

Can Electrification Find a Sweet Spot? Summarizing field data from electrification audits in commercial and industrial buildings.

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ABSTRACT

The allure of electrification is irresistible to many lawmakers, utilities, regulators, and environmentalists – carbon reductions, cost savings, environmental benefits: What’s not to like? But electrification’s success will depend on customers choosing to implement opportunities that are both cost-effective and address their business needs. Very few customers are going to gut fossil-fueled equipment for electric equipment without a convincing value proposition. Here, in the upper Midwest, the reality of low-cost natural gas and heavy-duty heating seasons leave customers justifiably cautious. The value proposition in new construction is frequently compelling with current market conditions, but for electrification to achieve its ambitions at least some existing buildings are going to need to retrofit fossil-fueled heating and process equipment.

This paper compiles measure recommendations from electrification audits conducted in four states to share which measures make the cut in retrofit applications. The field data can help others identify which combination of fuel source, rates, demand, equipment age, and performance can pass muster for commercial customers. Through follow-up conversations after the audits, the researchers are identifying which features of the identified solutions best address customer concerns and present project benefits that resonate with their needs. This paper summarizes the array of solutions and discusses the savings and financial benefits. It also provides recommendations on how to sell customers on electrification projects and how utilities can partner with customers on building electrification strategies in this sector.

Introduction

It only takes a skim through any conference preceding to see that electrification is a hot topic in the energy efficiency and utility industry. Technologies promise a new frontier of low carbon dioxide emissions and efficient end-uses that can replace fossil fuels across the economy. For a few sectors (residential space and water heating, new home construction, and vehicle electrification) electrification strategies are reaching the point of fairly clear consensus on the value proposition, allowing the focus to pivot toward the implementation of those technologies.

However, for a large swath of buildings (and their related carbon emissions) electrification technology solutions are not clear cut and neither is the value proposition. Commercial and Industrial (C&I) buildings consume 48% of energy (electricity and thermal sources) (EIA, 2022). The 33.9 quadrillion Btus of energy consumed annually in the combined C&I sector is almost three times the total energy consumed in the residential sector (EIA, 2022). This energy consumption serves a wide variety of end-uses, process loads, building

configurations, and business functions. The diversity of equipment, in form and function, results in a more complicated task to identify electrification technologies that might add value to a business. An air source heat pump water heater might be a good recommendation for a dental practice, but not for a commercial laundry facility. A paint booth might be able to integrate ultraviolet light to speed the paint drying, but existing processes or infrastructure could require upgrades to equipment across the entire line. Additionally, the value proposition of electrification needs to be profitable. All consumer sectors are sensitive to costs, but expectations of very quick simple paybacks (often as little as one or two years) are common. Many electrification technologies are capital intensive, making quick payback a challenge for adoption.

So, the challenge for the electrification of C&I facilities is this: 1) identify which technologies will be appropriate for the unique circumstances of each facility and 2) present those ideas in a way that passes economic and management thresholds for the customer. This paper will provide examples of projects that met those criteria from electrification studies conducted at facilities in the upper Midwest (Iowa, Minnesota, South Dakota, and North Dakota). Based on that data set the authors discuss insights into the cost and emissions drivers of measure selection, customer motivation, and ideas for program development.

Background

The fieldwork for the research came from customer electrification studies conducted under two programs. In the following section, we provide some context for the research objectives of each program and some background around the customer facilities studied.

Otter Tail Power Electrification Studies

Otter Tail Power is an investor-owned electric utility serving Minnesota, South Dakota, and North Dakota. They service 422 communities with 130,000 customers, covering 70,000 square miles. They primarily serve rural communities; the average town size served is 400 people. Roughly 50% of their communities do not have natural gas available, so in addition to electric heating being fairly common already in their territory, many customers use propane, fuel oil, or even coal for thermal energy. Because of this significant electric heating load, Otter Tail Power is a winter-peaking utility.

In 2019, Otter Tail Power developed an electrification feasibility study program. This is a marketing program for the utility, separate in both funding and scope from the utility's energy efficiency programs, because of regulatory requirements in Minnesota that prohibited fuel-switching promotion within the state's conservation improvement programs. Otter Tail developed the program as a result of feedback from customers regarding 1) dissatisfaction with current fossil fuel heating options and 2) interest in learning more about the value electric technologies could bring to their heating or processing equipment.

One unique dynamic about Otter Tail Power is that they have a robust set of rates developed around serving electric heating customers. Two rates, in particular, are commonly used to reduce the cost of electric heat. They offer a fixed time of delivery rate, which provides low-cost electricity only during the hours of 10 pm to 6 am (with, for example, an all-in cost of

\$0.043/kWh for electricity in Minnesota during the winter)¹. The rate is most applicable to electric thermal storage systems. They also offer a dual-fuel load rate, for applications where a backup fossil fuel heating system or a backup generator can pick up the load during curtailment events (all-in cost of \$0.053/kWh for electricity in Minnesota during the winter). These rates allow for electric heating to be cost-effective compared to other fossil fuel technologies. For Otter Tail adding electric heating loads under these two rates ensures that the additional load does not coincide with the system peak, which keeps the cost to serve these loads very low and improves overall system efficiency.

Facilities included in this research include a county courthouse in South Dakota, a tool manufacturing facility in North Dakota and a small regional hospital in Minnesota.

Iowa Electrification Research

In Iowa, the site data was collected as part of a research project funded by the Iowa Economic Development Council. One of the strategic objectives of the state's energy plan is to address natural gas expansion in underserved communities². It is in this context that the electrification research scope of work was developed. The project seeks to understand how the opportunity for electrification of industrial and agricultural end-uses might mitigate the need for natural gas expansion in rural areas. For some customers, natural gas supply shortages might be caused either by a lack of natural gas service or it might be caused by a lack of firm capacity on existing natural gas supply pipelines. In either case, the supply shortage limits facility and production expansion and economic development.

Cost-effective electric technologies could be leveraged to free up pipeline capacity and enable growth or enable economic development in regions without natural gas service. The field research within the project serves to identify which technologies would be specifically appropriate for Iowa's industrial and agricultural facilities and applications.

Fieldwork is ongoing for this project, but to date, four facility studies have been completed. These facilities include a grain dryer, an animal processing facility, a greenhouse, and a farm implement paint curing oven. These facilities are located across the state, within different utility service territories.

Methodology Background

The research for this paper compiled seven electrification studies conducted for different commercial and industrial facilities located in the upper Midwest. For anonymity the sites are identified by number. Table 1 below identifies each site by type and location.

¹ Otter Tail Power rate information is taken from their website:
<https://www.otpc.com/pricing/minnesota/commercial-rate-summary-mn/>

² Iowa Energy Plan: <http://www.iowaenergyplan.org/>

Table 1: Customer descriptions

Facility Number	Facility Type	State
1	Greenhouse	Iowa
2	Grain Dryer	Iowa
3	Paint Curing	Iowa
4	Meat Processor	Iowa
5	Hospital	Minnesota
6	County Courthouse	South Dakota
7	Tool Manufacturer	North Dakota

These studies were conducted between the fall of 2020 and the spring of 2022. Changes in fossil fuel pricing over the span of time as well as the geographic difference in energy pricing mean that each measure should not be directly compared to the other measures, except for within a specific customer grouping. Each measure is an evaluation of a specific technology, for a specific customer application, at a specific time. To explore some of the impacts of increasing fossil fuel prices we included a price sensitivity example in the analysis. Any energy cost data represents actual billed costs to that specific customer.

Baseline conditions also varied by customer. In some cases, existing fossil fuel equipment was expected to be used as backup equipment, in some cases, equipment upgrades were required regardless of technology, in which case, only incremental cost was used for that analysis. In one example a negative incremental cost was used because replacement equipment was required, and the electric boilers cost less than replacing the propane boilers. Beyond that unusual situation, any time where incremental cost was used for the analysis the measure is marked with a “†” symbol.

Utility rates, especially for summer peaking utilities, are designed to limit summer peak loads and are often not effective at giving customers options for their heating loads. Otter Tail Power’s heating rates are relatively unique, we found no such rates available from utilities serving customers in Iowa. This lack of pricing flexibility during the heating season made it more difficult to replace natural gas heating loads with electricity.

Analysis

The measures identified during the electrification audits varied widely. Table 2 highlights the full scope of measures identified from the fieldwork. Data includes electric savings (typically negative indicating additional electrification), natural gas, propane, or fuel oil savings, estimated project cost, estimated annual savings, and simple payback.

Table 2: Impacts from all measures recommended in studies

Facility # Measure #	Electrification Measure	Fuel Savings				Financial		
		Electrical (kWh/yr)	Natural Gas (Therms/yr)	Propane (Gal/yr)	Fuel Oil (Gal/yr)	Measure Cost (\$)	Energy Savings (\$/year)	Approx. Payback (Years)
1.1	Peak Hot Water Storage	-	500	-	-	\$40,000	\$300	133
2.1	Install Heat Pump Low Temperature Heating	(5,770)	14,000	-	-	\$200,000	\$13,000	15
2.2	Aeration Probes and Controls	12,000	-	-	-	\$35,000	\$1,600	22
2.3	Bin Aeration Controller and Transfer Unit	10,000	10	-	-	\$45,000	\$1,300	35
3.1	Heat Pump Water Heater with Pre-heat	(176,260)	14,000	-	-	\$35,000	(\$1,520)	N/A
3.2	Electric Backup and Infrared Preheat	(8,960,150)	450,000	-	-	\$750,000	(\$447,400)	N/A
3.3	Infrared Pre-Heating	(322,770)	85,000	-	-	\$43,000	\$19,000	2
3.4	Compressed air Heat Recovery	(15,790)	15,000	-	-	\$25,000	\$5,500	5
4.1	Install Electric Boiler (25% of Capacity)	(25,936,090)	1,400,000	-	-	\$1,000,000	(\$800,630)	N/A
4.2	Install Electric Superheater	(1,028,970)	450,000	-	-	\$300,000	\$230,000	2
4.3	Install Mechanical Recompressor	(859,640)	450,000	-	-	\$1,000,000	\$240,000	6
4.4	Continuous Rendering	89,000	1,950,000	-	-	\$50,000,000	\$1,290,000	39
5.1	Electric Steam Boiler †	(992,790)	-	37,000	-	(\$272,100)	\$500	N/A
5.2	Electric Hot Water Boiler and AHU Coils †	(912,070)	-	37,000	-	(\$112,500)	\$3,900	N/A
5.3	Ground-Source Heat Pumps †	(166,160)	-	41,000	-	\$980,000	\$36,000	25
6.1	Air Source Heat Pump Annex †	(45,880)	-	-	1,300	\$40,000	\$8,100	5
6.2	Dual Fuel Electric Boiler Annex †	(176,430)	-	-	3,900	\$38,000	\$2,300	16
6.3	Dual Fuel Electric Boiler w/ Air Source Heat Pump Courthouse †	(98,880)	60	-	2,900	\$52,000	\$2,800	17
7.1	Electric Storage Units †	(207,630)	-	10,000	-	\$11,000	\$600	3
7.2	Install an Electric Make-Up Air Unit †	(101,980)	-	4,600	-	\$25,000	\$600	37
7.3	Operate Process Paint Oven Using Electric Heaters	(428,690)	-	20,000	-	\$39,000	\$1,100	35
7.4	Replace Coal Boiler with Geothermal	(85,820)	-	10,000	-	\$220,000	\$2,400	92
7.5	Install an Electric Hot Water Boiler †	(215,890)	-	9,200	-	\$20,000	\$200	90

† Indicates that incremental cost was used for the measure analysis.

For the projects with Otter Tail Power's customers (facilities 5, 6, and 7) incremental cost was used as the basis of the analysis. This was done because the customers enrolled in the program because their current heating system had reached its end-of-life stage. As a result, there was an expectation that they would at least have to purchase equivalent fossil fuel-using equipment to continue operating. In some cases, we were able to justify repurposing that equipment as backup equipment, thus avoiding the upfront cost of new fossil fuel equipment (which results in negative incremental costs for measures 5.1 and 5.2).

On occasion, customers found positive electricity savings as a result of electrification. In a couple of these cases (2.2, 2.3), the measures are more standard efficiency measures but were included in the study because of being related to enabling or affecting a fuel-switching measure. In other cases, for example, in the continuous rendering measure (4.4) the savings is positive because of the increased efficiencies achieved under electrification.

Project payback was considered not applicable (N/A) for projects with either negative cost or negative savings. The simple payback on the remaining projects ranged from 2 years to 133 years.

In addition to a positive payback, customers might implement a project in order to achieve carbon emissions reductions. The CO₂ equivalent emissions (CO₂e) reduced for each project is shown in Table 3. Electricity emissions data were drawn from state-specific data published by the US Environmental Protection Agency (US EPA, 2020). South Dakota has the lowest CO₂e rate of the four states in the study at 340 lbs/MWh. Iowa's CO₂e rate is 615 lbs/MWh. Minnesota's CO₂e is 770 lbs/MWh. And North Dakota has the highest CO₂e rate of 1388 lbs/MWh.

Because of utility commitments to renewable energy and state policy, grid-level emissions reductions are expected during the useful life of the installed equipment. To approximate that a 15-year measure lifetime was applied to all of the measures. Modeled emissions data for the 15-year analysis period were gathered from the National Renewable Energy Laboratory's Cambium data for 2021 Standard Scenarios (Gagnon, 2021).

Due to the grid emissions intensity, some measures did not achieve CO₂e emissions reductions in the first year. In these cases, the baseline fossil fuel unit was less carbon-intensive than the proposed electrification alternative. Over a 15-year analysis period, all but two of those measures achieved some carbon reduction.

Finally, the cumulative emissions reduction was divided by the incremental measure implementation cost to determine the cost/ton of CO₂e emissions. The cost/ton of CO₂e avoided was not applicable for projects that resulted in increased emissions or had negative incremental cost.

Table 3: Carbon emissions from all measures

Facility # Measure #	Electrification Options:	Measure Cost (\$)	First Year Emission Reduction (tons CO2e/ year-one)	Cumulative Emission Reduction (tons CO2e/ 15-year lifetime)	Cost per ton CO2e avoided (lifetime)
1.1	Peak Hot Water Storage	\$40,000	3	44	\$911
2.1	Install Heat Pump Low Temperature Heating	\$200,000	78	1,200	\$167
2.2	Aeration Probes and Controls	\$35,000	5	63	\$560
2.3	Bin Aeration Controller and Transfer Unit	\$45,000	4	53	\$850
3.1	Heat Pump Water Heater with Pre-heat	\$35,000	5	312	\$112
3.2	Electric Backup and Infrared Preheat	\$750,000	(1,268)	(7,148)	N/A
3.3	Infrared Pre-Heating	\$43,000	350	5,785	\$7
3.4	Compressed air Heat Recovery	\$25,000	80	1,235	\$20
4.1	Install Electric Boiler (25% of Capacity)	\$1,000,000	(3,110)	(12,133)	N/A
4.2	Install Electric Superheater	\$300,000	2,148	34,167	\$9
4.3	Install Mechanical Recompressor	\$1,000,000	2,221	35,049	\$29
4.4	Continuous Rendering	\$50,000,000	11,268	171,749	\$291
5.1	Electric Steam Boiler †	-\$272,100	(410)	116	N/A
5.2	Electric Hot Water Boiler and AHU Coils †	-\$112,500	(360)	396	N/A
5.3	Ground-Source Heat Pumps †	\$980,000	200	3,374	\$290
6.1	Air Source Heat Pump Annex †	\$40,000	(20)	59	\$678
6.2	Dual Fuel Electric Boiler Annex †	\$38,000	(80)	42	\$902
6.3	Dual Fuel Electric Boiler w/ Air Source Heat Pump Courthouse †	\$52,000	(40)	149	\$349
7.1	Electric Storage Units †	\$11,000	(69)	242	\$45
7.2	Install an Electric Make-Up Air Unit †	\$25,000	(37)	89	\$281
7.3	Operate Process Paint Oven Using Electric Heaters	\$39,000	(148)	438	\$89
7.4	Replace Coal Boiler with Geothermal	\$220,000	10	665	\$331
7.5	Install an Electric Hot Water Boiler †	\$20,000	(81)	136	\$147

† Indicates that incremental cost was used for the measure analysis

Finally, a key driver of project cost-effectiveness is the fuel costs. Since these studies were conducted natural gas and propane costs have increased as a result of global volatility. In Table 4 we have escalated the cost of the fossil fuel input by 25% and 50% from the base cost, to show how that cost increase affects overall project return and project simple payback.

Table 4: Project sensitivity to increased fossil fuel prices

Facility # Measure #	Electrification Options:	Baseline		25% increase in fossil fuel costs		50% increase in fossil fuel costs	
		\$ Savings	Simple payback	\$ Savings	Simple payback	\$ Savings	Simple Payback
1.1	Peak Hot Water Storage	\$300	133	\$375	107	\$450	89
2.1	Install Heat Pump Low Temperature Heating	\$13,000	15	\$16,398	12	\$19,793	10
2.2	Aeration Probes and Controls	\$1,600	22	\$1,600	22	\$1,600	22
2.3	Bin Aeration Controller and Transfer Unit	\$1,300	35	\$1,302	35	\$1,305	34
3.1	Heat Pump Water Heater with Pre-heat	(\$1,520)	N/A	\$790	44	\$3,100	11
3.2	Electric Backup and Infrared Preheat	(\$447,400)	N/A	(\$373,150)	N/A	(\$298,900)	N/A
3.3	Infrared Pre-Heating	\$19,000	2	\$33,025	1	\$47,050	1
3.4	Compressed air Heat Recovery	\$5,500	5	\$7,975	3	\$10,450	2
4.1	Install Electric Boiler (25% of Capacity)	(\$800,630)	N/A	(\$569,630)	N/A	(\$338,630)	N/A
4.2	Install Electric Superheater	\$230,000	2	\$304,250	1	\$378,500	1
4.3	Install Mechanical Recompressor	\$240,000	6	\$314,250	3	\$388,500	3
4.4	Continuous Rendering	\$1,290,000	39	\$1,614,600	31	\$1,936,374	26
5.1	Electric Steam Boiler †	\$500	N/A	\$11,138	N/A	\$21,775	N/A
5.2	Electric Hot Water Boiler and AHU Coils †	\$3,900	N/A	\$14,538	N/A	\$25,175	N/A
5.3	Ground-Source Heat Pumps †	\$36,000	25	\$47,788	21	\$59,575	16
6.1	Air Source Heat Pump Annex †	\$8,100	5	\$8,799	5	\$9,498	4
6.2	Dual Fuel Electric Boiler Annex †	\$2,300	16	\$4,396	9	\$6,493	6
6.3	Dual Fuel Electric Boiler w/ Air Source Heat Pump Courthouse †	\$2,800	17	\$4,383	12	\$5,942	9
7.1	Electric Storage Units †	\$600	3	\$5,975	2	\$11,350	1
7.2	Install an Electric Make-Up Air Unit †	\$600	37	\$1,729	14	\$2,859	9
7.3	Operate Process Paint Oven Using Electric Heaters	\$1,100	35	\$6,010	6	\$10,920	4
7.4	Replace Coal Boiler with Geothermal	\$2,400	92	\$4,855	45	\$7,310	30
7.5	Install an Electric Hot Water Boiler †	\$200	90	\$2,459	8	\$4,717	4
	Average	\$26,507	26	\$63,646	15	\$100,661	11

† Indicates that incremental cost was used for the measure analysis.

Discussion of Results

The first observation from the measure collection is that there is a wide range of project costs, project benefits, and payback thresholds. Each of these measures reflects a specific customer's needs and operation, and the variety among the population is large. There are very few generalizations that can be made about general electrification opportunities for C&I customers. This diversity is one of the reasons these studies are being conducted so that specific

opportunities can be developed for specific customers instead of making assumptions about the fit and readiness of technologies for whole customer sectors.

A second observation is that there are some clear winning ideas for electrification among this list with strong financial benefits. There are also projects that can't make that strong financial case. For projects with negative cost savings, there might be a non-energy benefit for the customer pursuing the measure, but the negative cost will be a clear challenge for the project to overcome.

As a society, we need to address opportunities to reduce carbon emissions at the lowest cost per ton. In these electrification scenarios, the cost per ton expressed is the total project cost (what a customer would pay to implement the carbon reduction strategy) not the acquisition cost (what a program administrator would need to pay in a rebate to incentive the carbon emissions reduction). For most of these projects, the cost per CO₂e ton is affordable. To provide context, consider that the International Monetary Fund estimates the social cost of carbon is \$50/ton (that describes the financial impacts of emitting that carbon) and the cost of migration ranged from about \$130/ton to \$25/ton depending on the technology (from solar thermal on the high end to onshore wind on the low end) (Gillingham, 2019).

In contrast, excluding projects from the list that did not reduce carbon emissions, electrification projects achieved carbon emissions reductions at a cost of between \$7/ton and \$911/ton, with a median cost of \$281/ton. This cost could be reduced by calculating the figure based on the incentive that a program might need to pay to procure the resource (though paying a rebate, for instance) instead of the full incremental first cost. However, it should be made clear that not all projects reduced carbon emissions. Grid emissions from electricity are too high for some projects to net carbon reductions. And other projects only reduced emissions over a 15-year measure life, which results in low overall impact and a higher cost/ton.

Finally, low-cost electricity or, inversely, high-cost fossil fuels significantly drove project affordability and return on investment. The availability of a low-cost heating fuel rate enabled conversions where standard utility rates would have prevented the project. An example of this is the grain drying operation. The customer receives electricity from a cooperative utility in Iowa, and the utility does not have a rate class that would allow the customer to affordably use electricity for grain drying. Grain drying is a seasonal load, usually from September through November during the harvest season. This period of the year is a low demand period for the utility, so in general, the additional kWh use would not impact the utility peak or increase their generation costs significantly. As a result, grain drying would be a desirable load, however, the cooperative utility would need to develop a targeted rate that provided low-cost electricity only during the grain drying season.

Recommendations

Customer Motivation

Key among the lessons learned in conducting this batch of electrification audits is that customer motivation is different when considering whether to implement an electrification project as compared to an energy efficiency project. Customers' planning horizons and their

consideration of non-energy benefits play a more significant role in determining the project value. While the emphasis on cost savings remains consistent, the focus on the long-term investment nature of electrification allows for a different planning horizon.

Our typical metrics of kWh saved, and simple payback become more complicated after considering the change in fuel costs over time and expected reductions in the carbon intensity of electricity. Electric technologies installed today could be supplied with 100% renewable energy, if the customer selects a utility program, such as a renewable energy tariff, or has on-site generation. However, even if they do not opt for additional renewable energy the grid in the upper Midwest is becoming greener with significant amounts of low-cost wind and solar being added each year and nearly all coal plants in the region are scheduled for retirement.

In Otter Tail Power's territory, two of the customers who received recommendations have made plans to move forward with the implementation of electrification measures. In both cases, their motivation was a combination of dissatisfaction with their current fossil fuel system and the opportunity to move to a more consistent cost without the same exposure to price fluctuations. Otter Tail Power's low-cost dual fuel rate allowed both customers to achieve an affordable solution by installing backup generation or finding other acceptable backup plans. In the case of the tool manufacturer in North Dakota, they were using a coal-fired boiler which they were particularly interested in scrapping because of how dirty the coal dust made their site and facility. They also struggled to find qualified service technicians as few other facilities operate using coal. These non-energy benefits were significant motivations for that customer moving forward. The other customer, a county courthouse in South Dakota, installed air source heat pumps and plans to install an electric boiler to replace propane heat as their primary heating source while keeping the propane system as a backup. The major motivation for the courthouse was a chance to modernize its systems, lowering cost and kBtu per square foot per year while also providing cooling. Before the installation of heat pumps, the building was only partially cooled with window air conditioning units.

This discussion of non-energy benefits and their motivating role also bleeds into a discussion of holistically addressing customers' facility needs. The energy efficiency paradigm, in general, seeks to minimize fuel use within the buckets of assigned fuel use. For instance, if a customer uses natural gas for heating, the auditor finds ways to reduce that natural gas use while retaining the fuel for heating purposes. In an electrification program, the auditor is freed from that convention and able to think about how best to use the Btus required for comfort and/or productivity in ways that produce the best results for the customer. This is a paradigm shift for program delivery and for measure identification. Oddly though, it is less of a shift for customers, who hardly care what energy source they use as long as their operational needs are met or improved.

Finally, it's worth addressing price as a motivation. Obviously, customers communicate that they are motivated by price, and most of the decision-making we ask the customer to do in the context of energy efficiency is narrowly focused on return on investment. However, customers are also motivated by the perception of price. Customers who perceive propane to be expensive are more motivated to reduce their dependence on it. Customers, as well as their engineers and trade allies, often assume an electric heating solution will be more expensive to

operate and therefore don't explore the nuance of rates available at a utility. Trade allies who use rules of thumb to estimate that geothermal projects are expensive don't explore them deeply enough to determine if there are ways to moderate that cost.

Additionally, from a cost perspective, there is a value to having a steady operating cost as compared to the potential volatility of propane or fuel oil costs. As shown in Table 4, an increase in fossil fuel costs can greatly shift the overall financial feasibility of an electrification project. Equally, a more affordable electric rate can improve the cost-effectiveness of other measures.

Ideas for program development

In the upper Midwest, utility programs are the most likely entity to develop electrification programs providing direct incentives and/or technical assistance funding to support and meet customers' needs. In the case of Otter Tail Power, a small pilot program has worked with three customers and could work with more customers in the future. Further program development might be possible in Minnesota now that a long-standing prohibition on fuel switching within the efficiency programs has been shed (Arnold, 2022). However, outside of MN, other utilities struggle to address how to claim savings in fuel switching situations, which can be a barrier to paying out incentives. Depending on the state there may be other market actors seeking to influence the electrification of commercial and industrial facilities, including state and local governments, building code officials, trade allies, and equipment manufacturers.

Utility program development could use a variety of strategies, the work in this study does identify a few key lessons learned. One goal of utility programs in the future might be to help customers holistically address energy consumption, or specifically carbon emissions, through electrification and efficiency simultaneously. These goals are sometimes conflicting (for instance an electric boiler could be supplied with 100% renewable electricity today but would increase the total energy consumption for the facility). In navigating these elements, here are some C&I market sector insights to consider:

- Provide technical assistance/engineering studies early in the replacement cycle for long-term planning. Customer equipment will not be fully depreciated, and customers may not act immediately as a result. The alternative of waiting until equipment is near or at failure closes the window for outside-the-box approaches.
- Utilize the full variety of rates available to your utility to provide more affordable electrification options for non-peak periods. Managing energy rates (with backup fossil or backup generation) can be a strategy for lowering the operating cost of electric equipment throughout the year while preventing any additional load during system peaks. The reliability benefits of backup generation can serve as an additional feature in critical facilities (like rural schools or hospitals).
- Develop rates that can support electrification. For the grain dryer in rural Iowa, their electric cooperative did not have an electricity rate affordable enough to justify switching to electricity for grain drying. Since grain drying is a seasonal activity, the utility could offer a much lower cost rate without impacting their peak. A utility could control the meter so that only grain drying or seasonal usage was charged at that affordable rate.

- Trade ally education is essential. Frequently the authors have seen electrification projects, in particular ground source heat pump projects, not get off the starting blocks because of contractors using generic rules of thumb to dismiss projects.
- To the extent possible, standardize incentives with other utilities in the region to help create some market certainty for contractors working in your region.
- Market the program directly to customers in one-on-one meetings. Mass marketing of electrification is challenging because of the mix of baseline conditions. Customers with natural gas service are likely to have difficulty implementing electrification without incentives, financing, detailed utility rate design, and non-economic drivers.

Conclusion

Electrification strategies and implementation in the C&I sector are less fully developed than in the residential, new construction, and transportation sectors, however, the measures identified in these facility assessments indicate that there is potential for cost-effective carbon reduction from electrification in this sector as well. Those measures will need to be tailored to their specific business needs and operation and will need to deliver cost savings in order to be seriously considered by this financially minded sector of customers.

However, the sophistication of customers yields opportunities for complicated installations which can limit the amount of impact on the utility peak while reducing energy costs and carbon emissions for the majority of operating hours. Utility programs can be a valuable tool to provide technical assistance and project funding, as well as uniquely well-positioned to help customers understand rate optimization. Given the long-term investment horizon and the benefits of early planning from a customer perspective, now is the right time to begin these conversations with customers and develop program offerings.

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