related to consumer behavior.
- Weather variables used in the residential model are similar in concept to the weather variables described in the Monthly Zone Model section and will not be repeated here.
- The Year 2004, July 2007 and Year 2010 Plus binary variables are similar in concept to the same variables used in the Monthly Zone Model.

ComEd Small C&I Model

The dependent variable in the Small C&I Model is Small C&I use per day and the units are GWh per day. The independent variables within the model are:

- The monthly binary variables, weather variables and shift variables are similar in concept to the Monthly Zone Model and will not be repeated here.
- The residential customer variable is the total number of residential customers within the ComEd service territory. This economic variable reflects the influence of a growing service territory (i.e., residential customers) on Small C&I energy usage. The units are in thousands of customers.
- The Employment variable is an economic variable that measures the total non-manufacturing employment in the Chicago area. Job growth is correlated to Small C&I development and growth.
- The July 2007 and Year 2010 Shift Plus binary variable is similar in concept to the Monthly Zone model.
- The Delayed Bill variable is the month over month (current vs. one month prior) variance in the Small C&I's estimated usage (GWh) of bills that are delayed beginning in October 2009. This variable is used to inform the model about an increase in delayed bill activity primarily in 2010.

ComEd Street Light Model

The dependent variable in the Street Lighting Model is Street Lighting use per day and the units are GWh per day. The independent variables are:

- Monthly binary variables and a shift variable are similar in concept to the Monthly Zone Model.
- The residential customer variable is the total number of residential customers within the ComEd service territory. This economic variable reflects the relationship of a growing service territory (measured by the number of residential customers) and street lighting usage.

Appendix B-1

ComEd Procurement Period Load Forecast (Expected Load) Projected Energy Usage and Average Demand For Eligible Retail Customers (Weather Normal, Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2013	6	559,748	562,252	1,749	1,406
2013	7	718,755	636,125	2,042	1,623
2013	8	661,608	587,794	1,880	1,499
2013	9	449,784	455,422	1,406	1,139
2013	10	456,591	381,859	1,241	1,016
2013	11	436,348	463,447	1,364	1,159
2013	12	532,875	559,674	1,586	1,372
2014	1	561,025	545,218	1,594	1,391
2014	2	463,864	449,545	1,450	1,277
2014	3	431,591	458,550	1,284	1,124
2014	4	398,997	354,411	1,134	963
2014	5	385,325	391,797	1,147	960
2014	6	512,555	474,799	1,525	1,236
2014	7	643,142	571,753	1,827	1,459
2014	8	565,907	554,281	1,684	1,359
2014	9	425,651	393,658	1,267	1,025
2014	10	408,019	344,521	1,109	916
2014	11	374,061	440,146	1,230	1,058
2014	12	514,347	499,075	1,461	1,273
2015	1	493,088	527,323	1,468	1,292
2015	2	428,994	416,209	1,341	1,182
2015	3	418,295	408,978	1,188	1,043
2015	4	365,727	328,643	1,039	893
2015	5	335,435	377,872	1,048	891
2015	6	498,744	425,345	1,417	1,156
2015	7	628,950	514,635	1,709	1,369
2015	8	529,255	524,210	1,575	1,285
2015	9	397,798	370,001	1,184	964
2015	10	360,870	335,928	1,025	857
2015	11	369,192	398,006	1,154	995
2015	12	485,004	470,396	1,378	1,200
2016	1	444,579	519,814	1,389	1,226
2016	2	430,900	406,287	1,282	1,129
2016	3	416,951	375,227	1,133	998
2016	4	330,371	327,084	983	852
2016	5	338,173	347,223	1,006	851

ComEd Procurement Period Load Forecast (Expected Load) Projected Energy Usage and Average Demand For Eligible Retail Customers (Weather Normal, Line Loss and DSM Adjusted)					
Year	**Month**	**Total Load (MWh)**		**Average Load (MW)**	
		On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**
2016	6	482,748	406,057	1,371	1,103
2016	7	527,887	568,262	1,650	1,340
2016	8	567,000	462,709	1,541	1,231
2016	9	381,246	361,915	1,135	942
2016	10	333,311	339,213	992	831
2016	11	378,624	373,861	1,127	974
2016	12	451,965	479,735	1,345	1,176
2017	1	456,809	491,455	1,360	1,205
2017	2	397,269	387,895	1,241	1,102
2017	3	405,571	367,772	1,102	978
2017	4	305,593	331,025	955	828
2017	5	346,870	325,371	985	830
2017	6	473,948	395,848	1,346	1,076
2017	7	517,420	557,440	1,617	1,315
2017	8	553,523	454,801	1,504	1,210
2017	9	353,030	367,576	1,103	919
2017	10	341,267	317,647	970	810
2017	11	370,287	363,786	1,102	947
2017	12	418,729	487,719	1,309	1,150
2018	1	468,560	462,930	1,331	1,181
2018	2	386,430	379,684	1,208	1,079
2018	3	376,895	373,039	1,071	952
2018	4	313,661	309,541	934	806
2018	5	338,104	316,473	961	807
Totals		**26,719,266**	**25,879,262**		

Appendix B-2

ComEd Procurement Period Load Forecast (Low Load) Projected Energy Usage and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2013	6	450,489	487,388	1,408	1,218
2013	7	547,914	519,411	1,557	1,325
2013	8	489,957	452,397	1,392	1,154
2013	9	398,545	404,497	1,245	1,011
2013	10	386,303	318,753	1,050	848
2013	11	364,113	379,365	1,138	948
2013	12	442,905	469,109	1,318	1,150
2014	1	471,232	451,124	1,339	1,151
2014	2	366,475	361,214	1,145	1,026
2014	3	324,060	346,121	964	848
2014	4	297,357	269,935	845	734
2014	5	285,255	288,253	849	707
2014	6	334,211	329,901	995	859
2014	7	389,314	370,378	1,106	945
2014	8	315,715	341,041	940	836
2014	9	284,566	269,468	847	702
2014	10	254,341	219,575	691	584
2014	11	229,520	275,308	755	662
2014	12	318,380	317,547	904	810
2015	1	309,639	331,987	922	814
2015	2	252,212	253,355	788	720
2015	3	230,682	232,436	655	593
2015	4	198,094	189,738	563	516
2015	5	180,219	209,296	563	494
2015	6	244,807	218,261	695	593
2015	7	291,348	243,974	792	649
2015	8	226,188	238,145	673	584
2015	9	199,958	193,429	595	504
2015	10	171,499	164,835	487	420
2015	11	174,338	194,743	545	487
2015	12	233,794	236,777	664	604
2016	1	226,337	265,803	707	627
2016	2	211,908	202,327	631	562
2016	3	195,842	177,907	532	473
2016	4	156,041	159,179	464	415
2016	5	160,566	163,758	478	401

ComEd Procurement Period Load Forecast (Low Load) Projected Energy Usage and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	**Month**	**Total Load (MWh)**		**Average Load (MW)**	
		On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**
2016	6	213,421	174,732	606	475
2016	7	220,832	232,330	690	548
2016	8	226,455	183,440	615	488
2016	9	177,945	175,156	530	456
2016	10	149,753	157,719	446	387
2016	11	173,835	174,927	517	456
2016	12	216,294	234,195	644	574
2017	1	226,852	248,699	675	610
2017	2	191,415	192,372	598	547
2017	3	186,988	172,254	508	458
2017	4	143,125	157,762	447	394
2017	5	157,796	155,725	448	397
2017	6	204,209	168,786	580	459
2017	7	207,429	227,958	648	538
2017	8	214,178	179,344	582	477
2017	9	164,083	173,251	513	433
2017	10	152,059	144,736	432	369
2017	11	167,356	167,022	498	435
2017	12	198,116	232,275	619	548
2018	1	227,852	231,304	647	590
2018	2	182,634	185,729	571	528
2018	3	170,896	171,981	486	439
2018	4	146,492	143,909	436	375
2018	5	150,629	150,292	428	383
Totals		**15,084,768**	**14,982,633**		

Appendix B-3

ComEd Procurement Period Load Forecast (High Load) Projected Energy Usage and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2013	6	952,298	949,793	2,976	2,374
2013	7	1,258,538	1,163,095	3,575	2,967
2013	8	1,346,737	1,205,062	3,826	3,074
2013	9	707,370	708,059	2,211	1,770
2013	10	723,486	610,934	1,966	1,625
2013	11	742,133	800,401	2,319	2,001
2013	12	874,236	919,245	2,602	2,253
2014	1	906,729	881,295	2,576	2,248
2014	2	792,387	753,262	2,476	2,140
2014	3	700,112	764,022	2,084	1,873
2014	4	672,192	601,525	1,910	1,635
2014	5	605,603	623,428	1,802	1,528
2014	6	937,168	880,362	2,789	2,293
2014	7	1,222,873	1,113,870	3,474	2,842
2014	8	1,258,126	1,195,802	3,744	2,931
2014	9	698,370	664,609	2,078	1,731
2014	10	689,525	575,544	1,874	1,531
2014	11	668,866	794,391	2,200	1,910
2014	12	873,623	851,938	2,482	2,173
2015	1	828,015	880,256	2,464	2,157
2015	2	750,662	732,484	2,346	2,081
2015	3	713,921	696,231	2,028	1,776
2015	4	638,175	580,154	1,813	1,577
2015	5	544,040	623,889	1,700	1,471
2015	6	942,872	818,688	2,679	2,225
2015	7	1,252,011	1,022,548	3,402	2,720
2015	8	1,226,778	1,162,898	3,651	2,850
2015	9	671,918	647,870	2,000	1,687
2015	10	631,448	578,170	1,794	1,475
2015	11	679,077	744,107	2,122	1,860
2015	12	847,914	826,608	2,409	2,109
2016	1	765,879	894,273	2,393	2,109
2016	2	771,450	742,966	2,296	2,064
2016	3	746,142	643,756	2,028	1,712
2016	4	598,044	589,906	1,780	1,536
2016	5	569,716	583,883	1,696	1,431

ComEd Procurement Period Load Forecast (High Load) Projected Energy Usage and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	**Month**	**Total Load (MWh)**		**Load (MW)**	
		On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**
2016	6	947,305	796,472	2,691	2,164
2016	7	1,098,812	1,143,121	3,434	2,696
2016	8	1,305,005	1,100,450	3,546	2,927
2016	9	673,003	639,455	2,003	1,665
2016	10	593,877	605,206	1,767	1,483
2016	11	720,925	713,480	2,146	1,858
2016	12	812,310	862,285	2,418	2,113
2017	1	803,451	869,086	2,391	2,130
2017	2	731,340	723,296	2,285	2,055
2017	3	742,240	648,400	2,017	1,724
2017	4	566,854	613,792	1,771	1,534
2017	5	604,144	555,744	1,716	1,418
2017	6	957,083	795,048	2,719	2,160
2017	7	1,108,788	1,147,685	3,465	2,707
2017	8	1,306,171	1,115,544	3,549	2,967
2017	9	634,241	671,147	1,982	1,678
2017	10	621,899	583,782	1,767	1,489
2017	11	719,689	717,933	2,142	1,870
2017	12	773,238	897,680	2,416	2,117
2018	1	855,384	828,262	2,430	2,113
2018	2	743,250	712,920	2,323	2,025
2018	3	696,844	685,961	1,980	1,750
2018	4	598,602	587,674	1,782	1,530
2018	5	604,024	553,747	1,716	1,413
Totals		**49,026,913**	**47,393,494**		

Appendix D

Residential

Year	Base	2007 SAE Appliance Standards	2007 SAE Building Shell Efficieny	Difference 2007 SAE Appliance Standards	Difference 2007 SAE Building Shell Efficieny
2012	27,768	28,159	27,901	(391)	(133)
2013	27,232	27,626	27,375	(394)	(143)
2014	27,200	27,676	27,352	(476)	(152)
2015	27,340	27,890	27,502	(550)	(162)
2016	27,574	28,170	27,745	(596)	(171)
2017	27,641	28,220	27,818	(579)	(177)
		139,582	137,792	(188)	(44)
				(0.1%)	(0.03%)

Small C&I

Year	Base	2007 SAE Appliance Standards	Difference 2007 SAE Appliance Standards
2012	33,047	33,189	(142)
2013	33,390	33,569	(179)
2014	33,979	34,189	(210)
2015	34,613	34,852	(239)
2016	35,336	35,600	(264)
2017	35,786	36,063	(277)
		174,273	(135)
			(0.1%)

Appendix E

ComEd RPS Volume Targets

Planning Year	Reference Year	Reference Year Delivered Volume (MWH)	Planning Year RPS Target (%)	Planning Year RPS Target (RECs)
2013-14	2011-12	32,536,744	8.0%	2,602,940
2014-15	2012-13	18,971,928	9.0%	1,707,474
2015-16	2013-14	11,039,852	10.0%	1,103,985
2016-17	2014-15	10,036,819	11.5%	1,154,234
2017-18	2015-16	9,500,479	13.0%	1,235,062

ComEd RPS Budgets

Planning Year	Planning Year Delivered Volume (MWH)	RPS 2.015% Cost Cap ($/MWH)	Planning Year RPS Budget ($)
2013-14	11,039,852	1.8917	20,884,088
2014-15	10,036,819	1.8917	18,986,650
2015-16	9,500,479	1.8917	17,972,057
2016-17	9,208,355	1.8917	17,419,445
2017-18	8,993,229	1.8917	17,012,491

ComEd RPS Contract Quantities

Planning Year	LT Renewables (RECs)	Rate Stability (RECs)	Total (RECs)
2013-14	1,261,725	1,339,909	2,601,634
2014-15	1,261,725	623,577	1,885,302
2015-16	1,261,725	202,479	1,464,204
2016-17	1,261,725	299,672	1,561,397
2017-18	1,261,725	271,473	1,533,198

ComEd RPS Contract Quantity Costs

Planning Year	LT Renewables ($)	Rate Stability ($)	Total ($)
2013-14	22,366,000	1,714,269	24,080,269
2014-15	23,189,000	1,025,969	24,214,969
2015-16	22,613,000	490,678	23,103,678
2016-17	22,676,000	751,324	23,427,324
2017-18	23,139,000	581,034	23,720,034

LT Renewables Contract Quantity Reductions

Planning Year	Contract Quantity REC Cost ($)	Planning Year RPS Budget ($)	LT Renewables Contract Quantity REC Cost Reduction ($)	LT Renewables Contract Quantity REC Cost ($)	LT Renewables Quantity Reduction (%)
2013-14	24,080,269	20,884,088	3,196,181	22,366,000	14.3%
2014-15	24,214,969	18,986,650	5,228,320	23,189,000	22.5%
2015-16	23,103,678	17,972,057	5,131,622	22,613,000	22.7%
2016-17	23,427,324	17,419,445	6,007,880	22,676,000	26.5%
2017-18	23,720,034	17,012,491	6,707,542	23,139,000	29.0%

Appendix C-1

Final Report

Assessment of Energy Efficiency and Load Management Potential (2011–2016)

Prepared for:
Commonwealth Edison

February 17, 2010

Prepared by:
The Cadmus Group, Inc.

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Executive Summary

The Cadmus Group, Inc. was retained by Commonwealth Edison (ComEd) to conduct an assessment of residential, commercial, and industrial energy-efficiency and load management potentials in ComEd's Illinois service territory. ComEd identified five primary goals associated with the three core activities. The primary goals included:

- Identify fuel use statistics and gather electric energy use and building envelope characteristics from a representative sample of each of the ComEd customers.
- Collect building occupancy demographics and energy usage profiles for pertinent customer segments.
- Estimate recent, current, and potential end-use penetrations of specific efficient technologies.
- Estimate the hourly impacts of energy-efficiency measures and load management strategies.
- Identify the program potential of energy-efficient products and services for each of the residential, commercial and industrial markets.

This study addressed each of these goals. Cadmus conducted a substantial primary data collection effort, including over 1,250 telephone surveys and site visits with ComEd end-use customers and trade allies to meet the goals of the first two core activities. In addition, the study includes a comprehensive set of electric energy-efficiency measures applicable to the climate and customer characteristics of ComEd's service territory based on 239 *discrete* electric energy-efficiency measures, representing over 3,800 measures when considering all permutations of across customer sectors and segments. The data collection effort then served as the foundation for estimating the technical, economic, and realistically achievable potentials to address the goals of the third core activity.

Estimates of Resource Potentials

Consistent with accepted industry standards, this study's approach distinguishes among four definitions of resource potential widely used in utility resource planning:

- ***Naturally occurring conservation*** refers to reductions in energy use that occur due to normal market forces, such as technological change, energy prices, market transformation efforts, and improved energy codes and standards.
- ***Technical potential*** assumes that all available DSM measures and supplemental resource options may be implemented, regardless of their costs, or market barriers.
- ***Economic potential*** represents a subset of technical potential consisting of only measures that meet the cost-effectiveness criterion based on the ComEd avoided energy and capacity costs.
- ***Achievable potential*** is defined as the portion of economic potential that might be assumed to be reasonably achievable in the course of the planning horizon, given market barriers that may impede customer participation in utility programs.

General Approach to Estimating Resource Potentials

The general methodology utilized in this report is best described as a hybrid "top-down/bottom-up" approach. The top-down methodology component begins with the most current utility load forecasts, then decomposes them into their constituent customer sector, customer segment, and end-use components. The bottom-up component considers the potential technical impacts of various demand-side and supplemental resource technologies, measures, and practices on each end use, which are then estimated based on engineering calculations taking into account fuel shares, current market saturations, technical feasibility and costs.

Technical and Economic Energy-Efficiency Potentials

Table 1 shows the baseline electric sales and potential by sector forecast for the year 2016, the end of the 6-year study horizon. As shown, the results of this study indicate 22,117 GWh of technically feasible electric energy-efficiency potential will be available by 2016. This technical potential translates to an economic potential of 13,617 GWh. Were all of this potential cost-effective and realizable, it would amount to a 14% reduction in 2016 forecast retail sales. In addition, ComEd would experience a 10% reduction of load growth from 2011 to 2016 (Figure 1). The commercial sector has the largest economic potential (7,489 GWh), followed by the residential sector (4,564 GWh), and the industrial sector (1,564 GWh).

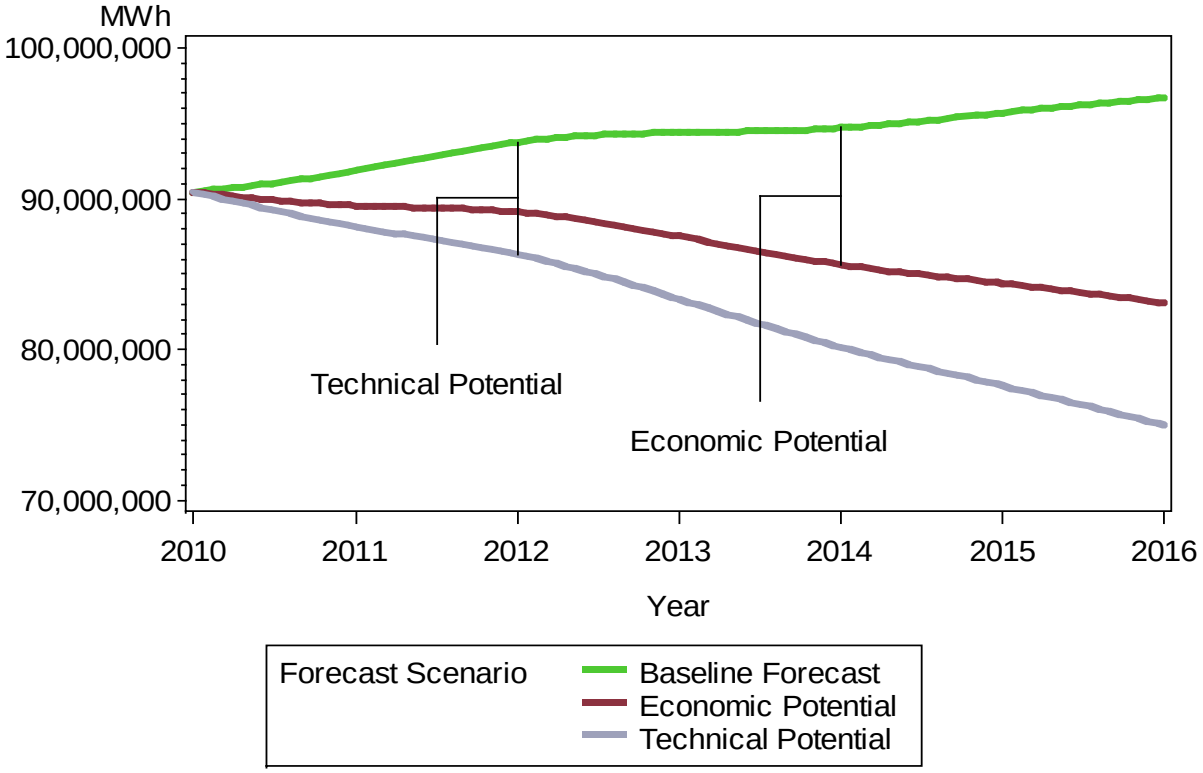
While the effects of EISA have been incorporated into the potential estimate, an alternative EISA scenario was modeled that considered the impact of CFLs as the new baseline, rather than the base scenario of approximately 30% improvement in baseline incandescent lighting efficiency. In this alternative scenario, residential economic potential in 2016 results in 3,665 GWh, representing a 20% decrease from the assumed EISA scenario (or a drop in economic potential, across all sectors, from 14% to 13% of baseline sales).

Table 1. Summary Technical and Economic Electric Energy-Efficiency Potential (MWh in 2016) by Sector

Sector	Baseline Sales	Technical Potential	Technical Potential as % of Baseline	Economic Potential	Economic Potential as % of Baseline	Economic Potential (MW)	Average Levelized Cost ($/kWh)
Residential	31,583,697	8,514,175	27%	4,564,469	14%	1,107	$0.04
Commercial	49,285,486	12,039,102	24%	7,488,711	15%	1,426	$0.05
Industrial	15,816,115	1,563,982[A]	10%	1,563,982	10%	217	$0.01
Total	96,685,298	22,117,259	23%	13,617,162	14%	2,750	$0.04

[A] Because the industrial sector uses a "top-down" approach based on cost-effective measures, the estimates of technical and economic potential are identical.

Figure 1. Sales Forecast with Energy-Efficiency Potential Scenarios



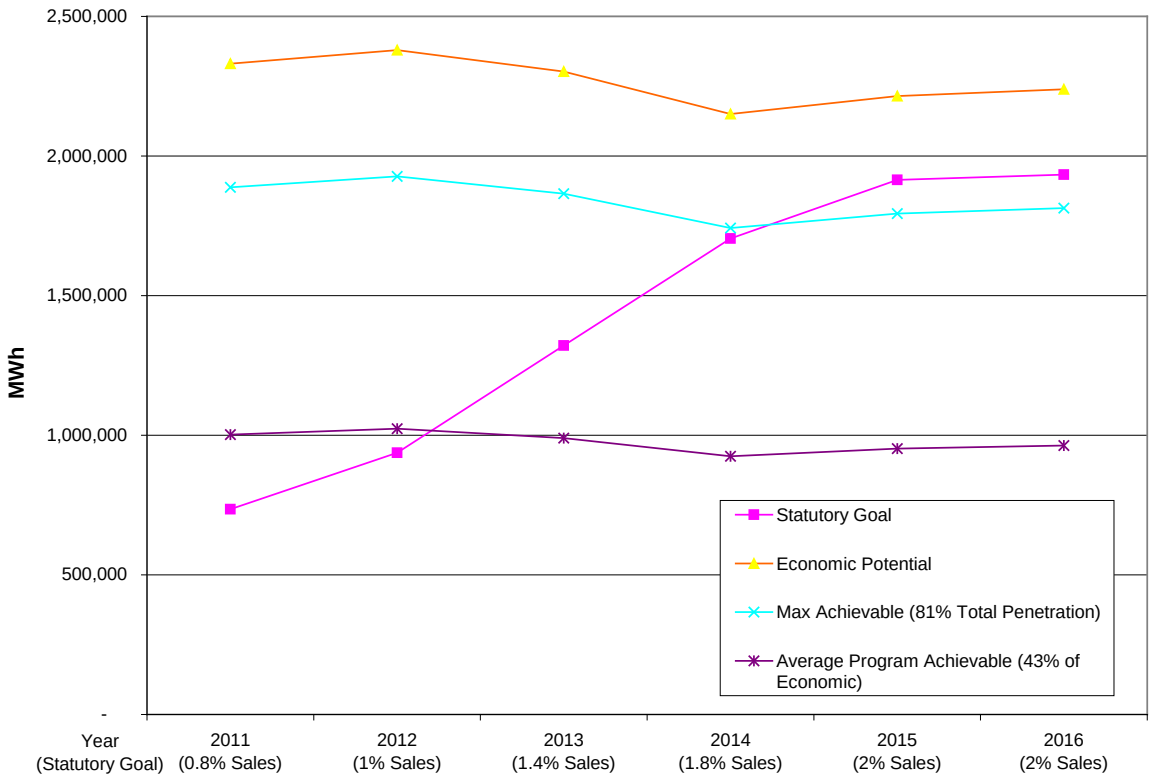
Achievable Energy-Efficiency Potential

Projections of achievable potential pose significant analytic challenges as they are inherently based on assumptions regarding market acceptance of energy-efficiency measures and programs offered by utilities. Levels of cost-effective, energy-efficiency potential realistically achievable depends on several factors, including customers' willingness to participate in energy-efficiency programs (which is only partially a function of incentive levels), retail energy rates, and a host of market barriers that have historically impeded the adoption of energy-efficiency measures and practices by consumers.

The most reliable way to estimate achievable potential is to examine actual achieved savings (i.e., historical program savings accomplishments) as a function of program delivery mechanisms, incentives, and marketing expenditures. However, because ComEd is only in its second year of recent program activity, limited historical data are available for this purpose. Alternatively, many studies examine achievable potential as a subset of economic potential. This report examined over 20 studies, and found that Program Achievable Potential typically is estimated at about 43% of economic potential (with a wide variance), with Maximum Achievable Potential at approximately 81% of economic potential.

As shown in Figure 2, the EISA lighting standards have a downward effect on economic potential, particularly in 2013 and 2014. Statutory goals, however, continue to rise (quite aggressively in 2015). As shown in the figure, ComEd will need to exceed the estimated maximum achievable percentage in 2015-2016 to meet the program goals.

Figure 2. Estimates of Achievable Potential (2011-2016)



Demand Response Potential

The demand response (DR) potential study examined four types of programs. The residential programs included a direct load control (DLC) program, currently offered to ComEd customers as the Smart Ideas Central Air Conditioning Cycling Program, which allows the utility to cycle the power to residential customers' central air conditioning units during peak times, plus a real-time pricing (RTP) program which encourages customers to reduce their load during peak times by billing them the real-time electricity prices. The non-residential programs included an interruptible tariffs load response (ILR) program, currently offered by ComEd as Capacity Based Load Response (CLR), which contractually obligates medium and large customers to reduce load when a DR event is called. The second non-residential program was a demand buy-back (DBB) program which encourages commercial and industrial customers to reduce load during an event by offering real-time voluntary incentives.

The residential programs showed some potential growth increases over the forecast period, while the non-residential programs were determined to be fairly saturated based on their current levels of participation. All programs are assumed to grow at least at the rate of overall peak capacity. Sector peaks were determined by the 2016 peak load forecast and hourly load shapes for each sector and end use. Technical potential was determined by the peak load of participants and end uses that qualify for each DR program (i.e., assuming 100% participation). Achievable, or

market potential was determined by the Cadmus forecast of each programs future growth and event participation rates. Table 2 shows a summary of these results.

Table 2. Demand Response Technical and Achievable Technical Potential (MW in 2016)

Sector	Sector Peak	Technical Potential	Achievable Technical Potential	Achievable Technical Potential As Percent of Sector Peak
Residential	10,988	9,886	342	3%
Commercial	11,444	3,422	563	5%
Industrial	2,678	1,609	274	10%
Total	25,110	14,917	940	4%

Note: Individual results may not sum to total due to rounding.
Note: Interactions between programs have not been taken into account.

1. Introduction

The Cadmus Group, Inc. was retained by Commonwealth Edison (ComEd) to conduct an assessment of residential, commercial, and industrial energy-efficiency and load management potentials in ComEd's Illinois service territory.

Overview

Studies of demand-side management (DSM) potentials are important tools for policy analysis, utility resource planning, and program design. As such, reasonably accurate projections of actual DSM potentials, as well as reliable estimates of their associated costs, are critical in guiding utilities as they design their resource acquisition programs. DSM objectives may be met through a broad range of technology- and activity-based measures, behavior modification, or legislative action such as the institution of energy-efficiency codes and standards. Demand-side resource potential also varies depending on a utility's load characteristics, customer mix, local market conditions, and climate.

ComEd identified five primary goals associated with the three core activities. The primary goals of the residential/commercial/industrial energy use survey were to:

- Identify fuel use statistics and gather electric energy use and building envelope characteristics from a representative sample of each of the ComEd residential, commercial, and industrial customer segments.
- Collect building occupancy demographics and energy usage profiles for pertinent customer segments (e.g., single-family homes, multi-family homes, office, and retail).

The primary goal of the market penetration study was to estimate recent, current, and potential end-use penetrations of specific efficient technologies.

The primary goals of the program potential assessment study were to:

- Estimate the hourly impacts of energy-efficiency measures and load management strategies.
- Identify the program potential of energy-efficient products and services for each of the residential, commercial and industrial markets, reflecting specific program designs and escalating annual funding, and corresponding energy savings targets of ComEd's programs.

This study addressed each of these goals. Cadmus conducted a substantial primary data collection effort, including over 1,250 telephone surveys and site visits with ComEd end-use customers and trade allies to meet the goals of the first two core activities. The data collection effort then served as the foundation for estimating the technical, economic, and realistically achievable potentials to address the goals of the third core activity.

Definition of Resource Potentials

Estimates of technical and economic potential in this study are based on best-practice research methods and analytic techniques that are standard in the utility. Consistent with accepted industry standards, this study's approach distinguishes among four definitions of resource potential widely used in utility resource planning.

Naturally occurring conservation refers to reductions in energy use that occur due to normal market forces, such as technological change, energy prices, market transformation efforts, and improved energy codes and standards. In this analysis, naturally occurring conservation is accounted for in several ways. First, the potential associated with certain energy-efficiency measures assumes a natural rate of adoption. For example, the savings associated with ENERGY STAR® appliances account for current trends in customer adoption. Second, current codes and standards are applied in the consumption characteristics of new construction. Finally, the assessment accounts for the gradual increase in efficiency as older equipment in existing buildings is retired and replaced by units meeting current standards. However, this assessment does not forecast changes to codes and standards; rather, it treats them as "frozen" at a given efficiency level.

Technical potential assumes that all available DSM measures and supplemental resource options may be implemented, regardless of their costs, or market barriers. For energy-efficiency resources, technical potential further falls into two classes: retrofit (discretionary) and equipment (phased-in or lost-opportunity resources). It is important to recognize that the notion of technical potential is less relevant to resources such as capacity-focused programs and distributed generation since most end-use loads may be subject to interruption through load curtailment or displacement by on-site generation from a strictly "technical" point of view.

Economic potential represents a subset of technical potential consisting of only measures that meet the cost-effectiveness criterion based on the ComEd avoided energy and capacity costs. For each energy-efficiency measure, the benefit-cost test is structured as the ratio of the net present values of the measure's benefits and costs. Only measures that have a benefit-to-cost ratio of 1.0 or greater are deemed cost-effective. The methodology for cost-effectiveness calculations and relevant benefit and cost elements is described in detail in Volume II, Appendix E.

Achievable potential is defined as the portion of economic potential that might be assumed to be reasonably achievable in the course of the planning horizon, given market barriers that may impede customer participation in utility programs. Achievable potential can vary sharply based on program incentive structures, marketing efforts, energy costs, customer socio-economic characteristics, and other factors. This study analyzed achievable potential in the context of the goals and budgets as legislated by the Illinois Power Agency Act.

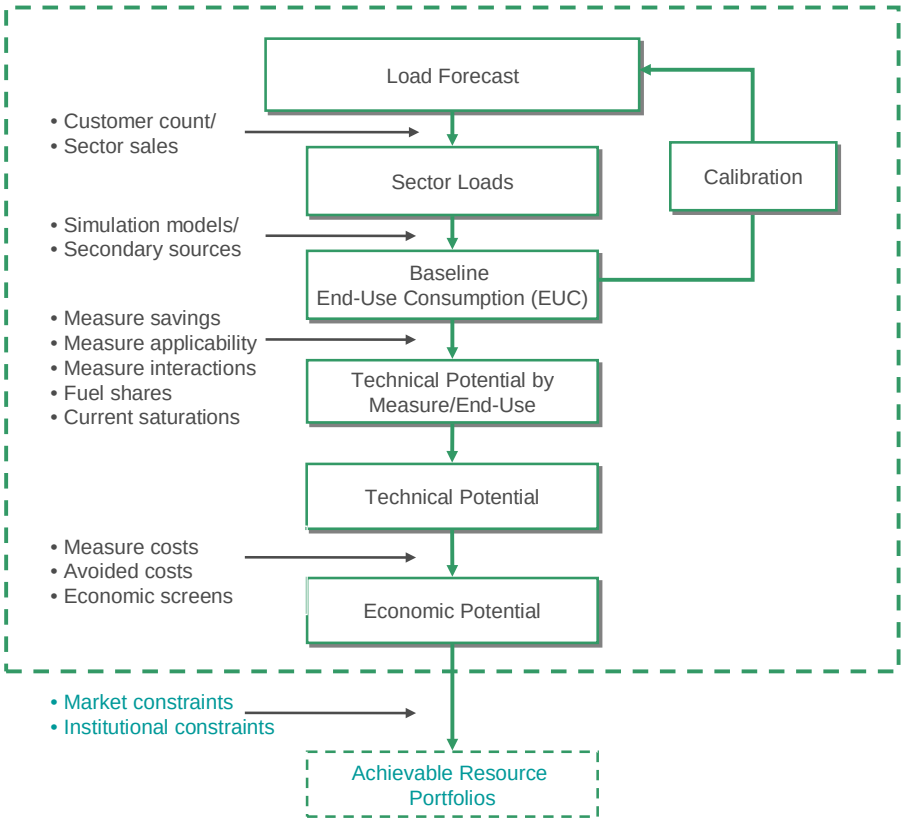
General Approach to Estimating Resource Potentials

Resources analyzed in this study differ with respect to several salient attributes, such as the type of load impact (energy or capacity), availability, reliability, and applicability to various customer classes and customer segments (business, dwelling, or facility types). They also require fundamentally different approaches in program design, incentive structures and delivery mechanisms for their deployment. Therefore, analysis of the potential for these resources requires methods tailored to address the unique technical and market characteristics of each

resource. These methods, however, generally spring from a common conceptual framework, and their applications to various resources rely on similar analytic methodologies.

This general methodology is best described as a hybrid "top-down/bottom-up" approach. As illustrated in Figure 3, the top-down methodology component begins with the most current utility load forecasts, then decomposes them into their constituent customer sector, customer segment, and end-use components. The bottom-up component considers the potential technical impacts of various demand-side and supplemental resource technologies, measures, and practices on each end use, which are then estimated based on engineering calculations taking into account fuel shares, current market saturations, technical feasibility and costs. These individual impacts are aggregated to produce estimates of resource potential at the sector, segment, and end-use levels. In many ways, the approach is analogous to generating two alternative load forecasts at the end-use level (one with and one without DSM and supplemental resources) and calculating resource potential as the difference between the two forecasts.

Figure 3. General Methodology for Assessment of Demand-Side Resource Potentials



Effects of the Energy Independence and Security Act of 2007

While this analysis does not attempt to predict how energy codes and standards may change in the future, it does capture legislation that has already been enacted, even if it will not go into effect for several years. The most notable of these is the Energy Independence and Security Act (EISA) of 2007, which sets new standards for general service lighting, motors, and other end-use

equipment. Because of the large role residential lighting plays in ComEd's energy-efficiency programs, it was particularly important to capture the effects of this legislation.

Most notably, EISA mandates higher energy-efficiency levels in light bulbs sold in or imported into the United States beginning in 2012. As shown in Table 3, EISA's performance standards correspond to approximately 30% improvements in efficiencies (measured in lumens-per-watt) over current incandescent technology. It is important to note that EISA is a performance-based standard; thus, the standards are "blind" to technology and do not ban incandescent bulbs.

Table 3. EISA Requirements for General Service Incandescent Lamps

Lumen Output	Typical Wattage: Current Incandescent Technology	EISA Requirements		
		Maximum Wattage	Minimum Lifetime (hours)	Effective Date
1490–2600	100	72	1,000	1/1/2012
1050–1489	75	53	1,000	1/1/2013
750–1049	60	43	1,000	1/1/2014
310–749	40	29	1,000	1/1/2014

A number of lighting scenarios may develop in response to EISA, including the following:

- ***EISA Scenario***. While EISA will preclude current incandescent technology, advanced incandescent (particularly halogen bulbs) may meet EISA's minimum standards. Advanced incandescent bulbs use a variety of approaches to increase efficacy, and there are already a number of incandescent products (e.g., some bulbs from the Philips Halogena series) that meet the requirements. These bulbs, however, currently cost $4 to $8 each (substantially more than the cost of a comparable CFL), and it is unknown how much the price might drop in the next few years.[1] So even though more products become available, they may cost more than CFLs, making CFLs both a lower cost and more efficient technology.
- ***CFL Baseline Scenario***. There is also evidence that CFLs may become the new baseline technology. Advanced incandescents not only may cost more than CFLs, some manufacturers, such as General Electric, have abandoned efforts to develop an advanced incandescent and instead are focusing on improved CFLs and Light Emitting Diodes (LEDs).[2] Current CFL limitations regarding color rendering, dimmability, and warm-up period have limited consumer acceptance, so improvements in performance are needed to increase sales. Even with technological improvements, however, consumer concerns about the use of mercury could prove to be a significant deterrent.
- ***LED Scenario***. There has been a significant interest in LED technology, which offers the bulbs that have longest lifetime and promises to offer very high efficacy (lumens per watt) bulbs in future bulb generations. While LED technology is not new (the first LEDs were produced in the 1960s), it is relatively new to mass-market applications and can still be considered an immature technology. Despite significant price drops, LED first costs are still extremely high, with incandescent equivalents selling for $20 to $30 per bulb.

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1 http://www.amazon.com/Philips-70-Watt-Halogena-Energy-2-Pack/dp/B001FA07UW and http://www.lutronstore.com/lutronproductsdetails.aspx?productid=151

2 http://greeninc.blogs.nytimes.com/2009/05/29/can-incandescent-bulbs-be-made-efficient/?pagemode=print

The selection of a scenario is quite important in terms of the baseline forecast and efficiency potential. For example, our analysis estimates that residential lighting accounts for 6% of total electricity sales. Even under the EISA scenario, with a 30% improvement in efficiency, baseline sales could drop 1% to 2%, depending on assumptions regarding naturally occurring adoption and use in the commercial and industrial sectors. The CFL scenario would even be more dramatic: assuming 75% efficiency (compared to current incandescent bulbs), the drop in sales could be in the range of 4% to 5%.

Because the potential estimates are calculated to ComEd sales forecasts, we chose to be consistent with the current load forecasting assumptions, which assume that baseline lighting will meet, yet not exceed, the EISA requirements (i.e., the EISA scenario). This approach assumes that a cost-effective intermediate technology between CFLs and current incandescents will be developed during the next two years. However, because of the uncertainty around this assumption, we also developed an alternative scenario that assumes this technology, even if it exists, may be more costly than CFLs and so not be cost-effective, making CFLs the less expensive, *de facto* baseline. For both of these scenarios we assumed that all sockets—even if prolonged by an incandescent stocking (or "hoarding") effect—would be eligible for replacement to the new baseline by 2016.

Organization of the Report

This report is organized in two volumes. The present document, Volume I, presents the methodology and findings and includes the following chapters:

- Chapter 2, ""Data Development," provides an overview of the methods and findings from the comprehensive data collection and analysis efforts.
- Chapter 3, "Technical and Economic Energy-Efficiency Potentials," presents the technical and economic potential available from energy-efficiency resources.
- Chapter 4, "Achievable Energy-Efficiency Potentials," describes the realistically achievable energy efficiency resources.
- Chapter 5, "Demand Response," presents the technical and economic potential available from demand response programs

Supplemental technical information, assumptions, data, and other relevant details are presented in Volume II as appendices. They are:

- Appendix A: Data Collection Instruments
- Appendix B: Summary of Findings from Primary Data Collection
- Appendix C: Detailed Frequencies from Primary Data Collection
- Appendix D: Measure Database
- Appendix E: Supplemental Material – Energy Efficiency, including Data & Assumptions and Detailed Results
- Appendix F: Supplemental Material – Demand Response
- Appendix G: Bibliography for Achievable Potential

2. Data Development

Assessment of energy-efficiency and load management potentials requires compiling a large and complex database of customer and equipment market data (e.g., structural characteristics, fuel shares, equipment saturations, and efficiency penetration), measure characteristics (technical specifications, life, savings, costs), and utility data (loads and sales forecasts). The approach for assembling these data is presented below.

Primary Data Collection

The 2009 Assessment of Energy and Capacity Savings Potential data collection efforts included a combined total of over 1,250 telephone and on-site surveys of residential and non-residential customers, trade allies, and contractors (Table 4 and Table 5).

This approach represented a concerted effort to ensure an accurate representation of the ComEd territory market for use in modeling the energy and capacity savings potential. To maximize the value of the data collection efforts, measures that represent disproportionately large savings potentials were given highest priority in the surveys. For these measures, the comprehensive survey effort collected three metrics critical to estimating efficiency potential:

- ***Equipment saturation***: The percentage of customers that own specific equipment that is energy-efficient or of standard efficiency (e.g., the percentage of single-family homes that have air-conditioning);
- ***Efficiency penetration:*** The percentage of the installed equipment stock considered efficient (e.g., the percentage of installed central air conditioners that exceed SEER 13); and
- ***Market share:*** The percentage of current sales of equipment that is considered efficient (e.g., the percentage of central air conditioners sold in the past 12 months that exceeded SEER 13).

Primary data collection findings were validated through comparisons to available state and regional secondary data. The findings of the data collection efforts were also presented to the Illinois Stakeholder Advisory Group.

The following tables present each of the residential and non-residential data collection efforts that were undertaken, the measures investigated, the sources of the samples, stratification methods, and the number of completed surveys. The data collection instruments, a summary of the findings, and the detailed tabulations of the results for each of these efforts are presented in Volume II, Appendix A, Appendix B, and Appendix C.

In addition, the data can be accessed via the Internet as part of an the online data analysis tool.[3] The Cadmus Online Data Analysis Tool serves two functions: an analysis environment for the primary data collected; and a repository of primary data collection instruments, data files, analysis, reporting and presentations. The online tool provides a single point of access to all information pertinent to primary data collection. Users may access standard reports and summary

[3] http://comedsurveytool.cadmusweb.com

presentations, exporting in MS Excel, Word, or PDF formats. Data sets area also available for download through the website. The website includes a data dictionary and a copy of the survey instruments available for the all users to reference. Any additional documentation regarding the data collection activities may also be included.

Table 4. Residential Primary Data Collection Efforts

Data Collection Effort	Method	Measures	Sources	Stratification	Number of Surveys/ Visits
Residential Appliance Saturation Survey (RASS)	Telephone Survey	Residential Appliances and Household Characteristics—primarily saturations and fuel shares	ComEd Single-Family Homeowners and Residents of Multi-Family Buildings Identified from Utility Customers Database	By Building Type	521
Residential On-Site Validation Effort	In-Person On-Site Audits	Residential Appliances and Household Characteristics—efficiency ratings and quantities of equipment	Participants in RASS Agreeing to Site Visits. Some site visits were recruited without the full survey.	By Building Type	140
Residential HVAC Trade Ally Survey	Telephone Survey	Residential Central Air Conditioners, Air and Ground Source Heat Pumps, Electric Furnaces Gas Furnaces, Boilers	Residential HVAC dealers and installers identified through Yellow Page searches and lists of participating trade allies from ComEd.	N/A	30
Retailer Survey	Telephone Survey	Thermostats, Water Heaters (Gas, Electric, Storage and Tankless), Clothes Washers and, Refrigerators, Freezers, Dishwashers, CFLs, Room ACs, Dehumidifiers, Lighting fixtures, Televisions, DVD Players, Windows	Retail Stores Installers Identified Through Yellow Page Searches.	By Measure Type	70
Residential Home Builder	Telephone Survey	Cooling Equipment, Heating Equipment, Ducts, Windows, Lighting, Siding, Framing, Barriers, Insulation	Builders Identified Through Yellow Page Searches, Lists of Participating Builders from ComEd.	N/A	26
Total Residential Surveys					787

Table 5. Non-Residential Primary Data Collection Efforts

Data Collection Effort	Method	Measures	Sources	Stratification	Number of Surveys/ Visits
Commercial End User	In-Person On-Site Audits	Heating and Cooling Systems, Controls, Refrigeration, Water Heating, Commercial Kitchen Equipment, Lighting and Lighting Controls	Utility-Provided Samples of Non-Residential Customers	Customer Segment/Building Type	316

Data Collection Effort	Method	Measures	Sources	Stratification	Number of Surveys/ Visits
Industrial End User	In-Person On-Site Audits	Heating and Cooling Systems, Controls, Refrigeration, Water Heating, Commercial Kitchen Equipment, Motors	Utility-Provided Samples of Non-Residential Customers	Customer Segment/Building Type	35
Non-Residential Builders	Telephone Survey	Lighting and HVAC Controls, Sensors, Insulation Cool Roofs, Ducts, Lighting, Windows, Lighting Equipment	Yellow Page searches and lists of participating trade allies from ComEd	N/A	25
Non-Residential Architects & Engineering Firms	Telephone Survey	Lighting and HVAC Controls, Sensors, Insulation Cool Roofs, Ducts, Lighting, Windows, Lighting Equipment	Yellow Page Searches and lists of participating trade allies from ComEd	N/A	21
Non-Residential Lighting Vendors	Telephone Survey	Lighting Equipment and Controls	Yellow Page Searches and lists of participating trade allies from ComEd	N/A	16
Compressed Air Vendors	Telephone Survey	Compressed Air Equipment, and control strategies	Yellow Page Searches and lists of participating trade allies from ComEd	N/A	15
Mechanical Contractors	Telephone Survey	Heating and Cooling Equipment, Controls, Motors and Drives	Yellow Page Searches and lists of participating trade allies from ComEd	N/A	16
Refrigeration Specialists	Telephone Survey	Refrigeration Equipment, Motors, Drives, Lighting, Insulation Measures, and Controls	Yellow Page Searches and lists of participating trade allies from ComEd	N/A	15
Electric Motor Dealers	Telephone Survey	Motors, controls,	Yellow Page Searches and lists of participating trade allies from ComEd	N/A	13
Total Non-Residential Surveys					472

Summary of Data Collection for High Priority Measures

The data sources for each of the high-priority measures are summarized in Table 6 and Table 7. The customer surveys provided the majority of the saturation data, and the site visits provided much of the penetration data, while the trade ally and other "upstream" market actor surveys provided the market share information.

Table 6. Summary of Data Sources for Residential Sector Measures

Measure Type	End-use Customer Telephone Surveys	Customer Site Visits	HVAC Trade Ally Surveys	Appliance Retailer Survey	Home Builder Survey
Residential Central AC	✓	✓	✓		✓
Geothermal/Air Source Heat Pumps	✓	✓	✓		✓
Programmable Thermostats	✓	✓	✓	✓	✓
Clothes Washers	✓	✓		✓	
Water Heating	✓	✓		✓	✓
Clothes Dryers	✓	✓		✓	
Dishwashers	✓	✓		✓	
Windows		✓			✓
Insulation		✓			✓
Refrigerators	✓	✓		✓	
Electronic Equipment Plug Load	✓			✓	
CFLs	✓	✓		✓	✓

Table 7. Summary of Data Sources for Non-Residential Sector Measures

Measure Type	Builders / A&E Firm Surveys	HVAC Contractors Survey	Mechanical Contractors Survey	Motor Vendors Survey	Lighting Vendors Survey	Compressed Air Vendors Survey	Refrigeration Vendors Survey
Central Air Conditioning	✓	✓	✓				
Furnaces	✓	✓					
Geothermal/Air Source/Add on Heat Pump	✓	✓	✓				
Boilers		✓					
Programmable Thermostats	✓	✓	✓				
Building Energy Management Systems	✓		✓				
Occupancy Sensors	✓				✓		
Heat Recovery from Exhaust Air to Water Heating	✓		✓				
Water Heating	✓	✓					
Windows	✓						
Insulation	✓						
Motors/ASDs	✓			✓			
Refrigeration	✓						✓
CFLs/T8 Lighting/High Bay Lighting/LED Exit/Pulse Start Metal Halide	✓				✓		
Compressed Air Systems and controls						✓	

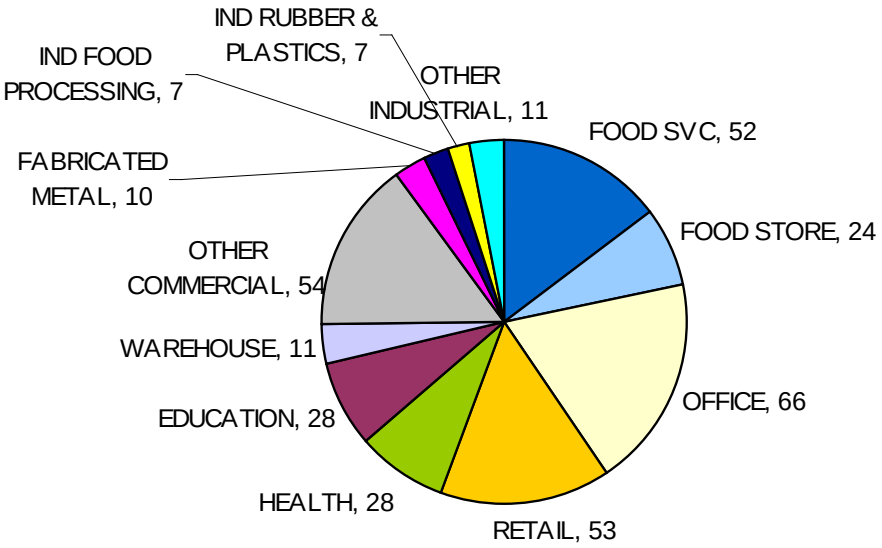
Data Collection Stratification

As noted above, the telephone and on-site audits of the residential sector were stratified by single-family and multifamily housing types. Of the 521 telephone surveys conducted, 431 were conducted with single-family customers and 90 with multifamily customers. For the on-site audits, 73 were conducted with single-family and 67 with multifamily customers.

For the non-residential data collection, the SIC codes of industry types that made up the highest level of energy sales were analyzed to determine the primary segments. For commercial customers, primary segments were education, food service (restaurants), food stores (grocery & convenience), health care, office, retail, warehouse, and an "other" category (Figure 4). Industrial segments included fabricated metals, food processing, rubber & plastics industries, and an "other" category.

The distribution of surveys across segments was controlled by setting quotas during the recruitment process. Priority was given to segments with the highest kWh in the population, including offices and restaurants, and the remaining segments were distributed proportionally. Further, Cadmus conducted statistical analyses on the total kWh of respondents to confirm that the survey respondent segments were representative of each segment's population. The overall energy use of the sample showed no significant difference from the overall energy use of similar segments of the customer population.

Figure 4. Stratification for Non-residential On-site Audits



Measure Database

The study includes a comprehensive set of electric energy-efficiency measures applicable to the climate and customer characteristics of ComEd's service territory. The analysis began by assessing the technical potential of 239 *discrete* electric energy-efficiency measures (Table 8). Considering all permutations of these measures across all customer sectors and segments, customized data had to be compiled and analyzed for over 3,800 measures.

Table 8. Energy-Efficiency Measure Counts

Sector	Electric Measure Counts
Residential	106 unique, 875 permutations across segments
Commercial	154 unique, 2,446 permutations across segments
Industrial	15 unique process improvements, 89 permutations across segments

Additional Utility Data for Potential Analysis

Extensive data sets were also provided by ComEd as key inputs into the study. These data, provided by sector where applicable, covered:

- Customer counts
- Electric sales (consumption)
- System hourly load shapes
- Peak demand history
- Sales and demand forecasts
- Historical demand and efficiency achievements
- Avoided costs
- Line losses

3. Technical and Economic Energy-Efficiency Potentials

Scope of Analysis

The primary objective of this assessment was to develop reasonable estimates of available energy-efficiency potential, essential for ComEd program planning efforts. To support these efforts, Cadmus performed an in-depth assessment of technical, economic, and achievable potential for electric resources in the residential, commercial, and industrial sectors.

Within each sector, the study distinguished between customer segments or facility types and their respective applicable end uses. Four residential segments (existing and new construction for single-family and multifamily homes), 16 commercial segments (existing and new construction for 8 building types), and 4 industrial segments (3 specific facility types and a miscellaneous segment) were analyzed.

The remainder of this section is divided into three parts: a brief description of the methodology for estimating technical and economic potential, a summary of resource potentials, and detailed sector-level results.

Methodology

The basic methodology for estimating energy-efficiency potential is consistent for all three sectors:

- **Develop baseline forecast:** A baseline forecast is created based on end-use consumption estimates, calibrated to ComEd's base year sales and official forecast. This provides accurate estimates of consumption by sector, customer segment, end use, and year.
- **Compile measure lists:** All measures applicable to ComEd's climate and customers were analyzed to accurately depict the energy-efficiency potential over the 6-year planning horizon. When expanded by customer segment, end use, and vintage (existing vs. new construction), this list totaled over 3,800 measures (as discussed above).
- **Estimate technical potential:** An alternate forecast was created where all technically feasible measures were assumed to be installed. The difference between this forecast and the baseline represents the technical potential in each year.
- **Estimate economic potential:** A second alternate forecast was created where all technically feasible and cost-effective measures were assumed to be installed. The difference between this forecast and the baseline represents the economic potential in each year.
- **Estimate achievable potential:** A subset of the economic potential was taken to reflect the maximum that could be achieved after accounting for market barriers, assuming ComEd was willing to pay up to 100% of incremental cost in incentives. A more detailed discussion of the methodology and results of achievable potential can be found in the subsequent chapter.

A detailed discussion of the methodology for estimating energy-efficiency potential is presented in Volume II, Appendix E.

Summary of Resource Potential

Table 9 shows the baseline electric sales and potential by sector forecast for the year 2016, the end of the 6-year study horizon. As shown, the results of this study indicate 22,117 GWh of technically feasible electric energy-efficiency potential will be available by 2016. This technical potential translates to an economic potential of 13,617 GWh. Were all of this potential cost-effective and realizable, it would amount to a 14% reduction in 2016 forecast retail sales. In addition, instead of a 5% increase in sales from 2011 to 2016, as forecasted, ComEd would experience 10% reduction of load growth from 2011 to 2016 (Figure 5).

The commercial sector has the largest economic potential (7,489 GWh), followed by the residential sector (4,564 GWh), and the industrial sector (1,564 GWh).

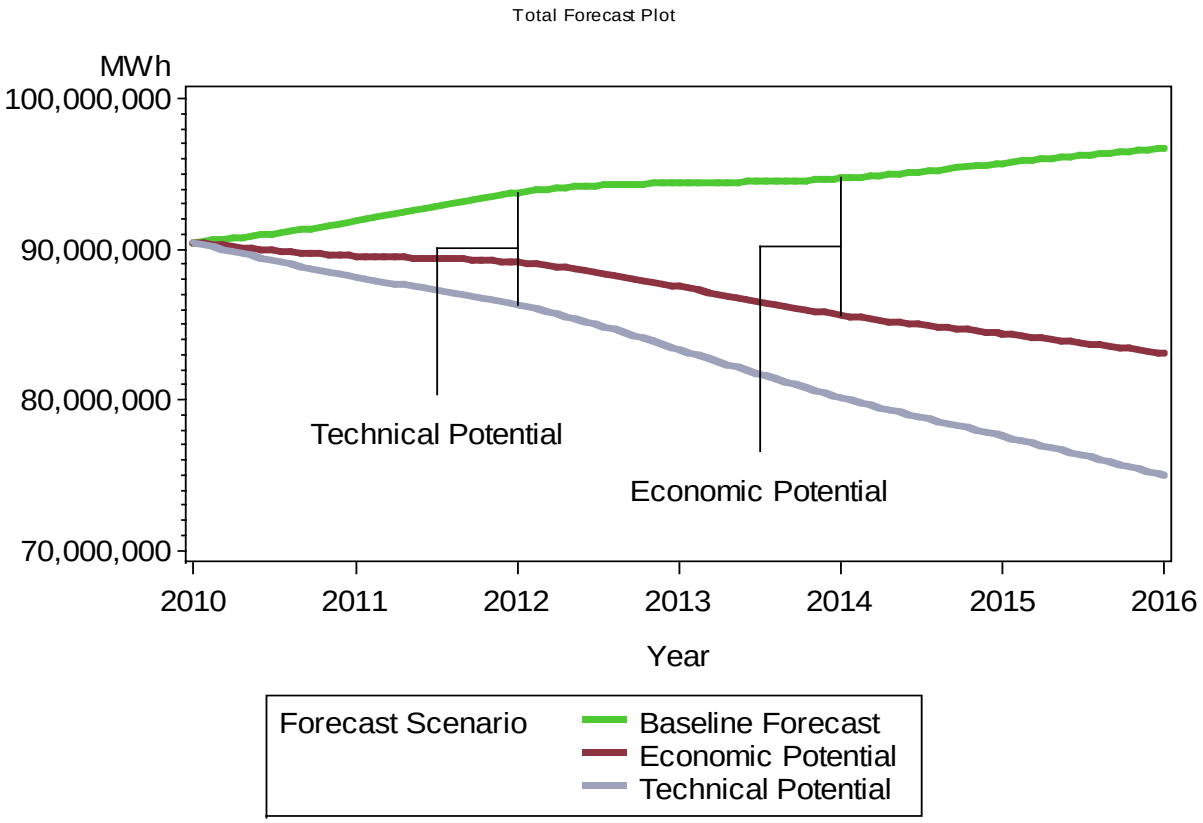
These savings are based on forecasts of future consumption absent any utility program activities. The estimated potential, therefore, is inclusive of—not in addition to—current or forecast program savings.

Table 9. Summary Technical and Economic Electric Energy-Efficiency Potential (MWh in 2016) by Sector

Sector	Baseline Sales	Technical Potential	Technical Potential as % of Baseline	Economic Potential	Economic Potential as % of Baseline	Economic Potential (MW)	Average Levelized Cost ($/kWh)
Residential	31,583,697	8,514,175	27%	4,564,469	14%	1,107	$0.04
Commercial	49,285,486	12,039,102	24%	7,488,711	15%	1,426	$0.05
Industrial	15,816,115	1,563,982[A]	10%	1,563,982	10%	217	$0.01
Total	96,685,298	22,117,259	23%	13,617,162	14%	2,750	$0.04

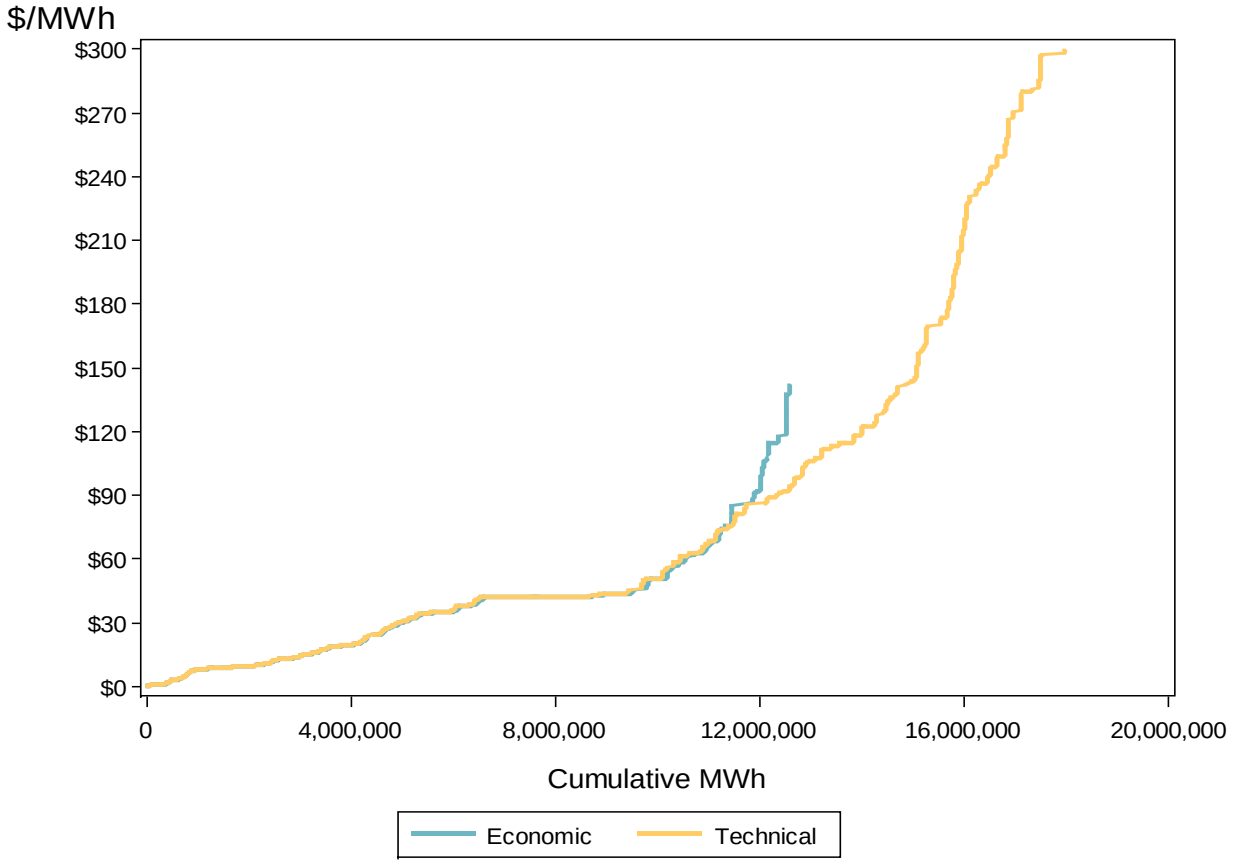
[A] Because the industrial sector uses a "top-down" approach based on cost-effective measures, the estimates of technical and economic potential are identical.

Figure 5. Sales Forecast with Energy-Efficiency Potential Scenarios



A diagram of the efficiency supply curve is presented in Figure 6. The economic potential is capped at approximately $142/MWh (or $0.142/kWh).

Figure 6. Energy-Efficiency Supply Curve



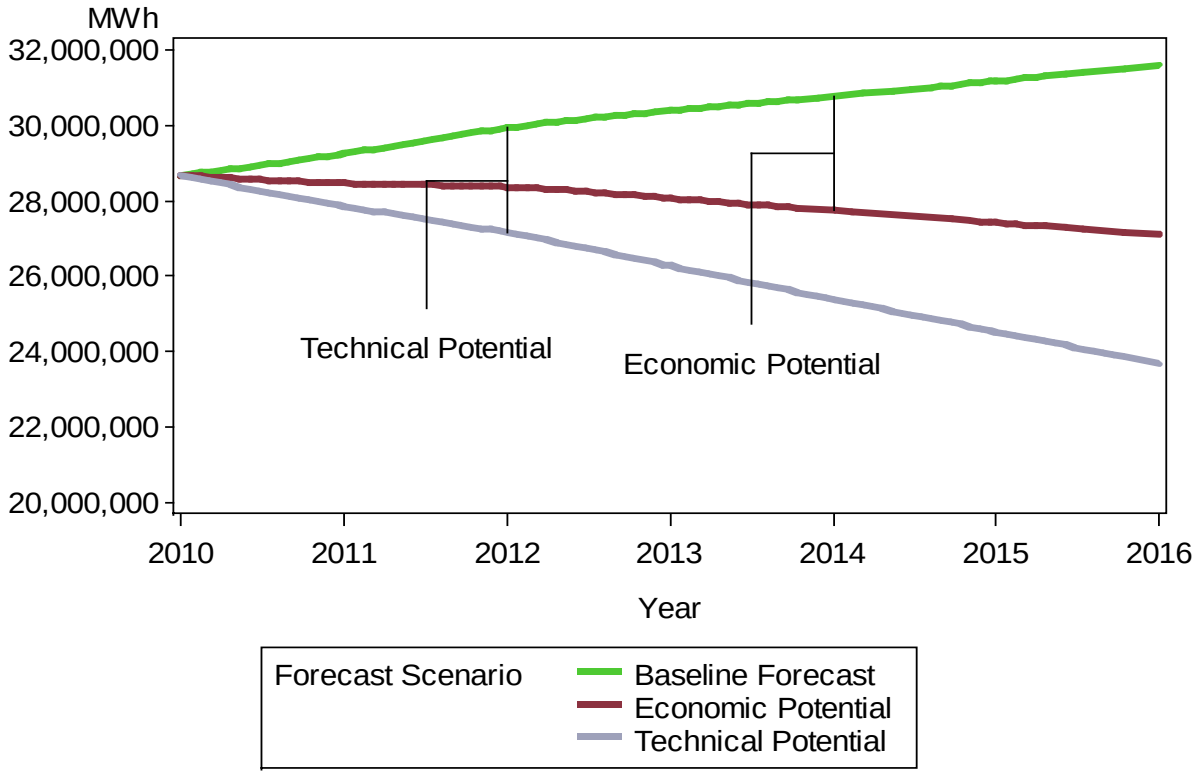
Detailed Resource Potential

Residential Sector

The 3.4 million residential customers in ComEd's service territory accounted for approximately 31% of baseline retail electricity sales in 2008. The single-family and multifamily dwellings that compose this sector present a variety of potential savings sources, including equipment efficiency upgrades (e.g., air conditioning, refrigerators), improvements to building shells (e.g., insulation, windows, air sealing), and increases in lighting efficiency (e.g., CFLs, LED interior lighting).

Electric economic potential in the residential sector is expected to be 4,564 GWh during the 6-year time horizon, corresponding to a 14% reduction of forecast 2016 residential consumption at an average levelized cost of $0.04/kWh (Table 9). Total economic potential, if all realized, would amount to an 8% load reduction from 2011 to 2016 (Figure 7).

Figure 7. Residential Sales Forecast with Energy-Efficiency Potential Scenarios



As shown in Figure 8, single-family homes represent 83% of the total economic residential potential and multifamily homes account for the remaining 17%. The main driver of these results is each home type's proportion of baseline sales, which is 78% for single-family and 22% for multifamily homes, but other factors, such as the presence of cooling or the current CFL saturation, also play a role in determining potential. A comprehensive list of the specific factors affecting the results is included in the segment-specific data in Volume II, Appendix E.

Figure 8. Residential Sector Economic Potential by Segment

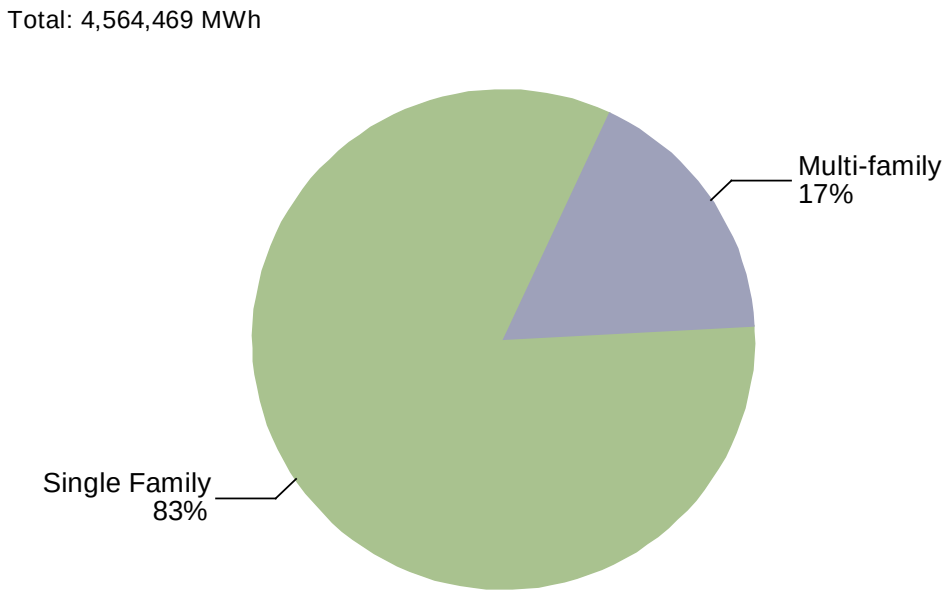
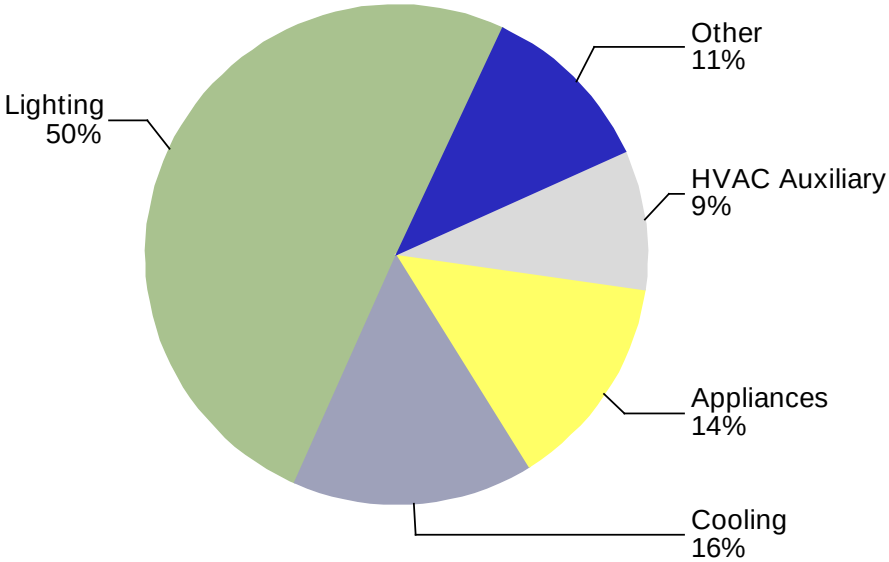


Figure 9 shows the total economic potential by end-use group. Lighting represents the largest portion (50%) of residential sector economic potential, followed by cooling savings (16%), appliances (refrigerators, freezers, dryers, etc., 14%), and HVAC auxiliary (e.g., fans and motors for heating and cooling equipment, 9%). Detailed sales and potentials by end use are presented in Table 10.

Figure 9. Residential Sector Economic Potential by End Use

Total: 4,564,469 MWh



Note: "Other" includes:
Space Heating: 4%, Water Heating: 4%, Plug Load: 3%, Heat Pump: <1%, Pool Pumps: <1%

Table 10. Residential Sector Energy-Efficiency Potential by End Use (GWh in 2016)

End Use	Baseline Sales	Technical Potential	Economic Potential
Central AC	5,088	2,756	681
Cooking	886	15	-
Dryer	727	17	17
Freezer	783	293	272
HVAC Auxiliary	2,274	572	411
Heat Pump	79	26	9
Lighting	6,502	2,833	2,296
Other	1,927	-	-
Plug Loads	7,606	633	152
Pool Pump	188	7	2
Refrigerator	2,380	483	344
Room AC	583	164	28
Space Heating	1,921	457	187
Water Heat	685	259	167
Total	31,584	8,514	4,564

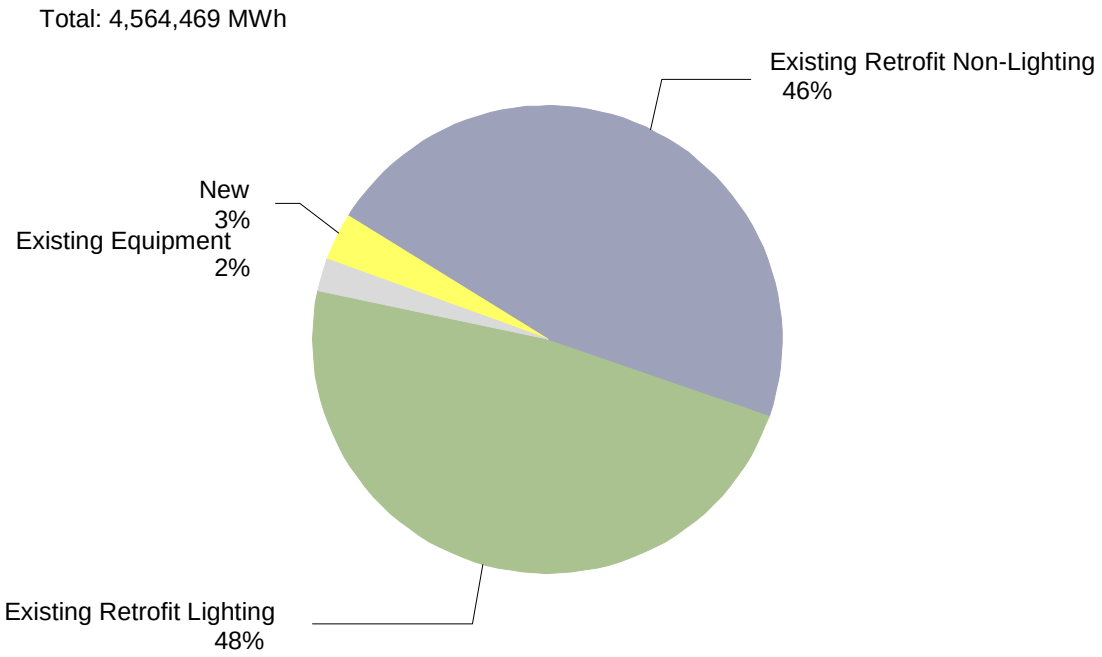
Figure 10 shows economic potential by vintage (existing buildings vs. new construction) and resource type (equipment or retrofit measures). About 3% of the residential economic potential is in new construction, representing both the depressed housing market and the fact that new construction already tends to be quite efficient (i.e., the incremental savings for new construction if typically far less than for existing homes).

In existing homes, potential is divided among retrofit (discretionary) and equipment (phased-in) measures. Discretionary measures are opportunities existing in current building stock (retrofit opportunities in existing construction), while phased-in measures rely on equipment burnout. Lighting, which for residential typically resembles an equipment (replace upon failure) measure, is also shown separately.[4] Lighting retrofit in existing construction accounts for the majority (48%) of the economic potential, followed by non-lighting retrofit measures (46%). Equipment measures represent only 2% of economic potential. It is important to note that the existing retrofit savings have been modeled to occur within the study's 6-year time horizon. For this reason, these discretionary resources will represent a slightly larger percentage of resource savings than if they occurred over a 10-year or 20-year period (i.e., more equipment would burn out and need to be replaced over a longer time horizon, thus providing additional opportunities for replacement with higher efficiency equipment).

The distinction between discretionary and phased-in measures becomes important in the context of timing of resource availability and acquisition planning. Phased-in resources are timing-driven: when a piece of equipment fails, there is an opportunity to install a high-efficiency model in its place. If standard equipment is installed in the absence of early replacement, the high-efficiency equipment could not be installed until the new equipment reaches the end of its normal life cycle. The same is true for new construction; resource acquisition opportunities become available only when a home or building is built. On the other hand, discretionary resources are not subject to the same timing constraints. Though program planning is outside the scope of this study, these considerations are vital for setting accurate annual program and portfolio goals.

[4] While the majority of fixtures are medium and small screw based sockets, which can be readily retrofitted with CFLs upon bulb failure, pin-based fixtures may require fixture retrofits to allow more efficient lighting. In addition, barriers resulting from performance issues (e.g., limited dimming capabilities of CFLs) are addressed separately under the estimates of achievable potential.

Figure 10. Residential Sector Economic Potential by Vintage and Resource Category



Effect of EISA 2007 Lighting Requirements

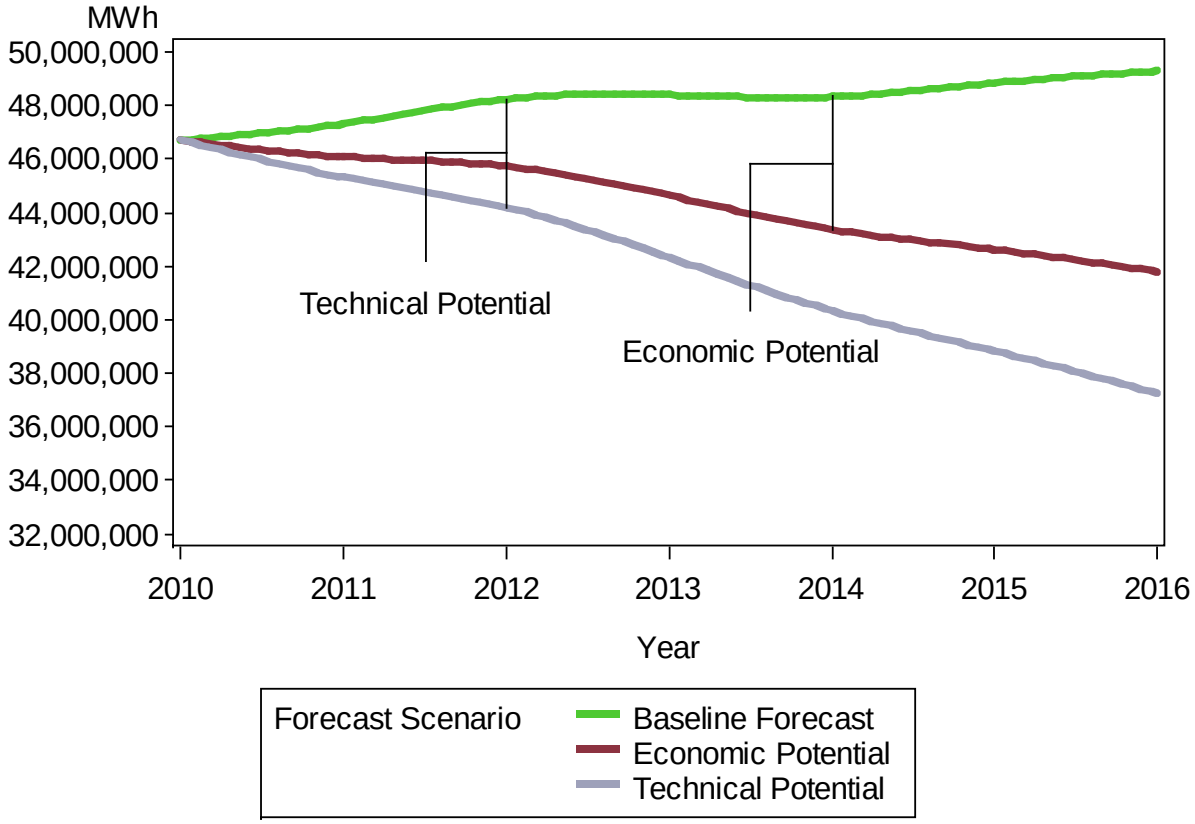
As noted above, the expected impacts of new lighting standards created in EISA 2007 have been accounted for in both the sales forecast and the potential estimate presented in this section.

While the effects of EISA have been incorporated into the potential estimate, an alternative EISA scenario was modeled that considered the impact of CFLs as the new baseline, rather than the base scenario of approximately 30% improvement in baseline incandescent lighting efficiency. Since the base EISA scenario is calibrated to the ComEd sales forecast, it is only appropriate to consider this alternative scenario relative to the potential estimate under the base scenario and not the baseline forecast. In this alternative scenario, residential economic potential in 2016 results in 3,665,467 MWh, representing a 20% decrease from the assumed EISA scenario. In other words, if EISA requirements are assumed to result in CFLs as the new lighting baseline, the residential economic potential would be 20% lower than the estimate currently presented in this report.

Commercial Sector

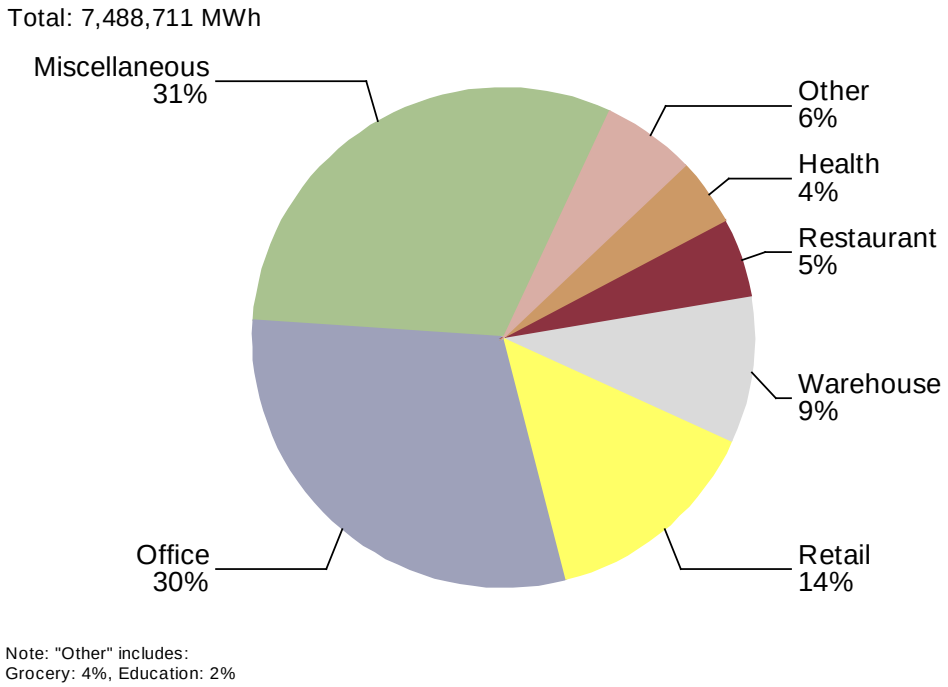
The 330,944 commercial customers in ComEd's service territory accounted for just over half (52%) of baseline electricity retail sales in 2008. Electric economic potential in the commercial sector is expected to be 7,489 GWh during the 6-year time horizon, corresponding to a 15% reduction of forecast commercial consumption in 2016 at an average levelized cost of $0.05/kWh (Table 9). Total economic potential, if entirely realized, would amount to a 12% load reduction from 2011 to 2016 (Figure 11).

Figure 11. Commercial Sales Forecast with Energy-Efficiency Potential Scenarios



The composition of the commercial sector varies more than the residential sector in terms of percentage of customers and sales by segment, which partially accounts for the difference in technical and economic potential as a percentage of 2016 sales. As shown in Figure 12, offices and miscellaneous buildings represent the largest shares (30% and 31%, respectively) of economic potential in the commercial sector. The miscellaneous segment is a combination of customers that do not fit into one of the other categories (e.g., agriculture) and those that would, but for which there was not enough information to classify them. Considerable savings opportunities are also expected in the commercial sector's retail (14%) and warehouse (9%) segments. Moderate savings are expected to be available in restaurants, education, health, grocery, and street lighting.

Figure 12. Commercial Sector Economic Potential by Segment

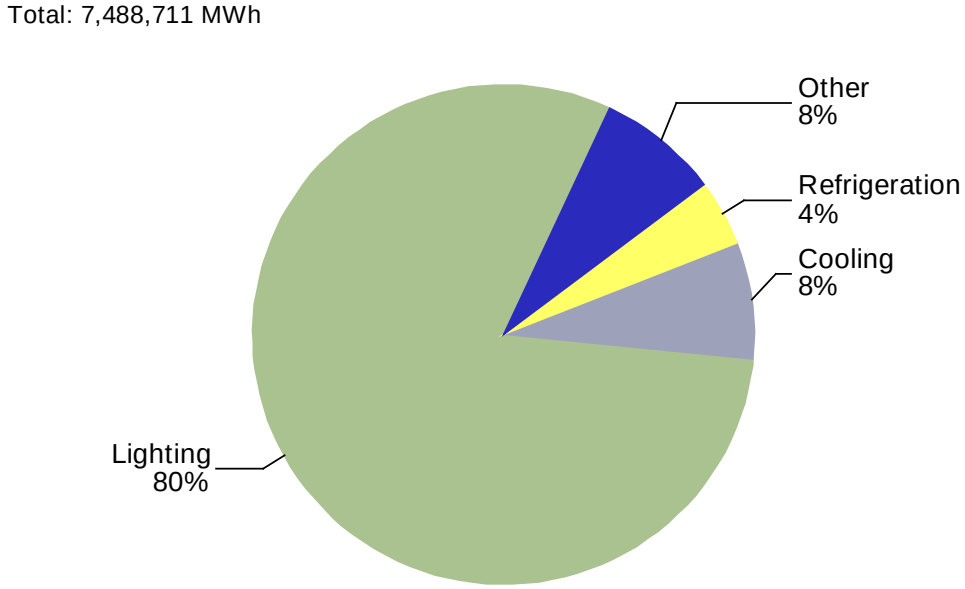


Lighting efficiency represents by far the largest portion of economic potential in the commercial sector (80%), followed by cooling (8%), and refrigeration (5%), as shown in Table 11 and Figure 13. The large lighting potential includes bringing existing buildings to code and exceeding code in new and existing structures.

Table 11. Commercial Sector Electric Energy-Efficiency Potential by End Use (GWh in 2018)

End Use	Baseline Sales	Technical Potential	Economic Potential
Cooking	104	2	1
Cooling Chillers	727	336	162
Cooling DX	2,817	1,590	401
HVAC Aux	6,945	705	84
Heat Pump	144	65	39
Lighting	24,380	7,968	6,021
Other	1,686	2	0
Plug Load	7,775	340	262
Refrigeration	2,092	400	322
Space Heat	1,461	460	168
Street Lighting	739	94	0
Water Heat	416	77	29
Total	49,285	12,039	7,489

Figure 13. Commercial Sector Economic Potential by End Use

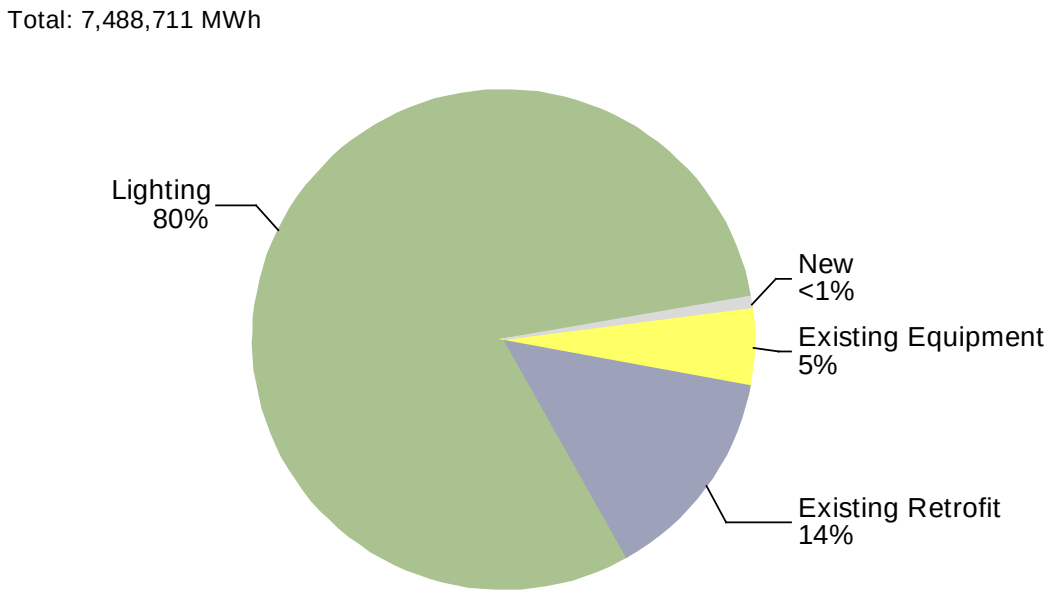


Note: "Other" includes:
Plug Loads: 4%, Heating: 2%, HVAC Auxiliary: 1%, Heat Pump: <1%, Water Heating: <1%, Cooking: <1%

Figure 14 shows economic potential by vintage (existing buildings vs. new construction) and resource type (equipment or retrofit measures). Lighting, which for the commercial sector represents a cross between equipment and retrofit, is once again broken out as a separate category.[5] Retrofit in existing construction accounts for the majority (58%) of the economic potential, followed by lighting measures (38%). Like the residential sector, a relatively small percentage of the economic potential is represented by equipment measures (5%) and new construction (less than 1%).

[5] The majority of lighting opportunities in the commercial sector are represented by retrofitting fluorescent T-12 lighting. While the bulbs do fail, and thus resemble an equipment measure, the replacement of the fixture itself requires a discretionary retrofit decision.

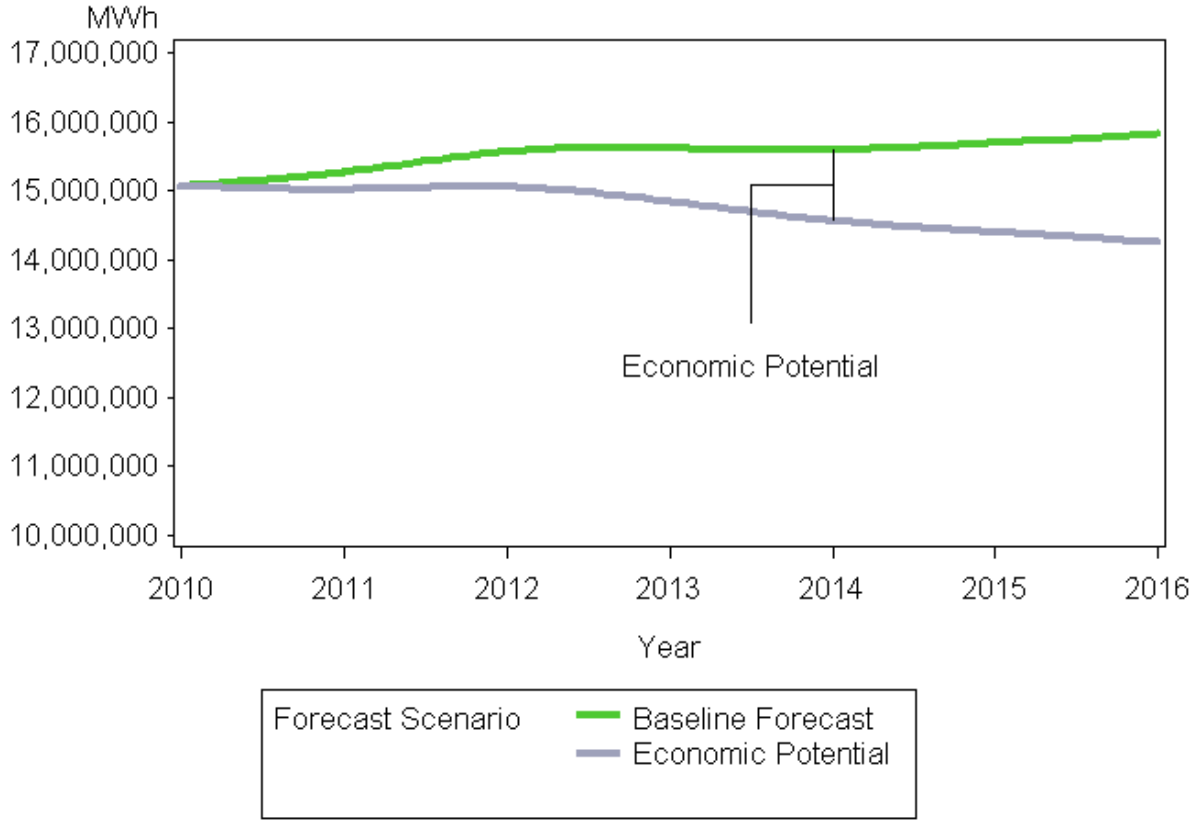
Figure 14. Commercial Sector Economic Potential by Vintage and Resource Category



Industrial Sector

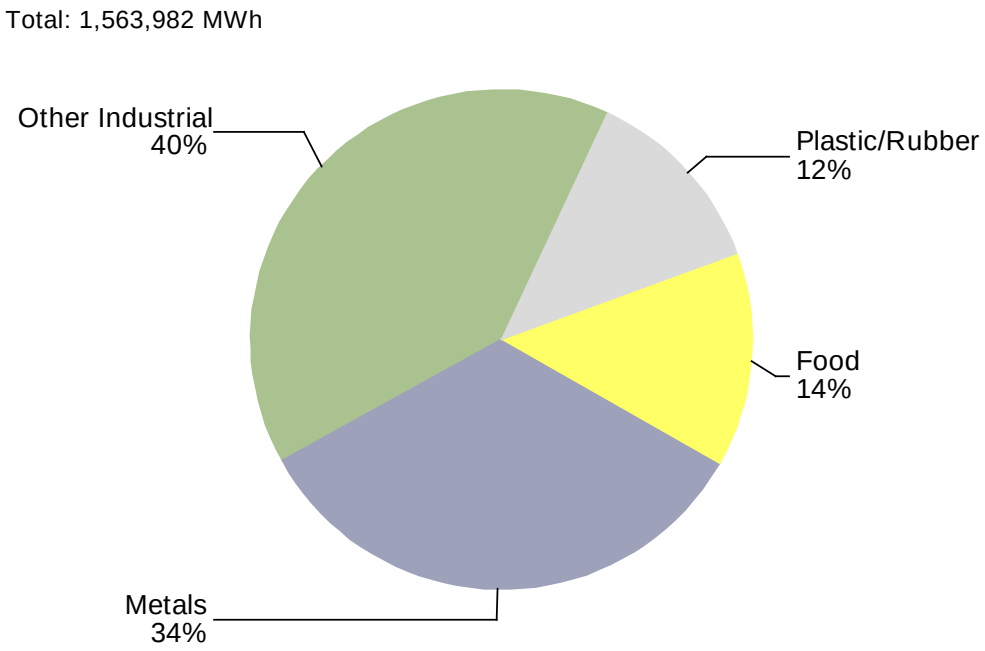
The 27,077 industrial customers in ComEd's service territory accounted for approximately 17% of baseline retail electricity sales in 2008. Electric economic potential in the industrial sector is expected to be 1,564 GWh during the 6-year time horizon, corresponding to a 10% reduction of forecast 2016 commercial consumption at an average levelized cost of $0.01/kWh (Table 9). Total economic potential, if entirely realized, would amount to a 7% load reduction from 2011 to 2016 (Figure 15).

Figure 15. Industrial Sales Forecast with Energy-Efficiency Potential Scenarios



Technical and economic energy-efficiency potentials were estimated for major end uses in four major industrial sectors. Current projected electricity usage in 2016 is 15,816 GWh for the industrial sector. Across all industries, annual economic potential totals approximately 1,563 GWh, corresponding to a 10% reduction of industrial consumption forecast for 2016. Figure 15 shows the breakout of the economic potential by segment, with metals representing the largest area for savings with 34%.

Figure 16. Industrial Sector Electric Economic Potential by Segment



The majority of electric economic potentials in the industrial sector (65%) is attributable to gains in process efficiency (heating, cooling, compressed air, etc.), followed by HVAC improvements (19%). Motors and lighting account for another 7% and 6% of economic potential, respectively. Figure 17 shows the allocation of the economic potential by end use. Table 12 presents the baseline energy usage by end use in GWh and the corresponding technical and economic potential for each end use type.

Note that all of the estimated technical potential in the industrial sector is considered economic. Because of the sector's tight cost margins, available measure data focus on technologies that are currently cost-effective. As such, the universe of available measures examined is smaller than those of the other sectors, possibly influencing the technical potential downward. Furthermore, the industrial potential estimates relied largely on energy audits that primarily examined individual measures and not on a systems approach; thus the actual economic potential may be slightly higher than that presented in this report. For a more complete description of the methodology used, please see Volume II, Appendix E.

Figure 17. Industrial Sector Electric Economic Potential by End Use

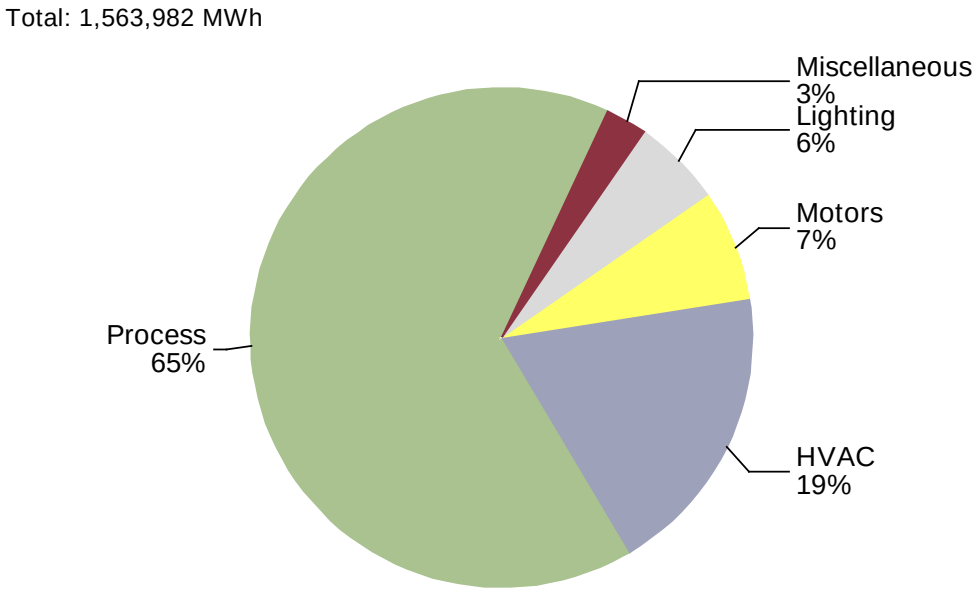


Table 12. Industrial Sector Electric Energy-Efficiency Potential by End Use

End Use	Baseline Sales (GWh)	Economic Potential (GWh)
Fans	939	48
HVAC	2,715	297
Indirect Boiler	2	0
Lighting	2,052	89
Motors Other	3,537	169
Other	879	42
Process AirComp	945	193
Process Cool	1,330	161
Process Electro Chemical	41	0
Process Heat	1,894	418
Process Other	70	8
Process Refrig	418	75
Pumps	994	64
Total	15,816	1,564

4. Achievable Energy-Efficiency Potentials

The previous chapter provided estimates of the technical and economic energy-efficiency potentials in the residential, commercial, and industrial sectors. This chapter expands on the analysis, estimating the subset of technical and economic potential that can actually be achieved through program activity.

Definitions of Achievable Potential

Achievable potential typically is defined in two ways:[6]

- ***Maximum Achievable Potential (MAP)*** is the amount of energy use that efficiency can realistically be expected to displace, assuming the most aggressive program scenario possible (e.g., providing end-users with payments for the entire incremental cost of more efficient equipment). MAP accounts for real-world barriers to convincing end users to adopt efficiency measures, recognizing that even if the full incremental cost of measures were to be paid for by utilities, some customers would still refuse to install efficient equipment. For example, some customers may reject CFLs, even if they are given away for free, because they do not like the light quality. Similarly, industrial customers may have been using fixed-speed motor systems for many years, and may be risk-averse to upgrade for variable frequency drives, even at no incremental cost.
- ***Program Achievable Potential (PAP)*** is the amount of energy use the ComEd efficiency programs realistically can be expected to displace from 2011 through 2016.[7] PAP reflects the market, financial, political, and regulatory barriers likely to limit the amount of savings that might be achieved through program activity. For example, new programs require a ramp-up period to educate customers and trade allies about program activity; the recent recession and housing crises also limit customer spending and interest in programs; and Illinois legislation requires a 2% annual spending rate cap. In addition, the six-year time horizon for this study means much of the discretionary measures (e.g., replacement of insulation or other shell measures) that do not require replacement from 2001–2016 will likely not be achieved, particularly since customers will not be in the market to replace such measures (i.e., the adoption of such measures will be substantially longer than that of a replacement measure, where a utility can devise a program-intervention strategy to educate customers and trade allies during the natural replacement cycle).

Projection of MAP and PAP pose significant analytic challenges as they are inherently based on assumptions regarding market acceptance of energy-efficiency measures and programs offered by utilities. Surely, levels of cost-effective, energy-efficiency potential realistically achievable depends on several factors, including customers' willingness to participate in energy-efficiency programs (which is only partially a function of incentive levels), retail energy rates, and a host of market barriers that have historically impeded the adoption of energy-efficiency measures and

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6 These definitions are consistent with the National Action Plan for Energy Efficiency (NAPEE) *Guide for Conducting Energy Efficiency Potential Studies*, November 2007.

7 Program Achievable Potential is also referred to as Realistically Achievable Potential.

practices by consumers.[8] These barriers tend to vary depending on the customer sector, local energy market conditions, and other, hard-to-quantify factors.

Estimating Achievable Potential

The most reliable way to estimate achievable potential is to examine actual achieved savings (i.e., historical program savings accomplishments) as a function of program delivery mechanisms, incentives, and marketing expenditures. However, because ComEd is only in its second year of recent program activity, limited historical data are available for this purpose.

Alternatively, many studies examine achievable potential as a subset of economic potential. These estimates implicitly assume the measure savings estimates, incremental costs, and other assumptions going into deriving economic potential are fixed during the time horizon of interest, and that a portion of economic potential can be achieved.

For example, a review of recent conservation potential assessment studies in North America indicates a wide range for achievable potentials, from 30% (New Jersey) to 75% (New England) of economic potentials across all sectors.[9] The available data indicate, on the whole, an estimated average PAP of approximately 47% across all sectors. A 2004 "meta-analysis" of potential found, on average, achievable potential was about 41% of economic potential.[10]

Due to differences in methodology, however, underlying assumptions (e.g., the length of the planning horizon), variations in local market conditions (e.g., customer mix, electric rates, and historical conservation efforts), and the calculated "average" or "typical" reported here should be interpreted in light of these limitations and be considered only as "indicative" measures of what might be achievable. For example, some studies calculate only achievable potential and not economic potential, making it difficult to compare the two estimates. Other studies, such as recent California estimates of efficiency potential, only include measures that need to be replaced in the next 10 years (i.e., discretionary or retrofit measures are not included).

The Power and Conservation Council in the Pacific Northwest, a region with a history of conservation planning beginning in the late 1970s, has historically assumed 85% of economic potential is likely to be achievable. Recent data from the Council indicates that while the region has indeed achieved significant portions of the expected economic potential since the early

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8 Consumers' apparent unwillingness to invest in energy efficiency has been attributed to certain market barriers for energy efficiency. A rich literature exists concerning what has become known as the "market barriers to energy efficiency" debate. Market barriers identified in the energy-efficiency literature fall into five broad classes of market imperfections thought to inhibit energy efficiency investments: (1) misplaced or split incentives; (2) high front costs and lack of access to financing; (3) lack of information and uncertainty concerning benefits, costs, and risks of energy-efficiency investments; (4) investment decisions guided by convention and custom; and (5) time and "hassle" factors. For an ample discussion of these barriers, see William H. Golove and Joseph H. Eto, "Market Barriers to Energy Efficiency: A Critical Reappraisal of the Rationale for Public Policies to Promote Energy," Lawrence Berkeley National Laboratory, University of California, Berkeley, California, LBL-38059, March 1996.

9 A full bibliography of studies used to inform achievable potentials estimates is included in Appendix G.

10 Nadel, Steven, et. al. "The Technical, Economic, and Achievable Potential for Energy-Efficiency in the U.S.—A Meta-Analysis of Recent Studies." 2004 ACEEE Summer Study on Energy Efficiency in Buildings.

1980s, a large portion of these savings have been achieved through implementation of energy codes and standards, particularly in Oregon and Washington.[11]

Several utilities have made more rigorous attempts to develop realistic estimates of achievable potentials. For example, a survey of about 30 national energy-efficiency experts (conducted for Tacoma Power in 2006) found between 30% to 48% of economic potentials are likely to be achievable across all sectors for existing buildings, assuming a 50% incentive and a 10-year planning horizon.

Another recent study by the Electric Power Research Institute (EPRI) examined the impacts of energy-efficiency programs around the country, combined with expert judgment, to estimate MAP and PAP through two adjustment factors:[12]

- ***Market Acceptance Ratios*** (MARs) are used to derive the MAP by recognizing some consumers will not select the most efficient equipment, even if programs offer perfect information and cover the full incremental cost of that equipment. As noted, many customers consider aesthetics, performance, and a myriad of additional product attributes as far higher priorities than energy efficiency. The MARs were developed based on current market data where available, such as ENERGY STAR sales figures, and have been augmented through an expert review process. In addition, the MARs generally increase through the forecast horizon, reflecting energy efficiency's growing acceptance.
- ***Program Implementation Factors*** (PIFs) account for recent utility experience and reported savings to estimate the percentage of the MAP that likely (realistically) can be acquired as PAP. The PIFs account for the many other factors that limit program accomplishments, including: a requisite ramp-up period to educate customers and trade allies about program activity; limited (and, in the case of Illinois, capped) resources for incentive and marketing budgets; and other market barriers, such as split incentives.

The values from the EPRI study, however, appear quite conservative in terms of identifying the percentage of economic potential that is considered achievable. For example, the MAR for residential central AC is only 25% in 2010, increasing to 50% in 2015. Extrapolating this to the 2011–2016 potential horizon, the maximum achievable potential for residential central AC would only be approximately 38%. The PIFs for the same measure would increase from 30% in 2010 to 40% in 2015. Once again, extrapolating to the 2011–2016 potential horizon, the program-achievable potential for this measure would only be approximately 14%.[13] Similarly low estimates have been projected for most measures; thus, this technique was not applied as part of this study.

Finally, Cadmus conducted an independent review of 60 potential studies covering 40 states, plus four national studies.[14] As shown in Table 13, the achievable potential as a percent of

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[11] "Achievable Savings: A Retrospective Look at the Northwest Power and Conservation Planning Assumptions," Council Document, 2007-7, Northwest Power and Conservation Council, May 2007.

[12] Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: (2010–2030). EPRI, Palo Alto, CA: 2009. 1016987.

[13] The program achievable percent is a subset of the maximum achievable potential; so PIFs are applied to the maximum achievable percent. As an example for central AC units, if the MAR is 25% and the PIF is 30%, the estimated achievable percent is the product of 25% and 30% (or 7.5% of economic potential).

[14] The full bibliography of studies is included in Appendix G.

economic potential ranges from an average of 38% at the low end to 81% on the high end (maximum achievable), with typical realistically achievable potential averaging about 43% of economic potential. Note the average number of years was 15 year, with an implied annual achievable of about 0.8% of baseline sales.

Table 13. Summary of Potential Study Research

Parameter	Number of Studies	Average Potential as Percent of Baseline Sales*	Average Potential as Percent of Economic*
Technical Potential	30	27%	NA
Economic Potential	33	21%	NA
Minimum Achievable Potential	14	8%	38%
Program Achievable Potential	11	9%	43%
Maximum Achievable Potential	38	17%	81%

* Cumulative % of End Year Sales

Figure 18 presents annual estimates of MAP and PAP compared against estimated economic potential as well as statutory Illinois' savings goals, which require energy savings of 0.2% of sales beginning in 2008, and ramping up to 2% of sales for 2015 and 2016. The PAP (43% of economic potential) and the MAP (81% of economic potential) are based upon the literature review above.

Note that the application of the PAP to the entire estimate of the economic potential, including the retrofit measures (e.g., insulation and other discretionary measures), assumes that in six years (the time horizon for the current study) that 43% of the potential can be achieved. Because most potential studies cover a longer time horizon (average of 15 years), most studies assume this same potential would be achieved over a much longer time horizon. If retrofit measures are assumed to need a longer time horizon to achieve the program potential, the PAP for retrofit measures would be reduced. For example, if a ten-year phase-in is assumed for retrofit measures, the PAP for these measures would be:

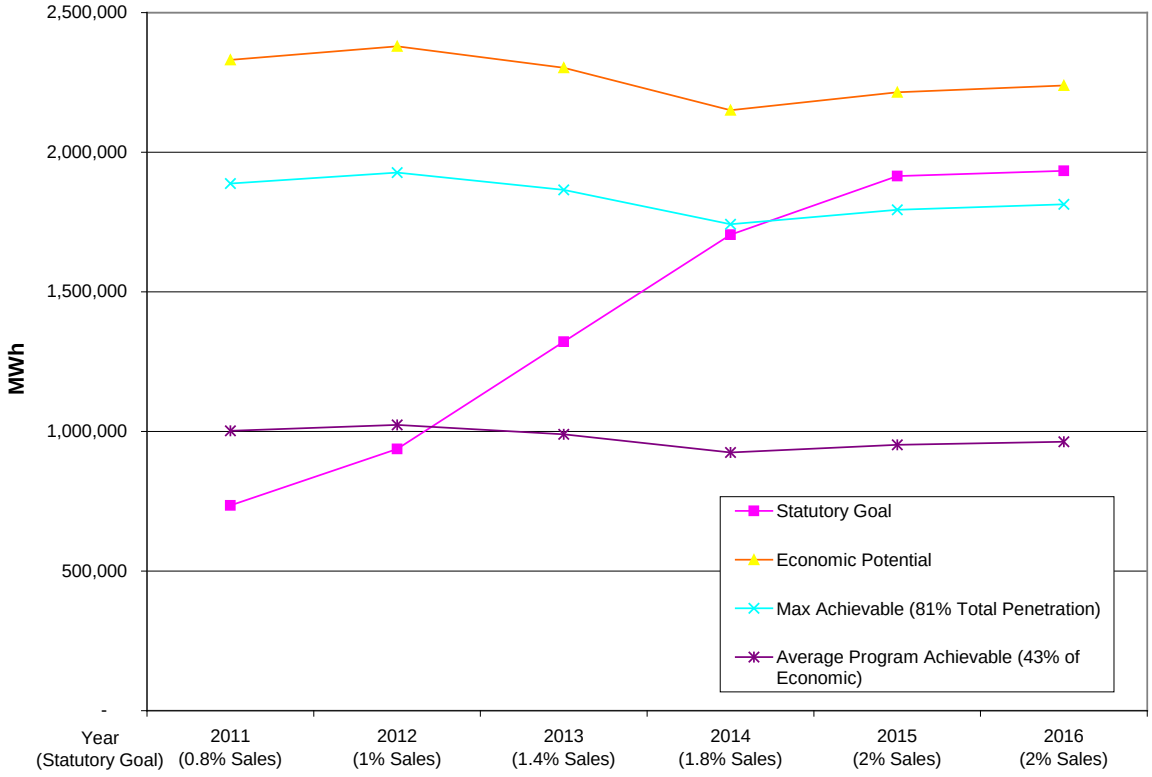
*Retrofit PAP = (Study Horizon/Phase-in) * 43%*

*Retrofit PAP = (6/10) * 43% = 25.8%*

The overall effect of this assumption would be reduce the total estimated PAP from 43% to about 35%.

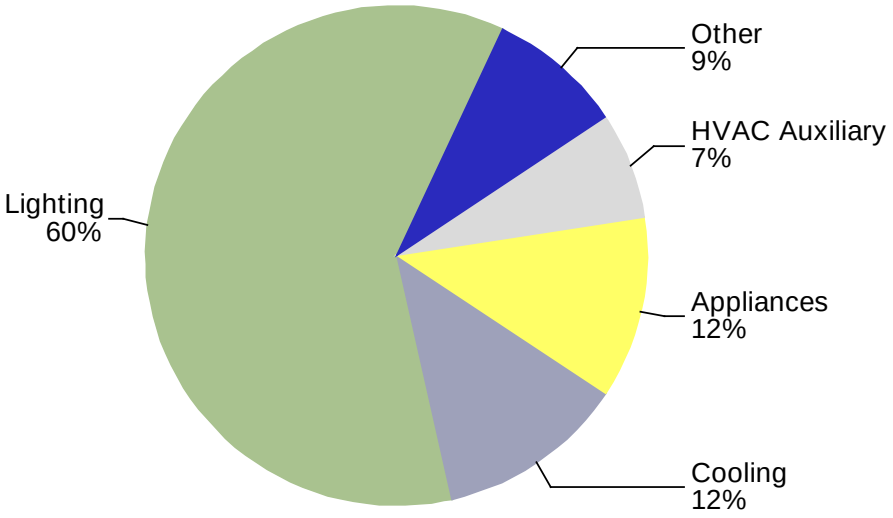
As shown in Figure 18, the EISA lighting standards have a downward effect on economic potential, particularly in 2013 and 2014. Statutory goals, however, continue to rise (quite aggressively in 2015). As shown in the figure, the EISA lighting standards have a downward effect on economic potential, particularly in 2013 and 2014. Statutory goals, however, continue to rise (quite aggressively in 2015). As shown in the figure, ComEd will need to exceed the estimated maximum achievable percentage in 2015-2016 to meet the program goals.

Figure 18. Estimates of Achievable Potential (2011-2016)



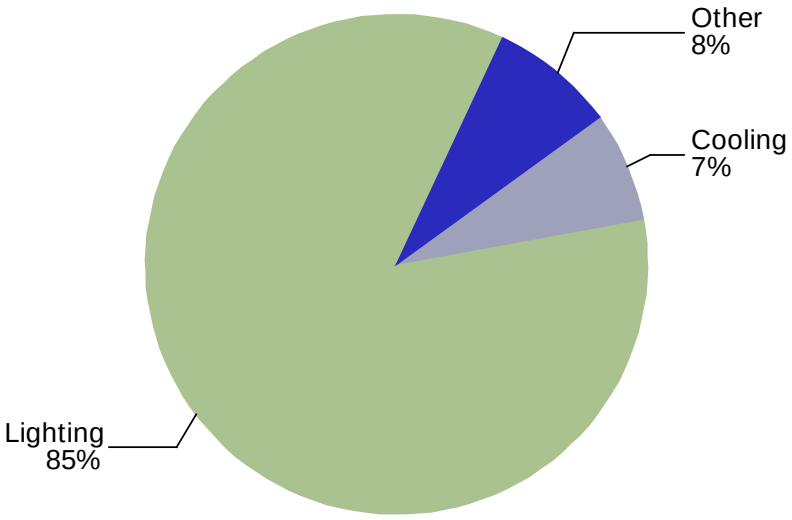
As shown in Figure 19 and Figure 20, lighting still remains an important end use for achievable potential for residential (45%), and is still the dominant end-use for commercial (85%). In addition, process improvements are still the primary sources for industrial potential (Figure 21).

Figure 19. Residential Sector Electric Achievable Potential by End Use (2016)



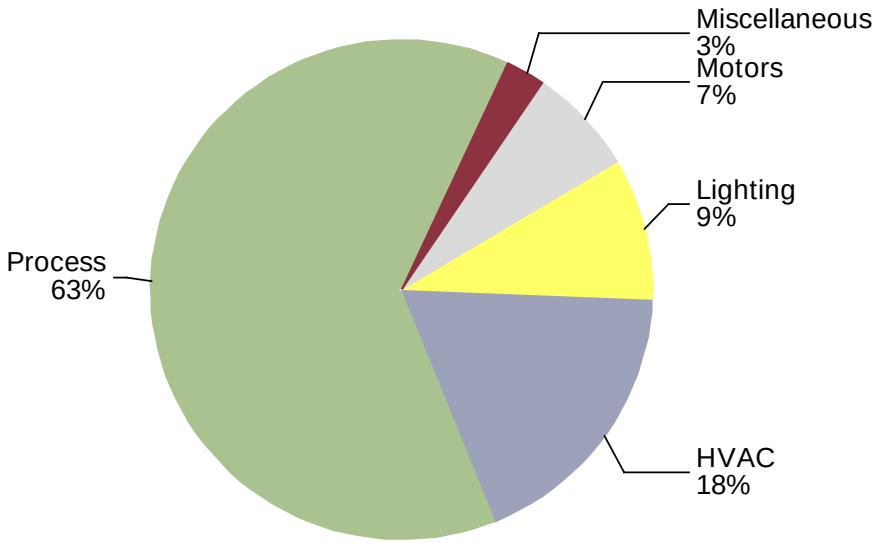
Note: "Other" includes:
Space Heating: 3%, Water Heating: 3%, Plug Load: 3%, Heat Pump: <1%, Pool Pumps: <1%

Figure 20. Commercial Sector Electric Achievable Potential by End Use (2016)



Note: "Other" includes:
Refrigeration: 3%, Plug Loads: 2%, Heating: 1%, HVAC Auxiliary: <1%, Heat Pump: <1%, Water Heating: <1%, Cooking: <1%

Figure 21. Industrial Sector Electric Achievable Potential by End Use (2016)



Comparison of Program Savings to Potential Estimates

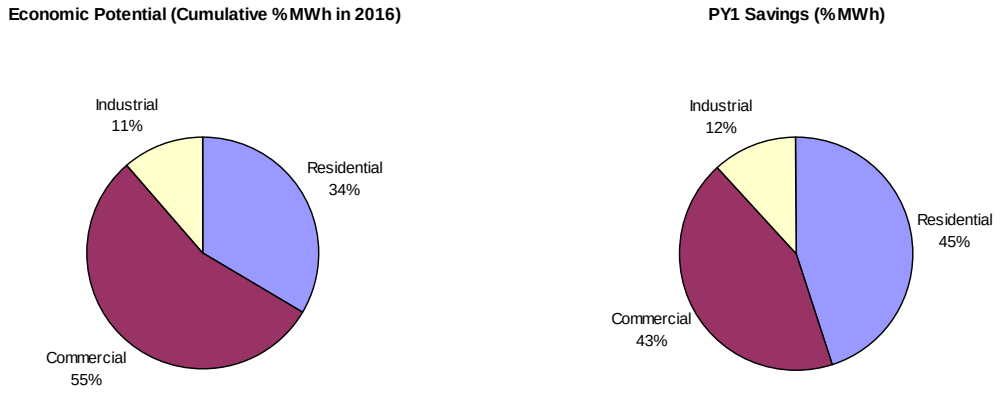
As noted above, actual program achievements provide important insight into achievable potential estimates. ComEd, however, has only recently completed one year of DSM program activity, and is planning more aggressive program activity during the next few years. To help highlight areas where ComEd should focus on achieving program savings, Cadmus developed a series of pie charts to compare the percentage of economic potential by sector, segment, and end-use with the percentage of Program Year 1 (PY1) achieved savings by the same categories.[15] "Slices" of the pie charts that are larger on the economic potential estimates compared to the PY1 achieved estimates represent areas that ComEd should consider targeting for future DSM program activities.

Comparison of Potential vs. Achieved Savings by Sector

As shown in Figure 22, in PY1 ComEd achieved savings in a mixture of residential (45%), commercial (43%), and industrial (12%) sectors. The percent of achieved savings was slightly lower in the commercial sector (43%) than the percent of commercial economic potential (55%), but in general the PY1 achievements represent a mix of savings for all sectors.

[15] Note that the PY1 valuation did not include the full resolution needed to conduct this analysis using the final net savings estimates, so the analysis supplemented these sources with gross savings estimates from the program tracking database, generated in October 2009. These data, therefore, may be considered illustrative, rather than conclusive, of PY1 results.

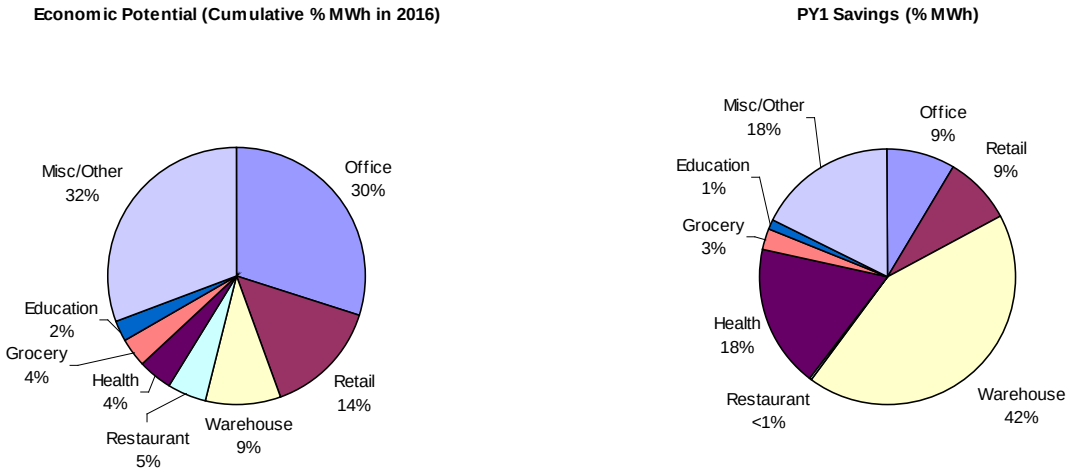
Figure 22. Economic Potential vs. PY1 Savings by Sector



Comparison of Potential vs. Achieved Savings by Segment

Because a significant portion of the savings from the residential sector were generated by CFL buy downs, and the "upstream" incented CFLs cannot be tracked to single family vs. multifamily homes, savings by residential segment were not available. For the commercial sector, a significantly higher percentage of savings were achieved in the warehouse segment (42%) compared to the percentage of economic potential in that segment (9%) (Figure 23). Analysis of the site visit data revealed that many of the warehouses visited had retrofitted their lights to more efficient lighting, possibly reflecting the achievements of the program.[16] Offices, which represent 30% of the economic potential but only 9% of the PY1 savings, may offer additional program opportunities.

Figure 23. Economic Potential vs. PY1 Savings by Commercial Segments



[16] The survey collected information on saturations, not purchases, so did not determine the timing for the retrofits or program attribution.

Comparison of Potential vs. Achieved Savings by End-Use

As shown in Figure 24, the residential savings in PY1 was dominated by lighting (82%). Although lighting represented the largest potential end-use in the residential sector (50%), the study found additional economic potential (and thus program opportunities) for cooling, HVAC auxiliary, space heating, and water heating measures. In the commercial sector, the PY1 savings were also dominated by lighting (84%), which also closely mirrored the findings from the potential study (Figure 25).

Figure 24. Economic Potential vs. PY1 Savings by Residential End-Use

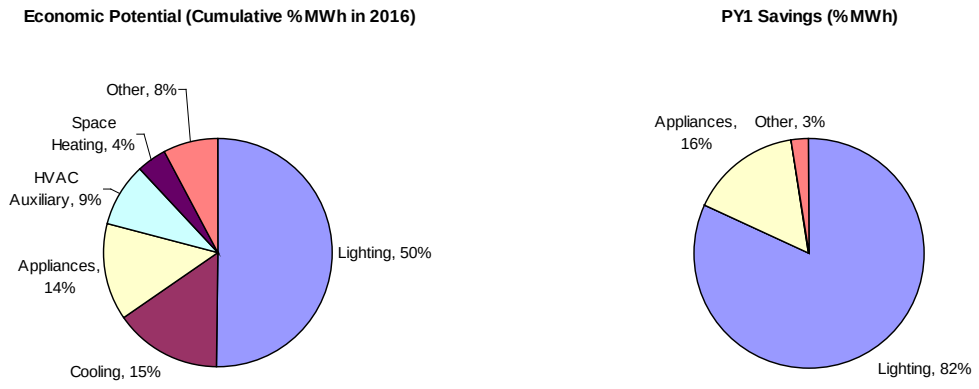
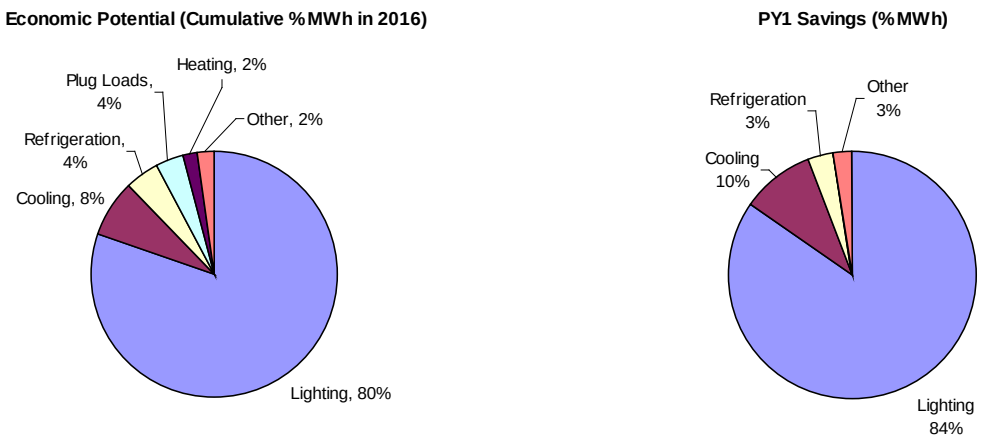


Figure 25. Economic Potential vs. PY1 Savings by Commercial End-Use



5. Demand Response Potential

Scope of Analysis

Demand response (DR) or load reduction programs, focused on reducing a utility's capacity needs, are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. These programs are designed to help reduce peak demand, promote improved system reliability, and, in some cases, may lead to the deferment of investments in delivery and generation infrastructure. DR objectives may be met through a broad range of price-based (e.g., time-varying rates and interruptible tariffs) or incentive-based (e.g., direct load control) strategies. In this assessment, the following demand-response strategies were analyzed:

1. ***Direct Load Control*** (DLC) programs allow a utility to remotely interrupt or cycle electrical equipment and appliances at a customer's facility or home. In this study, assessment of DLC program potential is analyzed for ComEd's existing residential central AC program. Within the program are two options for customers: a 50% cycling option and a 100% cycling option. The program analysis examines potential for summer peak demand reduction in customer-owned homes with central AC (including heat pumps).
2. ***Real-Time Pricing*** (RTP) is a tariff structure for customers to pay electric rates tied to market prices. The prices are posted by the utility, ISO, or program contractor based on day-ahead hourly prices, but are not guaranteed to match the day-of hourly prices that customers must pay. RTP price structures are suitable for large C&I customers with flexible schedules, and for residential customers interested in lowering their electricity bill by raising the cost of electricity during peak times. This analysis examines demand reduction under ComEd's existing Residential RTP (RRTP) program, which is open to all residential customers in ComEd's service territory.
3. ***Interruptible Tariffs*** (Capacity Based Load Response (CLR)) refer to contractual arrangements between the utility and its customers, who agree to curtail or interrupt their loads in whole or part for a predetermined period when requested. In most cases, mandatory participation is required once the customer enrolls in the program; however, these programs may include provisions for customers to exercise an economic buy-through of a curtailment event. Incentives are paid regardless of the quantity of events called each year (less any penalties associated with an event buy-through). This analysis evaluates ComEd's existing contractual Capacity-Based Load Response program (Rider CLR7) available to nonresidential customers who can provide 100 kW or greater of load reduction.
4. ***Demand-Bidding or Demand Buy-Back*** (Voluntary Load Response (VLR)) programs offer payments to customers for voluntarily reducing their demand at the utility's request. The buyback amount generally depends on market prices published by the utility in advance of the event, coupled with the customer's ability to curtail use during the hours load curtailment is requested. The reduction level achieved is verified using an agreed-upon baseline usage level specific to the participating customer. This analysis examines

ComEd's existing Voluntary Load Response (Rider VLR7) program available to nonresidential customers who can reduce their load 10 kW or more.

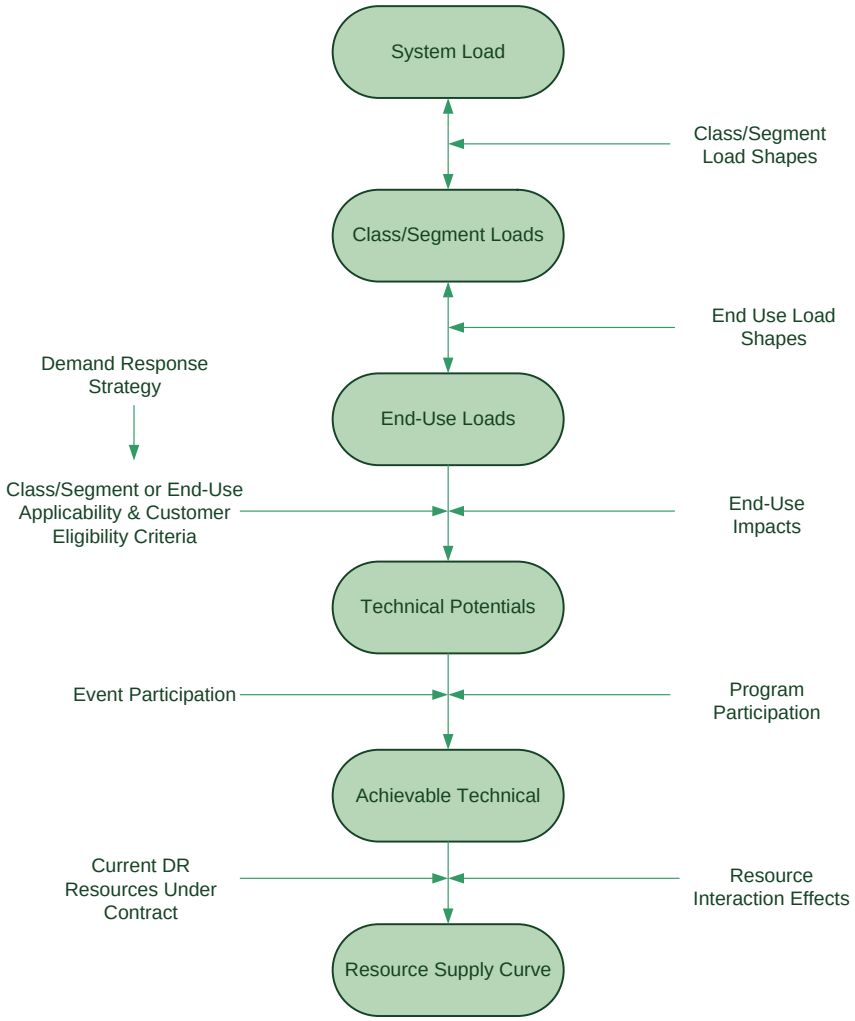
Program options listed above are based primarily on ComEd's existing vetted programs as well as thorough review of literature on DR strategies offered by utilities and regional transmission organizations across the country. For each program offering, data were collected on the offering's main features, such as objectives, program periods, eligibility criteria, curtailment event triggers, incentive structures, and technology requirements. These program options are described in more detail later in this section.

Methodology

The methodology for estimating DR potential was based on a combined "top-down"/"bottom-up" approach. Cadmus's DRPro® Model provided the basic framework for this analysis. As shown schematically in Figure 26, the approach begins with utility system loads, disaggregating them into sector, segment, and applicable end uses. For each DR program (or program component), potential technical impacts are calculated for all applicable end uses. The end-use load impacts are aggregated to obtain estimates of technical potentials. Ranges are assigned to probabilities of program and event participation around expected participation levels with lower and upper bounds based on market knowledge and other utilities' reported results. These market factor ranges are applied to the technical potentials and run through multiple Monte Carlo simulations to obtain the most likely and ranged probability estimates of achievable technical potentials. The methodology for calculating technical and achievable technical potentials is described in detail below.[17]

[17] Note the study does not examine changes in energy use that may occur from demand response programs. Some programs are expected to reduce energy use, while others may primarily lead to load shifting.

Figure 26. Schematic Overview of Demand Response Assessment Methodology



Estimating Technical Potential

DR technical potentials are first estimated at the end-use level, and then are aggregated to market segment, sector, and system levels. This approach was implemented in the following four steps.

1. **Define customer sectors, market segments and applicable end uses**. The first step in the process involved defining appropriate sectors, market segments, and end uses within each segment in accordance with ComEd's requirements. We used the following classification scheme for demand response:

   Customer classes/sectors: residential, commercial, and industrial.

   Market segments:

   1. Residential: single-family and multi-family.
   2. Commercial: education, food service, food stores, health services, office building, retail, warehouse, street lighting, and other commercial.

3. Industrial: fabricated metal products, food manufacturing, plastics and rubber products, and miscellaneous manufacturing.

End uses: central AC, central heat, cooking, cooking oven, cooking range, cooling chillers, direct expansion (DX) cooling, dryers, freezers, heat pumps, auxiliary HVAC, lighting, plug load, pool pump, commercial refrigeration, residential refrigerators, room AC, room heat, commercial space heat, street lighting, water heaters, industrial processes, and other.

2. **Screen customer segments and end uses for eligibility**. This step involved screening end uses for applicability of specific DR strategies. For example, hot water loads in hospitals were excluded (if no backup generation was available).

3. **Compile ComEd-specific sector/end-use loads**. Reliable estimates of DR potential depend on the correct characterization of sector, segment, and end-use loads. Load profiles were developed for each end use. Contributions to system peak for each end use were estimated based on end-use load shapes.

4. **Estimate technical potential**. Technical potential for each DR program is assumed to be a function of customer eligibility in each class, affected end uses in that class, and the expected impact of the strategy on the targeted end uses. Analytically, technical potential (*TP*) for a demand-response program *(s)* is calculated as the sum of impacts at the end-use level (*e*), generated in customer class (*c*), by the program; that is:

and

where,

- LE_{cs} (load eligibility) represents the percent of customer class loads that are eligible for strategy *s*,
- EUS_{cse} represents the share of end use *e* in customer class *c* eligible for DR strategy *s*, *and*
- LI_{se} (load impact) is percent reduction in end-use load *e* resulting from program *s*.

Load eligibility thresholds were established by calculating the percent of load by customer class and market segment that met minimum (or maximum) load criteria for each program, based on program filings.

Estimate Achievable Technical Potential

Estimates of expected load impacts resulting from various DR programs (LI_{se}) are based on a comprehensive review and assessment of DR program impacts offered by ComEd and other utilities throughout the United States. Program participation indicates the percent of participating customers, while event participation summarizes the percent of program participation that will participate in any one event.

Develop Supply Curves

Achievable technical potentials for each DR program strategy were combined with per-unit resource costs to produce "cumulative" resource supply curves. The supply curves show price/quantity relationships at the aggregate level. Interactive program impacts were not taken into consideration.

Program implementation costs were researched and documented by our engineering staff. All categories of costs were considered, generally falling into two categories:

1. Fixed program expenses, such as program infrastructure, administration, maintenance, and communication.
2. Variable costs, such as incentive payments to participants, customer-site hardware, customer-specific marketing/recruiting, and metering.

Summary of Resource Potential

Table 14 presents estimated resource potentials for all DR resources for the residential, commercial, and industrial sectors at peak capacity loads. Sector peak represents the average MW capacity over the time of the modeled load basis for each program. Technical potential is the sector peak times the percent of technically eligible load for each program. The achievable technical potential shows the estimate of load reduction over the load basis time period for each program at forecasted program and event participation rates. Achievable technical potential as a percent of sector load peak gives the expected capacity reductions as a result of all DR programs for ComEd.

Technical potential is highest in the residential sector due to the central AC direct load control (DLC) program. However, it has a relatively low achievable potential due to low participation in the program. In the summary table, the moderate participation scenario (10%) for residential DLC is included in the residential subtotal. Cadmus believes this higher than business-as-usual scenario is highly feasible. The residential sector also includes capacity reductions from the real time pricing program. Commercial and Industrial demand response programs include Rider VLR and Rider CLR, which continue to be successful programs for ComEd. Commercial business is the largest load sector for ComEd and has the highest achievable potential with the current programs. The industrial sector has a substantially smaller load than the residential and commercial sectors, yet has the achievable potential as a percent of sector load (10%). This is due to the success of the VLR and CLR Rider programs and the ability for industrial users to cut the most capacity use of all users. As noted previously, the analysis does not account for program interactions and overlap; thus, the actual total would be less than the sum of the individual programs.

Table 14. Technical and Achievable Technical Potential (MW in 2016)

Sector	Sector Peak	Technical Potential	Achievable Technical Potential	Achievable Technical Potential As Percent of Sector Peak
Residential	10,988	9,886	342	3%
Commercial	11,444	3,422	563	5%
Industrial	2,678	1,609	274	10%
Total	25,110	14,917	940	4%

Note: Individual results may not sum to total due to rounding.
Note: Interactions between programs have not been taken into account.

Resource Costs and Supply Curves

Utility costs for DR program options can vary significantly. Where possible, cost estimates were developed for each program option based on data available from ComEd and comparable programs across the region and nation. In certain cases, this level of specificity was difficult to establish as many utilities do not track or report program costs in sufficient detail. For example, development of a new DR program can be a significant effort for a utility, requiring enrollment, call centers, program management, load research, development of evaluation protocols, changes to billing systems, and marketing. Adding to the uncertainty is a growing number of independent contractors bidding against each other for a slice of the utilities' installation and administration budget. Background research on utilities across the nation indicated large variations in direct program costs.

In developing estimates of per-unit costs, program expenses were allocated annually over the expected program life cycle (10 years), then were discounted by ComEd's weighted average cost of capital to estimate the total discounted cost. The ratio of this value and the average annual kW reduction produced the levelized per-kW cost for each resource. Additionally, attrition rates were used to account for program turnover due to changes in electric service (i.e., housing stock turnover) and program drop-outs. The basic assumption for this analysis was an attrition rate of 3% for the residential sector and 2% for the commercial sector, based on averaged values experienced by ComEd and other utilities. Attrition requires reinvestment of new customer costs, including technology, installation, and marketing. In addition, the analysis assumed a measure life for the installed technology.

Table 15 displays the per-unit ($/kW-year) costs for the estimated achievable technical potential. Startup costs were not associated with these DR programs, as the infrastructure for them already existed.

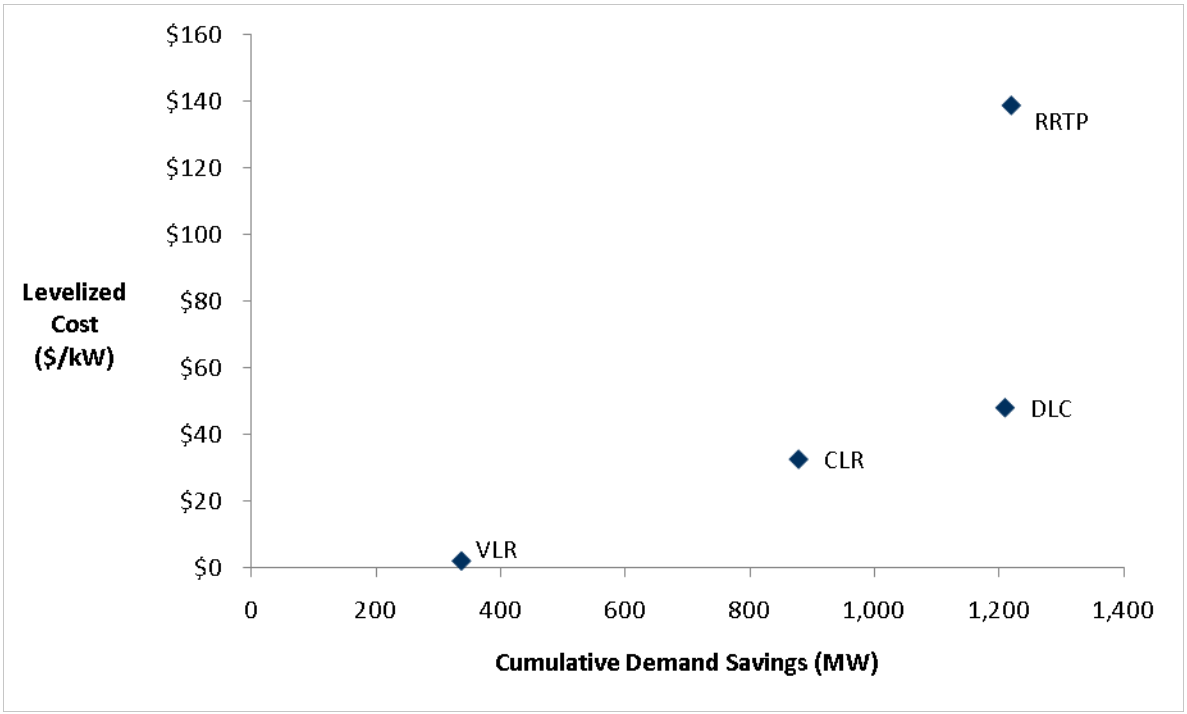
Table 15. Levelized Costs and Achievable Technical Potential (MW in 2016)

Strategy	Technical Potential (MW)	Achievable Technical Potential (MW)	Levelized Cost ($/kW)
Residential Direct Load Control	7,780	332	$48
Residential RTP	2,106	10	$139
C&I Interruptible Tarifs (CLR)	2,817	542	$33
C&I Demand Buyback (VLR)	2,212	336	$2

Note: Individual results may not sum to total due to rounding.
Note: Interactions between programs has not been taken into account.

Supply curves were constructed from quantities of estimated market resource potential and per-unit costs of each resource option. The capacity-focused supply curves, shown in Figure 27 and represent the quantity of each resource (cumulative achievable technical MW) that can be achieved at or below a given cost. Program interactions were not accounted for in this study.

Figure 27. Demand Response Supply Curve (Cumulative MW in 2016)



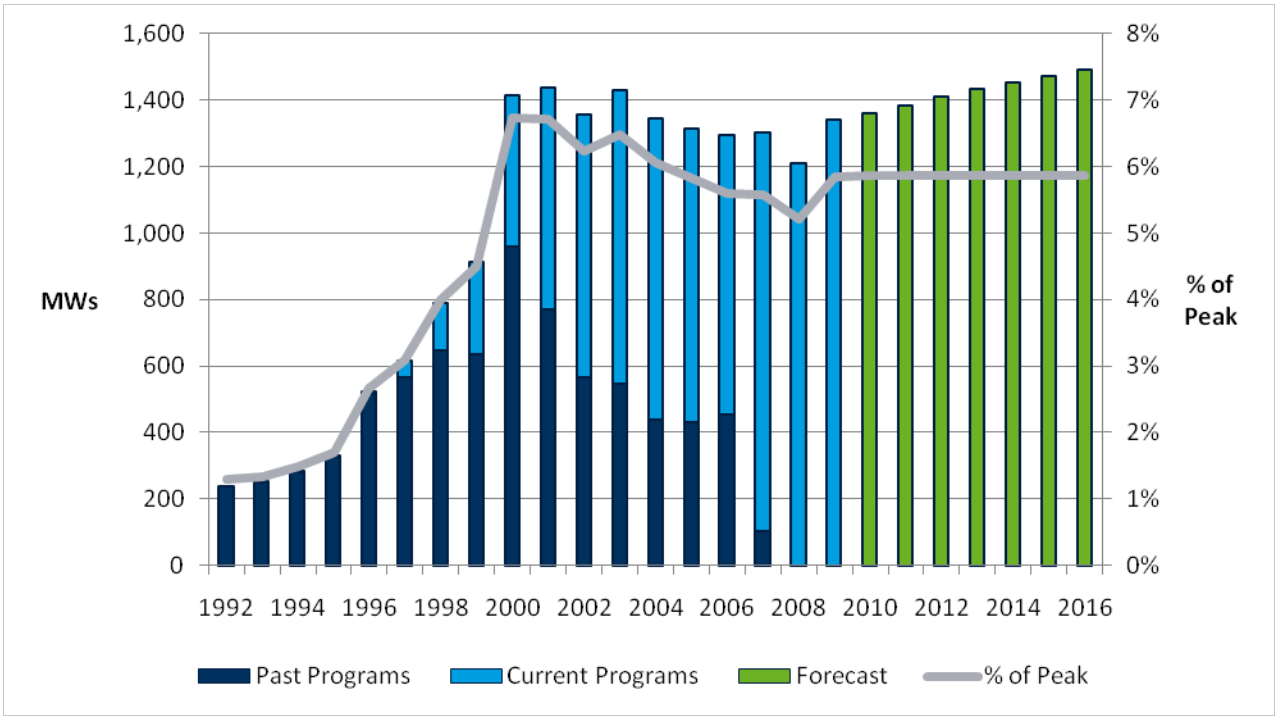
Resource Acquisition Schedule

Each program option has an associated ramping with the general logic that it requires 10 years to grow a new program from inception to full potential. The first three years have relatively slow growth; as more customers become aware of the DR programs, the participation rate will increase; finally, years nine and ten have a slow rate of increase due to the program reaching the maximum number of participating customers. After Year 10, the program levels increase at the rate of forecasted capacity growth only.

All of ComEd's programs, except for Residential RTP, have reached the 10-year saturation point and thus have assumed business-as-usual (BAU) growth matching only the sector capacity growth. The ComEd Residential RTP program, after a four-year pilot, was brought online in 2007 as a four-year program. It is assumed to have a high growth potential through 2010 with a goal of 13,000 customers. After this time, the program's marketing efforts will be reduced while a scheduled review of the program is conducted by the Illinois Commerce Commission. Due to the uncertainty in how the program will continue after the review, it is assumed by Cadmus to have small growth for the remainder of the forecast period. Due to its small relative size as a DR program, the 2010 growth in RRTP savings represents less than 1% of the total forecasted capacity reductions from DR. The bars in Figure 28 show the historical growth of all DR programs (including discontinued programs) as well as the forecasted growth of existing DR programs in megawatts of capacity. The figure also includes a line showing the percent of peak capacity that these DR programs represent. After 2009, the percentage does not increase over the forecast period due to the assumed complete saturation of enrollment in ComEd's DR programs.

Note that this business-as-usual (BAU) scenario assumes the status quo for the program offerings, the current marketing levels, and the regulatory statutes. As discussed for each program, there is still additional growth potential for many programs outside of the business-as-usual scenario. The BAU growth rate scenario is simply used as the baseline for percent penetration and capacity of ComEd's current DR programs. Upper and lower penetration scenarios that include smaller and larger program participation are discussed within each program's section.

Figure 28. DR Capacity Available for Curtailment



Detailed Resource Potentials

Direct Load Control

DLC programs are designed to interrupt specific end-use loads at customer facilities or homes through utility-directed control. When deemed necessary, the utility is authorized to cycle or shut off participating appliances or equipment for a limited number of hours on a limited number of occasions. Customers do not have to pay for the equipment or installation of control systems and are given incentives that are paid through monthly credits on their utility bills. For this type of program, receiver systems are installed on the customer's equipment to enable communications from the utility and to execute controls. Event participation is required once the participant enrolls and the receiver is installed, although malfunctioning equipment can lead to unintended non-participation.

DLC of air-conditioning has emerged as the most common load management program type. This analysis covers ComEd's existing residential AC cycling program, formerly known as Nature First and now known as Smart Ideas Central Air Conditioning Cycling. Values used in modeling have been standardized based on specific operating conditions and parameters provided by ComEd as well as general DR program research.

For the residential DLC program, two options are available to customers who choose to participate:

1. The 50% Option allows cycling off the AC unit for 15 minutes every half hour for no more than 6 hours. An incentive of $5 per month is applied to the customer's energy bill.
2. The 100% Option allows shutting off the AC unit for a continuous block of time lasting no more than 3 hours. An incentive of $10 per month is applied to the customer's energy bill.

Both options allow curtailment events on weekdays, 11am to 8pm, between June and September. Incentives are paid monthly only during the four months available for curtailment and are paid regardless of an event. All participants of the 100% option are available for curtailment at the 50% option level. For both options, receiver equipment switches are attached to the appliance, at no cost to the customer, allowing the machine to cycle or shut-off. A summary of program qualifications are presented in Table 16.

Table 16. Program Qualifications for Residential DLC Air-Conditioning Potential

Program Concept	Qualifications
Customer Sectors Eligible	Multifamily and Single Family Home Owners
End Uses Eligible for Program	Central AC (or Heat Pump)
Customer Size Requirements	N/A
Number of Events	Up to 20 Events per Year

The current program uses two types of meter equipment for communicating with the appliances. Most installed meters consist of only a one-way receiver that triggers the cycling event. A small percentage of customers have two-way communication meters installed that allow event triggering and collection of usage data from the appliance.

The first type of meter is primarily chosen by most utilities, though there is one major drawback. The utility does not receive confirmation that the appliance has actually shut off (i.e., with a one-way communication receiver no signal can be sent back to the utility to confirm the proper load control). This is, however, the least expensive approach.

The second type of meter involves additional charges: a more expensive communication receiver and a data storage charge. Although using these meters is more expensive than the one-way meter approach, two major advantages include improved reliability and future expense savings:

- Notification the equipment has shut off. Utilities have performed evaluation studies and determined not all receivers attached to appliances work properly. Using more switches with two-way communication capabilities would allow ComEd to confirm the appliance shuts off and would allow them to replace any nonfunctional receivers without having to field-test the units.
- As the two-way meter is capable of producing interval data, an evaluation study would be significantly less expensive than initiating a separate end-use load metering study, and far more reliable than relying on secondary data.

Business as Usual

Table 17 shows the estimated future technical and achievable technical potentials by customer class for ComEd's existing 50% option AC cycling program. All customers participating in the 100% option are eligible to be called on for a 50% option event and are also included in this part of the analysis. Achievable technical potential includes an 80% event participation rate based on previous reports of equipment failure rates.

Table 17. Baseline Residential DLC Air-conditioning 50% Option: Technical and Achievable Technical Potential (MW in 2016)

	Sector Peak Load Basis	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2016 Sector Peak
Multifamily	1,043.6	208.7	1.9	0.2%
Single Family	5,600.7	2,380.3	21.3	0.4%
Total	6,644.4	2,589.0	23.2	0.3%

Table 18 shows the estimated future technical and achievable technical potentials by customer class for ComEd's existing 100% option AC cycling program. About 60% of AC cycling participants are enrolled in the 100% option.

Table 18. Baseline Residential DLC Air-conditioning 100% Option: Technical and Achievable Technical Potential (MW in 2016)

	Sector Peak Load Basis	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2016 Sector Peak
Multifamily	1,046.2	418.5	5.6	0.5%
Single Family	5,614.6	4,772.4	64.1	1.1%
Total	6,660.7	5,190.9	69.8	1.0%

Additional Residential DLC Potential

ComEd's current participation rates for the residential DLC program appear low when compared to other utilities. For example, a number of utilities with mature residential DLC programs have up 20 to 30% of the eligible population in their programs, with some utilities reporting up to 50% of the eligible population. ComEd, on the other hand, currently only has about 3% of the eligible population in the program.[18]

Two additional scenarios, therefore, were run in order to examine the potential if program market penetration were increased. A program enrollment of a typical DLC program would be closer to 10% and a higher end successful program can reach 25% of market potential. If marketing efforts were increased and these market penetration percentages were achieved, ComEd's potential savings could be closer to those shown in Table 19. The table combines both multifamily and single family with the same participation rates. The number of customers enrolled in the program must increase over time to meet the same MW reductions due to the increasing efficiency standards of air conditioning units. Based on forecasted federal averages, the savings from each AC unit will have likely decreased by 20 percent in 2016. Note that participation percentages are measured in percent of eligible megawatts, not number of eligible participants.

Table 19. Potential Residential DLC Air-conditioning: Technical and Achievable Technical Potential (MW in 2016)

	Program Participation	Thousands of Customers	Achievable Technical Potential	Achievable Technical Potential as % of 2016 Sector Peak
Baseline	2.8%	80	93	1.4%
Medium	10%	285	332	5.0%
High	25%	713	830	12.5%

Program Cost

Annual levelized program costs to achieve the baseline savings of 93 MW in 2016 (23.2 MW from 50% Option and 69.8 MW from 100% Option) are $4.7 million dollars. This equates to $48 per kilowatt savings over the forecast period. This includes replacing customers who drop out and growing the customer base to meet forecasted reduction goals. A detailed list of cost and program assumptions is shown in Appendix F.

Real-Time Pricing (RTP)

Generally, under RTP programs, electricity prices vary each hour according to the expected marginal cost of supply and are typically established one day ahead of the time the prices are in effect. RTP programs utilize electricity wholesale prices, which change throughout the day.

[18] ComEd currently serves about 3.3 million residential customers. Based on the RASS, approximately 54% of customers (1.8 million) own their home and have a central AC or heat pump that only serves their unit, and thus qualify for the program. The current program, however, only has about 60,300 participants.

Programs can vary in how they notify customers of expected prices and can utilize day-ahead or hour-ahead price forecasts. Notification of the forecasted price schedule can occur via the Internet, text (SMS) messages, phone, or special technology-enabled devices (Internet- or radio-based devices).

ComEd's Residential RTP program uses a website to post day-ahead prices and real time hourly prices from the PJM ISO. Customers have the option to be notified via email, text (SMS) message, or automated phone call when day-ahead or real-time prices reach a threshold value selected by the customer (10 or 14 cents per kWh). While day-ahead prices can be used to plan the next day's energy use in the home, customers must pay the real time day-of hourly price which may differ.

A commonly cited reason for utilities introducing RTP is to build customer satisfaction and loyalty by providing an opportunity for customers to realize bill savings. Some programs incorporate a two-part rate, where only the difference in actual versus expected usage is subject to real-time prices. Additionally, programs can include price protection that enables RTP customers to manage their exposure to volatile prices. Many newer programs have unbundled the electricity commodity from transmission and distribution services, and the electricity component is priced according to hourly energy prices.

At this point, residential RTP is not widely implemented by utilities. In 2006, the state of Illinois was the first to pass legislation requiring large investor-owned utilities to offer residential RTP to all customers. After a four year pilot program, ComEd launched their first full-scale program in the spring of 2007. One important thing to note in RTP programs is, while a few programs have been very successful, it can be difficult to attract participants. Unfamiliar billing, a 12 month contract, the requirement to micro-manage energy use, an extra metering fee, and no guarantee of bill savings can dissuade residential customers from enrolling. ComEd's program is open to all individually metered residential customers, but only 8,244 are enrolled and 7,653 were actively participating at the end of the 2009 year (about 0.2% of households).

An interesting component of the ComEd RTP program is the option for customers to link their AC cycling with real time electricity prices. Customers who are enrolled in both the ComEd Residential DLC program and ComEd Residential RTP can combine the two to potentially increase savings even further. Called the Load Guard Automated Price Response Service, customers choose an hourly price (10 or 14 cents per kWh) for which their AC units cycle off and on. The AC unit will cycle every fifteen minutes for a two-hour period when the price trigger notifies the AC switch. While very few customers (around 670) have enrolled in this combo option, it has the greatest potential for reducing load with the least amount of customer micro-management. Since the same incentives are paid to DLC AC cycling customers as customers with Load Guard, no additional incentive costs are incurred by the utility but the capacity load is reduced much more significantly than with DLC AC cycling events alone. For comparison, the DLC AC cycling program has averaged 1.1 events per summer, while the Load Guard program has averaged over 137 events per summer for the 10 cent option and 42 events for the 14 cent option. Because of the program's greater ability to give more measurable results, the potential reductions for this specific Load Guard program is included below.

A summary of program qualifications for the Residential RTP Program with and without Load Guard are presented in Table 20 and Table 21.

Table 20. Program Qualifications for Residential RTP

Program Concept	Qualification
Customer Sectors Eligible	All Residential Customers
End Uses Eligible for Program	Total Load of All End Uses
Customer Size Requirements	None
Number of Events	N/A

Table 21. Program Qualifications for Residential RTP with Load Guard

Program Concept	Qualification
Customer Sectors Eligible	Multifamily and Single Family Home Owners
End Uses Eligible for Program	Central AC (or Heat Pump)
Customer Size Requirements	None
Number of Events	Up to 120 Hours per Year

Currently, 5.0 MW of potential capacity are enrolled in ComEd's Residential RTP program. About 9% of this load is enrolled in the Load Guard program, or 0.45 MW. At our assumed capacity growth rate for this program (as described in the Resource Acquisition Schedule section of this report), a potential of 8.6 MW Residential RTP capacity and 0.9 kW Load Guard capacity is achievable by 2016. Using the same efficiency gain assumptions as described for the DLC program, this equals about 1,180 customers enrolled in Load Guard and 14,440 enrolled overall. Table 22 shows there is 3,003.6 MW of technical potential for ComEd's RRTP program, with 9.5 MW of market potential.

Table 22. Residential RTP Load Guard: Technical and Market Potential (MW in 2016)

	Sector Peak Load Basis	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2016 Sector Peak
Load Guard	5,404.0	2,105.7	0.9	<0.1%
RRTP w/o Load Guard	5,404.0	3,003.6	8.6	0.2%
Total	5,404.0	3,003.6	9.5	0.2%

Program Cost

High administration, marketing and contractor costs, coupled with low growth assumptions for the program, have caused a high levelized cost. The annual levelized cost was calculated at a rate of $139/kW for ComEd's Residential RTP program. This includes the Load Guard customers as well as regular RRTP participants without Load Guard. A detailed list of cost and program assumptions is shown in Appendix F.

Interruptible Loads (Capacity-Based Load Response)

Interruptible load response (ILR) programs refer to contractual arrangements between the utility and its customers, typically nonresidential customers who agree to curtail or interrupt their operations, in whole or part, for a predetermined period when requested by the utility. In most

cases, mandatory participation or liquidated damage agreements are required once the customer enrolls in the program; however, the number of curtailment requests, both in total and on a daily basis, is limited by the terms of the contracts. ComEd's program is known as Rider CLR7 or Capacity-Based Load Response (CLR). Any commercial or industrial customer who can commit 100 kW or more of load reduction at the time of an event is eligible for the program. While this program has historically had many incarnations, going forward it will fall under the PJM ISO guidelines of a PJM Capacity-Based Load Response program.

Customers who choose to enroll are paid for their participation in individual events at the rate of their load reduction from their typical operating conditions multiplied by the market price of the avoided capacity. These rates can vary per depending on the market and the customer's specific CLR contract. Contracts require customers to curtail their connected load by a set wattage (e.g., reduce total load by 100 kW) or a predetermined level (e.g., reduce load to 900 kW), depending on the contract. Additional reductions beyond the contracted value will not receive compensation. Customers who fail to reduce their load when an event is called are responsible for any penalties or other economic consequences assessed by PJM or ComEd.

In this study, it is assumed nonresidential customers with a monthly demand of at least 200 kW for industrial users and 400 kW for commercial users would be technically eligible for such a program. General program qualifications for CLR program eligibility are shown in Table 23.

Table 23. Program Qualifications for Interruptible Nonresidential Potential (CLR)

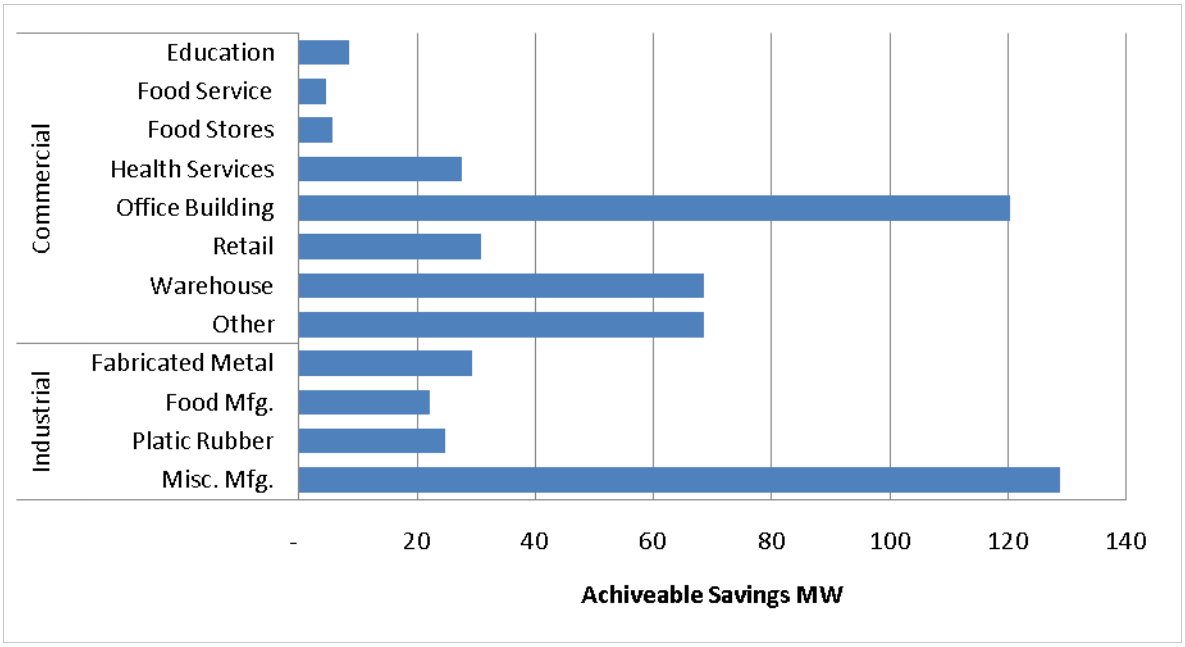
Program Name	Assumptions
Customer Sectors Eligible	Nonresidential
End Uses Eligible for Program	Total Load of All End Uses
Customer Size Requirements	Ability to reduce 100 kW or more
Event Timing	Up to 15 Events per Year (10 PJM + 5 ComEd)

In 2009, ComEd reported a total of 433 MW of available capacity in the CLR Program. Assuming program growth will follow forecasted nonresidential load growth, in 2016 there will be an estimated 2,817 MW of technical potential and 542 MW of achievable technical potential in 2016, totaling 4.7% of ComEd's 2016 nonresidential peak load (Table 24). This potential is largely in office buildings (120 MW) and manufacturing facilities (129 MW) (Figure 29). This is based on a one time, two hour event (much like a performance test audit event).

Table 24. CLR Technical and Achievable Technical Potential (MW in 2016)

	Sector Peak Load Basis	Technical Potential	Achievable Technical Potential	Achievable Technical Potential as % of 2016 Sector Peak
Commercial	6,863	1,718	336	3.0%
Industrial	2,203	1,101	206	7.6%
Total	9,066	2,817	542	4.7%

Figure 29. CLR Achievable Technical Potential by Sector (MW in 2016)



Uncertainty Regarding CLR Potential

It is important to know that in addition to ComEd, private curtailment service providers (CSPs) also offer incentives for ILR programs. In September 2009, there were a number of CSPs (including ComEd) serving the ComEd service territory with a reported 1,553 MW of unique available capacity.

ComEd's ILR program incentives are based on the PJM Base Residual Auction (BRA) capacity market. A PJM system-wide auction is held annually in which additional load capacity is submitted and chosen by PJM. The bidders, which include utilities and private CSPs, can place capacity on the market out three years, with the most recent auctions going out to 2012/2013. For a number of reasons, including the variety and volume of capacity providers, as well as the shift of old ILR programs into the market, the clearing price of this capacity can change through the auction period and will be unknown past that period. The latest auction included a much higher supply to the market than previous years due partly to new capacity from DR and EE resources coupled with the elimination of the old ILR alternative. This increased supply and decreased demand from preliminary peak load forecasts caused a dramatic drop in the BRA price, from $93.54/MW-day for 2011/2012 to $16.64/MW-day for 2012/2013. Cadmus believes this price will recover in future years as supply comes in line with demand.

This makes incentive levels for ComEd's customer variable over the forecast period, and Cadmus has done its best to use reasonable target numbers for future incentive pricing. The result of the auctions will determine future participation and returns of the program across PJM, ComEd's territory, and the number of customers who use ComEd as their curtailment service provider. It is possible that as incentives decrease (as seen in the 2012/2013 auction) privately-held CSPs will find less profit in managing ILR programs, and customers will select ComEd as their curtailment service provider. Forecasting future PJM prices, and the impacts of this price elasticity, are outside the scope of this project, and ComEd participation is assumed to follow forecasted load growth for nonresidential customers going forward.

Program Cost

The nominal levelized per year of continuing this program over the forecast period is expected to be about $15.9 million for a savings of 542 MW. This equates to approximately $33 per kilowatt peak load reduction. A detailed list of cost and program assumptions is shown in Appendix F.

Demand Buyback (Voluntary Load Response)

Under demand buyback (DBB) or demand bidding arrangements, the utility offers payments to customers for reducing demand when requested by the utility. Under these programs, customers remain on a standard rate, but they are presented with options to bid or propose load reductions in response to utility requests. The buyback amount generally depends on market prices published by the utility ahead of the curtailment event, and the reduction level is verified against an agreed-upon baseline usage level. At ComEd, the Rider VLR7, or Voluntary Load Response, most closely resembles a DBB program.

DBB is a mechanism enabling consumers to actively participate in electricity trading by offering to undertake changes in their normal consumption patterns. Participation requires the flexibility to make changes to their normal electricity demand profile, install the necessary control and monitoring technology to execute the bids, and demonstrate bid delivery. One of several Internet-based programs is generally used to disseminate information on buyback rates to potential customers, who can then take the appropriate actions to manage their peak loads during requested events. The ComEd program option in this analysis targets a wide range of small to large commercial and industrial customers. As a broad cut-off, Cadmus uses a minimum of 50 kW peak capacity per customer to use in the model.

Unlike curtailment programs, customers have the option to curtail power requirements on an event-by-event basis. Incentives are paid to participants for energy reduced during each event, based primarily on the difference between market prices and utility rates. In many ways, ComEd's VLR program is much like its CLR program but with less stringent requirements and load response contracts.

Compared with most other utilities, ComEd has a low minimum load reduction criterion of 10 kW. Consequently perhaps, program participation has been much higher than in other areas of the country. Their VLR program participants account for about 3.5% of its peak demand, while most other utilities are estimated to be less than one percent. Of course, participation in these programs is highly effected by market energy prices and can fluctuate from year to year. General program qualifications for eligibility are shown in Table 25.

Table 25. Program Qualifications for DBB (VLR) Potential

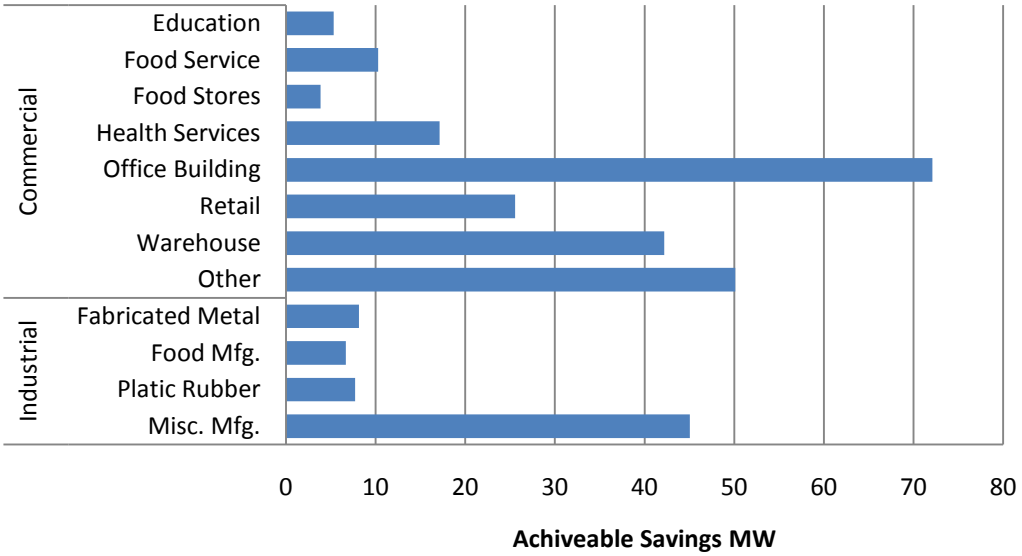
Program Name	Assumptions
Customer Sectors Eligible	All Non-Residential Market Segments
End Uses Eligible for Program	Total Load of All End Uses
Customer Size Requirements	Ability to reduce 10 kW or more
Number of Events	Unlimited Number of Events (1 to 8 hours each)

Table 26 shows that at peak demand, about 294 MW of achievable technical potential can be expected during a six-hour event call in 2016. This assumes a participation rate of 38% based on the most recent event call in 2006. It is assumed that close to 800 MW of capacity is on the enrollment sheets but most will not participate in the event.

Table 26. Demand Buyback (VLR): Technical and Achievable Technical Potential (MW in 2016)

	Sector Peak Load Basis	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2016 Peak
Commercial	10,802	1,704	227	2.1%
Industrial	2,730	508	68	2.5%
Total	13,532	2,212	294	2.2%

Figure 30. Demand Buyback (VLR): Achievable Technical Potential by Sector (MW in 2016)



Program Cost

Because participants are paid based on market energy rates and minimal administration costs are incurred, this program's total cost is lower than most DR programs. At an estimated levelized cost of $2/kW-year, this is ComEd's most cost effective program. New customer costs include hardware, marketing and program administration and all are relatively low. New participant costs must be reinvested due to a 2% annual attrition rates and a hardware life of 10 years. Incentives are paid based on real time electricity pricing and can vary greatly throughout the year and the forecast period. A detailed list of cost and program assumptions is shown in Appendix F.

Appendix C-2 - Energy Efficiency Analysis Summary

Program	Target Market	Number of Units	Busbar MWh	At-the-Meter MWh	Program Cost	TRC Test	Utility Cost Test (UCT) (Discount Rate = 0)	Cost of Conserved Energy ("CCE") [$/kWh]	Program Description
A	B	C	D	E	F	G	H	I	J
ComEd Programs				-					
Energy Efficient Lighting	Residential	1.8M bulbs installed	53,072	48,654	$ 7,522,617	1.05	1.07	$ 0.0400	A current portfolio element. Takes into account a reduction in kWh savings to 100W & 75W bulbs due to EISA, an incentive budget increase by $5M dollars and bulb levels were moved back to PY4 goals
Fridge & Freezer Rycycle Rewards ("FFRR")	Residential	10,000 additional participants	9,403	8,620	$ 2,534,671	1.02	1.16	$ 0.0494	A current portfolio element. Expanding the existing appliance recycling program by increasing the marketing effort is expected to increase participation by 25%.
Multi-Family Common Area Lighting	Small Commercial	3,400 bldgs	19,216	17,616	$ 3,000,000	1.03	1.48	$ 0.0300	Current portfolio element modification. Direct install into MF common areas. This would be a new element for the portfolio and a joint program with the gas company. Assume revisiting previous and new buildings. Program designed around ECW Study: Energy Efficiency and Customer Sited Renewable Energy: Achievable Potential Wisconsin 2006-2015 (Multifamily Common Area Lighting Program)
Small Business Direct Install	Small Commercial	24,000 sites	78,015	71,521	$ 19,503,901	1.78	2.98	$ 0.0300	A current portfolio element. Assumes offering current retrofit portion to customers as an additional free element. Perhaps a few new measures will be added. Assumes 24,000 customers @ an avg energy savings of 5,000 kWh per
Total - ComEd Programs			**159,706**	**146,412**	**32,561,189**				
Third Party Programs *(Vendor listed)*				-					
CSG	Residential	1000 homes	3,806	3,489	$ 807,417	1.01	2.54	$ 0.0236	All-Electric Single Family Retrofit Program
OneChange	Residential	25,000 Participants	7,117	6,525	$ 487,750	4.60	4.96	$ 0.0109	Door-to-door direct provision of free CFL's in low-income neighborhoods
Shelton Solutions	Residential	1000 Participants	1,091	1,000	$ 215,000	1.32	1.44	$ 0.0401	Faith-based behavioral program
Willdan Energy Solutions	Small Commercial (schools)	63 Sites	2,033	1,864	$ 801,328	2.80	3.87	$ 0.0200	Direct Install of measures in schools, coupled with education program.
Total - Third Party Programs			**14,047**	**12,878**	**$ 2,311,495**				
Combined Total			**173,753**	**159,290**	**$ 34,872,684**				
Total Passing UCT(0)			**173,753**	**159,290**	**$ 34,872,684**				

Appendix C-3 3rd Revision - Energy Efficiency Monthly Savings Curves (by program)									
MWh by Program - Total Savings by Month									
	ResLtg	MF_CAL	SmallBiz	FFRR	CSG	OneChange	Shelton	Willdan	Total
Annualized	53,072	19,216	78,015	9,403	3,806	7,117	1,091	2,033	173,753
Jun-13	145	-	-	64	26	49	7	-	292
Jul-13	337	-	-	133	54	101	15	-	640
Aug-13	732	-	-	200	81	151	23	-	1,187
Sep-13	1,371	158	641	258	104	195	30	17	2,774
Oct-13	2,352	326	1,325	333	135	252	39	35	4,796
Nov-13	3,257	474	1,924	386	156	292	45	50	6,585
Dec-13	4,211	653	2,650	466	189	353	54	69	8,644
Jan-14	4,644	816	3,313	532	215	403	62	86	10,072
Feb-14	4,127	884	3,591	541	219	409	63	94	9,928
Mar-14	4,011	1,142	4,638	666	269	504	77	121	11,428
Apr-14	3,030	1,342	5,450	708	287	536	82	142	11,579
May-14	2,315	1,632	6,626	799	323	604	93	173	12,565
Jun-14	1,744	1,579	6,412	773	313	585	90	167	11,663
Jul-14	2,022	1,632	6,626	799	323	604	93	173	12,272
Aug-14	2,929	1,632	6,626	799	323	604	93	173	13,179
Sep-14	4,114	1,579	6,412	773	313	585	90	167	14,033
Oct-14	5,644	1,632	6,626	799	323	604	93	173	15,893
Nov-14	6,515	1,579	6,412	773	313	585	90	167	16,434
Dec-14	7,218	1,632	6,626	799	323	604	93	173	17,468
Jan-15	6,966	1,632	6,626	799	323	604	93	173	17,216
Feb-15	5,503	1,474	5,985	721	292	546	84	156	14,761
Mar-15	4,813	1,632	6,626	799	323	604	93	173	15,062
Apr-15	3,306	1,579	6,412	773	313	585	90	167	13,225
May-15	2,315	1,632	6,626	799	323	604	93	173	12,565
Jun-15	1,744	1,579	6,412	773	313	585	90	167	11,663
Jul-15	2,022	1,632	6,626	799	323	604	93	173	12,272
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Dec-15	7,218	1,632	6,626	799	323	604	93	173	17,468
Jan-16	6,966	1,632	6,626	799	323	604	93	173	17,216
Feb-16	5,503	1,474	5,985	721	292	546	84	156	14,761
Mar-16	4,813	1,632	6,626	799	323	604	93	173	15,062
Apr-16	3,306	1,579	6,412	773	313	585	90	167	13,225
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Dec-16	7,218	1,632	6,626	799	323	604	93	173	17,468
Jan-17	6,966	1,632	6,626	799	323	604	93	173	17,216
Feb-17	5,699	1,527	6,198	747	302	565	87	162	15,288
Mar-17	4,813	1,632	6,626	799	323	604	93	173	15,062
Apr-17	3,306	1,579	6,412	773	313	585	90	167	13,225
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Dec-17	7,218	1,632	6,626	799	323	604	93	173	17,468
Jan-18	6,966	1,632	6,626	799	323	604	93	173	17,216
Feb-18	5,503	1,474	5,985	721	292	546	84	156	14,761
Mar-18	4,813	1,632	6,626	799	323	604	93	173	15,062
Apr-18	3,306	1,579	6,412	773	313	585	90	167	13,225
May-18	2,315	1,632	6,626	799	323	604	93	173	12,565
Jun-18	1,744	1,579	6,412	773	313	585	90	167	11,663
Jul-18	2,022	1,632	6,626	799	323	604	93	173	12,272
Aug-18	2,929	1,632	6,626	799	323	604	93	173	13,179
Sep-18	4,114	1,579	6,412	773	313	585	90	167	14,033
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Nov-18	6,515	1,579	6,412	773	313	585	90	167	16,434
Dec-18	7,218	1,632	6,626	799	323	604	93	173	17,468
Jan-19	6,966	1,632	6,626	799	323	604	93	173	17,216
Feb-19	5,503	1,474	5,985	721	292	546	84	156	14,761
Mar-19	4,813	1,632	6,626	799	323	604	93	173	15,062
Apr-19	3,306	1,579	6,412	773	313	585	90	167	13,225
May-19	2,315	1,632	6,626	799	323	604	93	173	12,565

	MWh by Program - Total Savings for IPA-bundled by Month								
	ResLtg	MF_CAL	SmallBiz	FFRR	CSG	OneChange	Shelton	Willdan	Total
Jun-13	44	-	-	19	8	15	2	-	88
Jul-13	101	-	-	40	16	30	5	-	192
Aug-13	220	-	-	60	24	45	7	-	356
Sep-13	411	41	166	77	31	58	9	4	799
Oct-13	705	85	343	100	40	76	12	9	1,370
Nov-13	977	123	498	116	47	88	13	13	1,875
Dec-13	1,263	169	686	140	57	106	16	18	2,455
Jan-14	1,393	211	858	160	65	121	19	22	2,849
Feb-14	1,238	229	930	162	66	123	19	24	2,791
Mar-14	1,203	296	1,201	200	81	151	23	31	3,186
Apr-14	909	348	1,412	213	86	161	25	37	3,189
May-14	694	423	1,716	240	97	181	28	45	3,424
Jun-14	478	305	1,238	232	94	175	27	43	2,592
Jul-14	554	315	1,279	240	97	181	28	45	2,738
Aug-14	803	315	1,279	219	89	166	25	33	2,928
Sep-14	1,127	305	1,238	212	86	160	25	32	3,184
Oct-14	1,546	315	1,279	219	89	166	25	33	3,672
Nov-14	1,785	305	1,238	212	86	160	25	32	3,842
Dec-14	1,978	315	1,279	219	89	166	25	33	4,103
Jan-15	1,909	315	1,279	219	89	166	25	33	4,034
Feb-15	1,508	285	1,155	198	80	150	23	30	3,428
Mar-15	1,319	315	1,279	219	89	166	25	33	3,444
Apr-15	906	305	1,238	212	86	160	25	32	2,963
May-15	634	315	1,279	219	89	166	25	33	2,760
Jun-15	453	251	1,020	201	81	152	23	27	2,208
Jul-15	526	259	1,054	208	84	157	24	27	2,339
Aug-15	762	259	1,054	208	84	157	24	27	2,575
Sep-15	1,070	251	1,020	201	81	152	23	27	2,825
Oct-15	1,467	259	1,054	208	84	157	24	27	3,281
Nov-15	1,694	251	1,020	201	81	152	23	27	3,449
Dec-15	1,877	259	1,054	208	84	157	24	27	3,690
Jan-16	1,811	259	1,054	208	84	157	24	27	3,625
Feb-16	1,431	234	952	188	76	142	22	25	3,069
Mar-16	1,251	259	1,054	208	84	157	24	27	3,065
Apr-16	859	251	1,020	201	81	152	23	27	2,614
May-16	602	259	1,054	208	84	157	24	27	2,415

Jun-16	438	224	911	194	79	147	23	24	2,038
Jul-16	508	232	941	200	81	152	23	25	2,161
Aug-16	735	232	941	200	81	152	23	25	2,389
Sep-16	1,033	224	911	194	79	147	23	24	2,633
Oct-16	1,417	232	941	200	81	152	23	25	3,070
Nov-16	1,635	224	911	194	79	147	23	24	3,236
Dec-16	1,812	232	941	200	81	152	23	25	3,465
Jan-17	1,749	232	941	200	81	152	23	25	3,402
Feb-17	1,431	217	880	188	76	142	22	23	2,978
Mar-17	1,208	232	941	200	81	152	23	25	2,862
Apr-17	830	224	911	194	79	147	23	24	2,430
May-17	581	232	941	200	81	152	23	25	2,235
Jun-17	429	205	834	190	77	144	22	22	1,923
Jul-17	497	212	861	196	80	149	23	22	2,041
Aug-17	721	212	861	196	80	149	23	22	2,264
Sep-17	1,012	205	834	190	77	144	22	22	2,506
Oct-17	1,388	212	861	196	80	149	23	22	2,932
Nov-17	1,603	205	834	190	77	144	22	22	3,096
Dec-17	1,776	212	861	196	80	149	23	22	3,319
Jan-18	1,714	212	861	196	80	149	23	22	3,257
Feb-18	1,354	192	778	177	72	134	21	20	2,748
Mar-18	1,184	212	861	196	80	149	23	22	2,727
Apr-18	813	205	834	190	77	144	22	22	2,307
May-18	569	212	861	196	80	149	23	22	2,113
Jun-18	420	188	763	186	75	141	22	20	1,815
Jul-18	487	194	788	192	78	146	22	21	1,929
Aug-18	706	194	788	192	78	146	22	21	2,147
Sep-18	992	188	763	186	75	141	22	20	2,387
Oct-18	1,360	194	788	192	78	146	22	21	2,802
Nov-18	1,570	188	763	186	75	141	22	20	2,965
Dec-18	1,740	194	788	192	78	146	22	21	3,181
Jan-19	1,679	194	788	192	78	146	22	21	3,121
Feb-19	1,326	175	712	174	70	132	20	19	2,628
Mar-19	1,160	194	788	192	78	146	22	21	2,601
Apr-19	797	188	763	186	75	141	22	20	2,192
May-19	558	194	788	192	78	146	22	21	2,000

MWh by Program – Total Savings for IPA-bundled by Year

	ResLtg	MF_CAL	SmallBiz	FFRR	CSG	OneChange	Shelton	Willdan	Total
Jun-13 to May-14	9,160	1,924	7,811	1,526	618	1,155	177	204	22,574
Jun-14 to May-15	14,546	3,709	15,057	2,617	1,059	1,981	304	415	39,688
Jun-15 to May-16	13,803	3,055	12,404	2,445	990	1,850	284	323	35,154
Jun-16 to May-17	13,375	2,736	11,108	2,367	958	1,791	275	289	32,899
Jun-17 to May-18	13,060	2,498	10,142	2,313	936	1,751	268	264	31,233
Jun-18 to May-19	12,794	2,287	9,284	2,266	917	1,715	263	242	29,768

Month	On-Peak Volumes (MW)						
	Expected Load Forecast (MW)	2011 Procurement (MW)	2012 Procurement (MW)	Long-Term Renewables Procurement (MW)	Rate Stability Procurement (MW)	Residual Volumes (MW)	2013 Procurement (MW) [1]
Jun-13	1,749	1,800	0	99	450	-600	0
Jul-13	2,042	2,250	0	59	450	-717	0
Aug-13	1,880	2,100	0	63	450	-733	0
Sep-13	1,406	1,300	0	92	450	-436	0
Oct-13	1,241	1,350	0	150	450	-709	0
Nov-13	1,364	1,450	0	187	450	-723	0
Dec-13	1,586	1,750	0	155	450	-769	0
Jan-14	1,594	1,500	0	164	450	-520	0
Feb-14	1,450	1,600	0	152	450	-752	0
Mar-14	1,284	1,400	0	174	450	-740	0
Apr-14	1,134	1,300	0	188	450	-804	0
May-14	1,147	1,350	0	196	450	-849	0
Jun-14	1,525	0	150	94	450	831	350
Jul-14	1,827	0	300	59	450	1,018	450
Aug-14	1,684	0	200	66	450	968	450
Sep-14	1,267	0	0	87	450	730	350
Oct-14	1,109	0	0	150	450	509	200
Nov-14	1,230	0	0	197	450	583	200
Dec-14	1,461	0	100	148	450	763	300
Jan-15	1,468	0	100	172	450	746	300
Feb-15	1,341	0	50	152	450	689	300
Mar-15	1,188	0	0	166	450	572	200
Apr-15	1,039	0	0	188	450	401	100
May-15	1,048	0	0	206	450	392	100
Jun-15	1,417	0	0	94	450	873	0
Jul-15	1,709	0	0	59	450	1,200	100
Aug-15	1,575	0	0	66	450	1,059	50
Sep-15	1,184	0	0	87	450	647	0
Oct-15	1,025	0	0	150	450	425	0
Nov-15	1,154	0	0	197	450	507	0
Dec-15	1,378	0	0	148	450	780	0
Jan-16	1,389	0	0	172	450	767	0
Feb-16	1,282	0	0	152	450	680	0
Mar-16	1,133	0	0	166	450	517	0
Apr-16	983	0	0	188	450	345	0
May-16	1,006	0	0	206	450	350	0
Jun-16	1,371	0	0	94	450	827	0
Jul-16	1,650	0	0	59	450	1,141	0
Aug-16	1,541	0	0	66	450	1,025	0
Sep-16	1,135	0	0	87	450	598	0
Oct-16	992	0	0	150	450	392	0
Nov-16	1,127	0	0	197	450	480	0
Dec-16	1,345	0	0	148	450	747	0
Jan-17	1,360	0	0	172	450	738	0
Feb-17	1,241	0	0	152	450	639	0
Mar-17	1,102	0	0	166	450	486	0
Apr-17	955	0	0	188	450	317	0

May-17	985	0	0	206	450	329	0
Jun-17	1,346	0	0	94	450	802	0
Jul-17	1,617	0	0	59	450	1,108	0
Aug-17	1,504	0	0	66	450	988	0
Sep-17	1,103	0	0	87	450	566	0
Oct-17	970	0	0	150	450	370	0
Nov-17	1,102	0	0	197	450	455	0
Dec-17	1,309	0	0	148	450	711	0
Jan-18	1,331	0	0	172	0	1,159	0
Feb-18	1,208	0	0	152	0	1,056	0
Mar-18	1,071	0	0	166	0	905	0
Apr-18	934	0	0	188	0	746	0
May-18	961	0	0	206	0	755	0

1. Assumes procurement stategy of procuring 30% of requirements in the procurement immediately prior to the delivery period, 35% one year earlier, and 35% two years earlier.

Month	Off-Peak Volumes (MW)						
	Expected Load Forecast (MW)	2011 Procurement (MW)	2012 Procurement (MW)	Long-Term Renewables Procurement (MW)	Rate Stability Procurement (MW)	Residual Volumes (MW)	2013 Procurement (MW) [1]
Jun-13	1,406	1,250	0	102	450	-396	0
Jul-13	1,623	1,800	0	83	450	-710	0
Aug-13	1,499	1,650	0	105	450	-706	0
Sep-13	1,139	1,050	0	101	450	-462	0
Oct-13	1,016	1,100	0	180	450	-714	0
Nov-13	1,159	1,250	0	196	450	-737	0
Dec-13	1,372	1,250	0	146	450	-474	0
Jan-14	1,391	1,300	0	180	450	-539	0
Feb-14	1,277	1,400	0	167	450	-740	0
Mar-14	1,124	1,250	0	194	450	-770	0
Apr-14	963	1,100	0	205	450	-792	0
May-14	960	1,100	0	162	450	-752	0
Jun-14	1,236	0	0	106	450	680	300
Jul-14	1,459	0	100	83	450	826	400
Aug-14	1,359	0	50	101	450	758	350
Sep-14	1,025	0	0	105	450	470	150
Oct-14	916	0	0	180	450	286	0
Nov-14	1,058	0	0	188	450	420	100
Dec-14	1,273	0	0	152	450	671	300
Jan-15	1,292	0	0	173	450	669	300
Feb-15	1,182	0	0	167	450	565	200
Mar-15	1,043	0	0	202	450	391	100
Apr-15	893	0	0	205	450	238	0
May-15	891	0	0	156	450	285	0
Jun-15	1,156	0	0	106	450	600	0
Jul-15	1,369	0	0	83	450	836	0
Aug-15	1,285	0	0	101	450	734	0
Sep-15	964	0	0	105	450	409	0
Oct-15	857	0	0	180	450	227	0
Nov-15	995	0	0	188	450	357	0
Dec-15	1,200	0	0	152	450	598	0
Jan-16	1,226	0	0	173	450	603	0
Feb-16	1,129	0	0	167	450	512	0
Mar-16	998	0	0	202	450	346	0
Apr-16	852	0	0	205	450	197	0
May-16	851	0	0	156	450	245	0
Jun-16	1,103	0	0	106	450	547	0
Jul-16	1,340	0	0	83	450	807	0
Aug-16	1,231	0	0	101	450	680	0
Sep-16	942	0	0	105	450	387	0
Oct-16	831	0	0	180	450	201	0
Nov-16	974	0	0	188	450	336	0
Dec-16	1,176	0	0	152	450	574	0
Jan-17	1,205	0	0	173	450	582	0

Feb-17	1,102	0	0	167	450	485	0
Mar-17	978	0	0	202	450	326	0
Apr-17	828	0	0	205	450	173	0
May-17	830	0	0	156	450	224	0
Jun-17	1,076	0	0	106	450	520	0
Jul-17	1,315	0	0	83	450	782	0
Aug-17	1,210	0	0	101	450	659	0
Sep-17	919	0	0	105	450	364	0
Oct-17	810	0	0	180	450	180	0
Nov-17	947	0	0	188	450	309	0
Dec-17	1,150	0	0	152	450	548	0
Jan-18	1,181	0	0	173	0	1,008	0
Feb-18	1,079	0	0	167	0	912	0
Mar-18	952	0	0	202	0	750	0
Apr-18	806	0	0	205	0	601	0
May-18	807	0	0	156	0	651	0

1. Assumes procurement stategy of procuring 30% of requirements in the procurement immediately prior to the delivery period, 35% one year earlier, and 35% two years earlier.

ComEd Procurement Period Load Forecast
(Base Case with Additional IPA EE Savings)
Projected Energy Usage and Average Demand For Eligible Retail Customers
(Weather Normal, Line Loss and DSM Adjusted)

		Total Load (MWh)		Average Load (MW)	
Year	**Month**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**
2013	6	559,705	562,207	1,749	1,406
2013	7	718,656	636,032	2,042	1,623
2013	8	661,424	587,622	1,879	1,499
2013	9	449,387	455,020	1,404	1,138
2013	10	455,841	381,240	1,239	1,014
2013	11	435,427	462,493	1,361	1,156
2013	12	531,660	558,434	1,582	1,369
2014	1	559,552	543,843	1,590	1,387
2014	2	462,412	448,207	1,445	1,273
2014	3	429,992	456,964	1,280	1,120
2014	4	397,230	352,988	1,128	959
2014	5	383,511	390,187	1,141	956
2014	6	511,132	473,629	1,521	1,233
2014	7	641,615	570,542	1,823	1,455
2014	8	564,355	552,905	1,680	1,355
2014	9	423,931	392,193	1,262	1,021
2014	10	405,970	342,898	1,103	912
2014	11	372,243	438,123	1,224	1,053
2014	12	512,218	497,100	1,455	1,268
2015	1	491,084	525,293	1,462	1,287
2015	2	427,203	414,573	1,335	1,178
2015	3	416,486	407,343	1,183	1,039
2015	4	364,092	327,315	1,034	889
2015	5	334,042	376,505	1,044	888
2015	6	497,485	424,396	1,413	1,153
2015	7	627,599	513,647	1,705	1,366
2015	8	527,898	522,992	1,571	1,282
2015	9	396,277	368,698	1,179	960
2015	10	359,122	334,396	1,020	853
2015	11	367,487	396,263	1,148	991
2015	12	483,091	468,619	1,372	1,195
2016	1	442,861	517,907	1,384	1,221
2016	2	429,278	404,841	1,278	1,125
2016	3	415,283	373,831	1,128	994
2016	4	328,994	325,847	979	849
2016	5	336,899	346,081	1,003	848

ComEd Procurement Period Load Forecast
(Base Case with Additional IPA EE Savings)
Projected Energy Usage and Average Demand For Eligible Retail Customers
(Weather Normal, Line Loss and DSM Adjusted)

		Total Load (MWh)		Average Load (MW)	
Year	**Month**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**
2016	6	481,578	405,188	1,368	1,101
2016	7	526,780	567,208	1,646	1,338
2016	8	565,627	461,692	1,537	1,228
2016	9	379,839	360,688	1,130	939
2016	10	331,743	337,710	987	828
2016	11	376,952	372,298	1,122	970
2016	12	450,246	477,990	1,340	1,172
2017	1	455,127	489,735	1,355	1,200
2017	2	395,721	386,465	1,237	1,098
2017	3	404,019	366,462	1,098	975
2017	4	304,366	329,822	951	825
2017	5	345,640	324,365	982	827
2017	6	472,841	395,033	1,343	1,073
2017	7	516,377	556,442	1,614	1,312
2017	8	552,223	453,836	1,501	1,207
2017	9	351,749	366,351	1,099	916
2017	10	339,703	316,280	965	807
2017	11	368,684	362,293	1,097	943
2017	12	417,159	485,970	1,304	1,146
2018	1	466,881	461,352	1,326	1,177
2018	2	385,006	378,359	1,203	1,075
2018	3	375,475	371,731	1,067	948
2018	4	312,441	308,454	930	803
2018	5	336,938	315,526	957	805
Totals		**26,634,557**	**25,802,424**		