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Ameren Illinois Company 2020 Business Program Impact Evaluation Report

Appendix D - Custom Initiative Project Reports

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Appendix D. Custom Initiative Project Reports

In this section, we present detailed project-level desk review, remote measurement and verification (M&V), and on-site M&V reports for 15 Custom Initiative projects evaluated as part of the 2020 Business Program impact evaluation.

Project 1800690

Project ID#:	1800690
Measure:	AHU Scheduling
Ex Ante Savings:	183,542 therms
Facility Type:	University/College
End Use:	Heating & Cooling
Sampled For:	Gas Savings
Wave:	3

Measure Description

This project involves adding new DDC controls to four campus buildings to allow for scheduling of their air handling equipment. These air handers were running continuously and were using steam heat in all four buildings, and chilled water from the central plant for cooling in three of the four buildings. Chilled water is generated with three steam turbine driven chillers, so cooling reductions as a result of shutting equipment off saves natural gas.

Key Findings

A billed data regression analysis does show the campus saving natural gas energy at the time this project was implemented. The evaluation team found the implementation team's calculations reasonable and without major errors, and because the regression indicated similar savings, no adjustments were made to the ex ante savings.

Table 1. Summary of Project 1800690 Savings

DDC Controls Scheduling	Therms
Ex Ante	183,542
Verified	183,542
Realization Rate	100%

Summary of the Ex Ante Calculations

The ex ante savings were based on spreadsheet calculations, but ultimately the claimed savings is based on the savings cap less two other projects claimed around the same time (1800689 & 1800623) which account for 162,678 therms. The implementation team converted the HVAC incentive cap ($415,463) to natural gas using a cost per therm of $1.20/therm to estimate savings of approximately 346,220 therms. After subtracting out the other projects implemented at the same time, the implementation team calculated a savings cap of 183,542 therms, which was used for the ex ante as it was lower than the spreadsheet savings.

The spreadsheet calculations use a set of hourly tables in the form of schedules (e.g. summer, break, fall session, spring session, etc.) and Typical Meteorological Year 3 (TMY3) weather data. The implementation team calculated the various states of the air handling unit (e.g. mixed air temp, supply air temp, etc.) for each hour of the year depending on a series of inputs. The baseline and proposed calculations use the same set of hourly calculations, but the baseline calculation adds all hours of the year, while the proposed only takes the sum of the hours within the scheduled periods.

Measurement and Verification Plan

The following is the unedited version of the original measurement and verification plan:

This project will be verified with a remote site visit. The customer will be asked to join the evaluation team in a teleconference to go over the details of the project and allow our team to observe the operation of the energy management system and ask about any relevant trended data that may be available.

Specific questions for the site contact include:

- When was the project started and completed?
- When is/was chilled water available on campus?
- When is/was steam available on campus?
- What are the system types?
  - What is ZRH-HHW? (constant volume reheat?)
  - What is HD-HHW?
  - What is MASZ-CV?
- Which units were scheduled?
  - What is the current schedule for each unit?
    - How much variation is there in the summer compared to the school year?
  - Has that been impacted by COVID? If yes, what would the schedule be otherwise?
  - What setback temperatures are now used?
- How were the units previously controlled?
  - Was there any fan speed control on any of the equipment?
  - Did all units have functioning economizers?
  - How was discharge air temperature controlled before the new DDC?
  - How is discharge air temperature controlled after the new DDC?
  - How were terminal reheats controlled?
  - How are the terminal reheats controlled now?
- How is the natural gas steam boiler controlled? How is the coal boiler controlled?
- Is there any additional cooling available in the chilled water plant besides the absorption chiller?
  - If so, how often is it used?

- December and January natural gas usage seems surprisingly low. Do you have any ideas why that might be?
  - November usage always seems to be the peak of gas usage, do you know why that might be?
- What other projects have you done over the last few years that may have saved natural gas usage?
- How has COVID impacted operations?
- How do you expect things to change once COVID is over?

Description of Verification

The evaluation team contacted the SIUC site contact. The site contact provided details as well as additional steam generation data for both the campus coal and natural gas boilers, as well as screenshots and trend data of the new building automation system showing the new controls in operation.

The site contact confirmed that they have aggressive night setback temperatures in zones with DDC thermostats (55°F heating and 85°F in cooling) so the evaluation team agrees that it is unlikely these systems cycle on much during the unoccupied periods. There are still several units that have pneumatic thermostats, so these units will not cycle on at all. The contact also mentioned that the system now has an optimal start period with ventilation that comes on a minimum of two hours before the occupied period, while under non-COVID-19 conditions the optimal start would be scheduled to come on a minimum of 20 minutes without ventilation before occupancy. These changes were reflected in the ex ante spreadsheet calculation.

The site contact also confirmed that scheduling was the only measure implemented at this time, although they are considering adding other resets, particularly for the units that have DDC VAV boxes.

Finally, the site contact did confirm the details of the campus plant. There are three steam turbine driven chillers and one electric chiller. The electric chiller is small and is only used in the winter periods when chilled water demand is low. All excess steam is condensed out using cooling towers and condensate is piped back to the central steam plant. He also confirmed that they have a large coal boiler which is base loaded, and the natural gas steam boiler picks up most of the variable capacity load. All buildings except Pulliam use central chilled water.

The evaluation team verified that the schedules shown in the virtual inspection report were consistent with the values in the calculation.

Verified Savings Calculation Description

First, the evaluation team reviewed the savings calculations. We identified a few issues such as the fact that the calculation does not factor in the energy required to return the building back to occupied temperature setpoints. However, overall the calculation was robust and did not have any significant errors. Because the calculation was ultimately not used due to the gas savings cap, the evaluation team did not adjust the savings calculation to account for the small issues identified as it would not have impacted the results.

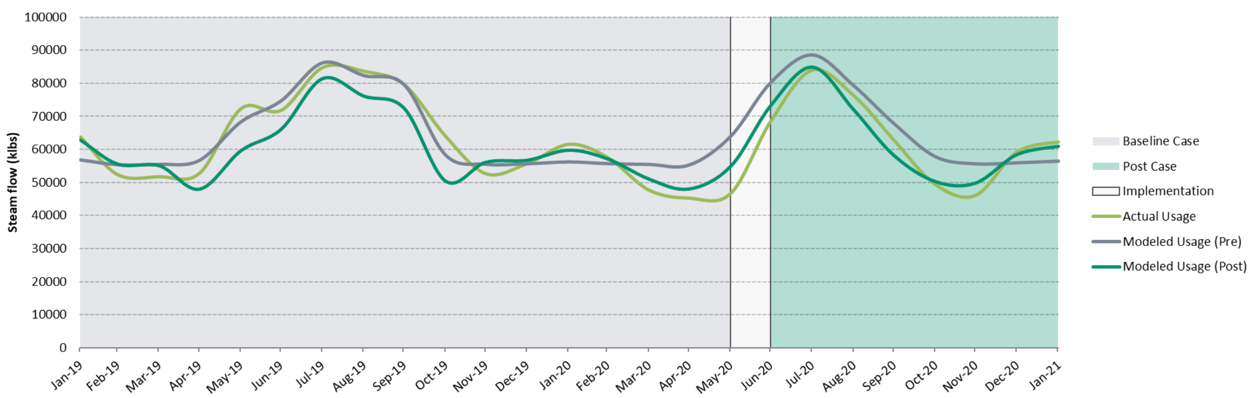
Next, the evaluation team did a set of rough calculations to verify savings were reasonable based on the size of the equipment and the extent of the shutdowns. These calculations showed that the savings values were reasonable.

Finally, the evaluation team used campus steam usage (klbs) provided by the site contact to create a usage regression. The regression had good fits (R^2=0.91 in the baseline and R^2=0.90 in the proposed case) and appeared to model the steam usage accurately. This regression showed average savings of approximately

422,000 therms. However, this regression includes the coal boiler usage, and the savings in several months exceed natural gas usage. To account for the coal boiler, the evaluation team made an adjustment to reduce the monthly gas savings based on the typical base loading of the coal boiler over the last 2 years, which reduced the expected savings to 234,000 therms. We then made an adjustment to the savings to account for the other two measures (the large 136,000 therm project was only in operation starting in December 2020, while the 26,000 therm project was assumed to have been generating savings throughout the post period). This adjustment brought the regression savings down to 174,000 therms, which is very close to the ex ante claimed savings.

The final comment the evaluation team has is that it the regression showed savings starting in March 2020 as shown in Figure 1. Because this coincides with the beginning of COVID-19 shutdowns, those first few months of savings may be anomalous.

Figure 1. Regression Models Compared to Actual Usage



Ultimately, the regression savings were not used to adjust the savings for this project for two reasons:

- It is unclear to us the extent that the impact of COVID-19 had on the project savings. While the campus ran all buildings as if they were regularly occupied, the campus population dropped by an estimated 2/3rds, so the loads on the building systems were impacted. It is unclear how this reduction of load impacts savings because reducing loads in the buildings will have somewhat offsetting impacts in the cooling and heating seasons.
- The project was not completely finished until a final building (Neckers) was completed in November. While this building was small compared to the others, its impact does not show up entirely in the regression analysis.

For these reasons, the evaluation team is confident this project has engineering merit and is accruing savings but does not have enough confidence in our analysis to adjust the ex ante savings.

Project 1900257

Project ID#:	1900257
Measure:	VSD Air Compressors
Ex Ante Savings:	659,747 kWh; 76.8 kW
Facility Type:	Manufacturing/Industrial
End Use:	Compressed Air
Sampled For:	Electric Savings
Wave:	1

Measure Description

This project consists of the replacement of an existing compressed air system serving a manufacturing facility. The existing system included three fixed-speed, lubricated, rotary-screw compressors, including one 125 HP compressor with load/no load controls, one 150 HP compressor with inlet modulation with blowdown, and one 200 HP compressor with inlet modulation control. Each compressor had dedicated controls with no central system to control compressor operation or sequencing.

The existing compressors were removed and replaced with two new variable-speed, lubricated, rotary-screw 100 HP compressors with 457 CFM capacity each. A new sequencer was installed with the new system to control compressor operation.

The project also included a system-level flow control valve and the replacement of the existing refrigerated air dryer with a cycling refrigerated air dryer. No savings were claimed for the new dryer or flow controller, but the reasons for not including savings for that equipment were not explained in the project documentation.

Summary of the Ex Ante Calculations

The implementation team established project savings using metered data from the old (baseline) system. The team collected baseline compressor current (amps), system pressure (psig), and total system flow (CFM) at 12-second intervals for a 1-week period from November 11 - 19 of 2018. The implementation team sorted total system flow (CFM) into bins and calculated the frequency of the system's operation in each bin. They then allocated flow (CFM) to each compressor for each bin. The calculation used compressor flow (CFM) to estimate compressor power for each bin based on the unloading curves for each unit's capacity controls.

The implementation team then calculated total average baseline power (kW) as the weighted average of total compressor power for each flow (CFM) bin, resulting in an average baseline power demand of 170.8 kW The implementation team estimated that the compressed air system operated 8,592 hours per year, so total baseline energy usage was calculated as the product of baseline average power and annual hours of use, or 1,227,964 kWh per year.

The implementation team modeled the new compressor system's operation using the metered data from the old system. The team first reduced flow (CFM) for each data point by 210 CFM to account for leak repairs. The leak repair project was not otherwise addressed in the project documentation, but it appears to have been part of a separate RCx project. Then, the team determined the new compressor system's power and energy usage by modeling new compressor operation. To model the new system's operation, the implementation team created a flow versus power regression model. In this model the power was the new system's power based on new unloading curves and the flow was the flow that was required in the metered data (post-leak repair). The implementation team's analysis resulted in an estimated annual energy consumption value of

568,195 kWh/year and an average power demand of 66.1 kW. The resulting estimated savings are 76.8 kW and 659,747 kWh/year.

Measurement and Verification Plan

The following was the original verification plan:

The evaluation team will verify this project through a review of documentation and calculations and a site visit to physically confirm equipment installation and assess its operation.

The site visit will include collection of compressor nameplate information, operating pressures, and other pertinent information. The type of controller installed will typically trend operating data for the compressors, including power or amperage, flow, and outlet pressures. Air flow to the system through the flow controller is also typically trended. We will request all available data from the customer.

The evaluation team will also ask the customer about operation of the new system and the facility in general, including the following questions:

- Were leak repairs done as part of this project? If not, was there a separate incentive for the repairs?
- How were the compressors originally staged? Manually? Cascading?
- Did you receive an incentive for the installation of the cycling dryer?
- What are your normal hours of operation? Have they changed as a result of the COVID-19 pandemic?
- Has production changed as a result of the COVID-19 pandemic?
- Have there been any other modifications to the compressed air system?
- Have there been any other energy savings projects completed in the last year?

If the customer reports that there has been no discernable effect due to the COVID-19 pandemic, the trended data will be used to establish the new system's energy usage and demand. If current operation is not expected to be representative of pre-COVID-19 operation, we will use the metered data from the old system to establish baseline compressor power and output flow (CFM) and to model operation of the new compressors and controller.

Instead of using a bin method, the evaluation team will calculate baseline power for each compressor for each data point and use those values to establish total hourly power demand and flow requirements (CFM) to develop a weekly profile. Specifically, we will calculate baseline power for each compressor using a linear curve fit of the metered flow (CFM) to current (amp) data. Then, for each data point, we will calculate the power (kW) requirement for the new system. New system power demand will be modeled using the flow (CFM) data available (either the original metered data or new trend data). Specifically, for each flow (CFM) data point, we will calculate the new power (kW) requirement using a curve fit to represent VFD operation.

If we verify that the leak repair reduction savings have been claimed under a separate project, we will not make any changes to the calculation to include savings from the 210 flow (CFM) reduction.

If we determine that the cycling dryer savings have not otherwise been included under a separate project and that the incentive for this project included an incentive for the cycling dryer, those savings may be calculated using metered flow (CFM) and local weather data.

Description of Verification

The evaluation team completed an on-site project evaluation on October 21, 2020. We interviewed the maintenance supervisor and verified the installation of the new compressors. The owner installed two 100 HP Sullair 7509V air compressors with variable speed drives (VSD). They left two of the old compressors in place, the 125 HP and 200 HP units, and the customer continues using them as an integral part of normal compressed air system operation. The new sequencer controls operation of the four compressors so that if air demand is greater than the capacity of the two new compressors, one of the old single-speed compressors will start up and the VSD compressors will act as the trim compressor to satisfy the remaining demand.

We discussed the operation of the new and old compressed air equipment. The customer completed installation of the new compressors, sequencer, and dryer in April of 2020. The COVID-19 pandemic initially resulted in a significant reduction in production due to reduced market demand. However, production at the plant has since returned to pre-COVID levels. Production is on a 24 hour per day, 5 day per week schedule with occasional weekend operation.

The facility ran the old compressors with on-board pressure control, with the 200 HP compressor being base-loaded and the other two compressors operating as needed to meet total air demand.

The new compressor sequencer includes trending functions, so we collected operating data for the three-week period from October 1st through October 21st of 2020.

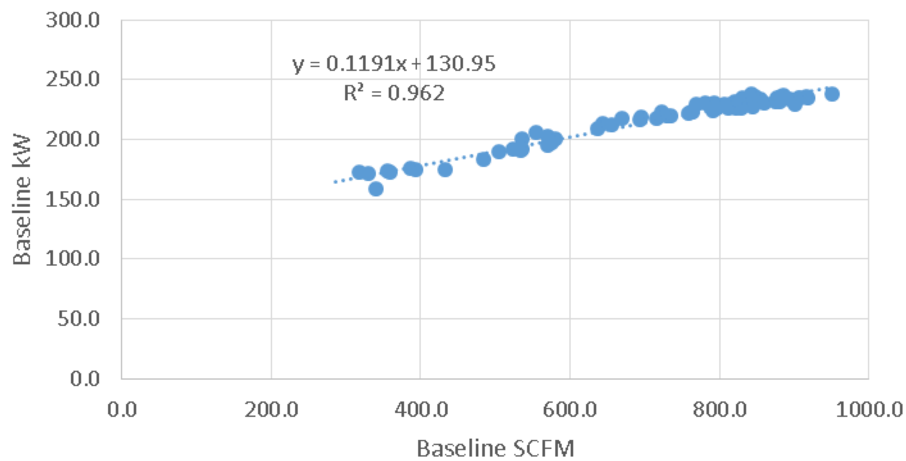
Summary of the Verified Calculations

The evaluation team used compressor data collected by the implementation team plus current operating data we collected during the on-site verification to establish operation of the baseline and new compressed air system. We observed that during the metering period with the old system running, the compressors were off on Sundays. The new compressors are now operating continuously seven days per week based on the trend data we collected. We also noted that the average compressed air volume in October of 2020 is higher than that observed during the metering period for the old system. Since the site contact reported that plant production was at near-normal levels, we assume that the three–week October period for which we collected trend data from the new system is representative of typical operation for both the baseline and the new system cases.

The evaluation team analyzed the new system data by aggregating it into hourly averages of total system flow (SCFM) and power. We established total annual compressor energy usage for the new system by extrapolating weekly usage to 50 weeks (not the full 52 per year to account for holidays). This analysis resulted in energy consumption of 1,329,220 kWh/year as opposed to the ex ante value of 568,195 kWh/year and peak power demand of 197.1 kW as opposed to the ex ante value of 66.1 kW.

The evaluation team then calculated total baseline system power for each of the data points recorded from the old system. We analyzed the data by aggregating average total compressor power and flow (SCFM) to create an hourly load profile for one-week period of operation. After removing outlier and zero values, we then developed a correlation between hourly compressor power and flow (SCFM), which can be seen in Figure 2 below.

Figure 2. Baseline Power to Flow Correlation



The evaluation team normalized baseline system operation to reflect the flow of the new system (since the site contact reported that plant production was at near-normal levels) by using the baseline correlation shown above and the new system's hourly flow (SCFM) from the trend data. This normalization allowed us to establish new values for hourly baseline compressor power and energy usage. The evaluation team then extrapolated the newly created baseline load profile to 50 weeks per year (not the full 52 per year to account for holidays).

We averaged power for the weekday periods between 1 PM and 5 PM to establish the baseline and new system peak demand.

Our calculations resulted in baseline energy consumption of 1,847,304 kWh/year and peak power demand of 240.2 kW as opposed to the ex ante values of 1,227,942 kWh/year and 142.9 kW. This new baseline and our new energy consumption and peak demand values for the new system resulted in the savings shown in Table 2 below.

Table 2. Summary of Project 1900257 Savings

Measure	kW	kWh
Ex Ante	76.8	659,747
Verified	43.0	518,085
Realization Rate	56.0%	78.5%

Project 1900500

Project ID#:	1900500
Measure:	HVAC Controls
Ex Ante Savings:	28,178.84 therms
Facility Type:	Medical
End Use:	HVAC
Sampled For:	Gas Savings
Wave:	1

Measure Description

This project covers the removal of outdated pneumatic controls, actuators, and sensors serving two air handling units (AHUs) in one wing of a medical center. The AHUs served variable air volume (VAV) systems with zone reheat, but the customer had disconnected the inlet vane controls. The contractor replaced the equipment with electronic components and local digital controllers. The contractor integrated the new controllers into the existing campus web-based building automation system (BAS). The project specifically claims savings for restoring proper economizer functionality, reducing the amount of outside air being introduced to the facility by the air handlers, installing variable frequency drives (VFDs), and scheduling operating room setbacks with reduced airflow when not in use.

Summary of the Ex Ante Calculations

The implementation team established measure savings using EnergyPlus modeling software. The team modeled the affected wing including building envelope areas and characteristics, hours of occupancy, and heating and cooling efficiencies. The wing does not have a dedicated meter, so the team prorated the facility's energy usage based on the ratio of the affected wing's area to the area of the entire facility. Based on a review of the energy model, the evaluation team believes the implementation team was aiming to achieve three measures:

- Fan schedule change for one of two AHUs:
  - Baseline = 24/7 operation
  - Measure = 7am-6pm, 7 days a week, with night cycling
- Economizer:
  - Baseline = Fixed Drybulb (limited at 65°F)
  - Measure = Fixed Enthalpy (limited at 21.5 btu/lb)
- Supply air temperature (SAT) reset:
  - Baseline = None
  - Measure = based on warmest zone resetting between 55°F and 60.5°F

Measurement and Verification Plan

The original measurement and verification (M&V) plan is as follows:

The evaluation team will verify this project through a site visit. We will interview the site contact about the operation of the building HVAC system and the new controls system. We will also review and inspect the new controls equipment. This project applies to only a portion of the total facility, so using a billed data regression to evaluate the project will not be feasible. The new controls have trending capability, so we plan to collect trend data and use it in spreadsheet-based engineering calculations to model baseline and post-project implementation conditions based on observed operation and information from the site contact on pre-project implementation operation. In the case that the trend data is not available or not representative of typical operations due to COVID-19 or some other non-routine event, we will request the ex ante simulation files to review inputs and adjust the model accordingly to match current operating conditions.

Specific questions for the site contact include:

- When was the project completed?
- What was the condition of the control system before the project was completed?
- How were the AHUs scheduled before and after the project?
- Were outdoor air dampers replaced? Repaired or otherwise altered?
- How were the outdoor air dampers controlled previous to this project?
- What are the exhaust requirements in the space and how are the exhaust systems currently controlled? How were they previously controlled?
- What were the space temperature set points before and after the project? Are there any spaces that were not scheduled as intended?
- How were the operating rooms controlled before and after the project? What air change rates were you trying to achieve in both occupied and unoccupied mode both before and after the project?
- How were the VAVs controlled prior to project? What are the current VAV minimum settings?
- Have there been any other changes to AHU controls, e.g. supply air temperature reset?
- Have operators been trained on the new control system? Who is able to change settings in the new control system?
- Have there been any other projects in the building since the controls upgrade that significantly impact the building energy use?
- What are the sources of AHU heating and cooling? What are their efficiencies?

COVID-19 specific questions may include:

- Has the operation of your facility been affected by COVID-19?
- If so, how has occupancy changed?
- Have the control settings changed due to COVID-19? If so, what changes were made to control settings, e.g. scheduling and setbacks?
- Will control settings return to proposed values when operation becomes ‘normal”? If not, what is your prediction for set points at that time?

Note that if the facility's operation was affected by COVID-19, we'll walk through the different phases of shutdown/reopening that the state has gone through and ask what changed during each phase.

Description of Verification

While the evaluation team had planned on an in-person site visit we resorted to a remote site visit due to the hospital's COVID-19 precautions. The remote site visit took place on October 29, 2020. We interviewed the controls vendor and confirmed system functions and setpoints by observing and collecting screenshots from the vendor.

We discussed the operation of the air handling equipment. The new controls do not add significant functions to the control system, but they provide enhanced remote monitoring and control. It appears that most of the savings are due to AHU damper and economizer repairs and controls. We collected trend data in order to review system functions, including fan speeds, economizer position, and mixed air, return air, and supply air temperatures. Screenshots of current operation are shown below in Figure 3 and Figure 4.

Figure 3. Surgery Room AHU Operation

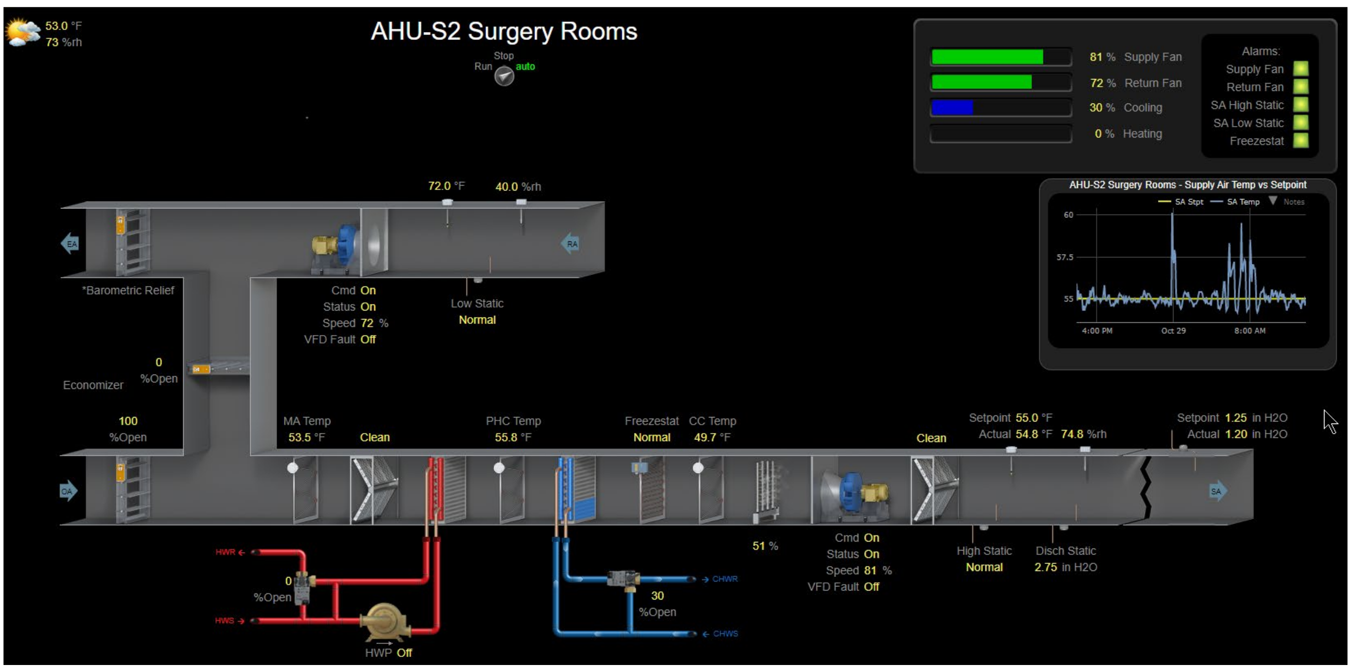
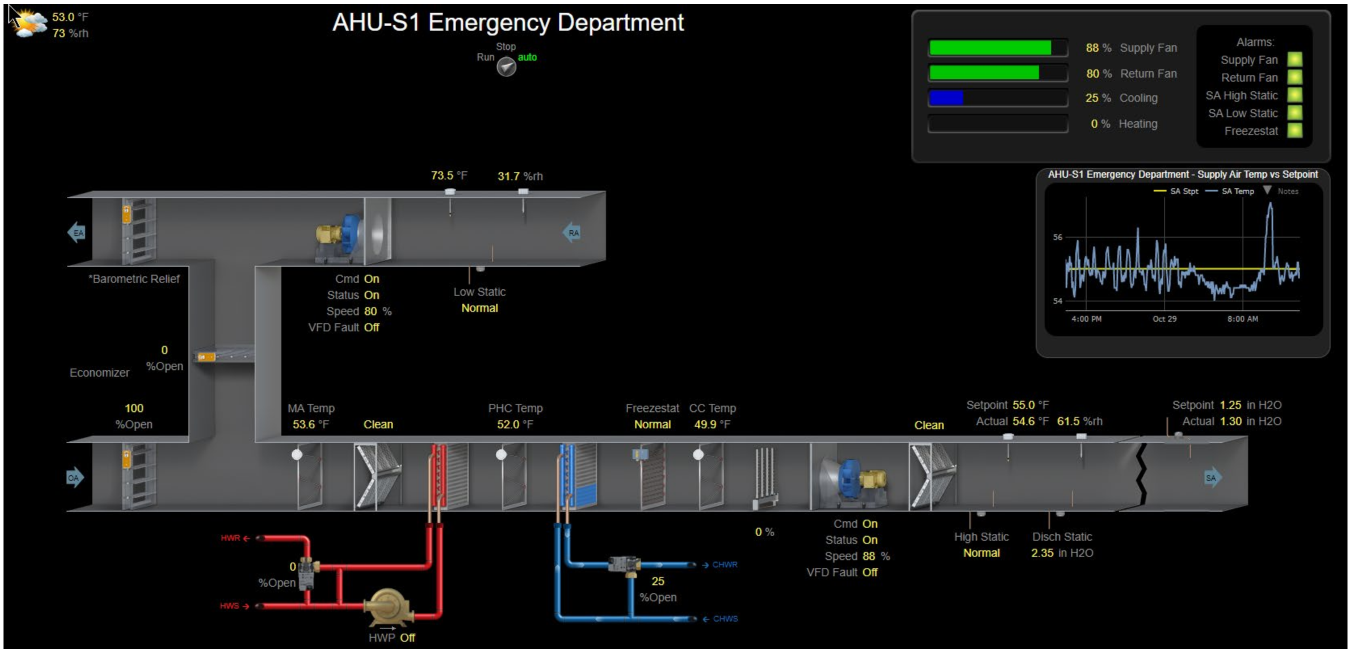


Figure 4. Emergency Department AHU Operation



Our review of trend data indicates that:

- Both AHUs are operating 24/7. It appears that there are no savings from schedule changes.
- Economizers appear to be functioning properly. Beginning in October, economizers began providing free cooling constantly—literally for weeks at a time. Plotted trend data show that the economizer cuts out at higher temperatures as programmed. Otherwise, fresh air intake does not appear to be turned down or off at any time.
- The economizer appears to be operating at times above the 65°F previous threshold.
- During the summer months, the fresh air damper position for both air handlers was 20%. It stayed in that position virtually all summer.
- Supply air temperature reset has been implemented.

Summary of Verified Calculations

The evaluation team reviewed and ran the baseline and energy efficient models created by the implementation team. While there are some inconsistencies between the models and the project files which caused us to doubt that the VAV systems were modeled properly, the evaluation team did not have enough information to make any adjustments to the models.

The evaluation team believes that the implementation team intended to include a schedule change for one of two air handlers in the energy simulation. That measure does not appear to be installed when reviewing the equipment's trend data. However, that measure was not modeled correctly so no scheduling savings were included in the ex ante calculations. Because this measure wasn't modeled correctly in the ex ante simulation, no adjustments had to be made to the verified savings. It is noteworthy that the savings from this measure would have been significant had they been modeled correctly. This would have caused the realization rate to be much lower for this project.

Only one of the two remaining measures (SAT reset) produced natural gas savings (only electric savings were claimed for the economizer measure). The savings we can see in the trend data from just the SAT reset measure appear to be comparable to the ex ante modeled savings. This level of savings seems reasonable to us given the significant amount of reheat that is required in this space. Therefore, we felt a 100% realization rate was appropriate for this project as shown in Table 3 below.

Table 3. Summary of Project 1900500 Savings

	Therms
Ex Ante	28,178.84
Verified	28,178.84
Realization Rate	100%

Project 1901411

Project ID#:	1901411
Measure:	Regenerative Thermal Oxidizer
Ex Ante Savings:	390,428.37 therms
Facility Type:	Manufacturing/Industrial
End Use:	Process
Sampled For:	Gas Savings
Wave:	2

Measure Description

This project covers the replacement of an existing catalytic oxidizer with a new regenerative thermal oxidizer (RTO). The oxidizer burns volatile organic compounds (VOCs) contained in the exhaust stream from the plant's painting processes. The new RTO will heat 6,000 cubic feet per minute (CFM) of process air to 1500ºF with 97% thermal efficiency to destroy 98% of the VOCs in the air stream.

Summary of the Ex Ante Calculations

The implementation team established measure savings using the Illinois TRM (IL-TRM) and the Institute of Clean Air Companies' (ICAC) guidance and default values where applicable. They calculated total heat input for 6,000 CFM at 242ºF RTO inlet temperature; the outlet temperature at 97% efficiency is 315.3ºF. The burner will also heat 180 CFM for combustion air, per IL-TRM Measure 4.8.11 (Efficient Thermal Oxidizers), from an ambient average temperature of 52.5ºF to the outlet temperature. The implementation team calculated the energy needs for the system as follows.

$$Energy_{Process} = 6{,}000\ CFM\ x\ (315.3ºF - 242ºF)\ x \frac{1.08\ BTU}{hr * CFM * ºF} = 474{,}864\ \frac{BTU}{hr}$$

$$Energy_{Combustion} = 180\ CFM\ x\ (242ºF - 52.5ºF)\ x \frac{1.08\ BTU}{hr * CFM * ºF} = 51{,}085\ \frac{BTU}{hr}$$

The implementation team calculated radiant energy losses from the RTO shell to be 240 BTU/hr.

As the VOCs in the exhaust stream are burned, the heat created will be recovered by the RTO and used to heat subsequent exhaust streams. The VOC load in the exhaust stream is 15 pounds per hour of toluene. The heat of combustion for toluene is 1,341 BTU per pound, so the implementation team calculated the heat released as it is burned as follows.

$$VOC\ energy\ released = 15\ lbs/hr\ x\ 1{,}341\ BTU/lb\ x\ 98\% = 19{,}713\ BTU/hr$$

The net energy required by the RTO is calculated using the following formula:

$$\begin{aligned} &Net\ energy\ RTO\ input \\ &\quad = Energy_{Process} + Energy_{Combustion} \\ &\quad + Radiant\ heat\ loss\ from\ RTO - VOC\ energy\ released \end{aligned}$$

Therefore, the implementation team calculated the net energy input for the RTO in this project as:

$$Net\ energy\ RTO\ input\ =\ 474{,}864\ BTU/hr\ +\ 51{,}085\ BTU/hr\ +\ 240\ BTU/hr\ -\ 19{,}713\ BTU/hr$$
$$=\ 506{,}477\ BTU/hr$$

The existing oxidizer was a catalytic type, so the implementation team considered the baseline to be a similar type with 40% thermal efficiency. The range of efficiencies for catalytic oxidizers (CO) is 30% to 40%, so the project baseline is at the upper limit for efficiencies. The implementation team established baseline net energy input using the same approach they used for the RTO. They used similar values for all factors, but the 40% thermal efficiency results in a 1,011.5°F outlet temperature. The baseline net energy input calculations are as follows:

$$Energy_{Process}\ =\ 6{,}000\ CFM\ x\ (1{,}011.5ºF - 242ºF)\ x\ \frac{1.08\ BTU}{hr * CFM * ºF}\ =\ 4{,}986{,}077\ \frac{BTU}{hr}$$

$$Energy_{Combustion}\ =\ 180\ CFM\ x\ (1{,}011.5ºF - 52.5ºF)\ x\ \frac{1.08\ BTU}{hr * CFM * ºF}\ =\ 186{,}421\ \frac{BTU}{hr}$$

Radiant energy losses from the catalytic thermal oxidizer are also 240 BTU/hr.

$$VOC\ energy\ released\ = 15\ lbs/hr\ x\ 1{,}341\ BTU/lb\ x\ 91\%\ =\ 18{,}305\ BTU/hr$$

$$Net\ energy\ CO\ input = \ 4{,}986{,}077\ BTU/hr\ +\ 186{,}421\ BTU/hr\ +\ 240\ BTU/hr - 18{,}305\ BTU/hr$$
$$=\ 5{,}154{,}433\ BTU/hr$$

According to the project documentation, the customer reported that "The oxidizer is always running when the paint line is running, and that's typically 6 days per week during full production, and about 5.5 days per week during slowdown period. We are also a 24-hour operation…". The plant operates 24 hours per day, 7 days per week, so the implementation team estimated annual hours of use to be 50 weeks per year, or 8,400 hours. They established the total proposed and baseline gas energy input as follows.

$$Proposed\ Gas\ Usage\ =\ 506{,}477\ BTU/hr\ x\ 8{,}400\ Hours\ /\ 100{,}000\ therms/BTU\ =\ 42{,}544\ Therms$$

$$Baseline\ Gas\ Usage\ =\ 5{,}154{,}433\ BTU/hr\ x\ 8{,}400\ Hours\ /\ 100{,}000\ therms/BTU\ =\ 432{,}972\ Therms$$

They calculated the gas savings as the difference between the two:

$$Gas\ Savings\ =\ 432{,}972\ Therms\ -\ 42{,}544\ Therms\ = 390{,}428\ Therms$$

Measurement and Verification Plan

The evaluation team will verify this project through a site visit. We will verify the installation and discuss the operation of the RTO with the site contact. We may request permission to install temporary on/off data loggers to confirm the operating hours of the RTO unless trended data or other information is available to confirm runtimes.

Specific questions for the site contact include:

- When was the project started and completed?
- What was the condition of the catalytic oxidizer before the project?
- What was the normal discharge temperature of the old oxidizer?

- What is the normal schedule for the new oxidizer?
- Has the schedule changed since pre-replacement?
- Is production seasonal? If so, how is RTO operation affected?
- How is the speed of the induced draft fan controlled?
- Are there any regular shutdowns?
- How many holidays are you closed?
- What is the status of the RTO when the paint line is not in operation, (i.e. is the RTO shut off until it is needed again)?
- If the RTO is idled on weekends, what is the warm-up period?
- What was the warm-up period for the old oxidizer?
- What is the VOC load on the oxidizer?
- Have there been any changes to the RTO's operation since its installation?
- Have there been any other projects in the last two years that significantly impact the building's gas usage?

COVID-19 specific questions may include:

- We noted that there was a plant layoff in April - has the operation of your facility returned to normal?
  - If not, how has production and oxidizer use changed compared to before the new RTO installation?
- Will oxidizer usage return to pre-project (prior to the installation of the RTO) usage when operation becomes 'normal"? If not, what is your prediction for operation at that time?

Note that we'll walk through the different phases of the COVID-19 shutdown/reopening that the state has gone through and ask what changed during each phase.

Description of Verification

The evaluation team completed an on-site project evaluation on December 15, 2020. We interviewed the Capital Project Engineer and verified the installation and operation of the new regenerative thermal oxidizer (RTO).

The RTO was commissioned and went online June 4, 2020. The existing catalytic oxidizer was not removed but was disconnected and is not available for service. The new RTO operates during working hours 24 hours per day, 6 days per week. The RTO is left in idle mode, where temperature is maintained, on Sundays and holidays. While idle mode uses energy to maintain temperature, it avoids warm-up periods for a small energy cost.

The RTO serves three separate production lines. Ductwork to each of the lines has an automatic damper that will shut off exhaust when its associated line is not in production. The RTO system draft fan has a 60 HP motor with variable frequency drive (VFD). The draft fan VFD speed is controlled by duct pressure to adjust total flow according to the number of operating lines.

The customer installed a dedicated gas meter on the line serving the RTO on August 11 and was able to provide RTO gas usage through December 14.

Summary of Verified Calculations

The evaluation team established RTO energy usage with customer-provided RTO gas consumption information and theoretical calculations.

The evaluation team estimated expected energy usage of the new RTO using the same algorithms as those used by the implementation team in the ex ante calculation, with some adjustments made based on information collected at the site. We modified the ex ante calculation's RTO combustion temperature from 1500˚F to 1620˚F to match site observations. We reduced hours of operation from 8,400 hours to 7,200 hours according to the schedule reported by the site representative. We also changed the inlet temperature from 242ºF to 160ºF as that was the inlet temperature we observed while on site. The estimated total annual proposed new RTO gas usage was 47,785 therms. We also used the RTO gas usage information provided by the customer to estimate annual RTO gas usage. The average metered gas usage was 3,989 therms per month, or about 47,872 therms per year, which confirms that our estimate for annual usage is realistic since most of the gas at this facility is used for the RTO.

For the baseline, the evaluation team assumed that the catalytic oxidizer (CO) has the same operating conditions (e.g. hours of operation and flow rates). The catalyst inside a CO allows VOC destruction at lower temperatures than for a thermal oxidizer. The normal operating range for a CO is about 650°F to 1,000°F, so we assumed that the baseline CO would operate at 1,000°F and did not include a thermal efficiency factor because no heat recovery occurs with a CO. We increased the VOC destruction rate for the baseline catalytic oxidizer to 98% as there was no data to substantiate the lower 91% used in the ex ante calculation and a brief review of manufacturers indicates that 99%+ is typical. Our calculations for the baseline condition are shown below.

$$Energy_{Process} = 6{,}000\ CFM\ x\ (1{,}000ºF - 160ºF)\ x\ \frac{1.08\ BTU}{hr * CFM * ºF} = 5{,}443{,}200\ \frac{BTU}{hr}$$

$$Energy_{Combustion} = 180\ CFM\ x\ (1{,}000ºF - 52.5ºF) x \frac{1.08\ BTU}{hr * CFM * ºF} = 184{,}194 \frac{BTU}{hr}$$

Radiant energy losses from the catalytic thermal oxidizer remained 240 BTU/hr.

$$VOC\ energy\ released = 15\ lbs/hr\ x\ 1{,}341\ BTU/lb\ x\ 98\% = 19{,}713\ BTU/hr$$

$$Net\ energy\ CO\ input = 5{,}443{,}200\ BTU/hr + 184{,}194\ BTU/hr + 240\ BTU/hr - 19{,}713\ BTU/hr = 5{,}607{,}921\ BTU/hr$$

$$Annual\ CO\ energy\ input = 5{,}607{,}921\ BTU/hr\ /\ 100{,}000\ btu/therm * 7{,}200\ hours = 403{,}770\ therms$$

The difference between the catalytic oxidizer energy consumption (403,770 therms) and the RTO (47,785 therms) results in savings of 355,985 therms as seen in Table 4.

Table 4. Summary of Project 1901411 Savings

	Savings (Therms)
Ex Ante	390,428
Verified	355,985
Realization Rate	91.2%

Project 1901698

Project ID#:	1901698
Measure:	LED Fixtures
Ex Ante Savings:	1,977,717 kWh and 442.68 kW
Facility Type:	Warehouse
End Use:	Cannabis Lighting
Sampled For:	Electric Savings
Wave:	3

Measure Description

This project is for the installation of efficient LED grow lights in a new construction indoor cannabis grow facility. The facility has three sections: base vegetation, indoor flowering, and greenhouse. This project is only for the greenhouse section, which was a change made after pre-approval. The baseline is high pressure sodium (HPS) lamps for flowering and greenhouse spaces.

Key Findings

The ex ante calculation method was reasonable. In the verified calculations, the evaluation team added an energy waste heat factor for a cooled space using IL-TRM Measure 4.1.11 (Commercial LED Grow Lights).

The resulting project savings are shown in Table 5 below.

Table 5. Summary of Project 1901698 Savings

	kW	kWh
Ex Ante	442.7	1,977,717
Verified	442.7	2,094,053
Realization Rate	100%	106%

Summary of the Ex Ante Calculations

The original ex ante calculation had light additions to the base vegetation, indoor flowering, and greenhouse areas. However, this project is only for 90,440 square feet of greenhouse. This adjustment in the ex ante calculation assumed (2,856) 1,000 W HPS baseline fixtures would be the baseline alternative for the proposed (4,284) Vypr-2P LEDs. The baseline fixture wattage was input as 1,100 W, and the proposed LED wattage was input 630 W. This resulted in a lighting power density (LPD) of 34.17 W/sf in the baseline and 19.8 W/sf in the proposed energy efficient case. Finally, a waste heat factor of 2% was used to account for the reduction in cooling load by using LEDs instead of HPS lamps. This analysis resulted in 442.7 kW demand savings and 1,977,717 kWh savings.

Summary of the Verified Calculations

Before discussing the specific details of this project, it is important to discuss the eligibility of savings claimed for cannabis lighting projects under the Illinois evaluation framework. We took the following considerations into account in our evaluation.

- The Illinois Cannabis Regulation and Tax Act (CRTA) includes energy efficiency requirements for some cannabis producing facilities. The relevant text is found in Section 20-15(a)(23) of the CRTA and indicates a specific “technology standard for resource efficiency” that must be met by facilities licensed under the CRTA, including requirements for lighting power density and HVAC.[1] The lighting density power standard required in the CRTA is quite high and requires an LED baseline for facilities subject to these requirements. The IL-TRM cites this standard and indicates a general “separate equipment definition” for cannabis cultivation facilities.
- However, this customer’s production license is one of a limited set of “Early Approval Adult Use Cultivation Center” licenses, issued under Section 20-10 of the CRTA. These licenses differ from those issued under Section 20-15, known as “Conditional Adult Use Cultivation Center” licenses.
- Notably, Section 20-15 is where the definition of the required “technology standard for resource efficiency” discussed above is provided. Section 20-10 does not include these requirements. To our understanding, there are no energy efficiency requirements currently defined by statute for cultivation facilities licensed under Section 20-10.
- This understanding is supported by notes from the March 11, 2020 Illinois Stakeholder Advisory Group (SAG) meeting at which the Illinois Department of Agriculture fielded questions from SAG on the CRTA.[2] Under Question 10 in the notes document circulated, the Department of Agriculture indicated that for early application licenses for recreational (the Early Approval Adult Use Cultivation Center licenses discussed above), quote, “Requirements were based on the Compassionate Use of Cannabis Act which meant there were not new requirements under these licenses.”

Therefore, we apply a standard practice baseline of HPS lighting for this project’s evaluation and for all other evaluations of cannabis lighting projects completed at Illinois facilities with Early Approval Adult Use Cultivation Center licenses.

The evaluation team conducted a phone interview with a site contact and the installation team for this project. The lights were installed and operating as expected. The vegetation room lights are on a timer; they are on 18 hours per day. The greenhouse and flowering room lights are on 12 hours per day. This building was not previously used for grow processes, therefore the new construction baseline is correct. The customer indicated all spaces are mechanically cooled.

The evaluation team agrees that the method for the ex ante calculation was reasonable. However, the team made one adjustment when calculated verified savings. There was a savings increase because the space is mechanically cooled, so the evaluation team applied an energy waste heat factor of 8% rather than 2%. This value is from IL-TRM Measure 4.1.11. The verified energy savings are 2,094,053 kWh.

The evaluation team calculated the coincident peak demand savings using the Illinois peak period of June through August, Monday through Friday, 1 PM through 5 PM. We calculated the coincident peak savings as the average demand (kW) savings during that period. The lights are on from 7am to 7pm, which overlaps with the coincident peak period entirely, so the demand savings are 442.7 kW.

[1] Illinois Cannabis Regulation and Tax Act: https://www.ilga.gov/legislation/ilcs/ilcs5.asp?ActID=3992&ChapterID=35
[2] Notes available online: https://ilsag.s3.amazonaws.com/SAG-Open-Cannabis-Questions_updated-3-19-2020.pdf

Project 2000077

Project ID#:	2000077
Measure:	Compressed Air
Ex Ante Savings:	441,296 kWh; 67.7 kW
Facility Type:	Manufacturing/Industrial
End Use:	Compressed Air
Sampled For:	Electric Savings
Wave:	1

Measure Description

This project changed out a fixed speed compressor with a heatless dryer and scheduled purge control to a variable speed drive (VSD) compressor with a heated dryer and dew point demand purge control. The baseline equipment was an Ingersoll Rand EPE200-2S 200 HP fixed speed rotary screw compressor and the new equipment is an Atlas Copco GA160VSD+, 215 HP rotary VSD compressor.

Summary of the Ex Ante Calculations

The implementation team used metered data for pressure (psig), flow (CFM), and total power (kW) measured every second for a one-week period, March 14, 2019 through March 21, 2019 from the existing (baseline) system to estimate baseline annual energy consumption. The implementation team calculated the average baseline power (kW) based on the metered data and then adjusted it to account for a compressed air leak repair that was not a part of the current project. The vendor estimated the leak repair resulted in a 9% reduction in pressure. After accounting for the leak repair, the implementation team estimated the baseline energy usage by multiplying the average power by the assumed hours of operation (6,135 hours/year).

The implementation team then calculated the new system's energy usage. After adjusting the baseline load profile for the leak repair, the implementation team created a flow versus power regression model. In this model the power was the new system's power based on new unloading curves and the flow profiles were based on the flow that was recorded in the metered data. This model allowed them to calculate the power (kW) required of the new system to provide the same overall flow but at a reduced pressure (due to the leak repair). The implementation team extrapolated both the baseline and new system operation parameters to the whole year, assuming that the operation of the metered week was representative of the other 51 weeks of the year.

The ex ante savings are 67.7 kW for demand and 441,347 kWh. The energy savings are due to 1) 303,682 kWh in savings from the VSD compressor reducing part load losses by 71%, 2) 137,665 kWh in savings from the dew point demand control reducing the dryer's hours of operation and 3) 25,851 kWh in savings from an assumed small (292 hour) reduction in compressor runtime. The hours that were reduced (or eliminated from the baseline) were hours where the compressor produced between 3 and 50 psi, which leads us to believe that the implementation team assumed that the new compressor would be able to start and stop more efficiently.

Measurement and Verification Plan

The evaluation team evaluated this project through a remote site visit. We planned to estimate the verified savings using the provided metered data and using extrapolation or other calculations as needed. Our team checked if production is continuing at the expected normal rate and remains unchanged due to COVID-19 or any other reason. For our remote site visit, we emailed the site contact the following questions prior to conducting the remote site visit itself:

- Is there an onboard controller that can be used to take measurements of current operating conditions (including flow, pressure and hours of operation) of the new equipment? If so, does it have any trend data we can use to better understand the current system operation?
- The calculation for the energy usage of the previous equipment used metered data from March 14th through March 21st, 2019. Is that week an accurate representation of normal production? Is that week an accurate representation of normal compressed air usage?
- There were two days of downtime, from Monday to Wednesday. How much downtime is typical, and why do you typically shut the system off?
- Does the new compressor start up and shut down more quickly than the previous one? If so, do you know if that is resulting in lower runtimes?
- What are the current operating/production hours?
- When was this project started and completed?
- Were any other (rebated or non-rebated) projects completed around the same time as this project?
- If so, did you receive rebates for any of them? Which ones?
- Has production/operation changed since installation of the new equipment? Since implementer verification?
- Has the operation of or production at your facility been affected by COVID-19? If so, how? (Note that if the answer is yes, we'll walk through the different phases of shutdown/reopening that the state has gone through and ask what changed during each phase.)

After we collected this data, we conducted a remote site visit to review the following:

- Was the equipment that was specified installed and is it operating as expected?
- Are the onboard controls visible and is the instantaneous operation in line with the VSD curves provided by the equipment specifications?

During the verification, we determined there were no major changes in operation from the pre-project installation operation. If there are no major changes, we plan to use the data collected in the baseline period to calculate the post-project installation case energy usage.

Description of Verification

The evaluation team completed a remote site visit on October 14, 2020. We interviewed the site contact and verified the installation and operation of the compressor.

Through the remote site visit the evaluation team confirmed that the new equipment was installed as specified and is operating as expected. The customer showed our team the onboard control system. The control system's readings at the time of the remote site visit are shown in Table 6.

Table 6. Snapshot of Compressed Air System Operating Parameters from Remote Onsite

Operating Parameter	Reading
System pressure set point	110 psi
System runtime[a]	4,701 hours
Typical VSD speed	40 – 60%

[a] This is the runtime since the installation of the new system

The controls system does not track real time flow, but the site contact told us that over the life of the new equipment it has accumulated a volume of 5,438,000 m^3. This volume converts to an average of 680 CFM when we consider the system runtime since installation.

The site contact also told us that the new dew point dryer was heating with operating parameter shown in Table 7.

Table 7. Dew Point Dryer Operating Parameters

Operating Parameter	Reading
Inlet pressure	108 psi
Inlet temperature	83°F
Outlet pressure	104 psi
Outlet temperature	99°F
Purge pressure	54 psi
Purge temperature	390°F
Dew point	-93°F

The site contact told us that the system runs continuously from Monday morning at 6am to Saturday morning at 6am and that the operation of the facility has not changed due to COVID-19.

The information and operating parameters provided to us by the site contact align with the ex ante assumptions and calculations. Therefore, we believe the week of metered data that was provided in the ex ante documentation is sufficient for the verified calculations.

Calculation Description

To estimate the energy savings from the new compressor we used the data collected in the baseline period to calculate the energy usage of the new equipment. We calculated baseline power (kW) and consumption (kWh) for the baseline and new compressor for each data point and summed them on a weekly basis. We modeled the new equipment's power profile using the metered flow data from the ex ante calculation. For each data point, we calculated the new power (kW) requirement given the baseline flow requirement using a regression curve fit to represent VSD operation.

Last, we re-analyzed the data from the baseline case. We calculated the power (kW) savings for every one second interval as the difference between the metered power (kW) of the previous compressor system and the regression-calculated power (kW) of the new compressor at every metered flow (CFM) point. We did this for both the leak repair-adjusted data and the unadjusted data to compare. We then extrapolated the energy usage for both the previous and new compressed air systems to the whole year. This resulted in an expected baseline energy usage of 958,667 kWh and new system usage of 655,765 kWh, resulting in 302,906 kWh savings per year just for the compressor change.

We recalculated the coincident peak demand savings using the Illinois peak period of June through August, Monday through Friday, 1pm to 5pm as defined in the IL-TRM. We calculated the average demand reduction during that time period to be 48.6 kW.

The savings and realization rates for the compressor measure are shown in Table 8.

Table 8. VSD Air Compressor Savings and Realization Rate

VSD Air Compressor	kW	kWh
Ex Ante	45.3	303,681
Verified	48.6	302,902
Realization Rate	107%	99.7%

For the dew point dryer control measure we maintained the ex ante assumption of 100 CFM average inlet pressure but adjusted annual hours of operation from 6,135 to the actual hours of 6,240 as confirmed by the site contact. This increased the annual energy savings.

For the dew point demand control measure, we recalculated the coincident peak demand savings using the Illinois peak period of June through August, Monday through Friday, 1pm to 5pm as defined in the IL-TRM. We calculated the average demand reduction during that time period to be 9.0 kW. The savings and realization rates for the dew point demand control measure are shown in Table 9.

Table 9. Dew Point Demand Control Savings and Realization Rate

Dew Point Demand Control	kW	kWh
Ex Ante	21.9	137,615
Verified	9.0	140,021
Realization Rate	41%	102%

The savings and realization rates for the entire project are shown in Table 10.

Table 10. Summary of Project 2000077 Savings

Full Project	kW	kWh
Ex Ante	67.7	441,296
Verified	57.6	442,924
Realization Rate	85%	100%

Project 2000078

Project ID#:	2000078
Measure:	New Construction Refrigeration System
Ex Ante Savings:	473,153 kWh, 54 kW
Facility Type:	Warehouse
End Use:	Refrigeration
Sampled For:	Electric Savings
Wave:	2

Measure Description

The customer is adding 72,865 ft^2 of freezer space maintained at -5°F and 31,130 ft^2 of cooler dock space to be maintained at 35°F. This project covers the installation of an independent ammonia refrigeration system serving the addition. The system consists of one 300 HP compressor with 127 tons low-stage capacity and side port for high-stage suction, one 150 HP compressor with 127 tons high-stage capacity, and one 300 HP swing compressor. Heat rejection is provided by a single evaporative condenser with three 20 HP fans and one 10 HP recirculating pump. Three evaporators, each with three 10 HP fans, provide cooling to the freezer. Five evaporators, each with five 0.75 HP fans provide cooling in the dock area. The new system includes the following energy efficiency measures (EEMs):

- EEM 1 – Upsized evaporative condenser and wet bulb (WB) controls. The new condenser is sized for a 12°F approach at design conditions. This measure also includes upgrading to wet bulb approach controls, which will allow for the reduction of fan operation during periods with high WB temperatures and low refrigeration loads. The baseline for this measure is condensers sized for an 18°F approach temperature with fixed-pressure controls.
- EEM 2 – The ammonia compressors are equipped with thermosiphon oil coolers that use heat exchangers with liquid refrigerant. The baseline is compressors with direct refrigerant injection into the oil to cool the compressors, which is standard equipment for this compressor.
- EEM 3 – Variable frequency drives (VFDs) control air flow through the evaporative condensers. The baseline is single-speed fans with cycling controls.
- EEM 4 – The cooler and freezer evaporators have 12°F design temperature difference or (DT), which is higher than industry standards. The measure baseline is evaporators designed for a 10°F DT.
- EEM 5 – Freezer evaporator fans will be equipped with VFD for speed control. The baseline for this measure is evaporators with single-speed fan motors and cycling controls.
- EEM 6 – VFDs will also control air flow through the cooler evaporators. The baseline for this measure is evaporators with single-speed fan motors and cycling controls.

Summary of the Ex Ante Calculations

The implementation team estimated measure savings using spreadsheet-based modeling of the baseline and proposed systems. They collected trended power data from the existing compressors over a one-year period from September 30, 2018 to September 30, 2019. They used these data to calculate cooling loads per square foot (sf) of the existing warehouse freezers and coolers as a function of WB temperature. They assumed that the cooling loads per sf would be similar for the addition and estimated the total cooling load based on the added areas served by the new refrigeration system.

The implementation team first calculated total baseline system power demand (kW) and annual energy usage (kWh). The baseline compressors, condensers, and evaporators have the same capacities and power ratings as the proposed units. The team used the estimated load profiles, local TMY3 data, and manufacturer performance curves to establish total compressor power demand for all 8,760 hours of the year. They used the same data to estimate hourly condenser and evaporator load profiles and power demand.

The implementation team calculated EEM savings sequentially (i.e. the baseline power and energy for EEM 2 were taken from the proposed values for EEM 1). The team first estimated system operation for EEM 1 at baseline conditions with an upsized condenser and WB controls. They estimated condensing temperatures for the proposed equipment using a 12°F approach temperature. This reduces high-stage compressor outlet pressure which leads to better compressor efficiency.

The team then estimated EEM 2 savings using manufacturer performance curves for compressors with thermosiphon oil cooling. Thermosiphon oil cooling reduces the total refrigeration load on the compressors and results in compressor and condenser energy savings.

The implementation team estimated the effect of EEM 3, VFDs on condenser fan power, by estimating fan speeds based on load factors on the condensers after EEM 1 and EEM 2 adjustments. They determined the proposed fan power requirements using standard affinity relationships, with an exponent of 2.7 between motor speed and power.

EEM 4 consists of evaporators that are equipped with heat exchangers with larger surface areas. The larger surface areas allow for a higher design DT. The higher design DT enables lower fan power without sacrificing capacity. The implementation team established EEM 4 savings by calculating the effect of reduced load factors on cycling fan operation.

The implementation team used the same approach used for EEM 3 to establish EEM 5, VFDs controlling air flow through the freezer evaporators, and EEM 6, VFDs controlling air flow through the cooler evaporators, savings. They used the load factors calculated for baseline operation (after EEM 1, EEM 2, EEM 3, and EEM 4 adjustments) to estimate average evaporator fan speeds. They determined the proposed system fan power requirements using standard affinity relationships, with an exponent of 2.7 between motor speed and power.

The evaporator fan energy savings translate into a reduced cooling load. The implementation team accounted for these savings in the compressor and condenser 8760 hr/yr calculations.

The implementation team assumed that demand savings (kW) were equal to the average kW savings. They divided total baseline energy use by 8760 hr/yr to determine average baseline demand (kW) and did the same with the proposed system energy use after accounting for all the EEMs to establish proposed system average demand (kW). The difference between the two was the estimated demand savings.

Measurement and Verification Plan

The original measurement and verification (M&V) plan is as follows:

The evaluation team will verify this project through a site visit. We will verify the installation of the refrigeration efficiency measures and discuss the operation of the system. We will request trend data, if available, collected by the facility energy management system. The team will use the data to establish as-installed system characteristics. The implementation team estimated baseline load profiles based on the existing part of the facility, so we will also use the trend data to establish baseline load profiles. We are confident that the customer will be able to furnish trend data similar to what they provided for the implementer's verification. However, if it is not available, we will collect operating information, e.g. set points, schedules, and control screen shots. We will use that information to adjust the implementer model as appropriate to characterize new system operation. We will ask for the following data points:

- Compressor amps/power/tons refrigeration, discharge pressures
- Condenser fan status and VFD speeds
- Condenser pump status
- Evaporator fan status' and VFD speeds
- Defrost cycle status

Specific questions for the site contact include:

- When did the project start and when was the project completed?
- When was the freezer fully occupied?
- How are the speeds of the evaporator fans controlled?
- How are defrost cycles controlled?
- Is dock traffic reduced on weekends? Holidays? Other time periods?
- How many holidays per year are you closed?
- How does this system compare to the refrigeration system installed in the original building?
- Are there any provisions for cross-connections or sharing cooling functions with the existing areas?
- Have there been any changes to the new refrigeration system operation (e.g. space temperatures), since installation?
- Is the new part of the building on a separate utility meter?

COVID-19 specific questions may include:

- Has operation been affected by COVID-19?
- If so, how and when were systems or conditions modified?
- Will (or has) warehouse operation return to pre-installation levels when conditions become 'normal"? If not, what is your prediction for operation at that time?

Note that if the COVID-19 pandemic has affected the facility, we'll walk through the different phases of the COVID-19 shutdown/reopening that the state has gone through and ask what changed during each phase.

Description of Verification

The evaluation team completed an on-site project evaluation on December 16, 2020. We interviewed the facilities manager and verified the installation and operation of the new refrigeration system.

- The installation of the following measures was physically verified or confirmed by the site representative:
- EEM 1 – Upsized evaporative condenser and wet bulb (WB) controls. This measure was confirmed by the site representative.
- EEM 2 – We physically verified the installation of thermosiphon oil coolers.

- EEM 3 – We physically verified the installation of the VFDs controlling air flow through the evaporative condensers.
- EEM 4 – The cooler and freezer evaporators have 12°F design temperature difference or (DT), which is higher than industry standards. This measure was confirmed by the site representative.
- EEM 5 – We physically verified the installation of the VFDs controlling air flow through the freezer evaporators.
- EEM 6 – We physically verified the installation of the VFDs controlling air flow through the dock cooler evaporators.

Construction of the freezer addition started in September 2019 and was finished June 2020. Although activity at the distribution center was reduced due to COVID-19, the new freezer has been operating at near capacity since shortly after completion. Some of this is due to the added convenience of moving materials into and out of the new freezer.

The space referred to as the cooler in the documentation is all part of the new loading dock area. The refrigeration system serving the new freezer and dock areas is independent of the rest of the facility and there are no provisions to share refrigeration with the existing part of the building.

The dock and freezer are in operation 24 hours per day year-round, and only close for Thanksgiving and Christmas holidays.

The site representative provided trend data for the period from August 1, 2020 To December 15, 2020. Evaporator data included set temperatures, fan speeds, and status (e.g. cooling, satisfied, and defrost). Evaporative condenser data included set and operating pressures, fan speeds, pump status, and outdoor wet bulb temperature. Suction and discharge pressures, slide valve positions, and motor power data were provided for the compressors.

Summary of Verified Calculations

The evaluation team established measure savings using a combination of assumptions and specifications used for the ex ante calculations, information collected at the site, and trend data provided by the customer.

The trend data included compressor suction and discharge pressures, percent capacity, and motor power for the three compressors plus evaporative condenser power. The data provided was recorded at 15-minute intervals for a 20-week period from August 1, 2020 through December 16, 2020. The evaluation team used the data, along with local temperature records, to establish relationships between wet bulb (WB) temperatures and total compressor power, compressor tons of refrigeration, and evaporative condenser power.

The evaluation team developed two-degree WB bin averages for total tons of cooling and compressor power. The data included observations for WB temperatures between 16^{o} F and 79^{o} F WB. One of the compressors includes a side port so that it can serve both the freezer and dock temperatures, but the data did not provide enough information to determine its contribution to the high-temperature side. We estimated high-temperature compressor power using data for the compressor dedicated to the high-temperature side. We did this by assuming a linear relationship between the highest average observed tons of cooling provided by the high-side compressor and the lowest temperature during which high-side cooling demand drops to zero. The results are shown in the graphs below.

Figure 5. Total Compressor kW vs. Wet Bulb Temperature

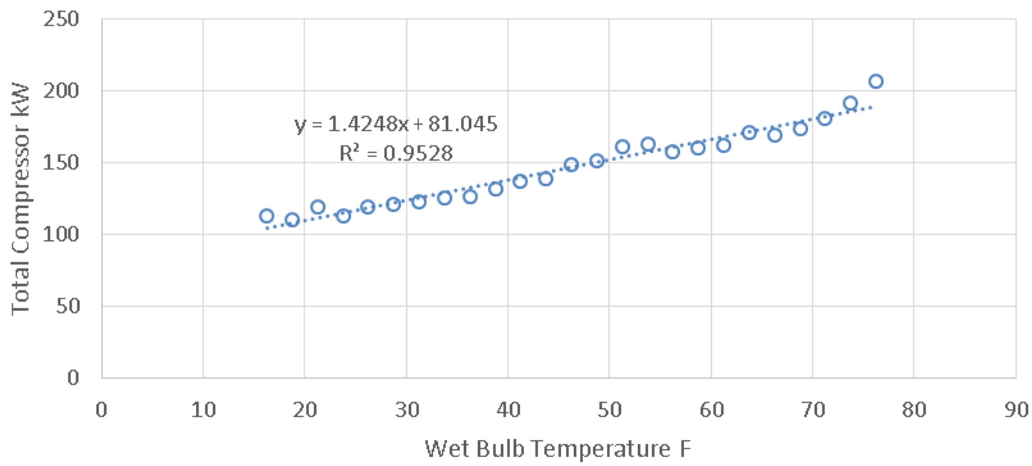
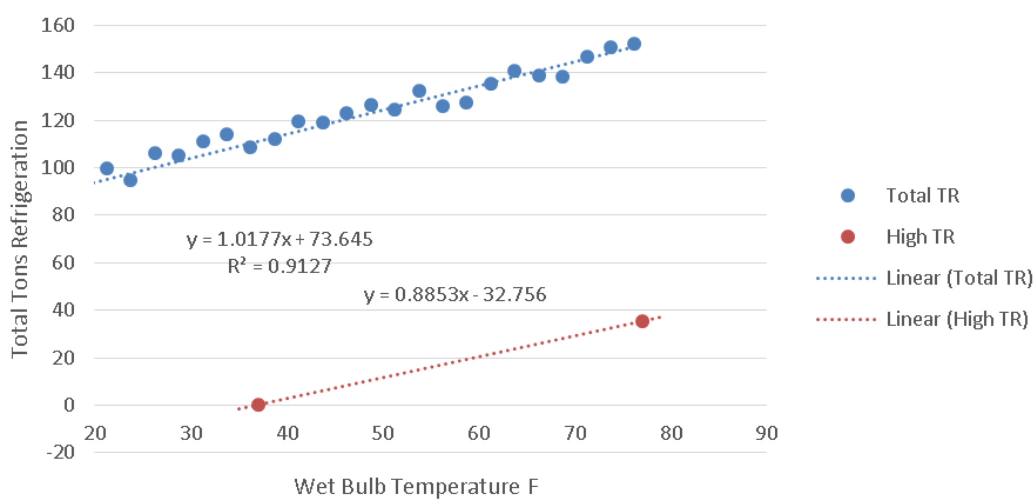


Figure 6. Total Tons of Refrigeration vs. Wet Bulb Temperature

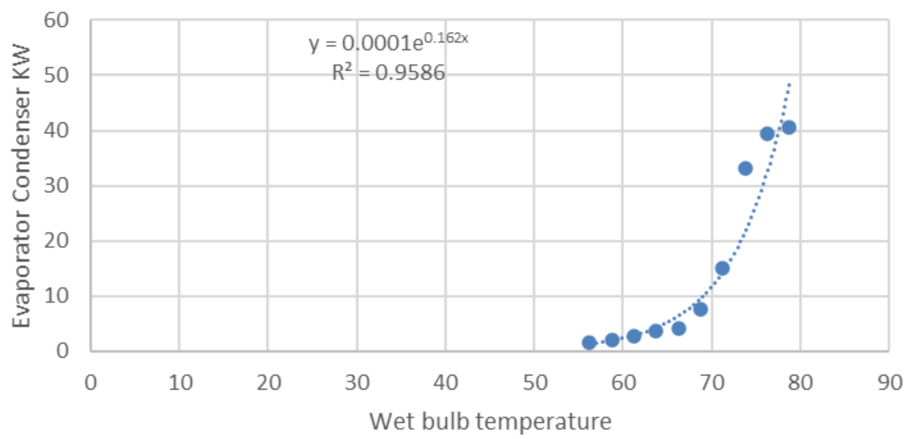


The evaluation team used the correlations between tons of refrigeration and WB temperatures to adjust the ex ante calculations for the baseline compressors. We used the correlations to calculate high side total tons of refrigeration from TMY3 WB data, with the difference being low-side tons of refrigeration. These results were entered into the ex ante baseline model to establish baseline compressor and evaporative condenser energy.

The difference between as-installed and baseline compressor power captures the effects of thermosiphon oil cooling and over-sized evaporators. The evaluation team used the correlation between observed total compressor power and WB temperature with TMY3 data to establish as-installed compressor power and energy.

The evaluation team used trended power data to establish a relationship between evaporative condenser fan power and WB temperatures. The fans did not run when WB temperatures were below about 40º F. A graph of the results is shown below.

Figure 7. Evaporator Condenser kW vs. Wet Bulb Temperature



Neither the ex ante nor the verified calculations included the effect of the evaporative condenser pump, as the difference between baseline and proposed conditions is likely to be insignificant.

The evaluation team used the TMY3 calculations to establish peak demand kW for the baseline and proposed operation. The average demand for the 1 PM to 5 PM period for June to August for the compressors, evaporators, and evaporative condenser was calculated, with the difference being the peak demand savings.

The increase in savings is due to the increase in baseline tons of refrigeration to match operation of the as-found conditions. The implementation team assumed that expansion-area cooling loads per square foot would be similar to the per square foot cooling loads of the existing warehouse. The result was an estimated annual average of 87 tons of cooling demand for the addition, while the evaluation verification found an average 124 tons of cooling demand. The ex ante baseline total energy use was 1,350,186 kWh, compared to the evaluation estimate of 2,048,482 kWh. While the proposed system energy use was also higher in the evaluation results, the higher baseline energy gives greater savings potential.

A summary of the savings and realization rates for the project can be seen in Table 11.

Table 11. Summary of Project 2000078 Savings

	kW	kWh
Ex Ante	54.0	473,153
Verified	73.4	550,286
Realization Rate	136%	116%

Project 2000111

Project ID#:	2000111
Measure:	Chilled Water Bridge Removal
Ex Ante Savings:	1,266,775 kWh, 190.46 kW
Facility Type:	Higher Education
End Use:	Cooling
Sampled For:	Electric Savings
Wave:	3

Measure Description

This project consists of the removal of existing building-side chilled water bridges in a college campus central chilled water loop served by a chiller plant containing four active centrifugal chillers. The bridges allowed supply chilled water to bypass tertiary chilled water loops in each campus building serving air-handling unit (AHU) coils and return to the chillers without passing through the building loops. This results in wasted pumping energy in the secondary chilled water loop because the water was pumped through the system only to return to the chillers without being used for any cooling.

The new system not only removes the bypasses, but also adds controls to automate the chiller staging and flow controls so that only the chillers needed for cooling loads are in use at any given time. That means that in addition to reducing secondary loop pumping energy by reducing required flow through that loop while still meeting cooling demand, this project has additional savings at the chiller plant itself. The chillers were previously manually staged on and off to supply both enough cooling capacity, and more importantly, enough chilled water flow in the system to meet demand from the secondary loop. A reduction in secondary loop flow means that some chillers that previously had to run in order to maintain loop flow now no longer need to operate, since it was flow requirements and not actual building cooling loads forcing them to run. This results in chiller energy savings. Due to the bypass issue, the secondary loop was previously operating at temperature difference ("delta T") values less than 4°F much of the time. Chillers are usually designed to operate at a 16°F delta T.

Project documentation shows a completion date of around November 18, 2020, which is after the cooling season was over. However, the trade ally said the project was completed in September 2020 and there were more than two months of post-project implementation operation.

Key Findings

The verified analysis corrected many issues we encountered in the ex ante analysis. That analysis did not account for many different energy engineering assumptions and constants, or utilize best practices for analyzing motor power, variable speed pump and fan operation, and others. Further, although the ex ante analysis used chiller plant submetered interval data to estimate the existing energy usage, the implementation team did not calibrate the chiller plant energy model for the new system using the same submetered interval data. Because the model for the new system was not calibrated prior to using it to estimate the energy usage of the new system, its results are questionable leading to a questionable savings estimate.

The evaluation team, after correcting all the engineering errors, applied the model to the existing system first to calibrate it using the provided chiller plant pre-project submetered data. However, the evaluation team was not able to calibrate the model to the data. We believe that there may be a problem with the submetered data as it is 30-50% higher than the combined power used by all the relevant equipment.

Therefore, we used a model of the existing system and compared it to an adjusted model of the new system using an elevated delta T based on curve fits from pre- and post-project metered data. As a result of these changes, the project savings declined significantly. The two biggest drivers of this decrease are 1) post-project data show that the new system is not able to hit the 16°F delta T target most of the time, and 2) significant inflation of power consumption in the chiller plant submeter data.

The trade ally indicated that this was the first of three projects aimed at increasing the plant delta T, and the other two projects (pressure independent control valves and additional controls) have yet to be completed. However, this project calculation computed savings based on an assumption of full delta T issue abatement.

The resulting project savings are shown in Table 12 below.

Table 12. Summary of Project 2000111 Savings

	kW	kWh
Ex Ante	190.5	1,266,775
Verified	8.8	107,430
Realization Rate	5%	8%

Summary of the Ex Ante Calculations

The ex ante analysis of this project involves a combination of trend data from the building automation system controlling the chilled water plant and theoretical calculations of the new chilled water system energy use. The trend data covers a six-month period prior to the project and includes the secondary loop flow rate, supply and return temperatures, and the total chiller plant power consumption in five-minute intervals. The chilled water plant is in use seven months per year, so all consumption values were scaled up to seven months from six.

The ex ante analysis uses the temperature and flow rate data to calculate the cooling loads on the system at each interval. From there, the analysis computes the new flow rate in the secondary loop using an assumed loop delta T of 16°F instead of the existing approximately 4°F delta T. This new flow rate impacts the secondary pump power and number of chillers running at any given time.

From there, the analysis calculates the average load on each chiller, chiller power based on a chiller performance curve taken from a different manufacturer than the actual chiller (due to issues with data availability from the actual manufacturer), and power demand of supporting equipment like cooling tower fans, primary pumps, and condenser water pumps. The total power demand of all this equipment (secondary pumps, chillers, cooling towers, and condenser water pumps) is the new system power. The analysis then compares this theoretical new system power with the metered existing system power.

Errors in Ex Ante Analysis

The evaluation team identified many calculation and assumption errors in the ex ante analysis. The bulleted list below summarizes these issues:

- First, the trade ally did not calibrate the theoretical model to the actual submetered power data by using the existing system flow rates and then adjusting loads until the power calculated by the model was close to the actual submetered data. Thus, it is not clear if the savings are from this project or simply the result of a poorly calibrated model and/or flawed submeter data. This issue has the most significant impact on savings.

- This analysis uses an oversimplified conversion of pump and fan rated horsepower to input power (kW) for all the pumps and fans in the project. The implementation team took the rated horsepower and multiplied by the kW to HP conversion factor of 0.746. This does not account for fan and pump efficiency, motor loading, motor efficiency, or VFD drive losses.
- To account for motor efficiencies declining at low loads on the secondary pumps, the analysis applies a 10% penalty. However, typical motor efficiency versus load curves are available and more accurate than an ad hoc 10% penalty.
- The ex ante analysis relies on trend data from the automation system and assumes that all data points are in five-minute increments. However, a small number of data points (23) do not fall within those increments and are reading errors that appear to be in one-minute increments. Thus, assuming 12 points per hour in the energy consumption calculations leads to a small error in energy consumption totals.
- The analysis uses the maximum demand for the existing and new systems for the peak demand savings, instead of limiting the analysis to the AIC peak demand period. Further, the implementer did not update the demand savings after making changes to the trade ally's analysis.
- The trade ally's calculations do not follow best engineering practices for calculating power demand changes in relation to speed changes on VFD-driven pumps and fans. Although they use the standard pump affinity law, that law does not match real-world performance due to static head. The preferred method is to use the equations presented in Richard Vaillencourt's paper.[3]
- The ex ante analysis uses discrete chiller performance points at each 10% load increment rather than a continuous polynomial curve fit of the available data. This introduces small error at loading levels between the 10% increments.
- The axial cooling tower fan power analysis does not account for variable speed fans.
- The column that totals up the theoretical new system power double-counts the secondary pump power.
- The chiller performance curve worksheet incorrectly uses a chiller capacity of 400 tons instead of 434 tons.
- There is no adjustment to the energy equation (BTU/h = 500 * GPM * delta T) constant of 500 BTU-min/gal-hour for the fact that the loop uses a 30% glycol solution. That value of 500 assumes 100% water. The specific heat of glycol at 30% is approximately 0.935 BTU/lb °F instead of the value of 1.0 for pure water. This results in a value of 467.5 for the constant.
- The cooling tower kW calculation shows increasing fan power and speed as the outdoor air wet bulb temperature decreases, which is the exact opposite of the actual relationship.
- The ex ante analysis takes the six months of metered data and scales it up to seven months to represent the annual run time of the chiller plant. However, the metered data does not cover precisely six months of time and months are not a consistent unit of measure since different months have different numbers of days.

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[3] "The Correct Formula for Using the Affinity Laws When There Is a Minimum Pressure Requirement". Vaillencourt, Richard R. https://studylib.net/doc/5909342/vfd-equation---canterbury-energy-engineering--llc

Description of Verification

The evaluation team corresponded with the trade ally via email. The trade ally answered several questions about the project. They confirmed the project was completed in September 2020 and the chilled water plant ran until November 24, 2020. They provided metered data from the building automation system controlling the chilled water plant covering the entire post-implementation period, including: supply and return water temperatures, secondary loop flow rates (GPM), and chiller plant power (in kW). This data is in five-minute increments and includes the same points and intervals as the data used in the ex ante analysis. The trade ally also provided design documents for the secondary pumps to confirm the design head for use in the verified analysis.

The trade ally answered two questions with the same answer. The questions and answer are shown below:

- Question 1: If you were able to test the new system, can it maintain a 16°F delta T in the secondary loop now? Are there controls set up to maintain the delta T at a constant 16°F?
- Question 2: Before the project, it sounds like the tertiary building pumps had to run at 100% speed, at least in some buildings near the end of the loop, to get enough flow to the AHUs. Do you know what speed the tertiary pumps run at after the project? If you do know, do you also know the pump HP on the tertiary pumps?
  - Answer: "The AHU chilled water valves were upgraded to pressure independent control valves, and the DDC controls for the AHUs were both upgraded after the chilled water bridge project, on a separate project. We will test the functionality of the chilled water valves and controls this spring when the chiller plant is put back into service."

The evaluation team believes these projects were recently installed after the chiller plant was taken offline and have not had a chance to be commissioned or impact the system data provided.

The evaluation team made use of the metered data to determine the actual achieved increase in delta T as a result of the removal of the chilled water bridges. From the trade ally's response, it is clear that the bridge removal is only one step in a three-step chilled water project and the full energy impacts will not be realized until all three steps are completed. Our analysis only considered the observable energy impacts of this first step, even though the later steps will likely increase the system delta T more.

Summary of the Verified Calculations

The evaluation team first corrected all the calculation errors in the ex ante model (Chiller Plant Ops Calcs sheet) described in the Errors in Ex Ante Calculations section above. Note that many of these changes resulted in a decrease in the proposed-case modeled energy usage and would have increased project savings by ~40% in the absence of the other issues (assuming a 16°F delta T and using the submetered plant kW) with the analysis.

Once these errors were corrected, we then attempted to calibrate the theoretical model of chiller plant power consumption to the actual metered plant power using the metered flow rates, temperatures, and outdoor air temperatures. It became clear that the difference between the modeled power (using manufacturer data for full load power for all equipment) and the actual submetered power was too great to permit accurate calibration. In order to approximately match the two, the chiller efficiencies had to be nearly doubled, resulting in unreasonably high kW/ton values. Based on what we know about the equipment in the plant (motor sizes and applications, staging, chiller curves, etc.) we cannot find a reason for the plant power to be 30-50% higher than the model, but that is what the submetered data show. Therefore, we suspect that this meter either includes power demand from equipment not part of the chiller plant or the meter has a reading/multiplier error.

We also used post-project temperature and flow data to check the chiller plant calculation model against post-project metered power. This analysis also showed that the submetered power was significantly higher than that calculated by the model.

The evaluation team cannot know for sure why the submetered data appears to be inaccurate, but due to these analyses we discarded the actual submetered chiller plant kW values that were used to estimate the existing energy usage in the ex ante analysis. Our attempt at calibration shows that a large portion of the ex ante savings are not due to this project, but rather due to issues with the metered data or an improperly calibrated model.

Considering the unreliability of the metered power data, we used a model-to-model savings approach. We started with our corrected version of the ex ante model of the chilled water plant and used it to compute the modeled energy and demand for the existing system. For this, we used the metered flow and temperature data from the existing system.

To determine the impact of this project on system operation, we used the post-project metered data supplied by the trade ally to plot secondary loop delta T against system load, in tons. We did the same for the existing system data and displayed them on the same chart (Figure 8). To make use of this data, we had to filter out outlier points, such as those where the load is negative and low loads below 100 tons, where the data is very noisy. The result in the chart in Figure 9. We used a linear regression of both data sets to determine the relationship between delta T and load for both the existing and new systems.

Figure 8. Raw Delta T vs. Tons

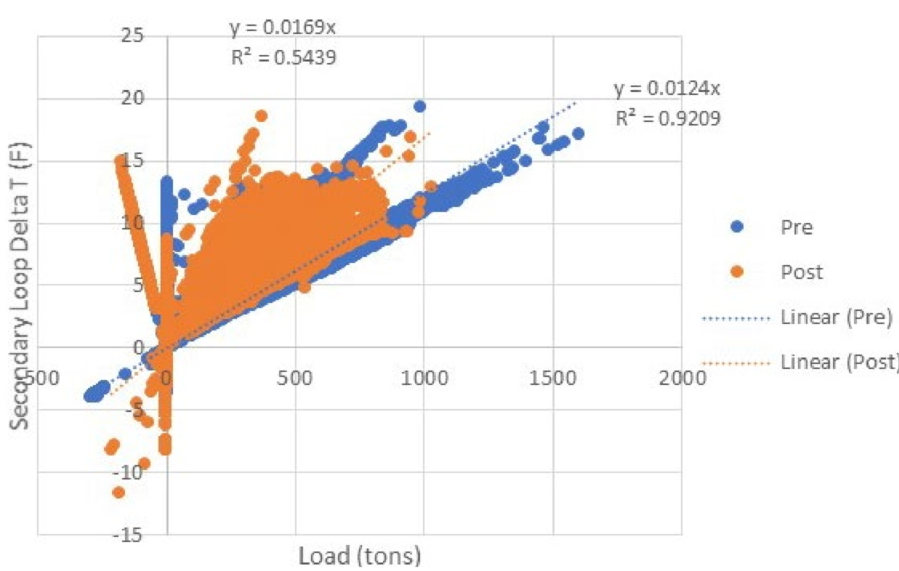
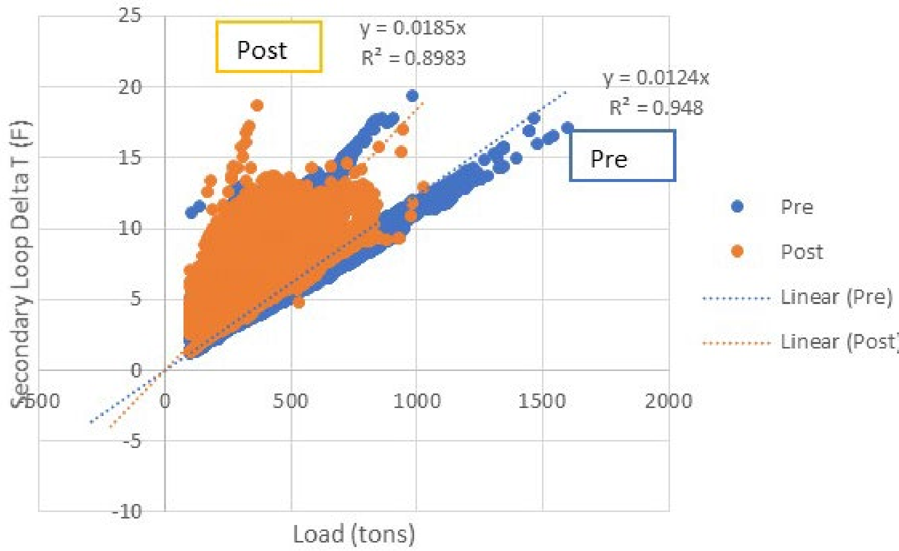
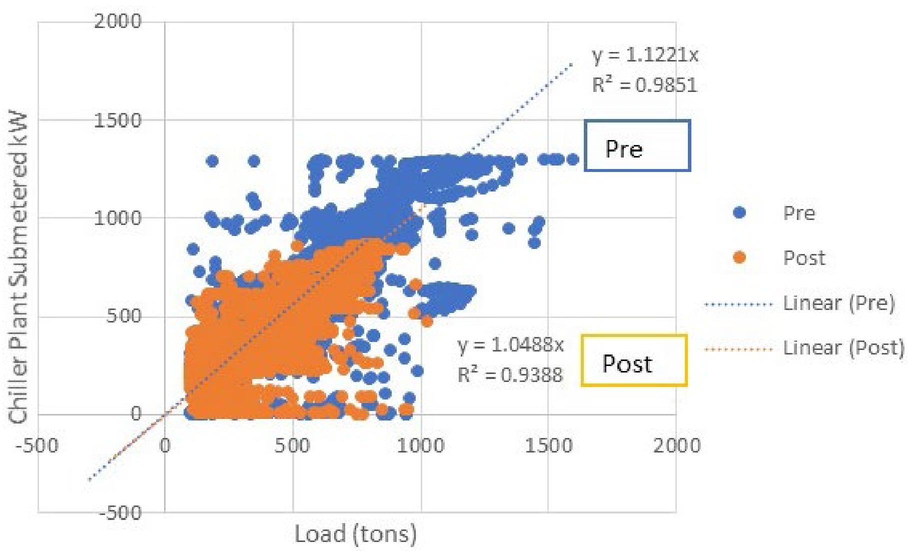


Figure 9. Adjusted Delta T vs. Tons



We did a similar exercise with the metered plant power for pre- and post-project data and the resulting chart is shown in Figure 10. We include this here, even though the metered power data is unreliable just to show that the overall power versus load trend remains roughly the same in both existing and new conditions, with a slight reduction in power after the project. The post-project data covers only two-plus months in the fall and therefore does not have as many higher load points as the pre-project data.

Figure 10. Chiller Plant kW vs. Tons (Adjusted)



To determine energy consumption of the post-project chiller plant, we first determined the predicted increase in delta T due to the project. We used the linear regressions of the existing and new systems to predict the existing and new delta T at each of the metered data's timestamp's load (in tons). We used load data from the existing metered data because it covers most of the cooling season. The difference between the predicted new delta T and the predicted existing delta T is the increase in delta T due to this project. Next, we added this increase to the delta T from the existing system metered data to arrive at the new system's delta T.

The evaluation team then used this calculated delta T value to determine the secondary loop flow rate required to achieve the metered load value. We computed the project savings from the outputs of both the existing and new system model worksheets.

Some other observations about this project from the evaluation team:

- The ex ante savings was a very high percentage of the baseline usage and this was only phase one of a three-phase chilled water project. Those projects are the AHU valve upgrade to pressure-independent valves, and the AHU controls upgrade, both mentioned in the trade ally response to our questions.
- We would expect the ex ante assumption that the post-project system can maintain a 16°F delta T might be possible after the other two phases of the chilled water system upgrades are complete. However, knowing that this is only one part of a larger project, it would have been prudent for the trade ally completing the analysis to use a less aggressive delta T assumption for this first phase.

Project 2000114

Project ID#:	2000114
Measure(s):	HVAC Controls
Ex Ante Savings:	980,319 kWh; 52.95 kW, 65,055 therms
Facility Type:	Medical
End Use(s):	HVAC
Sampled For:	Electric Savings, Gas Savings
Wave:	2

Measure Description

This project covers replacement of controllers for existing rooftop units (RTUs) and variable air volume (VAV) boxes in a medical facility and the implementation of new controls including reducing VAV minimum airflow rates, time-of-day scheduling, reset controls for supply air temperatures and pressures, and the installation of two ductless split heat pumps to provide cooling to individual spaces that require cooling outside of normal occupied hours.

Key Findings

The verified savings for this project were determined using regression analyses with daily electric usage and monthly gas usage information. Regressions were developed using local historical weather data, weekday/weekend variables, and variables to define the pre-implementation and post-implementation periods. Based on information provided by the customer, the COVID-19 pandemic is not expected to have a significant impact on the energy use of the facility, and no other projects were completed at the facility in the last few years that would have a substantial impact on the energy use. Therefore, the results of the regression analyses are the verified savings for this project.

While the verified energy savings are different from the ex ante savings, they are relatively close. This indicates that the models used to calculate the ex ante savings for this project were well-constructed and closely reflect the actual operation of the building and the impact of the project. The exact sources of the discrepancies could not be pinpointed, but throughout the evaluation team's review of the project, no systematic errors were identified in the modeling that was done for this project. The only real issue found in the savings calculations was in how the demand savings were determined – the project was assumed to reduce the peak demand by 5%, but no source of this percent reduction was ever found in the project documentation. The resulting project savings are shown in Table 13 below.

Table 13. Summary of Project 2000114 Savings

	kW	kWh	Therms
Ex Ante	52.95	980,319	65,055
Verified	106.68	763,629	76,182
Realization Rate	201.5%	77.9%	117.1%

Summary of the Ex Ante Calculations

The savings for this project were determined using simulations run with a building model in Trane Trace software.

In the Trane Trace models, the building has four RTUs that provide air to the various areas of the building. In the baseline model all four RTUs operate in occupied mode continuously. In the proposed energy-efficient model, RTU-1 remains running in occupied mode all the time, but time-of-day schedules are added to the other three RTUs. Additionally, the minimum VAV box airflow setpoints throughout the building were changed, many being changed from 50% to 30% of maximum air flow. In addition, the proposed energy-efficient model includes new HVAC systems to model the ductless split heat pump systems that were installed to provide cooling to select areas of the building which were previously served by RTU-2.

Simulations run with the Trane Trace software show that the annual energy usage of the facility during a typical meteorological year is projected to go from 4,190,530 kWh and 218,619 therms to 3,210,211 kWh and 141,993 therms, resulting in savings of 980,319 kWh and 76,626 therms. Utility billing data show that the facility now consumes 4,562,000 kWh and 235,000 therms per year. Given this data, the baseline appears to be modeled as being more energy-efficient than it was, resulting in a conservative estimate for energy savings. That said, the models appear to be reasonably well calibrated to the actual building use. The gas savings for this project were capped at 30% of the baseline annual consumption, which is 65,055 therms. The electric savings did not exceed the 25% cap for the project, so no adjustment to the simulated electric energy savings was needed.

The baseline simulations show that the peak demand for the facility is 1,058 kW. The model shows that the completion of this project is estimated to reduce peak demand by 5%, resulting in 52.95 kW of demand reduction. It is not clear whether this peak reduction is the reduction in the facility's peak demand or the facility demand reduction during the peak period as defined by the IL-TRM.

Measurement and Verification Plan

This project will be verified with a remote site visit. The customer will be asked to join the evaluation team in a teleconference to go over the details of the project and allow our team to observe the operation of the energy management system and ask about any relevant trended data that may be available.

- Specific questions for the site contact include:
- When was the project started and completed?
- What was the condition of the control system before the project was completed? Was it an existing EMS, pneumatics, or something else?
  - Were any schedules in place for any of the RTUs prior to the completion of the project? If so, which RTUs had schedules and what were they?
  - Did the RTUs previously have any change in outside air rates between night and daytime?
- Can you confirm that two standalone cooling systems were installed that serve individual spaces? These are noted to be a reading room and a computer room in the building model.
  - What was the reason for this? Do these spaces require cooling when other parts of the building do not?
- Did the RTUs have economizing controls prior to this project? Were they regularly maintained? How were they controlled? Do the RTUs have economizer controls now?

- Can you confirm that the RTUs are packaged units with air-cooled condensers?
- Is the boiler for the facility a hot water or a steam boiler?
  - If hot water, is it a condensing boiler, and what is the temperature setpoint or schedule for the hot water?
- What are the current schedule settings (times and temperatures)? Are there any spaces that were not scheduled as intended? If so, which spaces? Did any spaces previously have night-setback temperature setpoints?
- What are the current minimum airflow rates for the VAV boxes and the RTUs?
- What are the minimum and maximum supply air temperatures in heating and cooling modes for the RTUs?
- Are the RTU supply fans driven by VFDs? If so, were the VFDs in place prior to the project? If not, how was airflow controlled?
  - If the VFDs were in place previously, how were they controlled before the project was completed? How are they controlled now (if differently)?
- What are the minimum and maximum duct static pressures for the RTUs? How is the setpoint controlled?
- Are any of the VAV boxes throughout the building controlled with occupancy sensors? If so, what are the occupied and unoccupied settings for those spaces?
  - Were the occupancy sensors in place prior to completion of this project? If not, were they a part of this project?
- Have there been any other projects completed in the building since the controls upgrade that might significantly impact the building's energy use?

Trends of interest for confirming the implemented controls include:

- Supply air temperature (all four RTUs)
- Supply air static pressure (all four RTUs)
- Supply fan speed or on/off status (all four RTUs) and/or airflow rates (CFM)
- Zone temperatures for a sample of rooms

COVID-19 specific questions may include:

- Has the operation of the facility been affected by COVID-19?
  - If so, how have the hours and/or occupancy patterns been affected?
- Have the HVAC control settings changed due to COVID-19? If so, what changes were made, e.g. scheduling and setbacks? Ventilation rates?
  - If they have changed, will the control settings return to their prior setpoints/configurations when facility operation becomes 'normal" again?

Note that if the facility's operation was significantly affected by COVID-19, we'll walk through the different phases of shutdown/reopening that the state has gone through and ask what changed during each phase.

Description of Verification

While the evaluation team had planned on an in-person site visit, we resorted to a remote site visit due to COVID-19. A conference call with the vendor was conducted on February 10, 2021.

The vendor explained that a vast majority of the work for the project was upgrading the controls at the VAV boxes to implement dual-maximum controls. The existing controls were antiquated DDC with no advanced control capabilities, just basic setback controls. A lot of the night setback controls for the existing system had been bypassed due to select spaces in the building that required conditioning 24/7. The vendor confirmed that the minimum airflow rates in most areas of the building are now 25-30% of design flow, whereas before the project was done the minimum for most areas was 50% of design flow. The outdoor air dampers shut at night, only opening if the system calls for economizing. The vendor believes that reset controls for duct static pressure and supply air temperature were included with the new Energy Management System (EMS), whereas the old system just had setpoints with no reset schedules.

The areas of the building that ductless split systems were installed in were a server closet and an imaging lab that has a lot of equipment that produces significant internal gains. By installing ductless split systems for these areas, the rest of the building can have night setback controls rather than staying in occupied mode 24/7.

The rooftop units that supply conditioned air to the VAV boxes all have DX cooling and gas-fired heating, and the VAV boxes have hot water reheats that receive hot water via a heat exchanger from a gas-fired steam boiler.

The building is divided into three areas – an ambulatory surgery center, a prompt care unit, and a medical office area. The surgery center and the prompt care unit did not see any significant operational changes due to the COVID-19 pandemic, but the vendor was unsure if the pandemic had any significant impact on the occupancy levels or patterns in the medical office part of the building.

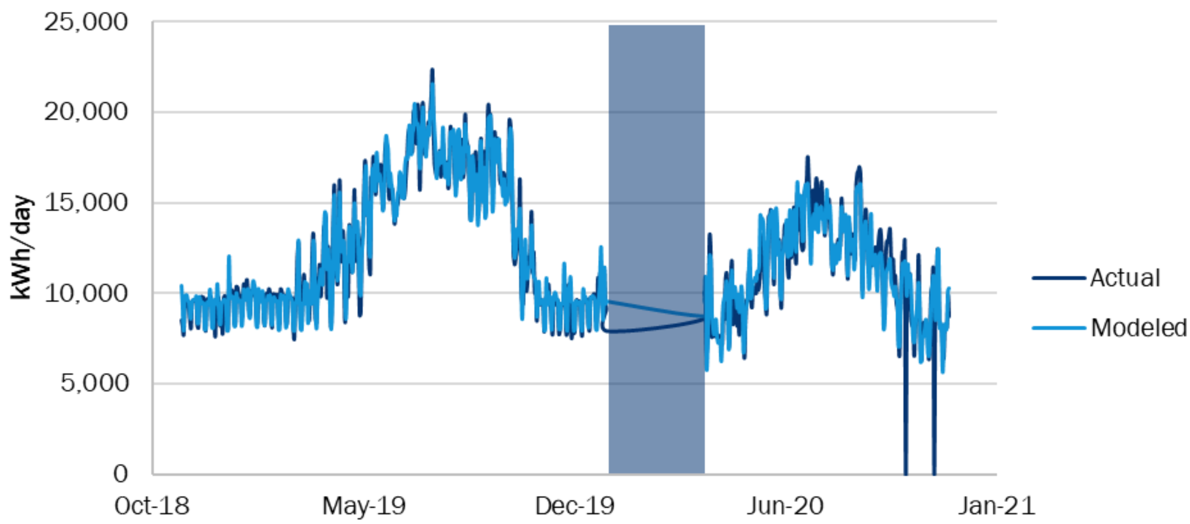
This project was started in early 2020 and was completed by the end of March 2020. No other projects have been completed at the facility in the last few years that would have any significant impact on the energy use.

Summary of the Verified Calculations

The evaluation team determined that a billed regression analysis would be the best approach to determine the verified savings for this project, as the claimed savings are a substantial portion of the annual energy use of the building, and the COVID-19 pandemic had little impact on the operations at the building.

Using interval electric use data from the facility, regressions were developed using weekly schedules and historical weather data. The regressions have a good correlation between the modeled energy use and the actual energy use of the facility. A comparison of the actual and modeled energy use is shown below in Figure 11.

Figure 11. Comparison of Actual & Modeled Energy Use



The implementation period is shown in the shaded box in Figure 11. The data from this period was omitted in the analysis. The regression analysis shows a clear reduction in electrical energy use resulting from the completion of the project, and the annual savings is calculated to be 763,629 kWh.

While energy management system projects do not typically result in demand savings, the interval data from before and after the project indicates that demand did go down. In the interval data the average demand during the peak period before the project was done is 868.73 kW, and after the project was done it is 762.05 kW, resulting in a reduction of 106.68 kW. This is the verified demand savings for this project.

To evaluate the gas savings, a regression analysis was performed using the monthly gas usage records for the facility. The gas regression analysis shows that the project results in gas savings of 76,182 therms. The actual monthly gas usage of the facility is compared to the baseline and proposed regressions in Figure 12 below, and a comparison between the baseline and proposed TMY3 regressions is shown in Figure 13.

Figure 12. Gas Monthly Regression Analysis

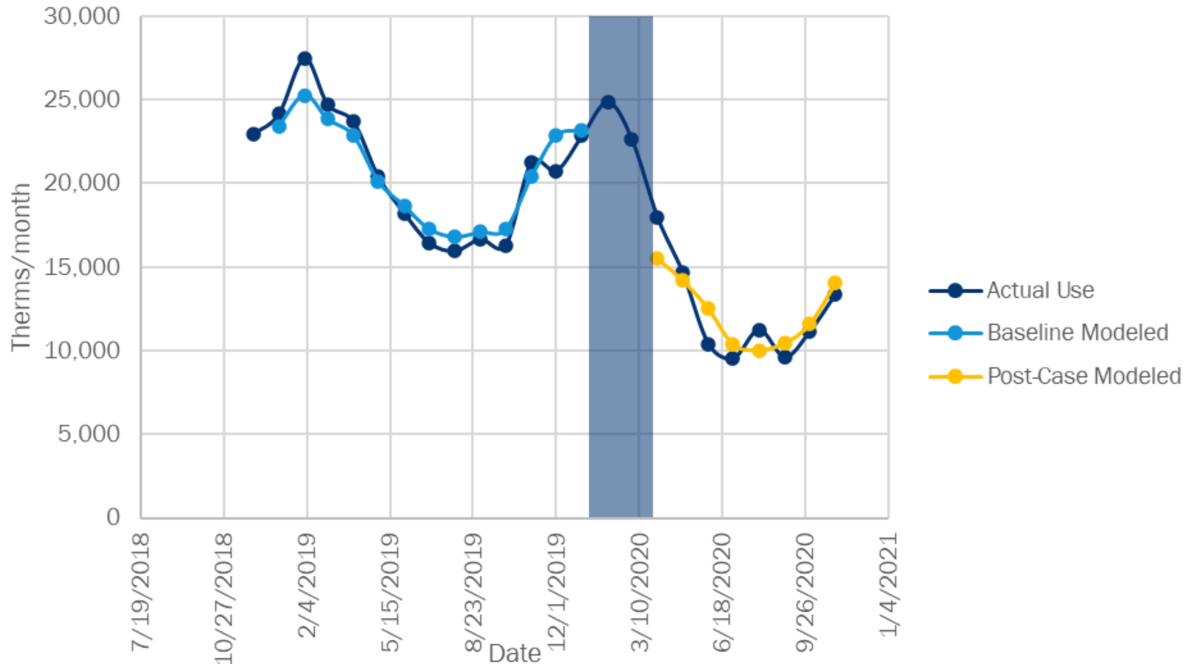
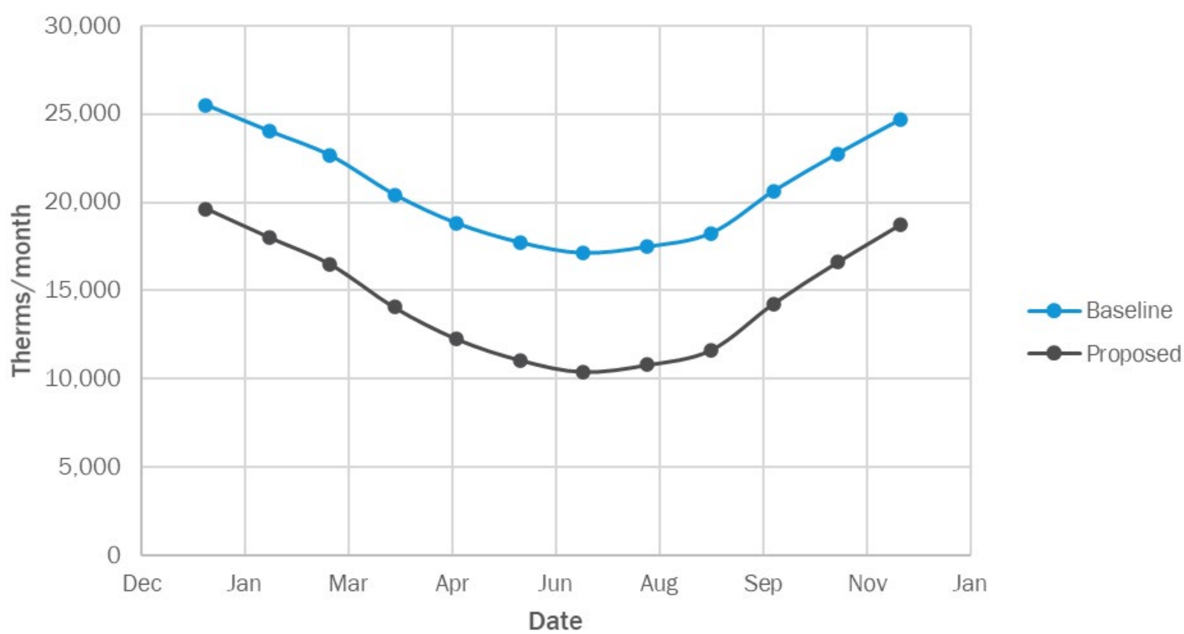


Figure 13. TMY3 Regression Comparison



Project 2000192

Project ID#:	2000192
Measure:	VRF
Ex Ante Savings:	12,788 kWh; 12.7 kW; 4,901 Therms
Facility Type:	Office
End Use:	VRF units and thermostatic restrictor valves
Sampled For:	Gas Savings
Wave:	1

Measure Description

This project consists of the replacement of an existing heating and cooling system with a Variable Refrigerant Flow (VRF) system in a public sector building.

The existing system consisted of window-mounted packaged terminal air conditioning (PTAC) units and building-wide gas heating with steam radiators. The existing steam system was controlled by a single thermostat in the basement of the building, which caused significant temperature control and comfort issues throughout the building.

The new system includes the installation of a Mitsubishi VRF heat pump system and integration with the existing Honeywell building management system to replace AC cooling and displace shoulder month heating and the installation of (31) Danfoss thermostatic radiator valves to control heating more efficiently.

The ex ante calculation claims both gas and electric savings due to fuel switching from gas heating to electric heating.

Summary of the Ex Ante Calculations

The implementation team established project savings using the SmartWatt tool provided by the trade ally. The team collected inputs for the tool from an audit completed in October 2019. The initial calculation by the implementation team did not account for interactive effects, resulting in double-counting from the two improvements made to the heating system. The implementation team corrected for this and reran the calculation. The implementation team assumed that the existing heating efficiency was 80% for the boiler and existing AC units had an efficiency rating of 8 EER in the first floor rooms and 12 EER in the atrium. The implementation team then decided upon a strategy to appropriately stack measures, accounting for the heating load displaced by the VRF units before calculating the savings from the thermostatic radiator valves. This reduced the savings from the radiator valve measure because the improvement is applied to a much lower load, which eliminated double-counting of savings. After accounting for measure stacking, the resulting project ran into eligibility issues due to payback. Because the savings from the thermostatic radiator valves are significantly lower after the VRF units are installed, the payback for that measure is outside the program eligibility threshold and pulls the whole project above a 10 year return on investment (ROI) before the incentive. As a result, the implementer removed both the savings and the costs of the radiator valves from the project. The program did not claim the savings from the radiator valves or award an incentive for them.

The implementation team calculated peak demand, annual energy usage, and gas usage for both the baseline and the VRF proposed case for changing temperatures on the first floor, changing the cooling efficiency on the first floor, and heating with the VRF system on the first floor and second floor. The SmartWatt tool calculated demand savings of 12.7 kW, annual electrical usage savings of 12,788 kWh and annual gas savings of 4,901 therms (completely eliminating gas usage from the baseline).

Measurement and Verification Plan

The evaluation team verified the project through a review of documentation and calculations, and an interview with the customer to confirm the installation and operation of the equipment.

We asked about operation of the new system and the facility in general, including the following questions:

- How were you dealing with the temperature control issues with the previous system? Do these issues still exist?
- What other systems in your building use gas? Hot water heaters, additional heaters? From the utility bills, it appears there is still some gas usage at site.
- Have there been any other modifications to the VRF system?
- COVID-19 related questions:
  - How has your operation changed due to COVID-19 restrictions? Reduced staff/occupancy?
  - Will any of these trends or changes continue beyond “normal” start-up (whenever that may happen)?
  - How have these changes (if any) affected the usage of the equipment in question?
- Program related questions:
  - What was your experience with the program? The application process?
  - If you could improve the program, what would you suggest improving?

Description of Verification

The evaluation team completed a customer interview on September 30, 2020. We interviewed the site contact and verified the installation and operation of the VRF system.

First, we discussed the operation of the original and new equipment. The project was finished in the spring of 2020, however, the exact completion date is unknown. All of the window AC units have been removed and permanent windows put in their place. The site contact indicated that on nice days some offices continue to use operable windows for fresh air. The site contact does not expect to need individual space heaters this upcoming winter (which had been used before). Other than the water heater in the boiler room, the site contact is unaware of any other gas usage. The impacts of COVID-19 on the facility have been minimal because their line of work is considered essential and has not shutdown.

Summary of Verified Calculations

During the verification, the evaluation team determined that there have been no major changes in operation from the ex ante calculations. Therefore, the evaluation team used the SmartWatt outputs for demand savings, annual energy usage, and gas consumption to recalculate verified savings using IL-TRM 9.0’s guidance for calculating savings for fuel switching projects. As there is no VRF measure in the IL-TRM, we followed the approach outlined for fuel switching for ground source heat pumps. Since the fuel switching formulae are measure-independent, this is appropriate.

Following this approach, the evaluation team converted baseline electric and gas usage to site BTUs. The evaluation team then converted the proposed electric heating to site BTUs. We then made an adjustment to this calculation to reflect an assumed 25% wasted space heat due to poor controls (prior to the VRF installation), and an average system COP of 6 due to the VRF heat recovery capabilities. We finally converted all these values to source BTUs, or BTUs required from the power plant. The evaluation team assumed that line losses are 11.1% (for AIC). The IL-TRM uses the latest EPA eGrid data for its site to source conversion equations as shown below.

Figure 14. Illinois TRM Version 9.0 Heat Rates

[417] These values are subject to regular updates so should be reviewed regularly to ensure the current assumptions are correct. Refer to the latest EPA eGRID data. Current values, based on eGrid 2018 are:

- Non-Baseload RFC West: 10,024 Btu/kWh * (1 + Line Losses)
- Non-Baseload SERC Midwest: 9,871 Btu/kWh * (1 + Line Losses)
- All Fossil Average RFC West: 9,575 Btu/kWh * (1 + Line Losses)
- All Fossil Average SERC Midwest: 10,369 Btu/kWh * (1 + Line Losses)

For AIC, the IL-TRM instructs users to use the SERC Midwest region formula. Using our assumed line losses of 11.1%, our conversion equation is the following:

$$Source\ BTU\ =\ (Site\ BTU * 10{,}369) * (1 + .111)$$

The evaluation team calculated electric savings excluding the heating from the heat pump. Gas savings are the difference between the total source BTUs and the proposed source BTUs with the electric BTUs savings removed. Removing the electric BTU savings is necessary to remove any fuel switching benefit. After recalculation, the evaluation team found that the electric savings increased but the gas savings decreased. Electric savings increased because the ex ante treated the increased electric heating usage as a penalty. However, this should be treated as fuel switching, so the electric heating usage was converted to source BTUs to adjust the therm savings and was therefore removed from the electric analysis, yielding more electric savings.

Additionally, the evaluation team calculated coincident peak demand savings using the Illinois peak period of June through August, Monday through Friday, 1pm to 5pm. The coincident peak savings were calculated as the average kW savings during the peak time period. Since this project generally saves energy during the heating period, the coincident peak savings is 12.7 kW. The evaluation team found the ex ante power savings to be accurate based on the assumptions that the building is 25,200 square feet (sqft) with a cooling requirement of 450 sqft/ton and the project increases efficiency from 1.3 kW/ton to 1 kW/ton with a load factor of 80%.

Table 14. Summary of Project 2000192 Savings

	kW	kWh	Therms
Ex Ante	12.7	12,788	4,901
Verified	12.7	19,385	3,246
Realization Rate	100%	152%	66%

Note: This project was sampled for gas impacts only and therefore electric impacts are not relevant to final Custom Initiative savings. However, the evaluation team presents these impacts for consideration given the unique nature of this project. In addition, we are considering how to update our sampling approach to independently consider fuel-switching projects such as this in future years to ensure unbiased savings estimates.

Project 2000193

Project ID#:	2000193
Measure(s):	Variable Frequency Drives
Ex Ante Savings:	1,204,256 kWh; 678.5 kW
Facility Type:	Municipality
End Use(s):	Drainage Pumps
Sampled For:	Electric Savings
Wave:	1

Ex Ante Measure Description

This project consists of the installation of two 500 HP motors with variable frequency drives (VFDs). The new motors drive existing vertical turbine pumps that are used to provide municipal drainage. Previously, two 350 HP diesel engines drove two existing pumps. A 500 HP electric motor with no VFD still drives a third pump. The contractor removed the diesel engines and replaced them with the new electric motors with VFDs. The contractor did not modify the existing 500 HP electric motor, which remains in place and is available for service.

Summary of the Ex Ante Calculations

Annual pump energy use varies according to rainfall and river levels and is therefore not consistent from year to year. There are no flow meters at the site, so the implementation team estimated the average annual gallons of water pumped using pump runtime hours and pump flow curves. Each pump ran an average of 1,600 hours per year at 55,000 gallons per minute (GPM), the latter based on pump specifications. The team estimated annual gallons pumped as follows:

Equation 1. Annual Gallons Pumped

$$3\ pumps * 55{,}000\ GPM * 1{,}600\ hrs * 60\frac{min}{hr} = 15{,}840{,}000{,}000\ gallons/year$$

Since the engines being replaced were diesel powered, the implementation team assumed a baseline of two new 500 HP motors without VFDs driving the existing pumps. They assumed the pumps would operate at an efficiency equal to the maximum efficiency taken from the pump curve. Using the pump specifications, the implementation team estimated a 63,750 GPM baseline pumping rate. Using this information, the implementation team calculated run times for each pump to be 2,071 hours. The team estimated baseline motor power kW assuming a 100% load factor. The team's calculations are shown below.

Equation 2. Baseline Pump Runtime

$$\frac{15{,}840{,}000{,}000\ gallons}{63{,}750\ GPM * 60\frac{min}{hr} * 2\ pumps} = 2{,}071\frac{hours}{year}$$

Equation 3. Baseline Motor kW

$$\frac{500\ HP * 0.746\frac{kW}{HP}}{96.2\%\ motor\ efficiency} = 388\ kW$$

Equation 4. Baseline Motor kWh

$$388\ kW * 2{,}071\ hours * 2\ pumps = 1{,}605{,}674\ kWh$$

The new system will run with the same motors as assumed in the baseline calculation but with VFDs installed. The implementation team assumed that the speed, and therefore flow rate, would be set to 50% under normal conditions. At an average 50% flow rate, each pump would run 4,144 hours per year. The team estimated the new motor power using the standard affinity relationship, with an exponent of three between pump speed and motor power, as shown below.

Equation 5. New Motor kW

$$388\ kW * 0.5^3 = 48.5\ kW$$

Equation 6. New Motor kWh

$$48.5\ kW * 4{,}144\ hours * 2\ pumps = 401{,}419\ kWh$$

Equation 7. Energy Savings

$$1{,}605{,}674\ kWh - 401{,}419\ kWh = 1{,}204{,}256\ kWh$$

Measurement and Verification Plan

The project evaluation plan included an on-site verification to confirm the installation and operation of the VFDs and motors. The plan was to record motor and VFD nameplate information and to collect the following information:

- Total hours of operation on the motors equipped with VFDs to date
- Average speed of the VFDs according to trend data or operator logs
- Hydraulic profile of pumping system
- Normal pump discharge pressure from trend data or logs
- Minimum VFD speed at zero flow conditions

In addition, the evaluation team planned to ask the customer the following questions:

- How often do operators change pump speeds? Can it be done remotely?
- Have the pumps been modified since motor installation?
- Was the speed of the diesel pumps modulated? If not, was full speed equal to the turbine speed of the new motor at 100% speed?
- What other options for motor replacement did you investigate? What would you have installed without the program rebate?

We assumed that COVID-19 has not affected operation but planned to verify and follow up with appropriate questions if it has.

The evaluation team planned to verify the appropriate baseline for the project and calculate verified savings with the information collected during the on-site visit. We expected that the motors represent most of the billed power, so we planned to use utility metered interval data to verify the operating power of the new motors. That information, along with system static and dynamic head, would be used to estimate operating power at 100% speed using the following formula:

Equation 8. Operating Power Estimate at 100% Speed

$$HP_1 = HP_D * \left\{ \sqrt{\frac{H_{min}}{H_D}} + \left[\frac{F_1}{F_D} * \left(1 - \sqrt{\frac{H_{min}}{H_D}} \right) \right] \right\}^3$$

Where:

HP_1 = Motor power with VFD
HP_D = Motor power at 100% speed
H_{min} = Static Head
H_D = Dynamic Head
F_1 = Flow with VFD
F_D = Flow at 100% speed

While this formula also uses an affinity exponent of three, it differs from the ex ante calculation in that it will account for static head pressure that is typical in many municipal pumping operations.

Description of Verification

The evaluation team completed an on-site project evaluation on October 21, 2020. We interviewed the pump station operator and verified the installation and operation of the pump motors and VFDs.

We discussed the operation of the original and new equipment. The project was finished in the spring of 2020. The municipality refurbished and modified the vertical turbine pumps when the new motors were installed. The optimum operating speed of the refurbished pump occurs when the VFD is set to 52.16 Hz, or about 87% of full speed.

The municipality manually operates pumps as needed to maintain the desired water level in the drainage ditch. The VFD speed for each pump has been set to 52.16 Hz and is not adjusted. Local precipitation is the primary factor influencing pumping demand. Flooding of the river from upstream snow melt and runoff also increases groundwater and therefore the drainage ditch water level.

The evaluation team discovered that the third pump had its diesel engine removed about two years ago and replaced with a 500 HP electric motor and VFD combination that is identical to those installed for this project. Note that this differs from the ex ante project description in that the new motor *does* have a VFD. The pumps are operated on a three-pump rotation so that run times are approximately equal for each pump.

Summary of Verified Calculations

The evaluation team collected two years of interval billing data and conducted a whole-facility billing analysis to establish post-installation operation. We verified with the site contact that the pumps represent nearly all of the metered energy use. We also confirmed that there had been no major changes to plant operation since project implementation. Given this information, we determined that the pump power and hours of operation could be accurately established using utility interval data.

The interval data show that the historical annual energy usage for a single electric motor driven pump at the site is approximately 550,000 kWh. This estimate is based on the energy consumption for the facility prior to the installation of the new electric motors (when the diesel motors were running). Assuming equal runtime and motor loading for each pump, the total energy usage for an all-electric three-pump pumping facility might be around 1,650,000 kWh. This indicates the ex ante project savings of 1,204,256 kWh, or 73% of the facility's baseline energy consumption, are unlikely.

To estimate the energy consumed by the two new pump motors, the evaluation team analyzed the interval data to determine the hours of use for the pumping system and the number of pumps on at any given time. Note that the site contact was unable to provide this information because the facility doesn't have trending capabilities. Using the utility interval data, we calculated the average operating power for each pump and the total pump runtime for a slightly longer than six-month period beginning after project completion. By looking at the interval data, we could see how many pumps were running based on the total power draw. We found that 9.7% of the total time one pump was running, 6.8% of the total time two pumps were running and 4.5% of the total time three pumps were running. From the interval data we estimated that the average operating power of each pump was 201.1 kW. By summing the hours that pumps were running in the interval data, we calculated total run time for the pumps in the period analyzed to be about 1,668 hours. We extrapolated this value to an annual pump operation time of 3,223 hours. This method likely overestimates expected annual operation because the period analyzed was the spring and summer when we would expect most of the year's precipitation. The new pumps share duty with the existing pump, so we assumed that the new pumps would have a combined total run time of approximately 2,148 hours per year. We calculated estimated energy usage for the new equipment as follows:

Equation 9. New Pump Motor Annual Energy Consumption

$$201.1\ kW * 2{,}148\ hours = 432{,}055\ kWh$$

In order to ensure that our estimate was reasonable, we looked at rainfall during the post-installation period and found it to be slightly higher than normal at 24.3 inches compared to a TMY3 average total 18.6 inches. We tried to correlate rainfall with energy consumption but could not come up with a reliable correlation. As there was no good way for us to normalize energy consumption by rainfall, we assumed that the post-installation interval data was a reasonable representation of expected operation.

The evaluation team then calculated baseline energy usage and demand power using pump performance information provided with the application documentation and site observations regarding head pressure. Using the information in the application documentation and pump curves we estimated that the baseline pump and motor had a capacity of 55,000 GPM at 20 feet of head pressure and 76.8% pump efficiency. The nameplate efficiency of the new motors is 96.8%. We estimated baseline pump-motor power using the following equations:

Equation 10. Baseline Pump Brake Horsepower

$$\frac{55{,}000\ GPM * 20\ feet}{76.8\%\ eff * 3{,}960} = 361.9\ BHP$$

Equation 11. Baseline Pump Motor kW

$$\frac{361.9\ BHP * 0.746\frac{kW}{HP}}{96.8\%\ eff} = 281.1\ kW$$

As a reality check, we found that the estimated 361.9 BHP baseline brake horsepower is comparable to the rated power of the old 350 HP diesel engines.

Next, we estimated the flow rate of the new pumps with VFDs using the equation introduced in the Measurement and Verification Plan section above. Information gathered from the site helped us to estimate the static head pressure on the system to be 5 feet. The flow rate of the new pumps at 87% speed (the constant setting for the new VFDs per the site contact) is about 79.5% of full-flow capacity. Using this information, we estimated baseline annual energy consumption as follows:

Equation 12. Average Baseline Pump Motor Power

$$281.1\ kW * 79.5\% = 223.53\ kW$$

Equation 13. Baseline Pump Motor kW

$$223.53\ kW * 2{,}148\ hours = 480{,}243\ kWh$$

The evaluation team then calculated annual energy savings as the difference between the baseline pump motor annual energy consumption (480,243 kWh) and the new pump motor annual energy consumption (432,055 kWh). The resulting energy savings are 48,188 kWh.

Per the site contact, there is no set schedule for pump operation, so the evaluation team calculated coincident peak demand savings as the average demand savings for the months of June through August. To do this we estimated percent run time for the new pumps from the utility interval data. The pumps ran about 22% of the time during that period, so we estimated coincident peak demand savings to be about 22% of the average demand savings as shown below.

Equation 14. Coincident Peak Demand Savings

$$(223.53\ kW - 201.10\ kW) * 22\% = 4.9\ kW$$

A summary of the savings and realization rates can be seen in Table 4.

Table 15. Summary of Project 2000193 Savings

Measure	Savings	
VFDs	kW	kWh
Ex Ante	678.5	1,204,256
Verified	4.9	48,188
Realization Rate	0.7%	4.0%

Project 2000227

Project ID#:	2000227
Measure(s):	Heat Recovery Air Compressor
Ex Ante Savings:	20,578 therms
Facility Type:	Manufacturing/Industrial
End Use(s):	Space Heating
Sampled For:	Gas Savings
Wave:	1

Measure Description

The project consists of the installation of equipment to direct heat recovered from a new 420 horsepower (HP) variable frequency drive (VFD) air-cooled air compressor. The recovered heat is ducted to adjacent production areas to supplement space heating currently provided by direct-fired makeup air units. AIC provided a separate incentive for the VFD compressor under a separate project number.

The heat recovery measure described above was intended to be a part of a larger project that also included the installation of a 1,000 cubic feet per minute (CFM) externally heated compressed air dryer. The customer postponed the dryer installation and AIC moved it to a separate incentive project.

Summary of the Ex Ante Calculations

The implementation team estimated annual savings using the manufacturer-specified 18,250 Btu/min of heat rejected by the VFD air-cooled air compressor at full-load operation. The team used data that was collected for the VFD compressor project to establish average loading of about 47.7% of full load. Average compressor heat rejection was calculated using the following equation:

$$Btu/hour\ available\ =\ 18{,}250\ Btu/min\ *\ 47.7\%\ *\ 60\ min/hour$$

The implementation team assumed that recovered heat would be used to offset natural gas usage for heating from November through March. They assumed that the efficiency of the direct-fired makeup air units was 92%. They established annual gas (therm) savings using the following equation:

$$Therm\ savings = Btu/hour\ available\ *\ Total\ hours\ (Nov - Mar)\ /\ (99{,}976.1\ BTU/Therm)/92\%\ efficiency$$

To move the recovered heat from the compressor room to the occupied space (or to the outside when not needed), the contractor added two 7.5 HP fans and. Only one of the fans was expected to operate at any given time, but fan operation will be continuous year-round. An electrical penalty for the fan was calculated using the fan specifications as follows:

$$Fan\ Power\ kW\ =\ 6.21\ BHP\ *\ 0.746\ kW/HP$$

$$Fan\ Energy\ Usage\ kWh\ =\ Fan\ Power\ kW\ *\ 8{,}760\ Hours/year$$

Note that this electric penalty is not subtracted from the ex ante savings value.

Measurement and Verification Plan

The original measurement and verification (M&V) plan is as follows:

The evaluation team will conduct an on-site verification to confirm the installation and operation of the new heat recovery system. We will collect information on the direct-fired makeup air units (MUAs) and their efficiencies. We will collect compressor and fan nameplate information and ask the customer the following questions:

- Has COVID affected operation? If so, how? (Note that if the answer is yes, we will walk through the various shutdown/reopening phases in the state and ask how operation changed during each phase)
- What are normal working hours?
- Does the 420 HP compressor run continuously? If not, how many hours per week does it run?
- Does the plant shut down for holidays or other shutdown periods? Which ones? When?
- Is the compressor off during shutdowns?
- What is the temperature set point of the facility?
- At what outdoor air temperature (OAT) is heating generally needed? (i.e. what is the balance point OAT?)
- Are there any temperature setbacks scheduled?
- Is heat recovery switchover automatic?
- What is the sequence of operation if there is no call for heating?
- What is the discharge temperature of the existing heating units?
- Did the old compressor room have any heat recovery/reuse capability?
- Do the compressors use dedicated outside air inlets?
- Are any trend data or operator logs available?

We will use the information collected to estimate gas savings due to the new heat recovery system. We will validate average compressor loading by examining available facility records or by confirmation with the site representative. We will use the average compressor loading to estimate available heat rejected by the compressor. We will estimate the hours of required heating from local TMY3 data and operating information provided by the site representative. Gas savings will be calculated as follows.

$$\begin{aligned} Therm\ Savings &\\ &= Average\ Heat\ Recovered\ (Btu/hr) \\ &* Hours\ of\ Heating\ Demand\ /\ MUA\ Unit\ Heating\ efficiency\ /\ (99{,}976.1\ BTU/Therm) \end{aligned}$$

The implications of fuel-switching pertaining to the additional electrical energy usage of the fans will be reviewed and, if determined to be necessary, will be considered in the savings calculations to account for source BTUs.

Process Evaluation Questions

Our priorities during the onsite are to 1) collect the information and data needed for a robust impact analysis and 2) ensure a positive customer experience. We understand that our on-site visits take valuable time away from AIC customers' workday. That said, if the opportunity arises, or if our point of contact starts to discuss their experience with the program, we will listen and take notes. If we have time, we may ask any of the following questions:

- What was your experience with the program? The application process?
- If you could improve the program, what would you suggest improving?
- Did you directly interact with AIC? If yes, what was your experience with their staff?
- Would you participate in the program again? Why or why not?
- Would you recommend the program to others? Why or why not?
- Without this program, would you have installed these measures? Different measures? Please explain.
- How did you hear about the program?
- Were there any areas where you were especially dissatisfied with the program?
- Were there any areas where you were especially satisfied with the program?

Description of Verification

The evaluation team completed an on-site project evaluation on December 16, 2020. We interviewed the facilities manager and verified the installation and operation of the new compressor and heat recovery system.

We discussed the operation of the air compressor and the facility heating system. The new compressor generally runs 24 hours per day, 7 days per week. The system includes several centrifugal air compressors in a separate mechanical room. During the week, the centrifugal compressors run base-loaded and the new compressor acts as the trim compressor. On weekends the new compressor is generally able to meet plant air demand.

The heat recovery system includes ductwork and dampers with actuators to direct warm air to the plant or outside as needed. Controls are in place to automatically re-direct warm air from the compressor to the plant when outdoor air temperatures (OATs) are about 60°F or lower. At higher temperatures, the recovered warm air is exhausted to the outdoors. Intake air is dedicated outside air ducted directly to the compressor.

Plant heating is provided by Cambridge makeup air units (MUAs) with direct-fired heating sections. Direct-fired MUAs have a 92% thermal heating efficiency. The temperature setpoint at the plant is between 65°F and 68°F and there are no setbacks for unoccupied conditions.

The evaluation team also discussed the customer's experience with the efficiency program. The site contact reported a positive experience with the program and would recommend it to other customers. The plant has previously used the program for significant re-lighting projects. The customer did not have much interaction with AIC staff because vendors have generally taken care of paperwork required throughout the application process.

Without the benefit of the program, the customer would probably have put in a water-cooled compressor without heat recovery. The site contact reported plans to install 1.8 MW of solar power at the facility. Overall, the customer is very satisfied with the program, although time spent on some application processes is a little challenging.

Summary of Verified Calculations

The evaluation team established measure savings using a combination of assumptions and specifications used for the ex ante calculations, information collected at the site, and TMY3 weather data. It appears that the 47.7% average compressor loading used for the ex ante calculations was derived from data collected for the VSD measure, so we used that assumption to calculate hourly potential heat recovery.

$$Btu/hour\ available\ =\ 18{,}250\ Btu/min\ *\ 47.7\%\ *\ 60\ min/hour\ =\ 522{,}284\ Btu$$

We assumed that heat recovery would be disabled from May through October. For the rest of the year, we assumed that the building temperature balance point was about 55°F and heat recovery would occur when OATs were below that value. Using TMY3 data, we calculated heat recovered for each hour of the year and totaled the results.

$$Therm\ Savings = Total\ Heat\ Recovered\ (Btu)\ /\ 92\%\ MUA\ Heating\ efficiency\ /\ (100{,}000\ BTU/Therm)$$

This analysis resulted in savings of about 21,000 therms. Therefore, we determined that the ex ante savings for this project were reasonable and did not adjust the claimed savings. As this project was selected as a part of the gas sample, and given that the subtracting the electric penalty from the gas savings would have a minimal impact on the project's realization rate, we did not evaluate the electrical penalty for the two fans. Note that while the calculations show a realization rate of 102%, we decided a 100% realization rate was more reasonable due to uncertainties regarding the true building balance point temperature and whether the electric penalty should be subtracted from the gas savings.

A summary of the savings and realization rate can be seen in Table 16.

Table 16. Summary of Project 2000227 Savings

Measure	Therms
Ex Ante	20,578
Verified	20,578
Realization Rate	100%

Project 2000703

Project ID#:	2000703
Measure:	Boiler Economizer
Ex Ante Savings:	44,963 Therms
Facility Type:	Manufacturing/Industrial
End Use:	Food Processing
Sampled For:	Gas Savings
Wave:	2

Measure Description

This project covers the replacement of an existing boiler stack economizer. The economizer was installed on a 1,500 HP steam boiler and will be used to preheat boiler feed water with energy that would otherwise be rejected to atmosphere. The existing economizer on this boiler had been out of commission for three years and was removed as part of this project. The boiler system includes two 800 HP boilers that are not included in this project because the 1,500 HP boiler produces most of the process steam used in the facility.

Summary of the Ex Ante Calculations

The implementation team used spreadsheet-based calculations to establish measure savings. The facility is a seasonal food processing plant that is in production from September to December. The implementation team estimated total annual hours of use to be for 16 weeks, 6 days per week, 24 hours per day, or 2,304 hours. The team assumed that the boiler would operate at 100% firing rate 8% of the time, at 75% rate for 40% of the time, at 50% for 32% of the time, and at 25% for 20% of the time.

Using the assumed hours of operation, the implementation team estimated total baseline gas usage using boiler efficiencies as a function of firing rate. They collected efficiencies by firing rate from vendor-provided combustion analysis testing. Using the run times and efficiencies, the team estimated baseline energy consumption assuming 62,100 lbs/hours boiler steam output. The enthalpy of steam at the operating pressure is 1,198 Btu/lb, while the enthalpy of the boiler feedwater is 180 Btu/lb resulting in 1,018 Btu/lb of heating input for the boiler feedwater. An example equation is shown below:

$$Boiler\ output\ at\ 75\%\ fire\ =\ 62{,}100\frac{lbs}{hr} * \ 75\%\ firing\ rate\ *\ 1{,}018\frac{Btu}{lb} =\ 47{,}395{,}652\frac{Btu}{hr}$$

$$Boiler\ output\ at\ 75\%\ fire\ =\ \frac{47{,}395{,}652\ \frac{Btu}{hr}}{79.5\%\ efficiency} * (40\% * 2{,}304\ hrs) * \frac{1}{100{,}000\ \frac{therms}{Btu}}$$

$$=\ 549{,}432\ therms$$

The team repeated these calculations, with efficiency, Btu/hr, and hours adjusted for each firing rate and summed the results for an estimated 1,076,697 therms used annually by the 1,500 HP boiler.

This result was close to the facility's total annual gas usage even though the implementer's calculation did not account for gas usage by the two backup boilers. The implementation team, with input from the program ally, reduced estimated baseline usage by 20% to account for the gas usage of the backup boilers and make the baseline gas consumption of the 1500 HP boiler more reasonable.

$$Baseline\ boiler\ gas\ usage\ =\ 1{,}076{,}697\ Therms\ *\ 80\%\ =\ 861{,}357\ Therms$$

The implementation team estimated the effect of the economizer using specifications and capacities provided by the vendor. The economizer is predicted to transfer 3,551,417 Btu/hr at 100% firing rate. Two percent of the heat will be lost through the economizer shell, so the implementation team established full-load heat recovery as follows:

$$Net\ heat\ recovery\ at\ 100\%\ fire\ =\ 3{,}551{,}417\ Btu/hr\ *\ 98\%\ =\ 3{,}480{,}389\ Btu/hr$$

The implementation team estimated gas usage with the economizer using the same hours and load profile as they used to establish baseline gas usage. The team calculated the boiler's efficiency with the economizer by assuming that heat recovered will offset gas consumed (input) as shown in the following example at 75% firing rate:

$$Boiler\ output\ at\ 75\%\ fire\ =\ 62{,}100\frac{lbs}{hr} *\ 75\%\ firing\ rate\ *\ 1{,}018\frac{Btu}{lb} =\ 47{,}395{,}652\frac{Btu}{hr}$$

$$Economizer\ heat\ recovery\ at\ 75\%\ fire\ =\ 3{,}480{,}389\frac{Btu}{hr} *\ 75\%\ firing\ rate\ =\ 2{,}610{,}291\frac{Btu}{hr}$$

$$Boiler\ input\ at\ 75\%\ fire\ =\ \frac{47{,}395{,}652\frac{Btu}{hr}}{79.5\%\ efficiency} =\ 59{,}617{,}172\frac{Btu}{hr}$$

$$Economizer\ efficiency\ improvement\ =\ \frac{2{,}610{,}291\frac{Btu}{hr}}{59{,}617{,}172\frac{Btu}{hr}} =\ 4.38\%$$

$$Boiler\ with\ economizer\ efficiency\ =\ 79.5\%\ +\ 4.38\%\ =\ 83.88\%$$

$$Boiler\ gas\ usage\ with\ economizer\ at\ 75\%\ fire$$
$$=\ \frac{47{,}395{,}652\ \frac{Btu}{hr}}{83.88\%\ \%\ efficiency} * (40\% * 2{,}304\ hrs) * \frac{1}{100{,}000\ \frac{therms}{Btu}} =\ 520{,}752\ therms$$

The implementation team repeated these calculations at each firing rate and summed the results for an estimated 1,020,493 therms used annually by the 1,500 HP boiler with the economizer. The team reduced this value by 20% as was done with baseline usage:

$$Net\ boiler\ gas\ usage\ with\ economizer\ =\ 1{,}020{,}493\ therms\ *\ 80\%\ =\ 816{,}395\ therms$$

$$Gas\ Savings\ =\ 861{,}357\ therms\ -\ 816{,}395\ therms\ =\ 44{,}963\ therms$$

Measurement and Verification Plan

The following is an unedited version of the original M&V plan:

The evaluation team will verify this project through a virtual site visit. We will verify the installation and confirm economizer model number, discuss the operation of the boilers and economizer with the site contact. We will request any operating data for the boilers (e.g. trend data, operator's logs). The team has determined that the general approach used by the implementation team is reasonable and we expect to use a similar approach.

Using the information collected, we will update the values used in the ex ante calculations as needed to match as-found conditions.

Specific questions for the site contact include:

- When was the project started and completed?
- What was wrong with the old economizer?
- How long was the old economizer in service?
- What are the steam end uses? Is it a continuous process?
- Can you provide any operating data (e.g. trend data of boiler input, % load, operator logs, hour-meters, make-up water volume)?
- What are typical temperature differences across the economizer?
- What is the normal daily operating schedule and production season?
- What are the other major end uses for gas?
- What is the steam contribution of the two backup boilers during production?
- Have there been any other projects in the last two years that significantly impact the building's gas consumption?
- How often is the boiler tuned-up and/or inspected?
- Are efficiency reports available for the boiler?
- Have there been any changes to boiler operation since installation?
- Are any production records available going back several years (monthly and annual)?

COVID-19 specific questions may include:

- Has operation of your facility been affected by COVID-19?
  - If so, how?
  - If so, will boiler use return to pre-installation usage when operation becomes 'normal"? If not, what is your prediction for operation at that time?

Note that if the facility has been impacted by the COVID-19 pandemic, we'll walk through the different phases of the COVID-19 shutdown/reopening that the state has gone through and ask what changed during each phase.

Description of Verification

The evaluation team interviewed the plant manager on February 18, 2021 and also communicated with the trade ally, who provided some of the project information.

The customer stated that the economizer is functioning as expected. This boiler is the primary source of process steam for the plant, with two other boilers providing about 30% of the process load. There are no provisions for logging or trending boiler use.

Production is seasonal, with processing generally taking place from mid-August through November. Production was not affected by the COVID-19 pandemic, and 2020 production was the highest on record for the facility.

Summary of the Verified Calculation

The evaluation team reviewed the ex ante approach to establishing savings and found it to be generally reasonable. We used those calculations as the basis of our calculations, with adjustments made based on the information collected during our evaluation. The trade ally provided the most-recent boiler test report, dated August 29, 2019, and we collected gas usage data through the end of December 2020.

We used billed usage for the months of September through December from 2018, 2019, and 2020 to calibrate boiler load factor calculations. We adjusted December usage for gas heating by assuming heating usage would be similar to January usage. Given the fact that we used 2020 billed energy usage to establish baseline conditions and the fact that the project was completed prior to the 2020 production season, we added back in the estimated 2020 gas savings from this measure to the billed data to ensure we approximated baseline conditions correctly. Production for the 2020 processing season was somewhat higher than for the previous two years, which increased the average annual gas usage. This resulted in higher load factors than those used in the ex ante calculations, which had the effect of increasing savings. That effect was mitigated somewhat by an increase in the estimated contribution of the backup boilers from 20% to 30%, per the trade ally. We made small adjustments to boiler efficiency to match the boiler test report we received.

The evaluation team also modified the calculations used to determine the contribution of the economizer to gas savings. The implementation team estimated the percent increase in efficiency due to the economizer and added it to the baseline boiler efficiency to estimate post retrofit gas usage. We estimated the heat recovered by the economizer and assumed that it was equivalent to boiler output. We then used the boiler efficiency to establish post-retrofit gas usage. Using the 75% firing rate example as shown above in the ex ante calculation section, we determined post retrofit gas usage as follows:

$$Economizer\ heat\ recovery\ at\ 75\%\ fire\ =\ 3{,}480{,}389\frac{Btu}{hr} * \ 75\%\ firing\ rate\ =\ 2{,}610{,}291\frac{Btu}{hr}$$

$$Boiler\ output\ at\ 75\%\ fire\ =\ 62{,}100\frac{lbs}{hr} * \ 75\%\ firing\ rate\ * \ 1{,}018\frac{Btu}{lb} =\ 47{,}395{,}652\frac{Btu}{hr}$$

$$Net\ boiler\ output\ =\ 47{,}395{,}652\frac{Btu}{hr} - \ 2{,}610{,}291\frac{Btu}{hr} =\ 44{,}785{,}360\frac{Btu}{hr}$$

$$Boiler\ input\ at\ 75\%\ fire\ =\ \frac{44{,}785{,}360\frac{Btu}{hr}}{80.9\%\ efficiency} =\ 55{,}358{,}912\frac{Btu}{hr}$$

$$Boiler\ gas\ usage\ with\ economizer\ at\ 75\%\ fire\ =\ 55{,}358{,}912\ \frac{Btu}{hr} * (524\ hrs) * \frac{1}{100{,}000\ \frac{therms}{Btu}}$$

$$=\ 290{,}169\ therms$$

As was done in the ex ante calculations, we repeated this exercise for the four different firing rates and added the results to obtain total baseline and post retrofit gas usage.

A summary of the ex ante and verified savings is provided below in Table 17.

Table 17. Summary of Project 2000703 Savings

	Therms
Ex Ante	44,963
Verified	46,728
Realization Rate	104%

Project 2001465

Project ID#:	2001465
Measure:	Lighting
Ex Ante Savings:	3,000,162 kWh and 423 kW
Facility Type:	Manufacturing/Industrial
End Use:	Cannabis Lighting
Sampled For:	Electric Savings
Wave:	3

Measure Description

This project is for the installation of efficient LED grow lights in an indoor cannabis grow facility. The facility is installing Spydr-2x LEDs instead of 8-lamp T5 linear fluorescents in a new portion of the facility. The customer operates a medical cannabis grow facility at the site of this project. This customer added a vegetation room with multi-level racking requiring (726) 342 W LED fixtures. The baseline lighting system for the vegetation room was (1,452) 8-lamp, 4-foot T5 fixtures with equivalent light output at 432 W input. This baseline was selected because it was the lighting used in the rest of the facility. Additionally, the customer replaced (168) 8-lamp, 4-foot T5 fixtures with (84) LED fixtures in a smaller existing vegetation room.

Key Findings

The ex ante calculation method was reasonable. There was an early review done by the evaluation team and the implementation team made the suggested changes. The reduction in demand savings results from the fact that the installed lights are off during the Illinois coincident peak period.

The resulting project savings are shown in Table 18 below.

Table 18. Summary of Project 2001465 Savings

	kW	kWh
Ex Ante	422.8	3,000,162
Verified	0.0	3,000,162
Realization Rate	0%	100%

Summary of the Ex Ante Calculations

The ex ante calculation was done separately for the Phase 5 veg room and legacy veg room. The implementers assumed the new LEDs will be an exact replacement for two 8-lamp T5 fixtures. The number of racks will remain the same, 42 in the legacy room and 363 in the Phase 5 room. The baseline requires four fixtures per rack whereas with the LEDs only two fixtures per rack are required. Both rooms require 18 hours on and 6 hours off per day for all the lights, every day. This equates 6,570 hours per year.

In the energy efficient case the customer installed 810 LED fixtures to replace (or instead of) 1,620 T5 linear fluorescents fixtures. The power input values for the new fixtures match the Fluence SPYDR-2x 342 W LED Grow Light that appears to be the model installed. The baseline T5 fixtures had an estimated 432 W input power per fixture, which is a reasonable value.

The implementers considered that the facility is mechanically cooled (the rooms are cooled with VFD compressor wall technology and rooftop units). Therefore, an energy waste heat factor was included in the final annual energy consumption savings calculation. In this case, using IL-TRM Measure 4.1.11, the waste heat factor is 8% (increasing overall savings).

The calculated peak demand savings are the simple difference between total baseline kW and total proposed kW without consideration of interactive effects or the peak period as defined in the IL-TRM. While the lights are expected to be on 18 hours per day every day, the documentation doesn't report the schedule.

Summary of the Verified Calculations

The evaluation team conducted an interview with a site contact to verify this project. The lights were installed and operating as expected. The vegetative rooms have timer-based lighting controls. The lights are on 18 hours per day from 5pm to 11am (they are off between 11am and 5pm). We confirmed that the spaces are mechanically cooled as described above.

The method for the ex ante calculation was determined to be generally reasonable. The baseline is appropriate considering that T5 lighting was already installed in the rest of the facility. For further discussion of the eligibility of this facility for this baseline, please see the discussion of Project 1901698. We believe the calculations for the energy efficient case are accurate. We made no changes to the energy savings calculation since the implementers made the suggested changes during the early review. The verified energy savings are 3,000,162 kWh.

The evaluation team calculated the coincident peak demand savings using the Illinois peak period of June through August, Monday through Friday, 1pm to 5pm. We calculated the coincident peak savings as the average demand (kW) savings during that period. The lights are off during the duration of this period, so the demand savings are 0 kW.

Project 2100011

Project ID#:	2100011
Measure:	Compressed Air
Ex Ante Savings:	1,552,849 kWh; 177 kW
Facility Type:	Manufacturing/Industrial
End Use:	Compressed Air
Sampled For:	Electric Savings
Wave:	3

Measure Description

This project is to replace a refrigerated air dryer with a heated blower purge desiccant dryer. The compressed air system at this facility is supplied by 3 air compressors with a total capacity of 9,735 cubic feet per minute (CFM) and is dried by refrigerated dryers. To improve the quality of compressed air, the customer upgraded to a desiccant dryer. On average the plant's compressed air load is about 3,500 CFM with peaks of about 5,500 CFM. To account for any growth or higher than normal usage, a new 7,000 CFM dryer was installed. The baseline dryer is a GPS-7000 heatless regenerative dryer. The proposed equipment is a GBS-7000 heated blower purge dryer.

Key Findings

The main reason for the savings adjustment was the reduction in run hours. The ex ante calculation assumed the dryers would run continuously but the interview with the site contact confirmed they shut down for several federal holidays and for maintenance every six months. The resulting project savings are shown in Table 19 below.

Table 19. Summary of Project 2100011 Savings

	kW	kWh
Ex Ante	177.27	1,552,849
Verified	177.27	1,514,560
Realization Rate	100%	98%

Summary of the Ex Ante Calculations

For this project, the implementation team established project savings using metered data from the old system. Compressor current (amps), system pressure in pounds per square inches (psi), and total system flow in cubic feet per minute (CFM) were collected at 12-second intervals for a 1-week period from April 29th to May 6th, 2020. The implementer sorted total system flow (CFM) into 4-hour averages. They used this compressor flow to estimate how much load each compressor will contribute to the overall system load.

The average system flow was determined to be 3,555 CFM, this is the load on the baseline and efficient dryer. The baseline and proposed equipment have a maximum load of 7,000 CFM. The baseline purge flow (CFM) was determined to be 15% of the maximum since it is a heatless dryer, the proposed purge is 490 CFM, or 7% for a heated dryer. Another difference between the two is that the heater demand in the proposed case is a maximum of 125 kW, with an average of 61.6 kW. Both the baseline and proposed are assumed to run continuously (8,760 hours per year).

The formula used for the baseline and proposed is as follows:

$$Avg\ Dryer\ kW = \left(\frac{Purge\ CFM * \%Purge}{Efficiency} + Heater\ kW + Blower\ HP * \%Blower * \frac{0.746}{0.93}\right) * \left(\frac{Load\ CFM}{Max\ CFM}\right)$$

In the equation above, the final term with the load CFM and max CFM only comes into account if the control strategy is dew point demand, otherwise that fraction is 1. In this case only the proposed equipment has this control type.

In both the baseline and proposed case, this average kW can be multiplied by the run hours to give kWh consumption. For this project the baseline consumption is estimated to be 2,052,984 kWh, proposed will be 500,134 kWh, and savings is 1,552,840 kWh.

The demand reduction calculation does not consider the peak period as defined in the IL-TRM, however, if the dryer really does run continuously then the coincident peak will be the same as the demand savings calculated here. For this project the baseline average demand is 234.36 kW and proposed is 57.09 kW, resulting in savings of 177.27 kW.

Measurement and Verification Plan

The following is an unmodified version of the original M&V plan for this project:

The evaluation team will evaluate this project through a remote site visit. We plan to estimate the verified savings using the provided metered data and using extrapolation or other calculations as needed. Our team will check if production is continuing at the expected normal rate and remains unchanged due to COVID-19 or any other reason. For our remote site visit, we will ask the site contact the following questions:

- Is there an onboard controller that can be used to take measurements of current operating conditions (including flow, pressure, and hours of operation) of the new equipment? If so, does it have any trend data we can use to better understand the current or previous system operation?
- The calculation for the energy usage of the previous equipment used metered data from April 29th to May 6th, 2020. Is that week an accurate representation of normal production? Is that week an accurate representation of normal compressed air usage?
- What is the current operating/production hours?
- When was this project started and completed?
- Were any other (rebated or non-rebated) projects completed around the same time as this project?
  - If so, did you receive rebates for any of them? Which ones?
- Has production/operation changed since installation of the new equipment? Since implementer verification?
- Has the operation of or production at your facility been affected by COVID-19? If so, how? (Note that if the answer is yes, we'll walk through the different phases of shutdown/reopening that the state has gone through and ask what changed during each phase.)

We conducted a remote site visit to review the following:

- Was the equipment that was specified installed and is it operating as expected?
- Are the onboard controls visible and is the instantaneous operation in line with the VSD curves provided by the equipment specifications?

Description of Verification

The evaluation team had a phone interview with the site contact. They confirmed the installation and operation of the new equipment. They stated that the project was completed in November of 2020 and the compressed air system has been running at about 3,500 average CFM with the new dryer. They confirmed that the dryer will be off for a couple days every six months and will shut down for federal holidays. This was not accounted for in the original calculations. The metered period last year should show accurate data for any time that the compressors are running continuously. This facility has not made any production or operation changes due to COVID-19.

Verified Savings

During verification, the evaluation team found that there have been no major changes in operation or production since the installation of the new dryer. The formula for calculating average demand was determined to be a good representation since it matches the formula in IL-TRM Measure 4.7.5, with modifications to the formula for the heated blower and dewpoint demand controls.

Therefore, the only change made to the annual savings was the reduction in hours from continuous (8,760 hours per year) to 8,544 hours per year. This takes into account four maintenance days per year plus Christmas Day, New Year's Day, Independence Day, Memorial Day, and Labor Day. The reduction in hours reduces savings to 1,514,560 kWh.

The evaluation team calculated the coincident peak demand savings using the Illinois peak period of June through August, Monday through Friday, 1pm to 5pm. We calculated the coincident peak savings as the average demand (kW) savings during that period and since the dryer will run continuously through the coincident peak period. The coincident peak demand reduction was found to be 177.27 kW, the same as the savings estimated by the implementer in the ex ante calculation.

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