City of Boston

Boston Planning & Development Agency

Raymond L. Flynn Marine Park District Energy Microgrid

MassCEC Feasibility Assessment

Task 6 Final Report

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in partnership with

S&C ELECTRIC COMPANY
Excellence Through Innovation

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I. Chapter 1: Summary and Recommendations

1.0 RLFMP Microgrid Feasibility Assessment Process

The Raymond L. Flynn Marine Park District Energy Microgrid (RLFMP Microgrid) Feasibility Assessment was initiated by the Boston Planning & Development Agency (BPDA) and executed by a Project Team comprised of staff representing Microgrid Institute, S&C Electric, and BPDA. The assessment addressed all Tasks defined by the Massachusetts Clean Energy Center (MassCEC) for its Community Microgrids Feasibility Assessment program, specifically:

- *Task 1:* Kickoff Meeting and Site Visits: Engaged customers and toured facilities in the project area to learn about site energy loads, systems, priorities, and plans, including microgrid and sustainable energy planning background;
- *Task 2:* Site Assessment and Description of Microgrid Characteristics: Analyzed energy load and cost data gathered from the utility bills and records of facility owners, as well as preliminary inputs from the electric utility serving the Project area (Eversource), to establish a preliminary design basis for the RLFMP Microgrid Project;
- *Task 3:* Preliminary Technical Design and Configuration: Further engaged the utility to gather information about distribution system infrastructure and configuration options, and revised the proposed design to establish a feasible microgrid solution;
- *Task 4:* Assessment of Microgrid's Commercial and Financial Feasibility: Identified and assessed proposed business model options for the Project; and
- *Task 5:* Information for Cost-Benefit Analysis: Produced metrics to quantify its likely costs and benefits to various parties – most notably customers, third-party investors, and the utility.

For this Task 6 Final Report, the Project Team updated the assessments in earlier Task Reports, and developed the following summary of outcomes and recommendations. The Project Team closely collaborated throughout the Project process to identify and obtain the required inputs and to focus assessment efforts on factors affecting the feasibility of the RLFMP Microgrid Project for prospective development by RLFMP stakeholders.

1.1 Findings, Observations, and Recommendations

• Discuss the observations and findings and recommendations, if any, from all Tasks, and avenues for further improvements, as appropriate.

The RLFMP Microgrid feasibility assessment process yielded several outcomes that inform opportunities for future development of resilient renewable energy systems – and for consideration in Massachusetts policy and planning efforts. Key findings and observations are discussed below, including the Project Team's recommendations where applicable.

1.1.1 Findings

The proposed RLFMP Microgrid envisions a close collaboration between the utility and prospective microgrid customers, with each financing, owning, and operating assets according to their respective interests and obligations. For study purposes, this proposed approach is termed a bring-your-own-PV (BYOPV) utility microgrid model.

The Project is designed, during outage events, to isolate a section of the Eversource distribution system and energize it with distributed photovoltaics (proposed and existing) and central battery energy storage and gas-fired standby generation. The microgrid would require distribution switching upgrades, a 250-foot segment of new underground cable, and distribution management system upgrades – *e.g.,* microgrid controls.

The envisioned system design, size, and ownership approach changed substantially during the microgrid feasibility assessment process. In its expression of interest responding to MassCEC's solicitation, BPDA described a business model relying on the formation of a public-private partnership (P3) with a third-party microgrid operator that would procure, own, and operate the proposed microgrid. This P3 concept resulted from a three-year process during which BPDA identified potential project participants, scope, and technology options. Toward that purpose, in March 2017, Mayor Marty Walsh filed a Home Rule Petition (HRP) with the Boston City Council requesting authorization to proceed with procurement under the proposed P3 structure[1]. Because the Massachusetts legislature failed to enact the Home Rule Petition, without necessary project-specific state law authority, the project team explored alternative structures

The proposed microgrid would use existing and new utility distribution infrastructure to form an intentional power island in the project area. Under this proposed model, the utility would own all microgrid infrastructure, switches, and applicable controls and management responsibility for those controls in all operating modes. After the HRP failed, the Project Team sought to have the RLFMP site serve as the location for a pilot project for the utility to explore its role in the development and operation of a microgrid and for State regulators to explore how best to regulate that development and operation

[1] The Home Rule Petition (HRP) sought to expand existing state statutory authority for a public entity to procure energy services, in this instance the quasi-municipal Economic Development Industrial Corporation (EDIC, *dba* BPDA) that is the underlying land owner of the RLFMP. The existing statute, Massachusetts General Laws, c. 25A, §11i, authorizes the procurement of a relationship of up to 20 years with an energy services company (ESCO) to assess, design, and build energy conservation measures via an energy savings performance contract. The statute authorizes project finance by requiring the ESCO to deliver investment grade assessments, guarantees of energy savings and, when applicable, energy generation, monitoring and verification of results, and payments by the ESCO to the public entity for any shortfalls in performance. Because the statute limits this procurement authority to energy work on the property owned by the public entity, the HRP sought to expand the authority of the EDIC to enter into an ESCO relationship for energy work to include property owners within the RLFMP other than the EDIC. The HRP proposal to allow EDIC for this one project to create the basic elements of a public-private partnership – design, build, and operate via guaranteed project finance – highlighted the lack of general 3P authority in Massachusetts State law. Beyond the failure of the State Legislature to enact the HRP, the Project Team also reassessed the viability of having the proposed P3 structure for the relatively small size of the proposed microgrid. The Project Team concluded that, even if the State Legislature adopted the HRP, a microgrid that serves multiple owners would require complex contractual agreements that would be administratively burdensome and thus not the best way to develop the proposed microgrid.

The Project Team considered options and factors affecting ownership and control of behind-the-meter (BtM) distributed energy resources (DER) (primarily rooftop-mounted PV systems) to energize the microgrid. The BYOPV model for BtM DER ownership was deemed the simplest and most viable approach, in particular because it would allow customers to pursue onsite renewable systems when doing so suits their specific objectives, and it would allow them to capture the value of investments in renewable energy and load management systems.

Additionally, options were considered for procurement, ownership, and operation of dispatchable DERs for grid forming and load balancing – namely, BESS and natural gas-fired standby gensets to be located within BPDA's Central Parking facility at 12 Drydock.[2] These dispatchable DERs would be, under the proposed business model, owned and operated by a third-party entity to be identified and engaged in early project implementation phases, and the third-party owner would provide capacity and energy to the microgrid through an agreement with the utility.

1.1.2 Observations

Although Project assessments yielded the technical, ownership, and cost-recovery approaches that are discussed above and detailed in subsequent chapters, key questions remain about how these approaches would be implemented in Project deployment phases.

For assessment purposes, the Team assumed that the utility's costs for distribution system upgrades and controls would be recovered through general rates. Rate-base treatment for the assets may be justified by the Project's research and development (R&D) value, as well as the opportunity for the utility to collaborate with customers including the EDIC piloting an approach to using local customer-owned renewables to support a resilient community microgrid. As discussed above, the Project Team sought for this assessment to become an opportunity for the utility and State regulators to use the proposed marine park site for both a technical and regulatory pilot project: to determine how to design, build, finance and regulate a microgrid in the RLFMP, including issues of utility rate-basing certain costs and State regulation of microgrid structures involving utility-owned assets

Further detailed analysis might focus on the precise combination of Massachusetts and utility rate-base support, as well as its fully weighted costs. Such factors will affect the utility's interest in supporting the Project. Utility support is assumed for assessment purposes, but no agreement exists among the utility and its stakeholders regarding the Project. Utility support for the Project would need to be formally established in development phases.

Another key assumption involves existing and new customer DERs. The BYOPV approach relies on customers to invest for their own benefit in DERs – including PV systems and load controls – and to configure those DERs to respond to microgrid signals during island-mode operations. Although the proposed dispatchable DERs would be sufficient for grid forming and standby generation, customer DERs would be required to enable the microgrid to meet the sustainable resiliency objectives defined for

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[2] Exact location to be determined based on further reviews with BPDA staff; the Central Parking facility was identified as a prospective location within the scope of this study.

the Project. As with the required utility investments, customers' plans to invest in onsite DERs would need to be established by mutual agreement in early phases of Project deployment.

Finally, assessments showed that the initially proposed gas-fired district energy system would not be well suited to the revised set of seven facilities in the Project area, due to limited potential for serving thermal loads. Additionally, goals for reducing fossil fuel consumption and greenhouse gas (GHG) emissions may diminish opportunities to use natural gas-fired combined heat and power (CHP) to support thermal and electric loads in a district energy microgrid.

Future assessments may demonstrate substantial long-term potential for a district energy system to provide resilient and efficient thermal and electric resources for maritime industrial activity. Although study findings ultimately omitted district energy from the proposed design, those findings also showed that district energy infrastructure would yield substantial benefits in terms of local resilience and overall energy efficiency, and accordingly may merit consideration in future development planning for the RLFMP.

1.1.3 Recommendations

A. Independent PV Investment Value: Results of cost-benefit analysis show that the proposed PV investments would substantially reduce customers' annual electricity costs, and on an independent basis would produce a positive 25-year net-present value. Additionally, the economic benefits of those PV systems will be greater to the degree investors can take advantage of higher investment tax credits than are assumed in the assessment.

The Project Team would recommend that customers consider installing behind-the-meter PV systems on their building rooftops at the earliest opportunity, and specifically that BPDA consider installing the proposed carport-mounted PV systems on the top deck of its central parking garage. These PV systems can begin producing benefits for customers in advance of prospective microgrid integration to follow in the future. Notably, however, if BPDA pursues development of the 12 Drydock carport system, design considerations should address how interconnection systems will enable remote net-metered operation for beneficial BPDA loads and also to directly charge microgrid batteries to be installed at a future date.

B. Valuing Sustainable Resiliency: Assessment findings indicate that the proposed microgrid systems – namely utility switching and controls, as well as dispatchable BESS and gas-fired standby generation – would provide substantial renewable-powered resiliency for RLFMP customers. However, notwithstanding the substantial economic value the system could provide in a long-duration emergency situation, the costs of systems required for sustainable resiliency exceed the direct economic benefits that were quantified in this assessment.

Utility system cost-benefit analysis traditionally has emphasized least-cost planning for capital expenditures. State requirements such as integrated resource planning and renewable portfolio standards have enabled solar and other renewable energy resources to grow in Massachusetts, but with few exceptions those resources are incapable of supporting local resiliency – and indeed the way they have been integrated has emphasized least-cost approaches to maximize the owner's financial benefits rather than produce resiliency or other operational benefits. As a result, utility system planning and cost-recovery processes have effectively prevented communities from using renewable energy to protect their critical facilities.

The Project assessment demonstrates an important lesson: To the degree the State of Massachusetts values resilient sustainable energy for critical community assets, it should provide funding mechanisms for those assets as it does for other infrastructure intended to serve the public good.

II. Chapter 2: Site Assessment and Description of Microgrid Characteristics

2.0 Summary of Task 2 Assessment

2.0.1 Project Goals and Objectives

The RLFMP Microgrid is envisioned to serve a group of vital facilities and maritime industrial assets within the RLFMP in South Boston. The Project Team initially identified a group of 11 facilities in close proximity with substantial electrical and thermal loads in various profiles (*see Figure 2.1: RLFMP Microgrid Area Map*). In later Project phases, four (4) facilities were omitted from the design for technical reasons based on inputs from the utility.

In advance of this study, BPDA considered a district energy microgrid to improve energy resiliency and efficiency at RLFMP, an important economic development zone that is vulnerable to climate change effects, including sea-level rise and storm surge. These considerations showed that in addition to improving resiliency against utility outages, a district energy microgrid also would provide modernized and highly efficient energy infrastructure to support BPDA development goals for the area. As described in the Master Plan for the RLFMP, the 191-acre RLFMP is vital waterfront job center in the City of Boston.[3] Although BPDA is the underlying land owner of the RLFMP, the quasi-State Massachusetts Port Authority (Massport) has significant ownership interests in the park through long-term ground leases. The Project Team has coordinated throughout this process with Massport.

The RLFMP Microgrid Project aims to achieve the following goals and objectives:

Goal #1: Support industrial and maritime activity and development at the RLFMP

Project Objectives:

a. Increase the efficiency, resiliency, and sustainability of energy service for RLFMP facilities
b. Support job growth and retention with modernized local energy infrastructure and services
c. Provide opportunities for customers to reduce thermal and electric energy costs

Goal #2: Support Eversource goals, objectives, and compliance obligations

Project Objectives:

a. Site, design, and interconnect distributed energy resources to support local distribution planning and asset management
b. Facilitate integration of new energy storage and renewable generation
c. Coordinate microgrid design and planning with Eversource's grid-modernization strategy

Goal #3: Support Imagine Boston 2030 goals and Boston Community Energy Planning.

[3] *RLFMP Master Plan Update,* December 2017: http://www.bostonplans.org/getattachment/820e6922-af1f-4470-bbbe-99dfa82df97c

Imagine Boston 2030 identified two prime locations for further analysis on community microgrids. The RLFMP is one of those locations. This feasibility assessment helps Boston stay aligned with the goals. This work will also continue to build on ongoing work that BPDA, the City of Boston, Massport, and other RLFMP stakeholders have pursued toward conceptualization and preliminary planning of a district energy microgrid to serve the RLFMP.

Goal #4: Support Boston Smart Utilities Vision planning and policy processes

Although the Smart Utilities Policy section specific to district energy microgrids applies to new development areas of 1.5 million square feet or greater, the feasibility assessment at the RLFMP helps build the BPDA's and the City's knowledge of and engagement with a similar level of analysis and planning for this technology.

Smart Utilities Vision objectives:

a. Promote utilities that are easier to build, maintain and upgrade
b. Reduce energy, water, and telecommunication costs for residents and businesses
c. Harden infrastructure against flooding and heat waves
d. Attract businesses through world-class utility services
e. Integrate cutting edge technologies for innovation (including district energy microgrids)
f. Support current District Energy Microgrid Feasibility Assessment and Master Plan process under the Smart Utilities Policy for Article 80 Development Review.

2.0.2 Alignment of MassCEC Community Microgrids Program Goals

The goals of the RLFMP Microgrid are in alignment with MassCEC's Community Microgrids Program goals. Figure 2.7 below details characteristics of the Project that address Program goals, and considerations for subsequent Task assessments.

2.1 Task 2.1 – Site Assessment

2.1.1 Size and scope of the proposed microgrid

To assess the required size and scope of the proposed microgrid, the Project Team performed an inventory of existing and planned buildings and assets to be served by the proposed system, and obtained available energy load data to support design modeling for feasibility assessment. Assessments are based on load data for the period from Sept. 1, 2017, through Aug. 31, 2018. Three of the initially assessed facilities (Innovation Square Phases 1 and 2 and Sword & Tuna Seafood) were under construction or advanced development during Task 2, and so their energy loads were estimated based on planning information supplied by the facility owners, as well as U.S. Energy Information Administration equivalent building energy consumption estimates.[4]

In addition to providing resilient electricity service, the preliminary RLFMP Microgrid proposal included a district heating and cooling system. However, not all of the initially identified 11 facilities were expected to be served by district energy supplies, for various reasons. Specifically, three facilities – 12 Drydock,

[4] https://www.eia.gov/consumption/commercial/data/2012/c&e/pdf/e6.pdf

Black Falcon Cruise Terminal, and Boston Ship Repair – have comparatively minimal and/or sporadic heating and cooling loads, and so they were excluded from thermal assessment for district energy service. Also, it was unclear during Task 2 assessments whether the 88 Black Falcon facility feasibly could be served by the proposed district energy loop, due to its location in the RLFMP. Nevertheless, 88 Black Falcon's heating loads were included in Task 2 assessment, in part because the exclusive use of electric heating at 88 Black Falcon suggested that energy cost savings could be obtained by converting the facility to use district hot and cold water supplies.

The preliminary group of 11 facilities assessed for the RLFMP Microgrid have an estimated coincident peak electric demand of 13.3 MW, and consume approximately 47,000 MWh of electric power annually. (*See Figures 1 and 2*). A substantial share of customers' electricity purchases serves cooling and refrigeration loads, producing an August peak electric load. Estimated thermal loads considered for district energy service total about 49,000 MMBtu of heating and 6.5 million kWh (22,000 MMBtu) of cooling and refrigeration annually (*see Figure 2.5*). With the exception of 88 Black Falcon, most of the heating load is served by natural gas.

Given Project objectives supporting future growth of maritime industries in the RLF Marine Park, design requirements include scalability of the proposed system to serve additional customers in the future. Chapter 3 addresses options enabling scalability both in terms of energy supply and new distribution infrastructure.

Fig. 2.1: RLFMP Microgrid (Preliminary) Area Map

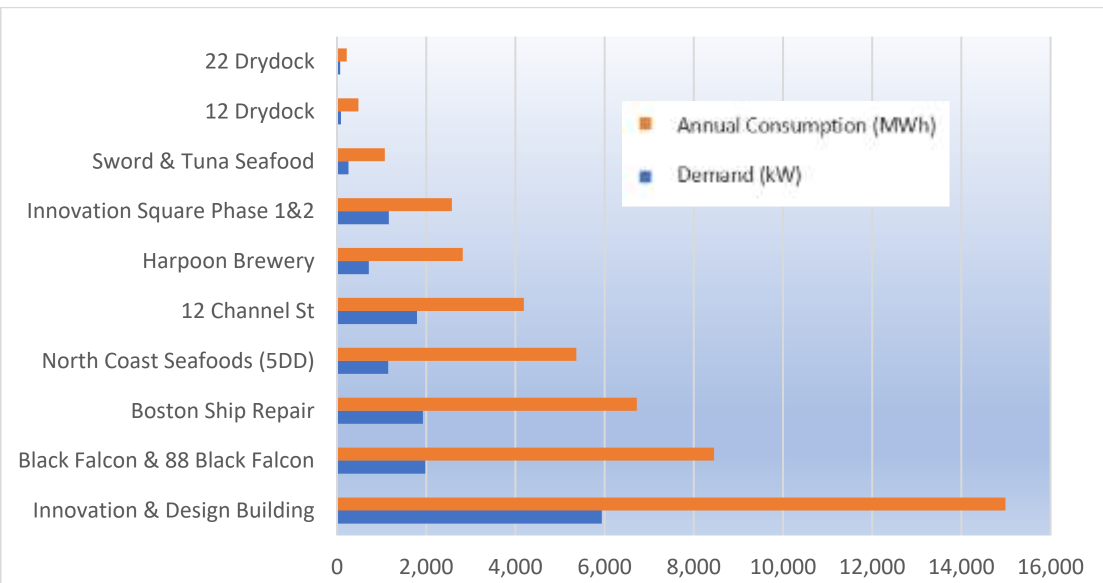
Fig. 2.2: RLFMP Microgrid (Preliminary) Modeled Facilities – Annual Electric Loads and Costs (9/17 through 8/18)[5]

Facility	Peak Demand (kW)	Annual Consumption (kWh)	Supply Cost	Demand Cost	Other Delivery Cost
Innovation & Design Building*	5,936	14,988,624	$1,647,820	$1,095,227	$525,604
Black Falcon Cruise Terminal *and* 88 Black Falcon	1,979	8,456,927	$792,532	$92,271	$32,588
North Coast Seafoods	1,146	5,365,062	$436,571	$222,052	$112,135
Harpoon Brewery	713	2,818,907	$179,640	$114,186	$33,144
12 Drydock	89	478,800	$56,872	$18,416	$16,050
22 Drydock	70	216,300	$26,410	$15,482	$4,873
Boston Ship Repair	1,927	6,722,440	$650,906	$316,595	$131,819
Innovation Square Ph 1&2	1,160	2,575,103	$286,020	$177,599	$103,118
12 Channel St	1,791	4,189,721	$479,785	$275,813	$180,910
Sword & Tuna Seafood	258	1,071,812	$89,454	$67,843	$22,764
Total (Preliminary Design)	**15,070†**	**46,883,696**	**$4,646,011**	**$2,395,485**	**$1,163,006**

**Innovation & Design Building includes Design Center, Bronstein Center, and 27 Drydock.*

†*Total represents the sum of non-coincident monthly demand peaks for all facilities. Monthly coincident system peak demand (in August) is 13.3 MW.*

Fig. 2.3: RLFMP Microgrid – Electric Load by Facility



[5] All loads were estimated for Design Center, and for 27 Drydock, loads were extrapolated from partial data. For 12 Channel St., tenant loads were estimated. Prospective future loads were estimated at the Innovation Square and Sword & Tuna Seafoods facilities, which were under development or construction during this study. Massport provided aggregated electric load data for Black Falcon Cruise Terminal and 88 Black Falcon, so the two facilities' loads are combined for analysis.`

2.1.2 Assessment of Loads, Resources, Infrastructure, and Programs:

A. Electric and heating/cooling loads

The Project Team's Task 2 site assessments focused on the following information and metrics for electric and thermal loads at the preliminary set of 11 facilities:

- Monthly and annual electricity consumption (kWh) and peak demand (kW); and
- Monthly and annual estimated heating and cooling loads (MMBtu).

Facilities management staff provided the Project Team with access to data for Task 2 analysis, including energy usage and cost summary data, and questionnaire inputs for facility surveys. Quantitative analysis focused on electric utility billing data and thermal load estimates to produce baseline critical resiliency requirements.

Fig. 2.4: RLFMP Microgrid - Electric Load Monthly Profile (All Facilities)

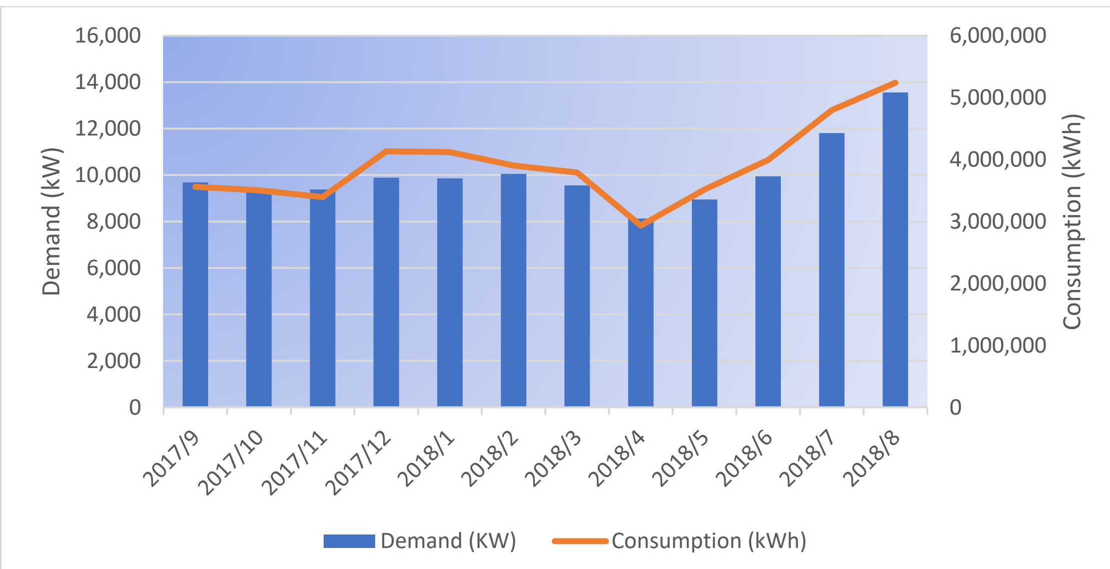
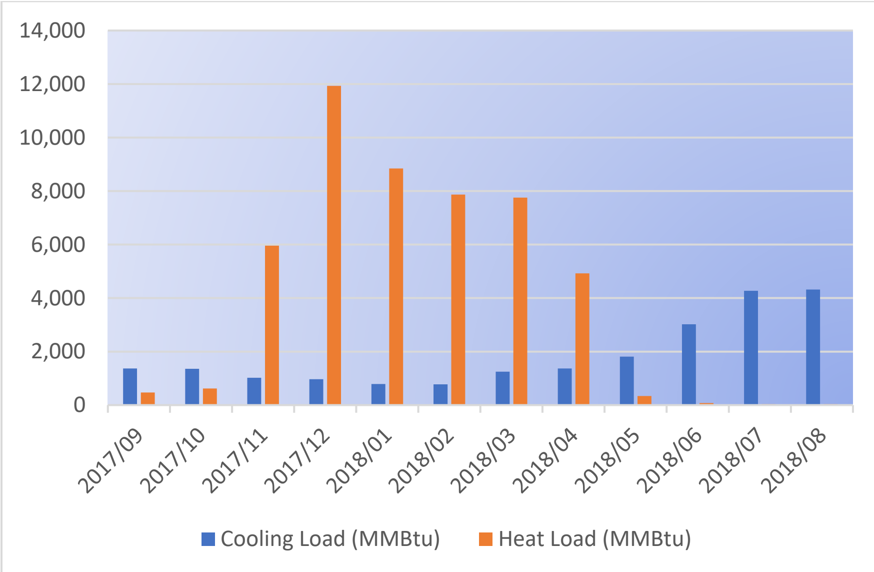


Fig. 2.5: RLFMP Microgrid – Estimated Thermal Load Monthly Profile (All Facilities)



B. Generation resources or other relevant technologies

BPDA's goals for the project support increased reliance on cost-effective renewable energy resources to the greatest practical extent, and to utilize natural gas-fired CHP and district energy technologies to provide efficient and resilient power to the RLF Marine Park.

Existing fossil-fueled standby generation systems would continue providing backup capacity for facility loads via existing transfer schemes. Standby diesel-fueled backup systems would not be used to energize the microgrid.

Existing and Planned Renewable Energy Systems: The RLFMP facilities currently host two rooftop PV systems and one CHP system (*Figure 2.6*). These facilities are interconnected behind the meter at their respective locations, where they reduce facility consumption of utility-supplied power. These facilities do not export power to the Eversource distribution system.

Fig. 2.6: RLFMP Existing Electric or Co-Generation

Facility	Generation Type	Electric Capacity	Thermal Production
Harpoon Brewery	Natural Gas CHP	255 kW	6,523,155 MMBtu/mo.
North Coast Seafood	PV	120.3 kW	0
Bronstein Center	PV	369 kW	0

Onsite PV and Battery Energy Storage System (BESS) Potential: Chapter 3 addresses PV and BESS capacity that may be necessary to serve microgrid loads. This new solar capacity likely would involve a combination of rooftop solar arrays in locations that can supply microgrid loads. Rooftop space in the project could, in principle, host up to 3,280 kW (AC) of PV capacity. Community-scale BESS capacity is expected to be required for reactive power and generation shifting to enable grid-forming, balancing, and transitions into and out of safe-island operating modes. PV potential and BESS capacity and siting options were further assessed in Task 3.

Other Renewable Resources: BPDA could consider biomass/biogas options for serving microgrid loads in future project phases, if cost-effective and reliable fuel sources and technology solutions become available.

Thermal Energy Resources and Systems: During Task 2 assessments, the Team gathered information about thermal energy systems, functions, and fuels at the microgrid facilities, and produced the following qualitative assessments:

a. *Seasonal Load Volatility:* As illustrated in Figure 2.5, above, thermal and electric loads vary dramatically by season, with a high electric summer peak and an even higher winter heating peak. This volatile seasonal load profile may reduce annual utilization of thermal system capacity – *e.g.,* capacity specified to meet thermal peak demands will sit idle for much of the year.
b. *Variation in Thermal Energy-Use Intensity:* Facilities to be served by the proposed district energy system use thermal energy resources in multiple ways, with various energy use intensities (EUI). In addition to space cooling, heating, and domestic hot water, facilities use thermal resources for large-scale refrigeration at a range of temperature levels (-30°F, -10°F, 38°F, 45°F), as well as process heat for commercial brewing. This wide range of requirements necessitates consideration of district energy solutions capable of displacing onsite cooling and boiler-generated heat across a range of EUI levels.
c. *Thermal Retrofits and Replacements:* The as-built environment in RLFMP utilizes heating and cooling systems of many types and vintages. Natural gas fuels a large share of space heating requirements, but electric resistance heating also is used in some facilities. Displacing onsite thermal production may require retrofits that provide pre-cooling and pre-heating for existing systems, as well as phased replacements of systems as they reach the end of their operating lifetimes.
d. *Existing Energy-Savings Programs:* Many of the microgrid facilities have, within five years, performed energy audits and implemented thermal energy-saving measures, as part of ongoing programs administered by facility owners including EDIC and Massport as well as private operators in the RLFMP. Facilities assessed have building energy management systems (BEMS) in place, but some performance opportunities may remain to be exploited, especially regarding advanced demand-response potential. Subsequent chapters address efficiency and load management among potential solutions to support microgrid requirements.

C. Distribution system infrastructure

Eversource owns and operates the local electric distribution system in the Project area. Task 2 assessment of local distribution infrastructure showed that facilities throughout RLFMP currently are served by 13.8 kV overhead and underground secondary distribution lines, energized via three circuits served by Eversource Substation #385. However, the utility plans to reconfigure and upgrade certain facilities in the RLFMP. Sometime after 2019, Eversource expects the area will be fed by two circuits from station #385 and four circuits from Substation #99. Design option assessments in Chapter 3 address Eversource's future distribution system design assumptions.

Meeting the project's thermal energy objectives requires consideration of new district heating and cooling infrastructure to distribute thermal resources from one or more CHP units to facilities to be served by district energy supplies. Factors affecting design and siting of the proposed district energy system are addressed in Chapter 3.

D. Utility assets including metering and interconnection

Electricity services for facilities included in the microgrid are metered primarily with traditional electromechanical and simple electronic metering systems. This fact leads to two primary consequences for the proposed microgrid:

a. *Limited Interval Data:* Assessed electric load data includes only monthly total energy consumption (kWh) and monthly peak demand (kW). The lack of advanced metering infrastructure (AMI) throughout the project area means granular interval data is unavailable for the studied facilities. As a result, facility electric load profiles are based on annual month-by-month trends in consumption and demand. Intra-week and intra-day load profiles were simulated in Task 3, based on similar facility load profiles, to help estimate time-of-day usage and likely system demand profile.
b. *No Remote Connect/Disconnect:* Most of the metering systems used in the project area do not support remote connect and disconnect. To utilize Eversource distribution lines, the proposed microgrid may need additional switching capabilities and circuit reconfiguration to prevent energizing non-microgrid loads during microgrid island-mode operations.

2.1.3 Existing energy efficiency programs

Property owners and operators in the Project area have implemented ongoing energy efficiency and conservation programs for their facilities. Upgrades have included new heating, ventilation, and air conditioning (HVAC) systems and lighting replacements with high-efficiency LED systems. Additional BEMS or other active load-control technologies would enable further efficiency improvements and peak-demand management capabilities.

2.2 Minimum Required & Preferable Microgrid Characteristics

2.2.1 Characteristics and capabilities that are required of the microgrid

Fig. 2.7: Assessment of Program and Project Objectives

MassCEC Program Goal/Objective	RLFMP Microgrid Goal/Objective
Explore benefits microgrids can offer to Massachusetts energy customers.	The Project is focused on assessing multiple types of benefits for various kinds of customers (government, commercial, and industrial).
Catalyze the development of community microgrids that can:	
Reduce customer energy costs.	Reduce customer energy costs through locally owned renewable energy investments and economically efficient district energy systems.
Reduce GHG emissions.	Reduce GHG emissions through energy conservation measures and by displacing inefficient fossil-generated power with efficient CHP-powered district energy and clean renewable energy generation.
Increase resiliency of critical facilities and infrastructure.	Improve the resiliency of several critical facilities in the RLFMP by providing local energy resources and safe-islanding systems to assure continued electric service during regional power disruptions.
Serve at least one, but preferably more, physically separated critical facilities located on one or more properties.	RLFMP Microgrid includes multiple physically separated critical facilities on multiple properties.
Include clean or renewable energy; diesel fuel may NOT be primary resource.	Excludes diesel fuel as a primary generation resource and reduces diesel consumption by preventing outages that cause dispatch of diesel backup generation.
Include energy efficiency upgrades to minimize new microgrid generation requirements.	Primary opportunities include some remaining LED lighting conversions and upgrades to BMS technologies.
Provide power to critical facilities, for a diverse group of customer and load types.	RLFMP Microgrid includes multiple critical facilities with differing customer and load types, including municipal planning and administration, transportation (public and freight), and commercial and industrial facilities.
Resilient to forces of nature that are typical and pose highest risk.	Improve resiliency against regional outages caused by the most prevalent natural threats, including major hurricanes and winter storms affecting the long-distance transmission system. Solutions also may avoid facility impacts from some outages caused by disruptions to local distribution service. Design will address risks of sea-level rise and storm surges affecting the Marine Park.
Provide one or more distribution system services, such as: Grid capacity support, black-start capability, facilitating renewables integration, etc. Services must be meaningful to the utility.	Support multiple distribution system services, including improvements in grid capacity, reliability, and ability to integrate renewable energy into local energy supplies. The Project Team has engaged the utility to identify local grid issues that meaningfully could be supported by microgrid upgrades.

2.2.2 Characteristics and capabilities that are preferable but not required

1. Advanced technologies and designs

During Task 2 assessment the Project Team identified potential to apply distributed automation and AMI technologies in the Project area to enable load management for microgrid resiliency purposes. In addition to new distribution system management devices, BEMS upgrades and microgrid controls and communications may support demand-response and load management for both operational and economic purposes. Chapter 3 addresses technology solutions required to support these and other requirements of the proposed microgrid.

2. Integrates energy storage technologies;

The Project requirements include BESS capacity to support grid forming and modal transitions, as well as reactive power and generation shifting. Project design scope considers a combination of facility-scale and community-scale BESS systems. Additionally, thermal energy storage (TES) systems could support load-management and system energy conservation for district hot and cold water supplies. Task 3 assessments evaluated potential to use BESS and TES capacity to produce operational and economic benefits, including monetizable ancillary services.

3. Integrates relevant technologies designed and/or manufactured in Massachusetts;

Specific technology products generally are not considered in the current assessment, except insofar as specifications of certain products are assumed as examples for modeling and assessment. In principle, technology solutions designed and/or manufactured in Massachusetts could be sourced for some aspects of the Project.

4. Leverages significant third-party investment, including private capital. Project characteristics should be informed by the Project Team's Expression of Interest and viability assessment;

The Project Team anticipates that implementation would require a combination of private third-party investments in new electric generation (primarily solar PV and gas-fired CHP capacity) and BESS capacity, as well as utility investment in distribution system upgrades or reconfiguration. This is consistent with the Project Team's Expression of Interest, which envisioned partnering with Eversource to develop a hybrid utility microgrid – with third-party ownership of generation and storage assets, and utility ownership of distribution system assets.

5. Additional required and/or preferable characteristics, as relevant.

Like any community setting, the RLFMP is a dynamic environment, with changes occurring in facilities and services within the Project area. To support quantitative modeling and analysis, the assessment focused on currently known or planned energy requirements and infrastructure. At the same time, however, meeting the proposed microgrid's goals for supporting growth and development of maritime industrial activity in the RLFMP requires consideration of future-phase development. This is a primary motivating factor for examining the viability of a district energy system capable of serving current and future thermal loads throughout the Project area; an investment in district energy infrastructure would support BPDA and Massport goals for attracting new private investments and employers in the RLFMP area.

III. Chapter 3: Microgrid Preliminary Design and Configuration

As noted, the preliminary design included 11 facilities and proposed a district energy system that would be served by a gas-fired CHP system. During Task 3 assessments the utility provided inputs that led the Project Team to omit four facilities from the design (12 Channel St., Boston Ship Repair, Sword & Tuna Seafood, and Innovation Square Phases 1 and 2), and to eliminate district energy and CHP assets for reasons discussed below. Figures in this chapter reflect the revised design.

3.1 Proposed Microgrid Infrastructure and Operations

3.1.1 Simplified Microgrid Diagrams

Fig. 3.1: RLFMP Microgrid (Revised) - Simplified Single-Line Diagram

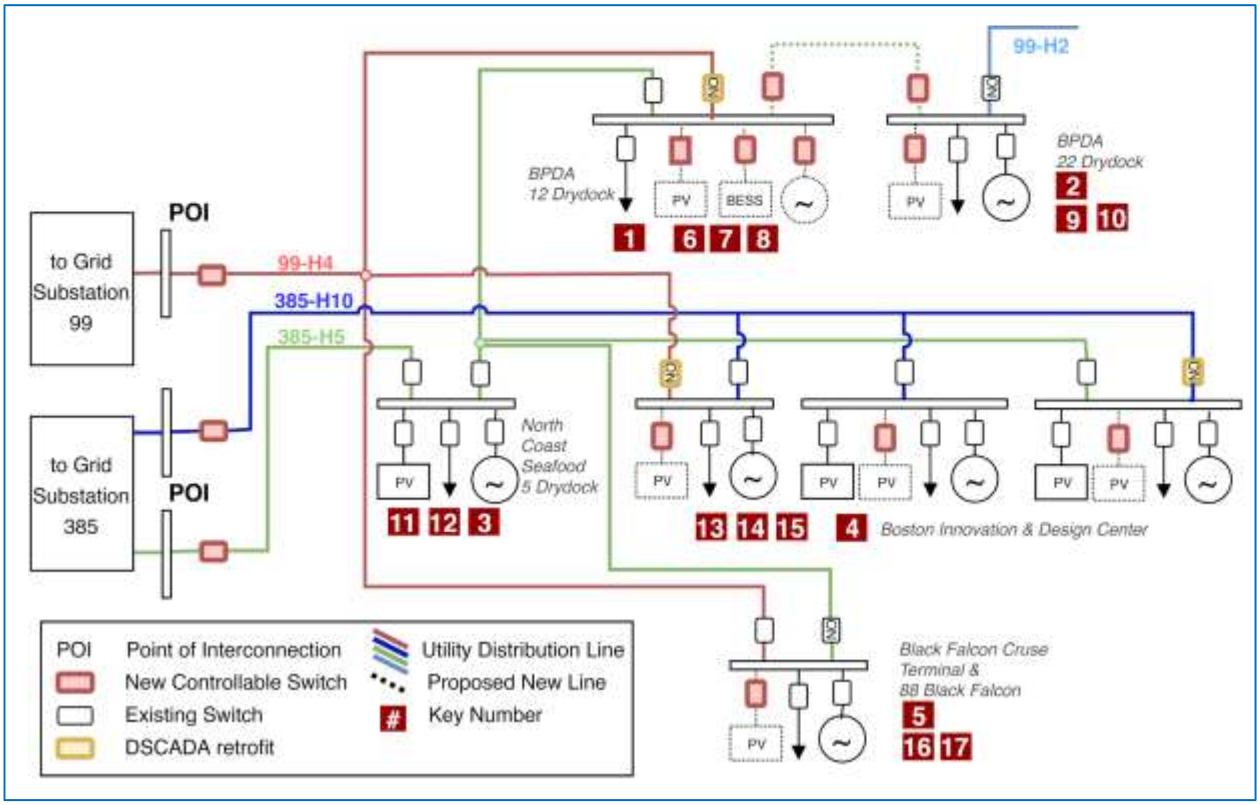


Fig. 3.2: RLFMP Microgrid - Geospatial Overview

Fig. 3.3: RLFMP Microgrid - Key to Loads, Resources, and Infrastructure

Key #	Facility or Component	Description	Existing or Proposed
1	12 Drydock	BPDA Central Parking	Existing
2	22 Drydock	EDIC/BPDA Offices	Existing
3	5 Drydock	North Coast Sea Foods	Existing
4	Boston Innovation & Design Building	Bronstein Center, Design Center, 27 Drydock	Existing
5	Black Falcon Cruise Ship Terminal & 88 Black Falcon	MassPort facilities	Existing
6	BESS	Central energy storage	Proposed
7	PV	Covered parking PV - 570 kW	Proposed
8	Standby Gensets	Natural gas fired gensets - 150 kW x 4 = 600 kW	Proposed
9	PV	Rooftop PV - 90 kW	Proposed
10	Standby Genset	Diesel genset - 80 kW	Existing
11	PV	Rooftop PV - 120 kW	Existing
12	Standby Genset	Natural gas fired genset - 30 kW	Existing
13	PV	Rooftop PV - 360 kW	Existing
14	PV	Rooftop PV - 330 kW	Proposed
15	Standby Gensets	Diesel gensets - 1,340 kW	Existing
16	PV	Rooftop PV - 270 kW	Proposed
17	Standby Genset	Natural gas-fired genset - 100 kW	Existing
Red Lines	Feeder 99-H4	Eversource feeder 13.8 kV	Existing
Light Blue Lines	Feeder 99-H2	Eversource feeder 13.8 kV	Existing
Green Lines	Feeder 385-H5	Eversource feeder 13.8 kV	Existing
Dark Blue Lines	Feeder 385-H10	Eversource feeder 13.8 kV	Existing
Dotted Line	New underground cable	Eversource feeder - 13.8 kV	Proposed

3.1.2 Microgrid Operations – Normal and Emergency Modes

Under normal conditions, the proposed microgrid will perform two primary functions. First, it will monitor and manage PV production to optimize BESS state of charge for customer objectives. Second, the microgrid control system will support customer economic objectives by monitoring the status of BEMS and, when appropriate, coordinating economic dispatch of DERs within the constraints of applicable operating use cases. For example, the microgrid operator may apply an economic dispatch protocol during critical peak pricing periods, which temporarily would seek to minimize customer energy costs with reduced priority on maintaining BESS state of charge for resiliency purposes.

During emergency conditions, including when utility power is interrupted, the microgrid will enter island-mode operations, applying active load management and DER dispatch to support applicable island-mode use cases. Such use cases include, for example, planned and unplanned outages of short and long durations. During outages that are expected to be very brief (*e.g.,* 15 minutes or less), the microgrid will seek to maintain semi-normal operations within buildings served by the microgrid, actively managing discretionary loads such as air conditioning to keep peak demand within available supply capacity. In the process, the microgrid will first apply battery resources, load controls, and PV generation, and only when loads exceed those resources will the microgrid dispatch gas-fired generation (*see Figure 3.10*). This dispatch schedule will reduce emissions during outages by prioritizing utilization of renewable resources and deferring startup of diesel-fueled standby generators. For outages of longer duration, the microgrid will dispatch resources and loads to support any of several possible operating protocols, including for example:

- Evacuation Support: Enabling safe evacuation and orderly shutdown of business, maintaining egress lighting, elevators, escalators, ventilation, and other emergency loads, including some loads that might not be served by standby generation only;
- Indefinite Islanding: Modulating and curtailing non-critical loads to indefinitely maintain minimum service level for critical loads; and
- Extend Time to Refuel: Reducing usage and extending time to refueling for onsite ATS-switched standby fossil-fueled generation units.

Control functionalities and technologies required to support emergency and business-as-usual objectives are described in greater detail in "Microgrid Operation," below.

Fig. 3.4, "RLFMP Microgrid Use-Case Summary," summarizes assessment factors and outcomes that led to the selected use cases. The Task 3 resource model and preliminary technical design are based on building loads, outage history, photovoltaic (PV) siting potential, new fossil-fueled central standby generation, and existing renewable generation resources (PV generation).

Fig. 3.4: RLFMP Microgrid Use-Case Summary

Use Case*	BESS-Only Duration	Rationale	Pros	Cons	Assessment Outcome
Minimum Resiliency	15 min.	Minimum battery capacity for microgrid islanding; Covers majority of short-duration outages actually experienced	Least cost; Could be sufficient for daytime islanding for longer than 15 minutes; Storage could be expanded in future	Minimal added resiliency may not justify cost of investment in parallel infrastructure.	Selected for further study
Moderate Resiliency	4 hours	Covers majority of short -and-long-duration outages actually experienced	Major resiliency upgrade supports investment in parallel microgrid infrastructure	Higher cost	Rejected due to high capital cost and inability to support timely payback

**Key constraints: 1) PV limited to rooftop capacity; and 2) Only minimal gas-fired standby generation to be considered.*

The RLFMP Microgrid will combine existing PV capacity (480 kW) with 1,260 kW of proposed new distributed PV capacity and 3,400 kW/842 kWh of proposed central battery storage capacity, together with 600 kW of new standby generation capacity, to support critical loads during utility outages (*See "3.3: Distributed Energy Resources Characterization").* PV production will be used to reduce microgrid customers' consumption of electricity from higher-cost sources and maintain the state of charge of the central battery system, which is expected to be located at the 12 Drydock Ave. Central Parking facility. New rooftop PV systems will be interconnected at each facility in accordance with the IEEE 1547 standard, supporting net-metered operations. PV output at most facilities will be largely or entirely consumed onsite, but export capabilities are required for all new PV systems to enable resource sharing for microgrid loads.

At some facilities, proposed rooftop PV capacity is expected to produce more energy annually than the host facility consumes. Most notably, the proposed array at 12 Drydock will produce an estimated 578,000 kWh (AC) of electricity annually, but the facility consumes only 479,000 kWh a year. Accordingly the system would be structured as a remote net-metered system; *during normal operations,* net excess energy will be exported into the utility distribution system, and will offset electricity purchases for BPDA's other accounts.

During island-mode operations, the microgrid control system will signal distribution switches to open, isolating the microgrid segments from the utility circuits. Upon loss of grid the interconnected resources will disconnect. The microgrid then will discharge the BESS to support grid forming, dispatch central standby generation (if needed to meet capacity and energy requirements), and actively manage building energy loads and BESS, PV, and central standby generation operation to keep demand and available supply in balance at all times, and to defer startup of onsite ATS-switched standby generators.

The RLFMP Microgrid design will be capable of supporting loads at an average-demand level during the majority of short-duration outages experienced in the project area[6] – lasting approximately 15 minutes – and maintaining service at reduced levels during outages of longer duration. 600 kW of new standby genset capacity will be integrated to support modular operation, allowing managed dispatch of four 150 kW gensets. Control functionalities and technologies required to support emergency and business-as-usual objectives are described in greater detail in "Microgrid Operation," below.

3.1.3 Interconnection and Protection Systems

The RLFMP Microgrid will create a safe island within the Eversource distribution system by signaling existing and new switches (*noted in Figures 3.1, 3.2, and 3.3, above*) to isolate segments serving the microgrid loads. Reverse power protection will be provided on the microgrid's points of interconnection by the corresponding circuit breakers (*i.e.,* isolating circuit breakers on the feeders 99-H4, 385-H10 and 385-H5) and protective relays to prevent power injection into the grid. In addition, PV resources will be provided with dedicated breakers and protection and control measures such as over/under frequency and voltage detection on interconnection couplings to sense an unintended outage and isolate the microgrid from the utility system according to the IEEE 1547 standard. Finally, the standby generator switchgear will be equipped with protective relays, current transformers (CT) and voltage transformers (VT) with capability to be synchronized across the breaker.

BESS interconnection will be configured to support grid forming on the isolated segments. Bi-directional protection schemes implemented on the microgrid's protective devices will selectively detect and isolate a fault on the network when the microgrid is operating in grid-connected mode. Control functionalities to support transitions to and from islanded mode are described in greater detail in "Microgrid Operation," below.

3.2 Load Characterization

3.2.1 Description of Loads Served by the Microgrid

The RLFMP Microgrid – Phase 1 deployment is designed to serve building-wide electricity loads at seven (7) facilities[7] comprising various commercial and light industrial uses. These seven facilities are a subset of those assessed in Task 2, selected with inputs from the utility for the Phase 1 design. Specifically, all but one of the microgrid facilities currently are served with three (3) underground feeders that can be readily reconfigured with some switching upgrades to create a safely islanding microgrid; the remaining facility (22 Drydock) will be connected to the microgrid via a new underground conduit approximately 250 feet long.

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[6] Customers to be served by the microgrid report experiencing, on average, several brief electricity interruptions per year, and one or two medium-duration outages per year lasting a few hours or longer.

[7] Three of the seven facilities are contained in a single building; Boston Innovation & Design Center houses the Design Center, Bronstein Center, and 27 Drydock facilities. Additionally, loads at the two Massport facilities, Black Falcon Cruise Terminal and 88 Black Falcon, also aggregated for this assessment.

The seven facilities' electric loads are predominately daytime loads, involving regular five-day weekly business hours, plus 24-hour/7-day cooling loads and second-shift operations at the 5 Drydock North Coast Seafoods facility, and 24/7 cooling loads for refrigerated warehouse space at 88 Black Falcon.

The utility provided reliability information for the project area, reported in terms of circuit average interruption duration and frequency metrics shown in Figure 3.5. Interruptions for the three circuits serving the project area totaled approximately 120 minutes, 351 minutes, and 93 minutes in 2018. Anecdotal reports from customers indicate most outages last less than 15 minutes, with occasional longer-duration outages lasting two hours or more.

Fig. 3.5: RLFMP Microgrid Circuit Reliability Metrics

CKAID/FI = Circuit Average Interruption Duration/Frequency Index

Period	Circuit	CKAIDI	CKAIFI
2016	385-H5	47.067	1.224
2017	385-H5	0.899	0.022
2018	385-H5	120.228	0.617
2019*	385-H5	32.300	1.000
2016	385-H7	N/A	N/A
2017	385-H7	195.366	1.591
2018	385-H7	350.957	1.196
2019*	385-H7	N/A	N/A
2016	385-H10	N/A	N/A
2017	385-H10	N/A	N/A
2018	385-H10	92.894	1.000
2019*	385-H10	N/A	N/A

**January through August 2019 data available at time of assessment.*

The Phase 1 deployment does not include any thermal generation resources, as had been assessed in Task 2. The long-term vision for energy services at the RLFMP include potential for deploying a district energy system that would generate thermal resources from one or more CHP systems. Task 3 analysis of infrastructure requirements and options, as well as options for siting CHP capacity in the vicinity of the primary loads, led the Project Team to conclude that district energy would not be suitable for the Phase 1 design. In addition to the challenges identified in Task 2 (varied thermal energy intensity and the presence of recently installed onsite thermal systems), the district energy option was deferred because the subset of facilities included in the Eversource-proposed microgrid boundary lack consistent thermal loads of the magnitude necessary to merit investment in thermal generation and distribution infrastructure.

3.2.2 Hourly Load Profile

Available metering data included only monthly consumption and peak demand information. The Project Team used HOMER Pro software to model hourly loads based on HOMER's library of representative load profiles. The Team selected profiles for typical commercial, light industrial, and office loads, and then scaled those profiles on the basis of actual peak demand values obtained from utility monthly metering data.

The proposed RLFMP microgrid loads were modeled as aggregated industrial loads and commercial loads for system modeling in HOMER Pro. 12 Drydock, 22 Drydock, and Boston Innovation & Design Center were categorized as commercial loads, and the North Coast Seafoods and Black Falcon & 88 Black Falcon facilities were categorized as industrial loads. These category definitions were based on the facilities' monthly facility load profiles, facility uses, and engineering judgements. Figure 3.6 summarizes facility electric loads, and Figure 3.7 illustrates the HOMER industrial and commercial load profiles modeled for this study.

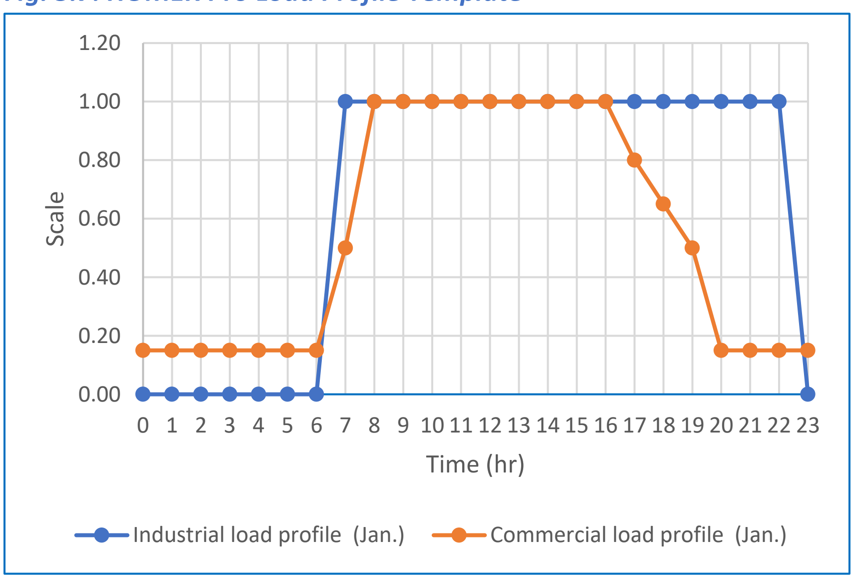
Fig. 3.6: RLFMP Microgrid Load Summary

Facility	Load Type	Peak Demand (kW)	Average Demand (kW)	Annual Consumption (kWh)
Innovation & Design Building*	Commercial	5,936	2,256	14,988,600
Black Falcon & 88 Black Falcon	Industrial†	1,712	651	8,456,900
North Coast Seafoods - Total	Industrial	1,118	425	5,365,100
12 Drydock	Commercial	89	34	478,800
22 Drydock	Commercial	66	25	216,300
TOTAL		**8,920**	**3,368**	**29,505,700**

* *Innovation & Design Center houses the Design Center, Bronstein Center, and 27 Drydock facilities.*

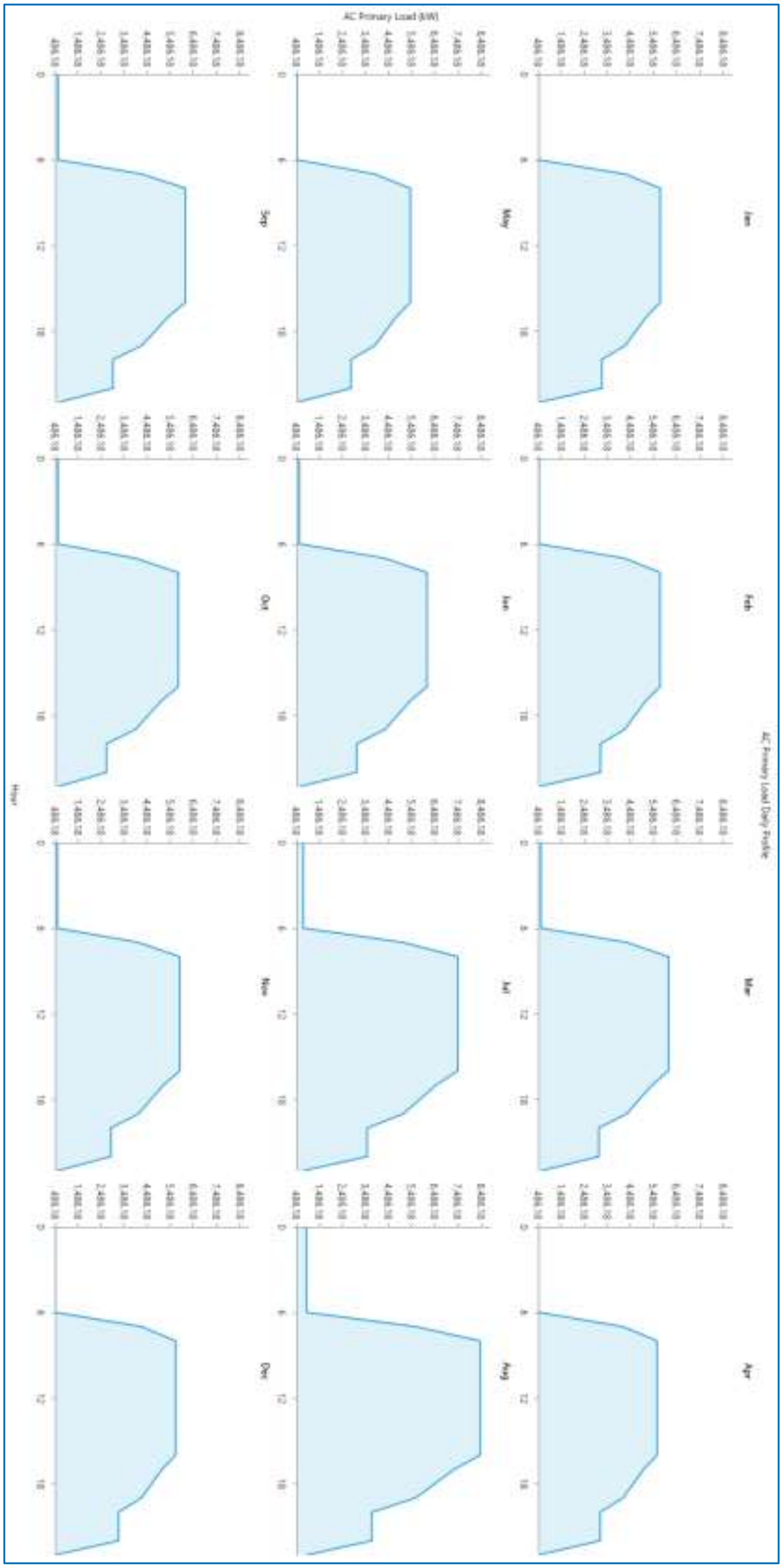
† *Massport provided load information for Black Falcon Cruise Terminal and 88 Black Falcon in aggregated form. Loads at 88 Black Falcon are commercial loads, but HOMER Pro's industrial load profile template best matches the metered monthly demand and consumption at the facility.*

Fig. 3.7: HOMER Pro Load Profile Template



The hourly load profile templates were scaled to match the actual load demand (kW) of the month and slightly modified to best match the actual energy consumption (kWh) for each month. The actual demand and consumption values are the aggregation of demand and consumption of facilities within each load category derived from the utility bills. Figure 3.8 illustrates the RLFMP Microgrid's average daily load profile for each month of the year.

Fig. 3.8: RLFMP Microgrid – Daily Load Profile



3.3 Distributed Energy Resources Characterization

The RLFMP Microgrid design includes solar PV, BESS, and standby generation systems in locations as summarized in Figure 3.9. Existing standby generation systems, including both diesel- and natural gas-fired gensets, will be left in place in their current ATS-switched configuration. Proposed new natural gas-fired standby capacity at 12 Drydock is intended to be dedicated solely to energizing the microgrid during utility outages. Rooftops and interior and exterior locations for each specified system are considered adequate for the purpose. One rooftop with uncertain weight-bearing capacity – at the Black Falcon Cruise Terminal – was omitted for PV siting consideration at this phase of study.

Fig. 3.9: RLFMP Microgrid DER Summary

Facility	PV (kW AC)		BESS (kW/kWh)	Standby Capacity (kW)		Diesel Storage (Gallons)
	Existing	Proposed	Proposed	Existing†	Proposed	Existing
Innovation & Design Building*	360	330	0	1,340	0	2,500
Black Falcon & 88 Black Falcon	0	270	0	100	0	NA
North Coast Seafoods - Total	120	0	0	30	0	NA
12 Drydock	0	570	3,400/842	0	600	NA
22 Drydock	0	90	0	80	0	275
TOTAL	**480**	**1,260**	**3,400/842**	**1,550**	**600**	**2,775**

**Includes Design Center, Bronstein Center, and 27 Drydock.*

† *Onsite standby generation will remain in ATS-switched configuration and will not energize the microgrid.*

3.3.1 DER Adequacy to Meet Demand

In the project area, different microgrid customers have varying demand for resilient energy supplies, but none require full-load support for long-duration outages. DER sizing is based on iterative analysis of real-world microgrid use cases and capacity requirements to support them.

The project team assessed various options for sizing DERs, specifying BESS capacity sufficient to support average building-wide loads for a duration as short as 15 minutes and as long as four hours. During this assessment, the project team determined that microgrid customers largely would shut down their operations in situations that cause long-duration utility outages of 24 hours or longer, irrespective of microgrid availability. For example, a hurricane that causes widespread damage and regional outages lasting many hours or days likely also would cause most of the microgrid's customers to evacuate the project area as a matter of safety and practicality. As a result, for long-duration outages, microgrid customers require resilient energy supplies for only a fraction of their normal daily electric loads, and microgrid resources were sized accordingly.

Based on this assessment, BESS capacity was sized to support approximately 3,400 kW of average building-wide demand for a period of 15 minutes, assuming maximum charge at the beginning of an outage. This capacity will be augmented and recharged by daytime output from 1,740 kW of existing and proposed PV generation, as well as 600 kW (150 kW x 4 units) of natural-gas fired standby generation proposed for the purposes of this study for installation at 12 Drydock. PV system capacity was estimated using Helioscope modeling software for available rooftop space to maximize system potential, with the objective of displacing higher-cost and higher-polluting power sources during grid-connected operations, and maximizing reliance on renewable generation during island-mode operations.

Figure 3.10 describes the proposed dispatch schedule for microgrid resources during three (3) outage scenarios. Although the modeled 4,000 kW of dispatchable capacity (BESS and central natural gas standby) is less than the typical daily peak demand of loads served by the microgrid, it is sufficient in most outage scenarios, when dispatchable capacity combined with PV generation is expected to meet or exceed the average demand. Advanced microgrid controls and BEMS will actively manage non-critical loads to ensure they remain within the microgrid's operating capacity, enabling the microgrid to sustain island-mode operations indefinitely at a reduced load level.

Fig. 3.10: RLFMP Microgrid DER Dispatch Sequence

#1	#2	#3	#4
BESS - 3,400 kW /842 kWh	Load Control	PV - 1,740 kW	Standby NG - 600 kW

All scenarios: BESS capacity will support black-start grid forming and resource balancing, and microgrid and building energy controls will manage loads to prevent coincident peaks and curtail discretionary loads. Upon microgrid islanding, PV generation will be dispatched first in all scenarios. Existing ATS-switched fossil-fueled standby generation will not energize the microgrid, but will remain in place as a backup for onsite emergency loads in the case of microgrid failure during a utility outage.

The team assessed potential for re-configuring existing fossil-fueled standby generation at customer sites to energize the microgrid during island-mode operations, and found that such an approach would require new generator controls as well as switching and protection systems to enable interconnected operation of several dispersed standby units. Those systems, together with engineering and construction requirements, were estimated to cost at least $800,000, and such an approach was deemed technically complex and risky, especially given the vintage of some of the standby units. Those cost and risk factors led the team to conclude that integrating existing standby generation into the microgrid is impractical and not cost-effective. Instead, the proposed microgrid relies on four (4) proposed 150-kW natural gas-fired standby generators, co-located with the BESS at the proposed 12 Drydock facility. The microgrid control system will dispatch these units in modular fashion to minimize fuel use and associated emissions.

The proposed new central standby capacity was sized to serve the estimated average loads supported by existing diesel- and natural-gas fired standby generation – *e.g.,* approximately 38 percent of 1,550 kW, or 589 kW. Additional central gas-fired standby generators could be installed in the future for redundant capacity or to serve expanded use-case requirements.

As detailed above and in Figure 3.4, the project team assessed potential to use BESS capacity to support economic use cases – *e.g.,* peak load shifting to reduce demand charges and avoid critical peak pricing. The assessment showed that smaller battery systems distributed behind each customer meter would be required to enable peak shifting, at a substantially higher capital cost. Additionally, to the degree BESS systems use Li-ion battery chemistry, using them for daily peak-shifting duty would accelerate degradation, leading to higher lifetime battery costs. These outcomes led the Team to select central BESS capacity for this microgrid, which cannot used for customer load shifting (*See Figure 3.4*). The specified BESS capacity would be maintained at optimal state of charge to support the resiliency objectives defined for the microgrid, which would limit its technical potential for demand response or other ancillary services if the utility wished to use the BESS for that purpose.

The microgrid will support peak shaving and market arbitrage in two ways: By generating as much solar electricity onsite as possible; and by modulating or curtailing loads via BEMS in the same way that it manages loads to achieve system balancing during island operations. The central BESS is sized to support the defined resiliency purposes only. Project objectives and options could change in the future, however, especially as battery prices continue declining. Future system upgrades could include expanded BESS capacity to support new use cases or system expansion.

3.3.2 Resiliency of DERs to Natural Forces

The specified DERS will be designed to withstand severe weather conditions that typically affect the project area. Snow cover would be expected to have minimal effect on PV output, given the angled orientation of panels and the tendency for PV panels to heat up with even minimal solar irradiance and shed snow quickly. In the most extreme snow accumulation scenarios, production would be affected for as long as conditions persist.

The project area is located in an area that is vulnerable to extreme coastal weather including hurricanes and storm surges. According to Boston Harbor Flood Risk Model prepared by Climate Ready Boston, a significant portion of the Project area is expected to be affected by a 1% annual coastal flood event by 2030. By 2050, a similar portion of the Project area is expected to be affected by a 10% annual coastal flood event (*see Figure 3.11*). In flood conditions when electrical systems are normally shut off for safety, the microgrid would de-energize affected supply circuits and interconnected DG would isolate itself. DERs and control systems will be sited and installed to protect them from flooding and other natural threats. Notably, the 12 Drydock location for the BESS and standby generators is located at an elevation above the referenced coastal-flooding 10% risk zone.

Fig. 3.11: RLFMP Coastal Flooding - 10% Annual Risk (2050s)

Source: Climate Ready Boston Map Explorer

3.3.3 DER Fuel Sources

Proposed new DERs would use solar energy and natural gas (standby only). Existing ATS-switched standby generation in the project area burns natural gas (130 kW) and diesel fuel (1,420 kW). The diesel generators are accompanied by 2,275 gallons of diesel fuel, sufficient for operating the onsite standby units at full load for approximately 29 hours or longer. Depending on the timing of an outage and the available solar irradiance, 1,740 kW of PV resources operating within the microgrid combined with 600 kW of new gas-fired standby generation will substantially reduce emissions and extend time to diesel refueling, by deferring startup of ATS-switched standby units in outage situations.

3.3.4 DER Capabilities

As variable renewable resources, the proposed PV systems are capable of serving microgrid loads and recharging depleted BESS capacity. BESS systems are specified to support all required microgrid operations, including black starting the microgrid, as well as following dynamic loads, serving partial or full loads within available battery capacity. Proposed new standby generation is capable of serving microgrid loads including BESS recharging in island-mode operations.

Advanced microgrid and distributed controls will operate resources to manage voltage and frequency, balancing loads and dispatching generating capacity to maintain service during island-mode operations. Ride-through capabilities will enable uninterrupted service during voltage and frequency events, and will manage resynchronization upon utility restoration, consistent with IEEE and utility standards.

3.4 Electrical Infrastructure Characterization

As illustrated in Figures 3.1, 3.2, and 3.3, the proposed RLFMP Microgrid would operate on three main utility incoming feeders: 385-H5 and 385-H10 from one substation and feeder 99-H4 from another substation. To operate the microgrid in islanded mode, the utility circuits will be disconnected using isolating circuit breakers. The generation sources (including the PV and BESS) will be configured to recognize the presence or absence of an energized electrical path to the utility and operate accordingly.

Several existing switches must be upgraded to enable the microgrid control system to open circuits and island the microgrid area. (*Refer also to "Sec. 3.5 Microgrid and Building Controls Characterization"*). Pad-mounted tie-switches between three feeders (99-H4, 385-H5, and 385-H10) require retrofits to enable remote operation. These retrofits include the addition of uninterruptible power supplies (UPS), voltage and current sensors, RTUs such as the SEL-2411 Programmable Automation Controller, and communication devices.

In addition to these tie switches, electric service for 22 Drydock must be re-configured to connect the facility to the microgrid. Currently 22 Drydock is served by overhead feeder 99-H2, which is not a part of the microgrid. The proposed design includes a new underground distribution line to serve 22 Drydock. Connecting 22 Drydock to the nearest microgrid feeder (99-H4) requires 250 feet of conduit and 650 feet of 4/0 15kV cable, and remote-control retrofits for the relevant switch (PMH-5462).

The electrical infrastructure will be highly resilient to natural forces that pose the greatest threats in the project area – namely severe storms, hurricanes, tidal surges, and extreme winter weather. The microgrid will rely entirely on underground distribution infrastructure, and all switches installed to enable island-mode operations will be submersible units installed in underground vaults. These systems can withstand natural forces of the kind affecting the project area for unlimited periods of time.

Fig. 3.12: Proposed Microgrid Capabilities

Capability	Comment
Automatically connecting to and disconnecting from the grid	Yes (Achieved with isolation circuit breakers such as S&C Vista Underground Distribution Switchgears)
Load shedding schemes	Yes (Achieved via BEMS)
Blackstart and load addition	Yes (Refer to section above)
Performing economic dispatch	Yes (Advanced microgrid controls operating with BEMS are capable of modulating loads and dispatching resources to support economic use cases. See Sec. 3.3.1 for discussion of BESS sizing)
Performing load following	Yes (DERs controlled to produce only enough power to meet the primary loads)
Demand response	Yes (through load management via BEMS)
Storage optimization	No (Since the BESS is used only to support resiliency objectives, and the BESS operates at voltage mode with frequency reference, and PV operates at current mode, no optimization is required. PV will serve the load as much as possible, and the rest of the demand is served by central gas-fired standby generation and BESS capacity using droop control functionality.)
Maintaining frequency and voltage	Yes (Achieved with BESS and generator)
PV observability and controllability; forecasting	Yes (achieved with advanced microgrid control functionality)
Coordination of protection settings	Yes
Selling energy and ancillary services	Yes (All new PV systems will be integrated to support net-metered operation. Rooftop PV on some facilities annually will produce more electricity than the facility consumes, requiring such PV either to be structured as a type of remote net-metered system serving multiple beneficial accounts, or to sell excess generation at avoided-cost or wholesale rates)
Data logging features	Yes

3.5 Microgrid and Building Controls Characterization

The RLFMP microgrid design will integrate BEMS for multiple purposes, primarily to control building loads for power system balancing. Load controls may be implemented with a hierarchical control system, or using an alternative distributed architecture. Both approaches will rely on DER controllers to monitor and manage device function, and will rely on BEMS to manage building electric loads at circuit and source levels.

3.5.1 Microgrid Control Architecture

The microgrid control system will monitor and manage all distributed energy resources including PV, BESS, the central standby generator, and BEMS, as well as automated circuit breakers, protective relays, and metering infrastructure. The control system will be managed and operated via a custom user interface, which will visually illustrate the microgrid and provide real-time equipment data, system alarms, and historical data. The microgrid control system will be interconnected through communication systems.

The microgrid can be controlled by three integrated control systems (Layers) as follows:

- *Layer 1: Device-level control*

This layer consists of controllers and sensors that provide direct, fast control of each device, e.g. the BESS controlling active and reactive power output while islanded to maintain system nominal frequency and voltage. In addition to BESS controller, switch controllers, central standby generation control systems such as exciter, governor, and generator paralleling controls, PV local controls, and protective relays are considered integral to the equipment in this layer. The Layer 1 protective devices will be responsible for protection of the DERs (including PV, BESS, and central standby generation) and the distribution system and will interpret and execute commands issued by Layers 2 and 3, if the device determines that it is safe both for the DERs and the system to do so. Another local controller in this level is BEMS, which controls the energy consumption of microgrid loads.

- *Layer 2: System-level control*

This layer consists of an automation controller platform or real-time automation controller (RTAC). This controller will connect to the Layer 1 control devices and other sensing devices as required to determine system status and will issue commands to devices based on the desired operating state of the system. This layer will be responsible for issuing general system commands to each Layer 1 device such as opening/closing circuit breakers and dispatching battery storage system and central standby generator.

- *Layer 3: Grid operator control*

This layer consists of SCADA controls issued by the utility operations center after evaluating the overall system conditions. This layer will communicate directly with the Layer 2 control platform to enact system control, enabling utility operation of the microgrid, if necessary.

3.5.2 Locations of Microgrid and Building Controls

Under the proposed design, microgrid supervisory controls would be co-located with the central BESS and inverter system and central standby generator in a protected area of the ground floor of the 12 Drydock Central Parking facility. The design also assumes that existing BEMS would remain in current locations, and any new BEMS will be located in each building’s electrical control room, with remote load controllers installed at key load points and circuit switching functionality implemented in applicable service panels. (*See Figure 3.2*).

3.5.3 Existing and New Controls

In order to develop the proposed control platform, several existing switches must be upgraded with distribution supervisory control and data acquisition (DSCADA) functionality. Tie switches, as shown in Figure 3.1, between the three feeders of 99-H4, 385-H5, and 385-H10 will be upgraded with DSCADA systems. These three manual pad-mounted switchgears, acting as tie switches, will be retrofitted for automated operation, including the addition of battery chargers, battery packs, voltage and current sensors, RTUs such as SEL-2411 Programmable Automation Controller, communication devices, and other components.

As mentioned in previous sections, the BPDA 22 Drydock load switch originally is normally connected to another feeder 99-H2, which is not part of the microgrid. To include this load in the microgrid and serve it in islanded mode, it will be connected to the closest feasible feeder, which would be feeder 99-H4 via the switch located at 12 Drydock. Further, to reduce the switching actions, as shown in Figure 3.1, the 22 Drydock switch to 99-H2 in grid-connected mode will be operated as normally open and its connection to 99-H4 will be operated as normally closed. As noted, this requires 250 feet of conduit and 650 feet of 4/0 15kV cable.

In addition to the aforementioned upgrades to the existing switches, three new isolating circuit breakers must be installed on these three feeders to separate the microgrid from the utility.[8]

For modeling purposes, system design was based on S&C Vista Underground Distribution Switchgear, automated using S&C 1000 relays with fault-interrupting capability, and S&C 6802 automatic switch controls and communication devices, mounted in an underground vault with street-side cabinet installation and concrete pad.

Another set of new control devices required for the microgrid design are the DER control devices. In general, BESS and PV inverters will be equipped with automation controllers. For load control, the microgrid will interact with existing BEMS, upgraded or replaced as necessary to support the required control of building loads. Finally, the central standby generators will be equipped with generator paralleling controls, which will interact with the microgrid controller.

3.5.4 Microgrid Operation

The microgrid will be capable of supporting a range of electric power services including the following:

- *Transition to Islanded Mode*

Transitioning for BESS from idle mode to islanded mode can happen automatically upon a loss-of-utility event. When a disturbance causes loss of utility voltage, the relay or switch control associated with the isolating circuit breaker will detect the loss of voltage and trip open the isolating circuit breaker. At this stage, the BESS is connected to the microgrid in idle mode and PV systems are expected to trip due to under-voltage or under-frequency protection.

After the isolating circuit breaker opens, the BESS controller will receive a command from the microgrid controller RTAC and starts the BESS in voltage source mode to restore the power in the feeder that hosts BESS, *i.e.,* green color feeder in Figure 3.1. The microgrid operation center will send SCADA commands to connect other feeders and the loads of 12 Drydock to the BESS by closing tie switches.

Only select tie switches are required to be closed to avoid creating a loop-circuit condition. At this stage, the second layer control monitors the loads, BESS, and PV output continuously, and applies appropriate load management schemes based on the status of the generation resources and loads to maintain

[8] In addition to the new and upgraded switches noted in Figure 3.1, Eversource identified two aging oil pressure-actuated switches (PMH-10594 and PMH-6355) located near 5 Drydock and Black Falcon Cruise Terminal, respectively, for replacement with new controllable switchgear. The Project Team determined these switches need not be replaced to enable microgrid islanding. Any requirement for load control at 5 Drydock and the Black Falcon Cruise Terminal instead will be accomplished by signaling building energy controls.

voltage and frequency at normal values. In this method, following a utility outage, the “black start” of the microgrid is carried out without the need for a reference voltage from the utility source.

- *Islanded Operation*

Under the islanded mode of operation, the system dispatches BESS to establish the new voltage and frequency references. Once these references are established, PV generation can be initiated. The PV generation does not need to be curtailed and it can exceed the load while the excess electricity charges the BESS. Depending on PV generation and BESS state of charge, the microgrid controller will dispatch central gas-fired standby generation units. The BESS and the generators both will be configured to operate in droop mode for both frequency/Watt and volt/VAR control. Some of the metrics required to properly monitor the overall system health during islanded mode will have to be added to the microgrid operation center SCADA screens. These metrics may include system’s phase-unbalance level, real power, reactive power, historical real power, historical reactive power, and historical phase unbalance on the substation feeders. Real-time load measurements and SCADA alarms will inform microgrid operators of potential overload conditions to allow appropriate remedial actions.

- *Transition to Grid-Connected Mode*

Upon restoration of utility service, the microgrid operation center will automatically initiate the process of transition back to the grid in an open transition as follows: 1) Microgrid operations center opens feeder ties; 2) The BESS switches back to idle mode and standby generators (if operating) are switched off; and 3) Layer 2 controller commands the isolating circuit breaker to close.

3.5.5 Island Contingency Generation Management

In the case of BESS failure or occurrence of any severe contingencies, the entire microgrid would shut down because the BESS functions as the voltage and frequency reference for the microgrid electric system. In the case of PV contingencies, since these generation resources function as current sources, the net load observed by the BESS would increase (if additional charge in the battery is available). Hence, either the BEMS can be used to reduce the load consumption or the BESS energy would be discharged at higher rate.

3.5.6 Resiliency of Microgrid and Building Controls

Microgrid controls will be installed in an interior above-ground location that is protected from natural forces affecting the project area. BEMS installed in basement electrical rooms could be vulnerable to flooding risks in certain scenarios. However, such scenarios also would force the microgrid to shut down for safety reasons as well as to prevent equipment damage from shorts caused by immersion of building circuits and electrical appliances.

As noted in Sec. 3.4, new isolation switches enabling microgrid islanding would be submersible, and installed in an underground service vault, providing strong resiliency against natural forces affecting the project area. Some existing tie switches in the project area are modular units mounted in enclosed modules that are highly resistant to severe weather conditions because they are not exposed to an open environment.

3.6 Information Technology (IT)/Telecommunications Infrastructure Characterization

3.6.1 IT Infrastructure Description

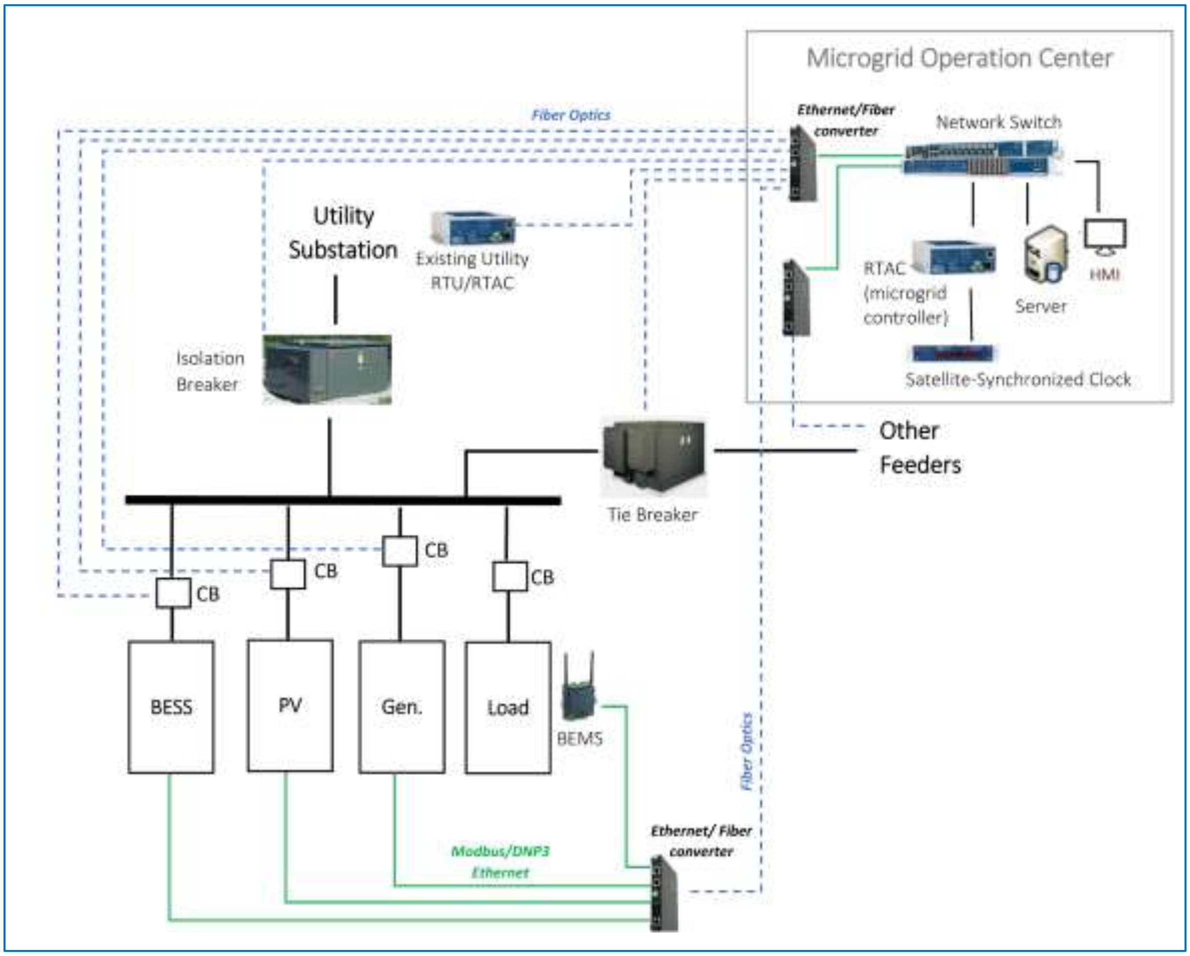
The microgrid control system uses both hardware and software systems to monitor and control microgrid components. A fiber-optic based network is recommended to facilitate communications between the microgrid relays, microgrid controllers, DERs, central generation, loads, and SCADA devices. The microgrid devices and controllers will report to the microgrid controllers via SCADA protocol of Modbus or Distributed Network Protocol (DNP3) over the communications network. The microgrid controller will issue commands to the DERs, BEMS and relays via the same network. Fiber-optic transceivers are required to make conversions among fiber and ethernet connections in the network. Devices will be connected through fiber optics media rather than radio-based communication media to provide resilient and secure communication. To implement forecast-based operating protocols, the microgrid or RTUs will require connectivity with reliable sources of real-time locational weather data.

The communication between microgrid devices will be performed via either proprietary or open-source encrypted protocols and secure networking. Communications with human-machine interfaces (HMI) also will be encrypted. Server architecture will support log collection and time synchronization functions.

3.6.2 IT and Telecommunications Infrastructure

Figure 3.13 presents a conceptual IT and telecommunications infrastructure on the simplified equipment layout diagram.

Fig. 3.13: Conceptual IT and Telecommunications Infrastructure



3.6.3 Utility Communication

The communication channel between the utility and the microgrid will be designed for monitoring or future expansion purposes. A fiber optics-based communication platform can be used to interconnect the utility remote terminal units (RTU) and real-time automation controllers (RTAC) to the microgrid controller. Usually, this communication channel from layer 3 to layer 2 control is designed for grid-connected mode of operations, such as to implement economic dispatch or demand response requests from the utility. It also will support microgrid operating mode transitions, and coordination of protection systems. During islanded mode, the microgrid automatically detects loss of utility source and microgrid controller can directly work with layer 1 devices and controllers.

3.6.4 IT and Telecommunications Infrastructure Resiliency

Resilient networks are characterized by providing and maintaining an acceptable level of service when facing failures and faults, which affect their normal operation. The communication infrastructure considered for the RLFMP Microgrid is a conventional hierarchical design.

Communication between layers of the controllers could be made more resilient with multiple communication paths. An alternative communication network to address the issue of the resiliency and reliability is the distributed architecture. A distributed architecture uses a community of controllers, which eliminates the traditional master controller concept. At any time, only one controller functions as the lead controller to ensure safe operations. Should that controller become unavailable, the system will sense the loss and would automatically reconfigure the microgrid to maintain operations. This approach eliminates the single point of failure and provides optimum redundancy under adverse conditions providing resiliency.

IV. Chapter 4: Assessment of Commercial and Financial Feasibility

4.0 Summary

The proposed ownership and operation model for the RLFMP Microgrid involves a close collaboration between the utility and prospective microgrid customers, with each financing, owning, and operating assets according to their respective interests and obligations. For study purposes, this proposed approach is termed a hybrid utility+bring-your-own-PV (BYOPV) microgrid model.

The envisioned ownership approach changed substantially during the course of the current feasibility assessment. In its expression of interest in response to MassCEC's solicitation, BPDA described plans to form a public-private partnership (P3) with a third-party microgrid operator that would procure, own, and operate the proposed microgrid. This P3 concept resulted from a three-year process during which BPDA identified potential project participants, scope, and technology options. Toward that purpose, in March 2017, Mayor Marty Walsh filed a Home Rule petition with the Boston City Council requesting authorization to proceed with procurement under the proposed P3 structure.[9] Because the Massachusetts legislature failed to enact the Home Rule Petition that would have provided Project-specific State law authority, the Project Team explored alternative structures.

Under the proposed approach, the microgrid would use existing and new utility distribution infrastructure to form an intentional power island in the project area, and it's proposed that the utility would finance, own, and operate that infrastructure. Additionally, the Project Team considered factors affecting ownership and control of BtM DERs (primarily rooftop-mounted PV systems); dispatchable DERs, including BESS and natural gas-fired standby generators; and microgrid system controls and operational responsibilities.

Behind-the-Meter Renewable Systems: Third-party, customer, or utility ownership options were considered. Customer ownership (termed "bring-your-own-photovoltaics" or "BYOPV" for study

[9] The Home Rule Petition (HRP) sought to expand existing state statutory authority for a public entity to procure energy services, in this instance the quasi-municipal Economic Development Industrial Corporation (EDIC, dba BPDA) that is the underlying landowner of the RLFMP. The existing statute, Massachusetts General Laws, c. 25A, §11i, authorizes the procurement of a relationship of up to 20 years with an energy services company (ESCO) to assess, design and build energy conservation measures via an energy savings performance contract. The statute authorizes project finance by requiring the ESCO to deliver investment grade assessments, guarantees of energy savings and, when applicable, energy generation, monitoring and verification of results, and payments by the ESCO to the public entity for any shortfalls in performance. Because the statute limits this procurement authority to energy work on the property owned by the public entity, the HRP sought to expand the authority of the EDIC to enter into an ESCO relationship for energy work to include property owners within the RLFMP other than the EDIC. The HRP proposal to allow EDIC for this one project to create the basic elements of a public-private partnership - design, build, operate via guaranteed project finance - highlighted the lack of general 3P authority in Massachusetts State law. Beyond the failure of the State Legislature to enact the HRP, the Project Team also reassessed the viability of having the proposed P3 structure for the relatively small size of the proposed microgrid. The Project Team concluded that, even if the State Legislature adopted the HRP, a microgrid that serves multiple owners would require complex contractual agreements that would be administratively burdensome and thus not a preferred approach to develop the proposed microgrid.

purposes) was deemed the simplest and most viable approach, in particular because it would allow customers to pursue onsite renewable systems if and when doing so suits their specific objectives, and it would allow them to capture the value of investments in renewables and conservation. Customers likely would contract with third-party developers to install and operate DERs and capture tax-benefit financing opportunities. Utility ownership of the proposed onsite PV was considered and rejected because it likely would diminish value for customers, and could raise regulatory and siting challenges.

Dispatchable Distributed Energy Resources: Multiple options were considered for procurement, ownership, and operation of BESS and natural gas-fired standby gensets required for microgrid resiliency. As proposed, these systems would be located within BPDA's Central Parking facility at 12 Drydock, and would be owned and operated by a third-party entity to be identified and engaged in early project implementation phases (either by the utility, or by another entity to be authorized by the City of Boston).

Microgrid Control Systems: In principle, the control systems required to operate the microgrid during both grid-connected and islanded operation could be owned and operated either by the utility or by a utility contractor. For the purposes of this study, the Project Team assumed utility ownership of all microgrid infrastructure, switches, and applicable controls and management responsibility for those controls in all operating modes. The proposed ownership and control approach treats microgrid control systems as equivalent to utility investment in distribution management systems. A potential benefit of the proposed system within this study includes providing the utility with valuable research and development (R&D) experience and data to help maximize the community resiliency value of local investments in renewable energy, storage, and load control systems.

4.1 Commercial Viability – Customers

Contractor shall describe the commercial terms/relationship between participants in the microgrid project, products expected to be produced by the microgrid and arrangements for sharing of benefits by addressing the following:

a. 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).

Figure 4.1 summarizes the number of employees and clients served onsite at the facilities in the microgrid project area.

Fig. 4.1: RLFMP Microgrid – Individuals Affected

Facility	Employees	Clients Served/Day
Bronstein Center and Design Center	3,289	500
27 Drydock	450	500
88 Black Falcon*	714	115
Black Falcon Cruise Terminal†	40	822
12 Drydock (Central Parking)	4	1,600
22 Drydock	49	29
North Coast Seafood*	263	0
Total	**4,809**	**3,566**

**Estimates based on public information and equivalent facility figures.*
† Employees when ship is in port. Clients served averaged from annual passengers embarking through the terminal.

b. Identify any direct/paid services generated by microgrid operation, such as ancillary services, or indirect benefits, such as improved operation, to the utility or ISO New England.

In principle, the utility could operate the microgrid or its resources to provide distribution ancillary services. However, opportunities to do this would be limited for two primary reasons: 1) the proposed battery capacity – sized for minimal battery autonomy – would be insufficient to provide meaningful generation shifting or reactive power services; and 2) BPDA agreed to contemplate new fossil-fueled generation for the project only as required to support microgrid resiliency, and to displace consumption of dirtier fuels (*e.g.,* diesel). Using the standby assets for ancillary services would increase fossil fuel consumed as well as emissions produced in the project area, and so would violate one of the project objectives.

The project's dispatchable generating and storage capacity is not expected to be large enough to provide meaningful or economical resources for ISO New England.

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

Owners and operators of several buildings in the RLFMP were engaged during the course of the feasibility assessment. The microgrid design described in the Task 3 Report included the following buildings:

- Boston Planning & Development Agency and building tenants (12 Drydock (Central Parking), 22 Drydock)
- Massport and tenants (88 Black Falcon and Black Falcon Cruise Terminal)
- Jamestown Property Management and tenants (Bronstein Center, Design Center)
- Related Beal and tenants (27 Drydock)
- North Coast Seafoods (5 Drydock)

As noted, most of these buildings are occupied by numerous tenants whose electric loads are served by the utility, either directly through individual metered accounts or via master-metered accounts managed by the building owners. In both cases, the utility would continue serving customers through DPU-approved rates. Moreover, the utility could expand the microgrid footprint to provide sustainable and resilient energy services for additional facilities, supporting the City of Boston's objectives for development of marine industrial activity in the RLFMP area.

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

Other customers could benefit from the microgrid in two ways. First, service continuity in the microgrid area would enable nearby customers to obtain basic services during a utility outage affecting their facilities. Second, by enabling staff in the microgrid area to shelter in place for a longer period of time, the microgrid would reduce traffic congestion and improve the safety and efficiency of evacuation processes in the Raymond L. Flynn Marine Park (RLFMP) area.

e. Describe the relationship between the microgrid owner and the purchaser of the power. Indicate which party/customers will purchase electricity during normal operation and during islanded operation. If these entities are different, describe why.

During Task 4 assessments, the project team considered several possible ownership models, ranging from 100% utility ownership of all microgrid assets, to a third-party public-private partnership (P3) to be formed by BPDA (*see Section 4.3-c for further discussion of the P3 option*). Through these assessments, the team identified a hybrid utility-customer ownership model, referred to as "utility+BYOPV."

Although other ownership models could be feasible, the utility+BYOPV model supports an important opportunity for development of resilient clean energy infrastructure in partnership with the local utility.

In this proposed hybrid utility+BYOPV model, the utility would own and operate the microgrid distribution infrastructure and controls, and microgrid customers would own and operate behind-the-meter renewable generation (and potentially BESS) that would serve microgrid-connected loads during islanded operations. A third party would own and operate dispatchable resources (BESS and natural gas-fired standby generation) required for resiliency.

During normal operations, all microgrid customers would be responsible for arranging their own energy supply resources, generally via their own onsite generation (PV and potentially BESS) and market supplies delivered by the utility.

During a utility outage, the utility would signal microgrid boundary switches to open and BEMS to enter critical operating modes. The utility then would operate dispatchable battery storage and gas-fired generation to form an intentional safe power island on the isolated microgrid segments of its distribution system. Once reference voltage is established, customer DERs automatically would resume operating as normal, serving onsite customer loads first, and then exporting power to the microgrid.

In addition to customers' existing and planned rooftop PV systems, dispatchable DERs would include new BESS and gas-fired standby generation to be owned by a third-party entity. This third-party entity would be selected through a procurement process to be established in early phases of project development.

The Project Team identified two viable approaches to procuring the dispatchable DERs. The simplest approach may be for the utility to enter an agreement with the third-party owner to purchase the required capacity and energy from the dispatchable DERs at wholesale rates, and then to use those resources to serve microgrid customer loads during island-mode operations.

As a potential alternative to utility procurement that was assessed for study purposes, microgrid customers could enter service agreements with the third-party owner, reserving dispatchable DER capacity and purchasing energy during island-mode operations. Under this approach, the third-party owner may qualify for regulatory exemption or minimal regulation,[10] allowing it to sell services that will be delivered to customers via the utility's distribution infrastructure during island-mode operations. In the absence of such an exemption or regulatory-light approach, the third-party owner may face uncertainties regarding its legal status to provide such services.

Under either approach the utility could, in principle, enter an agreement with the third-party owner to utilize the dispatchable DERs during grid-connected operations for voltage support and demand response purposes. However, as noted above, doing so may conflict with project objectives for resiliency and environmental benefits.

The proposed approach envisions the utility owning and operating microgrid controls in the same way it owns and operates other distribution control systems. Utility ownership of microgrid control systems would streamline operations, minimize the utility's concerns about security, and preserve the utility's relationship with customers. For their part, microgrid customers would retain control over their BtM energy assets as well as loads and BEMS. However, to receive resilient microgrid services, customers would be required to configure their BEMS to accept signals from the microgrid controls and adjust loads and usage patterns to support predetermined resiliency objectives. This opt-in approach would preserve the traditional boundary of utility control at the customer service entrance and revenue meter.

The Project Team considered approaches involving procurement and ownership led by EDIC; however, these options may face the same challenge explained above with the previous Home Rule Petition filed with the State Legislature. The Team considered utility direct procurement and ownership of the dispatchable DER assets, and deemed utility ownership even of standby fossil-fueled generation may be

[10] The City of Boston is influenced by the recommendation in the Final Report of the District of Columbia Public Service Commission (DCPSC) Modernizing the Energy System for Increased Sustainability (MEDSIS) (May 31, 2019) that the DCPSC establish a new regulated entity, "Microgrid Operator" (Section 5. 5, at pp. 178-187). The proposal introduces a "light touch" regulatory approach that the City of Boston is interested in promoting with the Massachusetts Department of Public Utilities. The City of Boston views this lightly regulated microgrid operator structure as a viable way for a third-party energy company to provide microgrid services to multiple properties with multiple owners. The City of Boston and the BPDA have long examined the policy issues involved in community energy planning, particularly in developing and operating multi-owner microgrids.

legally prohibited in Massachusetts. In principle the utility could own BESS systems, but the most viable option might be the proposed approach to utility procurement of third-party owned dispatchable DERs.

In the interests of supporting State goals for community resiliency, grid modernization, and renewable integration, special regulatory treatment would help minimize the project's structural complexities and regulatory costs resulting from the proposed arrangements among the utility, third-party DER owner, and microgrid customers. Specifically, the feasibility of the proposed approaches to procurement and ownership could be improved if the Massachusetts Department of Public Utilities (DPU) provided a limited regulatory exemption or "light" regulatory approach in considering and approving procurement of microgrid assets for the Project, as well as for the utility's application of a special microgrid tariff.

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

Existing contractual arrangements include:

- Rooftop PV at Bronstein Center, owned by Nexient and operated to serve loads under a long-term power purchase agreement with Jamestown Property Management. *NOTE:* Existing PV outputs at Bronstein Center never exceed connected loads and so they never export to the distribution system.

New contractual arrangements may include:

- Power purchase agreements (PPA) and site leases or other use agreements among microgrid customers and third-party owners of planned DERs; and
- Capacity and energy supply agreements among the third-party owner of dispatchable DERs and either the utility or the microgrid's customers.

A new special microgrid tariff may allow the utility to recover reasonable and necessary capital and operating costs. Establishing a new tariff structure would provide for appropriate regulatory oversight and customer protections. By comparison, a surcharge may be simpler to implement, but would not provide regulatory protections nor advance the regulatory framework for the benefit of microgrid customers.

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

BPDA has maintained an ongoing customer engagement process with microgrid customers, and would continue doing so, including supporting a collaborative process among customers to develop a workable framework for their participation in the proposed Project.

h. What other energy commodities (such as steam, hot water, chilled water) will the microgrid provide to customers?

Task 2 and 3 assessments determined that the initially proposed district energy system lacked sufficient thermal loads to justify the substantial investment in underground hot and chilled water distribution systems. Also, the utility's suggested revisions to the microgrid electrical boundary, based on distribution configuration options and resiliency issues, reduced overall loads that could be served by the contemplated CHP outputs. Finally, space for siting a central CHP plant is very limited in the RLFMP, and what space currently may be open is unlikely to remain available.

4.2 Commercial Viability - Value Proposition

Contractor shall describe the value the microgrid is expected to provide directly to its participants, to the community at large, to the local electric distribution utility and to Massachusetts by addressing no less than the following questions:

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

Benefits:

Economic development potential: The proposed microgrid will bring greater resiliency and sustainability to the RLFMP, supporting business growth and retention in an area with the goal to support marine industrial development.

Resiliency, operating uptime, public safety: The proposed microgrid will reduce disruption to facility operations and services from short-duration outages, and will increase the operability of those services during long-duration outage events. These benefits will reduce operating costs and risks of financial loss for microgrid customers. The microgrid will support BPDA command-center functions at 22 Drydock facility. Assuring electric service continuity in the microgrid area will enable people throughout the RLFMP to access facilities in the microgrid area to obtain basic services during a utility outage affecting their facilities. Also, by enabling staff and customers in the microgrid area to shelter in place for a longer period of time, the microgrid will reduce traffic congestion and improve the safety and efficiency of any evacuation process.

Local renewable energy production value: The proposed microgrid will add substantial new PV generation capacity in the RLFMP area, where very little solar energy capacity currently exists. Further, this new renewable energy capacity will be integrated into a resilient energy system with BESS capacity that could be expanded in the future to extend the value of renewable resources by making them available during high-demand periods.

Reduced customer demand charges with DERs: The PV generation specified for the microgrid will serve to reduce customer demand for utility-supplied energy. To the degree the utility's monthly peak demand charges are assessed on the basis of daytime peaks, the new PV generation will reduce customer demand charges.

Reduced carbon footprint and reduced emissions: The proposed PV generation can be expected to displace utility-supplied power responsible for 27,000 tons of CO_2e over the lifetime of the proposed PV assets.[11]

Reduced diesel consumption: The system will serve to defer startup of microgrid customers' diesel-fueled standby generation. The proposed new gas-fired standby generation is sized to support microgrid customers' managed critical loads for an indefinite period of time, effectively eliminating reliance on diesel standby generation.

Greater energy cost stability: Onsite PV generation will displace consumption of utility electricity that is subject to periodic price changes (usually upward).

Costs:

Renewable energy purchases and utility bill offsets: For energy production from DERs owned by third parties, customers will incur costs for that production, with corresponding utility bill offsets expected to yield net energy cost savings.

Utility tariffs for recovery of incremental microgrid costs (upgraded switching, underground cable infrastructure, and O&M): Under the studied approach, customers would pay any incremental costs for utility distribution system upgrades and operations that the utility would not otherwise incur. Incentives, grants, and other funds first will be applied to reduce net costs that must be recovered through utility bills.

Installation, O&M, and replacement costs for the proposed BESS and gas-fired standby generation: Capital and operating costs will be incurred for battery systems installed to support the microgrid. Incentives and grants will first be applied to reduce net costs of BESS installation.

Project development and management costs: Microgrid customers may incur costs for development and project management, in the form of labor hours for customer scope associated with microgrid project development. Any third-party or utility development and management costs will be included in other capital costs.

> *b. 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?*

The microgrid would directly benefit the utility in at least three ways. First, it would provide the utility with direct experience designing and implementing an advanced community microgrid within its distribution system, and developing business processes and tools that facilitate utility collaboration with municipal and private customers in making optimal use of distributed energy resources. Second, it would support utility operational and investment goals regarding renewable resources, grid

[11] CO_2 displacement estimated with HOMER Pro modeling software simulation. HOMER simulates the difference in CO_2 produced with and without the modeled renewable resources, using a constant grid emissions factor.

modernization, and environmental and climate mitigation. Third, it would strengthen the utility's local capacity to integrate and manage new solar energy resources.

The utility would incur costs for the following:

- Upgrading existing switching infrastructure to enable grid formation;
- Installing a new underground distribution line segment to connect 22 Drydock to the microgrid virtual bus;
- Integrating microgrid controls into its area distribution management systems; and
- Contracting a third party to install and operate dispatchable BESS and gas-fired generation at 12 Drydock.

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

The proposed project relies on a hybrid business model that combines utility ownership and financing of distribution infrastructure and microgrid controls; customer ownership and financing of BtM renewables and other assets; and third-party ownership and financing of dispatchable BESS and gas-fired generation.

Strengths:

1. The utility has indicated general support for a project that creates a microgrid in its distribution system at RLFMP using utility-owned infrastructure, and offered specific design suggestions to support project viability.
2. The proposed model could resolve concerns about public procurement of assets and services to benefit both public and private entities.
3. The model would encourage customer investments in solar PV assets in a project area that currently has very limited solar generation.
4. The model is comparatively simple and would avoid complex procurement and contracting structures.
5. The model supports state climate and environmental goals and uses multiple stakeholders to support State objectives.
6. The proposed approach can advance innovative partnering strategies as well as grid modernization and economic development opportunities.
7. Starting with a relatively small project, the proposed approach demonstrates a replicable model for increasing the resiliency of critical community assets across Massachusetts.

Weaknesses:

1. Although the utility has been supportive throughout the study process, it has not identified ongoing reliability or power quality issues in the project area that would justify system upgrades of the type envisioned for the project. As a result, the utility might not prioritize the project as a grid-modernization or R&D investment for general ratepayer benefit, and instead may seek to allocate to microgrid customers all of the incremental costs of upgrades and services.

2. Cost savings are paramount concerns for the private customers included in the microgrid. To the degree any microgrid costs substantially reduce the direct savings that customers would achieve with onsite PV generation alone, customers might withdraw their support for the microgrid.
3. In the event the utility declines to procure third-party DERs proposed for installation at BPDA's central parking garage, then the project may require a more complex arrangement that requires each microgrid customer to enter a separate agreement with the third-party DER owner.

Opportunities:

1. Customer investments in PV would produce both economic benefits and resiliency benefits, as opposed to non-microgrid PV, which would produce economic benefits but would be inoperable during a utility outage.
2. The utility could expand the system over time to integrate additional customers and expand resiliency benefits throughout the RLFMP.
3. Implementing the project would establish a model for utilities to collaborate with municipalities and other customers on multi-user community microgrid development. That model could support future projects in other locations.

Threats:

1. The utility reports that its position on owning and operating microgrid control systems and contracting for dispatchable DERs is under review and may be changing. Ongoing uncertainty about the utility's role could prevent timely project progress.
2. Utility control of customers' BtM assets and loads via microgrid controls could establish a precedent for utilities to assert jurisdiction over behind-the-meter assets and operations. Unless customer participation is arranged on an opt-in basis, this precedent could increase utility market power in ways that diminish competition for behind-the-meter services and limit customer options in the future.
3. The project's potential changed substantially during the current assessment phase, with customers exploring and pursuing alternative solutions. Continued changes in the project area could obviate or diminish the benefits achievable with microgrid solutions.
4. Current regulatory policies in Massachusetts lack clarity on storage and grid modernization, creating uncertainties for initiatives like the proposed microgrid that otherwise could support State objectives. A lack of replicable multi-user microgrid models creates excess cost burdens for innovation in deploying technologies that produce greater resiliency, efficiency, and sustainability compared to the legacy utility system. The Project Team views these concerns as reasons why the utilities and the Massachusetts DPU should use the marine park site as an opportunity for both a regulatory and technical pilot project where these questions can be resolved.

d. 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 project design has some novel aspects, but it cannot accurately be described as "unique." The system is intended to rely on commercially available and warranted technologies integrated in standard configurations.

Most notably, the design supports multiple operating modes depending on the outage scenario. In general the approach to dispatch is intended to minimize the amount of battery energy storage capacity that must be provided and reserved for microgrid customers' resiliency objectives, thereby minimizing project costs while also supporting resiliency for outages of short and long duration. Specifically, battery capacity is specified with sufficient power and energy capacity to cover outages of short duration – approximately 15 minutes – after which the system would dispatch gas-fired standby generation and apply deep load controls to maintain reduced electric service using customers' solar PV outputs augmented by the specified central gas-fired resources.

e. What makes this project replicable? Scalable?

The proposed project demonstrates an approach that is scalable both in terms of technical systems and customers.

Scalability in the project area is limited mostly by the configuration of the existing utility distribution system, and the utility's policy to avoid reliance on overhead distribution systems. However, the basic approach of installing switching capabilities at key points in the distribution system is inherently replicable and scalable, to the extent system design and configuration supports it. The energy resources and controls required for island-mode operations also could be replicated for other projects, or expanded to support additional facility loads.

The proposed business model also is inherently replicable for application in other locations, and scalable to integrate additional customers. If a microgrid virtual bus technically could be formed in a utility distribution area, or could be expanded to encompass additional facilities, then the same business model could be applied for other projects or for adding new customers.

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

A microgrid at the RLFMP would strengthen the resiliency of an important economic development zone that is vulnerable to climate change effects, including sea-level rise and storm surge, and it would provide modernized and highly efficient energy infrastructure to support BPDA and Massport development goals for the area. As described in the Master Plan for the RLFMP, the 191-acre RLFMP is a vital waterfront job center in the City of Boston.

The microgrid is designed for two primary resiliency purposes: 1) Eliminate service disruption caused by periodic short-duration outages (approximately 15 minutes) caused by localized system faults (outside the microgrid boundary); and 2) Enable resilient energy service for critical loads during long-duration outage scenarios. The second resiliency function is more challenging, and is driven by the risk of hurricanes, derechos, and severe winter weather that can cause long-duration outages by damaging both local and regional grid infrastructure.

The proposed system design would support island-mode operations for critical loads for indefinite periods of time. Task 3 assessments showed that during such events, electric loads in the project area are substantially reduced, and so the microgrid needs dispatchable capacity only to serve a portion of building loads to support long-duration resiliency objectives. The microgrid controls would accomplish this by signaling building energy management systems to curtail or reduce non-critical building loads, and by dispatching gas-fired standby generation as necessary to serve loads and maintain battery state of charge when loads exceed PV generation and BESS energy supply capacity.

The system would be resilient against some localized flooding events, but would be unable to maintain service during sustained and substantial flooding. Based on survey inputs from stakeholders, the current operations in the project area do not require resiliency against sustained flooding conditions, because such events would cause the area to be evacuated.

g. 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 Massachusetts).

The microgrid would produce value for microgrid customers in multiple ways:

- Reducing disruption and lost productivity caused by outage events.
- Enabling utilization of rooftop PV generation during utility outages.
- Reducing diesel fuel consumption and related emissions.
- Extending the time to refueling for onsite diesel-fueled standby generators.

The microgrid would increase public safety in the RLFMP area by enabling hundreds of workers to shelter in place for longer periods, reducing local traffic disruption and congestion associated with evacuation of the RLFMP. Additionally, it would establish resilient energy supplies for emergency operations functions at BPDA’s offices.

Developing a clean-energy microgrid in the RFLMP would support maritime industrial development by establishing modernized grid infrastructure and resilient green energy technologies to attract and retain employers.

The project would produce value for the utility by strengthening the potential for local infrastructure to integrate and manage new solar energy resources. It also would provide the utility with direct experience designing and implementing an advanced community microgrid within its distribution system, and developing business processes and tools that facilitate utility collaboration with municipal and private customers in making optimal use of distributed energy resources.

In addition to generating new business for marketing energy production, storage, and control equipment to customers in the RLFMP, the project would create value for suppliers and partners by establishing experience and replicable models for multi-user community microgrids, which heretofore have been difficult to develop except for very limited uses.

In addition to enhancing resiliency for Boston's vital Raymond L. Flynn Marine Park, the project would benefit the Commonwealth by demonstrating Massachusetts leadership in conceiving and demonstrating a new utility-customer hybrid business model, and by advancing State goals for renewable energy and grid modernization.

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

Microgrid customers will incur capital and operating costs associated with installation of new behind-the-meter onsite PV systems.

In addition to avoiding lost productivity during utility outages, microgrid customers will save annual electricity costs by offsetting utility purchases with solar PV production. Additionally, to the degree the microgrid defers standby generator startups, customers also would save diesel fuel costs.

Microgrid customers may be required to pay a special tariff to recover the utility's microgrid costs that are not financed by other sources (*e.g.,* grants or general rate-base cost recovery).

Customers also may incur costs associated with BEMS upgrades, standby generation, and BESS that are not covered by other financing sources.

i. How does the proposed project promote state policy objectives (e.g. RPS, Global Warming Solutions Act)?

The proposed project would promote state policy objectives in several ways:

- Facilitating development and optimizing integration of approximately 1,260 kW of new solar PV production in an urban area with very little existing renewable generating capacity.
- Displacing more than 27,000 tons of GHGs over the lifetime of the proposed PV assets.
- Supporting deployment of 3,400 kW/ 842 kWh of BESS capacity.
- Demonstrating community energy resiliency solutions and a hybrid utility-customer business model for replication by other Massachusetts communities.
- Advancing utility grid-modernization goals and utility experience with advanced grid technology systems designed to address local resiliency and clean energy goals.
- Exploring alternative methods to funding and finance community projects using P3 principles, BIDs, or standardized models to promote replication in other Massachusetts communities.
- Creating a platform for expansion and development of sustainable and resilient energy systems to attract and retain employers.

- Supporting development of customer-owned generation systems helps to retain economic value for local employers and the local community, to support competitiveness within the region and nationwide.
- Advancing and demonstrating Massachusetts leadership in energy technology and regulatory innovation.

j. How would this project promote new technology or technologies developed or manufactured by Massachusetts-based companies (including, but not limited to, generation, storage, controls, IT, AMI, other)? What are they?

Products referenced in Task 3 system conceptual design and modeling are intended as examples of commercially available technologies, and not as pre-approved equipment for specification. Advanced engineering design and procurement scope for the proposed project may include preferences for Massachusetts-based vendors.

4.3 Commercial Viability - Project Team

Contractor shall address the following in describing the structure of the Project Team and the roles, strengths and resources of its members and other necessary partners:

a. Describe the current status and approach to securing support from local partners such as municipal government, community groups, residents, and other relevant stakeholders.

Municipal Government: The City of Boston initiated the project and continues supporting it, directly and through BPDA.

Community Groups: BPDA maintains ongoing engagement with microgrid customers, supporting a collaborative process to develop a workable framework for their participation in the proposed project.

Residents: No residential facilities are included in the project area.

Other Relevant Stakeholders: BPDA maintains ongoing engagement with the utility and Massport, supporting a collaborative process to develop a workable framework for their participation in the proposed project.

Future outreach and engagement efforts may include informational meetings and materials provided to additional stakeholders including potential project partners, prospective future customers of the microgrid, and members of the public.

b. 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?

Applicant: BPDA will be a customer of the microgrid, will host rooftop PV systems on two buildings, and will host BESS and gas-fired standby generation.

Microgrid Owner: For the purposes of this study, the team conceived a model in which the utility would install and own the microgrid's switching and distribution infrastructure. The utility would own and operate the microgrid controls and procure the proposed third-party owned dispatchable DERs. The utility also would support workable approaches for financing incremental microgrid costs.

Contractors: Various contractors would be involved in the project, including consultants to facilitate collaboration among microgrid stakeholders; and microgrid contractors to support system engineering, procurement, civil engineering, system installation, configuration and integration, and operations and maintenance.

Suppliers: Suppliers of microgrid technologies and services, including a third-party owner of dispatchable DERs, will be selected during project procurement phases.

Partners: Microgrid customers would serve as project partners in at least four ways. First, they would collaborate to finalize system design, operational plans, and financial arrangements that support their organizational objectives for participating in the project. Second, they would arrange for installation of grid-tied rooftop PV systems on their facilities. Third, they would pay for microgrid resilient energy service during utility system outages, and may pay charges to help recover incremental microgrid costs. Fourth, they would configure their BEMS to accept microgrid control signals and manage loads to support predefined resiliency objectives.

Additional team members in future phases may include providers of legal, regulatory, and financial services to support project structuring, permitting, and financing.

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

The project does not envision formalizing a P3 corporate entity. However, public and private entities will collaborate, as described above, to finalize system design, operational plans, and financial arrangements that support their organizational objectives for participating in the project.

BPDA's earlier plans for the project had proposed to form a P3 among BPDA, Massport, and private microgrid customers. BPDA and the City of Boston filed a Home Rule petition before the Massachusetts Legislature in November 2017, seeking authorization to form a P3 that would contract with an energy service company (ESCo) to design, build, finance, and operate the RLFMP microgrid. The Home Rule Petition (HRP) sought to expand existing state statutory authority for a public entity to procure energy services, in this instance the quasi-municipal Economic Development Industrial Corporation (EDIC, *dba* BPDA) that is the underlying land owner of the RLFMP. The existing statute, Massachusetts General Laws, c. 25A, §11i, authorizes the procurement of a relationship of up to 20 years with an energy services company (ESCO) to assess, design and build energy conservation measures via an energy savings performance contract. The statute authorizes project finance by requiring the ESCO to deliver investment grade assessments, guarantees of energy savings and, when applicable, energy generation, monitoring and verification of results, and payments by the ESCO to the public entity for any shortfalls in performance. Because the statute limits this procurement authority to energy work on the property owned by the public entity, the HRP sought to expand the authority of the EDIC to enter into an ESCO relationship for energy work to include property owners within the RLFMP other than the EDIC. The HRP proposal to allow EDIC for this one project to create the basic elements of a public-private partnership – design, build, operate via guaranteed project finance – highlighted the lack of general 3P authority in Massachusetts State law. Beyond the failure of the State Legislature to enact the HRP, the Project Team also reassessed the viability of having the proposed P3 structure for the relatively small size of the proposed microgrid. The Project Team concluded that, even if the State Legislature adopted the HRP, a microgrid that serves multiple owners would require complex contractual agreements that would be administratively burdensome and thus not the best way to develop the proposed microgrid.

The current proposed approach replaces the P3 concept with a utility-customer partnership model, in which the utility – rather than the EDIC (*dba* BPDA) would be responsible for procuring microgrid assets that benefit multiple customers. BPDA continues supporting the project as a facilitator and as prospective host to microgrid assets.

d. For identified Project Team members (including, but not limited to, applicant, microgrid owner, contractors, suppliers, partners), what are their qualifications and performance records?

Applicant: The Boston Planning & Development Agency (BPDA) is the planning and economic development agency for the City of Boston. The BPDA plays a far-reaching role in shaping the City.

BPDA is comprised of 200 professionals who serve the City in a variety of ways -- from architects who review the smallest details of a historic building in Roxbury to project managers who host a community meeting for a new affordable housing project in Dorchester. The Agency works hand-in-hand with other City departments and community groups to make the City better.

BPDA has supported hundreds of successful development and construction projects of many kinds all around Boston, including in the RLFMP.

Owner: Eversource is the largest electricity delivery company in New England. The company's Massachusetts electric service territory includes 140 towns and covers 3,192 square miles. Eversource has collaborated with the City of Boston and other Massachusetts municipalities on locally beneficial projects, including three ground-mounted solar arrays.

Contractors and Suppliers: No contractors or suppliers have yet been identified for project implementation. All contractors and suppliers will be selected through compliant procurement processes to ensure they bring exemplary qualifications and performance records.

Partners: Other partners in the project include microgrid customers Massport, Jamestown Properties, Related Beal LLC, and North Coast Seafoods. These customers have extensive experience managing many types of facility development and construction projects. Additionally, Massport owns and operates the Port of Boston, including RLFMP properties included in the microgrid.

e. Are any of 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?

No contractors or suppliers have yet been identified for project implementation. Likely team members will include:

- Consultants to facilitate collaboration among microgrid stakeholders;
- Technical contractors to support system engineering, procurement, civil engineering, system installation, configuration and integration, and operations and maintenance;
- Suppliers of microgrid technologies and services, including PV, BESS, standby generation, distributing switching, and microgrid controls; and
- Providers of legal, regulatory, and financial services to support project structuring, permitting, and financing.

All contractors and suppliers will be selected through compliant procurement processes to ensure they bring exemplary qualifications and performance records.

f. Are any of 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?

Financing partners have not been identified at the current project phase. Financing will be required for three primary asset groups, each of which may require separate financing partners and structures.

Rooftop PV systems: Each customer will be expected to arrange financing for its own rooftop PV system. In effect these investments can be treated like any other onsite renewable energy asset, for which financing may come from various sources. Common and likely approaches include: tax-benefit financing for generating assets to be owned and operated by third-party solar developers, with costs recovered through PPAs with project hosts; and secured corporate financing for customer capital investments, with costs recovered through monthly electricity cost savings. Each customer will determine the best structure and funding source for its situation, which may vary substantially among the public and private entities participating in the microgrid.

Note: All of the PV systems in the project would be integrated behind the customer meter to enable onsite offsets of demand and energy consumption. Only one of the PV systems would be expected to overproduce on an annual basis – namely, the covered parking-mounted system on top of the BPDA Central Parking facility would generate more electricity than the host facility will consume in a year. This facility would be financed and operated as a virtual net-metered asset, offsetting not only Central Parking loads but also other loads at other BPDA beneficial accounts.

Microgrid infrastructure and controls: In addition to upgraded switching, communications, and control systems, the project will require one new underground line segment to connect one facility (22 Drydock) to the microgrid virtual bus. Under the proposed model, the utility would finance, own, and operate this infrastructure, and it would arrange financing for associated costs via the channels available to investor owned utilities in Massachusetts. Likely options include: grants and incentive financing for grid modernization and DER technology demonstration investments from the State of Massachusetts; utility capital and R&D investments to be recovered through general rates, with approval from the Massachusetts DPU; utility capital expenditures to be recovered through a special microgrid tariff paid by microgrid customers. Funding also could be raised through the sale of utility revenue bonds to fund project costs together with other utility investments in sustainability and resiliency, to achieve a better scale proposition and lower financing costs.

Dispatchable DERs: Under the proposed approach, the utility would enter an agreement with a third party to install, own, and operate new BESS and gas-fired standby generation proposed for the project. The utility would finance the incremental costs of these assets on the same basis that it finances other infrastructure investments.

Alternatively, if the utility is unable to contract for the third-party DERs, incremental costs for the DERs would be financed by the third-party owner on the basis of offtake arrangements with microgrid customers.

> *g. 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 feasibility assessment team includes legal and regulatory advisors, most notably Microgrid Institute Counsel Michael Zimmer. Mr. Zimmer is an energy industry attorney with more than 40 years of experience. He has national and international experience in serving energy/utility projects in 35 states and over 20 foreign countries during his legal career. However, he is not admitted to practice in Massachusetts and so his guidance in the project is comprised of general consultative support and not legal advice.

During future project phases, inside and outside counsel would be expected to support customer activities associated with installing onsite renewable generation and executing contracts for microgrid service. Additionally, BPDA likely would engage inside counsel to address issues related to procurement of assets and services.

One of the critical roles of counsel would be to facilitate, update, and provide guidance in modernizing regulatory policy and guidance and interpretations to support further needs of the city and its stakeholders, and to remove barriers of the past derived from legacy decisions. Ultimately, plans and strategies need codification to support proper interpretations in codes, ordinances, and statutes to better serve customers, stakeholders, and constituents in the 21st century.

V. Chapter 5: Information for Cost-Benefit Analysis

Develop and provide the information required to support an independent evaluation of project costs and benefits for this stage of analysis.

5.1 Facility and Customer Description

Describe all facilities that will be served by the microgrid. For each facility, indicate: Rate class to which the facility belongs; Economic sector to which the facility belongs; Whether multiple ratepayers are present at the facility; Whether there will be any financial criteria for prospective customers; Average annual electricity demand (MWh) and peak electricity demand (MW); Percentage of the facility's average demand the microgrid would be designed to support during a major power outage; In the event of a multi-day outage, number of hours per day, on average, the facility would require electricity from the microgrid; Quantified value of resiliency for each facility that would receive electricity from the microgrid during an outage.

As described in the Task 3 Report, the RLFMP Microgrid includes six buildings, with commercial, industrial, city services, and transportation loads. The Black Falcon Cruise Terminal and 88 Black Falcon buildings, both owned by Massport, are combined for analysis. Also, the Boston Innovation & Design Building is comprised of three properties (Design Center, Bronstein Center, and 27 Drydock) whose rooftop solar resources and tenant electric loads are combined for analysis.

Fig. 5.1: RLFMP Microgrid Facility and Customer Description

Facility	12 Drydock (Central Parking)	22 Drydock (BPDA)	5 Drydock (North Coast Seafoods)	Boston Innovation & Design Building	Black Falcon Cruise Terminal & 88 Black Falcon
Rate Class	Commercial	Commercial	Industrial	Commercial	Industrial
Economic Sector	City Services and Public Parking	City Services and Commercial/Offices	Food Processing	Wholesale & Retail Trade	Transportation, Wholesale Trade
Multiple Ratepayers?	No	Yes	No	Yes	Yes
Financial Criteria	Yes – Must Execute Agreement				
Annual Avg. Electricity Consumption (MWh)	478.8	216.3	5,365.1	14,988.6	8,456.9
Peak Demand (Annual (kW))	89	66	1,118	5,936	1,712
Average Demand (kW)	34	25	425	2,256	651
% of Avg. Demand Supported by Microgrid	18%				
Avg. Hours/Day of Microgrid Reliance	ESS & PV only: 15 min. Paired with gas generation: 24 hrs.				
Resiliency Value	24 hours/day of continued critical services; Deferred utilization of fossil-fueled standby generation (Diesel: 473 MMBtu/day; Natural Gas: 44 MMBtu/day)				

BESS capacity is sized to meet average site demand for about 15 minutes, to enable stable transition to islanded operations and balance PV generation. New gas-fired standby capacity (600 kW) is sized to enable limited service for all facilities even when battery state of charge is depleted and PV is not producing. The microgrid controller will signal BEMS to manage and curtail loads to maintain system balance. Site loads are minimal outside of business hours, and commercial activities are assumed to cease during a long-duration outage (based on current uses and surveys from stakeholders).

Additional dispatchable resources (BESS or generators) may be added in the future to support more critical loads and longer-duration microgrid service.

5.2 Characterization of Distributed Energy Resources

Describe the DERs the microgrid would incorporate, including for each: Energy/fuel source; Nameplate capacity; Estimated average annual production (MWh) under normal operating conditions; Average daily production (MWh/day) in the event of a major power outage; For fuel-based DER, fuel consumption per MWh generated (MMBtu/MWh); Amount of onsite fuel storage capacity.

During island-mode operations, the RLFMP microgrid will rely primarily on solar resources to support BEMS-managed daytime loads, with nighttime loads supported by BESS and, as needed, natural gas-fueled generation. BESS capacity will be reserved to support resiliency objectives, and gas-fired generation would not be utilized except during island mode operations.

Fig. 5.2: DER Operating Characterization – RLFMP Microgrid

Facility	12 Drydock (Central Parking)	22 Drydock			5 Drydock (North Coast Seafoods)	Boston Innovation & Design Building		Black Falcon Cruise Terminal & 88 Black Falcon
DER Type	Canopy PV	Rooftop PV	BESS	Gas Gen	Rooftop PV	PV	PV	PV
Capacity	570	90	3,368 kW / 842 kWh	600	120	360	330	270
Existing or Proposed	Proposed	Proposed	Proposed	Proposed	Existing	Existing	Proposed	Proposed (88 Black Falcon)
Fuel Storage	NA	NA	NA	NA	NA	NA	NA	NA
Annual PV Production (MWh/yr)	708.21	111.82	NA	NA	149.19	448.19	410.84	336.14
Daily Production (MWh/day)	1.94	0.31	NA	NA	0.41	1.23	1.13	0.92
Fuel Consumed (MBtu/kWh)	NA	NA	NA	399	NA	NA	NA	NA
Fuel Consumed (Mbtu/Day)	NA	NA	NA	5,749*	NA	NA	NA	NA

**Gas-fueled generation is specified for standby operation only. Fuel usage numbers reflect daily generation during outages.*

5.3 Capacity Impacts and Ancillary Services

Contractor shall provide estimates of the following services/value the microgrid is expected to provide, as applicable: Impact of the expected provision of peak load support on generating capacity requirements (MW/year); Capacity (MW/year) of demand response that would be available by each facility the microgrid would serve; Associated impact (deferral or avoidance) on transmission capacity requirements (MW/year); Associated impact (deferral or avoidance) on distribution capacity requirements (MW/year); Ancillary services to the local utility (e.g., frequency or real power support, voltage or reactive power support, black start or system restoration support); Estimates of the projected annual energy savings from development of a new combined heat and power (CHP) system relative to the current heating system and current type of fuel being used by such system; Environmental regulations mandating the purchase of emissions allowances for the microgrid (e.g., due to system size thresholds); Emission rates of the microgrid for CO2, SO2, Nox, and PM (emissions/MWh).

As indicated in Figure 5.3, demand response (DR) and other grid-services capacity is technically constrained by the maximum output capacity of the BESS and inverters, but in practical terms that capacity is reserved to meet the resiliency objectives defined for microgrid operation. As discussed in earlier phases of study, the customers' objectives for the RLFMP Microgrid BESS capacity prioritized increasing customer energy resiliency and reducing fossil fuel consumption during outages. Supporting resiliency objectives means the currently specified BESS capacity will not be sufficient to support substantial DR or other ancillary services.

Fig. 5.3: RLFMP Capacity Impacts and Ancillary Services

Service	Impact	Notes
Peak load support (MW/yr)	1,740	PV nameplate peak output
DR Capacity – Technical (MW/yr)	3,368	BESS 15-min. capacity
DR Capacity – Practical (MW/yr)	0	BESS reserved for resiliency
Transmission Capacity Impact (MW/yr)	0	
Distribution Capacity Impact (MW/yr)	0	
Ancillary Services to the Utility	0	
Environmental Regulations	NA	Below permitting threshold
Emissions Rates (kg/MWh)	CO_2: 0.17; SO_2: 0.0; NO_X: 0.006	

5.4 Project Costs

Provide the following cost information: Fully installed costs and engineering lifespan of all capital equipment; Initial planning and design costs; Fixed operations and maintenance (O&M) costs; Variable O&M costs, excluding fuel costs; Maximum amount of time each DER would be able to operate in islanded mode without replenishing fuel supply; and Amount of fuel the DER consume during this period.

Figure 5.4 provides estimated total project costs. Costs for PV and BESS assets ($3,853,112) include a 2022 10% federal investment tax credit plus equivalent 10% depreciation benefit. Sunset dates for higher rates may be extended, and other incentives may be available at the time of development, but are not included in these estimates. These costs are assumed to be financed by one or more third parties on 5-year terms with a 7 percent interest rate, with costs recovered through customer utility bill offsets. Costs for standby generation ($387,500) also are assumed to be financed by a third party, with costs recovered through an operating contract with the utility.

Utility costs for distribution and control system upgrades ($1,281,637) are assumed to be financed with 10-year corporate bonds carrying an effective interest rate of 4%.

Task 4 assessments considered multiple options for utility cost-recovery of its microgrid costs, including:

- Grants and incentive financing for grid modernization and DER technology demonstration investments from the State of Massachusetts;
- Utility capital and R&D investments to be recovered through general rates, with approval from the Massachusetts DPU; and
- Utility capital expenditures to be recovered through a special microgrid tariff paid by microgrid customers.

These options are not mutually exclusive; for example, the utility's costs for operations and maintenance might be recovered through a special microgrid tariff, while capital costs could be financed by a combination of state grants and DPU-approved general rate recovery. For purposes of this cost-benefit assessment, all utility capital costs are assumed to be financed with 10-year corporate bonds, and recovered through general rates. Such general rate recovery may be justified by the microgrid's value to Massachusetts ratepayers in serving as a pilot project, demonstrating how the utility can partner with public and private community stakeholders to achieve greater resiliency and sustainability to serve critical customer loads. Additionally, it would demonstrate an approach to overcoming regulatory and practical barriers to public-private partnering in achieving benefits that are difficult to monetize directly.

Fig. 5.4: RLFMP Total Project Cost - Summary

	Total Cost	Notes
Overnight Capital Cost	$5,522,249	(Net after tax credits)
Financing Cost	$1,038,580	See Figure 5.6
Total Cost incl. Financing	$6,560,829	
Initial Planning & Development	$518,842	Included in overnight capital cost
Project Lifespan	25 years	
Fixed O&M ($/kW-year)	Negligible	O&M costs limited to routine maintenance at minimal cost.
Variable O&M ($/MWh)	$0	
Max Operating Time w/o Refueling	NA	Fueled by natural gas pipeline

Fig. 5.5: RLFMP Total Project Cost – Component Subtotals

Component	System Total	Covered parking PV	Rooftop PV	Gensets	BESS (Battery + Inverter)	Microgrid & Load Controller	Distribution System Components
Overnight Capital Cost	$5,522,249	$1,174,200	$1,048,800	$387,500	$1,630,112	$242,907	$1,038,730
Total Cost Including Financing	$6,560,829	$1,395,034	$1,246,050	$460,378	$1,936,690	$288,591	$1,234,086
Financing Cost	$1,038,580	$220,834	$197,250	$72,878	$306,578	$45,684	$195,356

5.5 Current Costs to Maintain Service During a Power Outage

For each facility the microgrid would serve, describe its current backup generation capabilities, if any.

Existing standby generation systems will remain in their current automatic transfer switched (ATS) configuration, and will not be integrated to energize the microgrid. Figure 5.6 nonetheless includes inputs for the standby generators to support comparative analysis.

Costs of standby power are based on operation at stated load factor for 24 hours. In a scenario where neither microgrid assets nor standby generation is available, none of the facilities in the project area could operate, with the exception of diminished functions at the 12 Drydock Central Parking facility and the Black Falcon Cruise Terminal. In such a situation of short or medium duration (less than approximately 8 hours), costs would be limited to lost productivity. In a long-duration emergency, estimated costs include lost productivity and costs to remove perishable inventories from North Coast Seafoods and 88 Black Falcon's refrigerated warehouses and store them elsewhere.

Fig. 5.6: RLFMP Costs to Maintain Service during Outages (24-hour baseline)

Facility	12 Drydock (Central Parking)	22 Drydock	5 Drydock (North Coast Seafoods)	Boston Innovation & Design Center	88 Black Falcon	Black Falcon Cruise Terminal
Fuel Type(s)	Natural Gas	Diesel	Natural Gas	Diesel	NA	Natural Gas
Existing or Proposed	Proposed	Existing	Existing	Existing		Existing
Capacity (kW)	600	80	30	1,340		100
Fuel Storage (gallons)	NA	275	NA	3,500		NA
Avg. Load Factor during Outage (%/nameplate)	100%	70%	100%	100%		100%
Avg. Daily Production during Outage (MWh/day)	14.40	1.34	0.72	32.16		2.40
Fuel Used during Outage (MMBtu/day)	203	19	10	454		34
One-Time Costs	None	None	None	None	None	None
Daily Non-Fuel Costs	None	None	None	None	None	None
Emergency Costs w/Standby Power	$2,183	$204	$109	$4,875		$364
Emergency Costs w/o Standby Power	Lost parking fees	Lost productivity		$50,000*	$5,000*	NA

**Estimated daily rental costs for refrigerated trailer capacity to accommodate goods if refrigerated storage must be emptied in an extended emergency; These costs are unlikely to be incurred in first 24 hours of an emergency.*

5.6 Services Supported by the Microgrid

Estimate the population serviced by each facility and describe how a power outage would impact each facility's ability to provide services. If possible, estimate a percentage loss in the facility's ability to serve its population during a power outage, relative to normal operations (e.g., 20% service loss during a *power outage), both when the facility is operating on backup power and when backup power is not available.*

The microgrid area includes more than 100 separate commercial customers, many of which provide services affecting a substantial segment of Boston's population of 685,000 people and the 19 million tourists that visit Boston each year. Based on facility owners' inputs about the number of employees and client visitors per each employee per day, approximately 8,375 employees and clients utilize the project facilities each day.

Most of the project facilities require continued electric service to enable ongoing operations, with limited exceptions. According to MassPort, if necessary, during an outage the Black Falcon Cruise terminal could be used for debarking ship passengers, with notable impacts on safety and accessibility for passengers with mobility limitations. The cruise terminal is equipped with minimal backup generation for life-safety functions.

Fig. 5.7: Services Supported by the Microgrid

	Zone 1
Population Served (Employees and Clients)	8,375
Service Lost during Outage w/Standby Power or Microgrid Service	75%
Service Lost during Outage w/o Standby Power or Microgrid Service	90%

-END REPORT-