Foss Performance Materials
Utility Study

May 5, 2021

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1 Executive Summary

Foss Performance Materials has a number of interconnected resources that contribute to meeting its annual energy needs. These include a combined heat and power facility, a reciprocating engine generator, utility electric connections, boilers at multiple steam pressures, hot oil boilers, and steam driven absorption chillers. The purpose of this study was to develop a model of the facility energy loads that can be used to evaluate the current operation strategy and assess different equipment line ups.

1.1 Operation of the Combined Heat and Power Plant

A number of options were considered regarding operation, or non-operation of the Combined Heat and Power (CHP) plant. It was not found that utility savings could be achieved by connecting the entire facility to the electric grid and not running the gas turbine. There is a large amount of uncertainty regarding plant loads due to lack of metering, therefore range results were obtained by applying high and low bounds to uncertain values. The value of running the CHP in terms of annual utility savings, including the cost of CHP maintenance agreements, is likely between $400,000 and $1,400,000 per year. The variation is due to unknowns regarding the steam load, chilled water load, and facility capacity tag, a component of electric supply cost. Additionally, in order to not run the CHP, a significant capital investment would be required to upgrade the plant electrical system, possibly install another boiler, and optionally install electric chillers (included in the $400,000/yr operating cost increase estimate without CHP).

1.2 Energy Efficiency Improvements

Several energy efficiency improvements were considered based on the assumption provided by Foss that 50% of steam production from the HRSG may be condensed or vented. Steam condensing or venting results in wasted energy that could be used to offset existing gas loads. Utilizing all waste heat from the HRSG is the single most important means of improving plant energy efficiency and achieving savings. Options considered include upgrading the HRSG so that it can meet loads served by the 300 psig boiler, installing a steam to hot oil heat exchanger, installing a back-pressure steam turbine, and installing a hot oil heat recovery system on the gas turbine exhaust. These options show the potential for providing energy savings. High level simple paybacks were calculated for these options with the best, the hot oil heat recovery system, resulting in a 5 year payback when associated process equipment upgrades are considered a sunk cost and not included in the analysis.

1.3 Thermal Load Uncertainty

Due to the lack of steam and chilled water metering in the facility, there is a lot of uncertainty with regards to plant loads and therefore the results of this study. In order understand plant efficiency and accurately quantify potential energy savings measures, it is critical that metering and data logging be installed. The highest priority meters are those that would give the quantity of steam being wasted. This can be done by either metering the condensing and venting lines directly or by metering production and use.

1.4 Recommendations

This study showed that there is potential to improve energy efficiency and achieve savings, largely through the full utilization of waste heat generated by the CHP. Waldron recommends the following next steps:

i. *Install Metering*

There is a significant amount of uncertainty regarding the quantity of waste heat available, therefore the value of capturing it cannot be determined with enough confidence to recommend capital projects. In order to eliminate some of this uncertainty, Waldron recommends installing steam and chilled water flow meters with data logging capability so that the facility steam and chilled water demand can be monitored of the course of a year and the quantity of vented/condensed steam can be determined. Steam is the more critical system to meter, and can be done on either the production or use side. The HRSG has meters which only need data logging, so the production side may be easiest. Of upmost importance is to meter, directly or indirectly, is steam condensing and venting. Waldron has updated a schematic of the thermal system with recommended metering locations, included in Attachment A.

ii. *Develop Potential Energy Efficiency Projects Further*

When metering has been installed and there is a better understanding of Foss's thermal loads, the potential annual savings from a number of capital projects can be determined. The next step would be making a decision on which energy efficiency projects are most beneficial and to develop the design to the next level of detail to improve the accuracy of the project cost estimate. This study showed that the project with the best potential payback was the CTG Exhaust Gas/ Hot Oil Heat Exchanger project, including the conversion of coils in the ovens from steam to hot oil.

iii. *Consider Optimizing Chilled Water System*

During the course of the study Waldron noted that there may be opportunities to improve the chilled water system operation and efficiency. It was noted that chillers are not operating at their design ratings and that chilled water flow is roughly half of what it should be. It is recommended a separate study of the chilled water system be conducted and it is believed there is potential to increase system output and efficiency. Though increasing output would not provide savings, it could likely be done at minimal increased operating cost due to the unused waste heat from the HRSG, and could increase overall plant efficiency by reducing wasted steam.

2 Review of Existing System

2.1 Cogeneration Plant

The existing cogeneration plant consists of a natural gas fired Solar Turbines Taurus 60 Combustion Turbine Generator (CTG) with a Rentech Heat Recovery Steam Generator (HRSG). The CTG is rated nominally at 5.3MW, and the HRSG is rated nominally at 7,746 lb/hr of 140psig steam and 19,495 lb/hr of 15psig steam. Because the HRSG does not have a duct burner (to increase steam production) or a bypass damper (to decrease steam production), the steam production is tied directly to the operation of the gas turbine. Foss has a Long-Term Service Agreement (LTSA) with Solar Turbines for maintenance. This is a full service maintenance agreement that comes with a monthly fee.

To model the existing CHP, performance data from Solar Turbines was used to calculate the operating parameters of the turbine at different temperatures and load points. This performance data can be seen in Figure 2.1 below. The energy model developed for the study interpolates CTG performance based on % electric load and outdoor ambient temperature. The CTG exhaust flow and temperature, as well as some other parameters shown in Figure 2.2, are used to calculate HRSG steam production, shown in Figure 2.3. GE's gatecycle thermodynamics software was used to estimate HRSG exhaust temperature profiles at off design conditions which were used in calculation of HRSG steam production.

Ambient Temperature (deg F)	100% Output (kW)	75% Output (kW)	50% Output (kW)	100% Heatrate (Btu/kWh, LHV)	75% Heatrate (Btu/kWh, LHV)	50% Heatrate (Btu/kWh, LHV)
0	6,505	4,878	3,252	10,077	11,555	13,032
20	5,975	4,481	2,988	10,117	11,638	13,159
40	5,589	4,192	2,795	10,182	11,752	13,322
60	5,300	3,975	2,650	10,319	11,955	13,592
80	4,915	3,686	2,458	10,590	12,322	14,054
100	4,433	3,324	2,216	11,085	12,966	14,846

Ambient Temperature (deg F)	100% Exhaust Flow (lb/hr)	75% Exhaust Flow (lb/hr)	50% Exhaust Flow (lb/hr)	100% Exhaust Temp (deg F)	75% Exhaust Temp (deg F)	50% Exhaust Temp (deg F)
0	148,701	121,943	95,185	957	1,010	1,063
20	139,533	114,558	89,583	960	1,014	1,069
40	133,500	109,765	86,031	966	1,021	1,077
60	130,209	107,214	84,219	975	1,032	1,088
80	125,002	103,163	81,323	992	1,049	1,105
100	118,290	97,927	77,564	1,020	1,075	1,130

Figure 2.1 CTG Performance Data

Exhaust Gas Specific Heat (Btu/(lb-°F)	0.265
130 Steam Enthalpy (Btu/lb)	1195
15 Steam Enthalpy (Btu/lb)	1164
Feedwater Enthalpy (Btu/lb)	187
Flue Temperature After 130 Psig Section (°F)	~800
Flue Temperature After 15 Psig Section (°F)	~336

Figure 2.2 Parameters Used in HRSG Steam Output Calculation

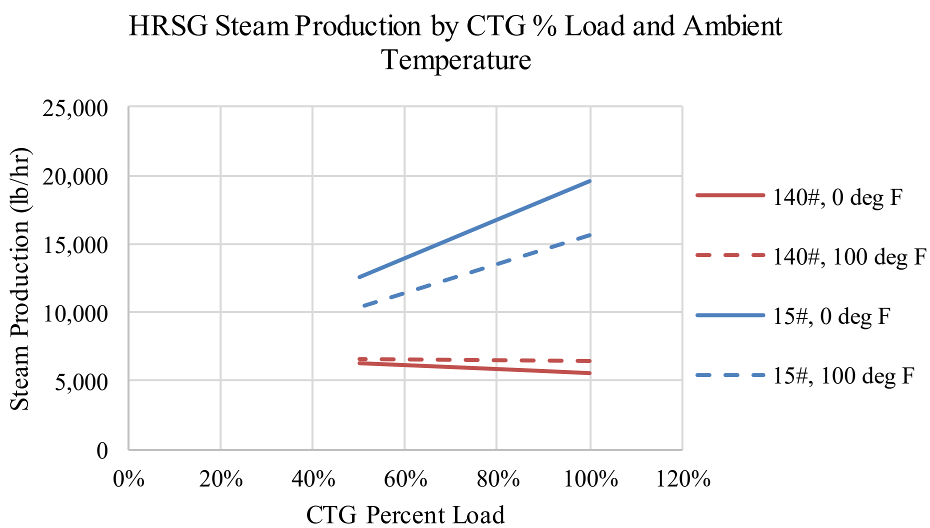


Figure 2.3 HRSG steam production by CTG percent load at the 15 and 130 Psig Level for 0/100 deg F ambient temperature

2.2 Boiler Summary

Steam is produced at three pressures in the boiler plant, 240 psig, 130 psig, and 15 psig. The boiler plant has three gas fired steam boilers in addition to the HRSG. Two of these boilers supply steam to the main 130 psig steam header to back up the HRSG. The third is the sole supply of 240 psig steam for the plant. A summary of the boilers can be seen in the figure below.

Equipment Name	Operating Pressure (psig)	Design Pressure (psig)	Temperature (°F)	Boiler Horsepower (BHP)	Approximate Capacity (lb/hr)
CB350LE	240	300	402	350	12,000
CB350	130	150	356	350	12,000
95 Boiler	130	150	356	95	3,000
HRSG	130	150	356	-	7,700
	15	20	250	-	19,500

Figure 2.4: Boiler Summary

There are pressure reducing stations which can cascade steam from the 240 psig header to the 130 psig header and from the 130 psig header to the 15 psig header. 15 psig steam can be condensed or vented to control header pressure when steam production outpaces demand.

2.3 Chiller Summary

The chiller plant consists of three single effect steam driven absorption chillers. These chillers use 15 psig steam to produce chilled water. Chillers 1 and 2 are aging, have many plugged tubes, and no longer make their rated output. Chiller 3 is new, but also does not make its rated output due to condensate back up. An ultra sonic flow meter was used to determine the actual chiller output on a design cooling day for chillers 1 and 3. Chiller 2 did not have a location that would work for placement of the meter so it was skipped, but it can be assumed that the de-rate for chiller 2 is likely similar to chiller 1.

Equipment Name	Rating (ton)	Measured Capacity (tons)	Rated Steam Consumption (lb/hr)
Chiller 1	211	79	3,775
Chiller 2	465	-	8,835
Chiller 3	565	382	10.135

Figure 2.4: Boiler Summary

3 Site Energy Requirements

3.1 Electric Load

The plant electric load was compiled on an hourly basis for the year 2017. This electric load was compiled using two data sources, hourly interval data from the electric utility Unitil, and CTG generation. This does not take into account any electric generation by G9, the 1MW reciprocating engine generator, because hourly data is not available for this unit. The sequential hourly electric load is shown in Figure 3.1 below.

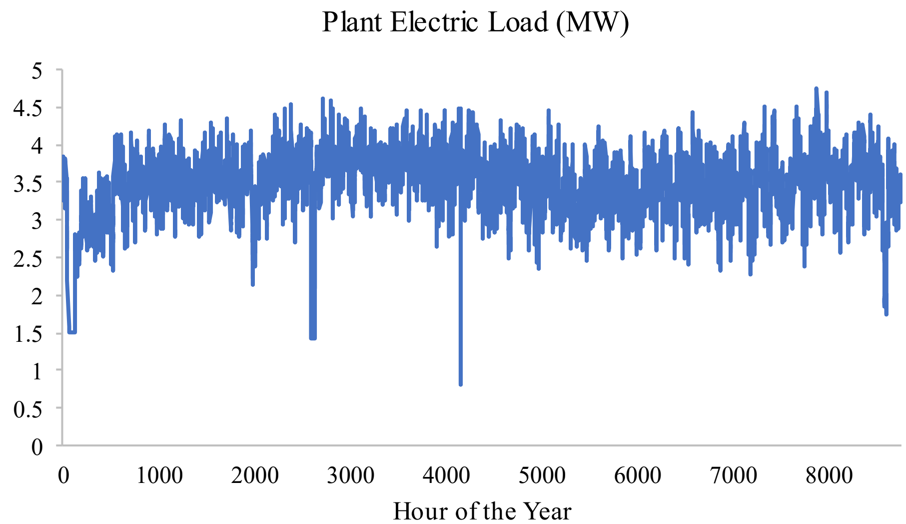


Figure 3.1 Hourly Electric Load 2017

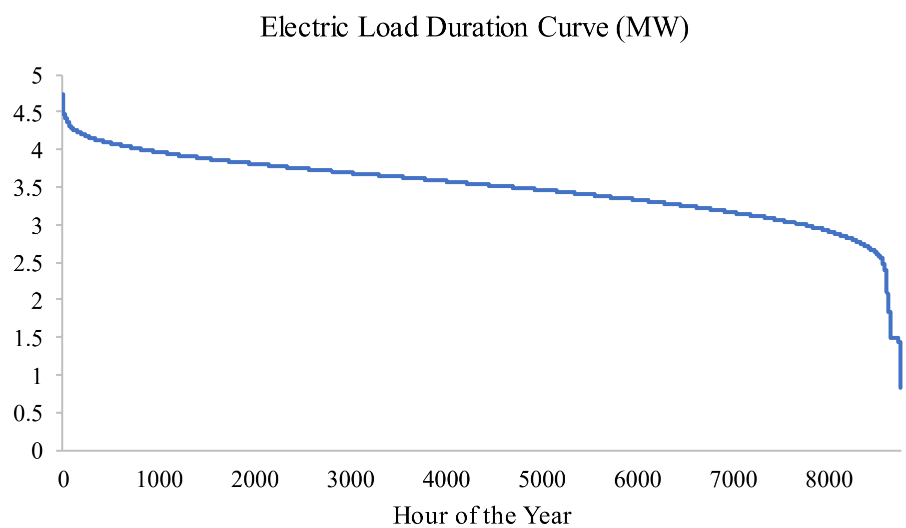


Figure 3.2 Electric Load Duration Curve 2017

Figure 3.2 shows the load duration curve for this data. A load duration curve is constructed by taking the hourly electric demand for an entire year, and organizing these 8,760 data points by magnitude from largest to smallest. The resulting display makes it easy to see how many hours per year the data is above a certain value. For example, it is easily seen that the plant electric demand in 2020 is above 3MW for approximately 8,000 hours.

3.2 Steam Load

Due to a lack of meters and data acquisition, the Foss steam load is largely unknown. In cases where steam usage metering is unavailable, production data can be used, though this is complicated by the un-metered steam condensing and venting practices. Monthly gas use in the fired boilers is available, and this was used to estimate the Steam production in the fired boilers. The HRSG steam production was estimated based on CTG performance and expected HRSG performance. The steam load is still largely unknown though due to the condensing and venting. According to Foss, up to 50% of the steam produced by the HRSG may be condensed or vented. The table below shows the monthly steam production by source and total estimated steam production. It also shows what the true steam load may be if 50% of the production is vented. In the analysis, the assumption of 0-50% vented/condensed steam will be used to bound the steam load, with the true load falling somewhere in this range.

2017 Monthly Boiler Gas Use (MMBtu)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
300# Boiler	1169	1856	1424	2161	3057	2527	2182	1707	1204	1276	1692	1655
150# Boilers	805	94	203	211	122	131	217	56	110	103	4001	1579

Figure 3.3 Gas Data Used in Calculation of Steam Load

Monthly Steam Load (1000 lb/mo)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
240# Steam Demand	928	1472	1130	1715	2426	2005	1731	1354	955	1012	1342	1313
130# Steam Demand Lower Bound	2684	2147	2450	2383	2402	2372	2501	2411	2361	2411	4782	3549
130# Steam Demand Upper Bound	4725	4220	4738	4598	4707	4638	4829	4778	4634	4740	6365	5835
15# Steam Demand Lower Bound	4182	4521	4982	4899	5223	4833	4883	4883	4739	4893	3435	4933
15# Steam Demand Upper Bound	8364	9042	9963	9798	10446	9665	9766	9766	9477	9786	6869	9867

Figure 3.4 Estimated Monthly Steam Load (1,000 lb/mo)

3.3 Chilled Water Load

The chilled water system, like the steam system, lacks metering and data logging. Unlike the steam system, the chilled water system lacks meters on the motive energy source (steam side) as well, so no estimate of chilled water load can be made. The chilled water load does not have a large impact on the study, and is only used for one comparison, steam vs electric chilling. A chilled water load was fabricated for this analysis, based on the capacity of the chillers on a peak summer day. It was assumed the chillers run at maximum load in the summer and taper off to 20% load in the winter. The figure below shows how the average chilled water load was assumed to vary throughout the year.

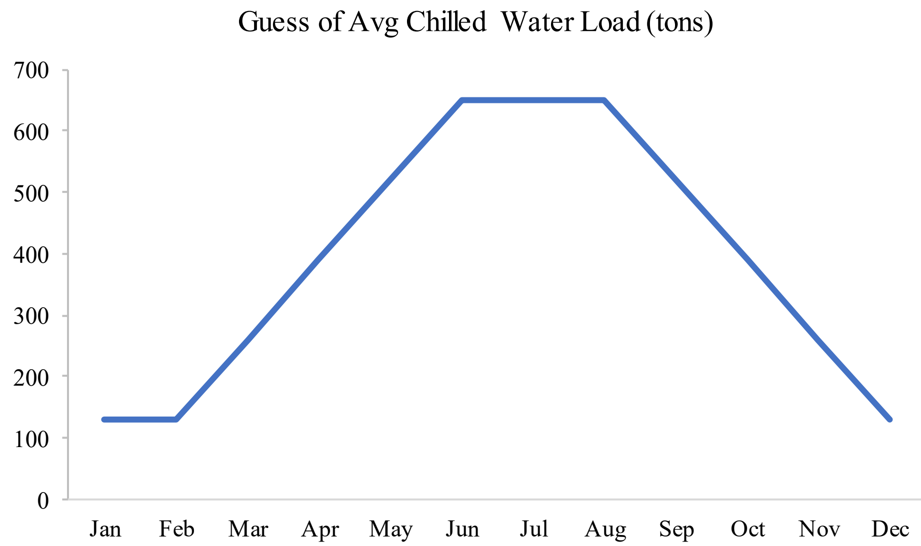


Figure 3.5 Estimated Avg Chilled Water Load by Month

4 Review of Current Operating Strategy

4.1 Electrical Dispatch

The standard electrical dispatch is to operate isolated from the utility and let the CTG carry the entire plant load. As the plant load swings up and down, the CTG output is adjusted to match the load. If the CTG approaches maximum load, Phase 6 can be switched over to the utility. If this is not enough to reduce load on the CTG, G9 can be started to provide roughly 1 MW of power, or T1 can be transferred to the utility to reduce the load.

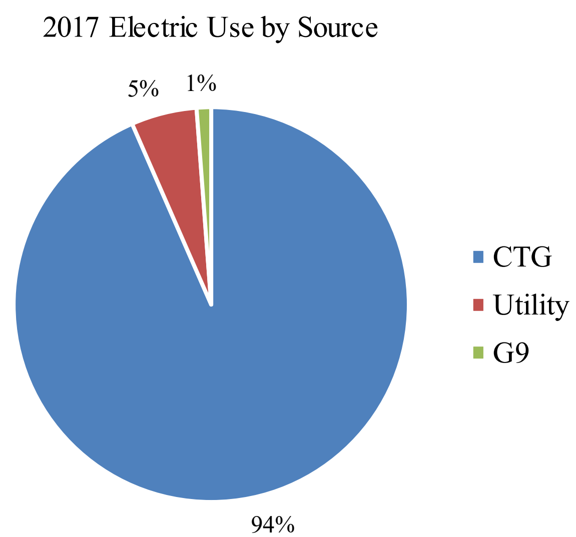


Figure 4.1 Electric Use by Source, 2017

4.2 Steam Dispatch

The HRSG is the lead boiler and, because there is no duct burner, its output is linked to the turbine output. As the turbine ramps up and down following plant load, the HRSG steam production also rises and falls. If there is not enough 130 psig steam production in the HRSG, then one of the gas fired boilers is used to make up the shortfall. If too much steam is produced at the 130 psig level, there is a back pressure regulator for the header which outlets to the 15 psig header. If there is too much steam a the 15 psig level, then it can be condensed or vented. There is only one boiler that can produce steam at the 240 psig level, and it is dispatched to meet the load.

Due to a lack of steam data as previously discussed, the exact steam production is unknown. Figure 4.2 shows an estimate of how much steam was produced by each source in 2017. The estimate is based on the methodology laid out in Section 3.2.

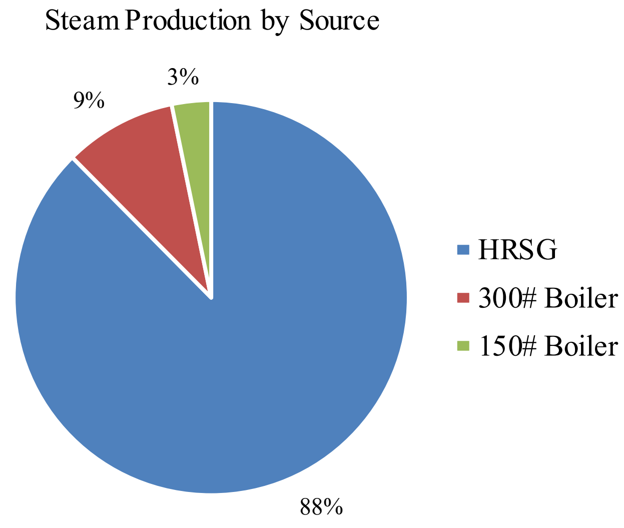


Figure 4.2 Annual Steam Production by Source

5 Model Development and Calibration

5.1 Model Overview

The utility model developed for this study is a combination of an hourly model and a monthly model. Some hourly plant data was available such as electric load and CTG performance. This enabled an hourly model to be developed to replicate the CTG dispatch. The hourly model developed for CTG dispatch is a tool that takes a variety of inputs and performs calculations on an hourly basis to determine what the CTG and HRSG output are. Model inputs include hourly plant electric energy profiles, equipment performance and availability data, and weather data. The model dispatches the equipment on an hourly basis to meet the plant electric load profile and calculates the equipment performance and required energy inputs. The electric profile was pieced together using data supplied by Foss and Unitil including data from the Solar historian and the utility.

The electric profile required a little manipulation for several reasons. Complete electric interval data from the utility was not available for Phase 6, so the monthly bills were converted to hourly profiles. The methodology for this conversion consisted of using a representative hourly profile of a week's electric load for Phase 6 electric load and assuming that Phase 6 is switched to the utility in hours when ambient temperature is highest, up to the point where monthly Phase 6 utility load matches the monthly utility bills. The second way the electric profile was modified involved the CTG auxiliary loads. CTG auxiliary loads were assumed to be 5% of CTG generation and were netted out from the initial electric profile. The model calculated electric auxiliaries when it dispatches the CTG and adds them back in, which accounts for changes in annual CTG auxiliary loads from changing CTG dispatching.

5.2 Weather Profiles

The model calculates equipment performance on an hourly basis based on weather profiles. The data that was received for the gas turbine includes hourly combustion air dry bulb temperature shown below.

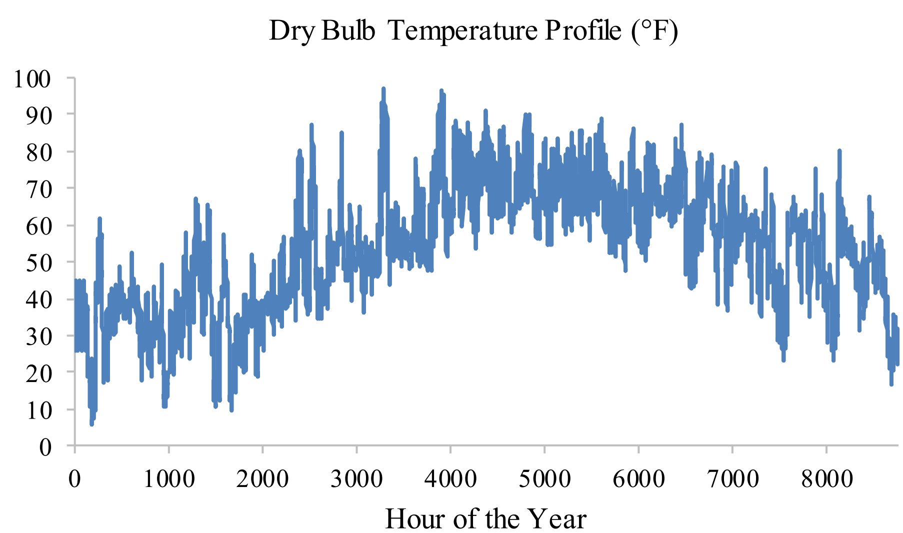


Figure 5.1 Hourly Dry Bulb Temperature for 2017

5.3 Model Calibration

To verify that the hourly model is accurate calculating CTG generation and fuel use, the data from the Solar historian for 2017 can be compared to the model output. The following figure shows this comparison.

CTG Electric Output (MWh)												
Actual	2205	2494	2727	2650	2922	2609	2616	2596	2528	2621	1052	2284
Model	2197	2487	2735	2696	2921	2609	2617	2590	2527	2620	1875	2682
% Dif	-0.4%	-0.3%	0.3%	1.7%	0.0%	0.0%	0.0%	-0.2%	-0.1%	0.0%	78.3%	17.4%
CTG Fuel Use (MWh)												
Actual	31368	33398	36727	34713	37821	34884	35132	35226	34304	35636	14353	31421
Model	31015	34017	37451	36325	38911	35622	36060	36051	35005	36246	25587	36719
% Dif	-1.1%	1.9%	2.0%	4.6%	2.9%	2.1%	2.6%	2.3%	2.0%	1.7%	78.3%	16.9%

Figure 5.2 CTG Calibration Model vs 2017 Historical Data

It is seen that in November and December the model shows higher CTG usage than the historical data. The CTG availability in 2017 was 93.6%. Much of this downtime was due to a major engine overhaul in November/December which only needs to be done every couple years. For this availability profile in the study, the 2017 availability profile was used, except the November outage was shortened and an additional short outage was taken in January. This results in a total availability of 96.5% for the CTG in the model.

The following figures show a comparison of the hourly actual and model CTG electric output and fuel use. The second week of January was chosen at random as the first week of the year the CTG did not have unavailability.

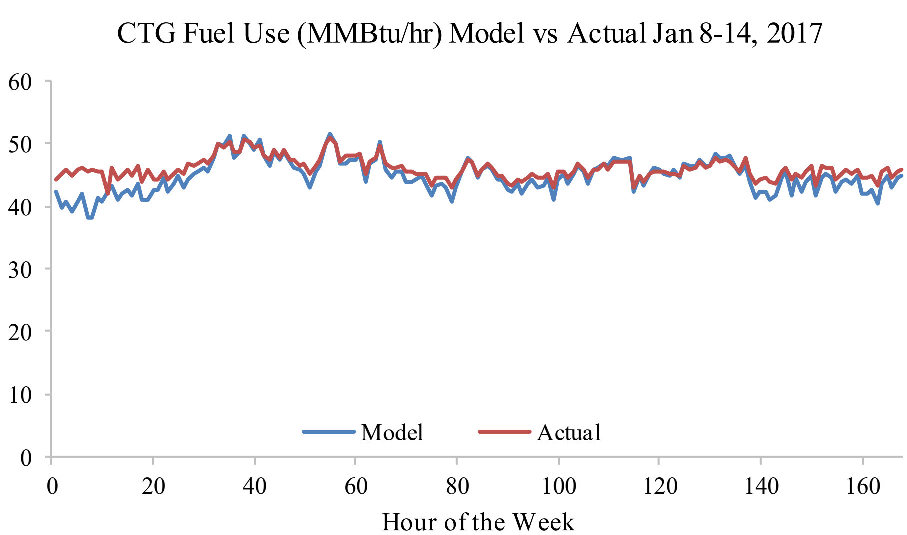


Figure 5.3 CTG Actual vs Model Fuel Use

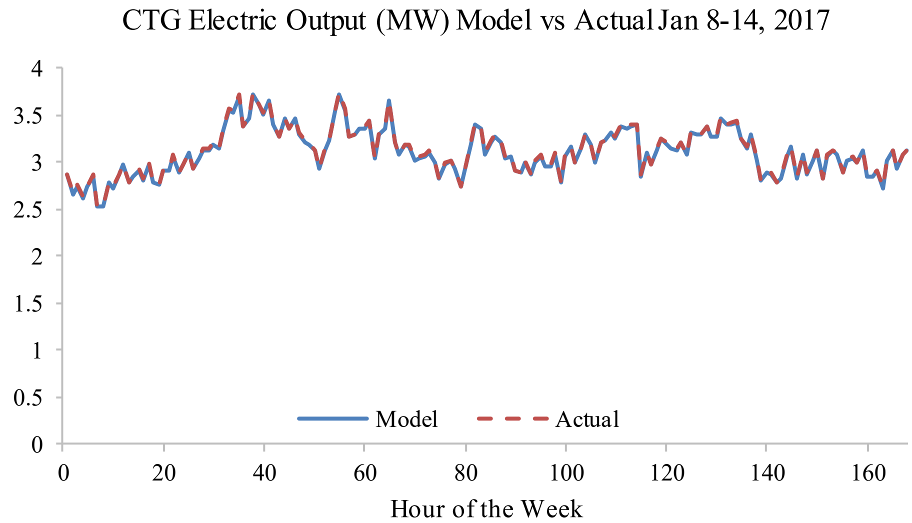


Figure 5.4 CTG Actual vs Model Electric Output

Due to the lack of data, the steam and chilled water production in the model cannot be calibrated.

5.4 Utility Cost

The utility cost was determined based on electric and gas bills that were received. Foss's gas Utility is Unitil and their gas supplier is Direct Energy. The gas costs were determined using the bills supplied. The following rates were used for natural gas.

Distribution First 20,000 MMBtu	Distribution After 20,000 MMBtu	Supply Cost
$/MMBtu	*$/MMBtu*	*$/MMBtu*
1.06	0.85	5.48

Figure 5.5 Gas Rates Used in Modeling

Foss's electric utility is Unitil and they fall under the G1 tariff. The electric supplier is Direct Energy and they buy electricity through Direct on the real time wholesale market. The following electric utility costs are based on the electric bills received.

Distribution Charge	Demand Charge
$/MWh	*$/MW*
$33	$7,410

Figure 5.6 Unitil Electric Distribution Charges Used in Modeling

It is important to note that Foss has a ratcheting demand charge. This means that the monthly demand is either the greater of the peak monthly utility import, or 80% of the largest demand in the past twelve months. This means that significant demand savings cannot be achieved by onsite generation if there are any times in the year where significant electric imports are made from the utility.

Figure 5.7 shows the breakdown of the electric supply cost. Note the wholesale energy cost represents the New Hampshire Average Real Time Locational Marginal Price. The Locational Marginal Price is the cost of electricity at a specific grid hub at a specific time. The cost not included in this breakdown is the capacity charge, which was assessed at $10.41/kW from June 2017 through May 2018. From June 2018 through May 2019 the capacity rate is $14.38/kW, while this rate is not used in the modeling, it is important to note due to the significant increase and the decisions to be made which may affect the capacity charge.

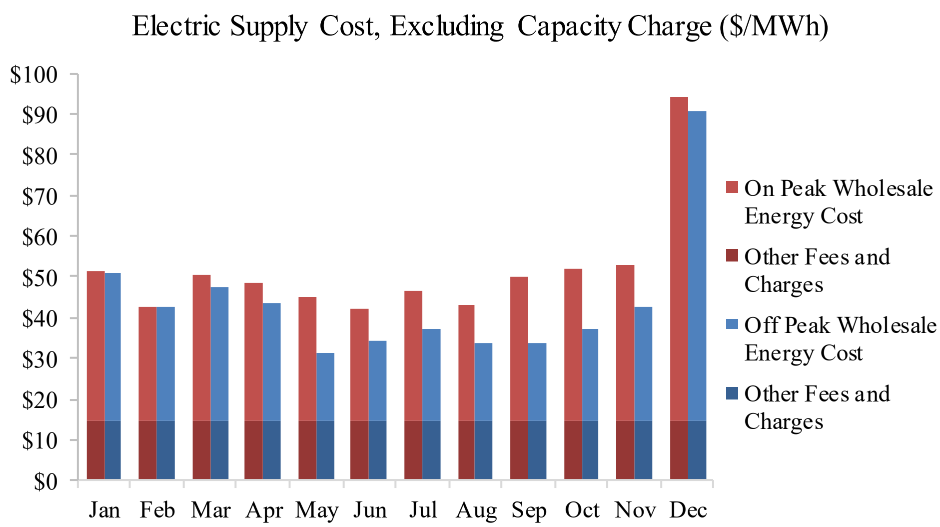


Figure 5.7 Electric Supply Cost by Month

6 Evaluation of CHP Operating Strategy

The model developed was used to make a number of operating cases. The first is the Base Case which represents the current plant operation and equipment line up. Other cases with different equipment lineups or different operating strategies were developed and cost and energy savings can be evaluated by comparing these cases to the Base Case. The table below shows a summary of these cases.

Case #	Case Name	Case Description
1	Base Case	Replicates the current operating strategy
2	Base Case Large ICAP	Replicates the current operating strategy, but shows the impact of switching T1 to the utility in the hour of the ISO peak
3	Sync Op	Shows the impact of running the CTG synchronous with the grid
4	Sync Op Backup	Shows the impact of only running the CTG synchronous with the grid in hours when part of the plant would otherwise switch to the utility
5	No CHP	Shows the impact of not running the CTG, assuming no steam is condensed in the Base Case, iCap tag is peak plant annual demand, steam chillers are still used for chilling, gas delivery discount still received, electric purchases based on NH avg monthly real time electric price
6	No CHP, Lower Steam Profile	Case 5, No CHP, but assuming 50% of CHP steam production is condensed in the Base Case
7	No CHP, Electric Chillers	Case 5, No CHP, but assuming electric chillers are used instead of steam chillers
8	No CHP, No Gas Discount	Case 5, No CHP, but assuming the gas delivery discounted rate is lost
9	No CHP, 25% Capacity Reduction	Case 5, No CHP, with ICAP at 75% of peak annual demand instead of 100%
10	No CHP, Day Ahead Elec	Case 5, No CHP, with electric purchases made on day ahead market instead of real time
11	CHP Back Up Only	Case 5, No CHP, but still paying the service charge to use it as a backup in case of utility failure
12	Best Case for No CHP	This case reflects the best case scenario of the No CHP cases. It is based on Case 6, No CHP Lower Steam Profile, but also reflects the use of electric chillers (Case 7), and a 25% Capacity Reduction (Case 9). It assumes the gas discount is retained.
13	Best Case for No CHP (8 cents per kW)	This case reflects the case twelve but updated with 8 cents per kWh as the electric supply cost all in including capacity charges.

Figure 6.1 Description of Operation Cases Considered

The figure below shows the annual operating savings as compared to the Base Case for each different operating strategy evaluated. It is seen that most cases show negative savings meaning operating cost actually increases.

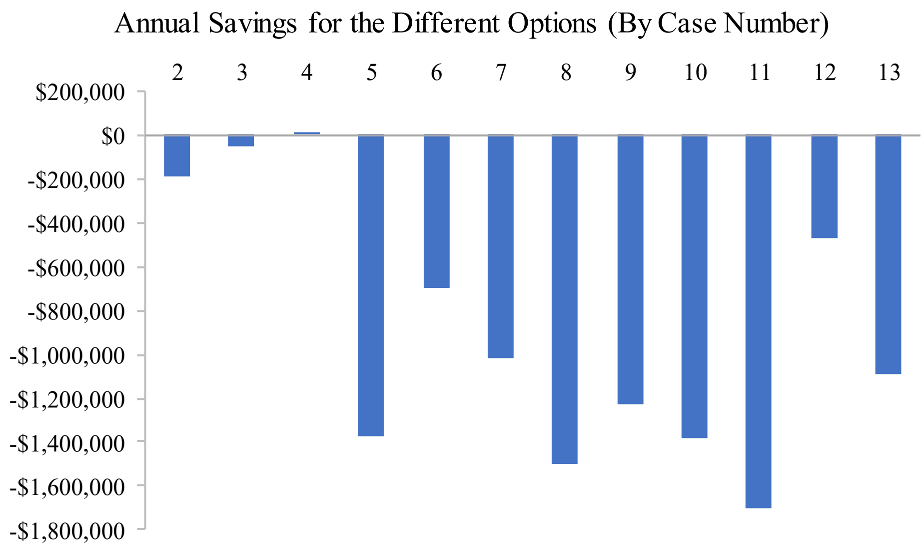


Figure 6.2 Summary of Annual Operation Savings by Option

Case 2 reproduces the Base Case equipment line up and operating strategy, but shows the impact of switching a transformer (T1) to the utility in the hour when the capacity tag is set. The capacity charge is the portion of the electricity supply bill that pays for the grid capacity market, which incentivizes electric generation facilities so that there is adequate generation capacity to meet the system wide electric load. Each purchaser is assigned a capacity tag (kW) which, along with the capacity charge rate ($/kW), determines the total capacity charge ($). The capacity tag is equal to the amount of electricity being imported in the hour when the New England electric grid hits its annual peak load (typically on a hot summer afternoon). In the Base Case, it is assumed T1 is being served by the gas turbine where as in Case 2 it is being served by the utility. This shows the potential impact of switching T1 to the utility in the hour when the capacity charge is set. In the Base Case, the capacity tag is 12kW where as in Case 2, the it is 1,500kW. The cost of this would have been around $186,000 in 2017, but would increase by around 40% based on 2018 capacity rates as discussed in Section 5.4.

Case 3 is based on the Base Case but evaluates the scenario where the CTG can be operated in parallel with the utility, meaning CTG power and utility power could serve common loads. Foss is not set up to do this right now but this may be accomplished with electrical system upgrades. If the CTG could sync with the utility and run in parallel, the turbine output would ramp up and down with plant load and the amount of power used from the utility could vary while maintaining a minimum import. This would increase operational flexibility, increase system reliability, and help to avoid large capacity tags. The minimum import setpoint used in this case was 5% of CTG rating, or 250kW, which is a common utility requirement. Based on Figure 3, it is seen there is a slight operating cost increase for Case 3. This is because Foss would be importing slightly more power and generating less due to the requirement to maintain a minimum import.

Case 4 shows the impact of running the CTG in parallel with the utility only in hours when the CTG is approaching max load, and the plant would otherwise switch T1 to the utility. This avoids the operating cost reduction from Case 3 where the CTG is operated in parallel with the utility all year, but reduces the reliability and some of the operating flexibility that comes with year-round synchronous operation. Neither of these cases provide justification to upgrade the facility's electric gear to allow synchronous operation based on operating savings, but show that if this goal is desired from a reliability perspective, the operating cost increase would be around $54k per year (Case 3).

Cases 5 through 13 show the impact of shutting the CTG down and just buying power from the grid all the time. Foss is not set up to do this right now, but this may be accomplished with electrical system upgrades. There are a number of factors that effect this analysis, which is why there are a number of cases. The following cases attempt to isolate the impact of different factors and serve as a sensitivity analysis.

Cases 5 replicates the loads from the Base Case, but assumes the CHP is not operated. The steam load is based on the assumption, admittedly incorrect, that none of the HRSG steam production is vented or condense. Due to the uncertainty associated with the plant steam load, two cases will be used to bound the cost increase associated with increase gas fired boiler use. This case, which assumes no vented steam in the Base Case and therefore a high plant steam load, serves as the upper bound for the boiler gas cost increase.

Case 6 replicates Case 5, except with a lower steam load. Case 6 is based on the assumption that 50% of steam production in the HRSG is vented or condensed. This results in Case 6 having a lower steam load than Case 5, therefore Case 6 represents the lower bound for the boiler gas cost increase. By comparing Cases 5 and 6 in Figure 6.2, it is seen that the plant steam load is a significant factor when evaluating the benefit of the CHP. Comparing these cases also indicates the value of the unused steam generated in the HRSG, if 50% is currently wasted.

Case 7 reproduces Case 5, but assumes electric chillers are used to meet the plant chilled water demand instead of steam chillers. This would not be a beneficial strategy if the CHP is in operation because the chillers currently run using steam generated by the HRSG which is essentially free energy because it would otherwise be wasted. Figure 6.2 shows that shutting down the CHP and using electric chillers is not beneficial from an operating cost perspective. By comparing Cases 5 and 7 however, it is seen that there would be operation savings associated with using electric chillers instead of absorption chillers if the decision had been made to not run the CHP for other reasons. Additionally, there would be a significant capital cost associated with new chilled water system equipment for this option, which is not captured in this savings analysis.

Case 8 reproduces Case 5, except a higher natural gas delivery rate is used. Foss currently receives a reduced rate from the utility, but it is possible that an outcome of shutting down the CTG is that Foss may lose this rate. The volume and stability of Foss's gas purchases are cited as one of the reasons for the discount, but if the turbine is not run, the volume of gas purchases would drop significantly, and monthly purchase volumes may begin to vary more with the seasons. The value of this discount in a scenario where the CHP is not used can be determined by comparing Cases 8 and 5.

Case 9 reproduces Case 5, but with a 75% reduction in capacity tag. In the no CHP cases, the capacity tag is assumed to be the maximum plant electric load, which is the upper bound. In Case 9, the capacity tag is lowered to 75% which may be achievable though capacity reduction measures. The value of reducing the Capacity tag by 25% can be seen by comparing Cases 5 and 9.

Case 10 reproduces Case 5, but with a different cost of power. It shows the impact of buying power on the day ahead market instead of the real time market. This has minimal impact, but it is possible that using monthly average values is not granular enough for this analysis to have merit.

Case 11 is based on Case 5, but assumes Foss still maintains the current service agreement with Solar Turbines. The impact of maintaining the current gas turbine maintenance agreement when the gas turbine is not operating is seen by comparing Cases 11 and 5, though Foss could try to renegotiate and lower this cost on an operating hours basis.

Case 12 shows the best scenario for not running the CHP, that is a combination of the previous scenarios that were most beneficial to not running the CHP. This shows what the maximum possible savings from not running the CHP would be. It uses the smallest steam profile, the lowest capacity tag, and the use of electric chillers. It shows that there are still no operational cost savings, and actually shows a $471k increase in annual operating cost.

Case 13 reproduces Case 12, but with a different electric supply cost. It reflects a higher electric supply cost of 8 cents per kWh (inclusive of capacity costs). It is seen that in this scenario, the operating cost increase is around $1.1 million annually.

The conclusion of this analysis is that it makes sense to continue to operate the CHP from an operating cost perspective. Shutting the CHP down and importing electricity for the grid would not only require a significant capital investment, but also result in an operations cost of at least a half million dollars.

7 Evaluation of Potential Energy Efficiency Improvement Projects

7.1 Annual Savings

When the plant steam load falls below the HRSG steam output, steam is condensed or vented to control steam header pressure. This condensed or vented steam represents an inefficiency in the current system, and if this vented or condensed steam could be reduced, there could be significant energy savings. When considering energy efficiency projects, Waldron focused on reducing the condensed or vented steam, because that represented the single most significant inefficiency in the system. If fifty percent of the steam produced by the HRSG is vented, the potential value of this steam can be estimated by comparing Cases 5 and 6, which represent cases where gas is burned to produce steam for the high and low steam profiles. Based on comparing the cost of these two cases, the potential value of offsetting gas loads with steam being wasted in the HRSG is between $0 and almost $700k. In order to utilize a higher percentage of steam produced by the HRSG, several options have been considered. It is important to note that the savings estimates presented for these options represent the likely upper limit of savings potential. If there is no condensed or vented steam, the potential savings from the following options would be zero, or result in cost increases.

Case 14 investigates the potential benefit of upgrading the HRSG to a 600 psig boiler. While this would reduce the quantity of steam produced and increase the stack exhaust temperature slightly, it would enable the HRSG to offset steam produced in the 300 psig and 150 psig boilers. This would increase the amount of the total plant steam load the HRSG could serve and reduce the quantity of steam vented or condensed.

Case 15 builds on Case 14 and includes the addition of a steam to hot oil heat exchanger. A steam to hot oil heat exchanger could offset steam produced in the Standby Hot Oil Boiler. According to Foss, the standby hot oil boiler operates for 16 hours a day at around 2MMBtu/hr. In the remaining 8 hours a day, the incinerator (main hot oil boiler) is used. The incinerator use could not be offset using waste heat because the incinerator is required for a plant process.

Cases 16 builds on Case 15 and includes the installation of a backpressure steam turbine. A backpressure steam turbine would reduce the load on the CTG which would result in fuel savings, so long as it does not offset useful HRSG steam production. This means that electric generated by the steam turbine is valuable until the point where steam is no longer being condensed or vented. These options are predicated on the assumption that there is significant steam venting, and the savings calculations for options 14 through 16 assume that 50% of the steam production by the HRSG is condensed or vented. Because there is so much uncertainty associated with the steam load, it is unknown what the benefit of a steam turbine would really be.

Case 17 is based on the same equipment line up as Case 16, but shows the impact of the steam load uncertainty on savings. It shows the case where only 25% of steam produced in the HRSG is currently condensed or vented, as opposed to 50%. Case 17 does not reflect the lower bound of potential savings, which would be zero as previously discussed, but shows the point at which savings begin to rapidly reduce as the assumed steam load increases.

Case 18 is based on the Base Case, but includes the addition of a CTG exhaust gas to hot oil heat exchanger. This heat exchanger would be similar to an economizer, but is located outside the existing HRSG. It is envisioned a HRSG bypass damper could be installed to direct some of the exhaust gas flow to a new hot oil heat exchanger instead of to the HRSG. This hot oil heat exchanger could be integrated into the existing hot oil system to offset the standby hot oil boiler load.

Case 19 is based on the Case 18, but assumes the Heat Setter Ovens which currently use 300# steam could be converted to hot oil. The amount of steam the ovens use on an annual basis is unknown, but Waldron guesses it may be 50% of the total 300# boiler steam production as there is only one other 300# steam load, the Annealers.

The following table summarizes the energy efficiency improvement projects discussed in this section for easy reference.

Case #	Case Name	Case Description
14	600# HRSG Upgrade	This case reflects the impact of upgrading the HRSG steam pressure to 600psig
15	600# HRSG Upgrade and Oil HX	This case reflects the impact of upgrading the HRSG steam pressure to 600psig, and adding a steam to hot oil heat exchanger
16	600# HRSG Upgrade Oil HX and BP STG	This case reflects the impact of upgrading the HRSG steam pressure to 600psig, and adding a steam to hot oil heat exchanger, and adding a 600 to 15 psig BP STG
17	600# HRSG Upgrade Oil HX and BP STG Lower Steam Load	This case reflects the impact of upgrading the HRSG steam pressure to 600psig, and adding a steam to hot oil heat exchanger, and adding a 600 to 15 psig BP STG. The steam profile assumes 25% of current HRSG production is vented, instead of the 25% assumed in Cases 14 – 16.
18	Hot Oil Waste Heat Recovery	This case reflects the Base Case but with the addition of a hot oil heat exchanger to recover heat from the CTG exhaust. It is assumed 50% of HRSG steam production is condensed/vented.
19	Hot Oil Waste Heat Recovery and Use in Ovens	This case reflects Case 18, but with conversion of the Heat Setter Oven coils to hot oil, therefore offsetting steam produced in the 300# boiler. The annual quantity of steam used in the oven is unknown, but Waldron guesses it may be 50% of steam produced in the 300# boilers.

Figure 7.1 Description of Energy Efficiency Improvement Cases

Figure 7.2 on the next page shows the savings associated with each of these options. It is observed from Cases 16 and 17 that the savings associated with a steam turbine are reduced by half if 25% or steam produced by the HRSG is vented instead of 50%. Comparing Cases 18 and 19 shows that the savings from the hot oil heat exchanger option can be doubled if the ovens can be added to the hot oil loop. It is also important to reiterate that these are high bound estimates of potential savings, and that if the quantity of steam condensed or vented is negligible, savings will also be negligible.

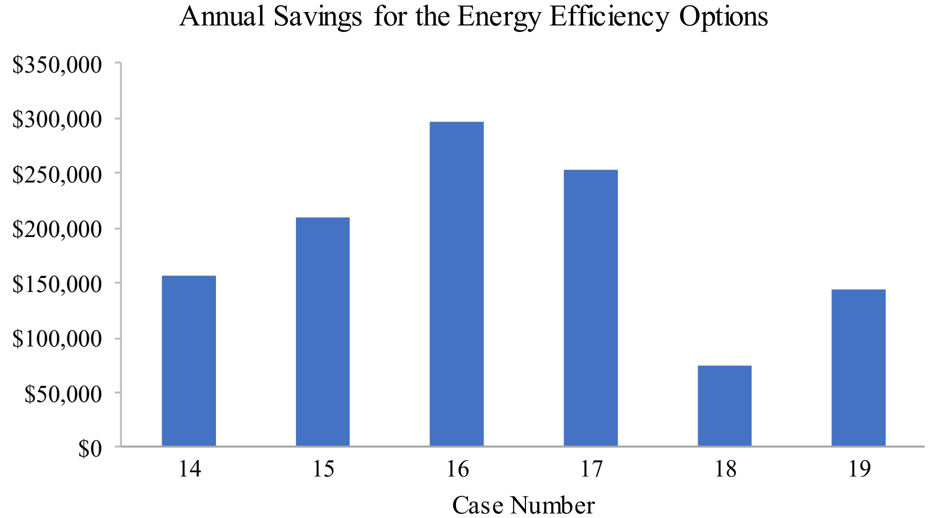


Figure 7.2 Summary of Annual Savings for Energy Efficiency Improvement Options

7.2 Equipment Cost

Waldron solicited quotes from equipment vendors for the major equipment in the energy efficiency improvement options. These costs are seen in Figure 7.3 below. The individual equipment cost is broken out for each option in Attachment C. The capital cost for Case 19 is not different than Case 18 because the cost of the oven retrofits for hot oil use are not included. This calls the payback analysis for this option into question, but if the cost of the oven upgrades is considered a sunk cost, then it is more accurate.

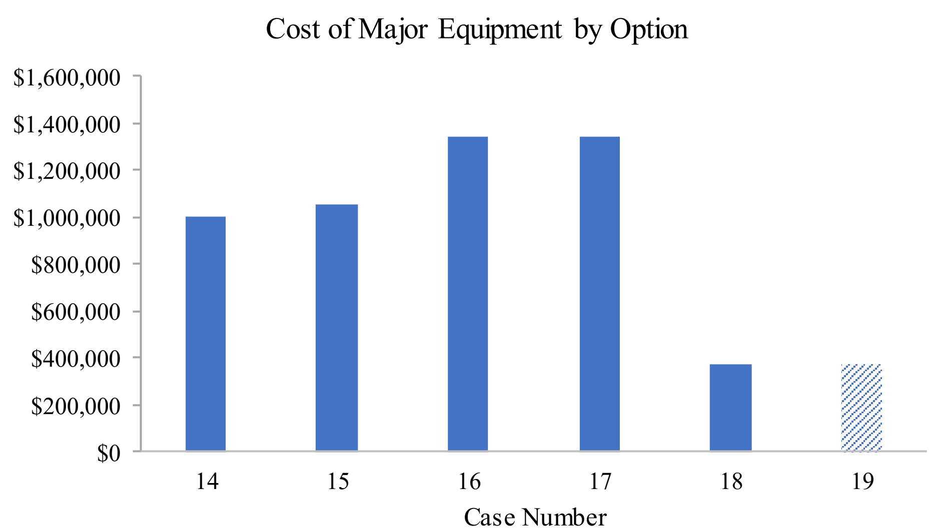


Figure 7.3 Summary of Equipment Costs by Option

7.3 Simple Payback Analysis

A simple payback analysis was completed to evaluate each of these options. Based on historical experience, Waldron has seen that a good rule of thumb for estimating project installed cost is that the installed cost is double the equipment cost. This rule of thumb was used in developing capital costs to use in the simple payback analysis.

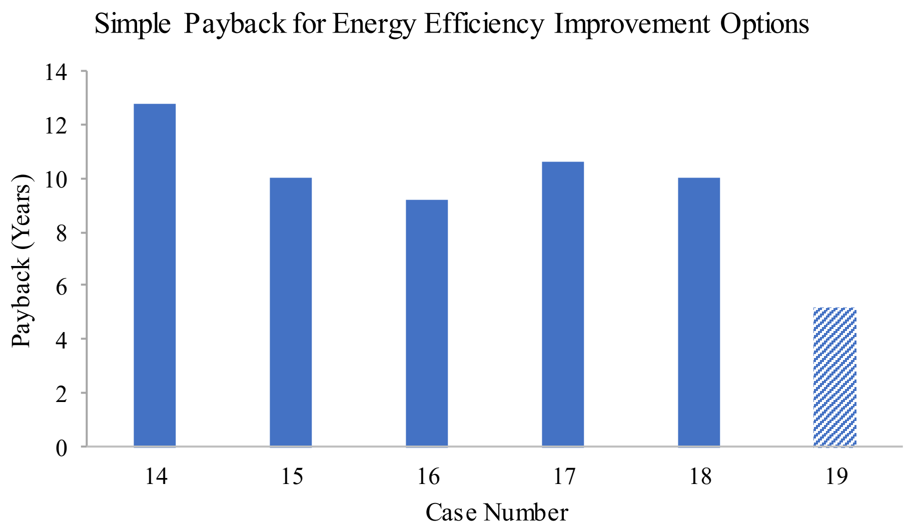


Figure 7.4 Simple Payback for Energy Efficiency Improvement Options

Figure 7.4 shows that the option with the fastest payback is Case 19, however if the cost of oven upgrades are included this may not be the case. After this was Case 16, with the BP STG. This case has more risk associated with it than other cases due to the unknown steam load and higher reduction of HRSG steam production.

Foss Performance Materials
Utility Study

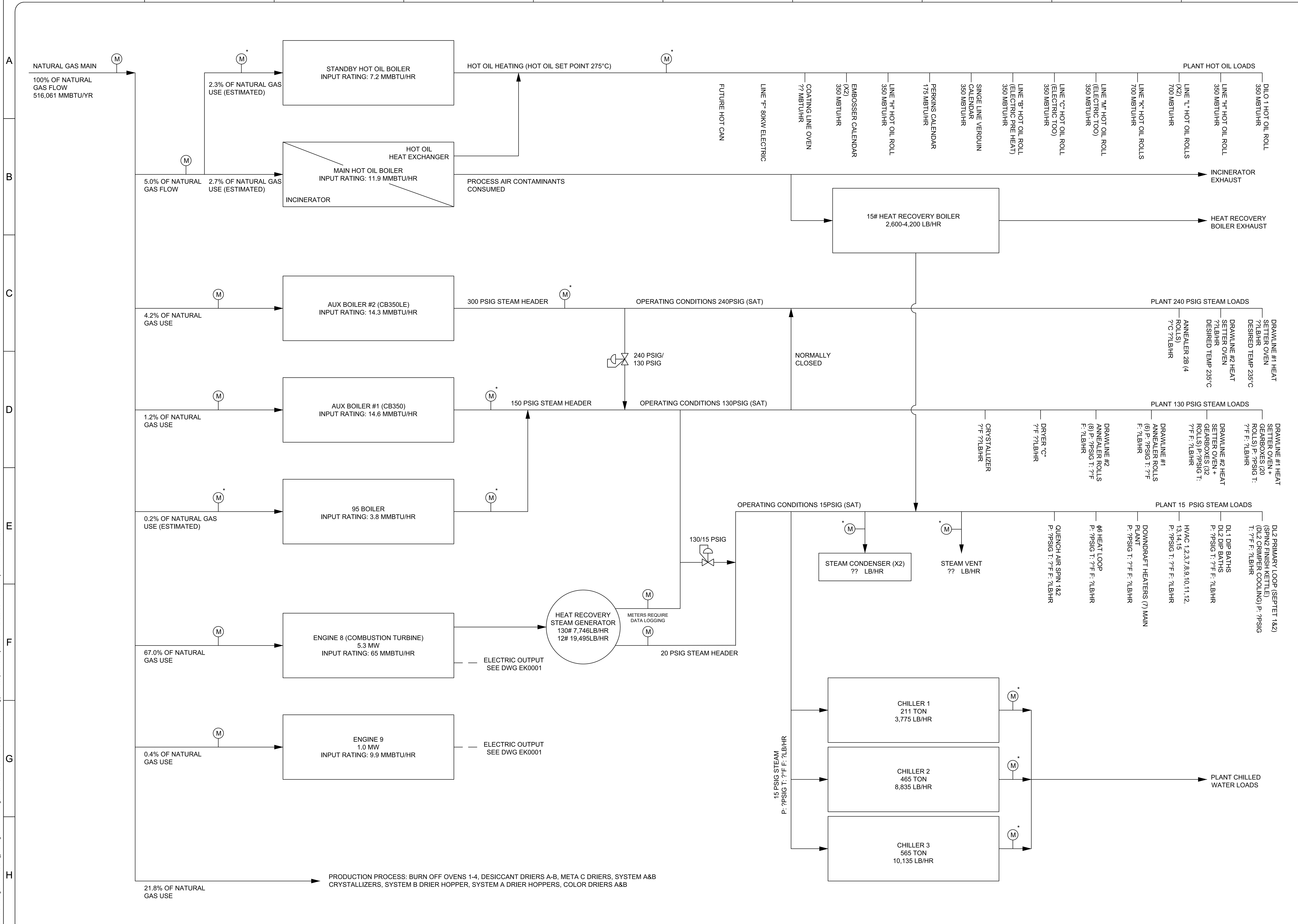
Attachment A- Power & Boiler Plant Process Map

December 27, 2018

Prepared by:

Waldron Engineering & Construction, Inc.
37 Industrial Drive
Exeter, NH 03833

Attachment A



NOTES:

1. GAS USE PERCENTAGES ARE BASED ON 2017 DATA
2. FUEL BURNING EQUIPMENT RATINGS ARE ESTIMATED BASED ON REASONABLE EFFICIENCIES
3. METERS MARKED WITH A * INDICATE RECOMMENDED POSITIONS FOR METER INSTALLATIONS. NOTE DRAWINGS IS SCHEMATIC AND ACTUAL PIPING ARRANGEMENT MAY DIFFER

REV. No.	REV. BY	DATE	DESCRIPTION	CHECKED BY	PROJECT MANAGER	LEAD ENGINEER
B	EM	12/27/2018	ISSUED FOR REVIEW	EM	MDL	EM
A	EM	8/09/2018	ISSUED FOR REVIEW	MDL	MDL	EM

SEAL

SIGNATURE DATE

WALDRON ENGINEERING & CONSTRUCTION, INC.
EXETER, NH WALDRON.COM

DATE 8/8/2018 | ANSI D

CLIENT
FOSS PERFORMANCE MATERIALS

DRAWING TITLE
ENERGY MODELING
POWER & BOILER PLANT PROCESS MAP

CLIENT DRAWING No. ####

W.E&C PROJECT No. 174.03

W.E&C DRAWING No. MK0001

Foss Performance Materials
Utility Study

Attachment B- Modeling Results

December 27, 2018

Prepared by:

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Case #	Confidence Level (1-Highest 5-Lowest)	1 Base Case	2 Base Case Large ICAP	3 Sync Op	4 Sync Op Backup	5 No CHP	6 No CHP, Lower Steam Profile
Electricity Balance							
Total On-Site Electric Demand (MW)	2	5.0	5.0	5.0	5.0	4.7	4.7
Base Electric Consumption (MWh)	2	30,679	30,679	30,679	30,679	30,679	30,679
Chiller Electric Consumption (MWh)	5	0	0	0	0	0	0
CHP Auxiliary Loads (MWh)	3	1,528	1,528	1,447	1,554	0	0
Total Electricity Required (MWh)	2	32,207	32,207	32,126	32,233	30,679	30,679
CTG Electricity Generated (MWh)	1	30,557	30,557	28,945	31,081	0	0
G9 or Rental Electricity Generated (MWh)	2	373	373	373	373	0	0
Total On-Peak Electricity Purchased (MWh)	2	738	738	1,350	419	14,633	14,633
Total Off-Peak Electricity Purchased (MWh)	2	537	537	1,458	359	16,045	16,045
Purchased Electricity Demand (MW)	2	3.6	3.6	3.6	3.6	4.6	4.6
Capacity Tag (kW)	1	12	1,500	250	12	4,737	4,737
Electricity Cost							
Electric Demand Charge ($)	2	$266,449	$266,449	$266,449	$266,449	$389,991	$389,991
Electric Distribution Charge ($)	2	$42,092	$42,092	$92,649	$25,688	$1,012,393	$1,012,393
Capacity Charge ($)	1	$1,437	$187,400	$31,233	$1,437	$591,801	$591,801
On-Peak Electric Energy Rate ($/MWh)	3	52	52	52	52	52	52
On-Peak Electric Energy Cost ($)	3	$36,676	$36,676	$70,072	$22,090	$753,800	$753,800
Off-Peak Electric Energy Rate ($/MWh)	3	44	44	44	44	44	44
Off-Peak Electric Energy Cost ($)	3	$22,199	$22,199	$63,801	$15,578	$699,881	$699,881
Net Electric Supply Cost (¢/kWh)	3	4.7	19.3	5.9	5.0	6.7	6.7
Total Electric Cost ($)	3	$368,854	$554,817	$524,205	$331,241	$3,447,867	$3,447,867
Steam Balance							
300# Steam Load (klbs)	2	17,383	17,383	17,383	17,383	17,383	17,383
150# Steam Load (klbs)	5	58,804	58,804	58,840	58,725	58,804	32,454
15# Steam Load (klbs)	5	112,810	112,810	109,202	114,010	112,810	56,405
Total Steam Load (klbs)	5	188,998	188,998	185,426	190,118	188,998	106,243
300# Boiler Steam Production (klbs)	2	17,383	17,383	17,383	17,383	17,383	17,383
150# CHP Steam Production (klbs)	3	52,700	52,700	52,736	52,620	0	0
150# Boiler Steam Production (klbs)	2	6,104	6,104	6,104	6,104	171,614	88,859
Total 150# Steam Production (klbs)	3	58,804	58,804	58,840	58,725	171,614	88,859
150# to 15# Pressure Reduction (klbs)	5	0	0	0	0	112,810	56,405
15# CHP Steam Production (klbs)	3	112,810	112,810	109,202	114,010	0	0
Total Steam Production (klbs)	3	188,998	188,998	185,426	190,118	188,998	106,243
Total Condensed Steam (klbs)	5	0	0	0	0	0	0
Gas Balance							
Gas to Hot Oil Boiler (MMBtu)	1-5	25,988	25,988	25,988	25,988	25,988	25,988
Gas to 300# Boiler (MMBtu)	1-5	21,910	21,910	21,910	21,910	21,910	21,910
Gas to 150# Boiler (MMBtu)	1-5	7,634	7,634	7,634	7,634	214,625	111,130
Gas to Combustion Turbine (MMBtu)	1-5	419,007	419,007	403,916	423,320	0	0
Gas to Engine 9 or Rental (MMBtu)	1-5	4,714	4,714	4,714	4,714	0	0
Total Gas Consumption (MMBtu)	1-5	479,253	479,253	464,162	483,566	262,523	159,027
Natural Gas Cost							
Natural Gas Supply Charge ($/MMBtu)	1-5	5.48	5.48	5.48	5.48	5.48	5.48
Natural Gas Supply Charge ($)	1-5	$2,626,306	$2,626,306	$2,543,610	$2,649,942	$1,438,624	$871,468
Natural Gas Distribution Charge ($)	1-5	$457,765	$457,765	$444,938	$461,431	$273,479	$168,569
Total Natural Gas Charge ($)	1-5	$3,084,071	$3,084,071	$2,988,548	$3,111,373	$1,712,103	$1,040,037
Total Operating Cost							
CHP Maintenance Cost	1	$332,868	$332,868	$327,293	$338,101	$0	$0
Total Cost	4	$3,785,793	$3,966,182	$3,840,046	$3,769,907	$5,159,970	$4,487,904
Difference From Base Case	4		$180,388	$54,253	-$15,886	$1,374,177	$702,111
Chilled Water Balance							
Avg Chilled Water Load % (Tons)	5	390	390	390	390	390	390
Electric Chiller Production (Ton-hr)	5	0	0	0	0	0	0
Electric Chiller Consumption (MWh)	5	0	0	0	0	0	0
Steam Chiller Production (Ton-hr)	5	3,428,880	3,428,880	3,428,880	3,428,880	3,428,880	3,428,880
15# Steam to Chillers (klbs)	5	68,578	68,578	68,578	68,578	68,578	68,578

	7	8	9	10	11	12	13
	No CHP, Electric Chillers	No CHP, No Gas Discount	No CHP, 25% Capacity Reduction	No CHP, Day Ahead Elec	CHP Back Up Only	Best Case for No CHP (Case 6,7,&9 Combined)	Case 12 with 8 Cent Electric Supply
Electricity Balance							
Total On-Site Electric Demand (MW)	4.9	4.7	4.7	4.7	4.7	4.9	4.9
Base Electric Consumption (MWh)	30,679	30,679	30,679	30,679	30,679	30,679	30,679
Chiller Electric Consumption (MWh)	2,057	0	0	0	0	2,057	2,057
CHP Auxiliary Loads (MWh)	0	0	0	0	0	0	0
Total Electricity Required (MWh)	32,736	30,679	30,679	30,679	30,679	32,736	32,736
CTG Electricity Generated (MWh)	0	0	0	0	0	0	0
G9 or Rental Electricity Generated (MWh)	0	0	0	0	0	0	0
Total On-Peak Electricity Purchased (MWh)	15,919	14,633	14,633	14,633	14,633	15,919	15,919
Total Off-Peak Electricity Purchased (MWh)	16,817	16,045	16,045	16,045	16,045	16,817	16,817
Purchased Electricity Demand (MW)	4.9	4.6	4.6	4.6	4.6	4.9	4.9
Capacity Tag (kW)	4,893	4,737	3,553	4,737	4,737	3,670	3,670
Electricity Cost							
Electric Demand Charge ($)	$413,016	$389,991	$389,991	$389,991	$389,991	$413,016	$413,016
Electric Distribution Charge ($)	$1,080,285	$1,012,393	$1,012,393	$1,012,393	$1,012,393	$1,080,285	$1,080,285
Capacity Charge ($)	$611,291	$591,801	$443,851	$591,801	$591,801	$458,468	$0
On-Peak Electric Energy Rate ($/MWh)	52	52	52	52	52	52	80
On-Peak Electric Energy Cost ($)	$815,857	$753,800	$753,800	$765,589	$753,800	$815,857	$1,273,538
Off-Peak Electric Energy Rate ($/MWh)	44	44	44	44	44	44	80
Off-Peak Electric Energy Cost ($)	$729,743	$699,881	$699,881	$697,997	$699,881	$729,743	$1,345,335
Net Electric Supply Cost (¢/kWh)	6.6	6.7	6.2	6.7	6.7	6.1	8.0
Total Electric Cost ($)	$3,650,192	$3,447,867	$3,299,917	$3,457,772	$3,447,867	$3,497,370	$4,112,174
Steam Balance							
300# Steam Load (klbs)	17,383	17,383	17,383	17,383	17,383	17,383	17,383
150# Steam Load (klbs)	58,804	58,804	58,804	58,804	58,804	32,454	32,454
15# Steam Load (klbs)	44,232	112,810	112,810	112,810	112,810	22,116	22,116
Total Steam Load (klbs)	120,420	188,998	188,998	188,998	188,998	71,954	71,954
300# Boiler Steam Production (klbs)	17,383	17,383	17,383	17,383	17,383	17,383	17,383
150# CHP Steam Production (klbs)	0	0	0	0	0	0	0
150# Boiler Steam Production (klbs)	103,037	171,614	171,614	171,614	171,614	54,570	54,570
Total 150# Steam Production (klbs)	103,037	171,614	171,614	171,614	171,614	54,570	54,570
150# to 15# Pressure Reduction (klbs)	44,232	112,810	112,810	112,810	112,810	22,116	22,116
15# CHP Steam Production (klbs)	0	0	0	0	0	0	0
Total Steam Production (klbs)	120,420	188,998	188,998	188,998	188,998	71,954	71,954
Total Condensed Steam (klbs)	0	0	0	0	0	0	0
Gas Balance							
Gas to Hot Oil Boiler (MMBtu)	25,988	25,988	25,988	25,988	25,988	25,988	25,988
Gas to 300# Boiler (MMBtu)	21,910	21,910	21,910	21,910	21,910	21,910	21,910
Gas to 150# Boiler (MMBtu)	128,860	214,625	214,625	214,625	214,625	68,247	68,247
Gas to Combustion Turbine (MMBtu)	0	0	0	0	0	0	0
Gas to Engine 9 or Rental (MMBtu)	0	0	0	0	0	0	0
Total Gas Consumption (MMBtu)	176,758	262,523	262,523	262,523	262,523	116,145	116,145
Natural Gas Cost							
Natural Gas Supply Charge ($/MMBtu)	5.48	5.48	5.48	5.48	5.48	5.48	5.48
Natural Gas Supply Charge ($)	$968,633	$1,438,624	$1,438,624	$1,438,624	$1,438,624	$636,473	$636,473
Natural Gas Distribution Charge ($)	$187,159	$395,913	$273,479	$273,479	$273,479	$123,113	$123,113
Total Natural Gas Charge ($)	$1,155,792	$1,834,537	$1,712,103	$1,712,103	$1,712,103	$759,586	$759,586
Total Operating Cost							
CHP Maintenance Cost	$0	$0	$0	$0	$327,293	$0	$0
Total Cost	$4,805,984	$5,282,404	$5,012,020	$5,169,875	$5,487,264	$4,256,955	$4,871,760
Difference From Base Case	$1,020,191	$1,496,610	$1,226,226	$1,384,081	$1,701,470	$471,162	$1,085,966
Chilled Water Balance							
Avg Chilled Water Load % (Tons)	390	390	390	390	390	390	0
Electric Chiller Production (Ton-hr)	3,428,880	0	0	0	0	3,428,880	2,057
Electric Chiller Consumption (MWh)	2,057	0	0	0	0	2,057	0
Steam Chiller Production (Ton-hr)	0	3,428,880	3,428,880	3,428,880	3,428,880	0	0
15# Steam to Chillers (klbs)	0	68,578	68,578	68,578	68,578	0	0

	14	15	16	17
	600# HRSG Upgrade	600# HRSG Upgrade and Oil HX	600# HRSG Upgrade Oil HX and BP STG	600# HRSG Upgrade Oil HX and BP STG, Higher Steam Load
Electricity Balance				
Total On-Site Electric Demand (MW)	5.0	5.0	5.0	5.0
Base Electric Consumption (MWh)	30,680	30,680	30,680	30,680
Chiller Electric Consumption (MWh)	0	0	0	0
CHP Auxiliary Loads (MWh)	1,528	1,528	1,416	1,416
Total Electricity Required (MWh)	32,209	32,209	32,092	32,092
CTG Electricity Generated (MWh)	30,556	30,556	28,257	28,257
G9 or Rental Electricity Generated (MWh)	373	373	373	373
STG Generation (MWh)	0	0	2,221	2,221
Total On-Peak Electricity Purchased (MWh)	740	740	723	723
Total Off-Peak Electricity Purchased (MWh)	536.0	536.0	517.0	517.0
Purchased Electricity Demand (MW)	4	4	4	4
Capacity Tag (kW)	12	12	12	12
Electricity Cost				
Electric Demand Charge ($)	$266,167	$266,167	$266,167	$266,167
Electric Distribution Charge ($)	$42,108	$42,108	$40,920	$40,920
Capcity Charge ($)	$1,437	$1,437	$1,437	$1,437
On-Peak Electric Energy Rate ($/MWh)	$52	$52	$52	$52
On-Peak Electric Energy Cost ($)	$36,780	$36,780	$35,965	$35,965
Off-Peak Electric Energy Rate ($/MWh)	$44	$44	$44	$44
Off-Peak Electric Energy Cost ($)	$22,126	$22,126	$21,420	$21,420
Total Electric Cost ($)	$368,618	$368,618	$365,909	$365,909
Steam Balance				
600#/300# Steam Load (klbs)	17,383	25,987	25,987	25,987
150# Steam Load (klbs)	32,454	32,454	32,454	45,629
15# Steam Load (klbs)	56,405	56,405	82,516	84,607
Total Steam Load (klbs)	106,243	114,846	140,957	156,223
600# CHP Steam Production (klbs)	151,032	151,032	146,806	146,806
600# STG Throttle Flow (klbs)	0	0	79,282	79,282
600#/300# Boiler Steam Production (klbs)	527	527	527	527
150# Boiler Steam Production (klbs)	3,285	3,285	3,995	9,665
600# to 300# Reduction (klbs)	16,856	25,460	25,460	25,460
600# to 150# Pressure Reduction (klbs)	85,575	85,575	28,459	35,964
150# to 15# Reduction (klbs)	56,405	56,405	2,110	2,332
Total Steam Production (klbs)	154,844	154,844	151,328	156,998
Total Condensed Steam (klbs)	48,601	39,998	10,371	775
Gas Balance				
Gas to Hot Oil Boiler (MMBtu)	25,988	17,695	17,695	17,695
Gas to 300# Boiler (MMBtu)	664	664	664	664
Gas to 150# Boiler (MMBtu)	4,108	4,108	4,996	12,088
Gas to Combustion Turbine (MMBtu)	419,009	419,009	397,897	397,897
Gas to Engine 9 or Rental (MMBtu)	4,714	4,714	4,714	4,714
Total Gas Consumption (MMBtu)	454,484	446,190	425,967	433,058
Natural Gas Cost				
Natural Gas Supply Charge ($/MMBtu)	$5	$5	$5	$5
Natural Gas Supply Charge ($)	$2,490,570	$2,445,124	$2,334,299	$2,373,160
Natural Gas Distribution Charge ($)	$436,711	$429,662	$412,472	$418,500
Total Natural Gas Charge ($)	$2,927,281	$2,874,786	$2,746,771	$2,791,659
Total Operating Cost				
CHP Maintenance Cost	$332,853	$332,853	$375,293	$375,293
Total Cost	$3,628,752	$3,576,257	$3,487,974	$3,532,862
Difference from Base Case	-$157,041	-$209,536	-$297,819	-$252,931
Chilled Water Balance				
Avg Chilled Water Load % (Tons)	390	390	390	390
Electric Chiller Production (Ton-hr)	0	0	0	0
Electric Chiller Consumption (MWh)	0	0	0	0
Steam Chiller Production (Ton-hr)	3,428,880	3,428,880	3,428,880	3,428,880
15# Steam to Chillers (klbs)	68,578	68,578	68,578	68,578

	18 Hot Oil HX	19 Hot Oil HX
Electricity Balance		
Total On-Site Electric Demand (MW)	5.0	5.0
Base Electric Consumption (MWh)	30,679	30,679
Chiller Electric Consumption (MWh)	0	0
CHP Auxiliary Loads (MWh)	1,528	1,528
Total Electricity Required (MWh)	32,207	32,207
CTG Electricity Generated (MWh)	30,557	30,557
G9 or Rental Electricity Generated (MWh)	373	373
Total On-Peak Electricity Purchased (MWh)	738	738
Total Off-Peak Electricity Purchased (MWh)	537	537
Purchased Electricity Demand (MW)	3.6	3.6
Capacity Tag (kW)	12	12
Electricity Cost		
Electric Demand Charge ($)	$266,449	$266,449
Electric Distribution Charge ($)	$42,092	$42,092
Capcity Charge ($)	$1,437	$1,437
On-Peak Electric Energy Rate ($/MWh)	52	52
On-Peak Electric Energy Cost ($)	$36,676	$36,676
Off-Peak Electric Energy Rate ($/MWh)	44	44
Off-Peak Electric Energy Cost ($)	$22,199	$22,199
Total Electric Cost ($)	$368,854	$368,854
HRSG Hot Oil		
Hot Oil Production (MMBtu)	9,443	18,206
HRSG Reduced 150# Steam (klbs)	4174	8036
HRSG Reduced 15# Steam (klbs)	9224	17798
Steam Balance		
300# Steam Load (klbs)	17,383	8,692
150# Steam Load (klbs)	32,454	32,454
15# Steam Load (klbs)	56,405	56,405
Total Steam Load (klbs)	106,243	97,551
300# Boiler Steam Production (klbs)	17,383	8,692
150# CHP Steam Production (klbs)	48,526	44,664
150# Boiler Steam Production (klbs)	6,104	6,104
Total 150# Steam Production (klbs)	54,630	50,769
150# to 15# Pressure Reduction (klbs)	22,176	18,314
15# CHP Steam Production (klbs)	103,586	95,012
Total Steam Production (klbs)	175,599	154,472
Total Condensed Steam (klbs)	69,357	56,921
Gas Balance		
Gas to Hot Oil Boiler (MMBtu)	14,185	14,185
Gas to 300# Boiler (MMBtu)	21,910	10,955
Gas to 150# Boiler (MMBtu)	7,634	7,634
Gas to Combustion Turbine (MMBtu)	419,007	419,007
Gas to Engine 9 or Rental (MMBtu)	4,714	4,714
Total Gas Consumption (MMBtu)	467,450	456,495
Natural Gas Cost		
Natural Gas Supply Charge ($/MMBtu)	$5.5	$5.5
Natural Gas Supply Charge ($)	$2,561,625	$2,501,593
Natural Gas Distribution Charge ($)	$447,732	$438,421
Total Natural Gas Charge ($)	$3,009,357	$2,940,013
Total Cost		
CHP Maintenance Cost	$332,868	$332,868
Total Cost	$3,711,079	$3,641,735
Difference from Base Case	-$74,714	-$144,058
Chilled Water Balance		
Avg Chilled Water Load % (Tons)	390	390
Electric Chiller Production (Ton-hr)	0	0
Electric Chiller Consumption (MWh)	0	0
Steam Chiller Production (Ton-hr)	3,428,880	3,428,880
15# Steam to Chillers (klbs)	68,578	68,578

Foss Performance Materials
Utility Study

Attachment C- Equipment Cost Summary

December 27, 2018

Prepared by:

Waldron Engineering & Construction, Inc.
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Summary of Equipment Costs for Options 14-19

Case 14 600# HRSG Upgrade

Equipment	Quantity	Cost	Extended
HRSG Modification	1	$695,000	$695,000
HRSG Superheater	1	$115,000	$115,000
HRSG Economizer	1	$85,000	$85,000
Feed Pumps	2	$55,000	$110,000
Total			$1,005,000

Case 15 600# HRSG Upgrade with Hot Oil Coil

Equipment	Quantity	Cost	Extended
HRSG Modification	1	$695,000	$695,000
HRSG Superheater	1	$115,000	$115,000
HRSG Economizer	1	$85,000	$85,000
Feed Pumps	2	$55,000	$110,000
Hot Oil HX	1	$48,461	$48,461
Total			$1,053,461

Case 16&17 600# HRSG Upgrade with Hot Oil Coil and STG

Equipment	Quantity	Cost	Extended
HRSG Modification	1	$695,000	$695,000
HRSG Superheater	1	$115,000	$115,000
HRSG Economizer	1	$85,000	$85,000
Feed Pumps	2	$55,000	$110,000
Hot Oil HX	1	$48,461	$48,461
STG	1	$288,508	$288,508
Total			$1,341,969

Case 18&19 CTG Exhaust Gas to Hot Oil HX w/Modulating Diverter

Equipment	Quantity	Cost	Extended
Hot Oil HX	1	$132,105	$132,105
HX Relief Valve	1	$2,000	$2,000
Hot Oil HX Controls	1	$50,000	$50,000
Exh Gas Diverter Damper w X-Jts	1	$112,500	$112,500
Exh Gas Isolation Dampers	2	$27,000	$54,000
HX X-Jts	2	$8,350	$16,700
Hot Oil Pump	1	$7,553	$7,553
Total			$374,858

Foss Energy Savings Measures

Replace High Bay Lighting Fixtures

Quantity	65
Old Usage per Fixture (Watts)	220
Old Usage Total	14300
Old Annual Usage (kWh)	125268
New Usage per Fixture (Watts)	137
New Usage Total	8905
New Annual Usage (kWh)	78007.8
kWh Savings/Year	**47,260**

Replace 8 Ft Fluorescent Lighting Fixtures

Quantity	228
Old Usage per Fixture (Watts)	153
Old Usage Total	34884
Old Annual Usage (kWh)	305583.84
New Usage per Fixture (Watts)	65
New Usage Total	14820
New Annual Usage (kWh)	129823.2
kWh Savings/Year	**175,761**

Add Small Compressor to reduce Large Compressor Run Time	Foss had two large air compressor system to feed plant air to our equipment. The main compressor was not quite enough to handle all the loads and this required the second large compressor to turn on to handle the requirements. The issue here was this second large unit was able to provide much more than we actually need. This caused a high energy usage for the benefit we were realizing. Foss purchased and installed a smaller unit properly sized to handle only the load we required. This resilted in an annual kWh savings of **455,520/Yr.**	Large Compressor		
			HP	212
			Volts	460
			Phase	3
			kW	160
			kWh	1401600
		Small Compressor		
			HP	75
			Volts	460
			Phase	3
			kW	56
			kWh	490560
		Total Savings		911040
		Time % Run		50%
		Calculated Savings		**455520**
Replace DC Motors with Efficient AC Motors	There is an ongoing process where Foss is replacing the DC motor controls systems with more efficient AC Motors and VFD's. This project has helps to increase our power factor number and as we switch over more loads it will continue to use. Foss has converted approximately 25 motors and drives so far.			