Industrial Sector DSM Potential Assessment for 2016–2035

April 2016

-Final Report-

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Prepared by:
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List of Acronyms

AAPOR: American Association for Public Opinion Research

AMI: advanced meter infrastructure

BPA: Bonneville Power Administration

BPU: Board of Public Utilities

C&I: commercial and industrial

CPP: Critical Peak Pricing

DEER: Database of Energy Efficiency Resources

DLC: direct load control

DOE: Department of Energy

DR: demand response

DSM: demand-side management

ESCO: energy services companies

EERS: Energy Efficiency Resource Standard

EIA: Energy Information Administration

EM&V: evaluation, measurement, and verification

GWh: gigawatt hours

HVAC: heating, ventilation, and air conditioning

IAC: Industrial Assessment Center

IPE: Industrial Process Efficiency

ISPP: Industrial Savings Potential Project

KIUC: Kentucky Industrial Utility Customers, Inc.

KU: Kentucky Utilities Company

kW: kilowatt

kWh: kilowatt hour

LG&E: Louisville Gas and Electric Company

MCF: thousand cubic feet of natural gas

MECS: Manufacturing Energy Consumption Survey

MW: megawatt

MWh: megawatt hour

NAICS: North American Industrial Classification System

PLS: permanent load shift

RECS: Residential Energy Consumption Survey

RFP: requests for proposals

RIM: Ratepayer Impact Measure Test

RR3: Response Rate 3

SEM: strategic energy management

SIC: Standard Industrial Classification

TOU: time-of-use

TES: thermal energy storage

TRC: Total Resource Cost Test

Executive Summary

Overview

This report summarizes the results of a comprehensive study to estimate the magnitude, timing, and costs of industrial demand-side management (DSM) measures, inclusive of electric and natural gas efficiency and electric demand response (DR) in Louisville Gas and Electric Company's (LG&E) and Kentucky Utilities Company's (KU) (collectively, the Company) service areas; the study examines a 20-year planning horizon from 2016 through 2035.

This study fulfills the requirements of the Kentucky Public Service Commission's final order in Case No. 2014-00003, which directed the Company to commission an industrial potential or market-characterization study. The Company and Cadmus identified the following specific objectives for the study:

- Assess the 20-year technical, economic, and achievable electric and natural gas energy-efficiency potential for the Company's industrial customers.
- Characterize the costs, savings, and applicability of industrial energy efficiency measures and DR strategies.
- Assess the potential for common DR programmatic options applicable to the industrial sector.
- Review and summarize industrial energy efficiency programs offered by other North American utilities. [1]

To the maximum extent possible, the study relied on Company-specific data, including load forecasts, industrial customer databases, avoided electricity and natural gas supply costs, and industrial customer billing data. Cadmus reached out to all of the Company's industrial customers to provide information about energy usage and current practices and attitudes toward energy efficiency and demand response; 154 responded to Cadmus' phone and online survey, and some customers who did not participate in Cadmus' survey provided information on their energy-saving initiatives.

The study also incorporates data from a variety of secondary sources, including the following: the U.S. Energy Information Agency's (EIA) Manufacturing Energy Consumption Survey (MECS); the U.S. Department of Energy's (DOE) Industrial Assessment Center (IAC) data on industrial energy efficiency measures; and the results from recent research on energy efficiency and DR by various governmental entities and national laboratories.

The study follows an industry-standard, top-down approach to estimating energy efficiency potential, beginning by disaggregating the Company's industrial load forecasts into industries and end uses, and

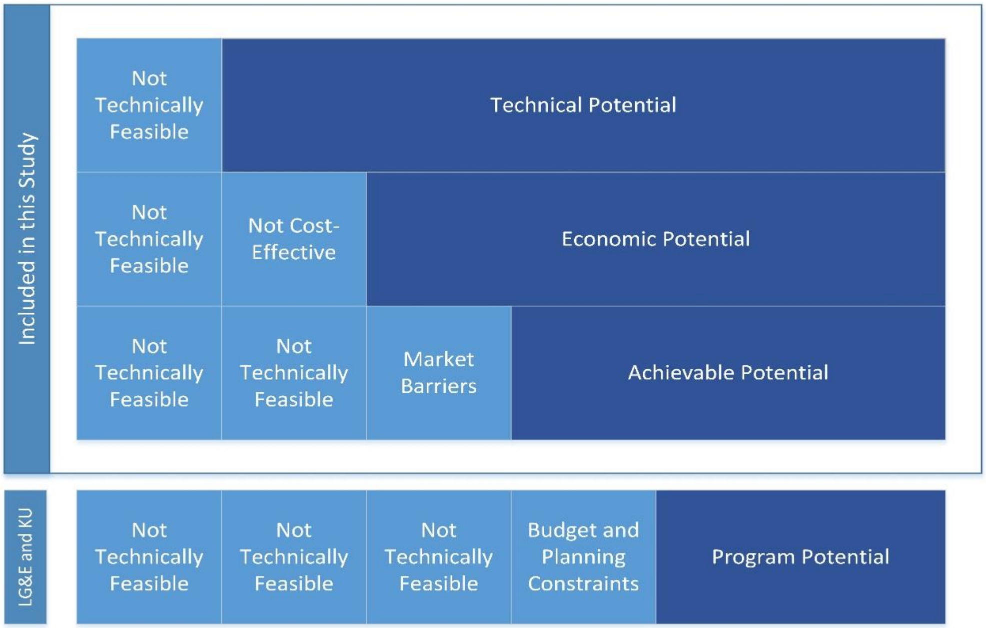
[1] Joint Application of Louisville Gas and Electric Company And Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy-Efficiency Programs P. 32 http://psc.ky.gov/pscscf/2014%20Cases/2014-00003//20141114_PSC_ORDER.pdf

estimating the potential savings and costs likely to be achieved from applicable energy efficiency measures. In adherence with standard industry practice, the study considers three types of energy efficiency potential:

- ***Technical Potential*** (in general) assumes complete adoption of all energy efficiency measures, regardless of the following: measure cost; program, policy, or funding sources (e.g., ratepayer-funded programs, privately funded projects, or energy codes and standards); or acceptability to consumers. The study examines 66 unique electric and 22 unique natural gas measures.
- ***Economic Potential*** represents a subset of technically feasible energy efficiency measures and actions that meet specific cost-effectiveness criteria. This study uses the Total Resource Cost (TRC) to identify cost-effective measures, based on the Company's forecasts of long-term electricity and natural gas energy and capacity costs.
- ***Achievable Economic Potential*** represents the portion of economic potential that might be reasonably achievable in the course of the 20-year study horizon, given normal market barriers that might impede customers' ability or willingness to invest in energy efficiency. Ramp rates, defined as the acquisition rates for specific measures, determine the amount of economic potential considered achievable on an annual basis, beginning in 2016. The study produces a range (e.g., low, medium, and high) of achievable potential to reflect different expenditure levels on incentives, program administration, and marketing.

This study did not consider the fourth type of energy efficiency potential—utility program potential. Program potential is the subset of achievable potential that can be realized through programs after accounting for budget constraints, regulatory factors, opt-out customers, implementation barriers, and other programmatic variables. While this study can inform estimates of program potential, it is not meant to set program targets. Outside this study, the Company will consider these factors as they explore possible industrial energy efficiency programs. Figure 1 illustrates the three types of potential included in this study and the fourth type of potential (program potential) excluded from this study.

Figure 1. Types of Energy Efficiency Potential



The study uses a similar approach to estimate DR potential, except that achievable potential is estimated directly from technical potential without first screening DR options for cost-effectiveness. Instead, the analysis calculates an estimate of a levelized, per-unit ($/kW) cost for each DR option. The cost-effectiveness of each DR option then could be determined by comparing the option's levelized cost with the levelized cost of the avoided capacity.

Summary of Results

Energy Efficiency Potential

Electricity

Study results indicate technical electricity saving potential of nearly 1,400 GWh in 2035, with approximately 1,200 (88%) expected as economic. Technical potential represents savings equivalent to 15.2% of the Company's projected industrial sales in 2035. The study estimates economic potential to account for 13.5% of the Company's 2035 sales forecast. Table 1 shows projected baseline sales, cumulative technical potential, and cumulative economic potential for each utility.

Table 1. Electric Technical and Economic Energy Efficiency Potential—Energy (MWh)

Utility	2035 Baseline Sales - MWh	20-Year Cumulative Potential - MWh		Percent of Baseline		Economic as a % of Technical
		Technical Potential	Economic Potential	Technical Potential	Economic Potential	
LGE	2,626,749	428,025	384,170	16.3%	14.6%	90%
KU	6,370,330	941,051	827,301	14.8%	13.0%	88%
Total	8,997,079	1,369,076	1,211,471	15.2%	13.5%	88%

Potential savings relative to baseline sales proves slightly higher in LG&E's service territory (16.3%) than in KU's (14.8%), a result driven largely by differences in the industry mix within the two service territories.

Savings potential varies across industries due to differing distributions of end-use consumption. For instance, KU has relatively more sales from customers in primary metal manufacturing. A high share of electricity consumption in these industries derive from arc furnaces and complex processes, as opposed to facility measures (mainly lighting and HVAC end uses). Specialized end uses in metal manufacturing produce lower savings potential because efficiency improvements for these end uses mostly have been implemented, and the remaining efficiency potential tends to be complex and costly to achieve.

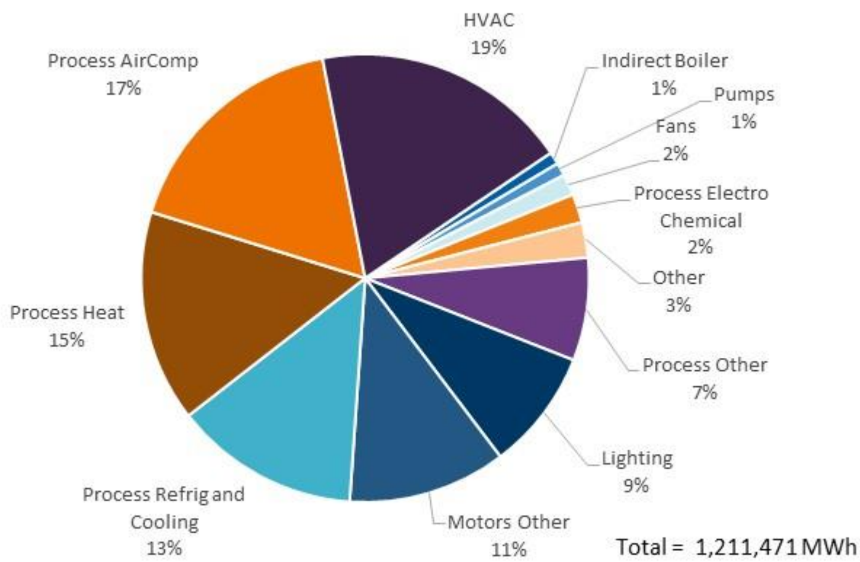
Table 2 shows cumulative peak demand savings by utility. Overall, economic potential can account for a 168 MW reduction in peak demand by 2035, nearly 89% (149 MW) of which is expected as economic. The estimated economic potential represents roughly 88% of the expected technical potential.

Table 2. Technical and Economic Electric Potential—Demand (MW)

Sector	20-Year Cumulative Potential - MW	
	Technical Potential	Economic Potential
LGE	53	48
KU	115	101
Total	168	149

As shown in Figure 2, electricity savings potential varies by end use. HVAC end uses offer the largest savings potential, accounting for 19% of total electric economic potential. Other major end uses, such as air compression and heat process improvements, account for 17% and 15% of total economic potential, respectively. Refrigeration and process cooling applications offer the next highest savings, representing 13% of total electric economic potential.

Figure 2. Distribution of Electric Economic Potential by End Use



Within these end uses, the highest savings can be attributed to waste heat recovery, building envelope improvements, cooling tower operation and maintenance, and installation of adjustable frequency drives on air compressors.

In estimating achievable potential, the study relied on secondary data to determine customers' willingness to adopt energy efficiency measures at various incentive levels. Cadmus determined the elasticity[2] between incentive levels and savings from an analysis of EIA Form 861 data. These data included historical information on expenditures and savings from energy efficiency programs by utilities around the country. A regression analysis of these data indicated a 100% increase in the utility incentive equated to roughly a 65% increase in savings.

As consumers' investment decisions at least partly depend (among other factors) on incentives available from the utility, achievable potential can best be presented as a range of estimates rather than a single-point estimate. This reflects the uncertainty involved in estimating actual savings. Cadmus performed the analysis under three scenarios, assuming incentives covering 25%, 50% and 75% of the energy efficiency measure's incremental costs.

Table 3 shows cumulative achievable potential, by utility, for each achievable scenario. Cumulative achievable savings range from nearly 400,000 MWh in the low scenario to roughly 812,000 MWh in the high scenario; these represent 4.4% to 9.0% of forecasted industrial sales in 2035. This potential

[2] Elasticity is defined as the change in a dependent variable from a unit change in an explanatory variable. In the study's context, it represents the percent savings likely to be achieved from a percent increase in incentives.

translates to approximately 49 MW of peak demand savings in the low scenario and 100 MW in the high scenario, as shown in Table 4.

Table 3. Electric Achievable Potential by Scenario—Energy (MWh)

Utility	20-Year Cumulative Potential - MWh		
	Low (25% Incentive)	Medium (50% Incentive)	High (75% Incentive)
MWh—Cumulative 20-year			
LGE	126,776	192,085	257,394
KU	273,009	413,651	554,292
Total	**399,785**	**605,736**	**811,686**
Percent of Baseline			
LGE	4.8%	7.3%	9.8%
KU	4.3%	6.5%	8.7%
Total	**4.4%**	**6.7%**	**9.0%**

Table 4. Electric Achievable Potential by Scenario – Demand (MW)

Utility	20-Year Cumulative Potential - MW		
	Low (25% Incentive)	Medium (50% Incentive)	High (75% Incentive)
LGE	16	24	32
KU	33	51	68
Total	**49**	**74**	**100**

Average annual achievable potential over the study horizon is between 0.22% in the low scenario and 0.45% in the high scenario, however, we expect that savings will be acquired at different rates for different measures, depending on the measure’s characteristics, applicability to different industries and the affected industrial processes. . Achievable potential, therefore, also accounts for the assumed annual implementation ramp rates. Figure 3 and Figure 4 show incremental and cumulative achievable potential for the medium scenario; savings ramps up gradually from approximately 25,000 MWh in year one to 65,000 MWh in year seven. After year seven, savings gradually diminishes.

Figure 3. Medium Scenario Incremental Achievable Potential

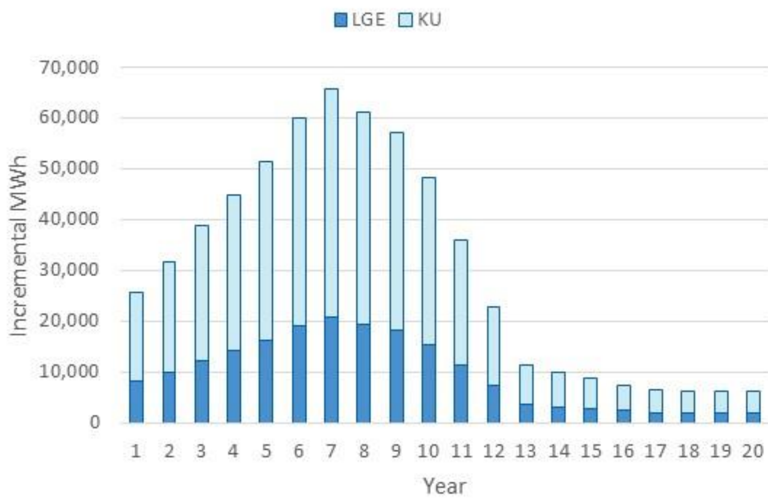
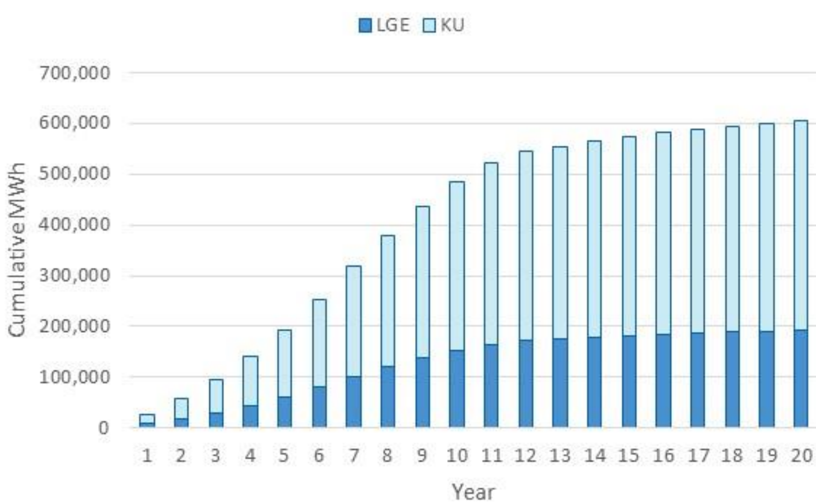


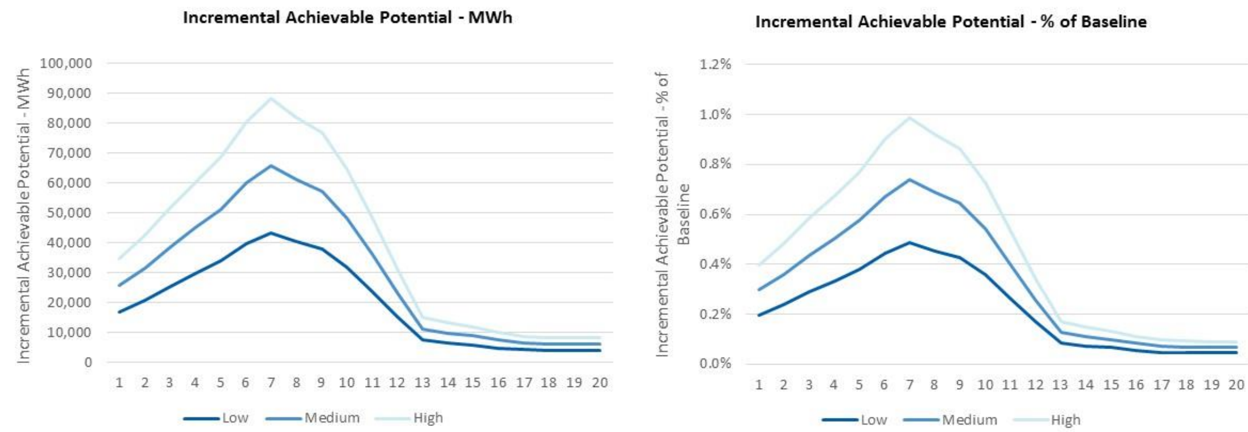
Figure 4. Medium Scenario Cumulative Achievable Potential



Medium scenario savings are roughly equivalent to 0.3% of baseline industrial sales in the first year, ramping up to 0.7% of baseline sales in the seventh year, and gradually diminishing until savings largely become exhausted by the 13th year (Figure 5). While ramp rates reflected in Figure 3, Figure 4, and Figure 5 capture the expected gradual build-up of a hypothetical industrial program, they make no assumption as to when a program would begin. Estimates of such programmatic considerations are outside the scope of this study.

Figure 5 show incremental achievable potential, both in MWh and as a percent of baseline sales, for each achievable scenario.

Figure 5. Incremental Achievable Potential by Scenario



Natural Gas

Cadmus also assessed the energy efficiency potential from natural gas measures for the Company's non-transport customers.[3] These measures include equipment upgrades, process optimization, and controls for natural gas end uses (e.g., boilers, furnaces, and various process-driven equipment). As shown in Table 5, overall, natural gas technical potential equals nearly 228,000 MCF in 2035, or 13% of projected sales. Economic potential equals nearly 226,000 MCF, or approximately 12.9% of projected sales. Economic potential accounts for roughly 99% of technical potential.

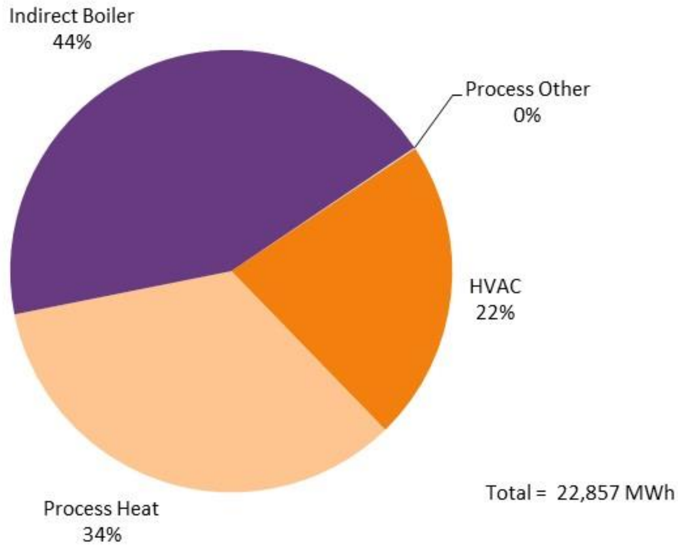
Table 5. Natural Gas Technical and Economic Potential - MCF

Sector	2035 Baseline Sales (MCF)	20-Year Cumulative Potential—MCF		Percent of Baseline		Economic as a % of Technical
		Technical Potential	Economic Potential	Technical Potential	Economic Potential	
LGE	1,753,580	227,955	225,893	13.0%	12.9%	99%

A large share of natural gas savings derives from boilers (44% of total), followed by process heat improvements (34% of total) and HVAC improvements (22% of total). Because the majority of natural gas measures considered in the technical potential proved cost-effective, a large fraction (99%) of technical potential is deemed cost-effective.[4] Figure 6 shows the distribution of natural gas economic potential by end use.

[3] Non-transport customers purchase natural gas directly from LG&E. Transport customers purchase natural gas from a third party and use LG&E's pipelines to receive the commodity.
[4] Cadmus characterized gas energy efficiency measures using DOE's IAC database, which only includes energy efficiency recommendations that meet the IAC's pre-defined payback criteria. Although the IAC database is the most comprehensive source for gas energy efficiency measure costs and savings, it does not include

Figure 6. Natural Gas Economic Potential by End Use



High-saving gas measures include energy management (process improvements), equipment upgrades (efficient furnaces and boilers), and waste heat recovery. These three improvements can apply to multiple end uses and account for nearly one-third of total natural gas technical potential.

As shown in Table 6, slightly under 75,000 MCF—representing 4% of baseline sales—are anticipated as reasonably achievable under the low-incentive scenario. A little over 150,000 MCF—or 9% of baseline sales—are anticipated as achievable under the high-incentive scenario.

recommendations that may be technically feasible, but not cost-effective. In effect, the IAC pre-screens measures for cost-effectiveness; this is why economic potential accounts for nearly 100% of the projected technical potential.

Table 6. Natural Gas Achievable Potential - MCF

Utility	20-Year Cumulative Potential - MCF		
	Low (25% Incentive)	Medium (50% Incentive)	High (75% Incentive)
LG&E	74,545	112,947	151,349
Percent of Baseline	4%	6%	9%

Comparisons to Similar Studies

Cadmus compiled results from nine recent studies of industrial-sector electric energy efficiency potential completed during the last three years.[5] In comparing the results of energy efficiency potential studies, it is important to consider the many factors that affect the results, including (but not limited to): the mix and vintage of industries; fuel use patterns; energy-management practices; and certain variations in analytic methods (such as the method used to account for local and national codes and standards). Therefore, results from a comparison of this and other studies should be considered indicative rather than conclusive.

Moreover, comparisons with other studies proves less meaningful for economic and achievable potential, given these estimates depend on variables such as avoided costs and local market conditions, which may differ significantly across utilities and result in spurious conclusions if not taken into account when making such comparisons. For instance, holding all else constant, a utility with higher avoided costs will likely produce higher estimates of economic potential, as more measures will be cost-effective for the utility (relative to a utility with low avoided costs).

Figure 7 shows technical potential as a percent of baseline sales for this study and the nine other studies considered. The figure clearly illustrates that the reviewed studies show estimated technical potentials ranging from 25% to 10%, and averaging at 18% of baseline industrial sales. The technical potential estimated in this study represents 15% of baseline sales, an amount slightly lower than the reviewed studies' average.

[5] Too few recent studies of industrial-sector natural gas potential studies have been conducted to provide a similar comparison for natural gas.

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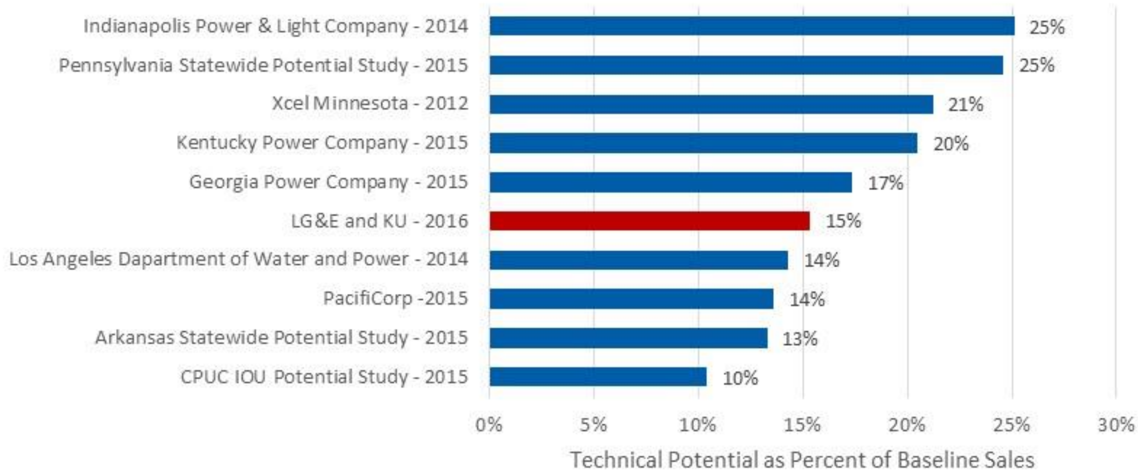
Figure 7. Technical Potential as Percent of Baseline Sales



Demand Response Potential

Cadmus estimated the 20-year potential for industrial section DR program options in LG&E's and KU's service territories. The DR assessment focused on a Critical Peak Pricing program and a Peak Load Reduction program. The analysis did not consider the Company's existing curtailable service rider (CSR).[6] If implemented, the Critical Peak Pricing program could expect to achieve 1.2 MW of peak reduction or 0.02% of system peak across both territories during a two-hour event. Estimates indicate a peak load reduction program would have a much larger impact, producing an expected 103.5 MW or 1.61% of peak load reduction achievable for a two-hour event across KU's and LG&E's territories. These are 20-year potential estimates; the programs will take an estimated three to five years to ramp up to full participation. If implemented, the Critical Peak Pricing program could expect to achieve 1.2 MW of peak reduction or 0.02% of system peak across both territories during a two-hour event. Estimates indicate a peak load reduction program would have a much larger impact, producing an expected 103.5 MW or 1.61% of peak load reduction achievable for a two-hour event across KU's and LG&E's territories. These are 20-year potential estimates; the programs will take an estimated three to five years to ramp up to full participation.

[6] The Peak Load Reduction program differs from the Company's existing curtailable service rider in several respects. First, only customers who contract for no less than 1,000 kVA individually may participate in the Company's CSR, while the Peak Load Reduction program only requires the customer have an interval meter and demand higher than 200 kW. A small number of customers participate in the Company's CSR, while Cadmus identified approximately 1,500 customers eligible to participate in a Peak Load Curtailment program. Second, the CSR allows for up to 375 hours of curtailment and has restrictions on when load can be curtailed (e.g. all available units must be dispatched and all off-system sales must be curtailed). In contrast, the Company has more flexibility on the timing and duration of curtailment with a Peak Load Reduction program. Finally, while the Peak Load Reduction program provides a $/kW incentive curtailment, while the CSR provides customers with a different rate.

Table 30Table 7 shows Cadmus' assessment of potential savings and levelized costs associated with implementation of Critical Peak Pricing and peak load reduction programs in LG&E's and KU's territory. Assessments for each program's potential load reductions assumed a two-hour and a four-hour DR event.

The Critical Peak Pricing potential load reduction is expected to be small, largely due to historically low participation rates for such programs. If implemented, the Critical Peak Pricing program would likely achieve 1.2 MW of peak reduction (or 0.02% of system peak) across both KU's and LG&E's territories during a two-hour event.

The Peak Load Reduction program is estimated to have a much larger impact, with an expected load reduction of nearly 104 MW (or approximately 1.6% of the Company's projected peak system load) in 2035. Due to relatively flat loads during the Company's system peak period, expanding event durations to four hours is expected to have minimal impacts on the two programs' load reduction potential.

Table 7. Summary of Potential Assessment for Critical Peak Pricing/Peak Load Reduction Programs[7]

Program	Event Length	Utility	Achievable Load Reduction in 2035	Percent Peak Reduction	Levelized Cost of Demand per Year ($/kW)
Critical Peak Pricing	2 hours	LG&E	0.4	0.02%	$265
		KU	0.9		$106
	4 hours	LG&E	0.4	0.02%	$266
		KU	0.9		$105
Peak Load Reduction	2 hours	LG&E	29.3	1.61%	$52
		KU	74.2		$43
	4 hours	LG&E	28.9	1.62%	$52
		KU	75.0		$43

Current Energy Efficiency Practices and Attitudes

Cadmus reached out to all of the Company's industrial customers by phone, mail, email, or a data request through the Company. Cadmus completed a survey of 154 industrial customers, with respondents derived from a population of 1,514 facilities, and covering all of Kentucky's 20 major industrial segments.[8] The surveys focused on gathering data addressing the following: facility characteristics and electricity end uses; recent energy management measures and practices; and attitudes toward and willingness to adopt energy-efficient measures. Information gathered through the surveys provided important supplemental information for calculating technical and achievable potential. A discussion follows of issues suggested by the survey findings.

Industrial customers displayed relatively high awareness regarding energy efficiency. Two-thirds of respondents reported making upgrades or retrofits (primarily lighting) or purchasing new energy-efficient equipment for their facilities over the last five years, and 61% of respondents indicated they intend to implement energy efficiency measures in the next five years.

One-quarter of respondents reported employing goals related to energy management or energy efficiency in place. About one-third of survey respondents had conducted assessments of energy-savings opportunities at their facilities, and 2% reported seeking energy management certification.[9] Respondents cited energy cost savings as the primary reason for energy-efficient actions and paybacks, and return on investment as the primary criteria for investing in energy efficiency. Payback expectations,

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7 Reduction shown at the generator, not the meter (i.e., line losses included). Future years assume a 1.9% rate of inflation and a discount rate of 6.48% for LG&E and 6.37% for KU.

Members of the Kentucky Industrial Utility Customers, Inc. did not participate in the survey; instead, some members responded to a data request and provided information in different formats, including PowerPoint presentations and reports on their energy-saving initiatives.

9 Through ISO 50001, the U.S. DOE Superior Energy Performance, or a similar certification method.

however, run high, with 95% of respondents indicating an expected payback of one year or less. This finding is consistent with survey findings that respondents report initial cost as the second-most important barrier to implementing energy efficiency measures.

Fewer than 10% of industrial customers have electric generation capability at their facilities, with gas generators the most common forms of on-site electricity generation. Only 30% of respondents indicated a willingness to participate in a utility-sponsored DR program with an incentive of $32 per kW; 37% would be likely to participate in DR with an incentive of $50 per kW.

Program Review

To provide insight into the programmatic initiatives designed to improve energy efficiency in the industrial sector, Cadmus reviewed the types of energy efficiency programs utilities typically offer to their large commercial and industrial (C&I) customers, with a focus on incentive levels and structures, marketing strategies, expenditures, barriers to participation and mitigation strategies, and performance metrics. Cadmus identified four common industrial program design categories and gathered details about key design features, structures, and delivery strategies. The programs included the following:

- **Prescriptive incentive programs,** which offer per-unit or savings-based incentives for specific technologies or equipment that enables savings calculations using a deemed value or partially deemed algorithm.
- **Custom incentive programs,** which generally offer incentives based on projected savings or on a percentage of project costs (for more complex equipment or whole-building efficiency projects that require a measured-savings calculation approach).
- **Pay-for-performance programs,** which typically offer performance-based incentives for large capital investment projects, either with or without savings from changes in operations and maintenance (O&M) or behaviors. Utilities may measure savings via on-site metering equipment, and the incentives are trued up following one year of post-installation data collection.
- **Strategic energy management (SEM) programs,** which generally entail a staged project installation and/or O&M process over a multiyear contract term. Utilities offer annual incentives based on completion of energy-savings actions each year.

Industrial energy efficiency projects offer several unique features; as a result, large industrial programs function differently from smaller commercial or residential efficiency programs. In many utility jurisdictions, industrial programs attract a relatively small number of participants, but, owing to their size, projects can generate significantly greater energy savings than any other programs in a portfolio. Projects can be large and complex, entailing whole-building efficiency measures, specialized process improvements, and complicated interactions that must be carefully analyzed and engineered. Mass media marketing to this sector generally does not prove effective, with customer recruitment requiring direct, in-person contacts with customers (either by the utility staff, a third party implementer, or program trade allies).

Common barriers in this sector include low program awareness, high upfront project costs, procurement policies favoring low-bid projects, and long project cycles that require significant commitment and dedication of resources on the customers' parts. The most successful programs overcome these barriers by offering attractive incentives, focusing on the long-term benefits of installing energy-efficient equipment, and by providing significant technical assistance to help customers identify and install the most beneficial energy-savings projects.

Most programs require a preapproval process in which customers must submit documentation showing the modeled energy savings impacts expected to result from installing a project or implementing O&M measures. Incentives typically are based on first-year kWh performance, but the programs also commonly offer per-unit incentives or those based on demand reductions or percentage of project costs are also used. Additionally, although marketing and project development costs can be significant, resulting energy savings can drive high program cost-benefit ratios. Evaluation, measurement, and verification (EM&V) generally proves more rigorous, often employing on-site metering to verify claimed savings.

Methodology

Overview of Methodology

Estimating energy efficiency potential draws upon a sequential analysis of various energy efficiency measures in terms of technical feasibility (technical potential), cost-effectiveness (economic potential), and expected market acceptance, considering normal barriers possibly impeding measure implementation (achievable potential).

Cadmus' assessment took the following primary steps:

- **Baseline forecasting*:*** Determining 20-year future energy consumption by sector, market segment, and end use. Cadmus derived baseline forecasts through a top-down disaggregation of the Company's industrial load forecasts.
- **Estimation of technical potential*:*** Estimating technical potential, based on alternative forecasts that reflect the technical impacts of specific energy efficiency measures.
- **Estimation of economic potential*:*** Estimating economic potential, based on alternative forecasts that reflect technical impacts of cost-effective energy efficiency measures.
- **Estimation of achievable potential:** Achievable economic potential, calculated by applying ramp rates and achievability percentages to the economic potential (as this section details).

A top-down approach offers two advantages:

1. First, savings estimates are driven by a baseline derived from the Company's forecasted sales (2015 through 2035), as opposed to summing deemed energy savings impacts for each potential measure. This ensures estimates represent realistic reductions to the Company's actual load.
2. Second, the approach maintains consistency among all assumptions underlying the baseline and alternative forecasts (e.g., technical, economic, achievable). The alternative forecasts changed relevant inputs at the end-use level to reflect energy efficiency measure impacts. As estimated savings represented the difference between baseline and alternative forecasts, they could be directly attributed to specific changes made to analysis inputs.

Cadmus' general methodology can be best described as a "top-down." As shown in Figure 8, the process began with the most current load forecast, then disaggregated this into its constituent customer segment and end-use components. Impacts could then be estimated, based on engineering calculations and accounting for end-use impacts, current market saturations, technical feasibility, and costs.

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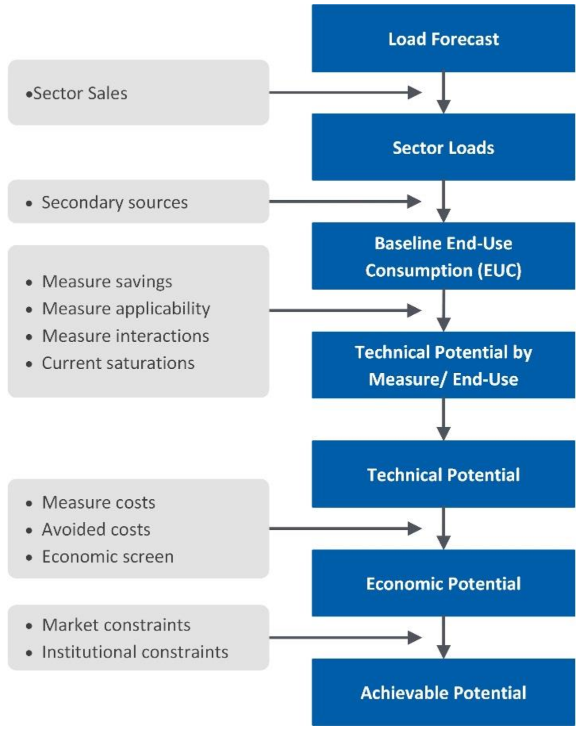
Figure 8. Methodology for Estimating Technical, Economic, and Achievable Energy Efficiency Potential



Developing a Baseline Forecast

Cadmus built a baseline forecast by disaggregating the Company's actual sales into industries and end uses and then applying this disaggregation to the Company's industrial load forecast. Table 8 shows data sources for Cadmus' baseline forecast.

Table 8. Baseline Forecast Data Sources

Input	Data Source
Baseline Sales	**LG&E and KU actuals**: Actual base year sales derived from the Company's customer database.
Forecasted Sales	**LG&E and KU industrial load forecasts:** The Company provided forecasts for each major customer class and individual forecasts for large customers.
% Sales by Industry	**LG&E and KU customer database:** Customer databases included standard industrial classification (SIC) and North American Industrial Classification System (NAICS) codes as well as the Company's industrial classification for each customer. Cadmus used these three fields to group each customer in one of the 22 industries considered

Input	Data Source
End-Use Energy Consumption	**EIA MECS:** This nationwide survey of industrial facilities produces estimates of electricity and natural gas consumption for each major end use. Using these data, Cadmus calculated the distribution of end-use consumption for each fuel, and then used these distributions to disaggregate the Company's load forecast.

The Company's industrial sales forecasts provided the basis for assessing energy efficiency potential. Prior to estimating potential, the study disaggregated load forecasts by customer segment (industry/facility types) and end uses (all applicable end uses in each customer segment).

The first step in developing the baseline forecasts determined the appropriate customer segments within each sector. Cadmus analyzed the Company's industrial customer sales data to determine the appropriate segmentation, grouping customers into one of 22 industrial segments—the three digit prefix of the North American Industrial Classification System code or the Company's own designation. Table 9 lists each industry considered and shows the corresponding three-digit NAICS code.

Table 9. Industries Considered

Industry	3-Digit NAICS
Mining	211; 212; 213
Food	311
Beverage and Tobacco Products	312
Textiles	313/314
Apparel	315
Wood Products	321
Paper	322
Printing and Related Support	323
Petroleum and Coal Products	324
Chemicals	325
Plastics and Rubber Products	326
Nonmetallic Mineral Products	327
Primary Metals	331
Fabricated Metal Products	332
Machinery	333
Computer and Electronic Products	334
Electrical Equip., Appliances, and Components	335
Transportation Equipment	336
Furniture and Related Products	337
Miscellaneous	339
Water	494
Wastewater	495

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Once Cadmus determined the appropriate industries, we disaggregated the Company's sales forecast into industries using a distribution of sales by industry, derived from the Company's 2014 customer data. We then disaggregated sales separately for each fuel and each utility. Table 10 shows the distribution of sales by industry for LG&E (electric and gas) and KU (electric). Chemical manufacturing, transportation equipment manufacturing, and primary metal manufacturing each account for 15% of total industrial sales, and three industries—transportation equipment, chemicals, and food—account for nearly three-quarters of total natural gas sales.

Table 10. Distribution of Sales by Industry

Industry	Electric			Natural Gas
	LG&E Electric	KU Electric	Total Electric	LG&E
Transportation Equipment	17%	13%	15%	33%
Chemicals	34%	7%	15%	27%
Primary Metals	1%	19%	15%	4%
Nonmetallic Mineral Products	9%	13%	12%	1%
Electrical Equipment, Appliances, and Components	9%	5%	7%	0%
Plastics and Rubber Products	2%	8%	7%	3%
Fabricated Metal Products	4%	6%	6%	4%
Food	5%	5%	5%	13%
Miscellaneous	3%	4%	4%	6%
Paper	5%	2%	3%	1%
Petroleum and Coal Products	1%	3%	3%	1%
Beverage and Tobacco Products	2%	2%	2%	7%
Printing and Related Support	1%	2%	2%	1%
Machinery	1%	1%	1%	1%
Water	1%	1%	1%	0%
Computer and Electronic Products	2%	0%	1%	0%
Wood Products	1%	0%	1%	1%
Furniture and Related Products	0%	0%	0%	0%
Apparel	0%	0%	0%	0%
Textiles	0%	0%	0%	0%

After identifying the distribution of sales by industry, Cadmus further disaggregated industry-specific sales into end uses. This process relied on the EIA's MECS to determine the distribution of end-use consumption for each industry. A national survey of industrial facilities, MECS can be used to determine building characteristics, end-use consumption, and energy expenditures. EIA conducted the first MECS in

1985 and completed the most recent survey in 2010. Typically, MECS draws from a nationally representative sample frame, representing nearly 98% of manufacturing payroll.[10]

Cadmus relied on MECS Table 5.1, which reported total energy consumption for each major fuel type (including electricity and natural gas) and each major manufacturing industry group, by end use.[11] Table 11 and Table 12 show the distributions of end-use consumption for each industry.

Table 11. Electric End Use Shares by Industry

NAICS	Industry	Fans	HVAC	Indirect Boiler	Lighting	Motors Other	Other	Process Air Compressors	Process Electro Chemical	Process Heat	Process Other	Process Refrig and Cooling	Pumps
311	Food	3%	8%	3%	8%	17%	5%	3%	0%	5%	1%	41%	7%
312	Beverage and Tobacco Products	5%	10%	2%	8%	13%	12%	5%	0%	6%	2%	29%	8%
313	Textile Mills	8%	13%	1%	8%	22%	4%	9%	0%	8%	0%	13%	14%
314	Textile Product Mills	6%	17%	1%	15%	18%	3%	7%	1%	10%	1%	9%	12%
315	Apparel	5%	32%	0%	20%	16%	6%	6%	0%	0%	2%	3%	10%
316	Leather and Allied Products	7%	22%	0%	13%	20%	4%	8%	0%	5%	2%	6%	13%
321	Wood Products	10%	6%	1%	8%	28%	5%	11%	1%	6%	1%	6%	18%
322	Paper	15%	4%	2%	4%	29%	5%	3%	1%	3%	4%	5%	24%
323	Printing and Related Support	6%	24%	1%	9%	18%	7%	7%	1%	4%	1%	8%	12%
324	Petroleum and Coal Products	11%	4%	1%	3%	32%	3%	13%	0%	0%	2%	10%	20%
325	Chemicals	7%	6%	1%	4%	16%	2%	16%	15%	4%	1%	12%	15%
326	Plastics and Rubber Products	6%	10%	1%	9%	17%	3%	7%	0%	19%	3%	14%	11%
327	Nonmetallic Mineral Products	7%	6%	0%	5%	21%	3%	8%	1%	26%	2%	7%	13%
331	Primary Metals	4%	4%	0%	3%	17%	2%	4%	26%	32%	3%	1%	2%
332	Fabricated Metal Products	6%	10%	0%	11%	16%	9%	7%	0%	22%	3%	6%	10%
333	Machinery	6%	21%	0%	15%	16%	6%	6%	0%	12%	3%	5%	10%
334	Computer and Electronic Products	5%	30%	1%	12%	9%	10%	1%	2%	10%	5%	10%	7%

[10] "About the Manufacturing Energy Consumption Survey." Available online: https://www.eia.gov/consumption/manufacturing/about.cfm

[11] U.S. Energy Information Agency MECS 2010 Survey Data. https://www.eia.gov/consumption/manufacturing/data/2010/

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NAICS	Industry	Fans	HVAC	Indirect Boiler	Lighting	Motors Other	Other	Process Air Compressors	Process Electro Chemical	Process Heat	Process Other	Process Refrig and Cooling	Pumps
335	Electrical Equip., Appliances, and Components	4%	16%	1%	10%	10%	7%	10%	5%	15%	4%	7%	10%
336	Transportation Equipment	4%	19%	1%	15%	10%	9%	10%	2%	11%	4%	8%	9%
337	Furniture and Related Products	6%	18%	1%	17%	18%	9%	7%	0%	5%	2%	4%	12%
339	Miscellaneous	5%	27%	1%	15%	20%	5%	5%	0%	12%	3%	5%	3%

Table 12. Natural Gas End Use Share by Industry

NAICS	Industry	HVAC	Indirect Boiler	Other	Process Heat	Process Other
311	Food	6%	57%	5%	30%	2%
312	Beverage and Tobacco Products	9%	69%	0%	23%	0%
313	Textile Mills	7%	57%	3%	33%	0%
314	Textile Product Mills	13%	50%	0%	38%	0%
315	Apparel	33%	33%	0%	33%	0%
321	Wood Products	12%	23%	4%	60%	1%
322	Paper	4%	59%	7%	29%	1%
323	Printing and Related Support	30%	23%	5%	40%	1%
324	Petroleum and Coal Products	1%	32%	8%	55%	4%
325	Chemicals	2%	54%	6%	34%	4%
326	Plastics and Rubber Products	21%	44%	1%	34%	0%
327	Nonmetallic Mineral Products	6%	4%	4%	86%	0%
331	Primary Metals	6%	12%	4%	74%	4%
332	Fabricated Metal Products	20%	14%	2%	63%	1%
333	Machinery	47%	9%	4%	41%	0%
334	Computer and Electronic Products	43%	35%	8%	13%	3%
335	Electrical Equip., Appliances, and Components	21%	18%	6%	56%	0%
336	Transportation Equipment	32%	24%	3%	35%	6%
337	Furniture and Related Products	50%	8%	0%	42%	0%
339	Miscellaneous	40%	33%	0%	27%	0%

Cadmus disaggregated industry-specific consumption using the end-use shares show above. This resulted in industrial end-use estimates that could be expressed using the following formula.

$$EUSE_{ij} = \Sigma_e USE_i * ENDUSESHARE_{ij}$$

Where:

$EUSE_{ij}$	=	Total energy consumption for end use *j* in customer segment *i*
USE_i	=	The total sales (kWh or MCF) in customer segment *i*
$ENDUSESHARE_{ij}$	=	The share of energy consumption in customer segment *i* for end use *j*

Total annual consumption could be determined as the sum of *EUSEij* across the end uses and customer segments. This total consumption equaled the Company's total industrial sales. Cadmus performed these calculations for each year of the study horizon (2016 to 2035), ultimately producing an end-use forecast for each industry.

Measure Characterization

Cadmus considered a list of efficiency improvements derived from the DOE's IAC database. This database includes data from over 17,000 publicly available IAC assessments, resulting in over 130,000 recommendations. Cadmus used IAC estimates of energy usage, energy savings, and recommendation costs to aggregate recommendations into typical energy efficiency measures.

Cadmus did not, however, solely rely on measures derived from IAC recommendations. Rather, we characterized lighting equipment and motors measures separately as these had to be adjusted for the impact of upcoming federal standards. Overall, Cadmus developed an electric list with 65 unique measures and a gas list with 21 unique measures.

Cadmus then expanded this list to all applicable industries and end uses. For each measure permutation, we calculated the following:

- **Energy savings**: End-use percent savings, kWh savings, MCF savings.
- **Costs**: Inclusive of equipment, labor, and annual O&M costs.
- **Measure life:** The expected useful lifetime of a given measure.
- **Applicability**: Consideration of applications where the measure proves not technically feasible and/or facilities already have implemented the measure.
- **Measure interaction**: Identification of measures that reduce baseline sales, thereby reducing the savings of subsequent measures installed (sometimes referred to as "measure stacking").

For each of these inputs, Cadmus compiled data from a number of sources. Table 13 lists data sources for each field in Cadmus' measure database.

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Table 13. Measure Data Sources

Data	Industrial
Energy Savings	DOE's IAC Database, Industrial Savings Potential Project (ISPP), Industrial Northwest Power and Conservation Council (Council) data, Cadmus research.
Equipment and Labor Costs	DOE's IAC Database, ISPP, Council data, Cadmus research.
Measure Life	Database of Energy Efficiency Resources (DEER), DOE's Industrial Technologies Program, Industrial Council data, Cadmus research.
Applicability	LG&E and KU customer survey, Industrial Council data, Cadmus research.
Measure Interaction	Cadmus research.

Incorporating Codes and Standards

Cadmus' assessment accounted for changes in equipment standards over the planning horizon. Though such changes affect customers' energy consumption patterns and behaviors, they determine which energy efficiency measures continue to produce savings over minimum requirements. The assessment captured current efficiency requirements, including those enacted but not yet in effect.

Cadmus did not attempt to predict how standards might change in the future; rather, we only factored in enacted legislation—notably, the Energy Independence and Security Act provisions, DOE rulemaking on electric motors, and DOE lighting standards scheduled to take effect over the course of the analysis.

About Estimating Technical Potential

Technical potential is defined as: the theoretical maximum amount of energy and capacity that could be displaced by efficiency, regardless of cost and other barriers that may prevent the installation or adoption of an energy efficiency measure. Only technical factors constrain technical potential (e.g., technical feasibility, applicability of measures). In theory, technical potential could be acquired immediately by including early replacement of functioning equipment.

For each DSM measure, Cadmus estimated savings using the following basic relationship:

$$SAVE_{ijm} = EUI_{ij} * PCTSAV_{ijm} * APP_{ijm}$$

Where:

$SAVE_{ijm}$	=	Annual energy savings for measure *m* for end-use *j* in customer segment *i*
EUI_{ije}	=	Annual end-use energy consumption for end-use *j* in customer segment *i*
$PCTSAV_{ijem}$	=	The percentage savings of measure *m* relative to the base usage for the end-use *ij*
APP_{ijem}	=	Measure applicability, a fraction that represents a combination of technical feasibility, existing saturation of the measure, end-use interactions, and any adjustments to account for competing measures

Cadmus' used a method for estimating technical potential based on the industry-standard, bottom-up approach, which estimated phase-in technical potential by introducing all technically feasible measures into the baseline forecast and calculating the resulting impacts.

This method fully captured interactive effects associated with the installation of multiple measures. Through this process, each measure reduced the baseline consumption that a subsequent measure was compared to, ensuring savings estimates did not exceed baseline loads.

This iterative approach produced more accurate results than considering measures in isolation: capturing all applicable measures required examining many instances where multiple measures affected a single end use. To avoid overestimating total savings, Cadmus assessed cumulative impacts, accounting for interactions among the various measures (i.e., "measure stacking").

The primary method to account for stacking effects establishes a rolling, reduced baseline, applied sequentially upon an assessment of measures in the stack, as illustrated in the equations below (applying measures 1, 2, and 3 to the same end use):

$$SAVE_{ij1} = EUI_{ije} * PCTSAV_{ije1} * APP_{ije1}$$

$$SAVE_{ij2} = (EUI_{ije} - SAVE_{ij1}) * PCTSAV_{ije2} * APP_{ije2}$$

$$SAVE_{ij3} = (EUI_{ije} - SAVE_{ij1} - SAVE_{ij2}) * PCTSAV_{ije3} * APP_{ije3}$$

After iterating all measures in a bundle, the final percentage of the reduced end-use consumption provided the sum of the individual measures' stacked savings, which we could divide by the original baseline consumption.

About Estimating Economic Potential

Cadmus estimates economic potential by applying cost-effectiveness criteria over a measure's expected useful life. Cost-effectiveness compares the full life-cycle cost of each technically feasible measure to the value of its savings in terms of avoided energy and capacity costs. Our methods for calculating cost-effectiveness closely follow guidelines established by the California Standard Practice Manual.

For each measure, this study began the TRC calculation with a valuation of the measure's benefits, as measured by the avoided, long-run, energy, capacity costs, and avoided line losses. Cadmus then compared the result to the measure's costs. Measure costs included the total installed cost of the measure. The study considered a measure cost-effective if the net present value of its benefits exceeded the net present value of its costs, as measured according to the TRC test.

Economic potential represented the savings resulting from the subset of measures that passed the cost-effectiveness criteria, according to the TRC test.

Test components include the following:

- **Benefit Components**. Benefits include the value of time-differentiated and seasonally differentiated avoided energy and capacity costs. As these costs typically are measured at generation, Cadmus adjusted for other avoided waste energy, such as transmission and distribution losses, and for co-benefits.

- **Cost Components**. The cost component of the TRC screening for the economic potential consisted only of incremental measure costs (e.g., incremental material and labor expenses associated with installation of the measure and—where applicable—its ongoing operation and maintenance costs).

In estimating economic potential, Cadmus assumed that, where two or more technically feasible and cost-effective measures compete for the same end use, the one with the highest savings would be installed first. After screening all measures, we applied the impacts of those deemed cost-effective to the baseline consumption estimates.

Data Collection

Data compiled from primary and secondary sources supported this study's analysis. Descriptions follow of sources and acquisition methods for each source. Cadmus mostly relied on data from various national sources (e.g., EIA, DOE, the American Council for an Energy-Efficient Economy [ACEEE], and various industrial market research and evaluation reports). The Methodology section of this report describes these data sources. The study also relied on data collected from the Company's industrial customers, including presentations and reports provided by some of the Company's largest customers and responses to a phone and online survey administered by Cadmus and Thoroughbred Research.

Primary Data Collection

Cadmus relied on data collected through a phone, e-mail, and mail survey, designed to inform estimates of energy efficiency and DR potential. Specifically, the survey covered the following topics:

- Facility characteristics and electricity end uses
- Energy management practices and adoption of energy efficiency measures
- Energy efficiency decision making
- Distributed generation and load shifting

Appendix A includes complete survey instruments.

Cadmus reached out to all of the Company's industrial customers (by phone, mail, e-mail, or a data request). For the survey's purposes, Cadmus defined a unique customer as a unique premise—not necessarily the same as a unique account, given some premises have multiple accounts. Cadmus identified unique premises using the customers' account name and address. Overall, the effort identified 1,514 unique customers (premises), spanning 2,245 unique accounts.[12]

Although all 1,514 unique customers were given an opportunity to complete a survey, only 154 completed surveys through Cadmus. Specifics are shown in the following tables. Table 14 shows the number of eligible customers and the number of completes for each survey type. The study completed 124 phone surveys and 30 surveys using mail or e-mail recruitment.

Table 14. Sample Frame by Survey Type

Category	Count	Completed Surveys
Industrial Accounts	2,245	N/A
Unique Customers	**1,514**	**154**
Phone Survey	668	124
Email survey	299	30

[12] The members of the Kentucky Industrial Utility Customers, Inc. declined to participate in the survey; instead, some KIUC members responded to a data request and provided information (PowerPoint presentations and reports) on their own energy-saving initiatives and accomplishments.

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Mail Survey	1,514	

Table 15 shows telephone survey dispositions (those for mail and e-mail surveys were not applicable).

Table 15. Telephone Survey Dispositions

Disposition	Total
Starting Sample	**668**
Bad Number (e)	87
Refusal (R)	349
Incomplete (partial interviews) (NC)	52
Incapable/Incoherent or Language Barrier/Non-English (NC)	13
Unknown Eligibility Non-Interview (U)	43
Completed Surveys (I)	**124**
Response Rate (RR3)	21.6%
Cooperation Rate (COOP3)	26.2%

The 21.6% survey response rate derives from the 124 completed telephone interviews, divided by the total number of potentially eligible respondents in the telephone sample. Cadmus calculated the response rate using standards and formulas set forth by the American Association for Public Opinion Research (AAPOR).[13]

For various reasons, Cadmus could not determine the eligibility of all sample units through the survey process, and, consequently, chose to use AAPOR Response Rate 3 (RR3), which includes an estimate of eligibility for these unknown sample units. Cadmus used the following formulas to calculate RR3 (Table 15 includes definitions of letters used in the formulas):

$$E = \frac{(I + R + NC)}{(I + R + NC + e)}$$

$$RR3 = \frac{I}{((I + R + NC) + (E * U))}$$

Cadmus also calculated a 26.2% cooperation rate—the number of completed interviews (124), divided by the total number of eligible customers contacted. In essence, the cooperation rate equaled the percentage of participants completing an interview out of all participants with whom survey staff spoke. Cadmus used AAPOR Cooperation Rate 3 (COOP3), calculated as:

$$COOP3 = \frac{I}{(I + R)}$$

13 AAPOR. *Standard Definitions: Final Dispositions of Case Codes and Outcome Rates for Surveys*. *8th Edition*. 2015. Available at: http://www.aapor.org/AAPORKentico/Communications/AAPOR-Journals/Standard-Definitions.aspx

Weighting

Cadmus applied case weights to correct for bias caused by the distribution of industries within the sample. The mix of industries participating in the survey differed from the overall mix of industries in the Company's service territory. Cadmus applied the weights shown in Table 16 to correct for this bias.

Table 16. Survey Weights

Industry	Population	Sample Size	Normalized Weight
Transportation Equipment	45	8	0.6
Nonmetallic Mineral Products	45	2	2.4
Printing and Related Support	20	3	0.7
Mining	21	2	1.1
Food	55	7	0.8
Miscellaneous	434	54	0.9
Furniture and Related Products	16	4	0.4
Electrical Equipment, Appliances, and Components	26	2	1.4
Plastics and Rubber Products	51	8	0.7
Fabricated Metal Products	172	32	0.6
Chemicals	44	3	1.6
Beverage and Tobacco Products	35	3	1.2
Wood Products	44	5	0.9
Petroleum and Coal Products	31	3	1.1
Primary Metals	33	4	0.9
Machinery	80	7	1.2
Paper	24	4	0.6
Water	10	1	1.1
Textiles	4	1	0.4
Computer and Electronic Products	13	1	1.4

The overall sample size of 154 is large enough to produce results at a 90% statistical confidence with a margin of error of ± 10% for most results.

Facility Characteristics and Electricity End Uses

Cadmus asked industrial customers to identify their industry, their facility's size (by square footage and the number of buildings at the facility), facility ownership, and electricity and natural gas consumption end uses. Figure 9 shows that most industrial customers only had one building at their facilities; customer facilities' averaged 95,064 square feet in floor space.

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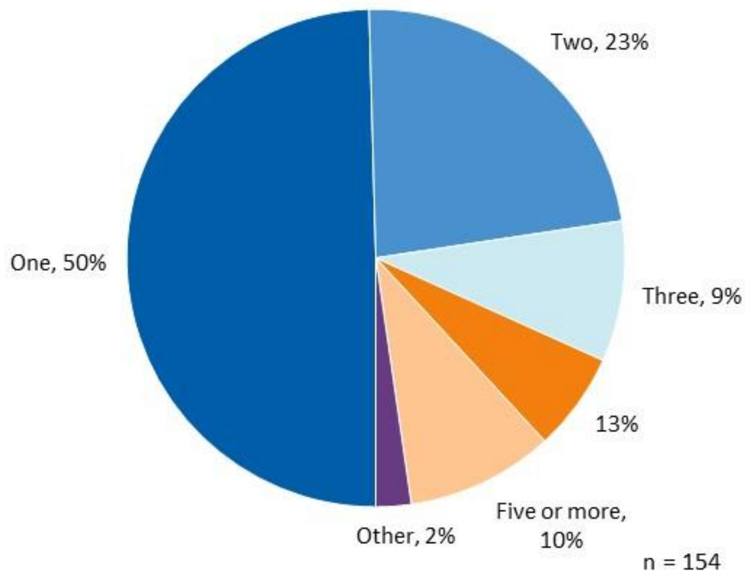
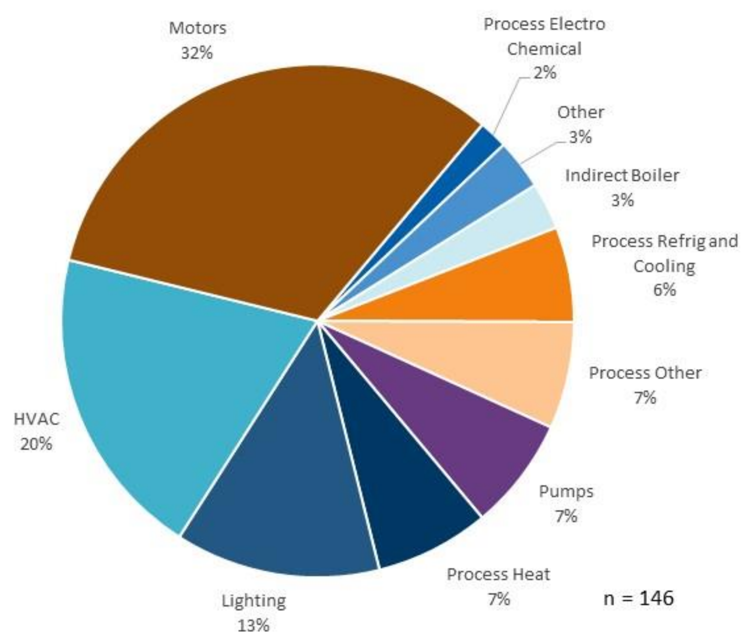
Figure 9. Number of Buildings at the Facility



Cadmus asked industrial customers to identify the percentage of annual electricity and gas consumption by end use. Across all industries, motors consumed 32% of customers' electricity. As shown in Figure 10, other primary reported electric end uses included facility HVAC (20%) and lighting (13%).

Figure 10. Distribution of Electricity Usage—Survey



Cadmus asked customers about end uses consuming electricity at their facilities; these questions sought to aid in understanding how facilities in the Company's service territory might differ from facilities across the country. We compared a distribution of energy consumption reported in the survey to a distribution developed using EIA MECS data.

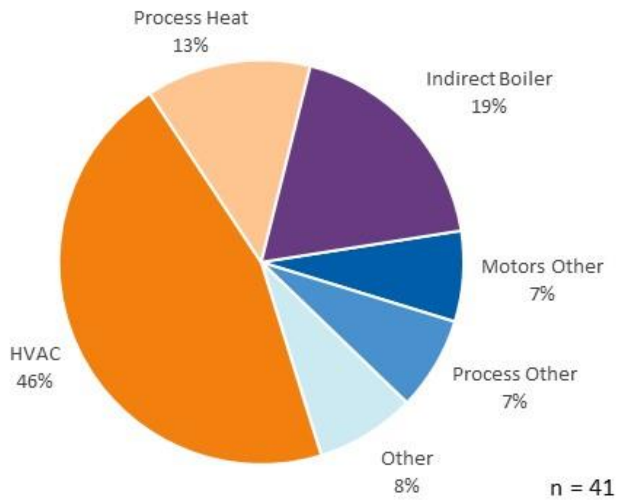
Overall, survey responses proved very similar to MECS data. Table 17 shows the respective distribution of electric end-use usage derived from the survey and from EIA MECS. Note: The summary of EIA MECS data accounts for the mixture of industries and consumption in the Company's service territory. That is, the MECS distribution is a weighted average of MECS usage, weighted by the industries and usage in the Company's service territory.

Table 17. Survey and EIA MECS Electric End-Use Consumption

End Use	Percent of Total	
	Survey (n = 146)	EIA MECS
Process Electro Chemical	2%	7%
Other	3%	5%
Indirect Boiler	3%	1%
Process Refrigeration and Cooling	6%	9%
Process Other	7%	3%
Pumps	7%	11%
Process Heat	7%	14%
Lighting	13%	7%
HVAC	20%	16%
Motors	32%	28%
Total	**100%**	**100%**

When asked about natural gas end-use consumption, survey participants said most of their natural gas usage resulted from facility heating, indirect boiler usage, and heating processes. Figure 11 shows survey respondents' reported distribution of natural gas usage by end use.

Figure 11. Distribution of Natural Gas Usage—Survey



Fewer survey participants reported natural gas usage—41 compared to the 146 reporting electricity usage. Due to the sample's smaller size, the natural gas end-use distribution results proved less certain than the electric end-use distribution results. This uncertainty becomes evident when comparing survey responses for natural gas to EIA MECS. While EIA MECS data also identify HVAC, process heat, and indirect boilers end uses as the highest consuming end uses, MECS attributes greater usage to process heat and indirect boilers. Table 18 shows the distribution of natural gas end-use usage derived from the survey and EIA MECS.

Table 18. Survey and EIA MECS Natural Gas End Use Consumption

End Use	Percent of Total	
	Survey (n = 41)	EIA MECS
Motors Other	7%	0%
Process Other	7%	3%
Other	8%	3%
HVAC	46%	28%
Process Heat	13%	32%
Indirect Boiler	19%	34%
Total	100%	100%

Energy Management Practices and Recent Energy Efficiency Activity

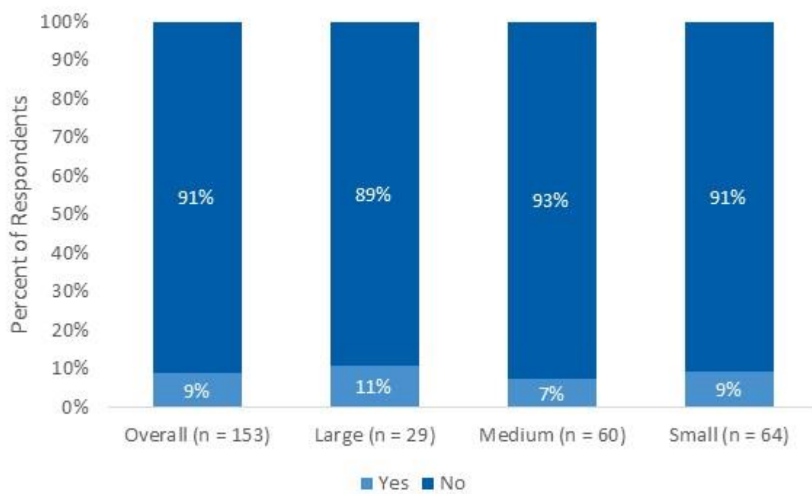
Cadmus analyzed questions pertaining to energy management practices and recent energy efficiency activity, both for the entire sample and for subsets of the sample, demarcated by size. We considered three groups: the top 30 consuming respondents (large); the middle 60 consuming respondents (medium); and the bottom 64 consuming respondents (small). Generally, the large group included customers with average monthly usage above 250,000 kWh, the medium group included customers with monthly usage between 13,000 and 250,000 kWh, and the small group included customers with monthly consumption under 13,000 kWh. Table 19 details monthly usage by group.

Table 19. Monthly Usage by Group

Group	Mean Usage	Median Usage	Standard Deviation
Large	1,564,554	875,075	1,741,887
Medium	72,137	44,415	62,395
Small	4,755	4,855	3,083
Overall	334,865	21,354	972,501

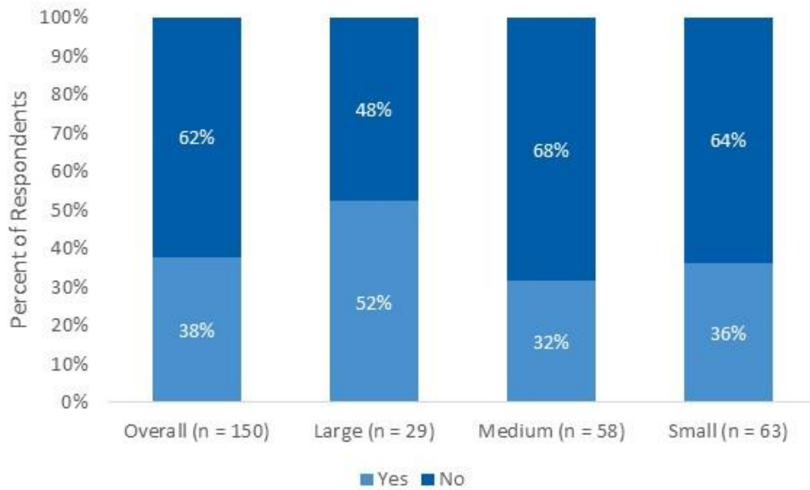
As shown in Figure 12, 91% of respondents (n=153) said they did not have an energy manager at their facility, a result consistent across the three usage groups.

Figure 12. Energy Manager Present on Site



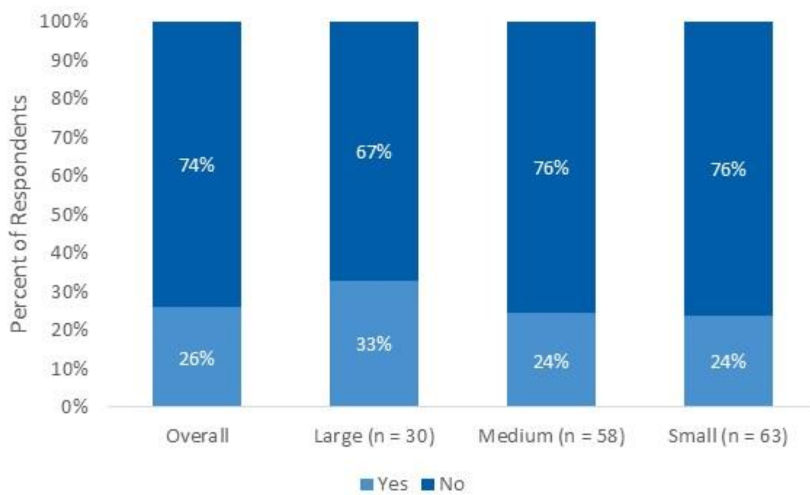
While a small proportion of sites reported the presence of a dedicated energy manager, approximately 38% of respondents said they had policies or plans that incorporated energy or energy efficiency. As shown in Figure 13, over one-half of the large customers said they had policies or plans that incorporated energy use, while roughly one-third of medium and small customers said they had such policies or plans.

Figure 13. Has Policies or Plans that Incorporate Energy Use or Energy Efficiency



As shown in Figure 14, 26% of customers (n=151) had goals related to energy or energy efficiency. Roughly one-third of large customers said they had energy-related goals, while one-quarter of small and medium customers said they had energy-related goals.

Figure 14. Has Goals Related to Energy Efficiency



Thirty-five percent of respondents (n=153) had conducted an assessment of energy-savings opportunities at their facility (n=153), but only 2% (n=59) reported that their facility currently sought

energy management certification.[14] Figure 15 and Figure 16 show responses for these questions by usage group.

Figure 15. Conducted an Assessment of Energy-Savings Opportunities

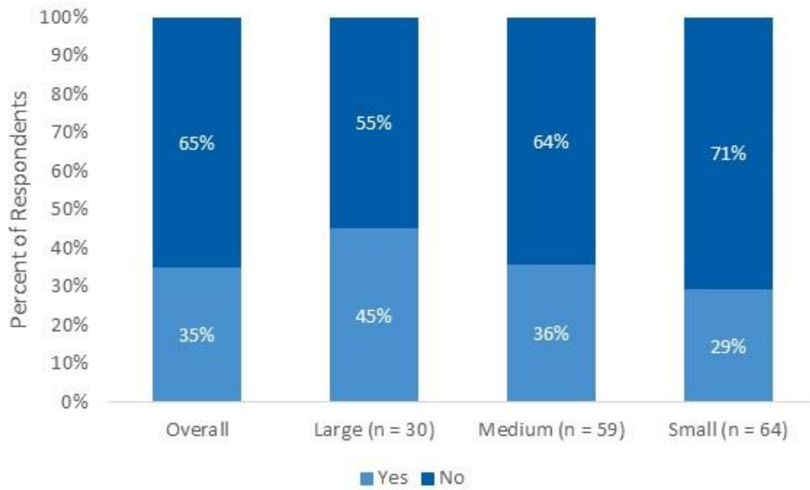
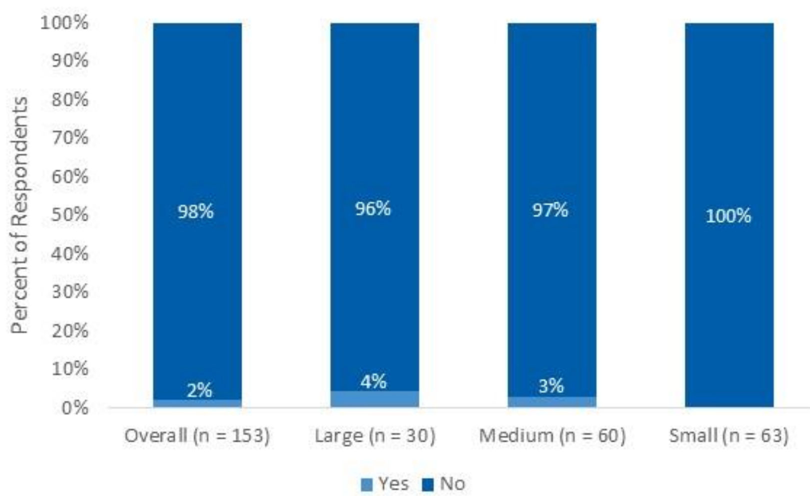


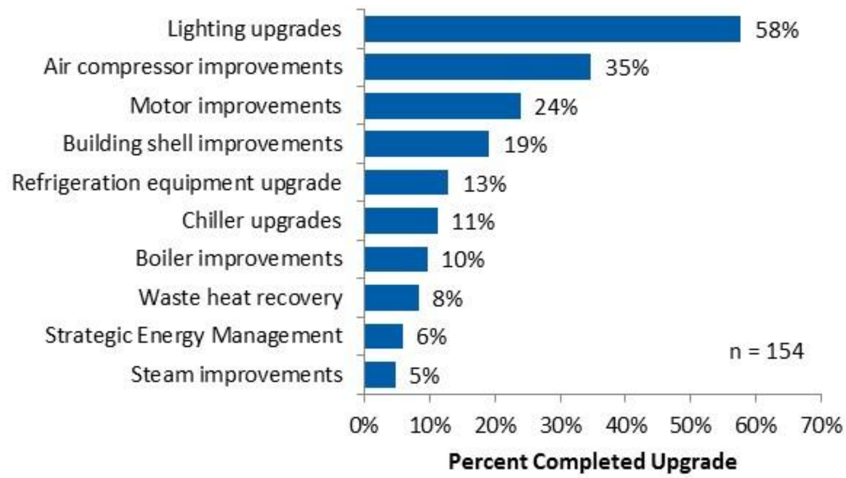
Figure 16.Pursued Energy Management Certification



14 Through ISO 50001, DOE Superior Energy Performance, or a similar certification method.

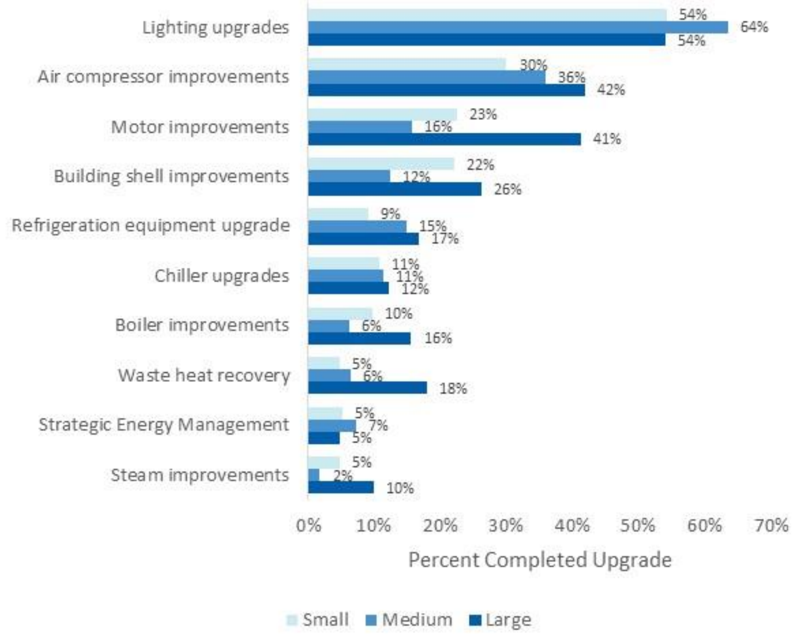
In the last five years, 65% of customers (n=153) made upgrades or retrofits or purchased new energy-efficient equipment for their facilities. As shown in Figure 17, respondents most commonly cited upgrades for lighting, air compressor improvements, and motor improvements.

Figure 17. Upgrades Completed by Type



Some types of upgrades (e.g., air compressor improvements, motor improvements, boiler improvements, waste heat recovery) proved more common in large facilities, compared to small and medium facilities. Figure 18 shows the proportion of respondents who completed upgrades, per upgrade type and usage group.

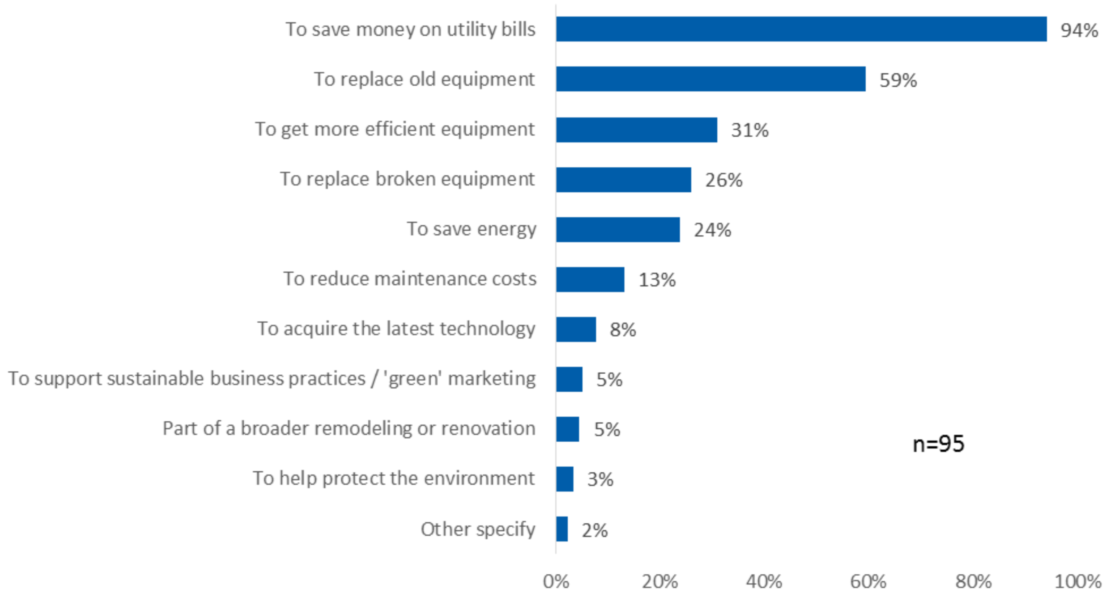
Figure 18. Percent Completed Upgrade by Usage Group



Energy Efficiency Decision Making

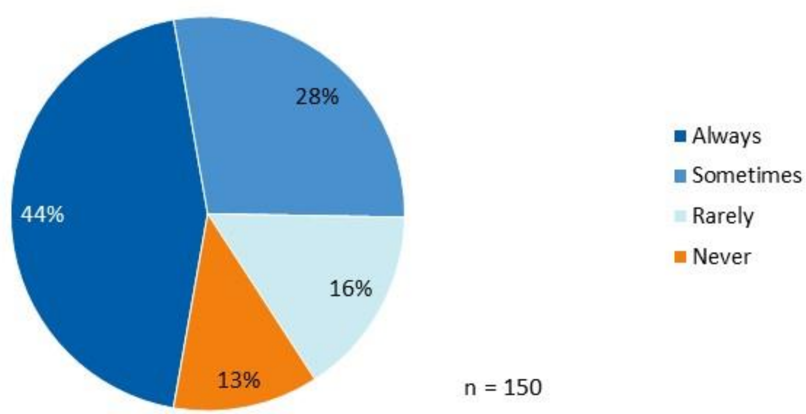
As shown in Figure 19, most industrial customers made energy upgrades to save money on utility bills (94%) or to replace old equipment (59%). Other reasons included procuring more efficient equipment (31%) or to replace broken equipment (26%).

Figure 19. Reasons for Making Energy Upgrades



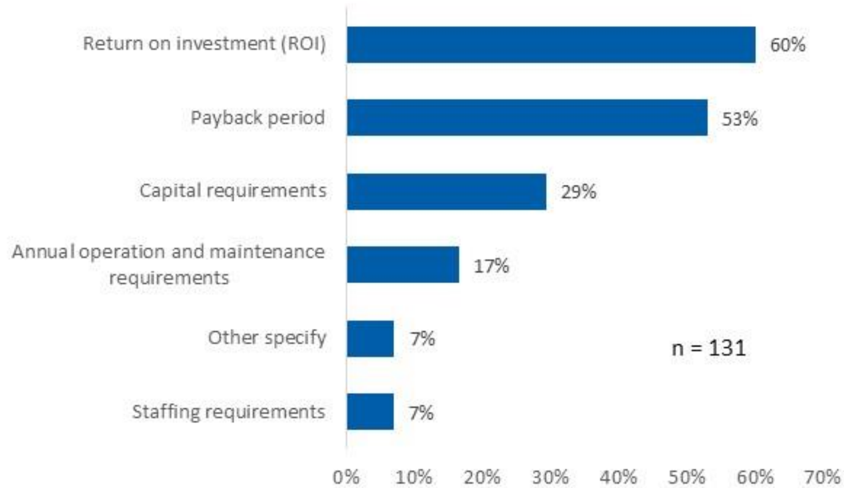
As shown in Figure 20, 61% percent of industrial customers (n=141) planned to install energy-efficient equipment at their facilities in the next five years, and 44% said they always considered energy use when buying new equipment.

Figure 20. Considers Energy Use When Purchasing Equipment



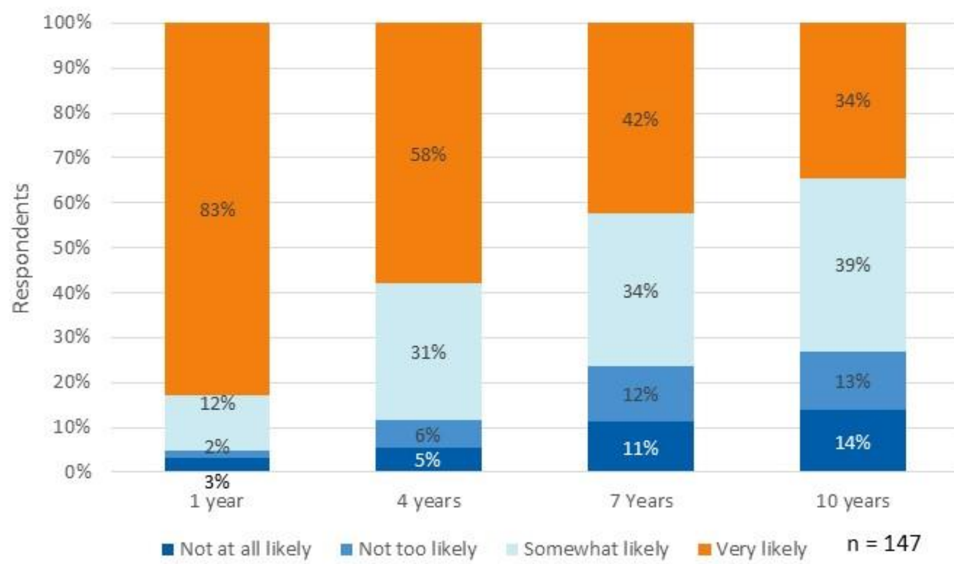
Respondents reported the primary criteria for deciding whether an industrial customer would make energy upgrades or choose energy-efficient equipment as the equipment's payback period (50%) and return on investment (29%). Figure 21 also shows other criteria that industrial customers consider.

Figure 21. Criteria for Making Energy Upgrades or Choosing Energy-Efficient Equipment



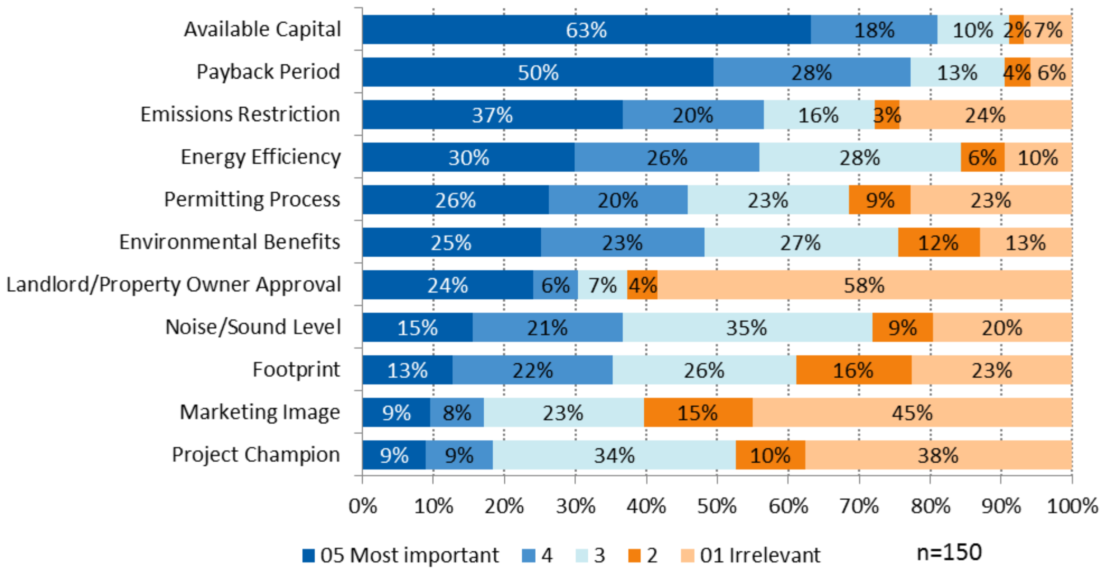
As shown in Figure 22, industrial customers most likely selected energy-efficient equipment when equipment payback periods fell within one year (95%). The longer the payback period, the less likely customers would select energy-efficient equipment.

Figure 22. Likelihood Respondent Will Select Energy-Efficient Equipment by Payback Period



Overall, industrial customers rated available capital as the most important factor when deciding to buy new equipment, as shown in Figure 23; they cited the payback period as the second-most important criteria, followed by emissions restrictions and energy efficiency.

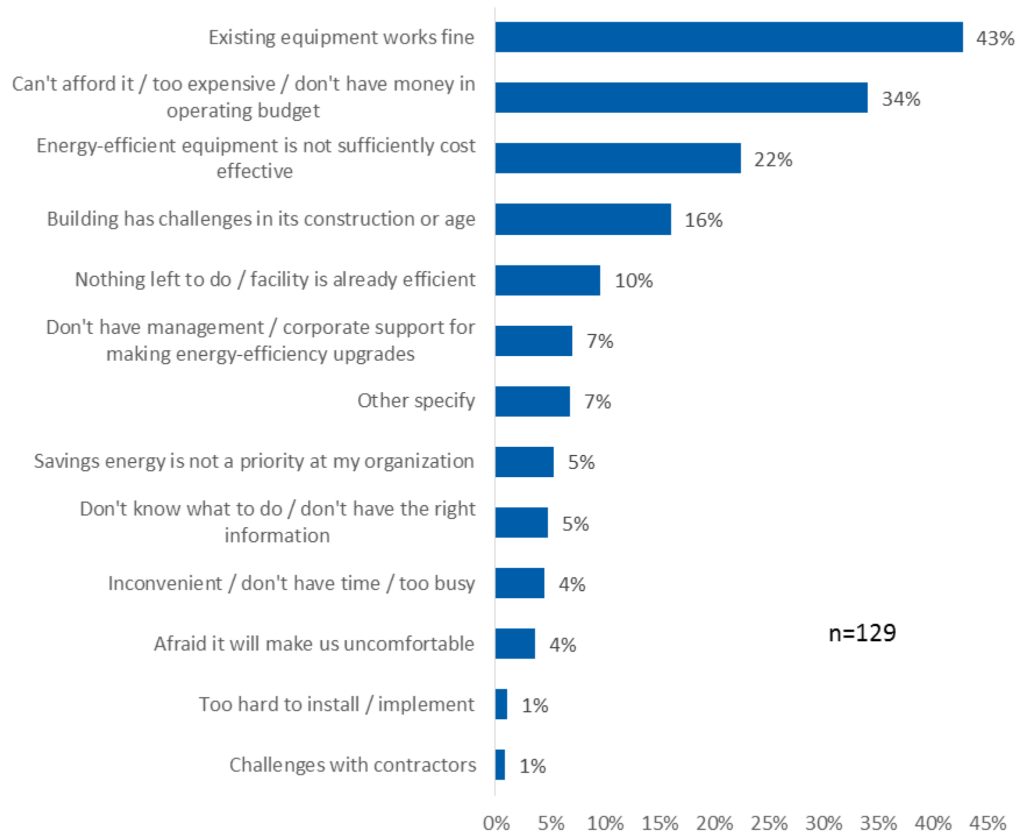
Figure 23. Reasons for Purchasing Energy-Efficient Equipment



The surveys found 61% of industrial customers (n=147) did not have money in their capital budgets for energy-efficient upgrades, and 71% (n=143) did not have money for energy-efficient upgrades in their operating budgets.

For most industrial customers, properly operating existing equipment proved the most prevalent obstacle to saving energy. As shown in Figure 24, the second- and third- most prevalent obstacles were lack of funds and finding energy-efficient equipment not sufficiently cost-effective.

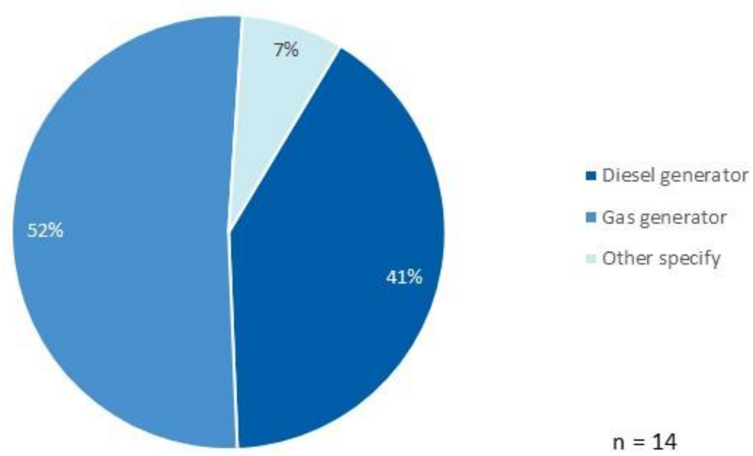
Figure 24. Reasons for Not Pursuing Energy Upgrades



Distributed Generation and Load Shifting

Only 10% of industrial customers (n=151) reported electric generation capabilities at their facilities. As shown in Figure 25, gas generators provided the most common form of on-site electricity generators, followed by diesel generators.

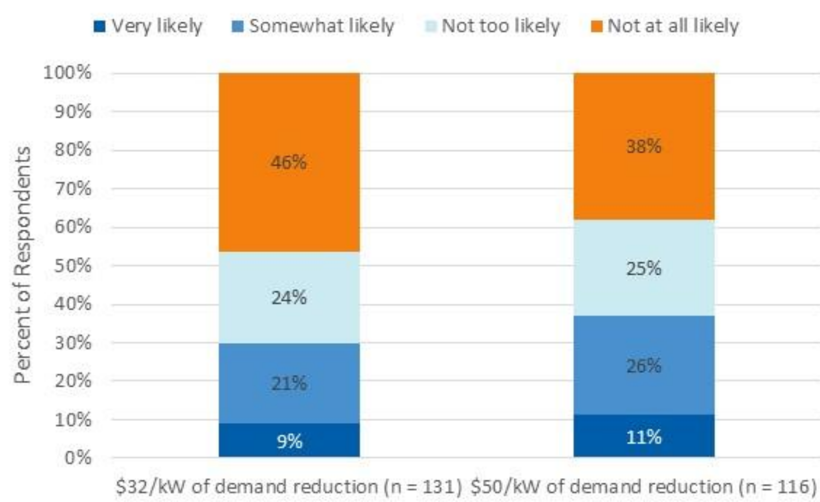
Figure 25. On-Site Generation



Industrial customers were unlikely to install distributed generation at their facilities in the next five years, 74% of customers (n=133) were not at all likely to install distributed generation, and 21% were not too likely to install it.

Cadmus asked survey participants about their general familiarity with demand response programs and whether they would be willing to participate in a program, if it were offered to industrial customers. Fifty-one percent of industrial customers (n=149) were familiar with DR programs. Most customers, however, were unlikely to enroll in a DR program, regardless of design, as illustrated in Figure 26.

Figure 26. Willingness to Enroll in Demand Response Programs

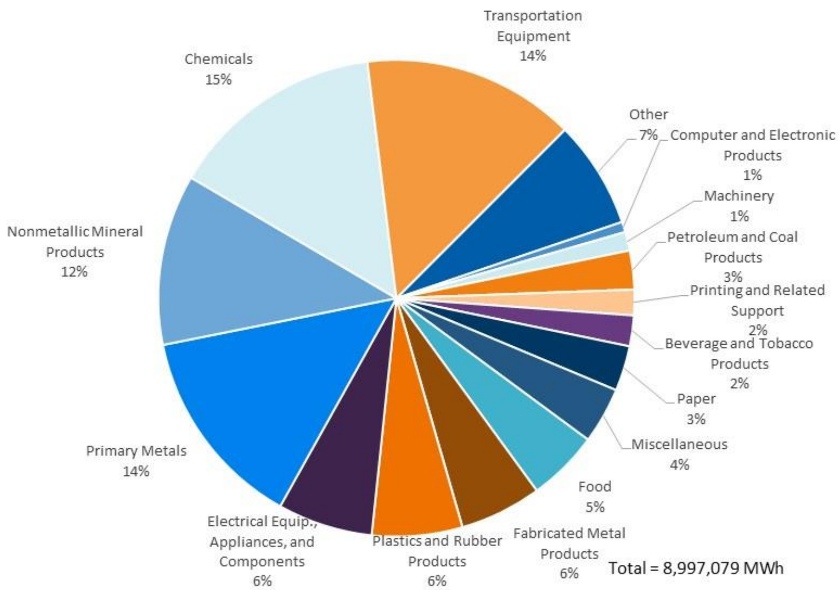


Baseline Forecasts

Electric

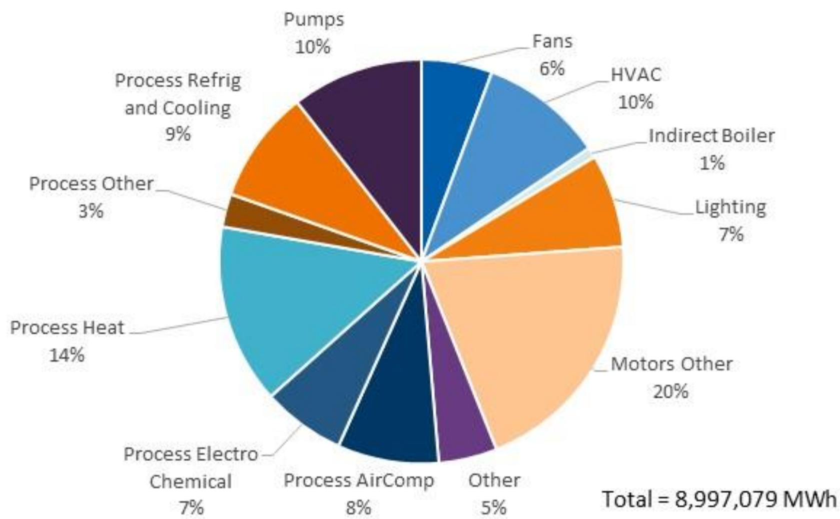
Cadmus developed baseline forecasts for 22 industrial segments and 12 electric end uses. We produced separate forecasts for each utility and ensured end-use forecasts matched utility-specific forecasts. Figure 27 shows the distribution of baseline sales by industry. Four industries consumed the greatest amount of electricity: transportation equipment manufacturing, chemical manufacturing, primary metal manufacturing, and nonmetallic mineral products. These accounted for roughly 55% of total industrial electric consumption.

Figure 27. Electric Baseline Consumption by Industry—2035



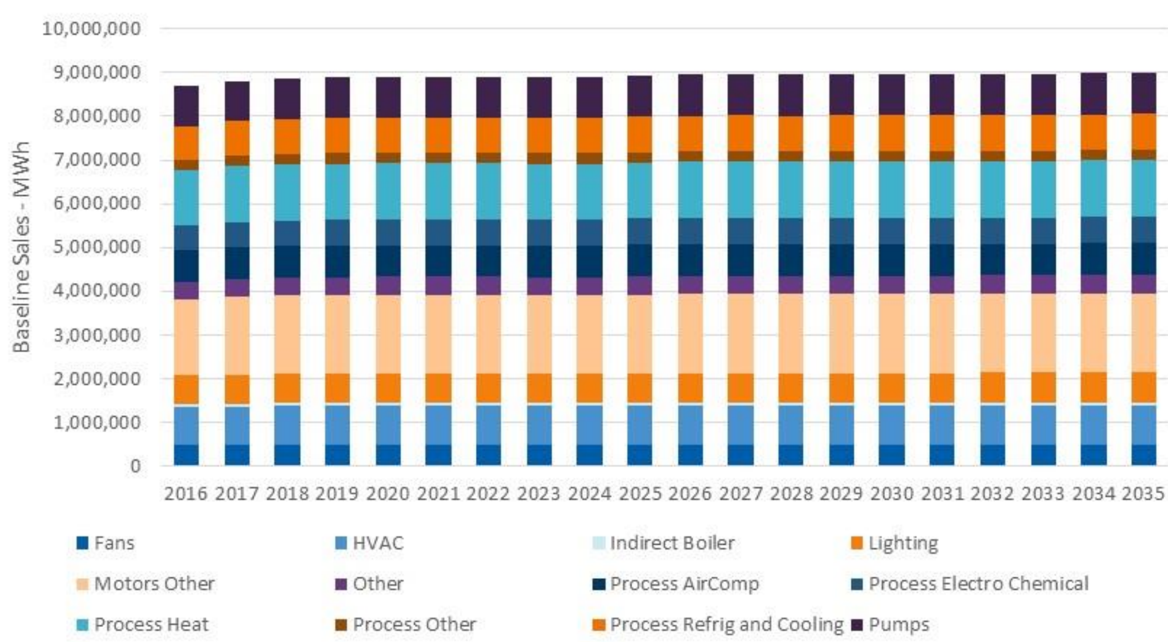
Industrial consumption spreads various motors, lighting, HVAC, and process end uses. Figure 28 shows the distribution of industrial electric consumption by end use. Motors account for roughly one-fifth of total consumption, followed by process heat (14%), HVAC (10%), pumps (10%), and refrigeration and cooling processes (9%).

Figure 28. Electric Baseline Consumption by End Use—2035



Industrial load growth remained relatively flat over the 20-year study horizon, with industrial electric consumption projected to grow 3.5% over the next 20 years. Figure 29 displays the industrial electricity consumption forecast.

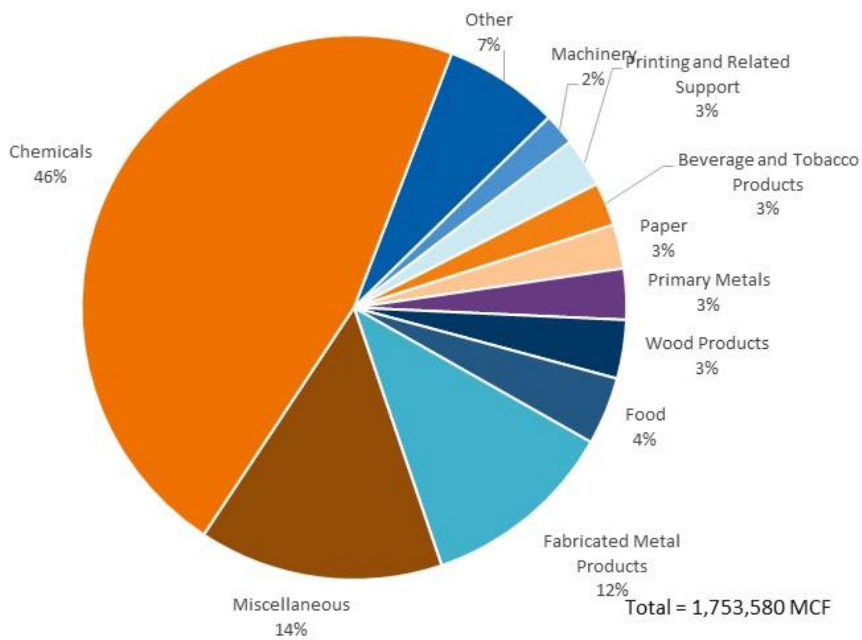
Figure 29. Electric Baseline Forecast by End Use



Natural Gas

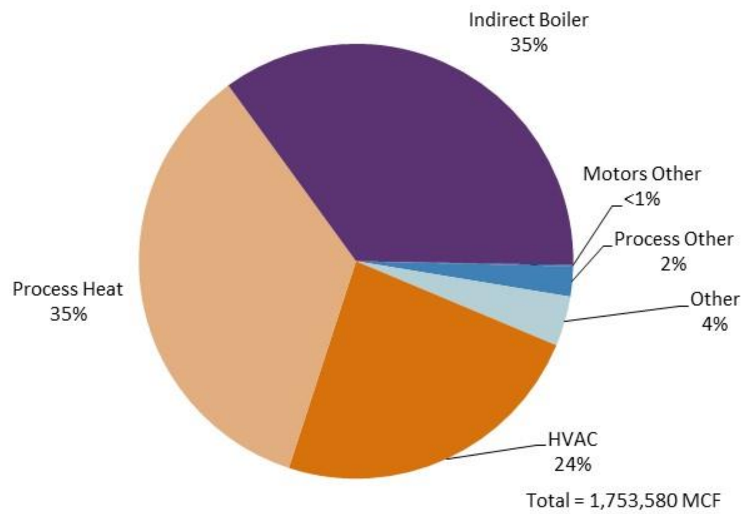
Cadmus produced end-use forecasts for the 16 industries provided natural gas by the Company, excluding transport customers. We disaggregated these industry-specific forecasts into six natural gas end uses. Chemical manufacturing accounts for nearly one-half (46%) of natural gas sales, followed by miscellaneous manufacturing (14%), and fabricated metal products (12%). Figure 30 shows the distribution of baseline natural gas consumption by industry.

Figure 30. Natural Gas Baseline Sales by Industry



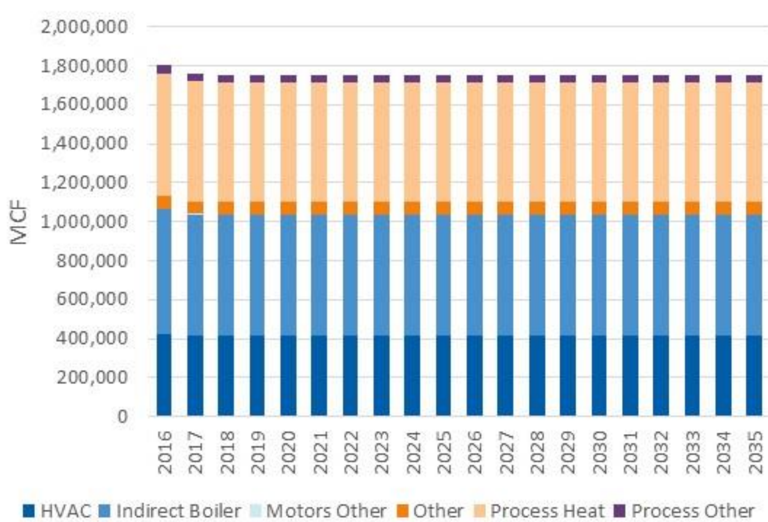
The indirect boiler, process heat, and HVAC end uses accounted for nearly all baseline natural gas consumption, representing 35%, 35%, and 24% of baseline natural gas consumption, respectively. Figure 31 shows the overall natural gas baseline distribution by end use.

Figure 31. Natural Gas Baseline Sales by End Use



Natural gas forecasts declined slightly over the study horizon, with baseline consumption dropping by 2.6% over the next 20 years. Figure 32 shows projected natural gas consumption by end use.

Figure 32. Natural Gas Baseline Forecast by End Use



Energy Efficiency Potential

Scope of Analysis

This assessment sought to produce reasonable estimates of savings available in each utility's service territory over a 20-year horizon (2016–2035). The process assessed technical and economic potential separately for each utility, divided by fuel type. Within each utility's assessment, the study further distinguished among industry types and their respective applicable end uses.

Cadmus assessed the technical potential for 66 unique electric and 22 unique natural gas energy efficiency measures, as shown in Table 20.

Table 20. Energy Efficiency Measure Counts

Sector	Unique Measures	Permutations by Utility Industry and End Use
Electric	66	1,769
Natural Gas	22	267

The list included an aggregation of recommendations made by Industrial Assessment Centers throughout the country and measures compiled from other studies, including the Northwest Power and Conservation Council's 6th Power Plan, and California's DEER. Considering all permutations across applicable industries, fuels, and end uses, Cadmus analyzed nearly 2,000 energy efficiency measures.

Electric Detailed Results

Table 21 summarizes electric technical and economic potential by utility. Cumulative technical potential can account for up to 15% of baseline sales by 2035, while economic potential can account for nearly 14% of the Company's 2035 sales forecast. Approximately 88% of technical potential is economic.

Table 21. Electric Technical and Economic Energy Efficiency Potential – Energy (MWh)

Sector	Baseline Sales in 2035	20-Year Cumulative MWh		Percent of Baseline		Economic as a % of Technical
		Technical Potential	Economic Potential	Technical Potential	Economic Potential	
LGE	2,626,749	428,025	384,170	16.3%	14.6%	90%
KU	6,370,330	941,051	827,301	14.8%	13.0%	88%
Total	8,997,079	1,369,076	1,211,471	15.2%	13.5%	88%

Cadmus used industry-specific hourly load shapes and Company peak definitions to convert estimates of energy savings into demand savings. Table 22 shows peak technical and economic potential by utility. Overall, energy efficiency in the industrial sector could produce 168 MW of technically feasible savings, with 149 MW from cost-effective measures.

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Table 22. Electric Technical and Economic Electric Potential – Demand (MW)

Sector	20-Year Cumulative Potential - MW	
	Technical Potential	Economic Potential
LGE	53	48
KU	115	101
Total	168	149

While the distribution of economic potential by industry is similar to the distribution of baseline sales, the two are not identical as potential savings vary from industry to industry. Figure 33 shows the distribution of economic potential by industry. Akin to the baseline forecast, transportation equipment manufacturing, chemical manufacturing, nonmetallic mineral products, and primary metals account for the largest share of total economic potential. However, the distribution of economic potential by industry is not identical to the baseline forecast. For instance, primary metal manufacturing facilities account for 14% of baseline sales, but only represent 11% of economic potential.

Figure 33. Electric Economic Potential by Segment—Cumulative 2035

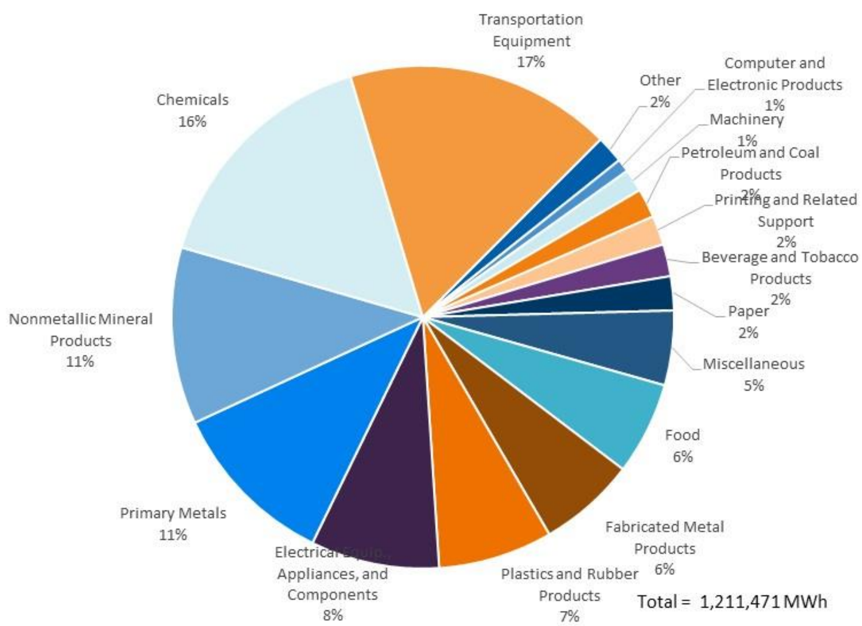

Table 23 shows baseline sales, and technical and economic potential for each industry. Industries with consumption primarily from motors and pumping (e.g., mining, water) tend to exhibit lower technical potential. In contrast, food manufacturing exhibits relatively high technical potential (22% of baseline sales) due to energy-savings opportunities in cooling and refrigeration processes that prove less common in other types of facilities.

Table 23. Electric Technical and Economic Electric Potential by Segment -- MWh

Segment	Baseline Sales in 2035—MWH	20-Year Cumulative—MWh		Percent of Baseline		Economic as a % of Technical
		Technical	Economic	Technical	Economic	
Apparel	14,367	2,029	1,732	14%	12%	85%
Beverage and Tobacco Products	187,331	27,859	24,974	15%	13%	90%
Chemicals	1,314,197	213,332	192,246	16%	15%	90%
Computer and Electronic Products	63,094	11,777	10,237	19%	16%	87%
Electrical Equip., Appliances, and Components	580,817	110,345	100,315	19%	17%	91%
Fabricated Metal Products	500,904	87,321	75,908	17%	15%	87%
Food	435,683	94,007	72,255	22%	17%	77%
Furniture and Related Products	22,547	3,305	2,796	15%	12%	85%
Machinery	114,138	19,999	17,635	18%	15%	88%
Mining	458,949	26,302	0	6%	0%	0%
Miscellaneous	343,218	63,550	58,106	19%	17%	91%
Nonmetallic Mineral Products	1,041,972	144,284	137,778	14%	13%	95%
Paper	275,859	30,250	26,538	11%	10%	88%
Petroleum and Coal Products	236,819	23,649	22,661	10%	10%	96%
Plastics and Rubber Products	551,607	101,824	89,164	18%	16%	88%
Primary Metals	1,236,746	138,020	131,566	11%	11%	95%
Printing and Related Support	155,993	25,588	22,824	16%	15%	89%
Textiles	690	105	91	15%	13%	86%
Transportation Equipment	1,300,150	226,966	207,802	17%	16%	92%
Wastewater	7,539	1,487	835	20%	11%	56%
Water	94,231	8,756	8,756	9%	9%	100%
Wood Products	60,224	8,319	7,253	14%	12%	87%
Total	**8,997,079**	**1,369,076**	**1,211,471**	**15%**	**13%**	**88%**

Most economic potential derives from measures applied to HVAC, process air compressors, process heat, and process refrigeration end uses. Collectively, measures applied to these end uses account for nearly two-thirds of total economic potential. Figure 34 shows the distribution of electric economic potential by end use.

Figure 34. Electric Economic Potential by End Use

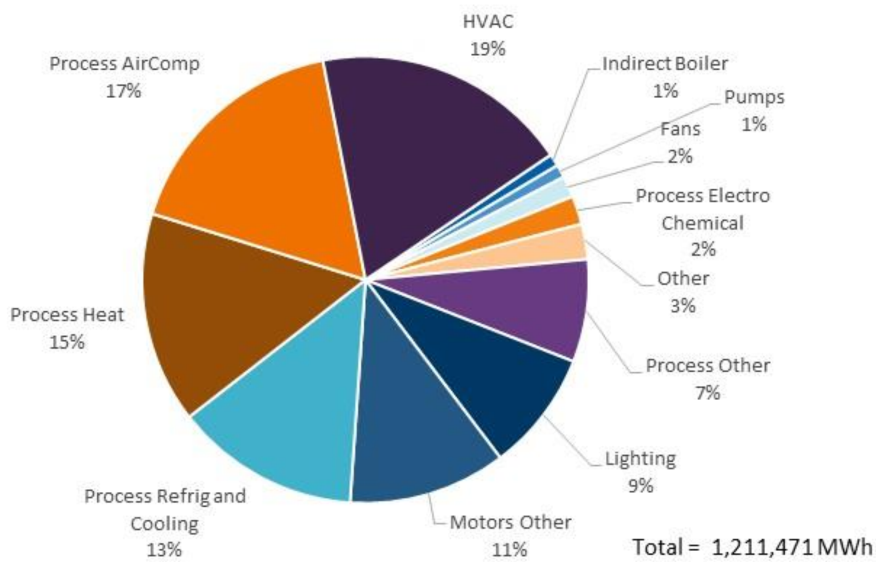

Table 24 shows baseline sales, technical potential, and economic potential for each electric end use. Savings potential varies significantly by end use. All high consuming end uses, air compressors, HVAC, process refrigeration and cooling, and lighting exhibit relatively high technical potential. Technical potential could account for 25% to 30% of baseline sales for each of these end uses.

Table 24. Electric Technical and Economic Potential by End Use -- MWh

Segment	Baseline Sales in 2035	20-Year Cumulative MWh		Percent of Baseline		Economic as a % of Technical
		Technical	Economic	Technical	Economic	
Fans	510,027	18,482	18,482	4%	4%	100%
HVAC	887,358	225,464	225,464	25%	25%	100%
Indirect Boiler	73,302	10,844	10,844	15%	15%	100%
Lighting	674,211	171,408	105,645	25%	16%	62%
Motors Other	1,810,053	170,661	138,440	9%	8%	81%
Other	420,487	39,353	30,894	9%	7%	79%
Process AirComp	729,208	207,984	207,984	29%	29%	100%
Process Electro Chemical	598,521	25,070	25,070	4%	4%	100%
Process Heat	1,293,471	185,322	185,322	14%	14%	100%
Process Other	239,538	89,898	89,898	38%	38%	100%

Segment	Baseline Sales in 2035	20-Year Cumulative MWh		Percent of Baseline		Economic as a % of Technical
		Technical	Economic	Technical	Economic	
Process Refrig and Cooling	813,301	212,938	162,024	26%	20%	76%
Pumps	947,600	11,651	11,403	1%	1%	98%
Total	**8,997,079**	**1,369,076**	**1,211,471**	**15%**	**13%**	**88%**

Table 25 lists the 10 highest-saving electric measures. These include waste heat recovery, building envelope and infiltration improvements, maintenance on HVAC equipment, variable frequency drives for air compressors, and efficient high-bay LED lighting. Nearly all measures listed prove cost-effective. One top 10 measure—efficient chiller equipment—did not pass the benefit-cost screen and had an overall levelized cost of roughly $0.055/kWh.

Table 25. Highest-Saving Electric Measures

Measure Name	20-Year Cumulative MWh		Percent of Total	
	Technical Potential	Achievable Potential (Medium)	Technical Potential	Achievable Potential
Thermal Systems Recover Heat And Use for Preheating, Space Heating, Power Generation, Steam Generation, Transformers, Exhausts, Engines, Compressors, Dryers, Waste Process Heat	109,471	54,736	8%	9%
Building Envelope Infiltration, Insulation, and Duct System Improvements	84,878	42,439	6%	7%
Cooling Tower Operation and Maintenance	79,861	39,931	6%	7%
Thermal Systems Add Insulation to Equipment, Reduce Infiltration, Isolate Hot or Cold Equipment	75,851	37,925	6%	6%
Optimize Chiller and Refrigeration Systems	57,601	28,801	4%	5%
Install Adjustable Frequency Drive for Variable Pump, Blower, and Compressor Loads	55,271	27,636	4%	5%
Lighting—High-Bay LED Packages	52,285	26,142	4%	4%
Equipment Upgrade—Replace Existing Chiller with High-Efficiency Model	50,914	0	4%	0%
Equipment Upgrade—Air Compressor	47,189	23,595	3%	4%
Install Compressor Controls	42,092	21,046	3%	3%

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Comparison to Other Studies

Cadmus compiled results from nine recent studies of industrial-sector energy efficiency potential completed in the last three years. In comparing the results of energy efficiency potential studies, it is important to consider the many factors that affect the results, including, but not limited to, mix and vintage of industries, fuel use patterns, energy-management practices and certain variations in analytic methods, such as the way local and national codes and standards are accounted for. Therefore, a comparison of the results between this and other studies should be considered indicative, rather than conclusive. A comparison of estimates of technical, economic and achievable potential across these studies are shown in Figure 35 through Figure 39 below.

Figure 35 shows technical potential as a percent of baseline sales for this study and the nine other studies considered. Study results indicate that approximately 15% of the Company's industrial sales can be met with technically feasible energy efficiency—this is slightly lower than the 18% average of the ten studies (which includes this study).

Figure 35. Technical Potential as Percent of Baseline Sales

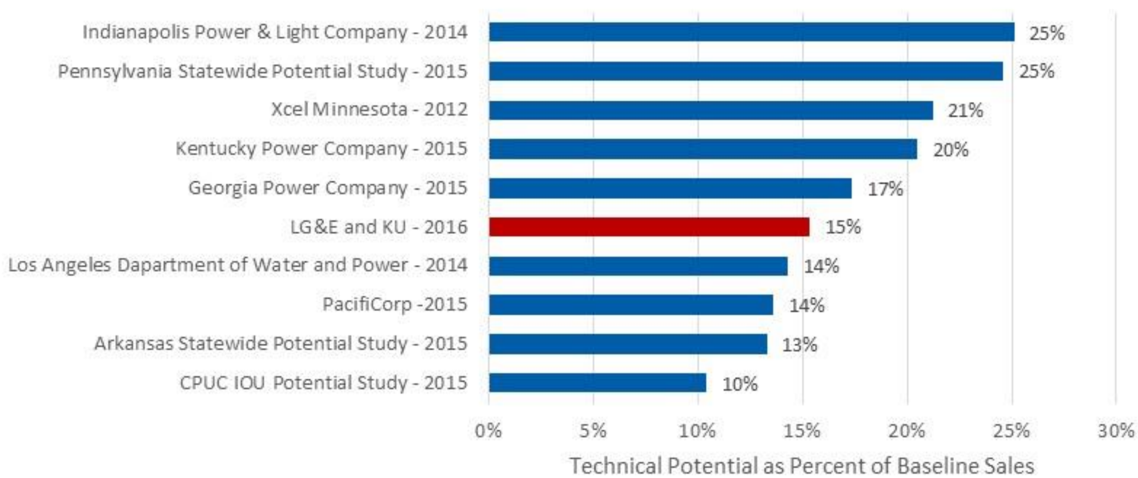
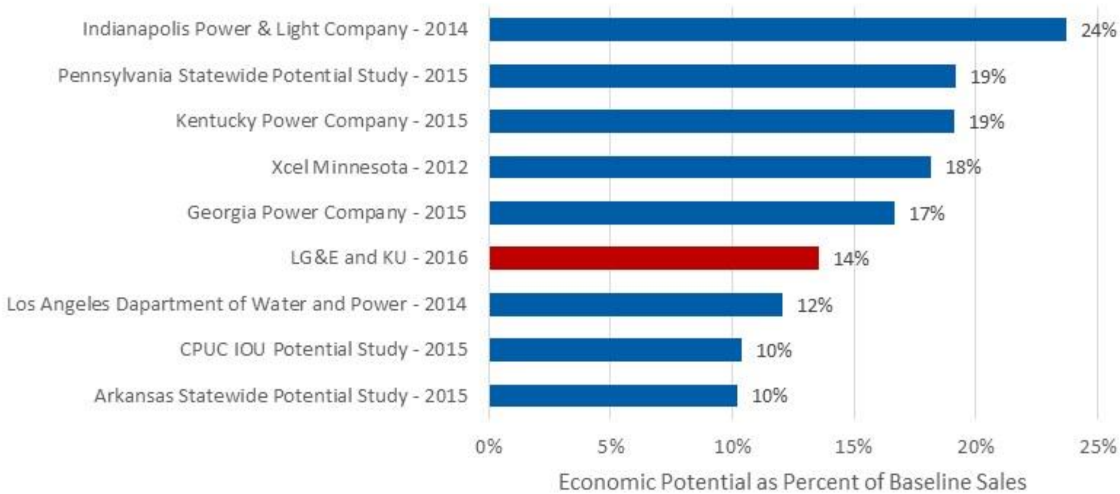


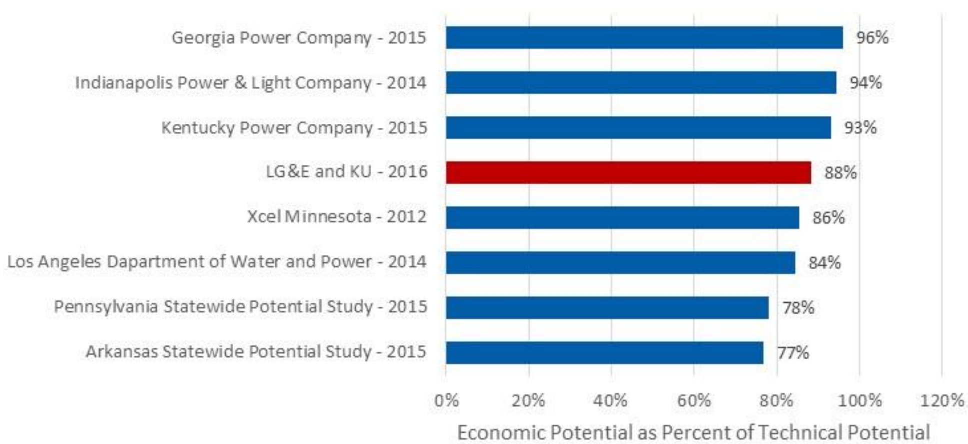
Figure 36 shows economic potential as a fraction of baseline sales. Approximately 14% of the Company's industrial sales can be met with cost-effective energy efficiency, compared to an average of 16% for all studies considered.

Figure 36. Economic Potential as Percent of Baseline Sales



When comparing economic potential across studies, it is useful to also look at economic potential as a fraction of technical potential, as shown in Figure 37. Generally, a higher fraction of technical potential is cost-effective in the industrial sector, compared to residential and commercial sectors. Study results indicate approximately 88% of technical potential is cost-effective, compared to an average of 87% for studies considered. However, this comparison may lead to erroneous conclusions due to differences among utilities in their avoided costs – a key determinant of cost-effectiveness

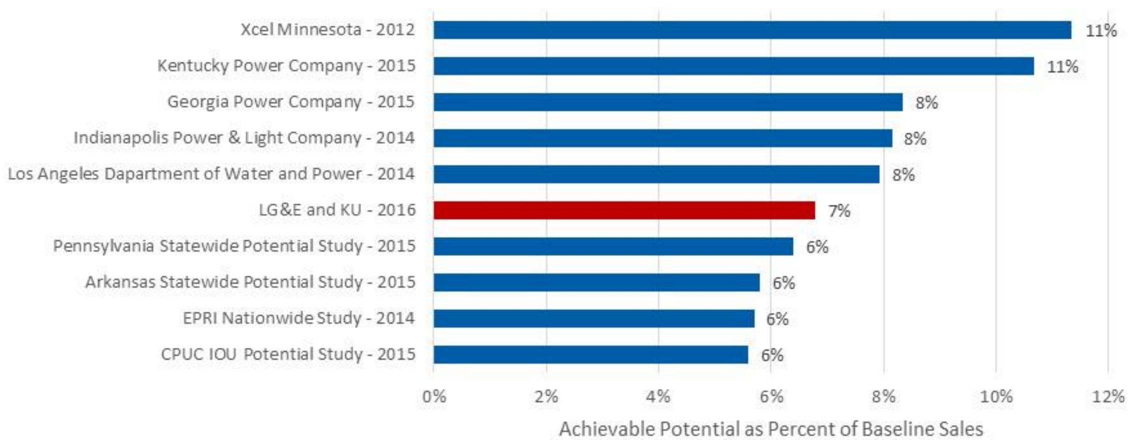
Figure 37. Economic Potential as Percent of Technical Potential - Comparison



Economic potential can vary from study to study and it is affected by factors including the utility's avoided costs, the components of the benefit-cost test, and discount rates. Also, administrative costs (often expressed as a fraction of incremental measure costs) can vary from study to study. Cadmus assumed an administrative cost equivalent to approximately 27% of incremental cost—this value represents an average of peer utilities.

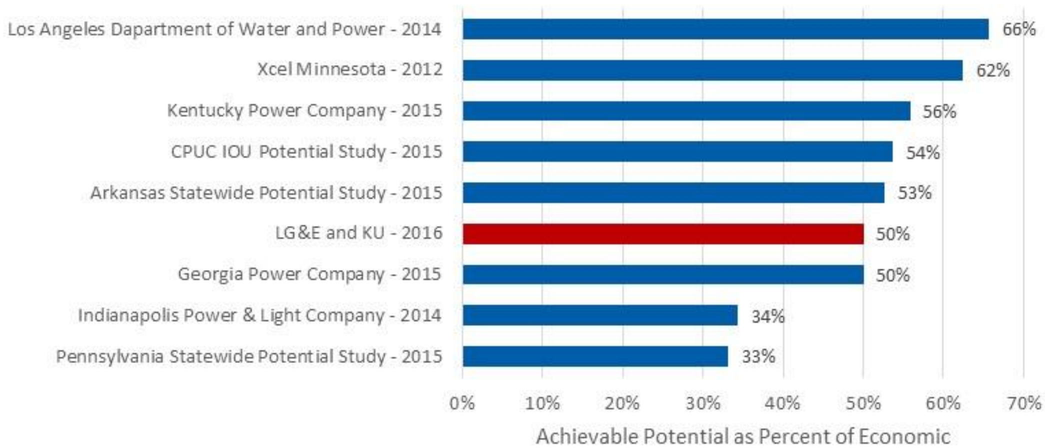
Figure 38 shows achievable potential as a fraction of baseline sales for each study reviewed. Each of these estimates represent the study's respective "medium" scenario. Cadmus found approximately 7% of the Company's industrial sales can be met with energy efficiency, compared to an average of 8% for all studies considered.

Figure 38. Achievable Potential - Comparison



Achievable potential expressed as a fraction of economic potential can provide a useful point of comparison, as shown for moderate achievable scenarios in Figure 39. Roughly half of the estimated economic potential is expected to be achievable under the medium scenario, compared to an average of 51% across all studies considered.

Figure 39. Achievable Relative to Economic Potential - Comparison



Natural Gas Detailed Results

Table 26 shows cumulative technical and economic potential over the 20-year study horizon. Technical potential can account for approximately 13% of baseline sales by 2035, and economic potential accounts for roughly slightly less than technical potential. Approximately 99% of technical potential comes from cost-effective measures.

Table 26. Natural Gas Technical and Economic Potential - MCF

Sector	Baseline Sales in 2035	20-Year Cumulative MCF		Percent of Baseline		Economic as a % of Technical
		Technical Potential	Economic Potential	Technical Potential	Economic Potential	
LGE	1,753,580	227,955	225,893	13.0%	12.9%	99%

Figure 40 shows the distribution of natural gas economic potential by industry. Chemical manufacturing accounts for the largest portion of natural gas economic potential (47%), followed by miscellaneous manufacturing (15%), and fabricated metal products (11%).

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Figure 40. Natural Gas Economic Potential by Industry

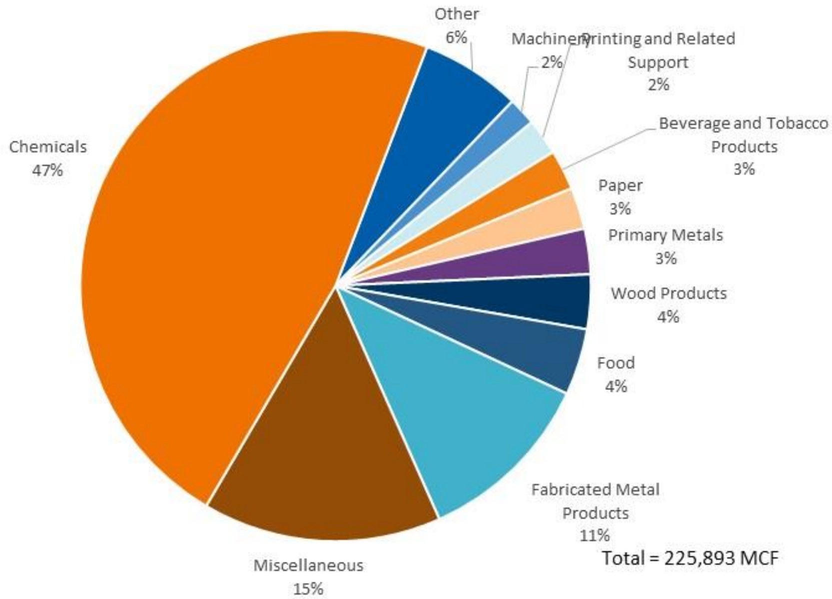

Table 27 shows baseline sales, technical potential, and economic potential by industry. For most industries, technical potential equals 10% to 14% of baseline sales.

Table 27. Natural Gas Potential by Industry - MCF

Segment	Baseline Sales in 2035	20-Year Cumulative MCF		Percent of Baseline		Economic as a % of Technical
		Technical Potential	Economic Potential	Technical Potential	Economic Potential	
Beverage and Tobacco Products	45,190	5,732	5,732	13%	13%	100%
Chemicals	816,108	108,158	107,002	13%	13%	99%
Fabricated Metal Products	202,668	25,783	25,722	13%	13%	100%
Food	70,656	9,546	9,508	14%	13%	100%
Furniture and Related Products	9,595	985	985	10%	10%	100%
Machinery	33,222	4,030	4,026	12%	12%	100%
Miscellaneous	254,391	34,175	34,175	13%	13%	100%
Nonmetallic Mineral Products	28,115	3,462	3,460	12%	12%	100%
Paper	46,007	6,265	5,930	14%	13%	95%
Petroleum and Coal Products	29,467	3,351	3,351	11%	11%	100%
Plastics and Rubber Products	25,539	3,501	3,501	14%	14%	100%
Primary Metals	53,086	6,574	6,499	12%	12%	99%
Printing and Related Support	51,222	5,178	5,178	10%	10%	100%
Textiles	571	0	0	0%	0%	N/A
Transportation Equipment	26,852	3,406	3,027	13%	11%	89%
Wood Products	60,891	7,811	7,797	13%	13%	100%
Total	**1,753,580**	**227,955**	**225,893**	**13%**	**13%**	**99%**

Most natural gas potential derives from measures applied to indirect boilers, process heat, or HVAC end uses. Economic potential for the indirect boiler end use accounts for 44% of total economic potential, while process heat and HVAC account for 34% and 22%, respectively. Figure 41 shows the distribution of natural gas economic potential by end use.

Figure 41. Natural Gas Economic Potential by End Use

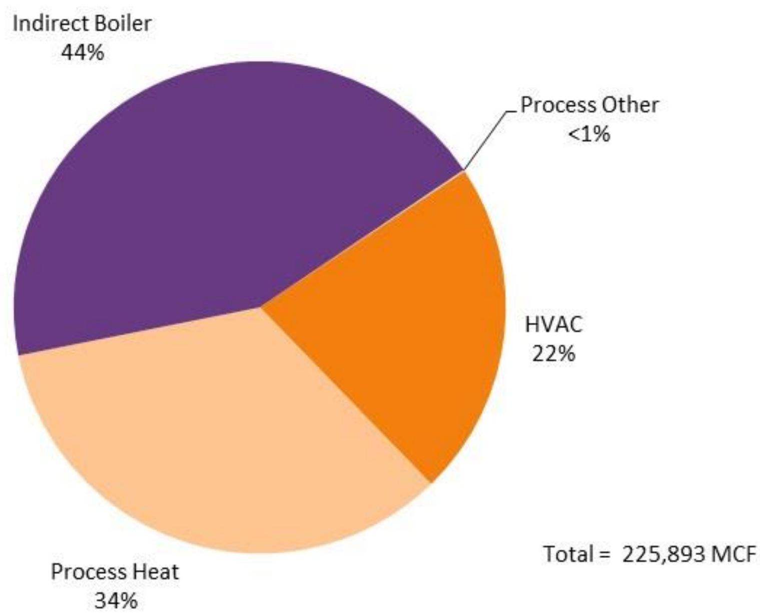

Table 28 shows baseline sales, technical potential, and economic potential by end use. Depending on the end use, technical potential, expressed as a fraction of baseline sales, falls between 7% and 16%.

Table 28. Natural Gas Economic Potential by End Use - MCF

Segment	Baseline Sales in 2035	20-Year Cumulative MCF		Percent of Baseline		Economic as a % of Technical
		Technical Potential	Economic Potential	Technical Potential	Economic Potential	
HVAC	415,425	49,881	49,881	12%	12%	100%
Indirect Boiler	618,799	99,017	98,694	16%	16%	100%
Motors Other	1,693	0	0	0%	0%	-
Other	65,040	0	0	0%	0%	-
Process Heat	613,369	77,409	77,083	13%	13%	100%
Process Other	39,254	1,648	236	4%	1%	14%
Total	**1,753,580**	**227,955**	**225,893**	**13%**	**13%**	**99%**

Table 29 shows the 10 highest-saving natural gas measures. These include strategic energy management (e.g., process improvement, optimization), equipment upgrades, waste heat recovery, and other various process improvements.

Table 29. Highest-Saving Natural Gas Measures

Measure Name	20-Year Cumulative MCF		Percent of Total	
	Technical	Achievable (Medium)	Technical	Achievable
Process Improvements To Reduce Energy Requirements	27,775	13,887	12%	12%
Waste Heat From Hot Flue Gases To Preheat	23,754	11,714	10%	10%
Install Or Repair Insulation On Condensate Lines And Optimize Condensate	20,486	10,243	9%	9%
Heat Recovery And Waste Heat For Process	19,130	9,565	8%	8%
Improve Combustion Control Capability And Air Flow	18,706	9,353	8%	8%
Equipment Upgrade - Replace Existing HVAC Unit With High Efficiency Model	18,332	9,166	8%	8%
Optimize Ventilation Air System	13,509	6,755	6%	6%
Equipment Upgrade - Boiler Replacement	12,827	6,413	6%	6%
HVAC Equipment Scheduling Improvements - HVAC Controls, Timers Or Thermostats	10,014	5,007	4%	4%
Optimize Heating System To Improve Burner Efficiency, Reduce Energy Requirements And Heat Treatment Process	9,883	4,942	4%	4%

Demand Response Potential

This section summarizes the results from an analysis of demand response (DR) potential for the industrial sector within LG&E's and KU's service territories. Demand response programmatic options seek to achieve the following:

- Help reduce peak demand during system emergencies or periods of extreme market prices;
- Promote improved system reliability; and
- In some cases, balance variable-load resources (particularly wind energy).

Benefits from DR resources accrue by providing incentives for customers to curtail loads during utility-specified events (e.g., direct load control [DLC] or load curtailment programs) or by offering pricing structures to induce participants to shift load away from peak periods (e.g., time-of-use [TOU] or Critical Peak Pricing programs).

Focusing on reducing a utility's capacity needs, DR programs rely on flexible loads that can be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. These programs seek to help reduce peak demand and promote improved system reliability. In some instances, the programs may defer investments in delivery and generation infrastructure.

DR objectives may be met through a broad range of strategies, both price-based (e.g., time-varying rates or interruptible tariffs) and incentive-based (e.g., DLC). This assessment focused on the most common DR strategies:

- **Thermal Energy Storage (TES)** refers to the installation of specialized equipment that allows customers to shift cooling loads to off-peak times. This equipment freezes large amounts of ice (typically at night, during low demand), which can be used for cooling during the day. Such programs often are coupled with TOU pricing, allowing TES participants to take advantage of lower electricity rates at night and reduce their usage during high-cost peak hours during the day.
- **Critical Peak Pricing** or extreme-day pricing refers to programs aiming to reduce system demand by encouraging customers to reduce their loads for a limited number of hours during the year. When such events occur, customers may curtail usage or pay substantially higher-than-standard retail rates. Critical Peak Pricing programs integrate a pricing structure similar to a TOU program, though Critical Peak Pricing uses more extreme pricing signals during critical events.
- ***Peak Load Reduction*** programs (sometimes called curtailment programs) utilize contractual arrangements between a utility and a third-party aggregator that works with utility customers. The third-party aggregator typically guarantees a specific curtailment level during an event period, achieving load reduction by working with utility customers that agree to curtail or interrupt their loads in whole or part when requested. In most cases, customers must participate once enrolled in the program, with incentives paid per curtailed kW. Customers may use backup generation to meet displaced loads. This is different from the Company's existing

curtailable service rider (CSR); the analysis does not consider the CSR. The analysis did not consider the Company's existing curtailable service rider (CSR).[15]

Table 30 shows Cadmus' assessment of the potential savings and levelized costs associated with implementation of Critical Peak Pricing and peak load reduction programs within LG&E's and KU's territory. If implemented, the Critical Peak Pricing program could expect to achieve 1.2 MW of peak reduction or 0.02% of system peak across both territories during a two-hour event. Estimates indicate a peak load reduction program would have a much larger impact, producing an expected 103.5 MW or 1.61% of peak load reduction achievable for a two-hour event across KU's and LG&E's territories. These are 20-year potential estimates; the programs will take an estimated three to five years to ramp up to full participation.

Table 30. Summary of Potential Assessment for Critical Peak Pricing, Peak Load Reduction Programs[16]

Program	Event Length	Utility	Achievable Load Reduction in 2035	Percent Peak Reduction	Levelized Cost of Demand per Year ($/kW)
Critical Peak Pricing	2 hours	LG&E	0.4	0.02%	$265
		KU	0.9		$106
	4 hours	LG&E	0.4	0.02%	$266
		KU	0.9		$105
Peak Load Reduction	2 hours	LG&E	29.3	1.61%	$52
		KU	74.2		$43
	4 hours	LG&E	28.9	1.62%	$52
		KU	75.0		$43

[15] The Peak Load Reduction program differs from the Company's existing curtailable service rider in a few ways. First, only customers who contract for no less than 1,000 kVA individually may participate in the Company's CSR, while the Commercial Peak Load Reduction program only requires the customer have an interval meter and demand higher than 200 kW. A small number of customers participate in the Company's CSR, while Cadmus identified approximately 1,500 customers eligible to participate in a Peak Load Curtailment program. Second, the CSR allows for up to 375 hours of curtailment and has restrictions on when load can be curtailed (e.g. all available units must be dispatched and all off-system sales must be curtailed). In contrast, the Company has more flexibility on the timing and duration of curtailment with a Peak Load Reduction program. Finally, while the Peak Load Reduction program provides a $/kW incentive curtailment, while the CSR provides customers with a different rate.

[16] The reduction shown occurs at the generator, not at the meter (i.e., line losses included). Future years assume a 1.9% rate of inflation and a discount rate of 6.48% for LG&E and 6.37% for KU.

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Methodology

Overview

Cadmus used two stages in assessing DR potential assessment for LG&E and KU: a research (or benchmarking) stage; and a data modeling stage.

In the benchmarking stage, Cadmus researched typical program characteristics for the three DR programs (e.g., Critical Peak Pricing, Peak Load Reduction, TES), reviewing several data sources to determine the appropriate program assumptions.

First, Cadmus reviewed data from the *FERC 2012 Assessment of Demand Response and Advanced Metering Staff Report*. We supplemented this with information from DR program evaluations for various utilities in North America, US DOE program reports (smartgrid.gov), the Demand Response Research Center at Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, the California Measurement Advisory Council database, and the Association for Demand Response & Smart Grid. LG&E and KU also provided information about their existing commercial load control programs.[17]

To conduct the analysis, Cadmus relied on our DR model, which utilizes a top-down approach (as described in the following section). Cadmus developed potential models only for Critical Peak Pricing and Peak Load Management programs. We investigated two different program designs, reviewing savings associated with short (two-hour) and long (four-hour) events, taking place in the top 40 hours during the summer months. As TES programs are relatively new, documentation of their impacts has yet to become widely available. Consequently, we performed a qualitative assessment for TES.

Approach

The DR potential analysis began with a top-down approach, which used data on utility system loads, disaggregated into sector, segment, and applicable end uses. Cadmus then estimated potential as a function of three variables: likelihood of participation, sheddability of process load (technical potential); and likelihood of event participation. The product of these program-specific assumptions could then be applied to the load profiles to estimate market potential for DR. The analysis used the following steps:

1. **Defined customer sectors, market segments, and applicable end uses.** In estimating the load basis, Cadmus first defined customer segments and applicable end uses, similar to those used in estimating energy efficiency potentials. We then disaggregated industrial loads into separate market segments:
    - Apparel
    - Beverage and Tobacco Products
    - Chemicals
    - Computer and Electronic Products
    - Electrical Equipment, Appliances, and Components
    - Paper
    - Petroleum and Coal Products
    - Plastics and Rubber Products
    - Primary Metals
    - Printing and Related Support

- Fabricated Metal Products
- Food
- Furniture and Related Products
- Machinery
- Mining[18]
- Nonmetallic Mineral Products
- Textiles
- Transportation Equipment
- Wastewater[1]
- Water
- Wood Products
- Miscellaneous

We further disaggregated segment load into the following end uses:

- Fans
- HVAC
- Indirect Boiler
- Lighting
- Pumps
- Motors (Other)
- Other
- Process
  - Air Compressor
  - Electrochemical
  - Heat
  - Refrigeration and Cooling
  - Other

2. **Compiled utility-specific sector end-use loads.** Establishing reliable estimates of DR potentials depends on accurate characterizations of sector, segment, and end-use loads. LG&E and KU provided system and industrial sector load profiles as well as annual percentages of sales for each of the above segments and end uses. Cadmus used these data to estimate the contribution of each end-use load to system peak loads. We modeled programs for KU and LG&E separately.
3. **Estimated technical potential**. The analysis assumed a constant technical load reduction potential across industrial market segments for Critical Peak Pricing and Peak Load Reduction. These values were based on benchmarking research.
4. **Estimated market potential**. Market potential accounts for customers' ability and willingness to participate in DR, subject to their unique business priorities, operating requirements, and economic (price) considerations. Cadmus derived market potential estimates from adjusting the technical potential by two factors: (1) expected program participation rates (the percentage of customers likely to enroll in the program); and (2) expected event participation rates (the percentage of customers that may participate in a particular DR event). We used data from secondary research and the customer survey to project event and program participation rates.
5. **Estimated costs.** Finally, Cadmus calculated the levelized cost (cost per kW per year) for each program option using estimates of program development, technology, incentive, administration, and communications costs.

[18] Market segments present in KU's industrial sector, but not in LG&E's.

Summary of Results

The following sections present potential study results for each utility by program. Each section includes: a program description; assumptions used in the analysis; and, where modeling was completed, a graph showing the 20-year potential.

Thermal Energy Storage

TES programs are designed to reduce demand associated with cooling during on-peak periods. Ice, made during off-peak periods (unoccupied times at night), is used to cool the building later in the day, during peak demand periods. Especially when conducted in conjunction with a TOU rate structure, TES systems mitigate high customer costs associated with cooling loads during on-peak summer hours. The benefits realized by the customer and utility derive from shifting load each day from on-peak to off-peak periods, when electricity is less expensive to generate and to buy, though TES systems may increase or decrease energy consumption. While some jurisdictions offer residential TES programs, this study assumed the program targets industrial customers.

Assumptions

While offered in a number of jurisdictions across the country, TES programs currently reach only a small number of customers. The Permanent Load Shift (PLS) program offered by several California IOUs began in 2012, following several pilots conducted in the state from 2008 to 2011. In 2012, a representative of Ice Energy (a leading manufacturer or TES systems) reported equipment costs near $2,200 per kW installed for new systems. In 2014, the program identified 11 active applications, anticipating enrollment of approximately 27 customers each year by 2025. In 2014, the California PLS program offered an incentive of $875 per kW shifted through installation of a new TES system.

Though TES systems affect only a building's cooling load, participants can almost entirely shift this demand (assuming the system is sized properly). Ice Energy reports its product can shift up to 95% of a customer's cooling load during peak hours. In some cases, however, customers may choose to implement a *partial shift*, installing a TES system capable of shifting some but not all of their cooling load.

In the 2014 impact evaluation of the California PLS program, seven of the nine customers (with sufficient data) planned to implement a full shift; the remaining two had designed systems for partial shift. Once installed, TES systems may last up to 20 years, with an impact degradation of approximately 2.5% annually past year five.

Results

With limited existing information on enacted TES programs, Cadmus did not perform a full potential study for this program type. As additional performance metrics become available these programs, the potential for savings may be reexamined.

Critical Peak Pricing

Under a Critical Peak Pricing program, customers receive a discount on their normal retail rates during non-critical peak periods in exchange for paying predetermined, premium prices during critical peak events. As the peak price has been set in advance, customers maintain some degree of certainty regarding participation costs. The basic rate structure follows a TOU tariff, with the rate using fixed prices for usage during different time blocks (typically: on-, off-, and mid-peak prices by season).

During Critical Peak Pricing events, the normal peak price under a TOU rate structure increases to a much higher price, generally set to reflect the utility's avoided supply cost during peak periods. The length of the Critical Peak Pricing window serves as an important driver in overall savings, as short windows may cause peak demand to occur in periods adjacent to the Critical Peak Pricing window. If LG&E and KU expect significant variation in the peak hour, a wider event window would be called.

Critical Peak Pricing programs require advanced meter infrastructure (AMI) deployment. Since AMI would provide LG&E and KU with operational benefits, Cadmus modeled two levelized cost scenarios: one in which the AMI cost was attributed to the program, and one where it was not.

Assumptions

Table 31 shows Critical Peak Pricing program assumptions.

Table 31. Critical Peak Pricing—Potential Study Assumptions

Inputs	Value	Sources or Assumptions
Annual Administrative Costs ($)	$37,500	Assumes annual administrator costs of 25% of one full-time employee with a rate of $150,000 per year.
Technology/Communication Cost (per new participant)	$350	Critical Peak Pricing programs can incur technology costs for AMI, communications, and other devices. Benchmarking for an assumption of $350 per participant includes: OG&E/PSO $350; TVA potential $180; and PSE analysis $515, including AMI costs. Costs are similar to AMI alone, with AMI meter and communications estimates ranging from $165-$220. Since AMI would provide LG&E and KU operational benefits, the program is modeled with and without AMI costs.
Marketing Cost (per new participant)	$500	Assumes 10 hours of effort by staff, valued at $50/hour. An additional hour per year is assumed for ongoing marketing and customer support.
Overhead: First Costs	$400,000	Standard program development assumption, including necessary internal labor, research, and IT/billing system changes; TVA potential study $400,000.
Technical Potential as percent of Load Basis	5%	In the 2010 CA Statewide Nonresidential Critical Peak Pricing Evaluation, program impacts ranged from 2.8%-5.26% of load for SCE, SDG&E, and PG&E. In 2011, load impacts ranged by utility: PG&E averaged 5.9%; SCE

		averaged 5.7%; and SDG&E averaged 5.8%. In 2013, OG&E achieved 12%.
Program Participation (%)	2%	Participation rates in opt-in Critical Peak Pricing programs are typically low. In 2005, California experienced a 1.1% participation rate across the state, accounting for a total of 2.9% of peak load. Individual utility participation rates of 3.5% for PG&E and 2% for OG&E have been noted.
Event Participation (%)	100%	Event participation is captured in the average load impact.

LG&E Results

Potential Savings

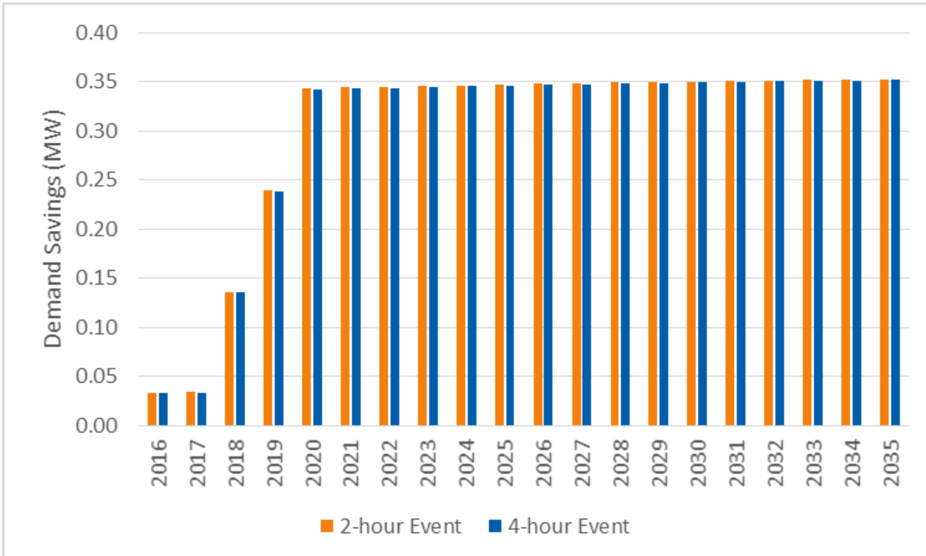
In order to assess the achievable savings from a Critical Peak Pricing program in LG&E territory, we examined the savings associated with the program for events lasting two hours and those lasting four hours during the top 40 hours in the summer season. The results of this analysis are shown in Table 32.

Table 32. LG&E Critical Peak Pricing Results for Different Peak Definitions, Event Lengths

Event Length	Achievable Load Reduction in 2035 (Undiscounted MW)*	Levelized Cost of Demand per Year ($/KW)	
		No Technology Cost	$350 Technology Cost
2-hour Events	0.4	$265	$342
4-hour Events	0.4	$266	$343

Figure 42 shows the LG&E Critical Peak Pricing program's achievable potential over a twenty-year time horizon from 2016 to 2035. This assessment assumes a pilot program in 2016 and 2017 with 10% of the potential program participation; thereafter, a 30% ramp rate is assumed until full participation is reached in 2020.

Figure 42. LG&E's Critical Peak Pricing Achievable Potential



KU Results

Potential Savings

In order to assess the achievable savings from a Critical Peak Pricing program in KU territory, we examined the savings associated with the program for events lasting two hours and those lasting four hours during the top 40 hours in the summer season. The results of this analysis are shown in Table 33.

Table 33. KU Critical Peak Pricing Results for Different Peak Definitions, Event Lengths

Event Length	Achievable Load Reduction in 2035 (Undiscounted MW)*	Levelized Cost of Demand per Year ($/kW)	
		No Technology Cost	$350 Technology Cost
2-hour Events	0.9	$106	$173
4-hour Events	0.9	$105	$171

*Reduction shown is at the generator, not at the meter (i.e., line losses are included). Future years assume a discount rate of 6.37%, and a 1.9% rate of inflation.

Figure 43 shows the KU Critical Peak Pricing program's achievable potential over a twenty-year time horizon from 2016 to 2035. This assessment assumes a pilot program in 2016 and 2017 with 10% of the potential program participation; thereafter, a 30% ramp rate is assumed until full participation is reached in 2020.

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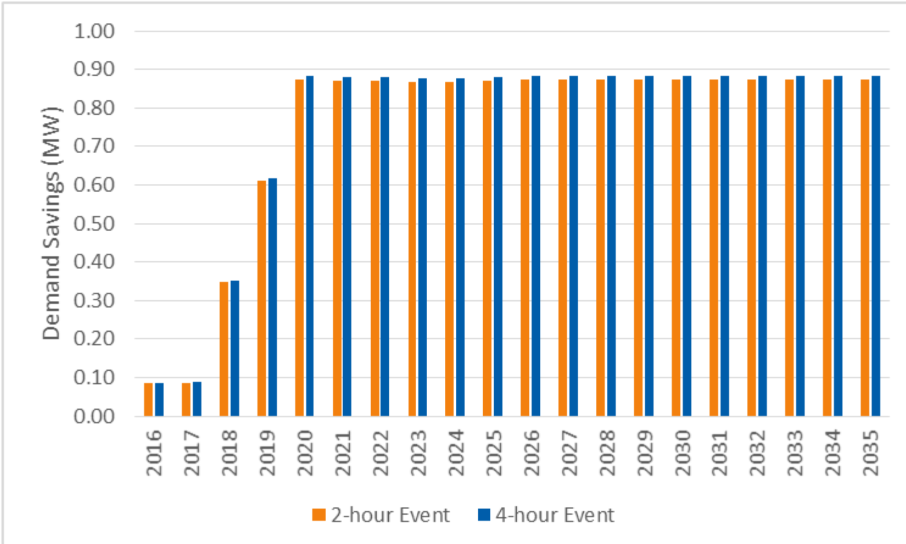
Figure 43. KU's Critical Peak Pricing Program Achievable Potential



Peak Load Reduction

Peak Load Reduction programs establish contractual arrangements between the utility, a third-party aggregator that implements the program, and utility nonresidential customers that agree to curtail 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 terms of each contract limit the number of curtailment requests—both in total and on a daily basis.

Generally, customers are not paid for individual events, but receive compensation through a fixed monthly amount per kW of pledged curtailable load, or through a rate discount. Typically, contracts require customers to curtail their connected load by a set percentage or to a predetermined level. Such programs often involve long-term contracts with penalties for non-compliance ranging from simply dropping the customer from the program to more punitive actions, such as requiring the customer to repay the utility for the committed (but not curtailed) energy at market rates.

Assumptions

Table 34 shows assumptions for the Peak Load Reduction program, modeled after LG&E's and KU's Commercial Demand Conservation program.

Table 34. Peak Load Reduction—Potential Study Assumptions

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	15%	Assumes administrative adder of 15%.
Enablement Cost (per new participant)	$13,000	Enablement per customer site for the Commercial Demand Conservation program.

Inputs	Value	Sources or Assumptions
Incentives (annual costs per participating kW)	$25/kW	LG&E and KU customers receive up to $25 per kW curtailed (incentives vary by actual kW reduction and number of events). PSO pays $32/kW and an additional 5% bonus to customers that participate in all events. CenterPoint Energy offers $35/kW, and Duke Energy offers $57/kW. Many programs determine a customer-specific incentive based on the kW pledged to the program.
Overhead: First Costs	$100,000	Program startup fee for the Commercial Demand Conservation program.
Vendor Costs	$218,000/year	Annual subscription fee for the Commercial Demand Conservation program.
Technical Potential for Load Shed	30%	Customers shed 27% to 34% of load for day-of and day-ahead events, respectively (2010 and 2011 Statewide Aggregator DR Programs: Final Report, Christensen Associates).
Program Participation (%)	30%	Two scenarios were modeled using different assumptions for participation. First, Cadmus relied on an Oak Ridge National Laboratory (ORNL) study that examined acceptability of participation by sector and process (*Assessment of Industrial Load for DR across U.S. Regions of the Western Interconnect*, Oak Ridge National Laboratory, 2013; Table C.4).
Event Participation (%)	95%	Range of PJM and MidAm programs (90%-95%).
Participation Criteria (kW Eligibility)	Customers with an interval meter and demand greater than 200 kW, with a 50 kW nomination	Program requirement for LG&E and KU's Commercial Demand Conservation program.

As part of its evaluation, Cadmus conducted a survey of LG&E and KU customers to assess (among other questions) customers' willingness to participate in DR programs. The team asked customers, "How likely would you be to participate in a new program offering, which would offer incentives to large industrial customers who voluntarily shift their energy use dung summer peak periods?"

To determine a participation rate, Cadmus weighted responses as follows: a response of *not at all likely* or *not too likely* corresponded with a 0% probability of participation; those indicating *somewhat likely* to participate received a 67% probability of participation; and those indicating *very likely* to participate received a 100% probability of participation. We then weighted responses by the average monthly kWh consumption of each customer, resulting in a 29.8% participation rate.

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For comparison purposes, Cadmus sought resources that might be used to indicate participation rates for load reduction programs within the industrial sector. An ORNL report—"Assessment of Industrial Load for DR across U.S. Regions of the Western Interconnect"[19] –provided estimates of program participation by industrial segment. While the ORNL report identified different participation rates for each industry, they were generally within 5 percentage points of Cadmus' assumed participation rate of 29.8%; overall, our assumed participation rate proved reasonable.

LG&E Results

Potential Savings

To assess achievable savings from a Peak Load Reduction program in LG&E's territory, Cadmus examined program savings for events lasting two hours and events lasting four hours, during the top 40 hours in the summer season. Table 35 shows the analysis results.

Table 35. LG&E Peak Load Reduction Results for Different Peak Definitions, Event Lengths, Survey-Based Participation

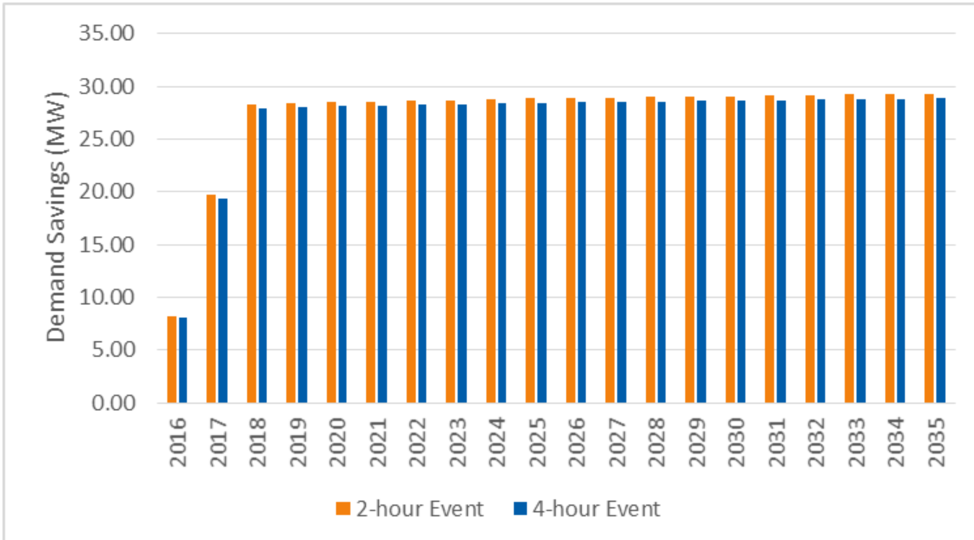
Event Length	Achievable Load Reduction in 2035 (Undiscounted MW)*	Levelized Cost of Demand per Year ($/kW)
2-hour Events	29.3	$52
4-hour Events	28.9	$52

*Reduction shown at the generator, not the meter (i.e., line losses included). Future years assume a discount rate of 6.37% and an inflation rate of 1.9%.

Figure 44 shows the LG&E Peak Load Reduction program's achievable potential over a 20-year time horizon. This assessment assumes the program attains 30% of its potential participation in 2016, 70% in 2017, and reaches full participation in 2018.

19 Starke, M. and Alkadi, N. *Assessment of Industrial Load for Demand Response across U.S. Regions of the Western Interconnect*. Oak Ridge National Laboratory. ORNL/TM-2013/407. September 2013.

Figure 44. LG&E's Peak Load Reduction Program Achievable Potential, Survey-Based Participation



KU Results

Potential Savings

To assess achievable savings from a Peak Load Reduction program in KU's territory, Cadmus examined savings associated with the program for events lasting two hours and events lasting four hours, during the top 40 hours in the summer season. Table 36 shows the analysis results.

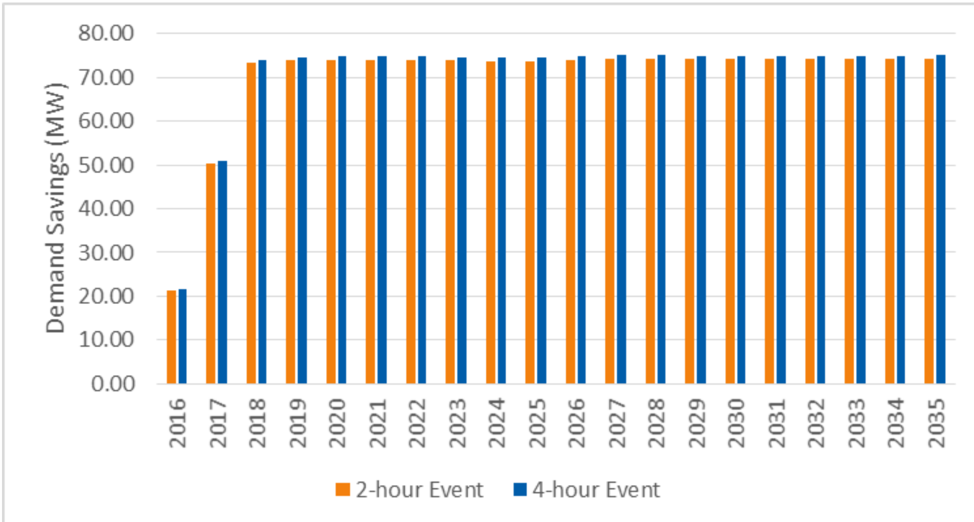
Table 36. KU Peak Load Reduction Results for Different Peak Definitions, Event Lengths, Survey-Based Participation

Event Length	Achievable Load Reduction in 2035 (Undiscounted MW)*	Levelized Cost of Demand per Year ($/kW)
2-hour Events	74.2	$43
4-hour Events	75.0	$43

*Reduction shown at the generator, not the meter (i.e., line losses included). Future years assume a discount rate of 6.37%, and an inflation rate of 1.9%.

Figure 45 shows the LG&E Peak Load Reduction program's achievable potential over a 20-year time horizon. This assessment assumes the program attains 30% of its potential participation in 2016, 70% in 2017, and reaches full participation in 2018.

Figure 45. KU's Peak Load Reduction Program Achievable Potential, Survey-Based Participation



Program Review

Introduction

The Company requested information about the strategies utilities in other jurisdictions use to capture energy savings for this sector. Under its potential study contract, Cadmus conducted a review of the types of energy efficiency programs utilities typically offer to their large C&I customers;[20] this included details on marketing strategies, incentive levels and structures, budget allocations, barriers and mitigation strategies, and performance metrics. This review also involved secondary research to identify and benchmark programs falling into four common industrial program design categories and to gather details about key design features, structure, and delivery strategies.

Throughout the United States, nearly every utility offering an energy efficiency program portfolio includes some industrial component. However, the type, size, and scope of these program offerings vary considerably and are subject to local conditions—most importantly, the mix of industrial customer and facility types, efficiency potential, plant vintage, and regulatory environment. Program participation also depends on local variables, most notably energy prices. In many jurisdictions, industrial efficiency programs serve as some of the largest (and cost-effective) producers of energy savings.

This report presents Cadmus' research findings on such utility C&I programs. Our research also explored the regulatory environments of states in which these programs operate and of savings achieved by select programs across the nation.

Research Methodology

To capture information to help inform the Company's investigation of industrial energy efficiency programs, Cadmus conducted secondary research on four common industrial program types:

- **Prescriptive incentive programs** offer per-unit or savings-based incentives for technologies or equipment that enable savings calculations using a deemed value or partially deemed algorithm.
- **Custom incentive programs** generally offer incentives based on projected savings or on a percentage of the project cost for more complex equipment or for whole-building efficiency projects that require a measured savings calculation approach.
- **Pay-for-performance programs** typically offer performance-based incentives for large capital investment projects, either with or without savings from changes in O&M or behavior. Utilities generally measure savings via on-site metering equipment, and the incentives are trued up following one year of post-installation data collection.

[20] Because many utility programs target large C&I customers under a single program offering, Cadmus did not attempt to limit its research to programs focusing only on the industrial sector.

- **Strategic Energy Management (SEM) programs** generally entail a staged project installation process over a multiyear contract term. Utilities offer annual incentives based on completion of energy savings actions each year.

Cadmus conducted thorough research on design characteristics and performance metrics associated with other utilities' and agencies' implementation and execution of these program types. We reviewed websites, published program information, marketing materials, evaluation reports, and other available information. Our research focused on the following questions, aimed at better understanding common approaches to marketing, designing, developing, and deploying energy efficiency programs in the industrial sector:

- What energy efficiency programs do peer utilities offer to industrial customers?
- What are the eligibility requirements for industrial customers to participate?
- What eligible measures do peer utility programs offer to industrial customers?
- What types of incentive strategies do peer utilities use to deliver programs?
- What marketing strategies do peer utilities employ to attract participation?
- What are peer utilities' typical expenditures on common program components?
- How do regulatory environments compare in states with industrial programs?
- What are peer utilities' typical benefit-cost ratios on industrial programs?
- What level of energy and demand savings do peer utilities capture from industrial programs?
- What are the common risks and barriers to a successful industrial energy efficiency program?

For each research question, we defined key performance indicators that contributed to our understanding of the question. We developed a customized workbook to capture information relevant to each performance indicator and to document design and performance elements from existing industrial energy efficiency programs in other jurisdictions. The following sections describe findings from Cadmus' research on the research questions listed above.

Research Findings

State Regulatory Environments

To provide context to our research, Cadmus studied the regulatory environments in which the examined utilities operated. Table 38 (following text below) summarizes the regulatory environment in each state, including whether or not a state energy efficiency resource standard (EERS) exists, whether C&I customers are allowed to opt out of energy efficiency programs, and whether any "self-direct" requirements are in place. Allowances for industrial opt-outs and self-direct provisions can impact program funding and savings acquisition; therefore, this information provides some context regarding the size of C&I programs and how savings and demand goals are set.

Benefit-Cost Ratios

For each program examined, Cadmus identified the associated benefit-cost test results (Table 41 and Table 46), as available.[21] Utilities typically measure program cost-effectiveness using one or more standard cost tests. Each test examines the benefits and costs from a different perspective:

1. ***Total Resource Cost (TRC) Test:*** This test examines the benefits and costs from the customer and utility perspectives. On the benefit side, it includes avoided electric and gas (where applicable) energy costs for generation, transmission, distribution capacity, and line losses. On the cost side, it includes costs incurred by both the utility (program administrative costs and incentives) and participants (measure costs).
2. ***Utility Cost Test (UCT):*** This test examines the benefits and costs solely from the utility's perspective. On the benefit side, it includes avoided electric energy costs for generation, transmission, distribution capacity, and line losses. On the cost side, it includes program administration, implementation, and incentive costs associated with program funding.
3. ***Ratepayer Impact Measure Test (RIM):*** All ratepayers (participants and nonparticipants) may experience rate increases designed to recover lost revenues. This test includes all program costs, incentives, and lost revenues. The RIM benefits are the same as the UCT test.
4. ***Participant Cost Test (PCT):*** From this perspective, program benefits include participant bill reductions due to the energy saved and incentives received from the program. PCT costs include a measure's incremental cost (compared to the baseline measure) plus installation costs incurred by the customer.

Table 37 summarizes the four tests' components.

Table 37. Benefits and Costs Included in Various Cost-Effectiveness Tests

Benefit/Cost		TRC	UCT	RIM	PCT
Benefits	Present value of electric avoided energy and capacity costs*	●	●	●	
	Present value of gas avoided costs*	●	●	●	
	Present value of bill savings and incentives received				●
Costs	Program administrative and marketing costs	●	●	●	
	Incremental measure costs incurred by participants	●			●
	Incentive costs		●	●	
	Present value of utility lost revenues			●	
	Installation costs				●

*The present value of electric avoided energy and capacity costs includes avoided line losses occurring from reductions in customer electric use. The present value also includes avoided transmission and distribution benefits.

[21] Although most, but not all, utilities conduct and report benefit-to-cost ratios using all four cost-effectiveness tests, considerable inconsistency occurs in the ways these results are calculated and reported. Therefore, research findings do not remain consistent across all utilities in terms of reported results, test(s) conducted, and years in which analyses were completed.

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Table 38. State Regulatory Structures

Program Administrator	State	EERS (Yes/No)	EERS Structure	kWh Target	kW Target	Opt-Out Provision (Yes/No)	Self-Direct (Yes/No)
Focus on Energy	Wisconsin	Yes	Incremental; 0.77% of sales per year	Not reported	Not reported	No	No
NIPSCO (Custom)	Indiana	No	N/A	86,684,000	10,167	Yes	No
Indianapolis Power and Light (Custom and Prescriptive)	Indiana	No	N/A	34,505,911	5,785	Yes	No
PPL Electric Utilities (Custom and Prescriptive)	Pennsylvania	Yes	2.3% cumulative savings from 2014-2016	Not reported	Not reported	No	No
SWEPCO	Arkansas	Yes	Incremental; 0.75% of sales reduction per year	16,214,883	2,090	Yes	Yes
Entergy	Arkansas	Yes	Incremental; 0.75% of sales reduction per year	124,679,000	13,351	Yes	Yes
New Hampshire Public Utilities Commission	New Hampshire	No	N/A	N/A	N/A	N/A	N/A
Energy Trust of Oregon	Oregon	Yes	Incremental; 1.3% of sales reduction per year	Not reported	Not reported		Yes
New Jersey Clean Energy Program	New Jersey	No	N/A	N/A	N/A	N/A	Yes
NYSERDA	New York	Yes	Incremental; 1% of sales reduction per year	20% savings per project	Not reported	N/A	N/A

Program Review

Prescriptive and Custom Incentive Programs

Cadmus reviewed several C&I programs that offer prescriptive and custom rebates to their customers. Many utilities offer separate prescriptive and custom incentive programs, but an increasing number have begun to consolidate these incentive offerings under one program umbrella, which in turn creates economies of scale and simplifies customer engagement.

The next sections briefly describe each program type. As these program types have evolved, their incentive structures have become more aligned with one another; the primary differentiating factor is in the way EM&V is performed.

Prescriptive Programs

Prescriptive programs historically have offered standard incentive rates on a per-measure basis, in which the customer receives a fixed dollar amount per unit installed. Some utilities, however, have begun to offer prescriptive incentives on a performance basis (i.e., $/kWh saved), blurring the lines between prescriptive and custom program strategies. These programs primarily differ in the ways they measure savings. Prescriptive program savings calculations typically are based on the following:

- Deemed savings values, which involve multiplying the number of units installed by their deemed savings value per measure; or
- Partially deemed algorithms, which calculate savings using customer inputs for baseline and measure characteristics (e.g., energy efficiency rating, heating fuel type) along with researched and peer-reviewed historical values for common metrics such as operating hours and building characteristics, normalized to account for local weather conditions.

As this EM&V approach proves less rigorous than others, it is less costly.

Custom Programs

Custom incentive programs typically offer incentives based on a projected reductions in energy use (on a per kWh basis), although some programs may use an incentive structure based on a percentage of the total project cost. Some programs also assign a per-project funding cap.

To qualify for an incentive, customers submit documentation showing the modeled energy savings impacts expected to result from installing a custom project. This pre-application process reserves funding from the utility's incentive budget for the completed project.

Once the project has been completed, the utility verifies that the installed project aligns with the pre-application documents submitted and may conduct post-installation measurements. Custom incentive projects tend to be larger and more complex than prescriptive projects, hence EM&V is generally more rigorous, often employing on-site metering to verify claimed savings.

Table 39 shows basic program parameters and incentive structures offered by the custom and prescriptive programs researched.

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Table 39. Custom and Prescriptive Programs

Program (State)	Target Sector	Program Type	Incentives
Wisconsin Focus on Energy Large Energy Users Program (WI)	C&I	Custom and prescriptive incentives	CUSTOM • $0.04/kWh • $1.25/peak kW • $0.40/Therm PRESCRIPTIVE • Measure based
NIPSCO C&I Custom Program (IN)	C&I	Custom incentives	• $0.08/kWh • $0.80/therm • Pre-qualification required
Indianapolis Power and Light Business Energy Incentive Program (IN)	C&I	Custom and prescriptive incentives	CUSTOM • $0.07/kWh; pre-qualification required PRESCRIPTIVE • Measure based
Alliant Energy, Nonresidential Prescriptive Program (IA)	C&I	Prescriptive incentives	Measure based
Alliant Energy, Nonresidential Custom Program (IA)	C&I	Custom incentives	150% of first year energy cost savings
SWEPCO C&I Energy Efficiency Program (AR)	C&I	Custom and prescriptive incentives	• Varies per measure Demand and energy savings incentives are offered
PPL Electric Utilities Custom Incentive (PA)	C&I	Custom incentives	• $0.05/kWh for combined heat and power projects • $0.08/kWh for all other projects
PPL Electric Utilities Prescriptive Incentive (PA)	C&I	Prescriptive incentives	Measure based

Many utilities offer custom and prescriptive programs as a joint offering. This more streamlined approach can realize economies of scale in delivery and marketing efforts, and it provides customers with greater flexibility in making facility upgrades.

Program Marketing and Delivery

Most large C&I programs rely on direct contact/outreach as their primary marketing channel. Generally, this approach is considered a best practice for marketing to large customers. In evaluations of numerous commercial and industrial energy efficiency programs, Cadmus has found mass media advertising, bill inserts, direct mail, and other forms of traditional marketing do not provide effective methods for capturing the attention of busy C&I decision makers. Our research indicates the most effective recruitment approach uses direct contact by key account managers, program managers, or program partners (e.g., trade allies, energy services companies [ESCOs]), equipped with relevant program information (e.g., brochures, case studies).

Each program Cadmus reviewed used a range of tactics to support program marketing and recruitment, from distributing marketing collateral to assigning devoted staff. Programs commonly use third-party program implementers, often responsible for turnkey program delivery (which can include marketing the program to customers, processing and verifying applications, and distributing incentives). All utilities listed in Table 39 use a third party to implement their C&I programs. In addition to direct, customer-facing roles, many implementers work with a trade ally network, providing training and other support to encourage network trade allies to promote the utility program as a benefit when selling upgrade projects to their customers.

The Wisconsin Focus on Energy Large Energy Users Program uses a notable recruitment strategy by relying on energy advisors. These industry-specific experts work for the program implementer, serving as consultants to the program and helping customers identify and introduce projects. SWEPCO uses energy advisors who perform services on behalf of customers, such as conducting building assessments, performing financial analysis, and assisting with applications. Alliant Energy employs key account managers to promote the program to its largest customers as well as to trade allies, which can provide services and promote the program to targeted customers.

Of C&I custom and prescriptive programs reviewed, program actors (e.g., implementers, trade allies, energy advisors) provided the most important marketing and outreach assets.

Program Performance

To inform the Company on the typical performance of industrial prescriptive and custom programs, Cadmus gathered data on energy and demand savings from the reviewed programs. Because large C&I customers typically serve as a utility's largest energy user, they also offer the greatest potential for energy savings. It should be noted, however, that overall program performance depends on multiple factors—such as market potential, program budgets and marketing, incentive amounts, and the existence of an active trade ally network—that may be difficult to normalize for comparison. Therefore, Table 40 shows overall and per-participant savings achieved by these custom and prescriptive programs as well as the year that these performance metrics were derived.

Table 40. Custom and Prescriptive Program Savings

	Total kWh Savings	kWh/ Participant	Total kW Savings	kW/ Participant
Focus on Energy Large Energy Users, 2013	145,735,249	389,666	18,871	50
NIPSCO Custom, 2013	124,241,627	Participation not reported	15,731	Participation not reported
Indianapolis Power & Light Custom, 2014	26,457,689	96,615	3,583	13
Indianapolis Power & Light Prescriptive, 2014	13,108,870	268	3,038	0.062
Alliant Prescriptive, 2014	24,979,377	8,285	3,425	1.14
Alliant Custom, 2014	80,413,847	390,358	9,879	47.98
Entergy C&I Solutions, 2014	105,997,000	125,292	15,148	18
SWEPCO CIEEP, 2014	14,501,399	68,403	2,286	11
PPL Electric Custom, 2014	5,394,000	96,321	500	9
PPL Electric Prescriptive, 2014	81,170,000	34,570	12,510	5

Table 41 provides the benefit-cost test results for programs Cadmus examined. Although all utilities do not necessarily calculate cost-effectiveness from all four test perspectives, the utilities we assessed do calculate TRC. Because large C&I prescriptive and custom programs tend to generate significant energy savings per customer project, they also tend to be very cost-effective from the TRC perspective—as proved true of the programs we reviewed.

Table 41. Benefit-Cost Ratios for Custom and Prescriptive Programs*

	TRC Ratio	RIM Ratio	PCT Ratio	UCT Ratio
Focus on Energy, Large Energy Users, 2013	6.9	Not reported	Not reported	Not reported
Alliant Prescriptive Program, 2014	3.59	1.05	2.46	7.00
Alliant Custom Program, 2014	4.89	1.00	3.36	6.44
Entergy C&I Solutions, 2014	1.53	1.49	2.50	2.32
SWEPCO CIEEP, 2014	1.53	0.67	2.43	2.61
PPL Electric Custom, 2014	1.74	Not reported	Not reported	Not reported
PPL Electric Prescriptive, 2014	2.41	Not reported	Not reported	Not reported

* Information for NIPSCO and Indianapolis Power & Light's programs was not available

Program Expenditures

Table 42 breaks out the costs incurred by each program. Notably, no standard way exists to categorize costs, and utilities allocate costs differently in each of these categories; therefore, considerable variation occurs in comparing these expenditures.

For example, one utility may develop and track budgets broken out for equipment costs, installation costs, and incentives, while others may categorize all of these costs as incentives. Likewise, one utility may categorize costs for trade ally network development as marketing or program implementation. Cadmus' review attempted to categorize cost centers across three common categories. However, as detailed information on utilities' budget and cost allocation methods typically are not publicly available, the information below provides an example of relative distributions of program funds. The key takeaway from this information is that nearly all utilities allocate a significant majority of the program funds to incentives and equipment. Among utilities we reviewed, all allocated 60% to 90% of their overall program budgets to incentives and equipment.

Table 42. Prescriptive and Custom Program Expenditures

Utility and Program	Incentives & Equipment	Marketing & Administration	EM&V	Total
	Budget Allocation and Percentage of Total Budget			
Focus on Energy Large Energy Users	$34,646,835	$4,469,494	Not reported	**$39,116,329**
	89%	11%	N/A	
Alliant Energy Prescriptive	$6,923,386	$657,529	$154,713	**$7,735,626**
	90%	9%	2%	
Alliant Energy Custom	$7,585,066	$1,387,511	$277,502	**$9,250,080**
	82%	15%	3%	
Entergy C&I Solutions	$15,598,022	$7,542,194	$1,559,892	**$24,700,108**
	63%	31%	6%	
SWEPCO CIEEP	$3,997,976	$631,767	$109,075	**$4,738,818**
	84%	13%	2%	
PPL Electric Custom	$210,316	$141,831	Not reported	**$352,147**
	60%	40%	N/A	
PPL Electric Prescriptive	$1,327,968	$823,996	Not reported	**$2,151,964**
	62%	38%	N/A	

Barriers and Mitigation Strategies

As with nearly all energy efficiency programs, cost is an industrial customers' primary barrier to installing energy-efficient equipment or projects. Cadmus investigated the barriers and challenges to industrial customers' participation in the researched programs. Although we found many barriers specific to the programs, a few common themes emerged, as shown in Table 43.

Table 43. Barriers and Mitigation Strategies

Barriers	Mitigation Strategies
Low program awareness results in low participation rates.	• Develop a logic model or "journey map" to understand how customers participate and where gaps may exist. • Actively market directly to decision makers and trade allies that regularly interact with customers. • Build strong relationships with trade allies and provide sales training so they promote the program and educate customers on energy efficiency benefits.

Barriers	Mitigation Strategies
Upfront costs are too high.	• Offer incentives to help reduce upfront project costs and improve a project's internal rate of return. • Educate customers on long-term savings generated from energy-efficient products. • Frame incentives as a means of increasing internal rates of return. • Provide technical support to help customers identify the most beneficial energy-saving projects and verify costs and savings.
Customers do not prioritize energy efficiency and replace equipment only on failure.	• Offer planning assistance and encourage businesses to plan for equipment replacements and inform customers about available energy efficiency choices prior to equipment failures. • Educate customers about the long-term benefits of energy efficiency, available incentives, and technical support.
Dealers and contractors do not promote the program or upsell energy-efficient equipment	• Provide training to trade allies regarding the long-term value of energy-efficient equipment. • Offer rewards for high-performing contractors that generate high participation rates and energy savings.

Pay for Performance and Strategic Energy Management Programs

Program Types

Cadmus reviewed several C&I pay for performance (P4P) and SEM programs across the country. These two similar program types offer incentives for a whole-building approach to energy efficiency. They primarily differ in their contract length, eligibility of O&M savings, and employee engagement. Each P4P program reviewed provided performance-based incentives over a single year. The SEM programs, however, typically engage customers in a long-term energy-savings strategy and provide incentives over a three- to five-year contract.

In addition, we found considerable variation occurs in how utilities approach P4P and SEM incentive structures: some programs offer incentives for O&M measures in addition to savings provided by capital improvements; and some programs do not differentiate between the savings sources. However, whether a program offers incentives for O&M measures did not necessarily distinguish between SEM and P4P programs.

Pay for Performance

P4P programs provide premium incentives for customers that take a whole-building approach to conserve energy in new construction or existing buildings. These programs typically offer a single, blended incentive rate for capital projects and O&M measures (where eligible) instead of measuring and applying a separate incentive rate for O&M savings (as do some SEM programs). P4P programs also frequently have incentive caps, commonly set at 50% of the project cost.

The Industrial Process Efficiency (IPE) program, however, a P4P program offered by the New York State Energy Research and Development Association (NYSERDA) behaves more like a SEM program and accounts for capital projects and O&M energy savings separately using different incentive rates. P4P program administrators (excluding NYSERDA's IPE) typically quantify whole-building energy savings using a single-building meter and do not attempt to parse O&M from capital project savings.

Additionally, the incentive payment structure can differ dramatically between utilities. For example, the P4P programs offered by New Jersey and New Hampshire are broken into three steps, with different incentives awarded upon the completion of each step. Regardless of the payment structure, however, these P4P programs use a single-year performance period during which the participant collects incentives for actual energy savings. Table 44 lists several P4P programs and their incentive structures.

Table 44. Pay for Performance and Strategic Energy Management Programs Summary

Program	Type	Incentive #1	Incentive #2	Incentive #3	Incentive Structure
New Hampshire Public Utilities Commission	P4P	<100 sf: $0.18/sf 100-200 sf: $0.15/sf >200 sf: $0.10/sf	Construction completion; $0.22/kWh saved	$0.08/kWh saved	Total performance incentives #2 and #3 are capped at $300,000 or 50% of project cost.
NYSERDA, Performance-Based Incentive (PBI) Program for Existing Facilities	P4P	N/A	N/A	Savings < 30% of current annual usage; $0.10/kWh Savings 31% to 50% of current annual usage; $0.12/kWh Savings > 50% of current annual usage; $0.15/kWh	Total incentive cannot exceed 50% of the project cost and is capped at the lesser of a one-year simple pack back or $500,000.
NYSERDA, IPE Initiatives	P4P	N/A	N/A	Process and efficiency: $0.12/kWh and $15/MMBtu O&M: $0.05/kWh and $6/MMBtu	Total incentive cannot exceed 50% of the project cost; capped at $5 million electric and $1 million natural gas.
New Jersey Board of Public Utilities (BPU) Clean Energy Program	P4P (Existing Buildings)	Ranges from $5,000 to $50,000; based on approximately	Up to 15% savings; $.09/projected kWh saved	Minimum 15% savings; $0.09/actual kWh saved For each percentage point over 15%, add	Total value of Incentive #2 and Incentive #3 may not exceed 50% of

Program	Type	Incentive #1	Incentive #2	Incentive #3	Incentive Structure
		$0.10/sf, not to exceed 50% of facility's annual energy expense.		$0.005/actual kWh saved Maximum Incentive = $0.11/actual kWh saved	the total project cost.
	P4P (New Construction)	$0.10/gross heated and conditioned sf	$1.00/sf of gross heated and conditioned space	15%-17% of goal; $0.35/sf of gross heated and conditioned space 18%-20% of goal; $0.45/sf of gross heated and conditioned space > 20% of goal; $0.65/sf of gross heated and conditioned space	The total incentive for #2 and #3 may not exceed 75% of the total project incremental cost.
Bonneville Power Administration (BPA) Energy Management Program	SEM	N/A	N/A	$0.025/kWh for behavioral changes $0.25/kWh for capital changes; weighted average rate used for utility bill analysis	Capped at 70% of project cost.
Energy Trust of Oregon SEM Program	SEM	N/A	N/A	$0.02 per kWh and $0.20 per therm saved for O&M savings $0.25/kWh and $2 per annual therm saved for capital projects	Capital project incentives are capped at 50% of project costs or $499,999.
Xcel Energy, Process Efficiency Rebates	SEM	N/A	N/A	Utility creates customized proposal for rebates and other support	Bonuses may be available to customers for achieving energy efficiency goals.

Strategic Energy Management

SEM programs provide premium incentives for customers striving to continuously integrate energy efficiency into their buildings and company culture; these incentives are typically offered over a longer contract period, averaging between three and five years. Through SEM programs, utilities also can provide technical support to help customers identify, plan for, and implement equipment upgrades and O&M or behavioral initiatives to produce long-term energy savings. Customers can develop measureable goals and outcomes and prepare an action plan to be conducted over the course of one or multiple years.

Some SEM programs offer incentives only for capital projects, O&M savings, or both. For example, BPA provides separate incentives for total energy saved through the SEM training offered by the utility (O&M savings) and for capital projects. Alternatively, Excel Energy's Process Efficiency Rebates programs only provide incentives for capital projects.

Marketing Strategies and Tactics

P4P and SEM programs reviewed use different marketing techniques and tactics to target specific customer segments, but most rely on direct contact and outreach as their primary marketing channel. As described in the section on prescriptive and custom programs, utilities rely more on direct outreach through utility staff, program partners, or trade allies to reach business decision makers than they do on mass media and other forms of traditional marketing. Some programs supplement these efforts with brochures, fact sheets, case studies, and the utility website.

Many programs rely on qualified trade allies as program partners. These ESCOs, engineering firms, equipment dealers, and other vendors serve as the primary—and most effective—marketing channel for recruiting participants. To help these trade allies learn about and stay up-to-date on programs, many utilities offer program training, and some require that trade allies take the training to work with the program. The SEM program offered by the Energy Trust of Oregon uses word-of-mouth to target potential participants by asking program partners to conduct direct recruiting.

Some utilities use a more formal recruitment process, issuing requests for proposals (RFPs) to targeted customers. For example, NYSERDA releases a Program Opportunity Notice once per year and selects projects on a first-come, first-served basis, subject to funding availability. This allows the program sponsor to better control the project timing and the development process. To apply for the program, building owners or program partners must submit an application during a limited, open enrollment period.

Program Performance

Though not as common as prescriptive and custom rebate programs, many P4P and SEM programs are offered by smaller, municipal, and nontraditional (i.e., not investor-owned) utilities. Therefore, Cadmus could not gather metrics for every utility reviewed. Even for those with reported performance metrics, the formats and contents of these metrics were not consistent. For example, the Energy Trust of Oregon reports savings, expenditures, and benefit-to-cost ratios at a sector level but does not provide similar information at a program level. Table 45 provides energy and demand savings for programs providing publicly available information.

Table 45. Energy and Demand Savings for P4P and SEM Programs

	Total kWh Savings	kWh/ Participant	Total kW Savings	kW/ Participant
NYSERDA PIE (2012)	188,020,000	630,939.6	21,500	72.14
New Hampshire P4P (year not available)	12,000,000	266,666.67	Not reported	Not reported
New Jersey BPU Existing Buildings P4P (2012)	Not reported	324,486	Not reported	85.8
New Jersey BPU New Construction P4P (2012)	Not reported	452,431	Not reported	389.0
Xcel Energy Process Efficiency (2013)	13,789,785	Not reported	1,572	Not reported
BPA Energy Management (2012)	13,084,135	817,758	Not reported	Not reported

Note: Information was not available for Energy Trust of Oregon.

Table 46 provides benefit-cost test results for programs that Cadmus examined, provided this information was publicly available.

Table 46. Benefit-Cost Ratios for P4P and SEM Programs

	TRC Ratio	RIM Ratio	PCT Ratio	UCT Ratio
BPA SEM*	1.04	Not reported	3.89	Not reported
Xcel Energy Process Efficiency	2.20	Not reported	Not reported	Not reported
BPA Energy Management	1.11	Not reported	1.20	1.03

*O&M measures only.

Note: Information was not available for BPU, NYSERDA, Energy Trust of Oregon, and New Hampshire.

Typical Expenditures

Similar to performance metrics, Cadmus found few utilities publish information on budgets and expenditures for P4P and SEM programs. Among those making funding allocations publicly available, the utilities—much like prescriptive and custom programs—allocate a significant majority of program resources to incentives and equipment. This approach generally remains consistent with program budgeting best practices. Table 47 shows expenditures for programs with budgeting information available.

Table 47. Program Expenditures for P4P and SEM Programs

Utility, Program	Incentives & Equipment	Marketing & Administration	EM&V	Total
	Budget Allocation and Percentage of Total Budget			
NYSERDA BPI	$3,726,058.23	$1,729,167.69	$866,249.08	**$6,321,475**
	59%	27%	14%	
NYSERDA IPE	$13,737,931.08	$1,230,756.96	$2,026,231.99	**$16,994,920**
	81%	7%	12%	
New Jersey BPU P4P Existing Buildings	$15,440,375.82	$174,600	$366,860.08	**$15,981,835**
	96%	1%	3%	
New Jersey BPU P4P New Construction	$33,259,239.66	$554,800	$508334.64	**$34,322,374**
	96%	1%	3%	

Note: Information was not available on expenditures for New Hampshire, Energy Trust of Oregon, BPA, and Xcel.

Risks, Barriers and Mitigation Strategies

Although many barriers Cadmus found specific to programs reviewed, a few common themes emerged between P4P and SEM programs, as illustrated in Table 48.

Table 48. Risks, Barriers, and Mitigation Strategies for P4P and SEM Programs

Common Barriers	Mitigation Strategies
Steep learning curve associated with defining the baseline and calculating building energy savings estimates.	Provide standardized software tools and offer training on baseline methodologies and calculating energy savings to customers and/or program partners.
P4P long project cycle, with large complex projects.	• Offer technical support to help customers identify and implement capital projects, complete documentation, locate equipment and service vendors, and resolve other issues. • Conduct periodic follow ups with customers to offer support and encourage their continued engagement.
Customer investment (time and money) can be significant. Successful SEM programs require a significant commitment, resources, and buy-in from facility staff.	• Offer incentives to help reduce upfront project costs and improve project internal rates of return. • Educate customers on long-term savings generated from energy-efficient products and practices. • Frame incentives as means of increasing internal rates of return. • Provide technical support to help customers identify the most beneficial energy savings projects and to verify costs and savings. • Provide technical support to guide participants through the process.

Common Barriers	Mitigation Strategies
Difficult to parse out capital from O&M savings for programs that require these to be reported separately.	Provide written guidelines, with standard methods and tools coupled with training on savings calculation, to customers and/or program partners.

Additional Resources

Considerable research has been conducted on the value, challenges, and regulatory factors associated with industrial energy efficiency programs. Links follow to some of these additional resources.

1. International Industrial Sector Energy Efficiency Policies (LBNL)
2. *Communicating the Value of Industrial Energy Efficiency Programs (ACEEE)*
3. Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector *(SEE Action).*
4. *Industrial Efficiency Programs Can Achieve Large Energy Savings at Low Cost (ACEEE).*
5. *The Dollars and Cents of Industrial Efficiency Program Investment (ACEEE).*
6. *Myths and Facts about Industrial Opt-Out Provisions (ACEEE).*
7. *Overview of Large-Customer Self-Direct Options for Energy Efficiency Programs (ACEEE).*