Report for :

Big Six Towers
Energy Supply Alternatives Assessment
New York, NY

August 22, 2022

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Attachments

1 Executive Summary

On behalf of Big Six Towers, Inc. ("Big Six Towers"), Waldron Engineering of New York, P.C., ("Waldron") has completed an analysis of energy supply alternatives that could be implemented upon retirement of the existing engine generators in the power plant. Decommissioning of the existing engines is driven by Local Law 38, which requires stationary engines to meet Tier 4 emissions requirements for operating permit renewals after January of 2025.

Legal requirements aside, the existing engines are also roughly forty years old, at the end of their useful lives, and relatively inefficient compared to present technology. Additionally, three of the six engines operate on diesel fuel, which has been 2-3 times as expensive as natural gas in recent years. So converting Big Six Towers' electricity supply to grid power or to new natural gas fired engines would both realize significant cost reductions compared to the current value.

The decision-making space is complex, however, as legislation at the local and state level mandates significant overhauls to the types of energy used within the City and State respectively. The primary objective of these laws is to achieve large reductions in greenhouse gas emissions in their respective jurisdictions, primarily by accelerating the integration of renewable energy supplies. The impact these laws will have upon the future cost of delivered energy remains to be seen, but in Waldron's opinion it is prudent to consider a range of future scenarios in the decision-making process, including electricity cost increases and their potential impacts to Big Six Towers.

The conclusion to this report thus includes not only a recommendation, but a review of the possible outcomes that energy supply alternatives will have in a range of futures. Certain facts about the various alternatives are clear, such as which will cost more to construct, and which will have the greatest impact on annual operating costs, but the alternatives are relatively closely grouped in terms of overall life cycle costs so the decision for Big Six Towers becomes one of risk assessment and navigation.

1.1 Energy Supply Alternatives

Three basic categories of energy supply alternatives were explored in this analysis as described in the table on the following page. Multiple alternatives were initially evaluated in each category, and then the best in each was selected for review in this Executive Summary.

The first category of alternatives, termed "Grid Connection" (GR) herein, includes the establishment of an electrical interconnection to the Con Edison grid and retirement of on-site electrical power generation. All electrical power would be supplied by the grid. The key distinctions between energy supply alternatives in this category are the nature of the Con Edison service—Low Tension vs High Tension—and the manner in which building heating and cooling needs would be met in the future. For the latter, the primary alternatives were to continue with the existing boiler plant, the absorption chiller, and the tenants' space cooling system, or to incorporate alternate technologies such as liquid biofuel, geothermal heating/cooling, or electric boilers. These alternatives would provide reductions in greenhouse gas emissions as compared to continued operation of the boiler plant and were considered for this reason.

The second category of alternatives, termed "Power Plant Only" (PP) herein, is based on repowering the existing power plant with new electrical generators, and continuing to operate without an interconnection to Con Edison. For this category of alternatives, the boiler plant, absorption chiller and existing tenant cooling equipment were modeled to operate in accordance with their historical norms. The key variables were the size and quantity of natural gas fired reciprocating engines that were considered. Alternative electrical generation technologies such as fuel cells and gas turbines were excluded from consideration for reasons given in the body of the report (refer to Section 9).

The third category of alternatives, termed "Grid Parallel" (PA), is a hybrid category that includes a new electrical interconnection to the Con Edison grid plus continued operation of the Big Six Towers power plant with new natural gas reciprocating engines. The assumption regarding the community's heating and cooling systems was the same as that of the Power Plant (PP) alternatives, and the key variable for this category of alternatives was the quantity and size of engines included. Cases were considered that were able to cover 100% of the Big Six Towers forecasted loads, as well as cases with a lesser quantity of engines that only cover the base load.

A summary of the alternatives studied in each category, with identification of the best alternative in each, is provided in the table below.

High Level Category	Energy Supply Alternatives Studied
Grid Connection (GR)	Low Tension Interconnection, Existing Boiler Plant High Tension Interconnection, Existing Boiler Plant High Tension Interconnection, Geothermal Heating/Cooling High Tension Interconnection, Air Source Heat Pumps High Tension Interconnection, Liquid Biofuel Heating High Tension Interconnection, Electric Boiler Plant Best Alternative: High Tension, Existing Boiler Plant
Power Plant Only (PP)	6x 635 kW Engines 4x 1,200 kW Engines Best Alternative: 6x 635 kW Engines
Grid Parallel (PA) * All cases were evaluated with Low and High Tension interconnections.	1x 1,200 kW Engine 2x 1,200 kW Engines 1x 850 kW Engine 2x 850 kW Engines Best Alternative: 1x 1,200 kW Engine, High Tension

Figure A: Energy Supply Alternative

Unless noted otherwise, the figures presented in the remaining portions of the Executive Summary are based on the "Best Alternative" within each category. Figures B and C on the following page show cumulative operating costs for the twenty-year study period, from 2024 – 2043, as well as the cumulative life cycle cost (operating + capital amortization) for the same period. With the inclusion of capital amortization, the best alternatives in each category are very closely ranked in economic performance.

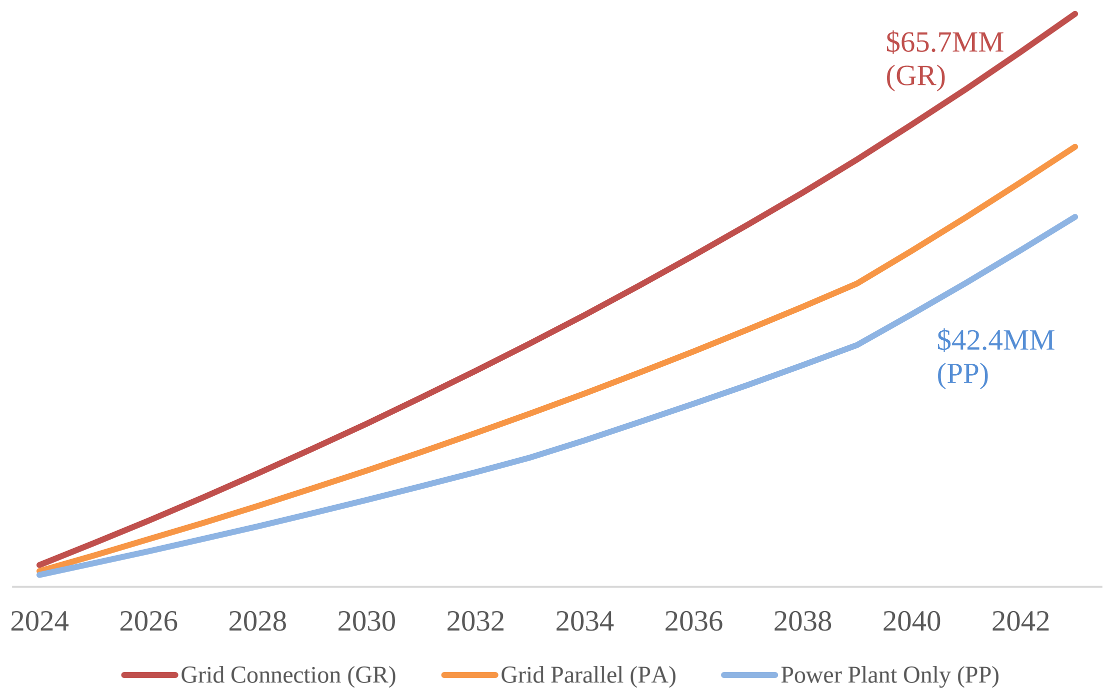


Figure B: Cumulative Operating Cost

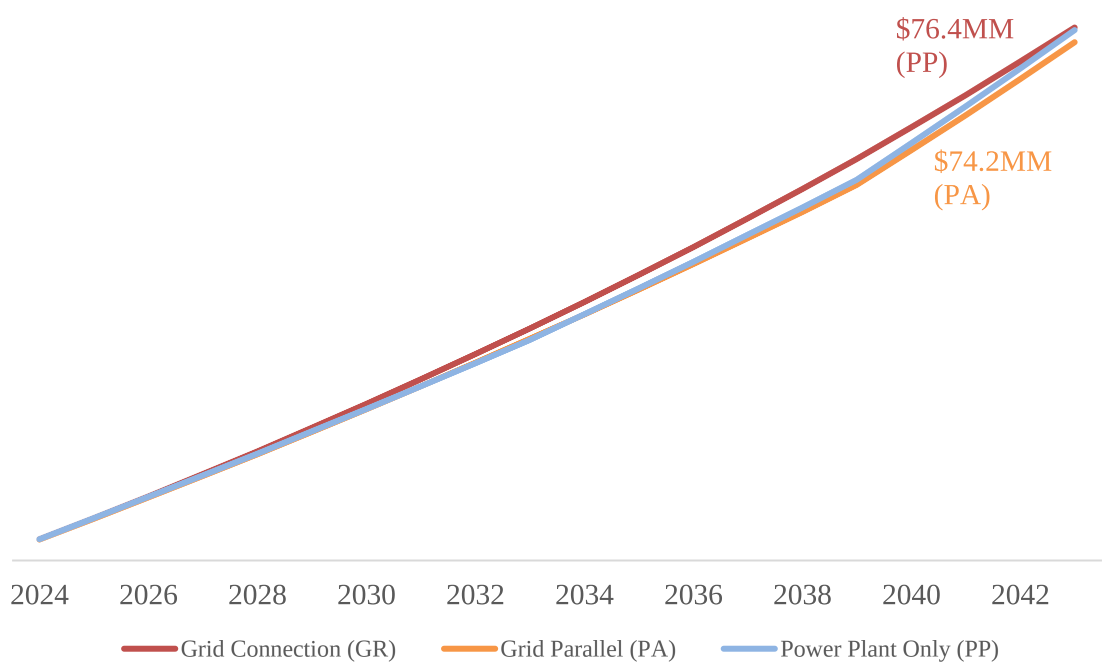


Figure C: Cumulative Life Cycle Cost (Operating Cost Plus Capital Amortization)

A summary of key project metrics is provided in the table below. The net present values and rates of return shown for the PP and PA alternatives are calculated against the incremental capital investment—above and beyond that required to construct the Grid Connection (GR) alternative—required to install them.

Energy Supply Alternative Parameter	GR	PP	PA
Capital Cost ($1,000's, 2023$)	$5,897	$18,509	$13,128
Cumulative Operating Cost (Then Current $)	$65.7	$42.4	$50.4
Cumulative Life Cycle Cost (includes capital)	$76.4	$76.0	$74.3
Net Present Value (6.5% discount rate)	-	$0.8	$1.40
Rate of Return	-	7.3%	8.9%

1.2 Climate Change Legislation and Greenhouse Gas Emissions Considerations

The Climate Leadership and Community Protection Act ("CLCPA"), was signed into law in 2019 by the New York State legislature. This legislation mandates 70% renewable energy in New York State by 2030 and 100% zero-emission electricity by 2040. The achievement of these targets will require extensive infrastructure upgrades in the form of transmission system upgrades, renewable electricity generation facilities, energy storage systems, and enhancements to the electrical grid for stability and control. Investments of this magnitude create uncertainty in future electricity pricing, and the impacts of various future electricity pricing scenarios on project economics was a key consideration of this analysis.

Within New York City, Local Law 97 establishes a greenhouse gas emissions threshold tied to energy use intensities for various building types, beyond which a penalty will be assessed beginning in Year 2024. Big Six Towers is exempt from the penalties through Year 2029 and is expected to remain exempt until Year 2034, at which time Waldron understands the Year 2024 thresholds would be applied. After this 10-yr grace period, Big Six Towers could face relatively high penalties for greenhouse gas emissions above the limits.

Key tasks of this analysis thus included a quantification of greenhouse gas emissions for the various alternatives studied, as well as a forecast of potential penalties that would be applicable to Big Six Towers in the future per Local Law 97. While the delay in applicability of the Local Law 97 penalties means they are not a significant driver of near-term project economics, it is important to understand their potential future value because different energy supply alternatives would expose Big Six Towers to varying degrees of penalty in future years, which could (in some alternatives) only be avoided through additional capital investments. Thus, the position in which Big Six Towers would find itself in twenty years, at the conclusion of the life cycle studied herein, will vary considerably for the alternatives studied.

Figure D on the following page shows the forecasted greenhouse gas emissions profile for the best energy supply alternative in each category, and Figure E provides forecasted Local Law 97 penalty costs for the same, in Year 2045. (Note that for the alternatives shown, the primary heating and cooling needs of the community are met in the same manner as they are currently, with the existing boiler plant and tenant space-cooling systems.)

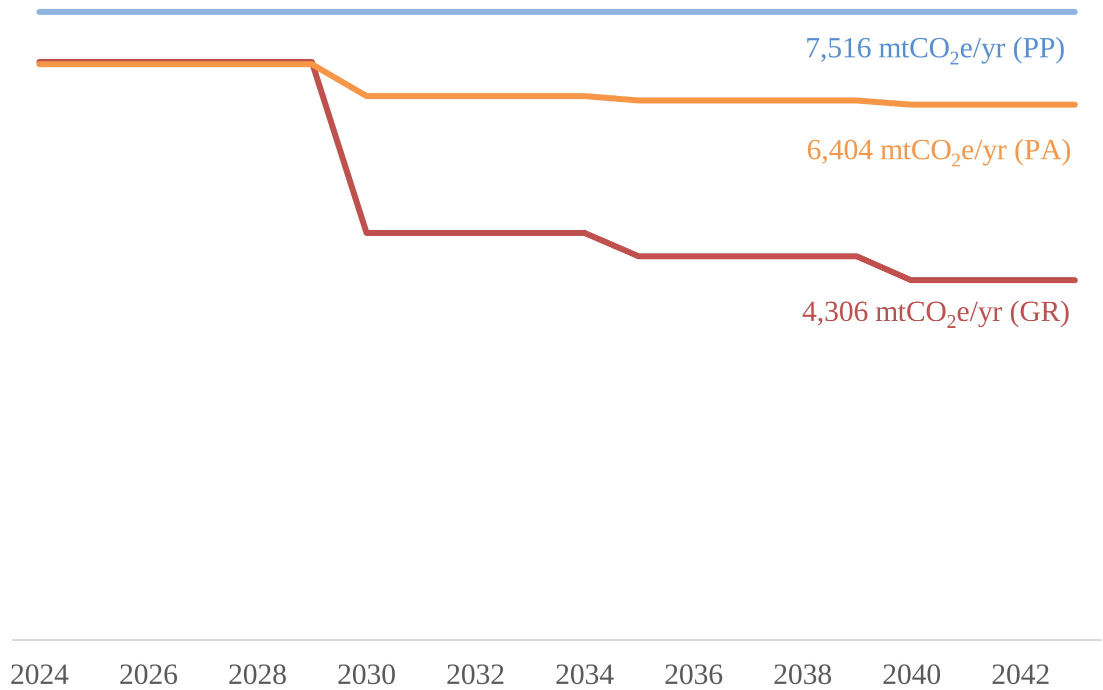


Figure D: Forecasted Annual GHG Emissions During Life Cycle Analysis Period

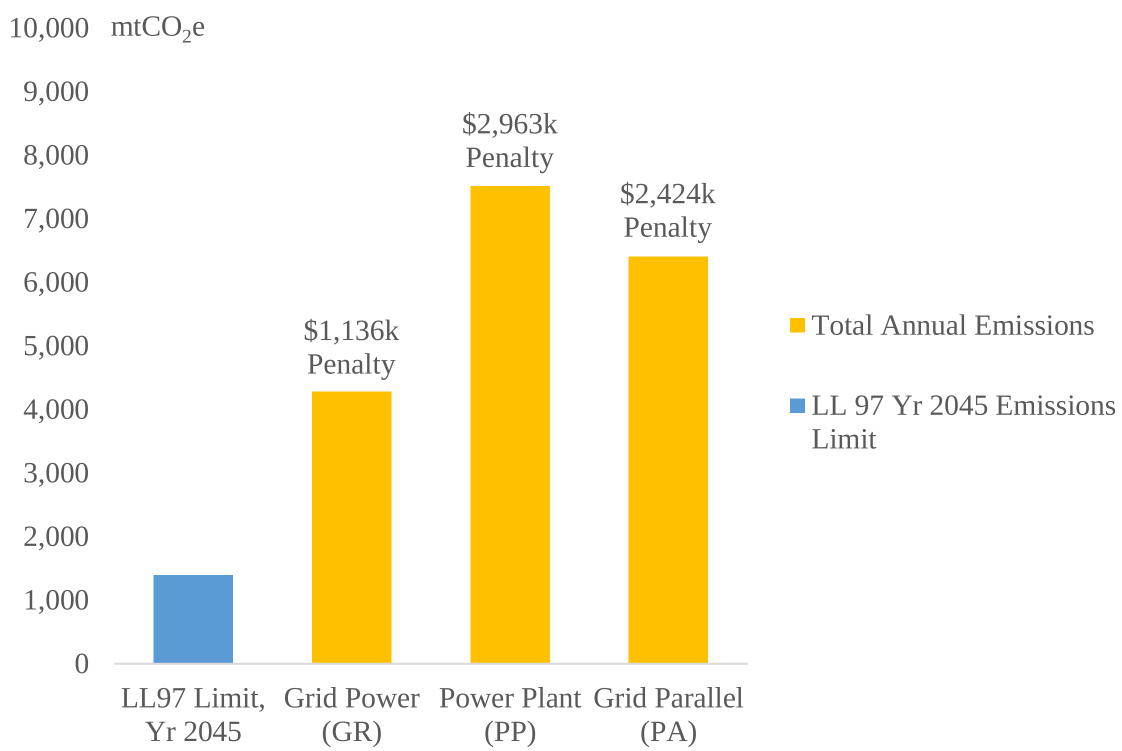


Figure E: Forecasted Yr 2045 GHG Emissions & Local Law 97 Penalty with 10-Yr Delay (TC$)

Because the capital cost of the engine installations would be paid for at the end of the life cycle studied, the engines in the Grid Parallel (PA) alternative could be shut down and used only as a resiliency asset to avoid roughly half of this penalty at no cost to Big Six Towers. In such a scenario, the penalty for the Grid Parallel (PA) alternative would be equal to the Grid Connection (GR) alternative. For the Power Plant (PP) alternative, this would not be an option, as a new Con Edison service with the associated capital costs would be required to supply electrical power to Big Six Towers in order to shut down the engines.

The residual penalties shown in Figure E are all based on zero emissions electricity from the grid and the continued operation of the Big Six Towers boiler plant on natural gas fuel. Although the grid electricity is carbon free, the emissions of operating the heating plant alone would still exceed the current limits contained in Local Law 97 using the metrics forecasted herein.

1.3 Low Carbon Alternatives

The previous section begs a question: how could the greenhouse gas emissions of the Big Six Towers community be reduced in order to avoid penalties in the future? This question was addressed at a screening level of analysis in this study because the financial necessity of implementing additional capital investment and/or incurring higher operating costs to reduce greenhouse gas emissions is not the most critical near-term factor in decision-making. Big Six Towers must secure an affordable energy supply alternative to its aging facility in the immediate future, and the carbon emission penalties noted above will not take effect (at the relatively high levels shown) for approximately two decades.

To assist in evaluating possible improvements to the facility that could reduce greenhouse gas emissions and avoid these penalties, Waldron considered multiple alternatives: the use of geothermal heating and cooling, the use of air-source heat pump heating and cooling, the use of a liquid biofuel for heating, and the electrification of the boiler plant. The capital and operating costs of these alternatives are shown in the figure below and are compared to the Grid Connection (GR). In essence, these are extensions of the Grid Connection case that require additional investment to reduce fossil fuel use in the existing boiler plant.

As Figure F on the following page shows, additional capital investment is required for each of the low carbon alternatives that was studied. The difficulty is that this capital investment does not yield operating cost reductions; in fact, with the exception of the geothermal alternative, the operating cost in each low-carbon alternative reviewed is forecasted to increase as well. The reason for this is that displacing natural gas fuel with electricity is predicted to result in an operating cost increase. Geothermal avoids this outcome because it has a higher efficiency than any other electrical option reviewed, but its applicability is limited.

The challenge with geothermal is the high construction cost associated with well-drilling, the associated collection piping systems, and the fact that the building systems themselves would have to be wholly retrofit to utilize geothermal hot water in lieu of steam. Also, the geothermal resource is limited by the size of the property. This analysis assumes all parking areas are utilized for well fields, and this is enough land area to shift just one of the seven towers from the boiler plant to geothermal heating and cooling.

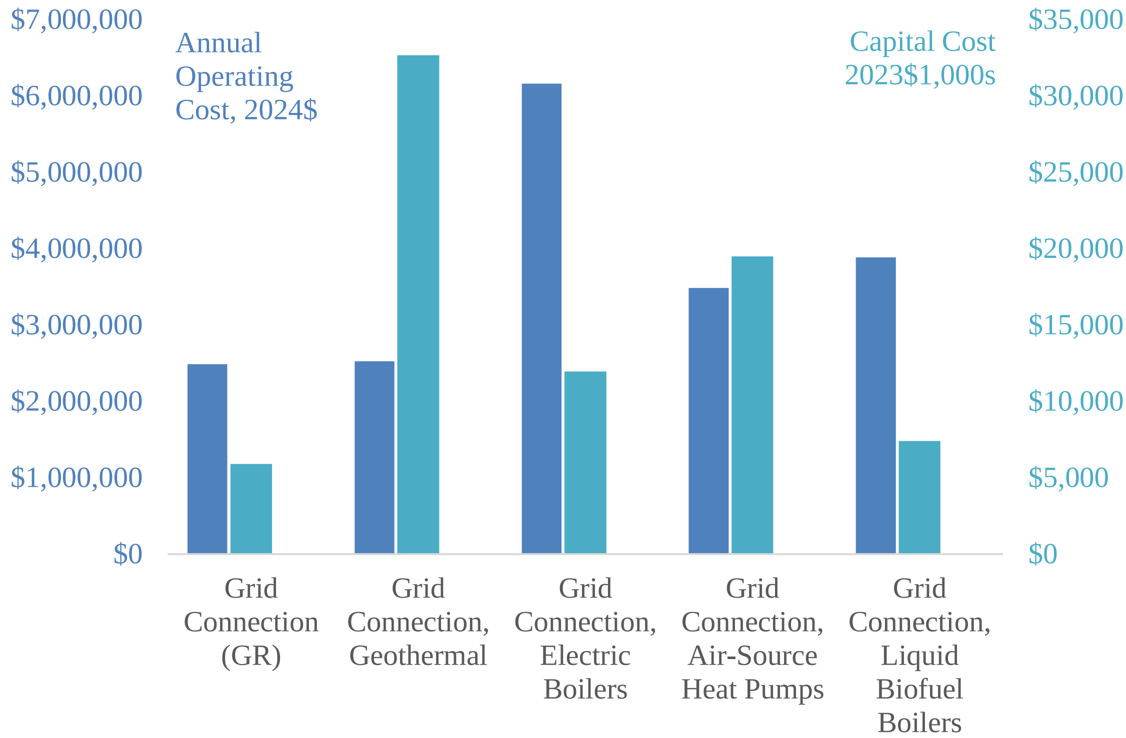


Figure F: Low Carbon Energy Supply Alternatives, Screening Level Assessment

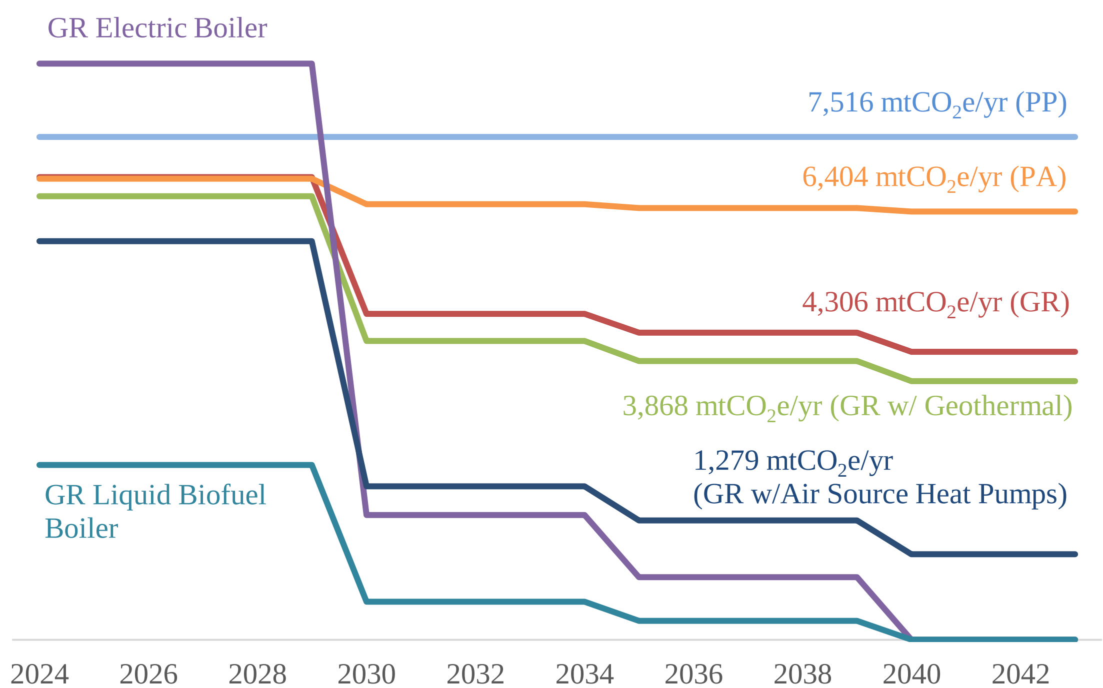


Figure G: Forecasted Annual GHG Emissions During Life Cycle Analysis Period

Figure G shows the annual greenhouse gas emissions for each of the low carbon alternatives studied, alongside of the conventional energy supply alternatives previously shown in Figure D. Based on information currently available, the low carbon alternative with the lowest unit cost of emissions reduction and the least impact on the existing infrastructure at Big Six Towers would be the use of a liquid biofuel in lieu of fossil fuels in the boiler plant. This would require modifications to both boiler fuel and fuel storage systems but would not require building modifications, so the capital investment is minimized. The tradeoff is the relatively high cost of the fuel.

There are various complexities to the entire greenhouse gas emissions analysis of this study that merit discussion, however. The figures above contain assumptions about the rate at which the electrical grid will be transformed to a zero-carbon electricity source for consumers. At present, the NYC/Westchester region of the electric grid is an area that forecasted to require dispatchable assets for the foreseeable future for grid stability. Those dispatchable assets presently include—and will likely include for the foreseeable future—natural-gas-fired power plants. Conventional wind and solar facilities are not dispatchable (without energy storage systems) because they depend on the environmental conditions. So there is uncertainty in this grid-transformation forecast. If the carbon intensity of the grid does not reduce as quickly as legislation requires, then the energy supply alternatives with on-site generation would perform closer to the Grid Connection (GR) case in terms of annual emissions.

Further, when the emissions of the PP and PA alternatives are compared to the emissions rates of the non-baseload, natural-gas-fired generators that are likely to be in use through much of the project life cycle for grid stability purposes, the alternatives studied are competitive in terms of greenhouse gas emissions.

1.4 Risk Assessment

The financial performance of the various alternatives is most sensitive to three primary parameters, in the order listed: electricity costs, capital costs and natural gas costs. The highest risk for Big Six Towers with regards to future energy costs is increasing electricity costs. In the Grid Connection (GR) alternative, for instance, purchased electricity accounts for roughly 75% of the annual operating cost. Because the other two alternatives generate savings proportional to those costs, the relative value of making the incremental investment to construct one of them is also most directly tied to future electricity prices.

Figures H through M on the following page depict the sensitivity of the economic performance of the various energy supply alternatives to these three parameters. In each set of figures, only one of the three parameters is varied in order to show how the life cycle cost and rate of return respond to those variations. The purpose of the graphics is to provide a sense of how sensitive the project economic outcomes are to these factors, and how changes to the values forecasted in the study models would impact the results.

As an example, Figure H on the following page shows that the life cycle cost for the alternatives with on-site generation decreases more slowly than the grid-connected alternative when electricity prices rise. Thus, the Grid Parallel (PA) alternative in particular works as a hedge against future increases in electricity costs: if electricity costs rise as compared to the baseline values modeled the overall life cycle cost exposure to Big Six Towers is lower than it would be for the Grid Connected (GR) alternative.

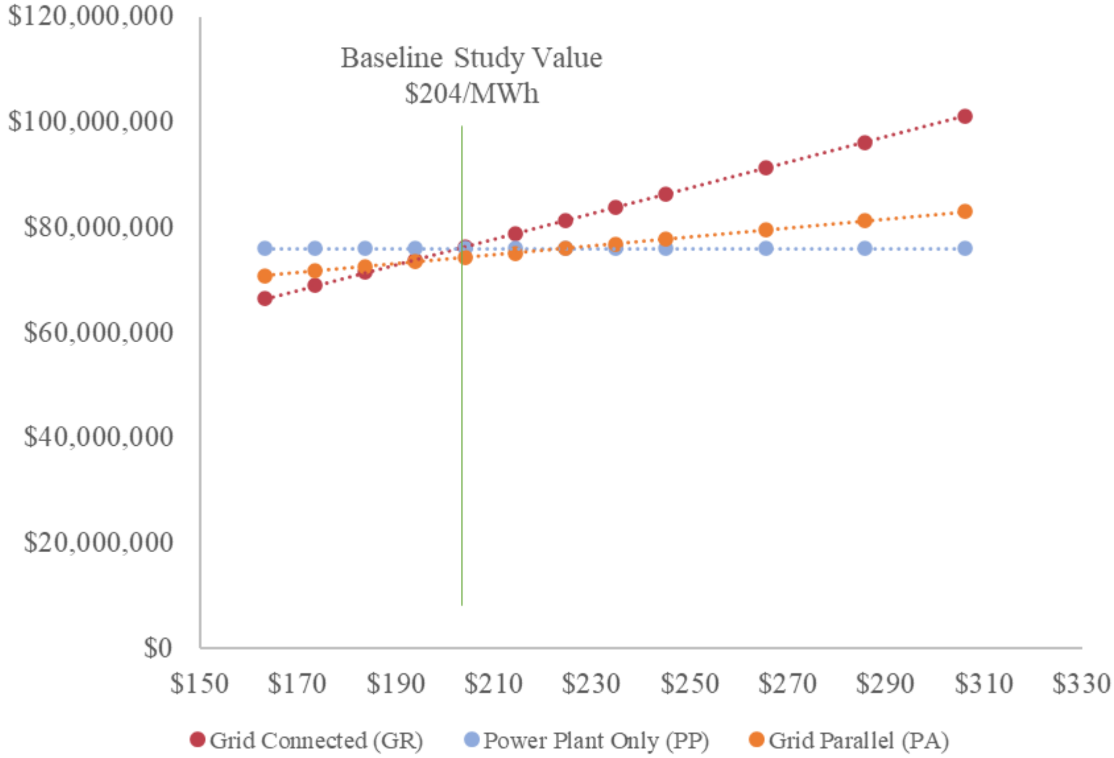


Figure H: Life Cycle Cost (TC$) as a Function of All-In Electricity Cost ($/MWh)

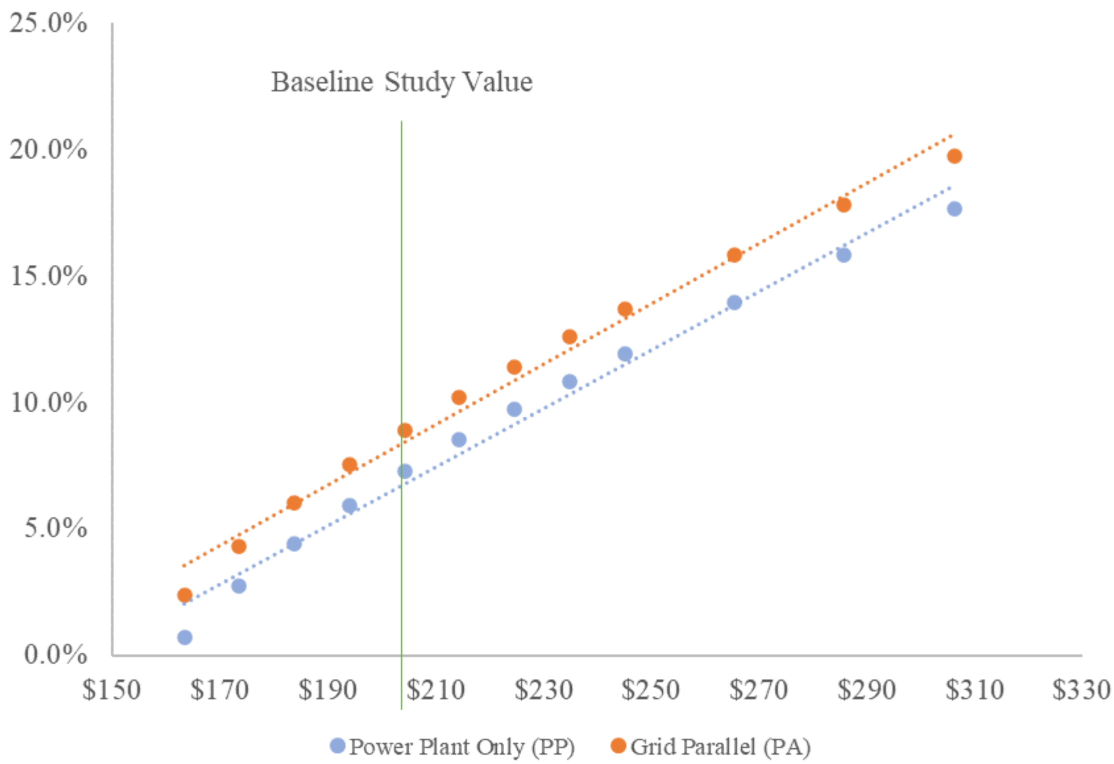


Figure I: Rate of Return as a Function of All-In Electricity Cost ($/MWh)

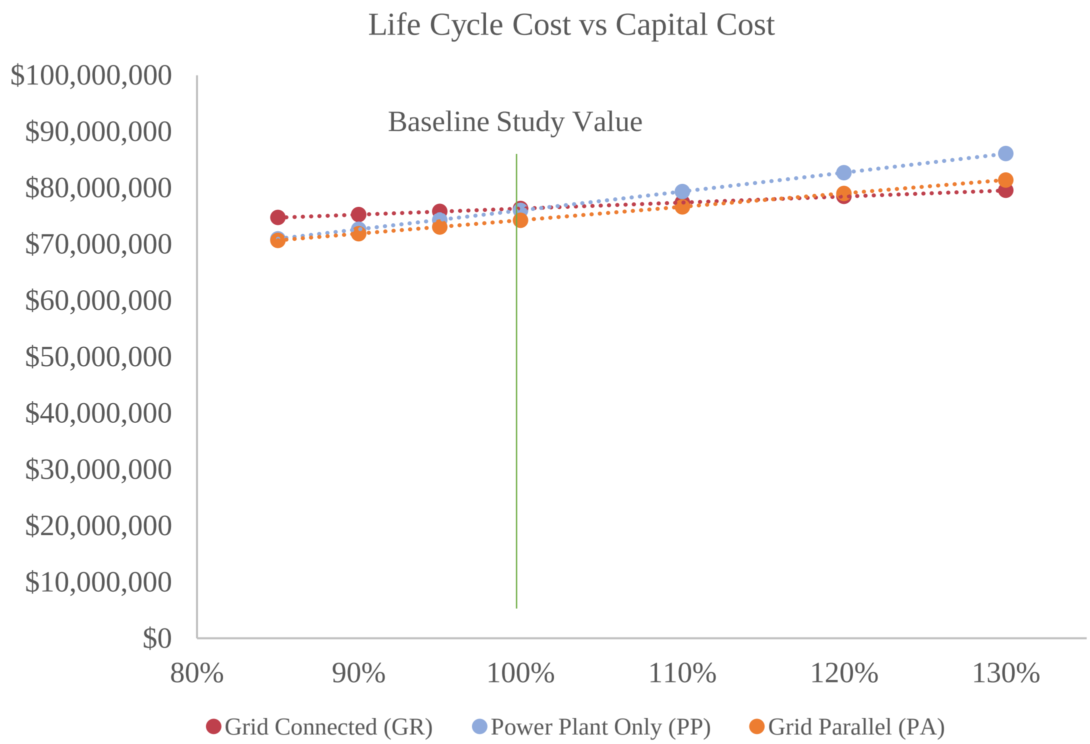


Figure J: Life Cycle Cost (TC$) as a Function of Capital Cost (% of Baseline)

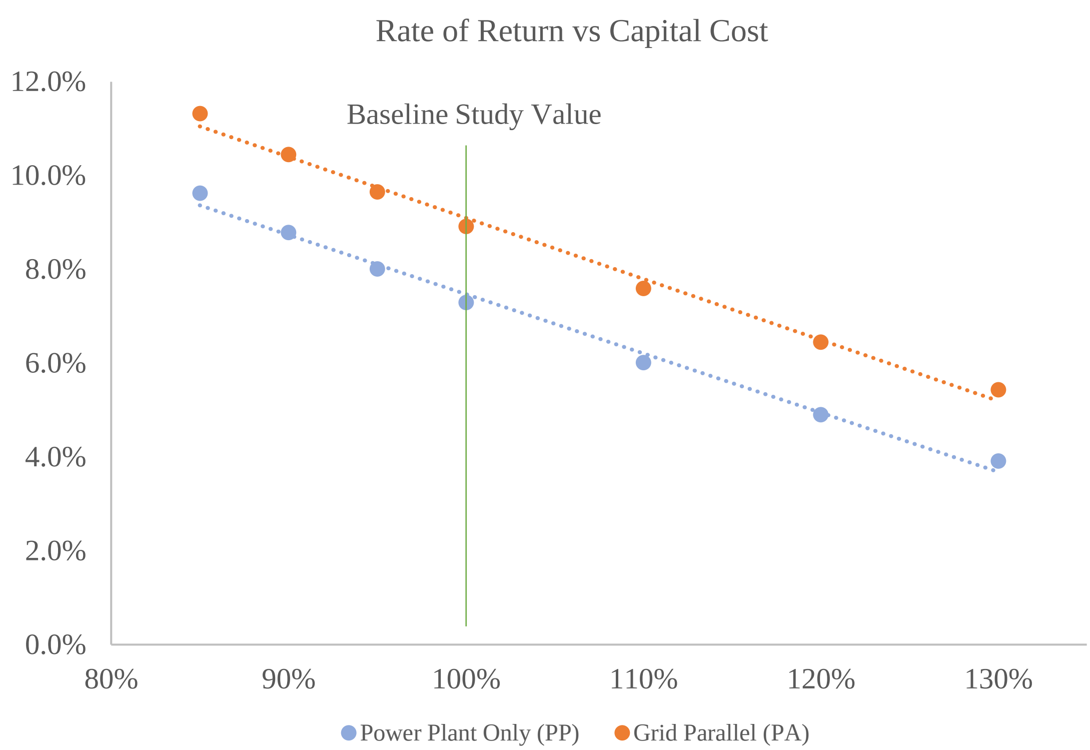


Figure K: Rate of Return as a Function of Capital Cost (% of Baseline)

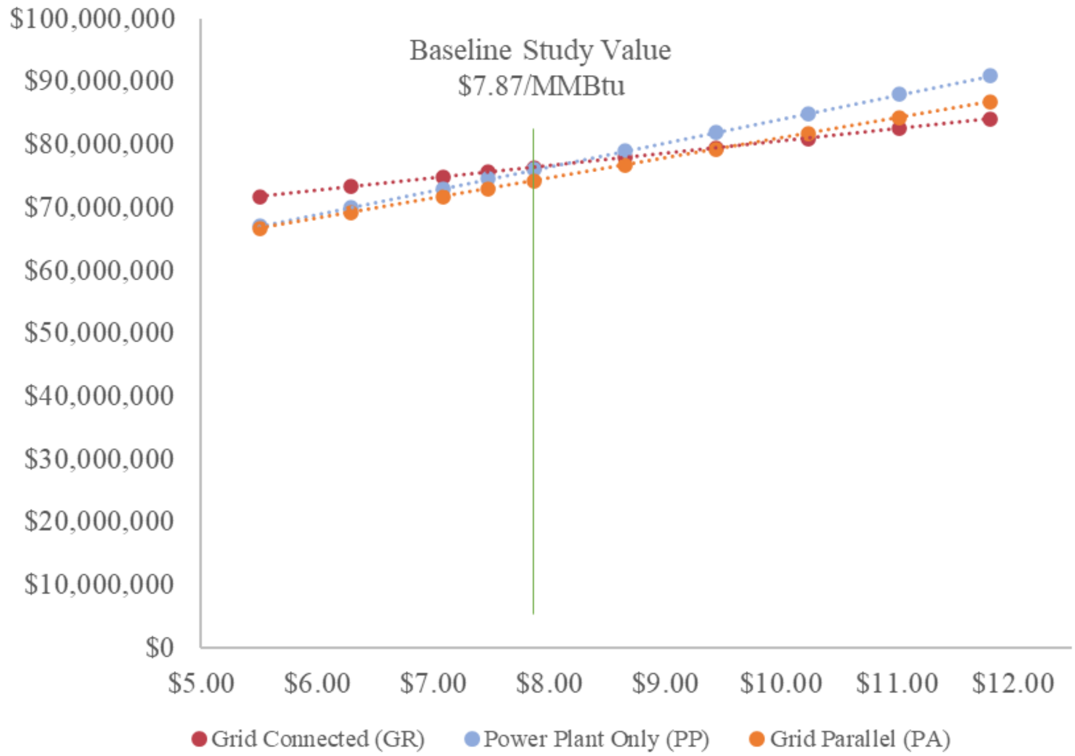


Figure L: Life Cycle Cost (TC$) as a Function of All-In Natural Gas Cost ($/MMBtu)

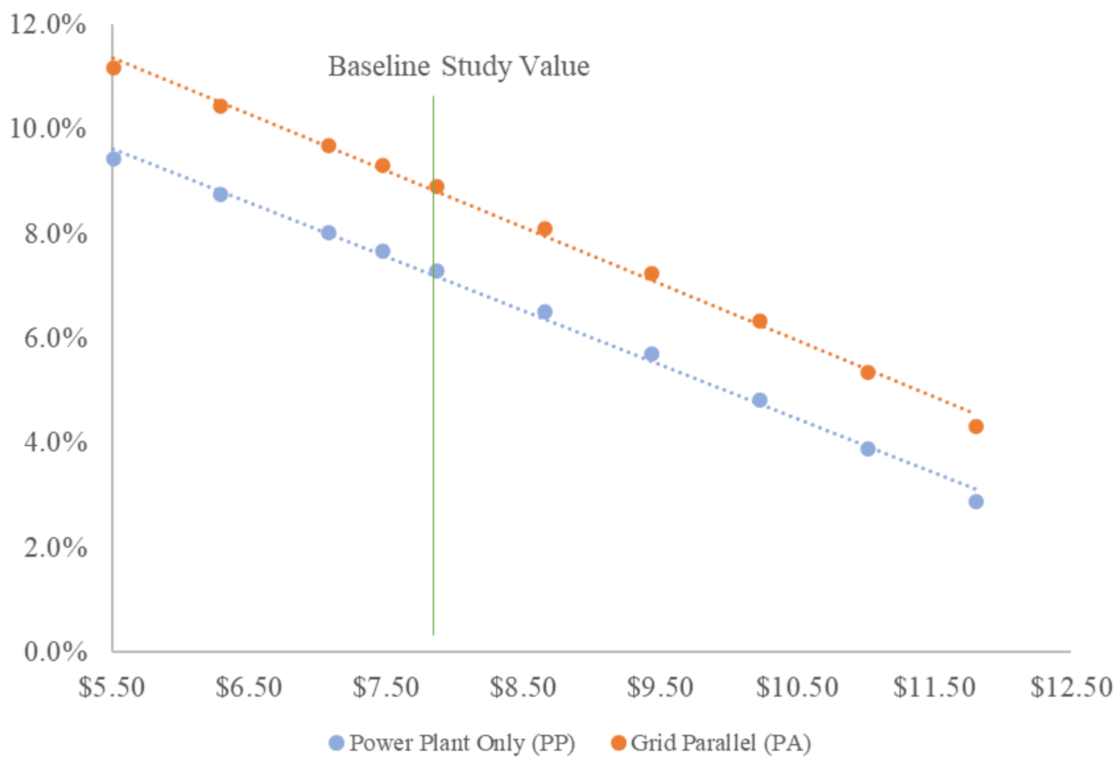


Figure M: Rate of Return as a Function of All-In Natural Gas Cost ($/MMBtu)

The graphics on the preceding pages depict project outcomes for cases when only a single parameter is varied at a time. The effects would compound for scenarios in which multiple parameters vary from the baseline assumptions. For instance, if electricity prices were to rise by 25%, capital costs to rise by 5%, and natural gas prices to rise by 5%, then the resulting rate of return for the grid parallel alternative (PA) would be 13.6%.

1.5 Recommendations and Next Steps

To make a decision on the energy supply alternative that is preferred for future development, Big Six Towers will need to weight the potential risks and benefits of the various alternatives. If minimizing capital investment is more important than mitigating risk exposure to future electricity prices, the grid-connected alternative (GR) would likely be the most attractive. On the other hand, if minimizing exposure to future year cost increases is paramount, given that future electricity prices are the most significant component of the operating budget as well as one of the most uncertain parameters of the analysis, then the grid parallel alternative (PA) would likely be the most attractive.

In Waldron's opinion, the Power Plant Only (PP) is the least attractive and could be removed from consideration. While the operating cost for this alternative is insensitive to the electricity markets, the higher capital cost results in a higher life cycle cost than the Grid Parallel (PA) alternative. Electricity prices would need to increase by roughly 30% in order for the life cycle cost of this alternative to equal the life cycle cost of the Grid Parallel (PA)alternative, and if electricity prices fall below the forecasted values the Power Plant (PP) alternative performs worst economically. It also exposes Big Six Towers to significant penalties at the conclusion of the life cycle period that could not be avoided without additional capital investments that the other options would not require.

Of the remaining two alternatives, assuming access to capital is not a hurdle, Waldron recommends the Grid Parallel (PA) case. The reason is that it provides a hedge against future electricity cost increases without a likely increase in life cycle cost, and if carbon emission penalties in the mid-2040's necessitate that the engines be curtailed in operation, the connection to the Con Edison grid would already be in place to provide a seamless transition. As low carbon technologies mature, the Grid Parallel (PA) case is flexible enough to accommodate either electrification or renewable fuel supply alternatives as may be required for roughly the same incremental cost as the Grid Connected (GR) alternative.

The recommended next steps will vary depending on the alternative that is most attractive to Big Six Towers. For the Grid Parallel (PA) option, Waldron would recommend the development of a conceptual engineering design suitable for use in creating a more detailed cost estimate of the work required. The purpose of this effort would be to scope out the project at a more refined level so that more accurate cost opinions could be developed. Further discussions with Con Edison, an environmental permitting consultant and the natural gas supplier, as well as possible commodity suppliers would also be recommended.

If the grid connected (GR) option is most attractive, the key step is continued engagement with Con Edison to define the scope of work and costs involved with establishing a grid connection for the supply of electricity.

2 Existing Systems

2.1 Overview

The Big Six Towers community consists of seven residential towers and a commercial property located in Woodside, NY along Queens Boulevard, between 59th Street and 61st Street, as shown below.

Figure 1: Big Six Towers Location (Map Data by Google)

Electrical power to the community is provided by a combined heat and power plant located on the south side of the commercial property. The plant provides 100% of the electrical needs of the community—(no connection to the Con Edison grid presently exists)—as well as a portion of the thermal energy needs. The major equipment located at the plant is summarized in the table below.

Equipment	Year Installed	Description
Reciprocating Engines		
Engine 1	~1980	550 kW, Natural Gas Fired
Engine 2	~1980	750 kW, Diesel Fired
Engine 3	~1980	550 kW, Natural Gas Fired
Engine 4	~1980	750 kW, Diesel Fired
Engine 5	~1980	550 kW, Natural Gas Fired
Engine 6	~1990	1,600 kW, Diesel Fired
Heat Recovery Boilers		
Engine 1 Waste Heat Boiler	~1980	~1.0 klbs/hr Steam Production
Engine 2 Waste Heat Boiler	~1980	~1.4 klbs/hr Steam Production
Engine 3 Waste Heat Boiler	~1980	~1.0 klbs/hr Steam Production
Engine 4 Waste Heat Boiler	~1980	~1.4 klbs/hr Steam Production
Engine 5 Waste Heat Boiler	~1980	~1.0 klbs/hr Steam Production
Engine 6 Waste Heat Boiler	~1990	~3.9 klbs/hr Steam Production
Absorption Chiller		
Steam Absorption Chiller	2022	200 tons Rated Capacity

Figure 2: Existing Power Plant Major Equipment

The primary equipment in the power plant is over forty years old and well beyond the life expectancy for such equipment. The engines operate relatively inefficiently as compared to new technology and the major equipment is in need of replacement, Local Law 38 issues notwithstanding.

A boiler plant is separately located in the basement of Building 3 that provides steam production to cover the heating (and domestic hot water) needs of the community not met by the power plant heat recovery systems. A summary of the various utility needs of the community is provided in the table below.

Utility Needs	Sources of Supply
Commercial Property / Tenants	
Electricity	Power Plant Engines
HVAC, Cooling	Power Plant Absorption Chiller (chilled water)
HVAC, Heating	Power Plant Waste Heat Boilers Boiler Plant
Residential Towers	
Electricity	Power Plant Engines
HVAC, Cooling	Power Plant Engines (through-wall units)
HVAC, Heating	Power Plant Waste Heat Boilers Boiler Plant
Domestic Hot Water	Power Plant Engine Jacket Heat Recovery Power Plant Waste Heat Boilers (back-up) Boiler Plant (back-up)

Figure 3: Utility Needs and Sources of Supply

Steam is generated at low pressure and distributed throughout the campus from both the power plant waste heat recovery boilers and the boiler plant. Each residential tower has a vacuum condensate system that recovers condensate from the heating system and forwards it to a central receiver at the boiler plant.

2.2 Existing Electrical Distribution

Electrical power is generated at 460V in the power plant and distributed to the various end users. The collector bus in the power plant contains breakers that feed the commercial spaces located along Queens Boulevard, as well as two breakers that feed the residential tower system.

Power to the residential tower system is stepped down from 460V to 120V by two transformers located outside of Building 3. Each transformer feeds a central distribution line-up located in the basement of that building. From the two distribution line-ups in the basement, power is fed radially to each tower. Note that each tower has only one feed, which originates in one or the other of the two line-ups.

Refer to Attachment D for an electrical one-line diagram of the existing system.

Existing electrical distribution system equipment is aging and recommended for replacement in accordance with the table below. Assessment of the electrical distribution system beyond the 120V Campus Distribution Switchgear located in Building 3 is outside of the scope of this study.

Equipment	Description
Power Plant Switchgear, 460V	This equipment was installed in 2013 and should be suitable for continued operation with any of the future electricity supply scenarios considered in this study.
460V:120V Distribution Transformers	One transformer was replaced in 2010. Based on its age, the other is recommended for replacement within the next 8-10 years. Testing is recommended in the short-term to justify continued use. Testing should include insulation resistance testing and thermography.
120V Campus Distribution Switchgear (Building 3)	Replacement is recommended as part of the next infrastructure upgrade. The original manufacturer is no longer in business, parts are difficult to obtain, and this equipment was subject to recent flooding.

Figure 4: Electrical Equipment Replacement Recommendations

2.3 Considerations for the Future

The power plant was constructed circa 1980 and with limited exceptions the original equipment has reached the end of its useful life. In order to secure the reliable supply of electricity in the future the existing power plant must be repowered with new equipment or, alternatively, the community must connect to the Con Edison electrical distribution system. A hybrid version in which a smaller power plant is operated in parallel with the Con Edison grid is also possible. Evaluation of these alternatives is the key objective of this analysis.

Compliance with New York City Local Laws 38 and 97 places additional pressure on Big Six Towers to make upgrades to the facility. Local Law 38, for instance, mandates that stationary engines such as those presently utilized by Big Six Towers for electricity generation must meet Tier 4 emissions standards as established by the EPA beginning in Year 2025. It will not be feasible to do so with the current engines. Thus, unless relief is received from the City on this requirement, alternate sources of electricity must be in place for the community within approximately three years.

Local Law 97 mandates future financial penalties for greenhouse gas emissions that exceed a threshold value established by the law. For many properties in the City the penalties and the associated energy use reporting requirements will take effect in Year 2024. Big Six Towers is exempted from the penalties by Paragraph 320.3.9 of the law because of its status as a provider of income-restricted housing. However, based upon conversations with the City that were reported to Waldron during this study, it is expected that the penalties and reporting requirements described in the Law will be applied to Big Six Towers with a 10-year delay. The cost implications of this have been incorporated into the financial models developed for this study. In addition, the estimated penalties that would apply to Big Six Towers if the community were *not* initially exempt from the Law have been described in Section 6 of this report.

3 Utility Load Profiles

Future electricity supply alternatives were evaluated utilizing a life cycle utility model that forecasts financial performance and greenhouse gas emissions for each year of a 20-yr life cycle. The primary inputs to this model are the utility load profiles, the equipment line-ups and performance curves, commodity pricing forecasts, and the applicable tariff models.

The model performs equipment dispatching and associated performance calculations on an hourly basis, for each hour of each year in the project life cycle. The primary task is to dispatch the equipment associated with each alternative as efficiently as possible to meet the corresponding utility loads of the community. The electricity and fuel consumed to do so are then totalized and their respective costs calculated using the tariff models.

The utility load profiles are an essential input to all of the modeling and assessment work. Because limited data on the historical energy usage was available, Waldron had to construct hourly utility load profiles for the community that could be utilized in the analysis. These hourly profiles were calibrated to the extent possible by comparison with the monthly fuel bills and the monthly plant performance information supplied by Big Six Towers. The process for generating each required utility load profile is described below.

3.1 Electric Load Profile

Monthly power plant electricity production records from July, 2020 through June, 2021 were utilized as the basis for development of the electric load profile. A two-step process was utilized to develop hourly usage values that would correlate closely to the historical monthly totals: first, a base load electric profile was developed that doesn't include space heating or cooling loads, and second, a profile reflecting the operation of the air-conditioning units within the residential units was developed. The total electric profile is the sum of these two.

In Waldron's experience when thermal utilities are removed from an electrical load profile the result is typically flat throughout the year. This base profile represents such loads as lighting, elevators, basic ventilation, laundry, plug and appliance loads. The base profile Waldron developed matched the monthly totals for November through April very well. Space heating is provided by the boiler plant primarily, so the effects of ambient temperature do not significantly impact the electrical load profile during this time period.

During the cooling season, however, which runs from approximately May through October, there is a component of the overall electrical usage that is based on operation of the tenants' air-conditioning systems. This second profile was developed by creating a set of equipment performance curves to represent the entire fleet of air-conditioning equipment and dispatching it against a cooling profile that was based on outside air enthalpy.

The final electric load profile for the model was a combination of these two profiles and demonstrated close agreement with the historical data after fine-tuning of the input assumptions.

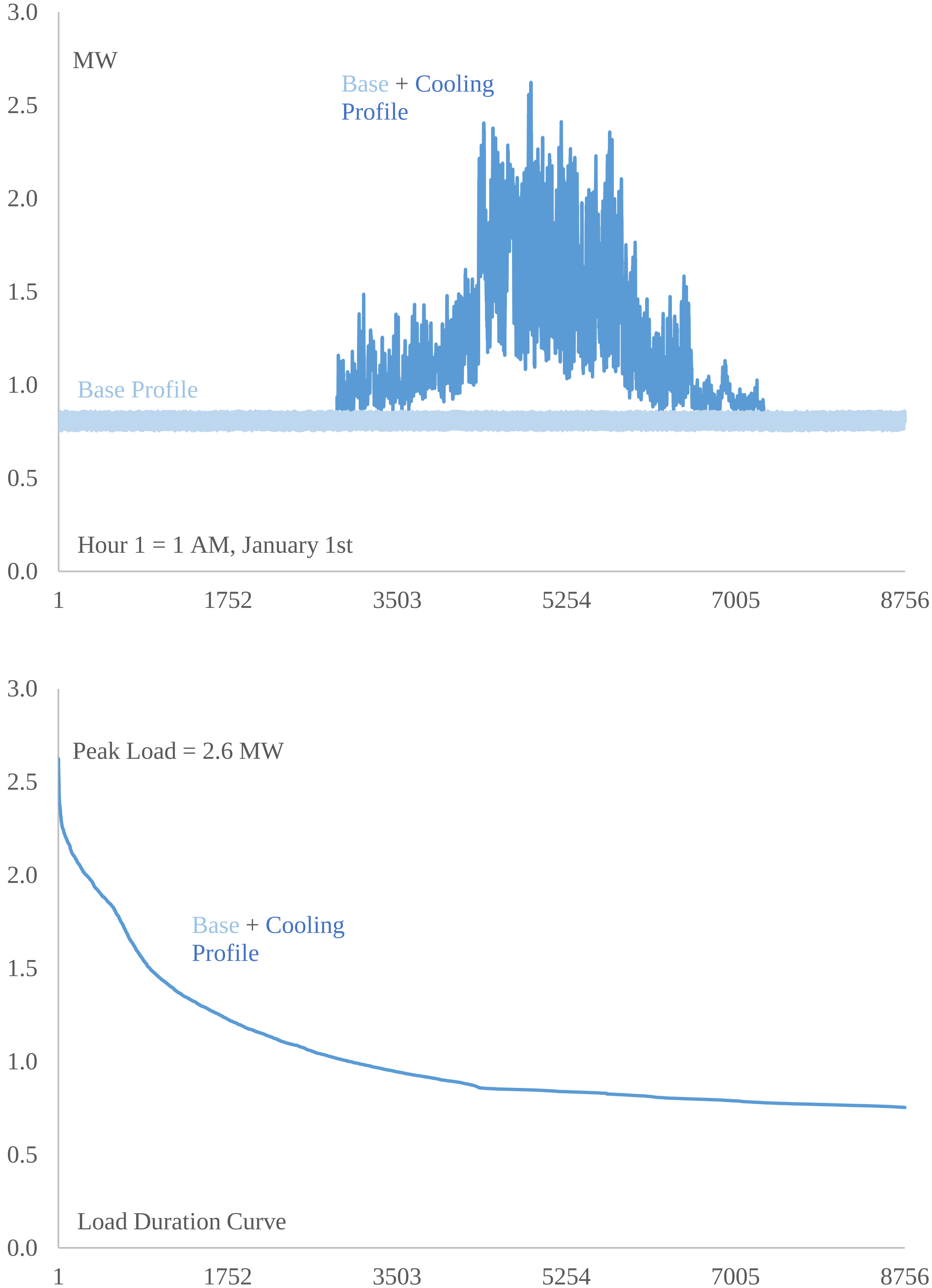


Figure 5: Big Six Towers Electric Load Profile

The lower curve in Figure 5 on the preceding page is a load duration curve. This curve contains the same load information as the graph above it, except that the hourly values are ordered from the largest value to the smallest. This format is useful for developing an understanding of how many hours per year the load profile is at or above a given value.

The table below shows how the monthly totals from Waldron's hourly load profile compare to the historical monthly values reported in the Big Six Towers power plant data.

	Waldron Profile (MWh)	Historical Data 2020-2021 (MWh)	Percent Difference (%)
Jan	598	602	-0.7%
Feb	540	581	-7.1%
Mar	598	592	1.0%
Apr	578	580	-0.3%
May	752	746	0.8%
Jun	841	840	0.1%
Jul	1,273	1,265	0.6%
Aug	1,174	1,172	0.2%
Sep	826	812	1.7%
Oct	687	647	6.2%
Nov	577	562	2.7%
Dec	597	572	4.4%
Total	9,041	8,970	0.8%

Figure 6: Electrical Load Profile Calibration Summary

3.2 Steam Load Profile

Steam is used at Big Six Towers for several purposes:

- motive steam to the steam absorption chiller in the power plant;
- back-up heating source for domestic hot water; and, primarily,
- space heating.

Waldron was provided with two primary sources of information that were utilized in developing an hourly steam profile: the boiler plant natural gas bills and monthly oil consumption records; and the power plant monthly steam totals.

Similar to the electric profile, the overall steam profile was developed as the sum of smaller profiles. The largest constituent profile was for the boilers in the steam plant. This profile was developed by creating an hourly load shape that was correlated to ambient temperature during the heating season and then calibrating this to the boiler natural gas bills.

The second profile developed was for steam to the absorption chiller. This was created by first developing a chilled water load for the commercial building space that was based on outside air enthalpy data and then dispatching a steam absorption chiller against this profile to determine the steam required to satisfy the cooling load. A value of 17,000 Btu/ton-hr, or 17 lbs steam per ton-hr, was assumed for chiller performance.

The third profile developed was an estimate of steam generated in the power plant from the waste heat recovery boilers that generate steam from the thermal energy contained in the engine exhaust gases. In order to develop this profile Waldron created models of the existing engine plant that dispatched the existing engines against the electric profiles described previously, and calculated the steam produced from heat recovery.

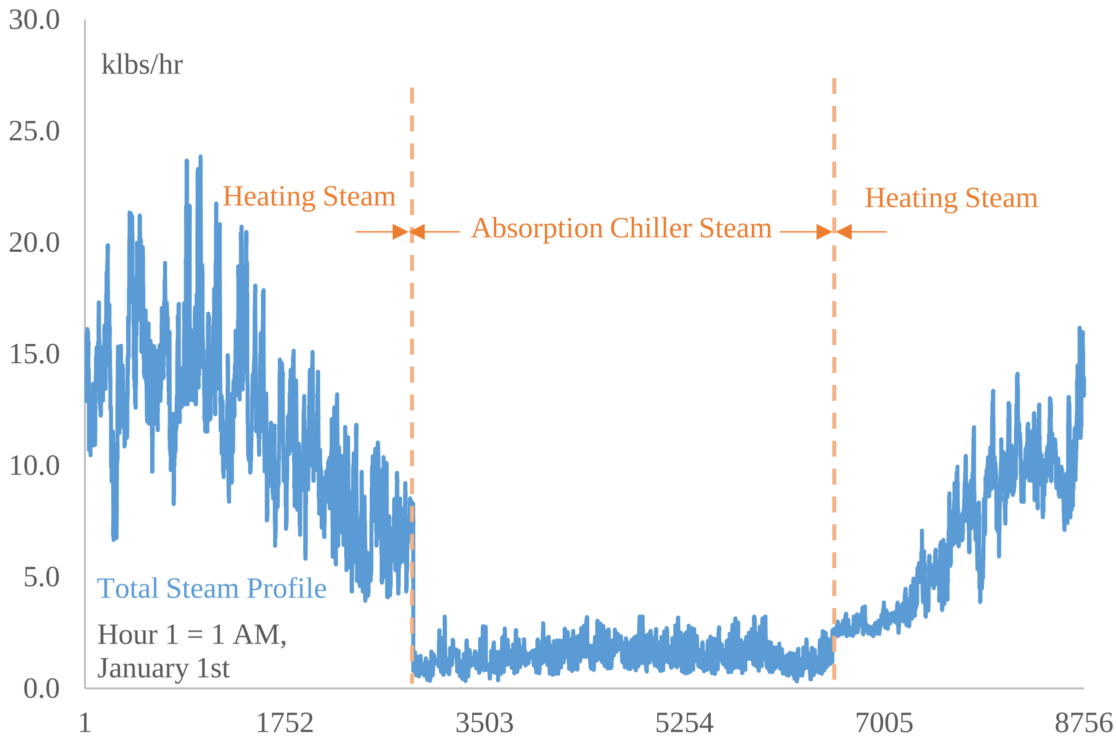
The engine heat recovery profile was necessary to develop because in the analysis of future scenarios, such as the retirement of the power plant and reliance on the Con Edison system for electrical power, the steam produced by the engines would no longer be available. This portion of the steam production would thus need to shift to the boilers, and so a reasonable estimate of this steam quantity was required.

The graphics on the following page depict the steam profiles that were developed and utilized in the subsequent analysis. The table below shows how the first portion of the profile—the boiler plant steam production—was calibrated to the historical natural gas bills. As with the electric profile development, the historical data from July, 2020 through June, 2021 was used in this work.

	Waldron Profile (lbs)	Steam Based on Gas Bills (2020-2021) (lbs)	Percent Difference (%)
Jan	9,432,547	9,451,840	-0.2%
Feb	8,473,972	8,531,680	-0.7%
Mar	6,917,536	6,885,120	0.5%
Apr	4,114,031	4,128,800	-0.4%
May	0	0	0.0%
Jun	0	0	0.0%
Jul	0	0	0.0%
Aug	0	0	0.0%
Sep	705	0	0.0%
Oct	873,824	876,720	-0.3%
Nov	3,719,520	3,700,880	0.5%
Dec	6,411,425	6,466,480	-0.9%
Total	39,943,561	40,041,520	-0.2%

Figure 7: Boiler Plant Heating Steam Profile Calibration Summary

Note that there was historical steam production from the boiler plant in the summer months, but this would not have been heating steam.



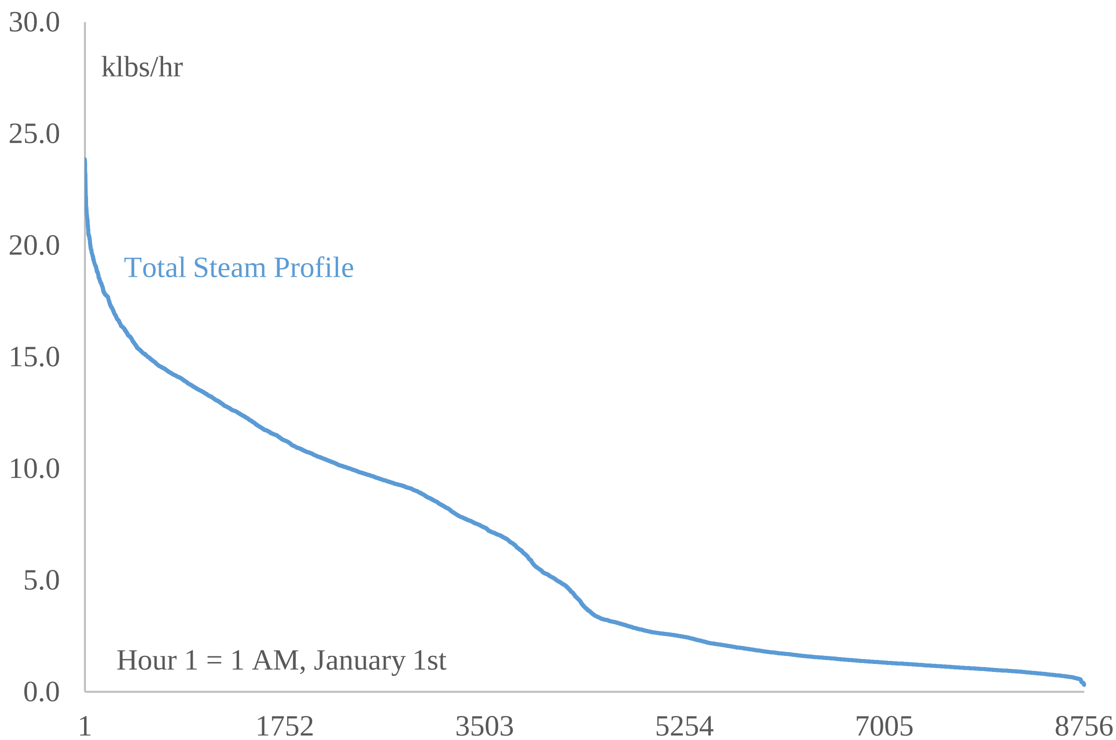


Figure 8: Big Six Towers Steam Load Profile

The steam profile development process revealed several nuances that merit explanation. First, the profile developed on the previous page is the estimated “useful” steam produced, and consists of steam that very likely served an end user. Boiler steam production during the heating season, for instance, when the community steam load clearly exceeded the steam produced from engine waste heat, would have been required to maintain steam header pressure in the boiler plant and could all be considered useful. Likewise, steam from engine waste heat recovery generated during the heating season could reasonably be considered useful because clearly there was sufficient load to utilize this steam, and lastly, steam required to generate chilled water in the absorption chiller would be useful.

During the summer, however, historical records and natural gas bills confirm that steam generated in the boiler plant, when combined with the forecasted steam production from the engine heat recovery systems in the power plant, yields a total steam production well in excess of the predicted absorption chiller steam load. Figure 9 below shows this graphically.

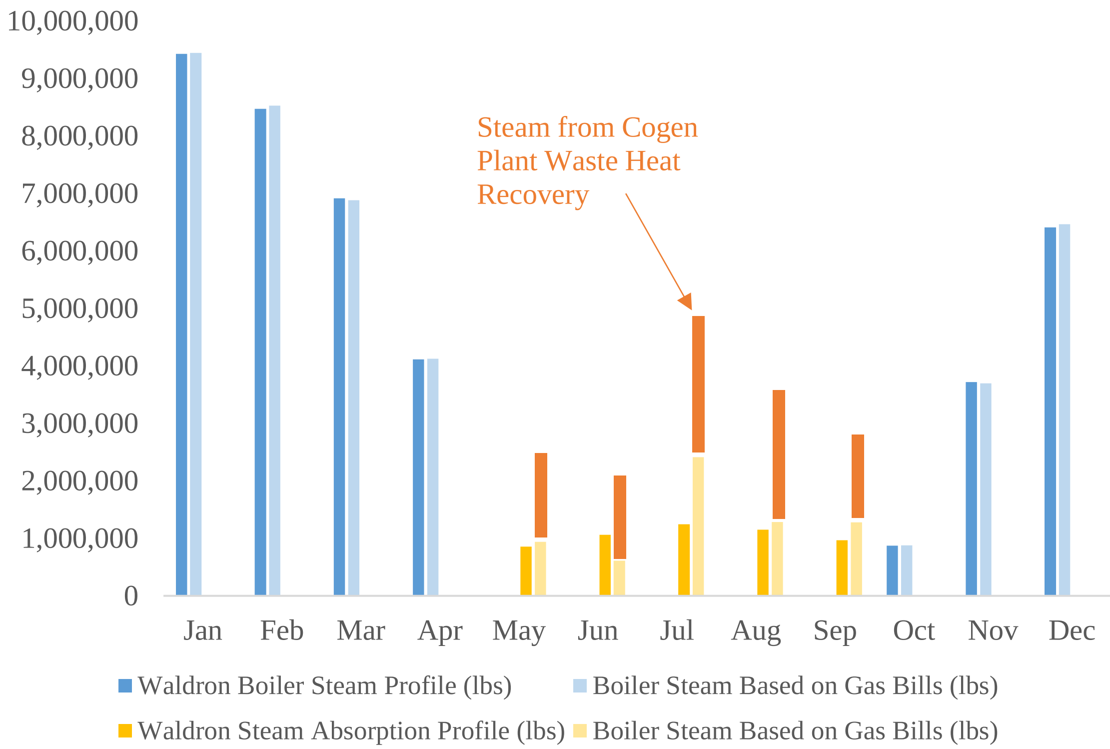


Figure 9: Analysis of Summer Steam Production

One possible explanation for this, which has not been confirmed, is that steam may be admitted as a secondary heat source to residential building domestic hot water systems during winter months when engine jacket water heat recovery alone may be insufficient to carry the entire load. If this steam were left “on” during the summer when it is no longer required, it would result in boiler operation to maintain header pressure. The excess energy would simply be rejected to the atmosphere at the power plant through the engine radiators. Another potential explanation is that steam trap leakage is the culprit, and the effect is not in fact seasonal, but year round. The annual cost of this potential excess steam production is $55k - $125k.

Because the excess summer steam production was not considered "useful," it was not included in the overall steam load profile that was used in the life cycle utility model.

3.3 Domestic Hot Water Profile

No metered data from Big Six Towers was available for use in development of the domestic hot water load profile. The primary heat source is the thermal energy recovered from the engine jacket cooling systems. Multiple heat exchangers in the power plant are utilized to convey this heat to hot water circuits that are routed underground to each of the residential towers. If the buildings do not utilize all the heat that is sent out from the power plant, the excess is rejected to atmosphere at the power plant through the cooling radiators located on the roof of the building.

A domestic hot water load profile was required in order to evaluate the additional heating fuel that would be required in cases when the power plant is no longer utilized and/or when a smaller quantity of engines are considered. Without the same quantity of engine jacket water heat available as the current system produces, the difference would need to be produced by additional boiler steam production.

Waldron developed a preliminary daily hot water usage quantity based on the number and type of residential units and estimates of hot water use per resident for various services such as bathing, laundry, food preparation, etc. The estimates for individual uses were based on published ASHRAE data and used to develop a daily total. This daily total was then assigned to each hour of the day utilizing a load shape that also was available from ASHRAE. Waldron's initial estimate yielded a total thermal demand of approximately 50 MMBtu per day.

When this was presented to Big Six Towers it was reported that approximately 50,000 cubic feet of natural gas per day has historically been required to satisfy the domestic hot water system during periods of time when the engine heat recovery systems were out of service for maintenance or otherwise unavailable. Utilizing a presumed steam boiler efficiency of 80%, this data point indicated Waldron's initial profile was about 20% too high. The profile was scaled accordingly to produce the final profile utilized in the model.

As shown in Figure 10 on the following page, the quantity of domestic hot water required when allocated to each hour of the day in accordance with the ASHRAE profile will exceed the quantity of engine jacket water heat available during winter months. In summer months, however, this is not likely the case. The reason for the difference in engine jacket water heat production is simply the electric load profile, which is roughly 800 kW during the winter months but higher in the shoulder and summer seasons. The increase in engine utilization during the summer results in a greater quantity of available jacket water heat.

This analysis suggested the hypothesis given on the previous page: that steam may be admitted to the domestic hot water systems at heat exchangers in the residential buildings to ensure the load is satisfied during the winter months. If the valve line-up necessary to accomplish this during winter is not adjusted in other seasons of the year it is conceivable that steam is still utilized in the summer even though it may not be required.

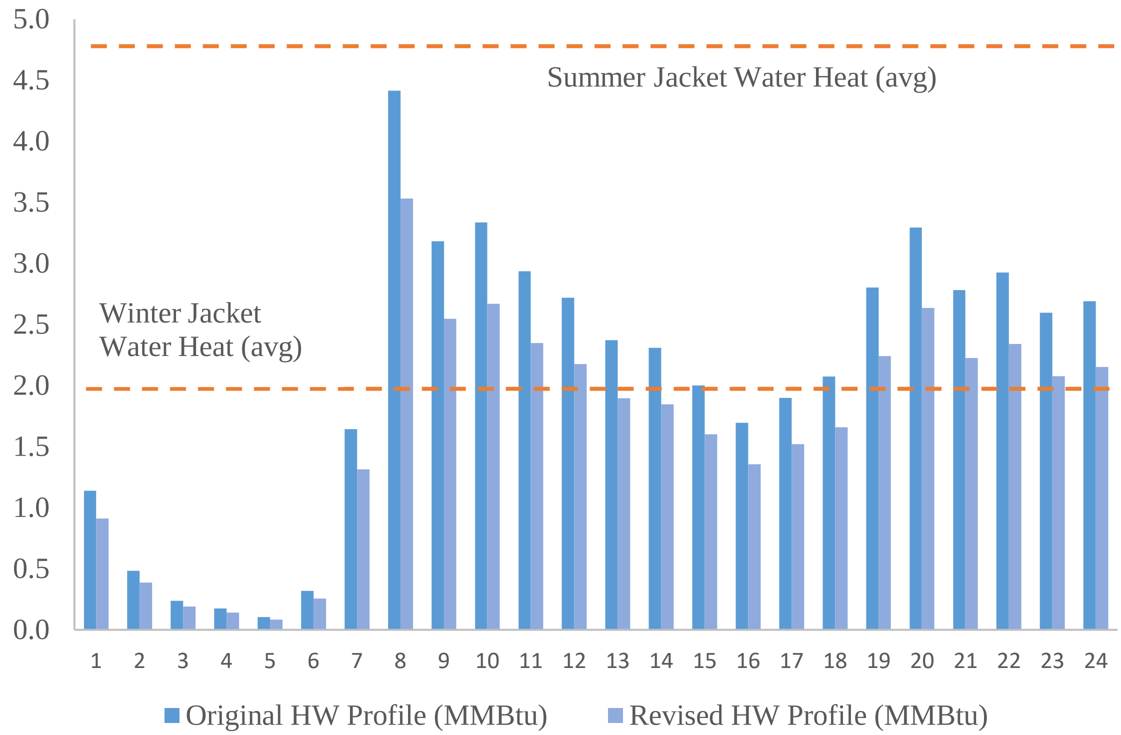


Figure 10: Big Six Towers Domestic Hot Water Daily Profile

3.4 Commercial Building Chilled Water Profile

The chilled water profile for the commercial building, which is fed solely by the absorption chiller in the power plant, was developed using the methodology described above in the Electric Load Profile section. The hourly profile was correlated to outside air enthalpy and calibrated with a peak of approximately 190 tons, which is just below the rated value of the 200-ton absorption chiller installed in 2022.

4 Fuel and Electricity Costs

The primary commodities considered in the model were purchased electricity from the grid and purchased natural gas. Fuel oil was considered as a back-up fuel for the boilers but was dispatched in minimal quantities and thus had no material impact on the analysis.

For both electricity and natural gas the billing determinants associated with the applicable utility tariffs were individually modeled, including time-of-day and month-of-year variations in applicable charges. These charges are published in the utility documents on-line.

The other principal component of the electricity and fuel costs is the cost of energy supply. For electricity this is essentially the cost of producing the electricity that is delivered to the end users by the local utility. For natural gas, and the purposes of this study, it is the cost of extracting/producing the gas and transporting it via pipeline to the New York City area. These may be considered the "wholesale costs" that retail providers must pay prior to reselling these commodities to local customers. Local utilities and suppliers vary with regards to the additional fees and mark-ups applied to these wholesale values.

Energy supply costs are subject to market conditions and cannot be precisely predicted. Variations in usage profiles and procurement strategy can also affect pricing from energy suppliers and yield appreciable differences in the costs incurred. The values used in this analysis should be considered reasonable expectations for future pricing based on historical patterns, without the impacts of hedging or significant exposure to short-term market volatility. In other words, the values utilized for electricity and natural gas supply costs are largely extrapolations of historical average values. Because of the uncertainty in this regard, sensitivity analyses for this parameter were completed for the most attractive alternatives.

A key historical pattern that has been retained in the forecasted energy supply costs is the relationship between natural gas supply cost and electricity supply costs. According to New York ISO[1], "In New York, the cost of natural gas and the price of electricity are closely correlated because, based on the current resource fleet, gas-fired generation often establishes the clearing price for electricity in the NYISO's wholesale electricity market." This is borne out in the historical wholesale electricity and natural gas pricing data that is publicly available. Refer to Figure 11 on the following page.

Because the future engine alternatives included in this analysis would all utilize natural gas as their fuel, the relationship between electricity and natural gas pricing is the key determinant of operating savings in these scenarios. Electricity supply charges represent approximately 55% (plus or minus) of the total delivered cost of electricity, and natural gas supply charges represent a comparable amount for the total delivered cost of natural gas (although this varies depending on whether or not the natural gas delivery tariff is firm or interruptible).

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[1] "FAQ: Winter Pricing." *NYISO Blog*, February 8, 2022, https://www.nyiso.com/-/faq-winter-pricing#:~:text=to%20produce%20electricity.-,In%20New%20York%2C%20the%20cost%20of%20natural%20gas%20and%20the,the%20NYISO's%20wholesale%20electricity%20market.

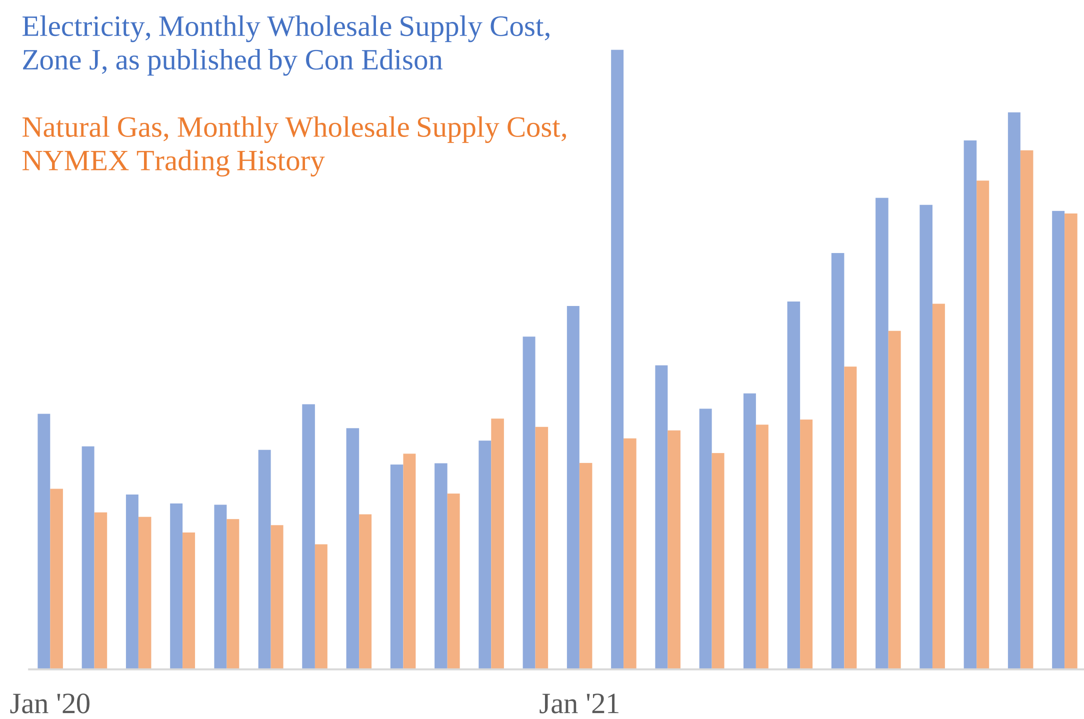


Figure 11: Historical Electricity and Natural Gas Wholesale Supply Costs

4.1 Market Forces: Purchased Electricity

It is not possible to provide a comprehensive assessment of the market conditions that impact electricity supply costs within this study; however, certain forces are worth noting as they are potential disruptors to the historical patterns on which the supply costs utilized in this study are based. These are noted because they come into play when considering the scenarios to explore in a sensitivity analysis.

One such market force is the array of policy changes related to decarbonization of energy supplies that has been enacted within New York City and New York State. Two key elements of this are the following:

- The Climate Leadership and Community Protection Act ("CLCPA"), signed into law in 2019 by the New York State legislature, targets 70% renewable energy by 2030 and 100% zero-emission electricity by 2040.
- Local Law 97 of the City of New York, which went into law in 2019 as well, establishes a greenhouse gas emissions threshold tied to energy use intensities for various building types, beyond which a penalty will be assessed beginning in Year 2024. (As noted elsewhere herein, Big Six Towers is exempt from the penalties stipulated for Years 2024 – 2029, and is expected to be exempted until 2034.)

Achievement of the targets contained in the CLCPA will require a substantial response by both suppliers and consumers of electricity, which is likely to have corresponding effects on the costs of energy. Large investments in renewable energy production and electrical infrastructure as well as building energy retrofits, including electrification, are expected to be necessary to achieve compliance with these laws. The impacts on energy costs to end users remain to be seen, and because of this uncertainty, sensitivity cases corresponding to various future pricing scenarios for natural gas and electricity were developed as described below (these numbers correlate to sensitivity case numbers given in Section 8):

1. Energy of all forms included in this analysis becomes more expensive due to a combination of the electrical investments noted above in combination with increased political pressure, perhaps in the form of a carbon tax, to reduce fossil fuel use. In this scenario both electricity and natural gas prices increase together over time.

2. Due to reduced demand for natural gas, prices fall relative to electricity costs. This scenario is perhaps unlikely in the near term, as natural gas has been forecasted by ISO New York[i] to continue to play an essential role in electrical grid operations through 2030 and beyond, but it is conceivable that overall gas usage will drop as renewable energy supplies are brought on-line, and potentially depress the price relative to electricity.

3. Necessary increases to the electrical transmission infrastructure and/or the installation of new grid-scale energy storage systems increases electrical distribution costs at a faster rate than natural gas supply or distribution costs.

4. The decarbonization goals of CLCPA are met, and as a result, penalties on carbon emissions in the future, such as those contained in Local Law 97, are increased. In this scenario natural gas and electricity prices are held constant but the future year penalties on carbon emissions are increased relative to the baseline value. This could be accomplished by significantly lowering the threshold energy use intensity values in Local Law 97, for instance, or targeting any fossil fuel use in future carbon penalty or taxation legislation.

5. The decarbonization goals of CLCPA are not achieved in the timeline intended, and during the next 20-30 years—the planning horizon for this study—the penalties and energy use intensity threshold values contained in Local Law 97 are held constant at their initial values. If the grid does not decarbonize in the timeframes intended it would be difficult to enforce lower carbon emission thresholds on property owners when no viable means of compliance is available.

Refer to Section 8 for additional discussion on these sensitivity models.

4.2 Natural Gas Costs

4.2.1 Natural Gas Supply Charges

The supply charges for natural gas, which were used for both the boiler plant and for future electricity supply alternatives with new power plant equipment, were based on NYMEX future prices available at the time the study model was developed. The NYMEX future prices at any given moment in time are the value at which natural gas futures are being traded and represent the market-based cost of supplying natural gas to the interstate pipeline transmission system.

The cost of transporting this gas through the pipeline to the local distribution utility in New York is called the "basis" and for this study a cost of $0.85/MMBtu was used in 2022. The basis was added to the NYMEX future value to create a total cost of gas supply, excluding the local delivery charges (which are discussed below). The basis value was escalated at a rate of 3%/yr throughout the study period.

As shown in Figure 11 previously, the NYMEX (or "wholesale") cost of natural gas experienced a steady increase in 2021 as compared to historical values. Figure 12 below expands the timeframe of this graphic to capture a greater historical duration. The NYMEX pricing in this graphic does not include any basis costs.

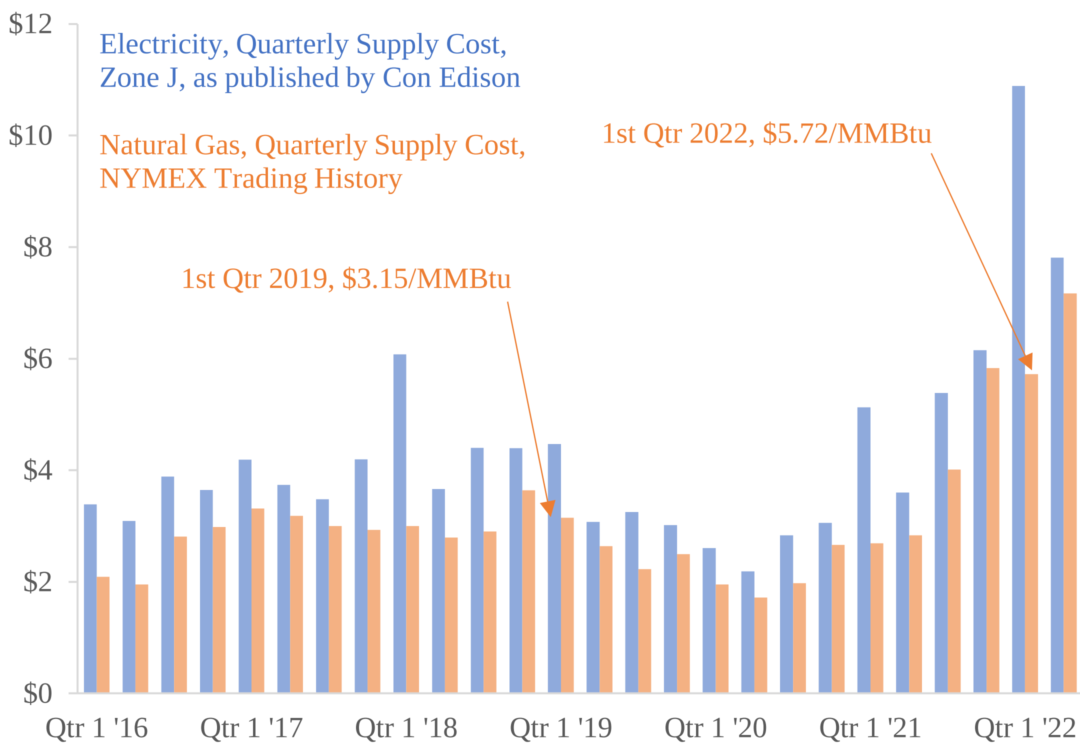


Figure 12 Historical Electricity and Natural Gas Wholesale Costs

Figure 13 on the following page contains the same historical data for natural gas along with the future values from NYMEX utilized in the study. Note that the basis costs are not included in the values shown. The expectation of the market is that the recent increase in natural gas pricing will settle down to lower levels, but not to levels as low as the historical averages shown above. After a period of adjustment a year-over-year escalation rate of approximately 3%/yr is contained in the future market trading values.

The values between the most recent data available in 2022 and the future values beginning in 2024 were not assessed because they are outside of the study window. Year 2024 was considered the first year that a new electricity supply system for Big Six Towers would be operational.

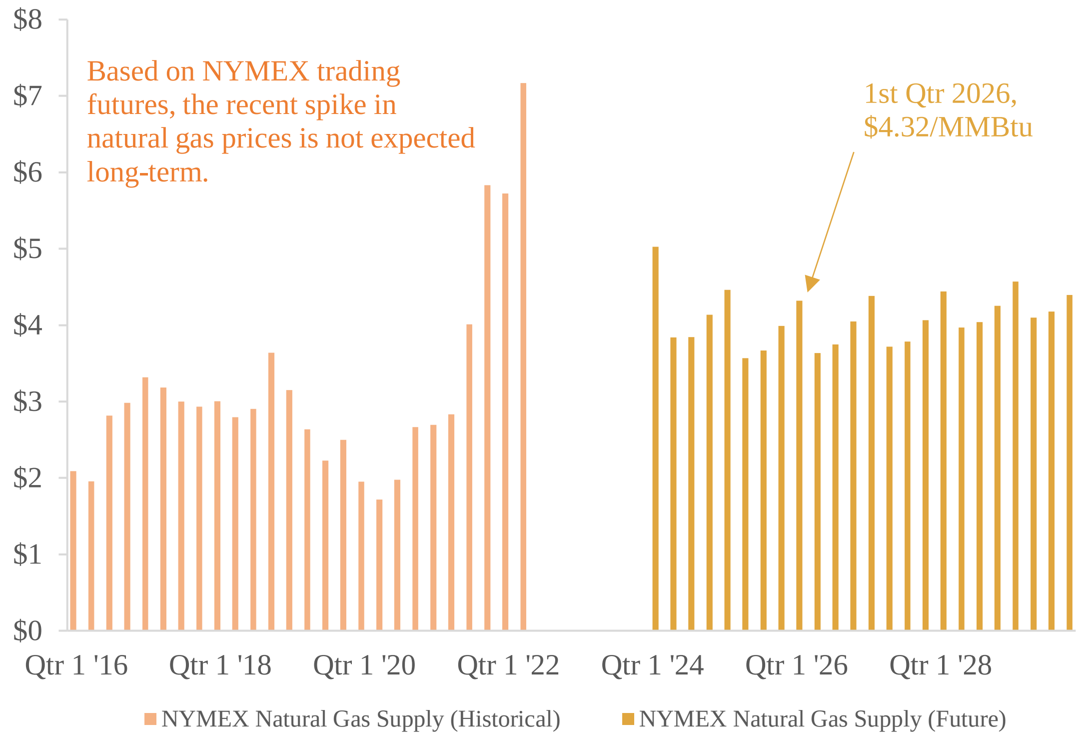


Figure 13: Future NYMEX Natural Gas Costs Utilized in Analysis

4.2.2 Boiler Plant Natural Gas Delivery Charges

Historically the boiler plant has received gas from National Grid under Service Classification No. 22 "Non-Firm Demand Response Sales Service." Specifically, the billing falls under Tier 1 of this tariff, which applies to customers with fully automatic switchover equipment. The tariff was modeled as published, with the billing determinants shown below:

Tariff Component	Published Cost (Yr 2022)
First 10 Therms	$375/mo
Additional Therms	$0.1933/therm

Figure 14: Boiler Natural Gas Tariff Components (SC 22)

The Year 2022 values were escalated at a fixed rate of 3%/yr in the study analysis.

4.2.3 Power Plant Natural Gas Delivery Charges

The power plant has historically received natural gas under the National Grid Service Classification No. 4A, which is a rate for firm service. In contrast to the boiler plant gas rate noted above, which is "non-firm," the power plant gas is procured on a firm basis to ensure availability during winter months. This increases the unit cost of natural gas for power plant operations as compared to the boiler plant.

Tariff Component	Published Cost (Yr 2022)
First 10 Therms	$250/mo
Next 990 Therms	$0.2696/therm
Additional Therms	$0.2696/therm

Figure 15: Boiler Natural Gas Tariff Components (SC 4A)

The Year 2022 values were escalated at a fixed rate of 3%/yr in the study analysis.

4.3 Electricity Costs

4.3.1 Electricity Supply Charges

As noted previously, it was considered important in this analysis to maintain a correlation between the supply cost of natural gas and the supply cost of electricity. The forecasted natural gas prices, described above, include a noteworthy increase relative to the historical costs of natural gas. (Refer to Figure 13 on the previous page.) An assumption of this analysis is that the supply costs of electricity will follow this trend.

The average NYMEX futures for natural gas in Years 2024 – 2027 represent a cost increase of approximately 40% over the average historical NYMEX trading values for Years 2016 – 2019. In order to maintain a reasonable correlation between the electricity and natural gas commodity costs, the electricity supply charges contained in the analysis were increased over historical values by a comparable magnitude. The challenge of this study is that the Big Six Towers are not presently connected to the electric grid and so there are no bills on which to establish a historical cost basis. Waldron thus considered commodity costs recently obtained from other clients in the area to arrive at a baseline historical annual average value of $0.09/kWh. This value was increased to an annual average value of $0.12/kWh in Year 2024, which reflects an increase of approximately 35%.

The values used in the analysis varied monthly to reflect historical cost patterns, as shown in Figure 16 on the following page. Figure 17 shows how the electrical and natural gas monthly load shapes compare. The natural gas historical monthly load shape is based on natural gas pricing history, whereas the electric is based on historical electric grid wholesale pricing data.

4.3.2 Electricity Delivery Charges

Because Big Six Towers is not presently connected to the Con Edison grid, no historical bills were available for use in developing a model of historical costs. Based on research of Con Edison's published tariffs it was determined that the Service Classification 8 "Multiple Dwellings – Redistribution" would be applicable to the Big Six Towers site.

Within this basic Service Classification two specific Rates were utilized. For future electricity supply alternatives with reconnection to Con Edison that do not contain any on-site power generation, Rate II "Time of Day" was used. For cases with new electrical generation in parallel with the Con Edison grid, Rate V "Standby Service" was used.

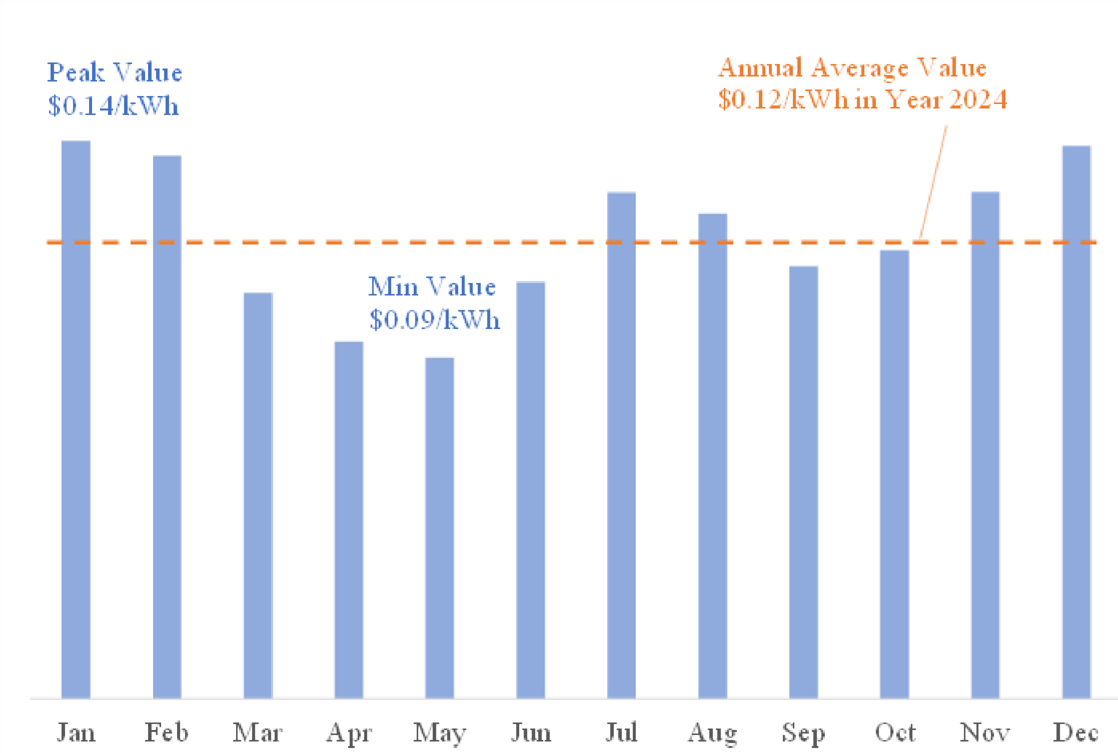


Figure 16: Year 2024 Monthly Electricity Supply Charges

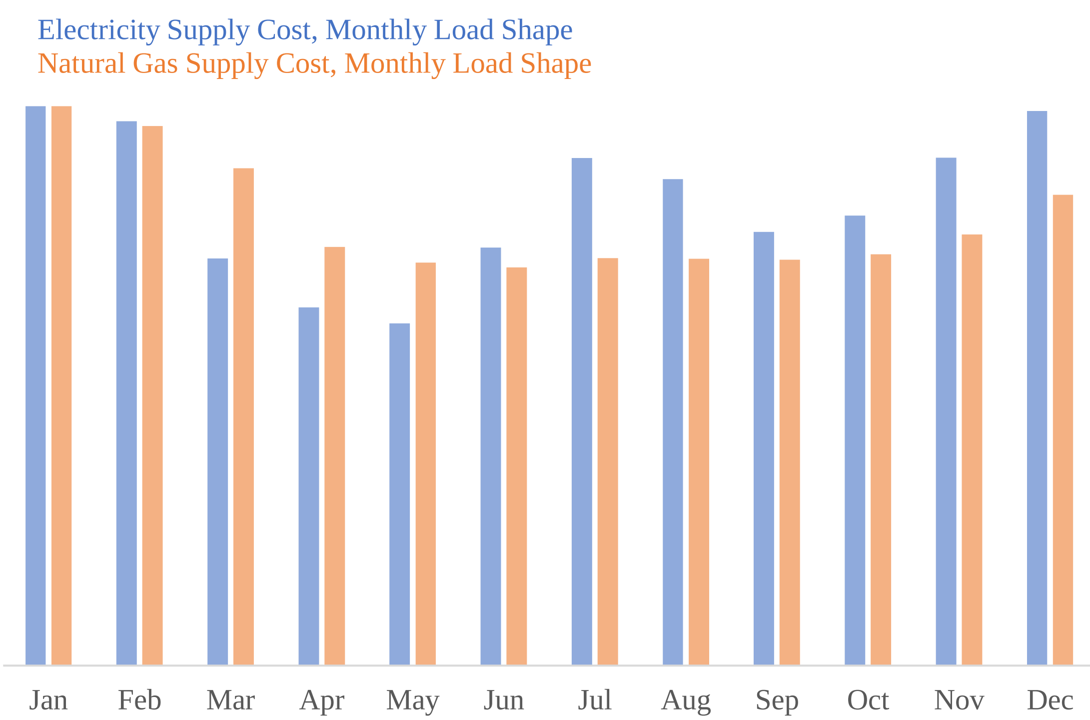


Figure 17: Comparison of Gas and Electric Monthly Load Shapes

The two rates utilized have very different demand charge structures, the components of which are summarized in the table below. At a high level the base rate (without generation in parallel with Con Edison) has various demand charges that apply to the maximum observed demand in each month, while the Standby Service rate (with generation in parallel with Con Edison) incorporates a fixed monthly charge called the Contract Demand that applies regardless of actual usage, plus Daily Demand charges that apply to the maximum import from the utility on a daily basis. The Contract Demand cost is calculated based on the maximum annual electrical demand the Big Six Towers site would experience, regardless of the electrical source.

Rate II Tariff Components	Published Cost (Yr 2022)
Energy Delivery	$0.0079/kWh
Demand Delivery, 8 AM – 6 PM	$10.63/kW June – Sept only
Demand Delivery, 8 AM – 10 PM	$25.62/kW June – Sept | $18.75 all other mos.
Demand Delivery, All Hours[1]	$20.81/kw June – Sept only

[1] applies to Low Tension service only.

Figure 18: Summary of Electric Tariff Rates without On-Site Power Generation

Rate V Tariff Components	Published Cost (Yr 2022)
Energy Delivery	Not Used
Contract Demand	$9.23/kW Low Tension $8.33/kW High Tension
Demand Delivery, 8 AM – 6 PM (Daily Demand)	$0.8039/kW June – Sept, Low Tension $0.8039/kW June – Sept, High Tension
Demand Delivery, 8 AM – 10 PM (Daily Demand)	$1.6222/kW June - Sept., Low Tension $1.0724/kW all other mos., Low Tension $0.5303/kW June - Sept., High Tension $0.6585/kW all other mos., High Tension

Figure 19: Summary of Electric Tariff Rates with On-Site Power Generation

4.4 All-In Natural Gas and Electricity Costs

Using the charges for natural gas and purchased electricity described in Sections 4.2 and 4.3 above, the all-in costs forecasted in Year 2024 for each commodity are shown in the table below.

Description	All-In Cost
Electricity, Low Tension Service	$0.229/kWh
Electricity, High Tension Service	$0.204/kWh
Power Plant Natural Gas, Firm Service	$8.71/MMBtu
Boiler Plant Natural Gas, Interruptible	$7.87/MMBtu

4.5 Liquid Biofuel Costs

The use of liquid biofuel in the boiler plant was considered at a screening level in this report as a means of lowering Big Six Towers' carbon footprint in the future. The value used was the cost of diesel fuel with a 1.3x multiplier, based on historical data published by the Department of Energy Alternative Fuels Data Center, as shown below.

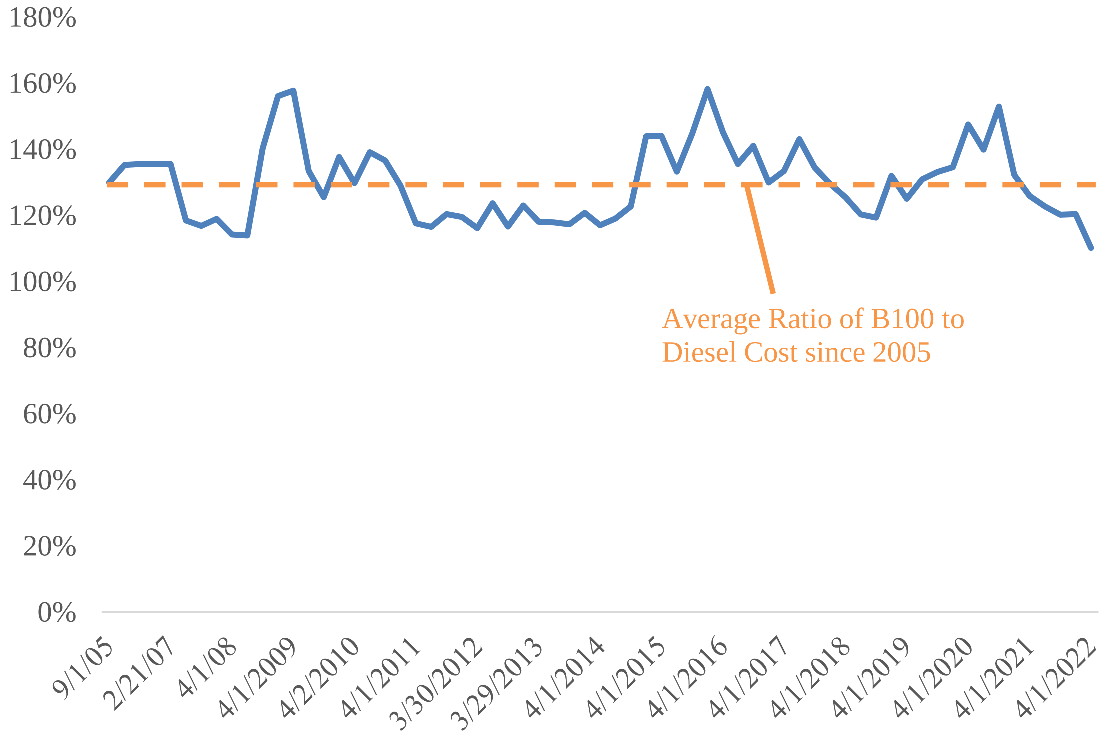


Figure 20: Historical Ratio of B100 Liquid Biofuel to Diesel Cost

For a diesel (and for No. 2 oil) cost, the study carried a value of $2.53/gal in 2022$, a cost that was based on historical data supplied by Big Six Towers. This value is likely low for near term future values due to recent fluctuations in global oil prices; however, the cost of diesel fuel is immaterial to the basic decision that must be made about how to supply electricity to Big Six Towers going forward. Because natural gas is considerably less expensive than diesel fuel, the economics are based on maximization of natural gas use and contain only minimal oil firing.

The risk of erroneous life cycle cost values is higher for the case that considers a liquid biofuel in the boiler plant, and if this approach is considered attractive to Big Six Towers, Waldron would recommend a survey of available suppliers and a more detailed assessment of those operating costs before proceeding.

5 Equipment Performance

The hourly utility model utilized in the analysis performs calculations of energy supply and demand that are based on performance curves for various pieces of equipment. The utility load profiles described previously in this report are inputs to the model. The outputs are purchased fuel quantities (and costs), purchased electricity quantities (and costs), and greenhouse gas emission totals. The relationship between the inputs and the outputs is defined by the performance curves for the various pieces of equipment contained in the model for a given scenario. As an example, the performance curves for a natural gas fired reciprocating engine provide the necessary relationship between electrical production (the output) and fuel consumption (the input).

5.1 Reciprocating Engine Performance

For equipment associated with the various energy supply alternatives that were studied, vendor quotations were obtained for engine performance at 50%, 75%, and 100% of rated electrical output. Curves were developed based on the vendor literature to predict the following parameters as function of engine load:

- Engine Heatrate, Btu/kWh, LHV (used to calculate fuel consumption)
- Jacket Water Heat Available, MMBtu/hr
- Exhaust Gas Mass Flow, lbs/hr
- Exhaust Gas Temperature, °F

For those cases that include on-site electrical generation, the engines were dispatched in the model to meet the electrical load such that no engine would operate below 50% of its rated output (to ensure the engines are operated within their emissions compliant operating envelope). The dispatching process determines how many engines must run in a given hour and establishes the load factors associated with the necessary electrical production. Interpolation between the engine performance curves at 50%, 75% and 100% load is then used to calculate the parameters above. A minimum electricity import from the utility was included for the grid parallel alternatives that were studied. These calculations are performed for each hour of the study period. A sample of the engine performance data is given in the table below.

635 kW Jenbacher Engine

Load %	Output (kW)	Heatrate (Btu/kWh, LHV)	Exhaust Flow (lbs/hr)	Exhaust Temp (deg F)	Jacket Water Heat (MMBtu/hr)
50%	314	10,024	4,270	982	0.828
75%	475	9,314	6,107	945	1.090
100%	635	8,975	7,998	894	1.407

Figure 21: Sample Engine Performance Data

Refer to Appendix F for the vendor literature containing the engine performance parameters that were utilized in the analysis.

As part of the dispatching process, a nominal annual availability factor of 92.5% was assumed for engine operation. Downtime was parsed across two scheduled outages, one in spring and one in fall, with the remainder spread across downtime randomly assigned throughout the year. This simulates the fact that equipment is not always available to run and is likely to trip offline unexpectedly on a periodic basis. Utility demand charges associated with the unplanned outages (and the planned outages) are captured by the model. The graphic below depicts each period of engine downtime as a colored vertical line to give an indication of how the outages were assessed throughout the year.

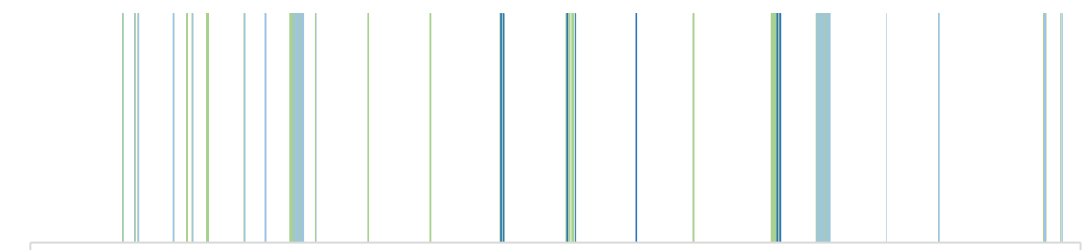


Figure 22: Sample Reciprocating Engine Availability Profile

Scheduled outages are typically represented by thicker lines than unscheduled outages. The key impact on the model is the demand charge that would be incurred by an outage, even if it was only for an hour. As the profile shows, the randomized outages outside of the two scheduled maintenance periods result in the assessment of daily demand charges throughout the year.

5.2 Boiler Performance

Boiler performance modeling was very straightforward in this analysis. Because boiler operation is required in all cases, and differences in boiler efficiency between the various cases will have a de minimis impact on the outcomes, a straight boiler efficiency of 82% was utilized, which is a reasonable value for a natural gas fired boiler.

As a reference the minimum thermal efficiency required in ASHRAE 90.1-2016 “Energy Standard for Buildings Except Low-Rise Residential Buildings) for boilers of the size contained in the Big Six Towers boiler plant is 79%.

5.3 Geothermal Cooling

Refer to Attachment H for a description of the geothermal analysis that was accomplished. The approach taken was to utilize surface parking areas as locations for boreholes, and to assess the total thermal resource of the combined areas using water-to-water heat pumps to provide heating and cooling to the community buildings. The subsequent energy analysis assumed a COP of 3.5 in heating mode and 5.0 in cooling mode for calculating the electricity consumed.

6 Local Laws & Regulations

As noted previously in Part 4.1 of this report, there are several laws in place that could have a material impact on the financial outcomes Big Six Towers will experience for the various electricity supply alternatives considered. At the state level, the CLCPA mandates a staged decarbonization of the electric grid in New York over the next eighteen years. At the city level, Local Law 38 requires that stationary engines utilized for electrical power generation must meet Tier 4 emissions standards by Year 2025, and Local Law 97 mandates penalties on carbon emissions above threshold values established in the regulations for various building types.

It is important to not only understand the requirements of these laws, including the potential financial penalties Big Six Towers could incur in various future scenarios, but also to understand what will be required by both suppliers and consumers of energy in order to achieve compliance. As will be shown below, the future thresholds established by Local Law 97 appear to hinge upon a statewide transformation of the electric grid, without which compliance will be virtually impossible to achieve by individual property owners through means within their control.

This creates a risk to property owners like Big Six Towers that is difficult to assess. On the one hand, if complete decarbonization of the electric grid is achieved within the timeframe established by the CLCPA legislation, then long-term compliance with the future carbon emission thresholds of Local Law 97 is achievable by property owners through electrification of their heating systems[2] and reliance on the grid for electrical power. In general, setting aside the possibility or probability of relief that the City could offer, operation of on-site power generation and gas-fired heating plants such as Big Six Towers presently employs would incur unavoidable penalties under the law, the cost of which is considered in Section 6.4 herein.

On the other hand, if the timeframe for achievement of the CLCPA goals is delayed due to the extensive challenges associated with implementing the large-scale infrastructure projects required, then the City would be faced with a difficult choice: either modulate the Local Law 97 thresholds to track with progress at the state level so that property owners are not harmed by forces outside of their control, or maintain the original thresholds and impose the stated penalties.

The intent of this section is to provide background on the manner in which the CLCPA and Local Law 97 requirements work together so that the primary risk factors related to Big Six Towers' and the decisions it faces regarding its own energy future may be better understood.

6.1 CLCPA Goals for the New York State Electric Grid

The CLCPA mandates two primary objectives related to the supply of electricity in New York State that

[2] Electrification here means the replacement of fossil fuel fired boilers for heating with electric alternatives such as air source heat pumps, ground source heat pumps, heat recovery chilling, or similar electric-driven heating technologies. Simple electric resistance heating would be a viable option for compliance with Local Law 97 but would be the least efficient from an operating cost perspective. Use of biofuels is also a potential alternative.

are relevant to this discussion:

- deliver electricity from 70% renewable sources by Year 2030, and
- deliver 100% zero-emission (zero carbon emissions) electricity by Year 2040.

The starting point for understanding the scope of infrastructure changes required to meet these goals is the Year 2020 eGrid data published by the United States EPA[ii]. This dataset provides a record of carbon emissions in the various electric grids around the country, including the three subregions that comprise New York State: NYC/Westchester, NY Long Island, and Upstate NY.

The data for Year 2020, which was published in January, 2022 and is the most recent available from the EPA as of the writing of this report, is summarized in the table below. For simplicity, the electricity sources have been consolidated into three blocks: fossil fuels, nuclear, and renewables. In the source data, fossil fuels are further broken down by coal, oil, natural gas, and other; and renewables are further broken down into hydro, biomass, wind and solar. (Note that due to rounding, as noted in the source EPA data, the percentages do not always add up to exactly 100%.)

Subregion	Total Electricity (MWh x10^3)	Emission Rates (lbs CO_2e/MWh)	Fossil	Nuclear	Renewable
NYC/Westchester	39,727	636.0	69.2%	29.9%	0.9%
NY Long Island	10,559	1,212.7	89.1%	0.0%	11.0%
Upstate NY	84,654	234.5	26.1%	31.4%	42.4%
Total	134,940	429.2	43.7%	28.5%	27.7%

Figure 23: Year 2020 eGrid CO_2e Emissions Data for New York State

The analysis contained in this report section does not treat nuclear energy as renewable. On this basis, to achieve the target of 70% renewable electricity by Year 2030, all of the state's present electricity contributions from fossil-fuel powered facilities would have to be replaced by generation from new renewable energy supplies.

There are several key infrastructure upgrades required to achieve this:

- installation and/or sourcing of new renewable energy generation facilities capable of producing approximately 59,000 MWh of electricity (or more based on load growth),
- capacity upgrades to the electrical transmission system as required to route this power to the load centers where it is required, depending on the geographical location of these facilities, and
- upgrades to other electrical grid components that may be required to maintain grid stability on peak demand days.

The New York ISO has studied the impacts of a conceptual 70% renewable grid in New York State and identified these high-level needs in its *2020 Reliability Needs Assessment Report*[i]. The purpose of noting them here is simply to foster an appreciation of the magnitude of the infrastructure changes associated with achieving the CLCPA goals. As noted above, property owners making decisions about modifying their building energy systems in order to achieve compliance with the future year carbon emission thresholds established by Local Law 97 will be driven towards electrification of their energy systems (or the use of historically expensive biofuels). And once such investments are made, their future penalty exposure to the law as presently written will hinge upon the on-time achievement of these infrastructure upgrades.

6.2 Local Law 97 Requirements

As previously noted in Section 2.3 of this report, Big Six Towers is exempted from the penalties by Paragraph 320.3.9 of the law because of its status as a provider of income-restricted housing. Further, based upon conversations with the City that were reported to Waldron during this study, it is expected that the penalties and reporting requirements described in the Law will be applied to Big Six Towers with a ten-year delay.

For the purpose of understanding how the requirements of Local Law 97 dovetail with the CLCPA targets and timelines described above, however, the initial discussion herein focuses on the Local Law 97 requirements as written for non-exempted properties. The carbon emission thresholds and the various carbon emission factors assigned to energy sources commonly utilized by buildings in the City are summarized in the table below. All values are for buildings designated as occupancy group R-2 Residential.

Time Period	Emissions Limit (tCO_2e/sq ft)	Grid Electricity Coefficient (tCO_2e/kWh)	Natural Gas Coefficient (tCO_2e/kBtu)	No. 2 Oil Coefficient (tCO_2e/kWh)
Years 2024 – 2029	0.00675	0.000288962	0.00005311	0.00007421
Years 2030 – 2034	0.00407	Not published	Not published	Not published
Years 2035 – 2050	0.00140[1]	Not published	Not published	Not published

[1] Occupancy specific values have not yet been published. This value is the target average for all buildings in the City.

[2] All values are in metric tons of CO2e per the definitions in Local Law 97.

Figure 24: Emissions Limits and Energy Use Coefficients of Local Law 97

Future year emissions coefficients are not given in the Law and will be published at a later date. Thus, in order to estimate the penalties that property owners will face in future years, some "educated guess" of these values must be made in order to perform the calculations. In Waldron's opinion it is reasonable to assume the factors for natural gas and No. 2 oil consumption will not change. The reason is that the quantity of CO_2 emitted when these fuels are burned is the product of fixed chemical laws and cannot be changed. The CO_2 could ostensibly be captured but this wouldn't change the source emissions.

The key question, then, is how the grid electricity coefficient will evolve in time. This *is* a mutable value because the installation of additional renewable energy sources on the New York electric grid will lower the average quantity of CO_2 emitted per unit of electricity production—assuming the renewable resources displace production from fossil-fuel-fired power plants.

Waldron's starting point for developing a future year forecast of this value is to understand how the first published value was established. The initial grid electricity coefficient of 0.000288962 tCO_2e/kWh contained in Local Law 97 can be converted to the same units as the eGrid data noted previously to provide a comparison. When this is done, the coefficient from Local Law 97 is found to be virtually identical to the 2020 eGrid value for the NYC/Westchester subregion, as shown in the simple analysis below.

0.000288962 tCO_2e/kWh x 2,204 lbs/tCO_2e = 636.9 lbs/MWh [Local Law 97]

NYC/Westchester subregion eGrid coefficient = 636.0 lbs/MWh [eGrid Value]

Figure 25: Local Law 97 Grid Electricity Coefficient vs NYC/Westchester eGrid Coefficient

If it is assumed that the future Local Law 97 grid electricity coefficients will remain closely correlated to the recorded greenhouse gas emissions within the NYC/Westchester subregion, the question of how the coefficient will evolve in the future becomes one of predicting what will happen within the subregion. For the purposes of this analysis, the key data sources used to make these predictions were the CLCPA legislation and the *2020 Reliability Needs Assessment Report*[i] published by New York ISO.

The second time block in Local Law 97 runs from Year 2030 through Year 2034. Year 2030 is also the year in which the CLCPA legislation targets a 70% renewable electric grid in New York State. Considering that nominally 30% of the State's electricity supply in 2020 came from nuclear sources, in order to meet this requirement the remainder would need to be supplied by renewable sources. However, based on the New York ISO analysis, dispatchable energy generation assets located within the NYC/Westchester subregion[3] will be required for a grid with 70% renewable generation. Such dispatchable assets would likely be natural-gas-fired peaking facilities.

To calculate the Year 2030 grid electricity coefficient within the NYC/Westchester subregion, Waldron made the assumption that fossil-fuel-fired electrical generation within the subregion would be greater than 0%, based on the New York ISO analysis, and something less than the CLCPA statewide non-renewable maximum of 30%. Waldron selected a value of 15%. The intent was to select a reasonable non-zero value consistent with the goals of the CLCPA. The value chosen equates to approximately 4.4% of the state's overall electricity budget and is equal to roughly a third of the power generation previously provided by the Indian Point nuclear power plant, which was recently retired. Thus, the value does not conflict with the CLCPA's stated goal of achieving 70% renewable electricity by Year 2030.

This yields a forecasted Local Law 97 grid electricity coefficient of 0.0000626 tCO_2e/kWh in Year 2030 within the NYC/Westchester subregion, a reduction of roughly 78% over the initial value. From there, the value was reduced linearly to zero in Year 2040 in five-year increments, the year in which the CLCPA mandates 100% zero emission electricity.

[3] The New York ISO report specifically references Zone J of the Con Edison electrical distribution system, which is a portion of the electric grid largely contained within the area described in the eGrid data as the NYC/Westchester subregion.

Time Period	Emissions Limit (tCO_2e/sq ft)	Grid Electricity Coefficient[3] (tCO_2e/kWh)	Natural Gas Coefficient[3] (tCO_2e/kBtu)	No. 2 Oil Coefficient[3] (tCO_2e/kWh)
Years 2024 – 2029	0.00675	0.000288962	0.00005311	0.00007421
Years 2030 – 2034	0.00407	0.000062641	0.00005311	0.00007421
Years 2035 – 2039	0.00140[1]	0.000031321	0.00005311	0.00007421
Years 2040 – 2050	0.00140[1]	0.000000000	0.00005311	0.00007421

[1] Occupancy specific values have not yet been published. This value is the target average for all buildings in the City.

[2] All values are in metric tons of CO2e per the definitions in Local Law 97.

[3] All values are in blue are future year predictions utilizing the methodology described above.

Figure 26: Emissions Limits and Energy Use Coefficients of Local Law 97, Future Predictions

The table above provides a summary of the Local Law 97 coefficients used in the analysis for future years, based on the methodology described on the previous page. As noted above, there is uncertainty in these forecasts, but they are founded on just a few key assumptions:

- the natural gas and No. 2 oil coefficients remain unchanged, as they are tied to basic chemistry,
- the CLCPA targets are met on schedule, and
- the near-term emissions in the NYC/Westchester subregion contain 15% fossil-fuel-fired electrical generation in Year 2030.

6.3 Example Scenario Using Median Data from NYC

The scenario depicted in this section is for a multifamily residential building that utilizes the same ratio of electricity to natural gas as Big Six Towers does, but has a Site Energy Use Intensity (Site EUI) of 82.4. This value is the median for multifamily properties in New York City based on the 2019 Local Law 84/133 reporting requirements, as reported in Urban Green's report entitled *New York City's Energy and Water Use Report*[iii]. The split between site electricity use and natural gas usage for a typical property, when expressed in the same energy units of kBtu, is approximately 25%:75%. For reference, Big Six Towers has an approximate ratio of 28%:72%.

The purpose of this exercise is to chart the impacts of the coefficients forecasted above on such a property in order to understand what the compliance alternatives might look like. As Figure 27 on the following page shows, the ability of property owners to avoid penalties long-term is contingent upon two outcomes:

- the grid transformation to low carbon electricity, and
- the replacement of conventional fossil-fuel-fired heating systems or supplies with low carbon alternatives.

Without the realization of both outcomes, compliance with the Local Law 97 emissions limits will not be possible. Building energy efficiency retrofits alone, for instance, will not be sufficient to avoid penalties, though they may be economically viable for other reasons.

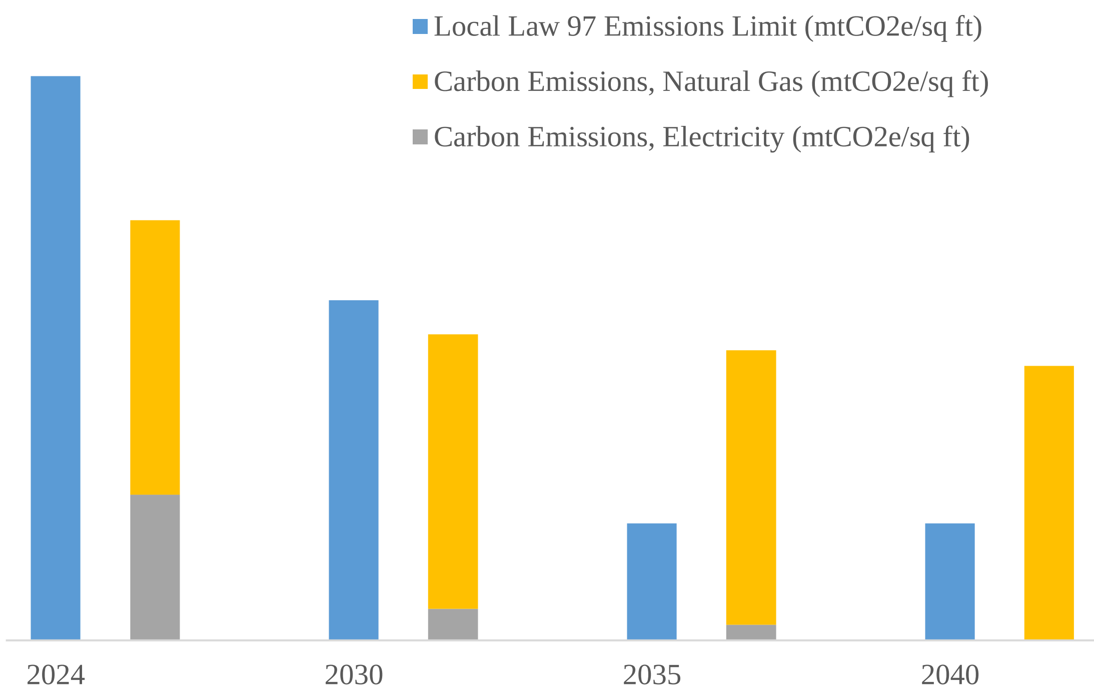


Figure 27: Local Law 97 Compliance Analysis for Typical Property | CLCPA Only

The figure above depicts the emissions per square foot of a typical building and how it would change over time with the realization of the CLCPA targets for renewable and zero-emissions electricity on the grid. No reductions in overall building energy usage are portrayed in this figure, and no shifts in building heating systems away from natural gas are considered. The reduction and disappearance of the gray column in future years, which is the carbon emissions of the building due to electricity use, is caused by the achievement of the CLCPA targets on the grid.

The figure shows that long-term compliance with Local Law 97 emissions limits (the blue columns) requires more than low-carbon electricity on the grid. Even with grid emissions going to zero, the natural gas consumption alone far exceeds the limit. A reduction in natural gas use of approximately 60% would be required to avoid penalties.

One way to achieve this is through electrification of the building's heating systems. Heat pumps, for instance, could be utilized in lieu of gas-fired boilers for most of the heating season. During the coldest days of the year, supplemental heat sources would be required as heat pumps have performance limitations on cold days, but it would be possible to use natural gas for this purpose and avoid penalties if the grid is able to supply renewable electricity on such days.

Another compliance alternative would be to replace natural gas with a biofuel. Historically biofuels have been more expensive than fossil fuels, however. On average, based on data published by the US Department of Energy[iv], biodiesel has cost roughly 30% more than conventional diesel over the last ten years. Based on this correlation, conversion from natural gas to biodiesel for a building heating system would roughly triple the cost of heating in future years.

On a high level, using the historical correlation between biodiesel cost and conventional diesel cost as well as the costs for natural gas and electricity utilized in this analysis, the cost of building heating with biodiesel or electric heat pumps is of the same order of magnitude. Refer to the figure below. This is a very high level analysis and intended only to show the order of magnitude values. The heat pump coefficient of performance (COP) used in this simplified model was a flat value of 2.0. This isn't an accurate forecast for every month but is intended to result in a reasonable annual average value.

Thus, depending upon how the biofuel markets in New York City evolve with time, conversion of the Big Six Towers boiler plant to a biofuel based facility for some or all of the heating season may be a reasonable means of achieving compliance with Local Law 97 emissions limits without making extensive building conversions to electric heating systems.

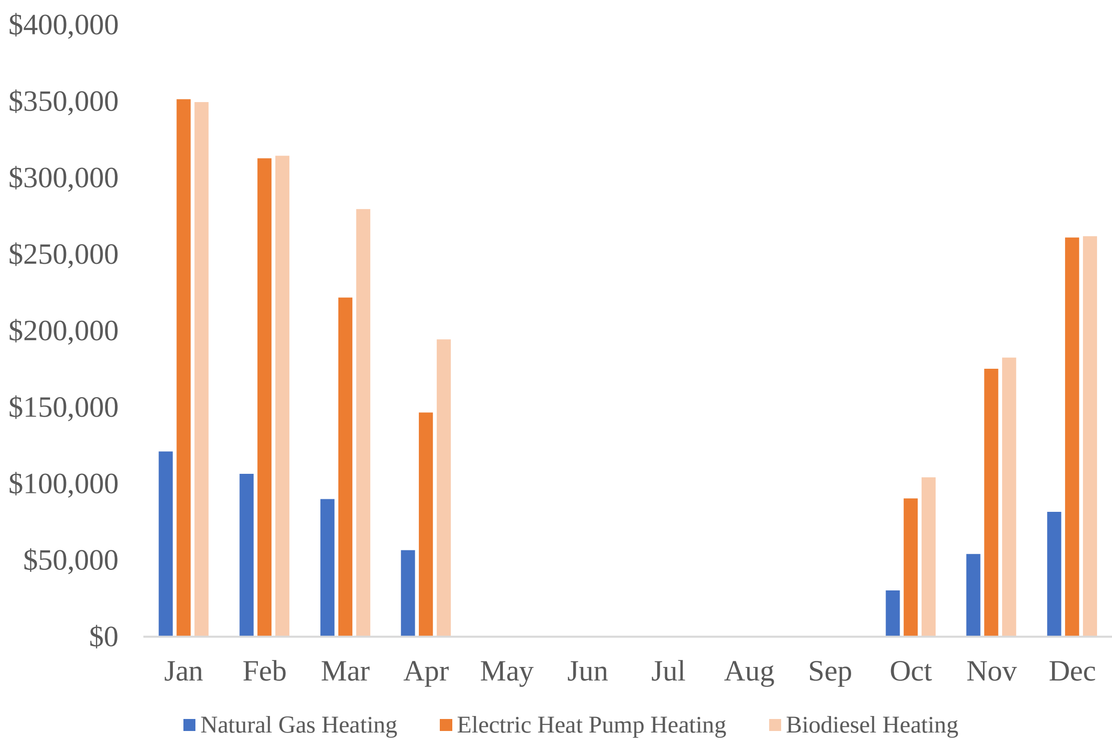


Figure 28: Heating Cost Comparison, Natural Gas, Electric Heat Pumps, Biodiesel

6.4 Considerations to Big Six Towers

Based on the data reported in the Urban Green report cited above, Big Six Towers utilizes approximately 30% more energy on-site per annum than the median multifamily dwelling in New York City. Thus, when Local Law 97 penalties become applicable to the property in Year 2034, and assuming Big Six Towers were to buy electricity from the grid and maintain its natural gas boilers—an approach similar to the typical property reviewed above—a modest penalty would be applied. The penalty would be considerably larger if the existing power plant were still the source of electricity, as this would significantly increase on-site fossil fuel usage, while a new cogeneration facility would be more efficient than the current power plant and would incur a much lower penalty.

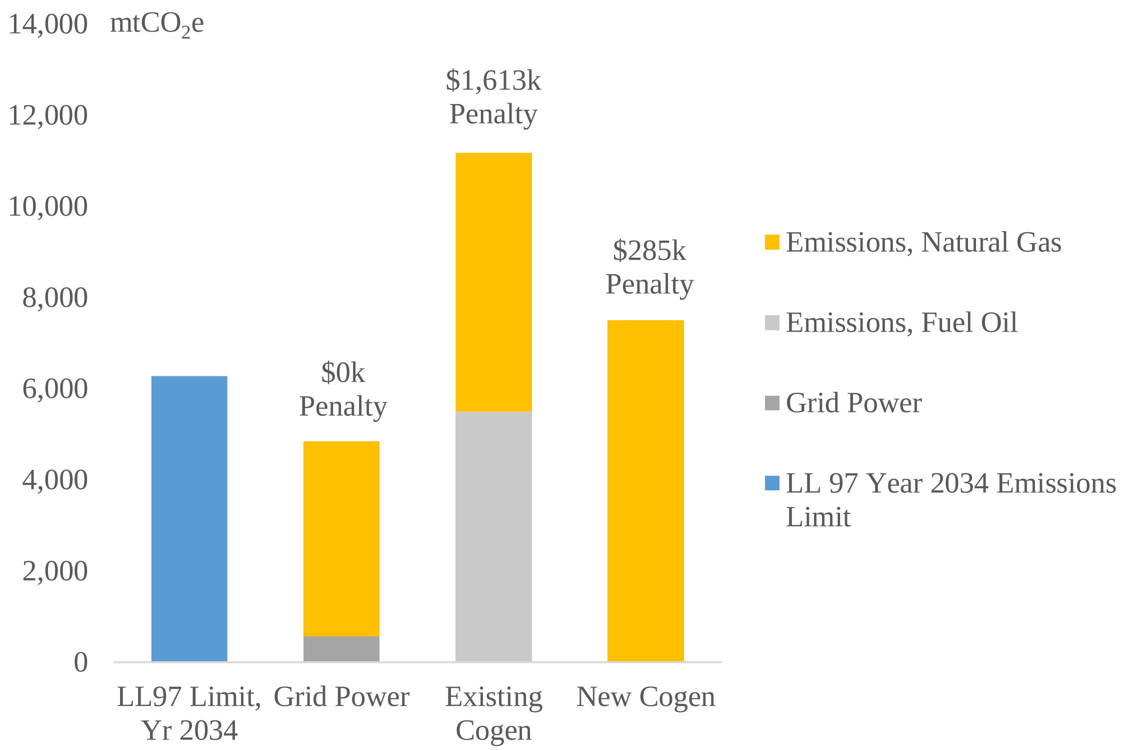


Figure 29: Three Big Six Towers Energy Scenarios, Local Law 97 Forecasted Penalties in Year 2034

The Local Law 97 emissions totals for each of these scenarios are depicted in Figure 29 above. Note that the emissions limit reflects the 10-year delay in penalty application to Big Six Towers, and that costs reflected forecasted Year 2034 values. The penalty costs in the current Local Law 97 legislation were escalated at 3%/yr in the analysis.

It is instructive to consider the penalties that would apply roughly a decade later as well, in Year 2045, as this is a year in which the lowest emissions limits presently published in Local Law 97 would apply to Big Six Towers. Those emissions limits are approximately 22% of those applicable in Year 2034. (Reference Figure 26 to see how the values reduce over time.) Using the assumptions for electric grid coefficients shown previously in Figure 26, the penalties for the three cases shown in Figure 29 would increase significantly in Year 2045. Reference Figure 29 on the following page.

Note that these values are all based on continued operation of the existing boiler plant, and do not incorporate any electrification measures for the community heating systems or conversions to biofuel. Also, the carbon contribution of grid power has dropped to zero by this time, under the assumption that the goals of the CLCPA legislation have been achieved.

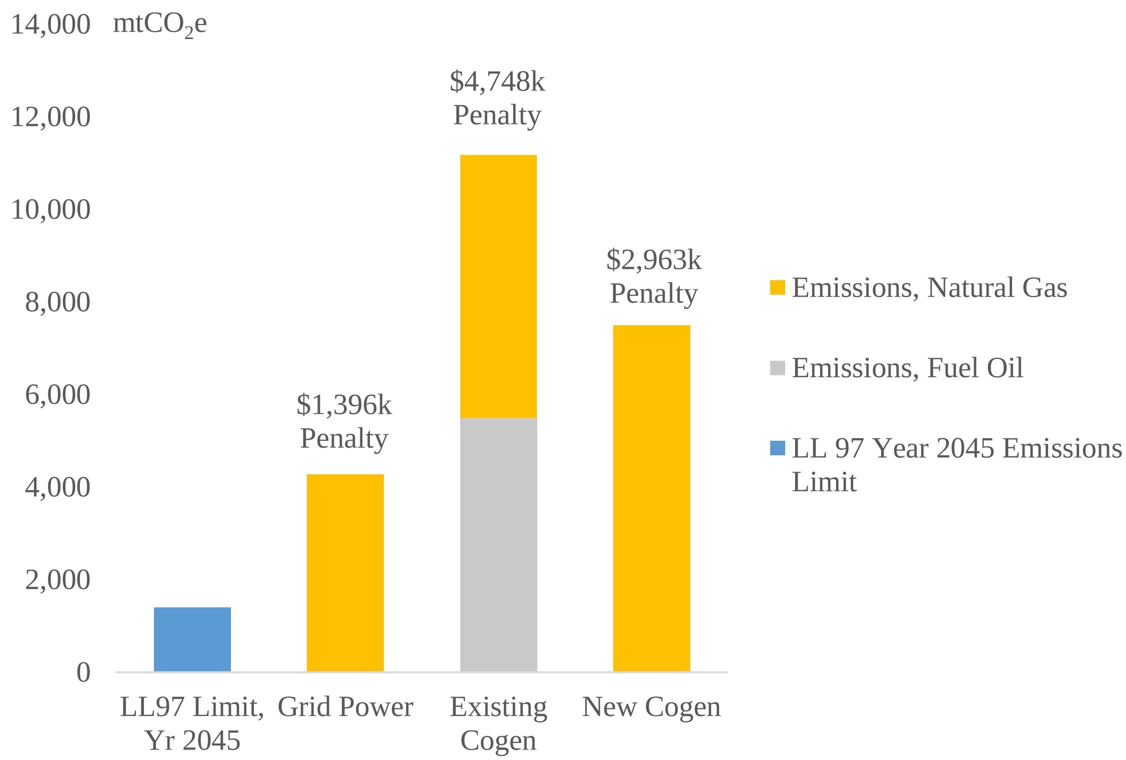


Figure 30: Three Big Six Towers Energy Scenarios, Local Law 97 Forecasted Penalties in Year 2045

Section 7 of this report, which contains the results of the integrated financial and environmental performance models discussed previously, will describe the life cycle results—including forecasted Local Law 97 penalties—for various energy alternatives Big Six Towers may consider. For the purposes of this section, however, the intent is simply to provide a baseline description of Local Law 97 penalties and show how they would apply over time for typical scenarios.

The forecasted costs shown in Figure 31 on the following page were developed for the "Grid Power" scenario depicted in Figures 29 and 30 above. *Note that in Year 2045, just after the life cycle period considered in this study, the penalties are forecasted to increase markedly, which is reflected in Figure 29 above.* In the "Grid Power" scenario depicted below, Big Six Towers retires the present power plant and connects to Con Edison for the supply of electricity, which is predicted to have the lowest forecasted Local Law 97 penalties of the alternatives studied, using the assumptions described in this Section, including the 10-year delay in penalty application. No energy efficiency upgrades or modifications to existing heating systems are contemplated in the forecasted penalties shown.

For this scenario, no penalties accrue until Year 2040 because using the assumptions of this Section electricity from the grid would have a very low grid emissions coefficient. This reduction in the carbon emissions associated with purchased electricity is sufficient to avoid penalties without any changes to the existing boiler plant operation. This would not be the case for options with on-site power generation. Figure 30 on the following pages shows the forecasted Local Law 97 penalties for the best energy supply alternative in each category that was considered.

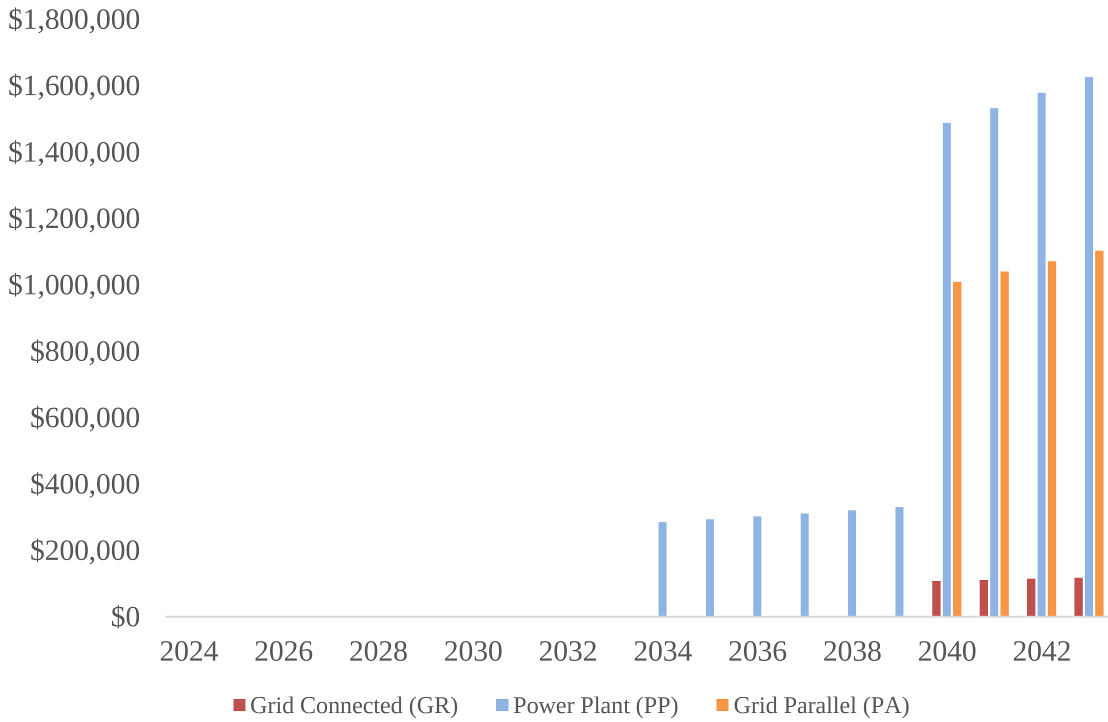


Figure 31: Local Law 97 Penalty Forecast for Best Alternative in Each Category

The slight year-over-year increase shown in the figure above are due to a 3%/yr escalation in the penalty value that was applied in the financial models. The larger “jumps” in the value are due to changes in the Local Law 97 emissions limit and/or the grid electricity coefficient (see Figure 25) that apply in a given year of the study period.

A key takeaway for Big Six Towers is that Local Law 97 penalties during the life cycle period considered in this analysis will be modest because of the 10-yr delay in their applicability to the property. This provides a reasonable period of time for Big Six Towers to payback a capital investment that may be made in new on-site power generation. The highest penalties presently envisioned by the legislation are more than twenty years away, and the penalties that will actually be applied that far in the future will likely depend upon the manner in which the market evolves in response to the CLCPA and Local Law 97 legislation.

7 Analysis Results

This report section contains the results of the financial and environmental models used to evaluate the electricity supply alternatives that were included in this study. As introduced in Section 3 of this report, the basis of the analysis is a life cycle utility model that forecasts financial performance and greenhouse gas emissions for each year of a 20-yr life cycle, for each alternative considered. The various inputs to this model have been described in Sections 2 through 6 of this report.

Sensitivity analyses for the best-performing alternatives are contained in Section 8. Also, detailed life cycle data outputs from the analytical model utilized in this study are provided in Attachment A.

In addition to the evaluation of future alternatives, the model developed for this study was used to evaluate alternate dispatch methodologies for the current power plant, primarily to evaluate the cost benefit of shifting electricity production from the oil-fired engines to the gas-fired engines to the extent theoretically possible. The results of this assessment are contained in Attachment G.

7.1 Description of Energy Supply Alternatives

Three basic categories of energy supply alternatives were studied:

- retire the existing power plant and rely exclusively on the grid for electricity,
- repower the existing power plant with new natural-gas-fired engines and remain independent from the grid, and
- hybrid cases, in which new natural-gas-fired engines are operated in parallel with the grid.

A summary of the alternatives evaluated is provided in the table below. For each alternative studied a scenario identification tag has been provided for easy reference in subsequent discussion.

Energy Supply Alternative	Description
Grid Electricity Only	
GR-1 (Grid Only)	All electricity from the grid
GR-2	GR-1, with geothermal heating/cooling
GR-3	GR-1, with air source heat pump heating/cooling
GR-4	GR-1, with liquid biofuel
GR-5	GR-1, with electric boiler
Power Plant Only	(no grid connection)
PP-1 (Repower)	6x 635 kW Jenbacher Engines
PP-2	4x 1,200 kW CAT Engines
Grid Parallel	
PA-1 (Parallel)	1x 850 kW Jenbacher Engine
PA-2	2x 850 kW Jenbacher Engines
PA-3	1x 1,200 kW CAT Engine
PA-4	2x 1,200 kW CAT Engines

Figure 32: Energy Supply Alternatives

With the exception of the alternatives highlighted in green above, all alternatives shown were initially studied with the applicable Low Tension tariff from Con Edison. They also utilized the existing boiler plant for steam supply. The options highlighted in green, which incorporated alternate heating and/or cooling strategies in order to assess opportunities for greenhouse gas emissions reductions, were refinements added to the final analysis that utilized the High Tension tariff as their starting point.

7.2 Life Cycle Operating Costs

Figure 33 below displays the cumulative operating costs for each alternative (excluding the low carbon alternatives highlighted in green above) in Then Current Dollars, meaning the commodity and tariff costs that were accrued in each year of the analysis included the nominal escalation rates described in Section 4. The components of the operating cost tabulation in each year included the following components:

- supply costs for purchased electricity and natural gas;
- delivery costs for purchased electricity and natural gas, per the applicable tariff;
- engine maintenance costs, accrued at a rate of $0.018/kWh of engine production and escalated at 3%/yr throughout the study life; and,
- Local Law 97 penalty charges, beginning in Year 2034.

No differential staffing costs were assessed in the various alternatives based on the fact that Big Six Towers presently staffs a full power plant facility, and the boiler plant would remain for all alternatives.

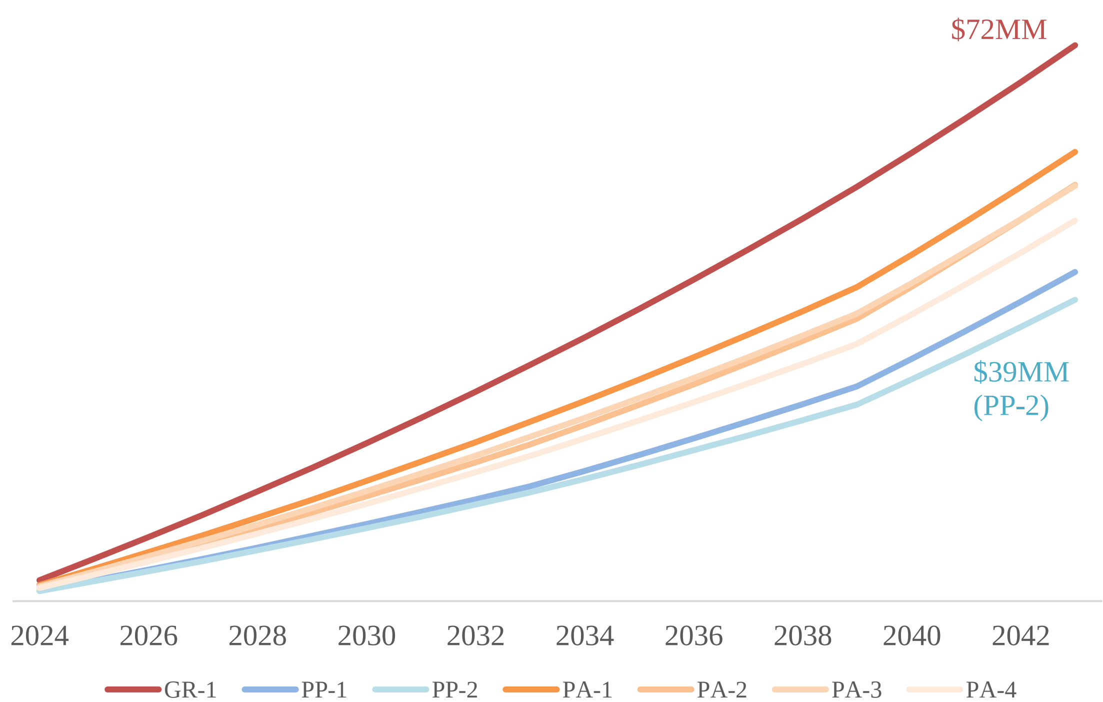


Figure 33: Cumulative Operating Cost of Energy Supply Alternatives (10-yr Delay on LL 97 Penalties)

The data show that from an operating cost perspective alone, the alternatives that remain disconnected from the Con Edison grid perform the best, while the alternative based on sourcing electricity exclusively from the grid is the most expensive. That said, the life cycle analysis period of twenty years does not include the years beyond in which the Local Law 97 penalties increase substantially (due to a lower emissions threshold).

A reasonable question is whether or not the maximum penalties that are forecasted to take effect in Year 2045 would change the relative ranking of the alternatives in terms of operating cost. The "what-if" scenario shown in Figure 34 below answers this question, by eliminating the 10-year delay in the applicability of Local Law 97 penalties in order to include the maximum penalties within the study period. This data is provided simply to show how the options would rank in an environment with the maximum Local Law 97 penalties in effect.

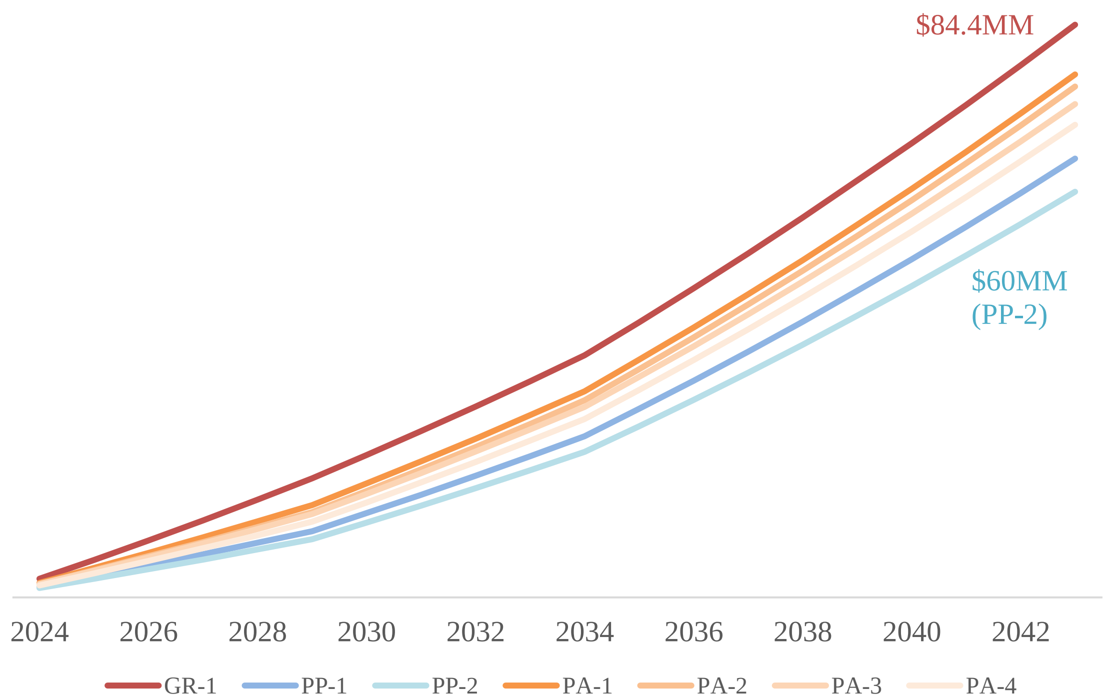


Figure 34: Cumulative Operating Cost of Energy Supply Alternatives (No Delay on LL 97 Penalties)

The key finding of this "what-if" scenario is that although the various options are more closely grouped in terms of their cumulative operating cost, the gaps between the options are still widening over time. This means that the annual operating costs projected in future years when Local Law 97 penalties are maximal still remain lower for the various engine cases than for the grid-only case. It should be noted there is considerable uncertainty in such a long-range forecast. But it does show that the value of the delay in application of Local Law 97 penalties to Big Six Towers is approximately $12 - $20 million in life cycle cost savings, depending on the alternative considered.

Another general takeaway from the operating cost analysis is that the second engine installation in the grid parallel cases (PA-1 through PA-4) generates very modest incremental savings.

7.3 Capital Costs

Capital costs utilized in the financial analysis are based on conceptual design concepts and Waldron's experience with comparable projects. At the present time, labor and equipment markets are experiencing instabilities related to elevated inflation rates, material supply chain bottlenecks, and labor shortages. The duration of these cost instabilities is beyond the scope of this effort to predict, so sensitivity analyses on project costs were included for the best alternatives in each basic category.

Capital cost opinions were developed for four primary project elements, as applicable to each alternative:

- Con Edison interconnection,
- Building Three electrical distribution system upgrades,
- power plant demolition, and
- power plant upgrades including new on-site electrical generation.

The Con Edison interconnection costs were based on the conceptual one-line diagrams provided in Attachment D. This line item generally includes the work from (and including) new Con Edison vaults located on Queens Boulevard, through buried ductbank on the Big Six Towers property, to the existing switchgear at the power plant. For the Grid Parallel alternatives, an incremental cost of $1.25 million was included to cover unforeseeable system upgrades that Con Edison may require at their existing substations to connect new engines to their system.

The Building Three electrical distribution system upgrade generally includes the cost for replacement of the older 460V/120V transformer located just outside of the building on the north side, plus replacement of the two 120V distribution line-ups located in the subbasement. Installation, rental, and removal of temporary equipment to minimize building downtime was included in the cost opinion.

The power plant upgrades generally include demolition of the existing engines and associated auxiliary systems, and the installation of new engines and auxiliaries as required for the given alternative.

The opinions of probable cost that were developed include labor, materials, equipment procurement, engineering, construction management and commissioning (excluding fuel and electricity consumed during commissioning). Other Owner project costs including but not limited to the cost of temporary facilities, environmental permitting, Owner's project management, Owner's engineering services, Owner's contingency, and project-related legal, accounting and insurance costs are not included. A summary of the capital costs used in the financial models is provided in the table below.

	GR-1	PP-1	PP-2	PA-1	PA-2	PA-3	PA-4
Con Edison Interconnection	$8,686	$0	$0	$9,998	$9,998	$9,998	$9,998
Building 3 Electrical Upgrades	$1,640	$1,640	$1,640	$1,640	$1,640	$1,640	$1,640
Pwr Plant Demo & Upgrades	$0	$16,869	$19,736	$4,613	$8,049	$5,919	$10,412
Total (2023$MM)	$10,326	$18,509	$21,376	$16,251	$19,688	$17,557	$22,050

[1] All values in thousands of Year 2023 dollars.

Figure 35: Capital Cost Opinions Used in Financial Models

7.4 Life Cycle Results with Capital Amortization

For the financial models utilized to compare the various alternatives, the capital cost values provided in the previous section were amortized over the twenty-year project life cycle period utilizing a 6.5% interest rate. These annual payments, when added to the operating costs previously described, yield the cumulative life cycle costs with capital amortization that are shown in Figure 36 below. The values shown include the expected 10-yr delay on the applicability of Local Law 97 penalties to Big Six Towers.

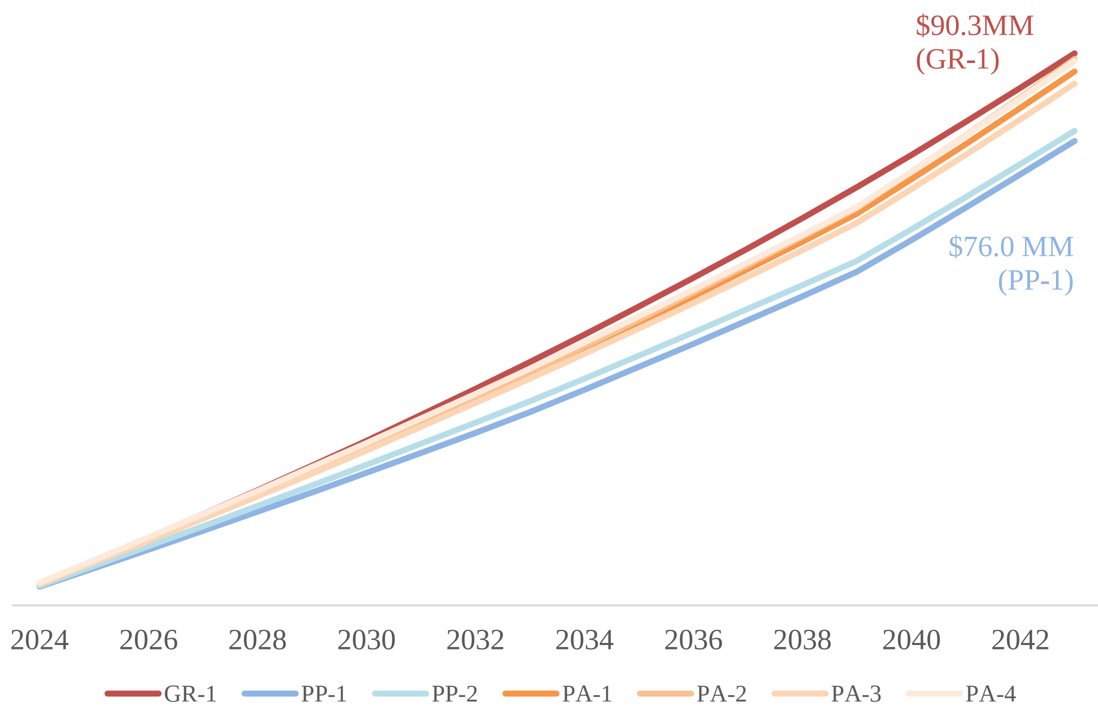


Figure 36: Cumulative Cost Analysis with Capital Amortization (LL 97 Penalties Delayed)

The cumulative life cycle cost with capital amortization, rate of return and net present value (6.5% discount rate) for the various alternatives studied are included in the table below. Alternative GR-1, because it requires the lowest capital investment of any alternative, was taken as the basis of comparison for evaluating the other alternatives. The rates of return and net present values shown are calculated on the incremental capital investment required to install the other alternatives.

	GR-1	PP-1	PP-2	PA-1	PA-2	PA-3	PA-4
Cumulative Life Cycle Cost, $MM	$90.3	$76.0	$77.6	$87.4	$89.4	$85.4	$89.0
Net Present Value (6.5%), $MM	N/A	$8.3	$7.0	$1.9	$1.1	$2.9	$0.9
Rate of Return	N/A	17.6%	13.5%	10.4%	8.0%	11.2%	7.5%

Figure 37: Financial Metrics for Energy Supply Alternatives (Low Tension Service)

7.5 High Tension vs Low Tension Service

All of the above results are based on a low tension service connection to the Con Edison system. For the best-performing alternatives in each basic category with a grid connection, GR-1 and PA-3, the incremental capital cost and the tariff adjustments associated with utilizing high tension service were modeled to determine the lowest cost approach for Big Six Towers.

The incremental capital cost necessary to move from a low tension to a high tension connection proved to be a net savings because of the Con Edison vaults that would be eliminated, the reduction in quantity of transformers required, and the lesser quantity of cabling required to the power plant switchgear. Refer to the One Line Diagrams in Attachment D for a description of the differences in vaults and equipment. As Figure 38 below shows, the savings in both capital and operating costs make high tension service the obvious choice for interconnection.

	Cost, 2023$MM
Con Edison Interconnection, Low Tension	$8.69
Con Edison Interconnection, High Tension	$4.26

Figure 38: Big Six Towers' Site Construction Cost for Low Tension vs High Tension Service

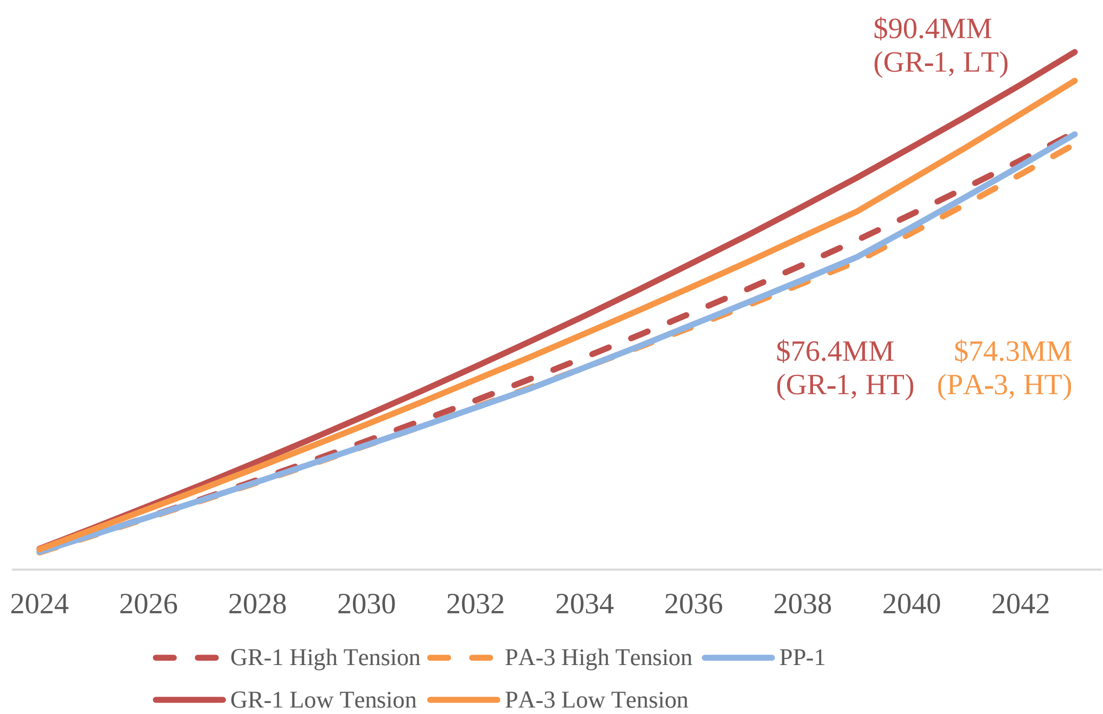


Figure 39: Cumulative Life Cycle Cost with Amortization, High Tension vs Low Tension Service

The shift to high tension service saves approximately $14 million in life cycle costs for the GR-1 alternative, and approximately $11 million for the PA-3 alternative. The reduction is lower for the option with on-site generation because the quantity of electricity purchased is roughly 75% less, so there is a smaller volume of purchased electricity to benefit from the lower rate.

Because the high tension option is clearly the better option for Big Six Towers, the net present value and rate of return for the PP-1 and PA-3 alternatives should be evaluated against this revised baseline. Their updated economic performance using the revised high tension base case is shown in the table below.

High Tension Cases	GR-1	PP-1	PA-3
Cumulative Life Cycle Cost, $MM	$76.4	$76.0	$74.3
Capital Cost, 2023$MM	$5.9	$18.5	$13.1
Net Present Value (6.5%), $MM	N/A	$0.8	$1.4
Rate of Return	N/A	7.3%	8.9%

Figure 40: Revised Economic Performance with High Tension Service

Because the savings associated with going to high tension service are greater for the grid-only alternative than for the alternatives with on-site generation, the economic performance of alternatives PP-1 and PA-3 erodes.

7.6 Evaluation of Low Carbon Grid-Connected Alternatives

Various alternate heating and cooling technologies intended to reduce carbon emissions were evaluated to assist Big Six Towers in understanding options that may be relevant in the future, particularly with increased carbon emissions penalties that will come into effect through Local Law 97. These alternatives were studied as variations to the Grid Connected (GR) alternative because they would generally displace waste heat recovered from engine operation in the other alternatives, which would make them less attractive from both an operating cost and greenhouse gas emission reduction perspective. They are most logically deployed as refinements to the Grid Connected (GR) alternative, but some, like conversion of the boiler plant to liquid biofuel capable boilers or to electric boilers, could be considered alongside of new engines in the power plant. This combination of alternatives was not explicitly evaluated at this time.

Figures 41 and 42 on the following page give the operating and life cycle cumulative cost graphics for these alternatives. Key elements of this analysis are as follows:

	GR-1	GR-2	GR-3	GR-4	GR-5
	-	Geothermal Heat Pumps	Air-Source Heat Pumps	Biofuel Boilers	Electric Boilers
Capital Cost Opinion, 2023$MM	$5.90	$32.7	$19.5	$7.4	$11.9
Year 2024 Operating Cost, $MM	$2.49	$2.52	$3.49	$3.89	$6.2

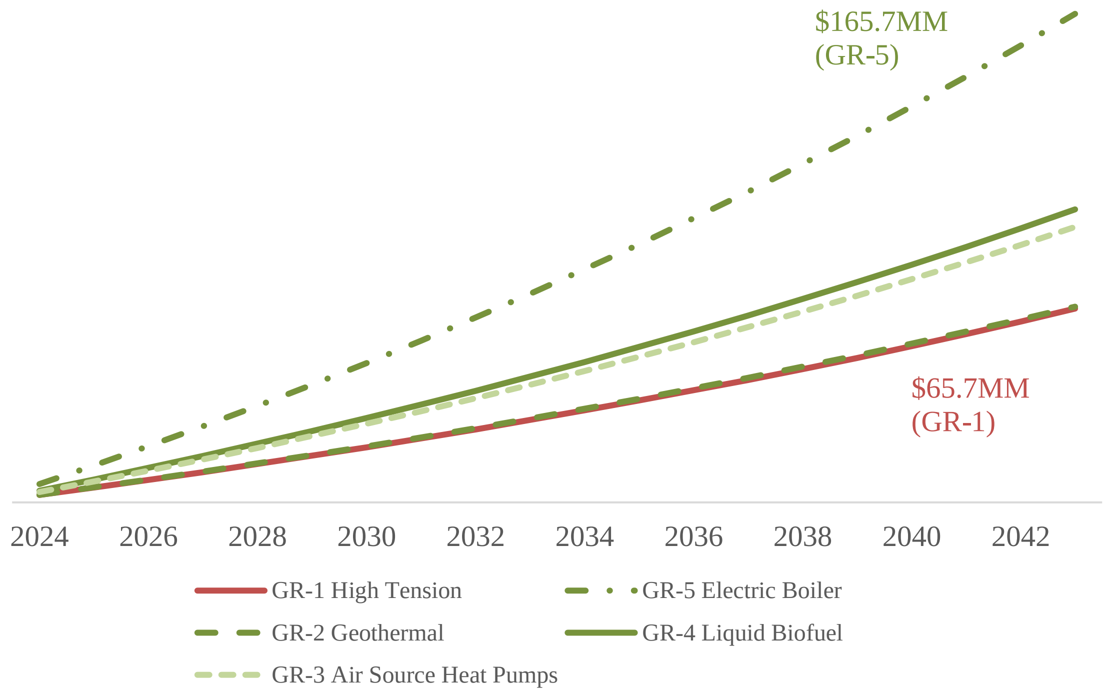


Figure 41: Operating Cost of Low Carbon Alternatives

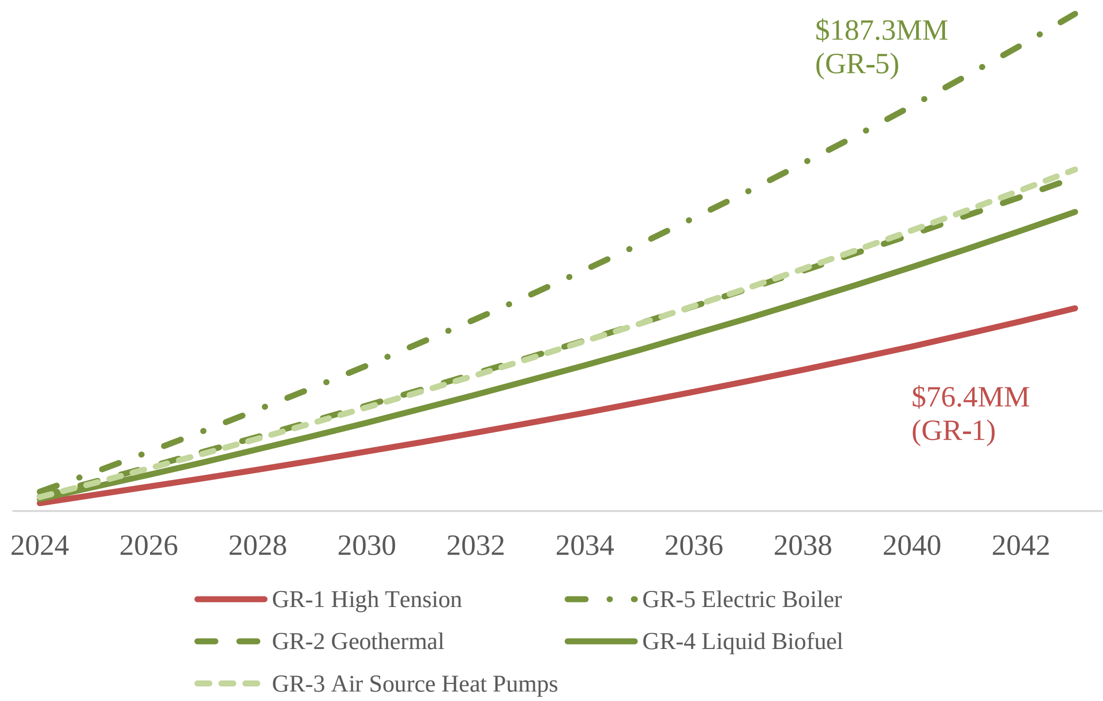


Figure 42: Life Cycle Cost (Operating + Capital Amortization) of Low Carbon Alternatives

Several items are worth noting in regards to the above results for the low carbon alternatives:

- As discussed in Attachment H, the geothermal system included in the above analysis provides heating and cooling to just one of the seven towers, based on the available thermal resource. As the subsequent section will show, this makes it an expensive method for achieving carbon reductions.
- The air-source heat pump alternative uses heat pumps only for heating and cooling of residential tenant spaces. The boiler plant, using natural gas fuel, is still utilized for domestic hot water and for generating steam for the absorption chiller that provides cooling to the commercial spaces.
- The electrification alternatives generate a significant increase in the community's peak electric demand compared to the current condition of approximately 2.6 MW. For the electric boiler alternative, the new peak demand is 8.9 MW. For the air-source heat pump alternative, the new peak demand is 4.3 MW.
    - Because the air-source heat pump case was based on a high level analysis with a fixed Coefficient of Performance (COP) for the heat pumps, the winter peak electric load is likely even higher, as the COP will approach that of the electric boiler on the coldest day of the year. Often a limited amount of boiler steam would be utilized on the coldest days of the year to keep the demand down, but this is a detail that requires further assessment.

7.7 Greenhouse Gas Emissions

As discussed previously, Local Law 97 imposes a penalty on annual greenhouse gas emissions that exceed the threshold values published therein. Such penalties have been taken into account in the financial analyses described previously in this section; however, the raw emissions data have not been presented. These are shown in Figure 43 on the following page.

The values shown are based on the parameters of the study model described previously herein, repeated here for clarify:

- The grid electricity coefficients for greenhouse gas emissions derived from purchased electricity are based on the series of declining values calculated in accordance with the CLCPA targets, as discussed in Section 6.2.

- The boiler plant at Big Six Towers continues to provide the primary source of heating steam to the community, and for those alternatives in which waste heat from engine operation at the power plant is non-existent or inadequate to serve the coincident heating loads, the boiler plant provides the difference.

The reductions over time are primarily due to the forecasted reductions in the carbon intensity of the electric grid. Note that in the short-term repowering options PA-1 and PA-3 do not increase the greenhouse gas emissions of the site, primarily because they are sized to operate with maximum thermal efficiency throughout the year. Compared to other alternatives with more engines, the waste heat available is more fully utilized.

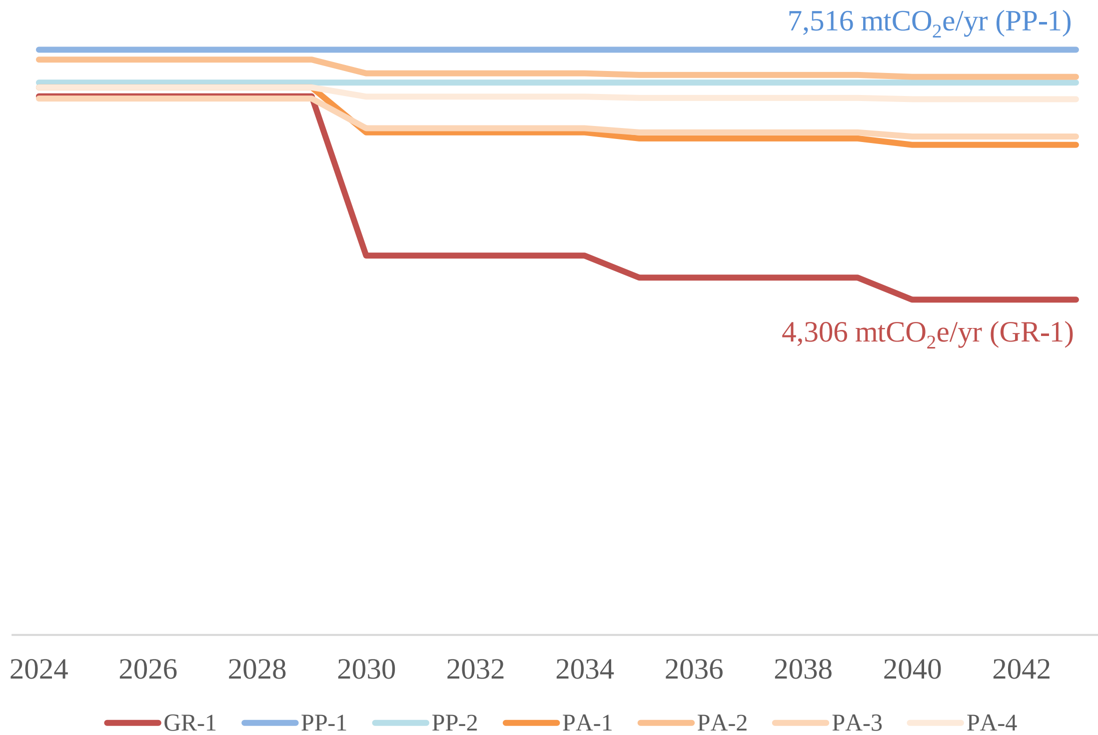


Figure 43: Greenhouse Gas Emissions of Energy Alternatives Studied ($mtCO_2e/yr$)

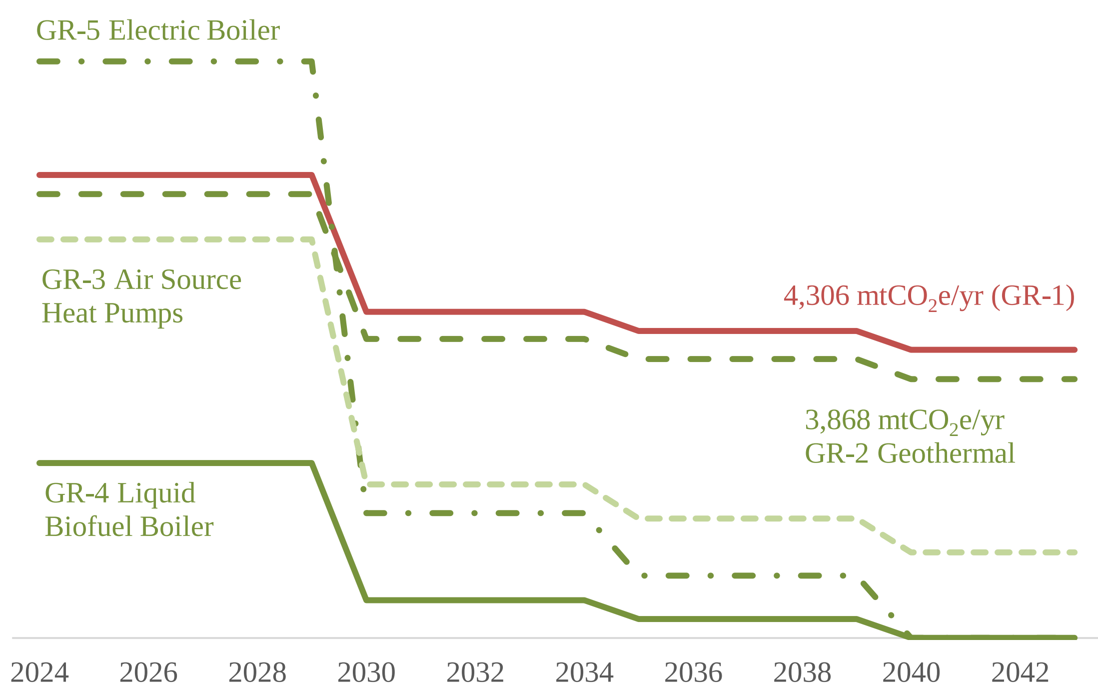


Figure 44: Greenhouse Gas Performance of Grid-Connected, Low Carbon Alternatives

It is also worth noting that within the NYC/Westchester subregion, the electric grid coefficient for "non-baseload" generators was 971 lbs CO_2e/MWh in the 2020 eGrid data[ii], a value roughly 50% higher than the NYC/Westchester subregion average on which the initial values in the figure are based. As noted in the New York ISO report[i] referenced previously herein, Zones J and K, which are within the NYC/Westchester subregion, will continue to require the support of dispatchable assets for various grid services even after the grid achieves the 70% renewable power target described in the CLCPA for Year 2030. This non-baseload emissions rate is very close to the emissions rate one would expect for natural-gas-fired peaking facilities, commonly deployed for this grid-support purpose.

Future energy supply alternatives PA-1 and PA-3 both have comparable emissions rates for straight electrical generation, and if a credit for avoided boiler fuel is given for the waste heat recovered, these options have a greenhouse gas emissions rate of approximately 625 lbs CO_2e/MWh. These values are summarized in the table below.

	NYC/Westchester Average	NYC/Westchester Non-Baseload	PA-1/PA-3 with Boiler Fuel Credit	PA-1/PA-3 w/o Boiler Fuel Credit
GHG Emissions Coefficient, lbs CO_2e/MWh	634.6	971.4	625	1080

Figure 45: Emissions Coefficient Comparison, Year 2020 NYC/Westchester vs Alternatives PA-1, -3

Thus, while the future average grid electricity coefficient will improve over time as the CLCPA targets are achieved, energy supply alternatives PA-1 and PA-3 are likely to remain comparable to the emissions rates of the non-baseload generators within the area.

7.8 Recommended Alternatives for Sensitivity Analysis

Due to the number and variety of factors that affect the decision-making process for Big Six Towers, the recommendation of an alternative for future implementation is not straightforward. The overall financial performance of the various alternatives is tightly grouped, and while several generate attractive rates of return as compared to relying solely on the grid for electricity, these alternatives also require the ongoing use of fossil fuels to produce those returns.

It is clear from recent legislation such as the CLCPA and Local Law 97 that the elimination of fossil fuels is an important political objective at both the city and state levels. Thus, investing in an option that relies on continued fossil fuel use to recover the capital expense over an extended time could be viewed as risky: it is impossible to forecast what additional costs, fees, penalties or taxes might be implemented in the future. That said, the best available information in this regard is the legislation itself, and if the Local Law 97 penalties remain as published and as evaluated herein, with the 10-yr delay for Big Six Towers, they will have minimal impact on the life cycle operating costs for the next twenty years.

Another consideration relative to greenhouse gas emissions is the need for new dispatchable power generation within New York City. The New York ISO[i] has indicated that a need exists for up to 700 MW of such assets within the New York City area by Year 2025. While energy storage facilities would be preferable to fossil-fuel-fired generation from a greenhouse gas emissions perspective, it is likely that natural-gas-fired units will remain an essential component of the non-baseload asset portfolio for the immediate future. Various energy supply alternatives studied for Big Six Towers are competitive with these non-baseload assets from a greenhouse gas emissions perspective.

The effects that the CLCPA and Local Law 97 legislation will have on energy prices over the next two decades is anything but clear and is beyond the capabilities of the report authors to predict. The large infrastructure projects required to accomplish the goals of the CLCPA and Local Law 97 could result in higher electricity prices, for instance, if the costs of such projects are passed on to the rate payers. In such a climate it could be financially advantageous for Big Six Towers to have a hedge against such cost increases by generating a portion of their electricity on-site. The best-performing grid parallel option PA-3, for instance, performs better economically than the grid-connected case if electricity prices increase, and comparable to the grid-connected case if they do not.

Given the complex interactions of the various forces that will collectively impact the future operating costs and legal compliance requirements for Big Six Towers, the decision-making process becomes one of risk assessment and navigation. In order to assist with fostering an understanding of how various energy supply alternatives would perform in future scenarios that differ from the one on which the results of this section were based, sensitivity analyses were performed. These analyses were developed for the energy supply alternative in each category that performed the best on an economic basis, as noted below.

- GR-1 | connect to Con Edison for electrical power, retire the power plant
- PP-1 | remain disconnected from Con Edison, generate electricity with 6x 635 kW engines
- PA-3 | connect to Con Edison and operate a single 1,200 kW engine in parallel with the grid

8 Sensitivity Analyses

8.1 General Trends

Several sensitivity cases were described in Section 4.1 of this report. Those are redefined and quantified in the table below, and the impacts on the life cycle cost of each alternative are shown graphically in the following figure. The costs shown in the graph are the cumulative life cycle cost values including capital amortization.

Sensitivity Case ID	Description
1A	All-in natural gas and electricity prices increase by 15%.
1B	All-in natural gas and electricity prices increase by 50%.
2A	Electricity costs are fixed; gas prices drop by 15%.
2B	Electricity costs are fixed; gas prices drop by 30%.
3A	Electric delivery charges increase by 25%.
3B	Electric delivery charges increase by 50%.
4	Discussed but not modeled. Will not have large impact due to the delay in applicability of Local Law 97 charges.
5	Discussed but not modeled. Will not have large impact due to the delay in applicability of Local Law 97 charges.
6A	Capital costs of all options increases by 50%.
6B	Capital cost of all options decreases by 25%.

Figure 46: Summary of Sensitivity Cases

Figure 47: Cumulative Life Cycle Costs for Sensitivity Cases

Several key trends are revealed by this analysis:

- As energy costs increase generally, the life cycle costs for the GR-1 alternative (no on-site generation) increase more rapidly than the other two alternatives. As the Section 8.2 (following) will show, this is because the life cycle cost comparison are most sensitive to electricity pricing. In essence, on-site generation would buffer Big Six Towers from the direct effects of energy price increases in the years ahead.

- It should be noted that this implies the converse is true as well. While not shown graphically above, if the all-in natural gas and electricity prices both drop by 15%, then the GR-1 and PA-3 alternatives would be approximately equal in cumulative life cycle cost, while alternative PP-1 would be more expensive by approximately 15%.

- Reductions in natural gas costs relative to electricity prices provides the most benefit to the alternatives with on-site generation. Alternately, increases in natural gas costs relative to electricity prices would raise the life cycle costs of alternatives PP-1 and PA-3 more rapidly than GR-1.

- Increases in electricity delivery charges (per the applicable Con Edison tariff) will have a greater impact on alternative GR-1 than either case with on-site generation.

- As shown by the 6A and 6B cases, changes in capital cost impact the alternatives with on-site generation more than option GR-1. Option PP-1 is most sensitive to this because it has the highest capital cost.

Consideration of these trends in light of the possible impacts of the CLCPA and Local Law 97 legislation will be further developed in Section 8.3.

8.2 Rate of Return Sensitivities for Alternatives PP-1 and PA-3

Energy supply alternatives PP-1 and PA-3, each of which involves on-site generation and continued operation of the power plant in some form, require a higher initial investment than alternative GR-1, which only requires the initial capital investment required to complete a Con Edison interconnection. Thus, an incremental investment analysis may be performed on these two alternatives to evaluate the rate of return that would be realized on the additional capital required to construct them.

The rates of return in the baseline modeling were provided previously in Figure 40, and are reprised here for convenience.

	GR-1	PP-1	PA-3
Rate of Return on Incremental Capital Investment	N/A	7.3%	8.9%

A sensitivity analysis was performed on the rates of return for these two alternatives utilizing independent variations in the values for purchased electricity, purchased natural gas, and capital cost. The results are presented below in the form of a tornado diagram. This type of diagram ranks the impact of the factors studied on the outcome in consideration—in this case the rate of return—and also depicts the order of magnitude of the impacts each factor has on that outcome.

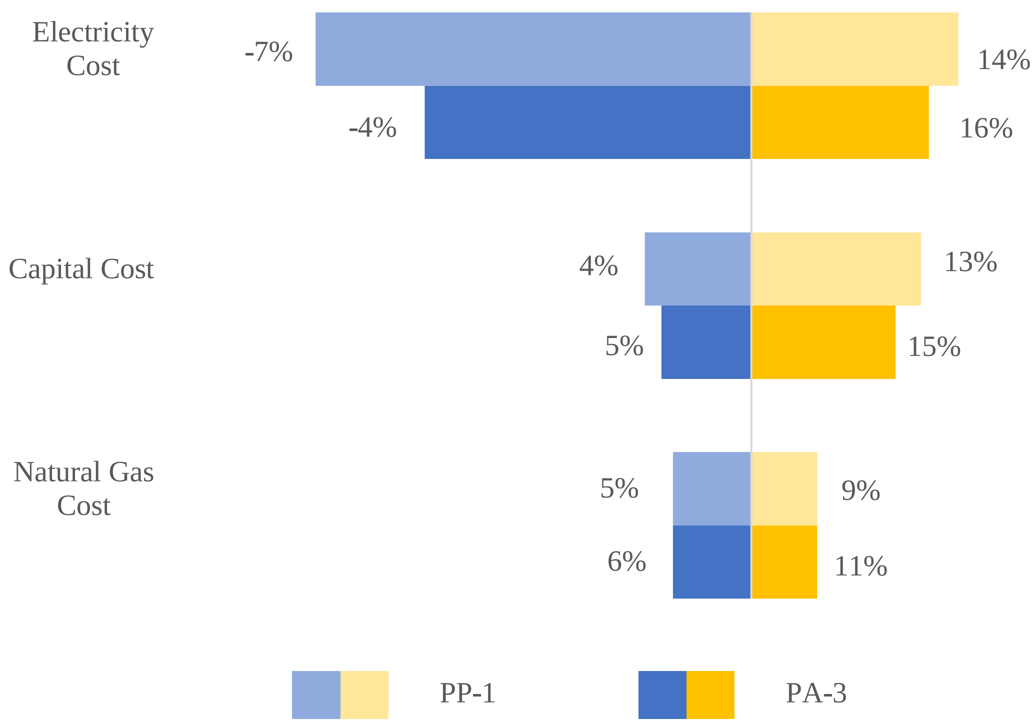


Figure 48: Rate of Return Tornado Diagram for Alternatives PP-1 and PA-3

The blue bars represent the magnitudes of the negative outcomes for each factor studied, while the yellow bars represent the positive magnitudes. The length of the bars is proportional to the magnitude of the change relative to the baseline rate of return for each alternative, and the numbers at the end of each bar are the resulting rate of return. Each factor—electricity cost, capital cost, and natural gas cost—was varied by plus and minus 30% in this analysis.

As an example, if electricity prices increase by 30% while capital costs and natural gas costs remain fixed, the rate of return on the PP-1 alternative would increase from the baseline value of 7.3% to the displayed value of 14%. Likewise, the rate of return for the PA-3 alternative would increase from the baseline value of 8.9% to the displayed value of 16% for the same 30% increase in electricity costs.

The graph shows that a 30% decrease in electricity prices would have a larger negative effect on each alternative's rate of return than a 30% increase in electricity prices would have. It also shows that the rate of return of both alternatives is more sensitive to electricity prices than to capital cost or natural gas prices.

The capital cost works in a slightly different manner, and that is because a decrease in capital cost results in an increase in rate of return. So for the capital cost bars, the increased rates of return for the two alternatives correspond to the case in which the capital costs are *reduced* by 30%.

With these trends in mind consideration may now be given to risk assessment and mitigation.

8.3 Risk Considerations

The alternative with the lowest greenhouse gas emissions and the lowest required capital investment is GR-1, the alternative in which Big Six Towers retires the power plant electrical generation and relies solely on Con Edison for electricity supply. The total annual cost for this option, meaning the cost of operation plus capital amortization, is virtually identical to the best options with on-site power generation for the forecasted commodity costs and capital costs contained in the baseline analysis. The energy supply alternatives realize further differentiation, however, if various factors contained in the analysis come to fruition differently than described herein. Thus, each alternative comes with a risk of unforeseen consequences.

The key risk factors Waldron has identified that are related to implementing a new energy supply alternative at Big Six Towers are the following:

- electricity cost increases driven by market responses to the CLCPA and Local Law 97 mandates;
- capital cost uncertainty and construction risk for the installation of new on-site electrical generation equipment; and,
- the possibility that new taxes and/or penalties on fossil fuel use, such as a direct tax on natural gas usage, could be imposed.

8.3.1 Electricity Cost Considerations

With regards to electricity costs, there is uncertainty in the commodity cost forecasts due to the pending transformation of New York State's electrical grid that is mandated by the CLCPA. Achievement of the goals identified therein will require significant investments in renewable energy sources as well as some combination of grid-scale energy storage systems and transmission system upgrades. The magnitude of this challenge is increased if one considers that the requirements of Local Law 97 will likely drive property owners in New York City to electrify their heating systems, which will increase overall electrical consumption as well. If the combined effect of these initiatives is to increase electricity prices, and those increases are passed on to the consumer, then the overall cost of alternative GR-1 will increase more rapidly than for the options with on-site generation.

To put this in perspective, a 15% increase in the cost of delivered electricity would increase the forecasted Year 2024 operating cost for alternative GR-1 from $2.49 million to $2.76 million. The operating cost for alternative PA-3 for the same year would increase from $1.80 million to $1.90 million. Thus, alternatives with on-site generation provide a financial buffer against potential increases in delivered electricity costs.

The downside of on-site generation is the likelihood that greenhouse gas emissions for the Big Six Towers community will be higher in the future than they would be if the community relied on the grid for electrical power and the mandates of the CLCPA are realized on schedule. It is worth noting, however, that the annual greenhouse gas emissions for alternatives PP-1 and PA-3 are forecasted to be approximately 33% and 38% lower respectively than historical values for Big Six Towers. These reductions are due to the improved efficiencies of newer engines and the significant reduction in No. 2 oil use that would be achieved. The greenhouse gas emissions benefits of alternative GR-1 will be realized over time as new renewable energy sources come on-line, and in the early years of the project life cycle are not forecasted to be significant.

8.3.2 Capital Cost Considerations

Waldron has recently observed a variety of construction project risks above and beyond the historical norms that are related to general inflationary pressures in the economy, supply chain bottlenecks, and material and labor shortages. The general effect of these conditions has been unstable prices for labor, materials and equipment as well as delays in shipment of materials and equipment.

The effect is inconsistent across project elements and varies over time for various markets, but two references are provided here to give a sense of the order-of-magnitude of the volatility observed in the last year. The Turner Construction Cost Index[v] shows an increase of approximately 7% from 1st quarter 2021 to 1st quarter 2022, while the Mortenson Construction Cost Index[vi] shows an increase of approximately 18% over the same time period.

As Local Law 38 requires that existing stationary engines in operation after January 1, 2025 will not have their operating permits renewed unless they comply with Tier 4 emissions criteria, there is schedule pressure on Big Six Towers to implement one of the alternatives explored in this study. Waiting for market conditions to stabilize, in other words, comes with risks of its own.

The obvious means of mitigating this risk is to minimize the scope of new construction. A comprehensive overhaul of the power plant such as alternative PP-1 requires, with six new engines, is clearly the most capital-intensive project, while alternative GR-1 requires only the electrical upgrades associated with a Con Edison interconnection and upgrades to electrical distribution equipment in Building Three.

As noted above, on the whole the alternatives studied herein are more sensitive to electrical cost increases than construction cost increases. It should also be noted that construction cost increases generally will also impact the infrastructure projects required to incorporate more renewable energy facilities into the grid. Thus, construction costs and future year electricity costs are likely to be at least weakly correlated.

Another construction risk is the presence of hazardous materials. Waldron's cost opinions presented herein do not contain any remediation or abatement of hazardous materials, and given the original construction dates of the facility the presence of asbestos within the power plant is a possibility. This risk could easily be mitigated by performing a hazardous materials assessment if one has not been performed previously.

8.3.3 Additional Carbon Penalties and/or Taxes

This risk is largely hypothetical and is intended to call attention to the fact that the policy landscape going forward is uncertain. It is possible, for instance, though it may seem unlikely as of today, that a federal tax on fossil fuel usage could be implemented. It is also possible that if the goals of the CLCPA are realized on-schedule that this will create the opportunity for future carbon emission penalties that are more significant than those modeled herein.

Policy changes that occur beyond the 20-yr life cycle planning horizon utilized in this study will not be consequential to present-day decision-making, as facility modifications could be made fifteen years in the future to meet the new requirements; however, changes within the planning horizon would have significant effects.

One way to insulate present-day decision-making from future unknowns is to ensure that the capital invested in a given alternative is paid back as soon as possible. If new on-site power generation is installed, for instance, and is paid for through operating savings within just a few years, then the likelihood of disruptions to the project economics as a result of unforeseen policy mandates will be less than if operation for twenty years is required to recover the initial investment. In this analysis, the capital cost of on-site generation has been amortized over twenty years but it could be repaid sooner from the savings generated. That said, there is not much difference in the payback periods for the PP-1 and PA-3 alternatives, 9.5 yrs for PP-1 vs 9.0 yrs for PA-3.

A second means of reducing risk exposure to future policy mandates or taxes related to carbon emissions is to build operational flexibility into the initial design. If the grid achieves the goals of the CLCPA on schedule, the alternative with the lowest carbon footprint will clearly be GR-1; however, if the grid does not realize the CLCPA goals on schedule the differentiation between alternative GR-1 and those involving on-site generation will not be as wide.

Alternative PA-3, which includes both a Con Edison grid interconnection and a single engine on-site, provides the most flexibility of any alternative to modulate the quantity of power generated on-site vs purchased over time. Thus, in the early years of the life cycle when base load operation is necessary to generate operating savings and recover the capital investment, the engine could be operated to the fullest extent possible. In later years of the life cycle the usage could be reduced so the engine only ran during on-peak hours or only during summer months, when it would provide maximum value per unit of electricity production. This flexibility could also be utilized to reduce carbon emissions in response to unforeseen policy changes.

8.3.4 Conclusions

The preceding discussion may be summarized in a few succinct bullets. For each bullet the energy supply alternatives have been ranked in terms of their performance relative to the stated criterion. This is a more qualitative than quantitative assessment.

- On-site electrical generation provides a means of buffering Big Six Towers from future electricity cost increases that may be realized as a result of construction cost increases and grid infrastructure upgrades that will be required to meet legislative goals for renewable energy.

    1. PP-1, 100% on-site generation
    2. PA-3, 80% on-site generation
    3. GR-1, no on-site generation

- On balance, alternatives with lower capital costs provide reduced risk exposure to construction risk in general, and specifically the present market volatilities associated with labor, material and equipment prices.

    1. GR-1, $5.9 million capital investment
    2. PA-3, $13.1 million capital investment
    3. PP-1, $18.5 million capital investment

- Incremental investments that pay for themselves in a short period of time are preferred over investments with longer payback periods, as this allows for greater freedom within the present planning horizon to modify facility operations in response to changing market or policy conditions without jeopardizing project economics.

    1. PA-3, 9-yr payback period on incremental capital investment
    2. PP-1, 9.5-yr payback period on incremental capital investment
    3. GR-1, no payback

- Alternatives with lower greenhouse gas emission footprints are least exposed to the risk of unforeseen policy changes related to carbon emissions. Assuming the CLCPA goals are realized on schedule, the rankings for the various alternatives is as follows:

    1. GR-1, lowest greenhouse gas emissions over time
    2. PA-3, mid-range greenhouse gas emissions with flexibility over time
    3. PP-1, highest greenhouse gas emissions over time

- Alternatives with the flexibility to either buy electricity from the grid or generate it on-site provide the ability to modify the operating approach over time in response to changing policy or market conditions.

    1. PA-3, provides flexibility to either purchase or generate electricity
    2. GR-1, no electrical source flexibility, commits Big Six Towers to the grid
    3. PP-1, no electrical source flexibility, commits Big Six Towers to grid independence

If relative rankings were assigned points—3 for first, 2 for second, and 1 for third—then the overall points total would be as follows:

	GR-1	PP-1	PA-3
Total Points	10	8	12

Figure 49: Relative Ranking of Energy Supply Alternatives in Sensitivity Analysis

This is not an entirely rational basis for decision-making, as the various categories are certainly not equal to one another in significance and the distinctions between the first, second and third place are hardly discrete, but it does reveal a general trend. The top-scoring alternative, PA-3, is ranked second or higher in every category.

The PA-3 alternative provides a hedge against elevated future electricity prices for roughly 60% of the capital investment of PP-1, and is the only alternative of the three selected for sensitivity analysis that affords Big Six Towers the flexibility to generate power on-site or buy it from the grid, depending on which is more advantageous. This flexibility is valuable given the uncertainty in the present markets. With a payback period less than 10 years, the project will likely pay for itself before the delayed Local Law 97 penalties come into effect. (Note that the 20-yr loan used to finance the project may still have ten years on its term, depending upon how quickly the note is repaid.)

For the reasons noted above, Waldron recommends the Grid Parallel (PA-3) alternative for further development.

9 Supplemental Information

The purpose of this section is to provide supplemental information on aspects of the analysis that were considered secondary to the primary task of determining the best overall strategy for meeting the future energy needs of Big Six Towers.

9.1 Electrical Generation Technologies

It would be reasonable to ask why the analysis did not contemplate fuel cells, combustion turbines or other conventional technologies that were not discussed above. The answers to this question are fairly straightforward.

- Fuel cells are more expensive than natural gas fired reciprocating engines for comparable electrical generation efficiency. Additionally, the waste heat from fuel cells is not hot enough for primary steam generation, so the use of fuel cells would eliminate the opportunity for waste heat recovery, or require significant infrastructure modifications.

- Combustion turbines are not typically a cost-effective approach to loads of the size evaluated herein. In the 1 – 2 MW range, combustion turbines are only about 60% +/- as efficient as the natural gas fired engines in converting fuel energy input to electricity. The quantity of waste heat developed would be much larger than the reciprocating engines, and while this may be valuable in winter months, for much of the year it would be wasted. This would hurt economics and increase greenhouse gas emissions for no real benefit to Big Six Towers.

- Microturbines—small, pre-packaged combustion turbines with integral heat recovery systems that may be deployed in a modular fashion—have better electrical generating efficiencies than conventional combustion turbine in this size range, but they are still only about 75% +/- as efficient as the natural gas fired reciprocating engines.

9.2 Solar PV

A simplified HelioScope model of solar photovoltaic arrays deployed on the roofs of the seven towers at Big Six was developed for this study. The installed capacity would be approximately 78 kW, and the annual production would be approximately 125 MWh, which is 1.4% of the annual needs of the community. This is a project that could be considered for implementation with any of the alternative studied, but it would not have an impact on the fundamental decision that must be made regarding which energy supply alternative to implement.

Installation of solar PV arrays at ground level is more challenging due to the shading created by the seven towers. There would certainly be incremental benefits but like the rooftop arrays, this project would only marginally lower the electric load of the community, and would not have an impact on the basic decision-making process regarding the energy supply alternatives.

9.3 Battery Energy Storage

Similar to the solar PV discussion above, a battery energy storage system could be deployed as part of any energy supply alternative Big Six Towers might choose to implement that includes a connection to the Con Edison grid. NYSERDA has developed a free calculation tool that may be used to estimate the net compensation for standalone energy storage systems, which Waldron has used to develop a simplified analysis of the value that could be generated by a battery. ("Standalone" in this context refers to energy storage systems not directly coupled to renewable energy systems.)

For this preliminary assessment, Waldron selected a battery with a nominal 1 MW inverter and 4 MWh of energy storage. High level metrics for this system that were calculated using the NYSERDA spreadsheet tool are noted below:

Installed Cost, 2023$	$2,100,000
Average Annual Revenue, TC$	$212,000
Annual Capital Amortization	$191,000
Payback Period, approx.	9 yrs
Rate of Return	8.4%

Based on this preliminary assessment, the inclusion of a battery is forecasted to generate a rate of return that is fairly similar to the energy supply alternatives with on-site generation capability. Its inclusion is not forecasted to have a significant impact on project economics, and similar to the roof-mounted solar PV systems, does not avoid any of the investments in the energy supply alternatives studied. The basic elements of each energy supply alternative are still required in order to meet the future energy needs of Big Six Towers, and in this sense the battery is an "optional" project that could be considered for implementation for modest financial benefit.

There is also a potential operating benefit to the deployment of a battery alongside of the Grid Parallel (PA) alternative. In the event the grid is temporarily unavailable and the community elects to maintain power supply to the community using engine(s) on-site, depending on the time of year and the magnitude of the community's load, the battery could serve to assist the engine in responding to load changes. This would increase the stability of the community's electrical system when operating in island mode. Note, however, that the optimal Grid Parallel alternative has only a single 1,200 kW engine, and for approximately half of the year the engine alone would be insufficient to provide power to the community without load-shedding.

10 References

[i] New York Independent System Operator. (2020). *2020 Reliability Needs Assessment Report*. https://www.nyiso.com/documents/20142/2248793/2020-RNAReport-Nov2020.pdf

[ii] United States Environmental Protection Agency. (2022). *eGrid Summary Data Tables*. https://www.epa.gov/system/files/documents/2022-01/egrid2020_summary_tables.pdf

[iii] Urban Green Council. (2020). *New York City's Energy and Water Use Report: 10 Years of Data*. https://www.urbangreencouncil.org/sites/default/files/2020_nyc_benchmarking_report.pdf

[iv] US Department of Energy, Alternative Fuels Data Center. (June, 2022). *Fuel Prices.* https://afdc.energy.gov/fuels/prices.html

[v] Turner Construction. *Cost Index*. https://www.turnerconstruction.com/cost-index

[vi] M.A. Mortenson Company. *Cost Index*. https://www.mortenson.com/cost-index

Attachment A

Modeling Results, Annual Totals for 20 Year Life Cycle

4x1.2 MW Recips

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Purchased Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Demand, May-June, 8AM-6PM (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand, 8AM-10PM (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand, All Hours, All Days (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136	43,136
CHP Steam Production (klbs)	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859	15,859
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998
Steam to Hot Water (klbs)	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Total Steam Use (klbs)	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997	55,997
Steam to Heating (klbs)	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665	48,665
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104	19,104
Steam to Hot Water (MMBtu)	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hot Water Production (MMBtu)	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150	21,150
Dumped Hot Water (MMBtu)	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455	6,455
Fuel																				
Gas to Generators (MMBtu)	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493	82,493
Gas to Boiler (MMBtu)	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670	50,670
Total Gas Consumption (MMBtu)	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163	133,163
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304
Total Oil Consumption (MMBtu)	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304
Electric Cost																				
Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, 8AM-10PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

4x1.2 MW Recips

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Fuel Cost										
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509
Boiler Gas Delivery Cost ($)	$108,562	$111,819	$115,174	$118,629	$122,188	$125,854	$129,629	$133,518	$137,524	$141,649
Boiler Gas Supply Cost ($)	$297,151	$275,998	$273,738	$277,910	$284,839	$293,427	$302,788	$308,942	$317,382	$326,188
Total Boiler Gas Cost ($)	$410,702	$392,956	$394,204	$401,990	$412,642	$425,064	$438,374	$448,595	$461,226	$474,347
Cogen Gas Delivery Cost ($)	$263,785	$271,698	$279,849	$288,245	$296,892	$305,799	$314,973	$324,422	$334,155	$344,179
Cogen Gas Supply Cost ($)	$450,562	$429,221	$434,296	$441,375	$462,096	$476,922	$493,106	$505,782	$520,227	$535,306
Total Gas Cost ($)	$1,125,048	$1,093,876	$1,108,350	$1,131,610	$1,171,630	$1,207,785	$1,246,453	$1,278,800	$1,315,607	$1,353,832
Oil Cost ($)	$6,349	$6,540	$6,736	$6,938	$7,146	$7,361	$7,581	$7,809	$8,043	$8,284
O&M Cost										
Equipment O&M ($)	$170,920	$175,193	$179,573	$184,062	$188,664	$193,380	$198,215	$203,170	$208,249	$213,456
Utility and O&M Cost										
Total Fuel, Electricity & O&M Cost ($)	$1,302,318	$1,275,608	$1,294,659	$1,322,610	$1,367,440	$1,408,526	$1,452,249	$1,489,779	$1,531,900	$1,575,572
GHG Emissions/LL 97 Cost, As Written										
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063
Engine GHG Emissions (Mton CO2e)	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381
Boiler Gas Emissions (Mton CO2e)	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$99,174	$102,150	$105,214	$108,370	$111,622	$114,970	$972,832	$1,002,017	$1,032,078	$1,063,040
GHG Emissions/LL 97 Cost, Delayed to 2034										
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	-	-	-	-	-	-	-	-	-	-
Engine GHG Emissions (Mton CO2e)	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381
Boiler Gas Emissions (Mton CO2e)	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost										
Total Cost with LL97 Penalties ($)	$1,401,492	$1,377,758	$1,399,873	$1,430,981	$1,479,062	$1,523,496	$2,425,081	$2,491,796	$2,563,978	$2,638,612
Total Cost with LL97 Penalties, Delayed ($)	$1,302,318	$1,275,608	$1,294,659	$1,322,610	$1,367,440	$1,408,526	$1,452,249	$1,489,779	$1,531,900	$1,575,572

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost										
Boiler Gas Minimum Charge ($)	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$145,899	$150,276	$154,784	$159,428	$164,210	$169,137	$174,211	$179,437	$184,820	$190,365
Boiler Gas Supply Cost ($)	$335,236	$345,022	$355,094	$365,460	$376,128	$387,108	$398,408	$410,039	$422,009	$434,328
Total Boiler Gas Cost ($)	$487,839	$502,203	$516,991	$532,213	$547,884	$564,017	$580,625	$597,722	$615,322	$633,441
Cogen Gas Delivery Cost ($)	$354,505	$365,140	$376,094	$387,377	$398,998	$410,968	$423,297	$435,996	$449,076	$462,548
Cogen Gas Supply Cost ($)	$551,582	$567,686	$584,259	$601,317	$618,873	$636,941	$655,537	$674,676	$694,374	$714,647
Total Gas Cost ($)	$1,393,927	$1,435,029	$1,477,344	$1,520,907	$1,565,755	$1,611,926	$1,659,459	$1,708,394	$1,758,772	$1,810,637
Oil Cost ($)	$8,533	$8,789	$9,053	$9,324	$9,604	$9,892	$10,189	$10,494	$10,809	$11,134
O&M Cost										
Equipment O&M ($)	$218,792	$224,262	$229,868	$235,615	$241,505	$247,543	$253,732	$260,075	$266,577	$273,241
Utility and O&M Cost										
Total Fuel, Electricity & O&M Cost ($)	$1,621,251	$1,668,080	$1,716,265	$1,765,847	$1,816,865	$1,869,361	$1,923,380	$1,978,963	$2,036,158	$2,095,011
GHG Emissions/LL 97 Cost, As Written										
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381
Boiler Gas Emissions (Mton CO2e)	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095
GHG Emissions Limit [Local Law 97] (Mton CO2e)	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$1,094,931	$2,114,582	$2,178,020	$2,243,360	$2,310,661	$2,379,981	$2,451,381	$2,524,922	$2,600,670	$2,678,690
GHG Emissions/LL 97 Cost, Delayed to 2034										
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381	4,381
Boiler Gas Emissions (Mton CO2e)	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691	2,691
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$133,282	$137,280	$141,399	$145,641	$150,010	$154,510	$1,307,405	$1,346,627	$1,387,026	$1,428,637
Total Cost										
Total Cost with LL97 Penalties ($)	$2,716,183	$3,782,662	$3,894,285	$4,009,207	$4,127,526	$4,249,343	$4,374,760	$4,503,885	$4,636,828	$4,773,701
Total Cost with LL97 Penalties, Delayed ($)	$1,754,533	$1,805,360	$1,857,664	$1,911,487	$1,966,875	$2,023,872	$3,230,785	$3,325,591	$3,423,184	$3,523,648

6x635 kW Recips

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030
Purchased Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030
Demand, May-June, 8AM-6PM (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand, 8AM-10PM (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand, All Hours, All Days (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031	40,031
CHP Steam Production (klbs)	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223	20,223
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087	5,087
Steam to Hot Water (klbs)	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320
Total Steam Use (klbs)	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167	55,167
Steam to Heating (klbs)	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561	48,561
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044	21,044
Steam to Hot Water (MMBtu)	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320
Hot Water Production (MMBtu)	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363	22,363
Dumped Hot Water (MMBtu)	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696	7,696
Fuel																				
Gas to Generators (MMBtu)	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104	94,104
Gas to Boiler (MMBtu)	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015	47,015
Total Gas Consumption (MMBtu)	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119	141,119
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290
Total Oil Consumption (MMBtu)	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290
Electric Cost																				
Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, 8AM-10PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

6x635 kW Recips

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost																				
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$100,732	$103,754	$106,866	$110,072	$113,374	$116,776	$120,279	$123,887	$127,604	$131,432	$135,375	$139,436	$143,619	$147,928	$152,366	$156,937	$161,645	$166,494	$171,489	$176,634
Boiler Gas Supply Cost ($)	$276,726	$256,792	$254,513	$258,395	$264,644	$272,598	$281,270	$286,928	$294,757	$302,923	$311,306	$320,393	$329,746	$339,372	$349,278	$359,474	$369,968	$380,768	$391,884	$403,324
Total Boiler Gas Cost ($)	$382,447	$365,684	$366,672	$373,919	$383,634	$395,157	$407,506	$416,951	$428,681	$440,865	$453,385	$466,735	$480,478	$494,626	$509,190	$524,184	$539,619	$555,509	$571,866	$588,706
Cogen Gas Delivery Cost ($)	$299,947	$308,946	$318,214	$327,761	$337,593	$347,721	$358,153	$368,898	$379,964	$391,363	$403,104	$415,197	$427,653	$440,483	$453,697	$467,308	$481,328	$495,767	$510,640	$525,960
Cogen Gas Supply Cost ($)	$514,549	$490,017	$495,703	$503,786	$527,328	$544,239	$562,704	$577,140	$593,615	$610,815	$629,372	$647,746	$666,657	$686,121	$706,152	$726,769	$747,987	$769,825	$792,301	$815,433
Total Gas Cost ($)	$1,196,943	$1,164,647	$1,180,589	$1,205,465	$1,248,555	$1,287,117	$1,328,363	$1,362,988	$1,402,260	$1,443,043	$1,485,861	$1,529,679	$1,574,789	$1,621,229	$1,669,040	$1,718,261	$1,768,933	$1,821,101	$1,874,808	$1,930,098
Oil Cost ($)	$6,051	$6,233	$6,420	$6,612	$6,811	$7,015	$7,225	$7,442	$7,665	$7,895	$8,132	$8,376	$8,627	$8,886	$9,153	$9,427	$9,710	$10,002	$10,302	$10,611
O&M Cost																				
Equipment O&M ($)	$170,765	$175,034	$179,410	$183,895	$188,492	$193,205	$198,035	$202,985	$208,060	$213,262	$218,593	$224,058	$229,659	$235,401	$241,286	$247,318	$253,501	$259,839	$266,335	$272,993
Utility and O&M Cost																				
Total Fuel, Electricity & O&M Cost ($)	$1,373,758	$1,345,913	$1,366,418	$1,395,972	$1,443,858	$1,487,337	$1,533,623	$1,573,415	$1,617,985	$1,664,200	$1,712,587	$1,762,113	$1,813,076	$1,865,516	$1,919,479	$1,975,006	$2,032,145	$2,090,941	$2,151,444	$2,213,702
GHG Emissions/LL 97 Cost, As Written																				
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998
Boiler Gas Emissions (Mton CO2e)	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497
Boiler Oil Emissions (Mton CO2e)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Total GHG Emissions (Mton CO2e)	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$212,796	$219,179	$225,755	$232,527	$239,503	$246,688	$1,107,878	$1,141,114	$1,175,348	$1,210,608	$1,246,926	$2,271,037	$2,339,168	$2,409,343	$2,481,624	$2,556,072	$2,632,638	$2,711,618	$2,792,966	$2,876,755
GHG Emissions/LL 97 Cost, Delayed to 2034																				
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998	4,998
Boiler Gas Emissions (Mton CO2e)	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497	2,497
Boiler Oil Emissions (Mton CO2e)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Total GHG Emissions (Mton CO2e)	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516	7,516
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$285,277	$293,735	$302,547	$311,624	$320,972	$330,602	$1,488,663	$1,533,323	$1,579,323	$1,626,702
Total Cost																				
Total Cost with LL97 Penalties ($)	$1,586,554	$1,565,092	$1,592,173	$1,628,499	$1,683,361	$1,734,025	$2,641,500	$2,714,529	$2,793,333	$2,874,808	$2,959,513	$4,033,150	$4,152,244	$4,274,860	$4,401,102	$4,531,078	$4,664,783	$4,802,559	$4,944,410	$5,090,457
Total Cost with LL97 Penalties, Delayed ($)	$1,373,758	$1,345,913	$1,366,418	$1,395,972	$1,443,858	$1,487,337	$1,533,623	$1,573,415	$1,617,985	$1,664,200	$1,997,864	$2,055,848	$2,115,623	$2,177,140	$2,240,451	$2,305,608	$3,520,808	$3,624,264	$3,730,766	$3,840,404

Con Ed Reconnection, Low Tension

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Demand, May-June, 8AM-6PM (MW)	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29
Demand, 8AM-10PM (MW)	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94
Demand, All Hours, All Days (MW)	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Total Steam Use (klbs)	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484
Steam to Heating (klbs)	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Hot Water Production (MMBtu)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel																				
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553
Total Gas Consumption (MMBtu)	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
Total Oil Consumption (MMBtu)	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
Electric Cost																				
Minimum Charge ($)	$1,983	$2,043	$2,104	$2,167	$2,232	$2,299	$2,368	$2,439	$2,512	$2,588	$2,665	$2,745	$2,828	$2,913	$3,000	$3,090	$3,183	$3,278	$3,376	$3,478
Electric Delivery (w/Riders) Cost ($)	$82,471	$84,945	$87,494	$90,119	$92,822	$95,607	$98,475	$101,429	$104,472	$107,606	$110,834	$114,159	$117,584	$121,112	$124,745	$128,487	$132,342	$136,312	$140,402	$144,614
Electricity Supply Cost ($)	$1,247,468	$1,284,892	$1,323,438	$1,363,141	$1,404,036	$1,446,157	$1,489,541	$1,534,228	$1,580,255	$1,627,662	$1,676,492	$1,726,787	$1,778,590	$1,831,948	$1,886,907	$1,943,514	$2,001,819	$2,061,874	$2,123,730	$2,187,442
Demand Cost, May-June, 8AM-6PM ($)	$101,771	$104,824	$107,969	$111,208	$114,544	$117,980	$121,520	$125,165	$128,920	$132,788	$136,772	$140,875	$145,101	$149,454	$153,938	$158,556	$163,312	$168,212	$173,258	$178,456
Demand Cost, 8AM-10PM ($)	$411,022	$423,353	$436,053	$449,135	$462,609	$476,487	$490,782	$505,505	$520,671	$536,291	$552,379	$568,951	$586,019	$603,600	$621,708	$640,359	$659,570	$679,357	$699,738	$720,730
Demand Cost, All Hours, All Days ($)	$221,424	$228,067	$234,909	$241,956	$249,215	$256,691	$264,392	$272,324	$280,494	$288,908	$297,576	$306,503	$315,698	$325,169	$334,924	$344,972	$355,321	$365,980	$376,960	$388,269
Total Electric Cost ($)	$2,066,139	$2,128,123	$2,191,967	$2,257,726	$2,325,458	$2,395,222	$2,467,078	$2,541,091	$2,617,323	$2,695,843	$2,776,718	$2,860,020	$2,945,821	$3,034,195	$3,125,221	$3,218,978	$3,315,547	$3,415,013	$3,517,464	$3,622,988

Con Ed Reconnection, Low Tension

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Fuel Cost										
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509
Boiler Gas Delivery Cost ($)	$172,600	$177,778	$183,111	$188,604	$194,263	$200,091	$206,093	$212,276	$218,644	$225,204
Boiler Gas Supply Cost ($)	$456,230	$427,124	$426,302	$432,941	$446,729	$460,481	$475,490	$485,979	$499,447	$513,502
Total Boiler Gas Cost ($)	$633,819	$610,040	$614,706	$626,997	$646,607	$666,355	$687,541	$704,391	$724,411	$745,215
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$633,819	$610,040	$614,706	$626,997	$646,607	$666,355	$687,541	$704,391	$724,411	$745,215
Oil Cost ($)	$7,836	$8,071	$8,314	$8,563	$8,820	$9,085	$9,357	$9,638	$9,927	$10,225
O&M Cost										
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Utility and O&M Cost										
Total Fuel, Electricity & O&M Cost ($)	$2,707,794	$2,746,235	$2,814,986	$2,893,286	$2,980,885	$3,070,661	$3,163,976	$3,255,119	$3,351,661	$3,451,283
GHG Emissions/LL 97 Cost, As Written										
Purchased Elec GHG Emissions (Mton CO2e)	2,612	2,612	2,612	2,612	2,612	2,612	566	566	566	566
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278
Boiler Oil Emissions (Mton CO2e)	28	28	28	28	28	28	28	28	28	28
Total GHG Emissions (Mton CO2e)	6,918	6,918	6,918	6,918	6,918	6,918	4,872	4,872	4,872	4,872
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$51,687	$53,237	$54,834	$56,480	$58,174	$59,919	$261,560	$269,407	$277,489	$285,814
GHG Emissions/LL 97 Cost, Delayed to 2034	0	0	0	0	0	0	0	0	0	0
Purchased Elec GHG Emissions (Mton CO2e)	-	-	-	-	-	-	-	-	-	-
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)										
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278
Boiler Oil Emissions (Mton CO2e)	28	28	28	28	28	28	28	28	28	28
Total GHG Emissions (Mton CO2e)	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,306
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost										
Total Cost with LL97 Penalties ($)	$2,759,481	$2,799,472	$2,869,821	$2,949,765	$3,039,059	$3,130,580	$3,425,536	$3,524,526	$3,629,151	$3,737,097
Total Cost with LL97 Penalties, Delayed ($)	$2,707,794	$2,746,235	$2,814,986	$2,893,286	$2,980,885	$3,070,661	$3,163,976	$3,255,119	$3,351,661	$3,451,283

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost										
Boiler Gas Minimum Charge ($)	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$231,960	$238,919	$246,086	$253,469	$261,073	$268,905	$276,972	$285,281	$293,840	$302,655
Boiler Gas Supply Cost ($)	$528,168	$543,587	$559,456	$575,789	$592,598	$609,898	$627,704	$646,029	$664,889	$684,300
Total Boiler Gas Cost ($)	$766,833	$789,412	$812,655	$836,584	$861,217	$886,576	$912,682	$939,556	$967,222	$995,703
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$766,833	$789,412	$812,655	$836,584	$861,217	$886,576	$912,682	$939,556	$967,222	$995,703
Oil Cost ($)	$10,531	$10,847	$11,173	$11,508	$11,853	$12,209	$12,575	$12,952	$13,341	$13,741
O&M Cost										
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Utility and O&M Cost										
Total Fuel, Electricity & O&M Cost ($)	$3,554,083	$3,660,279	$3,769,649	$3,882,287	$3,998,291	$4,117,762	$4,240,804	$4,367,522	$4,498,027	$4,632,432
GHG Emissions/LL 97 Cost, As Written										
Purchased Elec GHG Emissions (Mton CO2e)	566	283	283	283	283	283	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278
Boiler Oil Emissions (Mton CO2e)	28	28	28	28	28	28	28	28	28	28
Total GHG Emissions (Mton CO2e)	4,872	4,589	4,589	4,589	4,589	4,589	4,306	4,306	4,306	4,306
GHG Emissions Limit [Local Law 97] (Mton CO2e)	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$294,388	$1,185,010	$1,220,560	$1,257,177	$1,294,892	$1,333,739	$1,252,012	$1,289,572	$1,328,259	$1,368,107
GHG Emissions/LL 97 Cost, Delayed to 2034	566	283	283	283	283	283	0	0	0	0
Purchased Elec GHG Emissions (Mton CO2e)	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)				0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278
Boiler Oil Emissions (Mton CO2e)	28	28	28	28	28	28	28	28	28	28
Total GHG Emissions (Mton CO2e)	4,872	4,589	4,589	4,589	4,589	4,589	4,306	4,306	4,306	4,306
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$108,036	$111,277	$114,616	$118,054
Total Cost										
Total Cost with LL97 Penalties ($)	$3,848,471	$4,845,289	$4,990,209	$5,139,464	$5,293,184	$5,451,501	$5,492,815	$5,657,094	$5,826,286	$6,000,539
Total Cost with LL97 Penalties, Delayed ($)	$3,554,083	$3,660,279	$3,769,649	$3,882,287	$3,998,291	$4,117,762	$4,348,840	$4,478,799	$4,612,642	$4,750,486

Con Ed Reconnection, High Tension

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Demand, May-June, 8AM-6PM (MW)	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29
Demand, 8AM-10PM (MW)	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94
Demand, All Hours, All Days (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Total Steam Use (klbs)	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484
Steam to Heating (klbs)	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Hot Water Production (MMBtu)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel																				
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553
Total Gas Consumption (MMBtu)	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
Total Oil Consumption (MMBtu)	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
Electric Cost																				
Minimum Charge ($)	$1,983	$2,043	$2,104	$2,167	$2,232	$2,299	$2,368	$2,439	$2,512	$2,588	$2,665	$2,745	$2,828	$2,913	$3,000	$3,090	$3,183	$3,278	$3,376	$3,478
Electric Delivery (w/Riders) Cost ($)	$82,471	$84,945	$87,494	$90,119	$92,822	$95,607	$98,475	$101,429	$104,472	$107,606	$110,834	$114,159	$117,584	$121,112	$124,745	$128,487	$132,342	$136,312	$140,402	$144,614
Electricity Supply Cost ($)	$1,247,468	$1,284,892	$1,323,438	$1,363,141	$1,404,036	$1,446,157	$1,489,541	$1,534,228	$1,580,255	$1,627,662	$1,676,492	$1,726,787	$1,778,590	$1,831,948	$1,886,907	$1,943,514	$2,001,819	$2,061,874	$2,123,730	$2,187,442
Demand Cost, May-June, 8AM-6PM ($)	$101,771	$104,824	$107,969	$111,208	$114,544	$117,980	$121,520	$125,165	$128,920	$132,788	$136,772	$140,875	$145,101	$149,454	$153,938	$158,556	$163,312	$168,212	$173,258	$178,456
Demand Cost, 8AM-10PM ($)	$411,022	$423,353	$436,053	$449,135	$462,609	$476,487	$490,782	$505,505	$520,671	$536,291	$552,379	$568,951	$586,019	$603,600	$621,708	$640,359	$659,570	$679,357	$699,738	$720,730
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$1,844,715	$1,900,056	$1,957,058	$2,015,770	$2,076,243	$2,138,530	$2,202,686	$2,268,767	$2,336,830	$2,406,935	$2,479,143	$2,553,517	$2,630,123	$2,709,026	$2,790,297	$2,874,006	$2,960,226	$3,049,033	$3,140,504	$3,234,719

Con Ed Reconnection, High Tension

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost																				
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$172,600	$177,778	$183,111	$188,604	$194,263	$200,091	$206,093	$212,276	$218,644	$225,204	$231,960	$238,919	$246,086	$253,469	$261,073	$268,905	$276,972	$285,281	$293,840	$302,655
Boiler Gas Supply Cost ($)	$456,230	$427,124	$426,302	$432,941	$446,729	$460,481	$475,490	$485,979	$499,447	$513,502	$528,168	$543,587	$559,456	$575,789	$592,598	$609,898	$627,704	$646,029	$664,889	$684,300
Total Boiler Gas Cost ($)	$633,819	$610,040	$614,706	$626,997	$646,607	$666,355	$687,541	$704,391	$724,411	$745,215	$766,833	$789,412	$812,655	$836,584	$861,217	$886,576	$912,682	$939,556	$967,222	$995,703
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$633,819	$610,040	$614,706	$626,997	$646,607	$666,355	$687,541	$704,391	$724,411	$745,215	$766,833	$789,412	$812,655	$836,584	$861,217	$886,576	$912,682	$939,556	$967,222	$995,703
Oil Cost ($)	$7,836	$8,071	$8,314	$8,563	$8,820	$9,085	$9,357	$9,638	$9,927	$10,225	$10,531	$10,847	$11,173	$11,508	$11,853	$12,209	$12,575	$12,952	$13,341	$13,741
O&M Cost																				
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Utility and O&M Cost																				
Total Fuel, Electricity & O&M Cost ($)	$2,486,370	$2,518,168	$2,580,077	$2,651,329	$2,731,670	$2,813,970	$2,899,584	$2,982,795	$3,071,168	$3,162,374	$3,256,507	$3,353,776	$3,453,951	$3,557,118	$3,663,367	$3,772,791	$3,885,483	$4,001,541	$4,121,067	$4,244,163
GHG Emissions/LL 97 Cost, As Written																				
Purchased Elec GHG Emissions (Mton CO2e)	2,612	2,612	2,612	2,612	2,612	2,612	566	566	566	566	566	283	283	283	283	283	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278
Boiler Oil Emissions (Mton CO2e)	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Total GHG Emissions (Mton CO2e)	6,918	6,918	6,918	6,918	6,918	6,918	4,872	4,872	4,872	4,872	4,872	4,589	4,589	4,589	4,589	4,589	4,306	4,306	4,306	4,306
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$51,687	$53,237	$54,834	$56,480	$58,174	$59,919	$261,560	$269,407	$277,489	$285,814	$294,388	$1,185,010	$1,220,560	$1,257,177	$1,294,892	$1,333,739	$1,252,012	$1,289,572	$1,328,259	$1,368,107
GHG Emissions/LL 97 Cost, Delayed to 2034																				
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	566	283	283	283	283	283	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278
Boiler Oil Emissions (Mton CO2e)	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Total GHG Emissions (Mton CO2e)	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,872	4,589	4,589	4,589	4,589	4,589	4,306	4,306	4,306	4,306
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$108,036	$111,277	$114,616	$118,054
Total Cost																				
Total Cost with LL97 Penalties ($)	$2,538,057	$2,571,405	$2,634,912	$2,707,809	$2,789,844	$2,873,889	$3,161,144	$3,252,203	$3,348,657	$3,448,188	$3,550,896	$4,538,786	$4,674,511	$4,814,295	$4,958,260	$5,106,530	$5,137,494	$5,291,113	$5,449,326	$5,612,270
Total Cost with LL97 Penalties, Delayed ($)	$2,486,370	$2,518,168	$2,580,077	$2,651,329	$2,731,670	$2,813,970	$2,899,584	$2,982,795	$3,071,168	$3,162,374	$3,256,507	$3,353,776	$3,453,951	$3,557,118	$3,663,367	$3,772,791	$3,993,519	$4,112,819	$4,235,683	$4,362,217

1x1.2 MW Recip with Con Ed Reconnection

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351
Purchased Electricity (MWh)	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Demand, May-June, 8AM-6PM (MW)	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39
Demand, 8AM-10PM (MW)	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787
CHP Steam Production (klbs)	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119
Steam to Hot Water (klbs)	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402
Total Steam Use (klbs)	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131
Steam to Heating (klbs)	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452
Steam to Hot Water (MMBtu)	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402
Hot Water Production (MMBtu)	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854
Dumped Hot Water (MMBtu)	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124
Fuel																				
Gas to Generators (MMBtu)	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345
Gas to Boiler (MMBtu)	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797
Total Gas Consumption (MMBtu)	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310
Total Oil Consumption (MMBtu)	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310
Electric Cost																				
Minimum Charge ($)	$339,062	$349,233	$359,711	$370,502	$381,617	$393,065	$404,857	$417,003	$429,513	$442,399	$455,670	$469,341	$483,421	$497,923	$512,861	$528,247	$544,094	$560,417	$577,230	$594,547
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$234,190	$241,216	$248,452	$255,906	$263,583	$271,491	$279,635	$288,024	$296,665	$305,565	$314,732	$324,174	$333,899	$343,916	$354,234	$364,861	$375,807	$387,081	$398,693	$410,654
Demand Cost, May-June, 8AM-6PM ($)	$51,542	$53,088	$54,681	$56,321	$58,011	$59,751	$61,543	$63,390	$65,291	$67,250	$69,268	$71,346	$73,486	$75,691	$77,961	$80,300	$82,709	$85,191	$87,746	$90,379
Demand Cost, 8AM-10PM ($)	$138,199	$142,344	$146,615	$151,013	$155,544	$160,210	$165,016	$169,967	$175,066	$180,318	$185,727	$191,299	$197,038	$202,949	$209,038	$215,309	$221,768	$228,421	$235,274	$242,332
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$762,992	$785,882	$809,458	$833,742	$858,754	$884,517	$911,052	$938,384	$966,536	$995,532	$1,025,398	$1,056,159	$1,087,844	$1,120,480	$1,154,094	$1,188,717	$1,224,378	$1,261,110	$1,298,943	$1,337,911

1x1.2 MW Recip with Con Ed Reconnection

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost																				
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$115,261	$118,719	$122,280	$125,949	$129,727	$133,619	$137,628	$141,756	$146,009	$150,389	$154,901	$159,548	$164,335	$169,265	$174,343	$179,573	$184,960	$190,509	$196,224	$202,111
Boiler Gas Supply Cost ($)	$313,662	$291,662	$289,585	$294,018	$301,703	$310,836	$320,792	$327,413	$336,379	$345,735	$355,379	$365,753	$376,430	$387,418	$398,728	$410,368	$422,347	$434,677	$447,366	$460,426
Total Boiler Gas Cost ($)	$433,912	$415,519	$417,158	$425,418	$437,045	$450,238	$464,376	$475,305	$488,708	$502,634	$516,984	$532,207	$547,877	$564,009	$580,617	$597,713	$615,313	$633,432	$652,084	$671,285
Cogen Gas Delivery Cost ($)	$213,492	$219,897	$226,494	$233,288	$240,287	$247,496	$254,921	$262,568	$270,445	$278,559	$286,915	$295,523	$304,388	$313,520	$322,926	$332,613	$342,592	$352,870	$363,456	$374,359
Cogen Gas Supply Cost ($)	$364,609	$346,897	$350,562	$356,273	$372,494	$384,398	$397,436	$407,505	$419,111	$431,227	$444,242	$457,211	$470,559	$484,297	$498,436	$512,988	$527,965	$543,379	$559,243	$575,570
Total Gas Cost ($)	$1,012,012	$982,313	$994,213	$1,014,980	$1,049,826	$1,082,132	$1,116,733	$1,145,378	$1,178,265	$1,212,420	$1,248,141	$1,284,940	$1,322,825	$1,361,826	$1,401,978	$1,443,314	$1,485,870	$1,529,680	$1,574,782	$1,621,215
Oil Cost ($)	$6,478	$6,672	$6,872	$7,079	$7,291	$7,510	$7,735	$7,967	$8,206	$8,452	$8,706	$8,967	$9,236	$9,513	$9,798	$10,092	$10,395	$10,707	$11,028	$11,359
O&M Cost																				
Equipment O&M ($)	$139,024	$142,499	$146,062	$149,713	$153,456	$157,292	$161,225	$165,255	$169,387	$173,621	$177,962	$182,411	$186,971	$191,645	$196,437	$201,347	$206,381	$211,541	$216,829	$222,250
Utility and O&M Cost																				
Total Fuel, Electricity & O&M Cost ($)	$1,920,506	$1,917,366	$1,956,605	$2,005,513	$2,069,327	$2,131,451	$2,196,745	$2,256,984	$2,322,393	$2,390,025	$2,460,206	$2,532,478	$2,606,876	$2,683,464	$2,762,307	$2,843,471	$2,927,024	$3,013,037	$3,101,583	$3,192,735
GHG Emissions/LL 97 Cost, As Written																				
Purchased Elec GHG Emissions (Mton CO2e)	487	487	487	487	487	487	106	106	106	106	106	53	53	53	53	53	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524
Boiler Gas Emissions (Mton CO2e)	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	6,891	6,891	6,891	6,891	6,891	6,891	6,509	6,509	6,509	6,509	6,509	6,457	6,457	6,457	6,457	6,457	6,404	6,404	6,404	6,404
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$44,569	$45,907	$47,284	$48,702	$50,163	$51,668	$785,478	$809,042	$833,313	$858,313	$884,062	$1,877,790	$1,934,124	$1,992,147	$2,051,912	$2,113,469	$2,154,155	$2,218,779	$2,285,343	$2,353,903
GHG Emissions/LL 97 Cost, Delayed to 2034																				
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	106	53	53	53	53	53	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524
Boiler Gas Emissions (Mton CO2e)	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	6,404	6,404	6,404	6,404	6,404	6,404	6,404	6,404	6,404	6,404	6,509	6,457	6,457	6,457	6,457	6,457	6,404	6,404	6,404	6,404
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,010,179	$1,040,485	$1,071,699	$1,103,850
Total Cost																				
Total Cost with LL97 Penalties ($)	$1,965,075	$1,963,272	$2,003,889	$2,054,216	$2,119,490	$2,183,119	$2,982,223	$3,066,026	$3,155,706	$3,248,337	$3,344,269	$4,410,268	$4,541,000	$4,675,612	$4,814,219	$4,956,940	$5,081,179	$5,231,817	$5,386,925	$5,546,638
Total Cost with LL97 Penalties, Delayed ($)	$1,920,506	$1,917,366	$1,956,605	$2,005,513	$2,069,327	$2,131,451	$2,196,745	$2,256,984	$2,322,393	$2,390,025	$2,460,206	$2,532,478	$2,606,876	$2,683,464	$2,762,307	$2,843,471	$3,937,203	$4,053,522	$4,173,282	$4,296,585

2x1.2 MW Recip with Con Ed Reconnection

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510	8,510
Purchased Electricity (MWh)	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528	528
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Demand, May-June, 8AM-6PM (MW)	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78	19.78
Demand, 8AM-10PM (MW)	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44	20.44
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836	43,836
CHP Steam Production (klbs)	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916	14,916
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373	2,373
Steam to Hot Water (klbs)	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416
Total Steam Use (klbs)	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378	56,378
Steam to Heating (klbs)	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677	48,677
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991	17,991
Steam to Hot Water (MMBtu)	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416
Hot Water Production (MMBtu)	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407	20,407
Dumped Hot Water (MMBtu)	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704	5,704
Fuel																				
Gas to Generators (MMBtu)	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659	77,659
Gas to Boiler (MMBtu)	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494	51,494
Total Gas Consumption (MMBtu)	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153	129,153
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307
Total Oil Consumption (MMBtu)	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307
Electric Cost																				
Minimum Charge ($)	$339,062	$349,233	$359,711	$370,502	$381,617	$393,065	$404,857	$417,003	$429,513	$442,399	$455,670	$469,341	$483,421	$497,923	$512,861	$528,247	$544,094	$560,417	$577,230	$594,547
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$73,637	$75,847	$78,122	$80,466	$82,880	$85,366	$87,927	$90,565	$93,282	$96,080	$98,963	$101,931	$104,989	$108,139	$111,383	$114,725	$118,166	$121,711	$125,363	$129,124
Demand Cost, May-June, 8AM-6PM ($)	$8,847	$9,113	$9,386	$9,667	$9,958	$10,256	$10,564	$10,881	$11,207	$11,543	$11,890	$12,246	$12,614	$12,992	$13,382	$13,784	$14,197	$14,623	$15,062	$15,513
Demand Cost, 8AM-10PM ($)	$31,782	$32,736	$33,718	$34,729	$35,771	$36,844	$37,950	$39,088	$40,261	$41,469	$42,713	$43,994	$45,314	$46,673	$48,074	$49,516	$51,001	$52,531	$54,107	$55,730
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$453,329	$466,928	$480,936	$495,364	$510,225	$525,532	$541,298	$557,537	$574,263	$591,491	$609,236	$627,513	$646,338	$665,728	$685,700	$706,271	$727,459	$749,283	$771,761	$794,914

2x1.2 MW Recip with Con Ed Reconnection

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost																				
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$110,326	$113,635	$117,044	$120,556	$124,172	$127,898	$131,735	$135,687	$139,757	$143,950	$148,268	$152,716	$157,298	$162,017	$166,877	$171,884	$177,040	$182,351	$187,822	$193,457
Boiler Gas Supply Cost ($)	$301,714	$280,292	$278,042	$282,282	$289,371	$298,101	$307,618	$313,885	$322,464	$331,414	$340,613	$350,556	$360,789	$371,321	$382,161	$393,317	$404,798	$416,615	$428,778	$441,295
Total Boiler Gas Cost ($)	$417,028	$399,066	$400,380	$408,289	$419,158	$431,783	$445,309	$455,708	$468,541	$481,873	$495,586	$510,178	$525,200	$540,664	$556,584	$572,973	$589,844	$607,213	$625,093	$643,499
Cogen Gas Delivery Cost ($)	$248,725	$256,187	$263,873	$271,789	$279,942	$288,341	$296,991	$305,901	$315,078	$324,530	$334,266	$344,294	$354,623	$365,261	$376,219	$387,506	$399,131	$411,105	$423,438	$436,141
Cogen Gas Supply Cost ($)	$424,187	$404,099	$408,865	$415,527	$435,021	$448,978	$464,221	$476,149	$489,745	$503,940	$519,258	$534,418	$550,020	$566,078	$582,605	$599,614	$617,121	$635,138	$653,681	$672,766
Total Gas Cost ($)	$1,089,940	$1,059,352	$1,073,117	$1,095,605	$1,134,122	$1,169,101	$1,206,521	$1,237,757	$1,273,364	$1,310,343	$1,349,110	$1,388,889	$1,429,843	$1,472,004	$1,515,408	$1,560,093	$1,606,096	$1,653,455	$1,702,212	$1,752,407
Oil Cost ($)	$6,413	$6,605	$6,803	$7,008	$7,218	$7,434	$7,657	$7,887	$8,124	$8,367	$8,618	$8,877	$9,143	$9,418	$9,700	$9,991	$10,291	$10,600	$10,918	$11,245
O&M Cost																				
Equipment O&M ($)	$160,926	$164,950	$169,073	$173,300	$177,633	$182,073	$186,625	$191,291	$196,073	$200,975	$205,999	$211,149	$216,428	$221,839	$227,385	$233,069	$238,896	$244,869	$250,990	$257,265
Utility and O&M Cost																				
Total Fuel, Electricity & O&M Cost ($)	$1,710,608	$1,697,835	$1,729,930	$1,771,277	$1,829,197	$1,884,141	$1,942,102	$1,994,472	$2,051,824	$2,111,176	$2,172,963	$2,236,429	$2,301,752	$2,368,988	$2,438,193	$2,509,425	$2,582,742	$2,658,207	$2,735,881	$2,815,831
GHG Emissions/LL 97 Cost, As Written																				
Purchased Elec GHG Emissions (Mton CO2e)																				
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124
Boiler Gas Emissions (Mton CO2e)	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	7,035	7,035	7,035	7,035	7,035	7,035	6,915	6,915	6,915	6,915	6,915	6,899	6,899	6,899	6,899	6,899	6,882	6,882	6,882	6,882
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$83,078	$85,570	$88,137	$90,781	$93,505	$96,310	$915,340	$942,800	$971,084	$1,000,217	$1,030,223	$2,041,793	$2,103,047	$2,166,138	$2,231,122	$2,298,056	$2,359,880	$2,430,676	$2,503,597	$2,578,704
GHG Emissions/LL 97 Cost, Delayed to 2034																				
Purchased Elec GHG Emissions (Mton CO2e)																				
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124
Boiler Gas Emissions (Mton CO2e)	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735	2,735
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	6,882	6,882	6,882	6,882	6,882	6,882	6,882	6,882	6,882	6,882	6,915	6,899	6,899	6,899	6,899	6,899	6,882	6,882	6,882	6,882
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$68,574	$64,491	$66,426	$68,419	$70,471	$72,585	$1,215,904	$1,252,382	$1,289,953	$1,328,652
Total Cost																				
Total Cost with LL97 Penalties ($)	$1,793,686	$1,783,405	$1,818,067	$1,862,058	$1,922,702	$1,980,451	$2,857,442	$2,937,272	$3,022,908	$3,111,393	$3,203,186	$4,278,222	$4,404,799	$4,535,127	$4,669,316	$4,807,481	$4,942,622	$5,088,883	$5,239,478	$5,394,536
Total Cost with LL97 Penalties, Delayed ($)	$1,710,608	$1,697,835	$1,729,930	$1,771,277	$1,829,197	$1,884,141	$1,942,102	$1,994,472	$2,051,824	$2,111,176	$2,241,537	$2,300,920	$2,368,178	$2,437,407	$2,508,664	$2,582,010	$3,798,646	$3,910,588	$4,025,834	$4,144,483

2x850 kW Recips with Con Ed Reconnection

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259	8,259
Purchased Electricity (MWh)	779	779	779	779	779	779	779	779	779	779	779	779	779	779	779	779	779	779	779	779
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Demand, May-June, 8AM-6PM (MW)	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52	38.52
Demand, 8AM-10PM (MW)	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298	42,298
CHP Steam Production (klbs)	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815	17,815
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093	4,093
Steam to Hot Water (klbs)	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193
Total Steam Use (klbs)	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020	56,020
Steam to Heating (klbs)	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542	48,542
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482	18,482
Steam to Hot Water (MMBtu)	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193
Hot Water Production (MMBtu)	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675	20,675
Dumped Hot Water (MMBtu)	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978	5,978
Fuel																				
Gas to Generators (MMBtu)	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844	84,844
Gas to Boiler (MMBtu)	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683	49,683
Total Gas Consumption (MMBtu)	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526	134,526
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301
Total Oil Consumption (MMBtu)	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301	301
Electric Cost																				
Minimum Charge ($)	$339,062	$349,233	$359,711	$370,502	$381,617	$393,065	$404,857	$417,003	$429,513	$442,399	$455,670	$469,341	$483,421	$497,923	$512,861	$528,247	$544,094	$560,417	$577,230	$594,547
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$108,980	$112,249	$115,617	$119,085	$122,658	$126,337	$130,127	$134,031	$138,052	$142,194	$146,460	$150,853	$155,379	$160,040	$164,842	$169,787	$174,880	$180,127	$185,531	$191,097
Demand Cost, May-June, 8AM-6PM ($)	$25,041	$25,792	$26,566	$27,363	$28,184	$29,029	$29,900	$30,797	$31,721	$32,673	$33,653	$34,663	$35,703	$36,774	$37,877	$39,013	$40,184	$41,389	$42,631	$43,910
Demand Cost, 8AM-10PM ($)	$66,725	$68,726	$70,788	$72,912	$75,099	$77,352	$79,673	$82,063	$84,525	$87,060	$89,672	$92,362	$95,133	$97,987	$100,927	$103,955	$107,073	$110,285	$113,594	$117,002
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$539,807	$556,001	$572,681	$589,862	$607,557	$625,784	$644,558	$663,894	$683,811	$704,326	$725,455	$747,219	$769,636	$792,725	$816,506	$841,002	$866,232	$892,219	$918,985	$946,555

2x850 kW Recips with Con Ed Reconnection

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost																				
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$106,445	$109,638	$112,927	$116,315	$119,804	$123,399	$127,100	$130,913	$134,841	$138,886	$143,053	$147,344	$151,765	$156,318	$161,007	$165,837	$170,812	$175,937	$181,215	$186,651
Boiler Gas Supply Cost ($)	$291,764	$270,882	$268,597	$272,697	$279,420	$287,833	$297,003	$303,016	$311,292	$319,925	$328,790	$338,388	$348,266	$358,433	$368,896	$379,665	$390,748	$402,155	$413,895	$425,977
Total Boiler Gas Cost ($)	$403,197	$385,659	$386,816	$394,463	$404,839	$417,015	$430,060	$440,066	$452,453	$465,320	$478,548	$492,638	$507,144	$522,077	$537,449	$553,275	$569,566	$586,338	$603,603	$621,377
Cogen Gas Delivery Cost ($)	$271,098	$279,231	$287,608	$296,237	$305,124	$314,277	$323,706	$333,417	$343,419	$353,722	$364,334	$375,264	$386,522	$398,117	$410,061	$422,363	$435,033	$448,084	$461,527	$475,373
Cogen Gas Supply Cost ($)	$463,378	$441,387	$446,579	$453,887	$475,173	$490,417	$507,093	$520,110	$534,962	$550,468	$567,200	$583,759	$600,802	$618,343	$636,395	$654,975	$674,098	$693,778	$714,034	$734,881
Total Gas Cost ($)	$1,137,674	$1,106,277	$1,121,004	$1,144,586	$1,185,136	$1,221,709	$1,260,859	$1,293,593	$1,330,834	$1,369,510	$1,410,081	$1,451,661	$1,494,468	$1,538,537	$1,583,905	$1,630,612	$1,678,697	$1,728,200	$1,779,164	$1,831,630
Oil Cost ($)	$6,286	$6,474	$6,669	$6,869	$7,075	$7,287	$7,505	$7,731	$7,963	$8,201	$8,447	$8,701	$8,962	$9,231	$9,508	$9,793	$10,087	$10,389	$10,701	$11,022
O&M Cost																				
Equipment O&M ($)	$156,190	$160,095	$164,098	$168,200	$172,405	$176,715	$181,133	$185,661	$190,303	$195,060	$199,937	$204,935	$210,059	$215,310	$220,693	$226,210	$231,866	$237,662	$243,604	$249,694
Utility and O&M Cost																				
Total Fuel, Electricity & O&M Cost ($)	$1,839,957	$1,828,848	$1,864,451	$1,909,517	$1,972,173	$2,031,495	$2,094,055	$2,150,879	$2,212,911	$2,277,097	$2,343,921	$2,412,517	$2,483,124	$2,555,802	$2,630,613	$2,707,617	$2,786,881	$2,868,471	$2,952,454	$3,038,901
GHG Emissions/LL 97 Cost, As Written																				
Purchased Elec GHG Emissions (Mton CO2e)																				
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506
Boiler Gas Emissions (Mton CO2e)	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639
Boiler Oil Emissions (Mton CO2e)	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Total GHG Emissions (Mton CO2e)	7,392	7,392	7,392	7,392	7,392	7,392	7,216	7,216	7,216	7,216	7,216	7,191	7,191	7,191	7,191	7,191	7,167	7,167	7,167	7,167
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$178,837	$184,202	$189,728	$195,420	$201,283	$207,321	$1,011,544	$1,041,890	$1,073,147	$1,105,342	$1,138,502	$2,150,410	$2,214,923	$2,281,370	$2,349,811	$2,420,306	$2,482,424	$2,556,896	$2,633,603	$2,712,611
GHG Emissions/LL 97 Cost, Delayed to 2034																				
Purchased Elec GHG Emissions (Mton CO2e)																				
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506	4,506
Boiler Gas Emissions (Mton CO2e)	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639	2,639
Boiler Oil Emissions (Mton CO2e)	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Total GHG Emissions (Mton CO2e)	7,167	7,167	7,167	7,167	7,167	7,167	7,167	7,167	7,167	7,167	7,216	7,191	7,191	7,191	7,191	7,191	7,167	7,167	7,167	7,167
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$176,853	$173,108	$178,302	$183,651	$189,160	$194,835	$1,338,448	$1,378,602	$1,419,960	$1,462,558
Total Cost																				
Total Cost with LL97 Penalties ($)	$2,018,794	$2,013,050	$2,054,179	$2,104,937	$2,173,455	$2,238,816	$3,105,600	$3,192,770	$3,286,058	$3,382,439	$3,482,423	$4,562,927	$4,698,046	$4,837,173	$4,980,424	$5,127,923	$5,269,305	$5,425,367	$5,586,057	$5,751,512
Total Cost with LL97 Penalties, Delayed ($)	$1,839,957	$1,828,848	$1,864,451	$1,909,517	$1,972,173	$2,031,495	$2,094,055	$2,150,879	$2,212,911	$2,277,097	$2,520,774	$2,585,625	$2,661,425	$2,739,453	$2,819,773	$2,902,452	$4,125,329	$4,247,072	$4,372,413	$4,501,459

1x850 kW Recip with Con Ed Reconnection

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490
Purchased Electricity (MWh)	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548	2,548
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Demand, May-June, 8AM-6PM (MW)	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24	116.24
Demand, 8AM-10PM (MW)	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71	116.71
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080	45,080
CHP Steam Production (klbs)	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339	13,339
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	943	943	943	943	943	943	943	943	943	943	943	943	943	943	943	943	943	943	943	943
Steam to Hot Water (klbs)	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894
Total Steam Use (klbs)	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476	57,476
Steam to Heating (klbs)	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296	48,296
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127	14,127
Steam to Hot Water (MMBtu)	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894
Hot Water Production (MMBtu)	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022	18,022
Dumped Hot Water (MMBtu)	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283	3,283
Fuel																				
Gas to Generators (MMBtu)	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151	65,151
Gas to Boiler (MMBtu)	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968	52,968
Total Gas Consumption (MMBtu)	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119	118,119
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304
Total Oil Consumption (MMBtu)	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304
Electric Cost																				
Minimum Charge ($)	$339,062	$349,233	$359,711	$370,502	$381,617	$393,065	$404,857	$417,003	$429,513	$442,399	$455,670	$469,341	$483,421	$497,923	$512,861	$528,247	$544,094	$560,417	$577,230	$594,547
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$350,046	$360,547	$371,364	$382,505	$393,980	$405,799	$417,973	$430,512	$443,428	$456,730	$470,432	$484,545	$499,082	$514,054	$529,476	$545,360	$561,721	$578,572	$595,930	$613,807
Demand Cost, May-June, 8AM-6PM ($)	$76,730	$79,032	$81,403	$83,845	$86,361	$88,952	$91,620	$94,369	$97,200	$100,116	$103,119	$106,213	$109,399	$112,681	$116,062	$119,543	$123,130	$126,824	$130,628	$134,547
Demand Cost, 8AM-10PM ($)	$197,346	$203,266	$209,364	$215,645	$222,115	$228,778	$235,641	$242,711	$249,992	$257,492	$265,217	$273,173	$281,368	$289,809	$298,504	$307,459	$316,682	$326,183	$335,968	$346,047
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$963,184	$992,079	$1,021,842	$1,052,497	$1,084,072	$1,116,594	$1,150,092	$1,184,595	$1,220,133	$1,256,737	$1,294,439	$1,333,272	$1,373,270	$1,414,468	$1,456,902	$1,500,609	$1,545,627	$1,591,996	$1,639,756	$1,688,949

1x850 kW Recip with Con Ed Reconnection

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost																				
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$113,484	$116,889	$120,395	$124,007	$127,727	$131,559	$135,506	$139,571	$143,758	$148,071	$152,513	$157,088	$161,801	$166,655	$171,655	$176,804	$182,109	$187,572	$193,199	$198,995
Boiler Gas Supply Cost ($)	$308,630	$287,003	$284,984	$289,356	$296,955	$305,945	$315,747	$322,270	$331,099	$340,311	$349,815	$360,027	$370,537	$381,353	$392,486	$403,944	$415,736	$427,872	$440,363	$453,218
Total Boiler Gas Cost ($)	$427,103	$409,030	$410,672	$418,815	$430,297	$443,288	$457,210	$467,977	$481,177	$494,892	$509,033	$524,021	$539,451	$555,335	$571,687	$588,521	$605,850	$623,690	$642,055	$660,961
Cogen Gas Delivery Cost ($)	$209,776	$216,069	$222,551	$229,228	$236,105	$243,188	$250,484	$257,998	$265,738	$273,710	$281,921	$290,379	$299,090	$308,063	$317,305	$326,824	$336,629	$346,728	$357,130	$367,844
Cogen Gas Supply Cost ($)	$360,677	$342,550	$345,712	$351,314	$366,778	$378,459	$391,252	$401,035	$412,421	$424,307	$437,014	$449,772	$462,902	$476,417	$490,325	$504,640	$519,373	$534,536	$550,141	$566,203
Total Gas Cost ($)	$997,556	$967,650	$978,936	$999,357	$1,033,180	$1,064,935	$1,098,945	$1,127,010	$1,159,336	$1,192,909	$1,227,968	$1,264,172	$1,301,444	$1,339,815	$1,379,317	$1,419,985	$1,461,852	$1,504,953	$1,549,326	$1,595,008
Oil Cost ($)	$6,357	$6,547	$6,744	$6,946	$7,154	$7,369	$7,590	$7,818	$8,052	$8,294	$8,543	$8,799	$9,063	$9,335	$9,615	$9,903	$10,201	$10,507	$10,822	$11,146
O&M Cost																				
Equipment O&M ($)	$122,741	$125,809	$128,955	$132,178	$135,483	$138,870	$142,342	$145,900	$149,548	$153,286	$157,119	$161,047	$165,073	$169,200	$173,429	$177,765	$182,209	$186,765	$191,434	$196,220
Utility and O&M Cost																				
Total Fuel, Electricity & O&M Cost ($)	$2,089,837	$2,092,086	$2,136,476	$2,190,978	$2,259,890	$2,327,768	$2,398,969	$2,465,323	$2,537,069	$2,611,226	$2,688,068	$2,767,289	$2,848,849	$2,932,817	$3,019,264	$3,108,263	$3,199,889	$3,294,221	$3,391,338	$3,491,323
GHG Emissions/LL 97 Cost, As Written																				
Purchased Elec GHG Emissions (Mton CO2e)																				
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460
Boiler Gas Emissions (Mton CO2e)	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	7,032	7,032	7,032	7,032	7,032	7,032	6,455	6,455	6,455	6,455	6,455	6,376	6,376	6,376	6,376	6,376	6,296	6,296	6,296	6,296
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$82,346	$84,816	$87,361	$89,981	$92,681	$95,461	$768,227	$791,274	$815,012	$839,462	$864,646	$1,847,787	$1,903,221	$1,960,318	$2,019,127	$2,079,701	$2,107,776	$2,171,009	$2,236,140	$2,303,224
GHG Emissions/LL 97 Cost, Delayed to 2034																				
Purchased Elec GHG Emissions (Mton CO2e)																				
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460	3,460
Boiler Gas Emissions (Mton CO2e)	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813	2,813
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	6,296	6,296	6,296	6,296	6,296	6,296	6,296	6,296	6,296	6,296	6,455	6,376	6,376	6,376	6,376	6,376	6,296	6,296	6,296	6,296
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$963,801	$992,715	$1,022,496	$1,053,171
Total Cost																				
Total Cost with LL97 Penalties ($)	$2,172,183	$2,176,902	$2,223,837	$2,280,960	$2,352,571	$2,423,229	$3,167,196	$3,256,597	$3,352,081	$3,450,688	$3,552,714	$4,615,077	$4,752,071	$4,893,135	$5,038,391	$5,187,964	$5,307,665	$5,465,230	$5,627,477	$5,794,546
Total Cost with LL97 Penalties, Delayed ($)	$2,089,837	$2,092,086	$2,136,476	$2,190,978	$2,259,890	$2,327,768	$2,398,969	$2,465,323	$2,537,069	$2,611,226	$2,688,068	$2,767,289	$2,848,849	$2,932,817	$3,019,264	$3,108,263	$4,163,690	$4,286,935	$4,413,834	$4,544,493

1.2 MW Recip with Con Ed Reconnection, High Tension

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351	7,351
Purchased Electricity (MWh)	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687	1,687
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Demand, May-June, 8AM-6PM (MW)	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39	82.39
Demand, 8AM-10PM (MW)	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87	82.87
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787	45,787
CHP Steam Production (klbs)	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463	12,463
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119	1,119
Steam to Hot Water (klbs)	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402
Total Steam Use (klbs)	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131	57,131
Steam to Heating (klbs)	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443	48,443
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452	15,452
Steam to Hot Water (MMBtu)	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402
Hot Water Production (MMBtu)	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854	18,854
Dumped Hot Water (MMBtu)	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124	4,124
Fuel																				
Gas to Generators (MMBtu)	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345	66,345
Gas to Boiler (MMBtu)	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797	53,797
Total Gas Consumption (MMBtu)	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141	120,141
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310
Total Oil Consumption (MMBtu)	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310
Electric Cost																				
Minimum Charge ($)	$307,875	$317,111	$326,625	$336,424	$346,516	$356,912	$367,619	$378,648	$390,007	$401,707	$413,758	$426,171	$438,956	$452,125	$465,689	$479,659	$494,049	$508,871	$524,137	$539,861
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$234,190	$241,216	$248,452	$255,906	$263,583	$271,491	$279,635	$288,024	$296,665	$305,565	$314,732	$324,174	$333,899	$343,916	$354,234	$364,861	$375,807	$387,081	$398,693	$410,654
Demand Cost, May-June, 8AM-6PM ($)	$51,542	$53,088	$54,681	$56,321	$58,011	$59,751	$61,543	$63,390	$65,291	$67,250	$69,268	$71,346	$73,486	$75,691	$77,961	$80,300	$82,709	$85,191	$87,746	$90,379
Demand Cost, 8AM-10PM ($)	$54,740	$56,382	$58,073	$59,815	$61,610	$63,458	$65,362	$67,323	$69,343	$71,423	$73,565	$75,772	$78,046	$80,387	$82,799	$85,283	$87,841	$90,476	$93,191	$95,986
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$648,347	$667,797	$687,831	$708,466	$729,720	$751,611	$774,160	$797,385	$821,306	$845,945	$871,324	$897,463	$924,387	$952,119	$980,683	$1,010,103	$1,040,406	$1,071,618	$1,103,767	$1,136,880

1.2 MW Recip with Con Ed Reconnection, High Tension

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost																				
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$115,261	$118,719	$122,280	$125,949	$129,727	$133,619	$137,628	$141,756	$146,009	$150,389	$154,901	$159,548	$164,335	$169,265	$174,343	$179,573	$184,960	$190,509	$196,224	$202,111
Boiler Gas Supply Cost ($)	$313,662	$291,662	$289,585	$294,018	$301,703	$310,836	$320,792	$327,413	$336,379	$345,735	$355,379	$365,753	$376,430	$387,418	$398,728	$410,368	$422,347	$434,677	$447,366	$460,426
Total Boiler Gas Cost ($)	$433,912	$415,519	$417,158	$425,418	$437,045	$450,238	$464,376	$475,305	$488,708	$502,634	$516,984	$532,207	$547,877	$564,009	$580,617	$597,713	$615,313	$633,432	$652,084	$671,285
Cogen Gas Delivery Cost ($)	$213,492	$219,897	$226,494	$233,288	$240,287	$247,496	$254,921	$262,568	$270,445	$278,559	$286,915	$295,523	$304,388	$313,520	$322,926	$332,613	$342,592	$352,870	$363,456	$374,359
Cogen Gas Supply Cost ($)	$364,609	$346,897	$350,562	$356,273	$372,494	$384,398	$397,436	$407,505	$419,111	$431,227	$444,242	$457,211	$470,559	$484,297	$498,436	$512,988	$527,965	$543,379	$559,243	$575,570
Total Gas Cost ($)	$1,012,012	$982,313	$994,213	$1,014,980	$1,049,826	$1,082,132	$1,116,733	$1,145,378	$1,178,265	$1,212,420	$1,248,141	$1,284,940	$1,322,825	$1,361,826	$1,401,978	$1,443,314	$1,485,870	$1,529,680	$1,574,782	$1,621,215
Oil Cost ($)	$6,478	$6,672	$6,872	$7,079	$7,291	$7,510	$7,735	$7,967	$8,206	$8,452	$8,706	$8,967	$9,236	$9,513	$9,798	$10,092	$10,395	$10,707	$11,028	$11,359
O&M Cost																				
Equipment O&M ($)	$139,024	$142,499	$146,062	$149,713	$153,456	$157,292	$161,225	$165,255	$169,387	$173,621	$177,962	$182,411	$186,971	$191,645	$196,437	$201,347	$206,381	$211,541	$216,829	$222,250
Utility and O&M Cost																				
Total Fuel, Electricity & O&M Cost ($)	$1,805,860	$1,799,281	$1,834,978	$1,880,237	$1,940,292	$1,998,545	$2,059,852	$2,115,985	$2,177,164	$2,240,438	$2,306,133	$2,373,782	$2,443,419	$2,515,104	$2,588,896	$2,664,857	$2,743,052	$2,823,546	$2,906,406	$2,991,704
GHG Emissions/LL 97 Cost, As Written																				
Purchased Elec GHG Emissions (Mton CO2e)	487	487	487	487	487	487	106	106	106	106	106	53	53	53	53	53	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524
Boiler Gas Emissions (Mton CO2e)	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	6,891	6,891	6,891	6,891	6,891	6,891	6,509	6,509	6,509	6,509	6,509	6,457	6,457	6,457	6,457	6,457	6,404	6,404	6,404	6,404
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$44,569	$45,907	$47,284	$48,702	$50,163	$51,668	$785,478	$809,042	$833,313	$858,313	$884,062	$1,877,790	$1,934,124	$1,992,147	$2,051,912	$2,113,469	$2,154,155	$2,218,779	$2,285,343	$2,353,903
GHG Emissions/LL 97 Cost, Delayed to 2034																				
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	106	53	53	53	53	53	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton CO2e/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524	3,524
Boiler Gas Emissions (Mton CO2e)	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857
Boiler Oil Emissions (Mton CO2e)	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total GHG Emissions (Mton CO2e)	6,404	6,404	6,404	6,404	6,404	6,404	6,404	6,404	6,404	6,404	6,509	6,457	6,457	6,457	6,457	6,457	6,404	6,404	6,404	6,404
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,010,179	$1,040,485	$1,071,699	$1,103,850
Total Cost																				
Total Cost with LL97 Penalties ($)	$1,850,430	$1,845,188	$1,882,262	$1,928,939	$1,990,456	$2,050,213	$2,845,330	$2,925,027	$3,010,477	$3,098,751	$3,190,195	$4,251,572	$4,377,543	$4,507,251	$4,640,808	$4,778,326	$4,897,207	$5,042,325	$5,191,749	$5,345,607
Total Cost with LL97 Penalties, Delayed ($)	$1,805,860	$1,799,281	$1,834,978	$1,880,237	$1,940,292	$1,998,545	$2,059,852	$2,115,985	$2,177,164	$2,240,438	$2,306,133	$2,373,782	$2,443,419	$2,515,104	$2,588,896	$2,664,857	$3,753,231	$3,864,030	$3,978,106	$4,095,554

Existing Engines, Primary Dispatch Oil

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Electric																			
System Demand (MW)	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																			
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Purchased Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039	9,039
Demand, May-June, 8AM-6PM (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand, 8AM-10PM (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand, All Hours, All Days (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam																			
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131	40,131
CHP Steam Production (klbs)	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661	18,661
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460	4,460
Steam to Hot Water (klbs)	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474
Total Steam Use (klbs)	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332	54,332
Steam to Heating (klbs)	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573	48,573
Cooling																			
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																			
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416	25,416
Steam to Hot Water (MMBtu)	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474	474
Hot Water Production (MMBtu)	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890	25,890
Dumped Hot Water (MMBtu)	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249
Fuel																			
Gas to Generators (MMBtu)	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817	59,817
Gas to Boiler (MMBtu)	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133	47,133
Total Gas Consumption (MMBtu)	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950	106,950
Oil to Generators (MMBtu)	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131	74,131
Oil to Boilers (MMBtu)	289	289	289	289	289	289	289	289	289	289	289	289	289	289	289	289	289	289	289
Total Oil Consumption (MMBtu)	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420	74,420

Existing Engines, Primary Dispatch Oil

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Electric Cost										
Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, 8AM-10PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Cost	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509
Boiler Gas Minimum Charge ($)	$100,985	$104,015	$107,135	$110,349	$113,660	$117,069	$120,581	$124,199	$127,925	$131,763
Boiler Gas Delivery Cost ($)	$277,340	$257,375	$255,100	$258,992	$265,274	$273,249	$281,946	$287,622	$295,471	$303,658
Boiler Gas Supply Cost ($)	$383,314	$366,528	$367,527	$374,792	$384,548	$396,102	$408,484	$417,956	$429,715	$441,930
Total Boiler Gas Cost ($)	$424,046	$436,768	$449,871	$463,367	$477,268	$491,586	$506,333	$521,523	$537,169	$553,284
Cogen Gas Delivery Cost ($)	$732,580	$697,661	$705,741	$717,228	$750,703	$774,775	$801,049	$821,595	$845,044	$869,525
Cogen Gas Supply Cost ($)	$1,539,941	$1,500,956	$1,523,139	$1,555,387	$1,612,519	$1,662,463	$1,715,867	$1,761,074	$1,811,929	$1,864,739
Total Gas Cost ($)	$1,547,160	$1,593,575	$1,641,382	$1,690,623	$1,741,342	$1,793,582	$1,847,390	$1,902,812	$1,959,896	$2,018,693
Oil Cost ($)	$123,444	$126,530	$129,694	$132,936	$136,259	$139,666	$143,158	$146,737	$150,405	$154,165
O&M Cost										
Equipment O&M ($)	$3,210,545	$3,221,061	$3,294,214	$3,378,947	$3,490,121	$3,595,711	$3,706,414	$3,810,622	$3,922,229	$4,037,597

	2034	2035	2036	2037	2038	2039	2040	2041	2042
Electric Cost									
Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, 8AM-10PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Cost	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493
Boiler Gas Minimum Charge ($)	$135,715	$139,787	$143,980	$148,300	$152,749	$157,331	$162,051	$166,913	$171,920
Boiler Gas Delivery Cost ($)	$312,066	$321,175	$330,551	$340,200	$350,131	$360,352	$370,872	$381,698	$392,841
Boiler Gas Supply Cost ($)	$454,486	$467,868	$481,644	$495,827	$510,426	$525,456	$540,929	$556,857	$573,254
Total Boiler Gas Cost ($)	$569,883	$586,979	$604,589	$622,726	$641,408	$660,650	$680,470	$700,884	$721,910
Cogen Gas Delivery Cost ($)	$895,927	$922,083	$949,004	$976,710	$1,005,225	$1,034,573	$1,064,778	$1,095,865	$1,127,860
Cogen Gas Supply Cost ($)	$1,920,295	$1,976,931	$2,035,237	$2,095,263	$2,157,060	$2,220,680	$2,286,177	$2,353,606	$2,423,025
Total Gas Cost ($)	$2,079,254	$2,141,631	$2,205,880	$2,272,057	$2,340,218	$2,410,425	$2,482,738	$2,557,220	$2,633,936
Oil Cost ($)	$158,019	$161,970	$166,019	$170,169	$174,424	$178,784	$183,254	$187,835	$192,531
O&M Cost									
Equipment O&M ($)	$4,157,568	$4,280,532	$4,407,136	$4,537,489	$4,671,702	$4,809,889	$4,952,168	$5,098,661	$5,249,492

Existing Engines, Primary Dispatch Gas

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
System Demand (MW)	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Purchased Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Demand, May-June, 8AM-6PM (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand, 8AM-10PM (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand, All Hours, All Days (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254	40,254
CHP Steam Production (klbs)	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402	18,402
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428	4,428
Steam to Hot Water (klbs)	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368
Total Steam Use (klbs)	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228	54,228
Steam to Heating (klbs)	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575	48,575
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215	26,215
Steam to Hot Water (MMBtu)	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368
Hot Water Production (MMBtu)	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582	26,582
Dumped Hot Water (MMBtu)	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957	11,957
Gas to Generators (MMBtu)	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282	123,282
Gas to Boiler (MMBtu)	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279	47,279
Total Gas Consumption (MMBtu)	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561	170,561
Oil to Generators (MMBtu)	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112
Oil to Boilers (MMBtu)	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290	290
Total Oil Consumption (MMBtu)	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402	6,402

Existing Engines, Primary Dispatch Gas

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, 8AM-10PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$101,297	$104,336	$107,466	$110,690	$114,010	$117,431	$120,954	$124,582	$128,320	$132,169	$136,134	$140,218	$144,425	$148,758	$153,220	$157,817	$162,552	$167,428	$172,451	$177,625
Boiler Gas Supply Cost ($)	$278,161	$258,145	$255,870	$259,773	$266,081	$274,082	$282,805	$288,500	$296,374	$304,587	$313,021	$322,158	$331,562	$341,241	$351,203	$361,455	$372,007	$382,866	$394,043	$405,546
Total Boiler Gas Cost ($)	$384,447	$367,619	$368,628	$375,914	$385,706	$397,296	$409,716	$419,218	$431,013	$443,266	$455,860	$469,282	$483,100	$497,325	$511,969	$527,045	$542,564	$558,540	$574,987	$591,919
Cogen Gas Delivery Cost ($)	$409,836	$422,131	$434,795	$447,839	$461,274	$475,112	$489,366	$504,047	$519,168	$534,743	$550,785	$567,309	$584,328	$601,858	$619,914	$638,511	$657,667	$677,397	$697,718	$718,650
Cogen Gas Supply Cost ($)	$707,505	$673,819	$681,655	$692,756	$725,125	$748,378	$773,760	$793,613	$816,268	$839,917	$865,427	$890,693	$916,697	$943,460	$971,005	$999,354	$1,028,531	$1,058,560	$1,089,465	$1,121,273
Total Gas Cost ($)	$1,501,787	$1,463,569	$1,485,078	$1,516,509	$1,572,105	$1,620,786	$1,672,842	$1,716,878	$1,766,449	$1,817,926	$1,872,072	$1,927,285	$1,984,126	$2,042,644	$2,102,888	$2,164,910	$2,228,761	$2,294,496	$2,362,171	$2,431,842
Oil Cost ($)	$133,756	$137,769	$141,902	$146,159	$150,544	$155,060	$159,712	$164,503	$169,438	$174,521	$179,757	$185,150	$190,704	$196,425	$202,318	$208,387	$214,639	$221,078	$227,711	$234,542
Equipment O&M ($)	$123,449	$126,535	$129,698	$132,941	$136,264	$139,671	$143,163	$146,742	$150,410	$154,170	$158,025	$161,975	$166,025	$170,175	$174,430	$178,790	$183,260	$187,842	$192,538	$197,351
Total Fuel, Electricity & O&M Cost ($)	$1,758,992	$1,727,873	$1,756,678	$1,795,609	$1,858,913	$1,915,517	$1,975,716	$2,028,123	$2,086,297	$2,146,618	$2,209,854	$2,274,410	$2,340,855	$2,409,244	$2,479,636	$2,552,088	$2,626,661	$2,703,416	$2,782,419	$2,863,735

Con Ed Reconnection, High Tension, Air Source Heat Pumps

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
Total Electricity Load (MWh)	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Electricity to Residential Heating (MWh)	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152	7,152
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190	16,190
Demand, May-June, 8AM-6PM (MW)	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29
Demand, 8AM-10PM (MW)	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08	31.08
Demand, All Hours, All Days (MW)	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam																				
Steam Heating Load (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Steam Production (klbs)	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Total Steam Use (klbs)	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357	20,357
Steam to Heating (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Hot Water Production (MMBtu)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel																				
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012
Total Gas Consumption (MMBtu)	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012	24,012
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Total Oil Consumption (MMBtu)	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Electric Cost																				
Minimum Charge ($)	$1,983	$2,043	$2,104	$2,167	$2,232	$2,299	$2,368	$2,439	$2,512	$2,588	$2,665	$2,745	$2,828	$2,913	$3,000	$3,090	$3,183	$3,278	$3,376	$3,478
Electric Delivery (w/Riders) Cost ($)	$147,731	$152,163	$156,728	$161,430	$166,273	$171,261	$176,399	$181,691	$187,142	$192,756	$198,539	$204,495	$210,630	$216,948	$223,457	$230,161	$237,065	$244,177	$251,503	$259,048
Electricity Supply Cost ($)	$2,311,836	$2,381,192	$2,452,627	$2,526,206	$2,601,992	$2,680,052	$2,760,454	$2,843,267	$2,928,565	$3,016,422	$3,106,915	$3,200,122	$3,296,126	$3,395,010	$3,496,860	$3,601,766	$3,709,819	$3,821,113	$3,935,747	$4,053,819
Demand Cost, May-June, 8AM-6PM ($)	$101,771	$104,824	$107,969	$111,208	$114,544	$117,980	$121,520	$125,165	$128,920	$132,788	$136,772	$140,875	$145,101	$149,454	$153,938	$158,556	$163,312	$168,212	$173,258	$178,456
Demand Cost, 8AM-10PM ($)	$738,805	$760,969	$783,798	$807,312	$831,531	$856,477	$882,171	$908,636	$935,896	$963,972	$992,892	$1,022,678	$1,053,359	$1,084,959	$1,117,508	$1,151,033	$1,185,564	$1,221,131	$1,257,765	$1,295,498
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$3,302,127	$3,401,190	$3,503,226	$3,608,323	$3,716,573	$3,828,070	$3,942,912	$4,061,199	$4,183,035	$4,308,526	$4,437,782	$4,570,916	$4,708,043	$4,849,284	$4,994,763	$5,144,606	$5,298,944	$5,457,912	$5,621,650	$5,790,299

Con Ed Reconnection, High Tension, Air Source Heat Pumps

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Fuel Cost										
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509
Boiler Gas Delivery Cost ($)	$51,432	$52,975	$54,564	$56,201	$57,887	$59,624	$61,412	$63,255	$65,152	$67,107
Boiler Gas Supply Cost ($)	$125,634	$119,750	$121,251	$123,275	$129,151	$133,295	$137,842	$141,401	$145,448	$149,673
Total Boiler Gas Cost ($)	$182,054	$177,863	$181,108	$184,927	$192,653	$198,702	$205,212	$210,791	$216,920	$223,289
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$182,054	$177,863	$181,108	$184,927	$192,653	$198,702	$205,212	$210,791	$216,920	$223,289
Oil Cost ($)	$918	$945	$973	$1,003	$1,033	$1,064	$1,096	$1,128	$1,162	$1,197
O&M Cost										
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Utility and O&M Cost										
Total Fuel, Electricity & O&M Cost ($)	$3,485,098	$3,579,999	$3,685,308	$3,794,253	$3,910,259	$4,027,835	$4,149,219	$4,273,119	$4,401,118	$4,533,013
GHG Emissions/LL 97 Cost, As Written										
Purchased Elec GHG Emissions (Mton CO2e)	4,678	4,678	4,678	4,678	4,678	4,678	1,014	1,014	1,014	1,014
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275
Boiler Oil Emissions (Mton CO2e)	3	3	3	3	3	3	3	3	3	3
Total GHG Emissions (Mton CO2e)	5,957	5,957	5,957	5,957	5,957	5,957	2,293	2,293	2,293	2,293
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GHG Emissions/LL 97 Cost, Delayed to 2034										
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	-	-	-	-	-	-	-	-	-	-
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275
Boiler Oil Emissions (Mton CO2e)	3	3	3	3	3	3	3	3	3	3
Total GHG Emissions (Mton CO2e)	1,279	1,279	1,279	1,279	1,279	1,279	1,279	1,279	1,279	1,279
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost										
Total Cost with LL97 Penalties ($)	$3,485,098	$3,579,999	$3,685,308	$3,794,253	$3,910,259	$4,027,835	$4,149,219	$4,273,119	$4,401,118	$4,533,013
Total Cost with LL97 Penalties, Delayed ($)	$3,485,098	$3,579,999	$3,685,308	$3,794,253	$3,910,259	$4,027,835	$4,149,219	$4,273,119	$4,401,118	$4,533,013

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost										
Boiler Gas Minimum Charge ($)	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$69,120	$71,194	$73,329	$75,529	$77,795	$80,129	$82,533	$85,009	$87,559	$90,186
Boiler Gas Supply Cost ($)	$154,242	$158,746	$163,381	$168,151	$173,061	$178,114	$183,314	$188,667	$194,175	$199,845
Total Boiler Gas Cost ($)	$230,067	$236,845	$243,823	$251,007	$258,402	$266,015	$273,853	$281,921	$290,228	$298,779
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$230,067	$236,845	$243,823	$251,007	$258,402	$266,015	$273,853	$281,921	$290,228	$298,779
Oil Cost ($)	$1,233	$1,270	$1,308	$1,347	$1,388	$1,429	$1,472	$1,517	$1,562	$1,609
O&M Cost										
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Utility and O&M Cost										
Total Fuel, Electricity & O&M Cost ($)	$4,669,082	$4,809,031	$4,953,174	$5,101,638	$5,254,553	$5,412,050	$5,574,269	$5,741,350	$5,913,439	$6,090,687
GHG Emissions/LL 97 Cost, As Written										
Purchased Elec GHG Emissions (Mton CO2e)	1,014	507	507	507	507	507	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275
Boiler Oil Emissions (Mton CO2e)	3	3	3	3	3	3	3	3	3	3
Total GHG Emissions (Mton CO2e)	2,293	1,786	1,786	1,786	1,786	1,786	1,279	1,279	1,279	1,279
GHG Emissions Limit [Local Law 97] (Mton CO2e)	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$0	$144,989	$149,339	$153,819	$158,433	$163,186	$0	$0	$0	$0
GHG Emissions/LL 97 Cost, Delayed to 2034										
Purchased Elec GHG Emissions (Mton CO2e)	1,014	507	507	507	507	507	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275
Boiler Oil Emissions (Mton CO2e)	3	3	3	3	3	3	3	3	3	3
Total GHG Emissions (Mton CO2e)	2,293	1,786	1,786	1,786	1,786	1,786	1,279	1,279	1,279	1,279
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost										
Total Cost with LL97 Penalties ($)	$4,669,082	$4,954,020	$5,102,513	$5,255,457	$5,412,986	$5,575,237	$5,574,269	$5,741,350	$5,913,439	$6,090,687
Total Cost with LL97 Penalties, Delayed ($)	$4,669,082	$4,809,031	$4,953,174	$5,101,638	$5,254,553	$5,412,050	$5,574,269	$5,741,350	$5,913,439	$6,090,687

Con Ed Reconnection, High Tension, Electric Boilers

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Total Electricity Load (MWh)	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Electricity to Steam/HW (MWh)	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765	20,765
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803	29,803
Demand, May-June, 8AM-6PM (MW)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Demand, 8AM-10PM (MW)	61.56	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Demand, All Hours, All Days (MW)	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Total Steam Use (klbs)	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724	68,724
Steam to Heating (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Hot Water Production (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel																				
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Gas Consumption (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Oil Consumption (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Cost																				
Minimum Charge ($)	$1,983	$2,043	$2,104	$2,167	$2,232	$2,299	$2,368	$2,439	$2,512	$2,588	$2,665	$2,745	$2,828	$2,913	$3,000	$3,090	$3,183	$3,278	$3,376	$3,478
Electric Delivery (w/Riders) Cost ($)	$271,946	$280,104	$288,508	$297,163	$306,078	$315,260	$324,718	$334,459	$344,493	$354,828	$365,473	$376,437	$387,730	$399,362	$411,343	$423,683	$436,394	$449,485	$462,970	$476,859
Electricity Supply Cost ($)	$4,263,848	$4,391,764	$4,523,516	$4,659,222	$4,798,999	$4,942,969	$5,091,258	$5,243,995	$5,401,315	$5,563,355	$5,730,255	$5,902,163	$6,079,228	$6,261,605	$6,449,453	$6,642,936	$6,842,224	$7,047,491	$7,258,916	$7,476,683
Demand Cost, May-June, 8AM-6PM ($)	$178,277	$183,625	$189,134	$194,808	$200,652	$206,672	$212,872	$219,258	$225,836	$232,611	$239,590	$246,777	$254,181	$261,806	$269,660	$277,750	$286,082	$294,665	$303,505	$312,610
Demand Cost, 8AM-10PM ($)	$1,448,528	$1,491,984	$1,536,744	$1,582,846	$1,630,331	$1,679,241	$1,729,619	$1,781,507	$1,834,952	$1,890,001	$1,946,701	$2,005,102	$2,065,255	$2,127,213	$2,191,029	$2,256,760	$2,324,463	$2,394,197	$2,466,023	$2,540,003
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$6,164,583	$6,349,521	$6,540,006	$6,736,206	$6,938,293	$7,146,441	$7,360,835	$7,581,660	$7,809,109	$8,043,383	$8,284,684	$8,533,225	$8,789,221	$9,052,898	$9,324,485	$9,604,219	$9,892,346	$10,189,116	$10,494,790	$10,809,634

Con Ed Reconnection, High Tension, Electric Boilers

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost																				
Boiler Gas Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Boiler Gas Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oil Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M Cost																				
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Utility and O&M Cost																				
Total Fuel, Electricity & O&M Cost ($)	$6,164,583	$6,349,521	$6,540,006	$6,736,206	$6,938,293	$7,146,441	$7,360,835	$7,581,660	$7,809,109	$8,043,383	$8,284,684	$8,533,225	$8,789,221	$9,052,898	$9,324,485	$9,604,219	$9,892,346	$10,189,116	$10,494,790	$10,809,634
GHG Emissions/LL 97 Cost, As Written																				
Purchased Elec GHG Emissions (Mton CO2e)	8,612	8,612	8,612	8,612	8,612	8,612	1,867	1,867	1,867	1,867	1,867	933	933	933	933	933	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Oil Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total GHG Emissions (Mton CO2e)	8,612	8,612	8,612	8,612	8,612	8,612	1,867	1,867	1,867	1,867	1,867	933	933	933	933	933	0	0	0	0
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$505,718	$520,890	$536,516	$552,612	$569,190	$586,266	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GHG Emissions/LL 97 Cost, Delayed to 2034																				
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	1,867	933	933	933	933	933	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Oil Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	1,867	933	933	933	933	933	0	0	0	0
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost																				
Total Cost with LL97 Penalties ($)	$6,670,301	$6,870,410	$7,076,523	$7,288,818	$7,507,483	$7,732,707	$7,360,835	$7,581,660	$7,809,109	$8,043,383	$8,284,684	$8,533,225	$8,789,221	$9,052,898	$9,324,485	$9,604,219	$9,892,346	$10,189,116	$10,494,790	$10,809,634
Total Cost with LL97 Penalties, Delayed ($)	$6,164,583	$6,349,521	$6,540,006	$6,736,206	$6,938,293	$7,146,441	$7,360,835	$7,581,660	$7,809,109	$8,043,383	$8,284,684	$8,533,225	$8,789,221	$9,052,898	$9,324,485	$9,604,219	$9,892,346	$10,189,116	$10,494,790	$10,809,634

Con Ed Reconnection, High Tension, Solar PV

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Total Electricity Load (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Electricity to Residential Cooling (MWh)	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002	2,002
Incremental Auxiliary Loads (MWh)																				
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913	8,913
Solar PV (MWh)	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Total Electricity Supply (MWh)	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038
Demand, May-June, 8AM-6PM (MW)	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Demand, 8AM-10PM (MW)	15.74	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Demand, All Hours, All Days (MW)	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam																				
Steam Heating Load (klbs)	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804	48,804
Boiler Steam Production (klbs)	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Total Steam Use (klbs)	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484	68,484
Steam to Heating (klbs)	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127	48,127
Cooling																				
Residential Cooling Load (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549	1,898,549
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Hot Water Production (MMBtu)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel																				
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553
Total Gas Consumption (MMBtu)	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553	80,553
Oil to Generators (MMBtu)														0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
Total Oil Consumption (MMBtu)	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
Electric Cost																				
Minimum Charge ($)	$1,983	$2,043	$2,104	$2,167	$2,232	$2,299	$2,368	$2,439	$2,512	$2,588	$2,665	$2,745	$2,828	$2,913	$3,000	$3,090	$3,183	$3,278	$3,376	$3,478
Electric Delivery (w/Riders) Cost ($)	$81,334	$83,774	$86,287	$88,875	$91,542	$94,288	$97,116	$100,030	$103,031	$106,122	$109,305	$112,585	$115,962	$119,441	$123,024	$126,715	$130,516	$134,432	$138,465	$142,619
Electricity Supply Cost ($)	$1,230,584	$1,267,501	$1,305,526	$1,344,692	$1,385,033	$1,426,584	$1,469,381	$1,513,463	$1,558,867	$1,605,633	$1,653,802	$1,703,416	$1,754,518	$1,807,154	$1,861,368	$1,917,209	$1,974,726	$2,033,967	$2,094,986	$2,157,836
Demand Cost, May-June, 8AM-6PM ($)	$99,687	$102,677	$105,757	$108,930	$112,198	$115,564	$119,031	$122,602	$126,280	$130,068	$133,970	$137,989	$142,129	$146,393	$150,785	$155,308	$159,968	$164,767	$169,710	$174,801
Demand Cost, 8AM-10PM ($)	$405,365	$417,525	$430,051	$442,953	$456,241	$469,929	$484,026	$498,547	$513,504	$528,909	$544,776	$561,119	$577,953	$595,291	$613,150	$631,545	$650,491	$670,006	$690,106	$710,809
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$1,818,952	$1,873,520	$1,929,726	$1,987,618	$2,047,246	$2,108,663	$2,171,923	$2,237,081	$2,304,193	$2,373,319	$2,444,519	$2,517,854	$2,593,390	$2,671,192	$2,751,327	$2,833,867	$2,918,883	$3,006,450	$3,096,643	$3,189,543

Con Ed Reconnection, High Tension, Solar PV

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost																				
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$172,600	$177,778	$183,111	$188,604	$194,263	$200,091	$206,093	$212,276	$218,644	$225,204	$231,960	$238,919	$246,086	$253,469	$261,073	$268,905	$276,972	$285,281	$293,840	$302,655
Boiler Gas Supply Cost ($)	$456,230	$427,124	$426,302	$432,941	$446,729	$460,481	$475,490	$485,979	$499,447	$513,502	$528,168	$543,587	$559,456	$575,789	$592,598	$609,898	$627,704	$646,029	$664,889	$684,300
Total Boiler Gas Cost ($)	$633,819	$610,040	$614,706	$626,997	$646,607	$666,355	$687,541	$704,391	$724,411	$745,215	$766,833	$789,412	$812,655	$836,584	$861,217	$886,576	$912,682	$939,556	$967,222	$995,703
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$633,819	$610,040	$614,706	$626,997	$646,607	$666,355	$687,541	$704,391	$724,411	$745,215	$766,833	$789,412	$812,655	$836,584	$861,217	$886,576	$912,682	$939,556	$967,222	$995,703
Oil Cost ($)	$7,836	$8,071	$8,314	$8,563	$8,820	$9,085	$9,357	$9,638	$9,927	$10,225	$10,531	$10,847	$11,173	$11,508	$11,853	$12,209	$12,575	$12,952	$13,341	$13,741
O&M Cost																				
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Utility and O&M Cost																				
Total Fuel, Electricity & O&M Cost ($)	$2,460,607	$2,491,632	$2,552,745	$2,623,177	$2,702,673	$2,784,103	$2,868,821	$2,951,110	$3,038,531	$3,128,759	$3,221,883	$3,318,113	$3,417,218	$3,519,284	$3,624,398	$3,732,652	$3,844,140	$3,958,958	$4,077,206	$4,198,987
GHG Emissions/LL 97 Cost, As Written																				
Purchased Elec GHG Emissions (Mton CO2e)	2,576	2,576	2,576	2,576	2,576	2,576	558	558	558	558	558	279	279	279	279	279	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.063	0.063	0.063	0.063	0.063	0.031	0.031	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278
Boiler Oil Emissions (Mton CO2e)	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Total GHG Emissions (Mton CO2e)	6,882	6,882	6,882	6,882	6,882	6,882	4,864	4,864	4,864	4,864	4,864	4,585	4,585	4,585	4,585	4,585	4,306	4,306	4,306	4,306
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	$42,032	$43,293	$44,591	$45,929	$47,307	$48,726	$259,061	$266,833	$274,838	$283,083	$291,576	$1,183,561	$1,219,068	$1,255,640	$1,293,309	$1,332,109	$1,252,012	$1,289,572	$1,328,259	$1,368,107
GHG Emissions/LL 97 Cost, Delayed to 2034																				
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	558	279	279	279	279	279	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.031	0.031	0.031	0.000	0.000	0.000	0.000
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278	4,278
Boiler Oil Emissions (Mton CO2e)	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Total GHG Emissions (Mton CO2e)	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,306	4,864	4,585	4,585	4,585	4,585	4,585	4,306	4,306	4,306	4,306
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$108,036	$111,277	$114,616	$118,054
Total Cost																				
Total Cost with LL97 Penalties ($)	$2,502,638	$2,534,924	$2,597,336	$2,669,106	$2,749,980	$2,832,829	$3,127,882	$3,217,943	$3,313,369	$3,411,842	$3,513,459	$4,501,675	$4,636,286	$4,774,924	$4,917,707	$5,064,761	$5,096,152	$5,248,530	$5,405,466	$5,567,094
Total Cost with LL97 Penalties, Delayed ($)	$2,460,607	$2,491,632	$2,552,745	$2,623,177	$2,702,673	$2,784,103	$2,868,821	$2,951,110	$3,038,531	$3,128,759	$3,221,883	$3,318,113	$3,417,218	$3,519,284	$3,624,398	$3,732,652	$3,952,176	$4,070,236	$4,191,822	$4,317,041

Con Ed Reconnection, High Tension, Geothermal

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric																				
System Demand (MW)	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
Total Electricity Load (MWh)	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566
Electricity to Residential Cooling (MWh)	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755
Electricity to Geothermal Heat Pump (MWh)	775	775	775	775	775	775	775	775	775	775	775	775	775	775	775	775	775	775	775	775
System Electricity (Base Bldg Plug) Load (MWh)	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036	7,036
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566	9,566
Demand, May-June, 8AM-6PM (MW)	8.21	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
Demand, 8AM-10PM (MW)	16.87	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9
Demand, All Hours, All Days (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam																				
Steam Heating Load (klbs)	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834	41,834
Geothermal Heating Load (MMBtu)	6,970													6,970	6,970	6,970	6,970	6,970	6,970	6,970
Boiler Steam Production (klbs)	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Total Steam Use (klbs)	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514	61,514
Steam to Heating (klbs)	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157	41,157
Cooling																				
Residential Cooling Load (ton-hr)	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328
Commercial Cooling Load (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Residential HVAC Units (ton-hr)	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328	1,627,328
Absorption Chiller Production (ton-hr)	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923	310,923
Geothermal Cooling Production (ton-hr)	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221	271,221
Hot Water																				
Domestic Hot Water Load (MMBtu)	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Hot Water Production (MMBtu)	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071	15,071
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel																				
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364
Total Gas Consumption (MMBtu)	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364	72,364
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328
Total Oil Consumption (MMBtu)	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328	328
Electric Cost																				
Minimum Charge ($)	$1,983	$2,043	$2,104	$2,167	$2,232	$2,299	$2,368	$2,439	$2,512	$2,588	$2,665	$2,745	$2,828	$2,913	$3,000	$3,090	$3,183	$3,278	$3,376	$3,478
Electric Delivery (w/Riders) Cost ($)	$87,289	$89,908	$92,605	$95,383	$98,244	$101,192	$104,227	$107,354	$110,575	$113,892	$117,309	$120,828	$124,453	$128,187	$132,032	$135,993	$140,073	$144,275	$148,603	$153,062
Electricity Supply Cost ($)	$1,326,943	$1,366,752	$1,407,754	$1,449,987	$1,493,486	$1,538,291	$1,584,440	$1,631,973	$1,680,932	$1,731,360	$1,783,301	$1,836,800	$1,891,904	$1,948,661	$2,007,121	$2,067,334	$2,129,354	$2,193,235	$2,259,032	$2,326,803
Demand Cost, May-June, 8AM-6PM ($)	$100,826	$103,851	$106,966	$110,175	$113,481	$116,885	$120,392	$124,003	$127,724	$131,555	$135,502	$139,567	$143,754	$148,067	$152,509	$157,084	$161,796	$166,650	$171,650	$176,799
Demand Cost, 8AM-10PM ($)	$430,609	$443,527	$456,833	$470,538	$484,654	$499,194	$514,170	$529,595	$545,483	$561,847	$578,702	$596,063	$613,945	$632,364	$651,335	$670,875	$691,001	$711,731	$733,083	$755,075
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$1,947,651	$2,006,080	$2,066,262	$2,128,250	$2,192,098	$2,257,861	$2,325,597	$2,395,364	$2,467,225	$2,541,242	$2,617,479	$2,696,004	$2,776,884	$2,860,190	$2,945,996	$3,034,376	$3,125,407	$3,219,170	$3,315,745	$3,415,217

Con Ed Reconnection, High Tension, Geothermal

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fuel Cost																				
Boiler Gas Minimum Charge ($)	$4,989	$5,139	$5,293	$5,451	$5,615	$5,783	$5,957	$6,136	$6,320	$6,509	$6,705	$6,906	$7,113	$7,326	$7,546	$7,773	$8,006	$8,246	$8,493	$8,748
Boiler Gas Delivery Cost ($)	$155,050	$159,702	$164,493	$169,428	$174,510	$179,746	$185,138	$190,692	$196,413	$202,305	$208,375	$214,626	$221,065	$227,696	$234,527	$241,563	$248,810	$256,274	$263,963	$271,882
Boiler Gas Supply Cost ($)	$408,453	$382,684	$382,181	$388,150	$400,775	$413,135	$426,628	$436,109	$448,212	$460,843	$474,045	$487,884	$502,127	$516,786	$531,873	$547,400	$563,381	$579,828	$596,756	$614,178
Total Boiler Gas Cost ($)	$568,492	$547,524	$551,967	$563,030	$580,901	$598,664	$617,723	$632,937	$650,945	$669,658	$689,124	$709,415	$730,304	$751,809	$773,946	$796,736	$820,197	$844,349	$869,212	$894,808
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$568,492	$547,524	$551,967	$563,030	$580,901	$598,664	$617,723	$632,937	$650,945	$669,658	$689,124	$709,415	$730,304	$751,809	$773,946	$796,736	$820,197	$844,349	$869,212	$894,808
Oil Cost ($)	$6,848	$7,054	$7,266	$7,484	$7,708	$7,939	$8,177	$8,423	$8,675	$8,936	$9,204	$9,480	$9,764	$10,057	$10,359	$10,670	$10,990	$11,320	$11,659	$12,009
O&M Cost																				
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Utility and O&M Cost																				
Total Fuel, Electricity & O&M Cost ($)	$2,522,991	$2,560,658	$2,625,495	$2,698,763	$2,780,707	$2,864,464	$2,951,497	$3,036,724	$3,126,846	$3,219,835	$3,315,807	$3,414,899	$3,516,953	$3,622,056	$3,730,301	$3,841,782	$3,956,594	$4,074,838	$4,196,616	$4,322,034
GHG Emissions/LL 97 Cost, As Written																				
Purchased Elec GHG Emissions (Mton CO2e)	2,764	2,764	2,764	2,764	2,764	2,764	599	599	599	599	599	300	300	300	300	300	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843
Boiler Oil Emissions (Mton CO2e)	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Total GHG Emissions (Mton CO2e)	6,632	6,632	6,632	6,632	6,632	6,632	4,467	4,467	4,467	4,467	4,467	4,167	4,167	4,167	4,167	4,167	3,868	3,868	3,868	3,868
GHG Emissions Limit [Local Law 97] (Mton CO2e)	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055	4,055	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395	1,395
GHG Emissions Penalty ($)	0	0	0	0	0	0	131,840	135,795	139,869	144,065	148,387	1,028,494	1,059,349	1,091,129	1,123,863	1,157,579	1,063,455	1,095,359	1,128,220	1,162,066
GHG Emissions/LL 97 Cost, Delayed to 2034																				
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	599	300	300	300	300	300	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843	3,843
Boiler Oil Emissions (Mton CO2e)	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Total GHG Emissions (Mton CO2e)	3,868	3,868	3,868	3,868	3,868	3,868	3,868	3,868	3,868	3,868	4,467	4,167	4,167	4,167	4,167	4,167	3,868	3,868	3,868	3,868
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	6,725	6,725	6,725	6,725	6,725	6,725	4,055	4,055	4,055	4,055
GHG Emissions Penalty ($)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Cost																				
Total Cost with LL97 Penalties ($)	$2,522,991	$2,560,658	$2,625,495	$2,698,763	$2,780,707	$2,864,464	$3,083,338	$3,172,520	$3,266,715	$3,363,901	$3,464,195	$4,443,393	$4,576,301	$4,713,186	$4,854,164	$4,999,361	$5,020,049	$5,170,197	$5,324,835	$5,484,100
Total Cost with LL97 Penalties, Delayed ($)	$2,522,991	$2,560,658	$2,625,495	$2,698,763	$2,780,707	$2,864,464	$2,951,497	$3,036,724	$3,126,846	$3,219,835	$3,315,807	$3,414,899	$3,516,953	$3,622,056	$3,730,301	$3,841,782	$3,956,594	$4,074,838	$4,196,616	$4,322,034

Attachment B

Modeling Results, Year 2024 Monthly Results

4x1.2 MW Recips

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Purchased Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Demand, May-June, 8AM-6PM (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand, 8AM-10PM (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	9,909	8,906	7,411	4,592	42	16	0	0	26	1,144	4,188	6,902	43,136
CHP Steam Production (klbs)	1,065	963	1,066	1,031	1,262	1,451	2,268	2,069	1,424	1,165	1,030	1,066	15,859
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	325	354	1,005	898	415	0	0	0	2,998
Steam to Hot Water (klbs)	271	245	271	262	125	53	14	17	71	183	263	271	2,046
Total Steam Use (klbs)	10,974	9,868	8,477	5,623	979	1,113	1,263	1,171	1,034	2,309	5,218	7,968	55,997
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,126	4,955	7,697	48,671
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	1,264	1,143	1,265	1,224	1,573	1,777	2,703	2,489	1,743	1,436	1,222	1,266	19,104
Steam to Hot Water (MMBtu)	271	245	271	262	125	53	14	17	71	183	263	271	2,046
Hot Water Production (MMBtu)	1,536	1,387	1,536	1,486	1,698	1,830	2,717	2,506	1,814	1,619	1,486	1,536	21,150
Dumped Hot Water (MMBtu)	284	257	285	275	452	626	1,474	1,263	609	371	275	285	6,455
Fuel Balance													
Gas to Generators (MMBtu)	5,482	4,955	5,487	5,307	6,747	7,637	11,682	10,736	7,493	6,179	5,300	5,488	82,493
Gas to Boiler (MMBtu)	11,592	10,419	8,757	5,426	50	19	0	0	31	1,352	4,949	8,074	50,670
Total Gas Consumption (MMBtu)	17,074	15,374	14,244	10,733	6,797	7,656	11,683	10,736	7,524	7,531	10,249	13,562	133,163
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	117	105	0	0	0	0	0	0	0	0	0	82	304
Total Oil Consumption (MMBtu)	117	105	0	0	0	0	0	0	0	0	0	82	304
Total Cost Summary													
Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, 8AM-10PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$24,840	$22,325	$18,765	$11,626	$105	$38	-$1	$0	$64	$2,896	$10,604	$17,301	$108,562
Boiler Gas Supply Cost ($)	$74,934	$65,323	$51,246	$27,545	$246	$91	$2	$0	$152	$6,765	$25,724	$45,122	$297,151
Total Boiler Gas Cost ($)	$100,190	$88,064	$70,426	$39,587	$766	$545	$416	$416	$631	$10,077	$36,744	$62,839	$410,702
Cogen Gas Delivery Cost ($)	$17,644	$16,004	$17,661	$17,100	$21,586	$24,357	$36,957	$34,010	$23,909	$19,815	$17,079	$17,664	$263,785
Cogen Gas Supply Cost ($)	$37,474	$32,526	$33,629	$28,239	$34,747	$38,931	$60,695	$55,685	$37,754	$31,487	$28,082	$31,313	$450,562
Total Gas Cost ($)	$155,307	$136,594	$121,716	$84,926	$57,099	$63,833	$98,067	$90,111	$62,293	$61,379	$81,905	$111,817	$1,125,048
Oil Cost ($)	$2,446	$2,199	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,704	$6,349
Equipment O&M ($)	$11,294	$10,210	$11,307	$10,935	$14,210	$15,898	$24,046	$22,186	$15,615	$12,989	$10,919	$11,310	$170,920
Total Fuel, Electricity & O&M Cost ($)	$169,048	$149,003	$133,024	$95,862	$71,310	$79,731	$122,113	$112,297	$77,909	$74,367	$92,824	$124,831	$1,302,318
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Engine GHG Emissions (Mton CO2e)	291	263	291	282	358	406	620	570	398	328	281	291	4,381
Boiler Gas Emissions (Mton CO2e)	616	553	465	288	3	1	0	0	2	72	263	429	2,691
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	23
Total GHG Emissions (Mton CO2e)	915	824	757	570	361	407	620	570	400	400	544	726	7,095
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$99,174	$99,174
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	291	263	291	282	358	406	620	570	398	328	281	291	4,381
Boiler Gas Emissions (Mton CO2e)	616	553	465	288	3	1	0	0	2	72	263	429	2,691
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	23
Total GHG Emissions (Mton CO2e)	915	824	757	570	361	407	620	570	400	400	544	726	7,095
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$169,048	$149,003	$133,024	$95,862	$71,310	$79,731	$122,113	$112,297	$77,909	$74,367	$92,824	$224,005	$1,401,492
Total Cost with LL97 Penalties, Delayed ($)	$169,048	$149,003	$133,024	$95,862	$71,310	$79,731	$122,113	$112,297	$77,909	$74,367	$92,824	$124,831	$1,302,318

6x635 kW Recips

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	597	540	598	578	751	841	1,272	1,173	826	686	577	590	9,030
Purchased Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	686	577	590	9,030
Demand, May-June, 8AM-6PM (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand, 8AM-10PM (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	9,478	8,516	6,979	4,174	12	4	0	0	5	578	3,771	6,515	40,031
CHP Steam Production (klbs)	1,401	1,266	1,402	1,356	1,650	1,826	2,731	2,515	1,801	1,547	1,355	1,373	20,223
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	730	741	1,472	1,349	795	0	0	0	5,087
Steam to Hot Water (klbs)	176	159	175	170	75	29	10	12	44	108	171	191	1,320
Total Steam Use (klbs)	10,879	9,782	8,381	5,530	932	1,089	1,259	1,166	1,010	2,125	5,126	7,888	55,167
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,017	4,955	7,697	48,561
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	1,444	1,305	1,445	1,398	1,717	1,913	2,879	2,655	1,882	1,591	1,396	1,419	21,044
Steam to Hot Water (MMBtu)	176	159	175	170	75	29	10	12	44	108	171	191	1,320
Hot Water Production (MMBtu)	1,620	1,463	1,620	1,568	1,793	1,942	2,890	2,667	1,926	1,699	1,567	1,610	22,363
Dumped Hot Water (MMBtu)	372	336	372	360	547	738	1,646	1,423	722	458	359	362	7,696
Fuel Balance													
Gas to Generators (MMBtu)	6,388	5,774	6,394	6,185	7,733	8,615	12,971	11,960	8,474	7,146	6,177	6,286	94,104
Gas to Boiler (MMBtu)	11,088	9,963	8,247	4,933	14	4	0	0	6	683	4,456	7,622	47,015
Total Gas Consumption (MMBtu)	17,476	15,737	14,642	11,117	7,746	8,620	12,971	11,960	8,479	7,829	10,633	13,908	141,119
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	112	101	0	0	0	0	0	0	0	0	0	77	290
Total Oil Consumption (MMBtu)	112	101	0	0	0	0	0	0	0	0	0	77	290
Total Cost Summary													
Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, 8AM-10PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$23,759	$21,348	$17,672	$10,568	$28	$7	$0	$0	$10	$1,461	$9,547	$16,331	$100,732
Boiler Gas Supply Cost ($)	$71,673	$62,464	$48,261	$25,040	$68	$21	$0	$0	$27	$3,416	$23,161	$42,593	$276,726
Total Boiler Gas Cost ($)	$95,848	$84,228	$66,349	$36,024	$512	$445	$416	$416	$453	$5,293	$33,124	$59,340	$382,447
Cogen Gas Delivery Cost ($)	$20,468	$18,556	$20,486	$19,834	$24,654	$27,406	$40,970	$37,821	$26,965	$22,826	$19,810	$20,151	$299,947
Cogen Gas Supply Cost ($)	$43,673	$37,906	$39,191	$32,910	$39,821	$43,917	$67,391	$62,033	$42,694	$36,415	$32,729	$35,869	$514,549
Total Gas Cost ($)	$159,989	$140,690	$126,026	$88,767	$64,986	$71,768	$108,777	$100,270	$70,112	$64,534	$85,662	$115,360	$1,196,943
Oil Cost ($)	$2,340	$2,103	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,609	$6,051
Equipment O&M ($)	$11,295	$10,211	$11,308	$10,936	$14,211	$15,899	$24,046	$22,186	$15,615	$12,980	$10,919	$11,157	$170,765
Total Fuel, Electricity & O&M Cost ($)	$173,625	$153,003	$137,335	$99,704	$79,197	$87,666	$132,823	$122,456	$85,727	$77,514	$96,582	$128,126	$1,373,758
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Engine GHG Emissions (Mton CO2e)	339	307	340	328	411	458	689	635	450	380	328	334	4,998
Boiler Gas Emissions (Mton CO2e)	589	529	438	262	1	0	0	0	0	36	237	405	2,497
Boiler Oil Emissions (Mton CO2e)	8	7	0	0	0	0	0	0	0	0	0	6	21
Total GHG Emissions (Mton CO2e)	936	843	778	590	411	458	689	635	450	416	565	744	7,516
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$212,796	$212,796
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	339	307	340	328	411	458	689	635	450	380	328	334	4,998
Boiler Gas Emissions (Mton CO2e)	589	529	438	262	1	0	0	0	0	36	237	405	2,497
Boiler Oil Emissions (Mton CO2e)	8	7	0	0	0	0	0	0	0	0	0	6	21
Total GHG Emissions (Mton CO2e)	936	843	778	590	411	458	689	635	450	416	565	744	7,516
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$173,625	$153,003	$137,335	$99,704	$79,197	$87,666	$132,823	$122,456	$85,727	$77,514	$96,582	$340,921	$1,586,554
Total Cost with LL97 Penalties, Delayed ($)	$173,625	$153,003	$137,335	$99,704	$79,197	$87,666	$132,823	$122,456	$85,727	$77,514	$96,582	$128,126	$1,373,758

Con Ed Reconnection, Low Tension

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Demand, May-June, 8AM-6PM (MW)	0.00	0.00	0.00	0.00	0.00	1.62	2.61	2.30	1.76	0.00	0.00	0.00	8.29
Demand, 8AM-10PM (MW)	0.86	0.86	0.86	0.86	1.37	1.62	2.61	2.30	1.76	1.12	0.86	0.86	15.94
Demand, All Hours, All Days (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	11,983	10,780	9,486	6,599	1,901	2,204	2,464	2,317	2,040	3,539	6,194	8,977	68,484
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Total Steam Use (klbs)	11,983	10,780	9,486	6,599	1,901	2,204	2,464	2,317	2,040	3,539	6,194	8,977	68,484
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Hot Water Production (MMBtu)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Balance													
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	14,018	12,611	11,210	7,798	2,247	2,605	2,911	2,738	2,411	4,183	7,319	10,502	80,553
Total Gas Consumption (MMBtu)	14,018	12,611	11,210	7,798	2,247	2,605	2,911	2,738	2,411	4,183	7,319	10,502	80,553
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	142	127	0	0	0	0	0	0	0	0	0	106	375
Total Oil Consumption (MMBtu)	142	127	0	0	0	0	0	0	0	0	0	106	375
Total Cost Summary													
Minimum Charge ($)	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$1,983
Electric Delivery (w/Riders) Cost ($)	$5,450	$4,927	$5,456	$5,276	$6,857	$7,671	$11,602	$10,705	$7,534	$6,267	$5,268	$5,457	$82,471
Electricity Supply Cost ($)	$99,542	$86,534	$72,723	$64,735	$80,393	$109,540	$194,974	$159,920	$99,942	$90,642	$89,949	$98,574	$1,247,468
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$19,851	$32,057	$28,287	$21,576	$0	$0	$0	$101,771
Demand Cost, 8AM-10PM ($)	$18,611	$18,607	$18,611	$18,610	$29,738	$47,845	$77,262	$68,176	$52,001	$24,347	$18,607	$18,607	$411,022
Demand Cost, All Hours, All Days ($)	$4,002	$4,001	$4,002	$4,002	$6,854	$35,694	$57,641	$53,193	$38,795	$5,236	$4,001	$4,001	$221,424
Total Electric Cost ($)	$127,770	$114,234	$100,957	$92,789	$124,007	$220,766	$373,702	$320,446	$220,014	$126,657	$117,991	$126,805	$2,066,139
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$30,039	$27,024	$24,020	$16,710	$4,813	$5,580	$6,237	$5,865	$5,164	$8,961	$15,683	$22,505	$172,600
Boiler Gas Supply Cost ($)	$90,616	$79,069	$65,596	$39,587	$11,056	$12,689	$14,457	$13,572	$11,929	$20,926	$38,042	$58,692	$456,230
Total Boiler Gas Cost ($)	$121,070	$106,508	$90,032	$56,713	$16,285	$18,684	$21,110	$19,853	$17,509	$30,303	$54,140	$81,612	$633,819
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$121,070	$106,508	$90,032	$56,713	$16,285	$18,684	$21,110	$19,853	$17,509	$30,303	$54,140	$81,612	$633,819
Oil Cost ($)	$2,958	$2,661	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,216	$7,836
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fuel, Electricity & O&M Cost ($)	$251,799	$223,404	$190,989	$149,502	$140,292	$239,450	$394,812	$340,299	$237,522	$156,960	$172,131	$210,634	$2,707,794
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	173	156	173	167	217	243	367	339	239	198	167	173	2,612
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	745	670	595	414	119	138	155	145	128	222	389	558	4,278
Boiler Oil Emissions (Mton CO2e)	11	9	0	0	0	0	0	0	0	0	0	8	28
Total GHG Emissions (Mton CO2e)	928	835	768	581	336	381	522	484	367	421	556	738	6,918
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$51,687	$51,687
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	745	670	595	414	119	138	155	145	128	222	389	558	4,278
Boiler Oil Emissions (Mton CO2e)	11	9	0	0	0	0	0	0	0	0	0	8	28
Total GHG Emissions (Mton CO2e)	755	679	595	414	119	138	155	145	128	222	389	566	4,306
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$251,799	$223,404	$190,989	$149,502	$140,292	$239,450	$394,812	$340,299	$237,522	$156,960	$172,131	$262,321	$2,759,481
Total Cost with LL97 Penalties, Delayed ($)	$251,799	$223,404	$190,989	$149,502	$140,292	$239,450	$394,812	$340,299	$237,522	$156,960	$172,131	$210,634	$2,707,794

Con Ed Reconnection, High Tension

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Demand, May-June, 8AM-6PM (MW)	0.00	0.00	0.00	0.00	0.00	1.62	2.61	2.30	1.76	0.00	0.00	0.00	8.29
Demand, 8AM-10PM (MW)	0.86	0.86	0.86	0.86	1.37	1.62	2.61	2.30	1.76	1.12	0.86	0.86	15.94
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	11,983	10,780	9,486	6,599	1,901	2,204	2,464	2,317	2,040	3,539	6,194	8,977	68,484
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Total Steam Use (klbs)	11,983	10,780	9,486	6,599	1,901	2,204	2,464	2,317	2,040	3,539	6,194	8,977	68,484
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Hot Water Production (MMBtu)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Balance													
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	14,018	12,611	11,210	7,798	2,247	2,605	2,911	2,738	2,411	4,183	7,319	10,502	80,553
Total Gas Consumption (MMBtu)	14,018	12,611	11,210	7,798	2,247	2,605	2,911	2,738	2,411	4,183	7,319	10,502	80,553
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	142	127	0	0	0	0	0	0	0	0	0	106	375
Total Oil Consumption (MMBtu)	142	127	0	0	0	0	0	0	0	0	0	106	375
Total Cost Summary													
Minimum Charge ($)	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$1,983
Electric Delivery (w/Riders) Cost ($)	$5,450	$4,927	$5,456	$5,276	$6,857	$7,671	$11,602	$10,705	$7,534	$6,267	$5,268	$5,457	$82,471
Electricity Supply Cost ($)	$99,542	$86,534	$72,723	$64,735	$80,393	$109,540	$194,974	$159,920	$99,942	$90,642	$89,949	$98,574	$1,247,468
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$19,851	$32,057	$28,287	$21,576	$0	$0	$0	$101,771
Demand Cost, 8AM-10PM ($)	$18,611	$18,607	$18,611	$18,610	$29,738	$47,845	$77,262	$68,176	$52,001	$24,347	$18,607	$18,607	$411,022
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$123,768	$110,233	$96,955	$88,787	$117,153	$185,072	$316,061	$267,253	$181,219	$121,421	$113,989	$122,804	$1,844,715
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$30,039	$27,024	$24,020	$16,710	$4,813	$5,580	$6,237	$5,865	$5,164	$8,961	$15,683	$22,505	$172,600
Boiler Gas Supply Cost ($)	$90,616	$79,069	$65,596	$39,587	$11,056	$12,689	$14,457	$13,572	$11,929	$20,926	$38,042	$58,692	$456,230
Total Boiler Gas Cost ($)	$121,070	$106,508	$90,032	$56,713	$16,285	$18,684	$21,110	$19,853	$17,509	$30,303	$54,140	$81,612	$633,819
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$121,070	$106,508	$90,032	$56,713	$16,285	$18,684	$21,110	$19,853	$17,509	$30,303	$54,140	$81,612	$633,819
Oil Cost ($)	$2,958	$2,661	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,216	$7,836
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fuel, Electricity & O&M Cost ($)	$247,797	$219,403	$186,986	$145,500	$133,438	$203,756	$337,171	$287,106	$198,727	$151,724	$168,130	$206,633	$2,486,370
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	173	156	173	167	217	243	367	339	239	198	167	173	2,612
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	745	670	595	414	119	138	155	145	128	222	389	558	4,278
Boiler Oil Emissions (Mton CO2e)	11	9	0	0	0	0	0	0	0	0	0	8	28
Total GHG Emissions (Mton CO2e)	928	835	768	581	336	381	522	484	367	421	556	738	6,918
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$51,687	$51,687
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	745	670	595	414	119	138	155	145	128	222	389	558	4,278
Boiler Oil Emissions (Mton CO2e)	11	9	0	0	0	0	0	0	0	0	0	8	28
Total GHG Emissions (Mton CO2e)	755	679	595	414	119	138	155	145	128	222	389	566	4,306
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$247,797	$219,403	$186,986	$145,500	$133,438	$203,756	$337,171	$287,106	$198,727	$151,724	$168,130	$258,319	$2,538,057
Total Cost with LL97 Penalties, Delayed ($)	$247,797	$219,403	$186,986	$145,500	$133,438	$203,756	$337,171	$287,106	$198,727	$151,724	$168,130	$206,633	$2,486,370

1x1.2 MW Recip with Con Ed Reconnection

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	560	453	525	434	702	738	798	863	669	543	532	534	7,351
Purchased Electricity (MWh)	37	87	73	145	50	103	473	310	157	144	45	64	1,687
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Demand, May-June, 8AM-6PM (MW)	1.15	5.57	2.67	4.98	1.34	6.00	23.90	18.83	6.78	6.63	1.90	2.64	82.39
Demand, 8AM-10PM (MW)	1.15	5.57	2.67	4.98	1.34	6.00	24.30	18.91	6.78	6.63	1.90	2.64	82.87
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	9,992	9,164	7,624	5,054	80	157	320	80	279	1,651	4,305	7,081	45,787
CHP Steam Production (klbs)	1,021	825	956	790	1,172	1,177	1,227	1,333	1,077	940	971	974	12,463
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	251	182	197	271	219	0	0	0	1,119
Steam to Hot Water (klbs)	311	365	374	484	171	142	180	66	235	395	321	358	3,402
Total Steam Use (klbs)	11,013	9,989	8,580	5,844	1,001	1,152	1,349	1,143	1,137	2,591	5,276	8,055	57,131
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,196	4,955	7,697	48,741
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	1,194	966	1,119	924	1,466	1,533	1,654	1,790	1,392	1,140	1,135	1,140	15,452
Steam to Hot Water (MMBtu)	311	365	374	484	171	142	180	66	235	395	321	358	3,402
Hot Water Production (MMBtu)	1,505	1,331	1,493	1,408	1,637	1,675	1,834	1,856	1,627	1,535	1,456	1,498	18,854
Dumped Hot Water (MMBtu)	252	197	239	191	390	469	586	612	419	281	243	244	4,124
Fuel Balance													
Gas to Generators (MMBtu)	5,188	4,194	4,860	4,015	6,288	6,521	6,982	7,563	5,929	4,924	4,930	4,950	66,345
Gas to Boiler (MMBtu)	11,690	10,721	9,009	5,973	95	185	378	95	329	1,951	5,088	8,284	53,797
Total Gas Consumption (MMBtu)	16,877	14,915	13,869	9,988	6,383	6,706	7,360	7,657	6,259	6,875	10,018	13,235	120,141
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	118	108	0	0	0	0	0	0	0	0	0	84	310
Total Oil Consumption (MMBtu)	118	108	0	0	0	0	0	0	0	0	0	84	310
Total Cost Summary													
Minimum Charge ($)	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$339,062
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$6,200	$13,938	$8,901	$16,202	$5,307	$13,424	$72,571	$42,213	$18,944	$18,956	$7,051	$10,483	$234,190
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$5,568	$22,195	$17,482	$6,296	$0	$0	$0	$51,542
Demand Cost, 8AM-10PM ($)	$1,424	$6,904	$3,303	$6,169	$1,655	$11,237	$45,525	$35,430	$12,705	$8,218	$2,353	$3,275	$138,199
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$35,880	$49,098	$40,460	$50,626	$35,217	$58,484	$168,546	$123,380	$66,201	$55,429	$37,659	$42,013	$762,992
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$25,048	$22,972	$19,304	$12,798	$201	$394	$807	$201	$703	$4,179	$10,900	$17,751	$115,261
Boiler Gas Supply Cost ($)	$75,562	$67,216	$52,719	$30,321	$466	$902	$1,875	$471	$1,629	$9,762	$26,443	$46,297	$313,662
Total Boiler Gas Cost ($)	$101,027	$90,604	$72,439	$43,534	$1,082	$1,712	$3,098	$1,088	$2,748	$14,357	$37,759	$64,464	$433,912
Cogen Gas Delivery Cost ($)	$16,730	$13,636	$15,708	$13,078	$20,157	$20,880	$22,317	$24,124	$19,039	$15,907	$15,928	$15,989	$213,492
Cogen Gas Supply Cost ($)	$35,467	$27,534	$29,787	$21,365	$32,384	$33,239	$36,275	$39,225	$29,875	$25,091	$26,123	$28,244	$364,609
Total Gas Cost ($)	$153,224	$131,773	$117,934	$77,977	$53,623	$55,831	$61,690	$64,437	$51,661	$55,355	$79,810	$108,697	$1,012,012
Oil Cost ($)	$2,467	$2,263	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,748	$6,478
Equipment O&M ($)	$10,591	$8,566	$9,923	$8,198	$13,272	$13,950	$15,096	$16,330	$12,655	$10,272	$10,063	$10,107	$139,024
Total Fuel, Electricity & O&M Cost ($)	$202,161	$191,699	$168,317	$136,801	$102,112	$128,265	$245,332	$204,147	$130,517	$121,056	$127,532	$162,566	$1,920,506
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	11	25	21	42	14	30	137	89	45	42	13	18	487
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Engine GHG Emissions (Mton CO2e)	276	223	258	213	334	346	371	402	315	261	262	263	3,524
Boiler Gas Emissions (Mton CO2e)	621	569	478	317	5	10	20	5	17	104	270	440	2,857
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	23
Total GHG Emissions (Mton CO2e)	916	825	758	572	353	386	528	496	378	407	545	727	6,891
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$44,569	$44,569
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	276	223	258	213	334	346	371	402	315	261	262	263	3,524
Boiler Gas Emissions (Mton CO2e)	621	569	478	317	5	10	20	5	17	104	270	440	2,857
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	23
Total GHG Emissions (Mton CO2e)	905	800	737	530	339	356	391	407	332	365	532	709	6,404
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$202,161	$191,699	$168,317	$136,801	$102,112	$128,265	$245,332	$204,147	$130,517	$121,056	$127,532	$207,135	$1,965,075
Total Cost with LL97 Penalties, Delayed ($)	$202,161	$191,699	$168,317	$136,801	$102,112	$128,265	$245,332	$204,147	$130,517	$121,056	$127,532	$162,566	$1,920,506

1x1.2 MW Recip with Con Ed Reconnection, High Tension

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	560	453	525	434	702	738	798	863	669	543	532	534	7,351
Purchased Electricity (MWh)	37	87	73	145	50	103	473	310	157	144	45	64	1,687
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Demand, May-June, 8AM-6PM (MW)	1.15	5.57	2.67	4.98	1.34	6.00	23.90	18.83	6.78	6.63	1.90	2.64	82.39
Demand, 8AM-10PM (MW)	1.15	5.57	2.67	4.98	1.34	6.00	24.30	18.91	6.78	6.63	1.90	2.64	82.87
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	9,992	9,164	7,624	5,054	80	157	320	80	279	1,651	4,305	7,081	45,787
CHP Steam Production (klbs)	1,021	825	956	790	1,172	1,177	1,227	1,333	1,077	940	971	974	12,463
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	251	182	197	271	219	0	0	0	1,119
Steam to Hot Water (klbs)	311	365	374	484	171	142	180	66	235	395	321	358	3,402
Total Steam Use (klbs)	11,013	9,989	8,580	5,844	1,001	1,152	1,349	1,143	1,137	2,591	5,276	8,055	57,131
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,196	4,955	7,697	48,741
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	1,194	966	1,119	924	1,466	1,533	1,654	1,790	1,392	1,140	1,135	1,140	15,452
Steam to Hot Water (MMBtu)	311	365	374	484	171	142	180	66	235	395	321	358	3,402
Hot Water Production (MMBtu)	1,505	1,331	1,493	1,408	1,637	1,675	1,834	1,856	1,627	1,535	1,456	1,498	18,854
Dumped Hot Water (MMBtu)	252	197	239	191	390	469	586	612	419	281	243	244	4,124
Fuel Balance													
Gas to Generators (MMBtu)	5,188	4,194	4,860	4,015	6,288	6,521	6,982	7,563	5,929	4,924	4,930	4,950	66,345
Gas to Boiler (MMBtu)	11,690	10,721	9,009	5,973	95	185	378	95	329	1,951	5,088	8,284	53,797
Total Gas Consumption (MMBtu)	16,877	14,915	13,869	9,988	6,383	6,706	7,360	7,657	6,259	6,875	10,018	13,235	120,141
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	118	108	0	0	0	0	0	0	0	0	0	84	310
Total Oil Consumption (MMBtu)	118	108	0	0	0	0	0	0	0	0	0	84	310
Total Cost Summary													
Minimum Charge ($)	$25,656	$25,656	$25,656	$25,656	$25,656	$25,656	$25,656	$25,656	$25,656	$25,656	$25,656	$25,656	$307,875
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$6,200	$13,938	$8,901	$16,202	$5,307	$13,424	$72,571	$42,213	$18,944	$18,956	$7,051	$10,483	$234,190
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$5,568	$22,195	$17,482	$6,296	$0	$0	$0	$51,542
Demand Cost, 8AM-10PM ($)	$875	$4,240	$2,028	$3,788	$1,016	$3,673	$14,882	$11,582	$4,153	$5,046	$1,445	$2,011	$54,740
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$32,731	$43,834	$36,586	$45,646	$31,979	$48,322	$135,305	$96,934	$55,050	$49,658	$34,152	$38,150	$648,347
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$25,048	$22,972	$19,304	$12,798	$201	$394	$807	$201	$703	$4,179	$10,900	$17,751	$115,261
Boiler Gas Supply Cost ($)	$75,562	$67,216	$52,719	$30,321	$466	$902	$1,875	$471	$1,629	$9,762	$26,443	$46,297	$313,662
Total Boiler Gas Cost ($)	$101,027	$90,604	$72,439	$43,534	$1,082	$1,712	$3,098	$1,088	$2,748	$14,357	$37,759	$64,464	$433,912
Cogen Gas Delivery Cost ($)	$16,730	$13,636	$15,708	$13,078	$20,157	$20,880	$22,317	$24,124	$19,039	$15,907	$15,928	$15,989	$213,492
Cogen Gas Supply Cost ($)	$35,467	$27,534	$29,787	$21,365	$32,384	$33,239	$36,275	$39,225	$29,875	$25,091	$26,123	$28,244	$364,609
Total Gas Cost ($)	$153,224	$131,773	$117,934	$77,977	$53,623	$55,831	$61,690	$64,437	$51,661	$55,355	$79,810	$108,697	$1,012,012
Oil Cost ($)	$2,467	$2,263	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,748	$6,478
Equipment O&M ($)	$10,591	$8,566	$9,923	$8,198	$13,272	$13,950	$15,096	$16,330	$12,655	$10,272	$10,063	$10,107	$139,024
Total Fuel, Electricity & O&M Cost ($)	$199,013	$186,436	$164,443	$131,821	$98,875	$118,103	$212,090	$177,700	$119,366	$115,286	$124,025	$158,703	$1,805,860
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	11	25	21	42	14	30	137	89	45	42	13	18	487
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Engine GHG Emissions (Mton CO2e)	276	223	258	213	334	346	371	402	315	261	262	263	3,524
Boiler Gas Emissions (Mton CO2e)	621	569	478	317	5	10	20	5	17	104	270	440	2,857
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	23
Total GHG Emissions (Mton CO2e)	916	825	758	572	353	386	528	496	378	407	545	727	6,891
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$44,569	$44,569
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	276	223	258	213	334	346	371	402	315	261	262	263	3,524
Boiler Gas Emissions (Mton CO2e)	621	569	478	317	5	10	20	5	17	104	270	440	2,857
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	23
Total GHG Emissions (Mton CO2e)	905	800	737	530	339	356	391	407	332	365	532	709	6,404
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$199,013	$186,436	$164,443	$131,821	$98,875	$118,103	$212,090	$177,700	$119,366	$115,286	$124,025	$203,273	$1,850,430
Total Cost with LL97 Penalties, Delayed ($)	$199,013	$186,436	$164,443	$131,821	$98,875	$118,103	$212,090	$177,700	$119,366	$115,286	$124,025	$158,703	$1,805,860

2x1.2 MW Recip with Con Ed Reconnection

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	560	502	561	533	714	804	1,183	1,113	786	650	541	561	8,510
Purchased Electricity (MWh)	37	38	37	45	37	36	88	60	39	37	36	37	528
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Demand, May-June, 8AM-6PM (MW)	1.15	1.79	1.10	1.77	1.15	1.12	4.64	2.19	1.57	1.15	1.10	1.05	19.78
Demand, 8AM-10PM (MW)	1.15	1.79	1.10	1.77	1.15	1.12	5.30	2.19	1.57	1.15	1.10	1.05	20.44
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	9,992	8,997	7,494	4,700	57	26	10	3	35	1,268	4,269	6,985	43,836
CHP Steam Production (klbs)	1,021	915	1,022	972	1,207	1,383	2,013	1,903	1,347	1,124	987	1,022	14,916
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	261	279	766	735	332	0	0	0	2,373
Steam to Hot Water (klbs)	311	288	310	312	155	73	23	23	92	220	301	310	2,416
Total Steam Use (klbs)	11,013	9,912	8,516	5,672	1,004	1,131	1,256	1,171	1,049	2,392	5,256	8,007	56,378
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,172	4,955	7,697	48,717
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	1,194	1,070	1,196	1,137	1,495	1,698	2,488	2,343	1,656	1,364	1,155	1,196	17,991
Steam to Hot Water (MMBtu)	311	288	310	312	155	73	23	23	92	220	301	310	2,416
Hot Water Production (MMBtu)	1,505	1,358	1,505	1,449	1,650	1,771	2,511	2,366	1,748	1,583	1,456	1,505	20,407
Dumped Hot Water (MMBtu)	252	226	253	237	404	567	1,267	1,123	543	335	244	253	5,704
Fuel Balance													
Gas to Generators (MMBtu)	5,188	4,647	5,193	4,941	6,426	7,295	10,683	10,069	7,117	5,888	5,016	5,195	77,659
Gas to Boiler (MMBtu)	11,690	10,526	8,856	5,554	68	31	11	3	41	1,499	5,044	8,171	51,494
Total Gas Consumption (MMBtu)	16,877	15,173	14,049	10,495	6,494	7,325	10,695	10,073	7,158	7,387	10,060	13,366	129,153
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	118	106	0	0	0	0	0	0	0	0	0	83	307
Total Oil Consumption (MMBtu)	118	106	0	0	0	0	0	0	0	0	0	83	307
Total Cost Summary													
Minimum Charge ($)	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$339,062
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$6,200	$6,118	$4,525	$5,014	$3,980	$4,717	$13,542	$8,145	$4,746	$4,909	$5,609	$6,131	$73,637
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$1,041	$4,310	$2,034	$1,462	$0	$0	$0	$8,847
Demand Cost, 8AM-10PM ($)	$1,424	$2,213	$1,363	$2,190	$1,424	$2,100	$9,926	$4,105	$2,949	$1,424	$1,363	$1,301	$31,782
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$35,880	$36,586	$34,142	$35,459	$33,660	$36,113	$56,033	$42,540	$37,413	$34,589	$35,226	$35,687	$453,329
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$25,048	$22,555	$18,975	$11,900	$143	$64	$22	$5	$86	$3,209	$10,808	$17,509	$110,326
Boiler Gas Supply Cost ($)	$75,562	$65,994	$51,820	$28,194	$334	$149	$56	$17	$204	$7,498	$26,219	$45,666	$301,714
Total Boiler Gas Cost ($)	$101,027	$88,964	$71,211	$40,510	$893	$629	$494	$438	$706	$11,123	$37,442	$63,591	$417,028
Cogen Gas Delivery Cost ($)	$16,730	$15,047	$16,747	$15,961	$20,585	$23,290	$33,843	$31,931	$22,737	$18,911	$16,194	$16,751	$248,725
Cogen Gas Supply Cost ($)	$35,467	$30,509	$31,831	$26,293	$33,092	$37,184	$55,505	$52,227	$35,858	$30,007	$26,576	$29,639	$424,187
Total Gas Cost ($)	$153,224	$134,519	$119,789	$82,764	$54,571	$61,103	$89,841	$84,596	$59,301	$60,041	$80,213	$109,980	$1,089,940
Oil Cost ($)	$2,467	$2,221	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,725	$6,413
Equipment O&M ($)	$10,591	$9,489	$10,604	$10,088	$13,507	$15,214	$22,376	$21,056	$14,873	$12,285	$10,238	$10,607	$160,926
Total Fuel, Electricity & O&M Cost ($)	$202,161	$182,816	$164,535	$128,311	$101,737	$112,429	$168,250	$148,192	$111,587	$106,915	$125,677	$157,999	$1,710,608
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	11	11	11	13	11	10	26	17	11	11	10	11	153
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Engine GHG Emissions (Mton CO2e)	276	247	276	262	341	387	567	535	378	313	266	276	4,124
Boiler Gas Emissions (Mton CO2e)	621	559	470	295	4	2	1	0	2	80	268	434	2,735
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	23
Total GHG Emissions (Mton CO2e)	916	825	757	570	356	400	594	552	392	403	545	727	7,035
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$83,078	$83,078
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	276	247	276	262	341	387	567	535	378	313	266	276	4,124
Boiler Gas Emissions (Mton CO2e)	621	559	470	295	4	2	1	0	2	80	268	434	2,735
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	23
Total GHG Emissions (Mton CO2e)	905	814	746	557	345	389	568	535	380	392	534	716	6,882
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$202,161	$182,816	$164,535	$128,311	$101,737	$112,429	$168,250	$148,192	$111,587	$106,915	$125,677	$241,076	$1,793,686
Total Cost with LL97 Penalties, Delayed ($)	$202,161	$182,816	$164,535	$128,311	$101,737	$112,429	$168,250	$148,192	$111,587	$106,915	$125,677	$157,999	$1,710,608

2x850 kW Recips with Con Ed Reconnection

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	560	502	561	533	707	792	1,066	1,038	757	641	541	561	8,259
Purchased Electricity (MWh)	37	38	37	45	45	48	205	135	69	46	36	37	779
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Demand, May-June, 8AM-6PM (MW)	1.15	1.79	1.10	1.77	1.72	2.07	12.93	8.51	3.46	1.87	1.10	1.05	38.52
Demand, 8AM-10PM (MW)	1.15	1.79	1.10	1.77	1.72	2.07	13.90	8.55	3.46	1.87	1.10	1.05	39.52
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	9,814	8,838	7,316	4,531	18	13	30	14	20	801	4,097	6,807	42,298
CHP Steam Production (klbs)	1,180	1,057	1,181	1,124	1,631	1,809	2,218	2,198	1,692	1,401	1,142	1,181	17,815
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	700	719	970	1,033	670	0	0	0	4,093
Steam to Hot Water (klbs)	292	271	291	294	92	45	44	34	83	172	283	291	2,193
Total Steam Use (klbs)	10,994	9,895	8,497	5,655	949	1,103	1,278	1,179	1,042	2,202	5,238	7,988	56,020
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,030	4,955	7,697	48,574
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	1,227	1,099	1,229	1,169	1,672	1,833	2,335	2,294	1,736	1,472	1,186	1,229	18,482
Steam to Hot Water (MMBtu)	292	271	291	294	92	45	44	34	83	172	283	291	2,193
Hot Water Production (MMBtu)	1,519	1,371	1,520	1,463	1,764	1,878	2,379	2,328	1,819	1,644	1,470	1,520	20,675
Dumped Hot Water (MMBtu)	267	240	268	251	519	674	1,136	1,084	615	398	258	268	5,978
Fuel Balance													
Gas to Generators (MMBtu)	5,679	5,087	5,685	5,409	7,536	8,372	10,759	10,565	7,920	6,653	5,491	5,686	84,844
Gas to Boiler (MMBtu)	11,481	10,339	8,645	5,354	21	16	36	16	24	946	4,841	7,963	49,683
Total Gas Consumption (MMBtu)	17,161	15,427	14,330	10,763	7,557	8,388	10,795	10,581	7,944	7,599	10,332	13,650	134,526
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	116	104	0	0	0	0	0	0	0	0	0	80	301
Total Oil Consumption (MMBtu)	116	104	0	0	0	0	0	0	0	0	0	80	301
Total Cost Summary													
Minimum Charge ($)	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$339,062
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$6,200	$6,118	$4,525	$5,014	$4,796	$6,285	$31,509	$18,374	$8,367	$6,051	$5,609	$6,131	$108,980
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$1,919	$12,009	$7,899	$3,214	$0	$0	$0	$25,041
Demand Cost, 8AM-10PM ($)	$1,424	$2,213	$1,363	$2,190	$2,133	$3,872	$26,045	$16,017	$6,486	$2,319	$1,363	$1,301	$66,725
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$35,880	$36,586	$34,142	$35,459	$35,184	$40,332	$97,817	$70,545	$46,322	$36,625	$35,226	$35,687	$539,807
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$24,603	$22,155	$18,525	$11,471	$43	$32	$75	$32	$49	$2,026	$10,372	$17,063	$106,445
Boiler Gas Supply Cost ($)	$74,217	$64,826	$50,590	$27,178	$103	$77	$178	$79	$118	$4,734	$25,162	$44,502	$291,764
Total Boiler Gas Cost ($)	$99,236	$87,397	$69,530	$39,065	$561	$524	$669	$527	$583	$7,176	$35,950	$61,981	$403,197
Cogen Gas Delivery Cost ($)	$18,260	$16,417	$18,278	$17,418	$24,041	$26,646	$34,079	$33,475	$25,238	$21,292	$17,673	$18,282	$271,098
Cogen Gas Supply Cost ($)	$38,826	$33,397	$34,845	$28,782	$38,807	$42,678	$55,899	$54,798	$39,903	$33,905	$29,093	$32,445	$463,378
Total Gas Cost ($)	$156,321	$137,211	$122,653	$85,265	$63,409	$69,848	$90,646	$88,800	$65,724	$62,373	$82,716	$112,708	$1,137,674
Oil Cost ($)	$2,423	$2,182	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,681	$6,286
Equipment O&M ($)	$10,591	$9,489	$10,604	$10,088	$13,363	$14,986	$20,160	$19,637	$14,308	$12,121	$10,238	$10,607	$156,190
Total Fuel, Electricity & O&M Cost ($)	$205,215	$185,468	$167,399	$130,812	$111,956	$125,166	$208,623	$178,982	$126,353	$111,120	$128,180	$160,683	$1,839,957
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	11	11	11	13	13	14	59	39	20	13	10	11	225
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Engine GHG Emissions (Mton CO2e)	302	270	302	287	400	445	571	561	421	353	292	302	4,506
Boiler Gas Emissions (Mton CO2e)	610	549	459	284	1	1	2	1	1	50	257	423	2,639
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	22
Total GHG Emissions (Mton CO2e)	931	838	772	585	414	459	633	601	442	417	559	742	7,392
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$178,837	$178,837
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	302	270	302	287	400	445	571	561	421	353	292	302	4,506
Boiler Gas Emissions (Mton CO2e)	610	549	459	284	1	1	2	1	1	50	257	423	2,639
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	22
Total GHG Emissions (Mton CO2e)	920	827	761	572	401	445	573	562	422	404	549	731	7,167
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$205,215	$185,468	$167,399	$130,812	$111,956	$125,166	$208,623	$178,982	$126,353	$111,120	$128,180	$339,520	$2,018,794
Total Cost with LL97 Penalties, Delayed ($)	$205,215	$185,468	$167,399	$130,812	$111,956	$125,166	$208,623	$178,982	$126,353	$111,120	$128,180	$160,683	$1,839,957

1x850 kW Recip with Con Ed Reconnection

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	560	453	525	434	621	580	569	622	538	524	532	534	6,490
Purchased Electricity (MWh)	37	87	73	145	131	261	703	551	288	163	45	64	2,548
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Demand, May-June, 8AM-6PM (MW)	1.15	5.57	2.67	4.98	7.01	12.37	30.55	26.88	12.83	7.68	1.90	2.64	116.24
Demand, 8AM-10PM (MW)	1.15	5.57	2.67	4.98	7.01	12.37	30.95	26.96	12.83	7.68	1.90	2.64	116.71
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	9,814	9,020	7,457	4,917	109	239	441	212	350	1,472	4,136	6,912	45,080
CHP Steam Production (klbs)	1,180	954	1,105	913	1,248	1,164	1,142	1,249	1,080	1,055	1,122	1,126	13,339
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	300	157	109	174	203	0	0	0	943
Steam to Hot Water (klbs)	292	350	357	469	230	258	328	232	338	396	303	340	3,894
Total Steam Use (klbs)	10,994	9,974	8,563	5,830	1,057	1,246	1,474	1,288	1,227	2,527	5,258	8,038	57,476
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,131	4,955	7,697	48,676
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	1,227	992	1,150	950	1,343	1,254	1,230	1,346	1,164	1,134	1,166	1,171	14,127
Steam to Hot Water (MMBtu)	292	350	357	469	230	258	328	232	338	396	303	340	3,894
Hot Water Production (MMBtu)	1,519	1,342	1,506	1,419	1,573	1,513	1,558	1,578	1,501	1,530	1,470	1,511	18,022
Dumped Hot Water (MMBtu)	267	209	253	203	325	304	308	331	290	277	257	258	3,283
Fuel Balance													
Gas to Generators (MMBtu)	5,679	4,591	5,320	4,395	6,176	5,765	5,656	6,188	5,349	5,215	5,397	5,419	65,151
Gas to Boiler (MMBtu)	11,481	10,553	8,812	5,810	129	283	521	251	414	1,739	4,888	8,086	52,968
Total Gas Consumption (MMBtu)	17,161	15,144	14,132	10,206	6,305	6,048	6,176	6,439	5,763	6,955	10,285	13,505	118,119
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	116	107	0	0	0	0	0	0	0	0	0	82	304
Total Oil Consumption (MMBtu)	116	107	0	0	0	0	0	0	0	0	0	82	304
Total Cost Summary													
Minimum Charge ($)	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$28,255	$339,062
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$6,200	$13,938	$8,901	$16,202	$13,986	$34,006	$107,777	$75,104	$34,845	$21,552	$7,051	$10,483	$350,046
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$11,487	$28,370	$24,957	$11,917	$0	$0	$0	$76,730
Demand Cost, 8AM-10PM ($)	$1,424	$6,904	$3,303	$6,169	$8,679	$23,179	$57,985	$50,514	$24,048	$9,512	$2,353	$3,275	$197,346
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$35,880	$49,098	$40,460	$50,626	$50,921	$96,927	$222,387	$178,830	$99,065	$59,319	$37,659	$42,013	$963,184
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$24,603	$22,612	$18,883	$12,449	$274	$604	$1,114	$536	$885	$3,725	$10,472	$17,326	$113,484
Boiler Gas Supply Cost ($)	$74,217	$66,162	$51,568	$29,495	$635	$1,378	$2,586	$1,244	$2,049	$8,702	$25,404	$45,189	$308,630
Total Boiler Gas Cost ($)	$99,236	$89,190	$70,867	$42,360	$1,324	$2,398	$4,116	$2,196	$3,350	$12,843	$36,292	$62,931	$427,103
Cogen Gas Delivery Cost ($)	$18,260	$14,872	$17,141	$14,261	$19,806	$18,528	$18,186	$19,844	$17,232	$16,815	$17,382	$17,449	$209,776
Cogen Gas Supply Cost ($)	$38,826	$30,140	$32,607	$23,388	$31,804	$29,389	$29,383	$32,096	$26,951	$26,577	$28,598	$30,918	$360,677
Total Gas Cost ($)	$156,321	$134,202	$120,615	$80,010	$52,934	$50,315	$51,685	$54,137	$47,534	$56,235	$82,272	$111,297	$997,556
Oil Cost ($)	$2,423	$2,227	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,707	$6,357
Equipment O&M ($)	$10,591	$8,566	$9,923	$8,198	$11,738	$10,963	$10,754	$11,767	$10,171	$9,900	$10,063	$10,107	$122,741
Total Fuel, Electricity & O&M Cost ($)	$205,215	$194,092	$170,998	$138,834	$115,593	$158,204	$284,825	$244,733	$156,770	$125,454	$129,994	$165,124	$2,089,837
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	11	25	21	42	38	75	203	159	83	47	13	18	736
Local Law 97 Grid Emissions Factor (Mton/MWh)	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289	0.289
Engine GHG Emissions (Mton CO2e)	302	244	283	233	328	306	300	329	284	277	287	288	3,460
Boiler Gas Emissions (Mton CO2e)	610	560	468	309	7	15	28	13	22	92	260	429	2,813
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	23
Total GHG Emissions (Mton CO2e)	931	837	772	584	373	397	531	501	389	417	559	742	7,032
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$82,346	$82,346
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine GHG Emissions (Mton CO2e)	302	244	283	233	328	306	300	329	284	277	287	288	3,460
Boiler Gas Emissions (Mton CO2e)	610	560	468	309	7	15	28	13	22	92	260	429	2,813
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	6	23
Total GHG Emissions (Mton CO2e)	920	812	751	542	335	321	328	342	306	369	546	723	6,296
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$205,215	$194,092	$170,998	$138,834	$115,593	$158,204	$284,825	$244,733	$156,770	$125,454	$129,994	$247,470	$2,172,183
Total Cost with LL97 Penalties, Delayed ($)	$205,215	$194,092	$170,998	$138,834	$115,593	$158,204	$284,825	$244,733	$156,770	$125,454	$129,994	$165,124	$2,089,837

Existing Engines, Primary Dispatch Oil

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Purchased Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,039
Demand, May-June, 8AM-6PM (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand, 8AM-10PM (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	9,488	8,526	6,990	4,184	5	2	0	0	1	672	3,780	6,481	40,131
CHP Steam Production (klbs)	1,279	1,156	1,280	1,239	1,487	1,695	2,575	2,378	1,665	1,388	1,237	1,280	18,661
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	608	627	1,322	1,224	679	0	0	0	4,460
Steam to Hot Water (klbs)	65	58	64	62	27	10	4	1	22	33	63	64	474
Total Steam Use (klbs)	10,767	9,682	8,270	5,423	884	1,071	1,253	1,154	988	2,060	5,018	7,762	54,332
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,028	4,955	7,697	48,573
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	1,759	1,589	1,760	1,702	2,023	2,262	3,485	3,212	2,238	1,924	1,701	1,760	25,416
Steam to Hot Water (MMBtu)	65	58	64	62	27	10	4	1	22	33	63	64	474
Hot Water Production (MMBtu)	1,823	1,648	1,824	1,765	2,050	2,272	3,489	3,213	2,260	1,957	1,763	1,825	25,890
Dumped Hot Water (MMBtu)	579	524	580	561	807	1,069	2,246	1,970	1,057	715	560	581	11,249
Fuel Balance													
Gas to Generators (MMBtu)	4,046	3,657	4,050	3,917	4,823	5,480	8,319	7,686	5,387	4,488	3,913	4,051	59,817
Gas to Boiler (MMBtu)	11,100	9,974	8,260	4,945	6	3	0	0	2	794	4,467	7,582	47,133
Total Gas Consumption (MMBtu)	15,146	13,631	12,310	8,862	4,829	5,483	8,319	7,686	5,389	5,283	8,380	11,633	106,950
Oil to Generators (MMBtu)	5,060	4,573	5,064	4,898	6,023	6,667	10,233	9,424	6,588	5,643	4,892	5,065	74,131
Oil to Boilers (MMBtu)	112	101	0	0	0	0	0	0	0	0	0	77	289
Total Oil Consumption (MMBtu)	5,172	4,674	5,064	4,898	6,023	6,667	10,233	9,424	6,588	5,643	4,892	5,142	74,420
Total Cost Summary													
Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, 8AM-10PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$23,784	$21,372	$17,699	$10,594	$12	$4	$0	$0	$1	$1,700	$9,571	$16,246	$100,985
Boiler Gas Supply Cost ($)	$71,749	$62,535	$48,336	$25,101	$32	$14	$0	$0	$8	$3,974	$23,219	$42,372	$277,340
Total Boiler Gas Cost ($)	$95,949	$84,323	$66,451	$36,112	$459	$434	$416	$416	$425	$6,090	$33,206	$59,035	$383,314
Cogen Gas Delivery Cost ($)	$28,933	$26,207	$28,959	$28,029	$34,352	$38,402	$58,350	$53,857	$37,870	$32,125	$27,996	$28,965	$424,046
Cogen Gas Supply Cost ($)	$62,251	$54,029	$55,861	$46,909	$55,854	$61,917	$96,388	$88,742	$60,336	$51,627	$46,653	$52,013	$732,580
Total Gas Cost ($)	$187,133	$164,560	$151,271	$111,050	$90,666	$100,753	$155,154	$143,015	$98,631	$89,842	$107,854	$140,012	$1,539,941
Oil Cost ($)	$108,052	$97,653	$105,807	$102,339	$125,847	$139,296	$213,807	$196,892	$137,655	$117,890	$102,214	$99,707	$1,547,160
Equipment O&M ($)	$8,157	$7,375	$8,167	$7,898	$10,263	$11,482	$17,367	$16,023	$11,277	$9,381	$7,886	$8,169	$123,444
Total Fuel, Electricity & O&M Cost ($)	$303,343	$269,587	$265,245	$221,287	$226,776	$251,531	$386,328	$355,930	$247,563	$217,113	$217,955	$247,887	$3,210,545

Existing Engines, Primary Dispatch Gas

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	0.86	0.86	0.86	0.86	1.47	1.62	2.61	2.41	1.76	1.12	0.86	0.86	16.15
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Purchased Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Demand, May-June, 8AM-6PM (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand, 8AM-10PM (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand, All Hours, All Days (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	9,506	8,542	7,008	4,202	5	1	0	0	2	689	3,798	6,499	40,254
CHP Steam Production (klbs)	1,246	1,126	1,247	1,206	1,497	1,687	2,545	2,370	1,655	1,372	1,205	1,247	18,402
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	620	624	1,296	1,216	671	0	0	0	4,428
Steam to Hot Water (klbs)	49	44	49	48	26	4	0	0	20	30	48	49	368
Total Steam Use (klbs)	10,752	9,668	8,255	5,408	882	1,064	1,249	1,154	986	2,061	5,003	7,746	54,228
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,031	4,955	7,697	48,576
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	1,833	1,657	1,834	1,774	2,093	2,376	3,495	3,292	2,321	1,932	1,773	1,835	26,215
Steam to Hot Water (MMBtu)	49	44	49	48	26	4	0	0	20	30	48	49	368
Hot Water Production (MMBtu)	1,882	1,701	1,884	1,822	2,119	2,379	3,495	3,292	2,341	1,962	1,821	1,884	26,582
Dumped Hot Water (MMBtu)	641	580	642	621	875	1,176	2,252	2,049	1,139	721	619	642	11,957
Fuel Balance													
Gas to Generators (MMBtu)	8,760	7,917	8,767	8,480	10,504	11,811	14,595	14,148	11,416	9,646	8,471	8,769	123,282
Gas to Boiler (MMBtu)	11,121	9,993	8,282	4,966	6	1	0	0	3	814	4,488	7,604	47,279
Total Gas Consumption (MMBtu)	19,881	17,911	17,049	13,446	10,510	11,812	14,595	14,148	11,418	10,460	12,959	16,372	170,561
Oil to Generators (MMBtu)	0	0	0	0	0	25	3,357	2,535	195	0	0	0	6,112
Oil to Boilers (MMBtu)	112	101	0	0	0	0	0	0	0	0	0	77	290
Total Oil Consumption (MMBtu)	112	101	0	0	0	25	3,357	2,535	195	0	0	77	6,402
Total Cost Summary													
Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electric Delivery (w/Riders) Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, 8AM-10PM ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$23,830	$21,414	$17,746	$10,640	$11	$0	$0	$0	$4	$1,743	$9,616	$16,292	$101,297
Boiler Gas Supply Cost ($)	$71,888	$62,656	$48,463	$25,208	$31	$6	$0	$0	$14	$4,074	$23,329	$42,492	$278,161
Total Boiler Gas Cost ($)	$96,134	$84,486	$66,625	$36,263	$458	$422	$416	$416	$433	$6,233	$33,361	$59,200	$384,447
Cogen Gas Delivery Cost ($)	$27,852	$25,229	$27,875	$26,982	$33,284	$37,431	$56,479	$52,531	$36,729	$30,611	$26,952	$27,880	$409,836
Cogen Gas Supply Cost ($)	$59,885	$51,973	$53,734	$45,125	$54,094	$60,332	$93,266	$86,533	$58,496	$49,155	$44,882	$50,031	$707,505
Total Gas Cost ($)	$183,871	$161,687	$148,234	$108,369	$87,837	$98,185	$150,161	$139,479	$95,658	$85,999	$105,195	$137,112	$1,501,787
Oil Cost ($)	$2,347	$2,109	$0	$0	$0	$525	$70,134	$52,971	$4,066	$0	$0	$1,605	$133,756
Equipment O&M ($)	$8,157	$7,374	$8,166	$7,898	$10,263	$11,482	$17,370	$16,026	$11,278	$9,381	$7,886	$8,168	$123,449
Total Fuel, Electricity & O&M Cost ($)	$194,375	$171,171	$156,400	$116,267	$98,100	$110,192	$237,665	$208,476	$111,002	$95,380	$113,081	$146,885	$1,758,992

Con Ed Reconnection, High Tension, Air Source Heat Pumps

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	3.9	4.3	3.6	2.7	1.5	1.6	2.6	2.4	1.8	1.6	2.8	3.2	32
Total Electricity Load (MWh)	2,166	1,950	1,800	1,364	751	841	1,272	1,173	826	1,018	1,303	1,726	16,190
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)													
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Electricity to Residential Heating (MWh)	1,568	1,410	1,203	786	0	0	0	0	0	331	726	1,128	7,152
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	2,166	1,950	1,800	1,364	751	841	1,272	1,173	826	1,018	1,303	1,726	16,190
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	2,166	1,950	1,800	1,364	751	841	1,272	1,173	826	1,018	1,303	1,726	16,190
Demand, May-June, 8AM-6PM (MW)	0.0	0.0	0.0	0.0	0.0	1.6	2.6	2.3	1.8	0.0	0.0	0.0	8.3
Demand, 8AM-10PM (MW)	3.9	4.2	3.4	2.5	1.4	1.6	2.6	2.3	1.8	1.6	2.8	3.1	31.1
Demand, All Hours, All Days (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam Balance													
Steam Heating Load (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Steam Production (klbs)	1,280	1,156	1,280	1,239	2,137	2,299	2,529	2,434	2,204	1,280	1,239	1,280	20,357
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Total Steam Use (klbs)	1,280	1,156	1,280	1,239	2,137	2,299	2,529	2,434	2,204	1,280	1,239	1,280	20,357
Steam to Heating (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Hot Water Production (MMBtu)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Balance													
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	1,497	1,353	1,513	1,464	2,525	2,717	2,988	2,876	2,605	1,513	1,464	1,497	24,012
Total Gas Consumption (MMBtu)	1,497	1,353	1,513	1,464	2,525	2,717	2,988	2,876	2,605	1,513	1,464	1,497	24,012
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	15	14	0	0	0	0	0	0	0	0	0	15	44
Total Oil Consumption (MMBtu)	15	14	0	0	0	0	0	0	0	0	0	15	44
Total Cost Summary													
Minimum Charge ($)	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$1,983
Electric Delivery (w/Riders) Cost ($)	$19,761	$17,795	$16,429	$12,444	$6,857	$7,671	$11,602	$10,705	$7,534	$9,288	$11,894	$15,750	$147,731
Electricity Supply Cost ($)	$360,947	$312,562	$218,982	$152,678	$80,393	$109,540	$194,974	$159,920	$99,942	$134,338	$203,072	$284,488	$2,311,836
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$19,851	$32,057	$28,287	$21,576	$0	$0	$0	$101,771
Demand Cost, 8AM-10PM ($)	$84,339	$89,965	$72,772	$53,664	$29,738	$47,845	$77,262	$68,176	$52,001	$34,593	$60,719	$67,731	$738,805
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$465,212	$420,488	$308,349	$218,952	$117,153	$185,072	$316,061	$267,253	$181,219	$178,385	$275,850	$368,135	$3,302,127
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$3,207	$2,896	$3,239	$3,135	$5,410	$5,820	$6,402	$6,161	$5,580	$3,239	$3,135	$3,207	$51,432
Boiler Gas Supply Cost ($)	$9,680	$8,480	$8,851	$7,431	$12,426	$13,235	$14,839	$14,258	$12,889	$7,568	$7,608	$8,369	$125,634
Total Boiler Gas Cost ($)	$13,303	$11,792	$12,506	$10,981	$18,251	$19,471	$21,656	$20,835	$18,885	$11,223	$11,159	$11,991	$182,054
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$13,303	$11,792	$12,506	$10,981	$18,251	$19,471	$21,656	$20,835	$18,885	$11,223	$11,159	$11,991	$182,054
Oil Cost ($)	$316	$285	$0	$0	$0	$0	$0	$0	$0	$0	$0	$316	$918
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fuel, Electricity & O&M Cost ($)	$478,830	$432,566	$320,855	$229,933	$135,404	$204,543	$337,717	$288,087	$200,104	$189,608	$287,009	$380,442	$3,485,098
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	626	564	520	394	217	243	367	339	239	294	377	499	4,678
Local Law 97 Grid Emissions Factor (Mton/MWh)													
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	80	72	80	78	134	144	159	153	138	80	78	80	1,275
Boiler Oil Emissions (Mton CO2e)	1	1	0	0	0	0	0	0	0	0	0	1	3
Total GHG Emissions (Mton CO2e)	706	636	601	472	351	387	526	492	377	374	454	579	5,957
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)													
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	80	72	80	78	134	144	159	153	138	80	78	80	1,275
Boiler Oil Emissions (Mton CO2e)	1	1	0	0	0	0	0	0	0	0	0	1	3
Total GHG Emissions (Mton CO2e)	81	73	80	78	134	144	159	153	138	80	78	81	1,279
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$478,830	$432,566	$320,855	$229,933	$135,404	$204,543	$337,717	$288,087	$200,104	$189,608	$287,009	$380,442	$3,485,098
Total Cost with LL97 Penalties, Delayed ($)	$478,830	$432,566	$320,855	$229,933	$135,404	$204,543	$337,717	$288,087	$200,104	$189,608	$287,009	$380,442	$3,485,098

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	8.2	8.9	7.2	5.0	3.2	3.4	4.2	3.8	3.3	3.1	5.5	6.4	62.3
Total Electricity Load (MWh)	4,206	3,787	3,453	2,561	1,386	1,524	2,024	1,897	1,481	1,745	2,438	3,299	29,803
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)													
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Electricity to Steam/HW (MWh)	3,609	3,247	2,855	1,983	634	684	753	724	655	1,058	1,861	2,701	20,765
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	4,206	3,787	3,453	2,561	1,386	1,524	2,024	1,897	1,481	1,745	2,438	3,299	29,803
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	4,206	3,787	3,453	2,561	1,386	1,524	2,024	1,897	1,481	1,745	2,438	3,299	29,803
Demand, May-June, 8AM-6PM (MW)	0.0	0.0	0.0	0.0	0.0	3.4	4.2	3.7	3.3	0.0	0.0	0.0	14.5
Demand, 8AM-10PM (MW)	8.2	8.8	7.2	4.9	2.8	3.4	4.2	3.7	3.3	3.1	5.5	6.4	61.6
Demand, All Hours, All Days (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	11,945	10,746	9,449	6,563	2,100	2,263	2,492	2,397	2,168	3,502	6,158	8,940	68,724
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Total Steam Use (klbs)	11,945	10,746	9,449	6,563	2,100	2,263	2,492	2,397	2,168	3,502	6,158	8,940	68,724
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Hot Water Production (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Balance													
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Gas Consumption (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Oil Consumption (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Cost Summary													
Minimum Charge ($)	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$1,983
Electric Delivery (w/Riders) Cost ($)	$38,384	$34,555	$31,507	$23,372	$12,646	$13,911	$18,472	$17,313	$13,513	$15,921	$22,246	$30,106	$271,946
Electricity Supply Cost ($)	$701,113	$606,935	$419,964	$286,747	$148,272	$198,640	$310,416	$258,635	$179,247	$230,270	$379,810	$543,799	$4,263,848
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$41,203	$50,982	$45,247	$40,844	$0	$0	$0	$178,277
Demand Cost, 8AM-10PM ($)	$178,336	$190,814	$155,486	$106,323	$61,554	$99,306	$122,876	$109,053	$98,441	$68,075	$119,297	$138,965	$1,448,528
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$917,998	$832,470	$607,122	$416,607	$222,638	$353,226	$502,912	$430,414	$332,211	$314,432	$521,519	$713,036	$6,164,583
Boiler Gas Minimum Charge ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Boiler Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Boiler Gas Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oil Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fuel, Electricity & O&M Cost ($)	$917,998	$832,470	$607,122	$416,607	$222,638	$353,226	$502,912	$430,414	$332,211	$314,432	$521,519	$713,036	$6,164,583
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	1,216	1,094	998	740	400	441	585	548	428	504	704	953	8,612
Local Law 97 Grid Emissions Factor (Mton/MWh)													
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Oil Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total GHG Emissions (Mton CO2e)	1,216	1,094	998	740	400	441	585	548	428	504	704	953	8,612
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$505,718	$505,718
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)													
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Oil Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$917,998	$832,470	$607,122	$416,607	$222,638	$353,226	$502,912	$430,414	$332,211	$314,432	$521,519	$1,218,754	$6,670,301
Total Cost with LL97 Penalties, Delayed ($)	$917,998	$832,470	$607,122	$416,607	$222,638	$353,226	$502,912	$430,414	$332,211	$314,432	$521,519	$713,036	$6,164,583

Con Ed Reconnection, High Tension, Geothermal

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	1.1	1.1	1.0	1.0	1.4	1.6	2.6	2.4	1.7	1.1	1.0	1.0	17.1
Total Electricity Load (MWh)	725	655	696	642	745	829	1,259	1,161	816	710	637	690	9,566
Electricity to Residential Cooling (MWh)	0	0	0	0	133	228	596	507	215	77	0	0	1,755
Electricity to Geothermal Heat Pump (MWh)	128	115	98	64	14	23	66	56	23	36	59	92	775
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	725	655	696	642	745	829	1,259	1,161	816	710	637	690	9,566
Solar PV (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electricity Supply (MWh)	725	655	696	642	745	829	1,259	1,161	816	710	637	690	9,566
Demand, May-June, 8AM-6PM (MW)	0.0	0.0	0.0	0.0	0.0	1.6	2.6	2.3	1.7	0.0	0.0	0.0	8.2
Demand, 8AM-10PM (MW)	1.1	1.1	1.0	1.0	1.3	1.6	2.6	2.3	1.7	1.1	1.0	1.0	16.9
Demand, All Hours, All Days (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam Balance													
Steam Heating Load (klbs)	9,174	8,251	7,034	4,595	0	0	0	0	0	1,937	4,247	6,598	41,834
Geothermal Heating Load (MMBtu)	1,529	1,373	1,172	766	0	0	0	0	0	323	708	1,100	6,970
Boiler Steam Production (klbs)	10,454	9,407	8,314	5,833	1,901	2,204	2,464	2,317	2,040	3,217	5,486	7,878	61,514
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Total Steam Use (klbs)	10,454	9,407	8,314	5,833	1,901	2,204	2,464	2,317	2,040	3,217	5,486	7,878	61,514
Steam to Heating (klbs)	9,174	8,251	7,034	4,595	0	0	0	0	0	1,937	4,247	6,598	41,157
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	123,431	197,117	561,169	478,571	193,322	73,717	0	0	1,627,328
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	123,431	197,117	561,169	478,571	193,322	73,717	0	0	1,627,328
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	20,572	32,853	93,528	79,762	32,220	12,286	0	0	271,221
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Hot Water Production (MMBtu)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Balance													
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	12,230	11,005	9,824	6,893	2,247	2,605	2,911	2,738	2,411	3,801	6,483	9,216	72,364
Total Gas Consumption (MMBtu)	12,230	11,005	9,824	6,893	2,247	2,605	2,911	2,738	2,411	3,801	6,483	9,216	72,364
Oil to Generators (MMBtu)													
Oil to Boilers (MMBtu)	124	111	0	0	0	0	0	0	0	0	0	93	328
Total Oil Consumption (MMBtu)	124	111	0	0	0	0	0	0	0	0	0	93	328
Total Cost Summary													
Minimum Charge ($)	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$1,983
Electric Delivery (w/Riders) Cost ($)	$6,618	$5,977	$6,352	$5,862	$6,799	$7,569	$11,487	$10,594	$7,446	$6,480	$5,809	$6,297	$87,289
Electricity Supply Cost ($)	$120,880	$104,985	$84,662	$71,914	$79,716	$108,074	$193,036	$158,254	$98,765	$93,724	$99,183	$113,750	$1,326,943
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$19,458	$32,074	$28,107	$21,188	$0	$0	$0	$100,826
Demand Cost, 8AM-10PM ($)	$23,322	$23,304	$22,149	$21,142	$29,124	$46,896	$77,303	$67,742	$51,066	$24,608	$21,810	$22,143	$430,609
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$150,986	$134,431	$113,328	$99,083	$115,804	$182,161	$314,065	$264,863	$178,630	$124,977	$126,967	$142,356	$1,947,651
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$26,206	$23,582	$21,051	$14,770	$4,813	$5,580	$6,237	$5,865	$5,164	$8,144	$13,890	$19,748	$155,050
Boiler Gas Supply Cost ($)	$79,053	$68,999	$57,489	$34,993	$11,056	$12,689	$14,457	$13,572	$11,929	$19,018	$33,694	$51,503	$408,453
Total Boiler Gas Cost ($)	$105,675	$92,997	$78,957	$50,180	$16,285	$18,684	$21,110	$19,853	$17,509	$27,577	$48,000	$71,666	$568,492
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$105,675	$92,997	$78,957	$50,180	$16,285	$18,684	$21,110	$19,853	$17,509	$27,577	$48,000	$71,666	$568,492
Oil Cost ($)	$2,581	$2,323	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,945	$6,848
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fuel, Electricity & O&M Cost ($)	$259,242	$229,751	$192,285	$149,263	$132,089	$200,845	$335,174	$284,716	$196,139	$152,555	$174,967	$215,967	$2,522,991
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	210	189	201	186	215	240	364	335	236	205	184	199	2,764
Local Law 97 Grid Emissions Factor (Mton/MWh)													
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	650	584	522	366	119	138	155	145	128	202	344	489	3,843
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	7	24
Total GHG Emissions (Mton CO2e)	868	782	723	552	335	378	518	481	364	407	528	696	6,632
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)													
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	650	584	522	366	119	138	155	145	128	202	344	489	3,843
Boiler Oil Emissions (Mton CO2e)	9	8	0	0	0	0	0	0	0	0	0	7	24
Total GHG Emissions (Mton CO2e)	659	593	522	366	119	138	155	145	128	202	344	496	3,868
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$259,242	$229,751	$192,285	$149,263	$132,089	$200,845	$335,174	$284,716	$196,139	$152,555	$174,967	$215,967	$2,522,991
Total Cost with LL97 Penalties, Delayed ($)	$259,242	$229,751	$192,285	$149,263	$132,089	$200,845	$335,174	$284,716	$196,139	$152,555	$174,967	$215,967	$2,522,991

Con Ed Reconnection, High Tension, Solar PV

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Electricity Balance													
System Demand (MW)	1	1	1	1	1	2	3	2	2	1	1	1	16
Total Electricity Load (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Electricity to Residential Cooling (MWh)	0	0	0	0	154	262	674	576	248	89	0	0	2,002
Incremental Auxiliary Loads (MWh)													
System Electricity (Base Bldg Plug) Load (MWh)	597	540	598	578	598	579	597	598	578	598	577	598	7,036
Generated Electricity (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Electricity (MWh)	590	531	586	567	739	828	1,259	1,161	814	676	570	591	8,913
Solar PV (MWh)	8	9	12	11	13	13	12	12	11	10	7	7	125
Total Electricity Supply (MWh)	597	540	598	578	751	841	1,272	1,173	826	687	577	598	9,038
Demand, May-June, 8AM-6PM (MW)	0	0	0	0	0	2	3	2	2	0	0	0	8
Demand, 8AM-10PM (MW)	1	1	1	1	1	2	3	2	2	1	1	1	16
Demand, All Hours, All Days (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam Balance													
Steam Heating Load (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Boiler Steam Production (klbs)	11,983	10,780	9,486	6,599	1,901	2,204	2,464	2,317	2,040	3,539	6,194	8,977	68,484
CHP Steam Production (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Chilling (klbs)	0	0	0	0	857	1,060	1,249	1,154	966	0	0	0	5,286
Vented Steam (klbs)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (klbs)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Total Steam Use (klbs)	11,983	10,780	9,486	6,599	1,901	2,204	2,464	2,317	2,040	3,539	6,194	8,977	68,484
Steam to Heating (klbs)	10,703	9,624	8,206	5,360	0	0	0	0	0	2,259	4,955	7,697	48,804
Chilled Water Balance													
Residential Cooling Load (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Commercial Cooling Load (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Residential HVAC Units (ton-hr)	0	0	0	0	144,003	229,970	654,697	558,333	225,543	86,004	0	0	1,898,549
Absorption Chiller Production (ton-hr)	0	0	0	0	50,409	62,375	73,458	67,874	56,806	0	0	0	310,923
Geothermal Cooling Production (ton-hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hot Water													
Domestic Hot Water Load (MMBtu)	1,243	1,123	1,243	1,203	1,243	1,203	1,243	1,243	1,203	1,243	1,203	1,243	14,634
Jacket Water Hot Water Production (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Steam to Hot Water (MMBtu)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Hot Water Production (MMBtu)	1,280	1,156	1,280	1,239	1,280	1,239	1,280	1,280	1,239	1,280	1,239	1,280	15,071
Dumped Hot Water (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Balance													
Gas to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to Boiler (MMBtu)	14,018	12,611	11,210	7,798	2,247	2,605	2,911	2,738	2,411	4,183	7,319	10,502	80,553
Total Gas Consumption (MMBtu)	14,018	12,611	11,210	7,798	2,247	2,605	2,911	2,738	2,411	4,183	7,319	10,502	80,553
Oil to Generators (MMBtu)	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil to Boilers (MMBtu)	142	127	0	0	0	0	0	0	0	0	0	106	375
Total Oil Consumption (MMBtu)	142	127	0	0	0	0	0	0	0	0	0	106	375
Total Cost Summary													
Minimum Charge ($)	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$165	$1,983
Electric Delivery (w/Riders) Cost ($)	$5,381	$4,846	$5,349	$5,177	$6,740	$7,556	$11,489	$10,596	$7,432	$6,172	$5,204	$5,391	$81,334
Electricity Supply Cost ($)	$98,288	$85,116	$71,297	$63,517	$79,020	$107,893	$193,061	$158,295	$98,584	$89,270	$88,857	$97,386	$1,230,584
Demand Cost, May-June, 8AM-6PM ($)	$0	$0	$0	$0	$0	$19,477	$31,320	$28,204	$20,685	$0	$0	$0	$99,687
Demand Cost, 8AM-10PM ($)	$18,611	$18,607	$18,611	$18,608	$29,311	$46,943	$75,487	$67,976	$49,854	$24,142	$18,607	$18,607	$405,365
Demand Cost, All Hours, All Days ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Electric Cost ($)	$122,445	$108,734	$95,422	$87,468	$115,235	$182,034	$311,523	$265,236	$176,721	$119,749	$112,834	$121,550	$1,818,952
Boiler Gas Minimum Charge ($)	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$416	$4,989
Boiler Gas Delivery Cost ($)	$30,039	$27,024	$24,020	$16,710	$4,813	$5,580	$6,237	$5,865	$5,164	$8,961	$15,683	$22,505	$172,600
Boiler Gas Supply Cost ($)	$90,616	$79,069	$65,596	$39,587	$11,056	$12,689	$14,457	$13,572	$11,929	$20,926	$38,042	$58,692	$456,230
Total Boiler Gas Cost ($)	$121,070	$106,508	$90,032	$56,713	$16,285	$18,684	$21,110	$19,853	$17,509	$30,303	$54,140	$81,612	$633,819
Cogen Gas Delivery Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cogen Gas Supply Cost ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gas Cost ($)	$121,070	$106,508	$90,032	$56,713	$16,285	$18,684	$21,110	$19,853	$17,509	$30,303	$54,140	$81,612	$633,819
Oil Cost ($)	$2,958	$2,661	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,216	$7,836
Equipment O&M ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fuel, Electricity & O&M Cost ($)	$246,474	$217,904	$185,454	$144,181	$131,520	$200,718	$332,633	$285,089	$194,230	$150,052	$166,974	$205,379	$2,460,607
Greenhouse Gas Emissions, LL97													
Purchased Elec GHG Emissions (Mton CO2e)	170	153	169	164	213	239	364	336	235	195	165	171	2,576
Local Law 97 Grid Emissions Factor (Mton/MWh)													
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	745	670	595	414	119	138	155	145	128	222	389	558	4,278
Boiler Oil Emissions (Mton CO2e)	11	9	0	0	0	0	0	0	0	0	0	8	28
Total GHG Emissions (Mton CO2e)	925	833	765	578	333	378	518	481	363	418	554	736	6,882
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	6,725	6,725
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$42,032	$42,032
Greenhouse Gas Emissions, LL97 Delayed													
Purchased Elec GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Law 97 Grid Emissions Factor (Mton/MWh)													
Engine GHG Emissions (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
Boiler Gas Emissions (Mton CO2e)	745	670	595	414	119	138	155	145	128	222	389	558	4,278
Boiler Oil Emissions (Mton CO2e)	11	9	0	0	0	0	0	0	0	0	0	8	28
Total GHG Emissions (Mton CO2e)	755	679	595	414	119	138	155	145	128	222	389	566	4,306
GHG Emissions Limit [Local Law 97] (Mton CO2e)	0	0	0	0	0	0	0	0	0	0	0	0	0
GHG Emissions Penalty ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost with LL97 Penalties													
Total Cost with LL97 Penalties ($)	$246,474	$217,904	$185,454	$144,181	$131,520	$200,718	$332,633	$285,089	$194,230	$150,052	$166,974	$247,410	$2,502,638
Total Cost with LL97 Penalties, Delayed ($)	$246,474	$217,904	$185,454	$144,181	$131,520	$200,718	$332,633	$285,089	$194,230	$150,052	$166,974	$205,379	$2,460,607

Attachment C

Steam Trap Survey

Attachment C, Steam Trap Survey

Waldron was informed by Big 6 Towers operations staff that there was steam leaking into the condensate system, and cold water was being injected into the condensate system to maintain condensate temperature. Waldron performed a walkdown of steam traps in Buildings 1-7, including building traps in the basement of each building, as well as radiator traps in vacant apartments to identify potential steam trap leaks, causing steam to enter into the condensate system.

During the walkdown of steam traps, photos were taken of each of the observed traps using a thermal imaging camera. The photos were then evaluated to determine if steam was leaking by the traps. This was done by looking at the difference between the temperature of the upstream and downstream trap piping. The following table and photos identify the trap location, inlet piping temperature, and outlet piping temperature. Waldron is considering a trap to possibly be leaking if the outlet piping temperature was 170 °F or greater. The severity of the trap leak is determined by how close the outlet piping temperature was to the inlet piping temperature. The temperature difference between the inlet piping temperature and outlet piping temperature were divided up into the following categories:

- outlet piping temperatures within 5°F of the inlet piping temperature
- outlet piping temperatures between 6 and 15°F of the inlet piping temperature
- outlet piping temperatures between 16 and 30°F of the inlet piping temperature
- outlet piping temperatures between 31 and 50°F of the inlet piping temperature

During the walkdown, 42 traps were observed. The following tables include a breakdown of where the traps were located and how many traps were active based on thermal imaging.

Total Traps	Basement Traps	Radiator Traps
42	28	14

Active Traps	Active Basement Traps	Active Radiator Traps
33	23	10

The following table includes the results of the trap survey of the building-basement traps.

Active Basement Traps	Traps with Outlet Piping >170 °F	Outlet Piping Within 5 °F of Inlet Piping	Outlet Piping Between 6 and 15 °F of Inlet Piping	Outlet Piping Between 16 and 30 °F of Inlet Piping	Outlet Piping Between 31 and 50 °F of Inlet Piping
23	19	7	7	3	2
	83%	30.4%	30.4%	13.0%	8.7%

The following table includes the results of the trap survey of the individual radiator traps.

Active Radiator Traps	Traps with Outlet Piping >170 °F	Outlet Piping Within 5 °F of Inlet Piping	Outlet Piping Between 16 and 30 °F of Inlet Piping
10	2	1	1
	20%	10.0%	10.0%

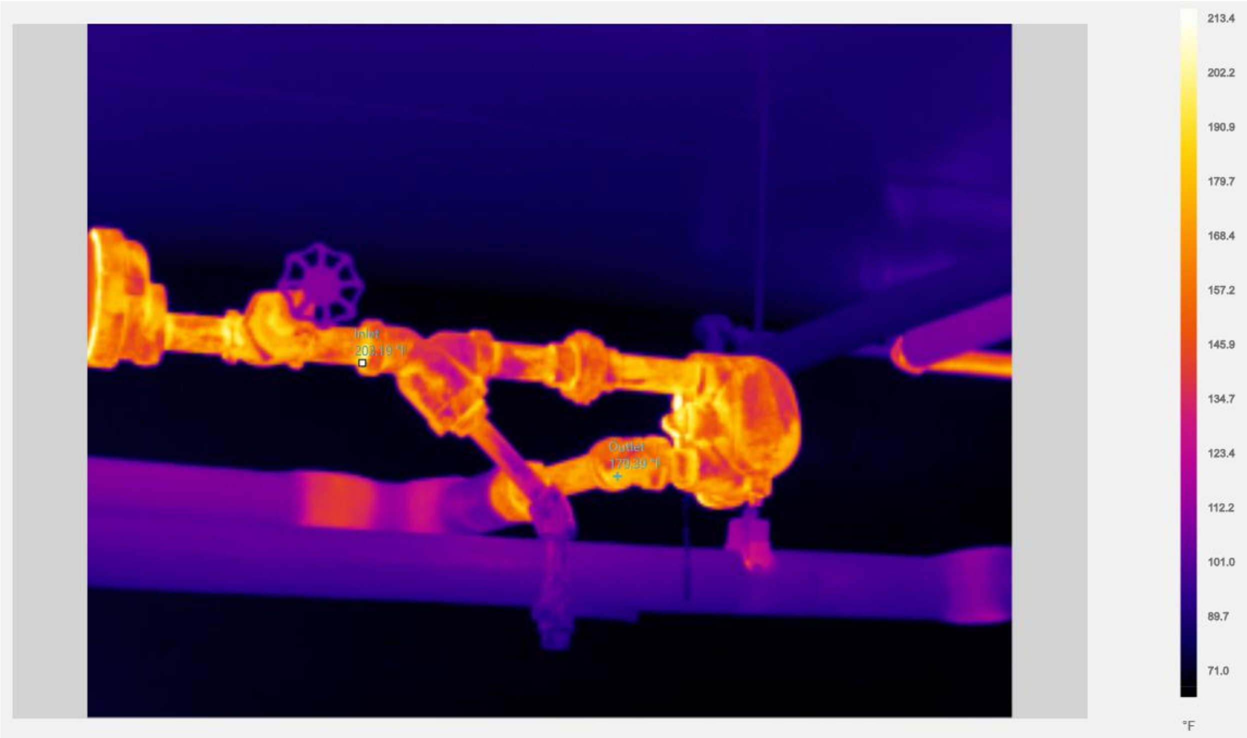
A leak-by analysis was performed only on the building-basement traps based on the difference between the trap inlet piping temperature and outlet piping temperature to estimate the amount of steam leaking into the condensate system. If the trap outlet piping temperature was within 5°F of the inlet piping temperature, it was assumed that there was a 10% leak-by rate in the trap. If trap outlet piping temperature was between 6 and 15°F of the inlet piping temperature, it was assumed that there was a 5% leak-by rate in the trap. If the difference between the trap outlet piping temperature and inlet piping temperature was greater than 15°F, it was assumed, for the purposes of this analysis, that the trap was not leaking. The elevated trap outlet piping temperature in these cases could have been caused by normal trap cycling and would require additional investigation to determine if the traps were leaking.

	Outlet Piping Within 5°F of Inlet Piping	Outlet Piping Between 6 and 15°F of Inlet Piping	Outlet Piping Between 16 and 30°F of Inlet Piping	Outlet Piping Between 31 and 50°F of Inlet Piping
% Leak	10%	5%	-	-
Trap Leak Rate (lb/hr)	225	11.25	-	-
# of Traps	7	7	-	-
Total Leak (lb/hr)	1575	78.75	-	-

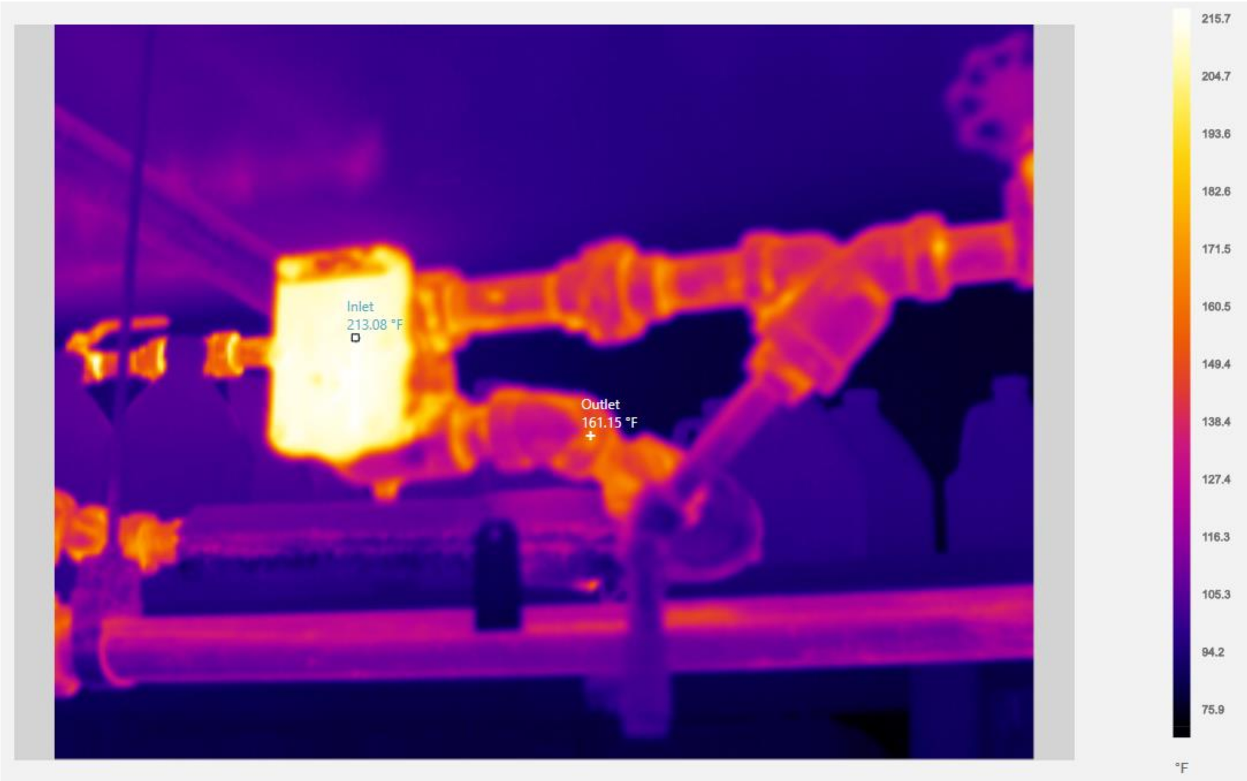
Based on the analysis described above, an estimated 1,654 lb/hr of steam is leaking by the building-basement traps and into the condensate system.

Waldron recommends a detailed trap assessment be performed to more accurately determine the quantity of traps that are leaking, and the severity of the leaks.

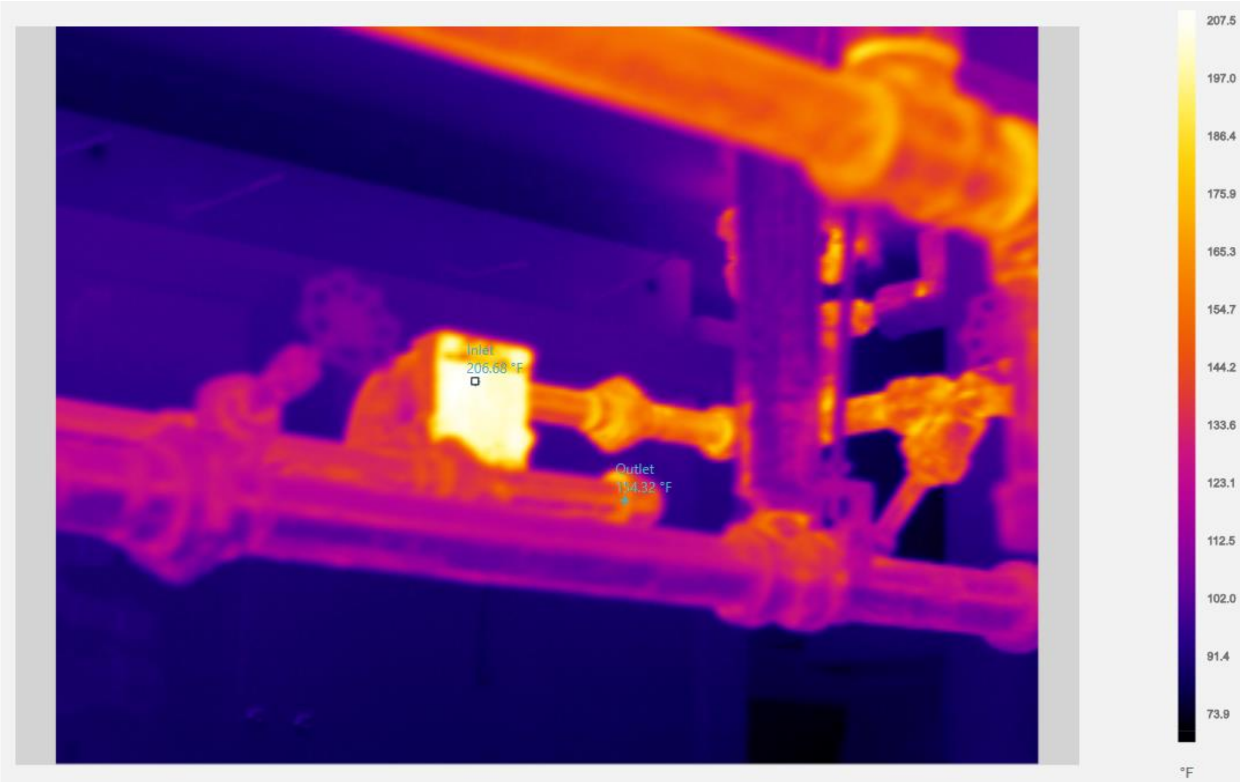
Trap Assessment Table			
Trap Location	Trap Label	Trap Inlet Temperature (°F)	Trap Outlet Temperature (°F)
Building 1 Basement	A	203	179
Building 1 Basement	B	213	161
Building 1 Basement	C	206	154
Building 1 Basement	D	226	221
Building 1 Apartment	A	201	150
Building 1 Apartment	B	130	114
Building 2 Basement	A	205	192
Building 2 Basement	B	199	180
Building 2 Basement	C	N/A	N/A
Building 2 Basement	D	183	180
Building 2 Basement	E	226	195
Building 2 Basement	F	209	200
Building 2 Apartment	A	108	101
Building 2 Apartment	B	N/A	N/A
Building 3 Basement	A	222	N/A
Building 3 Basement	B	N/A	N/A
Building 3 Basement	C	N/A	N/A
Building 3 Basement	D	N/A	N/A
Building 3 Basement	E	193	190
Building 3 Apartment	A	N/A	N/A
Building 4 Basement	A	210	205
Building 4 Basement	B	222	201
Building 4 Basement	C	210	199
Building 4 Basement	D	209	194
Building 4 Apartment	A	202	154
Building 4 Apartment	B	210	205
Building 5 Basement	A	114	87
Building 5 Basement	B	193	189
Building 5 Basement	C	228	197
Building 5 Apartment	A	141	126
Building 5 Apartment	B	145	126
Building 6 Basement	A	216	214
Building 6 Basement	B	216	213
Building 6 Basement	C	212	201
Building 6 Apartment	A	182	134
Building 6 Apartment	B	208	188
Building 6 Apartment	C	154	127
Building 7 Basement	A	119	113
Building 7 Basement	B	206	195
Building 7 Basement	C	209	200
Building 7 Apartment	A	85	79
Building 7 Apartment	B	N/A	N/A



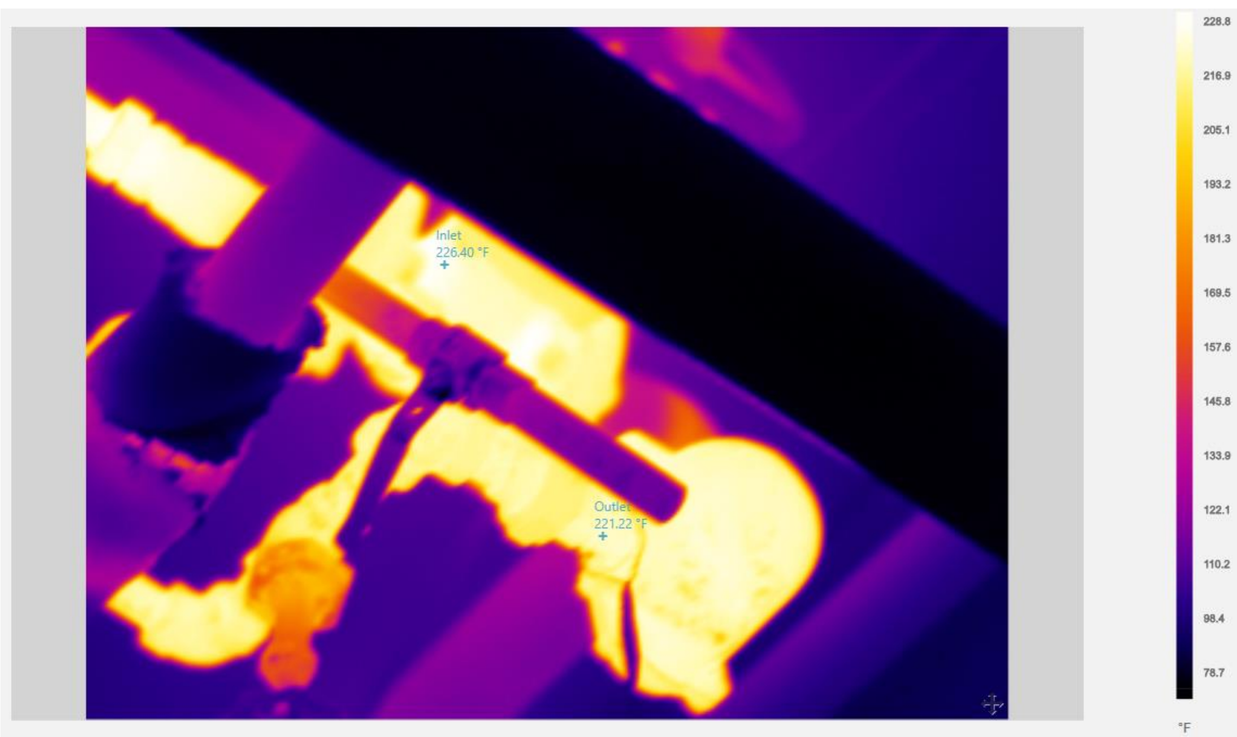
Building 1 Basement Trap A



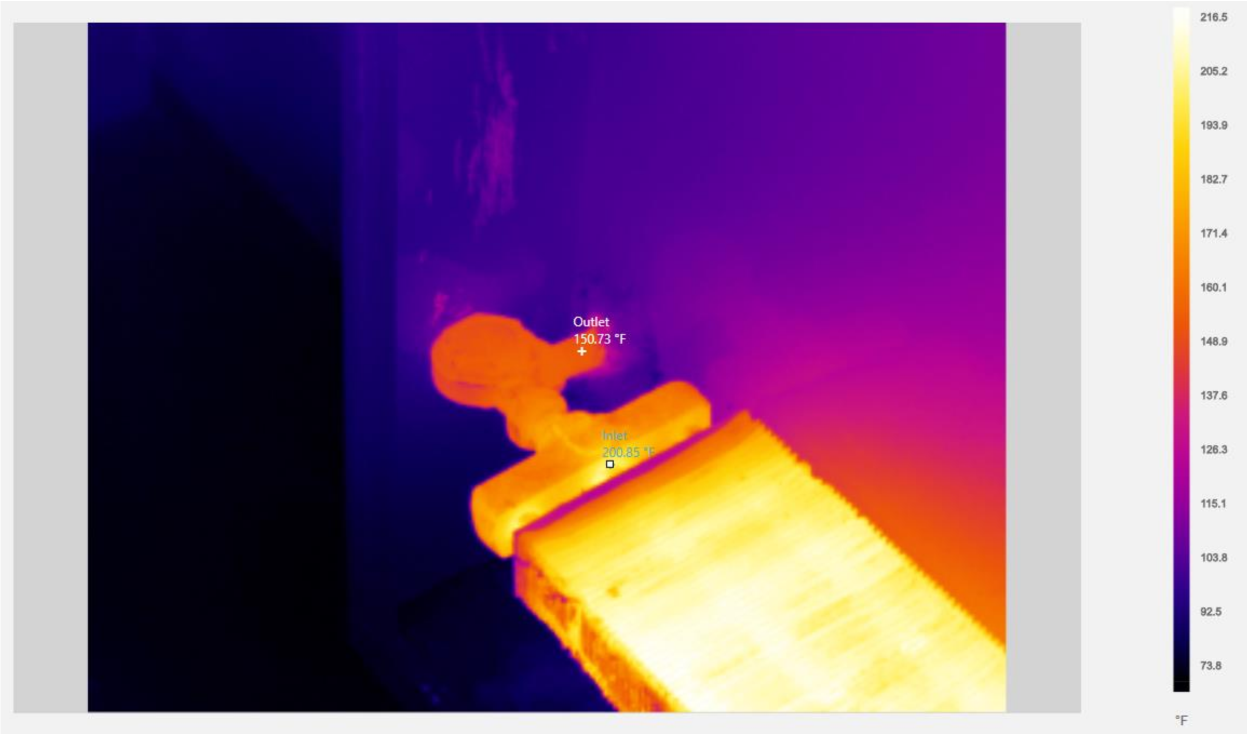
Building 1 Basement Trap B



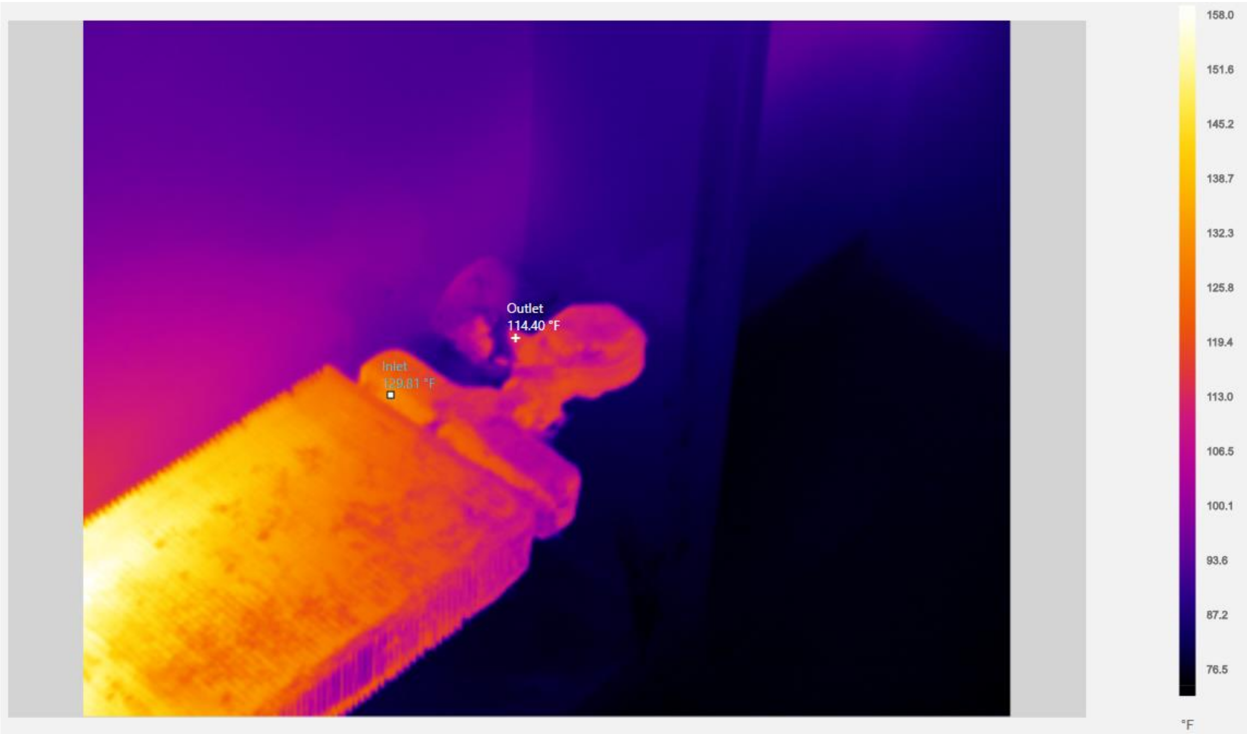
Building 1 Basement Trap C



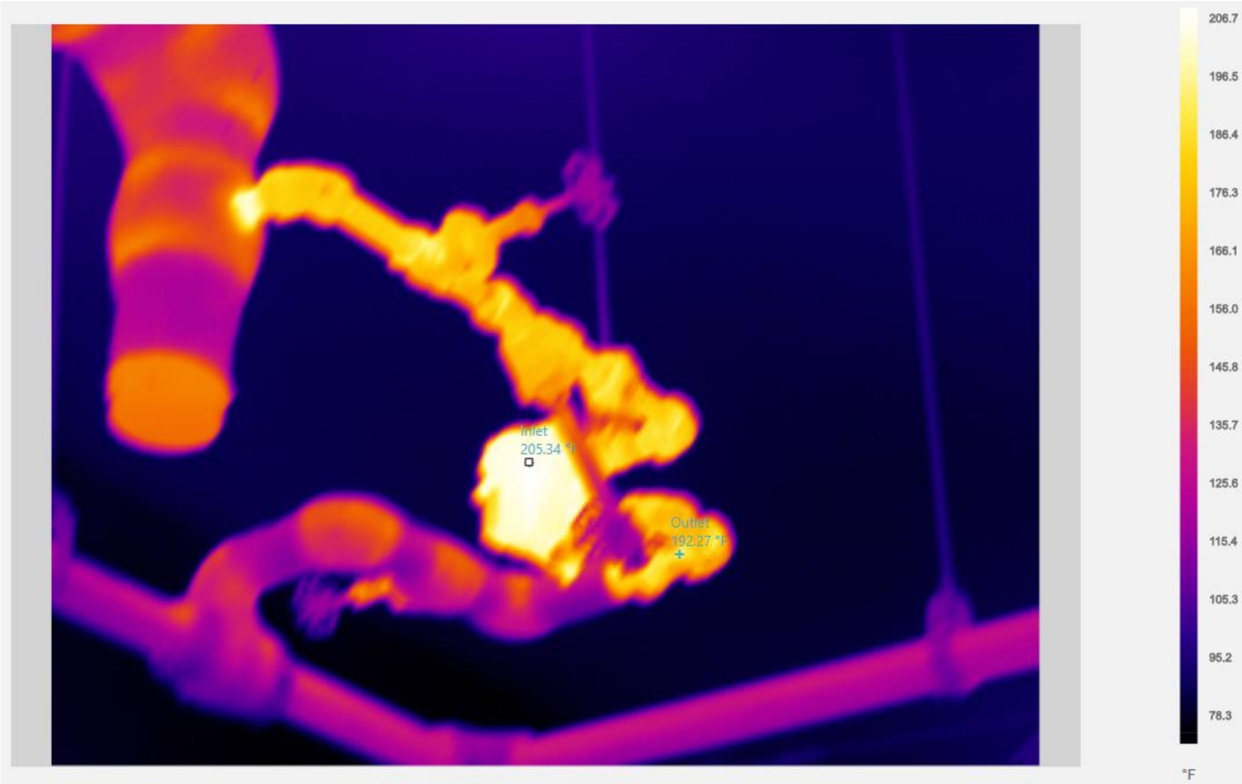
Building 1 Basement Trap D



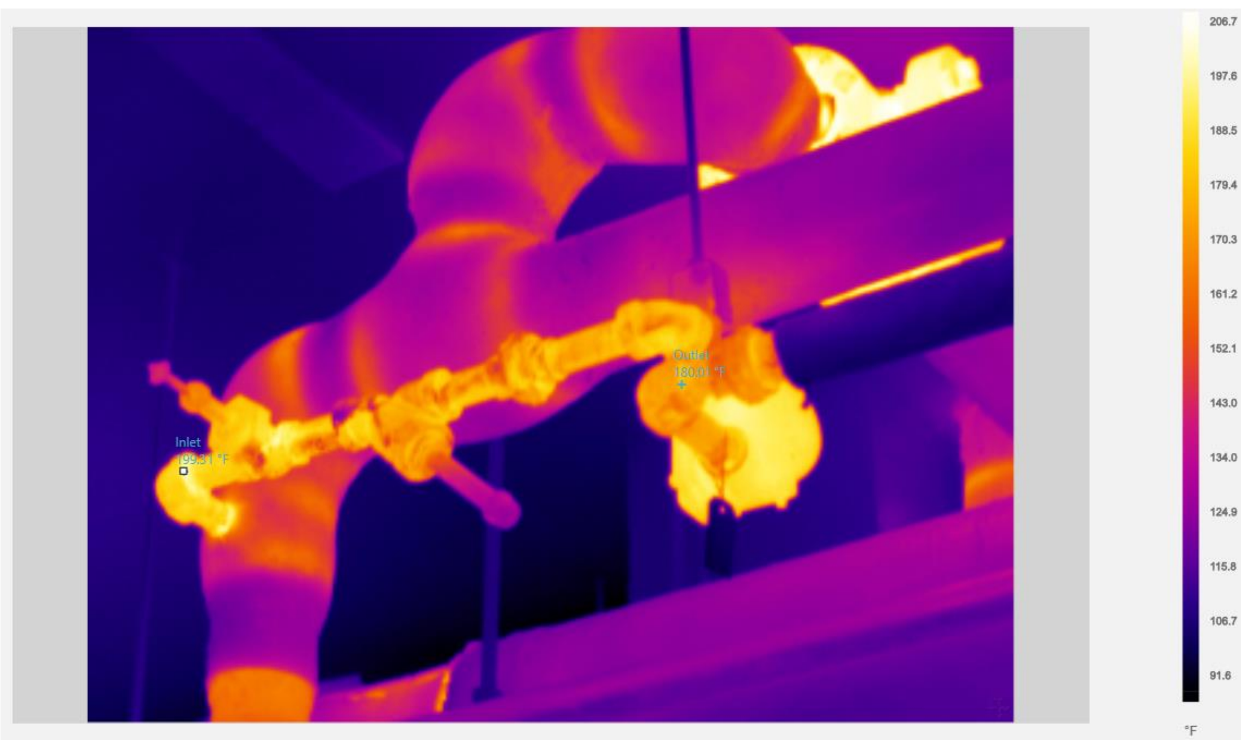
Building 1 Apartment Trap A



Building 1 Apartment Trap B



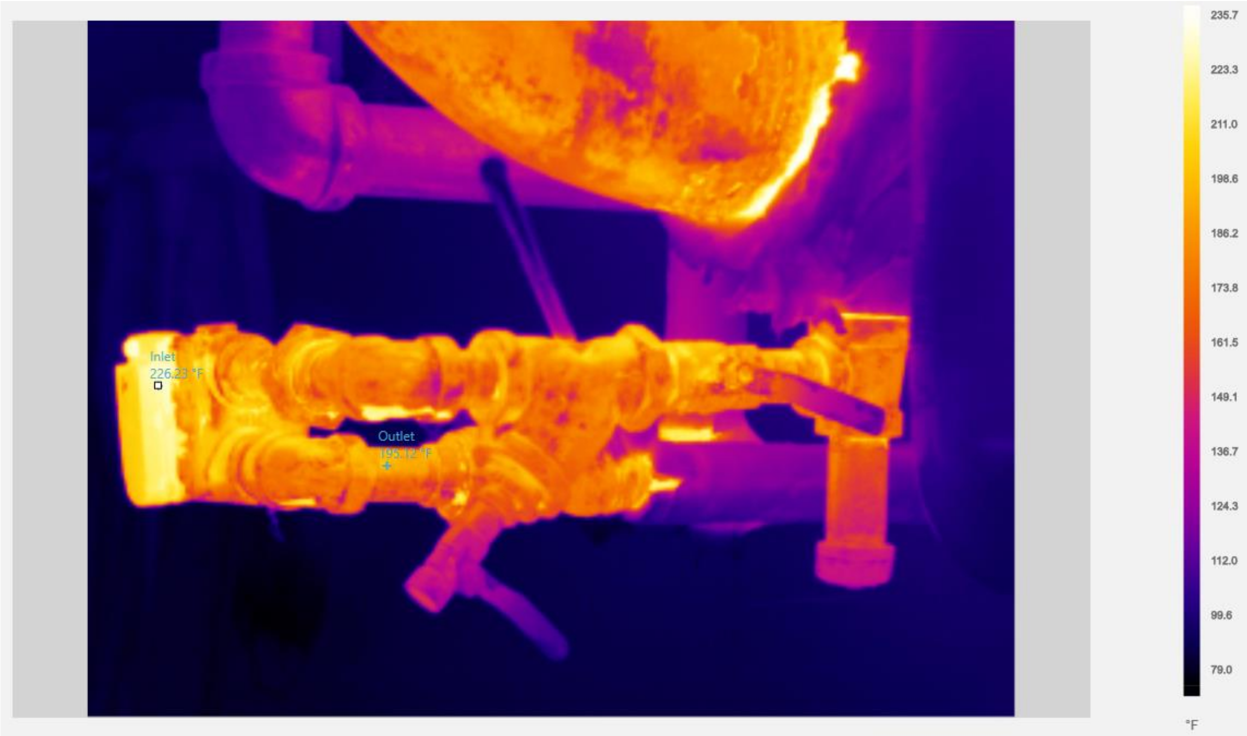
Building 2 Basement Trap A



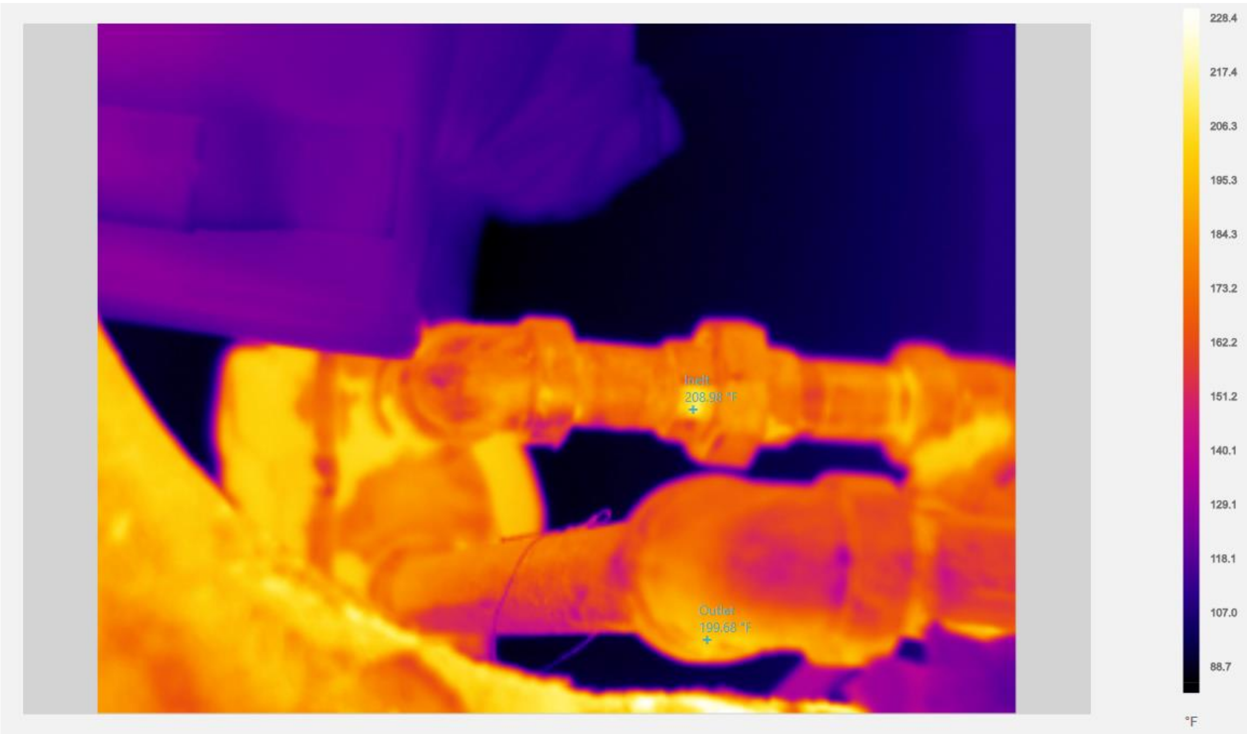
Building 2 Basement Trap B

Building 2 Basement Trap C (not active)

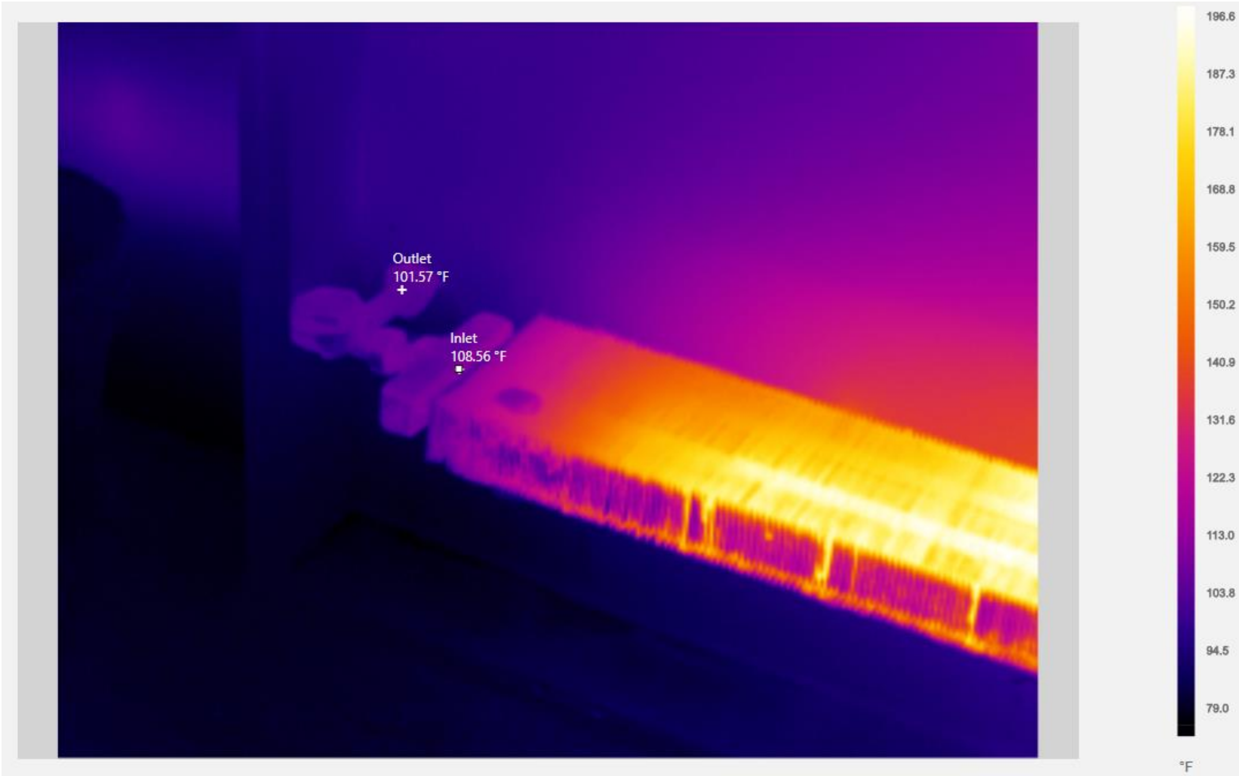
Building 2 Basement Trap D



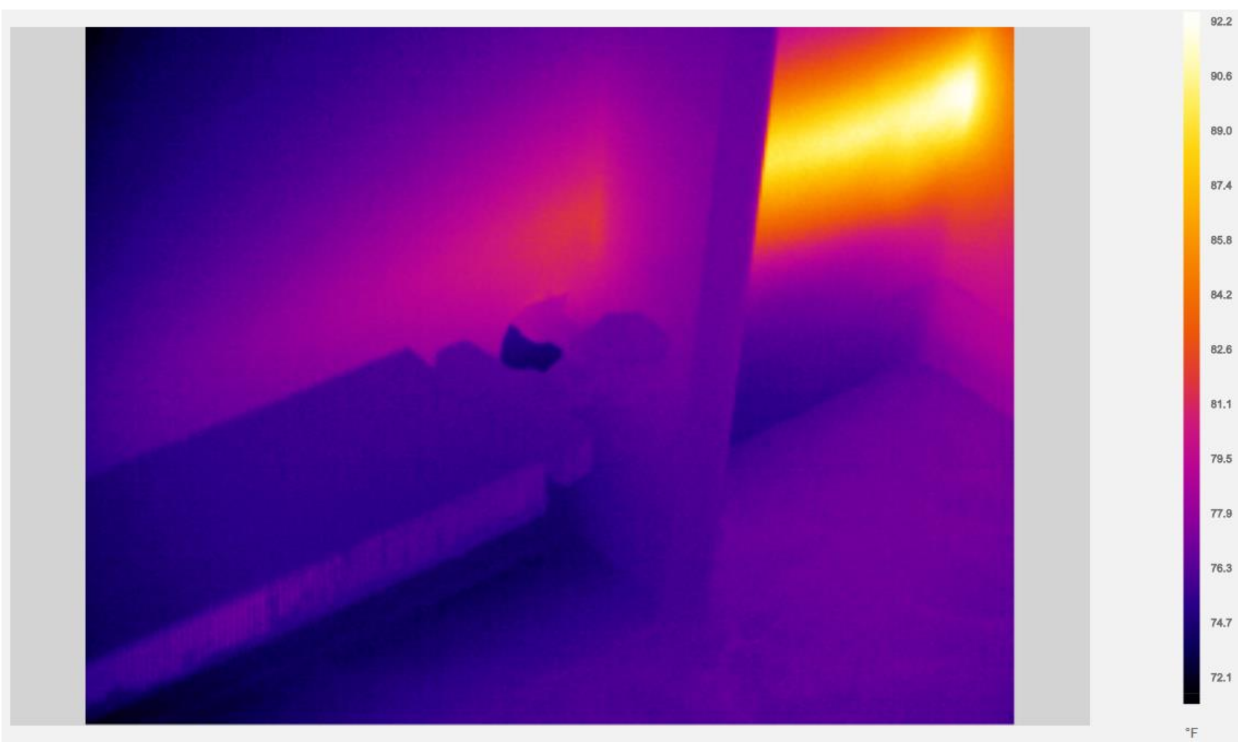
Building 2 Basement Trap E



Building 2 Basement Trap F



Building 2 Apartment Trap A



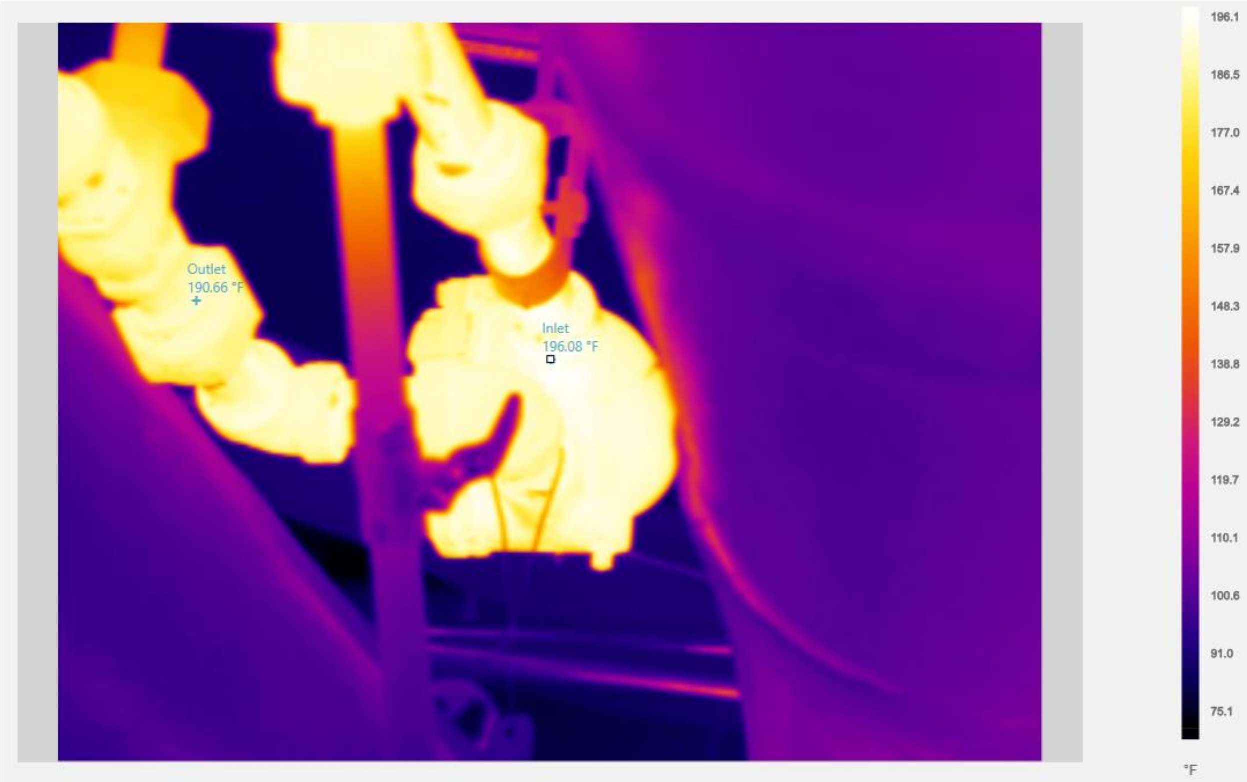
Building 2 Apartment Trap B (not active)

Building 3 Basement Trap A (outlet piping temp. obscured by insulation)

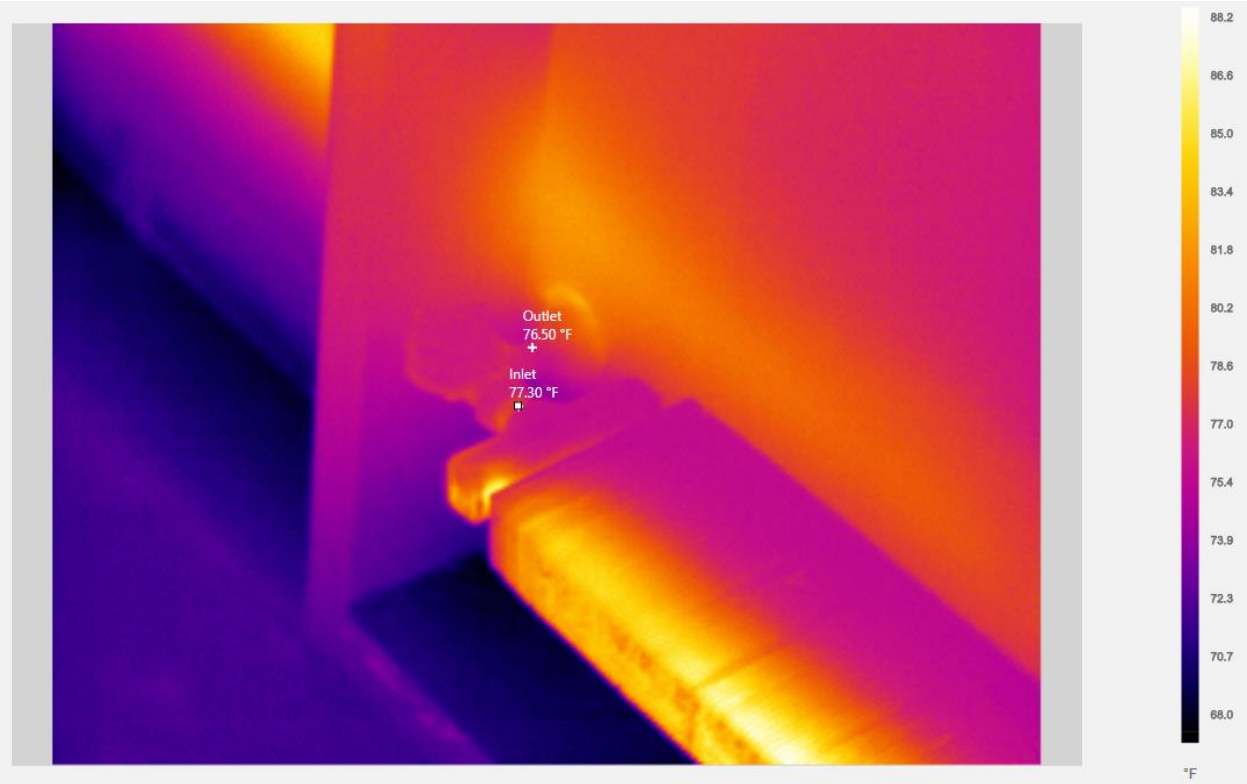
Building 3 Basement Trap B (not active)

Building 3 Basement Trap C (not active)

Building 3 Basement Trap D (not active)

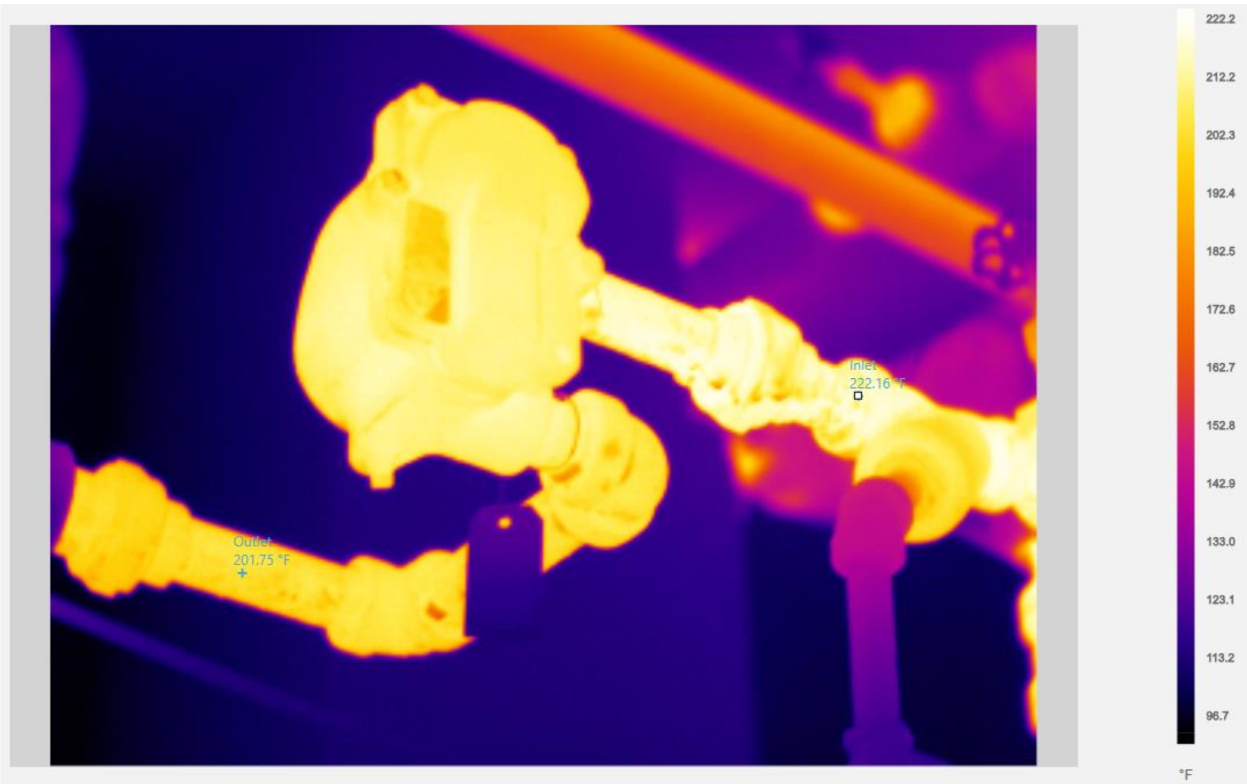


Building 3 Basement Trap E

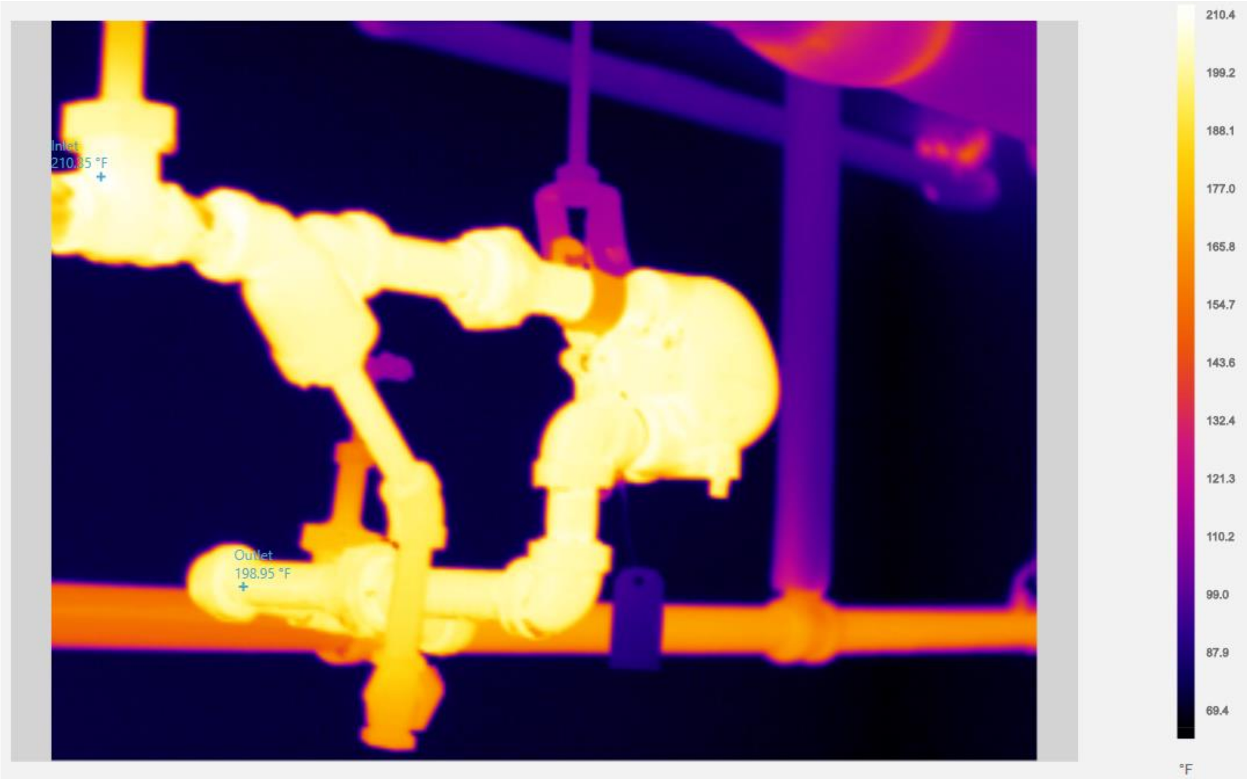


Building 3 Apartment Trap A

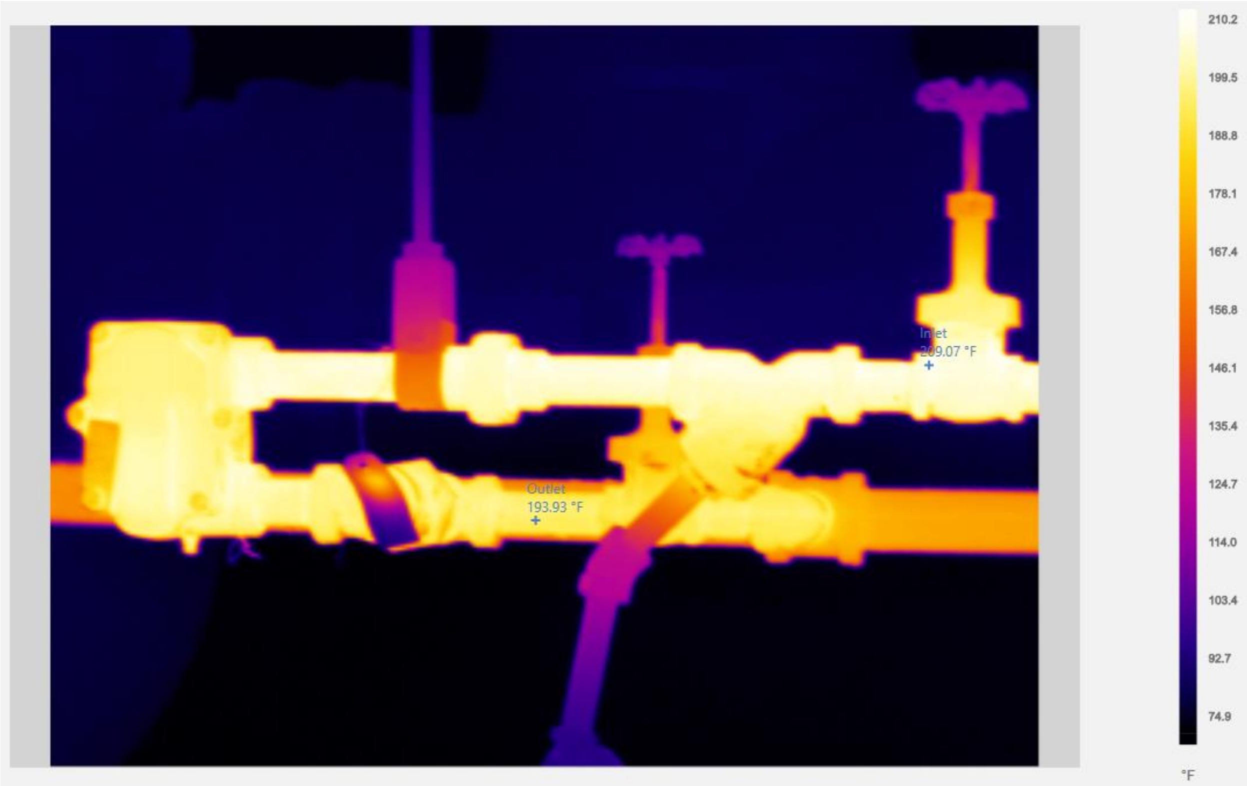
Building 4 Basement Trap A



Building 4 Basement Trap B

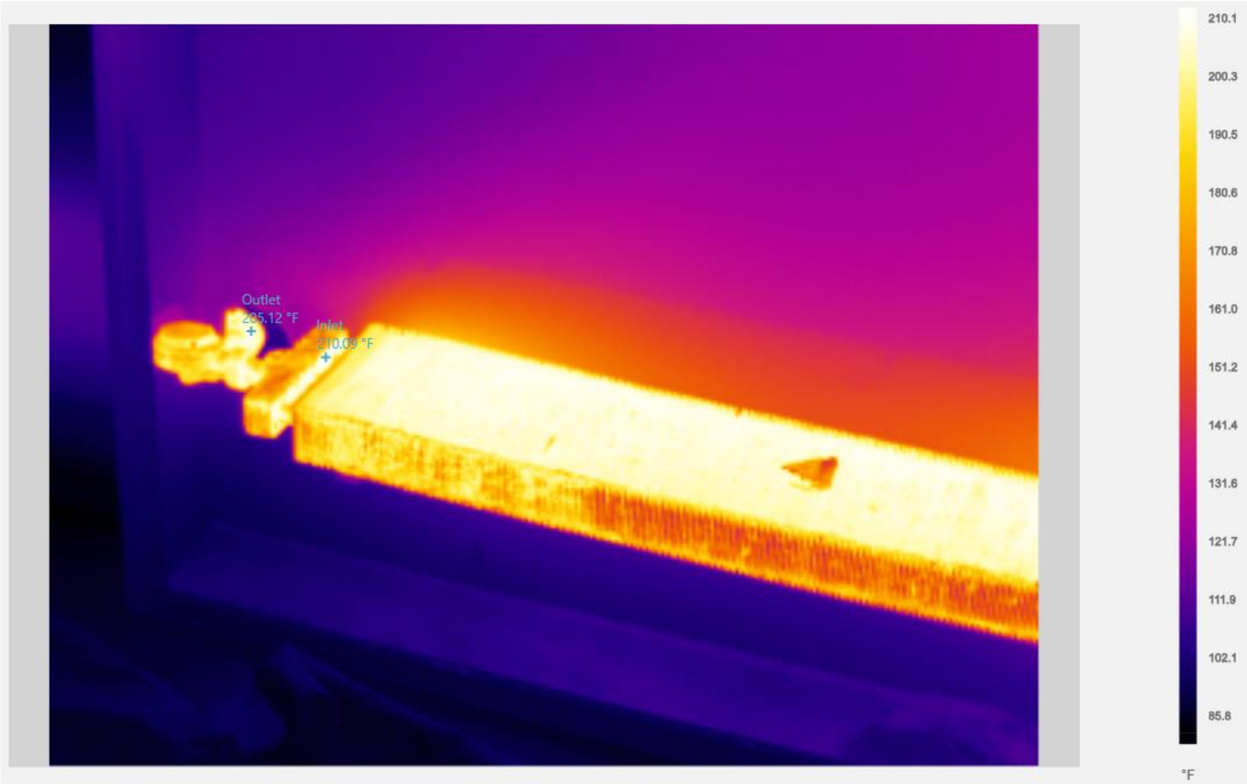


Building 4 Basement Trap C

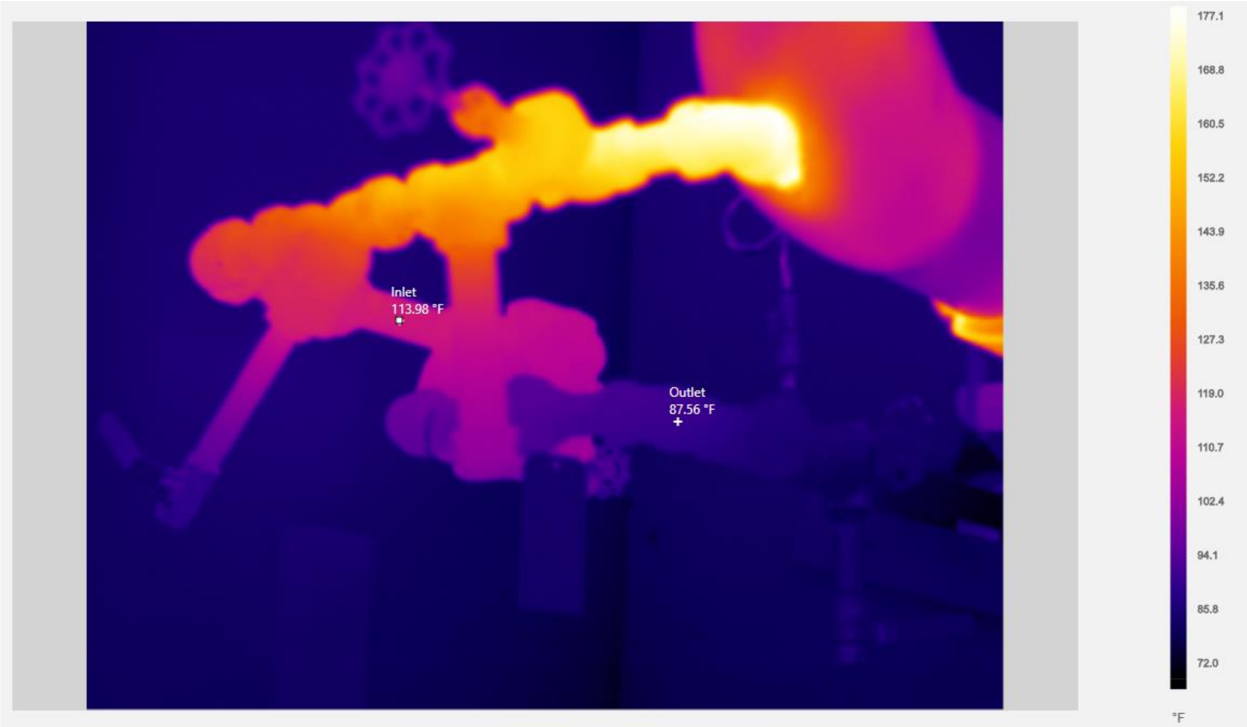


Building 4 Basement Trap D

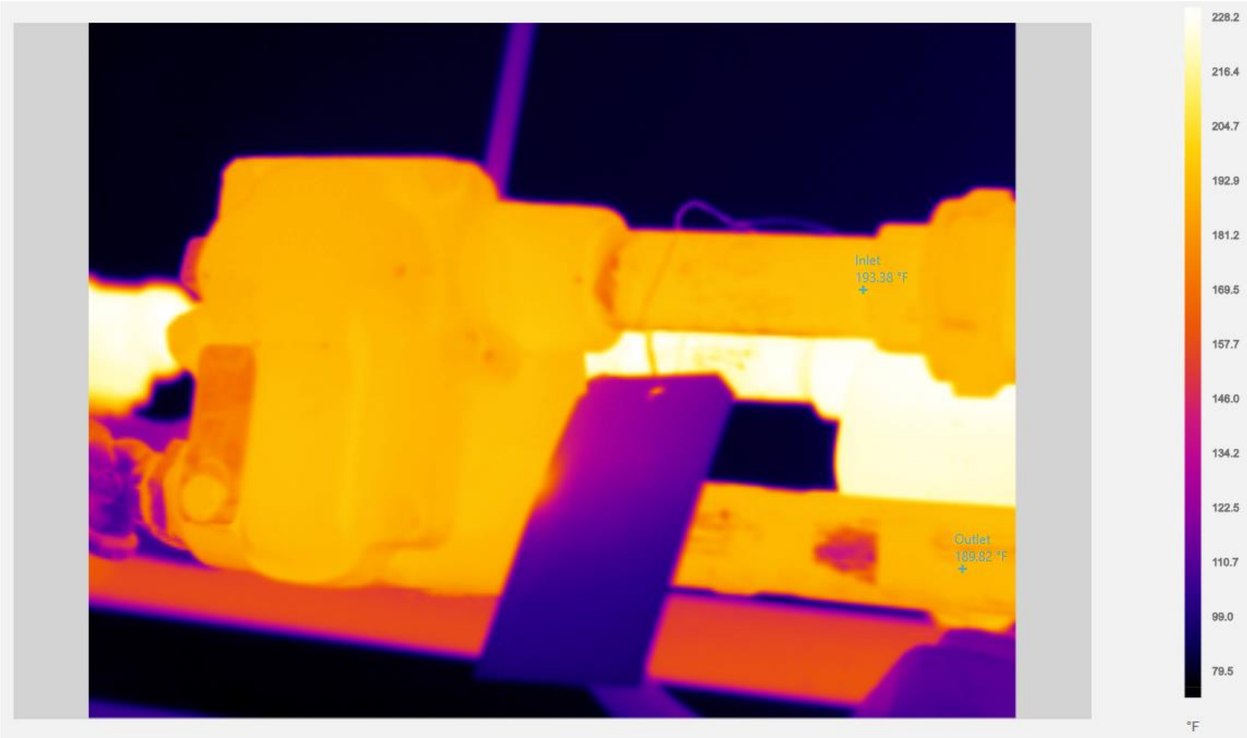
Building 4 Apartment Trap A



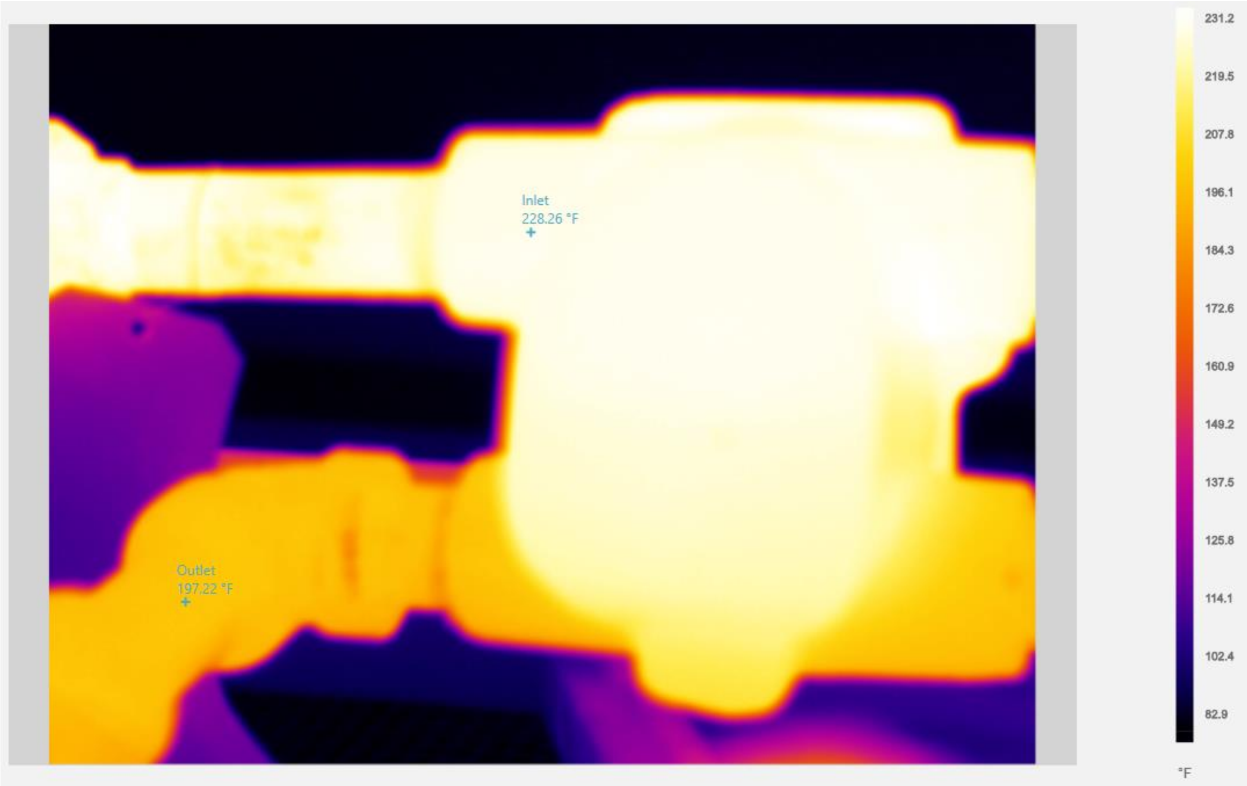
Building 4 Apartment Trap B



Building 5 Basement Trap A

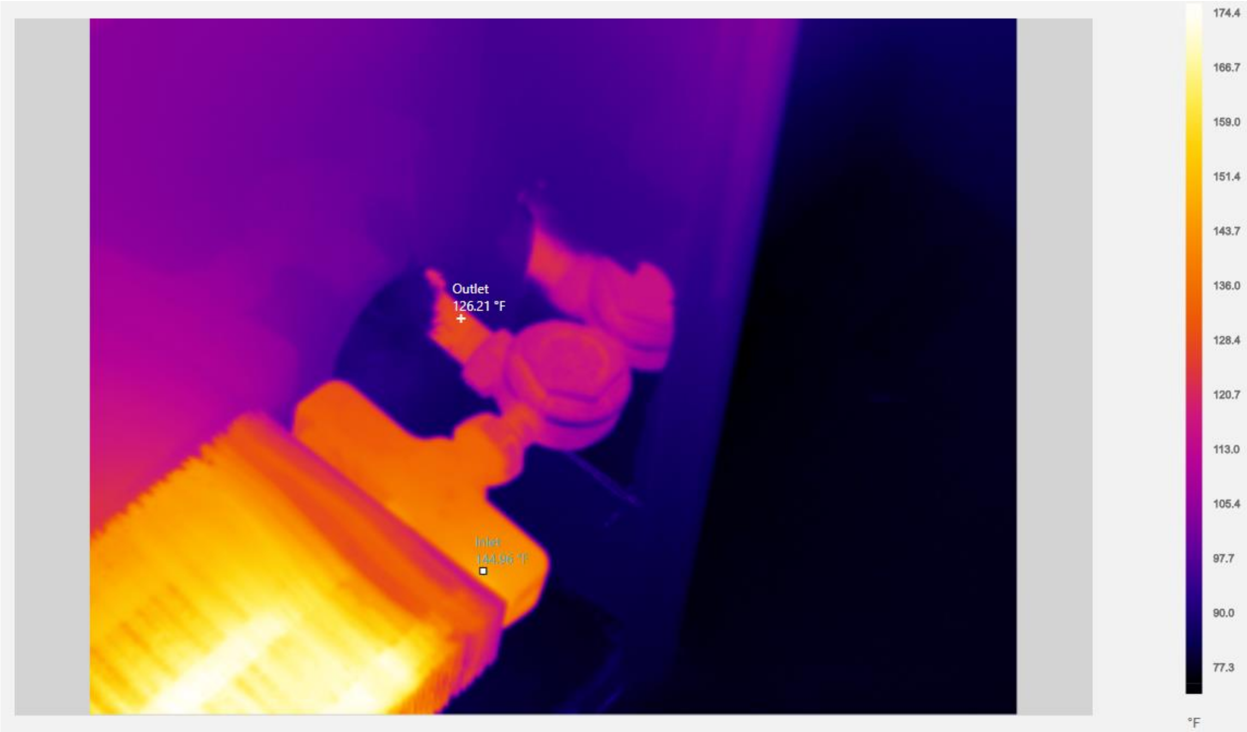


Building 5 Basement Trap B



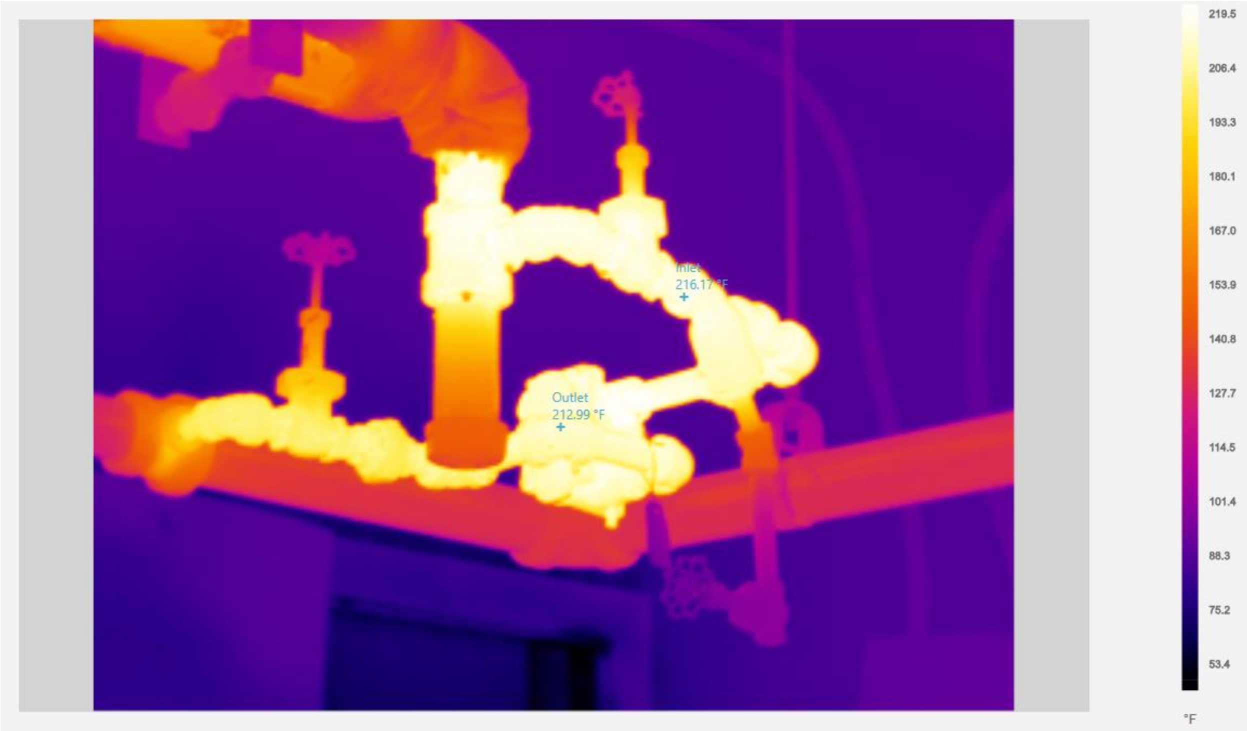
Building 5 Basement Trap C

Building 5 Apartment Trap A

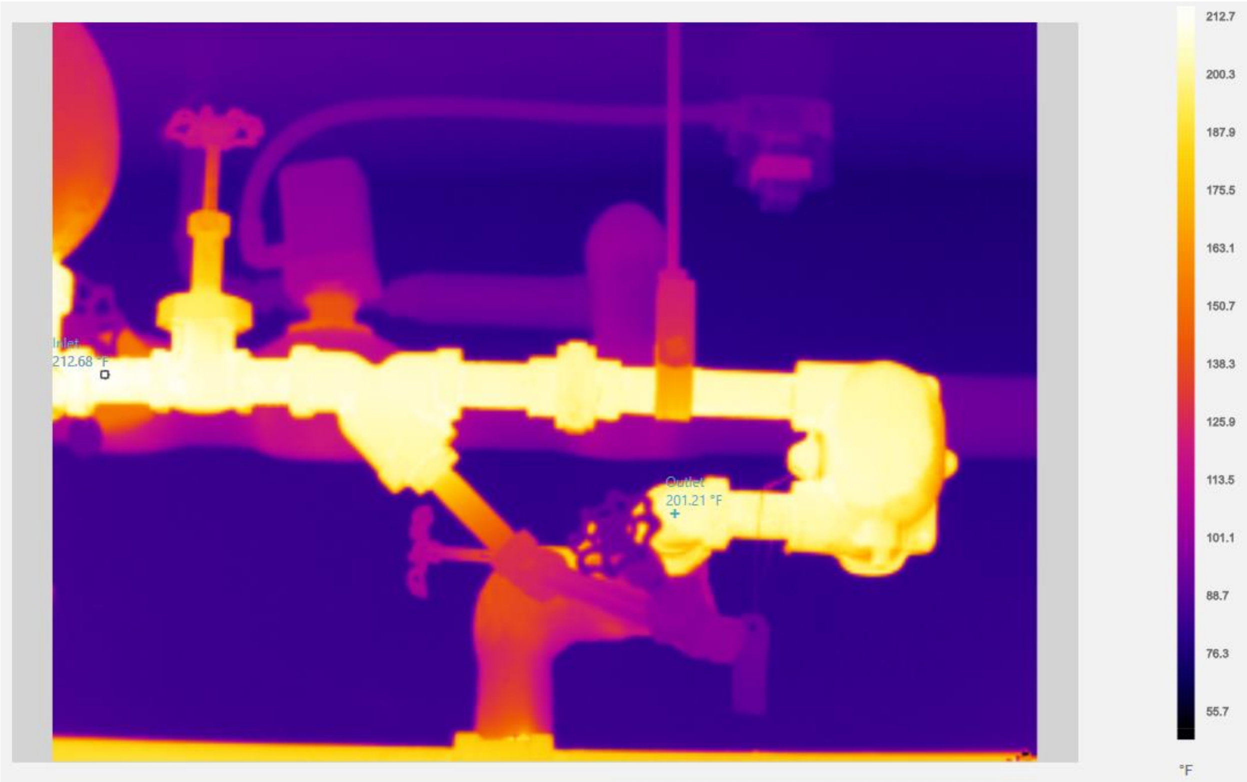


Building 5 Apartment Trap B

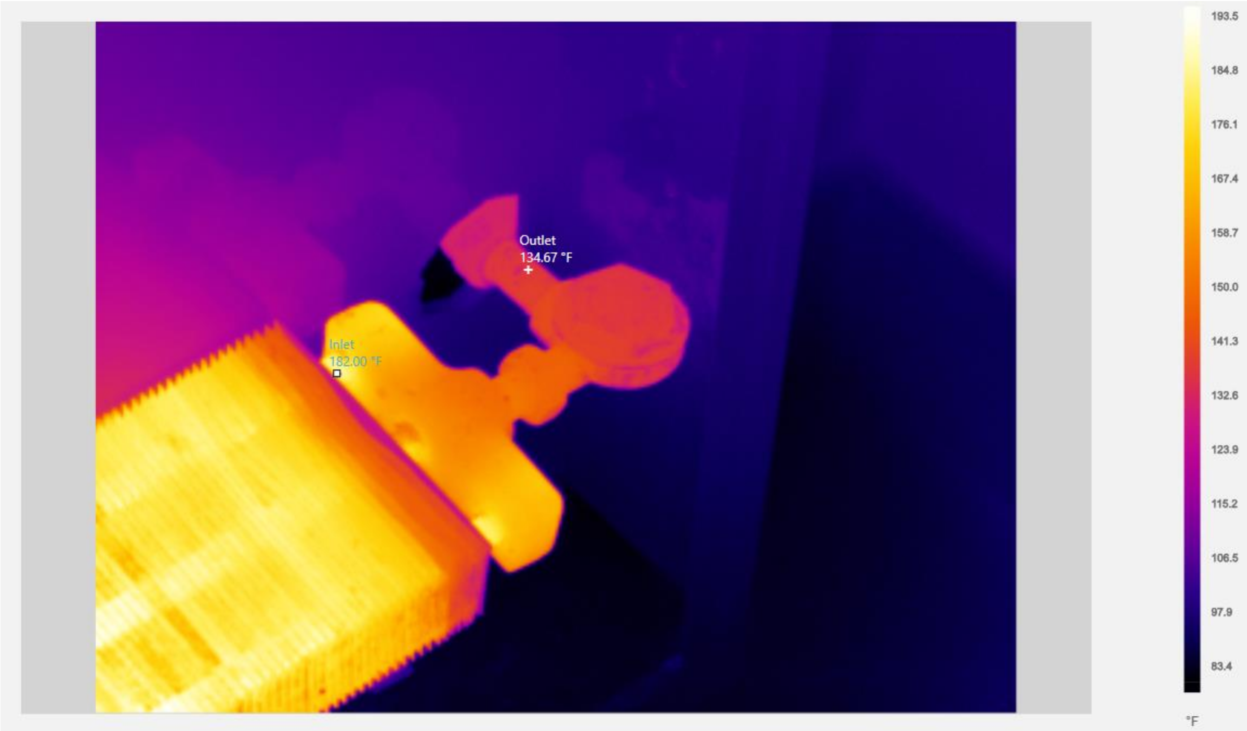
Building 6 Basement Trap A



Building 6 Basement Trap B



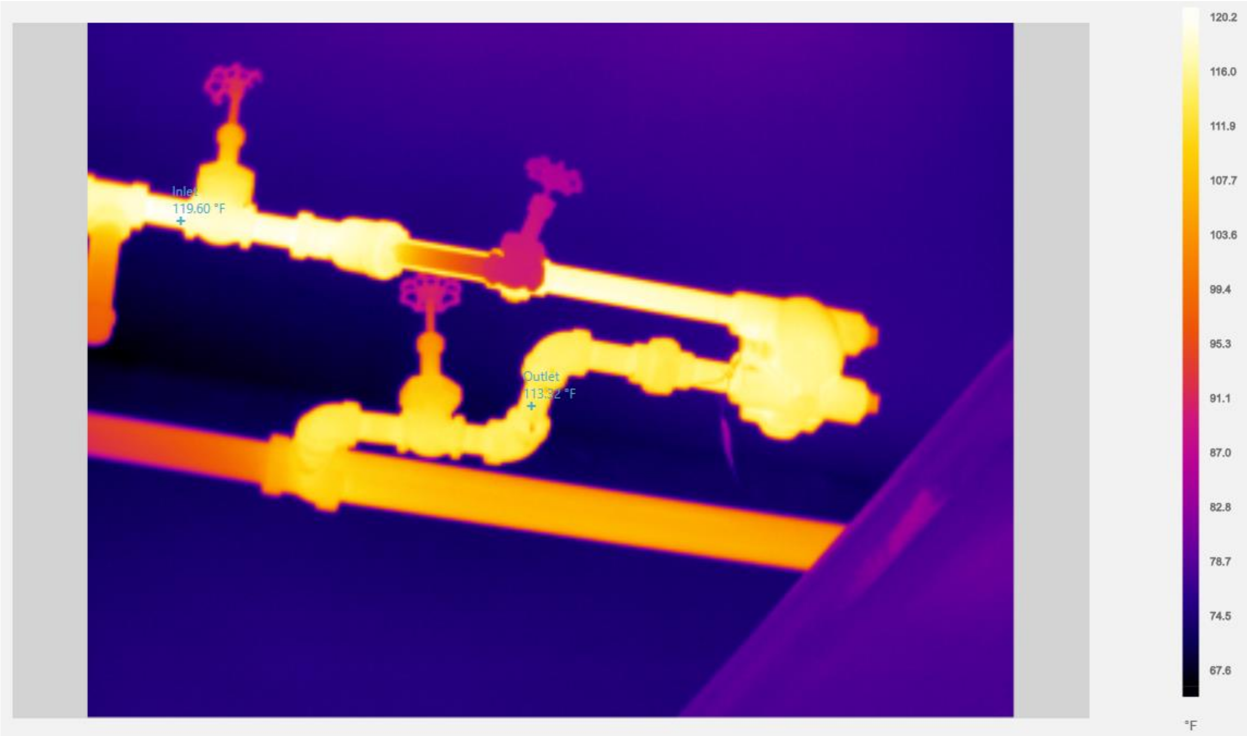
Building 6 Basement Trap C



Building 6 Apartment Trap A

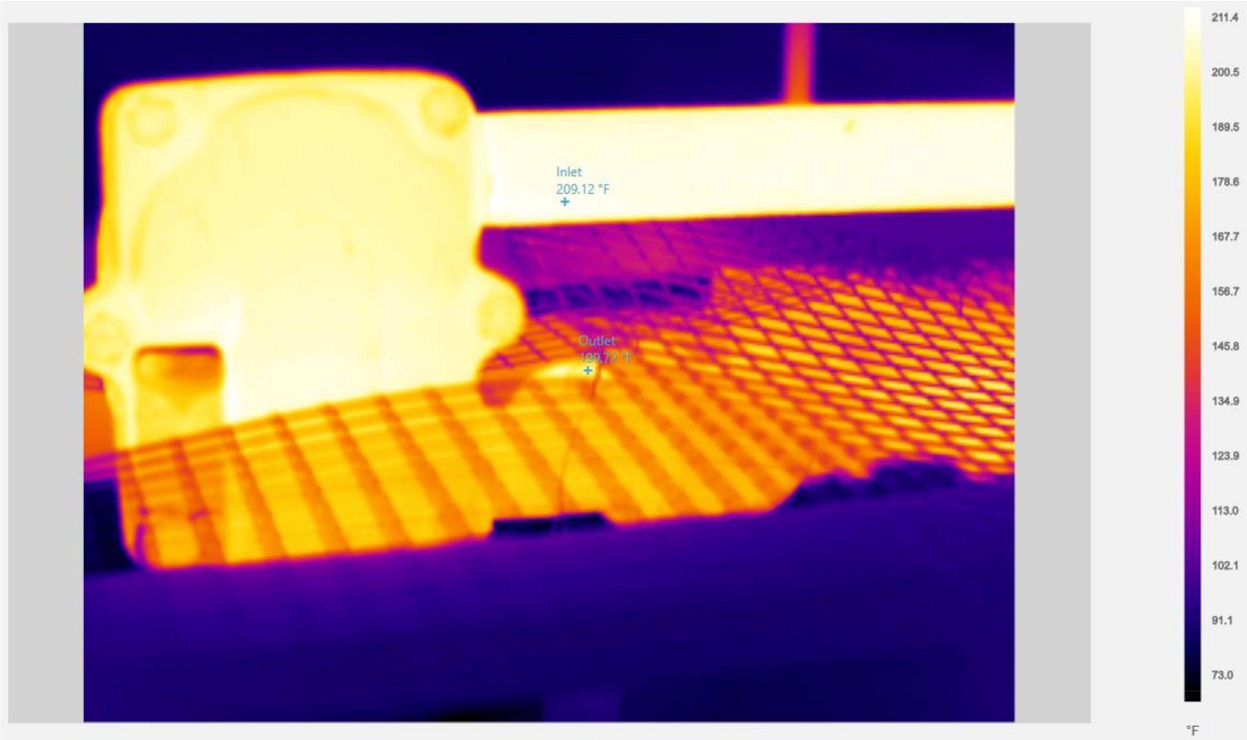
Building 6 Apartment Trap B

Building 6 Apartment Trap C



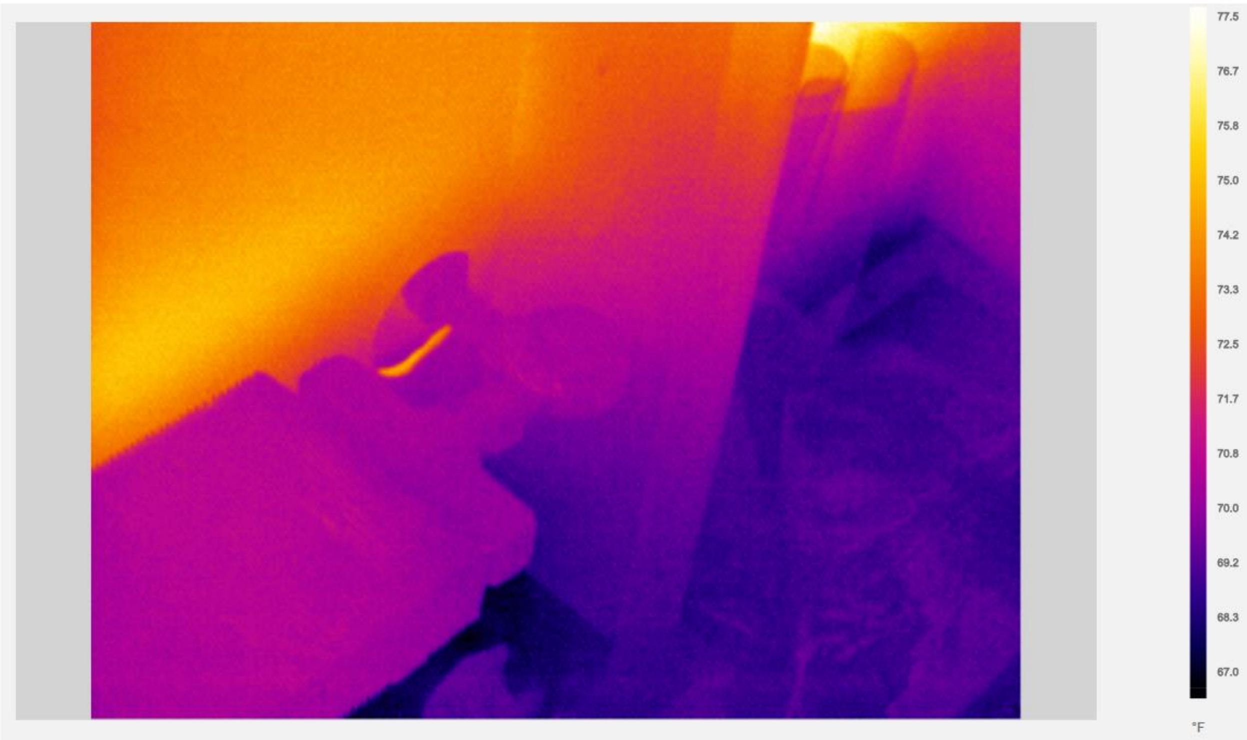
Building 7 Basement Trap A

Building 7 Basement Trap B



Building 7 Basement Trap C

Building 7 Apartment Trap A

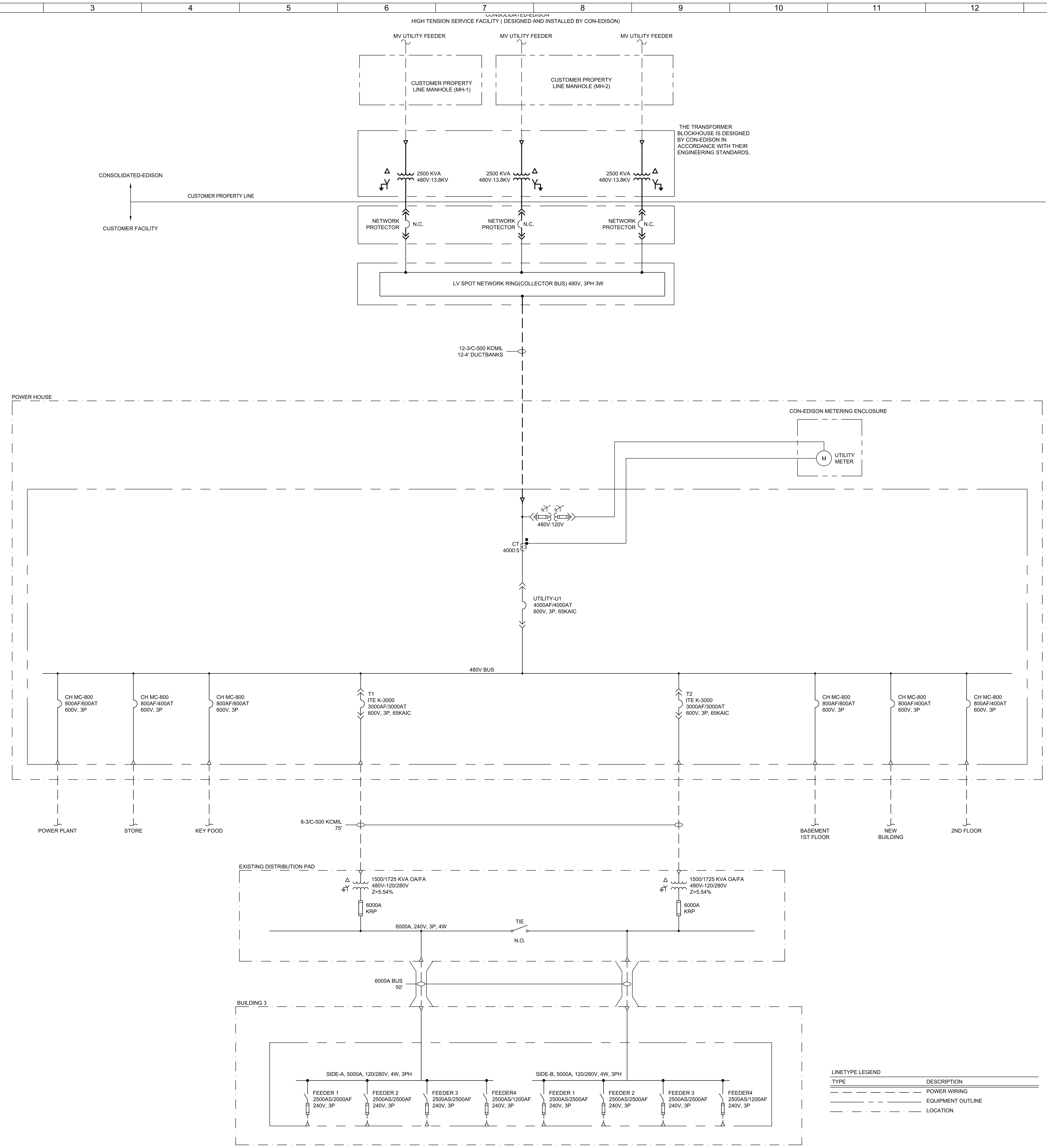


Building 7 Apartment Trap B (not active)

Attachment D

Energy Supply Alternative One Line Diagrams

WALDRON



LINETYPE LEGEND

TYPE	DESCRIPTION
— — — — —	POWER WIRING
——— – ———	EQUIPMENT OUTLINE
—— – – ——	LOCATION

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REV. No.	REV. BY	DATE	DESCRIPTION	CHECKED BY	PROJECT MANAGER	LEAD ENGINEER
C	AA	8/22/2022	ISSUED FOR REPORT	YSC	MLM	YSC
B	AA	7/21/2022	ISSUED FOR REPORT	YSC	MLM	YSC
A	BSC	07/08/2022	ISSUED FOR REPORT	YSC	MLM	YSC

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WALDRON.COM

DATE DRAWN: 6/28/2022
ORIGINAL SIZE: ANSI E

CLIENT DRAWING No.

W.E.N.Y. PROJECT No.
423.01

CLIENT
BIG SIX TOWERS, INC.
59-55 47TH AVE WOODSIDE
NEW YORK

DRAWING TITLE
BIG SIX TOWERS
REPOWERING STUDY

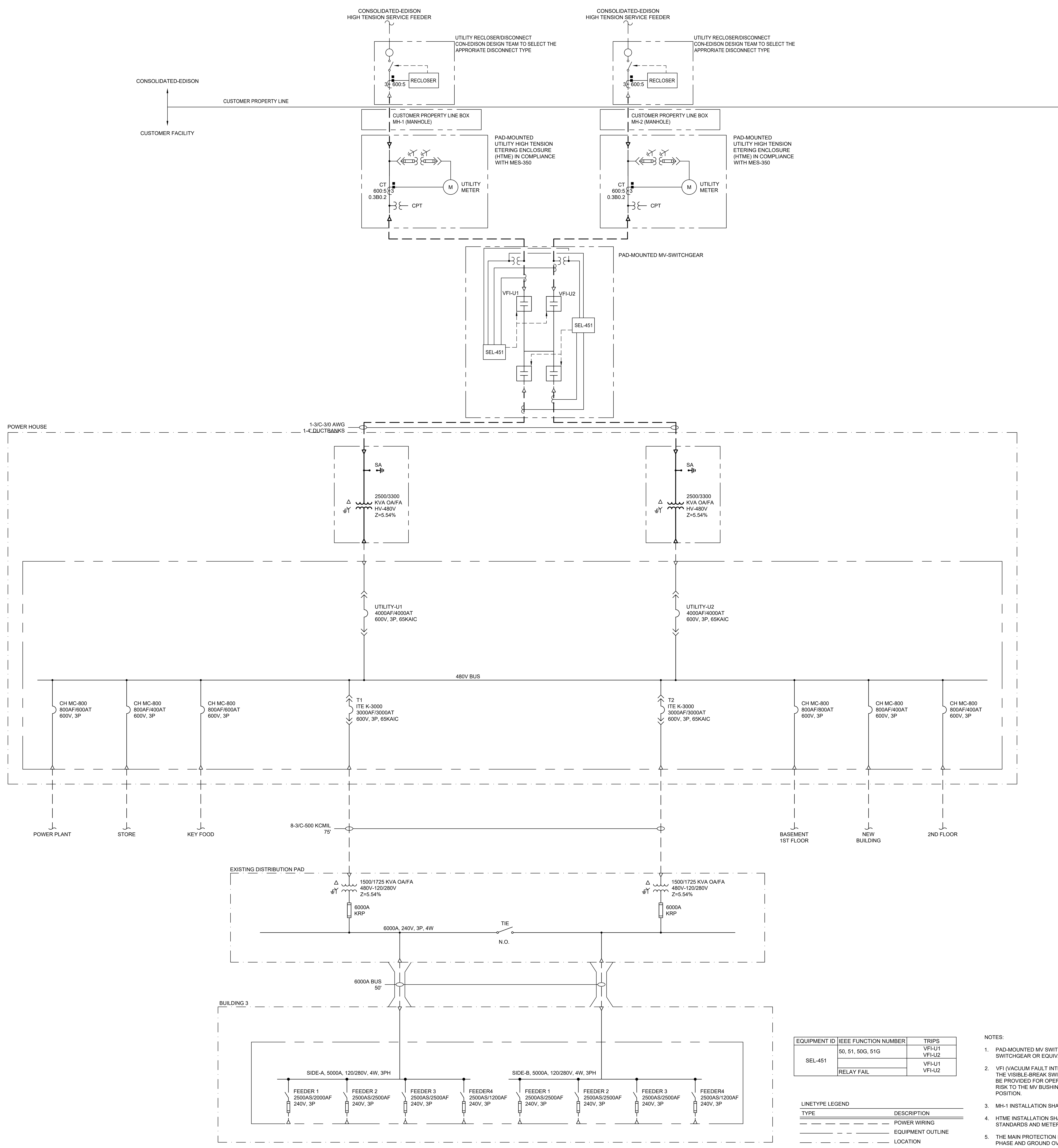
ONE LINE DIAGRAM LOW TENSION SERVICE

SEAL

SIGNATURE DATE

DWG No.
E-6002

SHEET No.
1 OF 1



EQUIPMENT ID	IEEE FUNCTION NUMBER	TRIPS
SEL-451	50, 51, 50G, 51G	VFI-U1 VFI-U2
		VFI-U1 VFI-U2
	RELAY FAIL	

LINETYPE LEGEND

TYPE	DESCRIPTION
— — — — —	POWER WIRING
———— — — ————	EQUIPMENT OUTLINE
—— · —— · ——	LOCATION

NOTES:

1. PAD-MOUNTED MV SWITCH SHALL BE COOPER POWER SERIES VFI DISTRIBUTION SWITCHGEAR OR EQUIVALENT.
2. VFI (VACUUM FAULT INTERRUPTER) WILL INTERRUPT THE CURRENT AND THEN THE VISIBLE-BREAK SWITCH MAY BE OPERATED. VISIBLE BREAK WINDOWS WILL BE PROVIDED FOR OPERATOR TO VIEW THE VISIBLE BREAK WITHOUT EXPOSURE RISK TO THE MV BUSHINGS. SWITCH SHALL BE LOCKABLE WHILE IN OPEN POSITION.
3. MH-1 INSTALLATION SHALL BE IN ACCORDANCE WITH CON-EDISON STANDARDS.
4. HTME INSTALLATION SHALL COMPLY WITH CON-EDISON HIGH TENSION SERVICE STANDARDS AND METERING MES-350.
5. THE MAIN PROTECTION RELAY (SEL-451) SHALL TRIP VFI-U1 AND VFI-U2 FOR PHASE AND GROUND OVERCURRENT FAULTS.

REV. No.	REV. BY	DATE	DESCRIPTION	CHECKED BY	PROJECT MANAGER	LEAD ENGINEER
C	AA	8/22/2022	ISSUED FOR REPORT	YSC	MLM	YSC
B	AA	7/21/2022	ISSUED FOR REPORT	YSC	MLM	YSC
A	BSC	07/08/2022	ISSUED FOR REPORT	YSC	MLM	YSC

WALDRON
WALDRON.COM

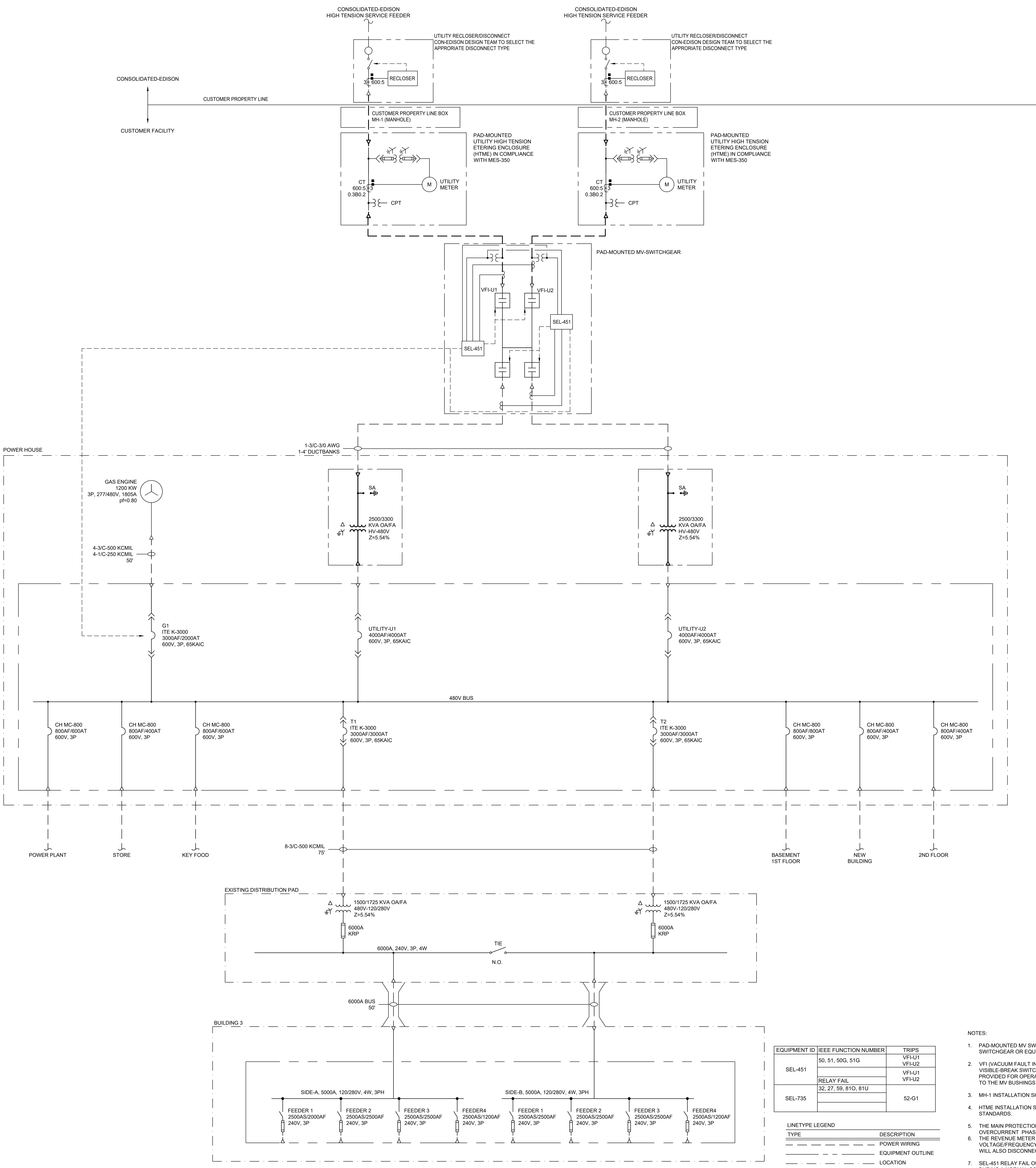
DATE DRAWN: 6/28/2022
ORIGINAL SIZE: ANSI E
CLIENT DRAWING No.
W.E.N.Y. PROJECT No. 423.01

CLIENT
BIG SIX TOWERS, INC.
59-55 47TH AVE WOODSIDE
NEW YORK

DRAWING TITLE
BIG SIX TOWERS REPOWERING STUDY
ONE LINE DIAGRAM HIGH TENSION SERVICE

SEAL
SIGNATURE DATE

DWG No. E-6003
SHEET No. 1 OF 1



EQUIPMENT ID	IEEE FUNCTION NUMBER	TRIPS
SEL-451	50, 51, 50G, 51G	VFI-U1 VFI-U2
		VFI-U1 VFI-U2
	RELAY FAIL	
SEL-735	32, 27, 59, 81O, 81U	52-G1

LINETYPE LEGEND

TYPE	DESCRIPTION
— — — — —	POWER WIRING
——— — — ———	EQUIPMENT OUTLINE
—— · —— · ——	LOCATION

NOTES:

1. PAD-MOUNTED MV SWITCH SHALL BE COOPER POWER SERIES VFI DISTRIBUTION SWITCHGEAR OR EQUIVALENT.
2. VFI (VACUUM FAULT INTERRUPTER) WILL INTERRUPT THE CURRENT AND THEN THE VISIBLE-BREAK SWITCH MAY BE OPERATED. VISIBLE BREAK WINDOWS WILL BE PROVIDED FOR OPERATOR TO VIEW THE VISIBLE BREAK WITHOUT EXPOSURE RISK TO THE MV BUSHINGS. SWITCH SHALL BE LOCKABLE WHILE IN OPEN POSITION.
3. MH-1 INSTALLATION SHALL BE IN ACCORDANCE WITH CON-EDISON STANDARDS.
4. HTME INSTALLATION SHALL BE IN ACCORDANCE WITH CON-EDISON HIGH TENSION STANDARDS.
5. THE MAIN PROTECTION RELAY (SEL-451) SHALL TRIP VFI-U1 AND VFI-U2 FOR OVERCURRENT PHASE AND GROUND FAULTS.
6. THE REVENUE METER SEL-735 SHALL TRIP THE GENERATOR FOR VOLTAGE/FREQUENCY DISTURBANCE IN ACCORDANCE WITH IEEE 1547. THE METER WILL ALSO DISCONNECT THE GENERATOR IF MINIMUM IMPORT IS NOT MET.
7. SEL-451 RELAY FAIL OUTPUT SHALL BE (b) CONTACT AND IT SHALL BE HELD OPEN DURING A NORMAL CONDITION. WHEN SEL-451 FAILS (LOSS OF DC POWER), THE CONTACT SHALL CLOSE AND TRIP VFI-U1 AND VFI-U2.

REV. No.	REV. BY	DATE	DESCRIPTION	CHECKED BY	PROJECT MANAGER	LEAD ENGINEER
B	AA	8/22/2022	ISSUED FOR REPORT	YSC	MLM	YSC
A	BSC	07/08/2022	ISSUED FOR REPORT	YSC	MLM	YSC

WALDRON
WALDRON.COM

DATE DRAWN: 6/28/2022
ORIGINAL SIZE: ANSI E
CLIENT DRAWING No.
W.E.N.Y. PROJECT No. 423.01

CLIENT
BIG SIX TOWERS, INC.
59-55 47TH AVE WOODSIDE
NEW YORK

DRAWING TITLE
BIG SIX TOWERS
REPOWERING STUDY

ONE LINE DIAGRAM HIGH TENSION SERVICE WITH ON-SITE GENERATION

SEAL

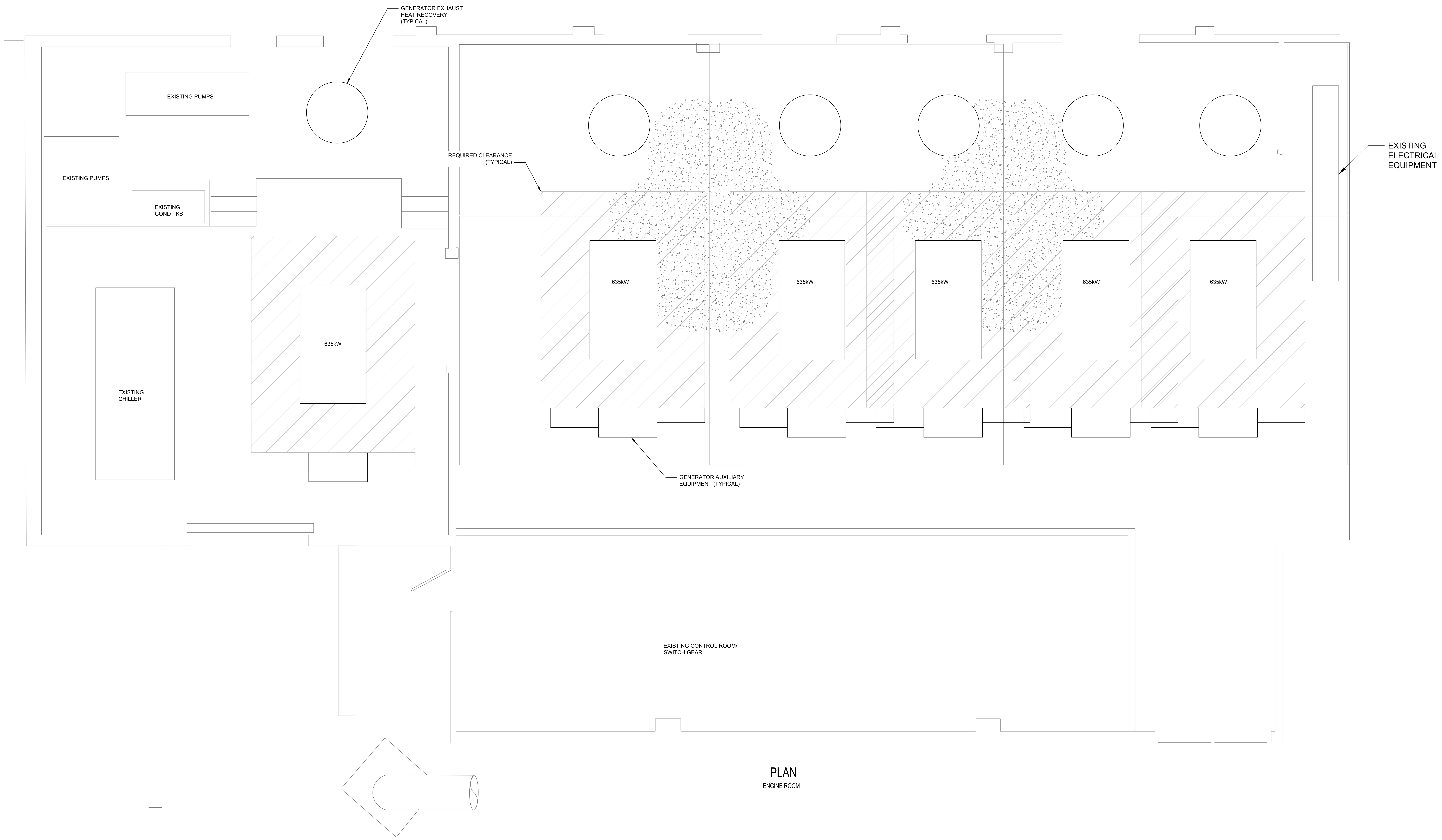
SIGNATURE DATE

DWG No. E-6004

SHEET No. 1 OF 1

Attachment E

Energy Supply Alternative Equipment Layouts



PLAN
ENGINE ROOM

REV. No.	REV. BY	DATE	DESCRIPTION	CHECKED BY	PROJECT MANAGER	LEAD ENGINEER
B	GMM	08/19/2022	ISSUED FOR FINAL REPORT NOT FOR CONSTRUCTION	MD	MLM	MLM
A	GMM	07/08/2022	ISSUED FOR REPORT	MPD	MLM	MLM

WALDRON
WALDRON.COM

DATE DRAWN	ORIGINAL SIZE
5/16/2022	ANSI E

CLIENT DRAWING No.

W.E.N.Y. PROJECT No.
423.01

CLIENT
BIG SIX TOWERS, INC.
59-55 47TH AVE WOODSIDE
NEW YORK

DRAWING TITLE
BIG SIX TOWERS
REPOWERING STUDY

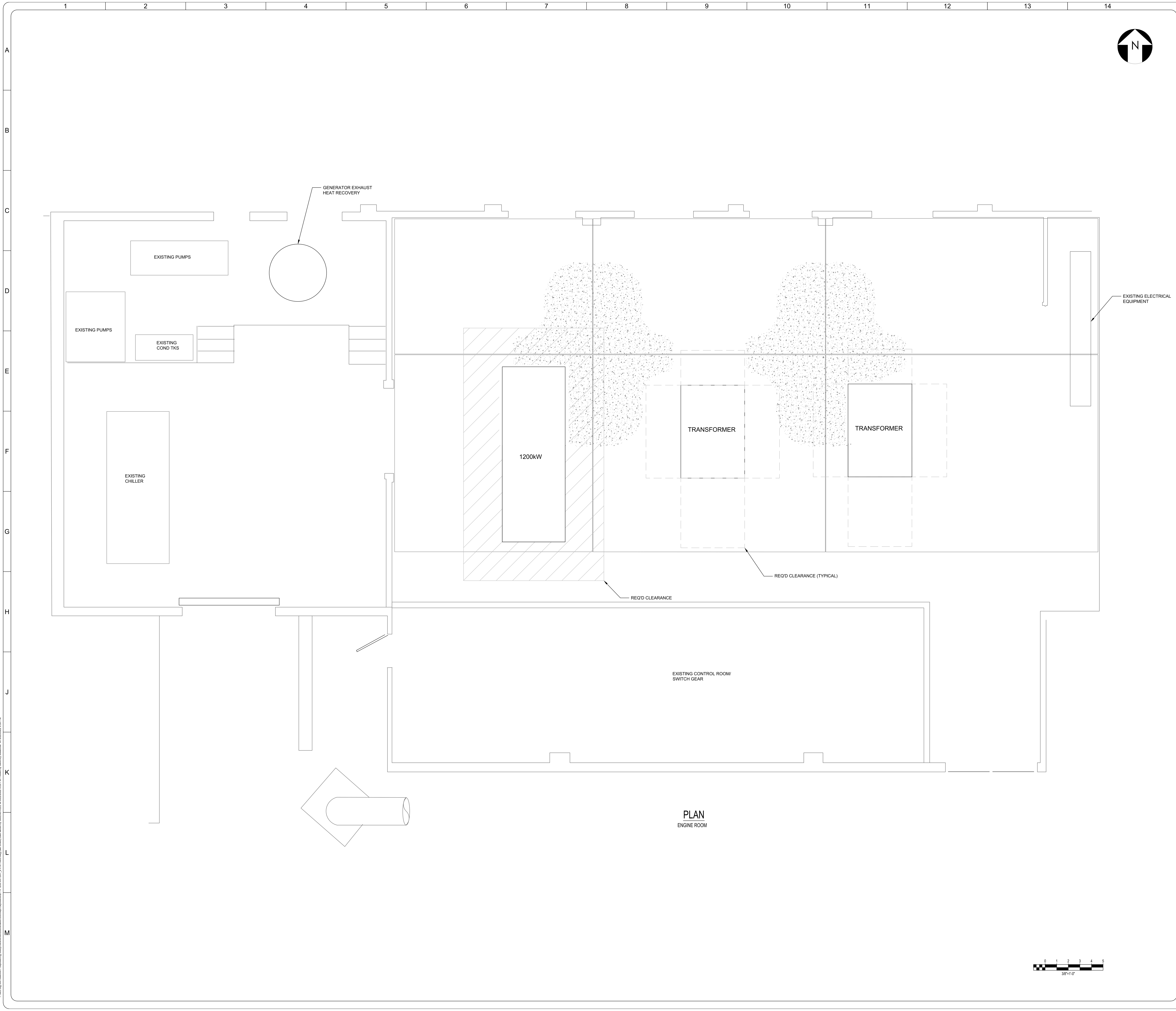
GENERAL ARRANGEMENT (6)
635KW ENGINES

SEAL

SIGNATURE DATE

DWG No.
CON1001

SHEET No.
1 OF 1



REV. No.	REV. BY	DATE	DESCRIPTION	CHECKED BY	PROJECT MANAGER	LEAD ENGINEER
B	GMM	08/19/2022	ISSUED FOR FINAL REPORT NOT FOR CONSTRUCTION	MD	MLM	MLM
A	GMM	07/08/2022	ISSUED FOR REPORT	MPD	MLM	MLM

WALDRON
WALDRON.COM

DATE DRAWN	ORIGINAL SIZE
5/16/2022	ANSI E

CLIENT DRAWING No.

W.E.N.Y. PROJECT No.
423.01

CLIENT
BIG SIX TOWERS, INC.
59-55 47TH AVE WOODSIDE
NEW YORK

DRAWING TITLE
BIG SIX TOWERS
REPOWERING STUDY

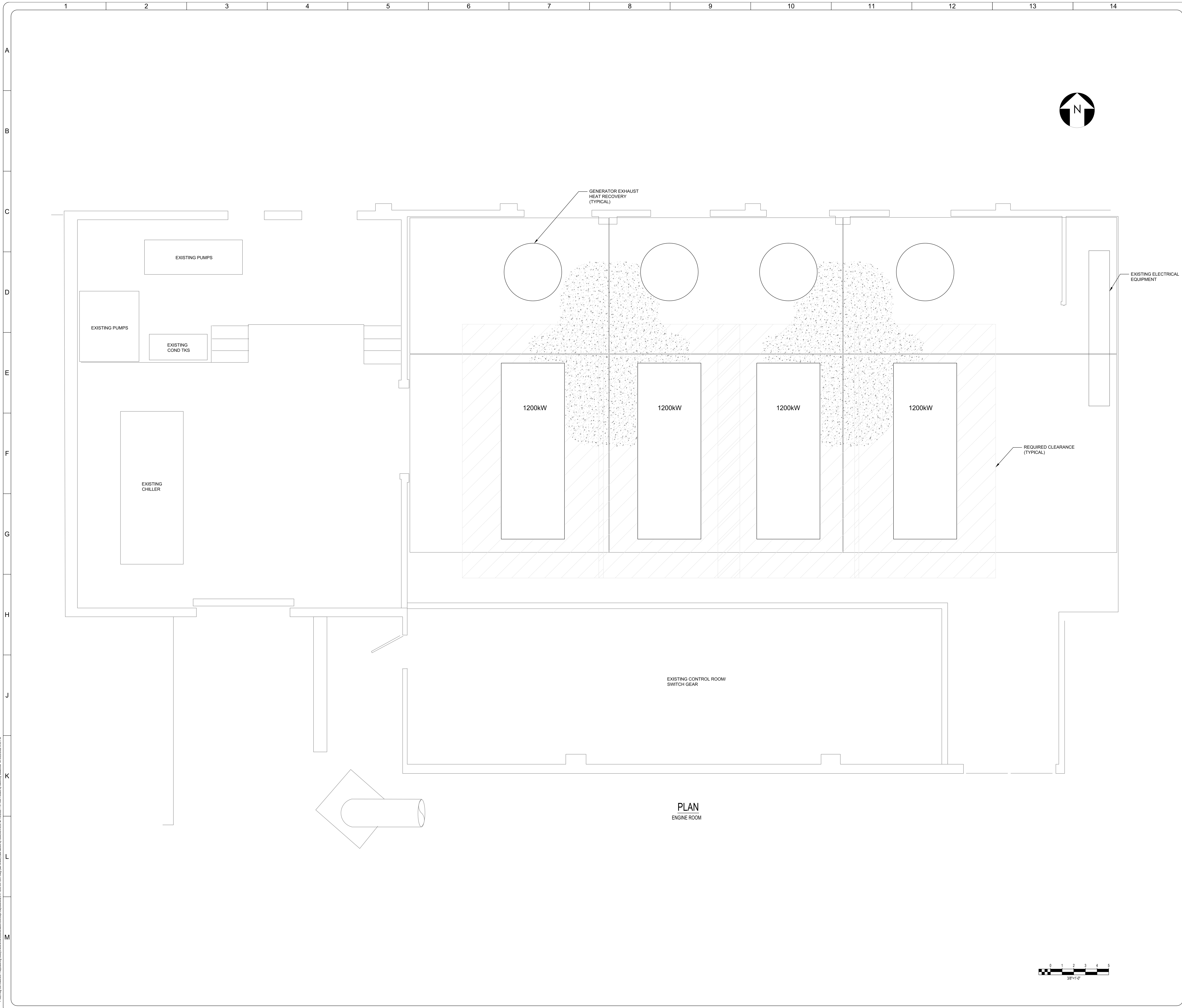
GENERAL ARRANGEMENT (1)
1200KW ENGINE (2)
TRANSFORMERS

SEAL

SIGNATURE DATE

DWG No.
CON1002

SHEET No.
1 OF 1



IT IS A VIOLATION OF NYS PROFESSIONAL ENGINEERING & LAND SURVEYING: LAWS, RULES & REGULATIONS: ARTICLE 145 FOR ANY PERSON, UNLESS HE IS ACTING UNDER THE DIRECTION OF A LICENSED PROFESSIONAL ENGINEER OR LAND SURVEYOR, TO ALTER AN ITEM IN ANY WAY ON THIS CONSTRUCTION DOCUMENT.

REV. No.	REV. BY	DATE	DESCRIPTION	CHECKED BY	PROJECT MANAGER	LEAD ENGINEER
B	GMM	08/19/2022	ISSUED FOR FINAL REPORT NOT FOR CONSTRUCTION	MD	MLM	MLM
A	GMM	07/07/2022	ISSUED FOR REVIEW	MLM	MLM	-

WALDRON
WALDRON.COM

DATE DRAWN: 5/16/2022
ORIGINAL SIZE: ANSI E

CLIENT DRAWING No.

W.E.N.Y. PROJECT No.: 423.01

CLIENT
BIG SIX TOWERS, INC.
59-55 47TH AVE WOODSIDE
NEW YORK

DRAWING TITLE
BIG SIX TOWERS
REPOWERING STUDY

GENERAL ARRANGEMENT (4)
1200KW ENGINES

SEAL

SIGNATURE DATE

DWG No.: CON1003

SHEET No.: 1 OF 1

Attachment F

Engine Vendor Quotations and Performance Information

WALDRON

Matthew Durant

From: Kreidemaker, Frank <Frank_Kreidemaker@miltoncat.com>
Sent: Friday, June 03, 2022 5:15 PM
To: Matthew Durant
Subject: RE: Queens NY Cogen Study
Attachments: CG170 LEBE0017-03.pdf; CG132B LEYE0020-02.pdf

Hi Matt,

Sorry for the delay on this – please see below and let me know if you have any questions.

CG170-12 rated 1200kW at 480V Continuous - CHP Package

- Remote cooling radiators (ship loose for installation on site by others)
- SCR emissions system (ship loose for mounting on enclosure roof by installing contractor.)
- HRSG (ship loose for installation on site by others)
- CHP control system with touchscreen HMI (ship loose for installation on site by others)

Budget: $1,816,980.00

For Sound Attenuated Outdoor Enclosure for CG170 CHP Package Add: $637,925.00
(HRSG would be mounted adjacent to generator enclosure and would be insulated for outdoor installation.)

CG132B-12 rated 600kW at 480V Continuous - CHP Package

- Remote cooling radiators (ship loose for installation on site by others)
- SCR emissions system (ship loose for mounting on enclosure roof by installing contractor.)
- HRSG (ship loose for installation on site by others)
- CHP control system with touchscreen HMI (ship loose for installation on site by others)

Budget: $1,364,275.00

For Sound Attenuated Outdoor Enclosure for CG132 CHP Package Add: $494,350.00
(HRSG would be mounted adjacent to generator enclosure and would be insulated for outdoor installation.)

Thank you,

Frank Kreidemaker
Milton CAT Power Systems
Energy Solutions Business Development
Cell: 774.217.8151
Frank_kreidemaker@miltoncat.com

reference data sheet

Technical data

1200 kWel; 480 V, 60 Hz; Natural gas, MN = 80

Design conditions

Inlet air temperature / rel. Humidity:	[°F] / [%]	77 / 60
Altitude:	[ft]	328
Exhaust temp. after heat exchanger:	[°F]	248
NO_x Emission (tolerance - 8%):	[g/bhph]	0,94

Fuel gas data: 2)

Methane number:	[-]	80
Lower calorific value:	[BTU/ft³]	983,74
Gas density:	[lb/ft³]	0,05
Standard gas:	Natural gas, MN = 80	

Genset:

Engine:	**CG170-12**	
Configuration code:	[-]	R
Speed:	[1/min]	1500
Configuration / number of cylinders:	[-]	V / 12
Bore / Stroke / Displacement:	[in] / [in] / [in³]	6,7 / 7,7 / 3241
Compression ratio:	[-]	13
Mean piston speed:	[ft/s]	32,2
Mean lube oil consumption at full load:	[lb/hr]	0,4
Generator:	**Marelli MJB 450 LB4 cUL or similar (*)**	
Voltage / voltage range / cos Phi:	[V] / [%] / [-]	480 / 10 / 1
Speed / frequency:	[1/min] / [Hz]	1800 / 60
Gear box:	**Eisenbeiss GU 320**	
Lube oil volume of gear box:	[gal(US)]	15

*CES reserves the right to change the alternator supplier and type during offer period. The genset data may thereby change slightly.
The power output will not change. CES will confirm the alternator type, brand and alternator data sheet with the order confirmation.

Energy balance

Load:	[%]	**100**	**75**	**50**
Electrical power COP acc. ISO 8528-1:	[kW]	**1200**	**900**	**600**
Engine jacket water heat:	[BTU/min±8%]	34835	26923	19353
Intercooler LT heat:	[BTU/min±8%]	6603	4440	2618
Lube oil heat:	[BTU/min±8%]			
Exhaust heat with temp. after heat exchanger:	[BTU/min±8%]	33241	27549	20890
Exhaust temperature:	[°F ±43°F]	777	824	876
Exhaust mass flow, wet:	[lb/hr]	14403	10920	7549
Combustion mass air flow:	[lb/hr]	13927	10551	7289
Radiation heat engine / generator:	[BTU/min±8%]	2334 / 1935	2277 / 1651	2049 / 1480
Fuel consumption:	[BTU/min+5%]	157497	121808	85835
Electrical / thermal efficiency:	[%]	43,4 / 43,2	42,1 / 44,7	39,8 / 46,9
Total efficiency:	[%]	86,6	86,8	86,7

System parameters 1)

Ventilation air flow (comb. air incl.) with ΔT = 15K	[lb/hr]	66800
Combustion air temperature minimum / design:	[°F]	41 / 77
Exhaust back pressure from / to:	[inWC]	12 / 20
Maximum pressure loss in front of air cleaner:	[inWC]	2
Zero-pressure gas control unit selectable from / to: 2)	[inWC]	8 / 80
Pre-pressure gas control unit selectable from / to: 2)	[psi]	7 / 145
Starter battery 24V, capacity required:	[Ah]	430
Starter motor:	[kWel.] / [VDC]	15 / 24
Lube oil content engine / base frame:	[gal(US)]	54 / -
Dry weight engine / genset:	[lb]	11200 / 28330

Cooling system 6)

Glycol content engine jacket water / intercooler:	[% Vol.]	35 / 35
Water volume engine jacket / intercooler:	[gal(US)]	29 / 5,3
KVS / Cv value engine jacket water / intercooler:	[ft³/h]	1624 / 1857
Jacket water coolant temperature in / out:	[°F]	176 / 199
Intercooler coolant temperature in / out:	[°F]	117 / 121
Engine jacket water flow rate from / to:	[gpm]	159 / 247
Water flow rate engine jacket water / intercooler:	[gpm]	191 / 176
Water pressure loss engine jacket water / intercooler:	[psi]	13,1 / 8,7

3332427EE14764

1) See also "Layout of power plants": 2) See also Techn. Circular 0199-99-3017 6) Gear oil cooling within intercooler coolant circuit

Frequency band f [Hz]	25	31,5	40	50	63	80	100	125	160	200	250	315	400	500	630	800	1k	1.25k	1.6k	2k	2.5k	3.15k	4k	5k	6.3k	8k	10k	12.5k	16k	L_{WA} [dB(A)]	S [m²]
Air-borne noise 3) $L_{W,Terz}$ [dB(lin)]	94,0	94,7	98,0	100,5	106,1	108,9	107,6	108,5	106,0	115,3	115,0	114,8	108,6	110,2	109,5	108,8	109,2	108,2	108,1	107,6	107,0	108,5	103,5	102,3	114,1	107,0	101,4	103,8	98,1	120,7 ±4dB(A)	114
Exhaust noise 4) $L_{W,Terz}$ [dB(lin)]	114,2	116,0	124,6	115,9	120,0	129,0	125,3	134,1	125,3	130,0	128,4	128,2	126,4	125,8	125,0	119,0	117,8	116,6	117,7	117,6	116,3	115,5	114,6	113,7	114,9	113,9	113,4	112,9	111,1	132,1 ±3dB(A)	15,5 5)

3) DIN EN ISO 3746 (σ_{R0}=±4 dB) 4) Measured in exhaust pipe (f ≤ 250Hz: ±5dB; f > 250Hz: ±3dB) L_W: Sound power level S: Area of measurement surface (S_0=1m²) 5) DIN 45635-11, Appendix A

Budget PROPOSAL FOR:

Waldron Engineering & Construction

Queens NY CHP

May 10,2022

NORTHEAST™
ENERGY SYSTEMS
Power Systems Specialists

Partnering with:
JENBACHER
INNIO

TABLE OF CONTENTS

Matthew Durant
Waldron Engineering & Construction, Inc

May 10, 2022

Northeast Energy Systems (NES) is pleased to present budget pricing for your Queens NY CHP application. We are presenting two CHP options (1) JMS 312 rated at 635 kW and (2) JMS 320 rated at 1,061 kW, both at 480V, 3 Phase, 1.0PF. We are also presenting an option for an intergraded container package for an outdoor application. The emission requirements for NYC seem to be changing and not sure if an SCR would be required for either option. Our base option is a.5g/NOx engine version with an oxidation catalyst. We are providing an option for a urea based SCR system. If an SCR system is required, we would use our 1.1g/NOx version because of the higher electrical efficiency. We understand heat recovery will include both hot water and 5 psig steam from the exhaust. We selected a CAINE HRSG package for budget proposes, however we can explore other HRSG suppliers if the project moves forward.

The NES team has extensive experience with combined heat and power systems in the metro NYC area with over 50 MWs installed. It can be very challenging with a number of city agencies that need to be delt with. NES can provide great assistance navigating through the process in NYC. Major CHP installations include Hudson Yards, NYU Langone, NYU, Coles, North River WWTP, Marriott Times Sq, 1199 housing development, North Shore Medical Center and a number of other CHP projects in the metro NYC area. A full list is presented in the experience section of this proposal

Sincerely
Fred Farrand
Fred Farrand
VP Sales
Northeast Energy Systems

1. SUMMARY OF PERFORMANCE & PRICE

Equipment Pricing & Details:

Option #1- JMS 312 Engine Generator Package	
Prime Mover OEM	Jenbacher
Engine Model	JMC 312 480V
Number of units	One (1)
Gross output (per unit)	635 kW @ 480V
Major balance of plant (BoP) equipment:	• JW heat recovery • HRSG Package • Silencer • Plate & Frame process heat exchanger • Radiators *(See Section 3 of proposal for full scope of supply)*
Proposal Value	**$708,626**
SCR Adder	**+$65,000**
Intergraded container Adder	**+$353,944**

Option #2- JMS 320 Engine Generator Package	
Prime Mover OEM	Jenbacher
Engine Model	JMC 320 480V
Number of units	One (1)
Gross output (per unit)	1,062 kW @ 480V
Major balance of plant (BoP) equipment:	• JW heat recovery • HRSG Package • Silencer • Plate & Frame process heat exchanger • Radiators *(See Section 3 of proposal for full scope of supply)*
Proposal Value	**$895,912**
SCR Adder	**+$91,000**
Intergraded container Adder	**+$372,243**

Engineering & Execution services that are included in our Equipment Pricing:

1. Development support from our Sales & Engineering teams
2. Engineering & Design support from a degreed Project Engineer
3. Construction & Installation support from a Field Project Manager
4. Greenhouse modular package assembly supervision
5. Startup & Commissioning from our factory-certified Commissioning Technicians
6. Training from our factory-certified team of trainers
7. Container assembly supervision

Services to be added in a Product Support Contract:

1. Remoting Monitoring & Support from our Asset Performance Management Center (APMC)
2. Maintenance plan, including preventative & corrective activity, lube oil, etc. tailored to your project from our Product Support team

2. OUR VALUE PROPOSITION

A partner throughout your project's lifecycle

Project Phase	Our Activities
Development	We assist with design & development work before a purchase order, including: • Provide "pre-submittal" engineering package before full submittal package is available • Review plant drawings and provide input based on previous projects • Conduct Design for "Maintainability" & "Affordability" Reviews
Engineering	We assign a degreed Project Engineer to assist your team in the design phase, including: • Regular meetings to refine scope & schedule • Provide input into design decisions such as sequence of operations, electrical integration, controls strategy, etc. • Develop full submittal package for NES scope of supply
Construction	We assign a Field Project Manager to be onsite during our installation, to assist with: • Supervision and direction on rigging & installation • Guidance on mechanical & electrically connecting into plant • Assembly supervision of the greenhouse modules • Troubleshooting issues & answering questions in real-time at jobsite
Startup & Commissioning	We have factory-certified Commissioning Technicians work thru our proven: • Pre-Commissioning Checklists • Commissioning Procedures • Testing Protocols • Handover checklists • All based in the USA
Training	We have factory-certified trainers that can provide: • Onsite training classes ranging from general operations to specific system-level training on the engine, controls and balance of plant • Classes at our training facility where your team can practice performing maintenance activities, clearing trips, etc. on our training engines & control systems
Remote Monitoring	We have an Asset Performance Management Center (APMC) with remote capabilities: • Remote monitoring and reporting of engine performance data • Predictive analytics to flag maintenance events before trips occur • Remote support to troubleshoot & solve issues with your operations team
Maintenance Plans	We have a full Product Support team with the following capabilities: • Create tailored long-term service agreements (LTSA) • 14+ technicians in the northeast who only focus on Jenbacher gas engines • 4 dedicated technicians for NYC • 10+ technicians on the west coast to provide additional support as needed • $4M+ of Jenbacher parts in inventory located two hours from the site • Access to INNIO Jenbacher's inventory located in the USA (another $10M+) • Ability to perform INNIO Jenbacher factory warranty work
Quarterly Reviews	We have developed operational rhythms with customers to: • Review operational data • Plan for upcoming maintenance activities • Identify areas for continuous improvement • Create the space for ongoing leadership communication

3. TECHNICAL PERFORMANCE & DETAILS

Northeast Energy Systems (NES) is pleased to present our budget proposal for your Queens CHP project. We are presenting two engine generator size options for your review (1) a Jenbacher JMS 312 rated at 635 kW@ 480V and (2) a Jenbacher JMS 320 rated at 1,062 kW @ 480V. We are assuming our lean burn technology (.5G NOx) and an oxidation catalyst is all that will be required for permitting. We are providing an adder for a urea based SCR system if required. An interrogated container solution is also presented for both options. Our basic assumptions for the project include:

- The proposed CHP will operate in parallel with the local utility
- The proposed CHP system should be equipped with black start and island operation
- Heat recovery includes hot water from the engine cooling systems and 5 psig steam from exhaust
- Standard package is .5g/NOx with an oxidation Catalyst
- Optional intergraded container package

Both power options will use the Jenbacher "type 3 series of engines". They are a V70º configuration, 135 mm bore, 170 mm stroke with a 2.43 lit displacement per cylinder. Over 12,000 units are in operation worldwide utilizing various gases including natural gas, biogas and landfill methane. It is one of the world's most widely used gas engines and legendry for its reliability. It will not require a major rebuild until 80,000 operating hours. No other type engine has more operating hours than the Jenbacher type 3 engines.

Type 3 Engine Installed Base:

- **Total**: +12,000
- **CHP**: 6,500
- **Biogas and Landfill gas +5,500**

Island Operation Discussion

Standard with all Jenbacher gas engines is the ability for black start and island operation. It can provide an additional layer of backup power for hospitals, universities, commercial developments, and major infrastructure facilities. During a major power outage, the engines will transition to island mode operation. Thousands of Jenbacher engines operate in island mode worldwide. Many developing countries rely on Jenbacher gas engines for their only source of power. Hospitals, universities, and wastewater treatment plants in the northeast have relied on Jenbacher gas engines to provide their critical power needs during utility outage periods. NES black start/island projects include the UMASS Medical centers in Worcester and Leominster MA, Wesleyan University, SUNY Old Westbury University LI, North Well Medical Center on long island (100% island), NYU Langone Medical Center, NYU School of Medicine, New York University Coles complex, Citi Bank Corporate Headquarters in NYC, Hudson Yards Development, Marriott Marque Times square, TWA hotel & conference center at JFK airport (100% island no utility), the North River NYDEP WWTP, Philadelphia Water Department, U.S. Coast Guard Baltimore, Adelphia University and over 40 other facilities in the U.S

Option #1- Single Jenbacher JMS 312 with support BOP and HRSG Package

1. One (1) Jenbacher JMS 312 B802/805 engine generator
2. One (1) STAMFORD (or equal) 480 generator
3. One (1) 24V electric starting system w/changer
4. One (1) Black start island operation package

5. One (1) Generator condensate heater
6. One (1) Engine black heater
7. One (1) Jenbacher DIA.NE generator set control system with generator protection
8. One (1) Vibration sensor
9. One (1) Input/export control signal
10. One (1) HT/LT circuits MODINE dual core radiator package
11. One (1) Radiator flexible braid connection package
12. One (1) 3-way Thermostatic warm up valve
13. One (1) Temperature control valve
14. One (1) HT circuit 40 gallon ASME bladder type expansion tank
15. One (1) LT circuit 15 gallon ASME bladder type expansion tank
16. Two (2) Pressure relief valves
17. Two (1) Air eliminator valves
18. Two (2) Air vent valves
19. Two (2) Triple duty valves
20. Two (2) Suction diffusers
21. Four (4) Butterfly valves WATTS LUG type
22. Four (4) Pressure gauges 0-100 PSIG
23. Four (4) Temperature gauges 20-240 Deg F w/thermowell
24. One (1) WEINMAN HT circuit pump
25. Two (2) HT pump 3.0" ASA x 3.0" S/S braid x 3.0" ASA x 12" L braid package
26. One (1) 16 AMP Non-fused disconnect switch
27. One (1) WEINMAN LT circuit pump
28. Two (2) LT Pump 2.0" ASA x 2.0" S/S BRAID x 3.0" ASA x 12" L
29. One (1) 16 AMP non-fused disconnect switch
30. One (1) HARCO/CLARIANT oxidation catalyst
31. One (1) Catalyst monitoring package temp and B/P
32. One (1) Oxidation catalyst Insulation blanket
33. One (10 Critical grade silencer

Optional Intergraded Container Package

NES is presenting an optional intergraded container package. It is as close to a "plug and play" package as possible. The container module includes the engine generator, generator breaker, MCC, utility protection relays and lube oil storage all installed, pre-wired & pre-wired in a sound attenuated weather tight enclosure. Additional equipment included, however shipped loose with assembly by others include radiators, air filter housing, silencer, oxidation catalyst, decoupling heat exchanger and stub stack. Additional requirements of NYC include UL certification and fire suppression system.

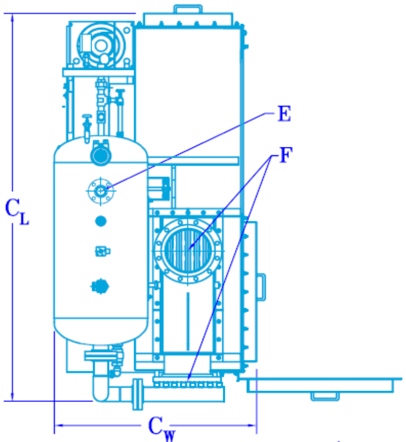
Additional Equipment and Services

1. Operator Training
2. Technical support
3. Project management
4. Container assembly supervision
5. my Plant® remote monitoring program and predictive maintenance software package
6. Startup and commissioning
7. First lube oil fill (engine sump only)
8. Glycol fill (container packages only

HRSG Package

NES is providing a HRSG package manufactured by CAIN Industries. It is an indoor package that includes an internal exhaust bypass. Other manufacturers can be explored if the project moves forward. The CAIN package presents performance and budget pricing for this level of development.

DATE: 5/2/2022 REF#: **64987** FOR: Northeast Energy Systems
REV#: **0** c/o: Cain Industries, Inc.
MODEL: ESG1-816B16CSS
HEAT SOURCE: Jenbacher JMS 312 Natural Gas Engine Bul.#10950

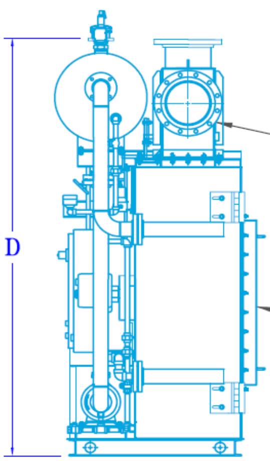


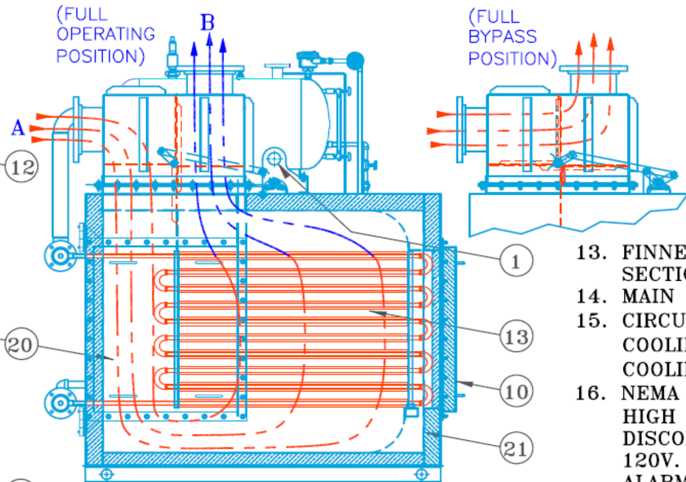
PARTS LIST
(SEE DESIGN DATA FOR CONSTRUCTION)
1. LIFTING EYE
2. STEAM PRESSURE CONTROLLER
3. MODULATING FEEDWATER VALVE
4. ASME STEAM SAFETY VALVE
5. STEAM OUTLET FLANGE (STEAM STOP & CHECK VALVE SUPPLIED BY OTHERS)
6. STEAM FLASH DRUM/DRY PIPES (INSULATED)
7. EXCESS STEAM PRESSURE SWITCH
8. WATER LEVEL CONTROL W/LOW & HIGH WATER CUTOUT & MANUAL RESET LOW LOW WATER
9. LOCALIZED PIPING CONNECTIONS: FEEDWATER, BLOWDOWN MANIFOLD, 100 PSIG CONTROL AIR (WHEN REQ'D FOR PNEUMATIC DAMPER ACTUATOR)
10. TUBE REMOVAL ACCESS DOOR
11. STRUCTURAL STEEL BASE
12. MODULATING EXHAUST BYPASS

ESG1

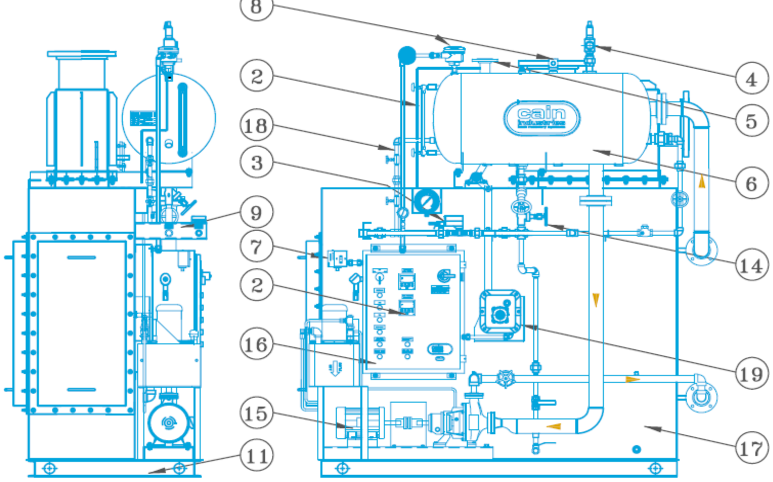
PERFORMANCE AND DIMENSION DATA

A.	901 °F
B.	310 °F
	5 PSI
	37 BHP
C.	97x58 "
D.	110 "
E.	5 " CONN.
F.	8-18"Dia. " CONN.
	8000 # WGT
	1,077 H.S.
	15 PSIG
	1000 TEMP.





13. FINNED TUBE HEAT TRANSFER SECTION
14. MAIN BLOW DOWN VALVE ASSY.
15. CIRCULATING PUMP ASSY W/SELF COOLING CIRCULATING PUMP (NO COOLING WATER REQUIRED)
16. NEMA 12 CONTROL PANEL: (SINGLE HIGH VOLTAGE CONN.) FUSE DISCONNECT MAGNETIC STARTER, 120V. STEPDOWN TRANSFORMER, ALARM LIGHTS
17. 10GA. SHELL (3" THKS. INSULATED)
18. CONTINUOUS SURFACE BLOWDOWN
19. MODULATING ACTUATOR W/FAILSAFE TO BYPASS
20. MAIN INSPECTION DOOR, HINGED
21. STAINLESS STEEL INTERIOR



NOTES:
A. OPTIONAL INSULATION AS REQ'D:
 -SHELL THICKNESS INSULATION:
 4" ✓ 6" ☐ 8" ☐ 12" ☐
 -BYPASS JACKET INSULATION:
 2" ☐ 3" ☐ 4" ☐ 6" ☐ 8" ☐
 (EXTERNAL PIPING INSULATION INSULATED BY OTHERS AS REQ'D)
B. EXHAUST FLANGE CONN.S:
 2x2 ANGLE RING (STANDARD)
 150LB ANSI HOLE PTN (OPTIONAL) ☐
C. A.S.M.E. & NAT'L BOARD STAMPED - SEC.I, DIV.I

CAIN INDUSTRIES Inc. PO Box 189 W194 N11826 McCormick Drive Germantown, WI 53022
Phone (262) 251-0051 (800) 558-8690 Fax (262) 251-0118 sales@cainind.com www.cainind.com

JMS 312 B802 Engine Performance (.5g NOx)

Ratings are per ISO-ICFN continuous power with the following standard reference conditions

- Barometric pressure 14.5 PSI, or 1,000 feet above sea level
- Air temperature 84 ° F
- Relative humidity 30 %

Our plan would be to use our ultra-low NOx engine (.5g/NOx) assuming an SCR is not required. The .5g/NOx performance is listed below. If an SCR is required, we would use our higher NOx engine (1.1g/NOx). It has better efficiency and lower heat rate. Performance is also listed below

JMS 312 B802 Engine generator Performance (.5g/NOx version)		
Electric Output	635 kW @ 480V	0% tolerance
Fuel Input	5.695 MMBTU/HR	+5% tolerance
Electrical efficiency	38.0%	+5% tolerance
Hot Water Heat Recovery	1.408 MMBTU/HR 190°F	-7% tolerance
Steam Production	1,260 LBS/HR of 5 PSIG steam w/210° feed water	-5% tolerance

JMS 312 B805 Engine generator Performance (1.1g/NOx version)		
Electric Output	635 kW @ 480V	0% tolerance
Fuel Input	5.548 MMBTU/HR	+5% tolerance
Electrical efficiency	39.0%	+5% tolerance
Hot Water Heat Recovery	1.329 MMBTU/HR 190°F	-7% tolerance
Steam Production	1,260 LBS/HR of 5 PSIG steam w/210° feed water	-5% tolerance

The ratings in this specification are valid for full load operation at a site installation of 750 ft and air intake temperature up to 90°F. Thereafter a derate of 0.89%/°F will occur until an air intake temperature of 104°F. Thereafter a derate of 1.1%/°F will occur.

Emission	**Untreated**	**Treated**
NOx	.5G/BHP-HR	.5G/BHP-HR
CO	2.5G/BHP-HR	.25G/BHP-HR
NMNEHC	.46 G/BHP-HR	.12G/BHP-HR

****
****

Option #2- Single Jenbacher JMS 320 with support BOP and HRSG Package

1. One (1) Jenbacher JMS 320 B802/805 engine generator
2. One (1) STAMFORD (or equal) 480 generator
3. One (1) 24V electric starting system w/changer
4. One (1) Black start island operation package
5. One (1) Generator condensate heater
6. One (1) Engine black heater
7. One (1) Jenbacher DIA.NE generator set control system with generator protection

8. One (1) Vibration sensor
9. One (1) Input/export control signal
10. One (1) HT/LT MODINE dual core radiator package
11. One (1) MODINE flexible braid connection package
12. One (1) 3-way Thermostatic warm up valve
13. One (1) Temperature control valve
14. One (1) HT circuit 40 gallon ASME bladder type expansion tank
15. One (1) LT circuit 15 gallon ASME bladder type expansion tank
16. Two (2) Pressure relief valves
17. Two (1) Air eliminator valves
18. Two (2) Air vent valves
19. Two (2) Triple duty valves
20. Two (2) Suction diffusers
21. Four (4) Butterfly valves WATTS LUG type
22. Four (4) Pressure gauges 0-100 PSIG
23. Four (4) Temperature gauges 20-240 Deg F w/thermowell
24. One (1) WEINMAN HT circuit pump
25. Two (2) HT pump 3.0" ASA x 3.0" S/S braid x 3.0" ASA x 12" L braid package
26. One (1) 16 AMP Non-fused disconnect switch
27. One (1) WEINMAN LT circuit pump
28. Two (2) LT Pump 2.0" ASA x 2.0" S/S BRAID x 3.0" ASA x 12" L
29. One (1) 16 AMP non-fused disconnect switch
30. One (1) HARCO/CLARIANT oxidation catalyst
31. One (1) Catalyst monitoring package temp and B/P
32. One (1) Oxidation catalyst Insulation blanket
33. One (10 Critical grade silencer

Optional Intergraded Container Package

NES is presenting an optional intergraded container package. It is as close to a "plug and play" package as possible. The container module includes the engine generator, generator breaker, MCC, utility protection relays and lube oil storage all installed, pre-wired & pre-wired in a sound attenuated weather tight enclosure. Additional equipment included, however shipped loose with assembly by others include radiators, air filter housing, silencer, oxidation catalyst, decoupling heat exchanger and stub stack. Additional requirements of NYC include UL certification and fire suppression system.

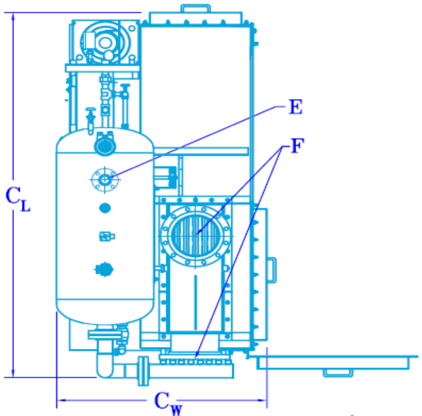
Additional Equipment and Services

1. Operator Training
2. Technical support
3. Project management
4. Container assembly supervision
5. my Plant® remote monitoring program and predictive maintenance software package
6. Startup and commissioning
7. First lube oil fill (engine sump only)
8. Glycol fill (container packages only
9. Optional SCR system with urea storage

HRSG Package

NES is providing a HRSG package manufactured by CAIN Industries. It is an indoor package that includes an internal exhaust bypass. Other manufacturers can be explored if the project moves forward. The CAIN package presents performance and budget pricing for this level of development.

DATE: 5/2/2022 REF#: **64986** FOR: Northeast Energy Systems
REV#: **0** c/o: Cain Industries, Inc.
MODEL: ESG1-A18D16CSS
HEAT SOURCE: Jenbacher JMS 320 Natural Gas Engine Bul.#10950



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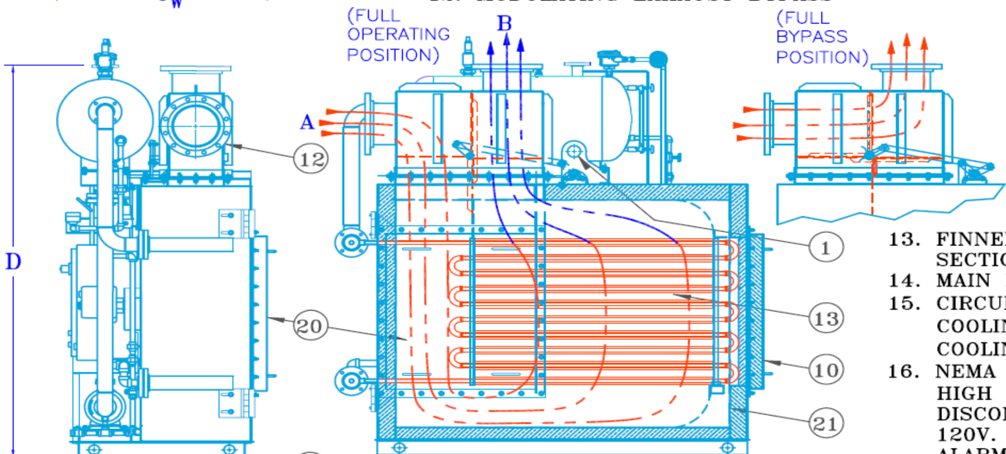
12. MODULATING EXHAUST BYPASS

ESG1

PERFORMANCE
AND
DIMENSION DATA

A.	900 °F
B.	288 °F
	5 PSI
	67 BHP
C.	97x64 "
D.	106 "
E.	5 " CONN.
F.	12-24"Dia. " CONN.
	9500 # WGT
	2,019 H.S.
	15 PSIG
	1000 TEMP.



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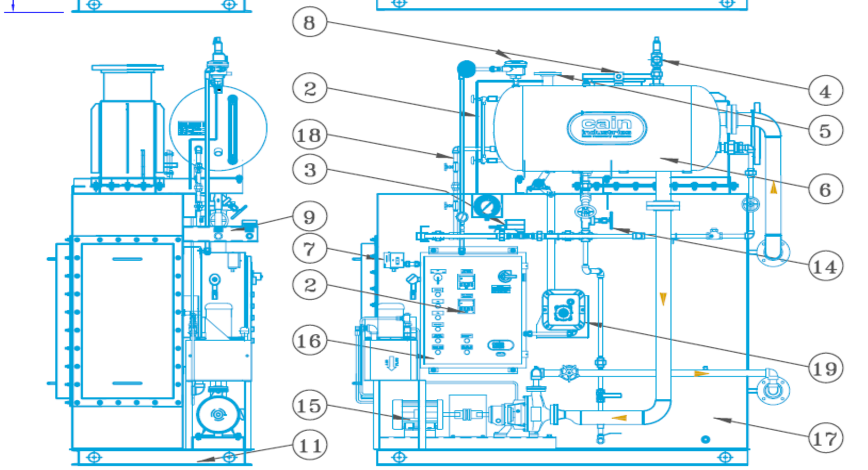

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- Barometric pressure 14.5 PSI,
  or 1,000 feet above sea level
  Air temperature 84 ° F
- Relative humidity 30 %

Our plan would be to use our ultra-low NOx engine (.5g/NOx) assuming an SCR is not required. The .5g/NOx performance is listed below. If an SCR is required, we would use our higher NOx engine (1.1g/NOx). It has better efficiency and lower heat rate. Performance is also listed below

JMS 320 B802 Engine generator Performance (.5g/NOx version)		
Electric Output	1,062 kW @ 480V	0% tolerance
Fuel Input	9.482 MMBTU/HR	+5% tolerance
Electrical efficiency	38.2%	+5% tolerance
Hot Water Heat Recovery	2.243 MMBTU/HR 190°F	-7% tolerance
Steam Production	2,278 LBS/HR of 5 PSIG steam w/210° feed water	-5% tolerance

JMS 312 B805 Engine generator Performance (1.1g/NOx version)		
Electric Output	1,062 kW @ 480V	0% tolerance
Fuel Input	9.247 MMBTU/HR	+5% tolerance
Electrical efficiency	39.2%	+5% tolerance
Hot Water Heat Recovery	2.211 MMBTU/HR 190°F	-7% tolerance
Steam Production	2,278 LBS/HR of 5 PSIG steam w/210° feed water	-5% tolerance

The ratings in this specification are valid for full load operation at a site installation of 750 ft and air intake temperature up to 90°F. Thereafter a derate of 0.89%/°F will occur until an air intake temperature of 104°F. Thereafter a derate of 1.1%/°F will occur.

Emission	**Untreated**	**Treated**
NOx	.5G/BHP-HR	.5G/BHP-HR
CO	2.5G/BHP-HR	.25G/BHP-HR
NMNEHC	.46 G/BHP-HR	.12G/BHP-HR

3. Engineering and Project Management

Engineering & Field Project Management Services Included

Northeast Energy Systems provides technical support through its engineering office located in Philadelphia PA. The office is staffed with both mechanical and electrical engineers along with Field Project Managers. They support projects pre-sale through commissioning and operations. This group will supply the submittal packages and support the detailed design for projects. The following is a list of activities and deliverables provided by our technical support group.

- Assist in the development of sequence of electrical operations for the Jenbacher engine
- Develop and customize engine, generator, and associated mechanical-electrical equipment drawings for all equipment outlined in this scope.
- Provide a system P&ID (to include NES supplied equipment)
- BOP equipment cut sheets, drawings and specifications
- Coordinate with and provide engineering assistance for integration of the Jenbacher DIA.NE control system
- Provide emissions data and support for air permitting and certified emission testing by others
- Develop and customize Jenbacher DIA.NE panel operating systems for site specific conditions and parameters.
- Develop and provide submittal documentation in electronic format for review by construction managers and sub-contractors.
- Attend bi-weekly conference calls and four (4) total in-person meetings design through construction
- Develop and provide as-built documentation, following final startup and commissioning, in electronic format for the owners use.

Onsite Field Project Management Services

- Supervision and direction on rigging & installation
- Guidance on mechanical & electrically connecting into plant
- Troubleshooting issues & answering questions in real-time at jobsite
- Container module assembly supervision

Factory Shop tests

All engines are factory tested before leaving the factory. The process includes a factory test using a representative generator operating at 1.0 PF. Testing is conducted at 100%, 75% and 50% for two hours. End user is welcome to witness the factory testing, however, is responsible for all travel expenses. Testing parameters include:

- Electric output
- Heat rate
- Electric efficiency
- Emissions (raw)

Certified testing reports will be issued at the conclusion of the factory testing or emailed to the end user following the test.

Commissioning Services

On site pre-commissioning and commissioning services is provided by Northeast Energy System commissioning technicians. Commissioning services will be scheduled only after receipt of completed installation checklists. A commissioning work scope will be provided 14 days prior to the startup date. Startup and commissioning will include all required travel and lodging. No load banks are included at this time. No technical support is required from Europe including commissioning. The NES product support group includes all technical resources required for commissioning and maintenance

Startup and Commissioning Services

- Pre-Commissioning checklists
- Commissioning by factory-certified NES personal located in USA
- Prepare performance test protocol
- Performance testing
- Punch list and turnover

4. COMMERCIAL DETAILS

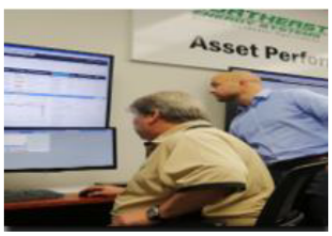
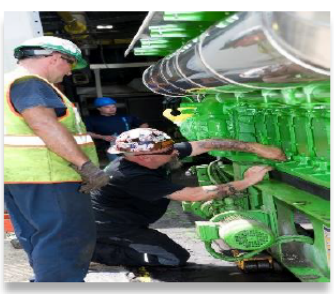
All budget prices are quoted F.O.B. jobsite on open top truck with rigging and removal required by others. No provisions are made for local taxes, bonds, permits, or fees. Pricing is valid 30 days from the date of this proposal. We have experienced unprecedented supply issues and cost increases covering both material and shipping costs. In some cases, quoted prices from suppliers are good for only 7 days.

Equipment Pricing & Details:

Option #1- JMS 312 Engine Generator Package	
Prime Mover OEM	Jenbacher
Engine Model	JMC 312 480V
Number of units	One (1)
Gross output (per unit)	635 kW @ 480V
Major balance of plant (BoP) equipment:	• JW heat recovery • HRSG Package • Silencer • Plate & Frame process heat exchanger • Radiators *(See Section 3 of proposal for full scope of supply)*
Proposal Value	**$708,626**
SCR Adder	**+$65,000**
Intergraded container Adder	**+$353,944**

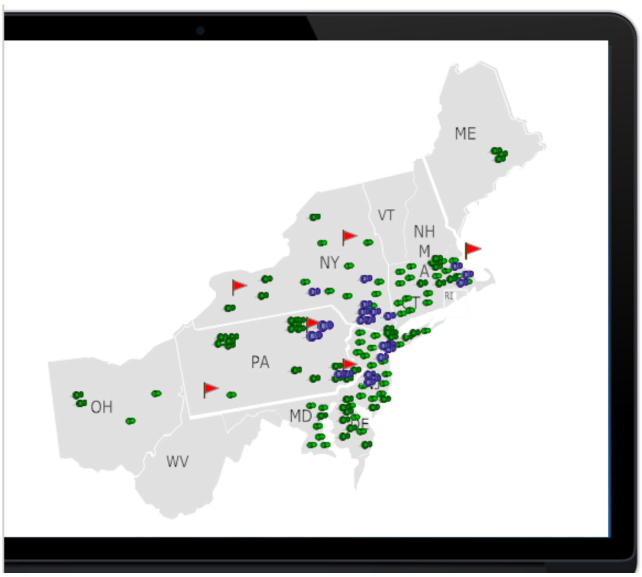
Option #2- JMS 320 Engine Generator Package	
Prime Mover OEM	Jenbacher
Engine Model	JMC 320 480V
Number of units	One (1)
Gross output (per unit)	1,062 kW @ 480V
Major balance of plant (BoP) equipment:	• JW heat recovery • HRSG Package • Silencer • Plate & Frame process heat exchanger • Radiators *(See Section 3 of proposal for full scope of supply)*
Proposal Value	**$895,912**
SCR Adder	**+$91,000**
Intergraded container Adder	**+$372,243**

5. Product Support

Parts and Service 	✓ Primary parts warehouse located in Bristol, PA ✓ Backed by INNIO warehouse in Waukesha, WI ✓ Authorized supplier of genuine Jenbacher Gas Engine spare parts ✓ $4M+ parts in NES inventory in USA ✓ 14+ resident technicians assigned across northeast
Training 	✓ Two (2) factory-certified Jenbacher trainers on NES-WES staff ✓ Training facility in California equipped with engine blocks, control systems, etc. ✓ Trainers go to customer site, or. customer can bring staff to our training center ✓ Multiple training classes and levels available
Remoting Monitoring & Support 	✓ Remote Monitoring for proactive maintenance ✓ Remote Support for diagnostics & alarms ✓ Allows for rapid resolution or technician dispatch ✓ Maximize plant reliability and availability ✓ Asset Performance Management Center (APMC) located in Bristol, PA and Brea, CA.
Maintenance Agreements 	✓ Tailored maintenance plans for each customer ✓ Technicians exclusively focused on gas power solutions ✓ Mechanical-electrical service capabilities for engines, generators, full balance of plant, controls ✓ Authorized service provider for AVK, Stanford alternators ✓ Authorized Q8 lube oil supplier
Product Warranty JENBACHER INNIO	✓ NES is the only Authorized INNIO Jenbacher distributor in the northeast USA ✓ As the authorized distributor NES can administer & execute the INNIO Jenbacher factory warranty ✓ Allows buyer to have recourse direct to INNIO factory if needed (unlike a "Sellers" warranty)

6. QUALIFICATIONS

<u>Northeast Energy Systems and Western Energy Systems</u> are the largest Jenbacher distributor in North America and has been selling and services Jenbacher engines in the U.S for seventeen years. NES/WES currently has over 240 gas engines in our fleet across North America, and we are proud that more than 50% of our engines are sold to repeat customers or partners. Our installed locations in the northeast are shown here:



Project Locations

Connecticut
- (6 engines in 4 projects)

Delaware
- (11 engines in 3 projects)

Maine
- (3 engines in 1 project)

Maryland
- (7 engines in 3 projects)

Massachusetts
- (17 engines in 9 projects)

New Jersey
- (16 engines in 8 projects)

New York
- (21 engines in 12 projects)

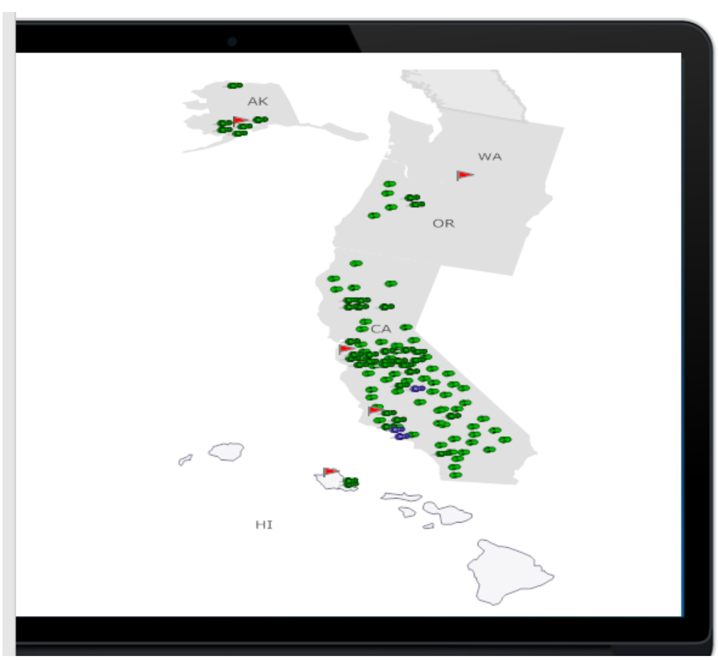
Ohio
- (4 engines in 2 projects

Pennsylvania
- (21 engines in 6 projects)

Fuel type (installed)
- Natural gas (NG) – 53
- Landfill gas (LFG) – 34
- Biogas (BG) – 16

Parts & Service
- Bristol, PA
- Woburn, MA
- Buffalo, NY
- Syracuse, NY
- Pittsburgh, PA
- Muncy, PA

Installations in West Coast United States



Project Locations

Alaska
- 6 engines in 2 projects

Northern California
- 46 engines in 23 projects

Southern California
- 39 engines in 27 projects

Hawaii
- 2 engines in 1 project

Oregon
- 5 engines in 4 projects

British Columbia
- 2 engines in 1 project

Fuel Type (Installed
- Natural Gas (NG) – 48
- Landfill gas (LFG) – 33
- Biogas (BG) – 19
- Syngas (SYN) – 1

GEJ Qualified technicians
- Northern California – 5
- Southern California – 5
- Anchorage, AK – 2

Parts & Service
- Brea, CA (WES HQ)
- Anchorage, AK
- Oahu, HI
- Auburn, WA

NYC and Related Experience in the Northeast:

Customer / Project	Engine type	Fuel type	Application
Citi Bank World Headquarters NYC	Two (2) x Jenbacher 620's	Natural Gas	CHP with black start/island
Marriott Marque NYC	Three (3)x Jenbacher 420's	Natural Gas	CHP with black start/island
Hudson Yards NYC	Four (4) x Jenbacher 620's	Natural Gas	CHP with black start/island
NYU Medical Center NYC	One (1) x Jenbacher 620	Natural Gas	CHP with black start/island
NYU Cole NYC	One (1) x Jenbacher 616	Natural Gas	CHP with black start/island
TWA Hotel/JFK NYC	Three (3) x Jenbacher 208's	Natural Gas	CHP 100% island, no utility
North Shore Medical Center LI NY	Two (2) x Jenbacher 420's	Natural Gas	CHP 100% island, no utility
Long Island Compost Ypack NY	Two (2) x Jenbacher JMC 420's	Natural Gas	CHP with black start for RNG facility
North River WWTP NYCDEP	Five (5) x Jenbacher 620's	Biogas/Natural gas	CHP with black start/island
Adelphi University LI NY	One (1) x Jenbacher 612	Natural Gas	CHP with black start/island
Montclair State	Two (2) x Jenbacher 616"s	Natural Gas	Utility Peaking
Wesleyan University	One (1) x Jenbacher 620	Natural Gas	CHP with black start/island
SUNY Old Westbury LI NY	One (1) x Jenbacher 612	Natural Gas	CHP with black start/island
OHIO Peaking Plant	Two (2) x Jenbacher 420's	Natural Gas	Utility Peaking
Novartis	Two (2) x Jenbacher 420's	Natural Gas	CHP with black start/island
UMASS Medical Center	One (1) x Jenbacher 616	Natural Gas	CHP with black start/island
UMASS Health Alliance	One (1) x Jenbacher 612	Natural Gas	CHP with black start/island
SEPTA Rail Division	Two (2) x Jenbacher 624's	Natural Gas	CHP with black start/island
IMG Phase 1	Ten (10) x Jenbacher 624's	Natural Gas	IPP Power station
IMG Phase 2	Five (5) x Jenbacher 624"s	Natural Gas	IPP power station
IMG Phase 3	Five (5) x Jenbacher 624"s	Natural Gas	IPP power station
Coviden Pharmaceutical	One (1) x Jenbacher 620 One (1) x Jenbacher 612	Natural Gas	CHP with black start/island
US Coast Guard – Baltimore Homeland Security Site	Four (4) x Jenbacher 320	Natural Gas/LFG	CHP with black start/island
Tosoh	Three (3) x Jenbacher 420's	Natural Gas	Standby / peaking
Marriott	Three (3) x Jenbacher 420's	Natural Gas	CHP with black start/island

8. Standard exceptions and Clarifications

1. Integration support is provided for NES supplied equipment only
2. P&ID will be provided for the NES supplied equipment
3. NES will provide shop drawings and equipment data sheets 75 days after receipt of approved purchase order.
4. Sales tax is not included in NES's offer
5. Wiring diagrams will be provided 30-60 days prior to delivery of the engine generator packages
6. Third party emission compliance testing is not included in our base scope.
7. Unloading of equipment at site is by others, however supervised by NES personal
8. Detailed engineering by others
9. Installation services by others
10. Four (4) design and project review meetings included with our proposal
11. Load banks not included
12. Permitting by others
13. Spring isolators not included, Jenbacher does not use spring isolators for vibration control
14. NES does not except any consequential damages or unlimited liability
15. Lube oil fill for engine sump only
16. Pricing based on using NES's standard terms and conditions
17. Standard engine generator package is not UL certified
18. All structural foundations and dunnage by others
19. NES transportation proposal includes delivering to first location only. If engine is delivered to storage this will be the first location.

Customer Responsibility

- Unloading and rigging of equipment
- Engineering and design
- Construction and assembly
- Civil and foundations
- Permitting
- Mechanical & electrical installation services
- Utility feed and interconnect
- Installation of shipped loose items including ground mounted radiators
- Communication line for remote monitoring

JENBACHER

Technical Description

Cogeneration Unit-Container

JMC 312 GS-N.L

Mains Parallel with Island Operations & Blackstart

Waldron-Queens CHP

JMC312 D802 480v

Northeast-Western Energy Systems

Full rating of the engine is for an installation at an altitude ≤ 100 ft and combustion air temperature (T1) ≤ 95°F. At air temperature (T1) 95°F < T < 113°F a de-rate of 0.67%/°F will apply. At (T1) T > 113°F a derate of 1.1%/°F will apply. Specific derate information may change upon factory order submission.

Electrical output	635	kW el.
Thermal output	1453	MBTU/hr

Emission values

NOx < 0.6 g/bhp.hr (NO2)

INNIO

JENBACHER

INNIO

0.01 Technical Data (on container)

			100%	75%	50%
Power input	[2]	MBTU/hr	5,695	4,422	3,146
Gas volume	*)	SCFH	6,210	4,822	3,431
Mechanical output	[1]	bhp	881	661	441
Electrical output	[4]	kW el.	635	475	314
Recoverable thermal output					
~ Intercooler 1st stage	[9]	MBTU/hr	244	107	29
~ Lube oil		MBTU/hr	375	304	246
~ Jacket water		MBTU/hr	788	679	553
~ Exhaust gas cooled to 894 °F		MBTU/hr	0	0	0
Total recoverable thermal output	[5]	MBTU/hr	1,408	1,090	828
Heat to be dissipated (calculated with Glykol 37%)					
~ Intercooler 2nd stage		MBTU/hr	200	147	53
~ Lube oil		MBTU/hr	---	---	---
~ Surface heat	ca. [7]	MBTU/hr	209	~	~
Spec. fuel consumption of engine electric	[2]	BTU/kWel.hr	8,975	9,314	10,024
Spec. fuel consumption of engine	[2]	BTU/bhp.hr	6,464	6,689	7,131
Lube oil consumption	ca. [3]	gal/hr	0.06	~	~
Electrical efficiency			38.0%	36.6%	34.0%
Thermal efficiency			24.7%	24.7%	26.3%
Total efficiency	[6]		62.7%	61.3%	60.4%
Hot water circuit:					
Forward temperature		°F	193.6	185.1	178.1
Return temperature		°F	156.0	156.0	156.0
Hot water flow rate		GPM	74.9	74.9	74.9
Fuel gas LHV		BTU/scft	917		

*) approximate value for pipework dimensioning
[_] Explanations: see 0.10 - Technical parameters

All heat data is based on standard conditions according to attachment 0.10. Deviations from the standard conditions can result in a change of values within the heat balance and must be taken into consideration in the layout of the cooling circuit/equipment (intercooler; emergency cooling; ...).

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Main dimensions and weights (on container)

Length	in	~ 490
Width	in	99-118
Height	in	~ 110
Weight empty	lbs	~ 46,090
Weight filled	lbs	~ 48,470

Connections

Hot water inlet and outlet [A/B]	in/lbs	3"/145
Exhaust gas outlet [C]	in/lbs	10"/145
Fuel gas connection (on container) [D]	in/lbs	3"/232
Fresh oil connection	G	28x2"
Waste oil connection	G	28x2"
Cable outlet	in	31.5x15.7
Condensate drain	in	~

Output / fuel consumption

ISO standard fuel stop power ICFN	bhp	881
Mean effe. press. at stand. power and nom. speed	psi	218
Fuel gas type		Natural gas
Based on methane number | Min. methane number	MN	94 | 75 d)
Compression ratio	Epsilon	12.5
Min./Max. fuel gas pressure at inlet to gas train	psi	1.16 - 2.9 c)
Max. rate of gas pressure fluctuation	psi/sec	0.145
Maximum Intercooler 2nd stage inlet water temperature	°F	122
Spec. fuel consumption of engine	BTU/bhp.hr	6,464
Specific lube oil consumption	g/bhp.hr	0.22
Max. Oil temperature	°F	~ 190
Jacket-water temperature max.	°F	~ 203
Filling capacity lube oil (refill)	gal	~ 57

c) Lower gas pressures upon inquiry
d) based on methane number calculation software AVL 3.2 (calculated without N2 and CO2)

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0.02 Technical data of engine

Manufacturer		JENBACHER
Engine type		J 312 GS-D802
Working principle		4-Stroke
Configuration		V 70°
No. of cylinders		12
Bore	in	5.31
Stroke	in	6.69
Piston displacement	cu.in	1,782
Nominal speed	rpm	1,800
Mean piston speed	in/s	402
Length	in	94
Width	in	57
Height	in	81
Weight dry	lbs	7,055
Weight filled	lbs	7,782
Moment of inertia	lbs-ft²	184.41
Direction of rotation (from flywheel view)		left
Radio interference level to VDE 0875		N
Starter motor output	kW	7
Starter motor voltage	V	24

Thermal energy balance

Power input	MBTU/hr	5,695
Intercooler	MBTU/hr	444
Lube oil	MBTU/hr	375
Jacket water	MBTU/hr	788
Exhaust gas cooled to 356 °F	MBTU/hr	1,160
Exhaust gas cooled to 212 °F	MBTU/hr	1,460
Surface heat	MBTU/hr	113

Exhaust gas data

			100/75/50%
Exhaust gas temperature at full load	[8]	°F	894
Exhaust gas temperature at bmep= 163.2 [psi]	**75%**	°F	~ 945
Exhaust gas temperature at bmep= 108.8 [psi]	**50%**	°F	~ 982
Exhaust gas mass flow rate, wet		lbs/hr	7,998 / 6,107 / 4,270
Exhaust gas mass flow rate, dry		lbs/hr	7,425 / 5,661 / 3,953
Exhaust gas volume, wet		SCFH	101,703 / 77,689 / 54,347
Exhaust gas volume, dry		SCFH	90,261 / 68,791 / 48,026
Max.admissible exhaust back pressure after engine		psi	0.870

Combustion air data

Combustion air mass flow rate	lbs/hr	7,743
Combustion air volume	SCFM	1,600
Max. admissible pressure drop at air-intake filter	psi	0.145

base for exhaust gas data: natural gas: 100% CH_4; biogas 65% CH_4, 35% CO_2

Sound pressure level

Aggregate a)		dB(A) re 20µPa	98
31,5	Hz	dB	83
63	Hz	dB	90
125	Hz	dB	94
250	Hz	dB	94
500	Hz	dB	93
1000	Hz	dB	92
2000	Hz	dB	89
4000	Hz	dB	89
8000	Hz	dB	92
Exhaust gas b)		dB(A) re 20µPa	115
31,5	Hz	dB	108
63	Hz	dB	119
125	Hz	dB	113
250	Hz	dB	117
500	Hz	dB	112
1000	Hz	dB	111
2000	Hz	dB	103
4000	Hz	dB	101
8000	Hz	dB	98

Sound power level

Aggregate	dB(A) re 1pW	118
Measurement surface	ft²	1,044
Exhaust gas	dB(A) re 1pW	123
Measurement surface	ft²	67.60

a) average sound pressure level on measurement surface in a distance of 3.28ft (converted to free field) according to DIN 45635 and ISO 3744, precision class 3.
b) average sound pressure level on measurement surface in a distance of 3.28ft according to DIN 45635 and ISO 3744, precision class 2.
The spectra are valid for aggregates up to bmep=217.55661 psi. (for higher bmep add safety margin of 1dB to all values per increase of 15 PSI pressure).
Engine tolerance ± 3 dB

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0.03 Technical data of generator

Manufacturer		STAMFORD e)
Type		CG 634 J e)
Type rating	kVA	867
Driving power	bhp	881
Ratings at p.f.= 1.0	kW	635
Ratings at p.f. = 0.8	kW	629
Rated output at p.f. = 0.8	kVA	786
Rated reactive power at p.f. = 0.8	kVAr	471
Rated current at p.f. = 0.8	A	945
Frequency	Hz	60
Voltage	V	480
Speed	rpm	1,800
Permissible overspeed	rpm	2,250
Power factor (lagging - leading) (UN)		0,8 - 1,0
Efficiency at p.f.= 1.0		96.6%
Efficiency at p.f. = 0.8		95.7%
Moment of inertia	lbs-ft²	531.64
Mass	lbs	5,071
Radio interference level to EN 55011 Class A (EN 61000-6-4)		N
Cable outlet		~
Ik'' Initial symmetrical short-circuit current	kA	9.64
Is Peak current	kA	24.53
Insulation class		H
Temperature rise (at driving power)		F
Maximum ambient temperature	°F	104

Reactance and time constants at rated output (saturated)

xd direct axis synchronous reactance	p.u.	1.789
xd' direct axis transient reactance	p.u.	0.145
xd'' direct axis sub transient reactance	p.u.	0.097
x2 negative sequence reactance	p.u.	0.127
Td'' sub transient reactance time constant	ms	30
Ta Time constant direct-current	ms	50
Tdo' open circuit field time constant	s	3.03

e) JENBACHER reserves the right to change the generator supplier and the generator type. The contractual data of the generator may thereby change slightly. The contractual produced electrical power will not change.

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0.04 Technical data of heat recovery

General data - Hot water circuit

Total recoverable thermal output	MBTU/hr	1,408
Return temperature	°F	156.0
Forward temperature	°F	193.6
Hot water flow rate	GPM	74.9
Design pressure of hot water	lbs	145
min. operating pressure	psi	51.0
max. operating pressure	psi	131.0
Pressure drop hot water circuit	psi	8.70
Maximum Variation in return temperature	°F	+0/-21
Max. rate of return temperature fluctuation	°F/min	18

General data - Cooling water circuit

Heat to be dissipated (calculated with Glykol 37%)	MBTU/hr	200
Return temperature	°F	122
Cooling water flow rate	GPM	66
Design pressure of cooling water	lbs	145
min. operating pressure	psi	7.0
max. operating pressure	psi	73.0
Loss of nominal pressure of cooling water	psi	~
Maximum Variation in return temperature	°F	+0/-21
Max. rate of return temperature fluctuation	°F/min	18

The final pressure drop will be given after final order clarification and must be taken from the P&ID order documentation.

connection variant 1Kc

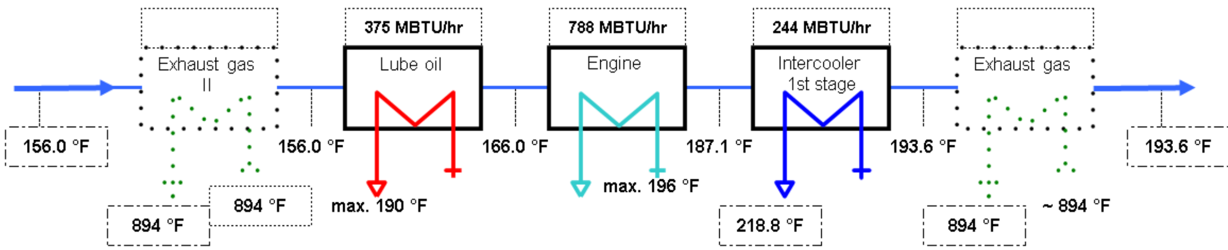
J 312 GS-D802

Hot water circuit

Recoverable thermal output = 1,408 MBTU/hr

(+12/-8 % tolerance)

Hot water flow rate = 74.9 GPM

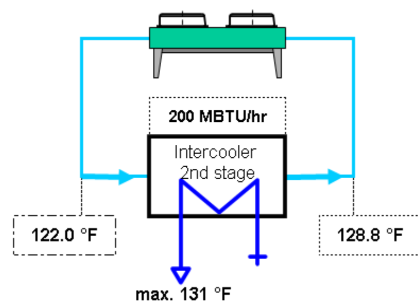


Low Temperature circuit (calculated with Glykol 37%)

Heat to be dissipated = 200 MBTU/hr

(+12/-8 % tolerance)

Cooling water flow rate = 66.0 GPM



0.10 Technical parameters

All data in the technical specification are based on engine full load (unless stated otherwise) at specified temperatures as well as the methane number and subject to technical development and modifications. For isolated operation an output reduction may apply according to the block load diagram. Before being able to provide exact output numbers, a detailed site load profile needs to be provided (motor starting curves, etc.).

All pressure indications are to be measured and read with pressure gauges (psi.g.).

[1] At nominal speed and standard reference conditions ICFN according to ISO 3046-1, respectively.
[2] According to ISO 3046-1, respectively, with a tolerance of +**5** %.
Efficiency performance is based on a new unit (immediately upon commissioning).Effects of degradation during normal operation can be mitigated through regular service and maintenance work.

[3] Average value between oil change intervals according to maintenance schedule, without oil change amount
[4] At p. f. = 1.0 according to IEC 60034-1:2017 with relative tolerances, all direct driven pumps are included
[5] Total output with a tolerance of +12/-8 %
[6] According to above parameters [1] through [5]
[7] As a guiding value at p.f. 0.8 and only valid for (engine, generator, TCM). Other peripheral equipment is not considered.
[8] Exhaust temperature with a tolerance of ±8 %
Note: an optimized operating mode to minimize methane slip can result in changed exhaust gas data (exhaust gas temperature, NOx emissions, etc.) and must be taken into account in the design of the exhaust gas aftertreatment
[9] Intercooler heat on:
*** standard conditions** - If the turbocharger design is done for air intake temperature > 86°F w/o de-rating, the intercooler heat of the 1st stage need to be increased by 2%/K starting from 77°F. Deviations between 77 – 86°F will be covered with the standard tolerance.
*** Hot Country application (V1xx)** - If the turbocharger design is done for air intake temperature > 104°F w/o de-rating, the intercooler heat of the 1st stage need to be increased by 2%/K starting from 95°F. Deviations between 95 – 104°F will be covered with the standard tolerance.

Radio interference level
The ignition system of the gas engines complies the radio interference levels of CISPR 12 and EN 55011 class B, (30-75 MHz, 75-400 MHz, 400-1000 MHz) and (30-230 MHz, 230-1000 MHz), respectively.

Definition of output
- ISO-ICFN continuous rated power:
  Net break power that the engine manufacturer declares an engine is capable of delivering continuously, at stated speed, between the normal maintenance intervals and overhauls as required by the manufacturer. Power determined under the operating conditions of the manufacturer's test bench and adjusted to the standard reference conditions.
- Standard reference conditions:
  Barometric pressure: 14.5 psi (1000 mbar) or 328 ft (100 m) above sea level

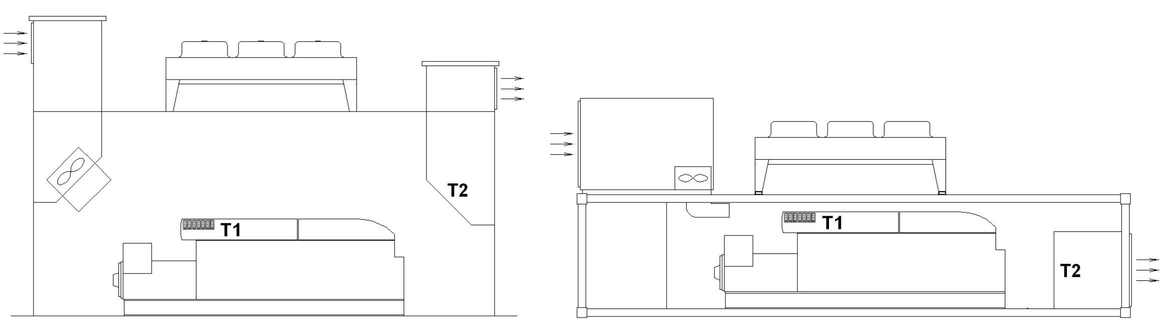
Air temperature: 77°F (25°C) or 298 K
Relative humidity: 30 %

- Volume values at standard conditions (fuel gas, combustion air, exhaust gas)
  Pressure: 1 atmosphere (1013.25 mbar)
  Temperature: 32°F (0°C)

Loss of engine performance
a) Performance reduction due to gas quality
If the reference methane number is not reached and the knock control responds, the ignition timing at full performance is adjusted in conjunction with the engine management system; only then is performance reduced.
H2 admixtures in the range of 3–5 Vol% into the natural gas network are generally regarded as non-critical. Prerequisites for this are rates of change according to TA 1000-0300, as well as the knock resistance (minimum methane number) of the natural gas-H2 mixture according to the specification. For reliable compliance with required NOx emissions, the JENBACHER LEANOX^{plus} control is recommended (measurement of NOx emissions and correction of the LEANOX controller). Higher H2 addition rates into the natural gas network must be assessed on a project-specific basis.

b) Performance reduction due to voltage and frequency limits
If the voltage and frequency limits for generators specified in IEC 60034-1 Zone A are exceeded, performance is reduced.

c) Performance reduction due to environmental conditions
Standard rating of the engines is for an installation at an altitude ≤ **100 ft** and combustion air temperature ≤ **95 °F** (T1)
Engine room outlet temperature: **122°F** (T2) -> engine stop



The minimum recommended air change ratio (C) must be observed to maintain the required air quality and prevent unwanted gas accumulations (refer to Section ⇨ Potentially explosive Atmospheres as per TA1100-0110). The calculation is based on TA 1100-0110 and is C_{min}= 50h^{-1} for JENBACHER modules.

Parameters for the operation of JENBACHER gas engines
The genset fulfills the limits for mechanical vibrations according to ISO 8528-9.
The following "Technical Instruction of JENBACHER" forms an integral part of a contract and must be strictly observed: **TA 1000-0004, TA 1100 0110, TA 1100-0111**, and **TA 1100-0112.**
Transport by rail should be avoided. See **TA 1000-0046** for further details

Failure to adhere to the requirements of the above-mentioned TA documents can lead to engine damage and may result in loss of warranty coverage.

Parameters for the operation of control unit and the electrical equipment
Relative humidity 50% by maximum temperature of 104°F.
Altitude up to 2000m above the sea level.

0.30 General information for connection to the public mains

Technical Instruction TA 1530-0188 describes the - possibly optional - functions and parameters for complying with the boundary conditions defined in the country-specific "Grid Codes".

Network operator-dependent requirements must always be coordinated with JENBACHER.

0.30.10 Generator operating range in mains parallel operation

Frequency:
Normal operation fn +/-2% - without power output reduction
Extended operation: fn +4/-6%- with power output reduction between 2 – 10%/Hz
Frequency-measurement resolution: <= 10mHz (resolution)
Generator - voltage range: +/-10% of generator Un
Generator power factor cos phi at the generator terminals: as specified in "0.03 Generator technical data"

FRT (Fault Ride Through) – capability: at mains connection point
Profile 1: 150ms/30%Un (applies to natural gas and biogas)
Profile 2 (150ms/5%Un) and Profile 3 (250ms/5%Un) upon request.

Requirement:
- mains short-circuit power must be at least 5 x SrE or 50MVA
- FRT capability of the onsite auxiliaries

Extended project requirements and country-specific design are optionally possible after consultation and approval with JENBACHER.

0.30.20 Possible mains operator requests

To protect the generating unit in mains parallel operation, appropriate mains protection monitoring functions are necessary to disconnect the generator from the mains in case of a mains fault.

The mains operator-dependent specifications such as e.g.: voltage and frequency range, active power limitation, load ramps, reactive power limitation and control, protection concept, necessary certification or declarations, process data and interfaces are to be specified in project enquiries and must be agreed with JENBACHER before conclusion of the contract.

- The mains operator questionnaire must be sent to JENBACHER. Check at what time the document must be available! On conclusion of the contract. Requirements must be clear!
- Project-specific requirements of the mains operator to be checked for feasibility
- Required verifications, confirmations and declarations of conformity: on-site by the system operator
- Selectivity assessment, protection tests and recurring tests: on-site by the system operator
- Control power provision via pool operator: on request e.g. primary, secondary, tertiary
- Black start capability and countering in own use: on request
- Power generation system (EZA) controller or central control: on-site or possible on request
- Process data scope / remote control:
  - System data must be provided by the connectee for the mains operator.
  - Remote control interface to the mains operator: on-site
  - Interface specification!

Billing measurements - installation, operation, maintenance, and remote data transmission: on-site.

Models of genset and generator: simplified models executed as effective value models for mains parallel operation optionally available.
Model formats: Powerfactory, or PSS/E (as of PP23)
Validated genset models in Powerfactory according to FGW TR3, TR4 and TR8 by a body accredited for this purpose according to DIN EN ISO/IEC 17065

Functional scope of the models in mains parallel operation:
- static voltage stability
- dynamic mains support
- Provision of reactive power
- Behaviour at active power setpoint
- Active power adjustment in the event of over frequency and underfrequency (LFSM-O, LFSM-U)
- Protective devices and settings

0.30.20.01 Active power adjustment in the event of over frequency and underfrequency

The following functions are available:
- LFSM-U: Limited Frequency Sensitive Mode - Underfrequency
- LFSM-O: Limited Frequency Sensitive Mode - Over frequency
- FSM

Reduced power output at over frequency: (LFSM-O function)
The frequency threshold is freely adjustable from fn + (200 - 500mHz) and the static from 2% to 12%.
Unless the relevant mains operator specifies otherwise for the LFSM-O mode, a threshold of fn + 200mHz and a static of 5% is set.

Power increase in the event of underfrequency (LFSM-U function) – (OPTIONAL as of XT4.5)
activated according to the mains operator's specifications
The frequency-sensitive active power feed-in has the effect that the generating plant

also moves permanently up and down on the frequency characteristic curve ("driving on the characteristic curve") in the frequency range between fn - 200mHz (unless otherwise specified by the mains) and fn - 2.5Hz with regard to its maximum possible active power feed-in.
The prerequisite for this is a corresponding power setpoint.

Reduced power output at underfrequency:
below 98% of fn, reduction by standard 10% of maximum capacity per Hz. Reduction up to maximum fn - 6%.
Lower reduction ramps of 2 - 10%/Hz on request
The FSM function is available as an option

The power generation system is capable of continuing to operate at this minimum power when the minimum power for controllable operation is reached.

1.00 Scope of supply - Module

Design:
The module is built as a compact package. The engine and generator are mounted on a common base when a low voltage generator is specified (<1000 V). In case of a medium voltage generator the engine base is bolted to the generator base.
The Engine output shafting is connected through a coupling to the generator. To provide the best possible isolation from the transmission of vibrations, the engine rests on the engine base-frame by means of anti-vibration mounts. The remaining vibrations are eliminated by mounting the complete module on isolating pads (e.g. Sylomer). This, in principle, allows for placing of the module to be directly on any floor capable of carrying the static load.

1.01 Spark ignited gas engine

Four-stroke, air/gas mixture turbocharged, aftercooled, with high performance ignition system and electronically controlled air/gas mixture system.
The engine is equipped with the most advanced

LEANOX®   LEAN-BURN COMBUSTION SYSTEM

developed by JENBACHER.

1.01.01 Engine design

Engine block
Single-piece crankcase and cylinder block made of special casting, crank case covers for engine inspection, welded steel oil pan.

Crankshaft and main bearings
Drop-forged, precision ground, surface hardened, statically, and dynamically balanced; main bearings (upper bearing shell: 3-material bearing / lower bearing shell: sputter bearing) arranged between crank pins, drilled oil passages for forced-feed lubrication of connecting rods.

Vibration damper
Maintenance free viscous damper

Flywheel
With ring gear for starter motor

Pistons
Single piece, made of light metal alloy, with piston ring carrier and oil passages for cooling; piston rings made of high-quality material, main combustion chamber specially designed for lean burn operation.

Connecting rods
Drop-forged, heat-treated, big end diagonally split and toothed. Big end bearings (upper bearing shell: sputter bearing / lower bearing shell: grooved bearing) and connecting rod bushing for piston pin.

Cylinder liner
Chromium gray alloy cast iron, wet, individually replaceable.

Cylinder head
Specially designed and developed for JENBACHER-lean burn engines with optimized fuel consumption and emissions; water cooled, made of special casting, individually replaceable; Valve seats and valve guides and spark plug sleeves individually replaceable; exhaust and inlet valve made of high-quality material.

Crankcase breather
Connected to combustion air intake system

Valve train
Camshaft, with replaceable bushings, driven by crankshaft through intermediate gears, valve lubrication by splash oil through rocker arms.

Combustion air/fuel gas system
Motorized carburetor for automatic adjustment according fuel gas characteristic. Exhaust driven turbocharger, mixture manifold with bellows, water-cooled intercooler, throttle valve and distribution manifolds to cylinders.

Ignition system
Most advanced, fully electronic high performance ignition system, external ignition control.

Lubricating system
Gear-type lube oil pump to supply all moving parts with filtered lube oil, pressure control valve, pressure relief valve and full-flow filter cartridges. Cooling of the lube oil is arranged by a heat exchanger.

Engine cooling system
Jacket water pump complete with distribution pipework and manifolds.

Exhaust system
Turbocharger and exhaust manifold

Exhaust gas temperature measuring

Thermocouple for each cylinder

Electric actuator
For electronic speed and output control

Electronic speed monitoring for speed and output control
By magnetic inductive pick up over ring gear on flywheel

Starter motor
Engine mounted electric starter motor

1.01.02 Additional equipment for the engine (spares for commissioning)

The initial set of equipment with the essential spare parts for operation after commissioning is included in the scope of supply.

1.01.03 Engine accessories

Insulation of exhaust manifold:
Insulation of exhaust manifold is easily installed and removed

Sensors at the engine:
- Jacket water temperature sensor
- Jacket water pressure sensor
- Lube oil temperature sensor
- Lube oil pressure sensor
- Mixture temperature sensor
- Charge pressure sensor
- Minimum and maximum lube oil level switch
- Exhaust gas thermocouple for each cylinder
- Knock sensors
- Gas mixer / gas dosing valve position reporting.

Actuator at the engine:
- Actuator - throttle valve
- Bypass-valve for turbocharger
- Control of the gas mixer / gas dosing valve

1.01.04 Standard tools (per installation)

The tools required for carrying out the most important maintenance work are included in the scope of supply and delivered in a toolbox.

1.02 Generator-low voltage

The 2 bearing generator consists of the main generator (built as rotating field machine), the exciter machine (built as rotating armature machine) and the digital excitation system.
The digital regulator is powered by an auxiliary winding at the main stator or a PMG system

Main components:
- Enclosure of welded steel construction
- Stator core consist of thin insulated electrical sheet metal with integrated cooling channels.
- Stator winding with 2/3 Pitch
- Rotor consist of shaft with shrunken laminated poles, Exciter rotor, PMG (depending on Type) and fan.
- Damper cage
- Excitation unit with rotating rectifier diodes and overvoltage protection
- Dynamically balanced as per ISO 1940, Balance quality G2,5
- Drive end bracket with re greaseable antifriction bearing
- Non-drive end bracket with re grease antifriction bearing
- Cooling IC01 - open ventilated, air entry at non-drive end, air outlet at the drive end side
- Main terminal box includes main terminals for power cables
- Regulator terminal box with auxiliary terminals for thermistor connection and regulator.
- Anti-condensation heater
- 3 pieces PTC thermistors for winding temperature monitoring+3 pieces PTC thermistors spare

Option:
Current transformer for protection and measuring in the star point
xx/1A, 5P10 15VA, xx/1A, 1FS5, 15VA

Electrical data and features:
- Standards: IEC 60034, EN 60034, ISO 8528-3, ISO 8528-9
- Voltage adjustment range: +/- 10 % of rated voltage (continuous)
- Frequency: -6/+4% of rated frequency
- Overload capacity: 10% for one hour within 6 hours, 50% for 30 seconds
- Asymmetric load: max. 8% I2 continuous, in case of fault I2 x t=20
- Altitude: < 1000m
- Max permitted generator intake air temperature: 5°C - 40°C
- Max. relative air humidity: 90%
- Voltage curve THD Ph-Ph: <4% at idle operation and <5% at full load operation with linear symmetrical load
- Generator suitable for parallel operating with the grid and other generators
- Sustained short circuit current at 3-pole terminal short circuit: minimum 3 times rated current for 5 seconds.
- Over speed test with 1.2 times of rated speed for 2 minutes according to IEC 60034

Digital Excitation system ABB Unitrol 1010 mounted within the AVR Terminal box with following features:

- Compact and robust Digital Excitation system for Continuous output current up to 10 A (20A Overload current 10s)
- Fast AVR response combined with high excitation voltage improves the transient stability during LVRT events.

- The system has free configurable measurement and analog or digital I/Os. The configuration is done via the local human machine interface or CMT1000
- Power Terminals
  3 phase excitation power input from PMG or auxiliary windings
  Auxiliary power input 24VDC
- Excitation output
- Measurement terminals: 3 phase machine voltage, 1 phase network voltage, 1 phase machine current
- Analog I/Os: 2 outputs / 3 inputs (configurable), +10 V / -10 V
- Digital I/O: 4 inputs only (configurable), 8 inputs / outputs (configurable)
- Serial fieldbus: RS485 for Modbus RTU or VDC (Reactive power load sharing for up to 31 JENBACHER engines in island operation), CAN-Bus for dual channel communication
- Regulator Control modes: Bump less transfer between all modes
  Automatic Voltage Regulator (AVR) accuracy 0,1% at 25°C ambient temperature
  Field Current Regulator (FCR)
  Power Factor Regulator (PF)
  Reactive Power Regulator (VAR)
- Limiters: Keeping synchronous machines in a safe and stable operation area
  Excitation current limiter (UEL min / OEL max)
  PQ minimum limiter
  Machine current limiter
  V / Hz limiter
  Machine voltage limiter
- Voltage matching during synchronization
- Rotating diode monitoring
- Dual channel / monitoring: Enables the dual channel operation based on self-diagnostics and setpoint follow up over CAN communication. As Option available
- Power System Stabilizer (PSS) is available as option. Compliant with the standard IEEE 421.5-2005 2A / 2B, the PSS improves the stability of the generator over the highest possible operation range.
- Computer representation for power system stability studies: ABB 3BHS354059 E01
- Certifications: CE, cUL certification according UL 508c (compliant with CSA), DNV Class B,

- **Commissioning and maintenance Tool CMT1000** (for trained commissioning/ maintenance personal)
- With this tool the technician can setup all parameters and tune the PID to guarantee stable operation. The CMT1000 software allows an extensive supervision of the system, which helps the user to identify and locate problems during commissioning on site. The CMT1000 is connected to the target over USB or Ethernet port, where Ethernet connection allows remote access over 100 m.
- Main window
  - Indication of access mode and device information.
  - Change of parameter is only possible in CONTROL access mode.
  - LED symbol indicates that all parameters are stored on nonvolatile memory.
- Setpoint adjust window
  - Overview of all control modes, generator status, active limiters status and alarms.
  - Adjust set point and apply steps for tuning of the PID.
- Oscilloscope
- 4 signals can be selected out of 20 recorded channels. The time resolution is 50ms.Save files to your PC for further investigation.
- Measurement
  - All measurements on one screen.

Routine Test
Following routine tests will be carried out by the generator manufacturer
- Measuring of the DC-resistance of stator and rotor windings
- Check of the function of the fitted components (e.g. RTDs, space heater etc.)
- Insulation resistance of the following components
  - Stator winding, rotor winding
  - Stator winding RTDs
  - Bearing RTDs
  - Space heater
- No Load saturation characteristic (remanent voltage)
- Stator voltage unbalance
- Direction of rotation, phase sequence
- High voltage test of the stator windings (2 x Unom. + 1000 V) and the rotor windings (min. 1500 V)

1.03 Module Accessories

Base frame
Common Base Frame fabricated with welded structural steel. Frame to mount the engine, jacket water heat exchangers, pumps, and engine auxiliaries, as well as generator.

Coupling
Engine to Generator coupling is provided. The coupling isolates the major sub-harmonics of engine alternating torque from generator.

Coupling housing
Provided for Coupling

Anti-vibration mounts
2 sets of isolation, one is arranged between engine block assembly and base frame. The second is via insulating pads (SYLOMER) for placement between base frame and foundation, delivered loose.

Exhaust gas connection
A flanged connection is provided that collects the exhaust gas turbocharger output flows, includes flexible pipe connections (compensators) to compensate for heat expansions and vibrations.

Combustion air filter
A Dry type air filter with replaceable filter cartridges is fitted. The assembly includes flexible connections to the fuel mixer/carburetor and service indicator.

Interface panel (M1 cabinet)
Totally enclosed sheet steel cubicle with hinged doors, pre-wired to terminals, ready to operate. All Cable entry will be via bottom mounted cable gland plates.

Painting: RAL 7035

Protection: External NEMA 3 (IP 54), Internal IP 20 (protection against direct contact with live parts)

Cabinet design is according to IEC 439-1 (EN 60 439-1/1990) and DIN VDE 0660 part 500, respectively. Ambient temperature 41 - 104 °F (5 - 40 °C), Relative humidity 70%

Dimensions:
- Height: 1000 mm (39 in)
- Width: 1000 mm (39 in)
- Depth: 300 mm (12 in)

Control Power Source: The starter batteries and the cabinet mounted battery chargers will provide the power source for this enclosure.

Interface Panel contents and control functions:
- The cabinet houses the unit Battery Charger and primary 24VDC Control Power Distribution (breakers, fuses, and terminals) from the unit Batteries
- Distributed PLC Input and Output cards, located in the cabinet, gather all Engine and Generator Control I/O. These cards transmit data via data bus interface to the central engine control of the module control panel located in the A1 cabinet. Data bus is via CAN and B&R Proprietary Data Highway (Data Cables provided by JENBACHER)
- Speed monitoring relays for protection are provided.
- Gas Train I/O Collection, including interface relays and terminals for gas train shutoff valves.
- Transducer for generator functions, such as excitation voltage.
- Door Mounted Emergency Stop Switch with associated Emergency Stop Loop interface relays.
- Miscellaneous control relays, contacts, fuses, etc. for additional control valves, and auxiliaries.
- Interface Terminal Strips

Skid Mounted 3 Phase Devices are Powered by 3 x 480/277 V, 60 Hz, 50 A

AC Power for engine mounted auxiliaries (heater, pumps, etc.) are routed through a separate J-box mounted on the side M1 cabinet (Box E1). This is done to maintain signal segregation (AC from control)

NOTE: Generator Current Transformer wiring is connected directly to the Generator and does NOT pass through the M1 cabinet.

1.03.01 Engine jacket water system

Closed cooling circuit, consisting of:
- Expansion tank
- Filling device (check and pressure reducing valves, pressure gauge)
- Safety valve(s)
- Thermostatic valve
- Required pipework on module
- Vents and drains
- Jacket water pump, including check valve
- Jacket water preheat device

1.03.02 Automatic lube oil replenishing system

Automatic lube oil replenishing system:
Includes float valve in lube oil feed line, including inspection glass. Electric monitoring system will be provided for engine shut-down at lube oil levels "MINIMUM" and "MAXIMUM". Solenoid valve in oil feed line is only activated during engine operation. Manual override of the solenoid valve, for filling procedure during oil changes is included.

Oil drain
By set mounted cock

Oil sump extension tank 79.3 gal
To increase the time between oil changes

Aftercooling oil pump:
Mounted on the module base frame; it is used for the aftercooling of the turbocharger; period of operation of the pump is 15 minutes from engine stop.
Consisting of:
- Oil pump 250 W, 480/277 V
- Oil filter
- Necessary pipework

1.04 Heat recovery

The heat exchangers are mounted to the engine and/or to the module base frame, complete with interconnecting pipe work.
The connection design of the heat exchangers is determined on a project specific basis. The connection design, temperatures and flow rates are shown on page 10 of this document. Interfaces to the customer circuit are shown as connection points A and B (see page 5).

The exhaust gas heat exchanger is not included in the J scope of supply.

The insulation of heat exchangers and pipe work is not included in JENBACHER scope of supply and should be provided locally if needed.

1.05.01 Gas train <500mbar (7.3 psi)

Consisting of:
- Manual shut off valve
- Gas filter, filter fineness <3 μm
- Pressure gauge with push button valve
- Gas admission pressure regulator
- Solenoid valves

- Leakage detector
- Gas pressure switch (min.)
- TEC JET
- Gas flow meter (option)
- p/t compensation (option)

The gas train complies with DIN - DVGW regulations.
The gas train complies with NFPA37.

1.07 Painting

• Quality:	Oil resistant prime layer Synthetic resin varnish finishing coat	
• Color:	Engine:	RAL 6018 (green)
	Base frame:	RAL 6018 (green)
	Generator:	RAL 6018 (green)
	Module interface panel:	RAL 7035 (light grey)
	Control panel:	RAL 7035 (light grey)

1.11 Engine generator control panel per module- DIA.NE XT4 incl. Single synchronization of the generator breaker

Dimensions:

- Height: 91 in (including 8 in pedestal *)
- Width: 32 -48 in *)
- Depth: 24 in *)

Protection class:

- external IP42
- Internal IP 20 (protection again direct contact with live parts)

*) Control panels will be dimensioned on a project specific basis. Actual dimensions will be provided in the preliminary documentation for the project.

Control supply voltage from starter and control panel batteries: 24V DC

Auxiliary equipment supply (by the supplier of the auxiliary equipment supply system)
The following network forms are possible for the supply of the auxiliary equipment. Depending on these, appropriate protective measures are provided:

Standard: TN- S (L1/2/3, N, PE)

- Power supply via the module control cabinet via connection terminals or directly at the 3-pole mains disconnection unit. Protection against electric shock by automatic disconnection with miniature circuit breaker or fuse.
- Additional protection for sockets with fault current breaker (RCD) type A, 30 mA
- Option:
  - According to national requirements or customer wishes, 4-pole mains disconnecting device can also be used. Especially if the neutral conductor is not considered to be reliably earthed.
  - Downstream outputs for auxiliary equipment with neutral conductors are fused using 2 or 4 poles.

Option: TN-C (L1/2/3, PEN)

- Power supply via the module control cabinet via connection terminals or directly at the 3-pole mains disconnection unit. Protection against electric shock by automatic disconnection with miniature circuit breaker or fuse.
- Additional protection for sockets with fault current breaker (RCD) type A, 30 mA

Option: TT (L1/2/3, N)

- Power supply via the module control cabinet via connection terminals or directly at the 4-pole mains disconnection unit. Protection against electric shock by automatic disconnection through integrated differential current monitoring (RCD) type A.
- Downstream outputs for auxiliary equipment with neutral conductors are fused using 2 or 4 poles.
- Additional protection for sockets with fault current breaker (RCD) type A, 30 mA
- Option:
  - When using frequency converters, an additional differential current monitoring device (RCD) type B is mounted.

Option: IT (L1/2/3, N, PE)

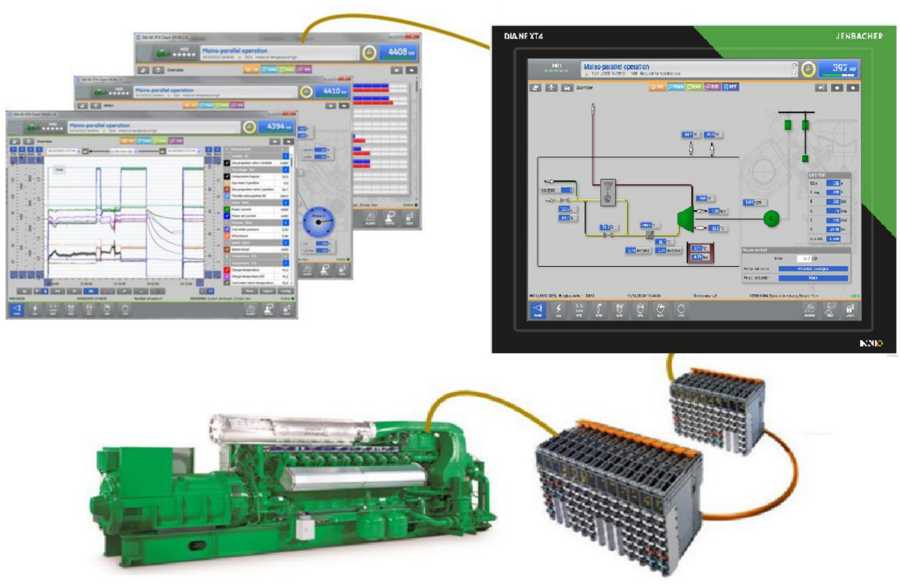
- Power supply via the module control cabinet via connection terminals or directly at the 4-pole mains disconnection unit. Protection against electric shock by automatic disconnection through integrated differential current monitoring (RCD) type A. Insulation monitoring is part of customer's scope of supply. Preparations have already been made for the transfer of error messages to the module control cabinet and alarm signaling via DIA.NE.
- Downstream outputs for auxiliary equipment with neutral conductors are fused using 2 or 4 poles.
- Additional protection for sockets with fault current breaker (RCD) type A, 30 mA
- Option:
  - When using frequency converters, an additional differential current monitoring device (RCD) type B is mounted.
- Option:
  - An insulation monitoring device connected to the auxiliary power supply with automatic disconnection in case of insulation faults. Alarm signaling via DIA.NE.
- Option:
  - Overvoltage protection for auxiliary equipment, protection module with integrated remote signaling.
  - SPD in conformity with EN 61643-11 type 2
  - Nominal voltage Un 230/400V

3 x **480**/**277** V, **60** Hz

Consisting of:
Motor - Management - System DIA.NE

Setup:

- a) Touch display visualization
- b) Central engine and unit control



Touch Display Screen:

15“Industrial color graphic display with resistive touch.

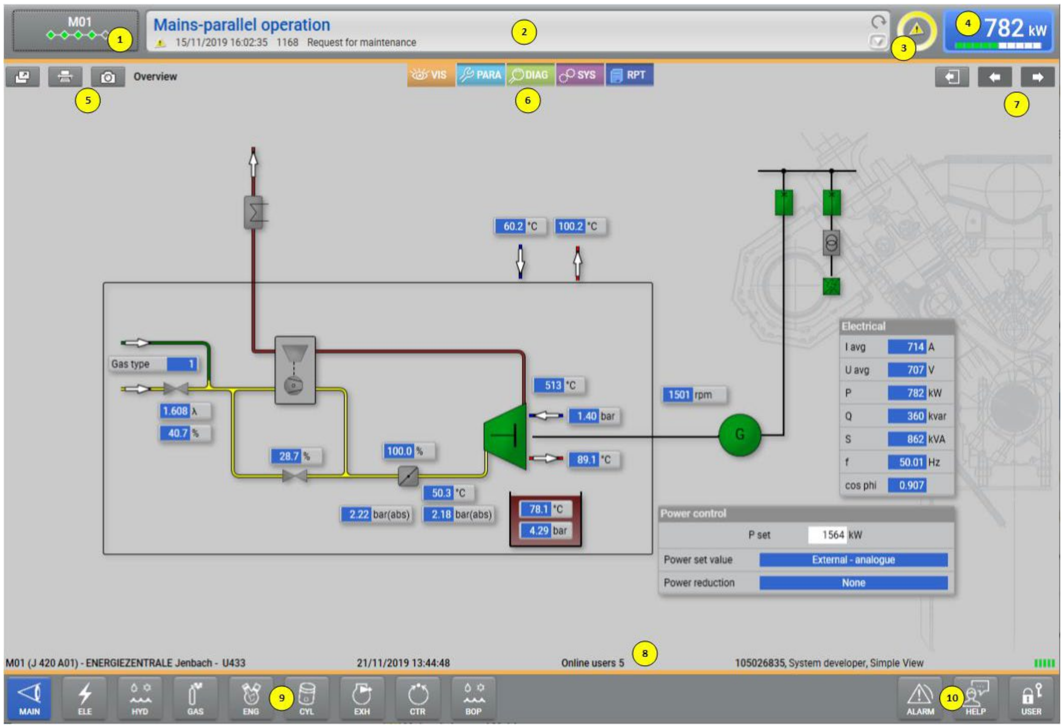
Protection class of DIA.NE XT panel front: IP 65

The screen shows a clear and functional summary of the measurement values and simultaneously shows a graphical summary.

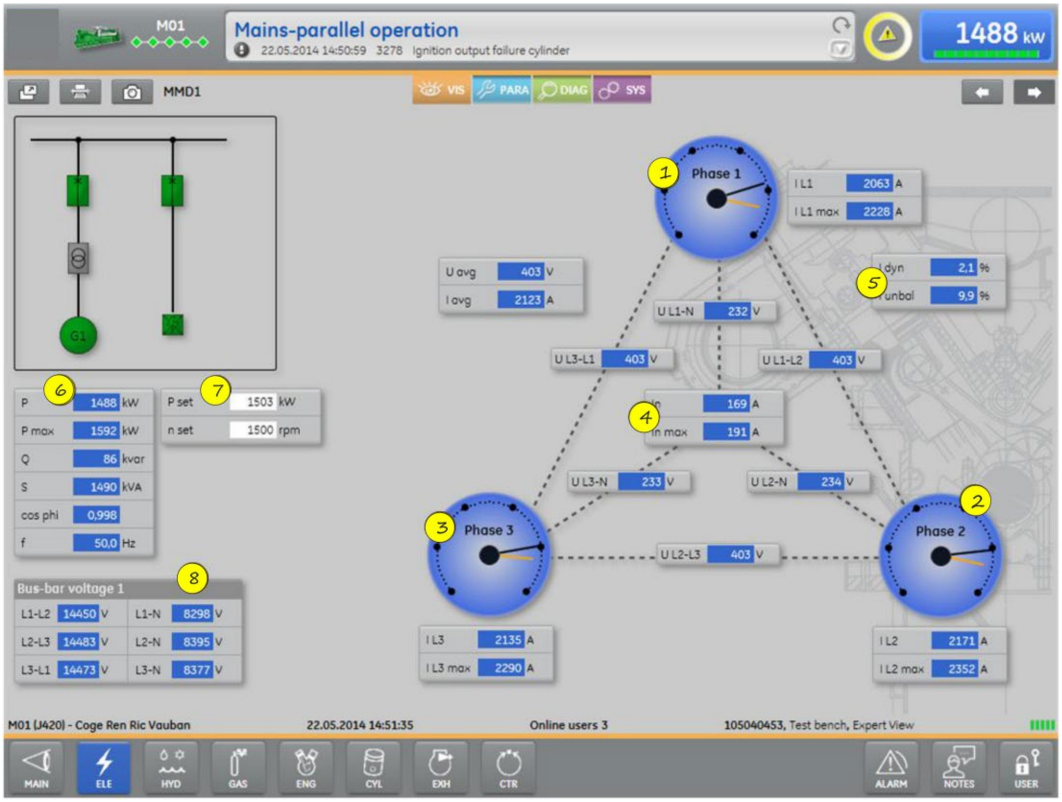
Operation is via the screen buttons on the touch screen
Numeric entries (set point values, parameters…) are entered on the touch numeric pad or via a scroll bar.
Determination of the operation mode and the method of synchronization via a permanently displayed button panel on the touch screen.

Main screens (examples):

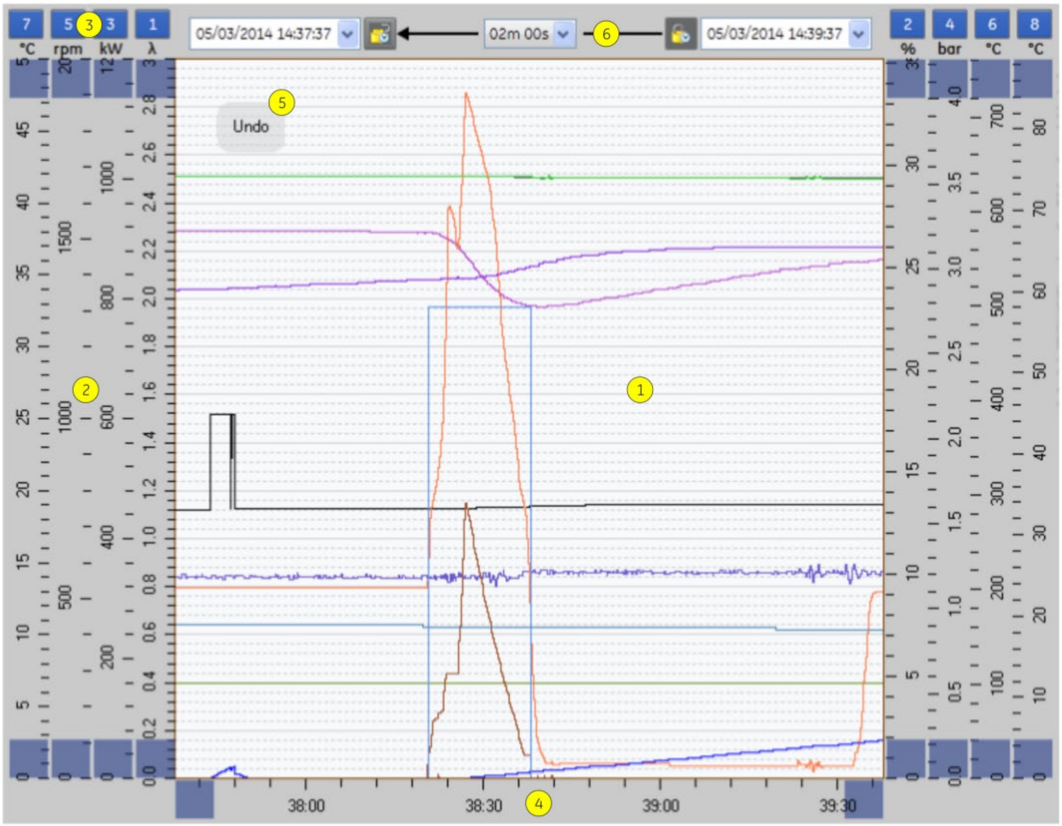
Main: Display of the overview, auxiliaries' status, engine start and operating data.



ELE: Display of the generator connection with electrical measurement values and synchronization status



Trending
Trend with 100ms resolution



Measurement values:
- 500 data points are stored
- Measurement interval = 100ms
- Raw data availability with 100ms resolution: 3 hours + max. 50.000.000 changes in value at shut down (60 mins per shut down)
- Compression level 1: min, max, and average values with 1000ms resolution: 1 day
- Compression level 2: min, max, and average values with 30s resolution: 1 month
- Compression level 3: min, max, and average values with 10min resolution: 10 years

Messages:
1.000.000 message events

Actions (operator control actions):
100.000 Actions

System messages:
100.000 system messages

Central engine and module control:

An industrial PC- based modular industrial control system for module and engine sequencing control (start preparation, start, stop, aftercooling and control of auxiliaries) as well as all control functions.

Interfaces:

- Ethernet (twisted pair) for remote monitoring access
- Ethernet (twisted pair) for connection between engines
- Ethernet (twisted pair) for the Powerlink connection to the control input and output modules.

Connection to the local building management system according to the JENBACHER option list (OPTION)

- MODBUS-RTU Slave
- MODBUS-TCP Slave,
- PROFIBUS-DP Slave (120 words),
- PROFIBUS-DP Slave (190 words),
- ProfiNet Slave
- OPC DA Server

Control functions:

- Speed control in idle and in island mode
- Power output control in grid parallel operation, or according to an internal or external set point value on a case-by-case basis
- LEANOX control system which controls boost pressure according to the power at the generator terminals, and controls the mixture temperature according to the engine driven air-gas mixer
- Knocking control: in the event of knocking detection, ignition timing adjustment, power reduction and mixture temperature reduction (if this feature is installed)
- Load sharing between engines in island mode operation (option)
- Linear power reduction in the event of excessive mixture temperature and misfiring
- Linear power reduction according to CH4 signal (if available)
- Linear power reduction according to gas pressure (option)
- Linear power reduction according to air intake temperature (option)

Multi-transducer to record the following alternator electrical values:

- Phase current (with slave pointer))
- Neutral conductor current
- Voltages Ph/Ph and Ph/N
- Active power (with slave pointer)
- Reactive power
- Apparent power
- Power factor
- Frequency
- Active and reactive energy counter

Additional 0 (4) - 20 mA interface for active power as well as a pulse signal for active energy

The following alternator monitoring functions are integrated in the multi-measuring device:
- Overload/short-circuit [51], [50]
- Over voltage [59]
- Under voltage [27]
- Asymmetric voltage [64], [59N]
- Unbalance current [46]
- Excitation failure [40]
- Over frequency [81>]
- Under frequency [81<]

Lockable operation modes selectable via touch screen:
- "OFF" operation is not possible, running units will shut down immediately.
- "MANUAL" manual operation (start, stop) possible, unit is not available for fully automatic operation.
- "AUTOMATIC" fully automatic operation according to external demand signal:

Demand modes selectable via touch screen:
- external demand off („OFF“)
- external demand on („REMOTE“)
- overide external demand („ON“)

Malfunction Notice list:

Shut down functions e.g.:
- Low lube oil pressure
- Low lube oil level
- High lube oil level
- High lube oil temperature
- Low jacket water pressure
- High jacket water pressure
- High jacket water temperature
- Overspeed
- Emergency stop/safety loop
- Gas train failure
- Start failure
- Stop failure
- Engine start blocked
- Engine operation blocked
- Misfiring
- High mixture temperature
- Measuring signal failure
- Overload/output signal failure
- Generator overload/short circuit
- Generator over/undervoltage
- Generator over/underfrequency
- Generator asymmetric voltage
- Generator unbalanced load

- Generator reverse power
- High generator winding temperature
- Synchronizing failure
- Knocking failure

Warning functions e.g.:
- Cooling water temperature min.
- Cooling water pressure min.
- Generator winding temperature max.

Remote signals:
(volt free contacts)

1NO = 1 normally open
1NC = 1 normally closed
1COC = 1 change over contact

• Ready for automatic start (to Master control)	1NO
• Operation (engine running)	1NO
• Demand auxiliaries	1NO
• Collective signal "shut down"	1NC
• Collective signal "warning"	1NC

External (by others) provided command/status signals:

• Engine demand (from Master control)	1S
• Auxiliaries demanded and released	1S

Single synchronizing Automatic

For automatic synchronizing of the module with the generator circuit breaker to the grid by PLC- technology, integrated within the module control panel.

Consisting of:
- Hardware extension of the programmable control for fully automatic synchronization selection and synchronization of the module and for monitoring of the generator circuit breaker closed signal.
- Lockable synchronization selection via touch screen with the following selection modes:
  - "MANUAL" Manual initiation of synchronization via touch screen button followed by fully automatic synchronization of the module
  - "AUTOMATIC" Automatic module synchronization, after synchronizing release from the module control
  - "OFF" Selection and synchronization disabled
    Control of the generator circuit breaker according to the synchronization mode selected via touch screen.
  - "Generator circuit breaker CLOSED/ Select" Touch-button on DIA.NE XT
  - "Generator circuit breaker OPEN" Touch-button on DIA.NE XT
  - Measurement Generator breaker closing time last synchronization

Status signals:
Generator circuit breaker closed
Generator circuit breaker open

Remote signals:
(volt free contacts)
Generator circuit breaker closed 1 NO

The following reference and status signals must be provided by the switchgear supplier:

- Generator circuit breaker CLOSED 1 NO
- Generator circuit breaker OPEN 1 NO
- Generator circuit breaker READY TO CLOSE 1 NO
- Mains circuit breaker CLOSED 1 NO
- Mains circuit breaker OPEN 1 NO

Mains voltage 3 x **480**/**277**V or 3x 110V/v3 other measurement voltages available on request
Bus bar voltage 3 x **480**/**277** V or 3x 110V/v3 – other measurement voltages available on request
Generator voltage 3 x **480 V** or 3x 110V/v3 – other measurement voltages available on request

Voltage transformer in the star/star connection with minimum 50VA and Class 0,5

The following volt free interface-signals will be provided by JENBACHER to be incorporated in switchgear:

- CLOSING/OPENING command for generator circuit breaker
  (permanent contact) 1 NO + 1 NC
- Signal for circuit breaker undervoltage trip 1 NO

Maximum distance between module control panel and engine/interface panel: 99ft
Maximum distance between module control panel and power panel: 164ft
Maximum distance between module control panel and master control panel: 164ft
Maximum distance between alternator and generator circuit breaker: 99ft

1.11 Motor control panel – Container design

Sheet metal IEC enclosure, components and assembly UL listed.
For distribution and protection of the module and container auxiliaries.
With cubicle lighting.

Dimensions:

- Height: 71 inch (1800 mm)
- Width: 39 inch (990 mm)
- Depth: 16 inch (405 mm)

Equipment:
Equipped with IEC type starters for each motor
With safety disconnect switches for every load
With step down transformer 480/120V, 4kVA for container consumers

1.11.01 Remote messaging over MODBUS-TCP

Data transfer from the JENBACHER module control system to the customer's on-site central control system via MODBUS TCP using the ETHERNET 10 BASE-T/100BASE-TX protocol TCP/IP.

The JENBACHER module control system operates as a SLAVE unit.
The data transfer via the customer's MASTER must be carried out in cycles.

Data transmitted:
Fault messages, operating messages, measured values (generator power, oil pressure, oil temperature, cooling water pressure, cooling water temperature, etc.) according to JENBACHER standard (interface list).

JENBACHER limit of supply:
RJ45 socket at the interface module in the module control cabinet

1.11.06 Remote Data-Transfer with DIA.NE XT4

General
DIA.NE XT4 offers remote communication using an Ethernet connection.

1.) DIA.NE XT4 HMI
DIA.NE XT4 HMI is the Human-Machine-Interface of DIA.NE XT4 engine control and visualization system for JENBACHER gas engines.
The system offers extensive facilities for commissioning, monitoring, servicing, and analysis of the site.
By installation of the DIA.NE XT4 HMI client program it can be used to establish connection to site, if connected to a network and access rights are provided.
The system runs on Microsoft Windows Operating systems (Windows 7, Windows 8, Windows 10)

Function
Functions of the visualization system at the engine control panel can be used remotely. These functions provide control, monitoring, trend indications, alarm management, parameter management, and access to long term data recording. By providing access to multiple systems, also with multiple clients in parallel, additional useful functions are available like

- Multi-user system
- Remote control

- Print and export functions
- Data backup.

The DIA.NE XT4 is available in several languages.

Option - Remote demand/blocking

If the service selectors switch at the module control panel is in position "Automatic" and the demand-selector switch in position "Remote", it is possible to enable (demanded) or disable (demand off) the module with a control button at the DIA.NE XT4 HMI
Note:
With this option, it makes no sense to have an additional client's demand (via hardware or data bus) or a self-guided operation (via JENBACHER master control, grid import /export etc.).

Option - Remote - reset (see TA-No. 1100-0111 chapter 1.7 and 1.9)

Scope of supply

- Software package DIA.NE XT4 HMI Client Setup (Download)
- Number of DIA.NE XT4 HMI - Client user license (Simultaneous right to access of one user to the engine control)

Nr. of license	Access
1	1 Users can be logged in at the same time with a PC (Workplace, control room or at home).
2 - “n“ (Optional)	2- “n” Users can be logged in at the same time with a PC (Workplace, control room or at home). If 2- “n” users are locally connected at Computers from office or control room, then it is not possible to log in from home.

Caution! This option includes the DIA.NE XT4 HMI client application and its license only – NO secured, encrypted connection will be provided by JENBACHER! A secured, encrypted connection – which is mandatory – has to be provided by the customer (via LAN connection or customer-side VPN) or can be realized by using option myPlant™.

Customer requirements

- Broad band network connection via Ethernet(100/1000BASE-TX) at RJ45 Connector (ETH1) at DIA.NE XT4 server inside module control panel
- Standard PC with keyboard, mouse or touch and monitor (min. resolution 1024*768)
- Operating system Windows 7, Windows 8, Windows 10
- DirectX 9.0 c compatible or newer 3D display adapter with 64 MB or higher memory

2.) myPlant™
myPlant* is the remote data transfer and diagnostics solution from JENBACHER

	BASIC	CARE	PROFESSIONAL
basic / advanced monitoring			
Liver operating status	✓	✓	✓
Historic and live data trending		✓	✓
Alarm management and notification	Alarm management only	✓	✓

Access to all engine documents	✓	✓	✓
Mobile app	✓	✓	✓
Daily status logbooks	✓	✓	✓
Remote access to engine controller		✓	✓
Fleet management		✓	✓
Engine status notifications (SMS/Email)		✓	✓
increased productivity / strong performance			
Recommended maintenance[1] (coming soon)	✓	✓	✓
Support case management[1]	✓	✓	✓
Predictive maintenance for spark plugs, oil, and air filters[2]	Spark plugs lifetime prediction only	✓	✓
Oil & coolant quality monitoring[3]		✓	✓
Fleet emission monitoring[4]	Engine emission monitoring only	✓	✓
artificial intelligence & predictive analytics			
Operator analytics package			✓
Historic performance analysis			✓
User-defined monitoring			✓
On demand: Access to myPlant data via API (Application Programming Interface) service[5]			✓

[1] Available soon for JENBACHER direct markets only
[2] Spark plugs, oil and air filters data might not always be available and is depending on the engine version/type ant the sensors installed
[3] Oil and coolant reports are available in myPlant for the following laboratories: Spectro, JetCare, Polaris, MIC GSM
[4] May require additional hardware installation for emission monitoring (available as upgrade)
[5] Might require development work on customer/service provider side and includes 70 API calls per engine per month

Scope of supply
- Access to myPlant™
- Integration of the plant in the myPlant™ system
- Access to Basic and Care level as per new installation contract
- Access to Professional level via separate contract

Equipment to be provided by the customer
- Permanent Internet connection (wired or wireless)
  (see also option 4)
- Technical requirements as per TA 2300-0008
- Outward data connection (from the plant server to the Internet) - INWARD connections are NOT PERMITTED!

CAUTION: The customer must take technical precautions to ensure that direct access to the plant server from the Internet is prevented (e.g. by means of a firewall):
This security measure CANNOT be assumed and guaranteed by JENBACHER

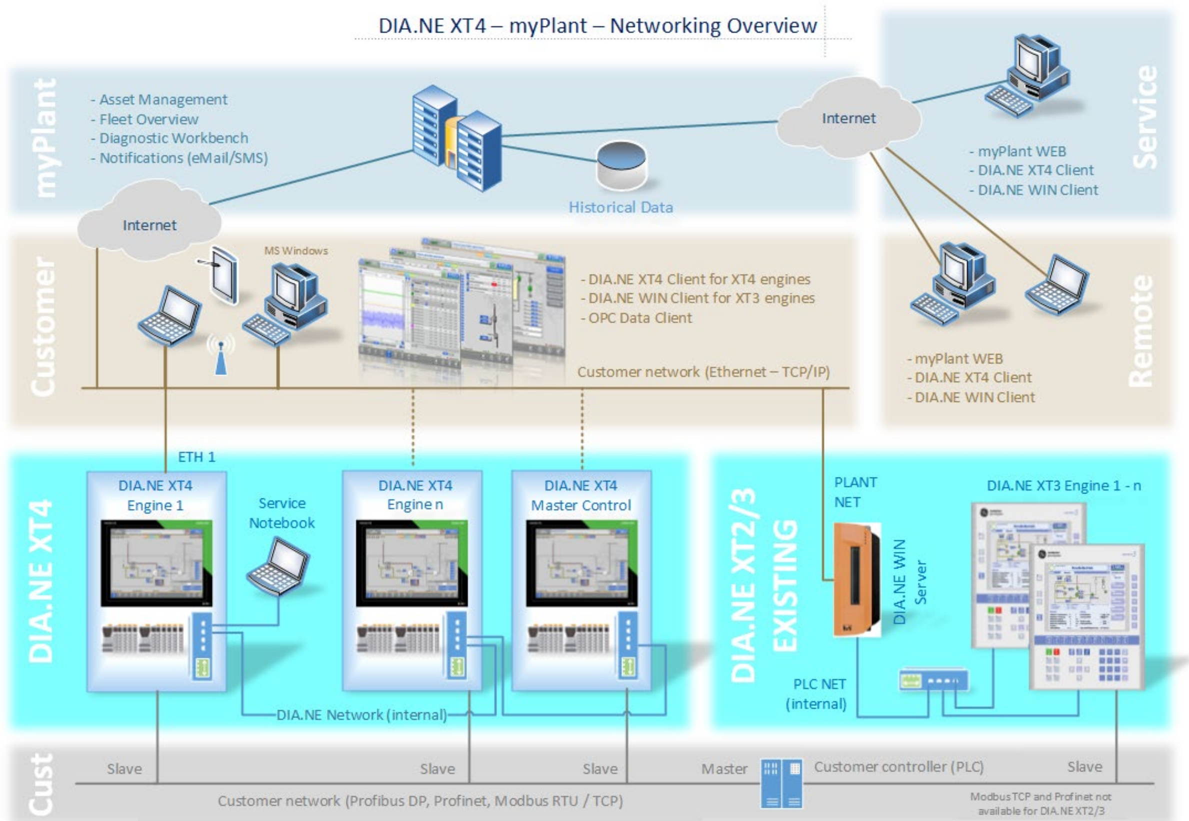
3.) Mobile Internet (OPTION)
Connection Plant - Customer via secured Internet - connection
See also technical instruction **TA 2300 - 0006**

Scope of delivery
- Mobile Internet router with antenna to connect to the DIA.NE Server XT4

Customer requirements
- SIM card for 3G / 4G

4.) Network overview

For information only!



1.11.10 Active power limitation, Reactive power control per module

Active power limitation:
The module can be operated with a reduced power output if the network operator requires a temporary limitation on feed-in power. Power logging is carried out at the generator terminals.

The customer has the option to engage in module control using the following signals:
- 0/4 - 20mA for the continuous limitation of generator active power from 100 % - 50(PMin) %
- 1 potential-free contact for blocking the module (without RESET function)

or
- 4 potential-free contacts for the limitation of generator active power from 100 % - 50(PMin) %
- 1 potential-free contact for blocking the module (without RESET function)

Reactive power control:
The reactive power/power factor control point is at the generator terminals

The module is designed for the process of reactive power control described below.
Set point setting via the customer using the following signals:

- 0/4 - 20mA for the continuous cos phi set point setting in the range of xx overexcited to xx under-excited

The following signal is provided to the customer by JENBACHER:

- 0/4 - 20mA for the actual value of generator reactive power
- 0/4 - 20mA for the actual value of generator active power

Further interfaces upon request!

1.11.25 Control Strategy and Options

Control Strategy – The following control modes will be available in the Diane Control

- Grid Parallel with KW Control – Real Power Load Control of the Generator set will be either via a 4-20mA input from the customer representing a unit KW load setpoint or a KW load setpoint entered on the Diane XT4 screen. Upon breaker closure, the unit will ramp to the setpoint at a maximum rate of (Rated Unit KW) / 180 seconds.

- Grid Parallel with PF Control – Reactive Power Load Control of the Generator set will be either via a 4-20mA input from the customer representing a unit Power Factory setpoint or a Power Factor setpoint entered on the Diane XT4 screen. Upon breaker closure, the unit will maintain the setpoint.

- Grid Parallel with Import/Export Control - Load Control via an Import/Export KW level entered on the Diane XT4 screen. Required will be a customer 4-20mA signal representing the Site KW (Imported and/or Exported Power) that is to be controlled. Upon breaker closure, the unit will ramp to a load that will drive the KW value represented by the 4-20mA input signal to the level entered on Customer Import/Export Setpoint entered in the Diane XT4 screen. Once at the setpoint, the unit will raise and lower load to maintain this value. If the generator load required to maintain this setpoint drops below the minimum load level of the generator set, the unit 52G circuit breaker will be opened.

- Island Mode Operations with Blackout Starting – Island Operations with Black start capability will allow the engine to start and run without utility being present. The engine will be able to start the engine on battery power, close the generator breaker against a dead bus, and operate independently of a utility power source. The customer must ensure that there is sufficient fuel gas and pre-chamber gas at pressure in the event of a Type 6 engine so configured. The engine will start without the normal confirmation of engine block temperature or operation of a circulating AC water pump. It will be required of the operators that once the engine is connected to the generator bus, power to the engine auxiliaries be restored. Load Management is expected to be limited by the operators to the limits of the engine, as per Jenbacher TI 2108-0031. This system will work in conjunction with a Jenbacher Master Synchronizing Control (see appropriate Spec Section) if so equipped. If this is a single unit and synchronization with the utility after assuming operations is required, a *Grid Parallel with Single Unit Island Operations* option will be required.

Per Unit Hot Water Loop Controls - Hot Water Loop Panel Controls and Software to include:

- Hot Water Pump (Panel Control Parts and SW Only) - The option will add specific contact output and feedback input to/from an MCC for the Hot Water Pump. This will include relays and software.

- Hot Water Monitoring (Panel Control Parts and SW Only) - This option will monitor 3 hot water loop switches, flow, pressure and temperature. This option includes hardwired relays added to the trip loop, and internal software

- Hot Water Return Temperature Control (Panel Parts and SW Only) - This feature will provide all necessary controls to operate a 3 Way temperature control valve. The customer will provide a PT100 as a feedback signal and the Diane will provide a 4-20mA Analog Output to a customer provided valve. Control and Display Software are also provided.

Per Unit Miscellaneous Controls - Diane XT4 System will be provided with the following additional features to operate a customer enclosure

- Additional Emergency Stop Signals - Additional Terminals for customer Estop switches

- Audible and Visual Alarm Indications - Hardware and software to drive a customer provided horn and strobe. Power for these devices is provided from the control system and is 24VDC

- SCR Control Signals – 2 additional discrete inputs and 1 analog will be required:
    - Discrete In 1 - Unit Operation/Engine Running (SSL20) to start the unit
    - Discrete In 2 - SCR Alarm (SS69) for display on the alarm Diane XT screen.
    - Analog Out 1 – Generator Power (0-100% = 4-20mA) for control of the SCR spray mechanism.

- Gas Flow Meter Trending - Gas Flowmeter Trending and Display (Flowmeter not included). Option includes a 4-20mA input that will accept the pressure and temperature corrected gas flow from a customer provided flow meter computer and will incorporate the signal into trending and displays in the Diane system.

- Gas Flow Meter Correction - Gas Flowmeter temperature and pressure compensation. Option includes three (3) 4-20mA inputs that will represent actual measured flow, pressure and temperature. Along with a customer provided flow meter calibration sheet, these 3 signals will be input to a calculation that will compensate the flowmeter flow signal to current gas conditions. The results will be incorporated into trending and displays in the Diane system.

- Exhaust By-Pass Control -The exhaust by-pass consists of two flaps (one open, one closed) housed in a tee section of piping, which are controlled by a single actuator. The position of the by-pass is determined by the outlet temperature of the process heat exchanger. A PT100 sensor is used to send the outlet temperature of the process heat exchanger to the DIA.NE XT. The DIA.NE XT monitors this temperature, and if the temperature is at or above set point, moves the flaps to reduce the flow to the Exhaust Heat Exchanger while increasing the flow to the exhaust bypass. For temperatures below set point, all flow is directed through the Exhaust Heat Exchanger (analog output = 20 mADC).

  [4 mADC = full bypass, 20 mADC = full Enalco. A broken wire or loss of signal of the PT100 sensor, the heat exchanger will be bypassed.]

    - Included in the control:

        - Dig. Input Release exhaust gas bypass
        - Analog Input Exhaust gas temperature after EHGE
        - Analog Input Temperature heating water supply

- Analog Output 4 – 20mA Setpoint bypass flap

1.20.03 Starting system

Starter battery:
2 piece 12 V AGM battery, 125 Ah (according to DIN 72311).

Battery voltage monitoring:
Monitoring by PLC.

Battery charging equipment:
Capable for charging the starter battery with I/U characteristic and for the supply of all connected D.C. consumers.
Charging device is mounted inside of the module interface panel or module control panel.

- **General data:**
  - Power supply **3 x 320 - 575 V, 47 - 63 Hz**
  - max. power consumption 1040 W / 1550 W (5 sec)
  - Nominal D.C. voltage 24 V(+/-1%)
  - Voltage setting range 24V to 28V (adjustable)
  - Nominal current (max.) 40 A
  - Degree of protection IP20 to IEC 60529
  - Operating temperature 32 °F – 158 °F (0 °C - 70 °C)
  - Protection class 1
  - Humidity class 3K3, no condensation.
  - Natural air convection
  - Standards EN60950,EN50178
    UL/cUL (UL508 / UL 60950-1)

Signalling:
Green Led: Output voltage > 21.6V

Control accumulator:
- Pb battery 24 VDC/18 Ah

1.20.05 Electric jacket water preheating

Installed in the jacket water cooling circuit, consisting of:
- Heating elements
- Water circulating pump

The jacket water temperature of a stopped engine is maintained between 133 °F (56°C) and 140°F (60°C), to allow for immediate loading after engine start.

1.20.08 Flexible connections

Following flexible connections per module are included in the JENBACHER -scope of supply:

No.Connection	Unit	Dimension	Material
2 Warm water in-/outlet	**IN/LBS**	**3"/145**	Stainless steel
1 Exhaust gas outlet	**IN/LBS**	**10"/145**	Stainless steel
1 Fuel gas inlet	**IN/LBS**	**2½"/232**	Stainless steel
2 Intercooler in-/outlet	**IN/LBS**	**2½"/**	Stainless steel
2 Lube oil connection	**IN**	**1.1**	Hose

Seals and flanges for all flexible connections are included.

2.00 Electrical equipment

Totally enclosed floor mounted sheet steel cubicle with front door wired to terminals. Ready to operate, with cable entry at bottom. Naturally ventilated or with forced ventilation.

Protection:	IP 42 external, NEMA 12 IP 20 internal (protection against direct contact with live parts)

Design according to EN 61439-2 / IEC 61439-2 / UL 508 A and ISO 8528-4.
Ambient temperature 41 - 104 °F (5 - 40 °C), 70 % Relative humidity

Standard painting:	Panel:	RAL 7035
	Pedestal:	RAL 7020 (Rittal TS8)
		RAL 7020 (Rittal VX25)

2.02 Grid monitoring device Standard 60Hz Profile 1

Standard for generating plants connected to the medium voltage grid with dynamic Grid Code requirements.

Function:
Monitoring device for immediate disconnection of the generator from the grid in case of grid failures.

Consisting of
- Voltage monitoring with two-stage undervoltage and two-stage overvoltage limit function
- Frequency monitoring with underfrequency and over frequency function.
- Separately adjustable, independent times for voltage and frequency monitoring.
- Monitoring of the limit line of the low voltage profile ULVRT
- Display of all measured values for normal operation or malfunction via an alphanumeric display and LEDs.
- Setting authorization through password against unauthorized changes.

Scope of supply:

- Digital grid protection relay with fault data storage, measured value display and self-monitoring.
- Rated input voltages: 100 V / 110 V /400V

Out of standard scope of supply:

- all necessary instrument transformers,
- additional protection equipment acc. to utility operator's specifications and guidelines.
- Site-specific acceptance test done by approved testing institute

Recommended setting value for Grid monitoring device:
The limit values need to be aligned site-specific with the utility operator!

Parameter	Parameter Limit	Time Delay	Comments
U>> [ANSI 59]	115 %U	0.2 s	Power capability reduction with 1 %Pn/%U above 105 %U
U> [ANSI 59]	111 %U	60 s	Power capability reduction with 1 %Pn/%U above 105 %U
U< [ANSI 27]	80 %U	1.5 s	Power capability reduction with 1 %Pn/%U below 95 %U
U<< [ANSI 27]	45 %U	0.2 s	Power capability reduction with 1 %Pn/%U below 95 %U
f> [ANSI 81O]	62 Hz	0.1 s	Power capability reduction with 10 %Pn/Hz above 61 Hz
f< [ANSI 81U]	57.0 Hz	0.1 s	Power capability reduction within the boundaries of 2 %Pn/Hz below 59 Hz; 10 %Pn/Hz below 59.5 Hz. Default: 10 %Pn/Hz below 59 Hz
Monitoring of the voltage profile U_{LVRT} [ANSI 27T]	28 %U	0 s	For symmetrical faults
	68 %U	0.17 s	
	83 %U	1.6 s	

2.04 Generator Low Voltage switchgear (for container design)

Sheet metal enclosure, UL listed, front-access

Dimensions:

- Height: 80 inch (2032 mm)
- Width: 28 inch (700 mm)
- Depth: 32 inch (800 mm)

Generator circuit breaker details

- In = **XXXX** A, drawn out type
- Short circuit breaking capacity: 65kA
- Spring drive 24VDC
- Close coil 24VDC
- Shunt trip coil 24VDC
- Under-voltage trip coil 24VDC
- Auxiliary contacts (a/b)
- Programmable Short Circuit Protection (Instantaneous and Duration)

Cabinet Fitted with

- 2 PT fused sets (Bus side/Gen side, 3 PTs in a Wye-to-Wye configuration)
- Surge Suppression

Per Phase Bus Bar Terminations and Ground Bar predrilled for customer terminations (maximum 4 cables per phase (Hardware not provided).

2.12 Gas warning device

Function:
The gas warning device continuously monitors the radiated air in the engine room and warns against gases which are injurious to persons' health and against explosive gas concentrations.
The measuring head (catalytic sensor) is attached on the covering or nearby the ground, dependent upon the gas source.

Scope of supply:
- Alarm unit		voltage:		24VDC
- 2 Gas sensor(s)

2.13 Smoke warning device

Function:
The smoke warning device in combination with the optical smoke detector (installed in the control room) and the thermal smoke detector (installed in the engine room) provide extensive early warning signal.

Design:
The device has an optical display for alarm and operation.
The smoke warning device is installed in a plastic housing.

Scope of supply:
- Alarm unit		voltage:		24 V
  2 Smoke detector(s)

3.01 Lube oil system

Consisting of:
- 79.3 gal fresh oil tank
- **79.3** gal lube oil tank
- Combined electric driven fresh oil and waste oil pump
- Level switches
- Shut-off devices
- Complete pipe work between oil tanks and module

Through simple switch over of the pumps following functions are given:
- Filling of the fresh oil tank from a cask
- Filling of the lube oil tank from a cask
- Filling of the oil pan from a cask
- Emptying of the oil pan into a cask
- Emptying of the waste oil tank into a cask

3.03.01 Exhaust gas silencer

Material:
Stainless steel

Consisting of:
- Exhaust gas silencer
- Flanges, seals, fixings

Insulation:
The insulation for reducing surface irradiations (heat and sound) of the exhaust gas silencer is not included in our scope of supply and must be provided locally. The insulation (4-inch (100 mm) rock wool covered with 0,03 inch (0,75 mm) galvanized steel sheet) is required to keep the sound pressure level of the container (65 dB(A) in 32 ft (10 m)).

3.10.03 Cooling system – dual-circuit radiator

The heat produced by the engine (jacket water, lube oil, intercooler) is dissipated through a radiator, installed outside.

Consisting of:
- Radiator
- Pump
- Electrical control
- Expansion tank

The radiator is designed for an ambient temperature of 95°F (35°C). Special versions for higher ambient temperatures are available upon request.

3.20 Container

40' ISO STEEL CONTAINER, Module Installation

Dimensions:
- Length: 40 ft (12192 mm)
- Width: 8 ft (2438 mm)
- Height: 8 ft, 6 in (2591 mm)

Sound pressure level
65 dB (A) at 32 ft (10 m) (surface sound pressure level according to DIN 45635)
See comments under MC 3.03.01

Ambient temperature:
The container is designed for an ambient temperature from **–4°F (-20°C)** to **90°F (32°C).**
Other temperatures are available upon request.

Base frame:
Self-supporting, i.e. the base frame is designed to withstand static loads from the installation of parts such as the engine, control panels, exhaust gas silencer and radiator.

To lift (to load) the container 4 screw able carrier lugs are mounted at the top of the container.

Construction:
Trapezoidal corrugated steel sheeting welded between the base frame and the top frame.
The sound absorbent surfaces are comprised of rock wool covered with perforated plating.
The container is of a weatherproof design and the roof is suitable for construction work.

A double door to bring in the engine is situated at the front of the container beside the air outlet.
There is a door into the control room at the front wall on the side of air inlet.
A door into the engine room is situated at the long side of the container.

The doors (engine room and control room) are fitted with identical cylinder locks. The doors are designed as emergency doors which could be opened in direction of the escape route. They are identified as such and can be opened from inside without other assistance (panic lock).

Dimension of door: appr. 3.28 ft (1000 mm) x 6.56 ft (2000 mm) (W x H)

Engine room:
The floor is made of steel sheet (checker – or diamond plate) and designed as a tightly sealed pan. This pan is used to collect any oil-leak of the lube oil circuit (engine and extension tank).
Connections from/to the engine room consist of:
- Top: Cooling water in/outlet; welded flange
  Exhaust gas outlet; tightly closed
- Roof:
  Suspensions for cable trough, gas train, gas pipes, ...
- Wall:
  Gas inlet; welded flange
  The wall between engine room and control room is design with recesses for the cables.

Control room:
The control room is ventilated by a lockable air intake opening. The air is aspirated by the fans of the engine room. For the cable's entry, a recess at the floor of the control room is planned. The control room is equipped with a plastic covering for shipment.

Module and container installation are essentially performed as follows:
- Installation and setup of the module
- Installation of the control equipment in a separate control equipment room
- Installation of the gas train
- Installation of the lube oil equipment
- Installation of the air intake and outlet ventilation system
- Installation of the exhaust silencer on the roof
- Installation of the radiator on the roof
- Installation of lighting in the container
- Installation of the auxiliary electrical installations
- Completion of exhaust, fuel, oil, and water piping, according to the defined scope of supply, including all necessary fittings, flexible connections, and reinforcements.
- Footboard above the tubes
- Rain drains
- Total signage

Fire protection classification:
The container is not classified for fire protection.

Coating:
- Installation:
  - Oil resistant base
  - Synthetic resin as coating varnish
  - Color Container:
    RAL6018 (green)

4.00 Delivery, installation, and commissioning

4.01 Carriage
According to contract.

4.02 Unloading
Unloading, moving of equipment to point of installation, mounting and adjustment of delivered equipment on intended foundations is not included in JENBACHER scope of supply.

4.03 Assembly and installation
Assembly and installation of all JENBACHER -components is not included in JENBACHER scope of supply.

4.04 Storage
The customer is responsible for secure and appropriate storage of all delivered equipment.

4.05 Emission measurement with exhaust gas analyzer
Emission measurement by JENBACHER personnel, to verify that the guaranteed toxic agent emissions have been achieved (costs for measurement by an independent agency will be an extra charge).

5.01 Limits of delivery - Container

Electrical
- Module:
  At terminals of generator circuit breaker

Mechanical
Suitable bellows and flexible connections **must be provided locally** for all connections.

Warm water
At inlet and outlet flanges on container

Exhaust gas
At exhaust gas outlet flange on top of the container; special stack provided locally

Combustion air
The air filters are set mounted, no external ductwork is necessary

Fuel gas
At inlet flange of the container

Lube oil
At lube oil connections on container

Condensate
At the condensate drains on container.

Insulation
The insulation of the heat exchangers, pipes, exhaust-gas silencers, and all components of the gas pressure control system installed outdoors is not included in our scope of supply and must be provided (on-site) by the customer.

5.02 Factory tests and inspections

The individual module components shall undergo the following tests and inspections:

5.02.01 Engine tests
Carried out as combined Engine- and Module test according to DIN ISO 3046 at JENBACHER test bench.
The following tests are made at 100%, 75% and 50% load, and the results are reported in a test certificate:
- Engine output
- Fuel consumption

- Jacket water temperatures
- Lube oil pressure
- Lube oil temperatures
- Boost pressure
- Exhaust gas temperatures, for each cylinder

5.02.02 Generator tests

Carried out on test bench of the generator supplier.

5.03 Documentation

List of standard pre-documentation provided based on the technical status at the time of order receipt:

- Module drawing **1)**
- Technical diagram **1)**
- Drawings of the cabinet views **3**
- Electrical interface list **2)**
- Technical specification of the control system **2)**

Before delivery (depending on progress in ordering the components, on request)

- Technical drawings for BoP components/accessories supplied separately (if included in scope of supply of INNIO Jenbacher GmbH & Co OG) **1)**

Upon delivery

- Circuit diagrams **3)**
- Cable list **3)**

Delivered with the engine

- Brief instructions (transport, erection, moving) **1)**

For commissioning

- Operation and maintenance instructions **4)**
- Spare parts catalogue **4)**
- Original supplier operation and maintenance instructions for any BoP components (installed in the INNIO Jenbacher GmbH & Co OG scope of supply) as Appendix **1)**

All the components found in the INNIO Jenbacher GmbH & Co OG scope of supply are described in the operation and maintenance instructions, and in the spare parts catalogue.
In addition, the manufacturer's original operation and maintenance instructions will be provided for every BoP component, in German and English as standard, as an Appendix for the operation and maintenance manual provided.

Additional costs of producing or providing the required documents using the KKS (power station coding system) and/or integration in subcontractors' documentation, or additional approval, design and proof of testing documentation must be negotiated or ordered separately.

This standard offer does not include:

- Approval documentation
- Design documentation
- Proof of testing documentation
- Printed copies and digital off-line versions (e.g. printed versions, CD, pdf, etc.) must be negotiated separately and ordered accordingly.

Attachment G

Existing Operations Overview

Attachment G: Existing Operations Review

At the request of Big Six Towers, Waldron performed a high level review of existing operations as part of this study. The key objectives of the analysis were to evaluate the potential savings available through decreasing the use of oil-fired engines in the power plant, and to review the data supplied for any obvious opportunities for energy efficiency improvements.

G.1 Existing Engine Operations

The data available for evaluation of the existing engines were the power plant natural gas bills, the plant logs of monthly fuel oil consumption, and the plant logs of monthly engine electrical production. In order to determine engine performance on each fuel Waldron developed a calculation (excerpts of which are shown below) that utilized the historical gas bills and diesel fuel monthly logs as an input, and engine electrical production as an output. The relationship between the two—the engine electrical efficiency—was the independent variable in this analysis. The efficiency was modified on a monthly basis for engine operation on both natural gas and diesel fuel, such that the total electrical output matched the monthly totals from the plant logs.

The results for the natural gas engines and the diesel engines, as well as the overall total generation values, are provided in the tables below.

	Engine Gas Use from Bills (Therms)	Engine Electrical Efficiency (HHV) [manual input] (Natural Gas)	Calculated Generation on Gas (MWh)
Jan	53,563	26%	270
Feb	30,351	28%	307
Mar	60,378	26%	245
Apr	48,954	24%	129
May	42,405	28%	577
June	38,308	27%	515
July	50,006	27%	255
Aug	37,490	27%	325
Sept	52,099	27%	299
Oct	38,281	28%	315
Nov	51,314	29%	406
Dec	54,531	25%	398
	557,680		4,041

Figure G.1: Existing Engine Operation on Natural Gas

	Engine Oil Use from Plant Logs (gallons)	Engine Electrical Efficiency (HHV) [manual input] (Diesel Fuel)	Calculated Generation on Diesel Fuel (MWh)
Jan	36,886	26%	378
Feb	28,336	26%	291
Mar	32,084	27%	342
Apr	40,676	28%	449
May	27,208	26%	279
June	36,343	26%	373
July	86,023	26%	882
Aug	72,113	25%	711
Sept	46,054	24%	436
Oct	32,373	26%	332
Nov	25,902	25%	255
Dec	24,203	25%	239
	488,201		4,967

Figure G.2: Existing Engine Operation on Diesel Fuel

	Calculated Total Engine Generation (MWh)	Historic Data Total Generation 2020-2021 (MWh)	Percent Difference
Jan	648	602	7.7%
Feb	598	581	2.9%
Mar	586	592	-0.9%
Apr	578	580	-0.4%
May	856	746	14.8%
June	888	840	5.7%
July	1,137	1,265	-10.1%
Aug	1,036	1,172	-11.6%
Sept	735	812	-9.5%
Oct	647	647	0.0%
Nov	662	562	17.7%
Dec	636	572	11.2%
Total	9,007	8,970	0.4%

Figure G.3: Calculated Total Engine Generation vs Historical Plant Data

While various monthly values show double-digit disparities, it is important to keep in mind that monthly gas bills may be slightly shifted from calendar months. Also, the periodicity and accuracy of plant log readings is unknown. The annual total is very close, and the fact that some months are high while others are low suggests this is a reasonable estimate on the macro level.

The engine efficiencies required to make the calculation work are low compared to a new engine, but this is not unexpected given the age of the equipment. The results of this analysis are shown graphically below.

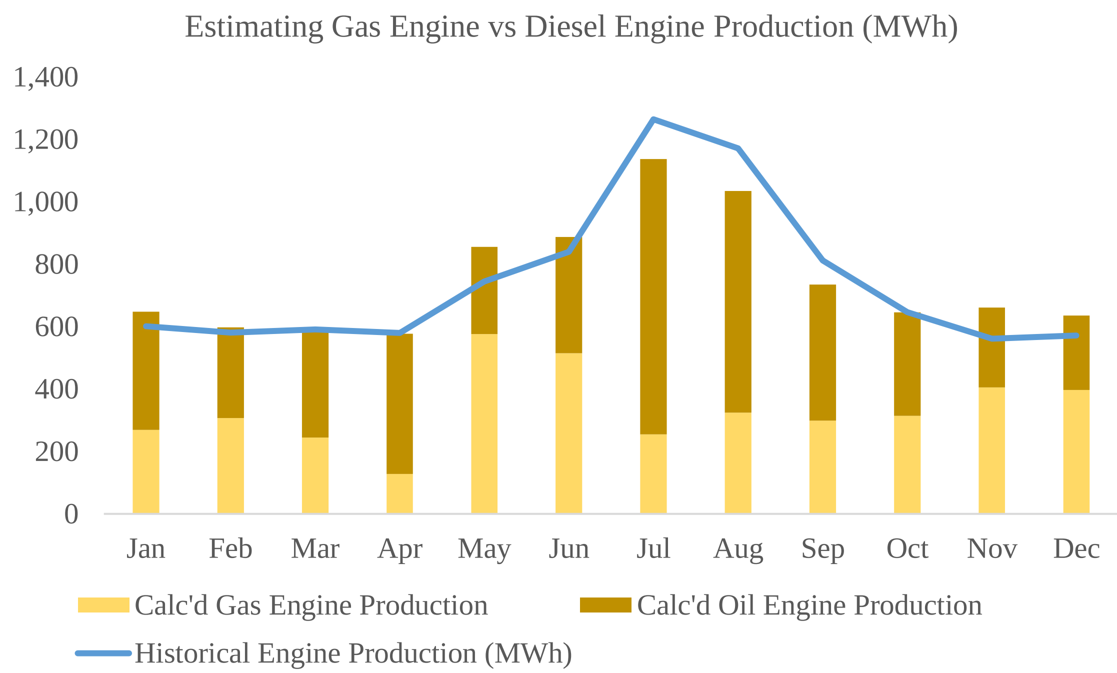


Figure G.4: Existing Engine Efficiency and Production Analysis

The key takeaway from this assessment is that historically diesel fuel accounts for approximately 55% of the annual electrical generation. This is the case despite the fact that the nameplate ratings of the natural gas engines, in total, is greater than the forecasted load for approximately 8,000 hours of the year. Based solely on nameplate ratings, if one assumes that all load above a threshold value of 1,500 kW would exceed the capability of the three natural gas fired engines (which are each rated at 550 kW), diesel fuel use would account for just 4% of the annual electrical production.

For a variety of reasons this theoretical limit is not attainable, but it is worth considering ways of maximizing natural gas utilization as compared to fuel oil, particularly when gas pricing has historically been very favorable compared to oil. In the following section Waldron has provided suggestions on two means of accomplishing this goal.

G.2 Maximizing Use of Natural Gas Engines

The primary reason for keeping diesel engines in operation in parallel with the gas engines is for reliability. The diesel engines can accommodate swings in electrical load better than the natural gas engines. That said, this is a costly form of resiliency and residential customers on the grid and throughout the country experience brief service interruptions on a periodic basis, so a question for Big Six Towers to answer is whether or not brief disruptions are truly as costly to the community as the oil purchases would suggest.

That said, there are some technical items that could be reviewed to make improvements. Waldron understands from speaking with the plant operators that the trip settings on the engine feeder breakers at the existing power plant switchgear are set very tight. Waldron has not reviewed the settings but understood from the conversation that they are set in a manner that is comparable to what a utility would require for grid-connected engine operation. If this is the case, those settings could be relaxed. One advantage of operating the engines without a utility connection in parallel is that the undervoltage and underfrequency limits can be based on engine capabilities and not the IEEE 1547 standards that apply to operation in parallel with the grid. Investigation of existing and determination of future settings appropriate for the existing engines is outside of the scope of this study, but is a relatively easy adjustment to make and should be investigated.

As an example of this, consider the table below, which provides IEEE 1547 settings for breaker trip settings as well as sample performance of a new natural-gas-fired engine. The existing engines may not be able to meet this performance, but the point is that the engine performance values generally allow for much more forgiving settings for the breaker trip levels than the IEEE 1547 requirements. It is reasonable to use the engine values for operation when disconnected from the grid, and doing so would reduce the likelihood of engine plant trip events during load changes in the Big Six community.

Trip Function	IEEE 1547 Setting	Clearing Time (seconds)	New Gas Engine Setting	Recovery Time (seconds)
Over Voltage 1	120%	0.16	125%	5.00
Over Voltage 2	110%	2.00	120%	7.00
Under Voltage 2	70%	2.00	85%	7.00
Under Voltage 2	45%	0.16	80%	5.00
Over Frequency 1	62 Hz	0.16	69 Hz	5.00
Over Frequency 2	61.2 Hz	300	66 Hz	10.00
Under Frequency 1	58.5 Hz	300	54 Hz	10.00
Under Frequency 2	65.5 Hz	0.16	48 Hz	5.00

Figure G.5: Comparison of IEEE 1547 Settings (2018 ed.) to New Gas Engine Capabilities

A second item to consider is the engine controls and the manner in which load sharing is accomplished between the gas engines and the diesels. Based on historical data it would seem that the engines share load roughly equally when on-line. If this is the case then it may be possible to reconfigure the controls such that a diesel engine is on-line in parallel with the natural gas engines, but normally takes only a fraction of the load. It could be operated at a low load that is equal to the largest single load that may need to be quickly rejected, for instance, allowing the natural gas units to carry the bulk of the load whenever possible, to the limits of their capabilities. Investigation of this opportunity is outside of the scope of this study.

G.3 Steam Leaks and Steam System Efficiency

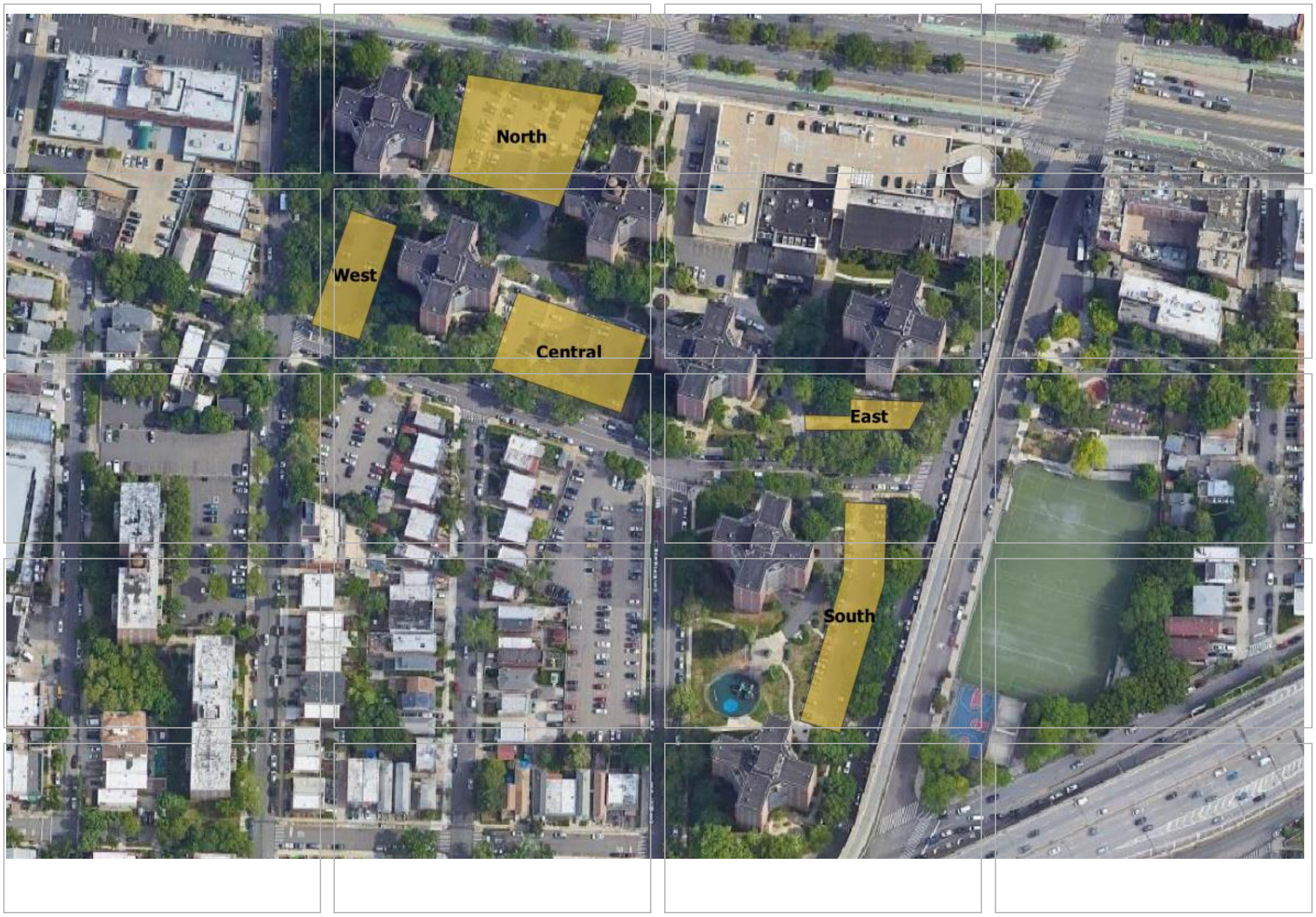
As noted in Section 3.2 of the report, there is a discrepancy between the expected quantity of steam required in the summer and the actual steam produced. One possible explanation is that steam is being introduced into the domestic hot water system when it is not required, as described in that section of the report. But another possibility is that steam trap leakage is the root cause of excess steam production. The difference between the quantity of steam produced and the quantity of steam that is required for domestic hot water and absorption chiller operation could be steam trap leakage.

In Attachment C Waldron estimate a trap leakage rate of approximately 1,650 lbs/hr assuming a leakage rate inversely proportional to the observed temperature difference across the trap. For a relatively high temperature difference, it was assumed the trap was functioning properly. For a low temperature difference a leakage rate of 10% was assumed. Using this methodology a total rate of 1,650 lbs/hr was calculated. This value corresponds to a monthly steam loss of about 1.2 million lbs, which is equal to the average monthly value of the excess steam production in summer. This value was calculated independently from the steam load assessment and should be considered coincidental, but it suggests the excess summer steam is of the order of magnitude of reasonable trap losses. This further implies that the excess steam production may not be only a summer phenomenon: It may be applicable to winter months as well, which would suggest the annual cost of trap leakage is in the vicinity of $125k/yr.

Attachment H

Screening-Level Geothermal Feasibility Study

WALDRON



Report
Screening-Level Geothermal Feasibility Study

Big Six Towers
Queens, NY

Prepared for:

WALDRON

July 2022

www.underground-energy.com

UE Project No. WAL.2022.01

Pursuing Geothermal Excellence

Underground ENERGY

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1.0 Introduction

Underground Energy, LLC (UE) prepared this Screening-Level Geothermal Feasibility Study of the Big Six Towers site in Queens, NY for Waldron Engineering and Construction, Inc. (Waldron). Our objective has been to assess at a high level the geothermal capacity available at the site, and the portion of building heating and cooling loads that could be met with a closed-loop geothermal system that uses parking areas for geothermal borefields (Figure 1).

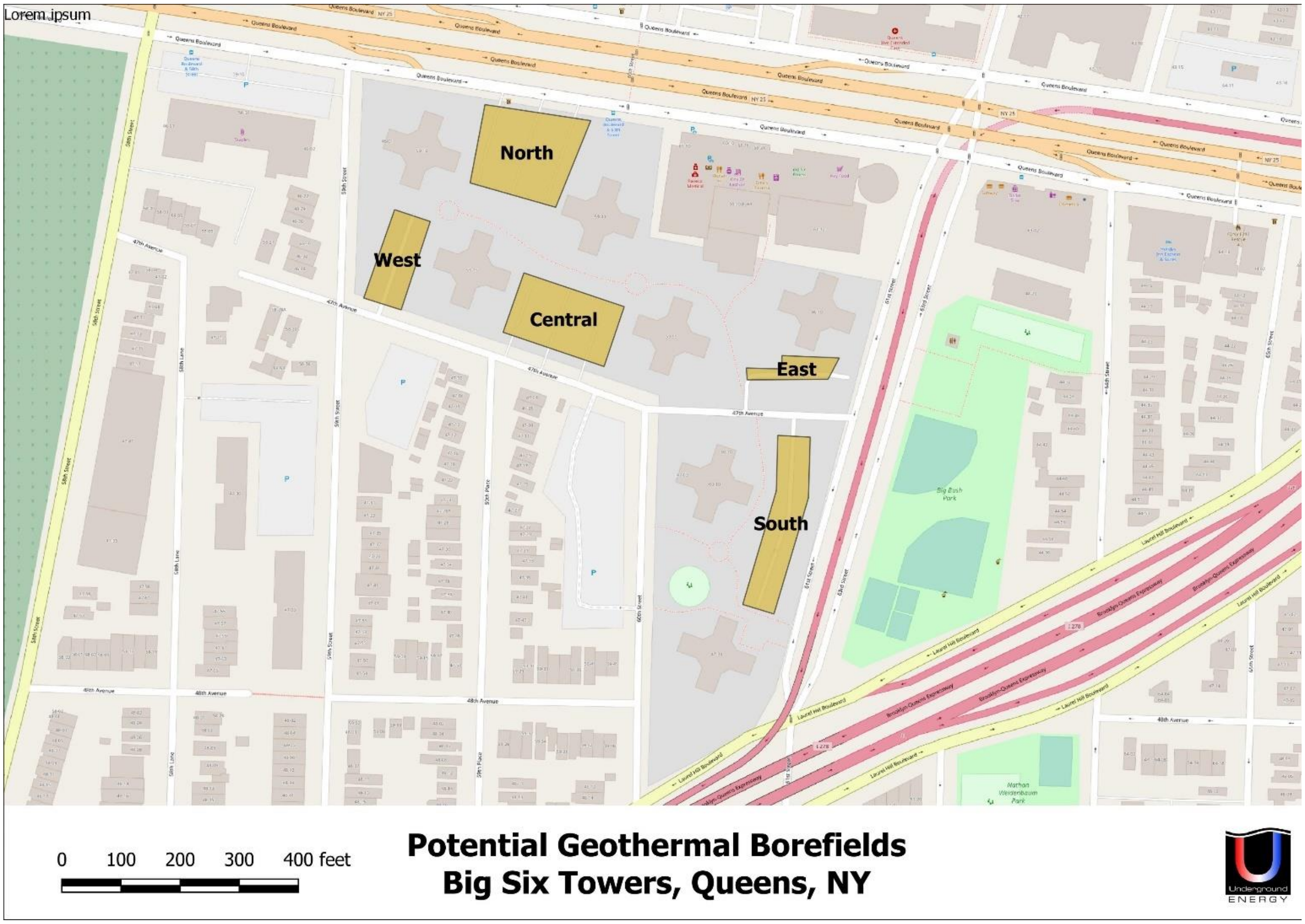

Figure 1 - Big Six Towers Site Plan and Potential Geothermal Borefields

2.0 Geothermal Conceptual Model

UE developed a screening-level Geothermal Conceptual Model (GCM) to systematically characterize ground conditions and subsurface heat transfer mechanisms at the site. This screening-level GCM involved a desktop study of online data.

2.1 Geology

2.1.1 Bedrock Geology

Estimated depth to bedrock depth at the site is 200 feet. The bedrock is mapped as the Hartland formation, a metamorphosed sedimentary rock of Cambrian age. The Hartland formation is comprised of quartz-feldspar schists, gneisses, amphibolites and marbles. A sample of the Hartland formation is shown in Figure 2.

Figure 2 - Hartland formation bedrock sample

2.1.2 Surficial Geology

The surficial geology at the site comprises:

- an estimated 100 feet of Pleistocene glacial deposits that may include highly variable amounts of outwash sand and gravel, clay and silt glaciolacustrine deposits, and dense, poorly sorted till. These deposits overlie
- a clayey deposit that extends to the bedrock surface at an estimated depth of about 200. This clay deposit is of upper Cretaceous age and is the upper member of the Magothy formation, which forms the Magothy aquifer further to the south and east.

2.1.3 Hydrostratigraphy

Figure 3 presents a hydrostratigraphic section that summarizes UE's estimation of ground conditions beneath the Big Six Towers site. Estimates of hydraulic conductivity and bulk thermal conductivity for each unit are included in Figure 3.

Depth (ft)	Hydrostratigraphic Description	Lithology	Est. Hydraulic Conductivity (ft/d)	Est. Thermal Conductivity (BTU/hr-ft-°F)
0 20 40 60 80	Glacial till and moraine deposits Low to moderate groundwater flux		0.1 - 10	1.1
100 120 140 160 180	Upper clay unit of Magothy formation Low groundwater flux in clay		0.01	0.9
200 220 240 260 280 300 320 340 360 380 400 420 440 460 480 500 520 540 560 580 600	Bedrock Hartland formation Low groundwater flux in bedrock fractures		0.01	1.5

Figure 3 – Generalized hydrostratigraphic section

2.2 Hydrogeology

No aquifers of sufficient thickness or transmissivity exist beneath the site. Therefore, open-loop geothermal or Aquifer Thermal Energy Storage is not feasible at this location.

Groundwater is expected to occur at shallow depths of less than 15 feet across most of the site, although subsurface utility inverts likely control groundwater elevation locally. Shallow groundwater flow direction in this area of Queens is toward the southwest, as indicated in Figure 4. Groundwater flux (the volume of groundwater that flows naturally across a unit area) is much higher in sandy shallow glacial deposits than in the low-permeability fine-grained deposits and crystalline bedrock at depth.

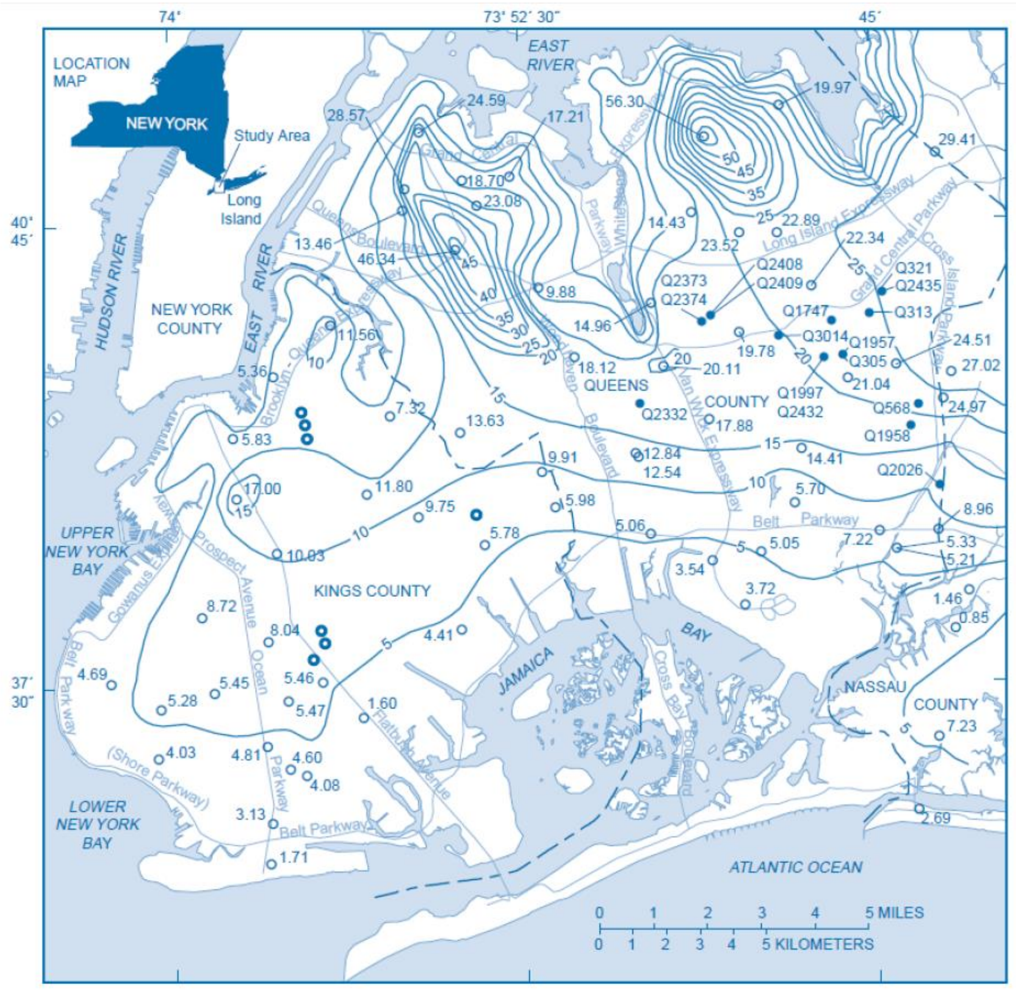

Figure 4 – Shallow groundwater contour map

2.3 Subsurface Thermal Properties and Heat Transfer

Estimated subsurface thermal properties are summarized in Table 1. UE did not find any thermal response test data specific to this site or to the Hartland formation. Therefore, our estimate of subsurface thermal conductivity is based on a bulk thermal conductivity value calculated by compositing the formation conductivity over the 0–500-foot depth interval. This is the depth interval in which borehole heat exchangers would be constructed.

Table 1 - Estimated subsurface thermal properties: 0-500-foot depth interval

Parameter	Value	Units
Ambient Ground Temperature	55-65	° F
Thermal Conductivity	1.3	Btu/(h·ft·°F)
Volumetric Heat Capacity	32	Btu/(ft^3·°F)
Thermal Diffusivity	0.98	ft^2/d

Heat conduction will be the dominant subsurface heat transfer mechanism at this site. Subsurface heat transport via advective groundwater flow is expected to be low in bedrock and in fine-grained deposits, and moderate in zones in sandy and gravelly zones within the glacial deposits.

3.0 Conceptual Ground Heat Exchanger Design

3.1 Building Loads

UE undertook the conceptual design of a closed-loop ground heat exchanger using the parking lots as small borefields as depicted in Figure 1. We used an estimate of aggregate building heating and cooling loads provided by Waldron. As shown in Figure 5, these loads are heating dominant, with about 46% more heating energy delivered per year than cooling energy.

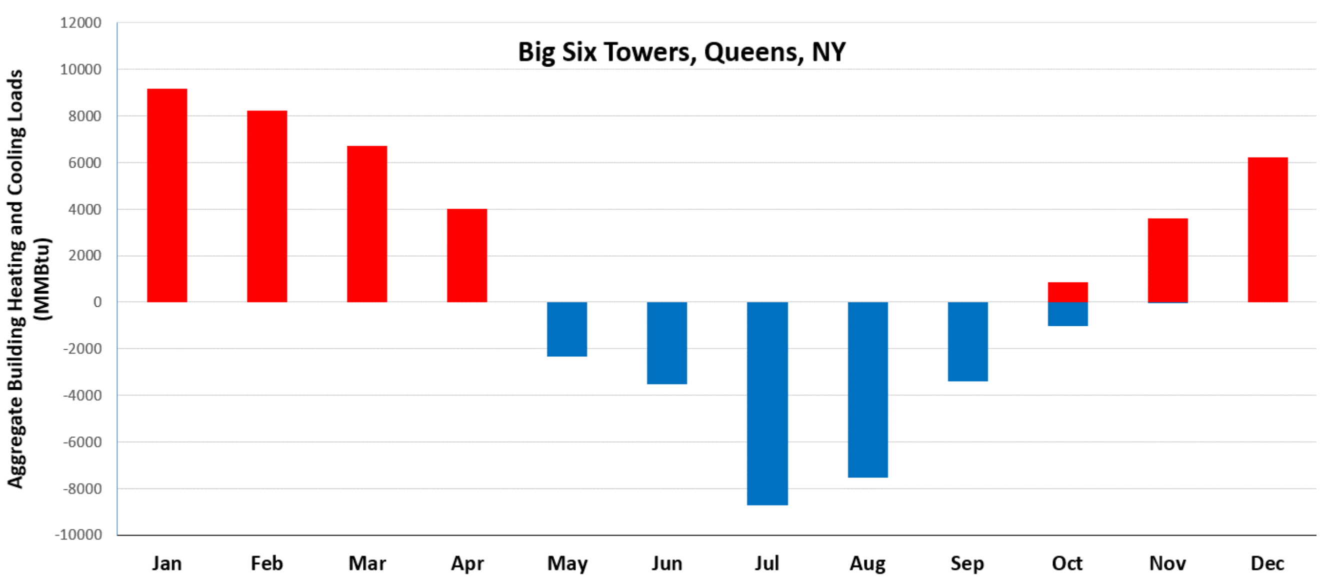

Figure 5 - Aggregate building thermal loads

However, assuming a heat pump Coefficient of Performance (COP) of 3.5 in heating mode and 5.0 in cooling mode, the loads at the ground heat exchanger are slightly cooling dominant, imbalanced by about 16%.

3.2 Borehole Heat Exchanger Concept Design

UE's conceptual design for the ground heat exchanger involves approximately 194 bores in the five areas shown in Figure 1. The geothermal bores and borehole heat exchangers will have the following properties:

- 499-foot deep bores (to avoid triggering the need for a mining permit for bores deeper than 500 feet);
- hexagonal grid layout with a 20-foot bore spacing;
- 1.25-inch HDPE pipe borehole heat exchanger with factory-fused U-bend; and
- grout thermal conductivity value of 1.2 BTU/h·ft·°F.

UE's conceptual design is based on a minimum BTES supply temperature of about 40 °F in heating mode. This would result in the ability to operate the BTES system without an antifreeze solution.

3.3 Simulation of Borefield Performance

UE used Earth Energy Designer (EED) software to simulate the performance of a 50-bore Borehole Thermal Energy Storage (BTES) system in the central parking lot. This parking area could accommodate about 50 bores spaced 20 feet apart in a 10 x 5 grid, therefore that is the borefield configuration selected for analysis in EED. The simulation used an ambient ground temperature of 60 °F along with the subsurface thermal properties in Table 1. The EED model for this BTES borefield simulation uses monthly thermal loads that represent 9% of the aggregate cooling loads depicted in Figure 5. We also balanced the thermal inputs at the ground heat exchanger by increasing the corresponding representative heating loads by 16%, to about 10% of the aggregate heating load. The annually-balanced monthly base loads used in EED simulation of the Central Parking Lot borefield are presented in Figure 6. Peak daily or hourly loads were not considered in this simulation; only monthly base loads. Figure 7 presents simulated BTES field supply temperatures after 10 years of operation.

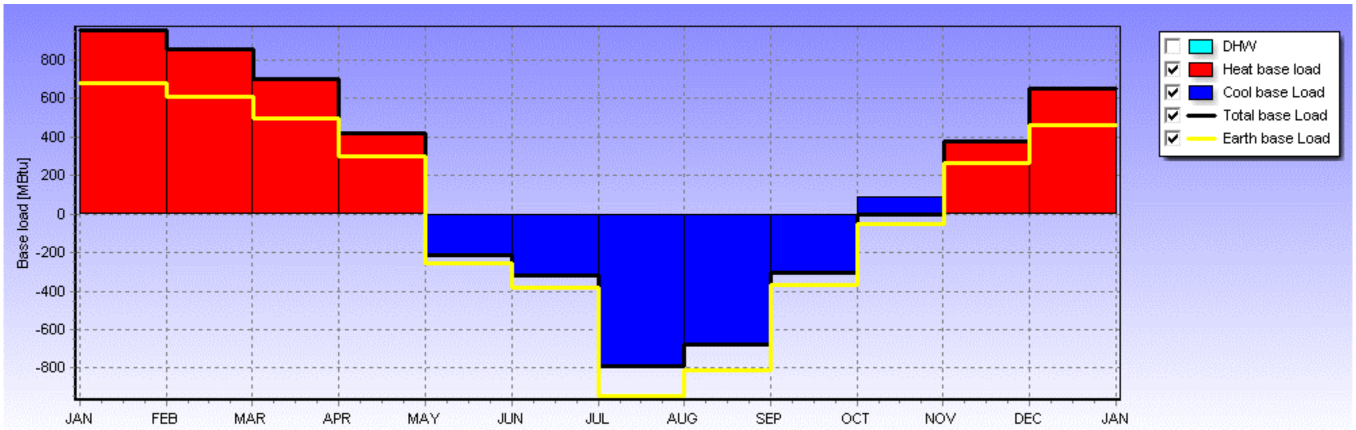

Figure 6 - Balanced loads used in simulation of central parking lot BTES

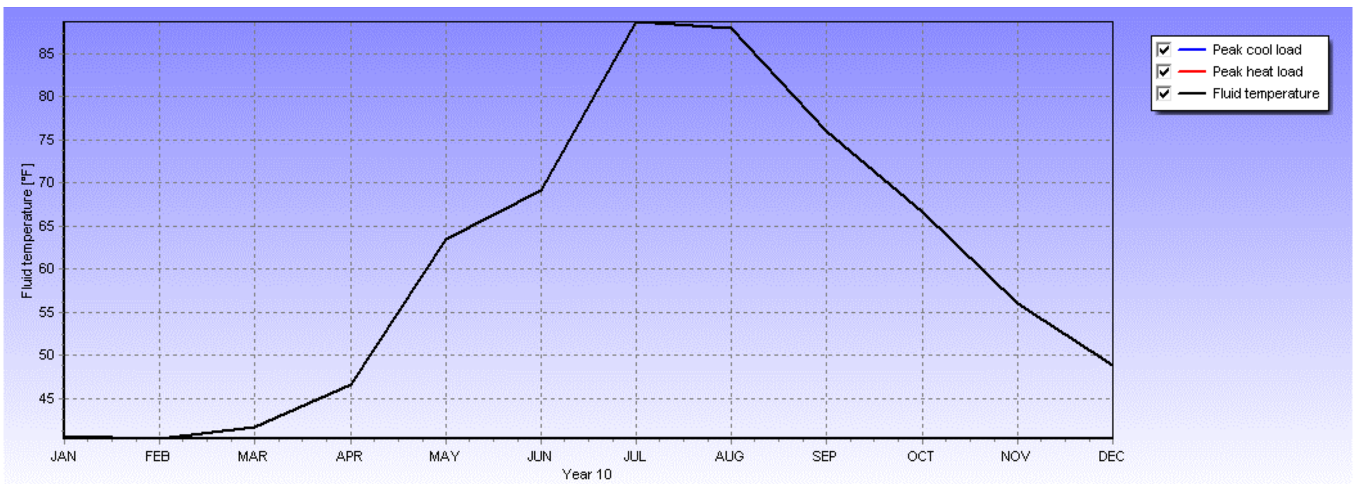

Figure 7 - Yearly supply temperatures from central parking lot BTES

We note that at the operating temperature range shown from about 40 °F to 89 °F, the BTES system would not require an antifreeze solution.

All EED input and output data are included in Appendix A.

4.0 Estimation of Thermal Capacity

The maximum monthly specific heat extraction calculated by EED for base-load heating is 123 Btu/h·ft at the end of January, while the maximum monthly heat injection rate is 170 Btu/h·ft at the end of July. With an overall bore length of about 24,950 ft, the central parking lot BTES has a base-heating-load thermal capacity of 3.1 MMBtu/h, while the base cooling load capacity is 353 tons.

UE performed a high-level analysis that extrapolated the central parking lot area simulation results to estimate base-load thermal capacity of other potential BTES borefield areas. A hybrid geothermal application at this site would use other heating and cooling means to meet peak demand, while the geothermal system would be operated within temperature parameters designed to provide a significant portion of reliable, base load geothermal energy. Table 2 presents the area and estimated base-load heating and cooling thermal capacity of the BTES field locations shown in Figure 1. These estimates are derived by extrapolating the simulation results from the central parking area to the other areas on a percentage-of-aggregate load per square-foot basis. The calculations used for this high-level analysis of campus geothermal potential are valid only for the ground conditions, load profiles and BTES design temperatures as described in this report.

Table 2 - Estimated thermal capacity of potential borefield areas

			Estimated Thermal Capacity	
Borefield	Area (ft^2)	No. Bores	% of Aggregate Cooling Load	% of Aggregate Heating Load
East	4500	11	2%	2%
North	24000	63	11%	13%
Central	19200	50	9%	10%
South	16600	43	8%	9%
West	10300	27	5%	6%
	74600	194	35%	41%

5.0 Capital Cost Estimate

UE developed a CAPEX estimate for geothermal drilling at the Big Six Towers utilizing a representative drilling cost in New York City from the document *Geothermal Heat Pump Manual – a design and installation guide for New York City*. That reference from 2018 provides a closed-loop cost of $35,000 per 400-500-foot bore, or $70 to $87.50/foot of bore, and typically includes the bore, borehole heat exchanger and manifold piping. Adjusting the mean value for inflation since 2018, we derive an installation cost of $98 per foot of bore. Accordingly, our CAPEX estimate is $9.5 million to install and manifold 194 bores in the parking areas identified in Figure 1.

6.0 Conclusions

UE's analysis has estimated subsurface hydrogeologic and geothermal conditions sufficiently to estimate performance of a 50-bore BTES borefield at the central parking lot. We extrapolated these results to other parking areas based on available area and number of geothermal bores that could potentially be installed. Our analysis concludes that 194 bores installed in the five different parking areas could meet about 35% of the aggregate cooling load and about 41% of the aggregate heating load, if other technologies were used for peak demand conditions. Our CAPEX estimate for this project is $9.5 million.

7.0 References

Soren, Julian, 1978, Subsurface geology and paleogeography of Queens County, Long Island, New York, USGS Water Resources Report 77-34.

Geothermal Heat Pump Manual – a design and installation guide for New York City, 2018, New York City Department of Design and Construction.

Appendix A

EED Design Report

Input file:C:\Users\markw\OneDrive\Desktop\UE\Projects\Waldron\Big Six Towers\data\EED\BIG SIX TOWERS V2.DAT
This output file: BIG SIX TOWERS V2.OUT Date: 7/13/2022 Time: 8:38:17 AM

MEMORY NOTES FOR PROJECT
[]

QUICK FACTS

Cost	-
Number of boreholes	50
Borehole depth	499 ft
Total borehole length	2.495E4 ft

D E S I G N   D A T A
=====================

GROUND

Ground thermal conductivity	1.3 Btu/(hÂ·ftÂ·Â°F)
Ground heat capacity	32 Btu/(ftÂ³Â·Â°F)
Ground surface temperature	60 Â°F
Geothermal heat flux	0 Btu/(hÂ·ftÂ²)

BOREHOLE

Configuration:	382 ("50 : 5 x 10 rectangle")
Borehole depth	499 ft
Borehole spacing	20 ft
Borehole installation	Single-U
Borehole diameter	6 inch
U-pipe diameter	1.66 inch
U-pipe thickness	0.15 inch
U-pipe thermal conductivity	0.24 Btu/(hÂ·ftÂ·Â°F)
U-pipe shank spacing	3.8 inch
Filling thermal conductivity	1.2 Btu/(hÂ·ftÂ·Â°F)
Contact resistance pipe/filling	0.01 (hÂ·ftÂ·Â°F)/Btu

THERMAL RESISTANCES

Borehole thermal resistances are calculated.
Number of multipoles 10
Internal heat transfer between upward and downward channel(s) is considered.

HEAT CARRIER FLUID

Thermal conductivity	0.57 Btu/(hÂ·ftÂ·Â°F)
Specific heat capacity	0.8 Btu/(lbÂ·Â°F)
Density	375.7 lb/ftÂ³
Viscosity	0.0015 lb/(ftÂ·s)
Freezing point	-1.5E-6 Â°F
Flow rate per borehole	5 US gal/min

BASE LOAD

Seasonal performance factor (DHW) 1
Seasonal performance factor (heating) 3.5
Seasonal performance factor (cooling) 5

Monthly energy values [MBtu]

Month	Heat load	Cool load	Ground load
JAN	955	0	682.1
FEB	857	0	612.1
MAR	701	0	500.7
APR	417	0	297.9
MAY	0	210	-252
JUN	0	316	-379.2
JUL	0	787	-944.4
AUG	0	677	-812.4
SEP	0	306	-367.2
OCT	88	93	-48.74
NOV	376	0	268.6
DEC	649	0	463.6
	-------	------	-------
Total	4043	2389	21.06

PEAK LOAD

Monthly peak powers [kBtu/h]

Month	Peak heat	Duration	Peak cool	Duration [h]
JAN	0	0	0	0
FEB	0	0	0	0
MAR	0	0	0	0
APR	0	0	0	0
MAY	0	0	0	0
JUN	0	0	0	0
JUL	0	0	0	0
AUG	0	0	0	0
SEP	0	0	0	0
OCT	0	0	0	0
NOV	0	0	0	0
DEC	0	0	0	0

Number of simulation years 10
First month of operation APR

C A L C U L A T E D V A L U E S
====================================

Total borehole length 2.495E4 ft

THERMAL RESISTANCES

Borehole therm. res. internal 0.68 (hÂ·ftÂ·Â°F)/Btu

Reynolds number 3.135E4
Thermal resistance fluid/pipe 0.003121 (hÂ·ftÂ·Â°F)/Btu
Thermal resistance pipe material 0.1306 (hÂ·ftÂ·Â°F)/Btu
Contact resistance pipe/filling 0.01 (hÂ·ftÂ·Â°F)/Btu

Borehole therm. res. fluid/ground 0.1411 (hÂ·ftÂ·Â°F)/Btu

Effective borehole thermal res. 0.1419 (hÂ·ftÂ·Â°F)/Btu

SPECIFIC HEAT EXTRACTION RATE [Btu/(hÂ·ft)]

Month	Base load	Peak heat	Peak cool
JAN	122.9	0	0
FEB	110.3	0	0
MAR	90.19	0	0
APR	53.65	0	0
MAY	-45.39	0	0
JUN	-68.31	0	0
JUL	-170.1	0	0
AUG	-146.3	0	0
SEP	-66.14	0	0
OCT	-8.78	0	0
NOV	48.38	0	0
DEC	83.5	0	0

BASE LOAD: MEAN FLUID TEMPERATURES (at end of month) [Â°F]

Year	1	2	5	10
JAN	60	43.05	41.29	40.6
FEB	60	42.29	40.96	40.31
MAR	60	43.38	42.33	41.69
APR	50.53	48.05	47.12	46.51
MAY	66.88	65	64.07	63.5
JUN	72.01	70.59	69.63	69.1
JUL	91.38	90.25	89.2	88.7
AUG	90.77	89.59	88.41	87.89
SEP	78.8	77.77	76.48	75.95
OCT	69.55	68.4	67.2	66.65
NOV	58.98	57.82	56.64	56.04
DEC	51.71	50.64	49.49	48.81

BASE LOAD: YEAR 10
Minimum mean fluid temperature 40.31 Â°F at end of FEB
Maximum mean fluid temperature 88.7 Â°F at end of JUL

PEAK HEAT LOAD: MEAN FLUID TEMPERATURES (at end of month) [Â°F]

Year	1	2	5	10
JAN	60	43.05	41.29	40.6
FEB	60	42.29	40.96	40.31
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MAY	66.88	65	64.07	63.5
JUN	72.01	70.59	69.63	69.1
JUL	91.38	90.25	89.2	88.7
AUG	90.77	89.59	88.41	87.89
SEP	78.8	77.77	76.48	75.95
OCT	69.55	68.4	67.2	66.65
NOV	58.98	57.82	56.64	56.04
DEC	51.71	50.64	49.49	48.81

PEAK HEAT LOAD: YEAR 10
Minimum mean fluid temperature 40.31 Â°F at end of FEB
Maximum mean fluid temperature 88.7 Â°F at end of JUL

PEAK COOL LOAD: MEAN FLUID TEMPERATURES (at end of month) [Â°F]

Year	1	2	5	10
JAN	60	43.05	41.29	40.6
FEB	60	42.29	40.96	40.31
MAR	60	43.38	42.33	41.69
APR	50.53	48.05	47.12	46.51
MAY	66.88	65	64.07	63.5
JUN	72.01	70.59	69.63	69.1
JUL	91.38	90.25	89.2	88.7
AUG	90.77	89.59	88.41	87.89
SEP	78.8	77.77	76.48	75.95
OCT	69.55	68.4	67.2	66.65
NOV	58.98	57.82	56.64	56.04
DEC	51.71	50.64	49.49	48.81

PEAK COOL LOAD: YEAR 10
Minimum mean fluid temperature 40.31 Â°F at end of FEB
Maximum mean fluid temperature 88.7 Â°F at end of JUL