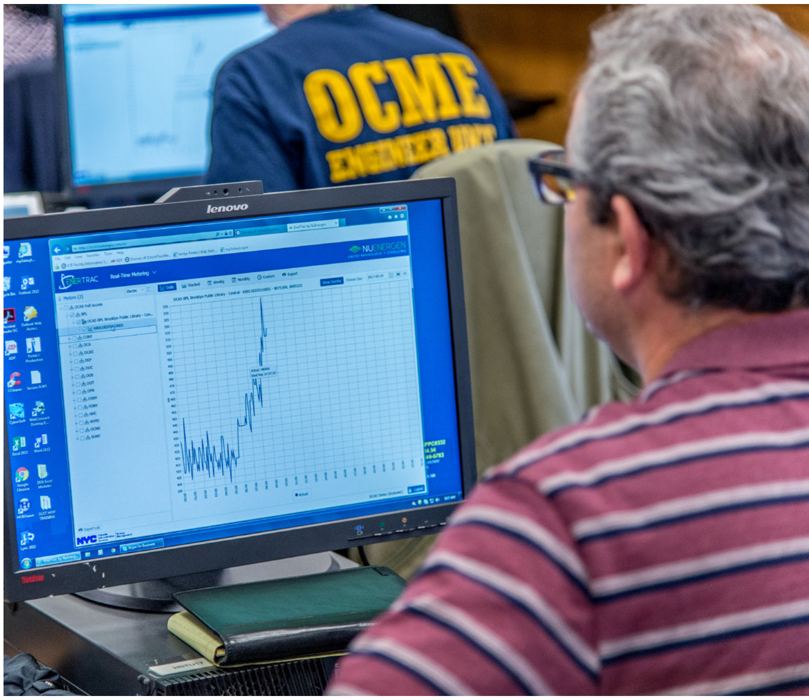
Strategic Guide to Deploying Energy Storage in NYC

Enhancing Renewable Energy, Resiliency, and Reliability

Prepared by the Department of Citywide Administrative Services in compliance with Local Law 181 of 2019.



NYC
DCAS
Citywide Administrative Services

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Enhancing Renewable Energy, Resiliency, and Reliability

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Department of Citywide Administrative Services

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Report Developed by
New York Power Authority (NYPA) and National Renewable Energy Laboratory (NREL) for NYC Department of Citywide Administrative Services (DCAS)

About DCAS

The NYC Department of Citywide Administrative Services (DCAS) makes city government work for all New Yorkers. Our commitment to equity, effectiveness, and sustainability guides our work providing City agencies with the resources and support needed to succeed, including:

- Recruiting, hiring, and training City employees
- Managing 55 public buildings
- Acquiring, selling, and leasing City property
- Purchasing over $1 billion in goods and services for City agencies
- Overseeing the greenest municipal vehicle fleet in the country
- Leading the City's efforts to reduce carbon emissions from government operations

About DCAS Energy Management

The DCAS Division of Energy Management leads the City's energy conservation and sustainability efforts. It oversees more than 10,000 utility accounts for city government agencies across 4,000 public buildings. It implements creative solutions to reduce energy consumption, promote energy efficiency in public buildings, and to generate clean energy on City-owned properties.

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Executive Summary

Local Law 181 of 2019 (LL181) requires the City of New York to conduct a feasibility study on the applicability of different types of utility-scale energy storage systems (ESS) on City buildings and to install such systems on those buildings where cost effective.[1] NYC's Department of Citywide Administrative Services (DCAS) has partnered with the New York Power Authority (NYPA) to perform this feasibility study.

This study aims to achieve the objective of LL181 by evaluating ESS technologies of variable size for applications both in front of the meter (FOTM)[2] and behind the meter (BTM). These applications will consist of distribution-scale ESS capped at a power rating of 5 megawatts (MW), which connect to the local utility rather than the bulk electric system, although these systems can still support the bulk electric system through wholesale market participation.

This study assesses the utility of these different ESS technologies and their applicability for various City-owned building types, based on current regulatory and market conditions, and identifies the optimal technology to meet varying objectives. Opportunities for the City to pursue large-scale energy storage applications are also covered in the Bulk Energy Services section of this study.

While LL181 does not define *utility-scale*, the electrical industry often interchanges *utility-scale* with the terms *large-scale* and *grid-scale*.[3] The U.S. Energy Information Administration defines *large-scale* as systems that are grid connected and have a nameplate power capacity greater than 1 MW.[4] LL181 also seeks information on building energy savings associated with the installation of utility-scale ESS. However, because utility-scale ESS are typically connected FOTM—to the bulk electric system at the transmission level, to distribution networks, or to power generation assets—utility-scale ESS are not generally designed to provide energy savings to particular buildings.

Additionally, the purposes of utility-scale ESS are typically: (i) providing frequency

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[1] Cost effective is defined in the Law as having cumulative savings in energy costs within 15 years of installation equal to or greater than the sum of expected costs for acquisition, installation, and maintenance minus the social cost of carbon as provided in paragraphs three and four of subdivision d of section 3-125. No federal, state or other non-city governmental assistance shall be included in the savings calculation.

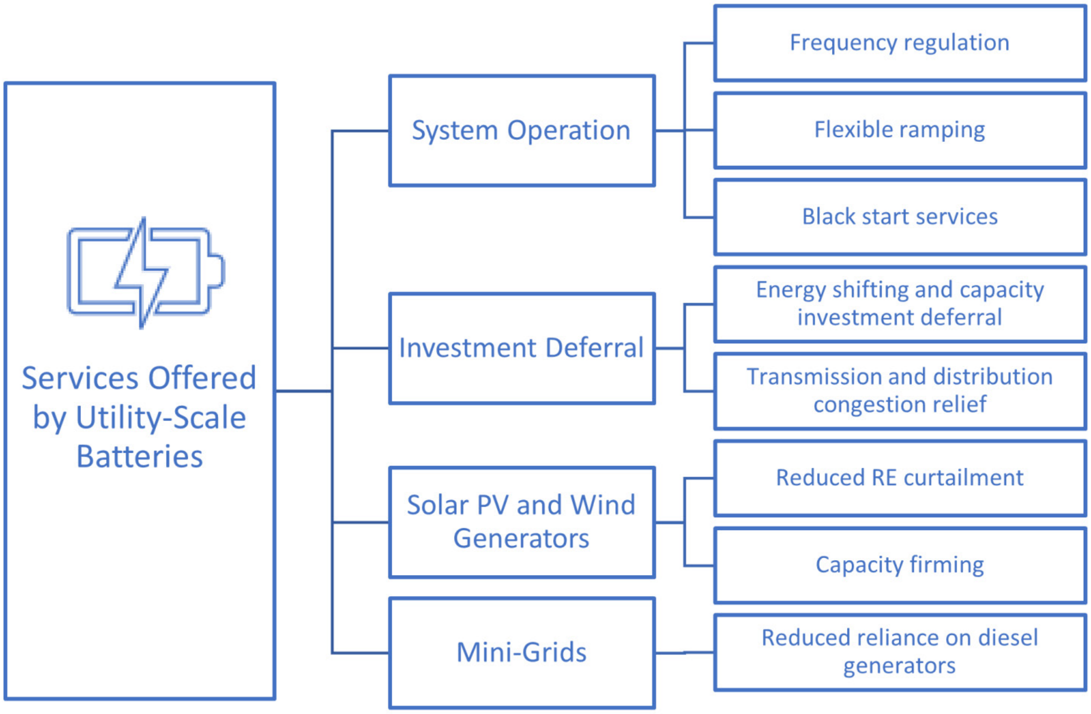
[2] *In front of the meter* means it is connected directly to the utility-owned distribution or transmission grid, and any power the customer feeds to the storage, or draws from it must pass through the customer's meter. This contrasts with *behind the meter* ESS where it is connected directly to the customer's facility, which can use the storage without electricity flowing through the meter.

[3] International Renewable Energy Agency (IRENA). 2019. *Innovation Landscape Brief: Utility-scale batteries*.

[4] U.S. Energy Information Administration. 2021. *Battery Storage in the United States: An Update on Market Trends*.

regulation, flexible ramping, or black start services to the bulk power system; (ii) transmission and distribution congestion relief; (iii) energy shifting and capacity investment deferral; (iv) reducing renewable generation curtailment or firming variable production renewable energy generation; and (v) supplying cleaner, more reliable energy to off-grid communities that might otherwise rely on diesel generation. To provide these benefits to the grid at adequate scale, such systems tend to be larger in capacity (10 MW or greater)[5] than is almost ever needed by an individual NYC facility, and larger in footprint than could almost ever be found within the City.

Figure 1: Services offered by utility-scale energy storage systems



BTM systems are interconnected behind the utility meter (i.e., the customer side) of a commercial, industrial, or residential customer, primarily aimed at electricity bill savings through demand-side management and serving load during brief power interruption events.[6]

This study approaches ESS based on the use case or application, either to (i) support the facilities where these systems can be installed (i.e., BTM) or (ii) to support the utility's distribution grid (i.e., FOTM). Financial sensitivity analysis was then performed based on the system sizes practical for each facility type, application,

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[5] International Renewable Energy Agency (IRENA). 2019. *Innovation Landscape Brief: Utility-scale batteries*.

[6] Energy Storage Association. 2018. *A Beginner's Guide to Energy Storage*.

and market policy and conditions (including incentives available or anticipated to be available). Additionally, the study details the qualitative feasibility and cost effectiveness of using ESS for resiliency purposes. Lastly, the study summarizes the scalability of system capacity that can be achieved under the different scenarios assessed, including both economic and environmental benefits for each.

In summary, this study finds that ESS currently have limited potential for cost-effective installation at City facilities. This result is due in part to sparse availability of data regarding small ESS at such facilities in NYC – granular analysis must be performed at each City site to better understand the viability of these systems. In general, BTM applications are shown to be quite limited, while larger FOTM applications are likely to be cost-effective with the adoption of an exemption from contract demand charges for energy export onto the grid.

Technology Overview

Energy storage is transforming the energy sector through its ability to support renewable energy and reduce grid reliance on carbon-intensive resources. By storing excess energy during demand lulls and discharging it as electricity during demand peaks, energy storage may cost-effectively lower consumers' utility bills, relieve stress on the grid, lower carbon emissions, and provide resilient power. There are many forms of energy storage, each with its own costs, challenges, and benefits.

The following section describes a high-level summary of various energy storage technologies. These are classified into four categories – mechanical storage, electrical storage, thermal storage, and electrochemical storage. Figure 2 shows several energy storage technologies and their suitability for distributed applications including pairing with distributed solar photovoltaic (DPV) power generation. This figure is not a comprehensive list of all existing and emerging storage technologies.[7] Table 1 expands on the storage technologies' characteristics (e.g., discharge cycle, efficiency, energy density, etc.) introduced in Figure 2.

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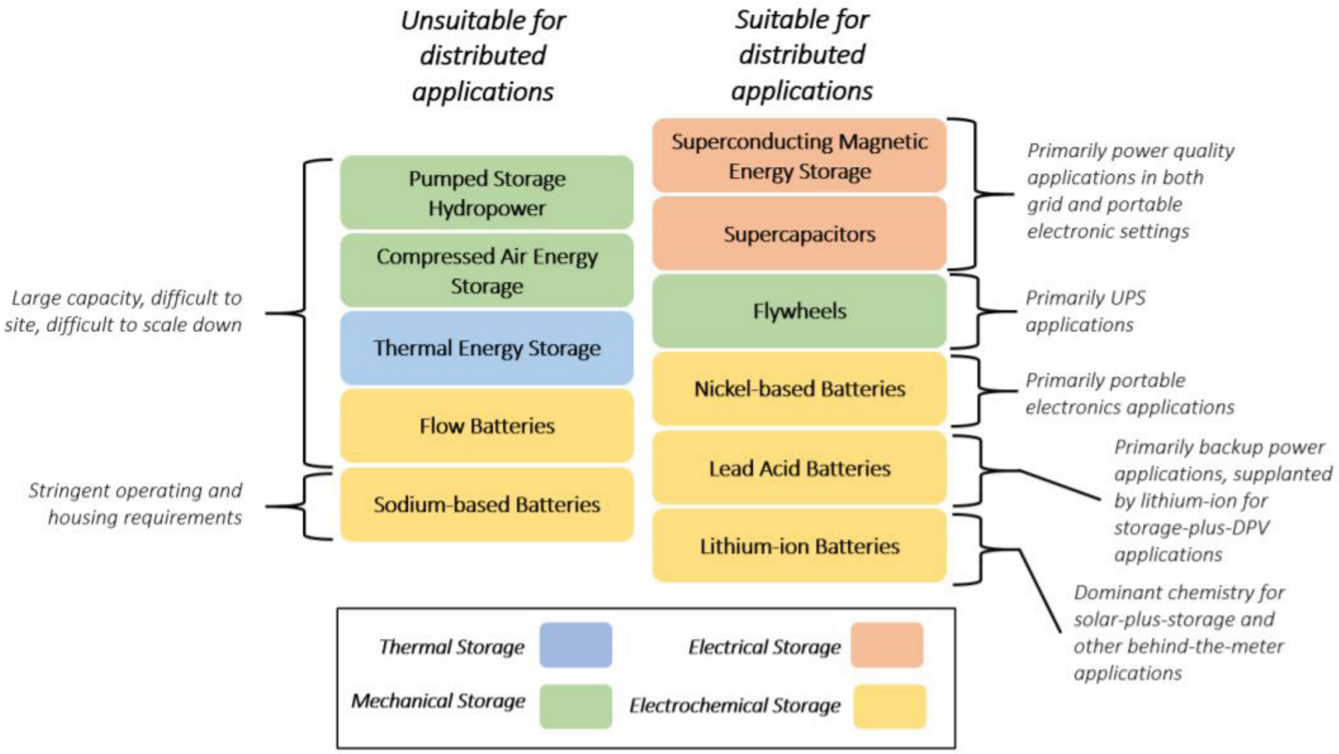
[7] Zinaman, Owen, Thomas Bowen, and Alexandra Aznar. NREL. 2020. *An Overview of Behind-the meter Solar-Plus-Storage Program Design: With Considerations for India*.

Figure 2: Energy Storage Technologies and Applications



Mechanical Storage

Pumped Hydro

Pumped Hydro uses electricity to pump water from one reservoir to another at different elevations. As Figure 3 shows, the process pumps water from a lower elevation reservoir to a higher-elevation reservoir when demand is low. Then, when demand is high, it releases water from the higher elevation reservoir to the lower elevation reservoir, which generates electricity by passing through turbines along the way. This technology currently accounts for 95% of all utility-scale energy storage in the United States (U.S.).[8] Pumped hydro can be categorized as *open loop*, if directly and continuously connected to a water body, or *closed loop*, if the reservoirs are not connected to an outside body of water. As shown in Figure 3, pumped storage is unlikely to be suitable in an urban setting such as NYC due to its siting and scale constraints. While it is possible to site pumped storage outside the city, the power generated would need to be connected to the city through transmission lines. Existing transmission into the city is already constrained, so such a development would likely require new transmission infrastructure. This would be a major undertaking, and due to the complexities of land acquisition, potential environmental impacts, cost, and time, further consideration of this technology is beyond the scope of this study.

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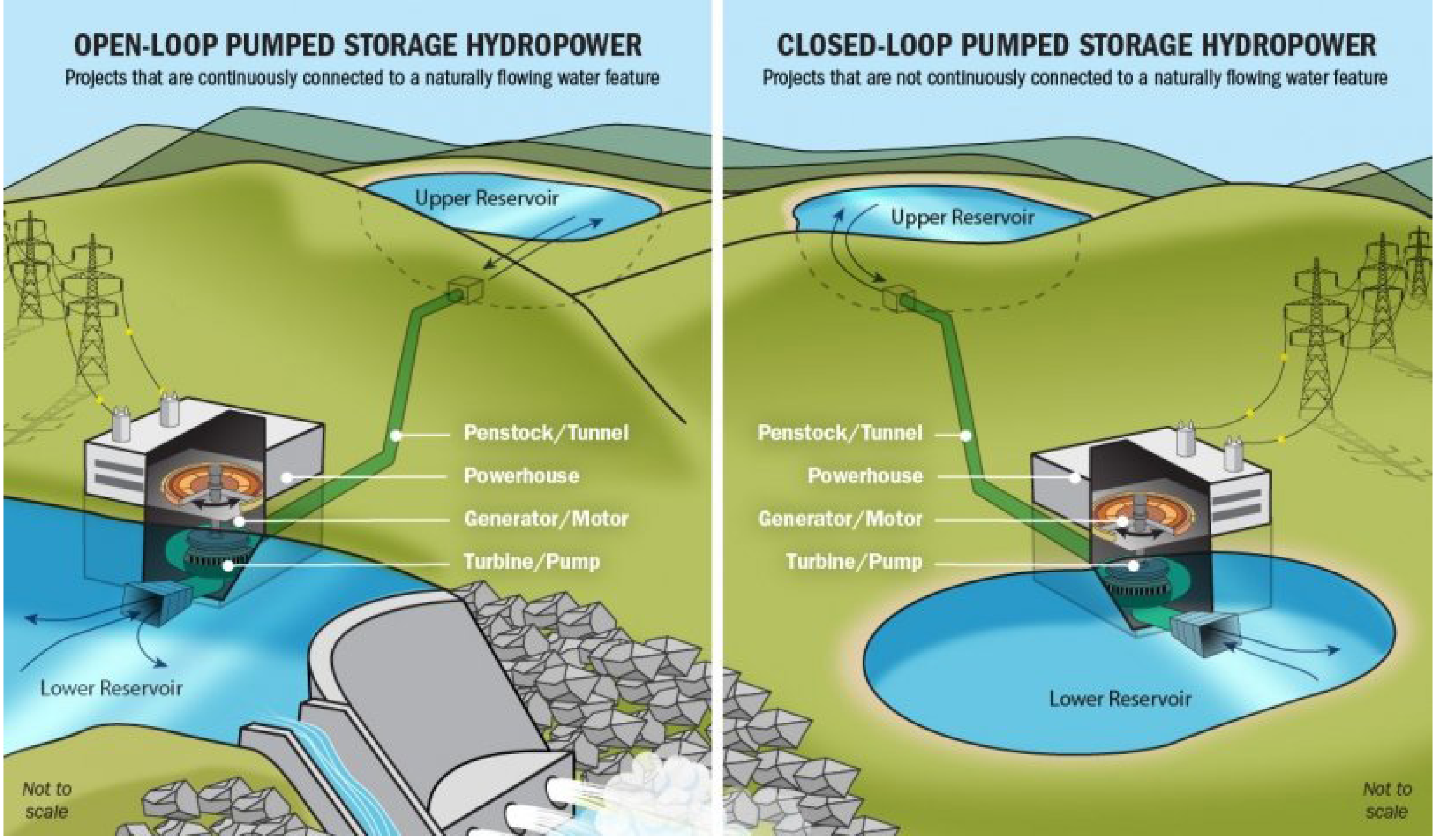
[8] U.S. Department of Energy. *Pumped Storage Hydropower*. Accessed 1 September 2021.

Figure 3: Open and Closed Loop Pumped Hydro Storage[8]



Compressed Air Energy Storage

Compressed air ESS use electricity to store air in a reservoir, either in underground caverns or in above-ground containers. As Figure 4 shows, the compressed air can then later be directed through a turbine to generate electricity during high peak demand times. Such systems require significant scale, and therefore land area, to be practical, making them better suited to grid-scale installations outside of urban areas. Additionally, compressed air energy storage is still an emerging technology – development has been largely limited to pilot projects, and the technology has not yet reached broad commercial viability.[9] Due to these siting and viability challenges, the technology is not currently suitable for deployment in NYC, and therefore is not further considered in this study.

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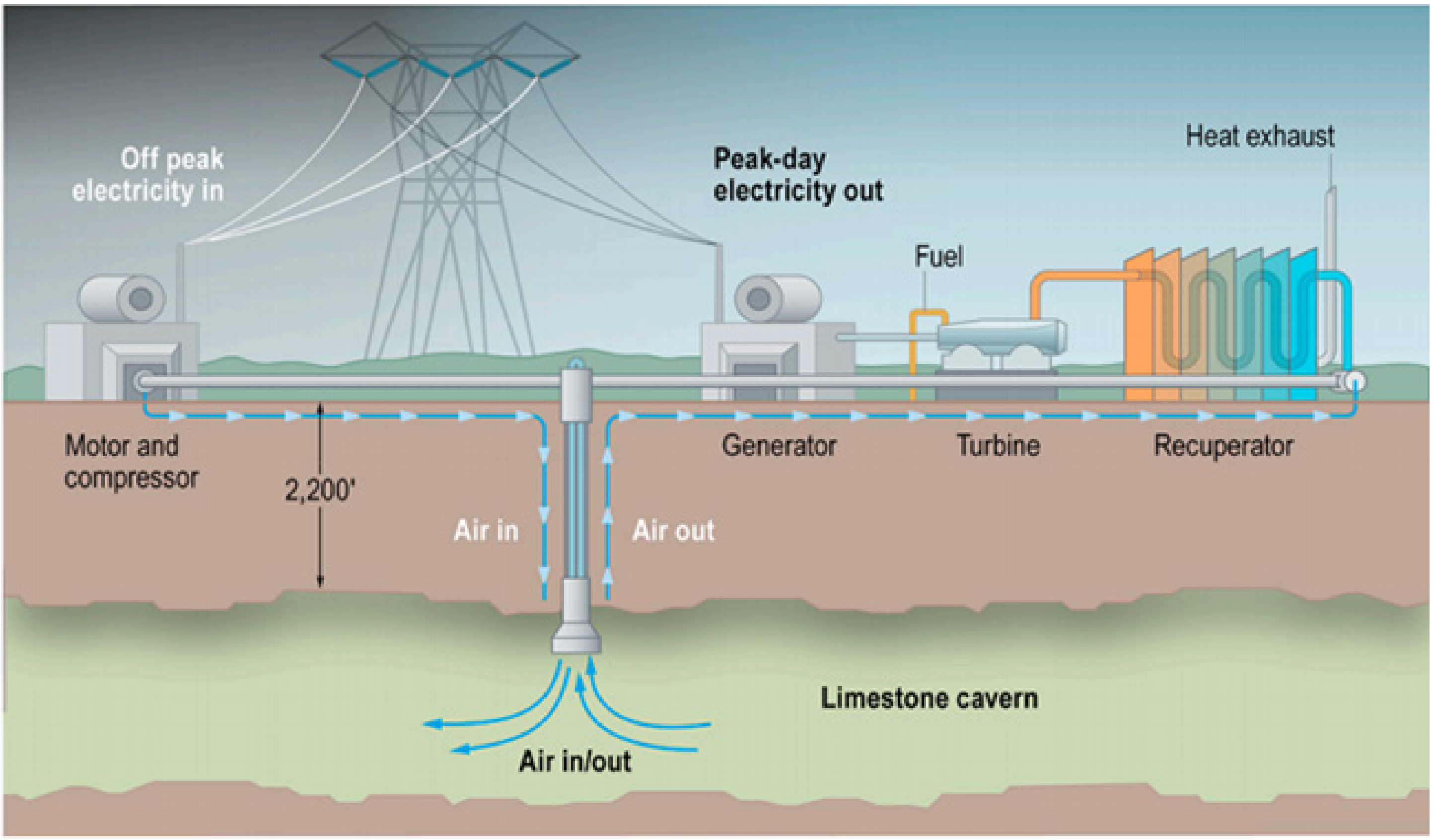
[9] Research and modeling does exist for residential and above-ground applications, but these are still in very early stages, and there have been no known pilots so far.

Figure 4: Illustration of Compressed Air Energy Storage System[10]



Flywheels

Flywheels use electricity to accelerate a rotor in a frictionless enclosure. Due to the lack of friction, the rotor continues to spin after acceleration, effectively storing kinetic energy. This stored energy can later be discharged by using the rotor to drive a generator, producing electricity. Mechanical storage technologies are typically utilized in large-scale, front of the meter (FOTM) projects, however flywheels may also be used behind the meter (BTM) in certain critical infrastructure settings, such as providing uninterruptible power.[7] Despite their potentially useful applications, flywheels are expensive and require a large footprint (as seen in Figure 5) due to low energy density, rendering them unsuitable for implementation in NYC.

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[10] NREL. 2012. *Renewable Electricity Generation and Storage Technologies. Vol 2. of Renewable Electricity Futures Study*.

Figure 5: Flywheel Energy Storage Technology[11]

Electrical Storage

Most electrical ESS can store energy for long periods but can only discharge at their full capacity for very short durations (i.e., seconds or minutes). These storage systems are in an early phase of development and have seen limited deployment in the power sector due to their short discharge duration and high cost.[12]

Superconducting Magnetic Storage

Superconducting Magnetic Storage systems store electricity in the magnetic field of a superconducting coil with low or nearly zero loss when a DC current is passed through the coil. This technology has an instantaneous dynamic response and a nearly infinite life cycle. Within these systems, electricity can be discharged by connecting an AC power converter.[13] Magnetic storage systems are not suitable for implementation in NYC because they are currently limited to power quality applications, require too large a footprint as seen in Figure 6, and have yet to reach market maturity.

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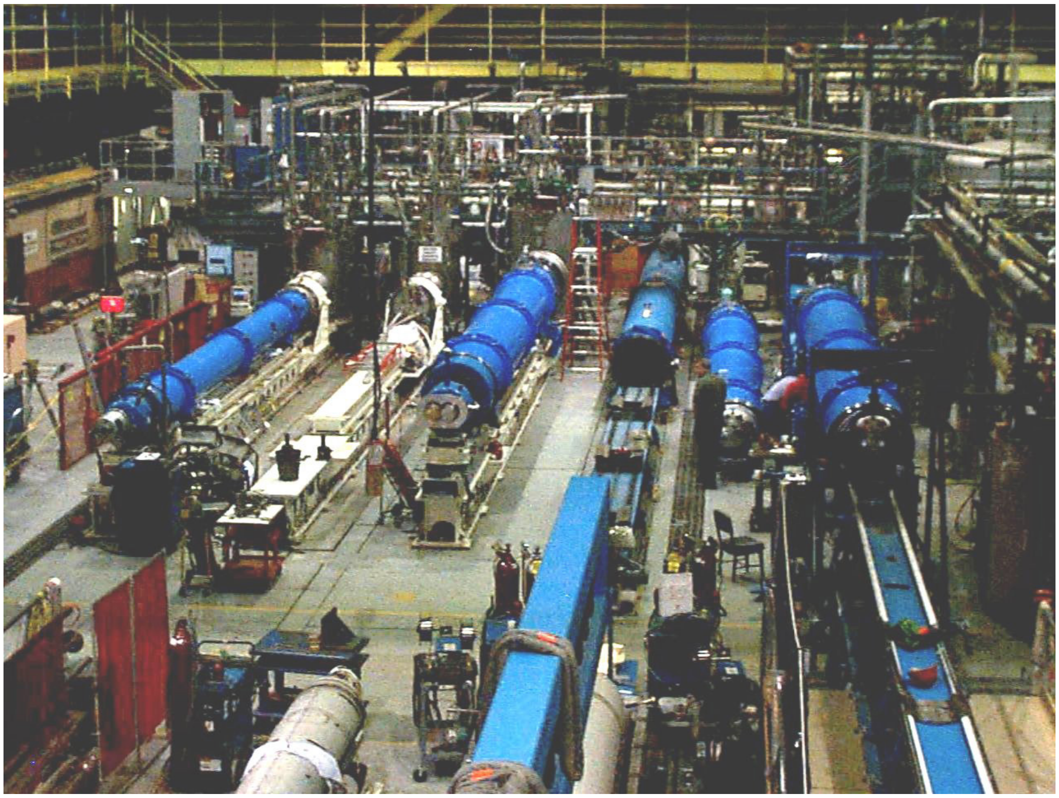
[11] Graff, Steve. U.S. Department of Energy. 2010. *'Recycling' Grid Energy with Flywheel Technology*. Accessed 1 September 2021.

[12] Akhil, Abbas, Georgianne Huff, Aileen Currier, Benjamin Kaun, Dan Rastler, Stella Bingqing Chen, Andrew Cotter, Dale Bradshaw, and William Gauntlett. Sandia National Laboratory. 2013. *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA*.

[13] Johnson, Samuel C., F. Todd Davidson, Joshua D. Rhodes, Justin L. Coleman, Shannon M. Bragg-Sitton, Eric J. Dufek, and Michael E. Webber. 2019. *Selecting Favorable Energy Storage Technologies for Nuclear Power, Chapter 5 of Storage and Hybridization of Nuclear Energy.*

Figure 6: Superconducting Magnetic Energy Storage[14]



Supercapacitors

Supercapacitors, also known as ultracapacitors, allow electrical energy to be stored as a charge in their electric field for extremely short durations, making them suitable for power quality applications. They have high power density but low energy density and are therefore not useful for bulk storage needs.[15] Given their high cost, low applicability, and low market maturity, supercapacitors are not currently practical for implementation in NYC.

Thermal Storage

Thermal storage stores energy by raising or lowering the temperature of a material, or by inducing a phase change in the material. Based on the size of the system, thermal energy can be stored in this material in timescales of hours to seasons. It can also be used for heating or cooling, or to generate electricity by creating steam. Thermal storage can be implemented using a range of technologies and approaches, perhaps most commonly as thermal tank ESS when paired with concentrated solar power as shown in Figure 7. Other common forms are building thermal storage (as shown in Figure 8) and pumped thermal energy storage (*Carnot* batteries).

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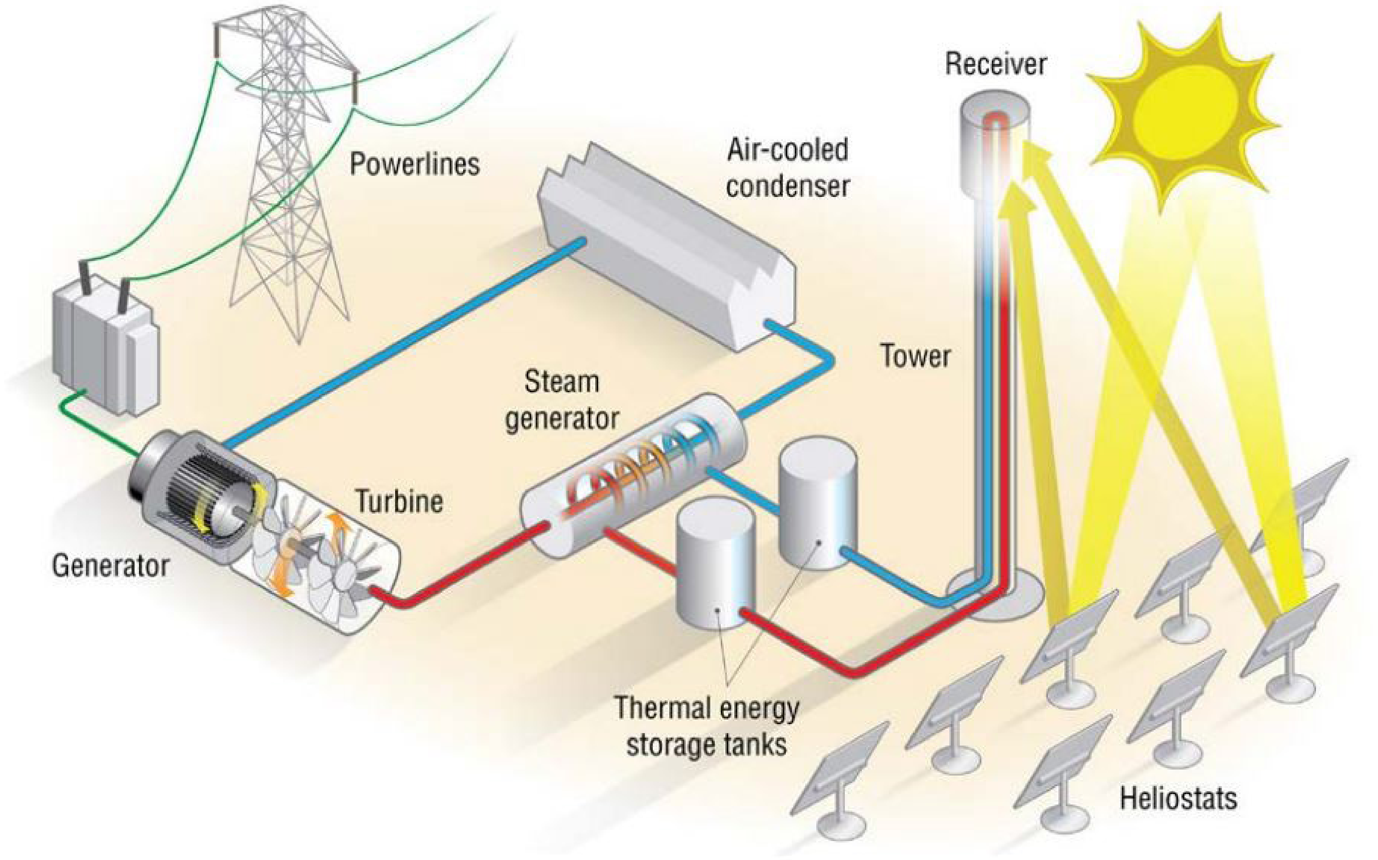
[14] United Nations Climate Technology Centre & Network. *Superconducting Magnetic Energy Storage*. Accessed 1 September 2021.

[15] World Energy Council. 2020. *Five Steps to Energy Storage: Innovation Insights Brief*.

Thermal tank ESS (Figure 7) have low volumetric energy density and thus require large capacities to be economic. In fact, the smaller the system is, the more it suffers from heat loss and an inability to store heat over long periods, so its effectiveness is diminished for urban grid-scale applications where space is limited.[16]

Figure 7: Illustration of Concentrated Solar Power with Thermal Tank Energy Storage[17]



On the other hand, ice thermal ESS for buildings (Figure 8) have higher energy density (and thus lower space requirements) compared to thermal tank systems. Nonetheless, they are still much less energy-dense than lithium-ion batteries. Thus, considering ice thermal ESS space requirements and their high initial costs, limits their potential as a practical option in comparison to lithium-ion batteries in urban areas.[18]

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[16] U.K. Department for Business, Energy, & Industrial Strategy. 2016. *Evidence Gathering: Thermal Energy Storage (TES) Technologies*.

[17] Kearney, David. NREL. 2013. *Utility-Scale Power Tower Solar Systems: Performance Acceptance Test Guidelines*.

[18] Nemtzow, David, Karma Sawyer, Sven Mumme, and Nelson James. U.S. Department of Energy. 2020. *Thermal Energy Storage Webinar Series: Ice Thermal Energy Storage*.

Figure 8: Trane® Thermal Energy Storage, Jefferson Community College, Watertown, NY[19]

Electrochemical Storage

Batteries come in various chemistries, each with different characteristics. Most relevant to this study are lithium-ion and lead acid chemistries, each of which include multiple sub-chemistries. Lithium-ion and lead acid batteries contain the same basic active elements in each cell – a cathode, an anode, and an electrolyte. Electric current travels between the cathode and anode through the electrolyte, with the direction of current depending on whether the cell is charging or discharging.

There are several types of electrochemical storage, each with a different chemistry and level of market maturity. These include lead acid, lithium-ion, flow, sodium-based, and nickel-based batteries. Lithium-ion chemistries are increasingly the batteries of choice across energy storage applications, due primarily to their declining costs and high energy density. As a result, as shown in Figure 9, lithium-ion batteries have scaling flexibility which enables them to serve both grid-scale and distributed applications. While flow batteries can support certain distribution

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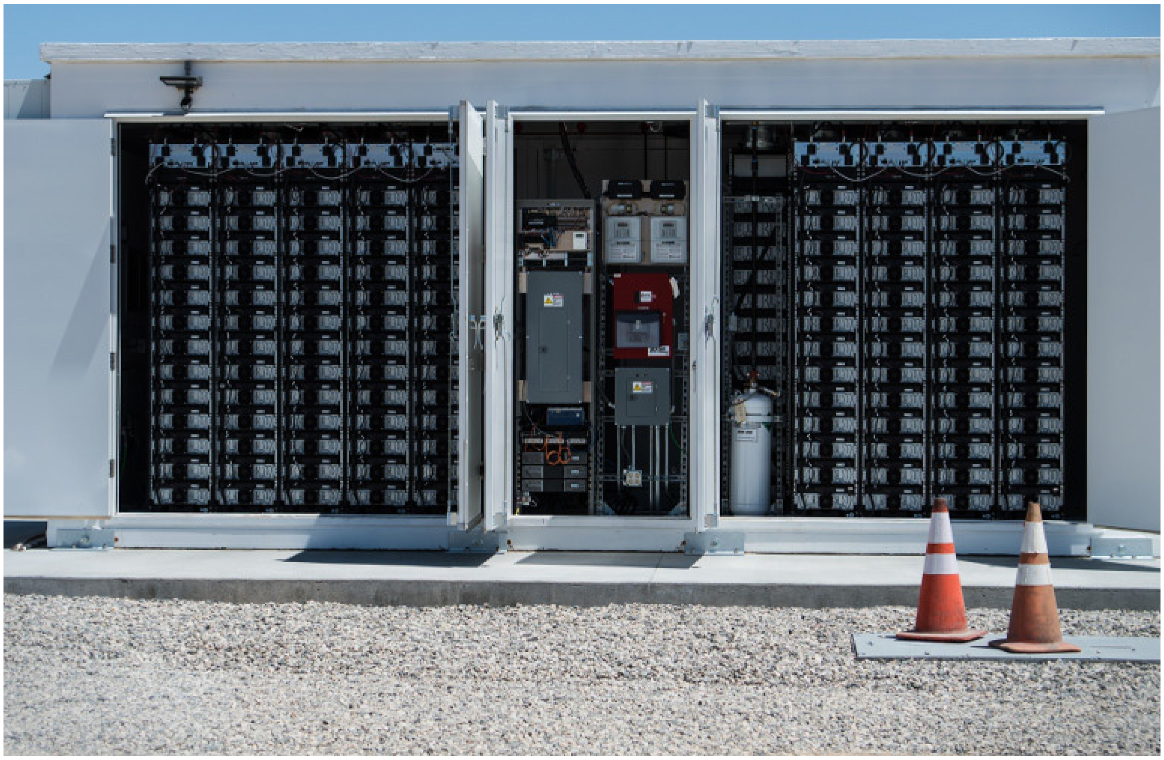
[19] Deru, Michael, Miles Hayes, Mark MacCracken, and Karl Heine. 2019. *Space Conditional Tech Team Webinar: Thermal Energy Storage, the Lowest Cost Storage*.

grid applications, their poor energy density, large footprint, and high costs compared to other mature technologies (such as lithium-ion) make flow batteries less desirable for distributed applications.

Compared to lithium-ion, all other batteries are less energy-dense, more expensive, and provide on-par or limited distributed energy service applications.

Figure 9: Picture of Lithium-ion Batteries stacked into BESS[20]



ESS Technology Comparison

Table 1 compares the characteristics of the different ESS technologies discussed in this section. The data in Table 1 shows why Battery Energy Storage System (BESS) technology, and specifically lithium-ion BESS, were chosen for the focus of analysis in this study: it is currently the least expensive technology with the largest market penetration and smallest footprint, making it most suitable for dense urban environments such as NYC.

Until very recently, cobalt-based chemistries dominated the Lithium-ion BESS market, as they feature the greatest energy density and cost-effectiveness. However, the market is increasingly shifting its focus to Lithium Ferrous Phosphate (LFP) alternatives. LFP is a sub-category of lithium-ion BESS that sacrifices some of cobalt BESS' energy density for improved thermal stability. This makes LFP more fire-safe and therefore preferred by permitting authorities, while remaining energy-dense and cost-effective compared to non-lithium BESS chemistries. Additionally, because LFP does not require cobalt, it bypasses significant human rights concerns regarding cobalt mining.

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[20] Pickerel, Kelly. Solar Power World. 2021. [DOE Sets Sights on Domestic Lithium Battery Manufacturing, Pledges $200 Million Toward Development](#).

Table 1: Summary of Technology Characteristics[21]

Technology Type	Sub Type	Efficiency	Dis-charge Time	Charge Time	Life-time (Years)	Volumetric Energy Density[22] (Wh/L)	Applications [23,36]	Technology cost relative to Li-ion system	Market Maturity	Recommended for NYC
Electrochemical Batteries	Lithium-Ion (Cobalt-Based)	85 – 95%	min – hr	hr – months	5 – 15	200-350	• Bulk energy services • Ancillary services • Customer Energy Management Applications	Baseline	High	Yes
	Lithium Ferrous Phosphate	85 – 95%	min – hr	hr – months	5 – 15	220-250		Baseline	High	Yes
	Flow	60 – 85%	hr	min – days	5 – 15	20-70		High	Medium	No
	Sodium-Based	75 – 90%	sec – hr	sec – hr	10 – 15	40		High	Medium	Yes
	Nickel-Based	60 – 80%	hr	sec – hr	10 – 20	30-150		Low	High	Yes
	Lead Acid	80 – 90%	min – hr	hr – day	3 – 12	50-80		High	High	No
Thermal Energy Storage		80 – 90%	min – hr	hr – months	30	70-210	• Bulk energy services • Customer Energy Management Applications	Medium	Medium	Yes (Geo dependent - Unlikely in dense urban areas)
Mechanical Storage	Pumped Hydropower	75 – 85%	1 – 24 hrs +	hr – months	40-60	0.2-2	• Bulk Energy Services • Ancillary Services	Medium	High	
	Compressed Air	70 – 89%	1 – 24 hrs +	hr – months	20 – 40	2-6	• Ancillary Services	Low	Medium	
	Flywheels	85 – 95%	ms – 15 mins	s – min	15 +	20-80	• Ancillary Services • Customer Energy Management Applications	High	High	No
Electrical Storage	Superconducting Magnetic Storage	95 – 98%	ms – 8s	min – hr	20 +	1-15	• Customer Energy Management Applications	High	Low	No
	Supercapacitors	90 – 95%	ms – 60 min	s – hr	10 – 15	1-35		High	Low	No

Sources:[24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35]

[21] Metrics listed in the table can help inform battery selection, but no single metric can fully determine a technology's suitability for a specific application.

[22] In this analysis, volumetric energy density is defined as the energy storage potential relative to the space the technology takes up. Volumetric energy density is a subset of energy density, and it is positively correlated with power density. Currently, Li-Ion batteries have higher energy and power density than all other technologies listed.

[23] Technology applications are classified into 3 categories. Bulk Energy Services, Ancillary Services, and Customer Energy Management Applications. More information of the applications can be found in Applications of Energy Storage Section below.

[24] World Energy Council. 2020. *Five Steps to Energy Storage: Innovation Insights Brief*.

[25] Mongird, Kendall, Vilayanur Viswanathan, Jan Alam, Charlie Vartanian, Vincent Sprenkle, and Richard Baxter. U.S. Department of Energy. 2020. *2020 Grid Energy Storage Technology Cost and Performance Assessment. Energy*.

[26] Luo, Xing. Jihong Wang, Mark Dooner, and Jonathan Clark. 2015. *Overview of Current Development in Electrical Energy Storage Technologies and the Application Potential in Power System Operation*.

[27] U.S. Department of Energy. 2020. *Electricity Storage Technology Review*.

[28] Mongird, Kendall, Vilayanur Viswanathan, Patrick Balducci, Jan Alam, Vanshika Fotedar, Vladimir Koritarov, and Boualem Hadjerioua. U.S. Department of Energy. 2019. *Energy Storage Technology and Cost Characterization Report*.

[29] U.S. Department of Energy. 2020. *Potential Benefits of High-Power, High-Capacity Batteries*.

[30] Bernard, Patrick and Michael Lippert. 2014. *Chapter 14: Nickel–Cadmium and Nickel–Metal Hydride Battery Energy Storage in Electrochemical Energy Storage for Renewable Sources and Grid Balancing*.

[31] Revankar, Shripad T. 2018. *Chapter 6: Chemical Energy Storage in Storage and Hybridization of Nuclear Energy*.

[32] Hart, David M., William B. Bonvillian, and Nathaniel Austin. Massachusetts Institute of Technology Energy Initiative. 2018. *Energy Storage for the Grid: Policy Options for Sustaining Innovation*.

[33] Bowen, Thomas, Ilya Chernyakhovskiy, Kaifeng Xu, Sika Gadzanku, Kamyria Coney. NREL and United States Agency for International Development (USAID). 2021. *USAID Grid-Scale Energy Storage Technologies Primer*.

[34] Zablocki, Alexandra. Environmental and Energy Study Institute. 2019. *Fact Sheet | Energy Storage (2019).* Accessed 1 September 2021.

[35] Sabihuddin, Siraj, Aristides E. Kiprakis and Markus Mueller. 2014. *A Numerical and Graphical Review of Energy Storage Technologies*.

Market & Policy Summary

Goals

Deployment of energy storage across the U.S. has increased significantly in the past decade, mostly driven by individual state and local government policies to support acceleration of renewable energy resources for a more robust, reliable, and resilient grid. In the third quarter of 2020, the U.S. deployed more than twice the energy storage capacity than it had in the previous quarter. Nonetheless, energy storage accounts for only about 2% of total U.S. energy capacity.[36] FOTM systems have driven the bulk of this growth in installed ESS capacity.

Under the Climate Leadership and Community Protection Act (CLCPA) passed in 2019, New York State (the State) established an ambitious goal for energy storage of 3 gigawatts by 2030. With a myriad of applications and benefits, this target is critical for the grid and enables greater integration of renewable energy technologies, such as solar photovoltaic (PV) and wind. Through the CLCPA and the Clean Energy Standard, the State has created a set of policies and requirements for utilities to procure ESS. Under this mandate, ConEdison (ConEd) is required to procure 300 MW of ESS by the end of 2022. 100 MW is already in the pipeline, with at least another 200 MW to be procured via ConEd's 2021 Bulk Energy Storage RFP.

NYC leads by example in achieving a cleaner future. The City has set aggressive climate change mitigation goals, aiming to be carbon neutral by 2050. It has taken on several initiatives to achieve this goal, including seeking to install 100 MW of solar PV at City-owned facilities by 2025. In addition, the City has set a citywide ESS deployment target of 500 MW by 2025.

Wholesale Market

The New York Independent System Operator (NYISO) is actively working on developing rules to open its wholesale energy markets to ESS. These market rules are being developed to allow ESS to fully participate in its wholesale markets, regardless of whether they are deployed as standalone systems or paired with renewable energy resources (hybrid or co-located systems). This potentially enables greater deployment of ESS in New York state as it creates new revenue streams and thus reduces risk to ESS project investors. These rules are being developed per the Federal Energy Regulatory Commission's (FERC) order 841 requiring regional transmission operators and independent system operators, such as NYISO, to remove barriers for ESS to participate in the energy, capacity, and ancillary services markets operated by such entities.

Secondly, in compliance with FERC Order 2222, NYISO is developing rules that will enable aggregated distributed energy resources (DERs), including distributed ESS, to participate in the same wholesale

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[36] Wood Mackenzie. 2021. *US Energy Storage Monitor: 2020 Year in Review*.

markets. This will create a level playing field among both traditional large energy resources and DERs, thus allowing ESS/ DERs project investors to maximize value while minimizing risk.

Furthermore, FERC is reviewing and regulating NYISO filings on rules associated with various orders to ensure any ESS resources that qualify as special case resources and offer demand response (DR) opportunities are valued accurately for their price offer to participate in such markets. This makes it more feasible for such resources to pass any tests that NYISO determines are needed to mitigate potential market price manipulation attempts. Simply put, the most recent FERC ruling allows DERs like ESS to benefit from both distribution level and wholesale or bulk-scale DR programs.

Wholesale market rules are constantly evolving, with input from market participants and other stakeholders. This ensures developed rules are clear and transparent and into the future it will create opportunities for resources to benefit from both distributed and wholesale markets and support New York state to achieve its aggressive energy storage targets.

Incentives

Federal

Investment Tax Credits

Under current U.S. policy ESS qualify for the federal Investment Tax Credit (ITC) when integrated with an eligible PV system. A new bill, *Energy Storage Tax Incentive and Deployment Act*, was introduced in March 2021 for standalone ESS and offers similar tax credit benefits for certain renewable energy sources. The storage industry anticipates this to be passed into law in 2022, and that it will apply to projects that achieved commercial operation after December 31, 2020, reducing the risks and uncertainty in energy storage project economics.

State

Bulk Energy Storage Incentives

To help accelerate deployment of ESS that participate in wholesale markets and support the bulk energy system, the State offers incentives at a fixed dollar per kilowatt hour ($ per kWh) of installed storage capacity. These incentives decline each calendar year and are set at $90 per kWh for year 2021. Bulk energy storage incentives are applicable to ESS projects between 5 and 20 MW in capacity and are available through the New York State Energy Research and Development Authority (NYSERDA).

Retail Energy Storage Incentives

Similar to the bulk energy storage incentives, NYSERDA incentivizes commercial scale ESS projects that are either standalone, grid-connected, or paired with new or existing clean DERs. Retail storage incentives are available to projects no greater than 5 MW in capacity and up to 15 megawatt hours (MWh), or for a 3-hour duration system. The incentive value varies by region and there is currently no available incentive for NYC.

To qualify for the state-offered incentives, whether bulk or retail, a customer must contribute to the *Systems Benefit Charge* (SBC) within its investor-owned utility territory. However, the City does not pay into the SBC and therefore cannot take advantage of any benefits the SBC might otherwise make available.

Value of Distributed Energy Resources

While not an incentive, the Value of Distributed Energy Resources (VDER) is a mechanism established by the New York Public Service Commission (PSC) designed to compensate DERs ESS for the benefits they provide to the utility grid. These values are calculated based on the price indices listed below, collectively referred to as the *Value Stack*:

- *Location Based Marginal Price (LBMP)* – Wholesale cost of energy.
- *Installed Capacity (ICAP)* – Averted costs of installed capacity.
- *Environmental Value (E)* – Clean Energy Standard Tier 1 Renewable Energy Credits or the Social Cost of Carbon, set by the PSC, whichever is greater.
- *Demand Reduction Value (DRV)* – Set based on the averted costs to the utility's marginal cost of service for the highest peak hours in a year.
- *Locational System Relief Value (LSRV)* – Set based on averted costs to the utility during the high peak hours in a congested area of service.

The largest drivers of Value Stack revenue for ESS are ICAP and DRV. The ICAP value fluctuates with the cost of wholesale power and varies by location. The DRV compensates for the benefit these systems provide to the distribution grid and is locked in for a period of 10 years. LSRV, while available only in limited areas of NYC, offers additional value to the project that significantly improves ESS project economics. The Environmental (E) value, which is currently fixed to the social cost of carbon set by the PSC ($27.41 per MWh), does not apply to ESS except for those paired with and charged by renewable energy resources.

New York State Real Property Tax Exemption

Section 487 of New York State's Real Property Tax Law offers a partial exemption, excluding the incremental increase in value for properties that install solar and other qualifying clean energy technologies, including ESS. Qualified projects receive this exemption for a period of 15 years. Although this benefit cannot be directly captured by City-owned projects, it may apply to third party owned (TPO) installations.

Local

New York City Solar and Energy Storage Property Tax Abatement

NYC offers property tax abatements to qualified building owners that install PV or ESS. The annual abatement for ESS is equal to the lesser of 10% of the system costs, or $62,500. This incentive is offered for a maximum period of four years and is scheduled to expire in 2024. However, the property tax exemptions do not apply to City-owned facilities and hence are not considered in evaluating the cost-effectiveness of ESS in this study.

Applications of Energy Storage

ESS are popular due to the numerous ways they offer operational flexibility to best suit the needs of a facility or the grid. These use cases or applications vary depending on system size, technology type, grid interconnecting mechanism, location, and integration with a renewable energy source, among other factors. The benefits of these applications vary depending on whether they are connected to the bulk energy system, local distribution system, or the onsite facility's electrical infrastructure.

Bulk Energy Services

At the bulk scale, ESS offer a wide range of potential services, including energy arbitrage, ancillary services such as voltage and frequency regulation, reserve capacity, black start capability, and other wholesale market services. In addition, they support the integration of intermittent renewable resources, such as PV and wind, by firming capacity to maintain the system output power at a set level. In other words, energy storage can reduce the intermittency and increase the dispatchability of renewable resources. As detailed in Tables 1 and 2, bulk ESS require large spaces, which are hard to find or very limited in an urban setting like NYC. Such systems may be considered for installing at large City-owned properties outside of the five boroughs or on a property such as Riker's Island. However, the limited incentives, along with lack of definite value streams, pose a challenge for bulk ESS to be economically practical under current market conditions. The only large scale ESS currently planned in New York state are a result of requests for proposals solicited by utilities such as Con Ed, per the state's mandates. ESS projects developed under such utility procurement solicitations offer a fixed revenue stream, lowering risk and making it an attractive opportunity for private developers and investors. For these reasons, this study does not further assess bulk scale ESS in NYC and focuses on distributed ESS that is more practical based on both physical space requirements and current market conditions.[37]

Demand Management

Demand management is the ability of a larger, demand-metered customer to lower the demand, or kilowatt (kW), portion of its electric bill. Such customers are billed both for the total volume of energy they consume (in kWh) and their monthly peak consumption (in kW). Utilities charge larger customers for peak kW in addition to total kWh because even brief moments of intense electric demand can stress the grid, requiring the rapid injection of additional supply. Demand charges are implemented to address the costs associated with the utility serving customers with peaky loads, and to offer an economic incentive

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[37] It should be noted that many of the energy storage services and benefits described above can be mutually exclusive, depending on system design and operation.

for customers to reduce their peaks. By charging from the grid when a customer's demand is low, and discharging when the customer's demand spikes, an ESS can help the facility meet its electricity needs while reducing its reliance on the grid to meet that demand.

Demand Response

The primary difference between demand management and demand response (DR) is that the former helps reduce the facility's peak demand, while the latter helps lower the utility's peak demand during specific events as called upon by the local utility. DR programs are also available in wholesale markets in which ESS can participate.

Con Edison in NYC has two DR programs currently in place: the Commercial System Relief Program and the Distribution Load Relief Program.

Commercial System Relief Program (CSRP)

Under CSRP, customers are given at least 21 hours of notice for their enrolled ESS to participate in the program. The value for CSRP participation varies by location and is paid in dollars per kWh for system performance.

Distribution Load Relief Program (DLRP)

With DLRP, customers are typically given a 2-hour notice for their enrolled ESS to participate in the program. The value for DLRP participation varies by location and is paid in dollars per kW per month based on the system capacity.

In addition to the distribution utility's program, ESS at customers' facilities can participate in wholesale markets' DR programs administered by the New York Independent System Operator (NYISO). The notification window and value for participation vary depending on the program.

Time-of-Day Rate Optimization

A customer on a time-of-day (TOD) rate schedule pays variable kWh charges, depending on the time of consumption. By leveraging an ESS to shift consumption to times with lower kWh pricing, a TOD customer can reduce its kWh charges, as well as its per kW demand charges. However, under 2% of the City's electricity accounts are TOD (94 of 5,411), so the potential for savings on TOD rate optimization is currently limited.

Con Edison Rider Q

An alternative to the TOD rate schedule is Rider Q. Con Edison created a tariff structure tailored for customers that are typically billed for demand charges and have onsite DERs. These customers can opt in to a more granular *standby* rate structure to manage their electricity bills more effectively. Under the standard demand tariff, the customer is charged for demand (dollar per kW) based on their highest consumption over the period of a month. Rider Q instead offers demand charges calculated daily. This offers flexibility to a customer that has ESS at its facilities to operate them for optimal economic value, without risking a missed peak load time that could significantly increase demand charges on its bills. The image below shows the difference between standard demand rate structure versus Rider Q.

Figure 10: ConEdison Rider Q[38]

Standard Demand-Billed Customer	Conventional Standby Rate or Rider Q Customer
1. Demand charge is a $/kW charge that is based on the customer's peak demand in a monthly billing period. • a. Some customers are billed based on a single month's peak. For others on a time- of-day rate, three charges are summed that are based on the highest peaks reached within three intervals during the month. • b. A single missed peak can result in a large increase in the bill for the entire month.	1. Demand charge is a $/kW charge calculated daily basis. The customer pays the sum of daily demand peaks in a monthly billing period. • Under the conventional standby rate, it is based on demand during Monday-Friday, 8 a.m.-10 p.m. in Con Ed's service territory. • Under Rider Q, option B (only available in Con Ed's territory), it is based on demand during the same time window as the conventional standby rate. However, the demand charges are significantly higher during an identified daily 4-hour peak window.
1. Flexibility to forego demand charge reduction on a particular day to pursue other value streams is limited.	Compensation can be optimized by electing to forego demand charge reduction (allowing a daily peak) to pursue other value streams (such as demand response), without potentially greatly increasing the entire month's bill.
A customer's load profile will have to be analyzed under each billing structure to determine the optimal business model. A thorough evaluation and understanding of the conventional standby rate and Rider Q is vital to successful value stacking, and thus providing the most value to customers.	

[38] New York Battery and Energy Storage Technology Consortium. NYSERDA. 2018. *Standby Rate + Con Ed Rider Q Fact Sheet*.

Utility Infrastructure Deferral

As demand grows, utilities are urged to make significant upgrades to existing grid infrastructure to accommodate the additional load. These upgrade projects involve high upfront capital investment. Utilities are seeking alternatives to the traditional, costly upgrade projects through *non-wire solutions*. *Non-wire solutions* solicitations encourage the deployment of DERs and ESS that are collectively capable of providing distribution or transmission system-level relief, as these deployments are frequently less expensive than utility infrastructure upgrades.

Table 2: Applications for Energy Storage and Associated System Requirements[39]

Grid Function		Typical System Size	System Dimensional Requirements	
Category	**Service**		**Needed Duration**	**Minimum Cycles/Year**
Bulk Energy Services	Electric energy time shift (arbitrage)	1 - 500 MW	<1 - 12 hours	> 250
	Electric supply capacity	1 - 500 MW	2 - 6 hours	5 - 100
Ancillary Services	Frequency regulation	10 - 40 MW	15 min - 1 hour	250 - 10,000
	Spinning, non-spinning, and supplemental reserves	10 - 100 MW	15 min - 1 hour	20 - 50
	Voltage support	1 - 10 mega volt-ampere reactive	Not applicable	Not applicable
	Black Start	5 - 50 MW	15 min - 1 hour	10 - 20
	Load Following/ Ramping support for renewables	1 - 100 MW	15 min - 1 hour	Varies widely
	Frequency response	> 20 MW	<1 minute	Varies widely

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[39] U.S. Department of Energy. 2020. *Potential Benefits of High-Power, High-Capacity Batteries*.

Grid Function		Typical System Size	System Dimensional Requirements	
Category	Service		Needed Duration	Minimum Cycles/Year
Transmission Infrastructure Applications	Transmission upgrade deferral	10 - 100+ MW	2 - 8 hours	10 - 50
	Transmission congestion relief	1 - 100+ MW	1 - 4 hours	50 - 100
Distribution Infrastructure Applications	Distribution upgrade deferral	500 kW - 10 MW	Varies widely	Varies widely
Customer Energy Management Applications	Power quality	100 kW - 10 MW	10 seconds - 15 minutes	10 - 200
	Power reliability	1 kW - 10 MW	Varies widely	Varies widely
	Retail energy time shift	1 kW - 1 MW	1 - 6 hours	50 - 250
	Demand charge management	50 kW - 10 MW	1 - 4 hours	50 - 500

Opportunity Assessment

This section focuses on assessing the feasibility of BESS for facility support applications or customer energy management applications connected BTM and grid support applications connected FOTM. It details the methodology used to process data provided by the City to identify facility types based on the functionality, electrical load profile, typical physical space available for installation of BESS, and specific facilities that are representative of each type. Identified representative facilities are assessed for various scenarios based on the application.

Facility Support Applications (BTM Systems)

Systems connected BTM to the facility's electrical infrastructure support its load first before exporting to the grid. In contrast, FOTM systems connect directly to, and support, the local distribution utility's grid.

Data

DCAS provided NYPA and NREL with a property database[40] and monthly meter

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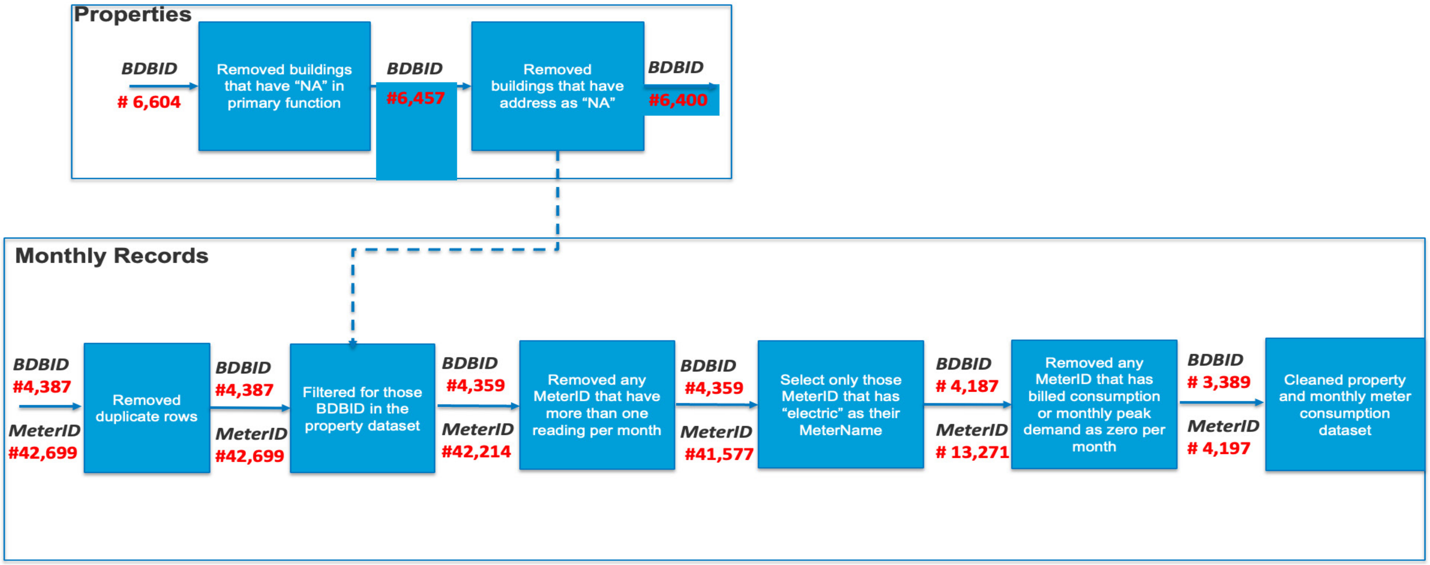
[40] This database excludes properties that are out of service, currently under construction, or not operated by city agencies.

consumption data for each property. The property dataset contained the general characteristics of the buildings including the name, address, facility function type, ownership, physical area, etc. The consumption data contained the monthly energy consumption and peak demand for years 2016 through 2020. Each building had several meters. The meters were classified in meter types based on fuel source (e.g., electricity, natural gas, fuel oil, kerosene, diesel, district stream, and liquid propane).

Data Cleaning

Figure 11 shows the methodology used for cleaning the data sets. BDBID refers to a unique identifier for each property. MeterID refers to a unique identifier for each meter associated with the property. Each BDBID can have multiple MeterIDs for different fuel sources. For example, for one BDBID, there could be a separate MeterID for each of the electric and natural gas meters. Facilities that may have more than one building as a complex, may have multiple meters for the same fuel source. The two data sets comprised 6,604 BDBIDs and 42,699 MeterIDs, which were cleaned to remove incomplete or unclear data and then matched using other cross-referencing data sets.

Figure 11: Data-Cleaning Procedure



Step 1: The raw property database had 6,604 buildings, each with its own BDBID. Two data filters were applied to this raw dataset – first, to remove buildings that had no primary function (or building type) listed, and second, to remove BDBIDs with blank addresses. After applying these two filters, the database was reduced to 6,400 BDBIDs.

Step 2: The next step was to clean the monthly meter consumption dataset. The raw dataset had 4,387 BDBIDs and 42,699 MeterIDs. After inspecting the dataset, it was found that no duplicate values existed.

Step 3: Next, the BDBIDs from the property database and the monthly meter consumption dataset were matched, and any BDBIDs not present in both datasets were removed, resulting in 4,359 BDBIDs and 42,214 MeterIDs. Then, MeterIDs with multiple readings per month were removed, which reduced the count to 41,577 MeterIDs; there was no change in the BDBID count.

Step 4: To maximize the benefits based on technology viability, MeterIDs associated with 'electricity' were considered for this study, while the rest were filtered out, reducing the count to 4,187 BDBIDs and 13,271 MeterIDs.

Step 5: Finally, MeterIDs with zero consumption data or monthly peak demand were removed. The final number of buildings in the cleaned dataset was 3,389 BDBIDs and 4,197 MeterIDs.

Building Type and Site Selection

The next step in the report methodology was to identify the specific sites at which to conduct the BESS feasibility analyses. DCAS classified the buildings into 54 different building types, sorted by their primary function, then finalized nine diverse building types for key functionality, as described below. For each building type, a representative site was selected.

The goal of the building type selection process was to identify building types with the highest potential cost-effectiveness for an optimal use case if a stand-alone storage system were installed. The primary building factors that impact cost-effectiveness are energy consumption patterns and rate tariffs, and therefore the selection process incorporated these two components. Additionally, selecting building types with higher annual consumption, peak demand, and ratio of peak demand to average demand, implies higher peak shaving potential at large volume. Finally, selecting building types with larger number of buildings helped identify a large set of potentially cost-effective systems.

The impacts of rate tariffs are captured indirectly because there was no way to jointly map rate tariffs and building types, since tariffs varied by building type, peak demand, and location. First, building types with time-of-day (TOD) charges were identified (Step 3). Second, the ratio of peak and average demand (inverse of load factor) for each building type was calculated to rank building types with lower load factor. Currently, TOD charges for commercial buildings are higher for summer months compared to winter months. Therefore, peak demand and ratio of peak demand to average demand were calculated only for summer months. This calculation identified building types that would have higher cost-effectiveness due to the TOD tariff structure.

The monthly dataset contained consumption and billing data for years 2016 through 2020. However, only the 2019 data was used for building type selection since 2019 is the most recent year that accurately captures how the buildings are operated. Year 2020 consumption data might not be representative of the actual consumption due to possible changes in facilities' operations because of COVID-19.

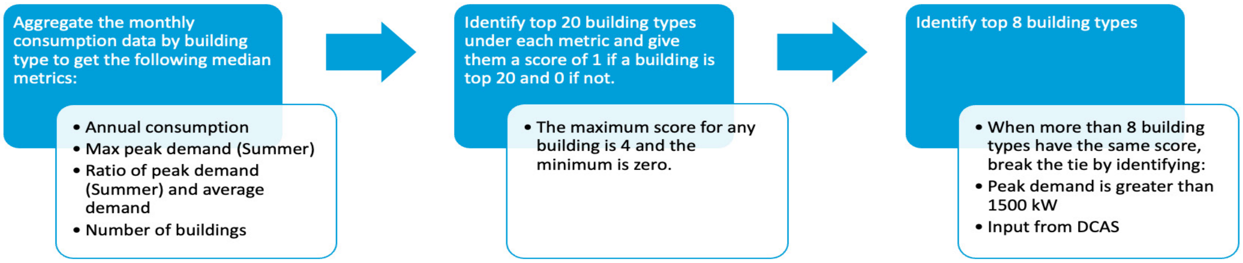
Building types to be further analyzed were identified using the steps below. Figure 12 describes building-type selection procedure.

Step 1: Key metrics were aggregated from the monthly dataset by building type. The key metrics included: 1) median annual consumption, 2) median of summer peak demand, 3) ratio of median summer peak demand to average demand, and 4) total number of buildings.

Step 2: Building types were scored as a *one* if they were in the top 20 building types for each metric above, and a *zero* if they were not in the top twenty. The maximum score for any building type is *four* and the minimum is *zero*. A building type with a score of *three* or *four* implies that they had multiple favorable indicators and may be good candidates for economic BESS deployment.

Step 3: Once all the scores were tallied, the top eight building types with the highest scores were identified. If multiple building types had the same score, building types with TOD rates were chosen. Note that TOD rates were automatically applied to any building that has a peak demand of 1,500 kW or more. Additional input from DCAS was solicited to validate the selected building types.

Figure 12: Building-type Selection Procedure



Aggregate the monthly consumption data by building type to get the following median metrics:

- Annual consumption
- Max peak demand (Summer)
- Ratio of peak demand (Summer) and average demand
- Number of buildings

Identify top 20 building types under each metric and give them a score of 1 if a building is top 20 and 0 if not.

- The maximum score for any building is 4 and the minimum is zero.

Identify top 8 building types

- When more than 8 building types have the same score, break the tie by identifying:
- Peak demand is greater than 1500 kW
- Input from DCAS

Table 3 shows the final score of the top building types. There are five building types with a score of *four* and seven building types with a score of *three*. Since only one building type (correctional facility) has a peak demand greater than 1500 kW and therefore qualifies for TOD rates, another building type with high peak demand (transportation or terminal station) was added. Based on input from DCAS the eight highlighted building types were selected from the top building types.

Table 3: List of Top Building Types[41]

Building types	Score	Number of Buildings[42]	Peak demand greater than 1500 kW	Source
K-12 School*	4	983	0	Algorithm
Office*	4	96	0	Algorithm
Fitness Center/Health Club/Gym*	4	30	0	Algorithm
Pre-school/Daycare*	4	101	0	Algorithm
Urgent Care/Clinic/ Other Outpatient*	4	24	0	Algorithm
Lodging/Residential*	3	58	0	Algorithm
College/University*	3	25	0	Algorithm
Courthouse	3	10	0	Algorithm
Police Station*	3	91	0	Algorithm
Correctional Facility*	3	8	1	Algorithm
Manufacturing/ Industrial Plant	3	3	0	Algorithm
Mall	3	2	0	Algorithm
Transportation or Terminal Station**	1	10	1	DCAS
Wastewater Treatment Plant**	2	17	1	DCAS

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[41] * Building types selected based on algorithm results **Building types selected as their peak demand was greater than 1500 kW.

[42] The number of buildings (unique BDBID) listed in the table represents a subset of the entire DCAS building portfolio (statewide) after applying the data cleaning procedure as mentioned above.

Next, a representative site was selected from each building type to analyze BESS feasibility using the following procedure:

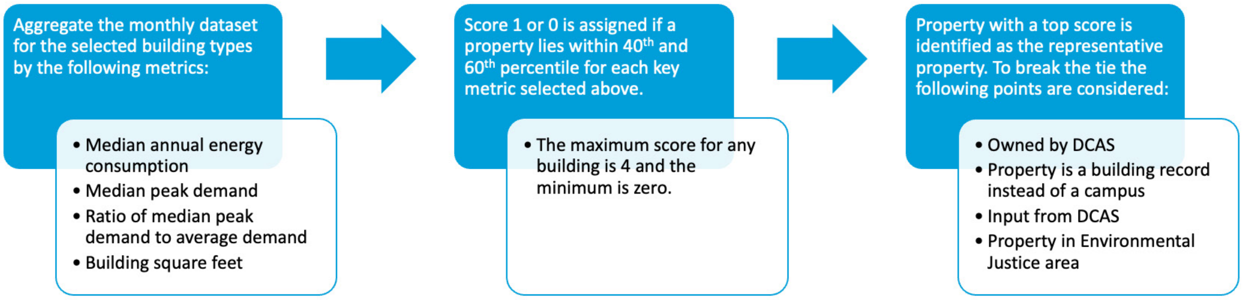
Step 1: The 2019 monthly dataset was filtered for the selected building types and evaluated the following metrics at each property: 1) median annual energy consumption, 2) median peak demand, 3) ratio of median peak demand to average demand, and 4) building square feet.

Step 2: For each property, a score of one was given if the property was within 40th and 60th percentile for each key metric selected above, or zero if it fell below 40th percentile or above 60th percentile. The maximum score for each property is four and the minimum is zero.

Step 3: The property with the highest score was selected as the representative property. If multiple properties had the same score, a property with a building record was chosen over others with a campus record. If the tie persisted further, buildings that are owned and operated by DCAS were chosen. The final criteria to break the tie was whether a property was in an environmental justice area (EJA), as established by New York state using U.S. Census data. Input from DCAS was also solicited for site selection.

The rationale for using the 40th to 60th percentile was to identify a representative property across all key metrics selected. If scoring was done based on the median (50th percentile) there could be scenarios where a tie could be difficult to break. For example, if a different site were selected for each metric, there would be four properties with a score of *one* each. Each property would be a representative site under one of the key metrics. To avoid such a tie, any building that fell close to the median for each metric made it easier to identify a representative site for each building type.

Figure 13: Site-Selection Procedure



Aggregate the monthly dataset for the selected building types by the following metrics:

- Median annual energy consumption
- Median peak demand
- Ratio of median peak demand to average demand
- Building square feet

Score 1 or 0 is assigned if a property lies within 40th and 60th percentile for each key metric selected above.

- The maximum score for any building is 4 and the minimum is zero.

Property with a top score is identified as the representative property. To break the tie the following points are considered:

- Owned by DCAS
- Property is a building record instead of a campus
- Input from DCAS
- Property in Environmental Justice area

Table 4 shows the selected properties and their consumption characteristics. Note that for three building types, the representative building was identified by DCAS and/or NYPA (not via the site-selection algorithm) as being a better representative of the type based on different factors including location, visibility, access to granular load data, potential to allow for stacking multiple use cases for increased economics. Further, Hunts Point Water Resource Recovery Facility (WRRF) was also added to represent properties with significantly higher consumption and demand compared to the eight other properties selected.

Table 4: Final Selected Properties and their Energy Consumption Characteristics[43]

ID	Building Type	Representative Property	Source	Annual Consumption (kWh)	Max Demand (kW)	Avg Daily Load Factor
129	**Pre-School /Daycare**	Labor and Industry for Education Inc	Algorithm	280,102	70	74.79%
1114	**Lodging /Residential**	George Daly House Residence	Algorithm	386,541	90	68.81%
3450	**Urgent Care/ Clinic / Outpatient**	Bedford Health Center	DCAS	530,502	167	67.10%
3478	**Transportation Terminal / Station**	3 Staten Island Ferry Terminal (Whitehall)	DCAS	2,440,935	554	85.68%
4398	**Office**	South Jamaica Multi Service Center	Algorithm	245,082	88	58.84%
4584	**Police Station**	122nd Precinct	DCAS	810,711	260	81.91%
6600	**K-12 School**	K158	Algorithm	421,141	140	56.07%
9104	**Correctional Facility**	Queens BH Campus: Queens Detention Complex Main Building	Algorithm	177,407	46	75.14%
9609	**Wastewater Treatment Plant**	Hunts Point WPCP Campus	DCAS	63,632,403	10,685	99.77%

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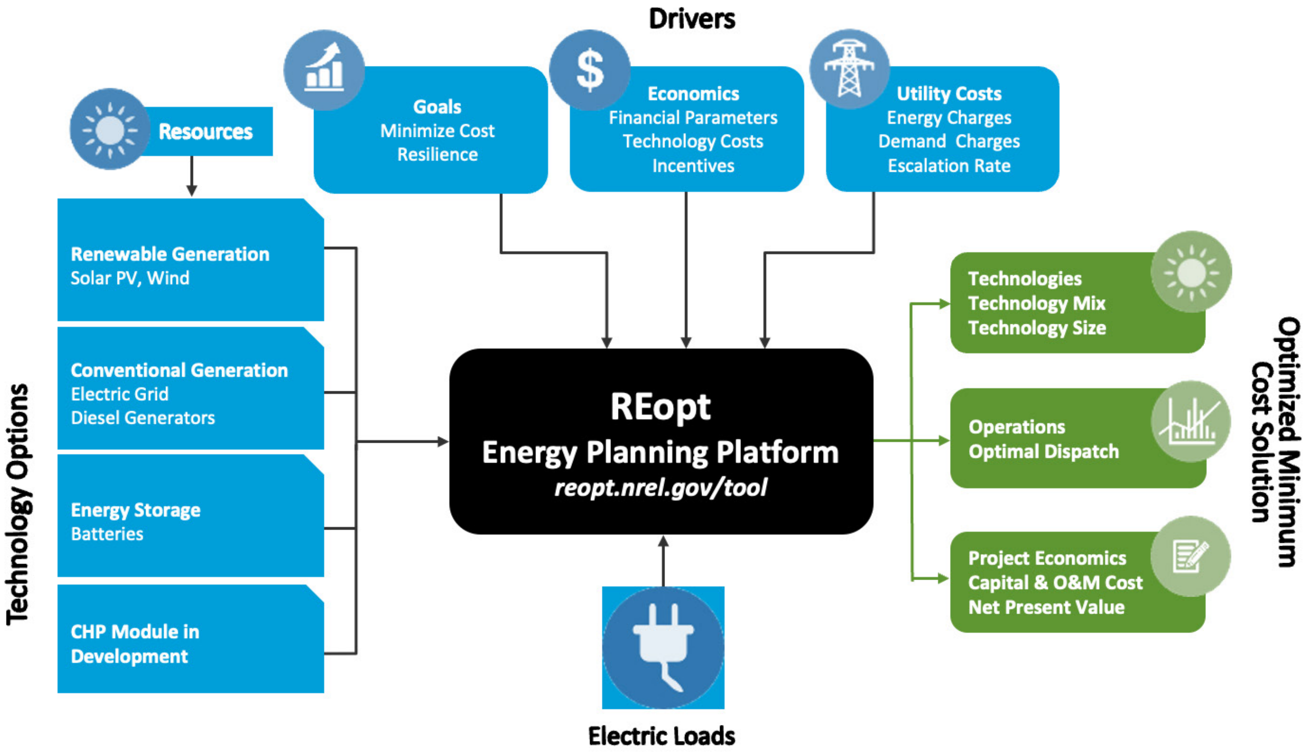
[43] Load factor is the ratio of average demand and peak demand. Higher load factors indicate flatter load profiles.

Modeling Tool

The modeling tool used to assess BESS feasibility was the Renewable Energy Integration and Optimization tool, REopt™ Lite. The REopt Lite tool evaluates the economic viability of grid-connected solar photovoltaics, wind, combined heat and power (CHP), and storage at commercial and small industrial sites. It is an optimization model, formulated as a mixed-integer linear program, used to solve for the optimal selection, sizing, and dispatch strategy of technologies chosen from a candidate pool such that loads are met at every time step at the minimum life cycle cost. Figure 14 shows a schematic of the REopt Lite model.[44]

Figure 14: Schematic of the REopt Energy Planning Program[44]



Assumptions

The BESS feasibility analysis for the nine selected sites was conducted using the assumptions listed in Table 5. They represent cost, technology, and financial assumptions DCAS currently uses to assess BESS (also referred to as the baseline scenario).

Technology assumptions include characteristics of the BESS. The BESS type is assumed to be lithium-ion since it is currently the least expensive BESS technology with the largest market penetration and lowest footprint, making it more suitable for dense urban environment such as NYC. Operating characteristics of the BESS, such as minimum state of charge and efficiency, are obtained from

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[44] NREL. 2020. *REopt Lite Web Tool: Capabilities and Features*.

Patsios et al. 2016[45]. The greenhouse gas (GHG) emissions coefficient is the 2020 electric grid emission factor provided by DCAS and developed by the Mayor's Office of Sustainability.[46] BESS life is assumed to be 10 years.[47,48]

Financial assumptions include the type of ownership and associated economic parameters to calculate the discounted cash flow of the project. DCAS expects to own and maintain BESS through direct purchasing; if multiple systems are planned then bulk purchasing of equipment is possible. As a public entity, DCAS assumes a real discount rate of 4% and an inflation rate of 2%. For this analysis the electricity cost escalation rate was conservatively estimated at 1% in real terms.[49] No state and federal incentives are available for BESS. Accelerated depreciation is not included in the analysis as it is not applicable to projects developed with tax-free debt financing.

In REopt Lite, BESS cost is specified by two parameters: energy capacity cost measured in $ per kWh and power capacity cost measured in $ per kW. The power components of the system (e.g., inverter, balance of system) are captured by the power metric of $ per kW and the energy components of the system (e.g., battery) are captured by the energy metric of $ per kWh[44]. The energy and power cost are assumed to be $420 per kWh and $840 per kW respectively based on meta-analysis of existing literature of storage costs.[50,51] This is on par with estimated installed costs of ESS in NYC based on unpublished market information from NYPA and is assumed to include any adjustments for labor costs in NYC.

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[45] Patsios, Charalampos, Billy Wu, Efstratios Chatzinikolaou, Daniel J. Rogers, Neal Wade, Nigel P. Brandon, and Phil Taylor. 2016. *An Integrated Approach for the Analysis and Control of Grid Connected Energy Storage Systems in the Journal of Energy Storage*.

[46] CO_2e coefficient (grid electricity): 0.289 kg per kWh of grid electricity purchased (fiscal year 2021)

[47] Mongird, Kendall, Vilayanur Viswanathan, Patrick Balducci, Jan Alam, Vanshika Fotedar, Vladimir Koritarov, and Boualem Hadjerioua. U.S. Department of Energy. 2019. *Energy Storage Technology and Cost Characterization Report*.

[48] DiOrio, Nicholas, Aron Dobos, and Steven Janzou. NREL. 2015. *Economic Analysis Case Studies of Battery Energy Storage with SAM*.

[49] National Institute of Standards and Technology (NIST), U.S. Department of Commerce. *NIST Energy Escalation Rate Calculator*.

[50] Wood Mackenzie. 2019. *U.S. Energy Storage Monitor: Q3 2019*.

[51] Lazard. 2020. *Lazard's Levelized Cost of Storage Analysis Version 6*.

Table 5: Technology Assumptions for the Baseline Scenario

	Parameter	Value	Source
Technology	**BESS Type**	**Lithium-Ion**	
	BESS Life	10 years	[47,48]
	Minimum State of Charge	20%	Patsios et al. 2016 (45)
	Initial State of Charge	50%	
	Rectifier efficiency	96%	
	Round trip efficiency	97.5%	
	Inverter efficiency	96%	
	BESS charging rules	BESS only charges from the grid	DCAS
	GHG Emission Coefficient	0.289015215 Kg of CO_{2eq} per kWh	DCAS
Financial	**Objective**	Minimize lifecycle cost (cost-effective projects)	DCAS
	Ownership model	Direct Purchase	
	Analysis period	10 years	
	Inflation rate	2%	
	Real discount rate	4%	
	Investment Tax Credit (Federal, State)	0%	
	Electricity cost escalation rate	1%/year	
	Accelerate depreciation	None	
Cost	**BESS Energy Capacity Cost ($/kWh)**	$420/kWh (DC)	Wood Mackenzie 2019;[50] Lazard 2020[51]
	BESS Power Capacity Cost ($/kW)	$840/kW (DC)	

	Parameter	Value	Source
Tariff	**91, Conventional – rate structure used for any commercial buildings with peak demand < 1500 kW**	Energy Production (cents/kWh) - Summer: 4.057 - Winter: 3.712 - Fixed charge: 1.2 Demand (High Tension) ($/kW) - 19.61	Note: Summer months are June to September. Peak hours are 8AM to 10PM on weekdays only
	91, TOD – rate structure used for commercial buildings with peak demand >=1500 kW	Energy Production (cents/kWh) - Summer Peak: 5.061 - Summer Off – Peak: 3.259 - Winter Peak: 4.243 - Winter Off – Peak: 3.275 Demand (High Tension) ($/kW) - Summer: 29.88 - Winter: 13.52	

Sensitivity Analysis

Sensitivity around the input assumptions listed in the baseline scenario is explored for the Staten Island Ferry Terminal. The Staten Island Ferry Terminal was chosen for analysis since it had the highest energy consumption and peak demand compared to the other sites. The water resource recovery facility was not considered since it is an extreme case with several orders of magnitude higher energy consumption and peak demand compared to the average DCAS building portfolio.

To conduct the sensitivity analysis, several scenarios were developed. Each scenario varies one or two inputs from the baseline case. Note that VDER is not applicable for any of the BTM scenarios.

1) *BESS life of 15 years:* In this scenario a BESS life of 15 years, five years more than baseline, was assumed.
2) *Analysis Period of 25 years:* The baseline scenario assumed an analysis period of 10 years since the law mandates DCAS to explore storage systems that have a maximum payback of 10 years. By exploring an analysis period greater than 10 years, the City may benefit from reductions in cost of the replacement system after 10 years. In this scenario, an analysis period of 25 years was explored with initial BESS costs of $420 per kWh and $840 per kW initially, and replacement BESS cost of 50% ($210 per kWh and $420 per kW) after 10 years.
3) *Breakeven scenario:* In this scenario, the maximum system size at which net present value (NPV) is zero (breakeven) was identified.
4) *TPO without Incentives:* The baseline scenario assumed DCAS owns and operates the BESS. However, a TPO business model could be explored to manage a large BESS fleet. In this scenario, TPO was modeled without any incentives. The discount rate and effective tax rate for the third-party owner was assumed to be 10.16% and 29.875% (21% Federal plus 4% State plus 4.875% Local),

respectively.

5) *TPO with Incentives:* While currently there is no ITC available for standalone storage systems, this scenario assumed an ITC at 26%, the same level as that of a solar PV system. For the reasons explained earlier in the *Incentives Section*, no state level incentives are assumed in this scenario.

6) *Reduced BESS Cost:* In this scenario the BESS cost was assumed to be 50% lower than the baseline scenario with a power cost of $420 per kW and an energy cost of $210 per kWh and analysis period was assumed to be 10 years.

7) *TOD - 91 (Electricity tariffs):* Electric tariffs play a significant role in determining cost-effectiveness of the BESS. In this scenario, a TOD rate structure was used instead of the baseline 91 rate schedule's conventional tariff that applies to commercial buildings.

8) *BESS size 5 MW and 15 MWh:* In this scenario, a BESS size of 5 MW operating for 3 hours with an energy capacity of 15 MWh was assumed, aligning with the maximum capacity for systems to qualify under NYSERDA's Retail Energy Storage Incentive program. While City-owned projects do not qualify for NYSERDA incentives, this allows for a comparison of value of ESS connected BTM against an FOTM application assessed in later sections of this report. This scenario represents the maximum system size assessed for this analysis.

9) *BESS size at 100% peak demand:* This scenario is similar to the previous scenario, except the BESS size was assumed to be at least 100% of the peak demand of the property (554 kW), with the capacity to discharge for three hours (1662 kWh).

10) *Roof-top PV Plus Storage System:* The baseline scenario evaluated a stand-alone storage system that charges using the grid. In this scenario, a PV + storage system was explored where the system charges from the grid and the PV system. The PV system size was not constrained in the analysis. The PV system capital cost was assumed to be $1600 per kW, operations, and maintenance costs $16 per kW-year[52], and a fixed standard roof-top module was assumed with an azimuth of 180 degrees and a tilt of 10 degrees. No incentives or depreciation was assumed for the system.

11) *Roof-top PV plus Storage system with BESS size at 100% peak demand:* This scenario is similar to the roof-top PV plus storage system except minimum BESS size was set to 100% of the peak demand of the property (554 kW) with the capacity to discharge for three hours (1662 kWh).

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[52] NREL. 2020. *2020 Annual Technology Baseline*.

Analysis & Results

Baseline Scenario Analysis Summary

In this section, the cost-optimal system size and performance for all selected properties are presented for the baseline scenario (see Table 6).

Under the specific given assumptions and inputs modeled above, this study determined that BESS for BTM application could be marginally cost-effective for all buildings studied. However, for every single building studied, the *cost optimal* BESS size[53] was quite small in relation to the building's load (i.e., only able to offset about 1 to 3% of the maximum peak demand of the building). Therefore, the most cost-optimized BESS would provide very little back-up power to any facility it was supporting. And even when the BESS is designed for cost optimization, the total economic benefits are small: varying between $97 to $10,934 of avoided cost per year.

Moreover, the actual annual avoided cost benefits are most likely significantly lower in real life than these modeled estimates indicate. The paucity of available data on battery cost curves (i.e., benefits of economies of scale) in NYC left the study with little choice but to use BESS capital and implementation cost estimates that most likely are significantly lower than they would be in real life for small systems. In other words, the only available real-world data for BESS costs with which to model were for large-scale BESS that almost definitely would have economies of scale, cost-per-unit advantages. Thus, although this study couldn't incorporate them, smaller BESS would most likely incur significantly higher per-unit equipment, installation, and O&M costs. These higher costs would dramatically reduce the already-meager, highest possible annual avoided cost for any given building's cost-optimal BESS. These higher BESS costs might even render many (if not most) of the modeled facilities' *cost-optimal* BESS not cost-effective at all in real life.

Detailed modeling results for each site are presented as tables and figures in the appendix.

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[53] *Cost optimal* means the highest total positive NPV of a BESS.

Table 6: Summary of the REopt Results from the Baseline Scenario Analysis of the Selected Properties[54]

Building Type	Representative Properties	Median Daily Load Factor	BESS Power (kW_{AC})	BESS Capacity (kWh_{AC})	Life Cycle Savings as compared to BAU*	Simple Payback Period (Years)	Capacity as % of max peak demand	No. of BESS discharge cycles per Year**
Pre-School / Daycare	Labor and Industry for Education Inc	0.65	2	6	$ 1,508 (0.52%)	5.85	3%	42
Lodging / Residential	George Daly House Residence	0.71	3	8	$ 1,856 (0.49%)	5.86	3%	39
Urgent Care/ Clinic / Outpatient	Bedford Health Center	0.66	4	11	$ 1,651 (0.3%)	6.35	2%	23
Transport Terminal / Station	Staten Island Ferry Terminal (Whitehall)	0.83	5	12	$ 3,138 (0.14%)	5.81	1%	21
Office	South Jamaica Multi Service Center	0.57	3	7	$ 1,546 (0.54%)	5.94	3%	43
Police Station	122nd Precinct	0.84	6	14	$ 2,921 (0.38%)	6.08	2%	45
K-12 School	K158	0.52	4	10	$ 2,643 (0.53%)	5.75	3%	45
Correctional Facility	Queens BH Campus: Queens Detention Complex Main Bldg	0.70	1	3	$ 976 (0.55%)	5.59	1%	35
Wastewater Resource Recovery Facility	Hunts Point WPCP Campus	0.96	166	381	$ 109,340 (0.2%)	5.66	2%	274

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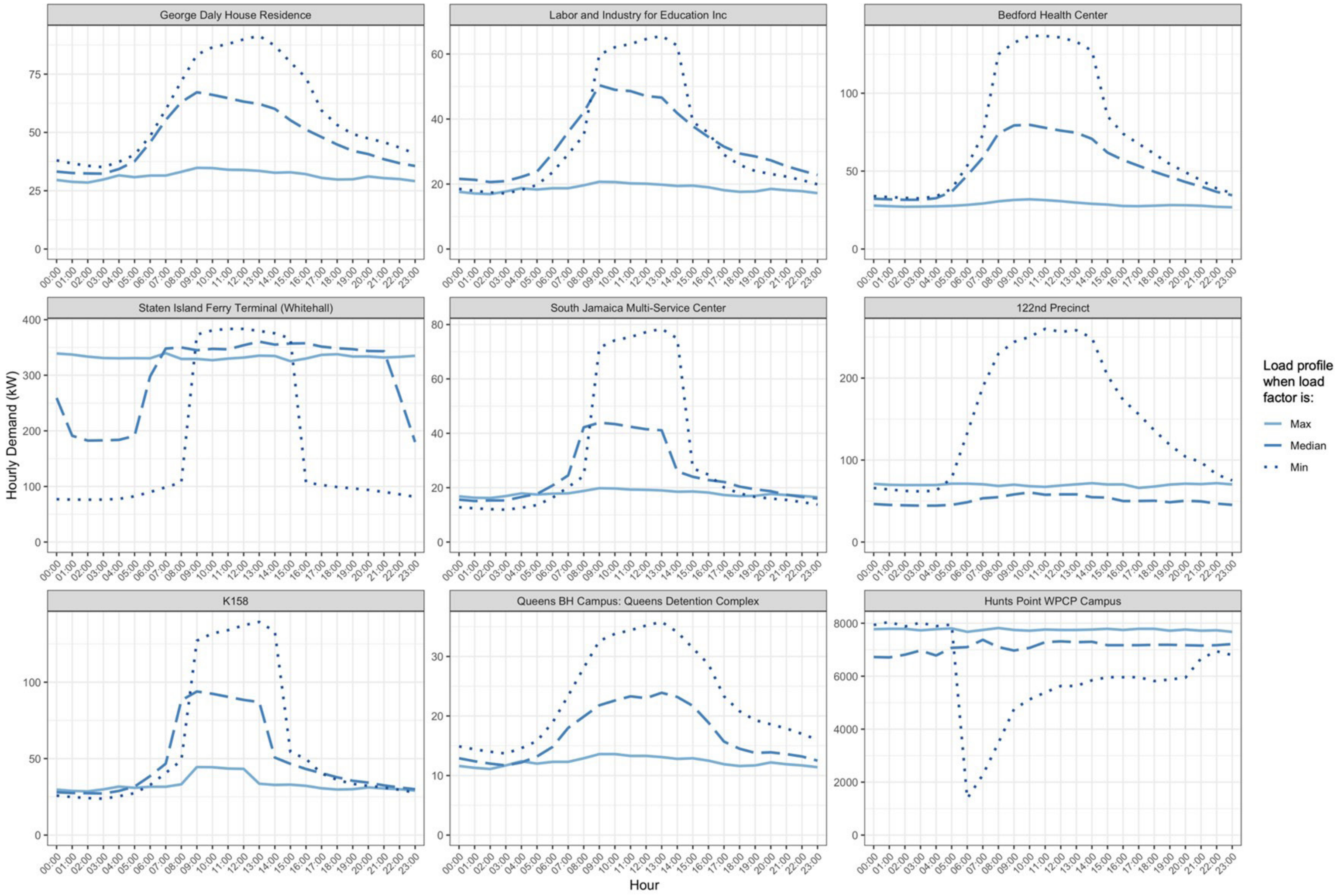
[54] **Life cycle savings of each building is provided in dollars as the total savings when compared to the business as usual (BAU) case and as percentage of savings to the total life cycle utility cost, in brackets. BAU is when the building is operating without a BESS.*
***Battery discharge cycle is defined as the number of continuous discharge operations to serve the load. The battery does not have to be fully discharged to be considered as a cycle.*

The data indicates BESS are marginally cost-effective due to the high demand charges, but high building load factors mean the models only recommend small BESS. The average daily load factor across the buildings varies from 56% to 99.7%. The lower the load factor, the higher the peakiness (i.e., the greater the steepness) of the load profile, and the easier it is for the BESS to reduce peak demand and optimize across differently priced time periods.

Figure 15 shows each building's load profile when the daily load factor is minimum, median, and maximum for the year 2019. The figures show that on an average day the load for each building is relatively flat with one peak that extends for several hours, much higher than typical BESS operation of about three to four hours. Therefore, only a small load is available for shaving at 1% to 3% of the demand as shown in Table 6. For the baseline scenario, the BESS discharges about two to three times a month for all buildings except for the WRRF, where the battery discharges almost every day for two hours between 5 and 7 p.m. While it may be ideal to find buildings with low load factors, they may not be representative of the selected building type and could skew the analysis when scaling. In summary, the representative building chosen for each building type has low peakiness.

Load factor may not be the only variable driving the determination of smaller system sizes as cost-optimal. The next section demonstrates the results of sensitivity analyses based on variations in tariff rates, cost of the system, life expectancy, and potential revenue streams.

Figure 15 shows Variation in the *Peakiness* of the Load by Building[55]



Sensitivity Analysis

The baseline scenario suggests a cost-optimal system size of a 5 kW power capacity and a 12 kWh energy capacity with an avoided cost of $314 per year. Building from that baseline, this study modeled 12 sensitivity scenarios at the Staten Island Ferry terminal. Table 7 summarizes the results.

Moving from direct purchase to TPO without incentives reduces the cost-optimal size of the system (to 2 kW and 3 kWh) and its avoided cost (down to $82 per year). This is expected since TPO models have higher discount rates compared to direct purchase models. With the 26% ITC, the TPO model performs slightly better than the baseline scenario with cost-optimal size of 6 kW and 12 kWh and an avoided cost of $324 per year. This result suggests that incentives are an important component for a cost-effective BESS under a TPO model.

[55] These graphs show the load profile associated with minimum, median, and maximum daily load factor in 2019 for all selected buildings. Peakiness is identified through load factor. Low load factor corresponds to high peakiness and vice versa. The variation is captured by identifying the days with minimum, median, and maximum load factor.

Siting BESS with a PV system can sometimes improve the feasibility of BESS due to price arbitrage. However, the REopt model shows that, given the baseline assumption, PV does not reduce lifecycle costs of energy. Therefore, the REopt model does not suggest installing PV (i.e., *PV system size equals zero*). The size of the BESS in this scenario is the same as in the baseline case.

Assuming the site is under a TOD rate structure, as opposed to a conventional rate structure, increases the optimal BESS size to a power capacity of 8 kW and an energy capacity of 20 kWh. Despite the greater than 60% increase in system size compared to the baseline, the resulting recommended BESS is still small, capable of offsetting about 1% of the facility's peak demand with an avoided cost of only $443 per year. Nonetheless, this result suggests that a TOD rate structure is beneficial for a viable BESS.

The baseline scenario assumes a 10-year BESS life. Changing that assumption to 15 years (i.e., a 50% increase in lifespan), increases the optimal system size and the life cycle savings by approximately three times the baseline estimates. The resulting system size is 13 kW and 37 kWh with cost savings of $753 per year. However, the system size in this scenario is still small, covering 2% of the peak demand. This result suggests that cost-effectiveness is highly sensitive to BESS life expectancy.

Increasing the analysis period to 25 years has a similar effect to reducing the cost of batteries. The baseline scenario assumes a 10-year analysis period during which there is no BESS replacement. In the 25-year analysis period there is one BESS replacement in year 10 at a lower price, thereby improving the cost-viability of the BESS when compared to the baseline scenario due to reduced lifecycle system cost. In this scenario, the cost optimal system size is 16 kW and 57 kWh, representing 3% of peak demand with an avoided cost of $883 per year.

Reducing the cost of batteries by 50% also increases the recommended BESS power capacity size by three times and the energy capacity by 4.6 times as compared to the baseline value. Similar to the previous results, despite the large increase, the cost optimal total system size is relatively small, offsetting only 3% of the peak demand. The avoided cost in this scenario amounts to $1,025 per year.

Identifying the system size with an NPV of zero or breakeven (over 10 years) produces a cost optimal system size similar to increasing the analysis period to 25 years. Note that REopt does not allow for optimizing NPV to zero, therefore a minimum system size was used to constrain the model through trial and error to achieve the final results. This scenario suggests that optimizing for a system with an NPV of zero increases the system size. However, the optimal system size in this scenario still is smaller than the ones the models recommend if the BESS's cost is reduced, or its life is increased to 15 years.

The last three scenarios evaluate the feasibility of a large BESS. In all the three cases, the storage systems would deliver negative life cycle savings (i.e., additional cost).

Table 7: Summarized REopt Results from the Sensitivity Analysis for Staten Island Ferry Terminal (Whitehall)[56]

Scenario	BESS Power (kW_{AC})	BESS Capacity (kWh_{AC})	Life Cycle Savings as Compared to BAU* (Avoided Cost)	Simple Payback Period (Years)	Capacity as % Max Peak Demand
Baseline (5kw and 12kWh)	***5***	***12***	***$ 3,138 (0.14%)***	***5.81***	***1%***
3rd party ownership (TPO) without incentives	2	3	$ 819 (0.03%)	5.8	0%
TPO with incentives	6	12	$ 3,242 (0.15%)	5.6	1%
Rooftop PV + BESS	5	12	$ 3,138 (0.14%)	5.81	1%
Time of Day (TOD) – 91 (Rate Schedule)	8	20	$ 4,435 (0.19%)	5.94	1%
BESS life of 15 years	13	37	$ 11,292 (0.36%)	7.38	2%
Reduced BESS cost	15	56	$ 10,251 (0.47%)	5.39	3%
25 year analysis period	16	57	$ 22,080 (0.49%)	10.65	3%
Breakeven scenario	14	38	$ 0	7.51	3%
BESS sized to meet 100% peak demand	554	1662	$ (937,592) (30%)	> 25 yrs.	100%
Rooftop PV + BESS (sized to meet 100% peak demand)	554	1662	$ (937,592) (30%)	> 25 yrs.	100%
BESS size 5MW and 15MWh	5000	15000	$ (10,103,283) (82.1%)	>25 yrs.	902%

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[56] *Life cycle savings in each scenario is provided: 1) in dollars as the total savings when compared to the business as usual (BAU) case, and 2) as percentage of savings to the total life cycle utility cost, in parentheses.

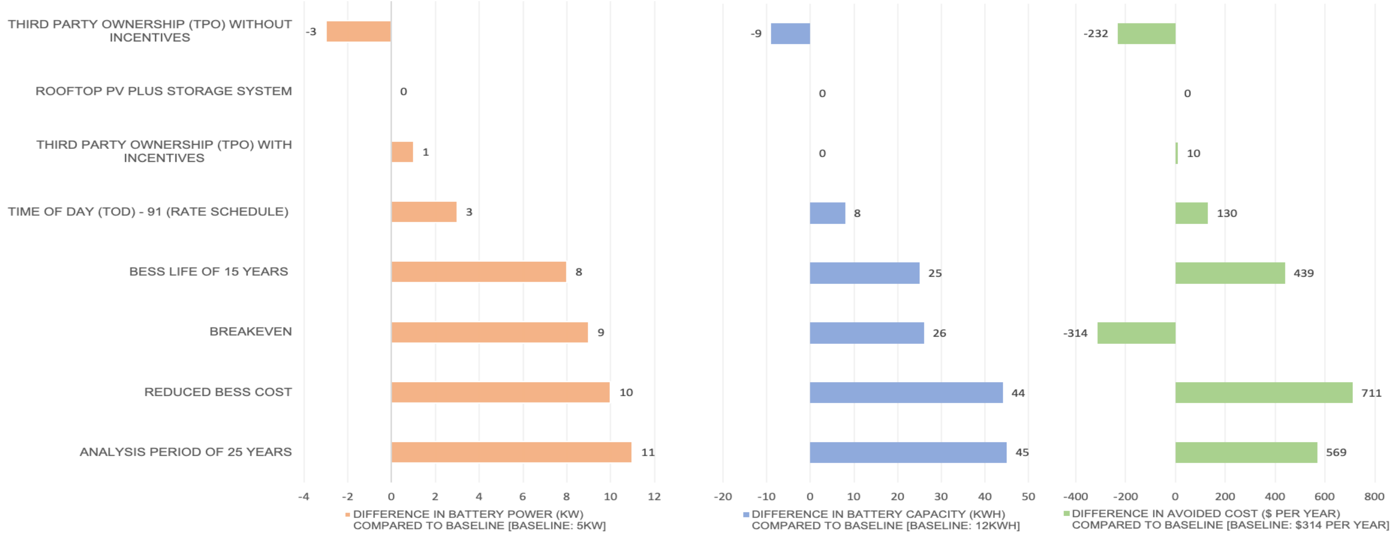
The major takeaway from the sensitivity scenario analysis is that under the specific, given assumptions and inputs modeled, BESS for BTM application could be, at best, marginally cost-effective. Large BTM BESS are not economically feasible.

Changes that could improve feasibility include:

1) Reduced cost of the system.
2) Longer BESS life.
3) Tariff structures with high demand charges and time of use components.
4) Financial incentives to offset procurement costs.

Figure 16 - *Change in System Size and Avoided Cost Compared to a Baseline Scenario under Sensitivity Analysis* lists the scenarios that provide the maximum benefit for increasing system size in ascending order. An analysis period of 25 years and reduced BESS cost increases the BESS size by 11 kW (45 kWh) and 10 kW (44 kWh) respectively from baseline scenario of 5 kW (12 kWh) and an increased avoided cost of $570 per year and $711 per year from the baseline avoided cost of $314 per year. While both system size and avoided costs are significantly greater compared to baseline scenario, this scenario still does not provide the scale at individual sites or collectively to make an impactful capacity or economic difference from that of the baseline.

Figure 16: Change in System Size and Avoided Cost Compared to a Baseline Scenario under Sensitivity Analysis[57,58]



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[57] The baseline scenario is 5 kW/12 kWh, and $314 per year.

[58] Only scenarios that had a positive NPV are shown.

Grid Support Applications

Whereas ESS sited BTM aim to provide value to the facilities where they are sited, ESS sited in FOTM provide value directly to the utility grid. A FOTM ESS may be located on a customer's property, as is the case in this analysis, but rather than connecting to the customer's load (behind its meter), it connects to the grid via a new meter.

Principally, the ESS may charge from the grid during lulls in demand, then discharge during peaks in demand. During these peaks, the utility must generate and deliver additional energy, generally at much greater cost than typical baseload power. The power plants that serve these high-demand needs tend to be carbon-intensive and expensive to operate. If demand continues to rise, eventually demand will outstrip supply, potentially causing grid outages or disruptions.

Energy storage can reduce reliance on these expensive power plants and improve the reliability and resiliency of the grid. By charging when demand is low and discharging when demand is high, the ESS can shore up supply, providing reliability and serving some of the grid's short-term needs in place of the expensive power plants the utility would otherwise have to operate. Under the VDER tariff, these benefits are monetized and offered to owner/operators of FOTM batteries in the form of dollar per kWh payments for exports made to the grid. The net value of these payments depends on the location of the ESS, its power (kW) and energy (kWh) ratings, and the costs incurred by charging from and discharging to the grid. ESS connected FOTM can offer flexibility to the grid in other ways as explained in the Applications section above.

In this analysis, the nine representative facilities reviewed in the Facility Support Applications section above, plus one additional site, are assessed for ESS siting feasibility. As under a FOTM scenario these facilities will not interact with the ESS, and the facility's electric consumption is irrelevant. Instead, the primary factor affecting feasibility for a FOTM ESS is the amount of viable physical space available for development.

The 10 selected sites were assessed for ESS siting feasibility, as were other sites of their type. For the purposes of this analysis, model ESS were sized according to the space available not just at the selected site, but also using the space typically available at other sites of its type. In other words, the ESS modeled in this analysis are scalable across sites similar to the representative sites assessed.

The representative sites were assessed for viable physical space available for ESS development either at ground level or on a rooftop. Ground-level BESS were deemed viable if they were either sufficiently elevated or could be raised to avoid flooding; for rooftop installations, general structural factors were considered. The resulting ratings in kW and kWh are based on the scale of a typical lithium-ion BESS that could be deployed given the viable square footage available.

Economics for each site is assessed based on the region, and system size as estimated above. The VDER value stack was considered to be the primary revenue stream and the charging algorithm is optimized to generate the highest revenue possible. A NPV was then calculated based on the modeled revenues and system costs.

Project economics for ESS are dependent on many factors that are mostly driven by policy. Three scenarios were run to account for the present ESS policy landscape as well as projected future market conditions:

Current Scenario ('As Is' Case)

The current scenario represents an *as is* case for where the market currently stands with regards to energy storage. This scenario assumes no federal or state incentives available for standalone energy storage as stated in the Market & Policy section.

Allocated Cost of Service (ACOS) – Contract Demand Charge Exemption

Another factor that impacts ESS economics is the contract demand charges. Unlike onsite renewable resources, ESS does not generate energy. It draws it from such a generation resource (whether through onsite renewables or from the grid) to be stored and discharged at a later time. Thus, an ESS utilizes the grid infrastructure at least two times and under the present standby and buyback service rate structure of the utilities, incurs costs not just for the ESS' kW charged from the grid, but for kW injected onto the grid during export. Whereas a renewable generation resource is exempt from such contract demand charges.

However, the NY Department of Public Service Staff and NYSERDA recently published a whitepaper on ACOS methods used to develop the standby and buyback service rates dictating the contract demand charges,[59] which recommends exempting standalone ESS from contract demand charges for exporting onto the grid (buyback). NYPA believed it reasonable to assess the ESS economics under this scenario.

Including Federal and State Incentives

Wholesale Market

The New York Independent System Operator (NYISO) is actively working on developing rules to open its wholesale energy markets to ESS. These market rules are being developed to allow ESS to fully participate in its wholesale markets, regardless of whether they are deployed as standalone systems or paired with renewable energy resources (hybrid or co-located systems). This potentially enables greater deployment of ESS in New York as it creates new revenue streams and thus reduces risk to ESS project investors. These rules are being developed per the Federal Energy Regulatory Commission's (FERC) order 841 requiring regional transmission operators and independent system operators, such as NYISO, to

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[59] NYSERDA. 2020. *Whitepaper on Allocated Cost of Service Methods Used to Develop Standby and Buyback Service Rates*.

remove barriers for ESS to participate in the energy, capacity, and ancillary services markets operated by such entities.

Secondly, in compliance with FERC Order 2222, NYISO is developing rules that will enable aggregated distributed energy resources (DERs), including distributed ESS, to participate in the same wholesale markets. This will create a level playing field among both traditional large energy resources and DERs, thus allowing ESS/DERs project investors to maximize value while minimizing risk.

Furthermore, FERC is reviewing and regulating NYISO filings on rules associated with various orders to ensure any ESS resources that qualify as Special Case Resources and offer demand response (DR) opportunities are valued accurately for their price offer to participate in such markets. This makes it more feasible for such resources to pass any tests that NYISO determines are needed to mitigate potential market price manipulation attempts. Simply put, the most recent FERC ruling allows DERs like ESS to benefit from both distribution level and wholesale or bulk-scale DR programs.

Wholesale market rules are constantly evolving, with input from market participants and other stakeholders. This ensures developed rules are clear and transparent and into the future it will create opportunities for resources to benefit from both distributed and wholesale markets and support New York state to achieve its aggressive energy storage targets.

As stated in this report's Incentives section, currently there is no ITC for standalone ESS, but the industry widely anticipates there will soon be an ITC of at least an equivalent to PV's 26%. Additionally, while the most recent retail energy storage incentive available through the New York state is accounted for by projects currently in development, it is anticipated that a new lower block of incentives will be made available, specifically for ESS projects in NYC. The third scenario assessed for FOTM systems is based on the assumptions that ESS projects will qualify for the ACOS buyback contract demand charge exemption, a federal ITC equivalent of current solar PV ITC, and a state retail energy storage incentive. These assumptions are based on market information and industry expectations of the different incentives that will be available soon for standalone storage systems.

Economic Analysis

The results summarized in this section were derived from the economic analysis used to calculate the NPV from ESS projects sized for each site under the three scenarios described above. This section also presents the assumptions used in these analyses.

Assumptions

- Capital expenditure - $700 per kWh
    - This value includes any ongoing operational expenses converted to an upfront capital cost.
- Discount rate – 4%
- ESS exempt from buyback contract demand charges.
- Federal ITC – 26%

- State retail storage incentive - $125 per kWh

Results

Table 8: NPV Summary for FOTM Scenarios

Facility Type	Property	ESS Capacity (kW/kWh)	NPV Summary		
			As Is	Contract Demand Charge Exemption	Contract Demand Charge Exemption + Incentives
Utility	Throgs Neck Sewage Pump Station (Non-building)	1200/1200	($634,602)	$376,042	$730,273
Wastewater Treatment Plant	Hunts Point WPCP Campus	2400/2400	($1,210,003)	$811,284	$1,519,745
Pre-School/ Daycare	Labor and Industry for Education Inc	1200/1200	($634,602)	$376,042	$730,273
Lodging/ Residential	George Daly House Residence	1200/1200	($658,274)	$352,369	$706,600
Urgent Care/ Clinic/ Outpatient	Bedford Health Center	1200/1200	($634,602)	$376,042	$730,273
Transportation Terminal/ Station	Staten Island Ferry Terminal (Whitehall)	2400/2400	($1,263,017)	$758,270	$1,466,732
Office	South Jamaica Multi Service Center	1200/1200	($634,602)	$376,042	$730,273
Police Station	122nd Precinct	1200/1200	($658,274)	$352,369	$706,600
K-12 School	K158	1200/1200	($634,602)	$376,042	$730,273
Prison/ Incarceration	Queens BH Campus: Queens Detention Complex Main Building	2400/2400	($1,210,003)	$811,284	$1,519,745

Applying the above assumptions at these sites, FOTM ESS at City buildings are not cost-effective under current market conditions. Under the second scenario, accounting for the exemption of contract demand charges for standalone ESS during export, ESS at all 10 representative sites are projected to be cost-effective in under 10 years, regardless of system size. Finally, by applying state and federal-level incentives in addition to the contract demand charge exemption (third scenario), NPVs across the ten sites yield over 90% better results compared to the scenario 2, and greater than 200% improvement compared to the *as is* market condition economics.

Changes to contract demand charges pursuant to ACOS appear to be imminent. The buyback contract demand charge exemption scenario presents ESS project viability should these changes go into effect, while the final scenario presents the best-case scenario.

Resiliency

ESS can also provide resiliency to the facilities at which they are sited. In this context, *resiliency* is the ability of a facility to quickly or immediately re-establish power to critical loads during grid outages. Reliable backup power is beneficial in all contexts, but for certain types of City buildings, such resiliency can be essential to effective operations. Among these are buildings that serve essential needs of the City's residents, such as hospitals, water treatment and supply plants, and transportation hubs. Other facilities can provide a safe gathering place for community members during grid outages, such as schools and libraries offering emergency refuge. At these and other facilities, ESS may have the potential to power critical operations serving vulnerable New Yorkers during grid power outage emergencies.

However, such emergency incidents may not occur often and are difficult to predict in their severity and longevity. Furthermore, outside of exceptions, such as manufacturing industries or financial institutions that can calculate a value of lost revenues from their products or services due to an outage situation, most facilities would not see a net economic benefit from installing ESS purely for resiliency purposes. Unlike BTM demand charge reduction or FOTM grid support, providing backup power to a critical facility does not generate savings or revenue under VDER. At facilities that would otherwise utilize fossil fuel-fired generators during grid outages, ESS backup provides cost savings and carbon reductions due to decreased fuel consumption; however, ESS are currently incapable of the durations achieved by fossil resources of similar footprint and capital cost. Additionally, due to the rarity and irregularity of grid outage events in New York City, the benefits of backup power are variable. *It is not that backup power is not valuable – rather, its value is difficult to quantify.*

Fortunately, as demonstrated in the Facility Support Applications and Grid Support Applications sections of this report, ESS can be cost-effectively deployed at many City buildings for other savings or revenue-generating purposes, provided the policy changes including incentives discussed in this report become available. Achieving ESS deployment at scale in the absence of incentives could be difficult due to the challenges posed by project economics. In addition to their facility or grid support services, these ESS can provide backup power to the buildings' critical loads, depending on their capacity. Standalone ESS connected BTM already power onsite loads during normal operations and can operate in an *island* mode during blackouts, effectively isolating the facility from the grid. Islanding during blackouts is required for safety purposes. Once islanded, ESS can power onsite loads for as long as they have capacity. Such islanding capability requires the addition of an Automatic Transfer Switch (ATS) and associated electrical infrastructure and programming, increasing overall system costs. Given the small kWh capacities of the cost-effective BTM ESS modeled in this report, the potential for BTM ESS to provide backup power at City buildings is limited.

ESS deployed FOTM at City buildings for grid support applications can be cost effective under certain scenarios that may materialize in the future and offer greater capacity than BTM ESS. FOTM ESS, such as those modeled for the ten facilities in the previous section, can leverage their large capacities (1.2 to 2.4 MWh) to provide critical onsite backup power during blackouts. Since under normal operations these ESS are connected directly to the grid, they are electrically isolated from their host sites, unlike BTM ESS directly connected to and supporting the facility. A FOTM ESS must therefore be connected by an ATS to the facility allowing it to connect to and serve the facility's critical loads during a grid outage.

The current ESS market has few, if any, practical options for long-duration storage. A 1.2+ MWh FOTM ESS can provide significant backup power, but for the applications studied in this report, only for a matter of hours. Longer-duration solutions have yet to reach adequate energy density, scale, and commercial viability. Nonetheless, a FOTM ESS that is cost-effective for grid support purposes can provide vital backup power at additional cost via an ATS. The costs of implementing an ATS for such a system range from minimal to prohibitive, depending on the site and application.

An ESS, paired with solar PV, can strengthen the resiliency benefits of the ESS. The resulting self-sufficient system is known as a microgrid. Whether the solar and storage systems are connected BTM or FOTM under normal operations, during a grid outage, the system would island from the grid and begin powering onsite loads. The ESS would provide instantaneous backup power, with the PV system providing supplemental power whenever it is productive. This solar power would serve current loads, if any, while excess power would be stored in the ESS for later use. Together, the solar and storage systems could extend the backup capabilities of the facility. The total duration of these backup operations would depend on the size of each system, the ESS state of charge at the time of blackout, the solar resource available, and the amount of onsite load.

Scalability

To maximize the economic, social, and environmental benefits of the City's efforts pursuant to Local Law 181, the City must deploy ESS at scale across its portfolio of buildings. However, as demonstrated in previous sections of this Study, scalability of ESS is dependent on several factors. Namely, adoption of the ACOS contract demand charge exemption renders all of the FOTM projects assessed cost-effective, while none are anticipated to be cost-effective in the absence of ACOS. At a site-specific level, facility type, application of ESS, and physical space available are the most important factors dictating each facility's most economic ESS size.

Scalability Based on Application

This study has focused on assessing the viability of ESS by facility type. Application based scalability is derived by assuming a representative facility for selected types and extrapolating for scale based on the number of facilities of each selected type. Under current market conditions it is difficult to realize an economic case for widespread ESS that serve the host facility (i.e., BTM applications). There may be scenarios where BTM systems can participate in ancillary programs beyond peak load shaving at the facility, such as local and wholesale demand response programs as explained in the Demand Response section. These programs can generate additional revenue, making larger systems BTM economically viable, and thus contributing to a greater scale. However, the programs may not be available for every facility and the revenues may only be available for a shorter term than the life of the project. These factors can only be determined on a case-by-case basis for each facility, making it difficult to quantify for scalability.

With certain regulatory changes, FOTM applications may be more scalable. These applications provide little direct benefit to the facility that hosts them but may increase the reliability of the local distribution system when sited in areas of grid constraint. Table 9: Scalability by Application summarizes the scale of ESS capacity that can be achieved by the City based on facility function type and the ESS application type.

Table 9: Scalability by Application

		System Size – Facility Support (BTM) (Optimal Cost)				System Size – Grid Support (FOTM) (Optimal Space)			
Facility Type	**#Facilities**	**Representative System Size**		**Scalability**		**Representative System Size**		**Scalability**	
		kW	**kWh**	**kW**	**kWh**	**kW**	**kWh**	**kW**	**kWh**
Pre-school/Daycare	**101**	2	6	194	582	1200	1200	116,400	116,400
Lodging/Residential	**58**	3	8	174	464	1200	1200	69,600	69,600
Urgent Care/Clinic/Other Outpatient	**24**	4	11	96	264	1200	1200	28,800	28,800
Transportation or Terminal Station	**10**	5	12	50	120	2400	2400	24,000	24,000
Office	**96**	3	7	285	665	1200	1200	114,000	114,000
Police Station	**91**	6	14	546	1,274	1200	1200	109,200	109,200
K-12 School	**983**	4	10	3,908	9,770	1200	1200	1,172,400	1,172,400
Correctional Facility	**8**	1	3	8	24	2400	2400	19,200	19,200
Water Resource Recovery Facility	**17**	166	381	1,660	3,810	2400	2400	24,000	24,000
Pumping Station	**12**	N/A	N/A	N/A	N/A	1200	1200	14,400	14,400
Total				***6,921***	***16,973***			***1,692,000***	***1,692,000***

Impact of Available Physical Space

While application type is one factor impacting scalability, the other is the physical space available at any facility. This section identifies a subset of facilities assessed where the system sizes can be larger than that chosen as a representative for that facility type. This is done for the FOTM application, as load profile dictates the system size for a BTM project, while physical space plays a greater role for FOTM ESS. For example, while the Staten Island Ferry Terminal is assessed to accommodate a 2,400 kW, one-hour duration System as a representative facility of type *Transportation or Terminal Station*, it can in fact accommodate a system with a duration of at least two hours, and thus increases the capacity of the system. Similar examples are shown in Table 10 for other facility types that can accommodate larger systems than assessed as representative facilities, along with the area identified for installing the energy storage system.[60]

The increase in ESS size may be in its power rating or its duration (or energy) rating. System footprint and application, and thus economics, vary depending on which of these two parameters are increased at any facility. It can be observed that the scale of ESS capacity that can be achieved at these individual facilities increased by over 200% when compared to the scale that can be achieved at a representative facility of the same type. The condition of an ESS installation's intended site is important as well, especially if paired with rooftop PV. A lithium-ion battery ESS typically can be installed in an enclosure or a containerized installation (e.g., a standard shipping container) and carry significant weight. The site identified at a facility must not only have the space required for adequate safety measures and maintenance

Table 10: Scalability by Available Physical Space

Facility Type	**Property**	**Representative System Size**		**Specific Facility System Size**		**Identified Area for ESS**
		kW	**kWh**	**kW**	**kWh**	
Transportation or Terminal Station	Staten Island Ferry Terminal (Whitehall)	2,400	2,400	2,400	4,800	Rooftop
Pumping Station	Throg's Neck Sewage Pumping Station	1,200	1,200	5,000	15,000	Ground Space/ Parking Lot
Office	South Jamaica Multi Service Center	1,200	1,200	5,000	15,000	Rooftop/Ground Space/Parking Lot
Police Station	122nd Precinct	1,200	1,200	5,000	15,000	Rooftop/Parking Lot
Urgent Care/ Clinic/Other Outpatient	Bedford Health Center	1,200	1,200	1,200	2,400	Ground Space/ Parking Lot
K-12 School	K158	1,200	1,200	5,000	15,000	Parking Lot
Wastewater Treatment Plants	Hunts Point WPCP Campus	2,400	2,400	2,400	4,800	Ground Space/ Parking Lot
Correctional Facility	Queens BH Campus: Queens Detention Complex Main Building	2,400	2,400	5,000	15,000	Ground Space
	Total	***13,200***	***13,200***	***31,000***	***87,000***	

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[60] System sizes assessed for specific sites is based on gross area available to install a system at those sites. No rooftop load bearing potential to support system weight, potential loss of parking spaces, code-compliant setbacks, chemical containments, or other permitting needs are considered. For the purposes of this preliminary assessment, it is assumed the rooftop structure can bear the load of such systems, and that other permitting and siting needs are met. The true viability of ESS deployment at each of these facilities will depend on further onsite analysis.

clearances, but also must be able to structurally bear the system's weight. This needs to be assessed on a case-by-case basis, specific to the facility and proposed system size, and per applicable local codes and standards.

Conclusion

NYC set an aggressive goal of achieving an 80% reduction in greenhouse gas emissions by 2050, compared with 2005 levels. As part of this goal, the City set a target to install 100 MW of PV at City-owned facilities by 2025. ESS could complement the effective deployment of this renewable generation in some instances, whether by improving solar self-consumption for BTM systems or optimizing VDER for FOTM systems. Its primary purpose is to capture energy during periods of low demand and low cost and deliver it during times of high demand and high cost. In some cases, the production of renewable energy does not match up to period of high demand, high cost. ESS can store and shift the use of the renewable energy to such times. While the carbon footprint of an ESS is dependent on the fuel source charging it, when paired with renewable resources energy storage will help optimize their performance and enhance their impact on carbon reductions. In tandem with solar PV, ESS will allow the City to reduce its reliance on fossil fuel-fired resources, improve reliability and resiliency, and provide other essential grid services.

This study acts as a strategic guide for deploying ESS by assessing viable technologies, applications for City facilities' own purposes versus fully supporting the grid, benefits, and shortcomings of such applications, and impacts on the scale that can be achieved by NYC. While there are no incentives available for standalone ESS either at the federal or state level, certain market policy changes such as the Allocated Cost of Service rates method whitepaper that is currently in process could make deploying ESS economically viable in NYC. Other incentives such as the Federal ITC may provide incremental benefits, allowing for greater deployment scale.

This study indicates that with current market conditions (e.g., rate structures, capital cost, power density, load profiles, space and load constraints, incentive landscape, etc.) the benefits of ESS deployment across municipal facilities may be marginal at best. However, due to limitations in real world data for modeling inputs of small system sizes, it is not recommended that the results from this study be relied on solely for determining cost effectiveness when making investment decisions. Rather, detailed, site-specific engineering and economic analysis should be conducted when improvements to buildings are being considered. For BTM applications, none of the 12 sensitivity cases examined significantly improved the economics of ESS. Rather, they allowed for slightly larger system sizes increasing from one percent of peak load in the baseline scenario to three percent. For FOTM applications, the sensitivity cases illustrated that changes to certain market conditions could allow for deployment of ESS at scale. This application was particularly sensitive to contract demand charges. If this rate design were to change, FOTM applications could become more economical. However, even under these circumstances FOTM applications are still dependent on where there are grid constraints. The results suggest that site specific engineering studies will need to be completed to determine economic and technologic feasibility.

Appendix

Detailed Modeling & Results

Transportation Terminal/Station (Staten Island Ferry Terminal)

Figure 17: 2019 Annual Load Profile of Staten Island Ferry Terminal

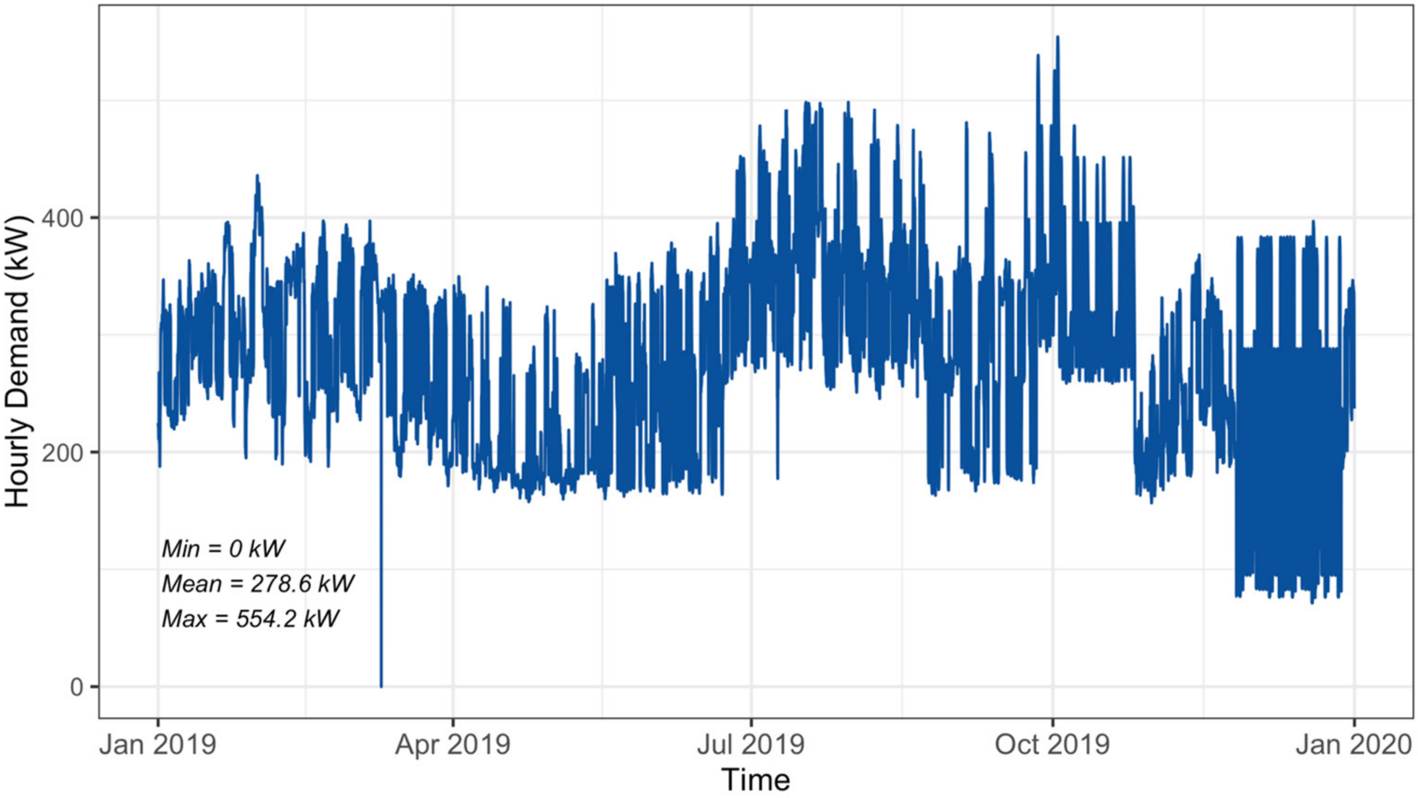

Table 11: REopt Results for Staten Island Ferry Terminal under Baseline Scenario

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	5 kW
BESS Capacity	n/a	12 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,440,947 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$123,134
Utility Demand Cost	$135,507	$134,011
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,050,874	$1,050,879
Utility Demand Cost	$1,156,475	$1,143,711
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$9,621
Total Life Cycle Costs	$2,207,349	$2,204,211
Net Present Value	n/a	$3,138
Payback Period	n/a	5.81 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	705.47

Pre-School/ DayCare (Labor and Industry Education Inc)

Figure 18: 2019 Annual Load Profile of Labor and Industry Education Inc.

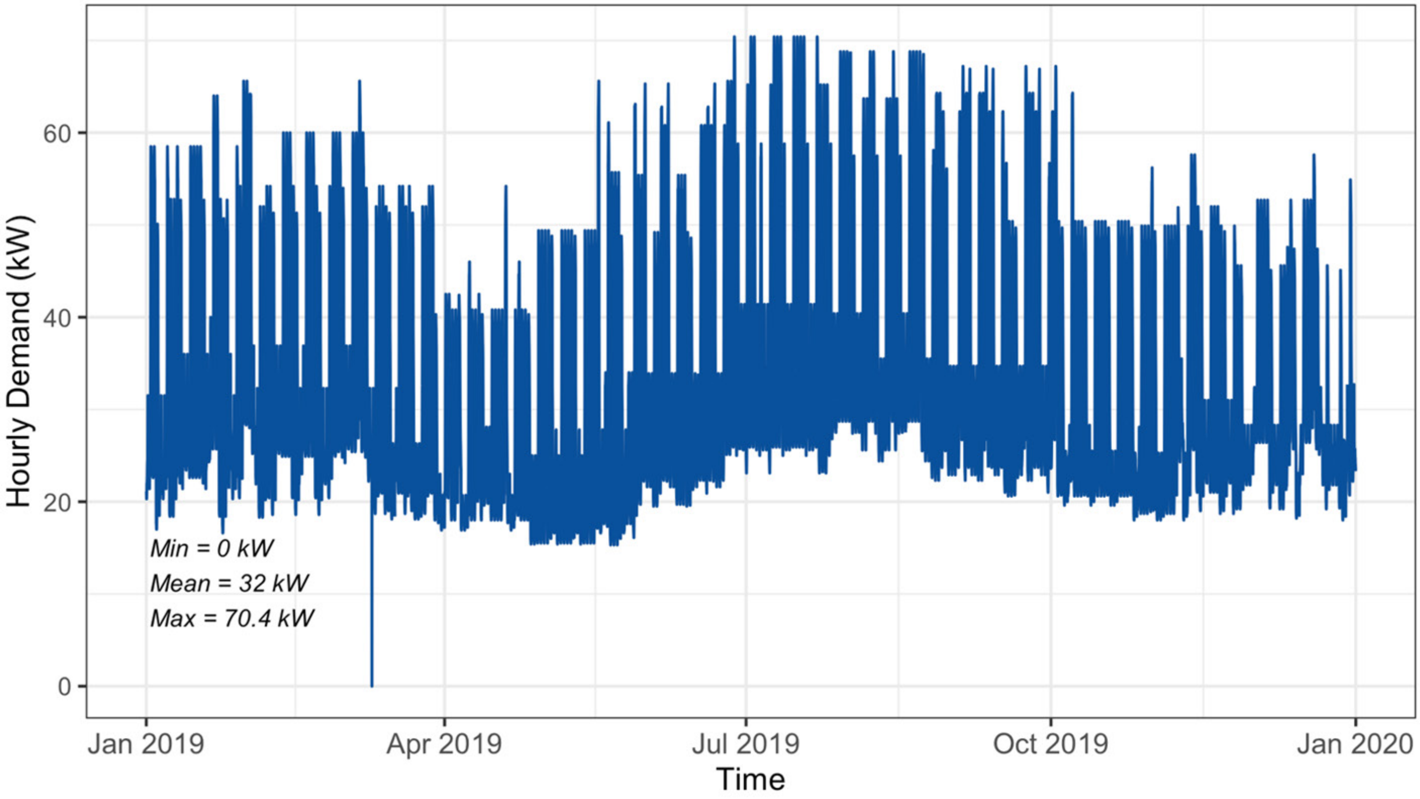

Table 12: REopt Results for Labor and Industry Education Inc. under Baseline Scenario

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	2 kW
BESS Capacity	n/a	6 kWh
Average Annual Energy Supplied from Grid	280,102 kWh	280,120 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$14,129	$14,130
Utility Demand Cost	$19,887	$19,151
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$120,586	$120,594
Utility Demand Cost	$169,722	$163,440
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$4,766
Total Life Cycle Costs	$290,308	$288,800
Net Present Value	n/a	$1,508
Payback Period	n/a	5.85 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	80.95	80.96

Lodging/ Residential (George Daly House Residence)

Figure 19: 2019 Load Profile of George Daly House Residence

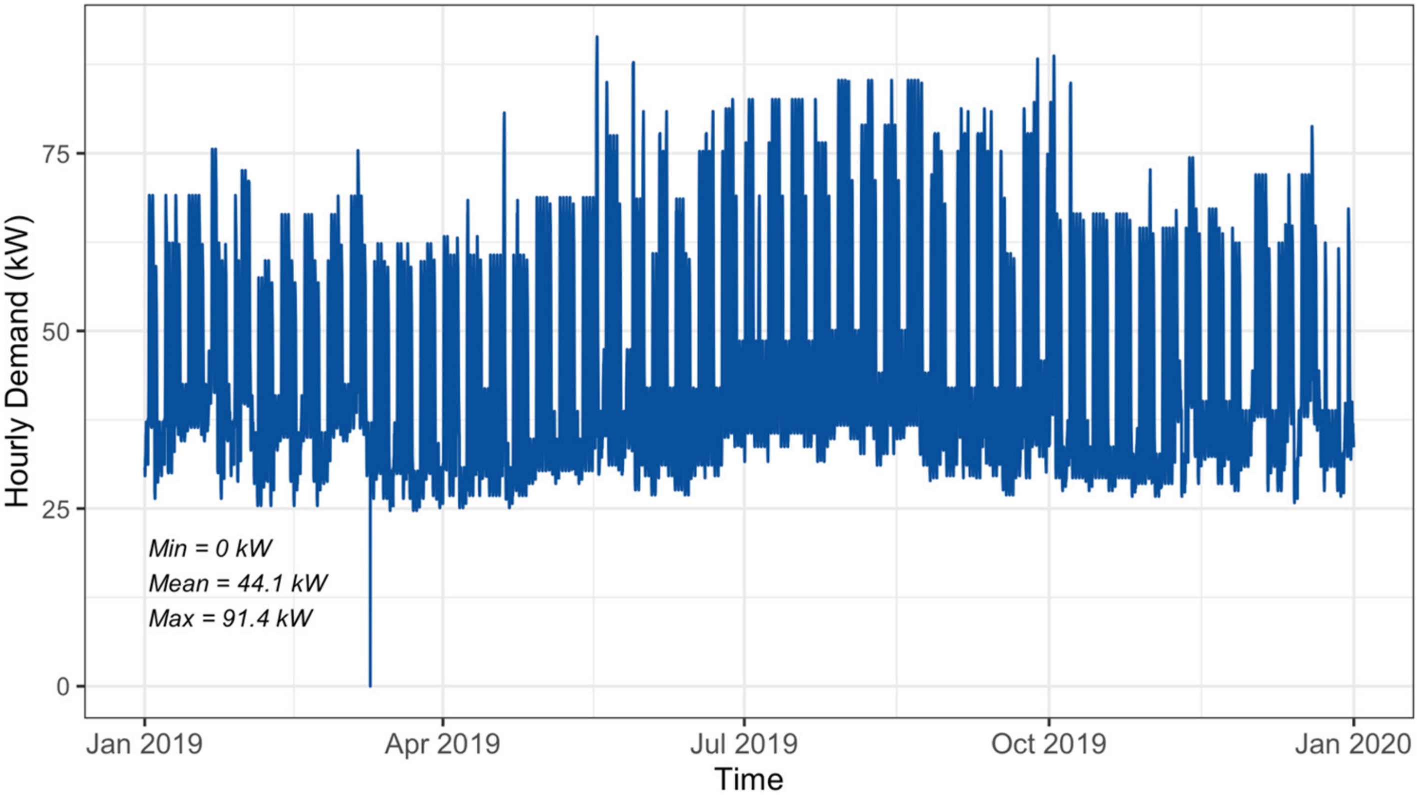

Table 13: REopt Results for George Daly House Residence under Baseline Scenario

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	3 kW
BESS Capacity	n/a	8 kWh
Average Annual Energy Supplied from Grid	386,541 kWh	386,555 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$19,466	$19,467
Utility Demand Cost	$25,099	$24,190
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$166,133	$166,139
Utility Demand Cost	$214,209	$206,449
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$5,898
Total Life Cycle Costs	$380,342	$378,486
Net Present Value	n/a	$1,856
Payback Period	n/a	5.86 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	111.71	111.72

Urgent Care/ Clinic/ Outpatient (Bedford Health Center)

Figure 20: 2019 Annual Load Profile for Bedford Health Center

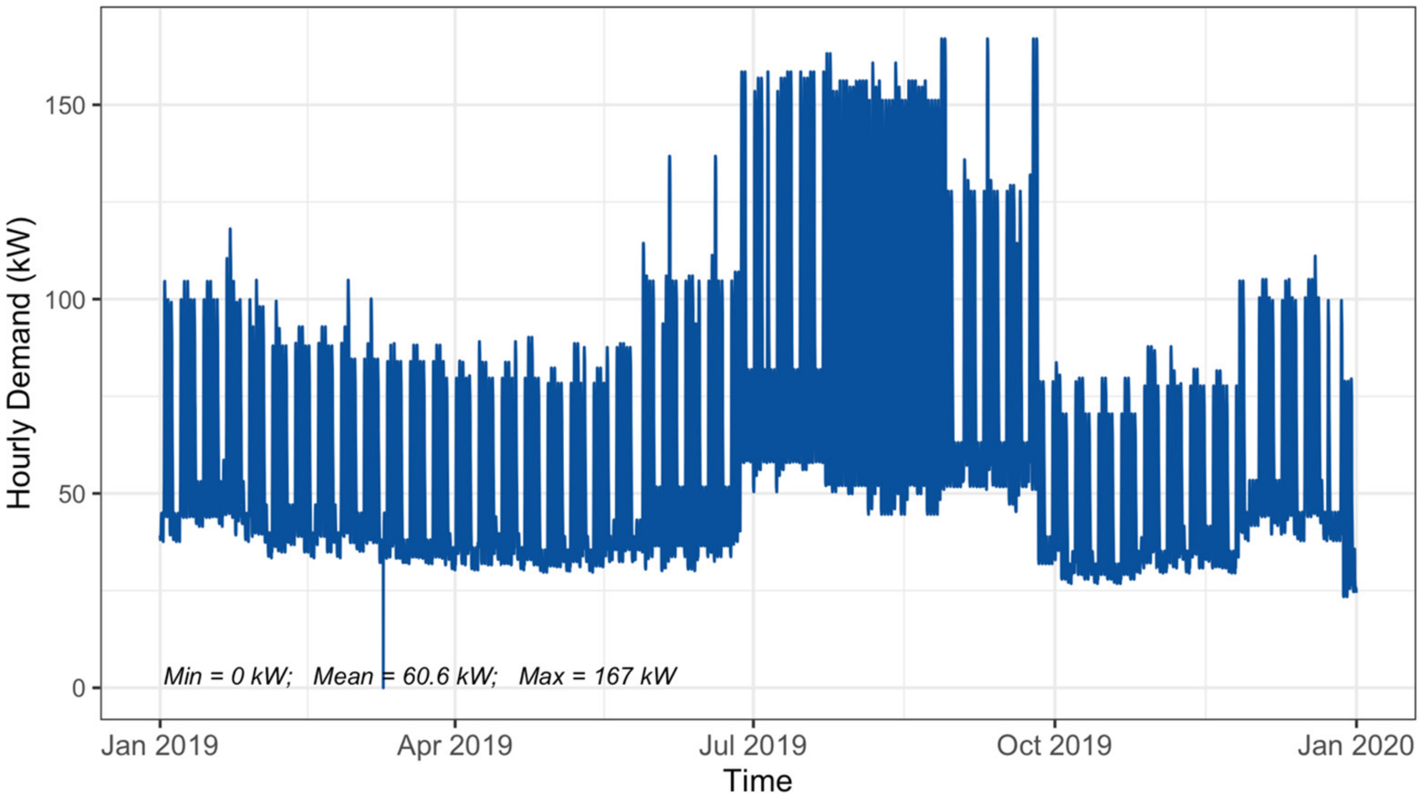

Table 14: REopt Results for Bedford Health Center under Baseline Scenario

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	4 kW
BESS Capacity	n/a	11 kWh
Average Annual Energy Supplied from Grid	530,502 kWh	530,519 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$26,844	$26,844
Utility Demand Cost	$38,186	$37,039
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$229,094	$229,101
Utility Demand Cost	$325,894	$316,109
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$8,127
Total Life Cycle Costs	$554,988	$553,337
Net Present Value	n/a	$1,651
Payback Period	n/a	6.35 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	153.32	153.33

Office (South Jamaica Multi-Service Center)

Figure 21: 2019 Annual Load Profile for South Jamaica Multi-Service Center

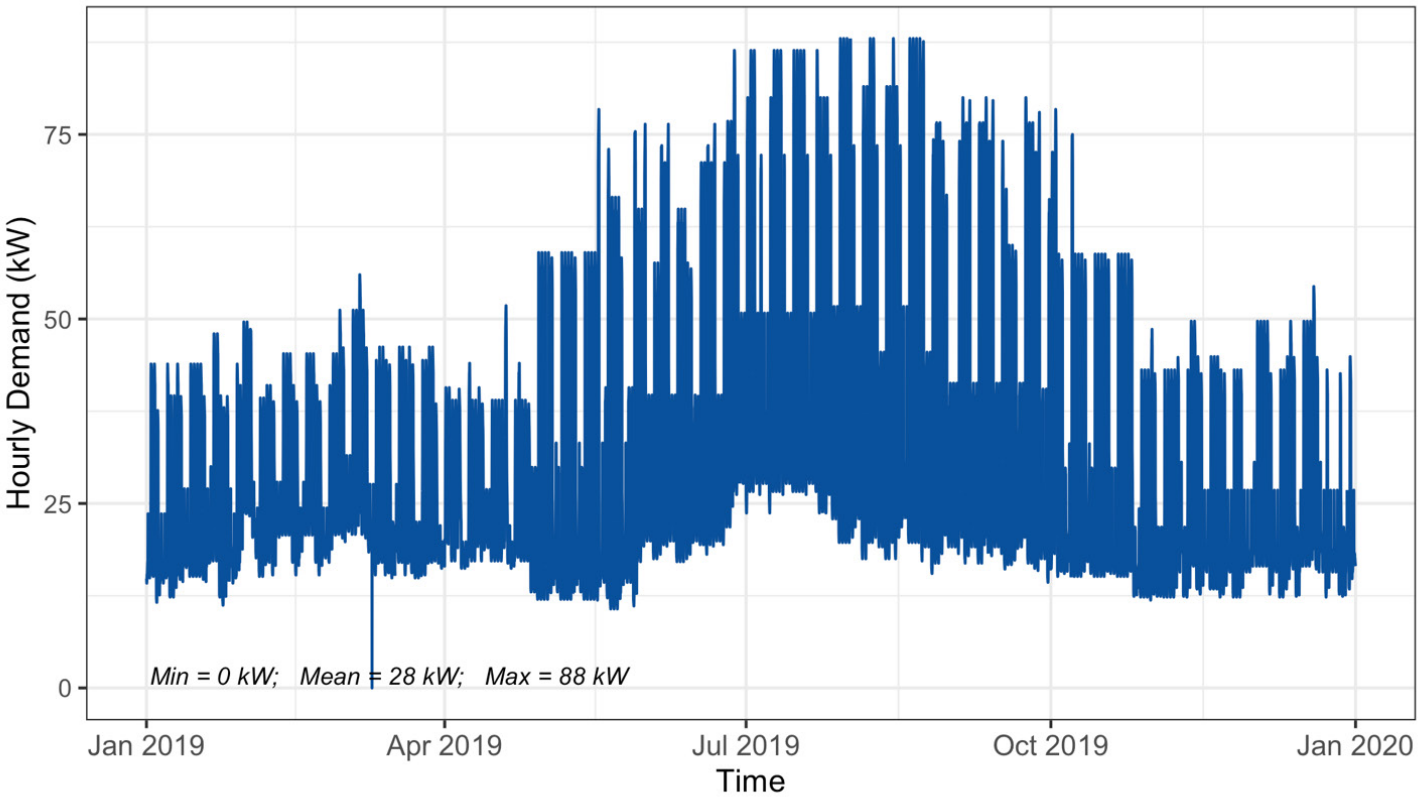

Table 15: REopt Results for South Jamaica Multi-Service Center under Baseline Scenario

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	3 kW
BESS Capacity	n/a	7 kWh
Average Annual Energy Supplied from Grid	245,082 kWh	245,099 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$12,400	$12,401
Utility Demand Cost	$21,036	$20,239
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$105,825	$105,832
Utility Demand Cost	$179,531	$172,727
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$5,249
Total Life Cycle Costs	$285,355	$283,809
Net Present Value	n/a	$1,546
Payback Period	n/a	5.94 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	70.83	70.84

Police Station (122nd Precinct)

Figure 22: 2019 Annual Load Profile for 122nd Precinct Police Station

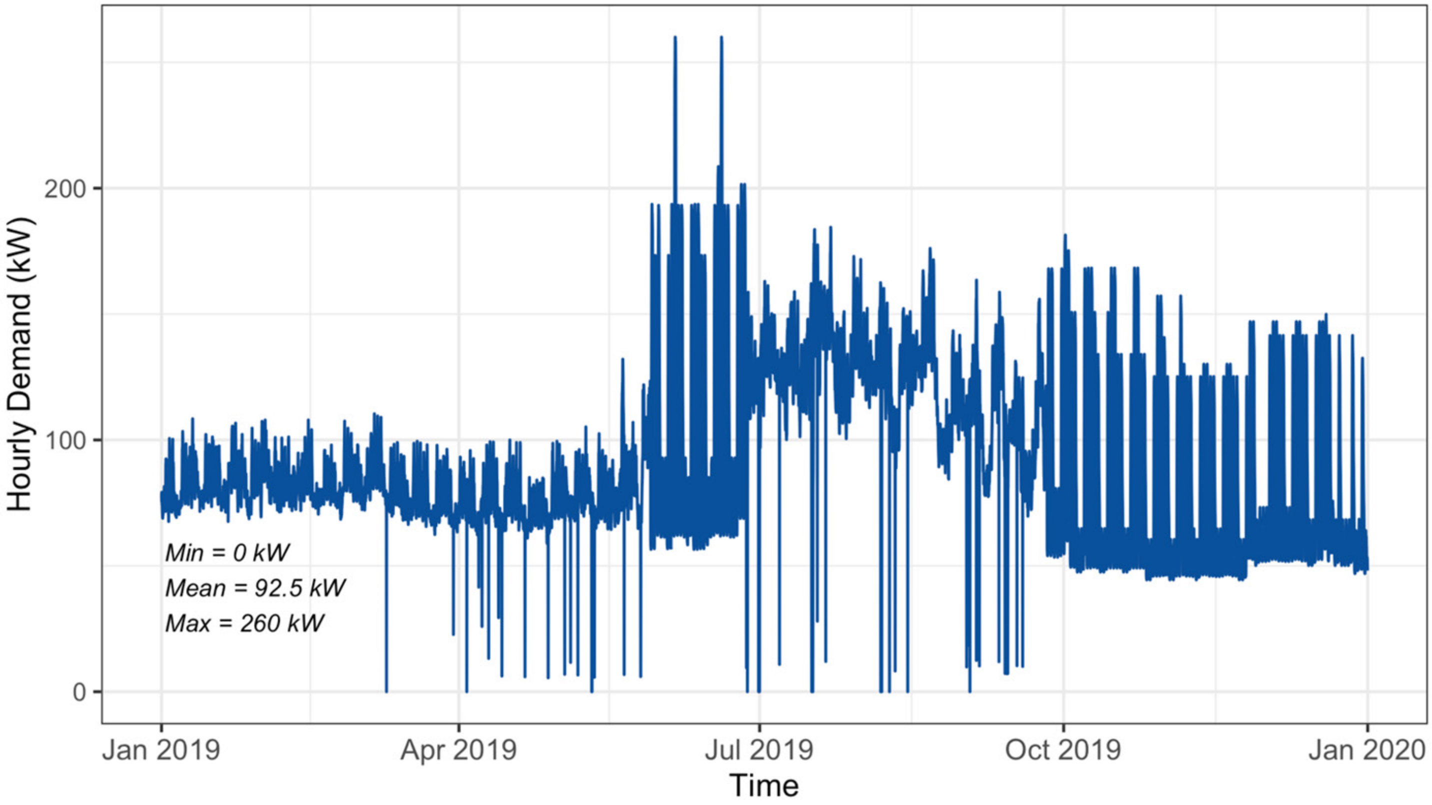

Table 16: REopt Results for 122nd Precinct Police Station under Baseline Scenario

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	6 kW
BESS Capacity	n/a	14 kWh
Average Annual Energy Supplied from Grid	810,711 kWh	810,739 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$41,007	$41,009
Utility Demand Cost	$48,724	$47,077
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$349,975	$349,986
Utility Demand Cost	$415,833	$401,779
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$11,122
Total Life Cycle Costs	$765,808	$762,887
Net Present Value	n/a	$2,921
Payback Period	n/a	6.08 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	234.3	234.31

K-12 School (K158)

Figure 23: 2019 Annual Load Profile for K158, a K-12 School

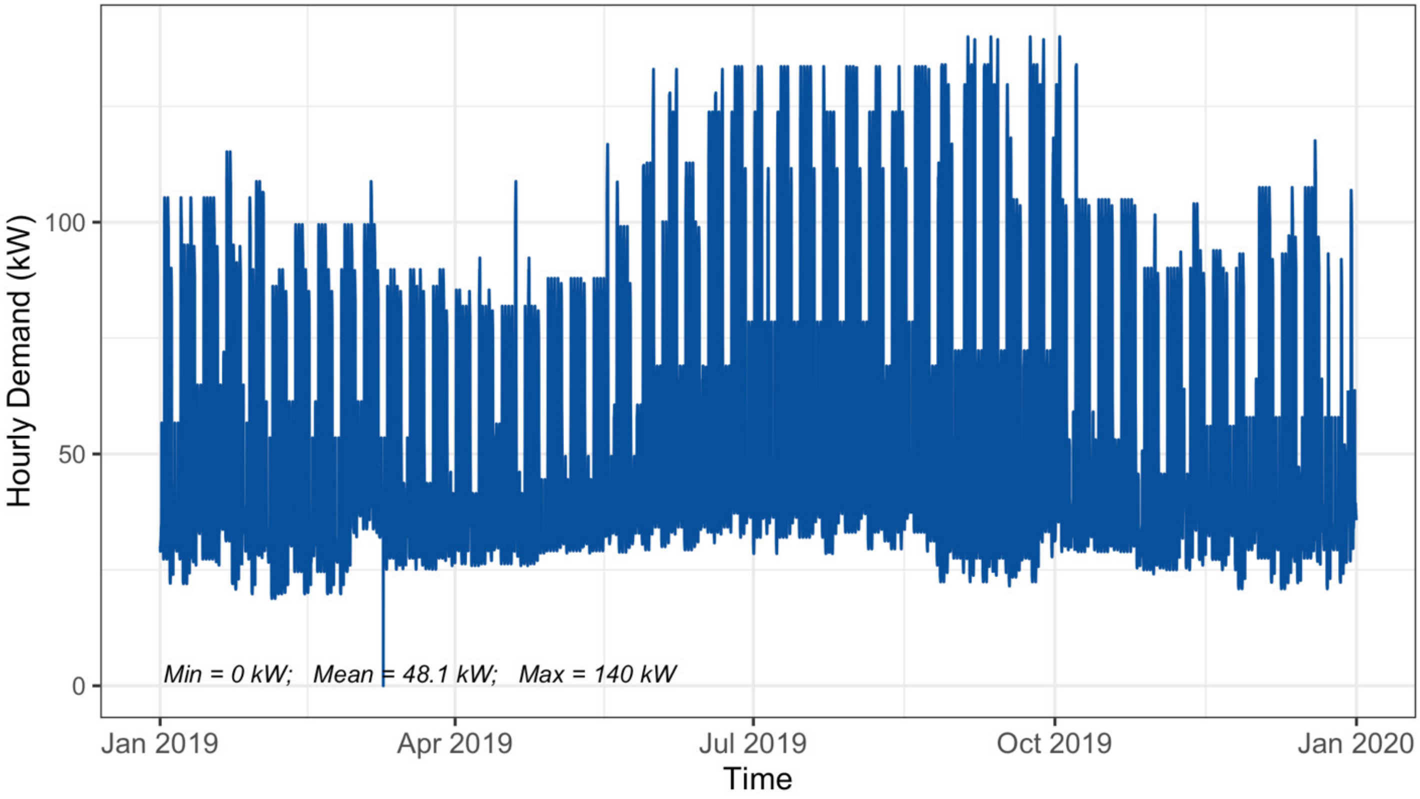

Table 17: REopt Results for K158, a K-12 School under Baseline Scenario

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	4 kW
BESS Capacity	n/a	10 kWh
Average Annual Energy Supplied from Grid	421,141 kWh	421,172 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$21,246	$21,247
Utility Demand Cost	$37,880	$36,661
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$181,319	$181,332
Utility Demand Cost	$323,286	$312,877
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$7,753
Total Life Cycle Costs	$504,605	$501,962
Net Present Value	n/a	$2,643
Payback Period	n/a	5.75 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	121.71	121.72

Correctional Facility: (Queens BH Campus: Queens Detention Complex Main and Auxiliary Building)

Figure 24: 2019 Annual Load Profile for Queens BH Campus: Queens Detention Complex Main and Auxiliary Building

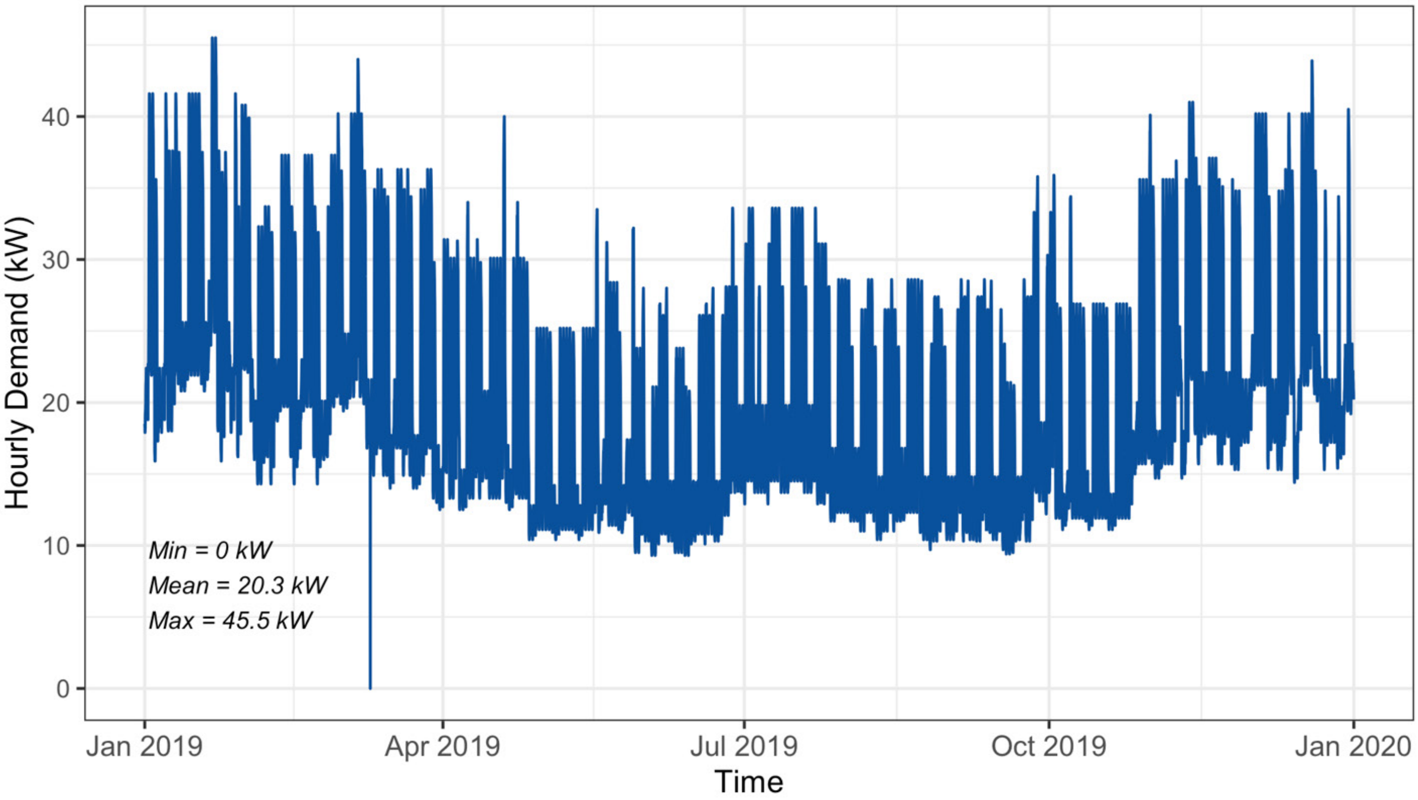

Table 18: REopt Results for Queens BH Campus: Queens Detention Complex Main and Aux. Building under the Baseline Scenario

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	1 kW
BESS Capacity	n/a	3 kWh
Average Annual Energy Supplied from Grid	177,407 kWh	177,414 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$8,888	$8,888
Utility Demand Cost	$11,810	$11,810
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$75,853	$75,857
Utility Demand Cost	$100,788	$97,250
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$2,558
Total Life Cycle Costs	$176,641	$175,665
Net Present Value	n/a	$976
Payback Period	n/a	5.59 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	51.27	51.28

Hunts Point WPCP Campus

Figure 25: 2019 Annual Load Profile for Hunts Point WPCP Campus

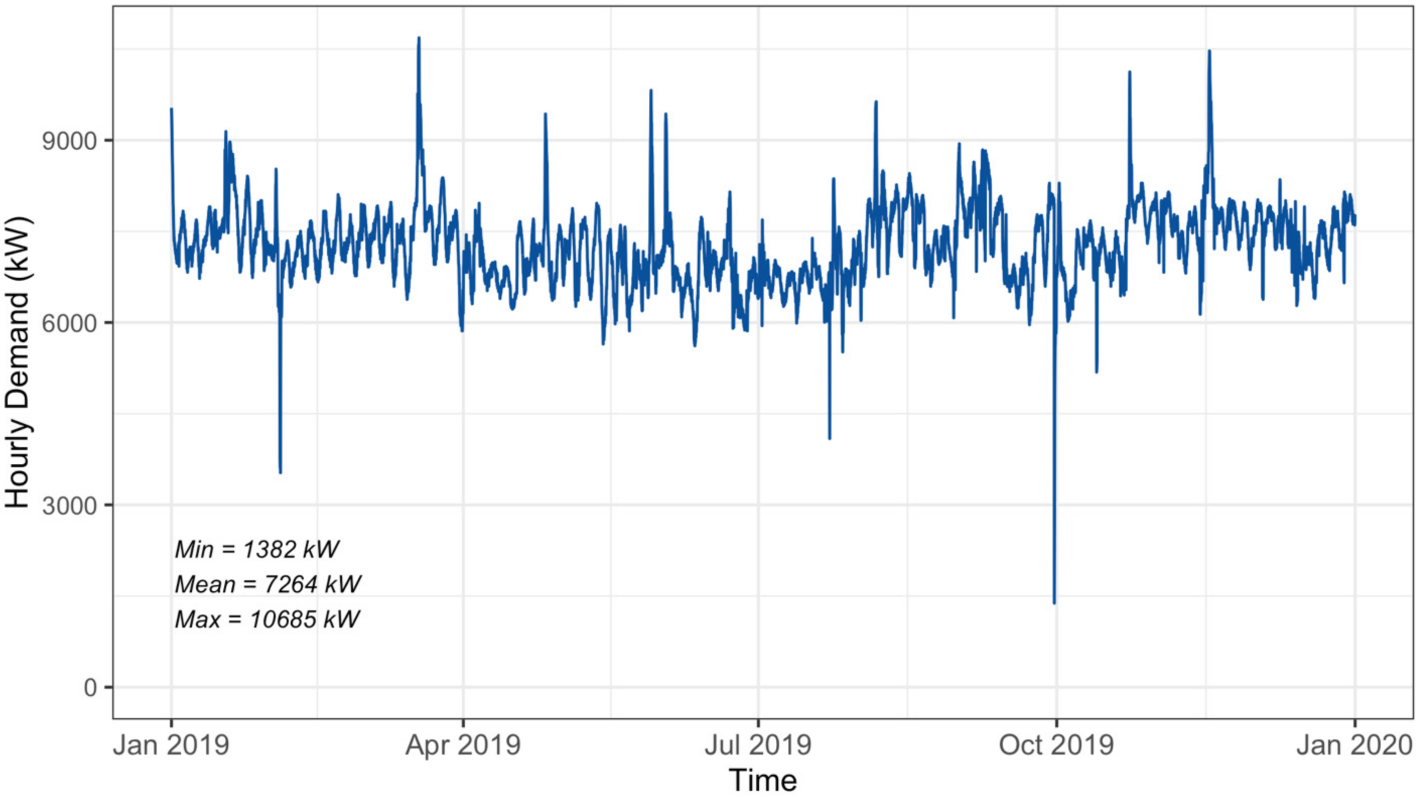

Table 19: REopt Results Hunts Point WPCP Campus under the Baseline Scenario

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	166 kW
BESS Capacity	n/a	381 kWh
Average Annual Energy Supplied from Grid	63,632,403 kWh	63,641,023 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$3,101,638	$3,101,095
Utility Demand Cost	$3,132,179	$3,084,818
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$26,470,715	$26,466,077
Utility Demand Cost	$26,731,363	$26,327,160
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$299,500
Total Life Cycle Costs	$53,202,078	$53,092,738
Net Present Value	n/a	$109,340
Payback Period	n/a	5.66 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	18,390	18,392

Detailed REopt results from the sensitivity analysis for the Staten Island Ferry Terminal:

BESS life of 15 years

Table 20: Detailed REopt Results for Scenario BESS Life of 15 Years

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	13 kW
BESS Capacity	n/a	37 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,440,975 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$123,135
Utility Demand Cost	$135,507	$132,340
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,470,992	$1,471,015
Utility Demand Cost	$1,618,809	$1,580,971
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$26,524
Total Life Cycle Costs	$3,089,802	$3,078,510
Net Present Value	n/a	$11,292
Payback Period	n/a	7.38 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	705.47

Minimum BESS size 5MW and 15MWh

Table 21: Detailed REopt Results for Scenario Minimum BESS Size of 5 MW and 15 MWh

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	5000 kW
BESS Capacity	n/a	15000 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,462,431 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$124,238
Utility Demand Cost	$135,507	$87,918
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,050,874	$1,060,298
Utility Demand Cost	$1,156,475	$1,060,298
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$10,500,000
Total Life Cycle Costs	$2,207,349	$12,310,632
Net Present Value	n/a	($10,103,283)
Payback Period	n/a	>25 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	711.68

TPO without Incentives

Table 22: Detailed REopt Results for Scenario TPO without Incentives

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	2 kW
BESS Capacity	n/a	3 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,440,938 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$123,134
Utility Demand Cost	$135,507	$134,963
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,050,874	$1,050,875
Utility Demand Cost	$1,156,475	$1,151,828
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$2,233
Total Life Cycle Costs	$2,207,349	$2,206,530
Net Present Value	n/a	$819
Payback Period	n/a	5.8 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	705.47

TPO with 26% ITC

Table 23: Detailed REopt Results for Scenario TPO with 26% ITC

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	6 kW
BESS Capacity	n/a	12 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,440,938 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$123,134
Utility Demand Cost	$135,507	$134,007
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,050,874	$1,050,879
Utility Demand Cost	$1,156,475	$1,143,677
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$5,574
Total Life Cycle Costs	$2,207,349	$2,204,107
Net Present Value	n/a	$3,242
Payback Period	n/a	5.6 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	705.48

Reduced BESS Cost ($450/kWh)

Table 24: Detailed REopt Results for Scenario Reduced BESS Cost ($450/kWh)

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	15 kW
BESS Capacity	n/a	56 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,440,999 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$123,137
Utility Demand Cost	$135,507	$131,556
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,050,874	$1,050,901
Utility Demand Cost	$1,156,475	$1,122,758
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$23,439
Total Life Cycle Costs	$2,207,349	$2,197,098
Net Present Value	n/a	$10,251
Payback Period	n/a	5.39 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	705.48

“Time of Day (TOD) - 91” (Electricity tariffs)

Table 25: Detailed REopt Results for Scenario “Time of Day (TOD) – 91” Electricity Tariffs

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	8 kW
BESS Capacity	n/a	20 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,441,386 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$120,929	$120,899
Utility Demand Cost	$150,555	$148,308
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,032,059	$1,031,804
Utility Demand Cost	$1,284,902	$1,265,724
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$14,999
Total Life Cycle Costs	$2,316,961	$2,312,526
Net Present Value	n/a	$4,435
Payback Period	n/a	5.94 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	705.39

Analysis Period of 25 years

Table 26: Detailed REopt Results for Scenario Analysis Period of 25 years

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	16 kW
BESS Capacity	n/a	57 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,441,000 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$123,137
Utility Demand Cost	$135,507	$131,524
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$2,146,463	$2,146,518
Utility Demand Cost	$2,362,157	$2,292,723
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$47,299
Total Life Cycle Costs	$4,508,620	$4,486,540
Net Present Value	n/a	$22,080
Payback Period	n/a	10.65 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	705.48

Minimum BESS size at 100% peak demand

Table 27: Detailed REopt Results for Scenario Minimum BESS Size at 100% Peak Demand

Parameters	Business As Usual (No BESS)	Cost Optimal BESS
BESS Power	n/a	554 kW
BESS Capacity	n/a	1,662 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,447,332 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$123,457
Utility Demand Cost	$135,507	$108,725
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,050,874	$1,053,635
Utility Demand Cost	$1,156,475	$927,905
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$1,163,400
Total Life Cycle Costs	$2,207,349	$3,144,941
Net Present Value	n/a	($937,592)
Payback Period	n/a	>25 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	707.31

Analysis Period of 10 Years

Table 28: Detailed REopt Results for Scenario Payback Period of 10 Years

Parameters	**Business As Usual (No BESS)**	**Cost Optimal BESS**
BESS Power	n/a	14 kW
BESS Capacity	n/a	38 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,440,977 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$123,136
Utility Demand Cost	$135,507	$132,257
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,050,874	$1,050,892
Utility Demand Cost	$1,156,475	$1,128,739
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$27,720
Total Life Cycle Costs	$2,207,349	$ 2,207,350
Net Present Value	n/a	($15,138)
Payback Period	n/a	7.51 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	705.47

Roof-top PV Plus Storage System

Table 29: Detailed REopt Results for Scenario Rooftop PV plus ESS

Parameters	**Business As Usual (No BESS)**	**Cost Optimal BESS**
BESS Power	n/a	5 kW
BESS Capacity	n/a	12 kWh
PV System size	n/a	0 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,440,947 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$123,134
Utility Demand Cost	$135,507	$134,011
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,050,874	$1,050,879
Utility Demand Cost	$1,156,475	$1,143,711
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$9,621
Total Life Cycle Costs	$2,207,349	$2,204,211
Net Present Value	n/a	$3,138
Payback Period	n/a	5.81 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	580.47

Roof-top PV plus Storage system with minimum BESS size at 100% peak demand

Table 30: Detailed REopt Results for Scenario Roof-top PV plus Storage system with Minimum Battery Size at 100% Peak Demand

Parameters	**Business As Usual (No BESS)**	**Cost Optimal BESS**
BESS Power	n/a	554 kW
BESS Capacity	n/a	1,662 kWh
PV System size	n/a	0 kWh
Average Annual Energy Supplied from Grid	2,440,935 kWh	2,447,332 kWh
Year 1 Utility Electricity Cost		
Utility Energy Cost	$123,134	$123,457
Utility Demand Cost	$135,507	$108,725
Life Cycle Utility Electricity Cost		
Utility Energy Cost	$1,050,874	$1,053,635
Utility Demand Cost	$1,156,475	$927,905
Summary Financial Metrics		
Total Upfront Capital Cost	n/a	$1,163,400
Total Life Cycle Costs	$2,207,349	$3,144,941
Net Present Value	n/a	($937,592)
Payback Period	n/a	>25 yrs.
Emissions		
GHG emissions (Annual) in tCO_2e	705.46	705.48

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