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Notice

City of Buffalo Downtown Energy District Feasibility Study

Task 5 Report

Prepared for City of Buffalo, Department of Public Works, Parks and Streets

In Support of NY Prize Community Grid Competition: Stage 1 Feasibility Study

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TABLE OF CONTENTS

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TASK 5: FINAL REPORT

Background and Organization of the Report

This feasibility study was conducted by the City of Buffalo (COB) under an NY Prize Community Grid Competition – Stage 1 grant award. It consists of a description and assessment of an electric microgrid in the downtown Buffalo area that is documented within five task reports. The core feasibility study is organized according to the four core technical content tasks of the NY Prize Stage 1 Feasibility Assessment requirements, which are listed below:

Task 1. Description of Microgrid Capabilities
Task 2. Develop Preliminary Technical Design Costs and Configuration
Task 3. Assessment of Microgrid's Commercial and Financial Feasibility
Task 4. Develop Information for Benefit Cost Analysis

The work performed under each of these core tasks is summarized and detailed in a separate report, all of which are found in Appendices A-D of this Task 5 Final Report. Each core task report describes the assumptions used in the analysis and assessment. The input data, methodologies, and tools used for modeling in Tasks 2 and 4 are also outlined in those reports.

Observations and Findings

Microgrid Capabilities and Configuration

As proposed, the microgrid would incorporate all of the minimum capabilities spelled out in Task 1. All of the "preferable" capabilities will be incorporated as well, with several qualifications:

- Beyond delivery of premium resiliency for a fee, the innovative services that would be offered to end use customers will depend on the customer needs and interests that are to be identified during a later development stage of the project.
- The baseline design of the microgrid will not include carbon-free energy. However, the microgrid controller will be capable of incorporating customer-owned distributed energy resources (DERs), including carbon-free generation resources (e.g., photovoltaic power (PV), biodiesel power generation, or wind energy). This would be combined with information services that provide customers the opportunity to interact with the grid in an optimal manner.

The proposed microgrid possesses two unusual characteristics worthy of note:

1. Unlike most microgrids, which contain a group of buildings in a campus-like arrangement that operates in parallel with the grid, the buildings powered by the COB microgrid are directly fed by the utility feeder in both grid-connected and islanded modes. The customers purchase power from the utility under normal conditions and would purchase power from the microgrid during an outage. To form an island, the microgrid would use a point of common coupling on the utility feeder, somewhere "upstream" of the generation site, as well as at least one islanding point on the "downstream" side. Customers isolated by the downstream point(s) of islanding would only get their power restored when the microgrid reconnects with grid power and reopens those islanding points.

2. The City's district heating plant, which is co-located with the Fire Headquarters, is incorporated into the microgrid, but only as a load and not a generating resource. Except for the Fire Headquarters, the district heating customers are, in fact, located on a highly reliable secondary (mesh) network, rather than the radial-type network on which the microgrid resides.

Benefits and Value

The primary benefit for microgrid customers will be added resilience in the face of power grid outages. For customers that offer services, this resilience will help them avoid service-related losses that would occur without the microgrid's backup power.

If a customer has backup generation with a limited fuel supply, the microgrid will enable the customer's generator to serve as a second level of resilience and it will overcome the fuel storage limitations. Customers may prefer the microgrid because they do not have to start up a generator and keep it running. It also avoids their exposure to unpleasant and unhealthy emissions associated with many types of generators.

For customers that do not currently have on-site backup generation, having power be provided via the grid itself will save them the cost of acquiring (say, renting) and using a backup generator during an outage – if that is even feasible during the winter storm scenario envisioned in this study.

The microgrid will ensure better continuity of critical government services, including the services of the Fire Department Headquarters, Emergency Services, and the COB and County administrative offices. A number of these services are of particular importance during the weather and other emergencies that have affected power grid operation. This benefit is experienced by both the providers of the services and the citizens who are using them.

Several specific community or neighborhood benefits are contingent on the characteristics of customers that actually participate in the microgrid. All potential customers are situated on the National Grid feeder served by the microgrid (feeder 3765, also called "F3765" in this report). The potential customers include a school, church, grocery store, hardware store, health center, FBI office, TV station, post office, and several other commercial entities. In addition, three residential developments could be served by the microgrid.

The benefit-cost analysis (BCA) performed by Industrial Economics, Incorporated (IEc) did not evaluate the thermal resiliency benefits provided by the district heating plant to its customers. Several of those customers are City and County buildings that should be considered critical infrastructure, so the value of the thermal resiliency that the microgrid would enable during a winter storm is significant. This value should be considered explicitly in the next phase of evaluation and design.

Roadblocks, Challenges, and Potential Solutions

The original hope for a downtown Buffalo microgrid was to produce power for the buildings already served by the COB district heating plant (DHP). Discussions with National Grid revealed that every building on the heating loop, except for the building that houses the heating plant itself, [1] is located on their secondary network. Each of those buildings is prevented from exporting power by a network protector. A generation resource could be located at the FH/DHP without a network protector, but feeding power to the other DHP customers would require very expensive infrastructure and could ultimately even degrade the level of reliability instead of enhancing it. For this reason, the team chose to base the proposed microgrid on the radial feeder that serves the FH/DHP. Finding a reasonable and affordable solution to allow DHP buildings to be powered from the microgrid has not been ruled out, but currently there are no proposed solutions to be studied.

Feasibility-level financial analysis shows that it is very difficult for the City to achieve the desired 20-year payback on the proposed radial-feeder-based microgrid. Specifically, in order to achieve break-even the City would need to sell excess power (i.e., above that needed to meet the needs of the FH/DHP) to National Grid at approximately 90% of the retail tariff it pays for power. Selling exported power at the NYISO wholesale price – the current default price absent a negotiated alternative arrangement between COB and National Grid – would not allow the project to break even within the desired time horizon.

In order for the COB to sell power to National Grid at 90% of the City's current rate, the utility will have to agree to pay that rate. The current rules for onsite distributed generation specify a default export rate equal to the wholesale price of power, but they do permit the parties to agree to a Special Contract. However, the rules governing Special Contracts only address the case of discounts to utility-provided power. It is not clear at this time whether there are limitations to Special Contracts that would prevent the City from reaching the necessary level of revenue, assuming that National Grid would be willing to pay the required rate.

There are also rules that permit Community Distributed Generation (CDG) to sell power to end users, and net metering rules, but those do not currently apply to non-residential combined heat and power (CHP) units. A regulatory change would be needed allow COB to earn the additional revenue available to CDG facilities or generators that qualify for net metering. Such regulatory changes would be consistent with the ongoing REV proceeding in New York State and specifically the Distributed System Operator (DSO) role that National Grid has accepted as its future, but have not been specifically proposed at the time of this writing.

From the standpoint of *societal-level benefits*, the IEc analysis determined that 10.4 days of one continuous outage event per year would be required for the societal benefit to justify the cost of the microgrid. This is less than our design emergency event duration of 14 days, but this level of outage event would need to occur on a highly unlikely year-over-year frequency of occurrence for break-even societal benefits.

The 14-day time horizon was chosen to "future proof" the microgrid in anticipation of worsening climate change impacts and resulting anticipated increase in both severity and frequency of long duration outage resiliency events. It has little impact on the economics of the system under the currently contemplated business model. However, an alternative business model could be envisioned that involve member organizations paying the City a sort of "resiliency insurance premium" against their avoided outage

[1] We refer to that building as the "FH/DHP," as it houses the Fire Headquarters and the DHP. The Buffalo Emergency Services department is also located in this building.

losses, rather than a per-kWh charge. In that case, much more careful statistical analysis and forecasting of climate data would be necessary to set a reasonable “insurance policy premium” for the microgrid members while still enabling substantial or complete recovery of capital and operating costs.

The study did investigate PV, both with and without storage, in the context of supplying power during a winter storm outage resiliency event. For an outage period longer than several hours, a reasonable amount of energy storage cannot sufficiently compensate the intermittent nature of PV output with respect to providing grid resiliency. In addition, solar irradiance is particularly low in this region during the winter months and the snow and/or ice from a major storm would block power production, often entirely.

Unfortunately, even without storage, and with all PV output being exported to National Grid at the FH/DHP’s retail rate via net metering, the economics are not satisfactory for the inclusion of this carbon-free technology in the microgrid. The reasons for this are listed below:

- The cost of capital, which for this microgrid is assumed to equal 2% on the assumption of a municipal bond, must be considered.
- No incentives are available from either the utility or NYSERDA for a project of this size and type.[2]
- Solar irradiance in this region is relatively low.

These factors could be mitigated by an incentive or by a source of interest-free capital. It is also recognized that an independent PV project could be pursued by COB under National Grid’s existing net metering program. However, while such an independent project would exhibit different (likely more favorable) economics, it would also fall outside the scope of this microgrid study given that any PV investment must be considered and modeled in combination with an accompanying CHP operation as proposed in the microgrid configuration that is the subject of this study.

Additional Information to Be Developed

In various places throughout the reports for Tasks 1-4 we identify information that would have been helpful to have as input for the feasibility study but will not or cannot be determined or decided until a more detailed design study (or even later work such as construction planning) is performed. For reference, these information items are summarized below:

- <u>Customer-related</u>
    - Detailed electrical and thermal load profiles for all buildings included on feeder 3765
    - Energy commodity and related service needs of potential microgrid customers
    - Spatial extent and boundaries of islanded operation – which buildings, how many points of islanding and their location

[2] NYSERDA does offer the NY-Sun program, which grants incentives to commercial and industrial PV installations larger than 200 kW. However, that program is primarily designed to offset the use of grid-supplied electricity at a project location. DER-CAM modeling has shown that economic viability of the microgrid depends on the 500 kW CHP unit being allowed to supplant the use of grid-supplied power at the FH/DHP to the greatest possible extent, thus installation of PV at the site would exclusively be used for loads in front of the FH/DHP meter. Even if this were allowed under the program, installation of other on-site production equipment (as in this project) generally results in a downward adjustment of the incentive. For these reasons we chose to assume that the microgrid would not be eligible for a material incentive amount under this program.

- Terms of agreement with customers
- Monitoring methods for customer usage during an outage

- Interconnection (electrical and thermal)
    - Interconnection of CHP heat with the DHP plant
    - Reverse power flow issue identification, remediation and related costs (via coordinated electric system interconnection review (CESIR))
    - Final determination of needed infrastructure changes and upgrades
    - Communications backbone architecture
    - Protection systems needed on F3765
- Microgrid operation and control
    - Additional microgrid controller services to enable (load shedding, economic dispatch, load following, energy services, etc.)
    - Definition of scheduled and unscheduled intentional islanding scenarios to be served by the microgrid operator
    - Greater detail regarding microgrid operational scheme
    - Microgrid DER asset dispatch rules
- Project-related
    - Potential sources of financing, including private financing
    - Choice of legal and regulatory advisors for the project
    - Finalized list of permits and approvals needed
    - Design team for remaining of development phase
    - Potential project partners
- Utility relationship and regulatory issues
    - Relationship and roles between COB and National Grid
    - Regulatory issues related to selling to customers in an outage
    - Regulatory issues related to unique in-feeder topology
    - The price that National Grid will pay for power received from the microgrid in grid-connected status

Lessons Learned

Described below are some of the lessons we learned during the feasibility study.

Viability of CHP-based microgrids. In typical CHP deployments where the CHP unit is displacing a boiler and is similarly sized to economically meet thermal demand, the key to a successful CHP project hinges on having a high-return use for the incremental electrical output.

The overall combined energy efficiency of CHP is quite high, relative to the efficiency of traditional fossil fuel electric energy-only generating equipment. However, that combined efficiency is "split" between the electrical and thermal energy produced, and utilization of both value streams is necessary to achieve the benefit of this higher combined efficiency value. Based on the sale of thermal energy alone, CHP cannot compete with dedicated thermal generation equipment that typically exhibit thermal efficiencies in excess of 80%. Thus, a CHP unit that cannot sell its electrical energy at a reasonable price can only compete with a boiler when the cost of operating that boiler is extremely high.

More specifically, the financial viability of a set of assets that includes CHP is a dynamic balance between the value of displaced electric energy now produced by the CHP output, the price of CHP electricity being sold to microgrid customers, the cost of natural gas (if that is the fuel), and the efficiency and cost of other thermal generating equipment:

- The electrical savings and/or earnings must counterbalance the higher price of the CHP's heat output compared to existing thermal alternatives.
- On the other hand, depending on the potential for electrical savings and/or earnings, there can be situations in which operating the CHP without having a concurrent use for the heat output is less economical than shutting down the CHP and purchasing grid power instead.
- Ensuring that this balance results in neutral or positive return affects the operating schedule of the CHP, sometimes on a fairly granular time scale. For example, DER-CAM predicts that strictly operating for optimum return can result in ramping output drastically up and down over the course of an hour. It can be difficult and/or impractical to operate the CHP unit optimally in such situations.
- Having a contribution from a rebate or other incentive program is another important factor in the viability of the CHP.

<u>Benefits and costs,</u>

- The BCA methodology employed for a project should account for providing resiliency to heating (and/or electrical) loads that are generation resources in their own right with associated benefits. For example, the DHP is a heating load for the proposed microgrid, but its enhanced resiliency imparts additional resiliency to its own thermal energy customers. Thus, the COB microgrid should be credited with providing resiliency to the DHP's customers.
- BCA results can be sensitive to input assumptions that carry a great deal of uncertainty. In the present analysis, the number and cost of backup generators assumed during an extended outage was a significant factor in the analysis results. In one scenario it was assumed that, without the microgrid, several residential buildings would rent individual generators for each apartment. This led to a significantly higher cost than renting a smaller number of shared large generators, which created a large avoided cost that was credited to the microgrid. At this feasibility level of analysis it was in fact not clear which of the alternatives would be chosen for the residential buildings, or if generators would be rented at all.

<u>Feeder configuration and topology.</u> As noted above, the electrical topology of the proposed microgrid is different from the typical grid-parallel campus-like microgrid. The microgrid, which we have labeled as an "in-feeder" type in the Task 3 report, might even be characterized as a grid-series arrangement of loads

and feeder instead. There are several important implications of this difference, which are summarized below:

- As previously mentioned, this configuration can result in more than one point of common coupling (POCC) with the power grid. A single POCC is only possible when one end of the group of buildings being islanded is at the farthest point of the feeder and there are no side branches that need to be isolated from the microgrid. Otherwise, at least two POCCs are needed, and when there are side branches or non-contiguous groups of buildings to be included in the island there can be a need for even more than two islanding points. This adds significant expense and complexity, from both a circuits and an operational point of view, to the project.
- Customers that are isolated by the downstream point(s) of islanding can only get their power restored when the microgrid reconnects with grid power and reopens those islanding points. It is not clear whether this is permitted under current regulations, or is otherwise acceptable to regulators, the utility, or the "stranded" customers.
- Other regulatory issues related to this topology need clarification, for example: (a) whether the proposed microgrid can be characterized as operating "in parallel" for the purposes of interconnection requirements, and (b) the applicability of different regulations governing distributed generation.

Recommendations

There are many remaining uncertainties related to the proposed microgrid. We recommend the following preliminary steps to clear the way for a definitive determination on carrying out the project:

1. The foremost uncertainty is whether the price of exported power can be set high enough to make the microgrid financially viable. The team should work with National Grid and legal and regulatory experts to resolve this issue, at least to the point of a preliminary understanding among stakeholders, prior to any further development efforts. This could either require a CESIR study to be performed for National Grid to be willing to commit to a potential arrangement with the City, or a tentative agreement could be reached pending a good outcome of a CESIR to be performed later.
2. If that hurdle can be overcome, the valuable resiliency benefits that would be realized for so many critical infrastructure buildings in the downtown area could make further investigation worthwhile. However, a more thorough analysis of the value of avoiding outages for the critical infrastructure would be warranted, with additional data collected to reduce the uncertainty of many input factors to the analysis (load, backup generation, avoided losses due to service continuation, etc.).
3. The microgrid could be found to be of sufficient value just for the resiliency it provides the FH/DHP and the DHP's customers, but it might also be clear that additional participation is needed to make the value proposition compelling. If the right group of customers can be found on F3765, the opportunity would be available for providing extended resiliency at a community level. The next step would thus be to connect with potential customers in order to understand their needs and constraints, whether there are services other than outage support that they might be interested in purchasing, and whether they are interested in participating in the microgrid.

With all of the above information the COB could then enter into a more concentrated level of development, perhaps by conducting a stand-alone preliminary design basis study or alternatively by entering the full design phase.

APPENDIX A: TASK 1 – DESCRIPTION OF MICROGRID CAPABILITIES

TABLE OF CONTENTS

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Task 1: Description of Microgrid Capabilities

This document describes the capabilities of a microgrid proposed by the City of Buffalo to meet the resiliency needs of a cluster of buildings in downtown Buffalo, NY. We refer to the project here as “COBD” (City of Buffalo Downtown).

The Present Situation

The City of Buffalo has a District Heating Plant (DHP) that is co-located with the City’s Fire and Emergency Services Headquarters in a single building (abbreviated here as the “FH/DHP” building). The DHP is fueled by natural gas and meets the heating needs of the FH/DHP building and supplies hot water or steam to five other buildings in the downtown district as well.

The FH/DHP building is located on National Grid’s radial feeder 3765 (referred to here as “F3765”). The entities within the FH/DHP complex share a single electric meter. The complex currently has two backup diesel generators, with capacities of 250 kW and 200 kW. Both generators are activated via an automatic transfer switch (ATS) when F3765 goes down.

The other buildings on the District Heat network are electrically connected to a National Grid mesh power network, rather than F3765 or some other radial feeder. The mesh network provides high reliability because every building in the network enjoys access to multiple feeders. Therefore, if a single feeder becomes unavailable its loss does not interrupt electric supply to any of the customers.

However, because F3765 is a radial feeder, when the feeder goes down the supply of power to the FH/DHP complex is interrupted. Because the Fire and Emergency Headquarters, and DHP are critical facilities, they require greater reliability than can be provided by a radial feeder.

Project Goals and Microgrid Options

The primary goals of the COBD project are to:

- Improve the resilience of the FH/DHP complex,
- Improve the resilience of all buildings served by the DHP, and
- Improve the financial viability of the DHP.

The study team first considered the feasibility of a microgrid that would cover all six buildings served by the DHP. This option would have required that the microgrid straddle and utilize National Grid mesh network, since the microgrid’s off-grid operation would require use of the distribution lines that belong to the mesh network. Discussions with National Grid ruled out the possibility of using the mesh network to provide off-grid microgrid connectivity, for several reasons. Primary among those is the fact that network protection devices prevent each building on the mesh network from supplying power to the grid. Overcoming this limitation would require a highly complex and expensive solution, one that could actually reduce the reliability of the downtown mesh power network.

The team then discussed an alternative microgrid solution with National Grid, encompassing the FH/DHP plus some or all of the other buildings that connect to F3765. The preliminary discussion with National Grid uncovered no major technical barriers to this alternative approach. The following near-term load forecast information was provided by National Grid for feeder F3765:

- The projected maximum (i.e., peak) load on F3765 in 2017 is 922 kW,
- Using a guideline supplied by National Grid, for feasibility purposes the minimum load on F3765 in 2017 should be considered to be 184 kW, and
- The design capacity of F3765 is 1,917 kW (266 Amps at 4.16 kV).

The FH/DHP building will serve as the anchor facility of the microgrid. This would provide disaster resilience to the FH/DHP complex and, to an extent, to the five other buildings served with thermal energy by the DHP. In addition, the proposed microgrid can serve some of the other buildings connected to F3765.

The team considered five initial microgrid concepts for providing benefit to F3765 via the installation of Distributed Energy Resources (DERs). The concepts are described in Table 1 below. All of them involve the installation of a Combined Heat and Power (CHP) unit in the FH/DHP building. The CHP unit would use natural gas as fuel to simultaneously generate electricity and useful heat. The heat would be used to support the District Heat system in one of several ways, such as producing hot water, preheating the water fed to the DHP boilers, or producing steam.

In addition, about 20,000 square feet of space appears to be available for a Photovoltaic (PV) installation on the FH/DHP roof. This might suffice for roughly 200 kW peak PV electrical power. If the Distributed Energy Resources Customer Adoption Model (DER-CAM) analysis finds PV and electric storage economical, those DERs will also be included.

The five initial concepts were screened down to two through a number of team discussions. The seven principal criteria considered in the screening process are listed below:

1. Being technically feasible (e.g., mesh network and reverse power issues, ability to island during a grid outage)
2. Providing sufficient power to generate value, while also having enough load to use the power generated
3. Presence of critical buildings on the microgrid
4. Ability to provide resiliency to the potential customers
5. Order of magnitude of cost (e.g., requires much costly equipment, requires installation of new underground cables)
6. Compatibility with the DHP system
7. Impact on the efficiency and cost of running the DHP system

Ultimately, the two concepts chosen for the feasibility analysis were the Feeder Minimum (Option 2) and Feeder Peak (Option 3) options (see Table 1). The sections that follow address the NYSERDA minimum capabilities and the NYSERDA preferred capabilities with respect to these two concepts.

Table 1. Initial Microgrid Concepts Considered For This Study

CHARACTERISTIC	CONCEPT				
	Nominal (1)	Feeder Minimum (2)	Feeder Peak (3)	Feeder Capacity (4)	DHP Thermal (5)
Basis for CHP capacity[3]	Supply FH/DHP electrical load at least for 80% of the time	Supply minimum electrical load of feeder F3765	Supply historical capacity electrical load of feeder F3765	Supply electrical capacity of feeder F3765	Supply entire thermal load of the existing District Heat Plant (DHP)
Grid-connected operation	• Powers FH/DHP load • Heat is used for district energy	• Powers FH/DHP load and loads in feeder F3765 • Heat is used for district energy	• Powers FH/DHP load and loads in feeder F3765 • Excess power exported to station 37 • Heat is used for district energy	• Powers FH/DHP load and loads in feeder F3765 • Excess is exported to Station 37 • Heat is used for district energy	• Powers FH/DHP load and loads in the downtown mesh network, via Elm Street Station • Heat is used for district energy
Islanded operation	FH/DHP load	FH/DHP load and possibly 1-2 buildings near FH/DHP	All or a large number of loads on F3765	All loads on F3765	FH/DHP load and many loads in downtown network
Reverse power issue?	No	No	Yes – at times[4]	Yes – always	Undetermined but likely
Load shedding when islanded?	Yes – within FH/DHP	Yes – within feeder F3765	No	No	No
Approximate electrical rating[5]	100 kW	184 kW	922 kW maximum	1,920 kW	8,000-11,000 kW
Other DERs (subject to analysis results)	PV and electric storage (size to be determined by analysis)	PV and electric storage (size to be determined by analysis)	PV and electric storage (size to be determined by analysis)	PV and electric storage (size to be determined by analysis)	PV and electric storage (size to be determined by analysis)

[3] "FH/DHP" is the building in which Buffalo Fire Headquarters, Emergency Services, and the District Heating Plant are located. "F3765" is National Grid's feeder 3765, a feeder sourced at Station 37.
[4] The specific instances in which the export power to feeder F3765 would create reverse power issues for National Grid would be determined during a Coordinated Electric System Interconnection Review (CESIR) study. The CESIR study would be performed once a specific microgrid proposal is developed.
[5] Ratings for Options 2-4 are estimates based on available information from National Grid. Option 1 rating is based on an assumption that the 20th percentile load is 100 kW. Option 5 rating is based on existing DHP capacity of 54.4 mmBtu/hr (boiler ratings of 625 BHP and 1,000 BHP).

CHARACTERISTIC	CONCEPT				
	Nominal (1)	Feeder Minimum (2)	Feeder Peak (3)	Feeder Capacity (4)	DHP Thermal (5)
Connection	Feeder F3765 (4.16 kV)	Feeder F3765 (4.16 kV)	Feeder F3765 (4.16 kV)	Feeder F3765 (4.16 kV)	Elm Street Station (multiple 23 kV feeders)
Challenges	• Does not create much value	• Interface to and operation on feeder F3765 • Expensive load shedding schemes during islanded operation • Coordination with utility for point of islanding and reconnection	• Interface to and operation on feeder F3765 • Contract agreement with utility to accept power export • Expensive CESIR interconnection study • Modifications to feeder/station 37 to allow reverse power flow	• Interface to and operation on Feeder 3765 • Contract agreement with utility to accept power export • Expensive CESIR interconnection study	• Large, lengthy new underground cable must be installed • Changes classification of CHP to Independent Power Producer (IPP) • IPP status entails greater regulations, cost, and load uncertainty
Result of screening process	**Rejected:** • CHP is likely not able to fully support FH/DHP critical load under many conditions	**Chosen for analysis**	**Chosen for analysis**	**Rejected:** • Significantly oversized with respect to resiliency of FH/DHP and feeder F3765 users • Greater modifications to feeder/station 37 to allow significant reverse power flow	**Rejected:** • Lengthy, highly expensive new underground cable is required to ship power to the Elm St. Station • Significant costs and drawbacks of IPP status

Sub Task 1.1 – Minimum Required Capabilities

As described above, only the Feeder Minimum and Feeder Peak concepts are considered in this feasibility analysis. Each of the minimum required capabilities for the two concepts selected for further analysis is discussed in turn below.

Table 1.1-A. Summary of Minimum Required Capabilities

Attribute	Minimum Capability	Addressed?	Description / Comment
Serves critical facilities	At least one, preferably more, physically separate	✓	FH/DHP plus several other government buildings
Generation sources	More than just diesel-fueled	✓	Natural gas, diesel, PV
Connection modes	Both grid-connected and islanded modes, using combination of resources	✓	As specified
Intentional islanding	Able to form intentional island	✓	Both planned and unplanned
Response to loss of utility source	Automatically separate from grid	✓	As specified
Response to normal power restoration	Automatically restore to grid	✓	As specified
Scheduled maintenance	All generation complies with manufacturer requirements	✓	Operating strategy to be optimized using DER-CAM.
24 x 7 utilization	Intermittent renewables need proper generation and/or storage	✓	Storage and/or backup generators
Grid-connected mode	Follow load, maintain grid V and frequency	✓	As specified
Islanded mode	Follow load, maintain V to ANSI C84.1	✓	As specified
Communication and control	2-way between microgrid and local distribution utility; automated, seamless integration	✓	As specified
Security and privacy	Secure and private control, communications, and data	✓	As specified
Diversity of customers	Critical facilities vs. other customer types; demand and load profiles	✓	Critical and non-critical. Government, commercial, residential, and institutional
Fuel supply	Uninterruptible or one week on-site	✓	Natural gas (highly reliable in severe weather)
Resilience	Critical facilities and generation resilient to typical/highest-risk forces of nature	✓	Underground power grid, sheltered equipment
Black start capability	Required	✓	As specified

The NYSERDA Task 1.1 questions and requirements are addressed in turn below. The text of each, highlighted in blue, is taken from the NYSERDA Statement of Work.

a. Serves at least one, but preferably more, physically separated critical facilities located on one or more properties.

NY Prize defines “critical infrastructure” to mean “systems, assets, places or things, whether physical or virtual, so vital to the State that the disruption, incapacitation or destruction of such systems, assets, places or things could jeopardize the health, safety, welfare or security of the state, its residents or its economy.”[6] NYSERDA Report 14-36 elaborates that such buildings include fire, police, and other emergency department buildings, government administration buildings, hospitals, pollution control facilities, and schools.

The FH/DHP complex is clearly critical infrastructure whose continued operation must be assured in the face of a loss of electric power. In addition, the DHP serves the thermal needs of five other buildings within the Downtown district:

1. Buffalo City Hall
2. Buffalo City Courthouse
3. Erie County Family Court building
4. Edward A. Rath County Office Building
5. Old City Court building (privately owned now)

All but the last are buildings that house government administration activities. We expect that all, or most, of them thus fall into the category of critical infrastructure.

The Feeder Minimum option ensures that the critical FH/DHP facility will have sufficient power to operate during a grid-down event. It also makes certain that the DHP will have electrical power to sustain its operation, ensuring that the six buildings on the district heating loop have their thermal needs met in full during a power outage.

The Feeder Peak option covers everything that Feeder Minimum does, and in addition ensures the following:

- All or a large number of loads in buildings served by the feeder F3765 are provided power, even when grid is down.
- The microgrid can earn revenue for power exported to F3765 during both on-grid and off-grid operation.

b. The primary generation source capacity cannot be totally diesel-fueled generators.

The options proposed here include the use of the following DERs:

[6] http://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/FAQs#critical-facility

- Natural gas fueled combined Heat and Power generators (e.g., micro-turbines, internal combustion engines),
- Existing diesel generators (e.g., for black start), and
- Solar photovoltaics (PV).

This analysis uses the Distributed Energy Resources Customer Adoption Model (DER-CAM), an economic and environmental model of customer DER adoption. The model has been in development at Lawrence Berkeley National Laboratory since 2000. The objective of the model is to minimize the cost of operating on-site generation and combined heat and power (CHP) systems, either for individual customer sites or for a microgrid. The DER-CAM model of the microgrid will determine the best technology mix and the capacities of the microgrid components.

c. A combination of generation resources must provide on-site power in both grid-connected and islanded mode.

Both options meet this requirement, as described above.

The electrical and thermal needs of the COBD community are being analyzed using the DER-CAM tool and will be described in Task 2. The following factors were considered for the COBD community with respect to grid-connected and islanded operations:

- Generating capacity requirements,
- DER optimization,
- The generation and load-serving plan,
- Performance targets and community objectives, and
- Business drivers.

d. Must be able to form an intentional island.

In both concepts (Feeder Minimum and Feeder Peak), an intentional island can be formed by disconnecting some or all of feeder F3765 from National Grid. The microgrid will be manually energized once F3765 has been disconnected from the grid.

The following scenarios will be evaluated in detail during the microgrid design stage:

- **Planned intentional islanding**
  - *Commanded planned islanding* – When the connection between National Grid and the microgrid is broken on purpose, whether in view of an impending emergency situation or in a test situation.
  - *Scheduled planned islanding* – A scheduled tariff transition or operating agreement dictates that the microgrid transition to an islanded mode at a specific time.
- **Unplanned/unscheduled intentional islanding** – Supported by the microgrid controller (the electronic control system for the entire microgrid), this function consists of two scenarios:

- *Outage-driven unplanned islanding* – A confirmed grid outage is detected by the recloser or switch at the Point of Common Coupling ("PCC"), which would open and start the unplanned/unscheduled islanded mode transition. The microgrid will automatically disconnect from the main grid in case of power loss in the grid. It will automatically reconnect when main grid power is restored.
- *Command-driven unplanned islanding* – A triggering event is detected by the monitoring platform that initiates the island recloser or switch at the PCC to open and start the unscheduled islanding transition. Alternatively, National Grid's operation center receives notification of the triggering event(s) and works with the Grid Operator to use the distribution management system (DMS) or supervisory control and data acquisition (SCADA) controller to open the recloser.

e. Must be able to automatically separate from grid on loss of utility source and restore to grid after normal power is restored.

As mentioned above, the microgrid will automatically disconnect from the grid when utility power is lost and will automatically reconnect when normal grid power is restored. The microgrid controller will perform a transition from grid-connected to islanded mode, and resynchronization with the grid, under intentional as well as unintentional islanding scenarios. The microgrid controller will ensure that the following necessary functions are available: voltage regulation, frequency regulation, protection coordination, and black start.

The microgrid controller will include the following technical and functional requirements of the U.S. Department of Energy Funding Opportunity Announcement (DOE FOA) 997[7] functionality requirements:

- Requirement C.1: Island Operation – Disconnection: Electric Power System (EPS) Point of Common Coupling (PCC) voltage/frequency controlled according to modified version of procedure in Institute of Electrical and Electronics Engineers (IEEE) Standard 1547.1
- Requirement C.2: Resynchronization and Reconnection
- Requirement C.3: Steady-State Frequency Range, Voltage Range, and Power Quality
- Requirement C.4: Protection
- Requirement C.5: Dispatch, and
- Requirement C.6: Enhanced Resiliency

f. Must comply with manufacturer's requirements for scheduled maintenance intervals for all generation; plan on intermittent renewable resources that will be utilized toward overall generation capacity only if paired with proper generation and/or energy storage that will allow 24 hours per day and 7 days per week utilization of the power produced by these resources.

[7] In partnership with National Grid, EPRI was awarded a $1.2 million grant to develop a commercially-viable standardized microgrid controller to complement, and enhance, the feasibility of an urban, community microgrid at the Buffalo Niagara Medical Campus (BNMC).

Generation equipment will comply with required maintenance schedules as specified by manufacturers. These schedules and associated maintenance costs are taken into account in the DER-CAM models being run to derive the best operating strategy for each DER asset. DER-CAM produces an operating strategy in which:

- Load and generation are in balance at all times, taking into account output variability and the ramping and discharge rates of the generation and storage,
- Economic return is maximized, and
- Overall project costs and risk are minimized.

The microgrid will comply with the IEEE 2030.7 requirements and standards listed in Table 1.1-B below.

Table 1.1-B. Standard Microgrid Functions for Integration within COBD Community.

Grid-Tied Functions	Islanded Functions

Grid Services
- Connect/disconnect (non-islanding)
- Utility SCADA and DMS coordination
- Connectivity and interface with power flow models, utility DMS and Distributed Energy Resource Management Systems (DERMS)
- Market interface for capacity, energy, and ancillary services
- kW availability at any given moment in time
	Microgrid Services
	- Disconnection
	  o Intentional, planned (scheduled, command)
	  o Intentional, unplanned (unscheduled)
	  o Unintentional, unplanned
	- Resynchronization
	- Voltage and frequency control
	- Grid configurations/operations
	- Isochronous/droop operations
	- Protection
	- Black start
	- DER anti-islanding (within the microgrid)
	- Market interface for capacity, energy, and ancillary services

Local Services (Optimization)
- Load, weather and price forecasting
- Energy management and dispatch
  o Max generation level control
  o Power quality (PQ), outage, fault detection
  o Voltage regulation
    ▪ Volt/VAR management and power factor (PF) control
    ▪ Power (Volt/Watt or frequency/Watt) curtailment/control
    ▪ Power smoothing
- Distributed generation (DG), storage, load management
- Voltage and frequency ride-through
	Local Services (Optimization)
	- Load, weather and price forecasting
	- Energy management and dispatch
	  o Max generation level control
	  o Load and generation following
	  o PQ and reliability
	  o Voltage regulation
	    ▪ Volt-VAR management and PF control
	    ▪ Power (Volt/Watt or frequency/Watt) curtailment/control
	    ▪ Power smoothing
	- DG, storage, load management

Grid-Tied Functions	Islanded Functions
Operator Services	Operator Services
– State/status monitoring	– State/status monitoring
– Communication with system operator (DSO/ISO/RTO)	– Communication with system operator (DSO/ISO/RTO)
– User interface and data management	– User interface and data management
– Billing	– Billing
– Event logging	– Event logging

g. Generation must be able to follow the load while maintaining the voltage and frequency when running parallel-connected to grid. It also needs to follow system load and maintain system voltage within ANSI c84-1 standards when islanded.

The DER portfolio selected for the feasibility study conforms to the requirements tables for islanded steady state operation:

- Maintains frequency in the range 59.3 Hz < f < 60.5 Hz, a range consistent with the frequency range for an area EPS and suitable for most loads.
- Maintains voltage according to ANSI 84.1-2006 standards, specifically the required voltage range for microgrid islanded steady-state operation of 0.95 pu < V < 1.05 pu at the PCC.
- Maintains power quality at the PCC in compliance with customer-specific requirements.

Preliminary analysis of the current and future DER portfolio will consider which DER assets need and/or are able to be paralleled with the grid (or if subsequent retrofits are required in order to achieve such functionality).

h. Include a means for two-way communication and control between the Community Grid owner/operator and the local distribution utility through automated, seamless integration. Include processes to secure control/communication systems from cyber-intrusions/disruptions and protect the privacy of sensitive data.

The microgrid controller selected for this project will guarantee these communication and control functions. Industry standards for communications will be implemented, using the following EPRI report as a reference: "Grid Interactive Micro-grid Controllers and the Management of Aggregated Distributed Energy Resources (DER): Relationship of Micro-grid Controller with Distributed Energy Resource Management System (DERMS) and Utility Distributed Management System (DMS)."

i. Provide power to critical facilities and a diverse group of customers connected directly to the microgrid—diversity should apply to customer type (e.g. residential, small commercial, industrial, institutional, etc.) and overall demand and load profile.

The microgrids proposed in Feeder Minimum and Feeder Peak concepts will serve the critical-infrastructure FH/DHP building. Another critical facility, the Federal Bureau of Investigation, is situated immediately next to the FH/DHP building and could be supplied power by the microgrid. Non-critical buildings that can be served by the microgrid include all or a number of the other buildings connected to feeder F3765. Those buildings, of various sizes, belong to many different types of customers, including commercial, institutional, and residential.

j. Must include an uninterruptible fuel supply or minimum of one week of fuel supply on-site.

The natural gas delivery system has historically demonstrated very high reliability, and it is not susceptible to the types of severe weather phenomena typically seen in this region, namely snow, ice, and wind storms. In the event of a grid outage, it is extremely unlikely that natural gas delivery would simultaneously be interrupted. Thus, in the event of a power outage, natural gas delivery pipelines delivering fuel to the CHP unit are unlikely to be interrupted.

Solar photovoltaics coupled with storage were also included as secondary sources of generation during islanded modes of operation.

k. Demonstrate that critical facilities and generation are resilient to the forces of nature that are typical to and pose the highest risk to the location/facilities in the community grid. Describe how the microgrid can remain resilient to disruption caused by such phenomenon and for what duration of time.

The entire electrical distribution infrastructure of feeder F3765 is underground, as is the thermal piping network for the DHP. The CHP plant, DHP, and electric storage are sheltered within the FH/DHP building.

The PV panels will be exposed to the elements, and thus vulnerable to severe weather. However, PV is a secondary source of power generation on this microgrid, and its survival is not critical to continued islanded operation of the microgrid.

l. Provide black-start capability

As resiliency is one of the key goals of the COBD microgrid, the system will have black-start capability. This feature will be enabled from existing back-up generation and/or the DER portfolio.

Motor starting is also important for black-start capability. If required, additional controls will be acquired for larger motors to protect against cold-load pickup issues, including excessive inrush current, during microgrid re-energization.

Sub Task 1.2 – Preferable Microgrid Capabilities

Table 1.2-A. Summary of Preferable Microgrid Capabilities

Attribute	Preferred Capability	Addressed?	Description / Comment
Advanced, innovative technologies	E.g., microgrid logic controllers, smart grid, smart meters, distribution automation, storage	✓	Microgrid controller; energy storage.
Active network control system	Optimizes demand, supply, network operations	✓	As specified. Automatic asset dispatch. Adaptive objectives during extended islanding.

Attribute	Preferred Capability	Addressed?	Description / Comment
Energy efficiency options	Minimize new generation requirements	✓	CHP and PV are efficient generation. Intelligent dispatch.
Connection to electric system	Address installation, O&M, and communications	✓	Will employ open communications standards
Innovative customer services	Coordinate with REV for service delivery platform	✓	As specified
Cost-benefit analysis	Account for at least utility, community, and developer perspectives	✓	Will be performed in Task 4, as specified.
Private capital	Leverage as much as possible (total private investment, private $-to-public $)	✓	As specified
Clean power sources	% of total community load covered by carbon-free generation	✓	PV, solar, and natural gas CHP
Tangible community benefits	Demonstrate benefits, e.g., jobs created, customers served, retrofits)	✓	Resiliency, continuity of critical government services
Grid strengthening	Incorporate innovation that strengthens surrounding power grid	✓	Will allow customer DER aggregation.
Information delivery to customers	Incorporate innovation that increases actionable information to customers	✓	As specified

The NYSERDA Task 1.2 questions and requirements are addressed in turn below. The text of each, highlighted in blue, is taken from the NYSERDA Statement of Work.

1. Integrate and demonstrate operation of advanced, innovative technologies in electric system design and operations, including, but not limited to, technologies that enable customer interaction with the grid such as, Microgrid Logic Controllers, Smart Grid Technologies, Smart Meters, Distribution Automation, and Energy Storage.

1.a Include an active network control system that optimizes demand, supply and other network operation functions within the microgrid

The microgrid controller will enable supervisory control in order to optimize the demand and supply of power within the COBD microgrid. It will automatically dispatch assets to meet the current operational criteria, including: maintaining local survival, supporting economic operations, minimizing environmental impacts, and all combinations thereof. When grid-connected, the controller will manage the local resources to ensure high power quality and readiness to island in case of emergency.

In addition, economic and environmental objectives issued by internal or external parties will also be evaluated, and will be supported by dispatching additional assets (or modifying current asset set points) if capacity is available. While islanded, the controller's primary objective will be to maintain critical loads and it will automatically dispatch or shed generation and load assets as necessary.

During extended islanded operation, the objectives may be modified to maximize survivability or to ensure continued black-start support. The allocation of assets will be determined by taking an account of each asset's availability, capabilities (e.g., capacity and dynamic responsiveness), and operational constraints against the current list of objectives. Some common objectives may include active and reactive power capacity, response time, minimum and maximum operating times, calendar constraints, etc.

The controller environment will have the capability to manage a database of the asset parameters that can be easily updated via a user interface to accommodate schedule changes or operational changes. The dispatch of assets may be configured to be automatic or to require operator acknowledgment.

1.b Include energy efficiency to minimize new microgrid generation requirements.

The proposed controller will enhance energy production efficiency as well reduce emissions within the community microgrid by using efficient generation sources coupled with CHP techniques that integrate renewables, if applicable. The controller will enable this by intelligently dispatching resources to maximize electrical generation efficiency while also meeting thermal loads. Furthermore, the microgrid controller can include and overcome the challenges of intermittent generation by providing intelligent dispatch of microgrid generation and utilizing storage to optimize renewable resources while still maintaining microgrid stability. With proper design and an intelligent controller, potentially large amounts of PV (relative to the total load) can be integrated into the microgrid and CHP applications are made more feasible.

1.c Address installation, operations and maintenance, and communications for the electric system to which interconnection is planned (e.g., underground networks, overhead loops, radial overhead systems).

The proposed microgrid controller will incorporate open communications standards, such as Enterprise Service Bus, DNP3, SEP2.0, SunSpec Alliance, IEC61850, ModBus, among others. Thus, the proposed controller platform will be capable of interfacing – i.e., receiving or transmitting information and/or control signals – with any SCADA, DMS, NOC (Network Operation Center) or attached DER assets that use open protocols.

As some individual buildings or loads might require seamless transition capability (or where it is prudent), uninterruptible power supply (UPS) systems will be employed.

1.d Coordinate with and support the objectives of the New York State Reforming the Energy Vision (REV) work to provide a platform for the delivery of innovative services to the end use customers.

The goal of the COBD microgrid is to improve the resiliency, reliability, quality, efficiency, and performance of the power grid, while advancing the adoption of clean energy. The COBD microgrid proposal supports these objectives through its integrated grid concept that seeks to ensure resiliency during weather-related events, as well as efficient, clean power whenever and wherever power is used or exported.

1.e Take account of a comprehensive cost/benefit analysis that includes, but is not limited to, the community, utility and developer's perspective.

The cost-benefit analysis (Task 3 and the accompanying analysis by ICe) will look at the microgrid concept holistically, from the perspective of the community, the City, and the developer. Aspects to be analyzed include, but are not limited to: the value of uninterrupted electric service to its end-use customers, energy and demand cost savings, fuel savings, sales to the grid, energy efficiency, power quality, and black-start support.

Benefits and costs for National Grid will also be evaluated, in terms of peak load management, demand response, increased generation efficiency, improved reliability benefits (e.g., decreasing System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI)), emissions reductions, improved distribution system visibility, etc. Some of this is captured as part of the societal benefits.

1.f Leverage private capital to the maximum extent possible as measured by total private investment in the project and the ratio of public to private dollars invested in the project.

At this time there is no identified private capital investment in the project. During the development phase the team will evaluate various forms of financing that leverage private capital, including Public-Private ownership, a special-purpose vehicle or entity, and utility ownership.

1.g Involve clean power supply sources that minimize environmental impacts, including local renewable resources, as measured by total percentage of community load covered by carbon-free energy generation.

The proposed microgrid's combination of solar PV, energy storage, natural gas generation, and combined-heat-and-power will help to substantially reduce environmental impacts.

The project will develop methods for monetizing various DER portfolios and penetrations. Using an estimate of power export revenue based on historical wholesale market prices, plus an estimate of the annual kWh generated by each type of DER, the project team will convert capital costs to an annual revenue requirement economic equivalent amount, which can be used to estimate the value or cost per kWh of annual DER generation.

1.h Demonstrate tangible community benefits, including but not limited to, e.g.: jobs created, number of customers service, number of buildings affected, scale of energy efficiency retrofits, etc.

The microgrid will provide tangible community benefits in several ways:

- It will bring greater resiliency to the buildings on feeder F3765 during grid outages. In the Feeder Peak scenario, all or a large number of the buildings on F3765 – along one mile of Niagara St. and Hudson Ave., plus several side branches – would be covered.
- The microgrid will ensure better continuity of critical government services, including those of great importance during severe weather or other emergencies that affect power grid operation. At a minimum, this includes Fire Department Headquarters and Emergency Services.
- Among the buildings situated along feeder F3765 are commercial establishments that provide for basic neighborhood needs, such as grocery stores and pharmacies. The microgrid will assure the continuity of their services and prevent business losses of frozen products, especially at grocery stores and restaurants.
- The microgrid will also provide backup and resiliency to residential buildings (e.g., Pine Harbor and Shoreline Apartments) on feeder F3765.

2. Incorporate innovation that strengthens the surrounding power grid and increases the amount of actionable information available to customers—providing a platform for customers to be able to interact with the grid in ways that maximize its value.

Through the COBD community microgrid's controller, customers on feeder F3765 will be able to take advantage of market opportunities through load and generation monitoring, DER aggregation, dispatch optimization, and communications with grid. The microgrid control system at FH/DHP can be re-engineered to take cognizance of any new DER at any other location and will, once re-engineered, be able to manage it as well as it does any local DERs.

APPENDIX B: TASK 2 – DEVELOP PRELIMINARY TECHNICAL DESIGN COSTS AND CONFIGURATION

TABLE OF CONTENTS

DISCLAIMER

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Task 2: Develop Preliminary Technical Design Costs and Configuration

1.1 Introduction

The City of Buffalo Fire Headquarters (FH) and District Heating Plant (DHP) share the same building complex, along with the Emergency Services Headquarters. This building complex is called FH/DHP in this document. Among its other functions, the DHP provides hot water and steam to five other buildings. The six buildings that rely for their space-heating needs on the DHP are listed in Table 1. This table also provides the floor area and heating load for each building.

Table 1 – Buildings that get their heat from the DHP

Building	Owner	Address	Area (sq. ft.)	Heating load (MMBTU/year)
FH/DHP	City of Buffalo	195 Court St.	99,977	5,058
City Court House	City of Buffalo	50 Delaware Ave.	232,929	11,785
Buffalo City Hall	City of Buffalo	65 Niagara Sq.	626,010	31,672
Family Court Building	Erie County	1 Niagara Sq.	130,025	6,578
County Office Building	Erie County	95 Franklin St.	513,188	25,964
42 Delaware Avenue	ABP Properties LLC	42 Delaware Ave.	71,120	3,598
		Total	**1,673,249**	**84,655**

As explained in Task 1, the FH/DHP complex is critical infrastructure whose continued operation must be assured in face of a loss of electric power. Even though it uses natural gas to service its thermal loads, the DHP requires electrical power to operate so it can serve its customers when the main grid is down. However, the City of Buffalo also needs to ensure that the combined heat and power (CHP) plant is able to generate electricity in order to continue operating equally well in both on-grid and off-grid situations.

All but the last are buildings that house government administration activities. We expect that all, or most of them, fall into the category of critical infrastructure.

We assume that all of the electricity requirements of FH/DHP are critical, meaning that they must be met even when the main power grid is down. Electricity must be supplied in order to allow the DHP to continue to provide heat and hot water to the five buildings it serves. In addition, the FH/DHP complex also houses other critical functions such as firefighting and emergency response.

As elucidated in Task 1, the initial plan for this project was to investigate the feasibility of a microgrid that encompasses these six buildings. However, all of the buildings listed in Table 1 except the FH/DHP are fed by a National Grid *mesh* network. It is a characteristic of a mesh network that every building served is fed by a multiplicity of feeders such that it is not vulnerable to the loss of any single feeder. The five buildings served by the mesh network already enjoy a considerable measure of resilience.

A microgrid encompassing these six buildings, as first envisaged, would have to work over and across the feeders that constitute the mesh network. The mesh network already provides a very high degree of reliability.[8] Any changes to a mesh network will need a very detailed system study. Modifications to the mesh network will be expensive and could result in less reliability than exists now. In view of these considerations, National Grid indicated that a microgrid may not make economic sense or result in increased reliability in that location.

In light of the above, the plan for investigating a microgrid that encompasses these six buildings was replaced with an alternative one that does not involve the downtown mesh network. What was proposed instead was a microgrid that would serve the FH/DHP as well as some or all of the sixteen other buildings listed in Table 2.

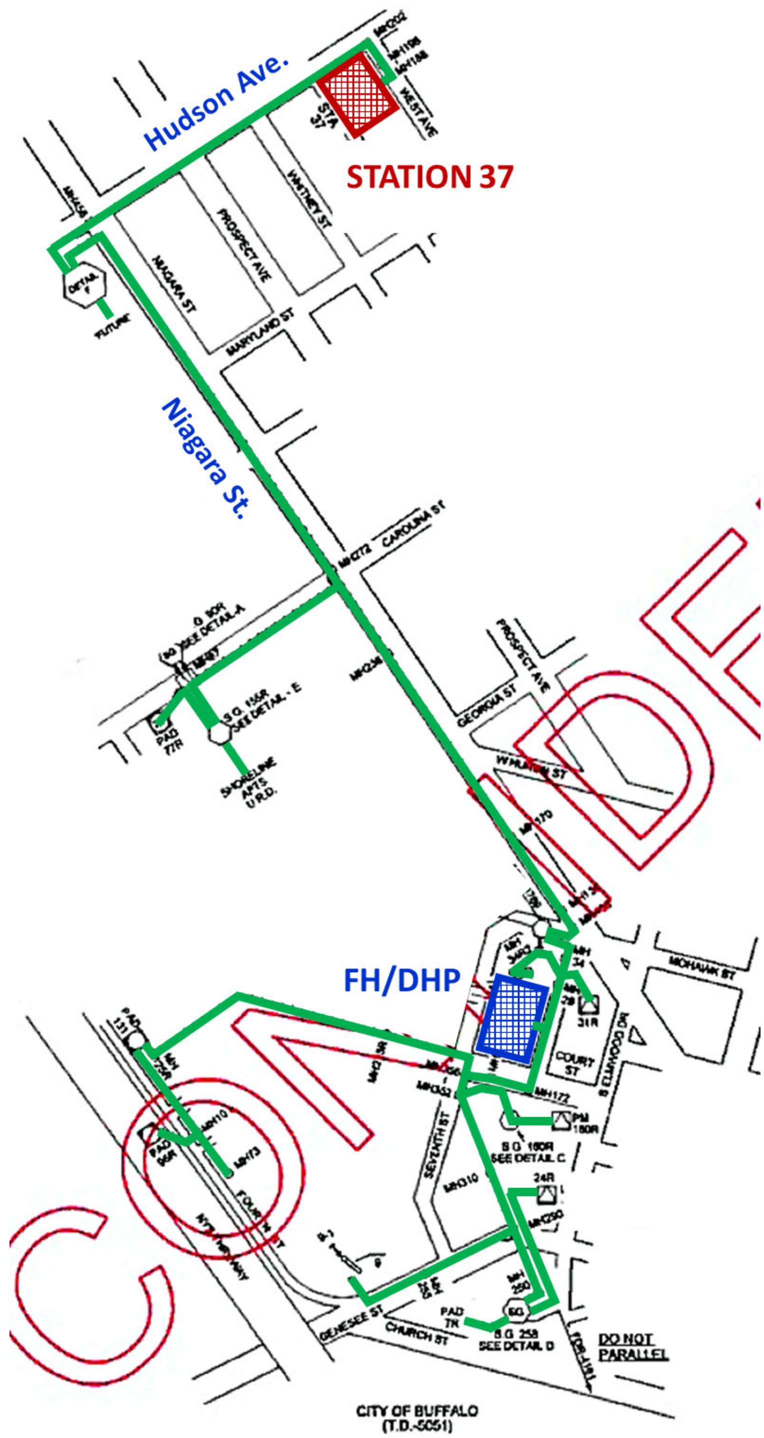
Table 2 – The seventeen buildings served by radial feeder F3765

No.	Building Name	Property function	Gross Floor Area (ft^2)	Average Demand (kW)	Annual electric load (kWh)
1	Shoreline Apartments	Apartments	420,200	59	1,721,981
2	S-1 Homes Inc.	Apartments	125,150	17.6	512,865
3	Pine Harbor Apartments	Apartments	220,496	30.9	903,593
4	PS 95 Waterfront Elementary School	Schools	177,752	176	2,371,401
5	Mattina Community Health Center	Health facilities	24,773	24.5	330,498
6	Edison Contracting Corporation	Manufacturing	2,937	2	25,422
7	Super Market Management Inc.	Office	4,200	3.4	54,484
8	Beir Nabala Satellite Comm. Inc.	Small structure	2,992	2.4	38,813
9	Mangione Hardware	Small structure	1,760	1.4	22,831
10	Blue Cross Blue Shield	Office	473,220	385	6,138,783
11	WKBW News	TV studio	28,136	27.9	375,364
12	Staats Street Group LLC	Auto shops	20,560	16.7	266,712
13	FBI Building	Office	100,869	82.2	1,308,510
14	Buffalo Metropolitan FCU	Bank	9,551	7.8	123,899
15	FH/DHP	Fire, Emergency, DHP	78,628	77.8	1,048,981
16	St. Anthony's of Padua RC Church	Church	6,050	6	80,713
17	US Post Office	Office	18,362	15	238,199

The common thread that unites the seventeen buildings listed in Table 2 is that they are all served by a single (radial) feeder, feeder 3765, referred to as *F3765* in this document. The buildings served by F3765 do not enjoy the same level of protection from power-supply interruptions as the six buildings listed in Table 1. Figure 1 shows the path of F3765, which starts at National Grid's Station 37, travels down Hudson Ave. and Niagara St., passes the FH/DHP, and splits into two separate branches (one of which splits again afterward).

[8] According to recent historical data from National Grid, the average number of faults on local radial feeders is nearly twice as large as faults on the mesh network. More importantly, due to the inherent redundancy of the mesh network, no customer interruptions were experienced on that network.

Figure 1 – Buffalo National Grid Feeder 3765. The feeder, which starts at Station 37, is designated by the green line.



In Task 1 the team determined that only the Feeder Minimum and Feeder Peak microgrid concepts would be considered for further exploration. (See the Task 1 report for the definitions of all five options.) In order to determine which of the two remaining concepts should be the focus of the feasibility study, it was necessary to estimate the microgrid's electric and thermal loads as full usage data was not available. The estimation process is described below.

1.2 Load and Tariff Calculations

We used hourly electric and thermal load values for an entire year to run computer simulations of the microgrid. The simulations were run with a computer software optimization package for microgrid planning called DER-CAM, which stands for "Distributed Energy Resources Customer Adoption Model." DER-CAM was developed by Lawrence Berkeley National Laboratories (LBNL).

DER-CAM requires load profiles to be specified as average energy consumption for each hour of the day. Three such profiles – weekday, weekend, and "peak day" – are required for each month of the year. Peak-day load profiles are constructed from the peak energy consumption that occurred during each hour, over the course of the month. The peak-day load profile is needed so that DER-CAM can ensure that the microgrid will be able to serve the worst-case loads on the microgrid. The DER-CAM load profiles are typically derived from data on electrical consumption during every hour of the year, which is often referred to as an "8760 load profile."

The electric loads to be supported by the microgrid are the load of the FH/DHP complex and the loads of some or all of the buildings on F3765.

FH/DHP Loads

No 8760 electrical load data exists for the FH/DHP, however monthly billing (energy consumption) and annual peak demand data are available. The team estimated an 8760 load profile using this available data, along with hourly load profiles developed by performing simulations of commercial reference buildings.[9] The reference building characteristics were defined by the U.S. Department of Energy (DOE) as a baseline for comparison when performing computer energy simulations.

Note that the electrical load of the FH/DHP is different from a typical load profile for an office, where the load is high in summer. It is also different from industrial load profiles, which are not seasonal. The important factor in the present situation is that the winter electrical load is dominated by the behavior of the DHP. Because the DHP's customers are office buildings, its behavior is in turn most similar to the behavior of an office building. Therefore, the FH/DHP was modeled on the basis of the DOE reference profile of a medium-sized office building in the Buffalo area. However, to account for different seasonal behavior, the reference profile was adjusted, using the available consumption and demand data, so that it would follow the FH/DHP energy use pattern.

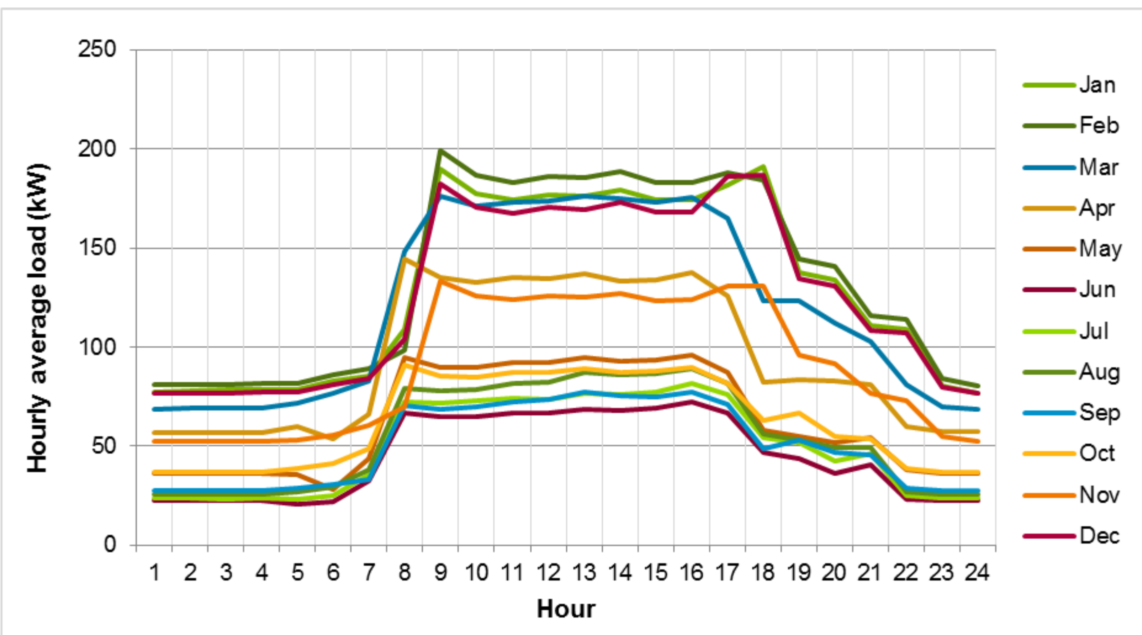
The medium-sized office building reference profile was adjusted to match the data according to the following steps:

[9] Available at: http://en.openei.org/datasets/files/961/pub/. Simulations were run for many locations in the U.S., using local climate data to ensure relevance for each location.

1. Electrical cooling and heating loads were removed from the reference profile to make it independent of the weather.
2. For each month, the profile's load values were scaled by a factor that resulted in the given month's electrical consumption matching the actual consumption by the FH/DHP for that month. This created profiles that follow the monthly consumption pattern of the FH/DHP.
3. This modified 8760 load profile was then processed, using software from LBNL, to create the DER-CAM weekday, weekend, and peak-day hourly profiles for every month. However, the resulting estimated annual peak demand for the FH/DHP complex was somewhat larger than the actual annual peak demand of the building.
4. To account for this difference in annual peak demand, the ratio of measured to estimated annual peak demand was used to scale the estimated peak-day profile. The resulting impact on estimated annual consumption was -5,960 kWh, a reduction of about 0.8%. To ensure that this adjustment did not alter the monthly energy consumption within DER-CAM, each weekday profile value was adjusted upward by 0.96 kW. The average impact on individual estimated weekday load values was 1.6%.
5. The cooling load profile was estimated by uniformly scaling the cooling loads of the reference profile by the average scaling factor used for electrical loads.

Thus, the resulting estimated FH/DHP load profile (Figure 2) leverages the DOE reference medium office profile while matching the actual monthly consumption of the heating plant and maintaining the peak value.

Figure 2 – Estimated electrical load of the FH/DHP on an hourly basis



DER-CAM also requires hourly space heating load profiles for weekdays and weekends, plus a peak-load profile. The FH/DHP heating load can be considered to be the aggregate of the loads of all six buildings served by the DHP. As with electrical consumption, no hourly heating load data was available for the FH/DHP or DHP customers. However, natural gas billing data was available for the FH/DHP complex.

In estimating the hourly heating load of the DHP, we used the DOE-based reference profiles for small, medium and large-size offices to calculate the heat demand of each DHP customer. Except for the FH/DHP, each building thermally served by the DHP was classified as either a large- or medium-size office on the basis of its floor area. The FH/DHP building itself was treated as a blend of a medium-size office (80%) and a warehouse (20%).

The hourly heating load of the FH/DHP was estimated according to the following steps:

1. For each reference building type, the floor areas of all of the DHP customer buildings of that type were summed. (Example: The City Court, City Hall, and Erie County Office Building are all large buildings under the DOE reference building classification. The sum of their floor areas is 1,372,127 square feet.)
2. Each sum of floor areas was divided by the floor area listed in the DOE reference building type characteristics to get an "effective number of buildings" of the given building type. (Example: The floor area of a DOE reference large office building is 498,588 square feet. Thus, on the DHP thermal loop there is the equivalent of 2.75 (1,372,127 ft^2/498,588 ft^2) DOE large office buildings.)
3. For each hour of the year, the total heating load on the DHP due to its customers was calculated by multiplying the loads of the reference building profiles by the effective number of buildings of each type, then summing them together:

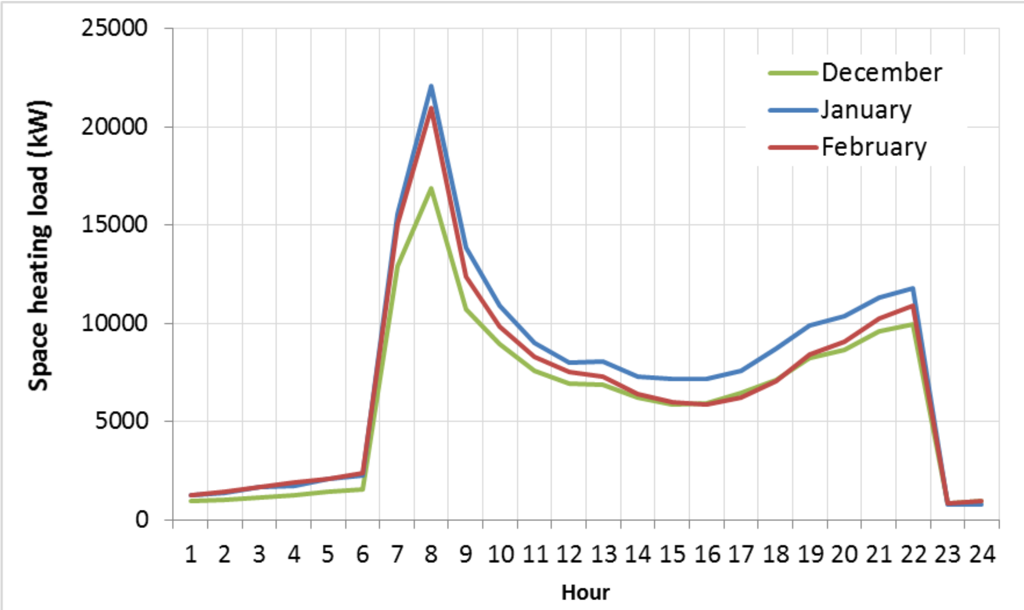
$$total\ load\ at\ hour\ t = \sum_{DOE\ building\ type\ T} (no.buildings)_{type\ T} * (ref.load\ at\ hour\ t)_{type\ T}$$

   The estimated total annual heating load from DHP customers was just the sum of all 8760 estimated hourly total load values.

4. Finally, the above estimated hourly heating loads do not incorporate the thermal losses of the DHP's distribution system or building consumption that is higher than assumed by the DOE reference specification (due to usage, building loss, or both). To account for these factors, the hourly estimated total heating loads calculated above were multiplied by a scaling factor so that the resulting computed total annual heating load would agree with the actual amount used by the FH/DHP. This scaling factor was the ratio of the *actual* to *computed* annual natural gas energy delivered to DHP customers:
   a. Actual gas energy delivered: The annual natural gas usage of the FH/DHP complex (from billing data), multiplied by an assumed average boiler efficiency of 82%.
   b. Computed gas energy delivered: The estimated total annual heating load calculated in step 3.

The analysis contains two implicit assumptions: (1) natural gas consumption by the DHP represents the vast majority of the FH/DHP complex's natural gas consumption, and (2) gas consumption during the non-heating season is also minimal compared to gas consumption during heating season. Both assumptions are well supported by the billing data for the FH/DHP. The first assumption is valid because the average natural gas consumption between June and September, when the DHP is shut down, is only 0.04% of the average natural gas usage during the remaining months. The second assumption follows from the data because even considering shoulder season gas consumption as "non-heating season," the non-heating gas usage is at most 5.5% of the annual total. The final estimated loads are shown in Figures 3 and 4. Note that the scaling factor applied in step four is quite large (5.0). This may be due to a number of issues such as particularly large pipe leakage or building inefficiencies, and it will be investigated during a later phase of the project.

Figure 3 – Estimated heat delivered by the DHP during the months December through February



Other Loads on Feeder F3765

Because the CHP exports power to National Grid (or potentially to NY ISO) during grid-connected operation, rather than selling it to individual customers on feeder F3765, DER-CAM does not require an electric load profile for F3765 for grid-connected mode. On the other hand, the CHP does export power to the feeder during an outage, and the outage scenario determined the generator size because the microgrid power was sized to cover 100% of the load of the islanded buildings. Therefore, an electrical load profile for all of the buildings on F3765, exclusive of the FH/DHP, was required to perform the DER-CAM runs involving a grid outage. However, for this purpose the primary load attribute of importance was the peak during the outage.

As was the case with the FH/DHP, no hourly electrical load data was available for the remainder of the buildings on F3765. Estimates of hourly electrical load data were therefore calculated, again using the DOE reference load profile of a typical building (small office) in the Buffalo area as the basis. This reference 8760 load profile was first processed to create the DER-CAM weekday, weekend, and peak-day hourly profiles for each month. The DER-CAM profiles were then scaled to match the aggregate load of all of the buildings on F3765 except the FH/DHP. The following ratio was used as the scaling factor:

$$\frac{(F3765_{peak} - FH/DHP_{peak}) - (F3765_{min} - FH/DHP_{min})}{(Ref_{peak} - Ref_{min})}$$

where “F3765” refers to the load on the entire feeder, “FH/DHP” refers to the load of the FH/DHP complex, and “Ref” means the reference building’s DER-CAM profiles. The subscript “peak” refers to the annual peak demand, and the subscript “min” refers to the lowest demand of the year. The calculated aggregate weekday electric load of the remainder of F3765 buildings is shown in Figures 5 and 6.

Figure 4 – Estimated heat delivered by the DHP from March through November

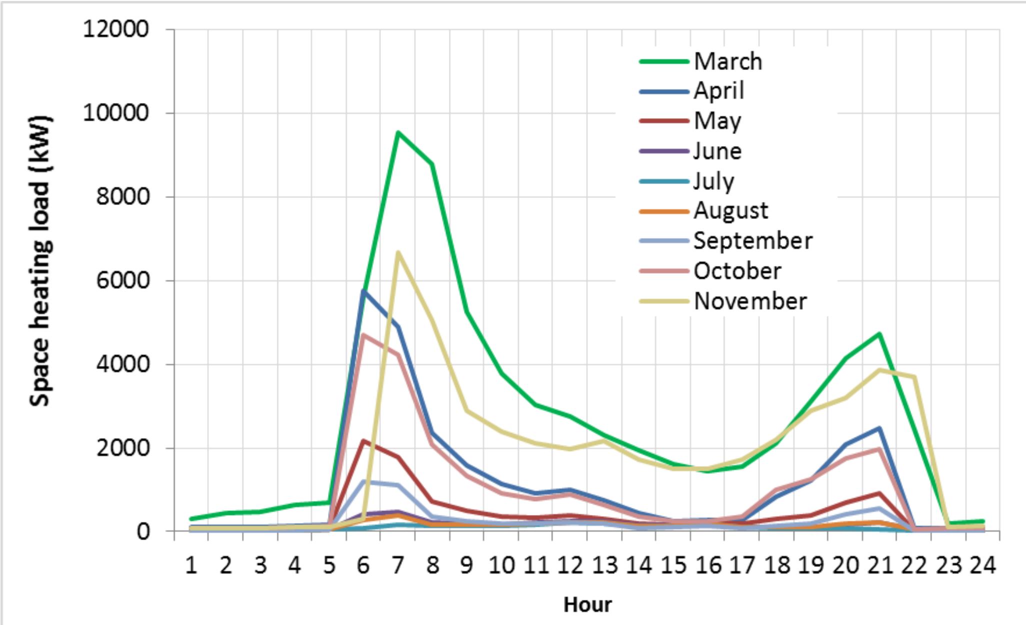


Figure 5 – Estimated weekday electrical load of the remainder of F3765 buildings, on an hourly basis, for the months January through June

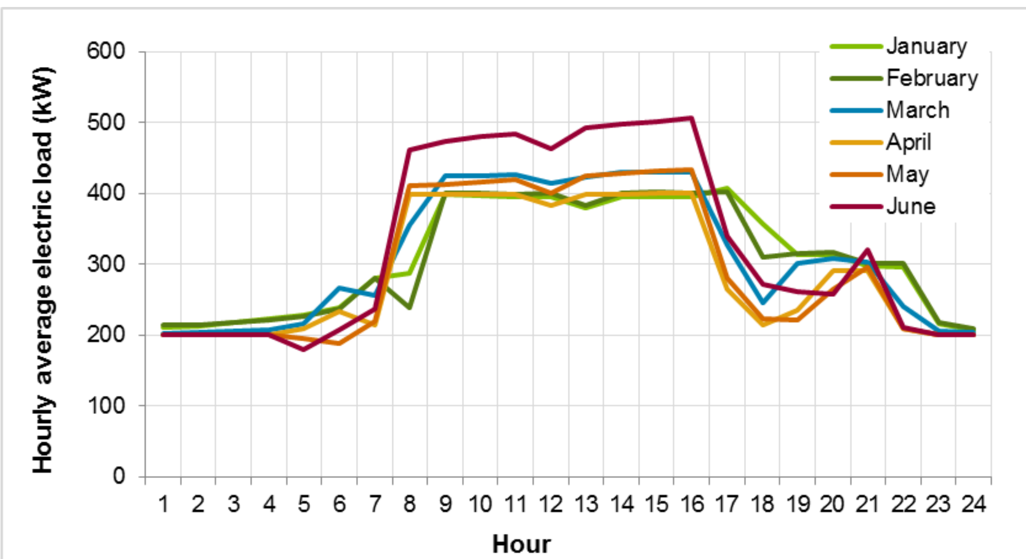
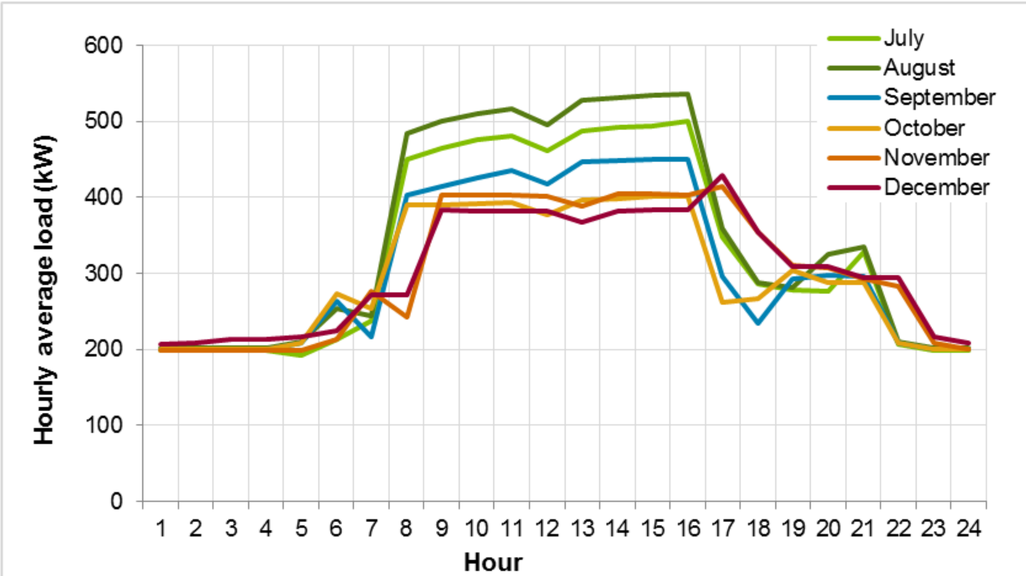


Figure 6 – Estimated weekday electrical load of the remainder of F3765, on an hourly basis, for the months July through December

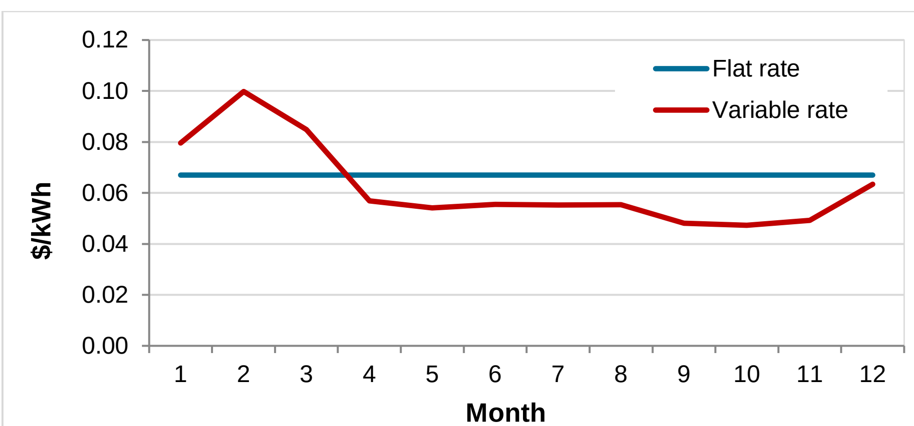


Heating loads for the non-FH/DHP buildings on F3765 were not calculated because they are not needed. The proposed microgrid is not designed to serve the heating loads of the rest of F3765.

Tariffs

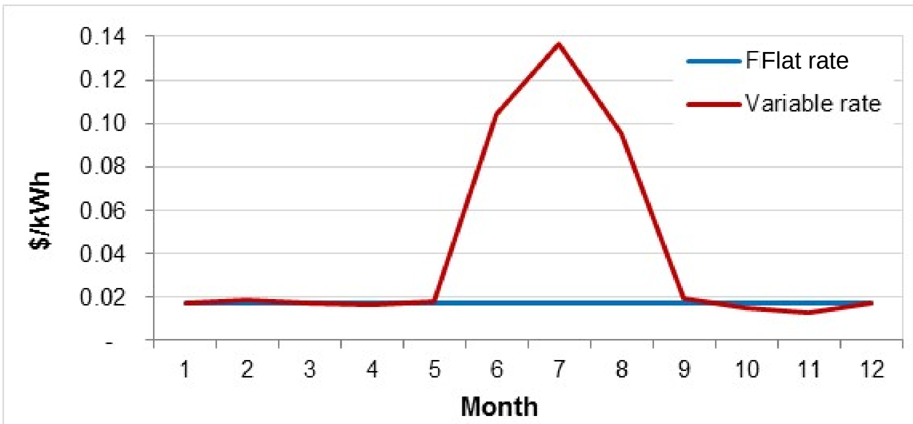
Electric and gas tariffs were calculated from actual monthly bills for the FH/DHP. Initially, DER-CAM simulations were run using both a constant average monthly rate and variable monthly rates. Final DER-CAM runs all used variable monthly rates for greater fidelity. For electricity tariffs (Figure 7), fixed-monthly, demand, and supply charges were calculated separately.

Figure 7 – Volumetric (per kWh) electric supply charges applied to the FH/DHP. Volumetric charges are one component of the electric tariff



Gas tariff charges (Figure 8) were likewise calculated from the amounts actually paid for gas usage. Because details of the tariff were not available, and bills were not available as well, the fixed monthly charge was estimated using linear regression. The plot of gas charges shows much higher than average supply charges during the months of June, July, and August, but during those months heating needs are minimal and gas usage is less than $200 a month on average. The higher supply charge is a result of the low usage.

Figure 8 – Volumetric (per kWh) natural gas supply charges. Usage during June, July, and August is minimal (less than $200 for the gas bill), resulting in a higher supply charge



For simplicity, the price that microgrid participants would pay to COB for electricity during an outage was assumed to be the same as the FH/DHP's National Grid tariff.

As mentioned in the Task 1 report, we eliminated the Nominal, Feeder Capacity, and DHP Thermal concepts from consideration prior to the Task 2 analysis, leaving the Feeder Minimum and Feeder Peak concepts to be explored in Task 2. In the Feeder Minimum concept the CHP rating is limited to 184 kW. We found that this cannot support any of the feeder loads outside of FH/DHP in an outage, especially if the outage happens during a winter month. As a result, we eliminated the Feeder Minimum option. The focus in the remainder of this Task is entirely on the Feeder Peak concept.

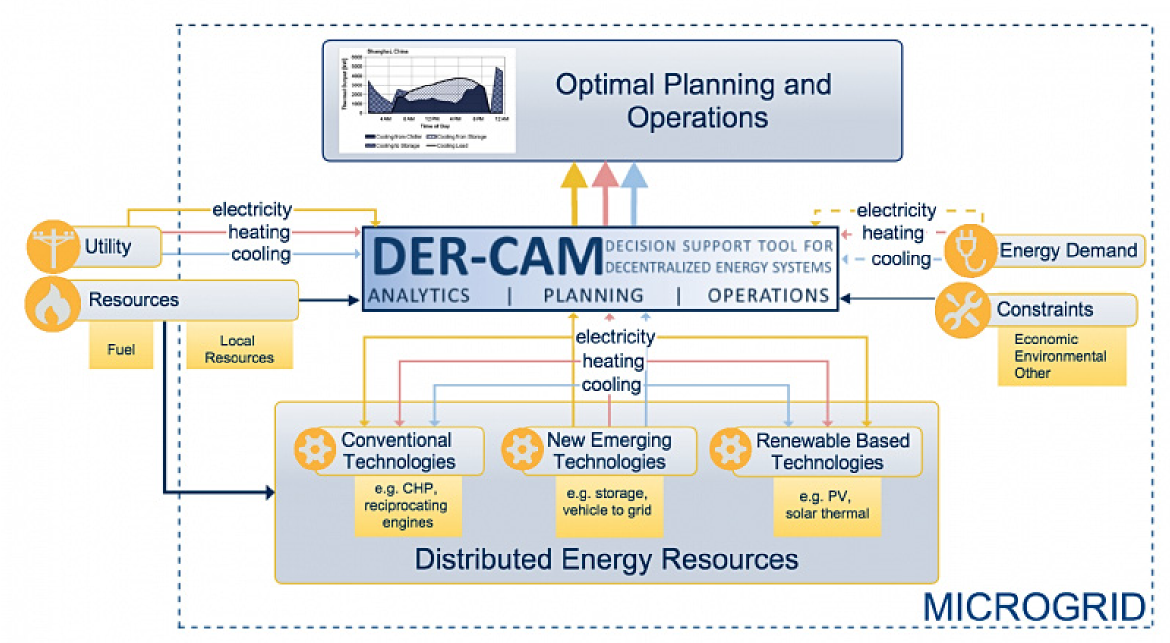
1.3 DER-CAM Modeling

DER-CAM is a program for optimizing the configuration and operation of distributed generation assets, from a cost perspective. DER-CAM was used for three purposes here: (1) to determine the generating assets and loads that define the microgrid, (2) to find the optimum performance of the microgrid so defined, and (3) to understand the operating scheme that leads to the best system performance.

In general, optimization techniques determine a mathematical function for a value (such as cost) to be optimized. This function, called an “objective function,” is then minimized or maximized, as desired, within the constraints imposed by the scenario. In DER-CAM, the objective functions used are the cost of energy produced and the carbon footprint, both of which should be minimized for best results.

DER-CAM is programmed using a mathematical computer language called GAMS (Generalized Algebraic Modeling System) that creates the objective function(s) and a set of constraint equations from the input data. DER-CAM feeds the objective functions and constraints to a computer routine that solves the optimization problem. Solver results are converted into spreadsheets and plots for the user. Figure 9 is a schematic of DER-CAM and its various inputs, showing the optimization output as well.

Figure 9 – DER-CAM modeling schematic showing inputs and outputs



Source: https://building-microgrid.lbl.gov/projects/der-cam

DER-CAM requires the following items as input:

- Loads
- Tariffs
- Permissible distributed energy resources (DERs)
- Financial parameters and goals
- Environmental conditions, such as those pertinent to solar and wind generation
- All the attendant properties, parameters, and attributes of such data

The Feeder Peak concept contains two different situations involving sale of power: (1) export and sale of power from the FH/DHP to National Grid during grid-connected mode, and (2) export and sale of power from the FH/DHP to buildings on F3765 during an outage. Because the customer for exported power is different in each situation, it was necessary to run DER-CAM separately on two different parts of the microgrid, the *FH/DHP* and an *assumed percentage of the rest of feeder F3765*. The results were combined appropriately afterward. The concept of "a percentage of the rest of F3765" is subtle and deserves further definition:

- To avoid the need for the equipment and coordination required to shed loads on the microgrid, we assumed the following: (1) the microgrid's outage coverage on F3765 would entail a contiguous group of buildings, and (2) the microgrid would cover 100% of the load of those buildings during the outage.
- The electrical peak load of the FH/DHP occurs in a different season as the peak load of the other buildings on F3765. This is due to the fact that the electrical peak of the FH/DHP happens during heating season when the DHP uses the most electricity, whereas the peak of the rest of the feeder occurs in the summer due to space cooling. The net load on F3765 thus varies greatly throughout the year and cannot be characterized by a single difference between the annual peak load of whole feeder and the annual peak load of the FH/DHP. The method we used to estimate the net load of F3765, described above, does provide such monthly profile variations.
- We computed the load profile for an assumed *percentage* of the rest of feeder F3765 by multiplying each hourly load of the "rest of F3765" load profile by that percentage (expressed as a fraction).

We ran several scenarios of the Feeder Peak concept in DER-CAM to determine best performance under three conditions: (1) a baseline scenario (i.e., no investment); (2) investment in various types of DER and varying output capacity, and (3) simulations of several different potential levels of payment (by National Grid) for power export during grid connection. Table 3, which lists the different scenarios modeled, is followed by the logic behind their selection. For brevity we use the following nomenclature in Table 3 and the remainder of the report to refer to various combinations of loads:

- "FH/DHP" refers to the electrical load of the FH/DHP complex, at any given point in time (as opposed to a peak or average load).
- "R-F3765" refers to all electrical loads on F3765, except for the load of the FH/DHP complex, at any given time.
- "R50-F3765" refers to 50% of the rest-of-F3765 electrical load, in the sense described above, at any given time.

Table 3 – Feeder Peak Scenarios Modeled in DER-CAM

#	CASE	CONNECTION	LOADS	DER	EXPORT	PRICE	COMMENT
1	Baseline	Grid	FH/DHP	None	None	N/A	
2	Baseline	Grid	R-F3765	None	None	N/A	
3	Baseline	Island (outage)	FH/DHP	Diesel	None	N/A	Outage cost $1.2M
4	Baseline	Island (outage)	R50-F3765[10]	None	None	N/A	Outage cost $5.2M
5	Investment	Island (outage)	- FH/DHP - R50-F3765	Diesel[11] with CHP, PV,[12] and storage allowed	F3765	Wholesale	Optimal CHP size found to be 500 kW
6	Simulation	Grid	FH/DHP	500 kW CHP	National Grid	Wholesale	Payback period: 45 yr.

[10] Calculations were also performed for outage scenarios in which the microgrid could cover significantly more than 50% of the rest of F3765, however these configurations were clearly oversized and could not export anywhere near the amount of power required to cover their cost.
[11] Existing diesel generator with 32 hours (max fuel supply).
[12] Photovoltaics, i.e., solar power.

#	CASE	CONNECTION	LOADS	DER	EXPORT	PRICE	COMMENT
7	Simulation	Grid	FH/DHP	500 kW CHP	National Grid	Retail	Payback period: 18 yr.
8	Simulation	Grid	FH/DHP	500 kW CHP	National Grid	90% retail	Payback period: 22 yr.
9	Simulation	Grid	FH/DHP	250 kW CHP, PV, storage	National Grid	Wholesale	Payback period: 32 yr.
10	Simulation	Grid	FH/DHP	250 kW CHP, PV, storage	National Grid	90% retail	Payback period: 27 yr.
11	Simulation	Grid	FH/DHP	500 kW CHP, PV	National Grid	90% retail	Payback period: 35 yr.
12	Simulation	Grid	FH/DHP	500 kW CHP, separate PV[13]	National Grid	90% retail	Payback period: 27 yr.

Note that the details of the economic analyses, including the capital costs, outage costs, revenue generated from power export, and payback periods, are described in the Task 3 report.

Estimation of current operational cost
Grid-connected baseline cases (#1 and #2) were run for the FH/DHP and R-F3765 loads, respectively. These runs were performed to obtain the cost of energy and the emissions produced if no changes are made to installed equipment.

Calculation of unmet load and outage costs
DER-CAM was run with two baseline outage cases – FH/DHP (#3) and R50-F3765 (#4) loads, respectively – in order to define the unmet load that would occur during an outage and the costs of the outage stemming from the unmet load. The scenario used was a 14-day outage in January, limiting diesel availability to 32 hours.

Sizing the DER
Case #5 simulated the operation of an islanded electric microgrid with DER for the combined loads of FH/DHP and R50-F3765. When multiple DER are allowed – in this case CHP, PV, and storage – DER-CAM chooses between them so that the optimum result is achieved. Two sets of DER that seemed most viable were tested: (a) a 500 kW CHP only, and (b) a 250 kW CHP together with PV and electric storage. The investment costs are about the same for each, however the continuous operation of a PV unit during a 14-day emergency outage is questionable, especially in winter. This makes CHP alone a more attractive choice for providing resiliency to the FH/DHP and R50-F3765 loads.

Economic analysis of grid-connected operation with DER
Because the majority of revenue generated by the microgrid is earned during grid-connected mode, the main part of the analysis consisted of seven grid-connected investment cases (#6 - #12), three with the 500 kW CHP and four with a combination of CHP and PV (with and without storage). The purpose of these runs was to determine if an export price exists, no greater than the FH/DHP's retail tariff from National Grid, which results in breakeven or near-breakeven performance over a 20-year horizon.

[13] "Separate PV" refers to a configuration in which the use of the CHP plant is not related to the power produced by the PV system (and vice versa).

500 kW CHP only

We first tested the situation in which the microgrid receives the wholesale (average ISO) price for power it exports to National Grid (case #6). This is in accord with current regulations with National Grid or NY ISO as the counterparty. This resulted in a predicted simple payback period[14] of 31 years. We also computed the payback period with an assumption that COB would issue a bond at 2% interest to fund the purchase of the system. For the bond case, which is the one reported in Table 3, the payback period is computed to be 45 years. This is far too long to be a viable option.

From the COB's perspective the best-case scenario – though it is also the most unrealistic – would be for the microgrid to be able to sell the power it exports to National Grid at the full retail price paid by the FH/DHP. We tested this microgrid concept, case #7, to see if it would be possible to break even under this best-case condition. The result was positive, with a simple payback of 15 years and a bond-based payback of 18 years.

Finally, we looked into how much less than full retail the export price could be while still allowing the microgrid to be paid back in approximately 20 years. With the price of power exported to National Grid assumed to be 90% of the retail price (case #8), the model predicts a simple payback of 18 years and a bond-based payback of 22 years.

CHP and PV, with and without storage

NYSERDA's preferred microgrid capabilities include involvement of "clean power supply sources that minimize environmental impacts, including local renewable resources." To determine whether the microgrid could achieve this goal via incorporation of PV, we also ran four grid-connected DER cases with CHP and PV, two of them also including electric storage.

For the first two scenarios (cases #9 and #10) we looked at PV and storage with a 250 kW CHP plant, as in case #5. Case #9 involved a wholesale export price and case #9 examined a scenario where the microgrid could earn 90% of the retail cost of electricity. Neither scenario reaches breakeven, but when the export price is retail the addition of PV does get faster payback than the non-PV case because the microgrid can sell PV power during the summer when CHP power is uneconomical.

The third green scenario we studied combined PV with a 500 kW CHP unit (case #11), on the hypothesis that the PV might pay for itself with grid-connected export even in the non-heating season. The assumed export price is 90% of retail. This combination of equipment has the virtue of having sufficient power to cover the entire aggregate load of the FH/DHP and R50-F3765 during an outage, regardless of PV performance. Because of this, no storage is needed.

However, the capital cost is still high because it involves a large CHP plant (compared to cases #9 and #10) as well as PV. Because PV does not require the purchase of fuel to operate, in the presence of sunshine its operational cost is much less than that of the CHP unit and DER-CAM prefers the PV. This increases the CHP asset's idle, unutilized time and lengthens its payback period. The predicted overall payback period for this scenario is lengthy at 35 years.

In the last scenario, case #12, the PV (without storage) was assumed to tie into the grid in front of the meter so that it could export as much as it can produce without impacting the operation of the (500 kW)

[14] Simple payback was computed as the net cost (after a presumed NYSERDA CHP Accelerator incentive of $833 per electrical kW) divided by the net yearly operational cost savings.

CHP behind the meter. Despite this more optimized operating scenario, calculations show a bond-based payback of 27 years. This exceeds the 20-year desired horizon so we did not consider this scenario feasible.

Final microgrid definition
Although case #7 gives the best payback, with an export power price equivalent to retail it is the least realistic scenario relative to revenue generation. No other scenario performed better than a 20-year payback period. The only other situation that produced a payback period that is very close to the desired time frame is case #8, which has the same configuration as case #7 but an export power price of 90% of retail. Given that there is uncertainty in input parameters, inherent simplification in modeling, and the fact that the microgrid will earn some revenue from export of power to buildings on feeder F3765 during outages, we considered 22 years to be essentially breakeven relative to the stated time horizon and based the remainder of this report on that scenario.

In summary, the microgrid configuration defined for the feasibility study is as follows:

Generating assets

- 500 kW CHP unit
- 200 kW diesel genset (FH/DHP backup)

Grid-connected loads

- FH/DHP building, whose loads include the Fire Headquarters, Emergency Services and District Heating Plant
- National Grid, destination unspecified, via export to feeder F3765

Emergency (outage) loads

- FH/DHP building, 100% of the loads within, i.e., no load shedding or curtailment
- R50-F3765, 100% of the FH/DHP complex load in addition to 100% of selected but not specified F3765 building loads with no requirement for load shedding or curtailment

Subtask 2.1 – Proposed Microgrid Infrastructure and Operations

Question 2.1.1
Provide a simplified equipment layout diagram and a simplified one-line diagram of the proposed microgrid, include location of the distributed energy resources (DER) and utility interconnection points. Identify new and existing infrastructure that will a part of the microgrid.

Existing equipment includes the electrical infrastructure at FH/DHP, including the two diesel generator sets. The proposed microgrid will have only one new DER, a 500 kW CHP. Additional equipment will be the switchgear and controls for the CHP plant. In addition, we also need equipment for islanding on the feeder F3765. The exact islanding location will be determined during the detailed design.

The site perimeter of the Buffalo Fire Department Headquarters/District Heat FH/DHP complex is quite congested and is landlocked. Space does exist in the courtyard around the tower that will allow for the installation of an outdoor Combined Heat and Power generator and the associated switchgear and transformer. The existing Kohler 250KW generator would be removed. New infrastructure would extend from the transformer and switch gear to the Fire Headquarters electrical service and feeder 3765. Refer to Figure 10 for the equipment layout and Figure 11 for the one-line diagram.

Note that we were unable to determine whether the diesel gensets are able to power every circuit within the FH/DHP complex, however it currently does power at least four of the boilers and many other circuits as well. Because the cost of modifying the electrical connections to ensure that the entire FH/DHP building is powered by a diesel generator is relatively small, we assumed that to be the case for our modeling and analysis.

Figure 10 – Equipment layout diagram

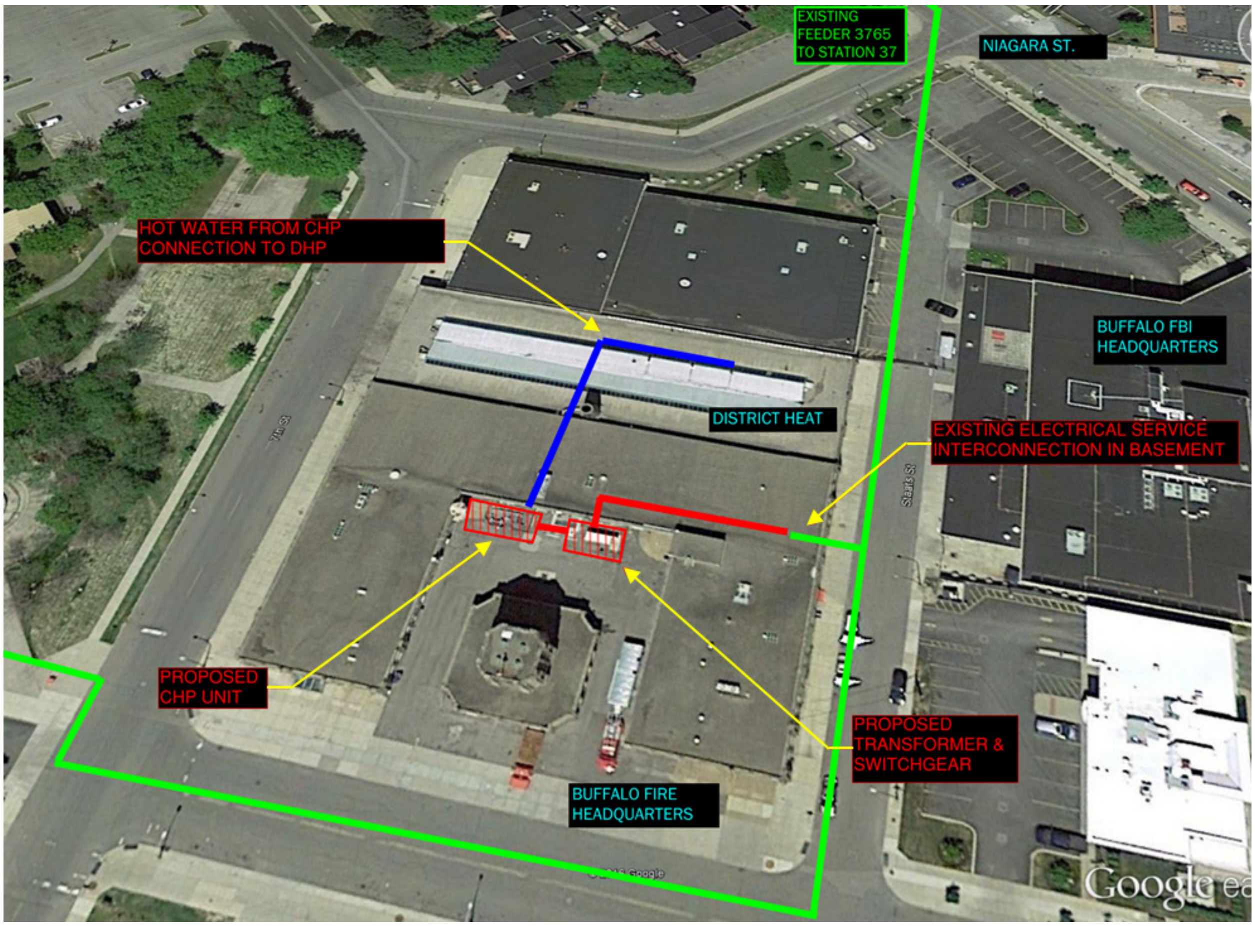
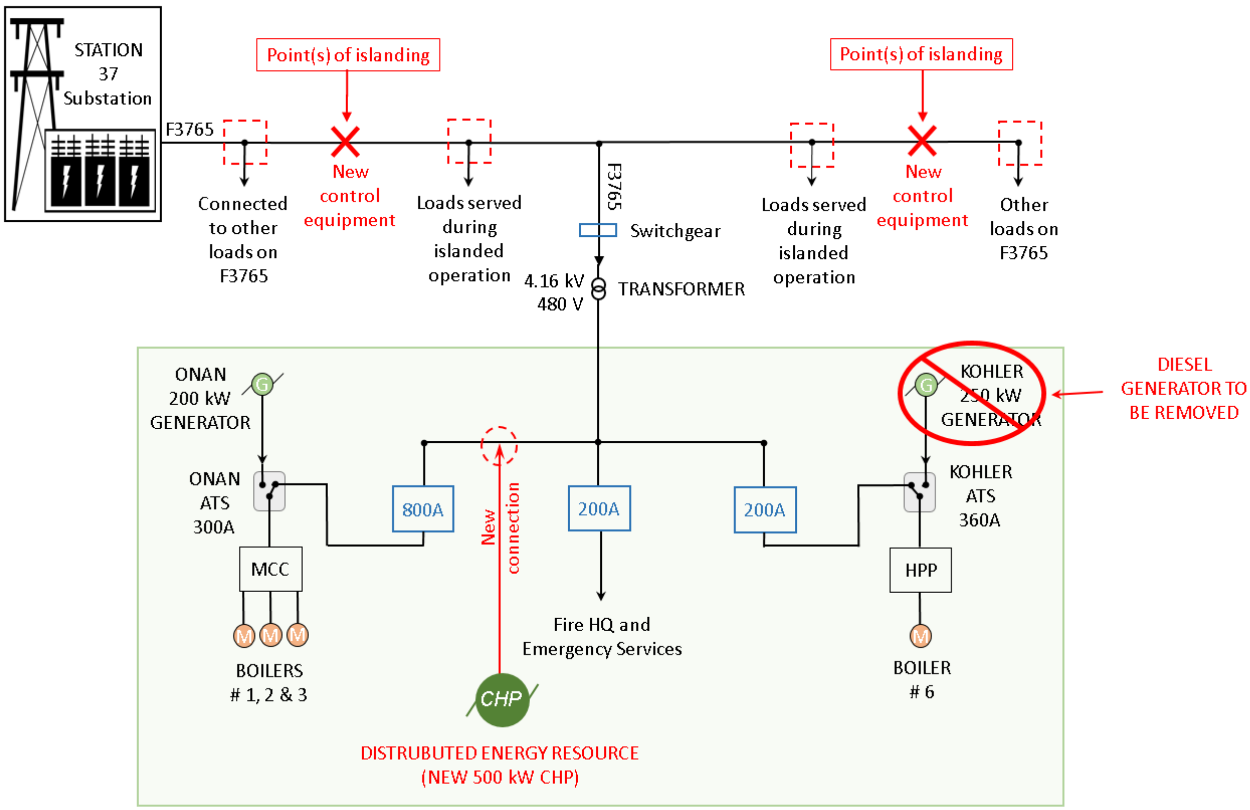


Figure 11 – Simplified one-line diagram of the proposed microgrid



Buffalo Fire Headquarters, Emergency Services and District Heating Plant (FH/DHP)

The hot water output of the CHP can be integrated into the DHP heating circuit in two principal ways, either in series or in parallel with the boilers. Parallel operation may not be practical because the thermal output of the CHP is much smaller than that of the boilers. Thus, it should be very difficult to regulate the CHP heat output when the boilers are in operation. In a series configuration, the CHP unit would be connected to either the common return supplying the hot water boilers or the common return from the heating system. As this type of connection involves minimal impact on the boiler circuit and its controls, it is commonly used when retrofitting CHP into an existing building. However, the appropriate type of connection will only be known with certainty as a result of a design study.

Question 2.1.2

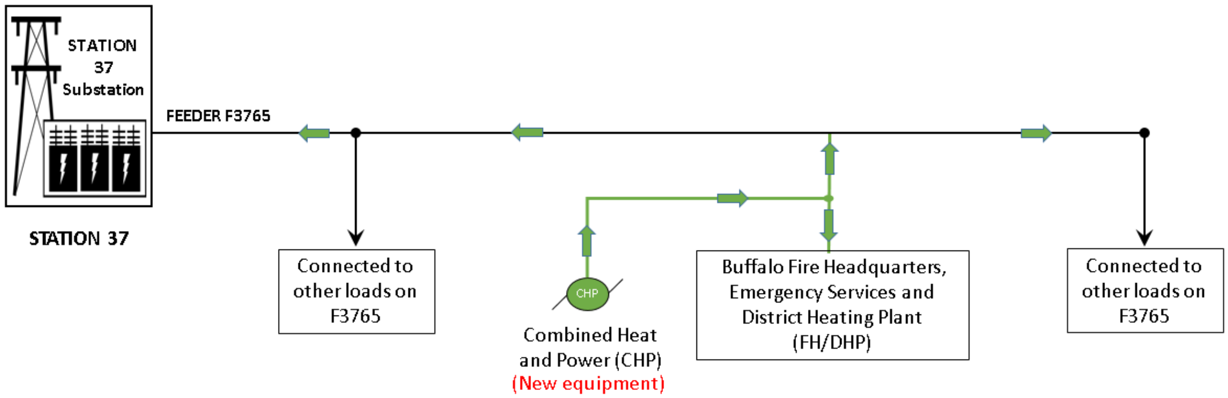
Provide a brief narrative describing how the proposed microgrid will operate under normal and emergency conditions. Include description of normal and emergency operations.

The DHP participates in the microgrid in the role of a load, rather than a generating asset. However, because both assets are owned by the City of Buffalo and co-located in the FH/DHP, the economic performance of the microgrid is tied to both assets. This was captured by the DER-CAM model, which sought to minimize the combined cost of operation through consideration of their electrical and thermal loads and the cost of fuel for both systems.

Normal (grid-connected) condition

Figure 12 shows the configuration of the microgrid under grid-connected operation. The CHP unit powers all of the FH/DHP loads and exports its excess power to feeder F3765.

Figure 12 – Grid-connected microgrid scenario



During grid-connected conditions, the DHP will use energy from multiple sources. These sources include power and heat (in the form of hot water) generated by the CHP, heat generated by gas-fired boilers and, at times, electricity from the utility. The microgrid control system will create an optimal dispatch schedule for the CHP from these different sources, based on the electrical and thermal load, the tariff, and the available price for export power. Note that, as a load, the DHP will not be operated by the microgrid controller.

The DER-CAM optimization runs produced an operating scheme that has the CHP unit run all day and all night during October through April, exporting electricity to the feeder at all times.[15] The CHP unit would not operate at all during the summer, because there is no opportunity to utilize the plant's heat output, and only in the daytime during the months of May and September.

Emergency (outage) conditions

Islanded operation can occur under the following conditions:

- Planned intentional islanding
  - *Commanded planned islanding* – When the connection between National Grid and the microgrid is broken on purpose, whether in view of an impending emergency situation or in a test situation.
  - *Scheduled planned islanding* – A scheduled tariff transition or operating agreement dictates that the microgrid transition to an islanded mode at a specific time.
- Unplanned/unscheduled intentional islanding – Supported by the microgrid controller, this function could consist of two scenarios:

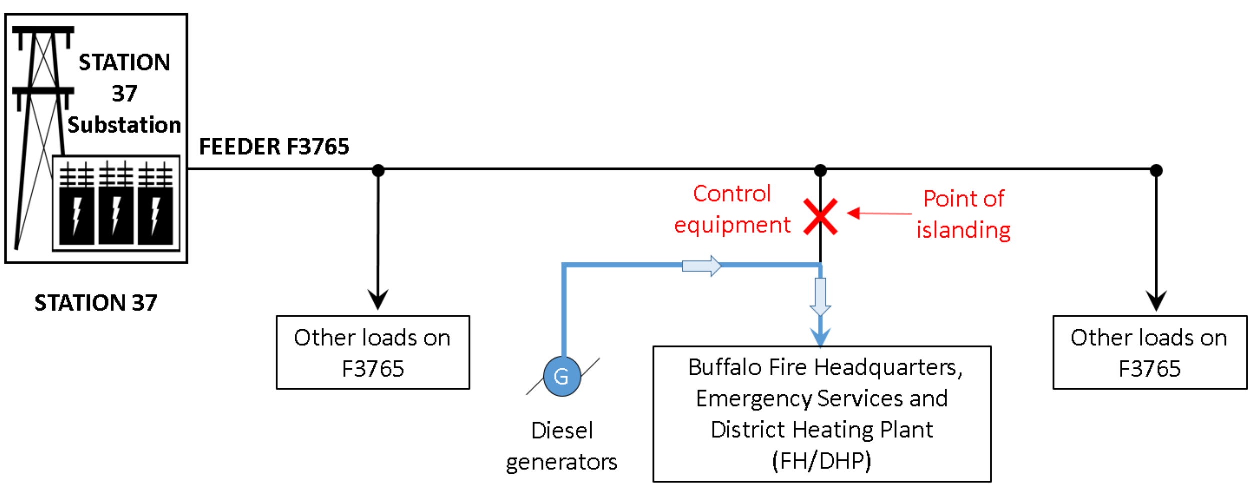
[15] Recall that the DER-CAM recommended operating plans are based upon assumed hourly loads, tariffs, and other factors. In real life, the microgrid would be operated for best performance based on the current and near-term-predicted conditions.

- *Outage-driven unplanned islanding* – A confirmed grid outage is detected by the recloser or switch at the Point of Common Coupling ("PCC"), which would open and start the unplanned/unscheduled islanded mode transition.
- *Command-driven unplanned islanding* – A triggering event is detected by the monitoring platform that initiates the island recloser or switch at the PCC to open and start the unscheduled islanding transition. Alternatively, the utility operation center receives notification of the triggering event(s) and works with the Grid Operator to use DMS/SCADA in order to open the recloser.

Based on discussions with the City of Buffalo, we modeled a two-week outage during a winter storm event in January. The current configuration of feeder F3765, including the FH/DHP building, during an outage is shown in Figure 13. Note that in the absence of any information about the existence of backup generation for other F3765 buildings we assumed that none is present. This assumption will need to be validated or modified during the next phase of the project.

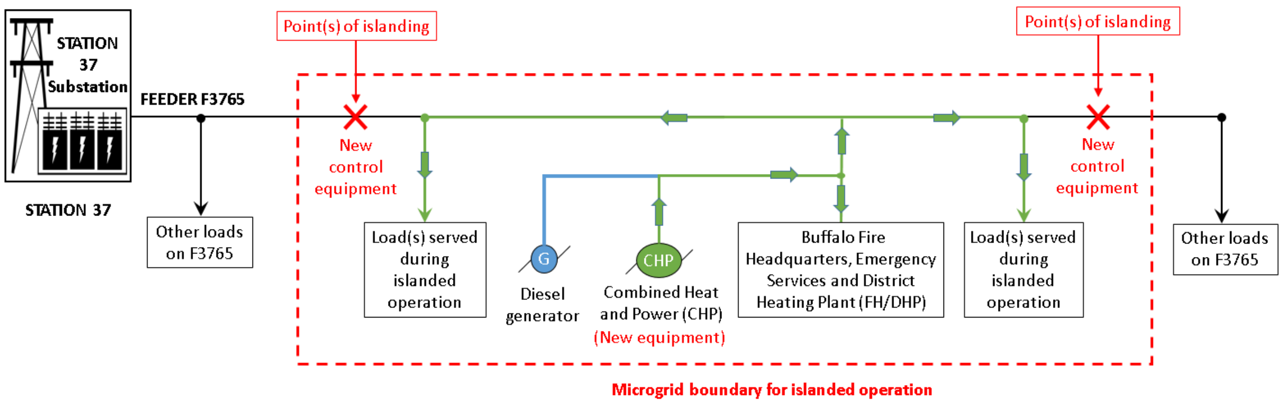
Given the current fuel tank capacity of the diesel gensets, which is estimated to give only 32 hours of runtime out of the 336 outage hours, outage costs would be heavy under the baseline (non-investment) scenario. When the microgrid is put in place one of the diesel gensets will be removed to make room for the new CHP. Only one genset will then remain connected and in service as backup. For modeling purposes it was assumed that this remaining genset will have enough fuel stored on premises to run for no more than 32 hours. Note that DER-CAM optimization results showed that there are very few times when diesel backup is preferred to the CHP.

Figure 13 – Emergency baseline scenario (no microgrid)



The proposed microgrid with 500 kW CHP would be able to serve all of the electric load of the FH/DHP plus the R50-F3765 electric load. There will be two points of islanding, at a minimum, at least one upstream of the FH/DHP and one or more downstream (see Figure 14). Given the topology of the feeder it appears that not many options exist for two points of islanding to isolate a load of 500 kW during the outage scenario. However, additional points of islanding are not preferred because they are expensive and add complexity to the microgrid's control scheme. The buildings to be included during an outage, and the locations of the points of islanding, can only be conclusively determined during a detailed study phase.

Figure 14 – Emergency (outage) scenario with 500 kW CHP



Subtask 2.2 – Load Characterization

Question 2.2.1

Fully describe the electrical and thermal loads served by the microgrid when operating in islanded and parallel modes: Peak KW, Average KW, annual /monthly /weekly KWh, annual/ monthly/ weekly BTU (consumed and recovered) and identify the location of the electrical loads on the simplified equipment layout and one-line diagrams.

The electrical load of the FH/DHP is primarily for captive use, though the portion used by the DHP has a significant impact on other buildings on the District Heating thermal loop. Conversely, the FH/DHP's thermal load is primarily used to produce hot water and steam for the space heating needs of the buildings on the District Heating loop; consumption by the FH/DHP building itself is only about 6% of the total DHP heating load.

The R50-F3765 electrical load is the aggregate of all the other building loads connected to the feeder when the microgrid is islanded. R50-3765 thermal loads are not part of the microgrid.

Parallel (grid-connected) mode

In grid-connected mode, the microgrid will serve the FH/DHP electrical load and will export any remaining power produced by the CHP to National Grid via feeder F3765. The CHP will provide thermal energy to the DHP in the form of hot water, which will take place within the FH/DHP complex. Figure 12 shows the locations of the grid-connected loads. Specific destinations for the loads served with exported power cannot be designated because these locations will vary in real-time according to demand on the grid and the amount of power that the CHP exports.

Table 4 lists the monthly and annual average, peak, and total electrical and heating load of the FH/DHP. Weekly data are not specifically provided for two reasons:

1. The profiles used by DER-CAM assume that weekly and monthly values are the same. That is, those profiles are the result of averaging over an entire month.
2. The raw 8760 profiles from which we created the DER-CAM profiles were not sourced from actual building data, but rather were profiles from simulations of DOE reference buildings. Given that using such reference building profiles has much uncertainty compared with using actual building data, we believe that studying the granular weekly averages from the reference data is more likely to show misleading artifacts than reveal actual usage insights.

Table 4 – Monthly and annual electric and heating loads statistics for the FH/DHP

Month	FH/DHP Electric load			FH/DHP Heating load		
	Average (kW)	Peak (kW)	Total (kWh)	Average (kBtu)	Peak (kBtu)	Total (kBtu)
January	130	199	94,464	2,207	14,043	1,651,452
February	135	207	88,140	2,002	14,448	1,456,630
March	121	214	87,555	820	12,394	751,598
April	94	159	66,153	331	6,232	285,536
May	63	112	45,527	121	2,265	103,923
June	45	84	31,347	45	605	35,583
July	50	94	36,711	28	148.587	21,545
August	55	95	39,742	39	485	29,636
September	50	97	36,032	68	1,599	67,167
October	62	109	45,395	285	5,191	257,299
November	90	151	63,083	569	5,946	470,342
December	126	199	92,790	1,808	14,501	1,401,150
Annual	**85**	**214**	**726,939**	**694**	**14,501**	**6,531,863**

Islanded mode

When islanded, the microgrid will still serve the FH/DHP electrical load and provide hot water to the DHP. However, it will also directly meet the electrical (but not thermal) needs of the islanded buildings, i.e., the F50-R3765 loads. Figure 14 shows the possible locations of those buildings on F3765, though the specific buildings to be served will not be determined until a design study is performed.

Table 5 – Monthly and annual usage statistics for electric and heating loads for the Rest of F3765

Month	R50-F3765 Electric load		
	Average (kW)	Peak (kW)	Total (kWh)
January	155	266	114263
February	154	251	102208
March	155	296	114199
April	145	265	102548
May	147	297	108280

Month	R50-F3765 Electric load		
	Average (kW)	Peak (kW)	Total (kWh)
June	164	352	116476
July	164	364	121927
August	174	351	128076
September	154	321	111063
October	148	287	109451
November	152	274	108040
December	152	274	112564
Annual	**155**	**364**	**1,349,095**

Question 2.2.2
Provide hourly load profile of the loads included in the microgrid and identify the source of the data. If hourly loads are not available, best alternative information shall be provided.

The hourly load profiles used for DER-CAM modeling are provided in Appendices B.1 through B.3. Included are the electrical profiles of the FH/DHP and R50-F3765, as well as the thermal load profile of the FH/DHP. Sources of the profiles are documented in Section 1.2 above.

Question 2.2.3
Provide a written description of the sizing of the loads to be served by the microgrid including a description of any redundancy opportunities (ex: n-1) to account for equipment downtime.

In grid-connected mode the microgrid fully meets the FH/DHP electric demand and can export any of its remaining capacity to feeder F3765. The capacity of the CHP is greater than the maximum (winter) FH/DHP electric demand by more than a factor of two. Depending on the FH/DHP demand at the moment, CHP output can drop to 40% or less of capacity and still fulfill the FH/DHP's needs. If the CHP's output drops below that, or if economic factors makes power from National Grid more cost-effective, the grid can cover the FH/DHP power needs as well. Thermally, even when running at full capacity the CHP's heat output (as hot water) is in no way critical to the operation of the DHP.

Under outage conditions, the microgrid is sized to fully cover the power needs of all buildings within the island. This includes the FH/DHP and R50-F3765 electrical loads. No provision has been made for automated load shedding under the feasibility study scenario, however as necessary manual load shedding and/or can be implemented if the CHP is not producing sufficient power for some reason. As in grid-connected mode, during an outage the CHP's thermal output contributes only a minimal amount to the heating load of the DHP. The DHP can operate at full capacity without the CHP's thermal contribution.

The onsite diesel generator can also be used to provide up to 200 kW for 32 hours if the CHP goes down, however, due to the critical nature of the FH/DHP building and the DHP loads, the diesel-generator power would be reserved for FH/DHP usage only.

We chose not to achieve additional redundancy by splitting the 500 kW into two 250 kW units, because that split would result in a higher capital cost, which is not economically practical for this project.

Subtask 2.3 – Distributed Energy Resources Characterization

Question 2.3.1
Provide the following information regarding Distributed Energy Resources (DER) and thermal generation resources that are a part of the microgrid: Type (DG, CHP, PV, boiler, solar water heater, etc.), rating (KW/BTU), and fuel (gas, oil etc.).

Table 6 lists the required specifications of the microgrid's DERs. Note that the FH/DHP building contains the District Heating Plant, a thermal generation asset. However, that equipment plays the role of a load, not a generation resource, on the proposed microgrid.

Table 6 – General specifications of microgrid DERs

DER	Type	Rating	Fuel
Combined Heat and Power unit	Internal combustion engine electric generator with CHP accessory	500 kW electrical (Approx. 980 kW thermal)	Natural gas
Diesel backup generator	Cummins Onan standby generator (model 200DF8D 37301E)	200 kW	Diesel fuel

Question 2.3.2
If new DER or other thermal generation resources are a part of the microgrid, provide a written description of the approximate location and space available. Identify the DERs on the simplified equipment layout and one-line diagrams. Differentiate between new and existing resources.

The proposed microgrid solution requires only one new DER, the 500 kW CHP unit. Space exists in the outdoor courtyard to accommodate the CHP generator if the existing 250 kW diesel generator is removed. The proposed location for the new CHP is shown in the equipment layout graphic, Figure 10. The electrical connection point of the new DER is shown on Figure 11, the simplified one-line diagram.

Question 2.3.3
Provide a written description of the adequacy of the DERs and thermal generation resources to continuously meet electrical and thermal demand in the microgrid.

See our response to Question 2.2.3 for details of the microgrid's coverage of demand in the microgrid. Figure 15 shows DER-CAM results for grid-connected CHP operation during a typical weekday in January. The dashed line show the electric load of the FH/DHP, which the CHP serves fully while also exporting power to F3765. Figure 16 shows DER-CAM results for the heating load of the DHP during the month of January. The heating load is very large since the DHP serves six buildings. Heat recycled from CHP can be seen to contribute very little to meeting the DHP heating load.

Figure 15 – DER-CAM results showing the CHP's ability to meet the FH/DHP's electric load, during the month of January, in grid-connected mode.

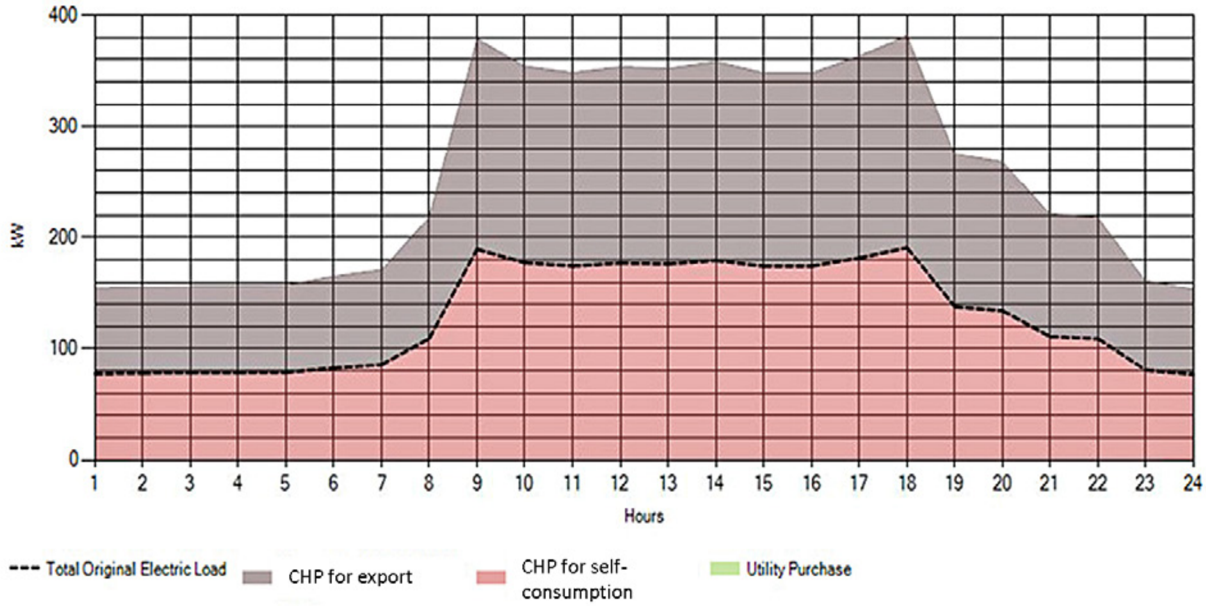
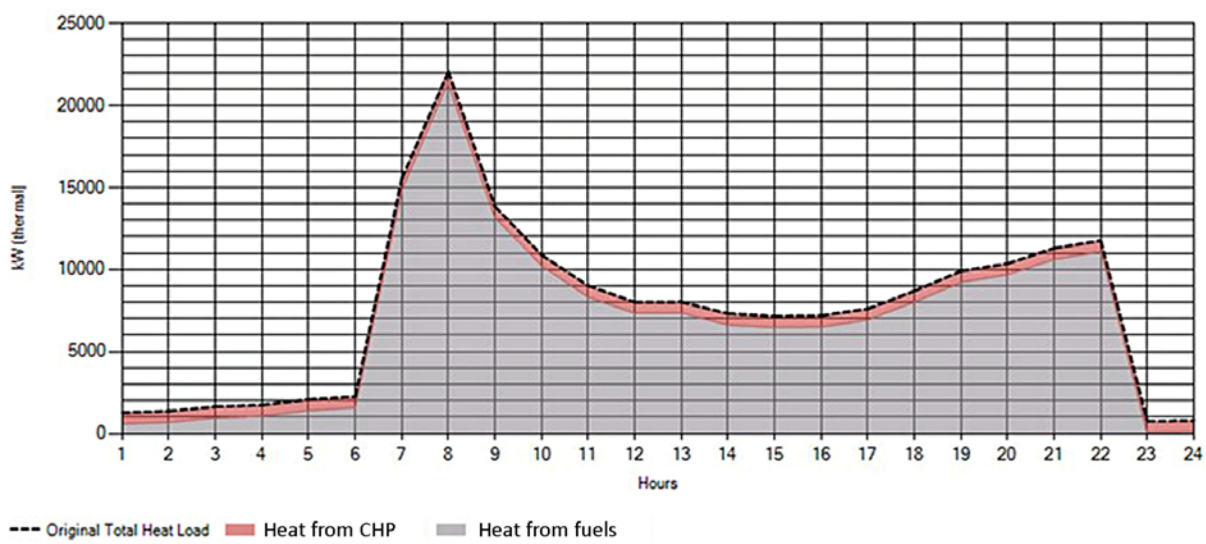


Figure 16 – DER-CAM results showing the CHP's contribution to the DHP's thermal load, during the month of January, in grid-connected mode.



Question 2.3.4

Describe how resilient the DERs and thermal generation resources will be to the forces of nature (severe weather) that are typical to and pose the highest risk to their operation (example, reduced or zero output due to snow cover over PV panels, potential flooding of low lying areas, etc.)?

Feeder F3765 is buried underground and will not be affected by severe weather. The diesel generator and its diesel tank is indoors and will likewise not be affected. The proposed CHP will be located outside the FH/DHP, in the courtyard that houses the tower. A rugged enclosure can easily be built around it to protect it from the snow and wind during the winter.

Question 2.3.5

Provide a description of the fuel sources for DER. Describe how many days of continuous operation of the microgrid can be achieved with current fuel storage capability? If additional fuel storage is required, provide a written description of needs required for this.

The FH/DHP's diesel genset has a fuel storage tank with 32 hours of capacity. According to DER-CAM optimization results, it should (and will) generally only be run as a backup to the CHP, rather than as a primary backup in the event of a grid outage.

The 500 kW CHP unit will run on natural gas. We assume the following three conditions: (1) Even in the case of a severe snowstorm natural gas will always be available, (2) there will never be an interruption in the supply of natural gas, and (3) the supply is for all practical purposes inexhaustible. (See Question 2.4.2 regarding the resilience of the natural gas supply.)

Question 2.3.6

Provide a written description of the capability of DERs including, but not limited to the following capabilities; black start, load-following, part-load operation, maintain voltage, maintain frequency, capability to ride-through voltage and frequency events in islanded mode, capability to meet interconnection standards in grid-connected mode.

The capabilities of the microgrid's DERs are described in Table 7.

Table 7 – Capabilities of the microgrid's DERs

Capability	Included	Description / Comment
Black start	✓	Will be designed into microgrid resources. CHP and diesel generators will be isochronous masters during islands.
Load-following	✓	CHP will actively follow load during islanded operation. Details to be determined during design phase.
Part-load operation	✓	The microgrid will be designed for part-load operation, however CHP efficiency will be low when loads are very low.
Maintains voltage and frequency	✓	CHP unit will operate in parallel with the grid during grid-connected mode. The unit will have voltage and frequency droops for voltage and frequency regulation. This will operate in conjunction with the higher level microgrid control system that will provide correction set points.
Ride-through voltage and frequency events in islanded mode	✓	CHP will provide the master voltage and frequency reference during islanded operation. Controls will be designed so that the CHP can ride through momentary voltage and/or frequency sags. Built-in protection relays will continuously monitor the voltage and frequency and will trip the CHP if sags go beyond the design limits.

Capability	Included	Description / Comment
Meets interconnection standards in grid-connected mode	✓	Microgrid will be designed to meet interconnection standards during grid-connected mode. This will include detailed analysis of feeder line rating, short circuit levels, transformer capacities, reverse power flow, voltage regulation issues etc., to ensure that the microgrid will have no adverse impact on the main grid.

Subtask 2.4 – Electrical and Thermal Infrastructure Characterization

Question 2.4.1

Provide a high-level written description of the electrical infrastructure (feeders, lines, relays, breakers, switches, current and potential transformers (CTs and PTs) and thermal infrastructure (steam, hot water, cold water pipes) that are a part of the microgrid. Identify the electrical and thermal infrastructure on the simplified equipment layout (with approximate routing) and one- line diagrams (electrical only). Differentiate between new, updated and existing infrastructure.

Electrical infrastructure

The proposed microgrid will cover both the FH/DHP and one or more buildings on F3765 (on one or both sides). Therefore, its infrastructure will include the electrical distribution network of both the FH/DHP and National Grid. The 500 kW CHP will be connected to the existing 480 V network within the FH/DHP complex. There will be some changes to the electrical distribution network within the building to facilitate CHP connection and microgrid operation. However, the National Grid electrical feeder F3765 and the cable lines will remain as is and will serve the same customers as are being served now.

We have assumed that the existing switchgear can handle the combined short circuit currents, so we do not anticipate any change to the existing 4.16 kV switchgear. However, National Grid will have to add switching devices at all points of islanding, which will include reclosers, breakers, CTs, PTs, relays, etc., with the capability of sensing, isolating, and reconnecting the microgrid with the main grid. Since the maximum load in the network during islanded operation will be less than 500 kW, there is no need for load shedding schemes. Microgrid control hardware will also be incorporated into the DERs and the microgrid controller software will be run on a workstation.

Tables 8-11 provide more detail about the infrastructure changes and upgrades required. The electrical infrastructure is shown in Figure 11 at the level of detail possible without the benefit of a design study.

Table 8 – Building electrical infrastructure upgrades

Infrastructure Upgrade	Component	FH/DHP	Rest of F3765
CHP connection	Switchgear at CHP location, if required – complete with controls and protection	✓	
	Matching transformer, if needed	✓	
	2x installation, wiring, testing, and commissioning	✓	
Switchgear modification work	Modification to existing 4 kV and 480 V network, as needed (to be determined)	✓	
	Installation, wiring, testing, and commissioning	✓	

Infrastructure Upgrade	Component	FH/DHP	Rest of F3765
Layer 2 controls - Backbone (PLC, Ethernet)	Installation, wiring, testing, and commissioning	✓	
	Data acquisition at 4 kV	✓	
	Layer 2 automation – covering 4 kV	✓	✓
	High-speed load shedding system (included with above)	✓	✓
	UPS for control system (included with above)	✓	✓
	Critical load desensitization (included with above)	✓	✓
	Control cabling (included with above)	✓	✓
	Communication network (included with above)	✓	✓
Power cabling	Changes to cabling – connection of CHP to switchgear; removal of 250 kW diesel genset cabling	✓	

Table 9 – Feeder infrastructure upgrades

Infrastructure Upgrade	Component	Included?
Installing re-closers on F3765	2x new 4 kV breakers	✓
	1x set of protection relays	✓
	1x set of control modification work	✓
	Installation/wiring/testing, commissioning	✓
Power system study by NG	Power system study by NG	✓

Table 10 – Communication infrastructure upgrades

Component	Included?
MG Supervisory Control System	✓
Interface to Utility system	✓
Interface to energy market system	✓

Table 11 – Total infrastructure upgrade costs

Component	Capital Cost ($)
Electrical infrastructure	$300,000
Thermal infrastructure	$15,000
Controls infrastructure	$100,000
Total	**$415,000**

Thermal infrastructure

Since the DHP functions as a load on the microgrid, rather than a thermal generating resource, the only thermal infrastructure required is that required for integration of the hot water output of the CHP into the DHP heating circuit. We assume in this study that the connection would be made in series with the boilers (see the response to Question 2.1.1). The specific connection details will be determined with a design study. However, components will include piping, valves, controls, sensors, and a pump. Other components could include headers and local thermal storage (which would also require a pump).

The equipment layout diagram, Figure 10, shows the general routing of the hot water connection from the CHP to the DHP. Again, placement of specific components will not be known until the design is worked out.

Question 2.4.2

Describe how resilient the electrical and thermal infrastructure will be to the forces of nature that are typical to and pose the highest risk to the location/facilities? Describe how the microgrid can remain resilient to disruption caused by such phenomenon and for what duration of time. Discuss the impact of severe weather on the electrical and thermal infrastructure.

DERs and electrical infrastructure

The highest-risk force of nature expected is severe weather, in particular wind and prolonged snow in large amounts. Feeder F3765 is buried underground and will not be affected by such weather. The diesel generator and its fuel storage tank is indoors and will likewise not be affected.

The proposed CHP will be located outside the FH/DHP, in the courtyard that houses the tower. Assuming that a rugged enclosure is built around it and piping is adequately insulated (and possibly heated), there will be little impact from severe weather. However, it will require inspection and upkeep at regular intervals, as well as snow and ice clearing to ensure ready access if needed. The controller workstation(s) will be housed indoors and well protected.

Natural gas supply

The underground nature of natural gas distribution system infrastructure provides exceptional resiliency in the face of severe weather phenomena typically seen in the Western New York area; namely snow, ice, and wind storms. Other types of natural disasters which could potentially have a greater impact on underground pipelines, such as severe earthquakes or flooding, are extremely uncommon in the Western New York area and, as such, pose very little risk to system reliability. In fact, according to the latest Federal Emergency Management Agency (FEMA) flood plain maps, the area around the FH/DHP and the majority of the City of Buffalo is classified as being outside even the predicted 500-year flood plain[16]. Additionally, gas delivery systems in Western New York have proven resilient in the face of extended periods of extreme cold. In the winters of 2013/2014 and 2014/2015 for example, two of the coldest on record, gas delivery continued with no significant disturbances.

Furthermore, the natural gas delivery system remains reliable even in the event of a significant and widespread grid outage as was concluded in a 2013 Massachusetts Institute of Technology (MIT) study

[16] FEMA Flood Map Service Center - https://msc.fema.gov/portal/search?AddressQuery=14216#searchresultsanchor

conducted for the Department of Defense (DOD).[17] This study analyzed the interdependence of the nation's electric generation and gas delivery systems and concluded as its number one recommendation that:

"DOD installations with large electricity loads should consider installation of natural gas generation or cogeneration plants to increase their energy security from the typical three days using diesel supplies to weeks-to-months using natural gas generation."

The Western New York area is also optimally positioned in terms of reliability of natural gas supply. In recent years, nationwide gas production has shifted significantly from traditional offshore rigs in the Gulf of Mexico to shale drilling. Since this time, the portion of the Marcellus shale region found in Northwest Pennsylvania has been one of the most productive regions of the country. This production is also expected to continue into the foreseeable future, as there is currently a backlog of completed wells awaiting the construction of new gathering and transmission pipeline capacity. The Marcellus region also sits directly beneath a network of different interstate, and midstream pipelines, on which National Fuel Gas Distribution Corporation (NFGDC) holds firm capacity, providing redundant delivery routes to NFGDC's city gate. The FH/DHP facility benefits from its proximity to this region of abundant gas supply, and pipeline capacity in that interstate pipeline constraints which can cause escalated pricing, and limited supply in areas such as New England are not of concern in Western New York. Finally, even in the extremely rare event of a supply shortage and gas curtailment situation, NFGDC's operating procedures dictate that steps be taken to prioritize service to critical care customers such as those being served by the proposed microgrid.

Question 2.4.3

Provide a written description of how the microgrid will be interconnected to the grid. Will there be multiple points of interconnection with the grid? What additional investments in utility infrastructure may be required to allow the proposed MG to separate and isolate from the utility grid? Provide a written description of the basic protection mechanism within the microgrid boundary.

Figure 11 shows the proposed microgrid and its interconnection with the grid. The microgrid will interconnect with the grid at a single location, which is the point of connection of the FH/DHP complex and the grid.

As described elsewhere, there will be two points of islanding, at a minimum, at least one upstream of the FH/DHP and one or more downstream. The buildings to be included during an outage, and the locations of the points of islanding, will only be determined by a design study. Utility infrastructure investment for separation and isolation is described in the response to Question 2.4.1.

The existing protection system will need to be reviewed to determine whether and where modifications are needed to take care of the following within the FH/DHP, the buildings that are part of the microgrid during islanded operation, and the National Grid distribution system:

[17] Interdependence of the Electricity Generation System and the Natural Gas System and Implications for Energy Security - https://www.serdp-estcp.org/News-and-Events/News-Announcements/Program-News/DOD-investigates-reliability-of-natural-gas-fired-generators-during-electric-grid-failures2

Grid-connected operation

- Additional short-circuit capacity (fault current levels) created by the CHP
- Reverse power flow from the CHP exporting power to feeder F3765. National Grid may need to modify existing reverse-power relays.

Islanded operation

- Detection of "missing grid" in the event of an outage
- Low short-circuit levels. When islanded, short-circuits many be difficult to identify on the basis of high current levels, so additional means of detection are needed. Relays should have dual settings to handle both grid-connected and islanded operation.
- Additional protection schemes may be required if standard overcurrent and short-circuit relays are not capable of detecting a fault in a microgrid.

The redesign of the protection system will be performed as part of the detailed design study.

Subtask 2.5 – Microgrid and Building Controls Characterization

Question 2.5.1
Provide a high-level written description of the microgrid control architecture and how it interacts with DER controls and Building Energy Management Systems (BEMS), if applicable. Identify the locations of microgrid and building controls on the simplified equipment layout diagram. Differentiate between new and existing controls.

The FH/DHP complex does not have a BEMS. Microgrid controls are identified on Figure 11 at the level of detail possible without the benefit of a design study.

The DERs will have hardware controls attached to, integrated into, or near the equipment. To operate the microgrid and achieve best microgrid benefits, an intelligent and holistic planning and control system with a robust communication backbone will be necessary. As part of this project, a scalable, intelligent local microgrid controller will be implemented. The microgrid controller will be a software program, operated on one or more computer workstations.

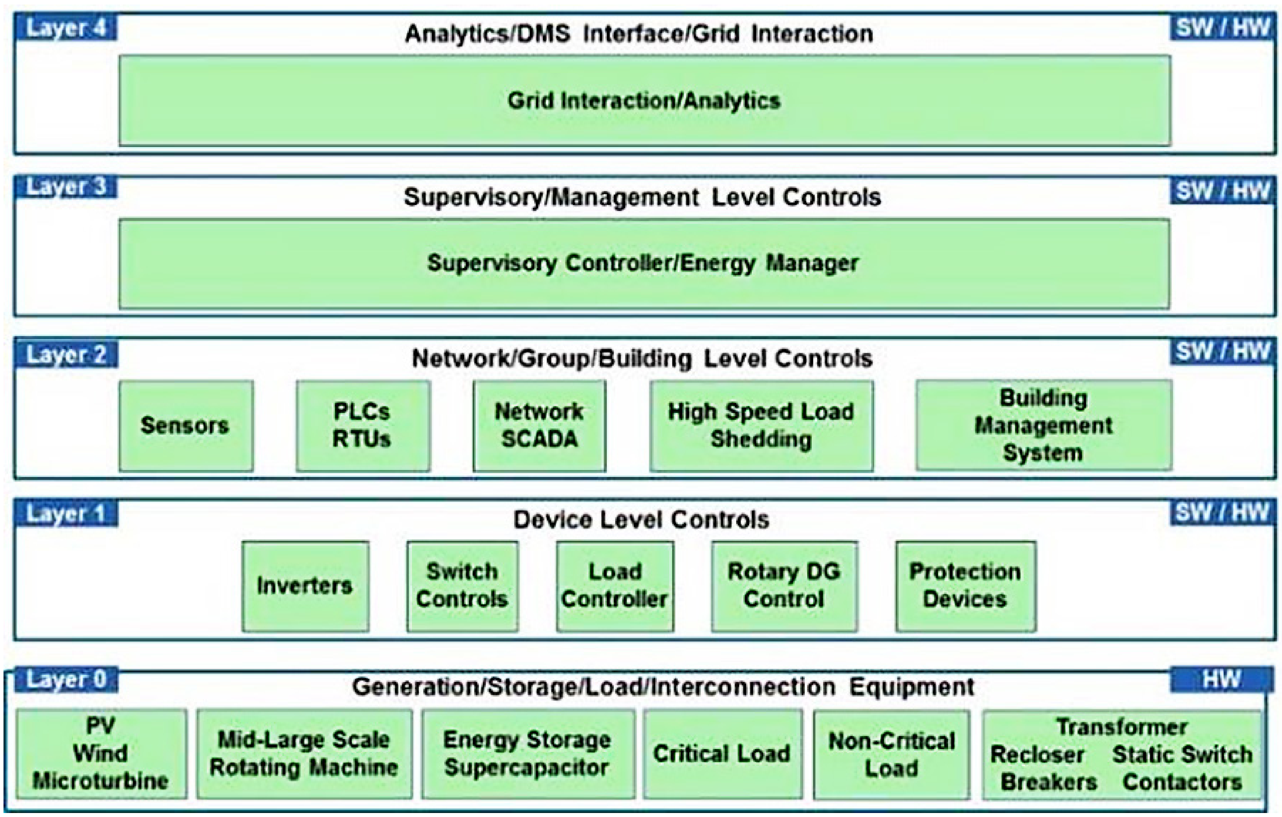
The project team will conduct a detailed analysis on the controller features, requirements, communication needs, and information technology (IT) infrastructure at the site. Features of the controller to be analyzed and considered will include the following elements:

- Optimal control of the flow of both electrical and thermal energies in order to take full advantage of Combined Heat and Power (CHP) technologies and thermal storage
- Ability to identify the operation mode (grid-connected or islanded) and adjust the optimization objectives and constraints to satisfy the relevant operating criteria
- Commercially available, standard capabilities for voltage control, frequency control, grid-connected and islanded operations, and open communication protocols

- Standardized information and communication protocols to meet designated the interoperability, communication, control requirements and to adhere to interconnection standards, protection, and safety requirements
- Connection to the National Grid D-SCADA backbone, plus features that enable security against cyber-attacks
- Adaptability to integrate with National Grid's protective devices at the site
- Use of open protocols and interfaces to communicate and coordinate with DER and loads. This can enable simple configuration, deployment, and operation of interfacing with both customer and utility-level control.
- Ability to connect to a (future) BEMS, either to command a specific operation or receive and send signals

The controller will follow an open multi-layered distributed architecture, in which control tasks will be distributed among four different layers (on top of a "zeroth layer" consisting of the DERs and interconnection equipment). The multi-layered control system will ensure stable, reliable, and optimized microgrid operation. The control system that we propose is also the basis for the IEEE 2030.7 standard and will include the four layers shown in Figure 17.

Figure 17 – Layered microgrid controller architecture from DER to grid interaction [Source: EPRI, LBNL, Microgrid Labs]



The specific layers identified here include *device level control*, *network level control*, *supervisory control*, and *grid interactions/analytics*. These are further discussed below.

- **Layer 0** captures the DER types and load types and pertains to energy generation (resources) and storage as well as load requirements.
- **Layer 1 (**device level control**)** includes the individual device level control, acting in the micro- to millisecond range.
- **Layer 2** (network level control) is the control layer which manages DER, including scheduling and dispatching and their network connectivity and where operational commands are sent out. Acts in the millisecond to seconds range.
- **Layer 3** (supervisory control) consists of supervisory control where energy management activities are performed, acting in the time range from one to several minutes.
- **Layer 4** (grid interactions/analytics) provides the grid connectivity to DMS, SCADA, and market.

Question 2.5.2
Provide a brief written description of the services that could be provided by the microgrid controls including, but not limited to the following:

- **Automatically connecting to and disconnecting from the grid –** The controller will provide this functionality.
- **Load shedding schemes –** This is not likely to be implemented under the configuration studied here, as the CHP is sized to be able to cover all assigned loads completely. However, the design study and use case development may indicate that this is necessary.
- **Black start and load addition –** Black start will be implemented, but whether or not it will be managed by the microgrid controller will be determined after the design study and use case development.
- **Performing economic dispatch and load following –** Load following will be implemented and economic dispatch is also planned. Both will be informed by the design study and use case development
- **Demand response –** At this point, this service is not needed but is potentially an option if that is what makes sense after the design study and use case development.
- **Storage optimization –** This will not be a control feature as there is no energy storage in this microgrid.
- **Maintaining frequency and voltage –** The CHP unit will operate in parallel with the grid during grid-connected mode. The unit will have voltage and frequency droops for voltage and frequency regulation. This will operate in conjunction with the higher level microgrid control system that will provide correction set points.
- **PV observability and controllability; forecasting –** There is no PV in the proposed microgrid so this feature is not applicable.
- **Coordination of protection settings –** This is a potential feature, to be determined after design study and use case development.
- **Selling energy and ancillary services –** As currently envisioned, energy will be exported to National Grid, rather than being sold to NYISO, so energy sales will probably not be provided by the controller.

However, energy sales may be found to be attractive after completion of the design study and use case development. The configuration studied here does not involve ancillary services, so this function will not be implemented.

- **Data logging features –** The controller will provide this functionality.
- **How resilient are the microgrid and building controls? Discuss the impact of severe weather on the microgrid and building controls.** Our response follows immediately below.

Resilience and reliability of microgrid controls
Because resilience and reliability are the result of specific system and component design approaches and choices at the planning and implementation stages, increased resilience and reliability cannot be obtained only by means of a specific controller function. However, the microgrid will provide increased resiliency and reliability for feeder F3765 in the following ways:

- Resilience:
  - Backup power during extreme, infrequent, and long-duration outage events
- Resilience – additional services:
  - Backup power for priority loads
  - Optimize islanding duration
  - Minimize load not served
- Reliability – minimum requirements:
  - Uninterrupted power
- Reliability – additional services:
  - Backup power during more regular, frequent outages
  - Improvement of SAIDI, SAIFI, CAIDI numbers
- “Downstream” power quality – additional services:
  - Mitigation of voltage/frequency sags and surges through load hardening efforts

Question 2.5.3
How resilient are the microgrid and building controls? Discuss the impact of severe weather on the microgrid and building controls.

There are no building controls at the FH/DHP. Microgrid controls will be part of the National Grid underground infrastructure, housed within the FH/DHP complex, or co-located with the DERs. Please refer to our responses to Questions 2.3.4 and 2.4.2 regarding the weather resilience of these microgrid components.

Subtask 2.6 – Information Technology (IT)/Telecommunications Infrastructure Characterization

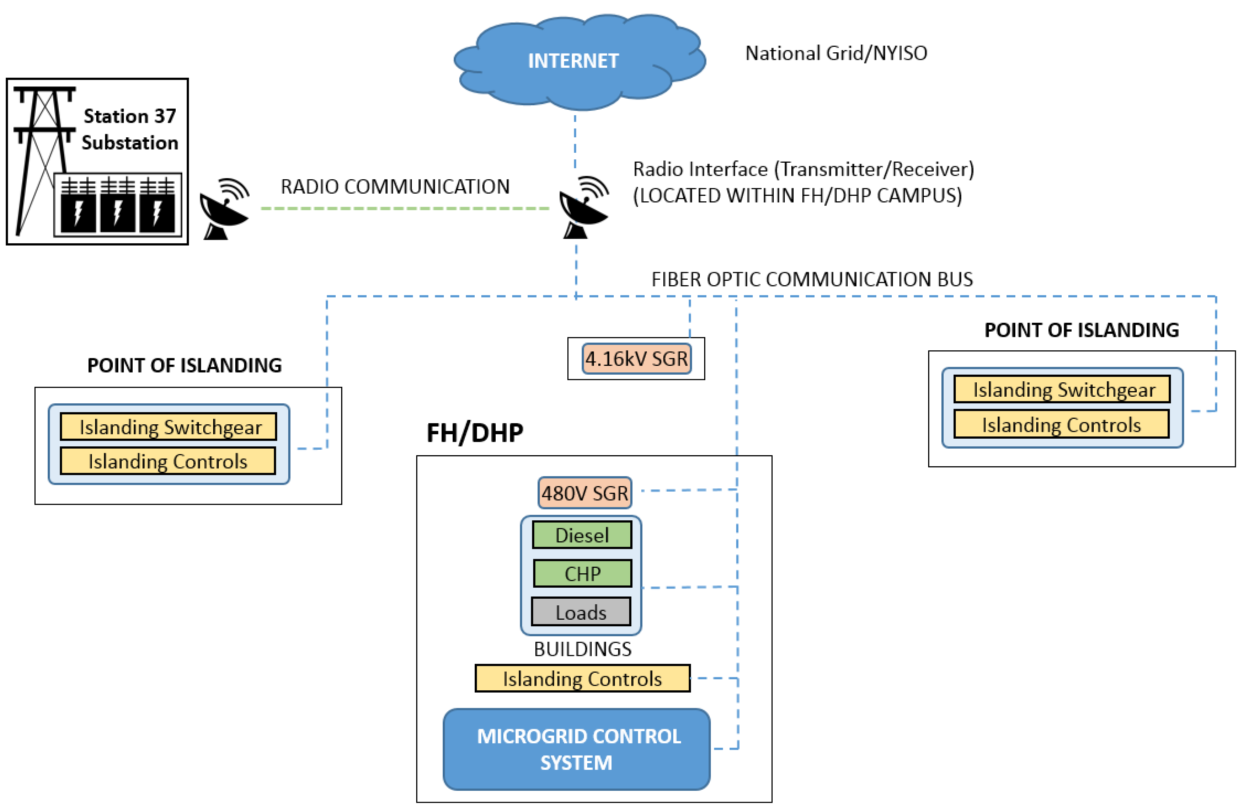
Question 2.6.1

Provide a high-level written description of the IT/Telecommunications Infrastructure (wide area networks, access point, Ethernet switch, cables etc.) and protocols. Identify the IT and telecommunications infrastructure on the simplified equipment layout diagram. Differentiate between new and existing infrastructure.

A new IT/communication network will be developed as part of this microgrid. To prevent unauthorized access to the City of Buffalo (FH/DHP) main information network, a physically separate network of fiber optic cables will be used for the control system infrastructure, which will be isolated from the main network. This prevents accessing the FH/DHP main information network, which may be connected to other assets, through intrusion into the control network. Local microgrid communications at the FH/DHP would be accomplished with underground fiber from the microgrid controller to all the proposed DERs, generators, switches, building management and RTUs.

The microgrid controller would be capable of either local autonomous control or remote control via SCADA. The proposed controller will be designed with open communications standards using an Enterprise Service Bus, DNP3, IEC61850, and ModBus, among others**.** In addition to these protocols, the controller platform will be capable of interfacing with any SCADA, DMS, or DER assets that use open protocols. The IT and telecommunications infrastructure are diagrammed in Figure 18.

Figure 18 – High-level IT/telecom infrastructure diagram



As part of the design analysis, the overall architecture for the communication backbone will be developed and an audit will be performed to see if the existing assets have the ability to be connected with the microgrid controller at the site. The communication protocols of the proposed microgrid controller will be based on an open architecture to enable integration with existing or future automation systems to perform network level controls. This enables use of existing power automation and Supervisory Control and Data Acquisition (SCADA) systems as the network control layer, reducing cost of new investment. This will in turn distribute the controller signals to the technologies or interface with a future building management system to perform load management based on the microgrid controller commands.

Telecom infrastructure at the FH/DHP

The telecom infrastructure for the microgrid will involve two tiers:

- **Tier 1 is the backhaul and inter-site interconnection.** Tier 1 is relevant to potential future microgrid expansion. This tier should be closely integrated with existing telecom infrastructure. It is assumed that all sites will have existing fiber for telephone and Internet services.

- **Tier 2 is the access network.** The access network (also known as a Field Area Network or FAN) provides connectivity to the microgrid devices – generation, reclosers, sensors, switches, relays, etc. and provides connection to the management systems. Tier 2 is the primary level for the microgrid as envisioned in this feasibility study.
  - If microgrid devices are in locations with Ethernet already installed, it is the preferred technology for the access networks. VLANs should be employed to isolate and secure the microgrid from other local networks.
  - The access network can also leverage existing wireless LAN infrastructure. For example, if a local Wi-Fi network is in place, a virtual SSID and private network can be overlaid to serve the microgrid, and isolate the microgrid network from other users.
  - A new access network can be built out. A Wi-SUN FAN could be deployed across the area. (Note: further use case analysis will be required, as some microgrid use cases require communications data rate and latency beyond the capability of Wi-SUN.)
  - Other FAN technologies in unlicensed or licensed spectrum may be considered.
  - A combination of access technologies can be used across the planned microgrid area.

Question 2.6.2

Provide a written brief description of communications within the microgrid and between the microgrid and the utility. Can the microgrid operate when there is a loss in communications with the utility? How resilient are the IT and telecommunications infrastructure?

The City of Buffalo microgrid network will include communications to National Grid. This can be achieved in several ways:

- The microgrid network can be interconnected as part of a utility Field Area Network. In this case, the reliability of the microgrid's communications is controlled by the utility and the FAN architecture.
- The microgrid can connect to the utility by a VPN tunneled over the public Internet or commercial cellular. In this case the reliability is determined by the service provider.

- For higher reliability and resilience, multiple interconnection paths (e.g. commercial cellular, fixed Internet Service Provider, and utility FAN) can be deployed in parallel, with automatic fail-over to backup technologies in case of communication outages.

Furthermore, the microgrid should be designed for autonomous operation, independent of connection to the utility. Local intelligence and control should enable essential use cases for the microgrid to operate without communication to the utility, assuming local communication between the microgrid devices remains available.

Appendix B.1 – Hourly Electric DER-CAM Load Profile for the FH/DHP

(kw)		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	week day	77.5	78.0	78.3	78.3	78.6	82.7	85.6	109.0	189.6	177.4	174.4	177.1	176.3	179.3	174.3	174.3	181.7	191.0	137.9	134.2	110.8	109.0	80.7	76.9
February	week day	81.1	81.1	81.4	81.5	81.8	86.1	88.9	98.6	199.4	186.5	183.4	186.3	185.4	188.7	183.3	183.3	187.9	184.2	144.7	140.7	116.1	114.1	84.4	80.3
March	week day	68.9	69.0	69.1	69.5	72.0	76.6	83.1	148.2	176.5	171.5	173.0	174.0	176.4	175.1	173.4	175.4	165.2	123.5	123.3	112.2	102.6	81.0	70.0	68.9
April	week day	57.1	57.1	57.1	57.1	60.2	53.9	66.3	144.5	135.2	133.0	135.1	134.8	137.1	133.3	134.0	137.9	125.6	82.3	83.7	82.6	81.2	60.1	57.1	57.1
May	week day	36.0	36.0	36.0	36.0	35.9	28.0	43.7	94.5	90.0	89.8	92.1	92.5	94.9	92.8	93.5	95.8	87.0	58.3	55.2	51.6	54.3	38.0	36.0	36.0
June	week day	22.3	22.3	22.3	22.3	20.7	22.1	32.4	66.6	64.7	64.9	66.5	66.4	68.9	68.1	69.2	72.5	67.0	46.8	43.7	36.6	40.6	23.5	22.3	22.3
July	week day	23.7	23.8	23.5	23.8	23.2	25.2	35.9	72.2	72.0	73.1	74.4	73.8	76.8	76.1	77.6	81.8	75.8	54.3	51.5	42.7	46.3	24.9	23.8	23.8
August	week day	25.5	25.5	25.5	25.5	26.9	29.6	38.1	79.0	77.7	78.8	81.4	82.3	87.4	86.0	86.7	89.0	81.9	56.2	52.9	49.1	49.1	26.9	25.5	25.5
September	week day	27.3	27.3	27.3	27.3	28.7	30.8	33.4	70.5	68.6	69.8	72.4	73.7	77.1	75.3	74.9	77.6	71.2	48.8	53.2	46.9	45.5	28.7	27.3	27.3
October	week day	36.7	36.7	36.7	36.7	38.6	41.1	48.7	90.8	85.4	84.8	87.2	87.3	89.2	87.5	88.1	90.0	81.8	63.3	66.5	54.9	53.5	38.5	36.7	36.7
November	week day	52.5	52.5	52.5	52.6	52.9	55.7	60.7	69.9	133.5	125.6	123.9	125.9	125.5	126.8	123.5	123.9	131.1	130.6	96.0	91.6	76.7	73.0	55.0	52.6
December	week day	76.5	76.8	76.9	77.0	77.2	81.1	84.2	104.3	182.6	170.7	167.7	170.4	169.7	173.2	168.3	168.4	186.5	186.8	134.7	131.1	108.7	106.9	80.0	76.5
January	peak day	67.8	67.8	67.8	67.8	67.8	72.1	73.0	104.7	198.2	184.6	181.5	184.6	183.8	187.5	181.6	181.5	194.2	192.6	131.5	127.4	101.2	99.2	67.6	64.5
February	peak day	70.6	70.3	70.6	70.3	70.6	74.9	76.1	100.7	206.5	192.4	189.1	192.4	191.6	195.4	189.4	189.2	194.0	192.2	138.5	133.1	105.5	103.3	71.3	68.7
March	peak day	59.9	60.1	59.9	60.1	63.5	76.1	98.4	191.0	183.9	190.6	202.6	208.1	214.0	209.1	207.0	209.5	192.7	153.8	143.7	120.6	115.1	88.4	60.3	56.9
April	peak day	48.4	48.1	48.4	48.1	51.8	54.5	63.1	148.6	143.1	143.7	149.8	153.9	159.1	155.4	152.3	153.2	138.1	90.0	92.1	86.2	85.1	50.5	47.2	47.2
May	peak day	29.4	29.4	29.4	29.4	31.4	37.7	52.3	105.1	99.1	99.6	104.4	105.9	110.0	108.4	109.6	111.3	101.6	66.5	63.7	56.2	60.2	31.4	29.4	29.4
June	peak day	17.8	17.8	17.8	17.8	16.8	30.8	42.0	77.1	74.9	75.7	78.0	78.6	83.6	80.5	78.7	81.1	75.8	52.8	48.6	40.6	46.7	19.0	17.8	17.8
July	peak day	24.1	19.3	23.9	19.3	23.6	38.1	47.3	90.6	86.8	86.6	89.0	88.1	92.4	91.7	91.6	93.4	84.6	58.4	57.0	49.1	52.7	20.6	19.3	19.3
August	peak day	20.5	20.5	20.5	20.5	21.9	43.2	48.6	91.9	86.5	87.0	89.3	90.5	92.9	91.2	92.5	95.0	87.0	59.6	57.5	55.2	55.0	21.9	20.5	20.5
September	peak day	22.2	22.2	22.2	22.2	23.7	43.5	47.9	88.9	83.2	85.0	92.2	93.9	96.8	95.3	95.3	93.9	84.4	58.6	63.4	57.6	56.8	23.7	22.2	22.2
October	peak day	30.8	30.9	30.8	30.9	32.8	43.0	56.5	103.9	97.1	96.4	101.0	105.1	109.1	105.9	106.4	108.1	98.6	71.3	71.2	57.9	56.5	32.2	30.2	30.2
November	peak day	44.4	44.1	44.4	44.1	46.3	49.9	71.6	135.6	149.4	133.3	134.3	140.2	142.6	144.4	139.0	139.3	149.7	150.2	97.4	87.1	69.2	67.8	46.3	43.3
December	peak day	67.1	67.1	67.4	67.1	67.4	71.7	72.6	104.1	198.6	191.6	192.4	193.8	191.0	186.8	180.6	180.6	197.2	191.6	130.8	126.7	100.7	98.6	67.7	64.5
January	weekend day	72.8	73.0	73.3	73.4	73.6	76.4	89.9	107.7	183.4	177.3	174.4	178.6	176.8	176.4	144.4	143.1	149.4	156.1	114.5	112.0	96.1	94.9	75.6	73.0
February	weekend day	75.7	76.0	76.6	76.9	77.0	79.7	93.6	98.7	191.1	184.8	181.7	186.1	184.2	183.8	150.5	149.1	152.5	145.9	119.3	116.7	100.3	99.0	78.9	76.4
March	weekend day	65.2	65.3	65.4	65.5	67.2	74.4	80.5	131.4	165.4	161.4	162.3	163.2	162.7	149.2	136.0	137.4	129.1	97.3	100.3	94.7	87.5	75.6	66.4	65.4
April	weekend day	53.7	53.7	53.7	53.7	55.4	56.8	63.8	132.3	130.2	129.2	133.6	133.5	134.6	109.4	107.3	108.5	93.9	61.2	64.8	71.5	69.9	55.4	53.7	53.7
May	weekend day	33.7	33.7	33.7	33.7	32.9	28.1	40.7	86.3	86.0	87.7	91.2	91.3	92.1	77.8	77.5	79.7	70.6	44.0	41.2	41.4	45.0	35.0	33.7	33.7
June	weekend day	20.6	20.6	20.6	20.6	18.6	21.5	30.3	61.0	61.0	61.3	63.3	63.7	65.5	58.0	58.0	59.6	53.7	34.6	33.2	27.3	32.1	21.4	20.6	20.6
July	weekend day	22.6	21.9	22.5	21.9	21.7	34.1	42.7	73.9	73.2	73.5	76.9	76.4	77.4	68.2	68.6	69.3	61.9	38.6	36.9	32.3	36.9	22.6	21.9	21.9
August	weekend day	23.5	23.5	23.5	23.5	24.3	33.1	39.4	74.6	76.2	77.4	80.1	80.8	83.3	73.6	73.7	75.1	68.1	42.3	39.9	39.5	39.3	24.3	23.5	23.5
September	weekend day	25.4	25.4	25.4	25.4	26.4	37.1	37.6	72.3	71.5	72.4	76.3	77.3	78.5	67.8	67.2	67.5	59.7	37.6	42.1	39.5	38.8	26.4	25.4	25.4
October	weekend day	34.6	34.6	34.6	34.6	35.8	42.8	48.4	87.5	84.6	84.0	86.6	86.0	86.1	70.8	70.1	71.7	62.7	49.0	53.4	45.7	45.1	35.8	34.6	34.6
November	weekend day	49.8	49.7	49.8	49.8	50.4	54.3	63.5	76.9	118.3	114.8	115.1	116.1	115.3	110.4	99.1	99.1	101.8	99.4	77.9	73.8	65.4	61.4	51.0	49.6
December	weekend day	72.4	72.5	72.6	72.8	73.1	75.8	89.4	105.6	182.6	177.4	175.0	178.9	176.9	175.5	143.7	142.4	159.3	156.5	113.9	111.5	95.5	94.3	75.0	72.3

Appendix B.2 – Hourly DER-CAM Heating Load Profile for the FH/DHP

(kw)		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	week day	1275	1377	1649	1753	2085	2269	15550	22071	13848	10897	9016	8019	8030	7314	7160	7191	7608	8698	9910	10367	11303	11774	762	804
February	week day	1270	1440	1642	1914	2104	2375	15025	20936	12402	9801	8270	7497	7278	6425	5978	5886	6248	7049	8404	9086	10252	10877	822	962
March	week day	307	436	468	631	681	5591	9533	8778	5257	3782	3018	2765	2298	1940	1618	1452	1559	2105	3111	4154	4738	2443	203	254
April	week day	102	115	115	126	160	5746	4887	2373	1588	1133	910	1012	743	429	251	270	283	841	1223	2071	2481	85	89	96
May	week day	48	44	48	43	71	2172	1790	714	488	371	324	378	303	187	166	216	177	299	384	698	906	37	36	38
June	week day	28	35	32	29	48	427	458	210	188	174	212	253	242	158	153	196	111	106	90	166	215	39	32	38
July	week day	25	36	28	31	45	89	154	138	144	138	174	214	199	136	123	164	96	87	67	70	41	27	29	36
August	week day	29	28	32	25	55	287	378	170	162	164	190	226	218	147	127	181	109	95	96	179	212	38	26	33
September	week day	37	28	31	31	41	1187	1117	349	244	184	187	209	194	83	102	131	73	147	189	402	542	24	34	28
October	week day	79	73	86	97	128	4687	4220	2075	1328	917	784	892	623	359	242	259	356	986	1240	1747	1981	65	68	68
November	week day	88	87	89	96	115	313	6668	5072	2893	2388	2122	1984	2165	1728	1487	1511	1733	2184	2886	3185	3862	3710	111	126
December	week day	934	1020	1154	1230	1437	1553	12926	16879	10735	8971	7609	6935	6859	6213	5849	5911	6467	7107	8234	8646	9613	9958	855	930
January	peak day	5770	6591	5956	6694	6094	6751	43353	47916	27021	22282	18899	16096	17386	17098	15953	16975	18343	19603	20925	21370	22848	23049	5665	6433
February	peak day	7497	7414	7878	7918	8274	7989	33857	49297	32532	29020	26912	25119	24555	22262	19929	18625	18992	21031	23928	25004	26686	27324	7309	7210
March	peak day	4578	5623	5146	6182	5674	22282	30525	42289	21306	16356	14072	13493	13900	12065	11256	11967	13387	15329	16505	18272	20064	21127	3753	4882
April	peak day	1123	1258	1368	1414	1566	20706	21264	11154	7105	4754	3747	3611	3226	4413	4892	5660	7017	3910	4640	5664	5909	726	852	1039
May	peak day	72	101	81	111	115	7730	5143	1954	1411	1159	1026	1292	891	819	776	913	1082	1533	1793	2544	2865	72	72	72
June	peak day	48	48	48	48	72	2063	1729	748	603	477	417	518	324	219	194	267	307	226	399	742	953	48	72	48
July	peak day	48	48	48	48	72	425	507	225	209	219	244	317	292	194	194	244	169	121	97	112	323	48	48	48
August	peak day	48	48	48	48	72	1655	1226	535	461	366	285	344	292	200	171	219	146	269	552	1014	1142	48	48	48
September	peak day	48	48	48	48	72	5455	4906	2826	1690	1187	1006	1157	825	1350	1353	1572	1993	1458	1585	2082	2341	48	48	48
October	peak day	526	613	643	733	762	17711	15623	8544	3859	3370	3194	3062	2993	4096	4456	4827	5358	2888	4103	5996	7231	319	406	524
November	peak day	882	1183	1143	1387	1244	10690	20035	20288	12580	9070	6522	4727	4895	3981	4012	4292	5187	6862	7387	8317	9985	10735	744	1024
December	peak day	7192	8339	7614	8574	7825	9032	32714	49479	31278	27022	22962	19463	17141	15742	16394	18445	19841	20495	20418	22269	24632	24534	6735	7834
January	weekend day	249	339	397	534	606	904	13867	20780	13875	10748	9066	8077	8059	7694	8500	9146	10114	11276	4591	4797	5199	5294	395	473
February	weekend day	255	358	429	596	747	959	14450	23879	15840	12454	10475	9036	8307	8029	8684	8892	9883	12005	5542	5933	6472	6799	474	588
March	weekend day	148	197	213	270	321	4985	11046	11145	7703	6222	5368	4753	4200	3880	4216	4382	4961	4828	2997	3625	4025	2367	176	206
April	weekend day	101	86	100	98	129	6190	5478	3124	2461	1950	1616	1501	1233	1437	1524	1842	2325	539	621	968	1148	69	78	74
May	weekend day	43	49	50	45	82	3095	2544	1136	812	642	550	584	443	366	248	300	340	161	206	388	590	38	39	45
June	weekend day	35	30	35	35	49	628	678	365	294	242	249	260	226	166	146	176	143	84	70	108	170	40	29	34
July	weekend day	35	35	30	35	41	140	214	149	143	152	168	184	179	117	118	141	99	65	67	59	89	27	38	22
August	weekend day	33	29	32	34	43	245	355	180	158	146	171	192	170	131	115	138	98	67	70	64	93	28	36	28
September	weekend day	29	29	34	32	56	1719	1703	855	632	505	450	451	381	391	370	443	511	149	190	341	446	41	32	27
October	weekend day	49	52	45	51	72	4986	4653	2866	2147	1757	1555	1588	1404	1644	1624	1803	2234	696	851	1165	1369	51	50	57
November	weekend day	189	238	241	284	284	2356	9127	8057	4845	3561	2875	2458	2334	2063	2022	2086	2649	3153	2040	2299	2769	2448	126	123
December	weekend day	200	300	333	398	508	597	13128	15963	11104	9301	8139	7549	7641	7032	7368	7779	8525	9690	4182	4368	4915	5150	278	345

Appendix B.3 – Hourly DER-CAM Electric Load Profile for R50-F3765

(kw)		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	week day	105.2	106.2	109.2	111.7	114.3	119.0	140.4	143.5	198.9	198.4	197.6	197.3	189.3	197.2	197.7	197.8	203.3	178.1	156.6	156.5	148.7	148.4	107.8	103.7
February	week day	107.2	107.5	109.0	110.6	113.6	118.4	139.9	119.7	200.1	199.7	199.6	199.7	191.7	199.8	200.6	200.4	201.2	154.8	157.9	158.1	150.7	150.4	108.9	104.4
March	week day	101.5	102.4	102.8	104.1	107.7	133.1	127.7	177.7	212.7	212.6	213.1	207.4	211.2	214.9	214.8	214.6	163.3	122.4	150.5	153.8	151.8	120.0	103.2	102.1
April	week day	100.0	100.0	100.0	100.0	104.2	116.5	107.5	199.5	199.4	199.4	199.4	191.0	199.3	199.3	199.7	200.3	132.8	107.6	117.6	145.8	145.8	104.2	100.0	100.0
May	week day	100.3	100.3	100.3	100.3	97.5	93.9	109.4	205.5	206.5	208.0	209.5	200.3	212.6	214.2	215.6	216.4	139.9	111.6	110.7	132.0	147.6	104.6	100.3	100.3
June	week day	100.6	100.6	100.6	100.6	89.5	103.6	118.1	230.6	236.2	239.9	242.2	231.4	246.4	248.7	250.4	253.1	170.0	136.1	131.1	129.0	160.3	105.1	100.6	100.6
July	week day	99.6	99.6	99.6	99.6	95.8	107.1	118.5	224.8	232.6	237.9	240.4	230.4	244.1	245.8	247.3	250.6	174.4	143.2	139.1	138.5	164.6	103.6	99.6	99.6
August	week day	100.8	100.8	100.8	100.8	105.4	127.3	122.4	242.2	250.0	255.4	258.3	247.9	264.1	265.8	267.2	267.8	180.0	143.6	140.6	162.2	167.3	105.4	100.8	100.8
September	week day	99.9	99.9	99.9	99.9	104.0	132.0	107.9	201.5	207.3	213.1	217.5	208.6	223.4	224.4	224.9	225.2	148.0	116.9	146.2	148.9	147.9	104.0	99.9	99.9
October	week day	99.8	99.8	99.8	99.8	103.8	136.3	126.8	195.0	194.9	195.5	196.7	188.6	198.2	199.4	200.6	200.4	131.0	133.3	152.3	144.2	144.2	103.8	99.8	99.8
November	week day	99.8	99.7	99.3	99.1	99.6	106.5	138.1	121.0	201.9	201.9	201.9	200.9	194.1	202.1	202.0	201.9	207.0	177.4	155.1	154.1	146.7	141.5	104.3	100.5
December	week day	103.5	104.5	106.3	106.5	108.3	112.1	136.1	135.6	191.6	191.3	191.1	190.9	183.3	191.1	191.5	191.7	214.9	177.4	154.7	154.5	147.3	147.4	108.0	104.0
January	peak day	139.4	131.6	139.4	133.0	139.4	140.0	152.7	167.2	250.9	250.9	250.9	250.9	239.7	250.9	250.9	250.9	266.4	208.4	175.0	175.0	163.8	163.8	128.6	120.9
February	peak day	138.0	134.1	138.0	134.1	138.0	141.8	152.7	151.6	250.9	250.9	250.9	250.9	239.7	250.9	251.0	250.9	250.9	192.8	175.0	175.0	163.8	163.8	126.8	123.0
March	peak day	133.0	131.6	134.8	131.1	137.0	153.8	151.6	252.0	256.1	269.6	278.9	269.7	290.9	296.4	296.3	293.4	250.9	169.5	176.6	175.0	166.1	163.8	118.3	120.9
April	peak day	102.8	107.0	107.0	107.0	113.2	152.7	128.3	251.4	251.8	252.4	253.5	243.8	261.8	265.2	265.0	262.8	164.8	129.8	151.6	163.8	163.8	108.4	102.8	102.8
May	peak day	102.8	102.8	102.8	102.8	108.4	114.3	129.9	262.4	269.2	271.9	274.4	263.2	285.9	292.5	296.9	295.1	185.9	145.8	141.5	163.8	169.1	108.4	102.8	102.8
June	peak day	102.8	102.8	102.8	102.8	92.8	136.5	159.4	318.0	330.8	335.9	339.0	328.1	352.4	347.6	344.2	343.0	236.0	190.5	180.6	169.5	201.6	108.4	102.8	102.8
July	peak day	102.8	102.8	102.8	102.8	108.4	183.4	189.3	339.5	349.4	352.6	354.8	337.8	359.2	364.1	364.0	362.9	248.4	201.2	198.5	195.0	220.9	108.4	102.8	102.8
August	peak day	102.8	102.8	102.8	102.8	108.4	176.4	172.0	322.8	333.5	339.0	341.6	330.8	347.5	347.9	351.2	351.4	241.4	193.0	183.9	205.2	208.9	108.4	102.8	102.8
September	peak day	102.8	102.8	102.8	102.8	108.4	165.2	141.9	288.4	291.1	303.9	313.3	304.5	321.2	319.8	318.3	318.2	211.1	163.0	191.7	189.0	187.8	108.4	102.8	102.8
October	peak day	102.8	102.8	102.8	102.8	108.4	154.0	167.2	252.4	256.8	263.5	268.6	261.3	282.5	283.3	286.7	287.1	182.0	175.0	177.0	163.9	163.8	108.4	102.8	102.8
November	peak day	111.1	112.9	120.3	124.5	126.7	153.0	167.2	250.9	251.9	251.1	251.6	254.4	253.2	253.0	253.0	254.0	274.2	208.4	175.0	175.0	163.8	163.8	108.4	102.8
December	peak day	138.0	134.1	138.0	134.1	138.0	139.7	152.7	167.2	250.9	250.9	250.9	250.9	239.7	251.0	250.9	250.9	274.2	208.4	175.0	175.0	163.8	163.8	126.8	123.0
January	weekend day	97.3	97.3	97.3	99.2	100.1	107.5	152.7	149.2	195.2	195.2	195.2	195.2	172.9	178.5	178.5	178.5	183.3	170.2	133.3	133.3	127.8	127.8	101.4	99.2
February	weekend day	97.3	97.3	97.3	98.4	100.4	107.6	152.7	128.8	195.2	195.2	195.2	195.2	172.9	178.5	178.5	178.5	178.5	145.0	133.3	133.3	127.8	127.9	102.0	100.7
March	weekend day	97.9	97.9	97.9	97.9	99.9	131.2	134.2	166.8	201.4	201.4	201.4	190.2	184.1	186.5	186.5	186.5	153.1	108.6	129.3	134.2	131.8	113.3	99.1	97.9
April	weekend day	96.6	96.6	96.6	96.6	99.1	131.3	115.9	189.1	189.2	189.3	189.5	166.0	172.2	172.8	172.8	172.6	121.8	82.1	92.4	123.7	123.7	99.1	96.6	96.6
May	weekend day	97.3	97.3	97.3	97.3	93.2	106.8	117.2	195.7	196.6	197.9	198.8	175.9	183.8	184.7	185.9	187.8	130.6	89.0	88.0	112.6	127.8	100.0	97.3	97.3
June	weekend day	97.9	97.9	97.9	97.9	85.4	115.6	124.9	219.6	225.8	228.9	230.1	206.6	217.3	219.0	221.1	223.6	158.4	105.5	103.0	105.3	137.2	101.0	97.9	97.9
July	weekend day	96.6	96.6	96.6	96.6	91.3	139.2	140.2	229.3	235.1	238.2	240.4	212.1	222.2	226.9	230.3	230.2	168.4	104.6	103.0	107.9	137.2	99.1	96.6	96.6
August	weekend day	97.3	97.3	97.3	97.3	100.0	143.6	131.0	227.3	237.1	244.4	248.4	223.8	233.9	235.8	238.3	237.6	173.7	112.1	109.8	138.2	141.0	100.0	97.3	97.3
September	weekend day	97.3	97.3	97.3	97.3	100.0	152.0	121.2	206.0	210.9	215.3	219.4	196.4	205.2	206.3	206.8	206.1	144.1	97.0	125.0	132.8	132.1	100.0	97.3	97.3
October	weekend day	97.3	97.3	97.3	97.3	100.0	153.1	139.5	195.4	195.3	195.2	195.3	173.1	179.4	179.6	179.5	179.3	125.5	114.9	133.3	127.8	127.8	100.0	97.3	97.3
November	weekend day	98.3	98.5	99.4	100.0	100.9	116.3	145.9	134.9	183.4	183.4	183.4	177.8	166.8	171.1	171.0	170.9	168.3	156.9	133.3	131.9	127.8	120.8	99.3	97.3
December	weekend day	97.3	97.3	98.5	99.3	101.1	105.7	152.7	146.7	195.2	195.2	195.2	195.2	172.9	178.5	178.5	178.5	200.2	172.2	133.3	133.3	127.8	127.8	100.6	98.8

APPENDIX C: TASK 3 – ASSESSMENT OF MICROGRID'S COMMERCIAL AND FINANCIAL FEASIBILITY

TABLE OF CONTENTS

DISCLAIMER

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Task 3: Assessment of Microgrid's Commercial and Financial Feasibility

As discussed in the Task 2 report, the proposed microgrid is configured to meet the power needs of the Buffalo Fire Headquarters, Emergency Services Headquarters, and District Heating Plant (FH/DHP), whenever it is economical to do so. When operating in grid-connected mode, any excess power would be exported to the National Grid feeder on which the FH/DHP is located, feeder 3765 (also referred to here as "F3765"). The power would be sold to National Grid rather than to specific end-use customers.

During a power outage on F3765, the microgrid would create an island and supply power to all of the customers in that island, without requiring any load shedding or curtailment. A detailed design study is required to determine which buildings would be included in the island and where the points of islanding should be located. The set of customer buildings to be covered during an outage will have a peak January load that is no more than 50% of the total load of all buildings on F3765, exclusive of the FH/DHP. This load and the buildings that produce it are referred to as "R50-F3765." (See Task 2 for specifics.)

Subtask 3.1 – Commercial Viability – Customers

Question 3.1.1
Identify the number of individuals affected by/associated with critical loads should these loads go unserved (e.g. in a storm event with no microgrid).

The microgrid will serve up to eight critical loads. These eight loads provide services to well over 3,000 individuals within the City of Buffalo and immediately surrounding area. Without a more detailed design study, we cannot be certain of which critical facilities will be served by the microgrid during an islanding event, except that the Buffalo Fire Headquarters, Emergency Services Headquarters, and District Heating Plant (FH/DHP) will be served in any scenario. The critical facilities that will potentially be served by the microgrid are described below.

- **FH/DHP**
    - The Fire HQ, Emergency Services, and DHP are co-located in a single building, occasionally referred to here as the "FH/DHP complex."
    - There is an average of 23 occupants during the day (40 peak occupancy), 6-8 occupants overnight, and seven occupants on weekends.
    - The Fire Department and Emergency Services Department are themselves critical loads.
        - There are existing diesel generators (200 kW and 250 kW) located at this facility, but the 250 kW generator would be removed to make room for the Combined Heat and Power (CHP) plant. The remaining diesel generator would continue to provide backup power during an outage for as long as there is diesel in the storage tank and a source of resupply. Our analysis assumes that the emergency event interrupts the resupply of the diesel generator after its stored fuel runs out (estimated at 32 hours).
    - Although the DHP is a *load* with respect to the microgrid, as opposed to a microgrid *resource*, it does serve several critical-infrastructure heating loads, including the heating load of the FH/DHP. Other critical infrastructure on the District Heat thermal loop includes the following:

    - Buffalo City Court: Occupied between 7 AM and 6 PM, weekdays. Typically four courtrooms, each with chambers and four offices, on each of nine floors. One of the floors has two court rooms and fifty-four cell blocks. The average number of occupants is 500 during weekdays (1,000 peak occupancy) and 100 on Saturdays.
    - Buffalo City Hall: Occupied between approximately 7 AM and 5 PM, weekdays. Typically contains 700-800 people at work, with a peak occupancy of 1,000 people when the public is included. The building is 32 stories tall, 26 of which are usable office space.
    - Rath County Office Building: Occupied by approximately 3,500 people from 7 AM to 7 AM on weekdays. Some people occupy the space on Saturdays from 8 AM to 3 PM as well.
    - Erie County Family Court: Estimated to have an average daily occupancy of 750 persons, from 9 AM to 7 PM on weekdays.

- **FBI Building**
    - The team estimated average occupancy using a study on space per office worker from the University of San Diego.[18] The average occupancy is estimated at 300 individuals.
- **PS 95 Waterfront Elementary School**
    - Estimated occupancy is 809 students plus 75 staff and 16 visitors, totaling 900 individuals.
    - Assumed hours of occupation are 7 AM to 4 PM (school hours are 8 AM to 2:30 PM).
    - Used as a shelter during emergencies
- **Mattina Community Health Center**
    - Hours of operation are 8 AM to 4:30 PM, three days weekly, plus 8 AM to 8 PM, two days weekly.
    - Based on maximum occupancy per square foot as specified in ANSI/ASHRAE Standard 62,[19] the Health Center is estimated to allow a maximum 450 occupants during operating hours. ASHRAE's building energy standards (90.1) prescribe a design for 80% of maximum during a number of hours of the week. On that basis, a reasonable estimate of occupancy is 360 people.

Other buildings on feeder 3765 (referred to here as "F3765") are not critical infrastructure, so their

[18] "Estimating Office Space per Worker," available at: https://www.sandiego.edu/pipeline/documents/EstimatingOfficeSpaceRequirementsMay12012.pdf. They cite real estate data for Federal office buildings, which averages to a median of roughly 350 ft^2 per worker.

[19] "Ventilation for Acceptable Indoor Air Quality," Appendix E. The entire space of the Mattina Center was assumed to have the same occupant density as rooms dedicated for medical activities (procedures, physical therapy, etc.).

loads are not listed here.[20]

Question 3.1.2

Identify any direct/paid services generated by microgrid operation, such as ancillary services, or indirect benefits, such as improved operation, to the utility or New York Independent System Operator (NYISO). If yes, what are they?

***Direct Paid Services**:*

The microgrid will provide the utility with the power remaining after the CHP meets the electricity needs of the FH/DHP building. It will not provide any other direct or paid services to National Grid.

The microgrid would not participate in the NYISO market because its capacity is under 5 MW, hence it would not be considered an Independent Power Producer. Rather, it would be considered a distributed generation asset that sells its excess power back to the utility. Although the microgrid would not participate in the NYISO market (including the ancillary services market), we assumed that its tariff for electricity export during grid-connected mode will be at least as high as average wholesale NYISO prices.

If distribution-level grid service markets are developed in the future, the microgrid may be able to participate in those markets.

***Indirect Benefits**:*

Feeder 3765 is a radial feeder and, as such, is less reliable than the mesh network in downtown Buffalo. With the microgrid tied to this feeder, the FH/DHP and a set of other buildings on F3765 would have microgrid-supplied power available during a grid outage.[21] By keeping some buildings powered during the outage, the microgrid should free up the utility to expend some of its power restoration efforts elsewhere. However, this benefit will depend on the location of the points of islanding, in particular whether there would be any buildings that would be unacceptably stranded by the island if National Grid reduced the priority of restoring power to the microgrid-protected area.

The City of Buffalo (COB) microgrid is unlikely to result in any deferral of distribution upgrades, as the current (and anticipated) peak load on the feeder is less than half of the capacity of the line. However, the microgrid could contribute to deferral of transmission upgrades. Similarly, while the microgrid is not expected to directly contribute to NYISO capacity markets, its energy contribution during peak periods may nonetheless help redirect constrained central station power capacity to other system needs during such periods.

Question 3.1.3

Identify each of the microgrid's customers expected to purchase services from the microgrid.

The purchasers of microgrid power fall into three groups:

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[20] Although these other buildings are not *critical infrastructure*, it was necessary to designate those other building *loads* as "critical" during DER-CAM modeling in order to ensure that the model would force the CHP to serve those loads at all times in islanded mode.

[21] Although the FH/DHP building has feeder 3769 as a contingency source, in the event of an issue on F3765, feeder 3769 would not automatically get connected to the FH/DHP or the other buildings on F3765.

1. City-owned entities (occupants of the FH/DHP): The microgrid and these purchasers are all owned by COB. The power provided to the FH/DHP building will be metered for measurement and verification (M&V) and internal recordkeeping purposes. However, there is no explicit payment arrangement at this time and none is currently expected to be put in place.
2. National Grid: This utility is the current supplier of electricity to the City. Under the scenario analyzed in this study, National Grid would only supply power to the FH/DHP under two conditions: (a) when the economics relative to using CHP power are favorable to do so, based on the utility's electricity price, the CHP's price of producing power, and the availability of a use for the CHP's heat output, and (b) when the CHP system is shut down for maintenance, repair, or other non-economic reasons. At all other grid-connected times, the CHP would export power to National Grid as an on-site generation facility.
3. R50-F3765 building owners or operators: The scenario envisioned in this study involves providing power to R50-F3765 buildings, which are National Grid customers, during an outage on the power grid. Agreements would be executed with the microgrid off-takers; specific terms of these agreements will be determined during the design stage.

Question 3.1.4
Identify other microgrid stakeholders; what customers will be indirectly affected (positively or negatively) by the microgrid?

The microgrid would provide tangible community benefits in several ways:

- It would bring greater resiliency to the FH/DHP and the R50-F3765 buildings on feeder 3765. Note that F3765 runs along Niagara St. and Hudson St., as well as toward the waterfront in several side branches.
- The microgrid will ensure better continuity of critical government services, including those of great importance during severe weather and other emergencies that affect power grid operation. At a minimum, this includes fire and emergency services.
- Among the buildings situated along feeder 3765 are a supermarket and a hardware store, which provide for basic neighborhood needs. To the extent that these are included in the islanded set of buildings, the microgrid would assure the continuity of their services and prevent business losses of refrigerated or frozen products at the supermarket.
- Any critical infrastructure buildings along feeder 3765 that are included in the islanded portion of the microgrid would maintain power during typical outages and emergency events. These potentially include the PS 95 Waterfront Elementary School, Mattina Community Health Center, and the FBI. Among the benefits would be continuity of services, ability to operate electric building systems, and security.

The following microgrid stakeholders are other entities, not on feeder 3765, that have been identified by the City of Buffalo as actual or potential indirect stakeholders in the microgrid project:

- Buffalo Urban Development Corporation (BUDC)
- Buffalo Municipal Housing Authority
- Buffalo Niagara Medical Campus

- Buffalo Niagara Partnership
- Buffalo Board of Education (BBOE)
- Erie Canal Harbor Development Corporation (ECHDC, a subsidiary of Empire State Development)
- Empire State Development (member of Regional Economic Development Council)
- Erie Community College
- Erie County Department Environment & Planning
- Erie County Industrial Development Agency
- National Fuel
- National Grid
- Regional Economic Development Council

Question 3.1.5

Describe the relationship between the microgrid owner and the purchaser of the power.

The City of Buffalo is assumed to be the owner of the microgrid assets, however other ownership scenarios will be investigated during later stages of the development phase. One of the purchasers of power is the FH/DHP, which is owned by the city. The other purchasers of power are National Grid and the R50-F3765 National Grid customers, none of which are owned by the COB.

Question 3.1.6

Indicate which party/customers will purchase electricity during normal operation. During islanded operation? If these entities are different, describe why.

In ***normal (grid-connected) mode***, the customers receiving microgrid services would be:

1. <u>Occupants of the FH/DHP complex.</u> Since both the FH/DHP and the CHP would be owned by COB, no explicit payment arrangement is expected for electric power received from the CHP. However, the amount of electricity provided will be metered for measurement and verification (M&V) and internal recordkeeping purposes. The CHP's heat output would go to the DHP in the form of hot water, without an arrangement for explicit payment.
2. <u>National Grid.</u> The utility would purchase all of the power remaining after the FH/DHP building is served. Under the utility's current electricity tariff, National Grid's standard purchase price for exported power falls into Service Classification No. 6 (SC-6). SC-6 specifies that National Grid pay either: (a) the NYISO Real Time Locational Based Marginal Price (Real Time LBMP), i.e., the wholesale price, or (b) a price negotiated under a Special Contract, in particular for generators who wish to negotiate a long-term contract or provide firm service.

   Note that the COB microgrid is exempt from National Grid's SC-7 tariff, Sale of Standby Service to Customers with On-Site Generation Facilities, due to the fact that the microgrid qualifies as an environmentally advantageous technology (EAT). In addition, with the current configuration the COB microgrid does not qualify as "community distributed generation" (CDG) under the National Grid tariff, because it does not qualify for net metering. If, in future rulings, microgrids for resilience or CHP-generated power were to be classified as CDGs, the COB microgrid would be able to sell power directly to customers on F3765 (so-called "CDG Satellites").

In ***islanded mode***, the customers paying for microgrid services would be:

1. Occupants of the FH/DHP complex. In islanded mode, the CHP would power the FH/DHP. In addition, the CHP's heat output would be used by the DHP in the form of hot water. Again, no explicit payment arrangement is expected for either electric power or thermal energy delivered by the CHP to COB customers.

   R50-F3765 building owners or operators. These National Grid customers would purchase power from the microgrid. Without a more detailed design study, the team cannot yet determine where the points of islanding would be located and which buildings would be included within the island. As mentioned above, under current regulations the microgrid does not qualify as CDG, so it may not be possible for COB to sell power directly to these customers without regulatory change. In addition, an agreement would need to be negotiated with the end-use customer (and possibly National Grid). For this study, we assumed that these customers would purchase power from the microgrid at a National Grid tariff rate[22] and additionally allowed for a 10% premium for the provision of an emergency service.

Question 3.1.7

What are the planned or executed contractual agreements with critical and non-critical load purchasers?

One critical load purchaser would be the FH/DHP building. That building is also owned by the City, so agreements will be internal. Depending on which buildings are included in the islanded-mode configuration, there may be other critical loads eligible to purchase power. These were discussed in the response to Question 3.1.1.

A letter of intent, preliminary agreement, or some other form of assurance will be obtained from the potential customers prior to making a decision for design and build of the microgrid. The nature of contractual agreements cannot be determined at this time because there is incomplete information about the microgrid's design, the buildings that will be part of R50-F3765, and the rate and contractual arrangements with National Grid.

Question 3.1.8

How does the applicant plan to solicit and register customers (i.e. purchasers of electricity) to be part of their project?

As part of the design process, the team will survey potential purchasers to define their needs and possible interest in microgrid services. Another partner could be brought onto the team to help develop the customer base.

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[22] For the purposes of this feasibility study we simplified the modeling task (documented in the Task 2 report) by assuming that all R50-F3765 customers served would pay the same tariff rate as the FH/DHP. Because the total outage duration is short compared to an entire year, the overall revenue results are very insensitive to this assumption.

Once the microgrid design is completed, the City will contact potential customers to discuss their participation. This may take place in the context of a meeting to inform and educate them about the microgrid, the benefits of joining, and the terms of membership.

Question 3.1.9

Are there any other energy commodities (such as steam, hot water, chilled water) that the microgrid will provide to customers?

There are no other energy commodities to be offered to microgrid customers. The DHP, located in the FH/DHP complex, currently provides steam and hot water heating to six buildings. However, that facility is a *load*, rather an energy-providing resource, of the microgrid.

Subtask 3.2 – Commercial Viability – Value Proposition

Question 3.2.1

What benefits and costs will the community realize by the construction and operation of this project?

The benefits of the microgrid would include improving the resilience of the FH/DHP complex and the R50-F3765 buildings on feeder 3765. By virtue of allowing the DHP to operate during an extended power outage, the microgrid would also be enabling all of the buildings it serves to receive heat. Thus, the microgrid would improve the resilience of the DHP's six customers.

In addition, the microgrid should provide a small improvement to the financial viability of the DHP. Exhaust heat from the CHP will be used to generate hot water, which will reduce the fuel used directly by the DHP for a given heating load. The CHP reduces the estimated annual direct fuel cost of the DHP by 16%.

The City believes that improving resiliency for certain customers (if it is possible to include them in the R50-F3765 set of buildings) would provide valuable societal benefits. For instance, some of the residential customers on F3765, such as tenants of Shoreline Apartments, include low-to-moderate income residents.

In addition, the community could also benefit from the microgrid if it allows easier future incorporation of distributed generation (DG), especially clean power sources such as PV arrays. A pre-existing microgrid lowers the barrier for inclusion of other DG power on the microgrid.

More details about the microgrid's benefits and costs are provided in Task 1, the response to Question 3.2.3, and Task 4.

Question 3.2.2

How would installing this microgrid benefit the utility? (E.g. reduce congestion or defer upgrades)? What costs would the utility incur as a result of this project?

Microgrids allow utilities to defer upgrades when the system is approaching capacity. In the case of National Grid's feeder 3765, no upgrades are being planned and the peak demand is not approaching feeder capacity. Currently, the summer peak on the feeder is 120 Amps, while its capacity is 266 Amps. When projected out to 2025, the load on the feeder remains less than half of the feeder's capacity. This means that the microgrid will not offer National Grid the benefit of deferring distribution system investment, as there is no need in the near future for such investment.

National Grid will still own and maintain all of their F3765 infrastructure in place prior to the microgrid. The utility will have to install switching devices at all points of islanding, which will include reclosers, breakers, CTs, PTs, relays, etc., with the capability of sensing, isolating, and reconnecting the microgrid with the main grid. In addition, National Grid's systems may need modification to accommodate reverse power flow from the CHP's exported power. Finally, there will be costs incurred with some level of integration of communications and control between National Grid and the microgrid. However, some or all of the above may be recoverable from the City in accordance with National Grid tariff SC-6 or other applicable requirements, so the final cost to the utility may be lower than their initial outlay.

As mentioned in the response to Question 3.1.2, the microgrid might free up the utility to expend some of its power restoration efforts elsewhere because it will keep some buildings powered during the outage. The benefit will depend on the location of the points of islanding; for example, whether there would be any buildings that would be unacceptably stranded by the island if National Grid reduced the priority of restoring power to the microgrid-protected area.

National Grid has been exploring microgrid service offerings in New York.[23] Similar services could be offered to COB as a source of revenue. Specifically, National Grid could sell services such as performing underground microgrid wiring, installing new electrical infrastructure, operating the microgrid itself, and handling microgrid billing.

Question 3.2.3

Describe the proposed business model for this project. Include an analysis of strengths, weaknesses, opportunities and threats (SWOT) for the proposed business model.

For the microgrid project to be commercially viable, the business model must provide a positive value proposition to its customers and stakeholders. For the City, the value proposition for the microgrid has several aspects, described below:

- Providing electrical resiliency for the FH/DHP and heating resiliency for the buildings served by the DHP. Nearly all of these buildings are critical infrastructure.
- Providing electrical resiliency for other buildings in the downtown Buffalo area (a societal benefit).
- Reducing operating costs of the DHP.
- Reducing emissions related to the operation of the DHP.

For the microgrid customers, the primary value proposition is an increase in electrical resiliency during grid outage periods. Without that resiliency, they might not otherwise be able to function properly during these outages, which could impact health and safety, commercial activities, and other activities of importance or value.

[23] See "National Grid to Test New Utility Microgrid Services" by Elisa Wood on *Microgrid Knowledge*, March 14, 2016: https://microgridknowledge.com/utility-microgrid-services/

To be financially viable, the business model for the microgrid must generate enough revenue to cover all operating costs, pay back any debt capital, and ideally provide a financial return. The business model is to capture the majority of its revenue for these purposes during normal "blue sky" operations. The COB would enter into a Special Contract with National Grid for the utility's purchase of power exported from the microgrid, and a Power Purchasing Agreement (PPA) or similar vehicle with microgrid customers. Financial success will hinge on the City being able to receive a price for its grid-connected exported power as close to retail rates as possible. (Modeling results at the feasibility level suggest a rate of 90% of retail.) Financing of the microgrid is currently envisioned to consist of a municipal bond plus reduction in capital expenditure via a NYSERDA CHP Acceleration Program incentive.

Table 1 presents an analysis of strengths, weaknesses, opportunities, and threats (SWOT) for the proposed COB microgrid.

Table 1 – SWOT Analysis

Strengths	Weaknesses
• COB is not a for-profit entity, so its financial return threshold is low. • Use of existing electrical infrastructure by the microgrid helps minimize installed costs. • Provides resiliency to many critical infrastructure buildings via the DHP. • Reduces the amount of fuel required to operate the DHP • Promotes New York REV objectives. • City of Buffalo can provide "lessons learned" for other downtown urban microgrid projects.	• A less-costly solution for providing resiliency to FH/DHP (but not R50-F3765) would be to increase the size of diesel storage tanks. • The utility's level of engagement with the project development team and process has been limited to responding to consulting team information requests within the narrow scope of its NY Prize support obligation as agreed with NYSERDA. • Expanding electrical resiliency to DHP customers on the mesh network would be difficult and/or expensive. • Even with the relatively small size of the CHP, there will still be reverse power flow on the power grid.
Opportunities	**Threats**
• The microgrid could serve as a replicable, scalable model for other municipal buildings and district heating plants on radial feeders. • With some changes to microgrid and business model, revenue can be earned from National Grid and/or a DSP by providing new grid services as a result of REV. (Examples: load/DER aggregation, load smoothing). • Owners of transmission lines may be able to defer future capital investments due to microgrid. • The microgrid can be expanded to add revenue-generating energy services for customers.	• Special approvals and/or changes in regulations may not occur or may be unfavorable to the microgrid business model. • There is a potential for reverse flow issues outside of feeder 3765 (i.e., flow into and beyond National Grid's Station 37). This could require additional investment to perform the necessary studies and fund infrastructure modifications. • Any surplus power sale price above the wholesale electric price may not be approved by the utility.

Question 3.2.4

Are there any characteristics of the site or technology (including, but not limited to, generation, storage, controls, information technology (IT), automated metering infrastructure (AMI), other, that make this project unique?

The site has several unique characteristics:

- The buildings served by the district energy (DE) plant are on a different type of electrical network than the buildings served by the power generating resources.

  Specifically, the buildings receiving heat energy from the DHP are located on the downtown mesh power network, rather than the radial network served by the CHP. Simply put, the buildings served by the DHP do not need the electrical resiliency offered by the CHP.

- The COB microgrid has a DE system configured as a load, rather than a generating asset.

  The team chose not to consider the buildings served by the DHP to be part of the microgrid because: (a) the CHP is unable to increase the buildings' electrical resiliency, and (b) the DHP already provides them with district heat.[24] Since the DHP itself is part of the microgrid as part of the FH/DHP, its role is necessarily that of a load.

  Typically, when DE is part of a microgrid it serves as one of the generating resources. The DE plant meets the space conditioning needs of a group of buildings,[25] and the other resources serve the buildings' electrical loads. In this common configuration, much or all of the electricity produced by a CHP unit can be used by the same buildings consuming DE output.

  Because the buildings served by the DHP are not on the microgrid (and they do not need additional electrical resiliency), the electricity produced by the CHP plant must be used elsewhere.

- In-feeder topology.

  Most microgrids cover a group of buildings in a campus-like, or otherwise aggregated, arrangement that operates in parallel with the grid and connects to it via a single point of common coupling. The COB microgrid does not involve this topology; rather, all of the buildings involved are in series with the grid. These buildings are directly on the utility feeder in both grid-connected and islanded modes, purchasing power from the utility in the first instance and from the microgrid in the second. To form an island, the microgrid uses a point of common coupling on the utility feeder, somewhere "upstream" of the generation site, and at least one islanding point on the "downstream" side as well. Customers that are isolated by the downstream point(s) of islanding can only get their power restored when the microgrid reconnects with grid power and reopens those islanding points.

With respect to the technologies included in this project, all of those have been installed, demonstrated, and proven in other projects. This includes the proposed generating and backup assets (CHP and diesel generators), minimal switchgear modifications, installation of re-closers, and the microgrid controls system. In this way, any new technology risk is minimized.

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[24] Adding a microgrid agreement to existing arrangements seems unnecessarily complex for a relatively small benefit. However, in the detailed design phase the City will consider inclusion of these customers on the basis of the microgrid increasing their heating resiliency during outages longer than 32 hours. The balance to consider is the cost of adding more customers who do not receive electrical services against the benefit that the microgrid might receive from their addition. Little or no new infrastructure is likely to be required, and the DHP will receive CHP heat energy in either case. On the other hand, a number of the buildings on the DHP thermal loop are already owned by the City and would provide no new revenue.

[25] In this situation only heating loads are served by DE.

Question 3.2.5

What makes this project replicable? Scalable?

This radial feeder microgrid is a relatively simple design, in particular in configurations with only two points of islanding (e.g., feeders without branches). Radial feeders are also much more common than mesh networks, even in urban environments. These factors makes the design both replicable and scalable.

The microgrid design also offers the feature of not requiring a campus-like arrangement of loads, so it can be used for groups of customers that are (initially) not affiliated.

Question 3.2.6

What is the purpose and need for this project? Why is reliability/resiliency particularly important for this location? What types of disruptive phenomenon (weather, other) will the microgrid be designed for? Describe how the microgrid can remain resilient to disruption caused by such phenomenon and for what duration of time.

This area contains many important facilities and critical infrastructure buildings. The FH/DHP complex is critical infrastructure for the City of Buffalo. Not only is the building home to the Fire Department and Emergency Services, but it also houses the district heating system that serves five other critical infrastructure buildings. In the vicinity are a number of other important facilities such as an FBI office, a health center, and an elementary school.

All of these facilities require continuity of services, or the ability to act as a shelter in emergency situations, that highlights the importance of reliability and resiliency. In winter months both heating and electricity are important to the critical facilities. The City of Buffalo experiences heavy precipitation in the form of snow throughout the winter months, from November through March or later depending on the year. Lake-effect snow events occur frequently throughout winter. Freezing rain can occur periodically, resulting in downed power lines and power outages. Additionally, rapid snow and ice melt can pose a flood risk to low-lying areas of the City.

The FH/DHP building currently has backup generation to serve its electric load in case of a power outage, but powering the building with a microgrid increases the level of reliability. The new microgrid will provide indefinitely long protection as opposed to the 32 hours permitted by the current backup diesel fuel supply. It expands the number of loads served by backup power, while also reducing backup-power emissions and increasing overall energy efficiency.

Finally, there is a low-to-moderate income residential development (Shoreline Apartments) located on Niagara Street. Providing this facility with electrical resilience could have positive energy justice implications.

Question 3.2.7

Describe the project's overall value proposition to each of its identified customers and stakeholders, including, but not limited to, the electricity purchaser, the community, the utility, the suppliers and partners, and NY State.

Table 2 summarizes the value proposition to each customer and stakeholder. These are further described as well in other responses within Task 3.

Table 2 – Value Propositions for Customers and Stakeholders

Customer/Stakeholder	Value Proposition
City of Buffalo	Provide more reliable and lower-priced electric power to City buildings and their activities. Lowers emissions related to the DHP.
Microgrid customers	The FH and DHP will pay less for power than the National Grid rate when the CHP is operating. All microgrid customers will have increased reliability for their electric loads.
Local community	The local Buffalo community will benefit from the greater reliability of the critical infrastructure and the critical services they provide.
Broader community (County, State, society at large)	Several Erie County buildings are DHP customers; enhanced DHP heating reliability helps Erie County deliver its services and avoid expenses caused by heating outages. Key learnings from the project will support the development of other microgrids throughout New York State and beyond. Emission reductions and fuel efficiency achieved by the microgrid benefit society at large.
National Grid	The microgrid could help reduce investment in the grid's generation and/or distribution capacity. In the event of an outage, National Grid is able to focus resources on restoring power to their other customers because the microgrid will serve the critical infrastructure loads within it. The project will provide the utility with lessons that may be used to inform and support other projects in the future.

Question 3.2.8

What added revenue streams, savings, and/or costs will this microgrid create for the purchaser of its power?

Table 3 describes the new revenue, savings, and cost streams that each of the microgrid's customers can or will receive or incur. These value streams are also described in the response to Question 3.2.3.

Table 3 – Actual or Potential Customer Value Streams

Customer	Value Stream	Basis	Revenue/ Savings/Cost?
FH and DHP	Thermal and electrical energy from microgrid (as opposed to utility)	Customer is the same as microgrid owner; no explicit payment	Savings
R50-F3765 customers	Payment for electricity from microgrid (during outage)	Elimination of outage losses and expenditures	Savings
R50-F3765 customers	Payment for availability of energy (electric, from microgrid) during outage	Fixed (or possibly negotiated) surcharge	Cost
National Grid	Payment for use of wires	Rate to be negotiated, if applicable	Revenue
National Grid	Interconnection fees and costs	Per tariff, based on costs incurred	Revenue

Customer	Value Stream	Basis	Revenue/ Savings/Cost?
National Grid	Payment for exported electricity from microgrid	Rate to be negotiated	Cost
National Grid	Reduction in volumetric energy payment	Retail rate times electrical energy exported by microgrid	Loss of revenue (i.e., cost)
National Grid	Potential deferral of future payments for transmission (and possible distribution) infrastructure upgrades	Based on required upgrade costs	Savings

Question 3.2.9

How does the proposed project promote state policy objectives (e.g. NY REV, Renewable Portfolio Standard (RPS))?

Though the analysis for this report is specifically designed and conducted to address the objectives of NY Prize, it also indirectly addresses other state policy objectives including those of REV such that NY Prize is a program within REV. Since REV is the overarching policy vehicle for all State energy-related policies, this microgrid project addresses multiple REV goals, as described in Table 4.

Table 4 – Potential to Promote State Policy Objectives

NY REV Goal	How This Project Supports the Goal
Making energy more affordable for all New Yorkers	This project will help the COB have more affordable energy via savings and new revenue streams. The project could also help make energy more affordable for National Grid's customers to the extent that it can help defer other infrastructure investment and can serve the loads on F3765.
Building a more resilient energy system	The microgrid's purpose is to provide additional resiliency for the City of Buffalo, the microgrid's customers on F3765, and the DHP's district heating customers.
Empowering New Yorkers to make informed energy choices	In grid-connected mode, the City of Buffalo will have control over dispatch of the CHP vs. purchasing power from National Grid. This project may also encourage additional DER deployment by the COB and/or community. Potential customers on F3765 will have a choice to improve their resiliency via the microgrid or keeping the *status quo*.
Creating new jobs and business opportunities	This microgrid project will create new opportunities for local firms for the design, development, and construction of the microgrid. The microgrid also provides the opportunity for existing COB staff to increase their skills and economic value, or will create new jobs (either within COB or at another organization) in operation and maintenance of the microgrid system.
Improving our existing initiatives and infrastructure	By providing feedback and lessons learned from the project to the State and National Grid, existing energy initiatives can be improved and areas for infrastructure improvement can be identified.

NY REV Goal	How This Project Supports the Goal
Cutting greenhouse gas emissions by 80% by 2050	Employing an energy-efficient CHP resource will reduce the COB's dependence on diesel back-up generation for resiliency. It will also improve the overall energy efficiency of the DHP, which results in less fuel consumption and a corresponding reduction in greenhouse gas emissions.
Protecting New York's natural resources	To the extent that this project helps to reduce greenhouse gas emission, it may help in combating climate change and thus help to protect natural resources.
Helping clean energy innovation grow	This project will be a new, innovative development for both the COB and National Grid. The lessons learned from this project regarding microgrid design for this unique "in-feeder" topology, and for this unique resource configuration, will help other, future projects to succeed.

Question 3.2.10

How would this project promote new technology (including, but not limited to, generation, storage, controls, IT, AMI, other)? What are they?

The proposed microgrid solution requires only one DER, a 500 kW ICE (Internal Combustion Engine) equipped with a CHP accessory.
However, the project will promote new microgrid technology *per se*, in that it involves a unique "in-feeder" microgrid topology (see our response to Question 3.2.4) that has the potential to be used in many other locations. Designing, developing, and implementing a microgrid for this unusual configuration of equipment, infrastructure, and loads would increase knowledge about the technology. With in-hand experience, more would be known about the strengths and weaknesses of this sort of microgrid. It would also give insight into defining opportunities to employ it elsewhere.

Subtask 3.3 – Commercial Viability – Project Team

Question 3.3.1

Describe the current status and approach to securing support from local partners such as municipal government? Community groups? Residents?

The local municipal government, i.e. the City of Buffalo, was the lead for this project during the application phase, and it continues to lead and support the development of this project. The City meets regularly with organizations at the City and County level to ensure that this project is aligned with other area initiatives. We have met with the following City and County stakeholders specifically about this project: City of Buffalo Department of Public Works, City of Buffalo Fiscal Cabinet, Buffalo Urban Development Corporation, Buffalo Niagara Partnership, Erie Canal Harbor Development Corporation, Erie Community College, Erie County Department Environment & Planning, Erie County Department of Public Works, Erie County Industrial Development Agency, National Fuel, and National Grid. Additional meetings with these stakeholders and others will take place as the project progresses.

Question 3.3.2

What role will each team member (including, but not limited to, applicant, microgrid owner, contractors, suppliers, partners) play in the development of the project? Construction? Operation?

Table 5 describes the current team and their role in the development of the project. No team members have officially been determined yet for the remainder of development, nor for construction or operation of the microgrid. However, the members listed here could play a similar role in the remainder of project development, including microgrid design.

Table 5 – Role of Individual Team Members

Team Member	Current Development Role
City of Buffalo	Applicant, owner, and advisor
Infrastructure Energy (formerly E Co.)	Project manager, consultant evaluating feasibility, advisor on district energy
Navigant Consulting	Lead consultant, coordinated all consultants, evaluated commercial and financial feasibility
EPRI	Consultant evaluating electrical, communications, and controls design feasibility
Microgrid Labs	Consultant evaluating microgrid configuration and operation feasibility
Wendel	Advisor on local issues and design, collected building and load data
Ramboll Environ	Advisor on district energy matters
National Grid	Not an official team member, but provided power grid information.

Question 3.3.3

Are public/private partnerships used in this project? If yes, describe this relationship and why it will benefit the project.

There are no public/private partnerships identified at this point. The city is considering developing such partnerships as the project progresses.

Question 3.3.4

Describe the financial strength of the applicant. If the applicant is not the eventual owner or project lead, describe the financial strength of those entities.

The City of Buffalo's 2015 ratings reports include an A+ from Fitch Ratings, an A1 from Moody's, and an A+ from Standard & Poor's. This means that COB is ranked in the upper portion of these reports and presents a low credit risk. The following link provides further information about COB's financial strength, including links to the financial rating reports and other reports: https://www.ci.buffalo.ny.us/Home/Leadership/City_Comptroller/investinbuffalo

Question 3.3.5

For identified project team members, including, but not limited to, applicant, microgrid owner, contractors, suppliers, partners, what are their qualifications and performance records?

Table 6 summarizes the qualifications of the existing team members.

Table 6 – Team Member Qualifications

Team Member	Relevant Qualifications
City of Buffalo	The City of Buffalo is a New York State municipality eligible for NYSERDA funding. The City is in the midst of a revitalization that includes a focus on downtown development. The City's urban areas flourished during the industrial revolution of the 1800's, and, with the construction of the Erie Canal, quickly monopolized economic growth. The City is now establishing itself as a mecca for both medical services and new technology, aiming for an energy hub that can drive commercial development in both sectors. Energy development is also seen as a necessary requirement for downtown growth -- energy efficiency and reliability are essential for attracting and retaining businesses. In 2015 the City developed an Energy Master Plan, of which the current project is one of the first implementation activities.
Infrastructure Energy (formerly E Co.) *(prime contractor)*	Infrastructure Energy is a financing and development platform for community-scale grid modernization projects. We are based in Los Angeles. Infrastructure Energy works with cities and utilities to solve the challenge of large-scale energy infrastructure development, helping build for the future. Funding for pilot energy projects can be obtained from a variety of sources, including, for example, NYSERDA's NY Prize. However, there are far fewer avenues available for cities like Buffalo that want build large-scale projects with major impact. Our project investment platform provides funding for large projects like the one proposed here. Our working model is based on partnership, both with the customized team we create for each project, and with the city itself. Our development process is a holistic one, one that includes the needs of businesses and residents, the goals of the city and its utility, state regulations, and the larger business and environmental context. This development approach is designed to remove the risk of large-scale development from both the city and its utility, while optimizing public sector value for money. As the lead sponsor of this project, we coordinate the overall team effort. We will also help in the development of the project business model, working to define potential revenue streams, balancing these revenues against the projected cost of the final project. We will advise our team partners from a project finance perspective, defining a project development structure most conducive to long-term financing

Team Member	Relevant Qualifications
Navigant *(subcontractor of Eco)*	Navigant is a specialized, independent consulting firm that combines deep industry expertise and integrated solutions. We assist companies in enhancing stakeholder value, improving operations, and addressing conflict, performance, and risk related challenges. Navigant's Energy Practice is comprised of over 450 professional staff that includes technology experts, mechanical and electrical engineers, project managers, project developers, economists, natural resource scientists, regulatory and public policy strategists, environmental permitting and compliance specialists, air quality modelers, and legislative and regulatory specialists, each of whom combines firsthand industry experience with his or her consulting expertise. Moreover, many of Navigant's consultants have held staff or management positions in utilities, government research labs, energy equipment manufacturers, financing companies, and diversified energy companies. This pool of talent enables Navigant to quickly assemble an interdisciplinary team capable of identifying efficient solutions to project assessment and development issues. Navigant has also provided support to NYSERDA to develop its commercial and financial viability assessment approach and information request requirements for NY Prize Task 3 requirements. Navigant advised NYSERDA on what information it should seek from each Stage 1, Feasibility Assessment awardee and why and how to use that information to assess each feasibility study report for potential design stage funding. However, NYSERDA has not disclosed its specific evaluation criteria to Navigant, and instead has positively encouraged Navigant to support feasibility study teams in order to help ensure NYSERDA receives high quality feasibility study reports.

Team Member	Relevant Qualifications
EPRI *(subcontractor of Navigant)*	EPRI conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety, and the environment. EPRI also provides technology, policy, and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI members represent 90% of the electric utility revenue in the United States with international participation in 35 countries. EPRI has been a leader and contributor in several industry wide efforts to support the integration of variable and distributed resources with planning and operations of the grid at all levels. EPRI brings 1) Thought Leadership in identifying issues, technology gaps and broader needs of the industry, 2) Industry Expertise to address these issues and gaps and 3) Collaborative Approach to include utilities, the broad technical community and other stakeholders to develop and implement new technologies and solutions. As part of its thought leadership for the future, EPRI initiated its Integrated Grid Research in a three-phase initiative to provide stakeholders with information and tools that is integral to our collaboration and very much aligned with the REV objectives. The development of a consistent framework supported by data from a global technology demonstration and modeling program will support cost effective, prudent investments to modernize the grid and the effective, large-scale integration of DER into the power system. Also, the development of a large collaborative of stakeholders will help the industry move in a consistent direction to achieve an Integrated Grid. In addition to its national and international research, EPRI has conducted numerous research projects specific to New York and New York utilities. EPRI has a working knowledge of the REV proceedings and is participating on numerous task forces and projects for the DPS, NYSERDA and utilities associated with the REV proceedings. EPRI has been actively engaged in research supporting REV activities for the DPS, NYSERDA, Joint Utilities and individual utilities from REV's inception. EPRI continues to support Con Edison in its non-wires alternative project for the Brooklyn Queens Demand Management project (BQDM). EPRI is also working with Con Edison and other utilities on advanced modeling case studies for both hosting capacity assessments and locational value of distributed resources.
Microgrid Labs *(subcontractor of EPRI)*	Microgrid Labs is a group of professionals with over 100 years combined experience covering all aspects of Microgrid and energy storage projects, ranging from initial assessment, mathematical modeling, and feasibility studies, to planning, design, and implementation. Their expertise covers all aspects of microgrids, including power generation, energy storage, power distribution, control systems, and IT. Their professionals come from leaders in the field such as Siemens, AT&T Bell Labs, Southwestern Bell Technology.

Team Member	Relevant Qualifications
Wendel *(subcontractor of Navigant)*	Wendel is a 75-year old professional services organization that is headquartered in Buffalo, NY. As a nationally recognized and award winning firm, Wendel is dedicated to the betterment of the communities and businesses it serves. Wendel provides integrated services that include architecture, engineering, energy management, project and construction management, commissioning, and grants and incentives services. In addition to design services, Wendel offers complete construction and project management services to developers, industrial and commercial clients. Offering a unique mix of knowledge, talent and project experience, Wendel delivers seamless transitions through the study, design and construction process. Wendel provides consulting services to clients who are as diverse as our range of services. Primary market sectors include healthcare, state and local government agencies and municipalities, private development, education, and public transportation. Wendel is committed to its clients, and it is shown through a history of top performance in their field. Collaborative partnerships are an important piece of Wendel's success. Wendel works closely with several State entities providing technical assistance, including National Grid, NYSERDA, and NYPA. Wendel has been a technical assistance consultant to NYSERDA since 1994, and continues to under these programs, Wendel assisted over 500 public and private entities across the State. Wendel has also been qualified through the U.S.
Ramboll Environ *(subcontractor of Navigant)*	Ramboll Environ is a leading engineering, design and consultancy company founded in Denmark in 1945. The company employs 12,300 experts in the Nordics, North America, the UK, Continental Europe, Middle East and India. Ramboll Environ is the world's largest district heating consultant and has worked with more than 200 district heating utilities.
CORE *(subcontractor of Navigant)*	CORE Environmental Consultants, Inc. (CORE) is a multi-disciplinary environmental consulting firm specializing in asbestos containing material survey, design, and abatement project monitoring, lead paint abatement oversight, and soil and groundwater investigations and remediation. CORE has provided a broad array of environmental services including—but not limited to—Phase I and II site assessments, Petroleum Bulk Storage (PBS) Tank audits, removals and closures, State Environmental Quality Review Act (SEQRA), City Environmental Quality Review (CEQR), Uniform Land Use Review Procedure (ULURP), remedial investigations, remedial studies, construction support, risk assessments, Resource Conservation Recovery Act (RCRA) audits, discharge permits (NYCDEP/SPDES), and asbestos and lead surveys and project monitoring. CORE is a Certified Woman Owned Business Enterprise and currently employs nearly 50 environmental professionals in two offices in New York State. CORE is well qualified to take on the challenges of any environmental project.

Question 3.3.6

Are the contractors and suppliers identified? If yes, who are they, what services will each provide and what is the relationship to the applicant? If no, what types of team members will be required and what is the proposed approach to selecting and contracting?

Beyond the current team members described in Question 3.3.2 there are no other contractors or suppliers engaged in project development at this time. Furthermore, though the type of technologies for the microgrid have been evaluated and selected in this study, COB and the project team have not yet made any definitive selection of equipment vendors.

As project lead and microgrid owner, COB will be responsible for selecting the future team members. COB will follow their established procurement process for infrastructure projects. However, COB may elect to assign project management responsibilities to another entity or team member, in which case the selection and contracting with the new team members would be the responsibility of the new project manager.

Question 3.3.7

Are the project financiers or investors identified? If yes, who are they and what is their relationship to the applicant? If no, what is the proposed approach to securing proposed financing? Will other members of the project team contribute any financial resources?

The City of Buffalo will finance the project. The City will actively explore other sources of project finance during the design phase, including finance that may be provided by Infrastructure Energy among other sources.

Question 3.3.8

Are there legal and regulatory advisors on the team? If yes, please identify them and describe their qualifications. If no, what is the proposed approach to enlisting support in this subject area?

The Buffalo City Council is currently assessing legal and regulatory matters, with input from the project team. The City plans to retain legal and regulatory advisors during the design stage of the project.

Subtask 3.4 – Commercial Viability – Creating and Delivering Value

Question 3.4.1

How were the specific microgrid technologies chosen? Specifically discuss benefits and challenges of employing these technologies.

Table 7 summarizes the benefits and challenges of the technologies we considered in this study.

Table 7 – Technologies Proposed for COB Microgrid

Technology	Benefit	Challenges
CHP (ICE-based)	• High energy efficiency • Integrates well with existing DHP • Well-developed and proven technology • Continuous generation resource • Financial incentives available	• Current low cost of electric power makes economics difficult when heat is not recovered • DHP only operates during heating season • COB staff not trained to operate CHP
Diesel generator	• Existing asset • Extra level of redundancy	• High emissions • Limited fuel storage relative to long outages

Technology	Benefit	Challenges
Microgrid controller	• Provides generation-load balance and resource optimization • Centralized controls of assets • Upgradeable for additional capabilities and feature	• Balancing controller feature set with cost • Upgrade for additional features can be costly
Solar photovoltaics (PV)	• Green generation • Financial incentives available	• Intermittent resource, so it requires storage to be practical for outages • Not cost-effective for current application • Snow cover in winter storm renders panels ineffective
Energy storage	• Complements and enables PV for certain applications • Enables voltage support, ramp rate controls and other grid market services	• High cost, communication and interface complexities • Current application doesn't require advanced capabilities • Not cost-effective for current application

The team chose a CHP-based generation resource for the following reasons:

- When the heat output is recovered and used, the overall efficiency is very high (in the range of 75%). This improves emissions and financial return.
- The DHP is a large "heat sink" that can utilize the heat output of the CHP. (The DHP is currently operated during the heating season only, however in many locations district energy plants operate year-round. If the DHP were to be upgraded to be a baseline heating plant, the CHP would be able to run at high efficiency at all times.)
- The resource is not inherently intermittent, so energy storage is not needed.
- The technology is well developed and proven.
- There are financial incentives offered for the purchase of CHP systems.
- CHP qualifies for exemption from National Grid's more expensive SC-7 Standby Tariff, as an "Environmentally Advantageous Technology," provided it meets certain emissions and efficiency requirements.
- Despite the partial-year availability of the DHP for using the CHP's heat output, modeling shows that the economics could work if the grid-connected export is sufficiently high (but not above National Grid's tariff rates).
- The responsibility for operating of the CHP unit can be outsourced.

Question 3.4.2

What assets does the applicant and/or microgrid owner already own that can be leveraged to complete this project?

The pre-existing assets that may be used as part of a microgrid are summarized in Table 8.

Table 8 – Existing Assets

Asset	Role	Owner	Size
Cummins Onan diesel generator	Backup generation	COB	200 kW
Kohler diesel generator (if space for it can be found at the FH/DHP)	Backup generation	COB	250 kW
City of Buffalo District Heating Plant (i.e., the DHP)	Load for CHP heat output	COB	70 MMBtu/h (hot water)

Question 3.4.3

How do the design, technology choice, and/or contracts ensure that the system balances generation and load?

The system is sized so that during islanded operation its capacity can always handle the FH/DHP and R50-F3765 loads. The microgrid controller will monitor and control the ramping up and down that is necessary to balance the load.
During grid-connected operation no load balancing is necessary because National Grid would purchase any excess power produced by the CHP after supplying the FH/DHP. End-users will purchase power through National Grid rather than directly from the City's microgrid.

Question 3.4.4

What permits and/or special permissions will be required to construct this project? Are they unique or would they be required of any microgrid? Why?

The required approvals for backup diesel power generators for the FH/DHP have already been met. The following permits and permissions would be required for the remainder of the microgrid. They are not unique to the COB project.

- National Grid interconnection agreement
- City of Buffalo Site Plan review
- Zoning review – Zoning permit and variance may depend on placement of system equipment. Projects within the City of Buffalo are subject to the current code; however, the adoption of the Green Code may impact the variance/permitting process.
- City of Buffalo building permit – Certificate of completion may be required. A certain level of code interpretation is anticipated and will be assessed as the project moves forward
- City of Buffalo Water and Buffalo Sewer Authority sewer approvals for any water, fire protection, sanitary and storm service connections
- Demolition and excavation permitting, if applicable

- City of Buffalo electrical permit
- Franchise/Revocable Consent for street cut permit, for new access points across rights of way
- Air emission permit through NYSDEC Title V to operate the generators
- State Environmental Quality Review

As the project moves into subsequent phases and design progresses, the list will be further refined.

Question 3.4.5
What is the proposed approach for developing, constructing and operating the project?

The development, construction, and operation of the microgrid will rely on a strong team of stakeholders, customers, and industry experts. Particularly at the development phase, this approach is crucial to anticipating risks and opportunities for this project so that they can be addressed early and reduce costs and missed revenue opportunities in future stages of the project.

Early development. Infrastructure Energy is acting as the primary contractor for this feasibility assessment, with Navigant as the secondary contractor and project manager. Navigant has contracted with four other organizations: EPRI, Wendel, Ramboll Environ, and CORE. EPRI has also subcontracted with Microgrid Labs to perform configuration and operations optimization modeling. COB will seek stakeholder feedback on the findings of this feasibility study. By compiling the collective knowledge of the various team members, COB has ensured that a strong analysis was completed at this early stage.

Late development. In the next stage of detailed design, COB may opt to keep the existing team in place, or they may modify the team composition, to obtain a full design, commercial and financial plans, and an investment grade benefit-cost analysis. Also at this time, COB and/or a designated project manager will start to consider project partners, in a more formal way, based on the planned system design and commercial business arrangements. COB will also establish contractual arrangements with microgrid customers.

Construction. During construction, all financing arrangements will be finalized and all contractual arrangements will be managed to ensure that major milestones are met. A construction project manager will be responsible for purchasing of equipment and subcontracting to each of the trades needed to support the project. The consultants used during the development and design of the project may continue to support the construction effort, for example by overseeing and/or verifying that the construction is completed in accordance with design plans.

Operation. The microgrid controller operator[26] will be responsible for the day-to-day operation, maintenance, and financial management of the microgrid. This will require the operator to review all contractual arrangements and to set the dispatch scenarios such that they meet the obligations under those agreements, optimize any non-contracted revenue, and meet any other needs not explicitly

[26] For the purposes of this report, "microgrid controller operator," "microgrid operator," and "operator" mean the organization – either COB or a partner organization – that is responsible for operating the microgrid. That organization will likely assign one or several individuals to carry out operational tasks, but our responses here refer to the responsibilities of the organization itself.

expressed within the contracts. The microgrid operator will report regularly to COB regarding the performance of the system.

Question 3.4.6

How are benefits of the microgrid passed to the community? Will the community incur any costs? If so, list the additional costs.

The buildings in the R50-F3765 group will need to opt in for service to realize the resiliency benefits of the microgrid. They will have to sign an electric service agreement, or other similar contract, with the City to receive power from the microgrid during a power grid outage.

In addition to resiliency as a community benefit, the community also benefits by having an opportunity to install future distributed generation that can be included on the microgrid. A pre-existing microgrid lowers the barriers for inclusion of additional renewables and DG, as the overall design of the microgrid will be completed, the points of islanding will be in place, and the appropriate partners will have been engaged.

The city would pay for all infrastructure investments needed, including the points of islanding. For those buildings eligible for microgrid emergency power but who do not opt in, the City would pay for switches needed to keep those buildings off of the microgrid during an islanding event. The CHP is sized so that it can supply power to all the loads during an islanding event, without the need for load shedding. Therefore, there will be no additional costs incurred for load shedding hardware or software.

Microgrid participants will likely be charged an administrative fee to cover COB costs for managing their membership and billing. As part of the design phase, methods for monitoring customer usage during an outage will be designed, perhaps based on existing metering according to a procedure and agreement with National Grid. The costs for this monitoring will be evaluated and an appropriate method of recovering those costs (e.g., an additional fee to customers) will be determined.

Question 3.4.7

What will be required of the utility to ensure this project creates value for the purchaser of the electricity and the community?

As the regulated utility, National Grid will continue to be responsible for ensuring that all of their customers, which includes customers of the microgrid, are served safely, reliably, and at a reasonable cost. This will require National Grid to support the development of this project in an advisory role, providing perspectives and expertise on design and regulatory issues that may affect their customers.

During the development of this project, National Grid will need to work with COB to address any policy, regulatory, or legal issues that may arise. These issues are identified in the response to Question 3.6.5. National Grid will have to complete a coordinated electric system interconnection review (CESIR) (at the COB's expense) to determine the impact the microgrid will have on the overall distribution grid.

National Grid will have to negotiate with COB the price they pay for the exported power from the microgrid in grid-connected mode. This feasibility study indicates that the city would have to get close to the retail rate for its exported power in order to be feasible. (By retail rate, we are referring to the rate that the City currently pays National Grid.)

For any investment made by National Grid to support this project that cannot be recovered from COB, they will need to determine how to justify the costs being rate-based. More specifically, National Grid will need to determine if such investment aids in deferring or avoiding other infrastructure investment. If that is the case, National Grid may be able to spread the costs across their entire rate-base. If not, National Grid will need to determine other means of cost recovery.
Also, during operation of the microgrid (both in normal and islanded operation), National Grid will be responsible for maintaining the stability of their distribution grid, including any distribution assets within the microgrid. This will require close coordination with the microgrid controller operator. Also, it may be possible that National Grid offers additional services to the microgrid owner and/or microgrid controller operator to help with the operation of the system.

Question 3.4.8

Have the microgrid technologies (including but limited to: generation, storage, controls) been used or demonstrated before? If yes, describe the circumstances and lessons learned.

All of the technologies proposed for the COB microgrid (CHP, microgrid controllers, and diesel generators) are mature technologies that have been used and demonstrated before. Of these technologies, CHP and diesel generators are considered by the industry as mature technologies. Microgrid controllers have been commercialized relatively recently, but their technology is undergoing significant continuing development. Table 9 summarizes the maturity of the proposed technologies.

Table 9 – Microgrid Technology Maturity

Technology	Maturity and Lessons Learned
CHP	CHP is a well-established technology. Manufacturers have sold many units. Examples can be found in the DOE CHP Database.[27]
Diesel generators	Diesel generators are an extremely well-established technology. These backup generation assets are currently in place at the FH/DHP.
Microgrid controller	A scalable, intelligent local microgrid controller with standard capabilities will be implemented at COB, a technology type proven in many other microgrid projects, including the Co-op City microgrid in the Bronx, NY. Lessons learned about microgrid controllers include: • It takes significant work to integrate different technologies under one controller. • Minimizing the number of vendors supporting the project can simplify the integration of technologies and the microgrid controller. If multiple vendors must be chosen, they should use similar technical protocols. • Integration of advanced controls and existing grid devices creates challenges.

[27] https://doe.icfwebservices.com/chpdb/

Question 3.4.9

Describe the operational scheme, including, but not limited to, technical, financial, transactional and decision making responsibilities that will be used to ensure this project operates as expected.

The City is considering partnering with another entity, such as the Buffalo District Energy Corporations (BDEC) Economic Development Group (EDC), or another third party, for operational management of the COB microgrid. EDG is a domestic non-profit organization that has been designated by COB as the preferred developer of a potential new district energy system. The City of Buffalo will develop the operational scheme in coordination with the selected third-party entity and the microgrid design team.

As identified in Task 2, it is expected that a microgrid controller will be established as part of this project and that it will be the responsibility of the microgrid controller operator to determine the appropriate operational schemes such that all technical, financial, and contractual obligations are met through moment-to-moment decision making. In this way, the microgrid controller operator will be responsible for becoming acquainted with and informed about all of the technical functionality and limitations of the microgrid.

The microgrid controller operator will also be responsible for knowing the proposed financial outlook and targets for the project. COB and, if different, the operator will be responsible for managing all contractual obligations that the microgrid has established with each of its customers. Table 3 describes the proposed commercial and financial value streams that will need to be understood and monitored by the microgrid controller operator.

The microgrid operator will also design the dispatch scenarios, thresholds, and criteria of the microgrid controller to balance all of the diverse interests and obligations of the microgrid owner, customer(s), and/or stakeholders.

Finally, the microgrid owner and/or operator will be responsible for completing or contracting for operations and maintenance (O&M), including establishing and executing a preventative maintenance plan. The operator will perform measurement and verification (M&V) activities for the microgrid and generate periodic reports to assess how it is performing compared to budget.

Question 3.4.10

How does the project owner plan to charge the purchasers of electricity services? How will the purchasers' use be metered?

The method for monitoring customer usage during an outage will be determined as part of the design phase, perhaps based on existing metering by National Grid according to a procedure and agreement to be established with them. An alternative would be to install a separate meter for every participating building, which is more costly but might be manageable because only a limited number of buildings will be served by the microgrid. Billing activities would be performed by the City's existing accounting organization for other services it provides.

Electrical usage by the FH/DHP building will be determined by subtracting the amount of electrical power going from the building to feeder 3765 from the total amount of power produced by the CHP, as both of those quantities will be metered already. A water flow meter will be installed at the CHP to measure hot water delivered to the DHP. As discussed in Questions 3.1.3 and 3.1.6, although usage will be monitored there will be no internal billing because all assets are owned by the City.

For modeling purposes, we assumed that non-COB customers will pay the National Grid tariff plus a 10% surcharge for the premium service of continuity in power.

Question 3.4.11

Are there business/commercialization and replication plans appropriate for the type of project?

The team is carefully documenting the feasibility process and will continue documenting through design and implementation. There is currently no plan to commercialize the resulting design. However, if the design proves successful in practice it would be valuable to REV objectives to produce case study or other documentation about the project so that others can replicate the success more easily. COB proposes to work with NYSERDA to produce this documentation, if desired.

Question 3.4.12

How significant are the barriers to market entry for microgrid participants?

For the team members of this microgrid project, the barriers to entry into the microgrid market are relatively low. All of the team members have experience in designing, evaluating, and advising on similar energy projects. Microgrids are a logical continuation of their service offerings in this area. Similarly, a number of the team members have been active in the microgrid market for an extended period, so identified barriers to market entry have already been assessed and addressed. The same assessment will be generally true for the technology companies to be considered for the design of the microgrid.

There are technical uncertainties, specific to this project, regarding the ability of National Grid's current distribution system to manage reverse power flows (during grid-connected operation) when the load on F3765 is less than the power exported by the CHP. These issues, if present, will be determined in the CESIR interconnection review.

Question 3.4.13

Does the proposer demonstrate a clear understanding of the steps required to overcome these barriers?

The team has met several times with National Grid to get clarification on many important issues affecting the project concept. National Grid has indicated that more specific input will require a preliminary proposal (which would be done during the design phase), at which point they will work with the team to resolve additional issues.

The CESIR process will clearly identify any technical issues related to the export of power to F3765. The consultant team is expert in power grid design, and they will work closely with National Grid to understand what steps would be necessary to overcome reverse power issues or any other problems identified. The team will evaluate the financial and technical implications of remedying any technical issues uncovered in the CESIR and consider those impacts in the design process.

Subtask 3.5 – Financial Viability

Question 3.5.1

What are the categories and relative magnitudes of the revenue streams and/or savings that will flow to the microgrid owner? Will they be fixed or variable?

The various revenue streams and savings that will flow to COB are listed in Table 10. All of the variable earnings are based on the model-predicted annual CHP output of 2,397 MWh and an outage period of 14 days. Although the fees to be charged to microgrid customers have not been determined, they are not expected to be on a higher order of magnitude than the revenue from selling power to those customers during an outage.

Table 10 – Revenue Streams and Savings

Category	Relative Magnitude	Type
Revenue from sale of exported power to National Grid	1.00	Variable
Savings in DHP natural gas usage	0.76	Variable
Savings in FH/DHP electricity purchase	0.48	Variable
Revenue from sale of power to R50-F3765 during outages	0.04	Variable
Revenue from fees from R50-F3765 customers	To be determined	Fixed and variable

Question 3.5.2

What other incentives will be required or preferred for this project to proceed? How does the timing of those incentives affect the development and deployment of this project?

It may be possible to receive an incentive under NYSERDA's CHP Program incentive, PON 2568 (also known as the CHP Acceleration Program). The program offers an accelerated procurement process, and there is technical assistance support for analyses and studies. The rapid procurement is facilitated by the requirement that recipients choose the CHP unit from a list of preapproved systems. Given the compressed time frame for implementing this incentive, the timing should not affect development and deployment of the project. The PON is effective until December 31, 2018.

Question 3.5.3

What are the categories and relative magnitudes of the capital and operating costs that will be incurred by the microgrid owner? Will they be fixed or variable?

Table 11 lists the categories and relative magnitudes of the capital and operating costs for the proposed microgrid.[28] All of the fixed costs listed except for O&M are the installed cost, not

[28] Note that the initial planning and design costs are not listed, as they are neither capital nor operating costs. However, their magnitude relative to the building infrastructure, is 1.1

accounting for the cost of capital. The fixed O&M and all other listed costs are on an annual basis. Variable costs are based on the predicted annual CHP output of 2,397 MWh.

Table 11 – Capital and Operating Costs

Category	Relative Magnitude	Type
Generating equipment, installed (ICE CHP)	1.00	Fixed
Variable O&M, annual (2,397 annual MWh assumed)	0.41	Variable
Building electrical and thermal infrastructure, installed	0.17	Fixed
Fuel, annual (2,397 annual MWh assumed)	0.14	Variable
Feeder upgrades, installed	0.12	Fixed
Communications infrastructure, installed	0.08	Fixed
Fixed O&M, annual	0.02	Fixed

Question 3.5.4
How does the business model for this project ensure that it will be profitable?

As discussed in Task 2 (see Section 1.3), a variety of microgrid configuration models were run to determine if an export price for the COB microgrid exists, no greater than the FH/DHP's retail tariff from National Grid, which results in breakeven or near-breakeven performance over a 20-year horizon. Because the majority of the revenue generated by the microgrid is earned during grid-connected mode, the main part of the analysis consisted of seven grid-connected investment cases, three with the 500 kW CHP and four with a combination of CHP and PV (with and without storage).

None of the CHP and PV combination cases, with or without storage, were found to be economically feasible, because of lengthy payback periods and high capital costs.

From the COB's perspective the best-case scenario – though it is also the most unrealistic – would be for the microgrid to be able to sell the power it exports to National Grid at the full retail price paid by the FH/DHP. We tested this microgrid concept to see if it would be possible to break even under this best-case condition. The result was positive, with a simple payback of 15 years and a bond-based payback of 18 years.

We also looked into how much less than full retail the export price could be while still allowing the microgrid to be paid back in approximately 20 years. With the price of power exported to National Grid assumed to be 90% of the retail price (case #8), the model predicts a simple payback of 18 years and a bond-based payback of 22 years.

Question 3.5.5
Describe the financing structure for this project during development, construction and operation.

The City will purchase the assets from its general fund, as well as take advantage of any available grants and/or incentives. At a later point in the development process, external financing will be considered, but no final decision has been made at this time. Sources of financing may include private sector developers, P3 finance and other social-good financiers.

There is a possibility that the microgrid will be operated through a partnership. When that decision is made, negotiations and arrangements will take place with the partners regarding how the operation will be funded.

Subtask 3.6 – Legal Viability

Question 3.6.1
Describe the proposed project ownership structure and project team members that will have a stake in the ownership.

The City of Buffalo will be the principal and potentially sole owner, and no other ownership role has been identified to date. Other ownership scenarios will be investigated during later stages of the development phase.

Question 3.6.2
Has the project owner been identified? If yes, who is it and what is the relationship to the applicant? If no, what is the proposed approach to securing the project owner?

Yes, the City of Buffalo, applicant, is the sole project owner unless other equity financial contributors are identified for participation on the team at a later date.

Question 3.6.3
Does the project owner (or owners) own the site(s) where microgrid equipment/systems are to be installed? If not, what is the plan to secure access to that/those site(s)?

Yes, the City of Buffalo owns the FH/DHP complex where the microgrid equipment will be located. There will be electrical switches and other equipment installed on feeder 3765, which is owned by National Grid. The project will work with National Grid to secure access to the feeder for this equipment. There may also need to be equipment installed by National Grid to accommodate reverse power flows. If this equipment is necessary, then National Grid will be responsible for installing the equipment and securing access if needed.

Question 3.6.4
What is the approach to protecting the privacy rights of the microgrid's customers?

Any agreements for services provided by City have their own privacy terms. The City cannot share information with third parties unless customers allow it. A City-wide MIS (Management Information System) regulates information sharing between parties. Information about the microgrid would be added to MIS, because the City is the microgrid owner.

Question 3.6.5
Describe any known, anticipated, or potential regulatory hurdles, as well as their implications that will need to be evaluated and resolved for this project to proceed. What is the plan to address them?

National Grid and the City of Buffalo will need to determine and/or agree upon the structure and rate used to value the electricity exported from the microgrid during grid-connected operation. If Special Contracts for export of power generated on-site do not permit negotiation of this price, or they cap the price too low for the microgrid to reach break-even returns, regulatory changes or waivers may be needed.

Under the current National Grid tariff, on-site generators can only sell power to other National Grid customers if they are a community distributed generator (CDG). The recipients of that power are called “CDG satellites.” To be a CDG, a generator must qualify for net metering, which is not true of the proposed microgrid. This restricts the microgrid’s ability to sell directly to customers in grid-connected mode. Further research, during the design phase, is needed to determine whether it also prohibits the microgrid from selling directly to National Grid customers during an outage. For the microgrid to be a CDG and sell directly to National Grid customers on F3765, the rules would need to be modified to allow microgrids for resilience, or facilities producing CHP-generated power, to be classified as a CDG.

The unusual topology of the microgrid with respect to the power grid (see our response to Question 3.2.4) may have regulatory implications. For example, it is not clear whether the proposed microgrid can be characterized as operating “in parallel” for the purposes of interconnection requirements and the applicability of different regulations governing distributed generation. Additional research will be required, during the design phase, to clarify issues related to the microgrid topology.

As mentioned in our response to Question 3.2.2, National Grid could perform important microgrid services for COB, including underground microgrid wiring, installing new electrical infrastructure, operating the microgrid itself, and handling microgrid billing. The utility has filed with the New York Public Service Commission to be permitted to offer similar services to a microgrid in Potsdam, NY.[29] Several of the services contemplated for this project are similar or identical to those of the Potsdam project, but at a minimum an additional filing would be needed for National Grid to take the role of microgrid operator for the COB microgrid. If current rules do not permit this role for a utility, it would require regulatory changes to enable such a relationship between National Grid and COB.

Finally, to the extent possible this project can and should align its operations and objectives with REV. REV provides an opportunity to reexamine current rules and regulations with the objective of rendering more mutually beneficial outcomes for all stakeholders. Similarly, new market opportunities are expected to be created through REV that could provide new future revenue streams for the project which reduce dependence on revenues from energy sales.

[29] See the article referenced in footnote 6 for details.

APPENDIX D: TASK 4 – DEVELOP INFORMATION FOR BENEFIT COST ANALYSIS

TABLE OF CONTENTS

DISCLAIMER

This report was prepared by Navigant Consulting, Inc. (Navigant) for Infrastructure Energy (formerly Energizing, LLC), solely for use by Infrastructure Energy and the City of Buffalo, Department of Public Works to meet the City of Buffalo, Department of Public Works' obligation under New York State Energy Research and Development Authority Agreement No. 66635 "NY PRIZE RFP 3044 Stage 1 Feasibility Assessment". The work presented in this report represents Navigant's professional judgment based on the information available at the time this report was prepared. Navigant is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

Task 4: Develop Information for Benefit Cost Analysis

Overview

Task 4 of the NY Prize Stage 1 Feasibility Assessment requirements involves development of information for the benefit-cost analysis performed by NYSERDA's contractor, Industrial Economics, Incorporated (IEc). All of the analysis input requirements of Task 4 are summarized in the form of questionnaires. The team developed the facility and microgrid questionnaires and submitted them to IEc, and their resulting Benefit-Cost Analysis Report is incorporated in its entirety below.

As discussed in Task 2, the proposed microgrid with 500 kW CHP would be able to serve: (1) the full electric load of the building complex that houses the Fire Headquarters, Emergency Services, and District Heating Plant (the "FH/DHP"), plus (2) the full electric load of an islanded group of buildings whose aggregate load is no more than 50% of the peak load that would occur during a winter extreme weather outage (the "R50-F3765" electric load). The team chose to island a subset of the buildings on the F3765 feeder, rather than supplying all buildings on the feeder, because the microgrid could serve their load during an outage without requiring load shedding. Load shedding of more than a dozen buildings would be too expensive and complex for a small microgrid such as the one being proposed.

Given the topology of the feeder, determining the buildings to be included during an outage, and the locations of the points of islanding, is a complex matter that can only be decided during a detailed study phase. Because of this, the team initially queried IEc about the possibility of running a simplified benefit-cost scenario in which all of the buildings on the feeder are served during an outage, but at the 50% level. According to IEc, a number of projects had similar difficulty in identifying the correct set of buildings to be islanded at the feasibility stage, and were analyzed in a similar way. IEc analyzed this whole-feeder-at-50% configuration in an initial analysis, which they refer to as Design Option 1.

Subsequently, the team determined that a critical infrastructure building close to the FH/DHP – the PS 95 Waterfront Elementary School – has an estimated load that would, when combined with the FH/DHP load, be close to the capacity of the proposed CHP during a winter weather event. At this preliminary stage of the project, islanding of the two buildings also seems to be simpler than islanding a number of the other possible groups of buildings. IEc agreed to run an analysis on an islanded configuration consisting of just the FH/DHP and the Waterfront Elementary School, which they call Design Option 2.

Because it is Design Option 2 that conforms to the proposed microgrid configuration analyzed here, the results of IEc's analysis of that option are the relevant results for the present feasibility study. The results of the Design Option 1 analysis should be considered informative and educational, but are not directly relevant to the microgrid configuration proposed here.

Please note that the original report did not provide a summary table and figure for Scenario 2 of Design Option 2. For completeness and clarity we provide those items in Appendix D-1, immediately following the IEc report.

IEc Benefit-Cost Analysis Report

Benefit-Cost Analysis Summary Report

Site 79 – City of Buffalo

PROJECT OVERVIEW

As part of NYSERDA's NY Prize community microgrid competition, the City of Buffalo and its partners are exploring development of a microgrid that would enhance the resiliency of electric service for a variety of facilities:

- The Buffalo Fire Department's Headquarters and Department of Public Works District Heating Plant;
- Shoreline Apartments, S-1 Homes, and Pine Harbor Apartments, three residential complexes in the downtown area;
- PS 95 Waterfront Elementary School;
- Mattina Community Health Center;
- The Federal Bureau of Investigation's Buffalo Field Office;
- A U.S. post office;
- St. Anthony's of Padua Roman Catholic Church; and
- Buildings housing a number of commercial establishments, including Edison Contracting Corporation, Super Market Management Inc., Beir Nabala Satellite Communications Inc., Mangione Hardware, Blue Cross Blue Shield, WKBW News, Staats Street Group LLC, and Buffalo Metropolitan Federal Credit Union.

Electricity for the Buffalo microgrid would be supplied by a new 500 kW natural gas-fired combined heat and power (CHP) system at the District Heating Plant. The operating scenario submitted by the project's consultants indicates that the unit would produce approximately 2,397 MWh of electricity per year, roughly 14 percent of the amount required to meet the average annual energy requirements of the facilities listed above. In the event of a loss of utility service, the project's consultants estimate that the capacity of the system would be sufficient to supply approximately 50 percent of the facilities' average aggregate load.

An alternative design option under consideration would limit the facilities the microgrid would serve to the Buffalo Fire Department's Headquarters, the Department of Public Works District Heating Plant, and PS 95 Waterfront Elementary School. In the event of a utility outage, the capacity of the system under this option would be sufficient to supply 100 percent of the three facilities' average aggregate load.

To assist with completion of the project's NY Prize Stage 1 feasibility study, IEc conducted a screening-level analysis of the project's potential costs and benefits. This report describes the results of that analysis, which is based on the methodology outlined below. The analysis evaluates both of the design options described above: Design Option 1, which would provide microgrid service to all 17 facilities listed; and Design Option 2, which would serve only the Buffalo Fire Department's Headquarters, Department of Public Works District Heating Plant, and PS 95 Waterfront Elementary School.

METHODOLOGY AND ASSUMPTIONS

In discussing the economic viability of microgrids, a common understanding of the basic concepts of benefit-cost analysis is essential. Chief among these are the following:

- *Costs* represent the value of resources consumed (or benefits forgone) in the production of a good or service.
- *Benefits* are impacts that have value to a firm, a household, or society in general.
- *Net benefits* are the difference between a project's benefits and costs.
- Both costs and benefits must be measured relative to a common *baseline* - for a microgrid, the "without project" scenario - that describes the conditions that would prevail absent a project's development. The BCA considers only those costs and benefits that are *incremental* to the baseline.

This analysis relies on an Excel-based spreadsheet model developed for NYSERDA to analyze the costs and benefits of developing microgrids in New York State. The model evaluates the economic viability of a microgrid based on the user's specification of project costs, the project's design and operating characteristics, and the facilities and services the project is designed to support. The model analyzes a discrete operating scenario specified by the user; it does not identify an optimal project design or operating strategy. (The four spreadsheets completed by IEc are found in the Excel files named "City of Buffalo Scenario X_option Y" enclosed with this report.)

The BCA model is structured to analyze a project's costs and benefits over a 20-year operating period. The model applies conventional discounting techniques to calculate the present value of costs and benefits, employing an annual discount rate that the user specifies – in this case, seven percent. It also calculates an annualized estimate of costs and benefits based on the anticipated engineering lifespan of the system's equipment. Once a project's cumulative benefits and costs have been adjusted to present values, the model calculates both the project's net benefits and the ratio of project benefits to project costs. The model also calculates the project's internal rate of return, which indicates the discount rate at which the project's costs and benefits would be equal. All monetized results are adjusted for inflation and expressed in 2014 dollars. With respect to public expenditures, the model's purpose is to ensure that decisions to invest resources in a particular project are cost-effective; i.e., that the benefits of the investment to society will exceed its costs. Accordingly, the model examines impacts from the perspective of society as a whole and does not identify the distribution of costs and benefits among individual stakeholders (e.g., customers, utilities). When facing a choice among investments in multiple projects, the "societal cost test" guides the decision toward the investment that produces the greatest net benefit.

The BCA considers costs and benefits for two scenarios:

- Scenario 1: No major power outages over the assumed 20-year operating period (i.e., normal operating conditions only).
- Scenario 2: The average annual duration of major power outages required for project benefits to

equal costs, if benefits do not exceed costs under Scenario 1.[30]

RESULTS

Table 1 summarizes the estimated net benefits, benefit-cost ratios, and internal rates of return for the scenarios described above. The results indicate that if there were no major power outages over the 20-year period analyzed (Scenario 1), the project's costs would exceed its benefits. Under Design Option 1, the average duration of major outages would need to equal or exceed 1.6 days per year (Scenario 2) in order for the project's benefits to outweigh its costs. Under Design Option 2, the breakeven point would increase to an annual average of 10.4 days without utility service. Design Option 2 is less attractive economically because it would provide reliability and resiliency benefits to a smaller number of facilities than Design Option 1, and would do so at what the project's consultant's estimate would be approximately the same cost.

The discussion that follows provides additional detail on these findings. It focuses primarily on Design Option 1, which offers a better breakeven point than Design Option 2.

Table 1. BCA Results (Assuming 7 Percent Discount Rate), Design Option 1

ECONOMIC MEASURE	ASSUMED AVERAGE DURATION OF MAJOR POWER OUTAGES	
	SCENARIO 1: 0 DAYS/YEAR	SCENARIO 2: 1.6 DAYS/YEAR
Net Benefits - Present Value	-$9,770,000	$153,000
Benefit-Cost Ratio	0.3	1.0
Internal Rate of Return	NA	14.1%

Note: For Design Option 2, net benefits under Scenario 1 would decline by an additional $740,000, while the breakeven point under Scenario 2 would increase to an annual average of 10.4 days without utility service.

Scenario 1

Figure 1 and Table 2 present the detailed results of the Scenario 1 analysis.

[30] The New York State Department of Public Service (DPS) requires utilities delivering electricity in New York State to collect and regularly submit information regarding electric service interruptions. The reporting system specifies 10 cause categories: major storms; tree contacts; overloads; operating errors; equipment failures; accidents; prearranged interruptions; customers equipment; lightning; and unknown (there are an additional seven cause codes used exclusively for Consolidated Edison's underground network system). Reliability metrics can be calculated in two ways: including all outages, which indicates the actual experience of a utility's customers; and excluding outages caused by major storms, which is more indicative of the frequency and duration of outages within the utility's control. In estimating the reliability benefits of a microgrid, the BCA employs metrics that exclude outages caused by major storms. The BCA classifies outages caused by major storms or other events beyond a utility's control as "major power outages," and evaluates the benefits of avoiding such outages separately.

Figure 1. Present Value Results, Scenario 1 (No Major Power Outages; 7 Percent Discount Rate), Design Option 1

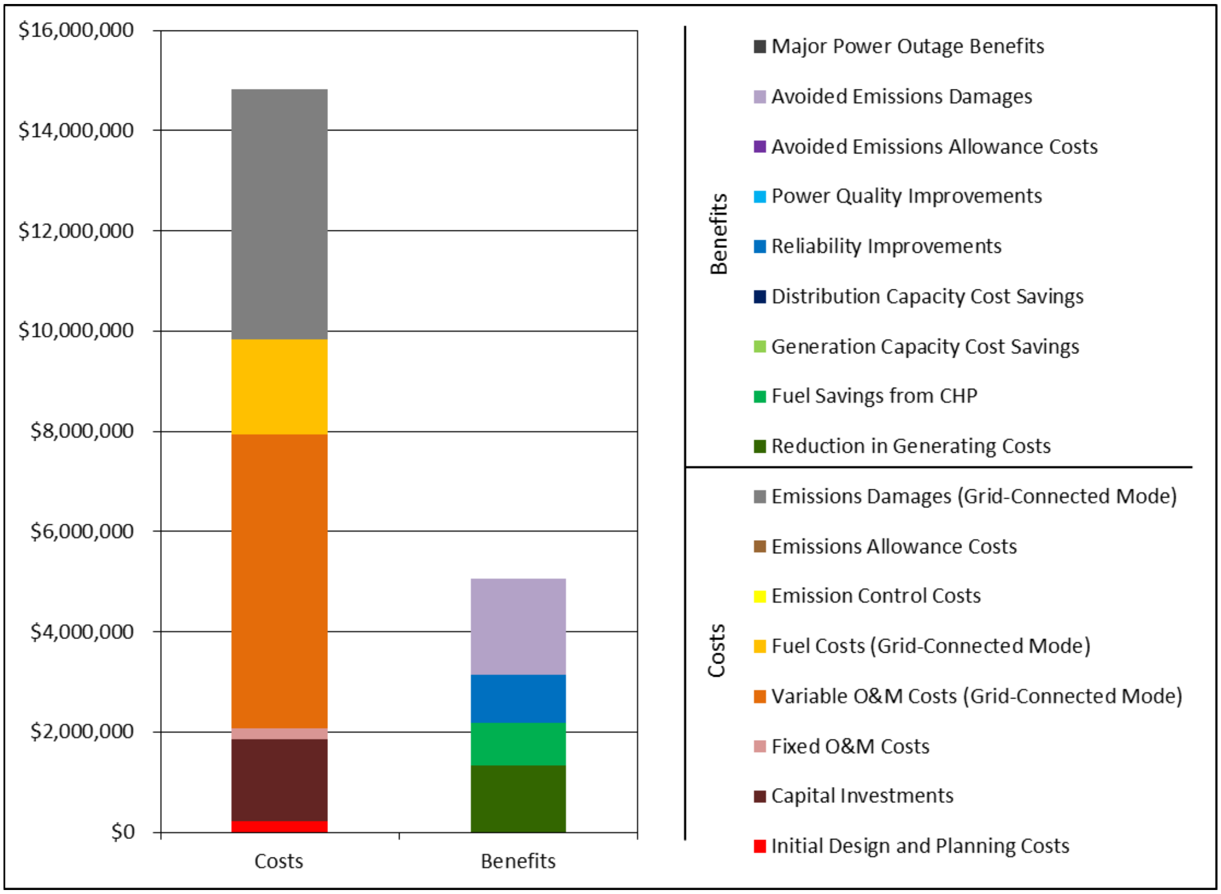

Table 2. Detailed BCA Results, Scenario 1 (No Major Power Outages; 7 Percent Discount Rate), Design Option 1

COST OR BENEFIT CATEGORY	PRESENT VALUE OVER 20 YEARS (2014$)	ANNUALIZED VALUE (2014$)
Costs		
Initial Design and Planning	$230,000	$20,300
Capital Investments	$1,620,000	$143,000
Fixed O&M	$227,000	$20,000
Variable O&M (Grid-Connected Mode)	$5,870,000	$518,000
Fuel (Grid-Connected Mode)	$1,900,000	$168,000
Emission Control	$0	$0
Emissions Allowances	$0	$0
Emissions Damages (Grid-Connected Mode)	$4,980,000	$325,000
Total Costs	**$14,800,000**	

COST OR BENEFIT CATEGORY	PRESENT VALUE OVER 20 YEARS (2014$)	ANNUALIZED VALUE (2014$)
Benefits		
Reduction in Generating Costs	$1,340,000	$118,000
Fuel Savings from CHP	$837,000	$73,800
Generation Capacity Cost Savings	$0	$0
Distribution Capacity Cost Savings	$0	$0
Reliability Improvements	$972,000	$85,800
Power Quality Improvements	$0	$0
Avoided Emissions Allowance Costs	$813	$72
Avoided Emissions Damages	$1,910,000	$125,000
Major Power Outage Benefits	$0	$0
Total Benefits	**$5,060,000**	
Net Benefits	**-$9,770,000**	
Benefit/Cost Ratio	**0.3**	
Internal Rate of Return	**NA**	
Note: Under Design Option 2, the costs and benefits of the project in most categories would remain unchanged. The exception would be benefits attributable to reliability improvements; the estimated benefits in this category would decline from a present value of $972,000 to $232,000, reflecting the smaller number of facilities the microgrid would serve in the event of an outage.		

Fixed Costs

The BCA relies on information provided by the project team to estimate the fixed costs of developing the microgrid. The project team's best estimate of initial design and planning costs is approximately $230,000. The present value of the project's capital costs is estimated at approximately $1.62 million, including costs associated with installing the new CHP unit and microgrid infrastructure. The present value of the microgrid's fixed operations and maintenance (O&M) costs (i.e., O&M costs that do not vary with the amount of energy produced) is estimated at approximately $227,000, based on an annual cost of $20,000.

Variable Costs

A significant variable cost associated with the proposed project is the cost of natural gas to fuel operation of the CHP unit. To characterize these costs, the BCA relies on estimates of fuel consumption provided by the project team and projections of fuel costs from New York's 2015 State Energy Plan (SEP), adjusted to reflect recent market prices.[31] Based on these figures, the present value of the project's fuel costs over a 20-year operating period is estimated to be approximately $1.9 million.

The BCA also considers the project team's best estimate of the microgrid's variable O&M costs (i.e., O&M costs that vary with the amount of energy produced). The present value of these costs is estimated at

[31] The model adjusts the State Energy Plan's natural gas and diesel price projections using fuel-specific multipliers calculated based on the average commercial natural gas price in New York State in October 2015 (the most recent month for which data were available when the current version of the model was finalized) and the average West Texas Intermediate price of crude oil in 2015, as reported by the Energy Information Administration. The model applies the same price multiplier in each year of the analysis.

approximately $5.87 million, or $216 per MWh for the microgrid as a whole.

In addition, the analysis of variable costs considers the environmental damages associated with pollutant emissions from the CHP unit, based on the operating scenario and emissions rates provided by the project team and the understanding that none of the system's generators would be subject to emissions allowance requirements. In this case, the damages attributable to emissions from the microgrid's CHP units are estimated at approximately $325,000 annually. The majority of these damages are attributable to the emission of NO_x. Over a 20-year operating period, the present value of emissions damages is estimated at approximately $4.98 million.

Avoided Costs

The development and operation of a microgrid may avoid or reduce a number of costs that otherwise would be incurred. These include generating cost savings resulting from a reduction in demand for electricity from bulk energy suppliers. The BCA estimates the present value of these savings over a 20-year operating period to be approximately $1.34 million. In addition, the new CHP systems would cut consumption of natural gas for heating purposes; the present value of these savings over the 20-year period analyzed is approximately $837,000. The reduction in demand for electricity from bulk energy suppliers and reduction in the amount of fuel needed for heating purposes would also reduce emissions of air pollutants, yielding emissions allowance cost savings with a present value of approximately $813 and avoided emissions damages with a present value of approximately $1.91 million.[32]

In addition to the savings noted above, development of a microgrid could in theory yield cost savings by avoiding or deferring the need to invest in expansion of the conventional grid's energy generation or distribution capacity.[33] It could also improve power quality for the facilities it serves. Based on information provided by the project team, such benefits are not expected for the City of Buffalo microgrid.

Reliability Benefits

An additional benefit of the proposed microgrid would be to reduce customers' susceptibility to power outages by enabling a seamless transition from grid-connected mode to islanded mode. For Design Option 1, the analysis indicates that development of a microgrid would yield reliability benefits of approximately $85,800 per year, with a present value of $972,000 over a 20-year operating period.[34] This estimate was developed using the U.S. Department of Energy's Interruption Cost Estimate (ICE) Calculator, and is based on the following indicators of the likelihood and average duration of outages in the service area:[35]

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[32] Following the New York Public Service Commission's (PSC) guidance for benefit cost analysis, the model values emissions of CO_2 using the social cost of carbon (SCC) developed by the U.S. Environmental Protection Agency (EPA). [See: State of New York Public Service Commission. Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Order Establishing the Benefit Cost Analysis Framework. January 21, 2016.] Because emissions of SO_2 and NO_x from bulk energy suppliers are capped and subject to emissions allowance requirements in New York, the model values these emissions based on projected allowance prices for each pollutant.

[33] Impacts to transmission capacity are implicitly incorporated into the model's estimates of avoided generation costs and generation capacity cost savings. As estimated by NYISO, generation costs and generating capacity costs vary by location to reflect costs imposed by location-specific transmission constraints.

[34] Under Design Option 2 the present value of reliability benefits would decline to $232,000**,** reflecting the smaller number of facilities the microgrid would serve.

[35] www.icecalculator.com.

- System Average Interruption Frequency Index (SAIFI) – 0.96 events per year.
- Customer Average Interruption Duration Index (CAIDI) – 116.4 minutes.[36]

The estimate takes into account the number of small and large commercial or industrial customers the project would serve; the distribution of these customers by economic sector; average annual electricity usage per customer, as provided by the project team; and the prevalence of backup generation among these customers. It also takes into account the variable costs of operating existing backup generators, both in the baseline and as an integrated component of a microgrid. Under baseline conditions, the analysis assumes a 15 percent failure rate for backup generators.[37] It assumes that establishment of a microgrid would reduce the rate of failure to near zero.

It is important to note that the analysis of reliability benefits assumes that development of a microgrid would insulate the facilities the project would serve from outages of the type captured in SAIFI and CAIDI values. The distribution network within the microgrid is unlikely to be wholly invulnerable to such interruptions in service. All else equal, this assumption will lead the BCA to overstate the reliability benefits the project would provide.

Summary

The analysis of Scenario 1 yields a benefit/cost ratio of 0.3 under either design option; i.e., the estimate of project benefits is approximately 30 percent that of project costs. Accordingly, the analysis moves to Scenario 2, taking into account the potential benefits of a microgrid in mitigating the impact of major power outages.

Scenario 2

Benefits in the Event of a Major Power Outage

As previously noted, the estimate of reliability benefits presented in Scenario 1 does not include the benefits of maintaining service during outages caused by major storm events or other factors generally considered beyond the control of the local utility. These types of outages can affect a broad area and may require an extended period of time to rectify. To estimate the benefits of a microgrid in the event of such outages, the BCA methodology is designed to assess the impact of a total loss of power – including plausible assumptions about the failure of backup generation – on the facilities the microgrid would serve. It calculates the economic damages that development of a microgrid would avoid based on (1) the incremental cost of potential emergency measures that would be required in the event of a prolonged outage, and (2) the value of the services that would be lost.[38,39]

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[36] The analysis is based on DPS's reported 2014 SAIFI and CAIDI values for National Grid.

[37] http://www.businessweek.com/articles/2012-12-04/how-to-keep-a-generator-running-when-you-lose-power#p1.

[38] The methodology used to estimate the value of lost services was developed by the Federal Emergency Management Agency (FEMA) for use in administering its Hazard Mitigation Grant Program. See: FEMA Benefit-Cost Analysis Re-Engineering (BCAR): Development of Standard Economic Values, Version 4.0. May 2011.

[39] As with the analysis of reliability benefits, the analysis of major power outage benefits assumes that development of a microgrid would insulate the facilities the project would serve from all outages. The distribution network within the microgrid is unlikely to be wholly invulnerable to service interruptions. All else equal, this will lead the BCA to overstate the benefits the project would provide.

At present, of the facilities that would be served by the City of Buffalo microgrid, only the District Heating Plant is equipped with emergency generators; others could rent a portable generator in the event of a prolonged outage. Table 3 summarizes the estimated cost of operating these generators. Table 3 also indicates the loss in service capabilities that is likely to occur while relying on these units, as well as the loss in service capabilities that would occur should these units fail. The information the table provides serves as an input to our analysis of the costs associated with a major power outage, based on the following assumptions:

- In all cases, the supply of fuel necessary to operate the backup generators would be maintained indefinitely.
- In all cases, there is a 15 percent chance that the backup generator would fail.

The costs of a major outage also depend on the consequences of a sustained interruption of service at the facilities of interest. The analysis calculates the impact of a loss in fire and emergency medical services at the Buffalo Fire Department's Headquarters, as well as electric service losses at the Shoreline Apartments, S-1 Homes, and Pine Harbor Apartments, using standard FEMA methodologies. The impact of a loss in service at the remaining 13 commercial facilities was estimated using the ICE Calculator, assuming 12 hours of microgrid demand per day during an outage.[40]

Table 3. Costs and Level of Service Maintained by Backup Generators, Scenario 2

FACILITY	ONE-TIME COSTS ($)	ONGOING OPERATING COSTS ($/DAY)	PERCENT LOSS IN SERVICE CAPABILITIES DURING AN OUTAGE	
			WITH BACKUP POWER	WITHOUT BACKUP POWER
Buffalo Fire Department Headquarters/District Heating Plant[1]	$1,000	$500	0%	100%
Shoreline Apartments[2]	$200,000	$8,640	80%	100%
S-1 Homes Inc. [2]	$1,000	-	80%	100%
Pine Harbor Apartments[2]	$104,000	$5,000	80%	100%
PS 95 Waterfront Elementary School[2]	$1,000[3]	-	80%	100%
Mattina Community Health Center[2]	$1,000	-	80%	100%
Edison Contracting Corporation[2]	$1,000	-	80%	100%
Super Market Management Inc. [2]	$1,000	-	80%	100%
Beir Nabala Satellite Communications Inc. [2]	$1,000	-	80%	100%
Mangione Hardware[2]	$1,000	-	90%	100%
Blue Cross Blue Shield[2]	$2,000	-	80%	100%
WKBW News[2]	$2,000	-	20%	100%
Staats Street Group LLC[2]	$2,000	-	80%	100%
FBI Buffalo Field Office[2]	$2,000	-	0%	100%

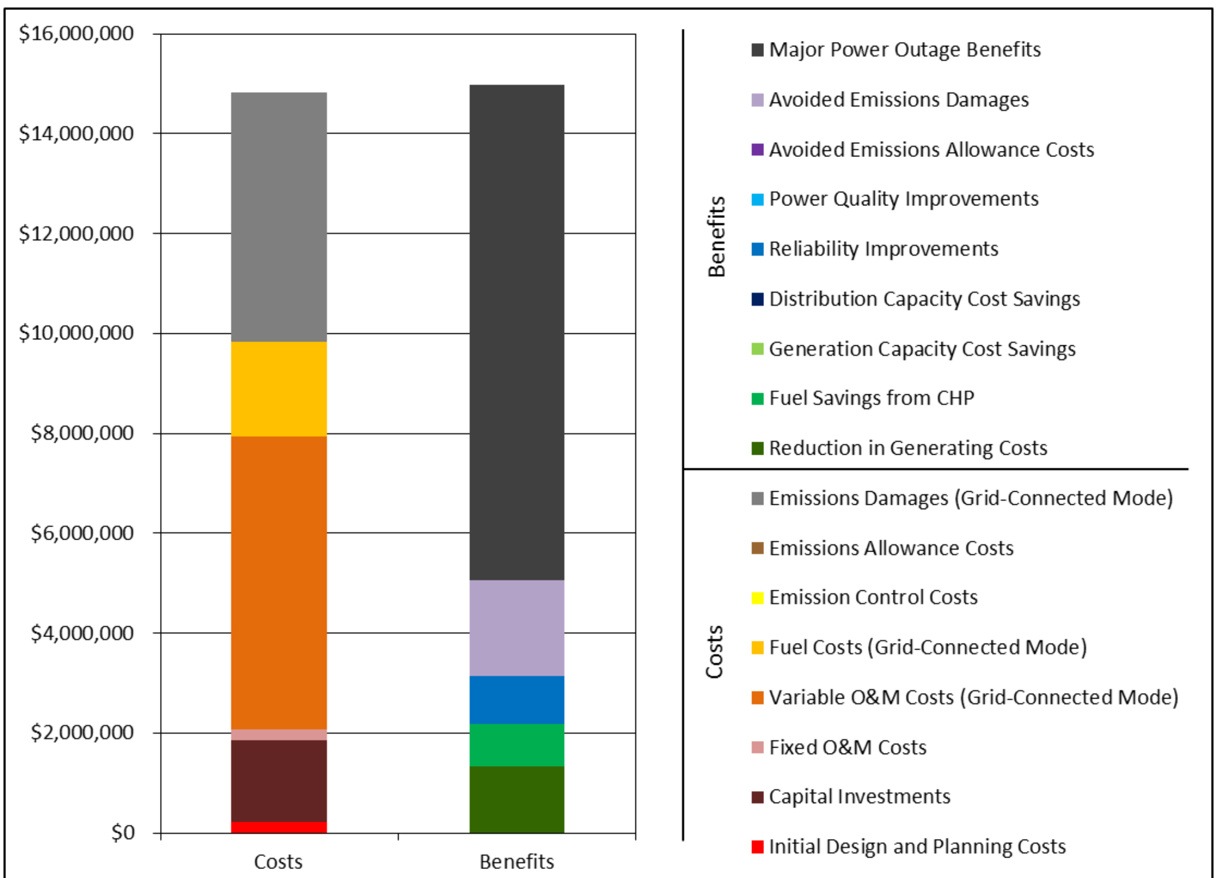
[40] http://icecalculator.com/.

FACILITY	ONE-TIME COSTS ($)	ONGOING OPERATING COSTS ($/DAY)	PERCENT LOSS IN SERVICE CAPABILITIES DURING AN OUTAGE	
			WITH BACKUP POWER	WITHOUT BACKUP POWER
Buffalo Metropolitan Federal Credit Union[2]	$2,000	-	90%	100%
St. Anthony's of Padua Roman Catholic Church[2]	$1,000	-	90%	100%
US Post Office[2]	$1,000	-	90%	100%
Notes: [1] Existing backup generator. [2] Rented generator. [3] Cost would only be incurred when school is in session (i.e., not on weekends or during the summer months).				

Summary

Figure 2 and Table 4 present the results of the BCA for Scenario 2 under Design Option 1. The results indicate that the benefits of the proposed project would equal or exceed its costs if the project enabled the facilities it would serve to avoid an average of 1.6 (consecutive) days per year without power. If the average annual duration of the outages the microgrid prevents is less than this figure, its costs are projected to exceed its benefits.

Figure 2. Present Value Results, Scenario 2 (Major Power Outages Averaging 1.6 Days/Year; 7 Percent Discount Rate), Design Option 1



Under Design Option 2, Scenario 2's breakeven point would increase to an annual average of 10.4 (consecutive) days without utility service.[41] Design Option 2 is less attractive economically because it would provide reliability and resiliency benefits to a smaller number of facilities than Design Option 1, and would do so at what the project's consultants estimate would be approximately the same cost.

Table 4. Detailed BCA Results, Scenario 2 (Major Power Outages Averaging 1.6 Days/Year; 7 Percent Discount Rate), Design Option 1

COST OR BENEFIT CATEGORY	PRESENT VALUE OVER 20 YEARS (2014$)	ANNUALIZED VALUE (2014$)
Costs		
Initial Design and Planning	$230,000	$20,300
Capital Investments	$1,620,000	$143,000
Fixed O&M	$227,000	$20,000
Variable O&M (Grid-Connected Mode)	$5,870,000	$518,000
Fuel (Grid-Connected Mode)	$1,900,000	$168,000
Emission Control	$0	$0
Emissions Allowances	$0	$0
Emissions Damages (Grid-Connected Mode)	$4,980,000	$325,000
Total Costs	**$14,800,000**	
Benefits		
Reduction in Generating Costs	$1,340,000	$118,000
Fuel Savings from CHP	$837,000	$73,800
Generation Capacity Cost Savings	$0	$0
Distribution Capacity Cost Savings	$0	$0
Reliability Improvements	$972,000	$85,800
Power Quality Improvements	$0	$0
Avoided Emissions Allowance Costs	$813	$72
Avoided Emissions Damages	$1,910,000	$125,000
Major Power Outage Benefits	$9,920,000	$876,000
Total Benefits	**$15,000,000**	
Net Benefits	**$153,000**	
Benefit/Cost Ratio	**1.0**	
Internal Rate of Return	**14.1%**	

Note: For Design Option 2, the costs and benefits of the project in most categories would remain unchanged. The exception would be benefits in the Reliability Improvements and Major Power Outage categories, which would be lower for Design Option 2 than for Design Option 1. As a result, Scenario 2's breakeven point would increase to an annual average of 10.4 days without utility service.

[41] The summary figure and table for Scenario 2 of Design Option 2 are found in Appendix A.

Appendix D-1 - Detailed BCA Results, Scenario 2 of Design Option 2

Figure D-1 and Table D-1 present the results of the BCA for Scenario 2 under Design Option 2. The results indicate that the benefits of the proposed project would equal or exceed its costs if the project enabled the facilities it would serve to avoid an average of 10.4 days per year without power. If the average annual duration of the outages the microgrid prevents is less than this figure, its costs are projected to exceed its benefits.

Figure D-1 – Present Value Results, Scenario 2 (Major Power Outages Averaging 10.4 Days/Year; 7 Percent Discount Rate), Design Option 2

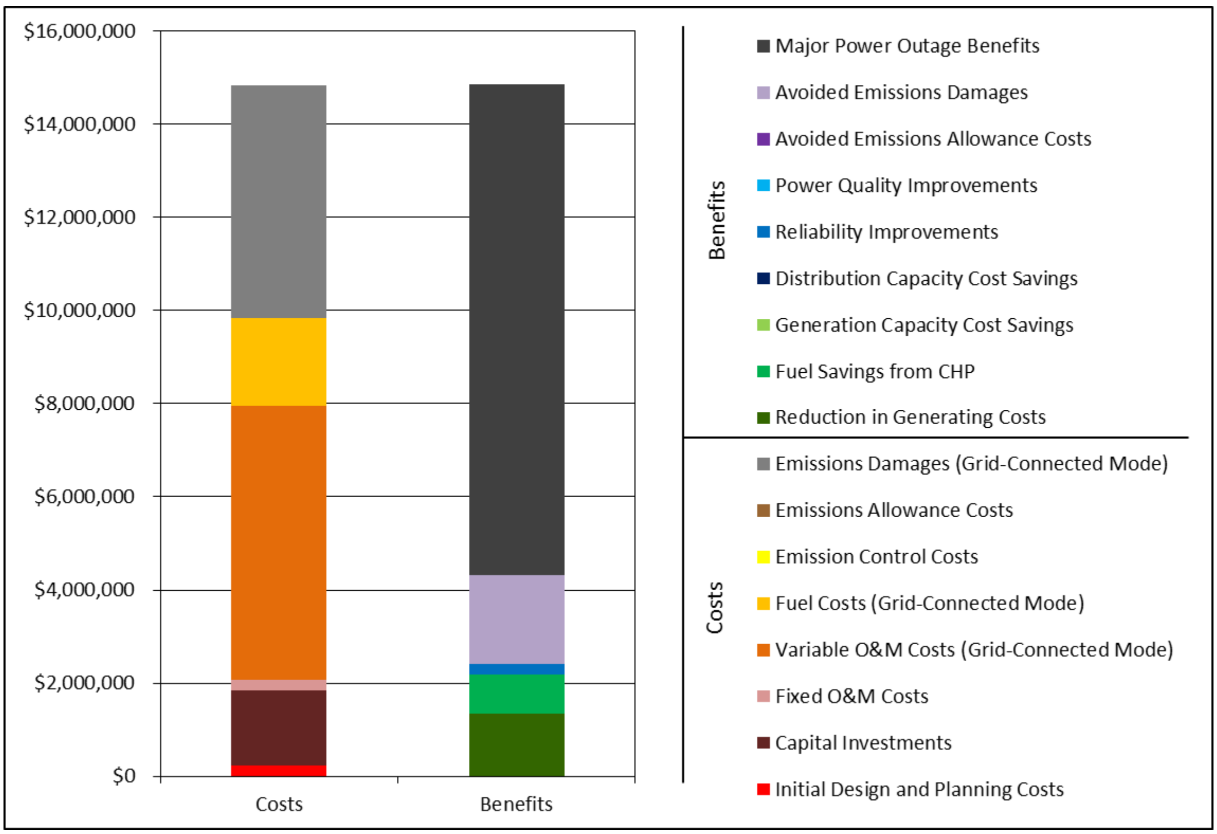


Table D-1 – Detailed BCA Results, Scenario 2 (Major Power Outages Averaging 10.4 Days/Year; 7 Percent Discount Rate), Design Option 2

COST OR BENEFIT CATEGORY	PRESENT VALUE OVER 20 YEARS (2014$)	ANNUALIZED VALUE (2014$)
Costs		
Initial Design and Planning	$230,000	$20,300
Capital Investments	$1,620,000	$143,000
Fixed O&M	$227,000	$20,000
Variable O&M (Grid-Connected Mode)	$5,870,000	$518,000
Fuel (Grid-Connected Mode)	$1,900,000	$168,000
Emission Control	$0	$0
Emissions Allowances	$0	$0
Emissions Damages (Grid-Connected Mode)	$4,980,000	$325,000
Total Costs	**$14,800,000**	
Benefits		
Reduction in Generating Costs	$1,340,000	$118,000
Fuel Savings from CHP	$837,000	$73,800
Generation Capacity Cost Savings	$0	$0
Distribution Capacity Cost Savings	$0	$0
Reliability Improvements	$232,000	$20,500
Power Quality Improvements	$0	$0
Avoided Emissions Allowance Costs	$813	$72
Avoided Emissions Damages	$1,910,000	$125,000
Major Power Outage Benefits	$10,540,000	$934,000
Total Benefits	**$14,900,000**	
Net Benefits	**$30,000**	
Benefit/Cost Ratio	**1.0**	
Internal Rate of Return	**13.6%**	

Note: For Design Option 2, the costs and benefits of the project in most categories would remain unchanged. The exception would be benefits in the Reliability Improvements and Major Power Outage categories, which would be lower for Design Option 2 than for Design Option 1. As a result, Scenario 2's breakeven point would increase to an annual average of 10.4 days without utility service.