State of Minnesota Electric Utility Infrastructure Energy Efficiency Potential Study

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- We would also like to thank individual utilities who provided data and took time to discuss the project with us. Especially considering that all utility contacts have other priorities. We cannot call out individuals by name or organization because most data for the study was collected under non-disclosure agreements. Thank You's will be sent individually to contributors.

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Definition of Terms and Acronyms

ACCC	Aluminum Conductor Composite Core (Conductor Type)
ACSR	Aluminum Conductor Steel Reinforced (Conductor Type)
AMI	Advanced Metering Infrastructure (or Smart Meters)
AVFC	Automated Voltage Feedback Control (equivalent to CVR)
CBA	Cost-Benefit Analysis
CC	Combined Cycle (Generation Technology)
CF	Capacity Factor
CHP	Combined Heat and Power
CIP	Commercial Building Energy Consumption Survey
COU	Consumer-Owned Utility
CT	Combustion Turbine (Generation Technology)
CVR	Conservation Voltage Reduction
DOC	Department of Commerce (State)
DOE	Department of Energy (Federal)
DSM	Demand Side Management
EIA	Energy Information Administration
EOL	End-Of-Line
ESP	Energy Savings Platform
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EUI	Electric Utility Infrastructure
EUL	Expected Useful Life
HR	Heat Rate
HVTL	High Voltage Transmission Line
GIS	Geographic Information System
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
kW	Kilowatt (power or capacity)
kWh	Kilowatt-hour (energy or savings)
LDC	Line Drop Compensation
LF	Load Factor
MMBtu	Million British Thermal Units
NDA	Non-Disclosure Agreement
NEEA	Northwest Energy Efficiency Alliance
NSR	New Source Review
NPV	Net Present Value
PUC	Public Utilities Commission
T&D	Transmission and Distribution
TRC	Total Resource Cost
TRM	Technical Reference Manual
UEC	Unit Energy Consumption
UCT	Utility Cost Test
VO	Voltage Optimization (equivalent to CVR)
VVO	Volt-VAR Optimization

1 Executive Summary

This potential study is designed to provide useful information to utility planners and energy policymakers as they develop strategies to achieve conservation goals in Minnesota. The study identifies and quantifies conservation opportunity in Electric Utility Infrastructure (EUI) assets owned and operated by utilities serving Minnesota consumers. Ultimately, the goal of this study is to improve understanding of EUI as a tool utilities can use to meet their conservation goals. The results presented here can be used to inform utility programs and policy decisions aimed at capturing the identified conservation opportunities.

The findings of this study indicate that that utilities should consider pursuing EUI conservation projects as an important component of their Conservation Improvement Program (CIP) plans. Further, policymakers should continue examining policies to lower barriers to implementation and drive utilization of EUI resources to meet CIP goals.

The results of the study show that EUI projects have the potential to deliver a portion of Minnesota utilities' conservation goals over the 20-year period between 2020 and 2039. The models estimate that achievable potential EUI conservation represents approximately 0.13% of electric sales (excluding CIP-exempt sales) over the course of the study. This corresponds to approximately 9% of utilities' predicted CIP goals. The identified potential is split between the generation sector (3.3% of goals) and the transmission and distribution (T&D) sector (5.7%). Technical conservation potential is estimated to be approximately 19.6% of electric conservation goals over the period of the study, suggesting that changes to policies could unlock additional potential for utilities to use EUI projects to meet their CIP goals.

This study uses a unique approach to estimate potential in EUI sectors. To our knowledge, there has not been a similar study conducted anywhere. Accordingly, there are important differences between this study and a conventional demand-side study that should be understood to properly interpret results. For example, the types of potential estimated by this study have the same meanings as in conventional potential studies but are derived from assumptions about utility costs and decision-making rather than consumer behavior. Full descriptions of the complete Methodology are included in this report.

After estimating the potential for conservation, the project team developed a set of recommendations for utilities to capture the identified potential. The recommendations are designed to build understanding and confidence in EUI as a CIP tool over time. We start with general recommendations for utilities to explore EUI opportunities in their systems, for example, by convening meetings between generation and T&D planners and CIP personnel. We also identify specific recommendations that could help advance EUI conservation such as tracking T&D system losses over time and considering accelerated AMI deployment.

Table 1-1 and *Generation potential reported in calculated equivalent MWh conserved

Table 1-2 present the high-level results of the study. Generation conservation potential is reported in equivalent MWh as calculated using the Minnesota Technical Reference Manual (TRM). Predicted sales includes all non-exempt retail electric sales statewide.

Table 1-1 Statewide Conservation Potential Total 2020-2039

Description	Generation MWh*	T&D MWh	Total MWh
Technical Conservation Potential	1,399,850	3,248,923	4,648,773
Economic Conservation Potential	786,782	2,515,143	3,301,925
Achievable Conservation Potential	786,782	1,342,519	2,129,301

*Generation potential reported in calculated equivalent MWh conserved

Table 1-2 Statewide Conservation Potential as a Percentage Predicted Electric Sales 2020-2039

Description	Generation	T&D	Total
Technical Conservation Potential	0.09%	0.21%	0.29%
Economic Conservation Potential	0.05%	0.16%	0.21%
Achievable Conservation Potential	0.05%	0.09%	0.13%

2 Introduction and Background

Background

The Minnesota Department of Commerce contracted with GDS Associates (GDS), Center for Energy and Environment (CEE), The Cadmus Group, and Demand Side Analytics (DSA) for the purpose of preparing an independent evaluation of the potential for energy conservation and carbon emission reductions by improving the efficiency of Electric Utility Infrastructure (EUI) in the state of Minnesota. The project is one in a series of projects aimed at clarifying a long-available, but underutilized provision of statute expected to become a more useful tool for utilities to meet their conservation goals in coming years.

The Next Generation Energy Act of 2007[1] established energy conservation as a primary resource for meeting Minnesota's energy needs while reducing greenhouse gases and other harmful emissions. The Act established an energy savings goal for Minnesota of 1.5 percent of gross annual retail electricity and natural gas sales (based on a three-year weather-normalized average), to be achieved directly through the utility Conservation Improvement Program (CIP), and indirectly through energy codes, appliance standards, market transformation programs, consumer behavioral changes, **efficiency improvements to utility infrastructure**, and other efforts to promote energy efficiency and conservation.

Specifically, Minnesota statute states:

> *"A utility may include in its energy conservation plan energy savings from electric utility infrastructure projects approved by the commission under section 216B.1636 or waste heat recovery converted into electricity projects that may count as energy savings in addition to a minimum energy-savings goal of at least one percent for energy conservation improvements. Electric utility infrastructure projects must result in increased energy efficiency than that which would have occurred through normal maintenance activity."*[2]

While the statute has explicitly allowed EUI projects to count toward utilities' conservation goals since 2007, there have not been a significant number of projects or coordinated efforts to increase EUI efficiency as a result. There are several possible reasons for the lack of adoption including low awareness of the opportunity, unclear project eligibility requirements, lack of prescriptive savings calculations, and unknown magnitude of the potential for savings. All of these issues are being addressed in a series of projects commissioned by the Minnesota Department of Commerce, of which this study is one.

[1] Laws of Minnesota 2007, Chapter 136, SF145. http://www.leg.state.mn.us/

[2] Minnesota Statutes, section 216B.241, Subd. 1c(d)

- In 2010, The Minnesota Department of Commerce published a report titled *Utility Infrastructure Improvements for Energy Efficiency*[3]*.* The study outlines technologies and strategies to achieve greater efficiency in infrastructure sectors.
- In 2011, The Minnesota Environmental Initiative produced a final report on the 1.5% Energy Efficiency Solutions Project funded by the MN Department of Commerce[4]. As one of the focus area, the report identified several barriers to implementation of EUI projects with some preliminary recommendations for overcoming them. The report called for more study and deeper understanding of EUI issues.
- In 2016, the Department of Commerce contracted GDS Associates to develop EUI measures for inclusion in the Technical Reference Manual (TRM)[5], which formalized prescriptive methods for calculating savings from specific infrastructure projects.
- In late 2018, a report including a statewide Action Plan for EUI policy is expected from a stakeholder engagement project funded by the Department of Energy, managed by the Department of Commerce, and led by GDS Associates[6].
- Also in late 2018, the results of a statewide Demand-Side potential study were published[7]. That project is funded by the Department of Commerce and led by Center for Energy and Environment. Although it is not focused on infrastructure issues, many of the data sources overlap with this study (sales forecasts, avoided costs, etc.). The project teams communicated as much as possible to ensure findings across the two concurrent potential studies are consistent and can be compared to each other.

The goal of this study is to build on the efforts in the state to advance robust energy policies and programs in Minnesota by providing critical data resources that will inform CIP decision-makers regarding which EUI improvements should be targeted to help realize energy efficiency potential in Minnesota. Specifically, our objectives of the project are to: 1) devise and conduct a potential study, 2) make recommendations to utilities to identify and assess EUI efficiency improvement opportunities, and 3) advance understanding of the policy landscape surrounding EUI with the intention of feeding into the larger effort to develop a comprehensive EUI policy Action Plan.

The Methodology section of this report describes the methods devised to conduct the potential study. The Results and Conclusions and Discussion of Results sections present the findings of the study in detail with discussion of their context and meaning. There is a subsection Utility Recommendations that outlines actions utilities can take to capture the identified potential through their conservation programs. We refrain from making policy recommendations in this report because a companion study

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3 *Utility Infrastructure Improvements for Energy Efficiency*. Minnesota Office of Energy Security, Department of Commerce. November. 2010.

4 *Final Report.* 1.5% Energy Efficiency Solutions Project, Minnesota Environmental Initiative. March 2011.

5 Minnesota TRM. http://mn.gov/commerce-stat/pdfs/mn-trm-v2.2.pdf

6 Project webpage hosted by Center for Energy and Environment. https://www.mncee.org/mnsupplystudy/home/

7 Minnesota Energy Efficiency Potential Study: 2020-2029. https://www.mncee.org/MNCEE/media/PDFs/MN-Potential-Study_Final-Report_Publication-Date_2018-12-04.pdf

funded by the U.S. Department of Energy (DOE) was commissioned after we began this study. The main objective of that project is to produce an EUI policy Action Plan based on feedback from a wide group of stakeholders.

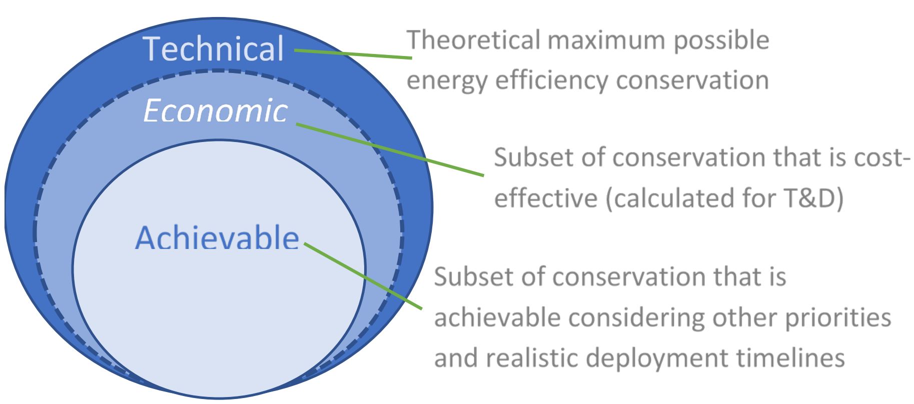
This study is a pioneering effort in that it is the first study we know of focused on calculating the potential for conservation improvements in an infrastructure system for the purpose of meeting statewide efficiency goals. Accordingly, the methodology was designed specifically for this study and honed over the course of completing it. Because the study is unique, the project team has included as much detail as possible in this report concerning the methodology used and recommended interpretation of results.

Types of EUI Potential

In conventional market potential studies, energy efficiency potential is grouped into the following three types: technical potential, economic potential, and achievable potential. The same three categories are used to present results of this study and the definitions of each are largely similar. However, there are ways in which the EUI methodology differs from typical studies (especially for the generation sector), which affects the meaning of each type of potential and impacts how results should be interpreted.

Technical and economic potential are theoretical energy savings limits to provide a measuring stick for existing conditions in the state and put the achievable potential in context. The technical and economic values can be used to inform discussions to consider whether policy changes might successfully unlock some of the potential that is currently unachievable. The reported achievable potential savings estimates are built on our understanding of actual decisions utilities make regarding reasonable planning objectives, maintenance activities, and competition for capital. Once identified, achievable potential represents an estimate of conservation opportunities that utilities can reasonably choose to implement under current policy and planning conditions over the period of the study. Figure 2-1 displays a visual representation of the types of potential and each is described in more detail below.

Figure 2-1 Visualization of Types of Potential



Technical Potential: Technical potential for energy efficiency conservation relative to the Minnesota statewide baseline energy forecast is estimated by assuming all feasible improvement opportunities are implemented by all utilities regardless of cost, competing priorities, or preference.

The definition of technical potential for T&D projects is directly analogous to the typical demand-side definition. For generation improvements, the meaning is also largely analogous, but with important differences in how it is calculated. Specifically, technical potential for generation sites is modeled at the facility level rather than at the individual project level. Also, there are *physically possible* generation improvements that are deemed to be infeasible because a plant is scheduled for retirement, runs for very few hours annually, or serves significant non-Minnesota load. These differences do not change the meaning of technical potential, but should be understood to aid interpretation of results. Reviewing the Methodology section is recommended for a thorough understanding of the calculation of technical potential in the Generation sector.

Economic Potential: Economic potential refers to the subset of the technical potential that is economically cost-effective over a given time period. For T&D, all projects that are not found to be cost-effective based on the results of a cost-benefit analysis are excluded from estimates of economic potential. For generation, economic potential is not calculated separately due to modeling limitations.

To determine cost effectiveness, cost-benefit tests were devised for this project based on similar tests used in demand-side potential studies and modified for EUI purposes. For T&D, a Total Resource Cost test (TRC) is used where the benefits are avoided costs (these avoided costs were also shared with the concurrent demand-side study) and test costs are actual estimated project costs. The TRC is used to screen identified technical potential to output a smaller potential value resulting from only the projects that pass the test. The meaning of economic potential for T&D projects is directly analogous to the typical demand-side definition.

For the generation sector, economic potential is not calculated separately. The reasons are explained in detail in the Achievable Potential Model subsection under Methodology. In short, the difference between economic and achievable potential is not instructive enough to warrant the additional effort required to model it in the generation sector. This is because the methodology used does not calculate accurate economic potential results and a methodology that can calculate accurate results would require far more effort than reasonable under the scope of this project. Although the chosen methodology does not produce a value for economic potential in the generation sector, it allows for accurate reporting of results in context, produces an achievable potential value that is directly analogous to other sectors, and does not require fully modeling all generation facilities in the population set (which is outside the scope of this study and would not add significant value to the results).

***Achievable Potential*:** Achievable potential is defined as the amount of energy that can be reasonably expected to actually materialize as conservation savings based on assumptions relating to funding levels, incentives, code/regulatory requirements and realistic utility efforts to implement EUI efficiency. Achievable potential takes into account barriers that hinder implementation of energy efficiency measures such as financial, political and regulatory barriers, and the capability of designers to ramp up activity over time. The meaning of achievable potential is the same among T&D, generation, and conventional demand-side studies.

For T&D projects, a ramp rate of expected implementation is applied to the calculated economic potential to develop achievable potential. For generation sector projects, the TRC test is used to evaluate cost-effectiveness of individual projects. An additional assumption is made that each generation site will be able to implement the one most cost-effective project at the site over the course of the study. The effects of those project are summed to develop achievable conservation potential estimates. In the TRC calculation, benefits are the net present value dollar savings from reduced fuel expenditures over the life of the project (including forecast fuel cost adjustments) and costs estimated actual project costs required to implement the identified improvement opportunity.

Study Approach

This study is the first we know of aimed at estimating energy efficiency opportunity in the electric infrastructure for the purpose of calculating conservation potential. Without a known precedent for methodological comparison, the GDS Team used its experience with conventional market potential studies combined with technical experience in infrastructure project design to devise models and methods used in the study. As the study progressed, adjustments to the models were made to make use of available data. The overall approach changed slightly over the course of the project to arrive at accurate estimates of EUI conservation potential in Minnesota.

Throughout the study, we relied on input from the Advisory Committee, the Department, secondary research references, generation and T&D experts and, most importantly, primary data from contributing utilities. The data collected from all sources was used to design our conservation estimation models and populate those models with appropriate inputs describing Minnesota utilities.

Compared to DSM conservation potential, EUI potential comprises a small number of measures that each describe large conservation projects with wide variability from one site to the next. The team modeled each conservation measure in detail based on the appropriate Minnesota TRM section. We then collected data to define a representative sample of existing Minnesota EUI conditions and possible improvements that could be made. We applied the defined measures to model the conservation impact of the measures and produce the final results.

At the beginning of the EUI projects, an Advisory Committee was convened to help steer activities toward accomplishing the desired goals. Advisory Committee members were expected to contribute more effort to the projects than the wider group of stakeholders. This involved activity between meetings to consider proposals and discuss the projects within their organizations. The Advisory Committee played an active role in improving the methodology and helping collect required data.

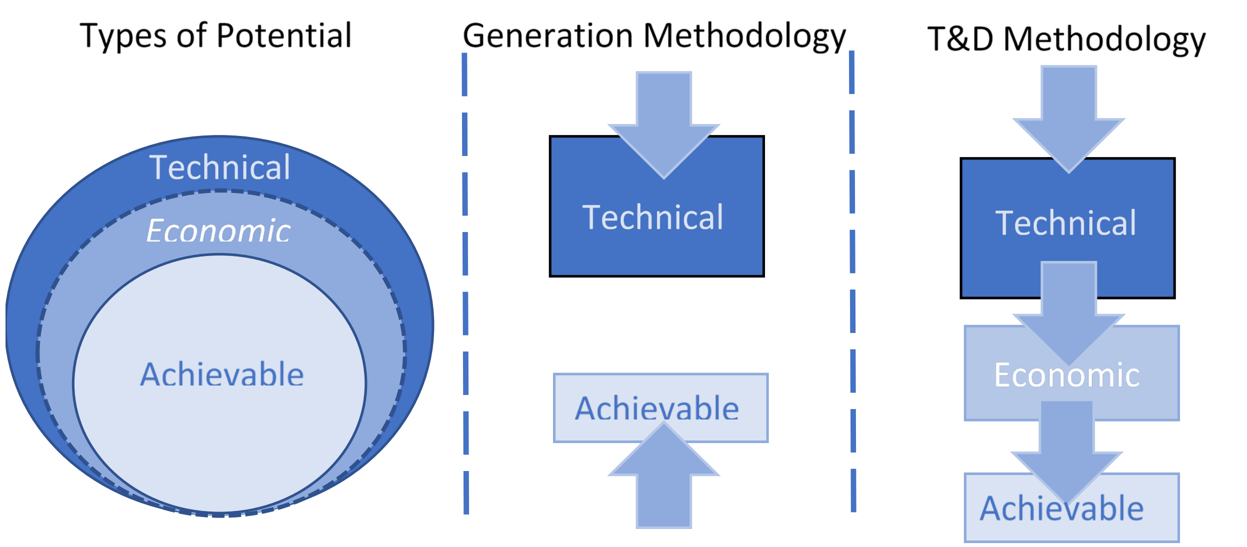
Table 2-1 – List of Advisory Committee Members

Name	Title	Organization
Nick Minderman	DSM & Renewable Policy Strategy Consultant	Xcel Energy
Clifford Haefke	Director	Energy Resources Center/DOE CHP TAP
Grey Staples	Managing Director	The Mendota Group
Jeff Haase	Strategic Energy & Efficiency Program Representative	Great River Energy
Jim Horan	Director of Government Affairs and Counsel	Minnesota Rural Utilities Association
Kevin Lawless	Principal	The Forward Curve LLC
Lisa Severson	Conservation Coordinator	Minnkota Power Cooperative
Nick Mark	Manager, Conservation & Renewable Energy Policy	CenterPoint Energy
Richard Sedano	Principal, Director of US Programs	Regulatory Assistance Project
Rob Scott-Hovland	State Legislative Representative	Missouri River Energy Services
Robert Jagusch	Director of Engineering and Policy Analysis	Minnesota Municipal Utilities Association
Tina Koecher	Manager - Customer Solutions	Minnesota Power
Will Nissen	Director, Energy Performance	Fresh Energy
Greg Anderson	Energy Efficiency Engineer	Otter Tail Power Company

3 Methodology

This section outlines the methodology used for the study. This study is unique in its focus on infrastructure measures, so a careful review of the methodology is recommended to properly contextualize the findings. For the generation sector, technical potential is calculated using a top-down, statewide approach of comparing Minnesota's generation fleet to facilities nationwide. Generation achievable potential is calculated differently, using a bottom-up approach to estimate realistic improvements that could be made looking at each facility's current operating characteristics. Economic potential is not calculated for the generation sector because it does not add significant understanding to the study. The transmission and distribution sector follows a more-traditional potential study strategy, using a top-down approach throughout. First technical potential is calculated by applying measure information to collected data about the existing systems. Then the identified technical potential is screened for cost-effectiveness to determine economic potential. Then realistic implementation ramp rates and replacement timelines are applied to further screen the economic potential to determine the achievable potential. A visual representation of the process is shown in Figure 3-1 and detailed descriptions of the full methodology follow.

Figure 3-1 Visualization of Project Methodology



Generation Sector Methodology

This section describes the methodology used to develop a high-level assessment of efficiency potential in generation facilities serving Minnesota load. To accomplish this goal, a model was devised based on the TRM EUI generation protocol (which, in turn, is based on net heat rate improvements) to estimate the possibility for improving existing generation facilities' heat rates.

There are two considerations that warrant mention early in this description. First, the study is designed to produce high-level estimates of conservation potential. It is outside the scope and budget of this project to perform detailed engineering analysis on individual generation facilities. Second, several sources of data used to complete the study shared information with the project team under the protection of a Non-Disclosure Agreement (NDA). Results are aggregated at the statewide level and into some high-level categories, but not at high resolution or in any format that could be used to identify individual sites or owners. This protects the anonymity of participating data providers. Further, the results are expected to be useful at the macro level. Reporting results at a higher resolution be limited in value and would risk violation of NDAs.

The first step in the methodology is to define the model for calculating CIP savings from possible Generation efficiency projects. The algorithm used comes from the Minnesota TRM and is based on heat rate improvements. The inputs to the algorithm provide a roadmap for the data that will be required to collect or calculate to model generation facilities in Minnesota and define the model. Inputs include fuel type, existing heat rate, capacity, capacity factor, and proposed improved heat rate.

Once the model is defined, the next step of the methodology is to create a set of generation plants to include in the study and collect baseline information about each. The complete set of data defines baseline conditions from which to model potential improvements. At this point, the goal is to cast a broad net to capture all facilities that could possibly contribute to conservation potential for Minnesota utilities.

Technical potential at each plant is calculated by determining the maximum possible heat rate improvement and applying the TRM algorithm to determine the resulting savings. Several filters are then applied to remove plants from the model that are not feasibly capable of realizing savings. The savings potential at the remaining plants is summed to calculate the statewide technical potential savings estimate.

Achievable conservation potential in the Generation sector is estimated by identifying a unique, cost effective heat rate improvement project that can be implemented at each class of facility. These projects represent the maximum potential savings that are economically viable for implementation. For each individual facility identified as possessing technical conservation potential, the implementation of the identified project type for that class is modeled and the resulting conservation is the achievable potential at the site. Due to assumptions chosen by the modeling team and explained in detail below, economic potential is not calculated separately from achievable potential in the generation sector because a separate model would be required, it is unlikely the economic value would be as accurate, and the difference is not likely to be instructive.

After reviewing the technical and achievable models, important assumptions are summarized in a separate section below. The assumptions are explained in the model descriptions, but are collected separately for reference. Also, a narrative of adjustments made to the study as it progressed is included to help readers understand why some assumptions/adjustments were made and the issues they were meant to resolve (also to provide an opportunity for inventing improved methods in future similar efforts).

Over the course of this project, we relied on a wide variety of data sources (much wider than originally anticipated). The final subsection below outlines data source for reference (except those that are protected under an NDA) and describes collection efforts to help put the study findings in context.

The main methodology for the generation sector is completed under the assumption that all facilities are eligible to claim CIP savings credit. Depending on the interpretation of statute, natural gas facilities greater than 50MW capacity may be automatically exempted by from CIP and may not be eligible to claim conservation credit. The impact of this interpretation is calculated in detail in the report section Modeled Impacts of Possible Policy Guidance to illustrate the importance of clarifying the policy.

Measure Characterization

The defined protocol from the TRM measure - Generation Heat Rate Improvements[8] was used as the basis to develop the generation efficiency potential model used for this study. The TRM protocol is based on measuring heat rate improvements made at generation facilities. Therefore, the potential model is based on determining the current heat rate of generation facilities, estimating the opportunity for improving them, and calculating the resulting equivalent kWh that can be claimed toward CIP goals. The following algorithm is the foundation of both the TRM protocol and the potential models.

Equation 3-1. TRM kWh Savings Algorithm for Heat Rate Improvements

$$\Delta\, kWh/yr = MNLd \times \left[\frac{(HR_0\ - HR_1)}{\mathrm{HR}_1} \times \mathrm{kW}_0 \times LF \times H\right]$$

Where:

MNLd is the percentage of load served by the generation facility that is located within Minnesota

HR_0 is the initial net heat rate of the facility described in the baseline model (Btu/kWh)

HR_1 is the final net heat rate of the facility as determined by the model (Btu/kWh). This is a different value in each of the potential models

LF is the load factor of the facility determined from collected baseline data (actual production at the site divided by possible full capacity production at the site)

kW_0 is the plant capacity (kW)

H is Hours per year (8760 in most cases)

[8] Minnesota TRM produced by the Department of Commerce. http://mn.gov/commerce-stat/pdfs/mn-trm-v2.1.pdf

The final results are re-calculated to show conservation in terms of input fuel savings using Equation 3-2. These results can be used to predict input fuel savings directly, but are not indicative of savings to be reported for CIP purposes. The TRM measure does allow claiming gas savings toward conservation goals (in MMBtu) for projects that reduce gas generation input fuel at eligible facilities, but we do not anticipate many projects will make use of this provision due to limited eligible projects. Only natural gas facilities under 50MW capacity proposing projects that result in input fuel reduction would be eligible to claim CIP savings in therms. There is also some uncertainty about whether gas facilities over 50MW capacity can claim *any* CIP conservation; further discussion of this topic can be found in report section Modeled Impacts of Possible Policy Guidance.

The fuel conservation presented using Equation 3-2 is the basis for calculating input fuel savings at each site in order to determine fuel cost savings that factor into the TRC test used to evaluate achievable potential. It is also used to determine carbon emission impacts of the identified savings potential.

Equation 3-2. TRM Input Fuel Savings Algorithm for Heat Rate Improvements

$$MMBTU/yr = MNLd \times \left((HR_0 - HR_1)\ \times\ kW_0\right) \times LF \times H/10\text{^}6$$

Baseline Generation Plant Data Set

The next step in the methodology is to define a set of generation plants that are included in the study and collect necessary baseline information about each. The goal at this step is to cast a broad net to capture all facilities in Minnesota or owned by Minnesota utilities that could possibly deliver any conservation potential. The set of facilities included in the potential models will be whittled down in the following steps.

To identify all relevant facilities, the team drew from an industry reference database[9] that collects generation plant data from FERC Form 1, EIA Form 923, EIA Form 860, and other sources. We began by sorting the database for facilities located in Minnesota or owned by Minnesota-based utilities. We included sites within 50 miles of the state border to ensure we did not miss any candidate plants.

Some important context for the study is reflected by sites *not* included in the final data set. The data set does not include small (<1MW) facilities because they are typically not required to file forms referenced to build the database. Most consumer-owned generation facilities are not included in the data set. Planned future facilities that are not yet operating are not included in the data set and were not added manually due to the effort required to estimate heat rate at a non-operating plant. Finally, the team removed plants that do not measure performance in terms of heat rate because the defined measure algorithm is based on heat rate improvements. This means the plant data set (and the study as a whole) does not estimate conservation potential from improving the efficiency of renewable, hydropower, or

[9] Database maintained by S&P Global based on generation facility filings (requires subscription to access). www.spglobal.com

nuclear generation facilities. All of these excluded facilities could theoretically contribute to conservation potential over the timeframe of the study and utilities should not ignore them as possible efficiency targets. However, the team agreed that the contribution is likely to be small and modeling results would be inconclusive. A qualitative discussion of the possible potential at excluded facilities is included in the Results section.

Another important assumption for context is the advantage of using actual plant operation data because it reflects actual maintenance activity at each site. Statue requires the chosen baseline for CIP purposes must reflect expected normal maintenance activity at the site. Most plants in the final model have five years of operational history, which is used to define the baseline heat rate at each site. This allows us to assume that normal maintenance activity at each site is already baked into the base case. That is, it can be reasonably assumed that identified heat rate improvements compared to the modeled baseline do not have to further adjust that baseline to account for normal maintenance activity. Actual proposed projects at real sites will have to defend a choice of baseline that shows that the project goes beyond the course of normal maintenance, but for the purposes of the generation portion of this study, the chosen methodology means that this issue can be safely tabled.

Table 3-1 shows an example of some of the data collected to populate the baseline model. Several of the utilities surveyed as part of this study participated under a Non-Disclosure Agreement, so information that can be used to individually identify utilities or sites has been removed from the public version of this report.

Table 3-1 Example of Baseline Model Data

Technology Detail	Fuel Type	Commercial Operation Date	State	Nameplate Capacity (MW)	5-year Average Operating Capacity (MW)	5-year Average Net Generation (MWh)	5-year Average Capacity Factor (%)	5-year Average Heat Rate (Btu/kWh)
Combined Cycle	Gas	2008	MN	644.0	600.0	1,763,864	33.55	7,150
Combined Cycle	Gas	2002	MN	324.8	292.4	609,941	23.80	7,750
Combined Cycle	Gas	2008	MN	250.0	229.2	625,254	31.28	7,150
Combined Cycle	Gas	2006	MN	210.0	200.0	426,911	24.32	11,527
Combined Cycle	Gas	2006	MN	160.0	160.0	194,031	13.83	11,600
Combined Cycle	Gas	2006	MN	370.0	360.0	364,795	26.00	7,667
Combined Cycle	Gas	2008	MN	606.0	606.0	541,011	33.27	7,300
Combined Cycle	Gas	2009	MN	585.9	491.6	1,889,362	43.77	7,250

The SNL database includes a significant portion of data required to describe the operation of the identified facilities in terms of capacity, capacity factor, and heat rate. We also collected owner, fuel type, generation technology, and location for each site.

There were gaps in the database and some uncertainty as to the accuracy of some of the contents, even after manually comparing to the most recent available public EIA form 923 data[10]. Therefore, the team devised a data request to circulate among Minnesota utilities to fill in the gaps and verify questionable values. By the end of the project the team is satisfied that the baseline data set is complete and accurate.

Technical Potential Model

Technical potential at each plant is calculated by determining the maximum possible heat rate improvement and applying the TRM algorithm to determine the resulting savings. Several filters are then applied to remove plants from the model that are not feasibly capable of realizing savings. The calculated potential at the remaining plants is summed to produce the statewide technical potential.

Table 3-2 Modeled Classes of Generation Facilities

Class	Fuel	Technology	Capacity	Age	Best-in-class heat rate (kWh/Btu)	Capped Maximum Improvement (%)
1	Coal	Subcritical	<200MW	48+	10,436	4%
2	Coal	Subcritical	<200MW	≤48	11,566	4%
3	Coal	Subcritical	>200MW	NA	10,036	4%
4	Coal	Supercritical	All	NA	8,998	2%
5	Gas	Combined Cycle	<200MW	NA	7,655	6%
6	Gas	Combined Cycle	>200MW	NA	7,150	6%
7	Gas	Steam Turbine	<50MW	48+	13,347	3%
8	Gas	Steam Turbine	<50MW	≤48	20,696	3%
9	Gas	Combustion Turbine	<50MW	48+	14,426	6%
10	Gas	Combustion Turbine	<50MW	≤48	15,829	6%
11	Gas	Combustion Turbine	>50MW	NA	10,500	6%
12	Biomass	All	All	48+	Case-by-case	5%
13	Biomass	All	All	≤48	Case-by-case	5%

The maximum possible heat rate improvement at each facility in the data set is determined by a multi-step process. First, all facilities are stratified into classes by fuel type, technology, capacity, capacity factor and age (see Table 3-2 for a list of classes). For each class, a high-performing plant is chosen as a benchmark, best-in-class comparison. The difference in heat rate between a given plant and the designated benchmark plant in its class represents a theoretical maximum improvement at each site.

[10] Form EIA-923 reporting monthly generation and fuel consumption. https://www.eia.gov/electricity/data/eia923/

However, the best-in-class is not an appropriate comparison in all cases, so for each class of plant, an upper limit on possible gains in terms of percentage heat rate improvement is developed based on engineering expertise and past project design experience (Table 3-2 also includes the cap applied to each class). For each plant, the lesser improvement between the best-in-class comparison and the defined upper limit for that class is chosen as the upper limit of technically possible heat rate improvement at each site. The TRM measure algorithm is then applied to the identified improvement to calculate the technical potential for savings at each site.

Before summing the technical potential at each site to get the statewide potential, several filters are applied to remove some plants from the data set. The filters applied impact the meaning of "technical potential" in the context of the Generation sector and should be considered when interpreting results.

- First, plants that are nearing retirement are removed. Retirement information comes from EPA reported planned retirement dates (captured in the referenced industry database)[11], Integrated Resource Plans (for IOUs), and conversations with plant owners. Most of the removed plants are either planned decommissioning/replacement projects or facilities built before 1970 that are more likely to be replaced than upgraded.
- Second, facilities with low capacity factors (operating less than 150 hours per year) are removed. The modeled technical potential at these sites is small, costs to complete upgrades are relatively high, the modeled conservation is less likely to be accurate, and conversations with operators indicated that upgrades beyond prevention of failure are unlikely. This filter results in the removal of a large number of facilities that contribute a relatively small amount to the overall generation output in the state.
- Third, plants serving significant load outside Minnesota are removed. This was done on a case-by-case basis, but for the most part correlates with plants located further from the state (with a few exceptions). Calculated conservation credit is de-rated by the percentage of load served in Minnesota. Projects completed to improve efficiency at sites that can only claim partial credit are unlikely at best and very difficult to model accurately.

Some of these filters could have been applied to the achievable potential instead of the technical potential, but were applied here instead after careful consideration. The technical potential removed by these filters represents *physically possible* conservation opportunity that is nonetheless deemed infeasible technically. Another way of describing these filters is that the potential they remove could be considered technical potential, but could not possibly have been shifted to achievable potential with any change to Minnesota policy or incentives. For example, a coal plant scheduled for retirement in 2022 could undergo a complete retrofit to improve the heat rate and achieve savings for two years, but there is no conceivable policy that could make that investment plausibly worthwhile. Additionally, the plants removed by these filters are some that have the lowest confidence in the modeled efficiency

[11] Database maintained by S&P Global based on generation facility filings (requires subscription to access). www.spglobal.com

improvement potential. Therefore, by removing them and carefully documenting the meaning of technical potential in the generation context, we arrive at more accurate final results.

After the filters are applied, the plants remaining in the model fit into 13 classes (there were 42 possible classes defined, but most did not describe any plants remaining in the final data set). Table 3-2 shows the classes used in the model, identified best-in-class heat rate, and capped maximum allowable improvement for each class. The total statewide generation conservation technical potential is produced by applying the TRM algorithm to calculate technical potential at all facilities and summing the results.

Achievable Potential Model

Achievable conservation potential in the generation sector is estimated by identifying a specific, cost-effective heat rate improvement project (one that passes a TRC test) to implement at each class of facility. These projects represent the greatest possible potential savings that can be implemented economically. For each individual facility identified as possessing technical conservation potential (previous section), the implementation of the identified project type for that class is modeled and the resulting conservation is the achievable potential at the site.

The GDS team includes individuals with experience designing and implementing actual heat rate improvement projects at generation facilities. From experience with a pool of past projects that were actually implemented or designed for real facilities, several example projects are characterized for each class of facility in terms of heat rate improvement, resulting fuel savings (using the TRM fuel conservation algorithm in Equation 3-2), degradation of improvements over time, and cost to implement as a function of plant capacity. The estimated costs for each example project type draw on actual past project costs. A recent EIA study[12] examining possible heat rate improvement projects generally corroborates the project costs chosen for the model.

The characterized example projects are then applied to a representative facility in each class. The model applies the example project to calculate estimated fuel savings over time (using the TRM algorithm in Equation 3-1). Fuel costs from Henry Hub projections via EPA[13] are then used to calculate fuel cost savings resulting from the project. A TRC score for each example project is calculated at the representative facility using the estimated project costs and fuel savings. For each class of facility, the example project that produces the greatest savings and has a TRC greater than 1.0 is selected as the project type to represent the maximum cost-effective potential for that class of facility (in all cases, this was the project type with the lowest passing TRC score). The selected project is then applied to all facilities of the same class to calculate potential at each.

[12] *Analysis of Heat Rate Improvement Potential* at Coal-Fired Power Plants. US Energy Information Administration. May 2015. https://www.eia.gov/analysis/studies/powerplants/heatrate/pdf/heatrate.pdf

[13] Projection of WTI and Henry Hub spot prices 2010-2050. EIA. https://www.eia.gov/outlooks/aeo/excel/figif1-7_data.xlsx

The facilities included in the achievable potential model are those that were identified in the previous section as having technical potential savings available. That is, all of the filters applied to remove plants from the technical potential model (planned retirement, low capacity factor, or non-MN plants) have been applied to the plant data set prior to calculating achievable potential.

This approach is similar to the typical achievable potential methodology used for demand-side studies in that achievable potential is drawn from sites with demonstrated technical potential and results in a smaller subset of possible conservation opportunity. However, the methodology is fundamentally different in that the achievable model is not directly screening the technical potential at the project level because the technical potential is calculated at the facility level. That is, the technical model is built from the system-level down and the achievable model is built from the project-level up. This is fundamentally different from a conventional potential study. Typically, either a top-down or bottom-up approach is chosen from the outset for the whole study. For this study, due to data availability and the inability to model all unique generation sites in the state, the technical potential uses a high-level top-down approach and the achievable potential uses a sampled bottom-up approach and extrapolates across the sector. The achievable model does produce lower conservation estimates for all sites compared to the technical potential model, which is expected and lends credence to the methodology.

Once we assume that a generation plant implements the identified achievable potential opportunity, we are not allowing for additional projects at the site over the course of the study. This is a choice made by the project team to limit uncertainty in the results. It is possible that those sites could identify and implement multiple economically viable projects to achieve additional savings over time. However, when we model multiple projects at a given site, the model does not translate to other sites well. Interactions between projects become complicated and even occasionally result in negative savings. Without doing engineering analyses on each site individually we are not comfortable estimating additional potential from implementing multiple projects though it likely exists at some specific sites. The results therefore can be interpreted as the combined conservation potential for implementing the single largest economically viable improvement opportunity at each site. It is reasonable to assume that as the largest project is implemented at one site a utility will shift focus to implement a large project at another site rather than a second project at the first site, so over the period of the study the missed achievable potential from this limitation can be reasonably assumed to be a small (but not negligible) percentage.

The limitation just described that prevents the models from accurately predicting the effects of multiple projects at a site is the main reason we do not calculate economic potential separately for the generation sector. For the achievable potential, it is reasonable to assume that utilities will be able to implement one economically viable improvement project at each candidate facility over the 20-year period of this study and that the project will be the one with the largest conservation opportunity. Removing this assumption and re-calculating the potential would be the appropriate method of calculating economic potential. However, to accurately predict the effects of multiple projects at a site would require full engineering analyses of opportunities on a case-by-case basis at each generation facility across the state. Therefore, we do not present results for economic potential value. We believe that the two values presented (technical and achievable) demonstrate the fullest picture of the potential for conservation in the generation sector within the scope of this study.

In addition to the final total estimated statewide potential, the results section includes detailed descriptions of three identified economically viable projects (Generation Sector Example Projects). These descriptions may help readers to frame the results or identify conservation opportunities at their own sites.

Cumulative EUI Potential Conservation Impacts

After estimating annual conservation potential, total savings are extrapolated over the course of the 20-year study period. Cumulative estimates illustrate the possible impact of CIP programs over time. This result is separate from the estimated claimable CIP savings because only first-year savings count toward goals.

Cumulative technical potential is calculated assuming that all technically feasible heat rate improvement projects are implemented in year one and maintained continuously for the duration of the study period. Effectively, this amounts to multiplying annual conservation potential by the number of years included in the study (20).

Cumulative achievable potential is estimated by establishing realistic timelines to implement identified projects and applying an assumed degradation of savings over time after each project is installed. The largest IOU owner of generation plants is assumed to implement one large project (>200MW facility) or two small projects (<200MW facilities) every two years. Smaller IOU and COU owners of generation facilities are assumed to implement one project every 5 years. On average, full savings from projects are expected to persist for three years, then subside back to baseline efficiency conditions at five years after the project implementation.

Important Modeling Assumptions and Adjustments during the Study

Over the course of the study, several assumptions were made as the team incorporated data and filled gaps in the available data. These are all described in other sections, but it may be useful as a reference to explicitly list the assumptions built into the models and methodology here.

- The technical potential model is a top-down approach that looks at conservation opportunity by examining each generation facility as a system. The achievable model is a bottom-up approach that applies discrete projects to each facility. The reason for choosing these approaches is the fact that a full engineering analysis required to look at each unique facility in complete detail is outside the scope of this study. The simplified approaches were chosen to fit within the study’s scope and still develop accurate estimates of statewide conservation potential.

- Technical potential is based on assuming each facility's heat rate is improved to match the identified best-in-class facility or capped at a maximum percentage improvement. Each class of facility has a maximum improvement based on the expertise of engineers with generation project experience.
- We assume that "normal maintenance" activity is baked into the baseline of measured plant performance. That is, all plant improvements identified are beyond normal maintenance as required for CIP by statute. Because our technical potential model looks at generation from a top-down view, we do not build in separate maintenance assumptions, but because we use 5 years of data to develop the baseline, it is fair to assume normal maintenance practices are reflected in that value. The identified specific projects used to estimate achievable potential (bottom-up approach) include verifying that they are beyond normal maintenance to comply with statutory requirements.
- The achievable potential estimate assumes that only one conservation project is completed per generation facility over the course of the study period. This is mostly because the interactive effects of several projects become too complicated to model within the scope of a potential study. We further assumed that that once a project is completed at one site, additional projects will be far less cost effective, so although it may be possible to identify those additional projects, they would contribute only a small amount to the estimated conservation potential.
- In the generation sector, we did not calculate economic potential separately from achievable potential. This is because the model outputs become inaccurate when assuming more than one project is completed per site. That limitation is reasonable to include in the achievable model, but not economic. There is not a reasonable way to model the possible additional economic potential that is not also achievable within the scope of the project.
- Many generation facilities that are eligible to claim conservation credit are removed from the study because they are assumed to provide too little opportunity, do not fit into the model, or are unlikely to be targeted for improvement by utilities. Specific reasons for exclusion are: plants that do not measure efficiency in terms of heat rate (renewables, hydro), nuclear plants, plants that serve significant non-MN load, plants close to retirement or old enough that we anticipate upgrades would not be considered, and plants that run for only a few (<150) hours per year.

As the study progressed, the team made some changes to the model based on the availability of data and feedback from stakeholders. The most important change was the original plan for the technical potential modeling called for grouping facilities with similar characteristics into overly-broad classes. Originally, only fuel and technology were used to differentiate facility classes. After discussions with the Advisory Committee, the class breakdown was refined to separate facilities by fuel type, generation technology (subcritical, critical, super critical; gas turbine, gas-steam turbine, combined cycle), capacity (two ranges, with separate threshold set for each technology), age of the facility (pre- or post-1970 construction), and capacity factor (low, medium, high). This resulted in 72 possible classes to assign each facility, 12 of which actually describe plants in the final data set used to model technical potential.

Data Collection

Data was collected from several sources to define the potential models and complete the conservation calculations. This section provides a collected description of all data sources used in the generation potential models.

Industry Database Records

A significant portion of the data required to complete the generation model came from an industry database repository of generation facility operation records (including from FERC Form 1, EIA form 923 and EIA form 860 as well as other sources).[14] For each generation facility in Minnesota, the data collected includes: plant name, owner, technology, fuel type, nameplate capacity, 5-year average gross and net operating capacities, 5-year average net heat rate, and age of the facility. These data points served as the basis to build the baseline model and the framework for the full potential model.

The database requires a subscription to access directly, but the information it contains comes mostly from publicly-available recorded filings. The data could have been collected separately without access to the database, but would have required significant additional effort. Though the database contains all major generation facilities and has all the fields required to complete the model, some of the fields were not populated or were out of date, so we relied on additional resources to fill in the gaps.

Public Records and Integrated Resource Plans

Additional data was collected from the most recent publicly available records of Form EIA-860 and Form EIA-923 filings through the EIA website[15] and from Integrated Resource Plans (IRPs) filed on the PUC docket for IOUs[16]. For the generation models, this data was mainly used to corroborate and update the more-detailed industry database records concerning plant capacities and planned retirements (IRPs were referenced more extensively in the T&D models).

Fuel Cost Projections

Achievable potential calculations depend on estimating the expected benefits of implementing conservation projects. For our modeling purposes, the benefits of generation heat rate improvement projects are comprised of input fuel savings. Therefore, each of those models depend on fuel cost

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[14] Database maintained by S&P Global based on generation facility filings (requires subscription to access). www.spglobal.com

[15] Form EIA-860 Detailed Data. https://www.eia.gov/electricity/data/eia860/

[16] Initial Filings of Integrated Resource Plans filed on Dockets: EU15/RP-15-690 (MN Power), ET15/RP-17-753 (SMMPA), ET2/RP-17-286 (Great River Energy), E002/RP-15-21 (Xcel Energy)

projections over the planning horizon. The fuel costs used come from the EIA Annual Energy Outlook 2018 and Henry Hub Projections from the EPA[17].

Advisory Committee Feedback

Over the course of completing this study, several changes were made to the methodology and new strategies or assumptions were introduced to address issues that arose. For many of the issues, the Advisory Committee provided much appreciated feedback. Four Committee meetings were held to discuss the project (along with the concurrent DOE stakeholder engagement project).

Committee members pointed out potential issues, offered recommendations for overcoming them, and helped the project team contact knowledgeable individuals at their organizations. For example, several outreach data requests (next section) were routed through Advisory Committee members to the generation operators with the information needed. Without the Committee's help much of the required data would have been inaccessible. As another example, the originally-planned definitions of plant classes to be used in the potential models were too broad and did not accurately capture the differences between plants. The correction to this issue (described in the previous section) was recommended by an Advisory Committee member.

Utility Outreach

After collecting as much data as possible from public and other identified outside resources, we reached out to Minnesota utilities to collect missing data or verify our data accuracy. We also held conversations with several plant operators to ensure the models incorporate an accurate understanding of the practical operation of facilities.

To collect missing data and verify our previously collected data, we devised a data request template. After an initial round of cumbersome data requests, the project team came up with a clear template to give to generation facility operators to fill out and return with updated/verified site information. Figure 3-2 is an example of one of the data requests submitted to a participating facility owner. The collected data was fed back into the models described above to improve the accuracy of the final results.

[17] Projection of WTI and Henry Hub spot prices 2010-2050. EIA. https://www.eia.gov/outlooks/aeo/excel/figif1-7_data.xlsx

Figure 3-2 Generation Data Request Template

Verify data collected from other sources if possible - low priority
Low priority data - would help put report in context, but not needed for direct calculations
Medium priority data - Would improve potential study direct calculations, but wouldn't prevent completion if unavailable
High priority data - needed to complete the study accurately

Owner	Tech.	Nameplate Capacity (MW)	2016 Gross MW	2015 Gross MW	2014 Gross MW	2013 Gross MW	2012 Gross MW	5-year Avg Gross MW	2016 Net MW	2015 Net MW	2014 Net MW	2013 Net MW	2012 Net MW	5-year Avg Net MW
[redacted]	ST	598.4	598.4	589.4	598.4	598.4	598.4	596.6	511.0	511.0	511.0	511.0	511.0	511.0
	GT	119.7												
	GT	119.7												
	GT	405.7	405.7	405.7	405.7	405.7	405.7	405.7	386.0	386.0	386.0	386.0	386.0	386.0
	GT	166.3												
	CC	136.9												
	CC	187.9												
	CC	299.0	324.8	324.8	276.8	276.8	276.8	296.0	298.0	298.0	215.0	232.0	232.0	255.0
	GT	56.7												

We reached out to all IOUs and most other generation facility owners to verify the accuracy of our data and fill in gaps. We also spoke to municipal utilities as part of our outreach (in conjunction with T&D data collection) to verify understanding of the operation of smaller facilities.

Anecdotally, for the most part IOUs typically required NDAs before sharing any data, while municipal utilities were more able to share their public data. Co-ops seemed to be in the middle where going through the NDA process was not worth the effort, but sharing data without it constituted too much risk. This phenomenon was more noticeable for T&D data collection and did not significantly impact the generation final results.

Sales Forecasts & Avoided Costs

Project partner CEE is also the project lead for the concurrent DSM potential study. As part of the DSM project, thorough models were developed to predict annual sales volume and avoided costs associated with energy conservation for each utility in the state over the 20-year period of the study. To prevent duplication of effort and to ensure consistency across the studies, CEE generously agreed to share the sales forecasts and avoided cost information for use in this study.

The sales forecasts and avoided costs are used extensively in the T&D models. For generation, the avoided cost data is not used. The sales forecasts are used to frame the potential results in terms of percentage of sales and percentage of CIP goal (where the CIP goal is 1.5% of gross sales excluding exempt customer sales).

Related White Papers & Study Reports

Over the course of the project, several useful reports were identified that helped to corroborate our findings. A 2015 report on heat rate improvement potential at coal-fired power plants published by EIA helped to confirm our methodology and verify the final results[18]. The report is accompanied by a spreadsheet model of possible coal plant improvement projects, which corroborate our estimated savings. Additionally, the report includes estimated costs for potential projects based on percentage heat rate improvement. That format is similar enough to our achievable potential screening methodology and produces similar enough results to bolster confidence in our findings.

A 1998 EPRI heat rate improvement reference manual also corroborated our methodology and general approach to determining heat rate impacts[19].

The Department of Commerce published a report in 2010 identifying potential conservation project ideas. These were considered in the development of models to ensure no major sources of potential savings were overlooked[20].

Several other references were also reviewed, but none contributed materially to the outcome of the generation potential modeling.

Transmission and Distribution Methodology

This section details the methodology used by the project team to estimate the 20-year technical, economic, and achievable potential for energy conservation measures applied to the distribution and transmission systems within the state of Minnesota.

Overview

The general methodology for the T&D portion of this study can best be described as a "bottom-up, units-based approach." The bottom-up approach considered the technical impacts of various energy conservation measures (ECMs) for each considered distribution and transmission component. Per-unit impacts were then estimated based on engineering calculations and available data.

The study assessed the following three types of potential:

1 ***Technical Potential*** assumes all technically feasible ECMs generally available at the time of the study will be implemented, regardless of their costs or of any market barriers. This theoretical upper bound of available conservation potential is estimated after accounting for technical

[18] *Analysis of Heat Rate Improvement Potential* at Coal-Fired Power Plants. US Energy Information Administration. May 2015. https://www.eia.gov/analysis/studies/powerplants/heatrate/pdf/heatrate.pdf

[19] *Heat Rate Improvement Reference Manual*, EPRI, Palo Alto, CA: 1998. TR-109546

[20] Utility Infrastructure Improvements for Energy Efficiency, Franklin Energy, for MN Department of Commerce, 2010

constraints. For ECM measures considered in this study, technical potential can be divided into three distinct classes:

- Retrofit ECMs
- Natural replacement ECMs
- New construction ECMs

Utilities can implement retrofit ECMs at any point in the planning horizon. Example of retrofit measures include the suite of technologies and practices considered as part of conservation voltage reduction (CVR). On the other hand, the potential model assumes that equipment turnover rates dictate the timing of natural replacement ECMs which included both transformers and conductors in this study.

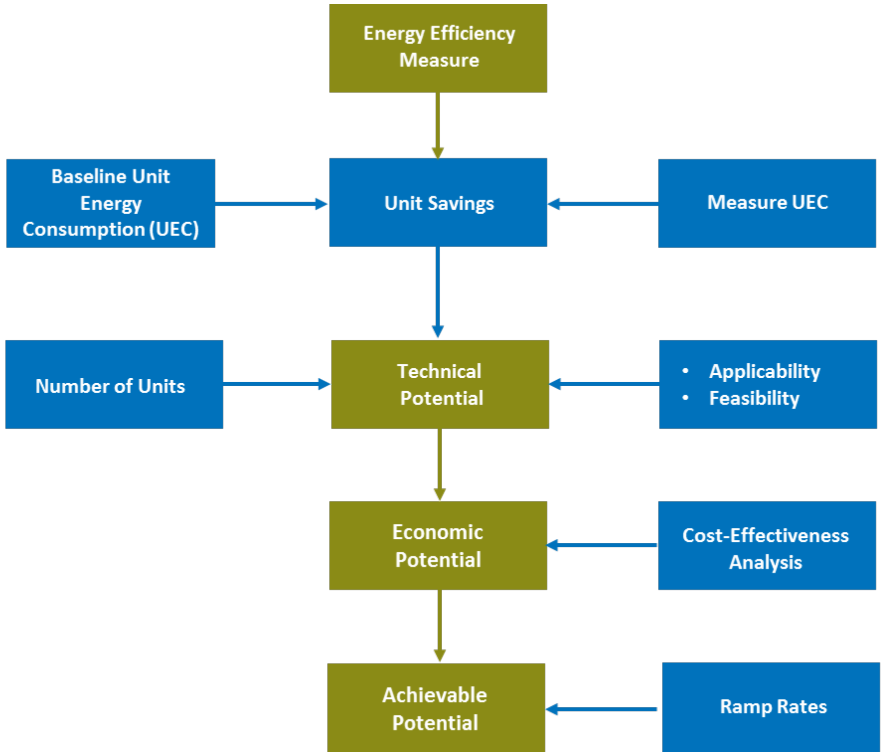
2. ***Economic Potential*** represents a subset of technical potential and consists only of measures meeting the cost-effectiveness criteria, set by the utility cost test. For each ECM, the study structured the benefit/cost (B/C) test as the ratio of net present values (NPV) for the ECM's benefits and costs, using typical benefit and cost inputs. Only measures with a benefit/cost ratio of 1.0 or greater were deemed cost-effective. This study considered the total resource cost test (TRC) as the primary B/C test for determining economic potential.

3. ***Achievable Potential*** derives from the portion of economic potential that might be assumed reasonably achievable in the course of the planning horizon, given market barriers that might impede adoption of electric utility infrastructure ECMs.

Technical and achievable potential have the same definition for the generation and T&D sectors. For the generation sector, economic potential is not calculated due to modeling restrictions. Figure 3-3 shows an overview of the distribution and transmission potential methodology.

The team built a model to estimate the statewide distribution and transmission potential using a limited set of utility-provided data to characterize current system conditions. For some categories of measures, the lack of available data required the team to extrapolate information provided by other utilities in order to estimate total, statewide potential. The report section Extrapolations from Sample Utility Data Extrapolations from Sample Utility Data provides details for the measure categories that required data extrapolations.

Figure 3-3 Methodology to Determine T&D Potential



Measure Characterizations

Characterizing distribution and transmission EUI measures required multiple data inputs to accurately estimate baseline and efficient characteristics of selected EUI measures. The study considered distribution and transmission measures within four distinct categories, including:

- Service transformers
- Substation transformers (distribution)
- Conductors (distribution and transmission)
- Conservation voltage reduction

The study focused solely on the distribution and transmission measures listed above. The Minnesota TRM developed approved and stakeholder-reviewed savings algorithms for the four measure categories listed above. There are, of course, other possible measures eligible for CIP credit that utilities could implement but were not included in this study either because no prescribed protocol for calculating savings exists (e.g. surge arresters) or because of a very small amount of EUI savings potential (lighting at substations).

Service Transformers

As described in the Minnesota TRM, electric transformers of any type are never 100% efficient, but in many cases a higher efficiency option can be installed to minimize losses. Loss characteristics of a transformer consist of both load losses and no-load losses. Load losses vary with the load on the transformer and are also known as winding losses because they occur primarily in the transformer's windings. No-load losses occur because of the electrical currents and magnetic fields necessary to magnetize the transformer core and are present at a constant value whenever the transformer is energized regardless of load conditions. This measure analyzes the energy savings potential of the installation of higher efficiency transformers with lower load and no-load losses.

As part of the distribution system, service transformers provide the final voltage in the power line that will be used by the customer or customers by stepping down the voltage to the appropriate level. For the purposes of this study, the project team characterized liquid-immersed distribution transformers as medium voltage service distribution transformer as the most common type. Table 3-3 provides measure permutations characterized for service transformers.

Table 3-3 Service Transformer Measure Permutations

Measure Identifier	Measure
Segment	Single phase: Residential-urban, residential-rural, commercial Three phase: commercial, industrial
Size	Single phase: 10 kVa, 15 kVa, 25 kVa, 37.5 kVa, 50 kVa, 75 kVa, 100 kVa, 167 kVa, 250 kVa, 333 kVa, 500 kVa, 667 kVa, 833 kVa Three phase: 15 kVa, 30 kVa, 45 kVa, 75 kVa, 112.5 kVa, 150 kVa, 225 kVa, 300 kVa, 500 kVa, 750 kVa, 1000 kVa, 1500 kVa, 2000 kVa, 2500 kVa

Energy Savings and Measure Interactions

The team estimated energy savings per unit for each ECM permutation. The methodology to estimate unit energy savings was based on the Minnesota TRM. This study assumes existing service transformers will be replaced at the time of failure. New construction transformers are assumed to be units that meet federal minimum efficiency standards. In all cases, the baseline condition represents transformers meeting current 2016 federal standard. For service transformers, two measure iterations were evaluated as potential efficient cases (high and premium efficiency).

The team relied on a number of sources to develop savings estimates:

- **Savings methodology** - Minnesota TRM

- **Measure efficiency** - ENERGY STAR Market and Industry Scoping Report Medium Voltage Distribution Transformers[21]
- **Baseline efficiency** - U.S. Department of Energy Technical Support Documents for Transformers[22]
- **Peak load assumptions -** Minnesota TRM
- **Load loss and no-load loss assumptions** - ENERGY STAR Product Specification for Distribution Transformers Eligibility Criteria Final Draft Version 1.0[23]

Measure Cost Estimates

The team estimated incremental measures costs for each ECM permutation and used these costs to calculate B/C ratios for determining economic potential. The team relied on ENERGY STAR Market and Industry Scoping Report to determine incremental costs. The cost data represented five kVa sizes and was interpolated to determine the remaining kVa sizes. Finally, all costs are in 2018$, using the GDP deflator.

The team did not assume any additional annual O&M costs for energy-efficient service transformers. It is assumed the base equipment and efficient equipment operate the same.

Measure Life

The project team used estimates of each measure's effective useful life (EUL) to calculate the lifetime net present value (NPV) benefits and costs for each measure permutation. This study relied on the Minnesota TRM to provide the 25 years EUL for service transformers.

Technical Feasibility

No technical limitations were placed on upgrading to energy efficient service transformers.

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[21] ENERGY STAR Market and Industry Scoping Report Medium Voltage Distribution Transformers February 2014 of Tier 4 (high efficiency) and Tier 6 (premium efficiency). Accessed May 2018: (https://www.energystar.gov/sites/default/files/asset/document/MV_Utility_Distribution_Transformers_Scoping.pdf)

[22] Final Rule: Distribution Transformers Liquid-Immersed Life-Cycle Cost Analysis Spreadsheets. Accessed May 2018: (https://www.regulations.gov/document?D=EERE-2010-BT-STD-0048-0767)

[23] Version 1.0. Assessed May 2018: (https://www.energystar.gov/sites/default/files/Final%20Draft%20Distribution%20Transformer%20Specification_0.pdf)

Substation Transformers

Substation transformers fit a similar description as service transformers, discussed above, where the higher efficiency option minimize losses. This measure analyzes the energy savings potential of the installation of higher efficiency transformers with lower load and no-load losses.

Substation (distribution) transformers typically take the high voltage electrical power from the transmission lines and step down the voltage to the appropriate level for the distribution system. In most substations there are multiple transformers to create redundancies in the system. For the purposes of this study, the team characterized each transformer bank within a substation as a high voltage liquid-immersed distribution transformer as the most common type. Table 3-4 provides measure permutations characterized for substation transformers. The team identified the size distributions using utility Minnesota data.

Table 3-4 Substation Transformer Measure Permutations

Measure Identifier	Measure
Segment	All
Size	Small ≤ 5 MVA Mid Small > 5 MVA and ≤ 12 MVA Mid Large > 12 MVA and ≤ 30 MVA Large > 30 MVA

Energy Savings and Measure Interactions

The methodology to estimate unit energy savings was based on the Minnesota TRM. Similar to service transformers, this study assumes substation transformers will be replaced at the time of failure. Substation transformers are large and do not have federal standard requirements; therefore, the model's baseline assumption represents existing (e.g. *in situ*) efficiency conditions. Two energy efficiency substation transformer measure iterations were evaluated (high and premium efficiency). Somewhat limited data were available for existing substation transformer baseline efficiencies. Therefore, the project team used the similar efficiency improvements as service transformers and applied those percentages to utility Minnesota loading data for substations.

Measure Cost Estimates

Due to their large size, substation transformers are typically custom built, therefore making costs difficult to standardize in aggregate. Therefore, the team extrapolated service transformer cost data to approximate the incremental cost of choosing energy-efficient transformer options. No additional annual incremental O&M costs were assumed for high-efficiency substation transformers.

Measure Life

This study relied on the Minnesota TRM to provide the 25 years EUL for substation transformers. The expected useful life of the equipment is longer than the planning horizon of this study.

Technical Feasibility

No technical limitations were placed on upgrading to energy efficient service transformers.

Low-Loss Conductors

As described in the Minnesota TRM, the size and type of conductor used on a transmission or distribution line has a significant effect on the efficiency of the line. Larger conductors and different designs have a lower resistance. Replacing a length of conductor (re-conductoring) with a relatively larger conductor to carry the same load has the effect of reducing the kW loss for that length. In addition, there are low-loss conductors available on the market in cases where installing larger conductors may not be economically feasible since it would require structural tower/poll upgrades to carry the additional weight. Aluminum Conductor Composite Core (ACCC) low-loss conductors provide an alternative since the same diameter wire can be replaced with a lower loss conductor without requiring additional structural upgrades. These ACCC conductors are currently available for the larger conductor sizes on the market (300 kCmil or larger).

This measure is designed to calculate the energy savings attributable to choosing to install low-loss transmission or distribution line conductors. Table 3-5 provides measure permutations characterized for underground and overhead conductors. The team identified the size distributions using Minnesota utility data.

Table 3-5 Conductor Measure Permutations

Measure Identifier	Measure
Segment	Residential-urban, residential-rural, commercial, industrial, mixed
Location	Underground or overhead
Size	Overhead replacement: 4 AWG, 2 AWG, 1/0 AWG, 4/0 AWG Overhead ACCC upgrade: 336 kCmil, 557 kCmil Underground: 1 AWG, 2/0 AWG, 600 kCmil, 750 kCmil, 1000 kCmil

Energy Savings and Measure Interactions

The project team estimated energy savings per unit for each ECM permutation. The methodology to estimate unit energy savings was based on Minnesota TRM. This study assumes conductors are replaced at end of life. Based on the Minnesota utility data available, Aluminum Conductor, Steel Reinforced (ACSR) represents the majority of the conductor types currently installed. Therefore, the team assumed ACSR conductors as the baseline in Minnesota and used ACSR conductor resistance values as the baseline efficiency. There are no federal standards for transmission and distribution conductors. The measure iterations include conductor replacement with larger diameter wire (larger conductors have lower resistances) and conductor upgrades to low-loss conductors. Based on the available Minnesota utility data, the measures shown in Table 3-6 represent the most common conductor sizes.

Table 3-6 Conductor Measures

Overhead Baseline	Overhead Measure	Underground Baseline	Underground Measure
6 AWG (ACSR)	4 AWG (ACSR)	2 AWG (ACSR)	1 AWG (ACSR)
4 AWG (ACSR)	2 AWG (ACSR)	1/0 AWG (ACSR)	2/0 AWG (ACSR)
2 AWG (ACSR)	1/0 AWG (ACSR)*	500 kCmil (ACSR)	600 kCmil (ACSR)
2/0 AWG (ACSR)	4/0 AWG (ACSR)	600 kCmil (ACSR)	750 kCmil (ACSR)
336 kCmil (ACSR)	336 kCmil (ACCC)	750 kCmil (ACSR)	1000 kCmil (ACSR)
557 kCmil (ACSR)	557 kCmil (ACCC)		

**1/0 AWG was used as the most likely replacement because overhead 1 AWG only represented a small fraction of the territory.*

The team relied on a number of sources to develop savings estimates:

- **Savings methodology** - Minnesota TRM
- **Measure efficiency** - Aluminum Association, Aluminum Electrical Conductor Handbook, 1989 for ACSR and CTC Global[24]
- **Baseline efficiency** - Aluminum Association, Aluminum Electrical Conductor Handbook, 1989
- **Current assumptions -** Specification sheets for General Cable[25]

Measure Cost Estimates

Incremental cost used for this study relied on manufacturer cost data from General Cable for each size conductor (underground and overhead). [26] A cost multiplier of 2.5 was used to estimate ACCC costs

[24] Conductor specifications for CTC Global ACCC product. Accessed May 2018: https://www.ctcglobal.com/accc-conductor/

[25] Conductor specifications for General Cable products. Accessed May 2018: https://generalcable.com/na/us-can/products-solutions/energy

[26] Ibid.

above ACSR costs based on a report prepared by Electric Power Research Institute.[27] Finally, all costs are converted to 2018$, using the U.S. Gross Domestic Product (GDP) deflator[28].

Measure Life

This study relied on the Minnesota TRM to provide the 25 years EUL for conductors.

Technical Feasibility

The technical limitations placed on conductors relate to large overhead conductors (over 300 kCmil), where replacing conductors with a larger and heavier wire would not be economically feasible since the structural tower/poll upgrades would be cost prohibitive. In these cases, ACCC conductor was used as a feasible upgrade.

Conservation Voltage Reduction

As described in the Minnesota TRM, Conservation Voltage Reduction (CVR) system, also called Automated Voltage Feedback Control system or Voltage Optimization system, is defined as controlling distribution substation source voltage and/or feeder line voltage(s) so that end-use loads consume less energy. CVR systems can use existing or concurrently deployed AMI technology to gather End-Of-Line (EOL) voltage measurements by polling meters or monitoring meter voltage alarms. CVR systems can also be implemented with dedicated EOL voltage sensors. For all types of installations, when the EOL voltage rises or falls outside designed setpoints, the CVR system continuously adjusts source voltage to bring EOL voltage back within setpoints.[29] Although CVR is also a component of Volt/Var Optimization (VVO), the study did not characterize additional VVO savings.

Table 3-7 provides measure permutations characterized for CVR. The team identified three measure tiers based on work done by Northwest Energy Efficiency Alliance (NEEA).[30] CVR is considered a retrofit measure where the model baseline represents the existing conditions without voltage control.

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[27] Electric Power Research Institute report "Demonstration of Advanced Conductors for Overhead Transmission Lines" prepared for California Energy Commission, July 2008. Accessed May 2018: http://www.energy.ca.gov/2013publications/CEC-500-2013-030/CEC-500-2013-030.pdf

[28] Gross Domestic Product: Implicit Price Deflator. Federal Reserve Bank of St. Louis. https://fred.stlouisfed.org/series/GDPDEF

[29] An in-depth description of CVR can be found the report by Franklin Energy to Minnesota Department of Commerce called "Utility Infrastructure Improvements for Energy Efficiency, Understanding the Supply-Side Opportunity", November 2010. Accessed April 2018: https://www.cards.commerce.state.mn.us/CARDS/security/search.do?method=showPoup&documentId=%7B1C8FD0EE-2177-4A75-98E9-E6810372C0E4%7D&documentTitle=34436&documentType=6

[30] RW Beck. "Northwest Energy Efficiency Alliance Distribution Efficiency Initiative Project Final Report." December 2007. Underlining data summarized within Northwest Power Planning Council Seventh Power Plan workbooks. Accessed May 2018: https://nwcouncil.app.box.com/v/7thplanconservationdatafiles

Table 3-7 CVR Measure Permutations

Measure Identifier	Measure
Segment	By substation group from Minnesota Geospatial Information Office (MnGeo) high voltage transmission line (HVTL) data[31]
Tier 1 – Without Improvements	ECM1: Lowers the distribution voltage level only using either Line Drop Compensation (LDC) or End-of-Line (EOL) voltage control methods.
Tier 2 – With Minor Improvements	ECM2: Includes Option 1 and adds system improvements including VAR management, phase load balancing, and feeder load balancing using either LDC or EOL voltage control methods.
Tier 3 – With Major Improvements	ECM3: Includes Option 2 and adds voltage regulators on 1 of every 4 substations with select reconductoring on 1 of every 2 substations.

Energy Savings and Measure Interactions

- The project team estimated energy savings per unit for each ECM permutation and CVR method (LDC and EOL). The CVR factor is the preferred metric to characterize the performance of the change in voltage. CVR factor is the percentage change in load resulting from a one percent reduction in voltage. The team reviewed available literature to determine the savings potential (CVR factors) for each system installed with CVR. The team reviewed the following reports:
- Global Energy Partners. NEEA: “Evaluation of the Utility Distribution System Efficiency Initiative (Phase I), Market Characterization and Assessment”, May 2005.
- RW Beck. NEEA: "Northwest Energy Efficiency Alliance Distribution Efficiency Initiative Project Final Report", December 2007.
- K. Schneider, J. Fuller, F. Tuffner, R. Singh. Pacific Northwest National Laboratory: “Evaluation of Conservation Voltage Reduction (CVR) on a National Level”, July 2010
- NEMA: “Volt/VAR Optimization Improves Grid Efficiency”, date unknown.
- Cooperative Research Network and National Rural Electric Cooperative Association. U.S. DOE/NETL: “Costs and Benefits of Conservation Voltage Reduction CVR Warrants Careful Examination”, May 2014.
- ADM Associates. Indiana Michigan Power Company: “Evaluation, Monitoring and Verification Report for I&M 2015 EECO Program”, June 2016.
- Michael Noreika, Puget Sound Energy (PSE): “PSE Evaluation Report Response, Conservation Voltage Reduction”, January 2018.

[31] Minnesota Geospatial Information Office (MnGeo). “Electric Transmission Lines and Substations, 60 Kilovolt and Greater, Minnesota, 2016”, August 2016. Data provided May 2018. Requires approval to access.

After reviewing these sources, the 2007 NEEA study by RW Beck is frequently sited and presents one of the more comprehensive studies that evaluated CVR impacts. This northwest study comprised of 13 regional utilities that either conducted pilot demonstrations of CVR or performed load research to assess the performance of implementing different ways of controlling the voltage and system improvements at the substation and feeder level. The team relied on the NEEA study to inform the CVR potential in Minnesota.

CVR factors used for this study are shown in Table 3-8 and are based on the 2007 NEEA study.

Table 3-8 CVR Factors by Tier

Measure	Tier	% Saving	Average Delta Voltage	Average CVR Factor
Voltage Reduction – LDC Without System Improvements	1	0.61%	1.897	0.658
Voltage Reduction – LDC Minor System Improvements	2	0.93%	2.398	0.671
Voltage Reduction – LDC Major System Improvements	3	1.28%	2.874	0.685
Voltage Reduction – EOL Without System Improvements	1	0.85%	2.730	0.658
Voltage Reduction – EOL Minor System Improvements	2	1.08%	2.814	0.671
Voltage Reduction – EOL Major System Improvements	3	1.44%	3.291	0.685

The team relied on a number of sources to develop savings estimates:

- ***Savings methodology*** - RW Beck. "Northwest Energy Efficiency Alliance Distribution Efficiency Initiative Project Final Report." December 2007. Underlining data summarized within Northwest Power Planning Council Seventh Power Plan workbooks.
- ***Substation data* -** Minnesota utility data[32]

Measure Cost Estimates

Cost data for each measure permutation also relied on the NEEA study. All costs are converted to 2018$, using the GDP deflator. Table 3-9 shows the cost for each CVR control (LDC or EOL) improvement per substation. The cost may be higher or lower depending on the average size of the substation. End of line improvements on substations with less than annual 40,000 MWh were assumed not applicable for this application.

[32] EIA utility sales data combine with utility substation counts were used to develop a prototypical average annual substation load for each major utility or utility group.

Table 3-9 CVR Measure Costs (2018 $)

Measure Size	Tier 1 - Without Improvements	Tier 2 - With Minor Improvements	Tier 3 - With Major Improvements	Unit
LDC - Small (Less than 40,000 MWH)	$18,214	$39,464	$60,715	Per Substation
LDC- Large (Greater than 40,000 MWH)	$30,357	$72,857	$115,358	Per Substation
EOL - Not applicable (Less than 40,000 MWH)	NA	NA	NA	Per Substation
EOL - Small (Less than 60,000 MWH)	$182,144	$203,394	$242,858	Per Substation
EOL - Large (Greater than 60,000 MWH)	$333,930	$388,573	$418,931	Per Substation

This retrofit measure also requires annual O&M costs for the life CVR operation. The O&M are shown in Table 3-10.

Table 3-10 CVR O&M Costs (2018 $)

Measure Size	Tier 1 - Without Improvements	Tier 2 - With Minor Improvements	Tier 3 - With Major Improvements	Unit
LDC - Small (Less than 40,000 MWH)	$1,214	$1,821	$2,429	Per Substation
LDC- Large (Greater than 40,000 MWH)	$1,214	$1,821	$2,429	Per Substation
EOL - Not applicable (Less than 40,000 MWH)	NA	NA	NA	Per Substation
EOL - Small (Less than 60,000 MWH)	$2,429	$3,036	$3,643	Per Substation
EOL - Large (Greater than 60,000 MWH)	$2,429	$3,036	$3,643	Per Substation

Measure Life

This study assumed a measure life of 15 years, based on the Minnesota TRM.

Technical Feasibility

There are several limitations when implementing prescribed CVR improvements (LDC and EOL tiers). First, these measure iterations compete both in terms of the voltage control type, LDC or EOL, and by efficiency tier (1, 2, or 3). EOL tier 3 had the highest savings potential and represents the technical potential iteration. When determining the economic potential, the savings and costs were shared (by savings) across all cost effectiveness tiers.

In addition to the CVR tiers, these improvements have limitations depending on the sector. The team based these sector limitations on the NEEA study, as shown in Table 3-11.[33]

[33] RW Beck. NEEA: Northwest Energy Efficiency Alliance Distribution Efficiency Initiative Project Final Report, December 2007. "Table 4-1, Percent of Energy by Customer Class, shows the percent of energy by customer type

Table 3-11 CVR Sector Limitations

Sector Distribution	Tier 1 - Without Improvements	Tier 2 - With Minor Improvements	Tier 3 - With Major Improvements	Unit
Residential	70%	80%	85%	% Residential Load
Commercial	40%	50%	60%	% Commercial Load
Industrial	5%	10%	15%	% Industrial Load

Low/Secondary Voltage Control

During our research some contacts suggested that there may be more effective applications for CVR becoming available in the near future. Distributed, or low/secondary voltage control may be able to compress, rather than simply lower, distribution voltage curves. There has not yet been a savings methodology defined for the advanced version of the measure and costs are not well understood at this time. It may be worth considering these technologies in the future as they become better understood.

Data Collection

The project team relied on data provided by Minnesota utilities and from several publicly available, secondary data sources. The team submitted multiple requests for data, set up and fielded phone calls, met individually with utility representatives, and re-submitted streamlined data requests in addition to researching and reviewing secondary sources of publicly-available data. The primary purposes of the collected data were to:

- Characterize the number of applicable units for each measure category,
- Provide estimates of the number of customers and sales by sector for extrapolations, and
- Determine appropriate, individual measure parameters.

The team reached out to three IOUs, 32 Co-operatives, and 36 municipal utilities to solicit data to build the baseline models (outreach conducted in parallel with generation data requests). Over the course of the study, responses to data requests resulted in robust, statistically representative models from which to extrapolate conservation estimates to the statewide population. Participating utilities provided information about their existing transmission and distribution assets in terms of inventories of transformer and conductors, historical system loading data, customer types, number of meters, GIS files or system maps, AMI deployment plans, maintenance protocols, and general discussion about how they operate their systems. Some utilities responded to our requests only under the coverage of Non-Disclosure Agreements, which means that we are not including raw data or presenting results in a form that can be used to identify contributors.

that was included in determining the potential energy savings for each utility. Percent of Energy by Customer Class increased as more system improvements were accounted for in the options."

Measure Units

Each measure category required an estimate of measure units to which unit energy savings estimates were multiplied to determine technical potential. The unit of account varied by measure category as did the number and type of identifiers determining the number of units for individual measures. Table 3-12 provides the unit of account, unit identifiers, and data sources for each measure category.

Table 3-12 Measure Unit Parameters

Measure Category	Unit of Account	Unit Identifiers	Data Sources
Transformers – Service	Per Transformer	Utility group, phase, segment, efficiency, size	Utility-provided data, including loss studies
Transformers – Distribution	Per Substation Transformer	Utility group, segment, efficiency, size	Utility-provided data, including loss studies
Conductors	Per Thousand Feet of Conductor	Utility group, phase, segment, location, size	Utility-provided and MnGeo HVTL data
CVR	Per Substation	Utility group	Utility-provided and MnGeo HVTL data

Transformers - Service

Utilities provided inventory data that included service transformer counts and descriptions in spreadsheet or report format. These data originated from a combination of utility geographic information systems (GIS), spreadsheets maintained by analysts, and report tables. Descriptive data included transformer size, location, phase, output voltage and configuration in addition to internal utility identification numbers and tracking systems. Although not every utility that responded provided similarly descriptive data, the team was able to gather a reasonable cross-section of information from those who were able to respond. Table 3-13 provides the number of utilities by utility group that provided service transformer data and the type of data provided.

Table 3-13 Service Transformer Data

Utility Group	Utilities Providing Usable Data	Service Transformer Data Provided
IOUs	One	Counts, phase, size, output voltage, configuration, location
Co-ops	Zero	n/a
Munis	Two	Counts, phase, size, location

The project team extrapolated the IOU-provided data to the IOU group using the ratio estimation method based on utility electric sales by sector. Likewise, we also extrapolated the municipal-utility provided data to the municipal utility group on a percentage of sales basis. Because we did not received data from any cooperatives, we extrapolated the municipal data to cooperatives on a percentage of sales basis. The section Extrapolations from Sample Utility Data describes this process in more detail.

Transformers – Substation

Utilities provided data that included substation transformer counts and descriptions in both database and spreadsheet formats and distribution and transmission system loss study reports. These data generally accompanied the service transformer data but, in some instances, only service transformer data were provided. Our team also received substation counts from some but not all utilities that provided substation transformer data. However, we collected substation counts for the entire state of Minnesota from the MnGeo HVTL data set. Table 3-14 shows the number of utilities that provided substation transformer data and the type of data provided by these utilities.

Table 3-14 Substation Transformer Data

Utility Group	Utilities Providing Usable Data	Substation Transformer Data Provided
IOUs	Three	Transformer counts, size, and loading
Co-ops	Zero	n/a
Munis	Zero	n/a

The team did not extrapolate the number of substations to cooperative and municipal utility groups because we relied MnGeo HVTL data set to inform the number of substations for these groups However, we did apply the number of transformers per substation and the distribution of substation transformer sizes from the IOU-provided data for both cooperative and municipal utilities.

Conductors

Utilities submitted conductor data in database formats that included estimates of segment lengths in addition to other descriptive variables such as size, location, and material. Conductor data provided by these utilities included distribution conductors but not transmission lines. We collected transmission line data from the MnGeo HVTL data set, which included lengths and voltage by line owner. Table 3-15 shows the type of distribution conductor data provided by utilities.

Table 3-15 Conductor (Distribution) Data

Utility Group	Utilities Providing Usable Data	Descriptive Conductor Data Provided
IOUs	Two	Both utilities provided lengths. One utility provided sizes, material type, and location.
Co-ops	Zero	n/a
Munis	Zero	n/a

Both IOUs provided distribution conductor lengths. Our team converted these lengths to thousand feet per customer and applied this value to the number of customers for the remaining IOU. For cooperatives and municipal utilities, our team used the ratio estimation method to extrapolate IOU-provided data, based on percentage of sales for distribution conductor lengths. The section Extrapolations from Sample Utility Data Extrapolations from Sample Utility Data of this report describes this process in more detail.

Estimates of the Number of Customers and Sales by Utility and Utility Group

Because not every utility was able to provide the requested data, the team relied on extrapolations of sample utility data to determine the number of applicable units for each measure category. These extrapolations required estimates of the number of customers and/or electricity sales for each sector (e.g. residential, commercial, and industrial) for each utility operating in the state of Minnesota. The team relied on the most recent (2016) figures from the U.S. Energy Information Administration's (EIA) Form 861[34] for these data. The team also required data in addition to those listed in Table 3-12 to determine the appropriate individual measure parameters.

Measure Parameter Data

The Minnesota TRM includes measure identifiers based upon the utility customer segments served by transformers and conductors. These segments include rural and urban residential customers, in addition to commercial and industrial customers. Because not every utility was able to provide data at this level of granularity, we needed to collect estimates of rural and urban residential customers.

To do this, our team downloaded a census block shapefile for Minnesota from the U.S. Census Bureau's 2010 Census[35]. Using ArcGIS, we calculated centroids for each census block and generated a text file containing the state, county, tract, and block IDs in addition to the latitude and longitude coordinates associated with each Minnesota census block. We determined the utility providers serving each census block using the National Renewable Energy Laboratory's (NREL) Application Programming Interface (API)[36]. When given a pair of latitude and longitude coordinates, the NREL Utility Rates by Census Region API returned the name of the utility company serving the specified location and the utility ID. We retrieved all utility names and IDs if multiple utilities served the same location. We then constructed a list of utility providers per census tract.

We assumed the population served by a single utility in a specific block to be the population of that census block. If multiple utilities served the same block, we assumed that each utility served an equal

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[34] Utility Electric Power Sales data from Form EIA-861. https://www.eia.gov/electricity/data/eia861/

[35] 2010 Census, 2017 Release V (2017 TIGER/Line® Shapefiles: Blocks (2010). https://www2.census.gov/geo/tiger/TIGER2017/TABBLOCK/

[36] NREL Application Programing Interface data. https://developer.nrel.gov/docs/electricity/census-rate-v3/

proportion of the population. The 2010 Census Block with Housing and Population Data for Minnesota provided population values for each census block[37]. We determined the total census tract population served by a utility by grouping utilities by utility ID and tract ID and summed the population served by group. We then calculated the proportion of the census tract population served by each utility by dividing the utility population served in a tract by that tract's total population. The population values for Minnesota census tracts originated from the 2010 Census Block with Housing and Population Data.

Finally, we downloaded the 2010 Rural-Urban Commuting Area (RUCA) codes from the U.S. Department of Agriculture Economic Research Service[38] and matched the census tract RUCA codes to the information on utilities and population served using the tract ID associated with each utility.

Extrapolations from Sample Utility Data

For reporting purposes, the team placed each Minnesota utility into one of three distinct reporting groups, based on ownership: investor-owned, cooperative, and municipal utilities. Our modeling framework differentiated individual measures and measure units by utility reporting group and estimated the technical, economic, and achievable potential for each group, separately. We then summed the potential across each group to determine the total, statewide potential. Because not all utilities provided data, the modeling framework required extrapolations from the sample of data received from utilities to each reporting group level to estimate total, applicable units for two measure categories: service transformers and conductors.

Service Transformers

The team utilized a ratio estimator to extrapolate the number of service transformers provided by one IOU respondent to the total, IOU reporting group. First, we characterized the transformers by phase and by size and assigned them – based on size - to residential, commercial, and industrial segments because the savings algorithm for service transformers differs based on segment. Then, we extrapolated the number of units by sector from the IOU sample to the IOU reporting group sector total. We did this by dividing the number of transformers by the ratio of respondent IOU's customers to total IOU customers, by sector. For example, if the respondent IOU provided 500 industrial, three-phase transformers for its 250 industrial customers – and the total number of IOU industrial customers was 500, then the total number of IOU industrial, three-phase transformers would be 1000.

The team performed a similar extrapolation for municipal utilities, based upon the service transformer data provided by two respondent utilities within that reporting group. Because we did not receive service transformer data from any cooperative utilities, our team extrapolated the total, estimated

[37] US Census Block data for Minnesota. https://catalog.data.gov/dataset/tiger-line-shapefile-2010-2010-state-minnesota-2010-census-block-state-based-shapefile-with-hou

[38] Rural-Urban Commuting Area Codes data. USDA. https://www.ers.usda.gov/data-products/rural-urban-commuting-area-codes.aspx

number of municipal utility service transformers by segment to the total cooperative reporting level, again relying on the ratio of municipal to cooperative customers, by residential, commercial, and industrial segments. Table 3-16 in the next section of this report provides the total, estimated number of service transformers by segment and utility reporting group.

Conductors

Two IOU respondents provided data for distribution conductors. From these data, we calculated the total length, in thousands of feet, for each utility. We then divided the total length by the number of customers to determine an average length per customer. Finally, we multiplied the number of customers for the third, non-respondent IOU times the average length per customer for the two responding utilities to determine the total distribution conductor length for the IOU reporting group.

Because the team did not receive significant, detailed data from either municipal or cooperative utilities, we extrapolated the total, estimated distribution conductor lengths for IOUs to cooperative and municipal utilities by dividing the total IOU lengths by the ratio of total IOU customers to cooperative and municipal utility customers, respectively. Without primary data, the team performed secondary research for comparisons of meter density among IOU, municipal, and cooperative utilities within Minnesota. However, our research produced no usable data. Therefore, it is likely that – for cooperative conductor lengths - our estimates are conservative, if it is reasonable to assume that distribution conductor lengths per utility customer are greater than for IOUs and municipal utilities.

We should note that, for transmission lines, no extrapolations were performed as these values were summed by utility group from the MnGeo HVTL data set.

Applicable Units

Determining the number of applicable units for each measure category required both utility-specific data and data from secondary sources, as described above, because no single data source exists that contains counts of all transformers, conductors, and substations by utility in the state of Minnesota. Furthermore, the utility-provided data varied widely in its granularity and quality.

As shown in Figure 3-4, the applicable measure units calculation is the product of the number of measure category units, saturation, applicability factor, and turnover rate for natural replacement measures, including transformers and conductors. For retrofit measures, including conservation voltage reduction in this study, the calculation is the same except that it excludes the turnover rate because the retrofit potential is available, theoretically, at any point in time as it is not limited by natural equipment turnover rates.

Figure 3-4 Baseline Units Calculation

To account for new transformers, conductors, and substations installed and built during the study horizon, we applied the underlying load forecast growth rates to calculate the number of "new construction" units for each year of the study. For example, if the underlying sales forecast growth rate for 2021 was 1.0%, the number of assumed new construction units – transformers, conductors, and substations - was 1.0% of the existing, applicable units. The model then added new construction units to the existing applicable units for each year of the study. We applied this linear growth rate because planned utility transformer, conductor, and substation installations were not available. The remainder of this section describes the methods employed by the project team to determine the existing applicable units for each measure category and the resulting values.

Service Transformers

The team combined utility-provided counts of service transformers with rural and urban residential population estimates and the distribution of electric sales and customers by utility and utility reporting group to determine the number of applicable service transformers. Table 3-16 provides the count of existing service transformers by utility reporting group and segment.

Table 3-16 Service Transformers by Utility Reporting Group and Segment

Service Transformers	IOUs	Co-Ops	Munis	Statewide
Single Phase-Residential-Rural	4,703	35,445	8,073	48,221
Single Phase-Residential-Urban	171,616	161,033	64,882	397,531
Single Phase-Commercial	5,258	10,566	3,923	19,747
Three Phase-Commercial	39,750	37,994	14,108	91,851
Three Phase-Industrial	7,027	3,045	1,131	11,203
Total	**228,354**	**248,083**	**92,117**	**568,554**

Substation Transformers and CVR

The team relied on both utility-provided counts of substations and substation transformers and MnGeo HVTL estimates of substations to determine the count of total substations by utility group and by size. Table 3-17 shows the number of existing substations by utility reporting group and by substation size. Table 3-18 shows the estimated number of transformers per substation. These data were used to estimate the applicable number of transformers, which was used to develop CVR potential estimates.

Table 3-17 Number of Substations

Substations	IOUs	Co-Ops	Munis	Statewide
Small ≤ 5 MVA	134	206	37	377
Mid Small > 5 MVA and ≤ 12 MVA	78	120	21	219
Mid Large > 12 MVA and ≤ 30 MVA	118	182	32	333
Large > 30 MVA	93	143	25	261
Total	**423**	**651**	**116**	**1,190**

Table 3-18 Number of Substation Transformers

Substations	Transformers / Substation
Small ≤ 5 MVA	1.22
Mid Small > 5 MVA and ≤ 12 MVA	1.26
Mid Large > 12 MVA and ≤ 30 MVA	1.82
Large > 30 MVA	2.18

Conductors

The applicable number of conductor units, in thousands of feet, were developed by the project team from both utility-provided and MnGeo HVTL data. Whereas the MnGeo HVTL data served as the source for transmission line lengths, conductor data provided by utilities represented the distribution line lengths. Data quality and granularity varied by utility. For example, some utilities provided very detailed information including lengths, conductor material type, conductor size, and conductor location (overhead or underground). Other utilities submitted just lengths. Table 3-19 shows the existing transmission and distribution conductor lengths by service type, location, and utility group. Transmission line lengths are included in the overhead, conductor replacement-mixed line and, as the data show, represent about 15% of the total, statewide conductor units.

Table 3-19 T&D Conductor Lengths

Service	Location	IOUs (Thousand Feet)	Co-Ops (Thousand Feet)	Munis (Thousand Feet)	Statewide (Thousand Feet)
Conductor Replacement-Residential-Rural	Overhead	3,699	1,849	724	6,272
Conductor Replacement-Residential-Urban	Overhead	134,959	67,474	26,423	228,856
Conductor Replacement-Commercial	Overhead	18,595	9,297	3,641	31,532
Conductor Replacement-Industrial	Overhead	97	48	19	164

Service	Location	IOUs (Thousand Feet)	Co-Ops (Thousand Feet)	Munis (Thousand Feet)	Statewide (Thousand Feet)
Conductor Replacement-Mixed	Overhead	38,955	41,209	3,692	83,856
Overhead Subtotal	**Overhead**	**196,304**	**119,878**	**34,499**	**350,681**
Conductor Replacement-Residential-Rural	Underground	2,612	1,240	486	4,338
Conductor Replacement-Residential-Urban	Underground	95,302	45,249	17,720	158,270
Conductor Replacement-Commercial	Underground	13,131	6,234	2,441	21,807
Conductor Replacement-Industrial	Underground	68	33	13	114
Conductor Replacement-Mixed	Underground	0	0	0	0
Underground Subtotal	**Underground**	**111,113**	**52,756**	**20,659**	**184,528**
Combined Total	**Both**	**307,417**	**172,634**	**55,158**	**535,209**

As noted above, not all utilities were able to provide conductor locations and sizes. Table 3-20 enumerates the extrapolated, statewide conductor length by conductor size and location.

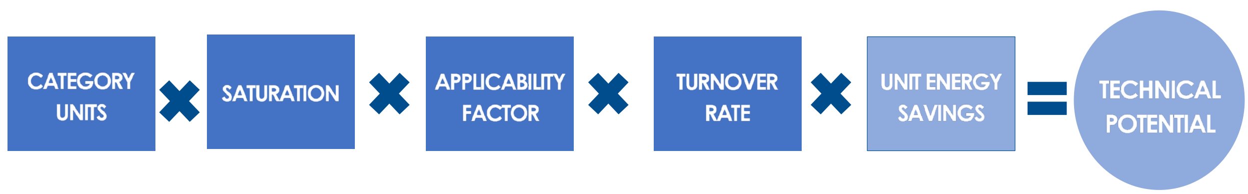
Table 3-20 Breakdown of Conductors Statewide

Conductor Location	Size	Statewide Length (Thousand Feet)
Overhead	1/0	9,894
Overhead	2	88,255
Overhead	2/0	29,971
Overhead	4	52,866
Overhead	6	60,428
Overhead	336	102,056
Overhead	556	7,212
Underground	1	1,283
Underground	1/0	80,298
Underground	2	45,808
Underground	2/0	32
Underground	500	10,814
Underground	600	6,779
Underground	750	35,681
Underground	1000	3,834

Estimating Technical Potential

Once the team fully populated the measure database, it used measure-level inputs to estimate technical potential over the planning horizon. To begin this process, the team estimated savings from all measures included in the analysis, then aggregated the results to the measure category and utility group reporting levels. The team characterized individual measure savings in terms of the annual per-unit energy savings. For each measure, the study estimated absolute energy savings using the equation in Figure 3-5.

Figure 3-5 Technical Potential Equation



By definition, technical potential assumes the most efficient option is installed for retrofit and natural replacement measures. For the suite of distribution and transmission ECMs considered within this study, both service and substation transformers offer multiple efficiency options. In the case of service transformers, "premium efficiency" are more efficient than "high efficiency" transformers. Therefore, all the technical potential accrues to premium efficiency transformers. Similarly, conductor measures considered in this study also offer multiple, efficient replacement options.

Estimating Economic Potential

Economic potential represents a subset of technical potential, consisting only of measures meeting cost-effectiveness criteria, based on each utilities' avoided supply costs for delivering electricity. The team used a modified Total Resource Cost test (TRC) in a manner consistent with energy efficiency programs. The study did not include program administration costs that would typically be employed in TRC screening for customer-based efficiency programs because they do not apply for EUI projects. Table 3-21 summarizes benefits and costs considered in calculating TRC B/C ratios to develop the economic potential that served as the basis for calculating achievable potential.

Table 3-21 Economic Potential Components

Type	Component
Costs	Incremental Costs
Costs	Annual operations and maintenance costs
Benefits	Avoided energy costs
Benefits	Avoided capacity costs (generation, transmission, and distribution)

The following list provides details of the components shown in Table 3-21:

- Incremental measure cost: This study considered equipment costs required to purchase a measure and sustain savings over each measure's EUL
- Annual operations and maintenance costs: The team assumed that, for some CVR measure applications, utilities would incur annual O&M costs to support the deployment of the measure. In all other cases O&M costs are the same for baseline and efficient cases (i.e. there are no measures where O&M costs are higher in the efficient case).
- Avoided energy costs: Avoided energy costs are the benefits of direct energy savings from implementing EUI measures.
- Avoided capacity costs: These include deferred generation and transmission and distribution capacity benefits.

In addition to each benefit and cost detailed above, the team employed standard line loss factors and discount rates for this study.

Avoided Energy and Capacity Costs

The team employed the same avoided electric energy and capacity cost forecasts that were used in the concurrent demand-side study - Minnesota statewide electric and natural gas energy efficiency potential study to determine cost-effective potential for distribution and transmission ECMs. Avoided energy costs were applied to the same utility groups and regions identified in that study. Each IOU and select COUs provided deferred transmission and distribution cost forecasts. The team employed a utility energy sales-weighted average to determine the avoided energy and capacity cost components used in economic screening calculations.

Figure 3-6 shows the utility sales-weighted average avoided energy costs. These avoided energy costs vary depending upon the time of the year, as reflected by the six avoided cost bins shown below.

Figure 3-6 Avoided Energy Cost Forecast

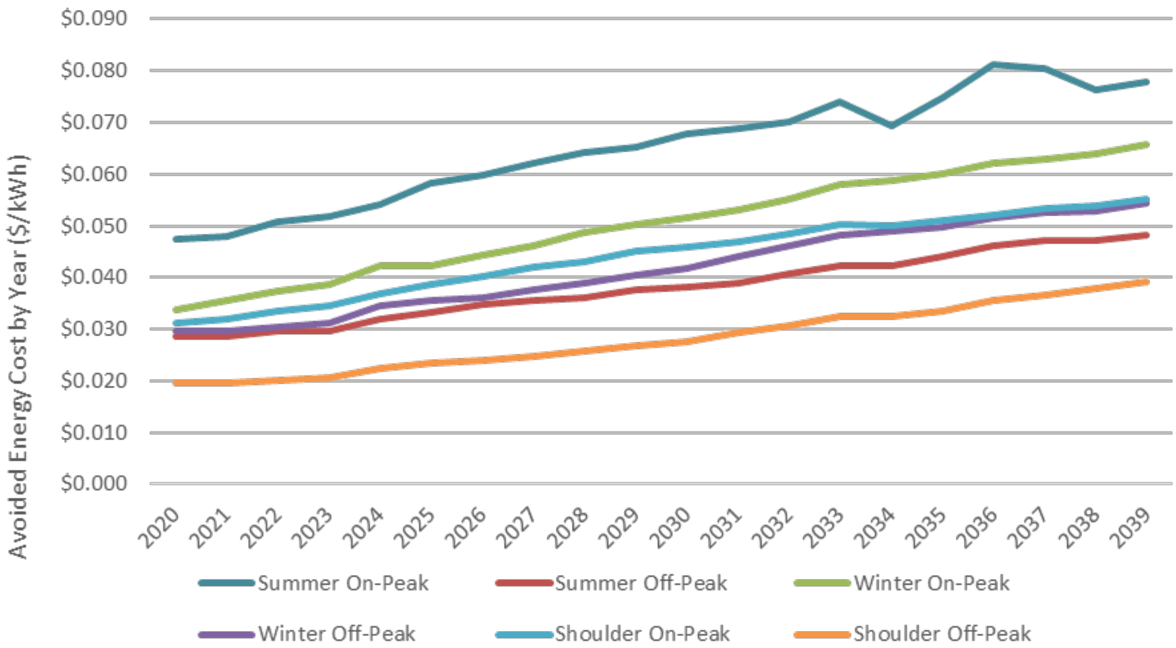


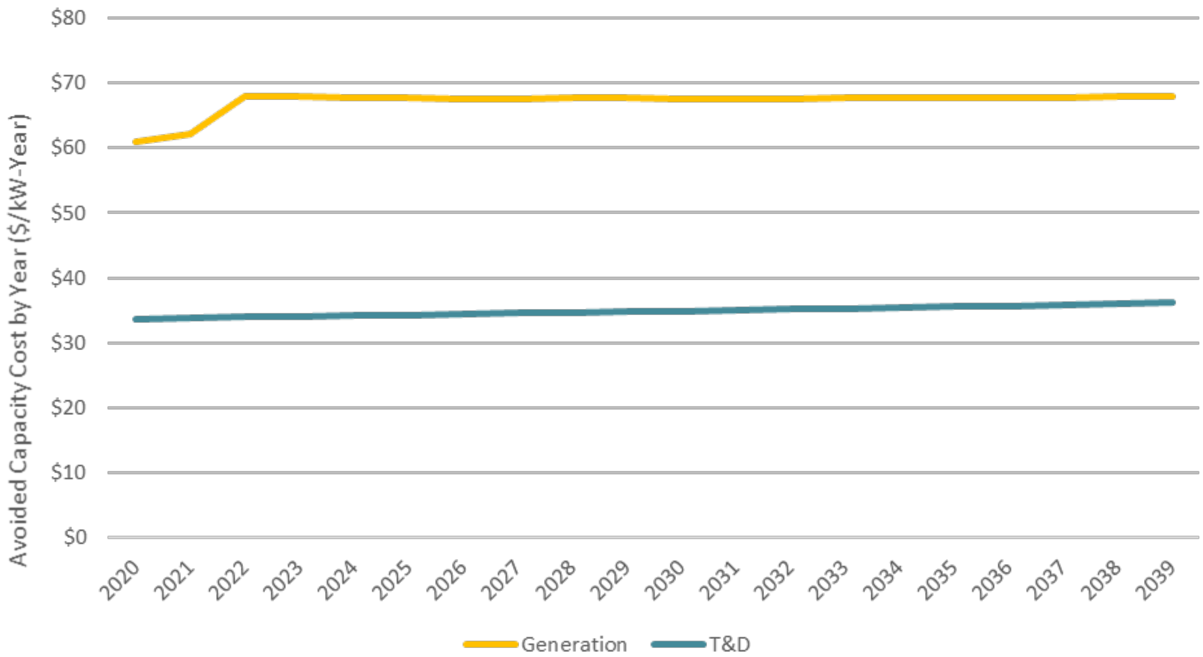
Table 3-22 provides the periods corresponding to each of the six avoided energy cost bins.

Table 3-22 Avoided Energy Cost Bin Periods

Season	On/Off Peak	Months	Days	Hours
Summer	On-Peak	June through August	Weekdays	9:00 AM to 10:00 PM
Summer	Off-Peak	June through August	Weekdays	10:00 PM to 9:00 AM
Winter	On-Peak	November through March	Weekdays	8:00 AM to 10:00 PM
Winter	Off-Peak	November through March	Weekdays	10:00 PM to 8:00 AM
Shoulder	On-Peak	April, May, September, and October (Weekdays) All Weekend Days	Weekdays: Weekend:	7:00 AM to 11:00 PM 9:00 AM to 11:00 PM
Shoulder	Off-Peak	April, May, September, and October (Weekdays) All Weekend Days	Weekdays: Weekend:	7:00 AM to 11:00 PM 9:00 AM to 11:00 PM

Figure 3-7 shows the avoided capacity cost forecast from 2020 to 2039. Avoided capacity costs include both deferred generation and transmission and distribution.

Figure 3-7 Avoided Capacity Cost Forecast



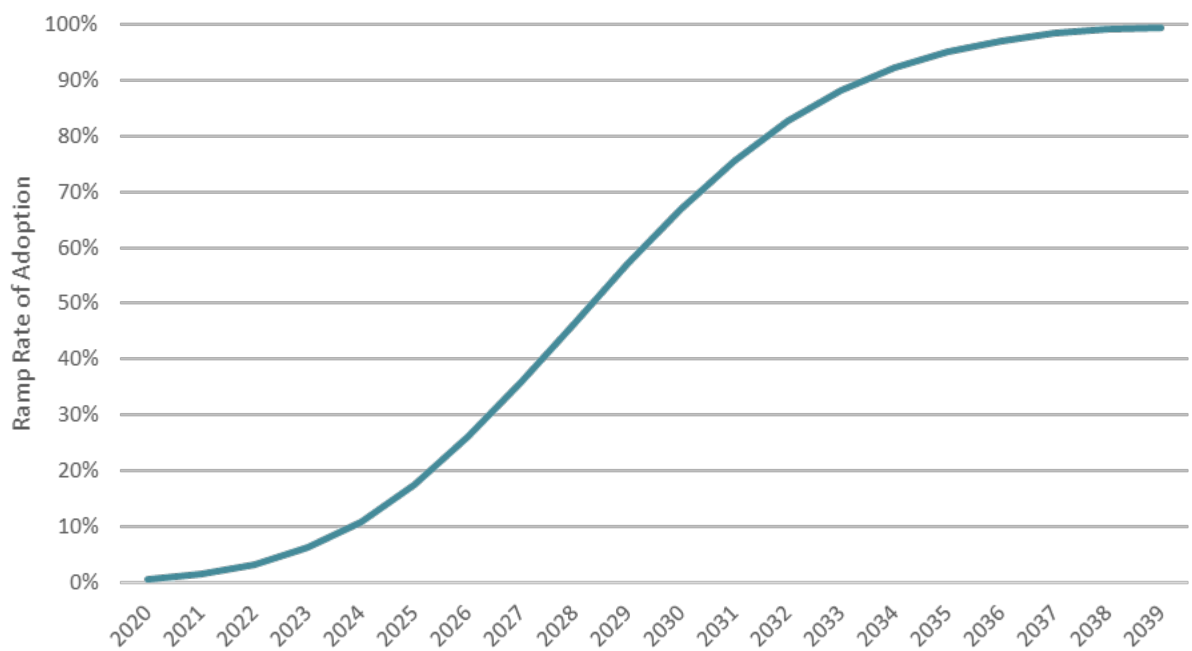
Ramp Rates and Estimating Achievable Potential

Achievable potential derives from the portion of economic potential that might be assumed reasonably achievable in the course of the planning horizon, given barriers that might impede adoption of electric utility infrastructure ECMs. Figure 3-8 shows the equation used to estimate achievable potential. This study assumed a long-run maximum achievability factor of 100%, assuming that utilities will adopt these measures over time as long as the potential remains cost-effective for them to do so. This is because the main utility barrier to adoption is competition for capital, but all identified cost-effective options (economic potential) can be viably implemented (achievable) over a long enough time frame.

Figure 3-8 Achievable Potential Penetration Estimates

The team applied a conservative ramp rate to determine the pace of distribution and transmission achievable potential over time. This ramp rate was previously developed by the Northwest Power and Conservation Council during the Seventh Power Plan for estimating the potential for distribution efficiency ensures. The team adjusted this ramp rate slightly to ensure that the modeled rate of CVR measure adoption did not outpace the *expected* rate of AMI adoption within the state of Minnesota (because cost effective deployment of CVR depends on the existence of AMI). Expected rates of deployment for COUs are based on conversations with utility personnel. As shown in the 2016 EIA Form 861 data, the current penetration rate of AMI meters across all customer classes is 17%[39]. As Figure 3-9 shows, the ramp rate of adoption for these measures does not reach 17% until 2025, which is the sixth year of the study horizon.

Figure 3-9 Distribution and Transmission Ramp Rate of Adoption



Loss Study Alternative Methodology

After beginning the study, discussions with the Department, Advisory Committee, and stakeholders participating in the concurrent DOE-funded project led the team to consider the possibility of using a system-level approach to measure conservation potential. The idea is that instead of modeling EUI improvements at the individual unit level (transformers, conductors, etc.), the efficiency of a T&D system (or just distribution alone) can be measured in terms of overall losses. Efficiency improvements can then be measured in terms of their effect on reducing system losses over time. Unfortunately, the existing loss study data is not robust enough to complete a rigorous estimate of conservation potential, but the identified data was used to corroborate the main methodology findings and to inform the discussion or results and recommendations.

The main advantage of the loss study approach to estimate potential study would be that a detailed model of individual components is not necessary because they're all baked into the measured overall

[39] For residential, AMI penetration is 18% and commercial and industrial are both 15%.

system losses. Further, in the long-term, measuring impacts on the system level lends itself to goal setting. For example, utilities' CIP plans could target system loss reductions by a set percentage annually instead of predicting quantities and impacts of discrete measures.

The plan to use loss study data to estimate conservation potential follows the same pattern as the generation technical potential methodology. The team would collect available loss studies from as many Minnesota utilities as possible to describe baseline conditions in the state. We would then identify high-performing systems across the country to compare to. Minnesota systems would be compared to high-performing systems with similar characteristics (number of customers, meter density, customer make-up, etc.). The Minnesota systems would be modeled to estimate the annual energy conservation potential assuming improvement from the baseline system losses to match the high-performing comparison system losses. Results would be used to corroborate findings from the main methodology and test the concept of using system losses to measure conservation.

The team identified three comprehensive loss studies, one for each of the large electric IOUs in the state. Of those, the most recent was completed in 2016 and the oldest was in 2007. Losses as a percentage of distribution energy delivered ranged from 5.75% to 9.59% (one study reported a separate value of 11.07% losses during peak loading periods). We also found that some COUs conduct internal estimates by tracking wholesale purchases subtract retail sales, which gives an approximate value for distribution system losses.

Unfortunately, our findings reveal that existing loss studies cannot be used to develop a high-confidence estimate of conservation potential. There is not enough historical data on any one system to track improvements over time. Further, each loss study is conducted slightly differently, making it difficult to compare different studies. Each T&D system is unique enough that it is not appropriate to compare across systems as we had intended.

However, non-rigorous estimates using the loss study approach can be used as a high-level gut check on the results of the main study methodology (see the Overall Results section). Also, some of the raw data underlying the loss studies helped to inform the main methodology modeling inputs. Finally, the process leads to a better understanding of how loss study data can fit into CIP efforts to inform discussion of results and recommendations (see the Conclusions and Discussion of Results section).

4 Results

Generation Sector Estimated Potential

Full Generation Sector Potential

The total cumulative statewide technical potential for conservation over the period of this study in the generation sector is estimated to be 1,399,850 equivalent MWh. Of that technical potential, approximately 786,782 equivalent MWh are estimated to be achievable, which represents approximately 3.3% of total statewide projected CIP electric conservation goals from 2020-2039. The following series of figures and tables presents the findings from the study in a variety of useful formats. No results are reported as economic potential separate from achievable for the generation sector because it was determined that the results would not be accurate and instructive enough to warrant the additional modeling effort required.

Table 4-1 and Table 4-2 summarize total estimated statewide conservation potential over the period of the study (technical and achievable potentially, respectively). The result is presented in equivalent MWh using the TRM algorithm from Equation 3-1, which translates generation savings into the CIP electric conservation metric. The final value is the total CIP-claimable savings estimated over the 20-year period of the study. That is, the results show the total first-year savings for all conservation projects completed over the course of the 20-year study.

The potential conservation is then shown as a percentage of total statewide electric sales (not including sales to CIP-exempt customers) over the course of the study. Finally, the percentage of CIP goals (right-most column in these tables) is the conservation potential divided by projected statewide CIP electric goals over the period studied. That is, if all identified potential is captured it represents 5.90% (technical) or 3.32% (achievable) of the projected CIP goals for utilities across the state over the period from 2020-2039.

All conservation potential in this section is calculated with the assumption that large natural gas facilities (greater than 50MW capacity) are eligible to claim conservation credit as electric utility generation assets. There is some uncertainty about this reading of statute. The section Modeled Impacts of Possible Policy Guidance presents recalculated results under the assumption that large gas facilities are not eligible. The results in that section and this section both reflect the same gathered data and use the same modeling methodology. The only difference is the interpretation of policy regarding large gas facility eligibility.

Figure 4-1 and Figure 4-2 display the estimated potential broken out by generation technology.

Table 4-1 Statewide Generation Technical Potential in Equivalent MWh

Plant Type - Fuel	Plant Type -Technology	Technical Potential (equivalent MWh)	Percentage of Sales*	Percentage of CIP Goals
Coal	Subcritical	967,595	1.22%	4.08%
Coal	Supercritical	89,370	0.11%	0.38%
Gas	Combined Cycle	195,779	0.25%	0.83%
Gas	Steam Turbine	7,335	0.01%	0.03%
Gas	Combustion Turbine	23,160	0.03%	0.10%
Biomass	All	116,612	0.15%	0.49%
Total	**Statewide combined**	**1,399,850**	**1.77%**	**5.90%**

**Not including CIP-exempt electric sales*

Figure 4-1 Technical Potential for Conservation by Generation Technology

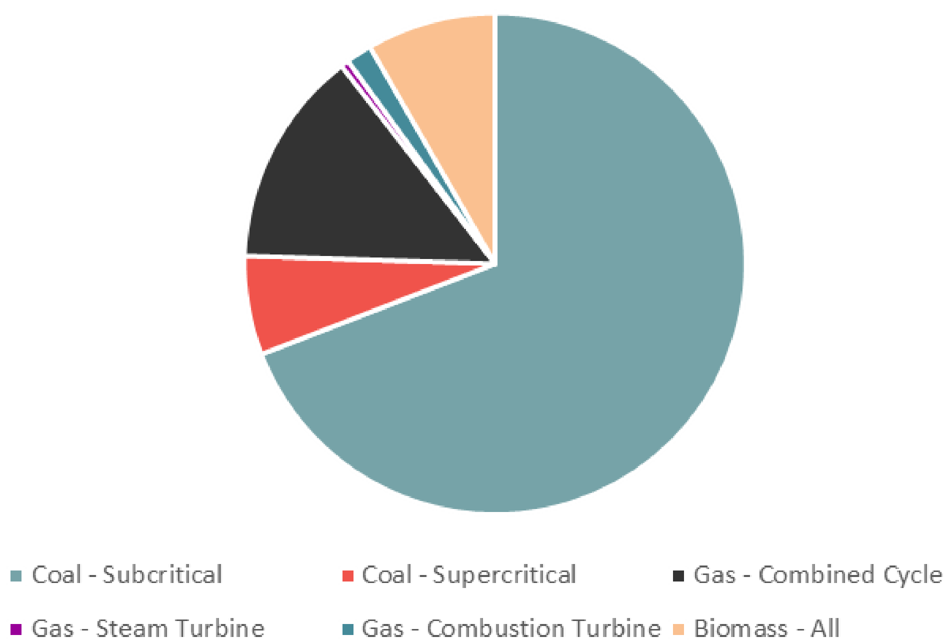


Table 4-2 Generation Sector Achievable Potential in Equivalent MWh

Plant Type - Fuel	Plant Type - Technology	Achievable Potential (equivalent MWh)	Percentage of Sales*	Percentage of CIP Goals
Coal	Subcritical	399,914	0.51%	1.69%
Coal	Supercritical	73,730	0.09%	0.31%
Gas	Combined Cycle	191,496	0.24%	0.81%

Plant Type - Fuel	Plant Type - Technology	Achievable Potential (equivalent MWh)	Percentage of Sales*	Percentage of CIP Goals
Gas	Steam Turbine	6,277	0.01%	0.03%
Gas	Combustion Turbine	22,076	0.03%	0.09%
Biomass	All	93,289	0.12%	0.39%
Total	**Statewide Combined**	**786,782**	**0.99%**	**3.32%**

**Not including CIP-exempt electric sales*

Figure 4-2 Achievable Potential for Conservation by Generation Technology

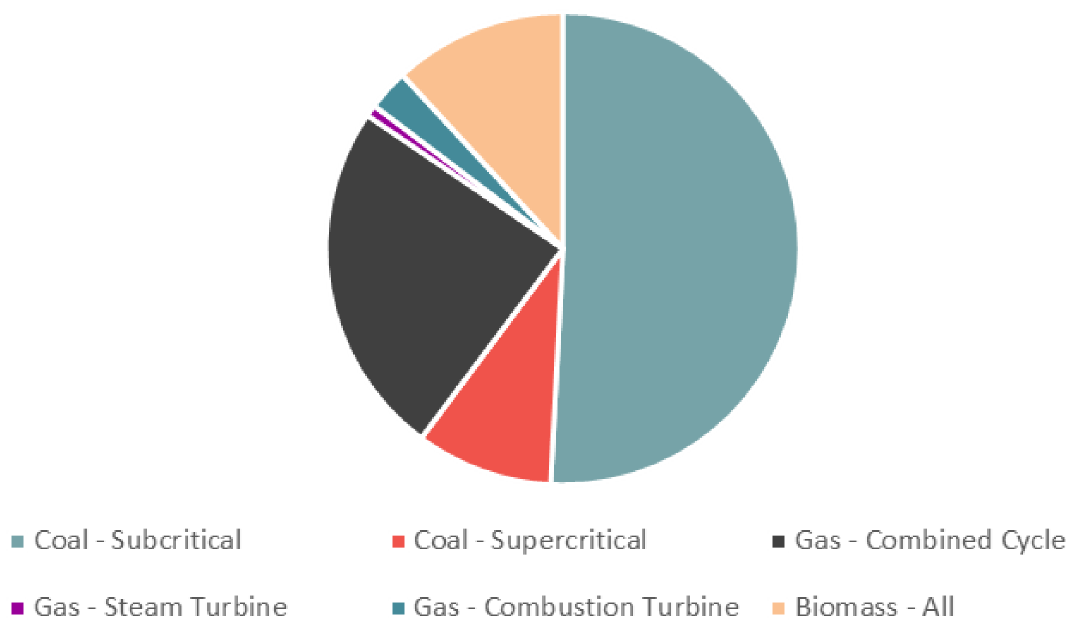


Table 4-3 and Table 4-4 present the associated reduction in annual input fuel measured in MMBtu resulting from the identified conservation potential (technical and achievable, respectively). For non-exempt natural gas facilities, conservation could be claimed toward gas utility conservation goals rather than converting to equivalent electric conservation, but this opportunity represents only a small portion of facilities. These values represent fuel savings, not claimed CIP gas savings. The total technical potential for input fuel conservation in MMBtu is approximately 1.2% of total annual fuel consumption by utilities in the state excluding biomass facilities. Achievable potential for input fuel conservation is approximately 0.6% of total fuel consumed annually by non-biomass facilities. These estimates are made by referencing EIA monthly electric power reports though March, 2018[40].

[40] Monthly EIA data through May 2018 showing generation fuel consumption by state. https://www.eia.gov/electricity/monthly/current_month/epm.pdf

Table 4-3 Generation Sector Technical Potential Input Fuel Reduction

Plant Type - Fuel	Plant Type - Technology	Technical Potential (MMBtu input fuel)
Coal	Subcritical	9,625,078
Coal	Supercritical	777,762
Gas	Combined Cycle	937,626
Gas	Steam Turbine	103,316
Gas	Combustion Turbine	267,875
Biomass	All	2,310,787
Total	**Statewide Combined**	**14,022,444**

Table 4-4 Generation Sector Achievable Potential Input Fuel Reduction

Plant Type - Fuel	Plant Type - Technology	Achievable Potential (MMBtu input fuel)
Coal	Subcritical	4,028,174
Coal	Supercritical	641,654
Gas	Combined Cycle	915,372
Gas	Steam Turbine	78,884
Gas	Combustion Turbine	267,074
Biomass	All	1,848,629
Total	**Statewide Combined**	**7,779,787**

Table 4-5 breaks out the achievable conservation potential (in equivalent MWh) by investor-owned utilities vs. consumer-owned utilities.

Table 4-5 Generation Sector Achievable Potential by Utility Type

Utility Type	Equivalent MWh	Percentage
IOU	509,022	65%
COU	277,760	35%
Total	**786,782**	

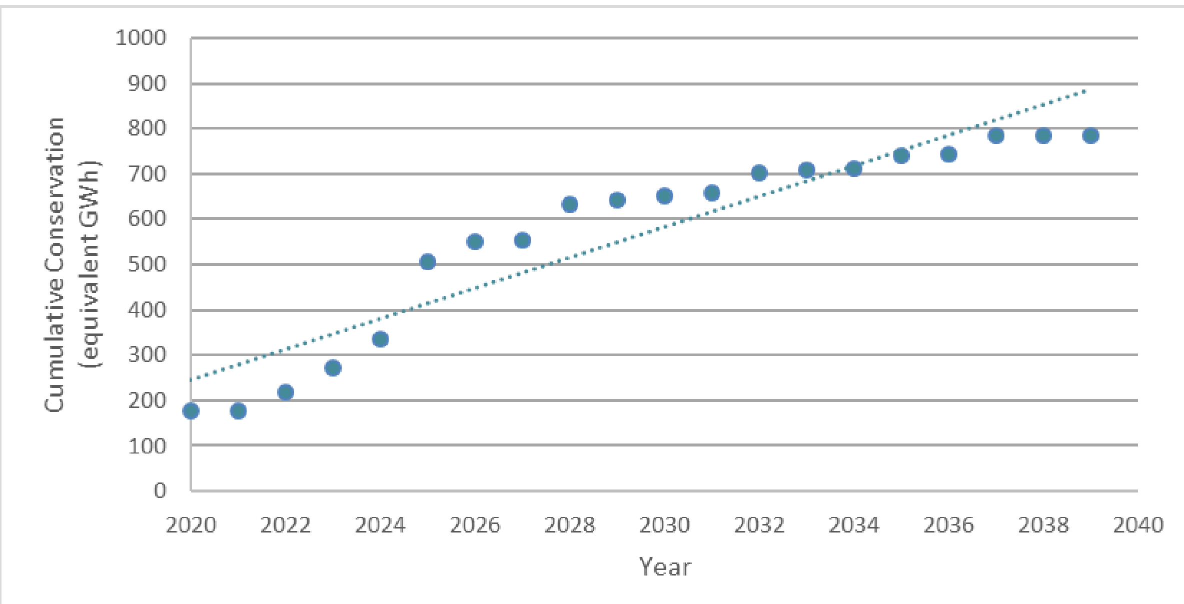
Table 4-6 presents the annual potential for conservation in the generation sector in terms of reduced carbon emissions. Estimates are made by multiplying the reduced input fuel (Table 4-3 and Table 4-4) by the carbon content[41] of each fuel type. Biomass generation is excluded from carbon emission considerations.

Table 4-6 Generation Sector Annual Carbon Emission Reduction Potential

Potential Type	Equivalent Tons CO_2 reduction
Technical Potential	1,191,230
Achievable Potential	574,160

The following Figure 4-3 presents the cumulative achievable first-year conservation potential by year over the 20-year period of the study. This format of results makes the assumption that projects with large conservation opportunity are targeted sooner than lower-opportunity options. These results should be viewed as an approximate trendline of achievable opportunity, but may not reflect actual project implementation decisions precisely on a year-by-year basis. The graph represents total, cumulative 1st-year savings as they are claimed over the period of the study.

Figure 4-3 Generation Sector Cumulative Achievable Conservation



The final format of results is cumulative persistent savings. These results are an estimate of cumulative potential impacts of generation conservation projects on the system and environment separate from claimable CIP savings (only first-year impacts of projects are reflected in CIP metrics). Persistent cumulative energy savings are shown in Figure 4-4 and cumulative persistent carbon emission reductions are shown in Figure 4-5.

[41] EIA data showing carbon content of fuel types. https://www.eia.gov/tools/faqs/faq.php?id=73&t=11

Achievable cumulative persistent conservation estimates assume that each generation facility with identified potential opportunity implements one project over the course of the study, full savings persist for 3 years, savings reduce to baseline levels after 5 years, and that utility owners implement projects at a reasonable pace. These estimates are most usefully viewed as a trendline of conservation impacts over time rather than a prediction of year-by-year outcomes. These results could vary depending on implementation priority and maintenance of project impacts over time.

Figure 4-4 Generation Sector Cumulative Persistent Achievable Conservation Potential

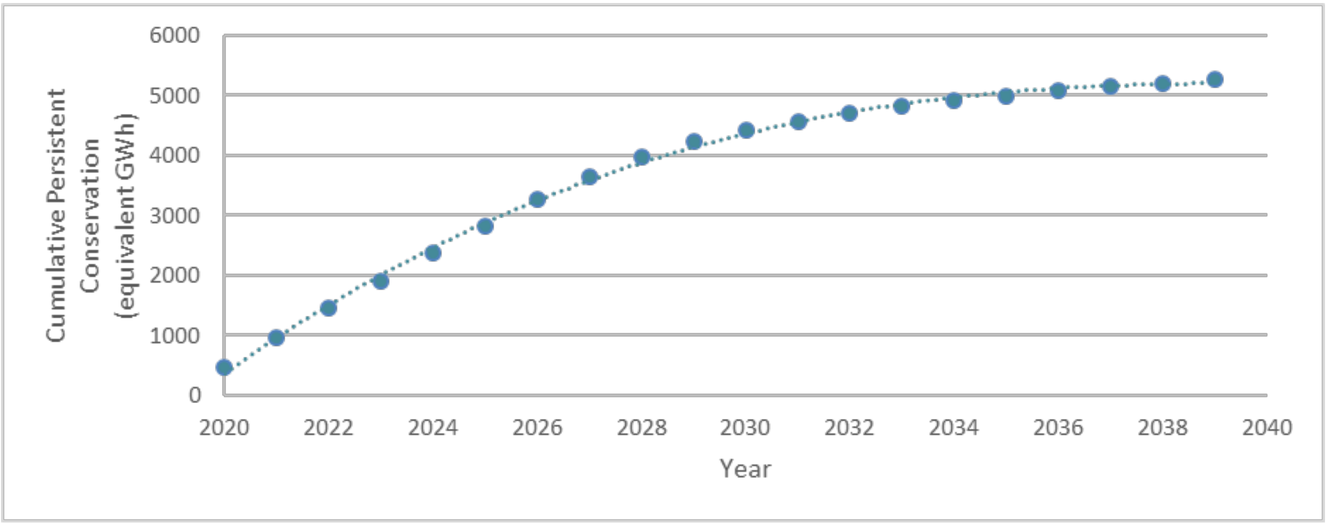
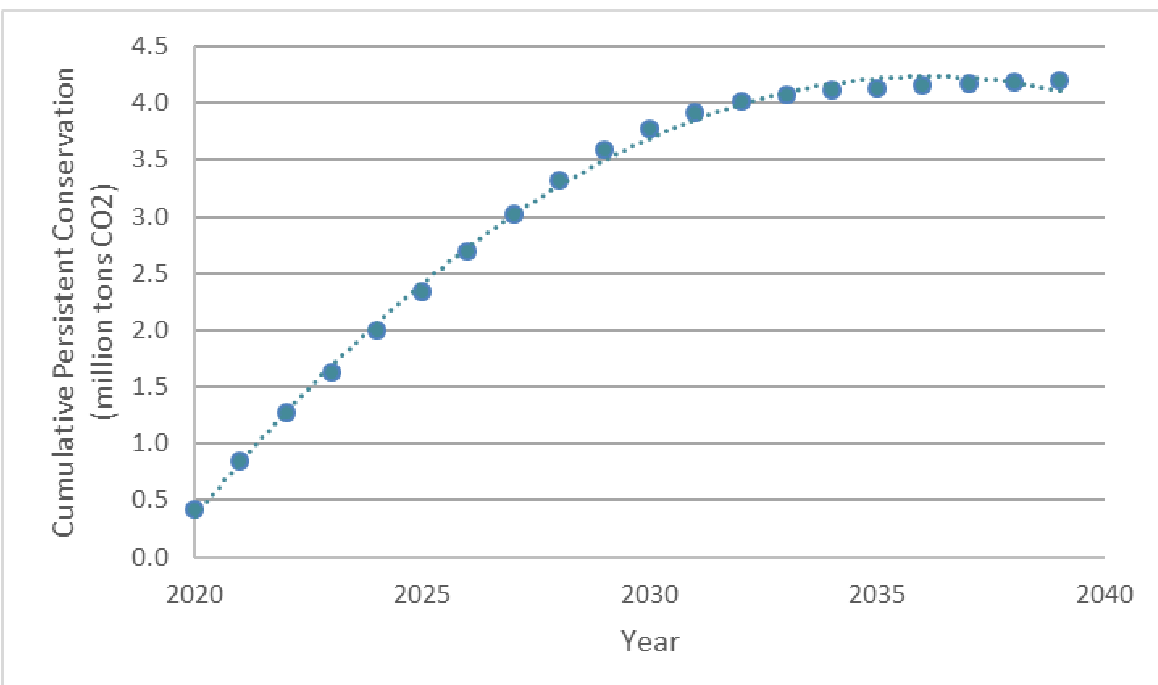


Figure 4-5 Generation Sector Cumulative Persistent Carbon Emission Reduction Potential



Transmission and Distribution Estimated Potential

Total Transmission and Distribution Results

Table 4-7 shows cumulative technical potential, technical potential as an average, annualized percent of sales, and technical potential as a percent of annual CIP goals by utility group and the Minnesota state total. Study results indicated more than 3.2 GWh of technically feasible distribution and transmission system energy efficiency potential by 2039, the end of the 20-year study horizon.

Table 4-7 Technical T&D Potential by Utility Type

Group	2039 Cumulative Technical Potential (MWh)	Technical Potential as an Average, Annualized Percent of Sales	Technical Potential as a Percent of Annual CIP Goals (1.5% of Sales)
IOUs	1,560,235	0.19%	12.4%
Co-ops	277,703	0.29%	18.9%
Munis	410,153	0.14%	9.3%
Statewide	**3,248,092**	**0.21%**	**13.7%**

Conductors represent the largest amount of technical potential among the distribution and transmission measure categories, with almost 1.5 GWh of cumulative potential by 2039, as shown in Table 4-8. Conservation voltage reduction represents 26% of the total distribution and transmission potential and transformers represent 28%.

Table 4-8 Technical T&D Potential by Measure Category

Measure Category	2039 Cumulative Technical Potential (MWh)	Technical Potential as an Average, Annualized Percent of Sales	Technical Potential as a Percent of Annual CIP Goals (1.5% of Sales)
Conservation Voltage Reduction	851,547	0.05%	3.6%
Conductors	1,483,479	0.10%	6.3%
Transformers	913,065	0.06%	3.9%
Total	**3,248,092**	**0.21%**	**13.7%**

Table 4-9 provides the cumulative economic potential, economic potential as an average, annualized percent of sales, and economic potential as a percent of CIP goals by utility group and the Minnesota state total. The study estimated approximately 2.5 GWh of cost-effective and technically feasible (i.e., economic potential) by 2039. The study found over three-fourths of technical potential was economic. The economic potential equated to electric energy savings as a percentage of sales on an annual basis of

0.16% which is equivalent to 10.7% of the Minnesota CIP 1.5% annual energy efficiency target as a percent of sales.

Table 4-9 Economic T&D Potential by Utility Type

Group	2039 Cumulative Economic Potential (MWh)	Economic Potential as an Average, Annualized Percent of Sales	Economic Potential as a Percent of Annual CIP Goals (1.5% of Sales)	2039 Economic Potential as a Percent of Technical
IOUs	1,224,109	0.15%	9.8%	78.5%
Co-ops	985,588	0.22%	14.8%	77.1%
Munis	305,446	0.11%	7.0%	74.5%
Statewide	**2,515,143**	**0.16%**	**10.7%**	**77.4%**

Table 4-10 shows cumulative achievable potential, achievable potential as an average, annualized percent of sales, and achievable potential as a percent of annual CIP goals by utility group and the Minnesota state total. The study identified over 1.3 GWh of achievable potential by 2039. The achievable potential equates to 41% of technical potential and 53% of economic potential. On an annual percentage of sales basis, achievable potential equated to 0.09% which is equal to 5.7% of the 1.5% annual energy efficiency target, as a percentage of sales.

Table 4-10 Achievable T&D Potential by Utility Type

Group	2039 Cumulative Achievable Potential (MWh)	Achievable Potential as an Average, Annualized Percent of Sales	Achievable Potential as a Percent of Annual CIP Goals (1.5% of Sales)	2039 Achievable Potential as a Percent of Technical
IOUs	656,633	0.08%	5.3%	42.1%
Co-ops	523,617	0.12%	7.9%	41.0%
Munis	162,269	0.06%	3.7%	39.6%
Statewide	**1,342,519**	**0.09%**	**5.7%**	**41.3%**

Table 4-11 presents the total, cumulative technical, economic, and achievable potential by distribution and transmission measure category. Conductors represented 46% of overall technical potential and 49% of economic and achievable potential, respectively. CVR represented 26% and 33% of technical and economic and achievable potential, respectively, whereas transformers accounted for 28% and 18%, respectively. The distribution of savings potential across measure categories is the same for economic and achievable potential because the same ramp rate and maximum achievable percentages are applied to each measure category.

Table 4-11 Cumulative T&D Potential by Measure

Measure Category	Cumulative Technical Potential (MWh 2020-39)	Cumulative Economic Potential (MWh 2020-39)	Cumulative Achievable Potential (MWh 2020-39)
CVR	851,547	838,072	461,053
Conductors	1,483,479	1,226,736	641,319
Transformers	913,065	450,334	240,147
Total	**3,248,092**	**2,515,143**	**1,342,519**

Figure 4-6 displays the estimated annual achievable distribution and transmission potential in graph form. Figure 4-7 shows cumulative achievable transmission and distribution potential over the period of the study.

Figure 4-6 Annual Incremental Achievable T&D Potential

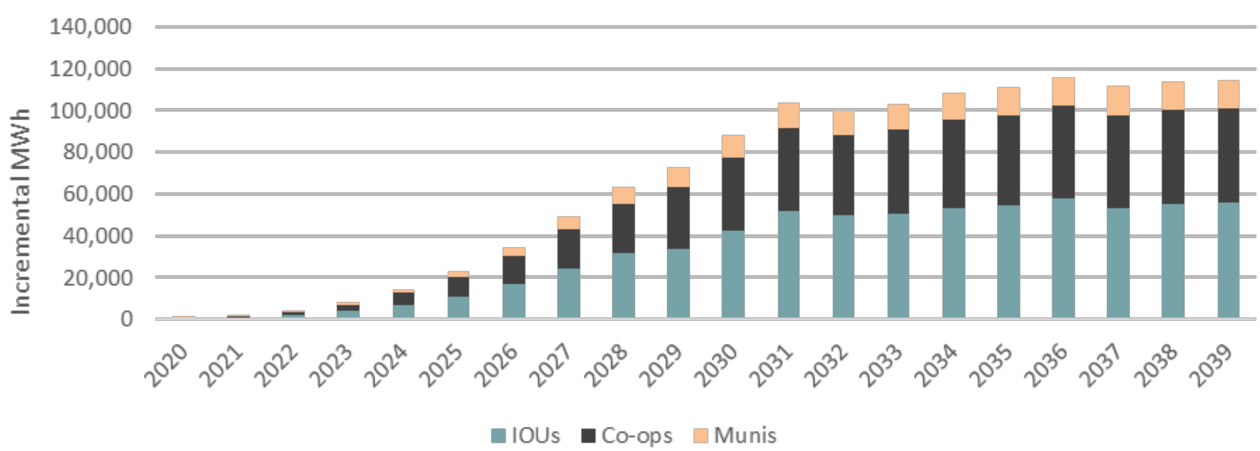
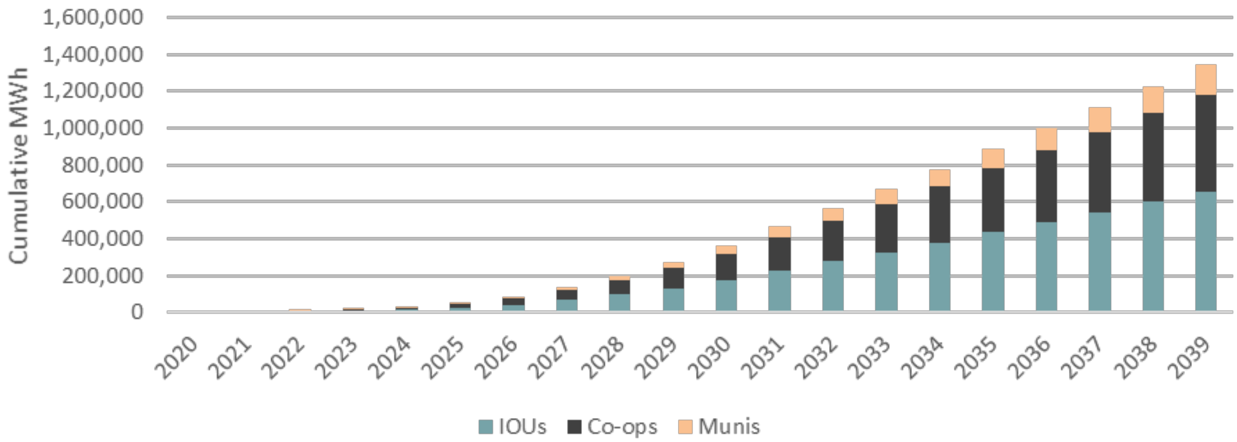


Figure 4-7 Cumulative Achievable T&D Potential



Estimated Potential from Transformers

Transformers – both service and substation – represented nearly 913,000 MWh or 28% of the total, cumulative transmission and distribution technical potential, as shown in Table 4-12. Despite representing a smaller share of forecast energy sales, cooperatives actually represent a greater percentage of transformer potential than IOUs primarily because there are more substations – and therefore more substation transformers - in cooperative service areas than IOUs, as shown in the MnGeo HVTL data set.

Table 4-12 Cumulative Transformer Technical Potential

Group	2039 Cumulative Technical Potential (MWh)	Technical Potential as an Average, Annualized Percent of Sales	Technical Potential as a Percent of Annual CIP Goals (1.5% of Sales)
IOUs	331,877	0.04%	2.7%
Co-ops	460,413	0.10%	6.9%
Munis	120,774	0.04%	2.8%
Statewide	**913,065**	**0.06%**	**3.9%**

Table 4-13 provides the cumulative economic and achievable potential for transformers by utility group and for the state of Minnesota. The transformer economic and achievable potential represent 1.9% and 1.0% of annual CIP goals, respectively. The study determined that 49% of technical potential was cost-effective and 26% of technical potential was achievable.

Table 4-13 Cumulative Transformer Economic and Achievable Potential

Group	2039 Cumulative Economic Potential (MWh)	Economic Potential as an Average, Annualized Percent of Sales	Economic Potential as a Percent of Annual CIP Goals (1.5% of Sales)	2039 Cumulative Achievable Potential (MWh)	Achievable Potential as an Average, Annualized Percent of Sales	Achievable Potential as a Percent of Annual CIP Goals (1.5% of Sales)
IOUs	136,670	0.02%	1.1%	72,731	0.01%	0.6%
Co-ops	264,298	0.06%	4.0%	141,322	0.03%	2.1%
Munis	49,367	0.02%	1.1%	26,094	0.01%	0.6%
Statewide	**450,334**	**0.03%**	**1.9%**	**240,147**	**0.02%**	**1.0%**

Estimated Potential from Conductors

Conductors accounted for almost 1.5 GWh or 46% of the total, cumulative transmission and distribution technical potential. This potential equated to 6.3% of the annual CIP goals, as shown in Table 4-14. IOUs account for approximately 52% of the total conductor technical potential, followed by cooperatives (37%), and municipal utilities (11%).

Table 4-14 Cumulative Conductor Technical Potential

Group	2039 Cumulative Technical Potential (MWh)	Technical Potential as an Average, Annualized Percent of Sales	Technical Potential as a Percent of Annual CIP Goals (1.5% of Sales)
IOUs	768,214	0.09%	6.2%
Co-ops	554,982	0.13%	8.4%
Munis	160,284	0.06%	3.7%
Statewide	**1,483,479**	**0.10%**	**6.3%**

Table 4-15 provides the cumulative economic and achievable potential for conductors by utility group and for the state of Minnesota. Conductor economic and achievable potential represent 5.2% and 2.7% of annual CIP goals, respectively. The study determined that 83% of technical potential was cost-effective and 43% of technical potential was achievable.

Table 4-15 Cumulative Conductor Economic and Achievable Potential

Group	2039 Cumulative Economic Potential (MWh)	Economic Potential as an Average, Annualized Percent of Sales	Economic Potential as a Percent of Annual CIP Goals (1.5% of Sales)	2039 Cumulative Achievable Potential (MWh)	Achievable Potential as an Average, Annualized Percent of Sales	Achievable Potential as a Percent of Annual CIP Goals (1.5% of Sales)
IOUs	638,055	0.08%	5.1%	336,680	0.04%	2.7%

Group	2039 Cumulative Economic Potential (MWh)	Economic Potential as an Average, Annualized Percent of Sales	Economic Potential as a Percent of Annual CIP Goals (1.5% of Sales)	2039 Cumulative Achievable Potential (MWh)	Achievable Potential as an Average, Annualized Percent of Sales	Achievable Potential as a Percent of Annual CIP Goals (1.5% of Sales)
Co-ops	455,012	0.10%	6.9%	235,806	0.05%	3.6%
Munis	133,669	0.05%	3.1%	68,634	0.02%	1.6%
Statewide	**1,226,736**	**0.08%**	**5.2%**	**641,319**	**0.04%**	**2.7%**

Table 4-16 shows the cumulative technical, economic, and achievable potential for conductors by location. Overhead conductors represented 71% of the total conductor achievable potential.

Table 4-16 Cumulative Conductor Potential by Location

Conductor Location	2039 Cumulative Technical Potential (MWh)	2039 Cumulative Economic Potential (MWh)	2039 Cumulative Achievable Potential (MWh)
Underground	364,503	356,607	186,532
Overhead	1,118,977	870,130	454,787
Total	**1,483,479**	**1,226,736**	**641,319**

Estimated Potential from Conservation Voltage Reduction

Conservation voltage reduction contributed nearly 852,000 MWh or 26% of the total cumulative transmission and distribution technical potential. This potential equated to 3.6% of annual CIP goals, as shown in Table 4-17. IOUs represented 54% of the total CVR technical potential, followed by cooperatives (31%) and municipal utilities (15%).

Table 4-17 Cumulative Conservation Voltage Reduction Technical Potential

Group	2039 Cumulative Technical Potential (MWh)	Technical Potential as an Average, Annualized Percent of Sales	Technical Potential as a Percent of Annual CIP Goals (1.5% of Sales)
IOUs	460,144	0.06%	3.7%
Co-ops	262,308	0.06%	3.9%
Munis	129,095	0.04%	3.0%
Statewide	**851,547**	**0.05%**	**3.6%**

Table 4-18 provides the cumulative economic and achievable potential for CVR by utility group and for the state of Minnesota. Economic and achievable potential represent 3.6% and 2.0% of annual CIP goals, respectively. The study determined that 98% of technical potential was cost-effective and 54% of technical potential was achievable.

Table 4-18 Cumulative Conservation Voltage Reduction Economic and Achievable Potential

Group	2039 Cumulative Economic Potential (MWh)	Economic Potential as an Average, Annualized Percent of Sales	Economic Potential as a Percent of Annual CIP Goals (1.5% of Sales)	2039 Cumulative Achievable Potential (MWh)	Achievable Potential as an Average, Annualized Percent of Sales	Achievable Potential as a Percent of Annual CIP Goals (1.5% of Sales)
IOUs	449,384	0.05%	3.6%	247,222	0.03%	2.0%
Co-ops	266,278	0.06%	4.0%	146,489	0.03%	2.2%
Munis	122,410	0.04%	2.8%	67,342	0.02%	1.6%
Statewide	**838,072**	**0.05%**	**3.6%**	**461,053**	**0.03%**	**2.0%**

Overall Results

This section presents a series of tables to summarize the results of the study and show combined Minnesota statewide EUI conservation potential over the period from 2020-2039.

All results are calculated assuming that all natural gas generation facilities owned by electric utilities (including those greater than 50MW capacity) are eligible to claim conservation credit as electric utility infrastructure assets. See the section Modeled Impacts of Possible Policy Guidance for further discussion on this topic.

Table 4-19 through Table 4-24 all present conservation potential in terms of the total first-year savings over the 20-year course of the study. That is, they present estimated claimable CIP savings in different useful formats. Table 4-24 presents cumulative carbon emission reductions resulting from the identified conservation potential over the 20-year study period.

Table 4-19 Total Statewide Conservation Potential 2020-2039

	Generation	T&D	Total
Technical Conservation Potential	1,399,850	3,248,092	4,647,942
Economic Conservation Potential	786,782	2,515,143	3,301,925
Achievable Conservation Potential	786,782	1,342,519	2,129,301

Table 4-20 Statewide Conservation Potential as a Percentage of electric sales* 2020-2039

	Generation	T&D	Total
Technical Conservation Potential	0.09%	0.21%	0.29%
Economic Conservation Potential	0.05%	0.16%	0.21%
Achievable Conservation Potential	0.05%	0.09%	0.13%

*Forecast statewide retail sales excluding CIP-exempt sales

Table 4-21 Statewide Conservation Potential as a Percentage of CIP Electric Goals 2020-2039

	Generation	T&D	Total
Technical Conservation Potential	5.9%	13.7%	19.6%
Economic Conservation Potential	3.3%	10.7%	13.9%
Achievable Conservation Potential	3.3%	5.7%	9.0%

Table 4-22 Total Conservation Potential in MWh by Sector and Utility Type

	IOU Generation	IOU T&D	IOU Total	COU Generation	COU T&D	COU Total
Technical Potential	965,385	1,560,235	2,525,620	434,465	1,687,856	2,122,321
Economic Potential	509,022	1,224,109	1,733,131	277,760	1,291,034	1,568,794
Achievable Potential	509,022	656,633	1,165,655	277,760	685,886	963,646

Table 4-23 Percent of Total Conservation Potential by Sector and Utility Type

	IOU Generation	IOU T&D	COU Generation	COU T&D
Technical Conservation Potential	20.8%	33.7%	9.3%	36.2%
Economic Conservation Potential	15.4%	37.1%	8.4%	39.1%
Achievable Conservation Potential	23.9%	30.8%	13.0%	32.2%

Table 4-24 Total Cumulative Potential for Carbon Emissions Reductions in Tons CO_2

	Generation	T&D	Total
Technical Conservation Potential	23,824,603	17,119,304	40,943,907
Economic Conservation Potential	11,483,198	12,761,647	24,244,845
Achievable Conservation Potential	11,483,198	4,953,622	16,436,820

Generation Sector Example Projects

The following example projects are included as a reference to demonstrate achievable generation conservation opportunity. Project details are based on actual past projects and are chosen as examples because they achieve conservation goals and pass a TRC test. These examples are meant to illustrate that such projects exist in the real world beyond the high-level models developed for the study and to provide ideas for similar projects that may be viable at MN facilities. Some of these projects are the same ones used to design the achievable generation potential model.

Example 1: Subcritical Cogeneration Coal Unit

Size:	65,000 kW
Heat Rate:	13,100 BTU/kWh
Operation Date:	1978
Expected Life:	50 Years
Capacity Factor:	59.2%
Fuel Costs:	\$35.00/Ton
	\$1.99/MMBtu

Project: Replace existing boiler superheater

Cost:	\$1,200,000
Installation Date:	2018
Heat Rate Improvement:	1.65%
Generation Increase:	0 kW
Life Cycle:	40 Years
Retirement Date:	2028

Discussion: This project would replace the superheater in the boiler due to degradation over time. The superheater heat transfer capability decreases due to erosion, buildup of scale inside the tubes and deposits on the outside of the tubes. Although the life of the replacement superheater is 40 years, the plant is scheduled for retirement in 2028. Thus, a 10-year lifecycle will be used in the analysis. Also, the heat rate improvement will degrade over time, so the analysis uses a simple assumption the heat rate benefit decreases by 2.0% per year.

Equation 4-1. Example 1 – Subcritical Cogeneration Coal Unit

$$\Delta\, MMBTU/yr = MNLd \times \left((HR_0 - HR_1)\ \times\ kW_0\right) \times LF \times H$$

$$\Delta\, MMBTU/yr = 100\% * \left(\left(13{,}100 \frac{Btu}{kWh} - 12{,}884 \frac{Btu}{kWh}\right) * 65{,}000kW\right) * 59.2\% * 8{,}760\ hr/yr$$

$$\Delta\, MMBTU/yr = 72{,}861\ MMBtu/yr$$

Fuel Cost Savings = 72,861MMBtu/yr *$1.99/MMBtu = $144,993.39/yr

NPV 10 Year Savings with Degradation (1.5% Inflation Rate) = $1,219,257

TRC Test = NPV Savings/Total Cost = $1,219,257/$1,200,000 = 1.016

$$\Delta\, kWh/yr = MNLd \times \left[\frac{(HR_0\ - HR_1)}{\mathrm{HR}_1} \times \mathrm{kW}_0 \times LF \times H\right]$$

$$\Delta\, kWh/yr = 100\% \times \left[\frac{(13{,}100\frac{Btu}{kWh} - 12{,}884\frac{Btu}{kWh})}{12{,}884\frac{Btu}{kWh}} \times 65{,}000\mathrm{kW} \times 59.2\% \times 8{,}760 hr/yr\right]$$

Eligible CIP savings claim = 5,651,219 equivalent kWh

Example 2: Combustion Turbine Peaking Unit

Size:	75,000 kW
Heat Rate:	12,200 BTU/kWh
Operation Date:	1998
Expected Life:	40 Years
Capacity Factor:	22.3%
Fuel Costs:	EIA Data

Project: Install Foggers for Inlet Air Cooling

Cost:	$2,400,000
Installation Date:	2018
Heat Rate Improvement:	5.33%
New Heat Rate:	11,549 Btu/kWh
Generation Increase:	0 kW
Life Cycle:	20 Years
Retirement Date:	2038

Discussion: This project would install foggers to chill the combustion turbine inlet air entering. The ambient design conditions for combustion turbines is based upon 50 °F inlet air. During hot summer periods, the peaking plant heat rate increases and the net output drops. Inlet air foggers bring operation closer to design conditions.

Equation 4-2. Example 2 – Combustion Turbine Peaking Unit

$$\Delta\, MMBTU/yr = MNLd \times \left((HR_0 - HR_1)\ \times\ kW_0\right) \times LF \times H$$

$$\Delta\, MMBTU/yr = 100\% * \left(\left(12{,}200\,\frac{Btu}{kWh} - 11{,}549\,\frac{Btu}{kWh}\right) * 75{,}000kW\right) * 22.3\% * 8{,}760\ hr/yr$$

$$\Delta\, MMBTU/yr = 95{,}379\ MMBtu/yr$$

1st Year Fuel Cost Savings = 95,379 MMBtu/yr *$3.04/MMBtu = $289,952/yr

NPV 10 Year Savings with Degradation (1.5% Inflation Rate) = $3,214,556

TRC Test = NPV Savings/Total Cost = $3,214,556/$2,400,000 = 1.34*

$$\Delta\, kWh/yr = MNLd \times \left[\frac{(HR_0\ - HR_1)}{\mathrm{HR}_1} \times \mathrm{kW}_0 \times LF \times H\right]$$

$$\Delta\, kWh/yr = 100\% \times \left[\frac{(12{,}200\frac{Btu}{kWh} - 11{,}549\frac{Btu}{kWh})}{11{,}549\frac{Btu}{kWh}} \times 75{,}000\mathrm{kW} \times 22.3\% \times 8{,}760 hr/yr\right]$$

Annual CIP savings claim = 8,258,607 equivalent kWh (if operated to increase capacity)

OR

Annual CIP savings claim = 953,790 Therms (if operated to reduce input fuel)

**The TRC calculation here uses avoided fuel costs as the benefits to maintain a consistent format for comparison across Generation conservation projects. In reality, this project would likely result in increased capacity at peak hours, which is likely to provide more value than the equivalent avoided fuel costs used here. This illustrates the unique nature of generation projects and the need to evaluate each individually while demonstrating that there is potential for cost effective efficiency improvements.*

Example 3: Combined Cycle Unit

Size:	550,000 kW
Heat Rate:	7,350 BTU/kWh
Operation Date:	2002
Expected Life:	40 Years
Capacity Factor:	46.5%
Fuel Costs:	EIA Data

Project: Upgrade hot gas path with new burners and cooling system to allow higher firing temperature.

Cost:	$31,000,000
Installation Date:	2018
Heat Rate Improvement:	5.8%
New Heat Rate:	6,922 Btu/kWh
Generation Increase:	0 kW
Life Cycle:	20 Years
Retirement Date:	2042

Discussion: This project would upgrade the burners of the combustion turbine with new advanced hot gas path burners and dry low NOx combustion process. This results in improved performance which was captured in this example by improved heat rate. This upgrade could also produce higher net output for the plant.

Equation 4-3. Example 3 – Combined Cycle Unit

$$\Delta\, MMBTU/yr = MNLd \times \left((HR_0 - HR_1) \times kW_0\right) \times LF \times H$$

$$\Delta\, MMBTU/yr = 100\% * \left(\left(7{,}350\,\frac{Btu}{kWh} - 6{,}922\,\frac{Btu}{kWh}\right) * 550{,}000kW\right) * 46.5\% * 8{,}760\ hr/yr$$

$$\Delta\, MMBTU/yr = 958{,}878\ MMBtu/yr$$

1st Year Fuel Cost Savings = 958,878 MMBtu/yr *$3.04/MMBtu = $2,911,634/yr

NPV 10 Year Savings with Degradation (1.5% Inflation Rate) = $32,317,164

TRC Test = NPV Savings/Total Cost = $32,317,164/$31,000,000 = 1.04

$$\Delta\, kWh/yr = MNLd \times \left[\frac{(HR_0 - HR_1)}{\mathrm{HR}_1} \times \mathrm{kW}_0 \times LF \times H\right]$$

$$\Delta\, kWh/yr = 100\% \times \left[\frac{(7{,}350\frac{Btu}{kWh} - 6{,}922\frac{Btu}{kWh})}{6{,}922\frac{Btu}{kWh}} \times 550{,}000\mathrm{kW} \times 46.5\% \times 8{,}760 hr/yr\right]$$

Eligible CIP savings claim = 138,526,200 equivalent kWh (if operated to increase capacity) *

OR

Eligible CIP savings claim = 9,588,780 Therms (if operated to reduce input fuel)

**This actual project was designed for a large facility and would result in sizeable savings. Unfortunately, there are no similar plants (large enough, running at high enough capacity factor, and not already close to the best-in-class efficiency level) that could achieve this significant of savings in the modeled results.*

5 Conclusions and Discussion of Results

Discussion of Results

Our primary goal in completing this study is to provide critical data resources to inform CIP decision-makers as to the viability of EUI as a CIP resource and outline which EUI improvements should be targeted to help realize energy efficiency potential in Minnesota.

Our findings indicate that Electric Utility Infrastructure projects have the potential to deliver a portion of Minnesota utilities' conservation goals over the 20-year period between 2020 and 2039. The models estimate that achievable potential EUI conservation represents approximately 0.13% of electric sales (excluding CIP-exempt sales) over the course of the study. This corresponds to approximately 9.0% of annual electric conservation goals statewide. The identified potential is split between the T&D sector (approximately 0.08% of sales or 5.7% of goals) and generation sector (approximately 0.05% of sales or 3.3% of goals). Technical conservation potential is estimated to be approximately 19.6% of electric conservation goals over the period of the study, suggesting that changes to policies or incentives could unlock additional potential for utilities to use EUI projects to meet their CIP goals.

Ultimately, the study results show that utilities should consider including EUI conservation projects in their CIP plans. Further policymakers are justified in pursuing policies to lower barriers to implementation and drive utilization of EUI resources to meet CIP goals.

Effects on CIP Programs

One of the main goals of this study is to determine the magnitude of potential EUI savings in Minnesota in terms of the possibility to help utilities meet their CIP goals. The first question to answer is whether EUI conservation potential is large enough to warrant putting effort into capturing it. The results of this study show that there is opportunity in EUI sectors that utilities should consider as options for inclusion in their CIP plans. It is worth developing initiatives to target the sector that may deliver approximately 9.0% of CIP goals over the study period, especially as "low-hanging fruit" measures like LED lighting become less reliable sources of conservation.

The converse of asking whether there is enough EUI potential to target is asking whether there might be too much. Another reason for undertaking this study was a concern that large EUI projects could displace demand-side projects as the primary tool for meeting Minnesota conservation goals. While EUI efficiency should be considered as a complimentary tool to demand-side efficiency programs, it is not intended to replace those programs on a large scale. EUI conservation is allowed by statute to count toward CIP goals up to 0.5% of retail sales[42], or, up to one third of a utility's annual conservation goal.

[42] Deputy Commissioner's Decision, Filed Date in Docket No. E,G999/CIP 17-856

The results of the study show approximately 9.0% of CIP goals are achievable with EUI projects on average, over time. This is significantly lower than one third of the goal, suggesting that large-scale displacement of DSM activities is unlikely.

While individual EUI projects can deliver a large percentage of a given utility's annual conservation goal, the results of the study indicate it is unlikely that such projects will do so over multiple years. The Department recently issued guidance allowing EUI savings to carry forward for CIP purposes up to five years. This means that if utilities achieve EUI savings in excess of goals, that excess can be claimed in future years if they fall short of goals. This helps to reduce uncertainty about the value of large EUI projects over time.

Important Context

Readers of this report should keep in mind key methodology decisions that went into developing the final models to ensure results are understood in the proper context. Importantly, the meanings of technical, economic, and achievable potential are somewhat different for this EUI study compared to conventional DSM potential studies.

Several sources of data used to complete the study shared information with the project team under the protection of an NDA. Results are aggregated at the statewide level and into some high-level categories, but not at high resolution or in any format that could be used to identify individual sites or owners.

Generation Sector

The model used to estimate conservation potential in the generation sector is based on the MN TRM measure that prescribes a savings algorithm based on improving heat rate at generation facilities.

Generation potential results should be viewed as high-level estimates. Determining all physically possible conservation potential at all generation facilities owned by all utilities in MN would require engineering analysis at each individual plant, which is well outside the scope of this project.

The most useful reference for the generation results may not be the potential numbers, but the example projects instead. Examples are based on actual past projects (clients and site information anonymized) chosen to meet our definition of economically viable to 1) illustrate that such projects exist in the real world and 2) provide ideas that may work for MN utilities. See the section Generation Sector Example Projects for specific examples of generation projects.

Some important context for the study is reflected by sites *not* included in the final generation plant data set.

- The data set does not include plants that do not measure performance in terms of heat rate because the defined measure algorithm is based on heat rate improvements. This means the plant data set (and the study as a whole) does not estimate conservation potential from improving the efficiency of renewable, hydropower, or nuclear generation facilities.

- Small (<1MW) facilities are not included in the model because they typically are not required to file forms used to build the reference database.
- Most end-user-owned generation facilities are not included in the reference database.
- Planned future facilities were not added to the model because they are difficult to model in terms of heat rate and it is assumed that new plants will operate efficiently over the majority of the period of the study
- Plants scheduled for planned retirement were removed from the model. Further, most plants over the age of 48 (built before 1970) are not included. All of these plants are assumed to be more likely to be decommissioned or replaced rather than improved.
- Plants with low capacity factors (run for less than 150 hours annually) were removed from the model under the assumption that improvements are unlikely to be undertaken beyond avoiding plant failure. This resulted in the removal of a large number of plants, but they do not account for a large percentage of generated energy.
- Plants serving significant load outside MN were removed from the model. Conservation projects at these sites would be de-rated by percentage of load served in MN and we assumed that those projects will be less cost-effective and therefore not achievable.

All of these excluded facilities could theoretically contribute to conservation potential over the timeframe of the study. Utilities should not ignore these facility types completely as possible efficiency targets. On a case-by-case basis, it may be possible to identify conservation opportunities at these sites (especially new construction plants as they age near the end of the study period). However, they are likely to contribute a relatively small amount to potential conservation and should be lower priority targets.

Technical potential is modeled top-down by looking at whole facilities and using net heat rate to compare them to high-performing facilities of the same type (fuel, technology, age, capacity factor, etc.). Achievable potential is modeled bottom-up by looking at individual heat rate improvement projects to apply to each generation facility. The fact that the technical and achievable models take different approaches is unusual for potential studies, but is required by the unique nature of the study (specifically, it is impossible to model each site individually).

Importantly, the achievable potential model allows for only one project per site over the course of the study. This limits the potential estimate output by the model. Additional projects could be implemented at a given site over the course of the study period, but our models are not equipped to handle them well. Further detailed modeling of individual sites is outside the scope of the study. Therefore, the reported achievable potential can be interpreted as a lower bound of existing opportunity. However, the single largest cost-effective opportunity at each site is captured in the model, so missing potential is likely to be small compared to reported potential.

Finally, the chosen methodology does calculate economic potential separately from achievable potential for the generation sector. The methodology used does not lend itself to calculating economic potential easily and achievable potential illustrates the main findings of the study. Calculating the difference between economic and achievable potential was deemed not worth the required effort to model. Achievable results are reported, economic potential is not. In cases where generation is compared with T&D results, generation achievable potential is used as a conservative “floor” estimate of economic potential.

New Source Review and Fossil Plant Lifetime

During the project, a concern was raised that generation efficiency projects may trigger an otherwise unnecessary New Source Review (NSR), which could pose an unsurmountable hurdle to completing the project. Further, improving the efficiency of fossil fuel plants may extend their life or result in increased run hours, which could have the unintended consequence of increasing emissions compared to the baseline scenario. The project team met with the Minnesota Pollution Control Agency (PCA) to gain a better understanding of the issues.

We determined that a NSR is very unlikely to impact utility conservation considerations. If a proposed upgrade project will not trigger an NSR, the marginal additional consideration of conservation is very unlikely to change that fact.

Extending the lifetime or annual runtime of fossil fuel facilities is not the intended impact of conservation efforts. The models used do not include either effect when calculating conservation potential. Further, the TRM algorithm does not calculate additional savings for increased runtime, so there is no conservation credit for increased runtime. The project team believes that any actual effect on emissions caused by increased fossil plant runtime will be outweighed by the reduced emissions achieved by increased efficiency. However, projects that may fall into this category may be examined closely on a case-by-case basis to better understand the possible effects before they are approved for conservation credit.

Loss Studies

Existing loss studies cannot be used to directly estimate conservation potential because there are not enough loss studies, they are not robust enough to draw strong conclusions, and the methods used across loss studies are not consistent. However, loss studies can be used as a high-level gut check on the results of the main methodology findings. The estimated achievable conservation of approximately 1.2 million MWh over the course of the study corresponds to a combined improvement of reducing T&D losses by slightly over 1% statewide (a baseline of 9% losses improving to 7.9% corresponds to approximately the modeled estimated achievable potential). This is within a reasonable range of possible improvement (possibly a slightly conservative estimate) which helps to corroborate the study findings at a high level.

Utilities that are able to track losses over time can use that information to identify improvement opportunities and verify conservation calculations. One utility conducting periodic loss studies using the same methodology each time is currently the only viable use for loss studies in terms of CIP. Even back-of-the-envelope loss studies that compare wholesale purchases to retail sales can be used by utilities for internal tracking to understand the system efficiencies and how they change over time.

The experiences during this study suggest the possibility of using system losses to track improvements and report conservation accomplishments is not yet a viable option. Using loss studies to track T&D conservation could have an advantage because details about discrete projects don't have to be meticulously tracked and because loss studies lend themselves to long term goals (for example, a goal could be the reduction of 0.1% system losses each triennial period). In order to use loss studies for this purpose, there would need to be prescribed standards for completing loss studies, established baselines for all utilities, and a method to account for system expansion and normal maintenance. These are not insurmountable hurdles, but they need to be addressed before being used.

Interesting Additional Findings

The following findings are not directly important to the main goals of the study, but readers may find them interesting.

The EIA estimates that approximately 12-15% of electricity consumed nationally is in the EUI sector[43]. The findings that approximately 9.0% of conservation goals can be met with EUI projects suggests that infrastructure assets operate closer to optimal efficiency than demand side applications.

Savings for generation *operations* changes are unlikely – per discussion with experts and utility interviews. Small plants do not run for enough hours per year and large plants already employ sophisticated controls that are effectively optimized for heat rate (after optimizing for higher-priority considerations like reliability and safety). If a utility could demonstrate adjustments to their control strategy resulting in improved average heat rate that would count toward CIP goals, but it is unlikely such projects will contribute significant savings. That is, it is likely most generation improvement projects will consist of equipment replacement or retrofits.

Utility Recommendations

As a preface to this section, the following recommendations all suggest dedicating resources toward EUI conservation. We recognize that utilities have many competing priorities and the value returned for expending these resources is somewhat uncertain at this time. These recommendations are meant to use results from this study to build certainty about the value of EUI conservation and lay the groundwork now toward a future where EUI efficiency is a well-understood, viable tool to achieve conservation goals. It is anticipated utilities can implement some of these recommendations in the short

[43] Forsten, K. *Tomorrow's T&D*: The most economical energy savings might be found in grid efficiency. Public Utilities Fortnightly. February 2010. http://www.fortnightly.com/pubs/02012010_TomorrowsTD.pdf

term, hopefully share experiences across the state, and eventually build to more robust efforts over time. Overall, we want to emphasize that we hope EUI conservation becomes a *tool* to meet existing CIP goals. The aim of these recommendations is to help understand EUI tools, not to complicate the lives of utility planning personnel unnecessarily.

Process and Policy Recommendations

1. Convene periodic conversations between CIP personnel and infrastructure personnel (distribution/transmission engineers and generation plant operators). Goals should be to:
    (a) Raise general awareness of opportunity to claim CIP credit from EUI projects.
    (b) Discuss high-level ideas for implementing efficiency initiatives as part of ongoing infrastructure construction, operation, and maintenance.
    (c) Incorporate efficiency considerations into the Integrated Distribution Planning process recently established by the MN PUC.
    (d) Identify systems or facilities that are likely to offer efficiency opportunity (note, in conversations with the project team, system operators typically have good ideas where there is room for efficiency improvement, it's just not the top priority to address)
    (e) Invent ideas for efficiency opportunities utilities are not even considering yet.
2. Conduct high-level assessments of possible EUI conservation projects. This does not have to take much time or effort. The point is to familiarize utilities with EUI conservation calculation methods and possibly identify conservation opportunities. As a part of this project, high-level Excel-based project screening tools were developed as a possible starting point.
3. Use the Department of Commerce as a resource. If there is uncertainty about a potential project's eligibility or how to calculate conservation savings, reach out to build better understanding. Especially for utilities that have not completed EUI projects yet, reach out to begin climbing the learning curve
4. Review technology and related initiative documents to stay current on potential efficiency opportunities.
5. Be aware of recently-issued guidance establishing a 5-year carry-forward provision for excess EUI conservation savings and clarifying 1% demand-side requirement (EUI savings are not lost if the DSM threshold is not met in a given year). Both documents reduce uncertainty surrounding EUI projects and may improve their value.
6. Follow up with the results of the DOE stakeholder process to be published in mid 2019. The project is expected to result in additional policy guidance and an overall EUI Action Plan for the state. Particularly useful may be guidance concerning how to determine the meaning of "Normal Maintenance" and guidelines to reduce uncertainty about the Department's EUI project review process.

Generation Recommendations

1. Generation operators – examine similar plants (fuel, technology, capacity, capacity factor) to find those that operate at lower heat rates to determine what would be necessary to achieve similar conditions at a given plant. In conversations, operators are typically well-aware of opportunities for heat rate improvements and would be willing to adopt them if they were a priority and had funding.
2. Coal plants that are not planned for decommissioning offer the most opportunity for improved heat rates and energy conservation, according to our findings. These sites should be examined for heat rate improvement opportunities because there are likely to be cost-effective options.
3. Examine operating protocols. There may not be significant opportunity for improvement, but changes to protocols could inexpensive or simple to implement. It may be possible to leverage CIP credit to drive marginal improvements. As a note, most generation efficiency is likely to come from equipment replacement or upgrades. Large plants are already controlled with sophisticated software that effectively optimizes heat rate and less-optimally-operated plants are typically smaller or don't run for significant hours per year. Operations are still worth examining due to cost-effectiveness if opportunities are found.

Transmission & Distribution Recommendations

1. Consider AMI deployment or accelerating existing deployment plans. AMI enables significant efficiency opportunity (there are many drivers of AMI deployment, enabling energy efficiency opportunities makes AMI incrementally more valuable in addition to other drivers). To help understand the possible added value of CVR that can be implemented with AMI:
   (a) Review CVR pilot programs to find one that applies to your situation.
   (b) Evaluate AMI functionality to ensure the ability to implement efficiency opportunity (marginal cost of features that allow CVR, dynamic rates, or load management are likely worth it. AMI deployment is often driven by operational savings, but not all meters have functionality to deliver value beyond that)
2. Conduct a system loss study and track results over time. Even a high-level estimate performed by subtracting retail sales from wholesale purchases can be instructive in terms of identifying potential opportunity and tracking improvements.
3. Update maintenance protocols to incorporate efficiency considerations. If existing plans for repairing/replacing equipment can be updated to include higher efficiency adjustments, incremental conservation can be achieved continually as already-required periodic actions are performed.
4. Remember that traditional demand-side conservation projects (HVAC, lighting, motors, etc.) at sites owned by utilities are eligible for conservation credit.

5 Examine protocols for replacing conductors on failure or end-of-life. Many specialized conductors (low sag for height restrictions or river crossings, for example) can be installed in non-specialized situations to achieve conservation goals and reduce operating costs. Our research indicates that the upfront costs of some low-loss conductors have dropped in recent years relative to standard options (Note: this assessment was made before proposed national raw metals import tariffs were announced, which may make low-loss conductors even more cost-effective relatively).

General Recommendations

1 Utilities may want to explore generation conservation opportunities in the near term as T&D opportunities will become more viable later in the planning horizon (as AMI penetration rates rise and implementation strategies are streamlined). Especially if the largest generation opportunities are targeted sooner, this will spread EUI conservation more evenly over coming years.

2 As new generation facilities or T&D system expansion are planned, consider options for increasing efficiency. Upfront decisions are typically much easier to implement than retrofits after the fact. Carefully work with the Department to verify eligibility of identified opportunity – especially the choice of baseline.

Appendix A – Useful Reference for Utilities includes several relevant documents utilities may find helpful. Several were used developing this list of recommendations.

High Level Screening Tools

As one of the project deliverables, the team developed Microsoft Excel-based high-level screening tools that can be used to evaluate potential EUI conservation projects in terms of estimating energy savings they may achieve and their cost effectiveness. These tools are based on the savings algorithms in the TRM and reflect some of the same calculations used in the models for this project. The tools can be found on the project web page[44] or the Department of Commerce webpage[45].

The tools are meant to lower the barrier to implementing EUI projects by providing a starting point for utilities to consider whether projects are worth pursuing. They are not rigorous engineering design or financial planning resources, but they may be a useful first step to reduce uncertainty about EUI

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44 EUI studies web page. https://www.mncee.org/mnsupplystudy/home/

45 Electric Utility Infrastructure Efficiency Project Screening Tool. http://mn.gov/commerce-stat/xls/electric-infrastructure-efficiency-screening.xlsx

conservation opportunities. Tools were developed to estimate savings potential for the following project types:

- Generation Heat Rate Improvements
- Conservation Voltage Reduction
- Low-loss Conductors
- High Efficiency Transformers

6 Modeled Impacts of Possible Policy Guidance

Description of Modeled Policy Guidance

As part of the study, the GDS team was asked to model the impacts of a possible policy change or clarification in terms of how the policy may impact the potential for EUI efficiency projects to deliver conservation. During the study, several possible policy recommendations were raised. From the list of options, one policy change was selected to be modeled for the impact on EUI conservation potential. For more detail, fully developed policy recommendations in the form of an Action Plan are expected as an outcome of the concurrent DOE-funded stakeholder engagement project in late 2018.

The policy chosen to model is the uncertainty surrounding large natural gas facilities. The relevant statute says that gross retail energy sales exclude gas sales to large energy facilities (those with generating capacity greater than 50MW[46]) for the purposes of Conservation Improvement Programs[47]. Historically, this has meant that large gas facilities are automatically excluded from participating in gas conservation programs and that sales to those facilities are automatically exempted from the calculation of gas utilities' conservation goals. The policy is clearly meant to exempt sales to generation facilities for the purpose of establishing retail conservation goals, but there is uncertainty about how the statute should be interpreted for CIP eligibility status of natural gas generation facilities as infrastructure assets.

The main methodology for calculating conservation potential in the generation sector assumes that large gas facilities are only exempted from CIP programs as *gas utility* customers, but that they are allowed to claim conservation credit as *electric utility* infrastructure assets. This reading of the statute has not been confirmed at the time of publication of this report. The issue has been recommended for review as part of the DOE-funded stakeholder project to clarify EUI policies and may be addressed through policy guidance in late 2018.

The following section presents recalculated conservation potential results under the assumption that large gas facilities are not eligible to claim savings. Compared to the main methodology, the adjusted assumption reduces the number of sites that can claim savings, reduces the average savings per site, and decreases the likelihood that a project will be cost effective enough to qualify as achievable.

[46] Minnesota Statute §216B.2421, subdivision 2, clause (1)

[47] Minnesota Statute §216B.241 Subdivision 1(g), clause 1(i)

Recalculated Conservation Potential Results Excluding Large Natural Gas Facilities

The results in the main body of the report (Generation Sector Estimate Potential section) reflect an assumption that all generation facilities are eligible to claim conservation credit as electric utility infrastructure assets. There is some question as to whether natural gas facilities greater than 50MW capacity are eligible to claim savings by statute. See the previous section for a full discussion of the issue, including a plan to resolve the uncertainty as part of the concurrent EUI policy stakeholder process (possibly resulting in clarifying policy guidance in late 2018). Because the issue is not yet clarified, the following results present the potential for conservation in the generation sector under the assumption that natural gas facilities greater than 50MW are not eligible to claim CIP credit. The results in the main body of the report and this section both reflect the same gathered data and use the same modeling methodology. The only difference is the interpretation of policy regarding large gas facility eligibility.

The total cumulative statewide technical potential for conservation over the period of this study in the generation sector (excluding natural gas facilities greater than 50MW) is estimated to be 1,180,696 equivalent MWh. Of that technical potential, approximately 572,831 equivalent MWh are estimated to be achievable, which represents approximately 2.4% of total statewide projected CIP electric conservation goals from 2020-2039. The following series of figures and tables presents the findings from the study in a variety of useful formats. No results are reported as economic potential separate from achievable for the generation sector because it was determined that the results would not be accurate and instructive enough to warrant the additional modeling effort required.

Figure 6-1 and Figure 6-2 summarize total estimated statewide conservation potential over the period of the study (technical and achievable potentially, respectively). The result is presented in equivalent MWh using the TRM algorithm from Equation 3-1, which translates generation savings into the CIP electric conservation metric. The final value is the total CIP-claimable savings estimated over the 20-year period of the study. That is, the results show the total first-year savings for all conservation projects completed over the course of the 20-year study.

The potential conservation is then shown as a percentage of total statewide electric sales (not including sales to CIP-exempt customers) over the course of the study. Finally, the percentage of CIP goals (right-most column in these tables) is the conservation potential divided by projected statewide CIP electric goals over the period studied. That is, if all identified potential is captured it represents 4.98% (technical) or 2.41% (achievable) of the projected CIP goals for utilities across the state over the period from 2020-2039.

All conservation potential in this section is calculated with the assumption that large natural gas facilities (greater than 50MW capacity) are ineligible to claim conservation credit as electric utility generation assets. There is some uncertainty about this reading of statute. The main findings (Full Generation

Sector Potential) present results calculated under the assumption that large gas facilities are eligible. The Overall Results section also assumes large gas facilities are eligible and should be adjusted to reflect the findings in this section if such facilities are ultimately determined to be ineligible.

Table 6-1 and Figure 6-1 display the estimated technical potential broken out by generation technology. Table 6-2 and Figure 6-2 display the estimated achievable potential broken out by generation technology. All tables in this section exclude large natural gas facilities.

Table 6-1 Statewide Generation Sector Technical Potential

Plant Type – Fuel	Plant Type - Technology	Technical Potential (equivalent MWh)	Technical Potential as a Percentage of Sales*	Technical Potential as a Percentage of CIP Goals
Coal	Subcritical	967,595	1.22%	4.08%
Coal	Supercritical	89,370	0.11%	0.38%
Gas	Combined Cycle	3,640	0.00%	0.02%
Gas	Steam Turbine	2,708	0.00%	0.01%
Gas	Combustion Turbine	771	0.00%	0.00%
Biomass	All	116,612	0.15%	0.49%
Total	**Statewide Combined**	**1,180,696**	**1.49%**	**4.98%**

**Not including CIP-exempt electric sales*

Figure 6-1 Generation Technical Potential - Excluding Large NG Facilities

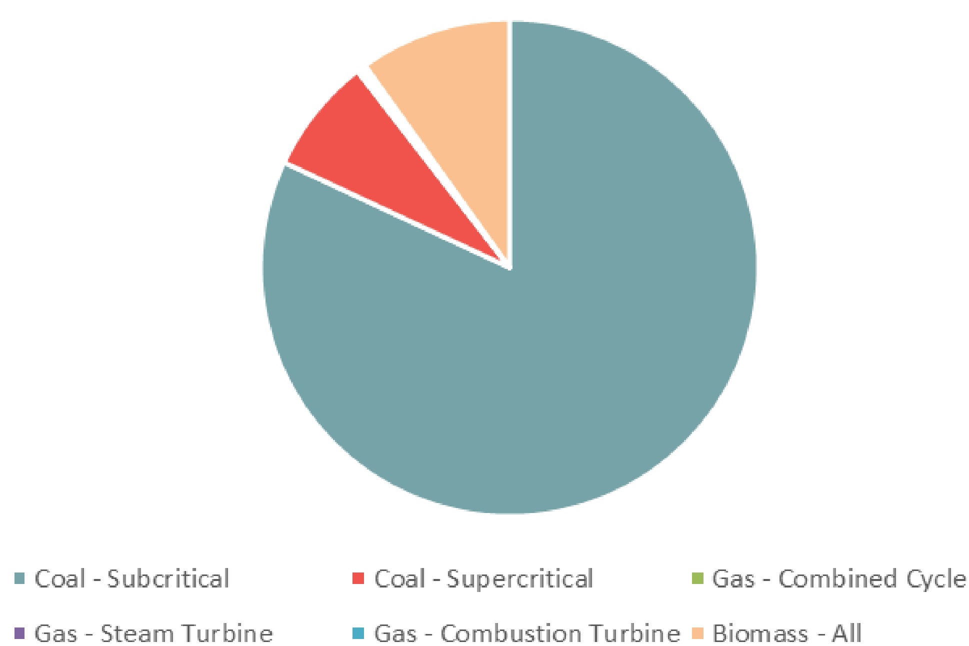


Table 6-2 Statewide Generation Sector Achievable Potential

Plant Type - Fuel	Plant Type - Technology	Achievable Potential (equivalent MWh)	Achievable Potential as a Percentage of Sales*	Achievable Potential as a Percentage of CIP Goals
Coal	Subcritical	399,914	0.51%	1.69%
Coal	Supercritical	73,730	0.09%	0.31%
Gas	Combined Cycle	3,519	0.00%	0.01%
Gas	Steam Turbine	1,650	0.00%	0.01%
Gas	Combustion Turbine	728	0.00%	0.00%
Biomass	All	93,289	0.12%	0.39%
Total	**Statewide Combined**	**572,831**	**0.72%**	**2.41%**

**Not including CIP-exempt electric sales*

Figure 6-2 Generation Achievable Potential - Excluding Large NG Facilities

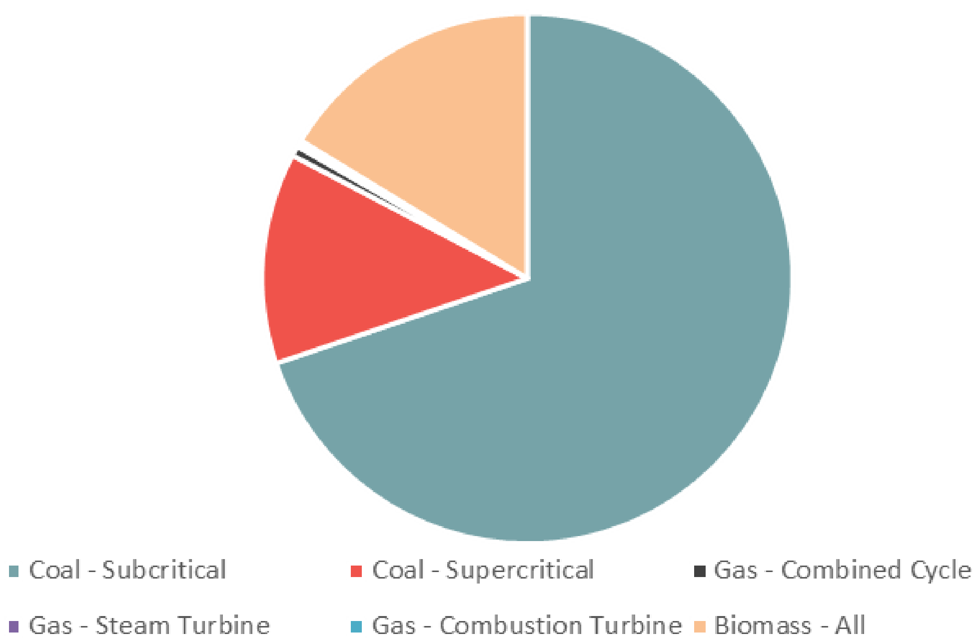


Table 6-3 and Table 6-4 present the associated reduction in annual input fuel measured in MMBtu resulting from the identified conservation potential (technical and achievable, respectively). For non-exempt natural gas facilities, conservation could be claimed toward gas utility conservation goals rather than converting to equivalent electric conservation, but this opportunity represents only a small portion of facilities. These values represent fuel savings, not claimed CIP gas savings. The total technical potential for input fuel conservation in MMBtu is approximately 1.0% of total annual fuel consumption by utilities in the state excluding biomass facilities. Achievable potential for input fuel conservation is approximately 0.5% of total fuel consumed annually by non-biomass facilities. These estimates are made by referencing EIA monthly electric power reports though March, 2018[48]. All tables and figures in this section exclude large natural gas generation facilities.

Table 6-3 Statewide Generation Technical Potential Input Fuel Reduction

Plant Type – Fuel	Plant Type - Technology	Technical Potential (MMBtu input fuel conserved)
Coal	Subcritical	9,625,078
Coal	Supercritical	777,762
Gas	Combined Cycle	43,453
Gas	Steam Turbine	54,293
Gas	Combustion Turbine	14,650
Biomass	All	2,310,787
Total	**Statewide Combined**	**12,826,023**

Table 6-4 Statewide Generation Achievable Potential Input Fuel Reduction

Plant Type – Fuel	Plant Type - Technology	Achievable Potential (MMBtu input fuel conserved)
Coal	Subcritical	4,028,174
Coal	Supercritical	641,654
Gas	Combined Cycle	42,005
Gas	Steam Turbine	29,861
Gas	Combustion Turbine	13,849
Biomass	All	1,848,629
Total	**Statewide Combined**	**6,604,172**

Table 6-5 breaks out the achievable conservation potential (in equivalent MWh) by investor-owned utilities vs. consumer-owned utilities.

[48] Monthly EIA data through May 2018 showing generation fuel consumption by state. https://www.eia.gov/electricity/monthly/current_month/epm.pdf

Table 6-5 Statewide Generation Sector Achievable Potential by Utility Type

Utility Type	Equivalent MWh	Percentage
IOU	394,997	69%
COU	177,833	31%
Total	**572,831**	

Table 6-6 presents the annual potential for conservation in the generation sector in terms of reduced carbon emissions. Estimates are made by multiplying the reduced input fuel (Table 4-10 and Table 4-11) by the carbon content[49] of each fuel type. Biomass generation is excluded from carbon emission considerations.

Table 6-6 Generation Annual Carbon Emission Reduction Potential

Potential Type	Equivalent Tons CO_2 reduction
Technical Potential	1,121,240
Achievable Potential	505,386

Figure 6-3 Generation Cumulative Achievable Conservation

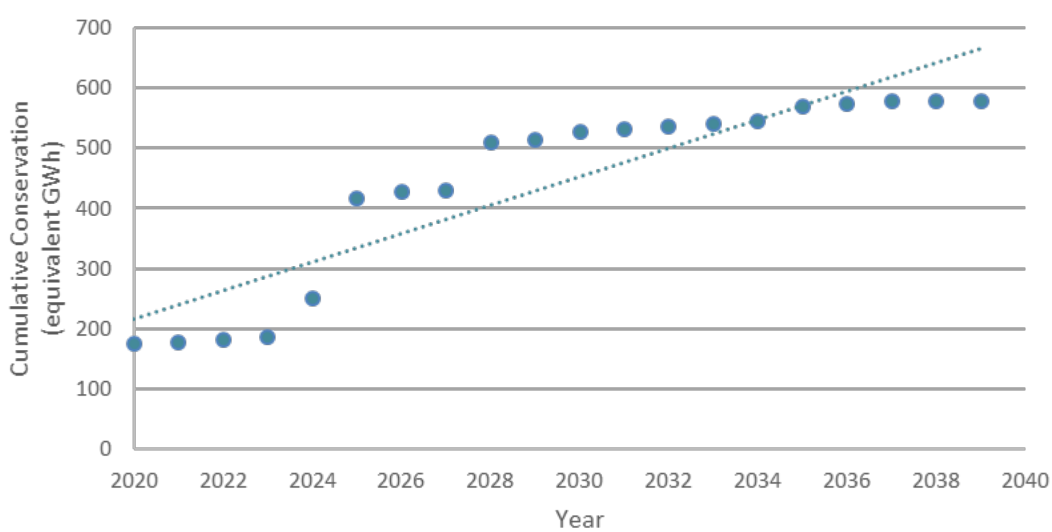


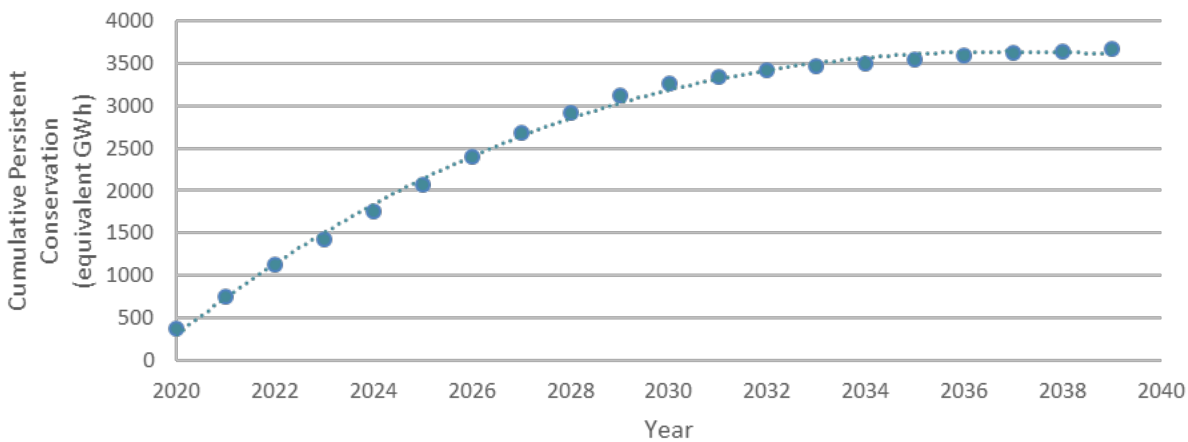
Figure 6-3 depicts the cumulative achievable first-year conservation potential by year over the 20-year period of the study in equivalent GWh, again excluding large natural gas generation facilities. This format of results makes the assumption that projects with large conservation opportunity are targeted sooner than lower-opportunity options. These results should be viewed as an approximate trendline of

[49] EIA data showing carbon content of fuel types. https://www.eia.gov/tools/faqs/faq.php?id=73&t=11

achievable opportunity, but may not reflect actual project implementation decisions precisely on a year-by-year basis.

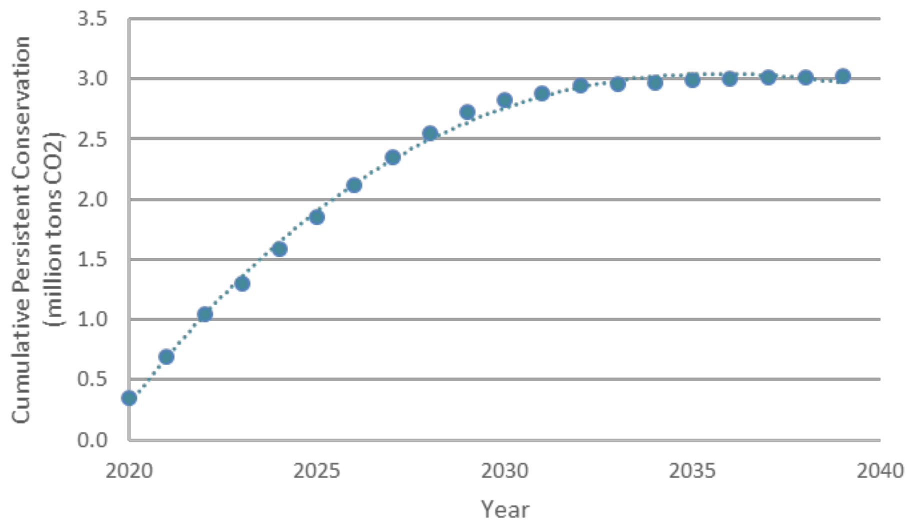
The final format of results is cumulative *persistent* savings (Figure 6-4). These results are an estimate of cumulative potential impacts of generation conservation projects on the system and environment separate from claimable CIP savings (only first-year impacts of projects are reflected in CIP metrics).

Figure 6-4 Generation Cumulative Persistent Achievable Conservation Potential



Achievable cumulative persistent conservation is shown in Figure 6-5. Conservation is in equivalent reduced tons of CO_2 emissions. These estimates assume that each generation facility with identified potential opportunity implements one project over the course of the study, full savings persist for 3 years, savings reduce to baseline levels after 5 years, and that utility owners implement projects at a reasonable pace. These estimates are most usefully viewed as a trendline of conservation impacts rather than a prediction of year-by-year outcomes. These results could vary depending on implementation priority and maintenance of project impacts over time. Results exclude large natural gas facilities.

Figure 6-5 Generation Cumulative Persistent Carbon Emission Reduction Potential



Discussion of Adjusted Modeling results

The recalculated results demonstrate the importance of clarifying the policy surrounding large natural gas facilities. Comparing the results from Table 4-5, Table 6-5, and Table 4-19, we show that EUI conservation potential in large natural gas facilities makes up approximately 27% of the total achievable conservation potential in the generation sector and 10% of total statewide EUI conservation potential over the course of the study. Clarifying that large natural gas facilities are eligible as electric utility assets can enable utilities to pursue approximately 213,951 MWh of conservation potential between 2020 and 2039. The significance of the impact of the competing interpretations of statute demonstrate the value of clarifying eligibility with policy guidance. Table 6-7 summarizes the impact of large natural gas facilities on EUI conservation potential in the state.

Table 6-7 Effect of Natural Gas Facility Eligibility on Generation Sector Achievable Potential

Utility Type	Equivalent MWh – All NG Eligible	Equivalent MWh – Large NG Facilities Exempt	Percentage Reduction in Achievable Potential if Large NG Facilities Exempt
IOU	509,022	394,997	22.4%
COU	277,060	177,833	36.0%
Total	**786,782**	**572,831**	**27.2%**

Alternative Policy Modeling Option

The team also considered modeling the impacts of allowing EUI conservation expenditures to count toward the shared savings financial incentive mechanism established by the Public Utilities

Commission[50]. The assumed impact of that policy change would have been to improve the economic viability of EUI projects, effectively unlocking some of the technical potential for economic and achievable pursuit. However, further discussions revealed that such a policy change may have significant second-order effects. Further, the practical impacts of the change may be reflected in utility decision-making in terms of competition for capital among projects rather than directly improving the economics of individual projects. Therefore, the attempt to model impacts was deemed outside the scope of this study and the discussion was referred to the DOE policy analysis project for further discussion and possible recommendations in the near future.

50 Minnesota Statute §216B.16, subdivision 6c

7 Appendix A: Useful References for Utilities

Below is a list documents that may be useful for utilities to reference when looking into implementing EUI projects. References used to develop the report are shown in footnotes and are not necessarily the same as the references below.

Minnesota-specific resources

Minnesota EUI Efficiency Projects webpage. (https://www.mncee.org/mnsupplystudy/home/)

Minnesota PUC Grid Optimization Proceedings (including Integrated Distribution Planning) – Docket CI-15-556.

Minnesota Technical Reference Manual (including EUI measures) (http://mn.gov/commerce-stat/pdfs/mn-trm-v2.1.pdf)

EUI Policy Guidance concerning 5-year carry-forward provision and clarification of DSM 1-percent threshold to enable EUI eligibility. Deputy Commissioner's Decision, Filed Date in Docket No. E,G999/CIP-17-856

Policy Guidance concerning the determination of "Normal Maintenance" baseline and outline of EUI project review process. Open for comment as of 8/23/2018. Docket CIP-18-543

Integrated Resource Plans. Examples include those filed on Dockets: EU15/RP-15-690 (MN Power), ET15/RP-17-753 (SMMPA), ET2/RP-17-286 (Great River Energy), E002/RP-15-21 (Xcel Energy)

Utility Infrastructure Improvements for Energy Efficiency. Franklin Energy. Prepared for MN Department of Commerce. 2010.

Relevant EPRI technology studies

Demonstration of Advanced Conductors for Overhead Transmission Lines, prepared for California Energy Commission, July 2008. http://www.energy.ca.gov/2013publications/CEC-500-2013-030/CEC-500-2013-030.pdf

Range and Applicability of Heat Rate Improvements. EPRI, Palo Alto, CA: 2014. 3002003457 (https://www.eenews.net/assets/2014/08/14/document_gw_01.pdf)

Capital and Maintenance Projects for Efficiency Improvements. EPRI, Palo Alto, CA: 2009. 1019002

Production Cost Optimization Project 2010. EPRI, Palo Alto, CA: 2010. 1019704

Efficiency Improvement for Cycling Service. EPRI, Palo Alto, CA: 2010. 1021205.

Heat Rate Improvement Program Guidelines. EPRI, Palo Alto, CA: 2012. 1023913.

Evaluation of Remote Monitoring for Heat Rate Improvement. EPRI, Palo Alto, CA: 2011. 1023075.

Green Circuits: Distribution Efficiency Case Studies. EPRI, Palo Alto, CA: 2011. 1023518

For a summary of an EPRI presentation to stakeholders, see: Minnesota EUI Statewide Energy Efficiency Policy Review Stakeholder Meeting #1 – EUI, Technologies. GDS, July 28, 2017. (https://www.mncee.org/getattachment/MNsupplystudy/Committee-Work/FINAL_Stakeholder-Meeting-1-combined-slides.pdf.aspx)

Other relevant technology studies

Analysis of Heat Rate Improvement Potential at Coal Fired Power Plants. EIA. May 2015. (https://www.eia.gov/analysis/studies/powerplants/heatrate/pdf/heatrate.pdf)

Tomorrow's T&D: The most economical energy savings might be found in grid efficiency. Forsten, K. *Public Utilities Fortnightly*. February 2010. (http://www.fortnightly.com/pubs/02012010_TomorrowsTD.pdf)

Power Loss Management for the Restructured Utility Environment, Second Edition. NRECA. 2004.

The Impact of Improved Transmission System Efficiency and Utilization on Reducing Electricity Industry Carbon Footprint. CIGRE: 2012. C3-211

CVR Case studies

Analysis of Sacramento Municipal Utility District Conservation Voltage Reduction (CVR) Tests: June 2013 – June 2014. EPRI, Palo Alto, CA: 2014. 3002004930.

Evaluation of Conservation Voltage Reduction (CVR) on a National Level. KP Schneider, JC Fuller, FK Tuffner, R Singh. 2010. (http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf)

Costs and Benefits of Conservation Voltage Reduction: CVR Warrants Careful Examination. NRECA-DOE Smart Grid Demonstration Project Final Report. DE-OE0000222NRECA. May 31, 2014. (https://www.smartgrid.gov/files/NRECA_DOE_Costs_Benefits_of_CVR_0.pdf)