Sizing and Siting of Energy Storage in Distribution Systems

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IESO White Paper

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Nomenclature

BY	Energy storage replacement in years
δ	Bus voltage angle
DER	Distributed energy resource
$\overline{EB}$	Maximum energy storage energy in MWh
EG	State of change of microgrid energy storage in kWh
$\overline{EG}$	Maximum state of charge of microgrid energy storage in kWh
ES	Energy storage
f_B	Annualized ES cost
f_{Ic}	Annualized customer interruption cost
f_{mcB}	Annualized maintenance cost for ES
f_{mcf}	Annualized maintenance cost for feeders
f_{SF}	Annualized feeder cost
f_{repB}	Annualized ES replacement cost
g	Index for denoting generators or ES
G	Generators
HT	Number of hours in each period of the day
i,j	Indices denoting buses
IC	Net present value of investment cost of generators
$ICES$	Net present value of investment cost of ES
K_{r0}	Customer interruption cost in $/MWh at present time
K_{rr}	Growth rate of customer interruption cost
K_{Bf}	Maintenance cost constant of energy storage in $/MW-Yr
K_{Bv}	Variable maintenance cost of energy storage in $/MWh
K_{mf0}	Initial maintenance cost of the feeder in $ at present time
K_{mf}	Growth rate of maintenance cost
K_P	Round trip efficiency of energy storage
K_E	Self-discharge efficiency of energy storage
$k1$	Variable for representing operation planning periods
$k2$	Variable for representing installation planning periods
KF	Cost constant of the feeder in $/MVA
KBP	Cost constant of ES power in $/MW
KBE	Cost constant of ES energy in $/MWh
$KBPR$	Replacement cost constant of battery ES power in $/MW
$KBER$	Replacement cost constant of battery ES energy in $/MWh
KGC	Capital cost of generators $/kW
KGO	Operation and maintenance cost of generators $/kWh
KS	Cost of electricity from the transmission grid $/kWh
LD	Local distribution company
NB	Number of buses
NC	Number of feeder circuits
$\underline{NC}$	Minimum number of feeder circuits
ND	Number of days in a season
NT	Number of time periods in a day

NL	Number of branches
NPV	Net present value factor
NR	Number of energy storage replacements
NX	Number of batteries
NY	Index for number of years in the planning period
NYP	Years in a microgrid planning period
NYT	Number of microgrid planning periods
n	Index for denoting years within the planning period
$ONMC$	Net present value of total operation and maintenance cost
PB	Battery charge/discharge power
PD	Bus real power demand in kW
PG	Real power supply from generators/transmission grid or ES in kW
$\overline{PG}$	Maximum real power generation limit of generators or ES
$\underline{PG}$	Minimum real power generation limit of generators or ES
PI	Bus real power injection in kW
QD	Bus reactive power demand in kVAr
QG	Reactive power supply from generators/transmission grid in kVAr
$\overline{QG}$	Maximum reactive power capacity of generators or ES
$\underline{QG}$	Minimum reactive power capacity of generators or ES
QI	Bus reactive power injection in kVAr
PSC	Net present value of total cost of real power supply from the transmission system to the microgrid
pu	per unit
PV	Photovoltaic
r	Yearly discount rate
s	Index for denoting seasons of the year
$SAIDI$	System average interruption duration index (hr/year)
$\overline{SB}$	Maximum energy storage power
SB_{it}	Apparent power supplied from energy storage located at bus i
$\overline{SB_i}$	Maximum energy storage power in MVA
SD_{it}	Apparent power demand at bus i
SG_{it}	Apparent power generation at bus i
$\overline{SF_l}$	Feeder planning limit in MVA
$\overline{SF_E}$	Feeder emergency rating in MVA
SF_m	Feeder peak loading in MVA
SF_{lt}	Power flow between buses 'i' and 'j' at time't' in MVA
SL	Line power flow in MVA
t	Index for denoting time periods of the day
TL	Transmission system
θ	Angle of an element of bus admittance matrix
V	Bus voltage
Y	Magnitude of element of bus admittance matrix
y	Index for denoting microgrid planning period

Executive Summary

Objective of this Work

Due to the rapid price reduction of solar PV and ES, electricity consumers drive the integration of DER into distribution systems. Distribution companies need to adapt to the fast changing techno-economic environment. Optimal investment and operation strategies are important to reduce the supply cost and maintain the supply reliability. Mathematical formulations of two different long-term distribution planning strategies are presented in this white paper. The first formulation specifically discusses distribution feeder circuit deferral using ES, and the objective of the second formulation is operating a distribution network as a microgrid.

Strategy 1: Using ES for feeder investment deferral

The developed formulation looks at the long-term planning aspect of the investment deferral problem and the different cost items associated with feeder circuits and ES. Furthermore, it recognizes the inter-temporal relationship between energy and power in each ES. Daily and seasonal variations of power demand and renewable electricity supply have also been considered for developing this mathematical formulation. Sizing and siting ES for avoiding costly feeder investments is the objective of this mathematical formulation. An investment deferral case study considering a distribution feeder in Ontario is also presented.

Strategy 2: Distribution system operation as a microgrid

The objective of this strategy is to minimize the total investment and operation cost of microgrid excluding investments on network assists. A mathematical formulation was developed to investigate this objective. ES are to be used to manage islanded microgrids with renewable energy sources. It is assumed that the distribution network is already built. Investment and operation costs of generators and ES are compared to develop the least-cost long-term economic plan. A case study carried out considering a benchmark microgrid is presented to validate the developed formulation.

Conclusion Strategy 1: For the distribution system feeder deferral, battery ES is an option to be considered, even with the current prices of ES and distribution circuits. If the feeder has a considerable penetration of PV, battery ES are more economical than distribution feeder investments.

Conclusion Strategy 2: The case study with the benchmark microgrid with the current retail time-of-use electricity prices demonstrates that ES are not the best option to manage microgrids. However, if the microgrid has been built for a remote community, where the electricity generated from conventional sources is very expensive, ES are economical to manage the demand and renewable energy supply variations. Most of the battery ES technologies are economical for the considered ES options.

1. Introduction

Due to the rapid price reduction of consumer level renewable energy sources, consumers are becoming prosumers connected to electricity distribution systems. Reducing electricity bills, improving supply reliability and emissions reduction are the major objectives of this consumer level renewable energy supply growth. The penetration of Distributed Energy Resources (DER) has mixed effects on the distribution system assets and their operation. Therefore, distribution system operators are keen on investing, managing and controlling these DER. Energy Storage (ES) can provide the required flexibility against the supply fluctuations of distributed generation sources and power demand fluctuations. Therefore, the use of ES in power networks, especially in distribution networks, is rising. A brief review of recent research on this topic is presented below to highlight the importance of optimal siting and sizing of ES in distribution systems.

The technical benefits of ES are numerous; however, the economic attractiveness is limited and governed by the most optimal location, size and usage pattern [1]. In order to evaluate such benefits of ES, the authors of [1[propose a model that co-optimizes the size, site and charge/discharge profile of ES resources in the distribution network .The model is applied and validated on the Australian MV network. The main finding of the paper is that the financial feasibility of battery energy storage systems (BESS) as a solution for network upgrade deferral tends to reduce with increases in either load growth rate or PV penetration level. Optimal sizing and siting of ES in distribution networks have been thoroughly investigated in research work for different objectives. In]2[, a bi-level optimization model was proposed to determine the optimal installation site and the optimal capacity of BESS in distribution networks to accommodate the integration of DER. Methods of determining the installation site and the optimal capacity of the BESS to attain load leveling are discussed in [3]. Applying the method to the Georgian system proved the improvement of the daily load factor. The authors of [4[propose a method for determining rated power and energy capacity of a BESS, which is required to accommodate a particular penetration level of PV on a distribution feeder, or conversely, the amount of photovoltaic that could be installed on a feeder with a minimal investment in BESS capacity. The aim of the work is to develop a method for BESS sizing that can address feeders experiencing very high levels of PV penetration such that problems like the infamous Duck Curve can be mitigated. In [5[, a planning framework to determine the minimum storage sizes at multiple locations on distribution networks is presented. The framework aims to reduce curtailment from renewable DER, specifically wind farms, while managing congestion and voltages. The analysis demonstrates the importance of high granularity data to truly quantify the curtailment level that could be achieved by a given storage facility. A study focused on the optimal allocation of dispersed storage systems in distribution networks by finding the optimal trade-off between technical and economic goals is given]6[. Some of the issues that it accounts for are network voltage deviation, feeders/lines congestions, network losses and cost of supplying loads (from the external grid or local producers). The study concluded that optimally allocated dispersed storage systems can represent a valid solution for active distribution networks operators that do not want to deploy massive distributed generation controls. The authors of]7[present a review and thorough description of the state-of-the-art models and optimization methods applied to the energy system storage sizing and siting problem.

One of the main applications where ES is deployed in distribution systems is asset deferral. According to]8[, investment deferral is considered to be one of the most important benefits brought by integrating DER into distribution networks. In[8], a method was proposed to assess the optimal allocation of DER and ES for investment deferral. A method for quantifying the impacts of DER on the deferment of demand and system security-related network reinforcements is presented in [9[. Results show that ,despite differences between technology types, significant economic benefits can be harnessed when strategically incorporating DER at the planning stage. The authors of [10[examine different regulations for distribution network operators' ownership of DER in order to capture the effects of network investment deferral. Overall, the paper highlights the need for proper legislation at a European level, potentially obliging network operators to require for local power generation as an alternative to distribution networks reinforcement and for innovative financial rewards for distribution-level ancillary services within which DER can compete. Studies in [11] and [12] focus on the integral assessment of energy storage systems as a flexible option for investment deferral into the expansion planning of the power grid considering both economic and technical constraints. ES can provide considerable benefits to a distribution system which operates as a service aggregator. In this case, distribution network operators buy and sell energy and ancillary services, including voltage regulation, voltage control/reactive power, and frequency control to guarantee safe, reliable, and high-quality electricity delivery]13[. An aggregator's role also covers managing the services that are offered by the consumer side. An industrial scale experimental setup for evaluating a particular type of aggregators is presented in [13]. The aggregator aims to provide distribution grid services from industrial thermal loads through a direct control policy. Demand response is one such service which plays an essential role in enhancing consumer participation in electricity markets. Results showed that by aggregating the flexibility of different DERs, the aggregator could provide the aforementioned distribution services to a satisfactory level. The authors of [14[propose a stochastic model to optimize the performance of a demand response aggregator to take part in the day-ahead energy, ancillary services and intraday demand response exchange markets. Numerical results revealed that the formation of intraday exchange markets could bring opportunity for DR aggregators. In [15], an energy management system for aggregation of controllable loads in the distribution system is presented. The goal of the controller is to provide a schedule for the controllable loads while considering both local solar PV generation and provision of ancillary services. Simulation results show that provision of local reserves to support the loss of PV generation will result in an increase in the aggregator cost.

This white paper explains mathematical models for locating and sizing energy storage in distribution systems. The mathematical models differ from one application to another due to their primary objective(s). Therefore, two different major application of ES are considered in the paper. The first major application of ES is deferring distribution assets upgrades using suitable ES installations in the feeder. In the current context, this is a considerable application for distribution utilities in Ontario. A mathematical model developed for PowerStream to investigate investment deferral using ES is presented in Chapter 2. A case study was conducted and tested for a distribution system in Ontario. The second major application of ES considered in this paper is enabling the function of a distribution operator as a service aggregator using ES. The mathematical model for modeling the function of service aggregator is presented in Chapter 3. It looks at a futuristic approach where distribution utilities can buy and sell different services in the market and to the consumers. The paper provides several case studies conducted using a benchmark microgrid [16].

2 Feeder Investment Deferral using Energy Storage

The main objective of a distribution company is upgrading and maintaining distribution feeders at minimum cost. The asset upgrades are costly decisions and need to be considered carefully. Therefore, application of ES as an option to defer feeder investments needs to be investigated. This section explains energy storage sizing and siting for feeder investment deferral in distribution systems. There are no mathematical tools that have been reported to analyze this complex investment deferral problem. Ryerson Center for Urban Energy worked on this problem with industry partners, and completed a mathematical tool for studying distribution investment deferrals. The mathematical formulation was developed to model one of PowerStream's feeders. The model was presented to PowerStream with appropriate analysis. The developed model is explained below.

2.1 Rationale for Energy Storage in Distribution Feeder Deferral

The typical line power flow during a day is shown by profile 1 in Fig 1. Due to the extra flow (shown in red), one feeder circuit is not sufficient for supplying the load. Therefore, an extra feeder circuit is required to supply the load, but the extra feeder circuit is underutilized most of the time. If ES can reshape the power variation, and bring it to the power flow profile 2 (shown in green), one feeder circuit can supply the demand. In order to flatten the power curve from profile 1 to profile 2, ES should be connected at the far end bus, and increase the line flow by storing energy during low demand times and reduce the line flow by releasing energy during high demand times. The storage capacity should be large enough to store energy during the low demand hours. In other words, it is very important to connect the ES near the loads and size it appropriately such that it can reduce the line flows to a level below the capacity of one feeder circuit.

To justify expensive feeder investment decisions, high utilization factors are required. If the extra demand in Fig. 1 (shown in red) is very small, the second feeder utilization is low and ES has a clear opportunity to defer the feeder investments. Furthermore, in such cases, the size of ES required to bring the power variation to a level below the capacity of one feeder circuit is small. Therefore, ES investments are economical for such cases. There is no readily available tool to investigate this deferral problem. The mathematical formulation presented below has been developed to investigate this investment deferral problem.

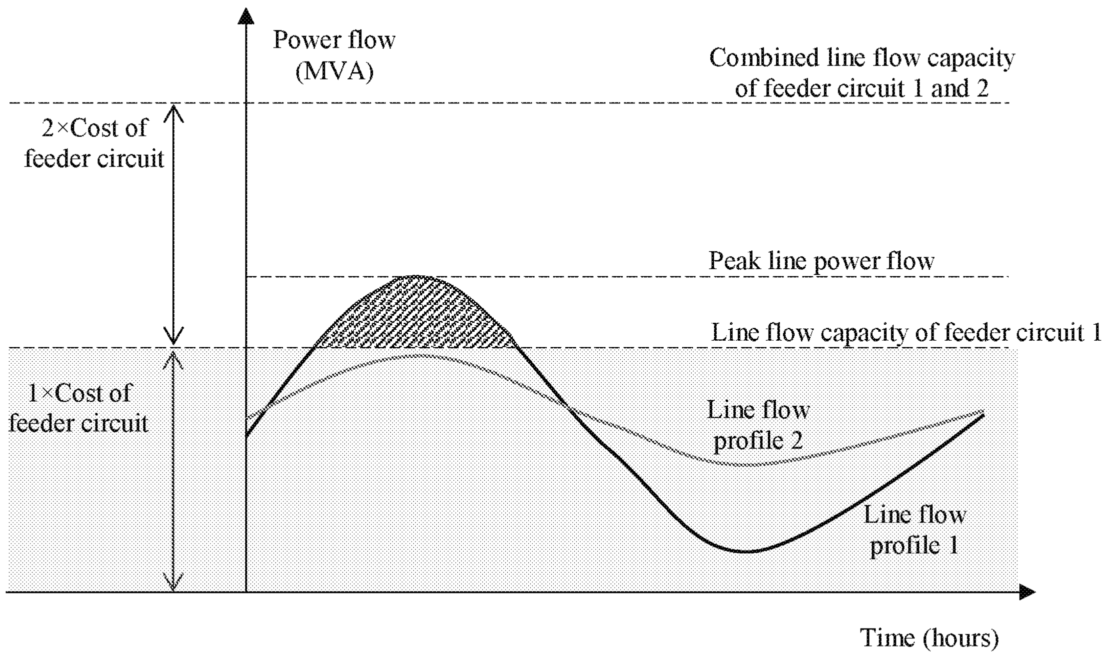

Figure 1 – Line Power Flow Profile and Feeder Circuit Requirement

2.2 Optimization Formulation for Feeder Investment Deferral

2.2.1 Objective Function

The new investments in feeder upgrades are decided considering the peak power demand and its growth. Feeder circuits are large discrete investments. If the peak demand is slightly higher than for one feeder circuit, a second circuit should be installed, and that feeder will be underutilized most of the time. In general, it seems reasonable to use ES technologies to reduce the peak power demand and minimize the costly feeder investments. On the other hand, feeders have different lifetimes and maintenance costs compared to ES technologies. These differences also should be compared to find the least-cost long-term solution. In this context, the objective of distribution system companies is to minimize the total cost associated with distribution system investments (feeder and DER), operation and maintenance. This objective function can be written considering the annualized costs as given in (1).

$$Minimize\ Total\ Annualized\ Cost,$$
$$f_{SF}\,(\overline{SF}, NY) + f_B\,(\overline{SB}, \overline{EB}, NY) + f_{repB}(\overline{SB}, \overline{EB}, NY) + f_{Ic}\,(SF_m, NC, NY) + f_{mcf}\,(NY) + f_{mcB}\,(\overline{SB}, NY). \tag{1}$$

where f_{SF} is the annualized feeder cost, f_B is the annualized ES cost, f_{repB} is the annualized ES replacement cost, f_{Ic} is the annualized customer interruption cost, f_{mcf} is the annualized maintenance cost for feeders, f_{mcB} is the annualized maintenance cost for ES. Each of these cost components can be illustrated as below.

$$f_{SF}\,(\overline{SF}, NY\,) = \left(\sum_{l=1}^{NL} KF_l \cdot \left(NC_l - \underline{NC_l}\right).\overline{SF_l}\right)\left[\frac{r(1+r)^{NY}}{(1+r)^{NY}-1}\right]. \tag{2}$$

$\overline{SF_l}$ is the feeder planning limits of branch *l*, KF_l is the cost of a feeder in branch *l*, NC_l is the number of feeder circuits in branch *l*, $\underline{NC_l}$ is the minimum number of feeder circuits in branch *l*, *r* is the interest rate, *NY* is the index of the planning period.

$$f_B\,(\overline{SB}, NY\,) = \left(\sum_{i=1}^{NX}(KBP_i \cdot \overline{SB_l} + KBE_i \cdot \overline{EB_l})\right)\left[\frac{r(1+r)^{NY}}{(1+r)^{NY}-1}\right]. \tag{3}$$

$$f_{repB}(\overline{SB}, \overline{EB}, NY) = \left(\sum_{i=1}^{NX}\left((KBPR_i \cdot \overline{SB_l} + KBER_i \cdot \overline{EB_l})\sum_{n=1}^{NR}\frac{1}{(1+r)^{n \cdot BY}}\right)\right)\left[\frac{r(1+r)^{NY}}{(1+r)^{NY}-1}\right], \tag{4}$$

$$NR \geq \frac{NY}{BY} - 1\,. \tag{5}$$

where $\overline{SB_l}$ is the maximum energy storage power in MVA at bus *i*, $\overline{EB_l}$ is the maximum energy storage energy in MWh at bus *i*, KBP_i is the cost constant of battery ES power in \$/MW, KBE_l is the cost constant of battery ES energy in \$/MWh, $KBPR_i$ is the replacement cost constant of battery ES power in \$/MW, $KBER_l$ is the replacement cost constant of battery ES power in \$/MWh, *BY* is the energy storage replacement in years, *NR* is the total number of energy storage replacements.

The annualized customer interruption cost,

$$f_{Ic}\,(SF, NY) = \left[\frac{r(1+r)^{NY}}{(1+r)^{NY}-1}\right] \cdot \sum_{n=1}^{NY}\sum_{l=1}^{NL} SAIDI\ per\ section \cdot \left(Kr_0(1+Kr_r)^{NY}\right) \cdot \frac{1}{(1+r)^n}. \quad (6)$$

where Kr_0 is the customer interruption cost in \$/MWh at present time, Kr_r is the growth rate of customer interruption cost. SAIDI is the System Average Interruption Duration Index (hr/year), SF_{lm} is the Feeder peak loading in MVA, $\overline{SF_E}$ is the Feeder emergency rating in MVA. SAIDI can be expanded as below (7) [20].

$$SAIDI\ per\ section = \frac{SAIDI\ per\ feeder\ circuit}{Number\ of\ feeder\ circuits} = \frac{0.177\left(\frac{SF_{lm}}{NC_l.\overline{SF_E}}\right)^2 + 1.11\left(\frac{SF_{lm}}{NC_l \cdot \overline{SF_E}}\right) + 0.8}{NC_l}\ . \quad (7)$$

The feeder maintenance cost,

$$f_{mcf}\,(NY) = \left(\sum_{n=1}^{NY}\left(K_{mf0}\left(1+K_{mf}\right)^n\right)\frac{1}{(1+r)^n}\right)\left[\frac{r(1+r)^{NY}}{(1+r)^{NY}-1}\right]\ . \quad (8)$$

where K_{mf0} is the initial maintenance cost of the feeder in \$ at present time, K_{mf} is the growth rate of maintenance cost. The maintenance cost of ES,

$$f_{mcB}\,(\overline{SB}, NY) = \left[\frac{r(1+r)^{NY}}{(1+r)^{NY}-1}\right] \cdot \left(\begin{array}{l}\displaystyle\sum_{i=0}^{NR-1}\sum_{n=1}^{BY-1}\overline{SB_l} \cdot K_{Bf} \cdot (1+K_{Bv})^n \cdot \frac{1}{(1+r)^{n+i\cdot BY}} + \\ \displaystyle + \sum_{n=1}^{NY-NR*BY}\overline{SB_l} \cdot K_{Bf} \cdot (1+K_{Bv})^n \cdot \frac{1}{(1+r)^{n+NR\cdot BY}}\end{array}\right). \quad (9)$$

where K_{Bf} is the maintenance cost constant of energy storage in \$/MW-Yr, K_{Bv} is the variable maintenance cost of energy storage in \$/MWh.

2.2.2 Constraints

The above objective function can be written for any number of feeder circuits, NC_l. The number of feeder circuits is decided by the line power flow requirement to serve the power demand at each bus at each period of the day. Variations of connected loads and generators, line admittances, and allowed bus voltage limits also affect the line flow. Furthermore, batteries and power generators have upper and lower limits. Considering these limitations, the constraints of the above cost minimization objective are given below. The power balance equation at bus *i* at period *t* is written as

$$SD_{it} + SL_{it}(V_{it}, \delta_{it}) - SG_{it} - SB_{it} = 0 \ . \tag{10}$$

where *SL* is the bus power injection from bus *i* at time *t*. The line flow can be expressed as below.

$$SF_l - V_{it}\angle\delta_{it} \cdot \left[\left(V_{it}\angle\delta_{it} - V_{jt}\angle\delta_{jt}\right) \cdot Y_l\angle\theta_l\right]^* = 0 \, . \tag{11}$$

Energy storage is subject to inter-temporal power and energy relationships (12). The state of charge at any period is expressed as the addition of the state of charge at the previous period and the charged/discharged energy.

$$EB_{it} = HT_t \cdot \max(PB_{it} \cdot K_P, \frac{PB_{it}}{K_P}) + EB_{i(t-1)} \cdot K_E \qquad i = 1,2 \ldots NX \tag{12}$$

Bus voltage maximum and minimum limits for each bus and generator maximum and minimum power limits for each generator can be written as.

$$V_{min} \leq V_{it} \leq V_{max} \quad . \tag{13}$$

$$SG_{i_{min}} \leq SG_{it} \leq SG_{i_{max}} \quad . \tag{14}$$

The line flow could be positive or negative considering the direction of the flow. Therefore, the absolute value of line flows is bounded by the limit of power flow from all selected feeder circuits.

$$|SF_{lt}| \leq NC_l \cdot \overline{SF_l} \quad . \tag{15}$$

The minimum and maximum energy and power limits of the energy storage are given below.

$$0 \leq EB_{it} \leq \overline{EB_i} \;;\; i = 1,2 \ldots NX \quad . \tag{16}$$

$$-\overline{SB_i} \leq SB_{it} \leq +\overline{SB_i} \;; i = 1,2 \ldots NX \quad . \tag{17}$$

2.3 Ontario Case Studies

The above algorithm was coded in Matlab, and tested with a distribution system feeder located in Ontario. It is assumed that feeder circuits have not been installed, and the optimal number of feeder circuits needs to be decided. Therefore, the main optimization decision variables are the number of feeder circuits and the size of ES. The location of the ES is decided based on the load concentration. It is recommended to conduct the study for different ES locations in the network.

Firstly, the considered feeder was simplified to three buses considering load concentration on the feeder (Fig. 2). Generally the feeders are designed to distribute power to consumers. However, today's distribution feeders could have a significant presence of solar and wind generations. In order to study this scenario of heavy renewable DER penetration and the benefit of ES, four different cases were studied and compared. Definitions of these cases are given below.

Case 1: Decide the optimal number of feeder circuits (There are no PV or ES connected to the system)

Case 2: Decide the optimal number of feeder circuits with PV connected at bus 3. (There is no ES connected to the system)

Case 3: Decide the optimal number of feeder circuits with ES (There is no PV connected to the system)

Case 4: Decide the optimal number of feeder circuits with PV and ES connected at bus 3

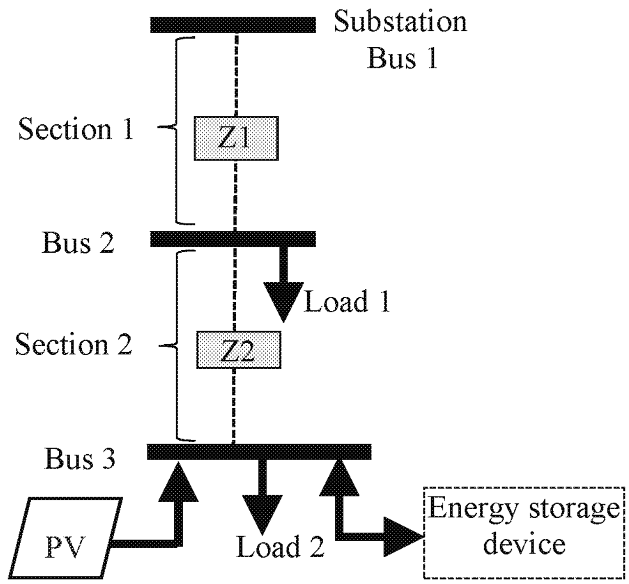

Figure 2 – Three Bus System with Energy Storage and Solar PV

Each of above cases was studied with different power demand and solar generation periods of the day. Battery energy storage was considered as a viable option for the feeder investment deferral. The considered data and results of the case studies are presented below.

2.3.1 Modified PowerStream M21 Feeder

The feeder data was taken from one of PowerStream's distribution systems. The simplified feeder is shown in Fig. 2. Data for the simplified system is given in Table 1. Impedance values were changed to match with the analysis. Bus voltage for the Case 1 is also given in Table 1. For modeling the daily charging and discharging of the battery, chronological variations of the load and the PV output were considered. These PV and load values for different periods of the day are given in Table 2.

Table 1 – Network Data and Voltage Solution of the Simplified Network

<table>
<tr><th colspan="7">Line Data</th></tr>
<tr><td></td><td colspan="2">Impedance Notation</td><td>R (Ω)</td><td>X (Ω)</td><td>Line flow per circuit (MVA)</td><td>Feeder Planning Limit (MVA)</td></tr>
<tr><td>Section 1</td><td colspan="2">Z1</td><td>0.0761</td><td>0.2283</td><td>20</td><td>20</td></tr>
<tr><td>Section 2</td><td colspan="2">Z2</td><td>0.0761</td><td>0.2283</td><td>7.3</td><td>20</td></tr>
<tr><td colspan="3">Load Data</td><td colspan="2">System Base</td><td colspan="2">Voltage Solution (Case I)</td></tr>
<tr><td></td><td>PD (MW)</td><td>Power Factor</td><td>Vbase</td><td>27.6 kV</td><td>Bus 1</td><td>$1.033\angle 0^0$ pu</td></tr>
<tr><td>Load 1</td><td>12</td><td>95%</td><td>Sbase</td><td>1 MVA</td><td>Bus 2</td><td>$1.032\angle 0.069^0$ pu</td></tr>
<tr><td>Load 2</td><td>7</td><td>95%</td><td>Zbase</td><td>761 Ω</td><td>Bus 3</td><td>$1.031\angle 0.094^0$ pu</td></tr>
</table>

Table 2 – Power Demand Data and PV Input Data

	Power Demand and PV input (MW)		
Time zone	1	2	3
PD	4.75 (25% peak load)	11.4 (60% peak load)	19 (100% peak load)
PV	30 (100% PV)	12 (40% PV)	0 (0% PV)

Table 3 shows the feeder and ES requirements for the least-cost investment plan for the four cases explained above. Without PV and ES, each feeder section needs at least one feeder circuit (Case 1). Comparing Case 1 and Case 2, it is clear that a PV penetration of 15 MW requires three additional feeder circuits to manage the PV supply. This additional feeder circuit requirement can be deferred with 8 MW battery with 34.5 MWh energy capacity (Case 4).

Table 3 – Results of the Four Cases – M21 Feeder

Case	Case Description	No. of feeder circuits	ES Capacity		Cost of feeders $M	Cost of ES $M
			Power (MW)	Energy (MWh)		
1	No PV, No ES	1 , 1	0	0	3.19	0
2	Yes PV, No ES	2 , 2	0	0	5.91	0
3	No PV, Yes ES	1 , 1	0	0	3.19	0
4	Yes PV, Yes ES	1 , 1	8.23	36.14	3.11	2

A sensitivity analysis was carried out varying the price of ES (both in terms of price of power capacity and energy capacity). The 100% ES price is KBE = 400 $/kWh, KBP = 400 $/kVA and KF = $135,000 per km per MVA. Six more sensitivity cases were studied, five cases by increasing the ES price by 20% in each case, and one by increasing the price by 10% at the 150% level. Comparing results of the sensitivity analysis in Fig 3, it is clear that use of energy storage is cost effective to defer feeder investments even when ES price is 160% higher. With the increase of battery price, the selected capacity decreases. Beyond 140% of price increase, one more feeder circuit is required. Beyond 160% cost level of price increase, two more feeder circuits are required, and ES is not used. This long-term investment deferral analysis is carried out before installing the feeders. Annual savings of $3.267 Million can be realized with the current ES and feeder prices.

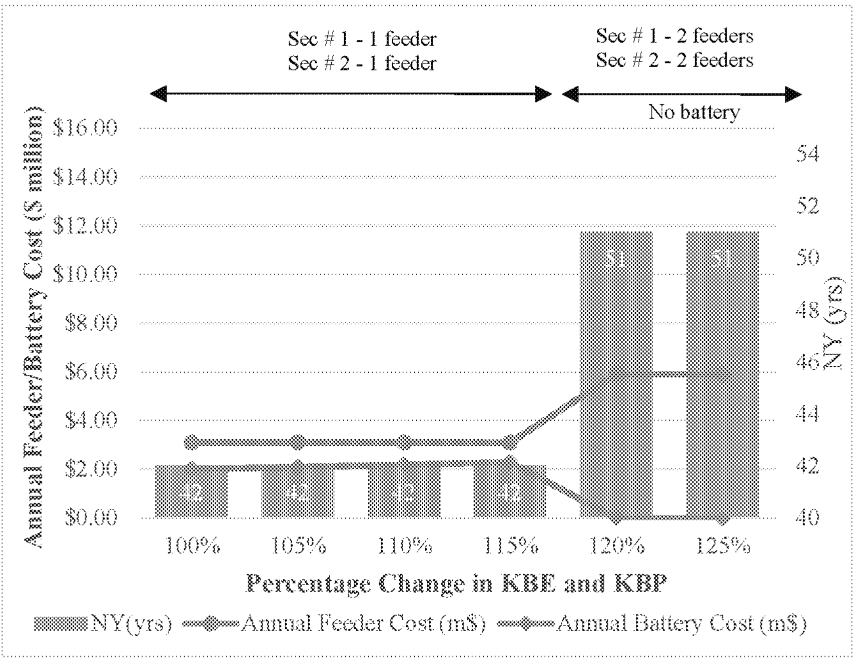

Figure 3 – Feeder and ES Selection of M21 Feeder against Battery Price

2.4 Key Conclusions

1. Even with current ES and feeder costs, ES can be used for feeder investment deferrals.
2. ES is an attractive option to avoid feeder installations demanded by higher penetration of renewable generators. ES can absorb the generation supply fluctuations and reduce the number of feeder circuits to its minimum required by the loads.

3 Distribution System Function as a Service Aggregator (Microgrid)

This subchapter explores the potential distribution operator as a service aggregator in the electricity market. A distribution system can provide a series of services integrating with energy storage (ES) system and generation sources. Services include load curve smoothing, energy arbitrage and voltage support. A mathematical formulation was created to determine the suitable location and size of energy storage required for achieving the cost minimization objective of the aggregator.

3.1 Mathematical Formulation of ES Sizing and Siting in Microgrids

Generally, if the distribution system network has been installed, investment decisions on other technologies are taken considering peak demand of the next 5 – 10 years. The distribution utilities minimize system cost over this investment period. Grid operation and DER investment costs need to be considered for this planning problem. Some of the DER such as the wind, solar PV generators and flywheels last about 20 years while other technologies such battery ES last about 5-8 years. It is important to consider these different life spans for developing a long-term least-cost investment plan. All these technologies have different capital, operation and maintenance costs. The total life cycle economic cost and salvage values also need to be included in the planning tool. Furthermore, it is important to note that ES size is decided based on the daily and seasonal variations of power demand and renewable generations. The location of DER connection in the network is decided based on the network loss considerations. Therefore, power demand and generation variations and network admittances should be considered in studying sizing and siting of ES in microgrids.

3.1.1 Objective Function

The long-term objective of the microgrid is to minimize the total cost (investment and operation) during a selected planning period. To simplify the planning problem, a 21 year planning period is considered with three investment periods of seven years each. Generators and flywheel ES can operate throughout the planning period of 21 years while the other ES technologies need to be installed in each investment period. Due to the small size of assets, the salvage value of investments is neglected. Assuming all distribution network assets (distribution lines) have been already built, the objective of this planning problem can be written as below.

$$Minimize\ Total\ Cost,\quad PSC\left(PG_{TL\,t\,s\,y}\right) + ONMC\left(PG_{g\,t\,s\,y}\right) + IC\left(PG_{gt\,s\,y}, QG_{g\,t\,s\,y}\right) + ICES\left(PG_{gt\,s\,y}, QG_{g\,t\,s\,y}, EG_{g\,t\,s\,y}\right)\ . \tag{18}$$

Where PSC_s is the NPV of total cost of power supply from the transmission grid during the planning period, ONMC is the NPV of operation and maintenance costs of generators and ES over the planning period, IC is the NPV of investment cost of the generator over the planning period, ICES is the NPV of investment cost of energy storage systems over the planning period. The above cost parameters can be illustrated by the following expressions. The cost of power supply from the transmission grid,

$$PSC\left(PG_{TL\,t\,s\,y}\right) = \sum_{y=1}^{NYT}\sum_{s=1}^{NS}\sum_{t=1}^{NT}(PG_{TL\,t\,s\,y}\cdot k1_{TL\,y}\cdot HT_t\cdot KS_t\,\cdot)\cdot ND_s\cdot NYP\cdot NPV_y\ . \tag{19}$$

where $PG_{TL\,t\,s\,y}$ is the real power supply from the transmission grid at each daily period t in kW, HT_t is the length of the period in hours, KS_t is the cost of power from the grid in (\$/kWh), ND_s is the number of days in the considered season, NYP is the number of years in the investment period, NPV_y is the net present value factor for the considered investment period.

The operation and maintenance costs of generators and ES are given in (20). It is assumed that the ONMC(PG_g) depends on the power generation. A generator or a flywheel ES has about a 20 year lifetime. Therefore, it is assumed that any generator investment can supply power during the full planning period.

$$ONMC\left(PG_{gt\,s\,y}, QG_{g\,t\,s\,y}\right) = \sum_{y}^{NYT}\sum_{s}^{NS}\sum_{t}^{NT}\sum_{g}^{NG+NES} PG_{g\,t\,s\,y}\cdot k1_{g\,y}\cdot KGO_g\cdot HT_t\cdot ND_s\cdot NPV_y \quad \forall\, g\in\{G, ES\}. \tag{20}$$

where KGO_g is the operation cost of the generator and $k1_g$ is a binary variable to represent the operated investment period of the generator or ES.

The investment cost of generators can be written as below (21). Except for flywheels, all other ES technologies have shorter life spans. It is assumed that the life spans of those ES technologies equal one-third of the planning period. With these assumptions, the capital cost of ES (except flywheels) can be written as (22). The capital cost of flywheels is written as (23).

$$IC(PG_{g\,t\,s\,y}, QG_{g\,t\,s\,y}) = \sum_{g}^{NG} KGC_g \cdot k2_{g\,y} \cdot max\left(\sqrt{PG_{g\,t\,s\,y}{}^2 + QG_{g\,t\,s\,y}{}^2}\right)$$

$$\forall\, g\ \in \{G, Flywheels\}. \quad (21)$$

$$ICES(PG_{g\,t\,s\,y}, QG_{g\,t\,s\,y}, EG_{g\,t\,s\,y}) = \sum_{g}^{ES}\left(KBP_g \times k1_{g\,y} \times max\left(\sqrt{PG_{g\,t\,s\,y}{}^2 + QG_{g\,t\,s\,y}{}^2}\right) + KBE_g \times k1_{g\,y} \times \max(EG_{g\,t\,s\,y})\right)$$

$$\forall\, g\ \in \{ES\ \notin Flywheels\}\ . \quad (22)$$

$$ICES(PG_{g\,t\,s\,y}, QG_{g\,t\,s\,y}, EG_{g\,t\,s\,y}) = \sum_{g}^{ES}\left(KBP_g \times k2_{g\,y} \times max\left(\sqrt{PG_{g\,t\,s\,y}{}^2 + QG_{g\,t\,s\,y}{}^2}\right) + KBE_g \times k2_{g\,y} \times \max(EG_{g\,t\,s\,y})\right)$$

$$\forall\, g\ \in \{Flywheels\}. \quad (23)$$

Where *k1* is the variable representing the operation of the generator or ES in an investment period. If a generator or ES operated in an investment period, the value of *k1* is one. It is possible to operate a generator or ES in all three investment periods. Therefore, *k1* of a generator or an ES can be a one for all three investment periods. The variable *k2* represents the investment period when a generator or a flywheel is firstly installed. If a generator is installed in the first investment period, *k2* of the generator is one only for the first investment period and zero for other investment periods. The computation of *k1* and *k2* are given in the constraints section below.

3.1.2 Constraints

Microgrid network constraint and the inter-temporal constraint of ES are the main two constraints for the above objective function. Furthermore, the relationship of finding the investment periods and operation periods of generators and ES also should be included as constraints. Besides these constraints, power outputs and state of charge of ES should be bounded by the upper and lower power and energy limits. Mathematical formulations of these constraints and bounds are presented below.

Power capacity limits of DER

$$\underline{PG_g} \le PG_{g\,t\,s\,y} \le \overline{PG_g} \qquad \forall\, g\, \in \{G, ES\}\ . \tag{24}$$

$$\underline{QG_g} \le QG_{g\,t\,s\,y} \le \overline{QG_g} \qquad \forall\, g\, \in \{G, ES\}\ . \tag{25}$$

Inter-temporal energy constraints of ES

$$EG_{g\,t\,s\,y} - EG_{g\,t-1\,s\,y} = HT \cdot PG_{g\,t\,s\,y} + \left(1 - K_p\right) \cdot abs\left(PG_{g\,t\,s\,y}\right) \ \ \forall\, g\, \in \{ES\}. \tag{26}$$

$$EG_{g\,1\,1\,1} = EG_{g\,NT\,NS\,NY} \qquad \forall\, g\, \in \{ES\}\ . \tag{27}$$

$$EG_{g\,t\,s\,y} \le \overline{EG_g} \qquad \forall\, g\, \in \{ES\}\ . \tag{28}$$

The power balance at each bus of the network for every period of the day

$$PG_{i\,t\,s\,y} - PD_{i\,t\,s\,y} = V_{i\,t\,s\,y} \sum_{j}^{NB} V_{j\,t\,s\,y} \cdot Y_{ij} \cdot Cos\left(\delta_{i\,t\,s\,y} - \delta_{j\,t\,s\,y} - \theta_{ij}\right) \ \ \forall\, i, j, t, s, y\,. \tag{29}$$

$$QG_{i\,t\,s\,y} - QD_{i\,t\,s\,y} = V_{i\,t\,s\,y} \sum_{j}^{NB} V_{j\,t\,s\,y} \cdot Y_{ij} \cdot Sin\left(\delta_{i\,t\,s\,y} - \delta_{j\,t\,s\,y} - \theta_{ij}\right) \ \ \forall\, i, j, t, s, y\,. \tag{30}$$

The investment periods for which a generator or an ES is operated can be found by $kI_{g\,y}$. According to (31), if a generator supplies any power, the value of $kI_{g\,y}$ has to be one. Otherwise, it is forced to be zero by the minimizing sense of the objective function. The same constraint is presented for ES in (32).

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$$k1_{gy} \cdot \sum_{s}^{NS}\sum_{t}^{NT}\sqrt{PG_{gtsy}^{2} + QG_{gtsy}^{2}} = \sum_{s}^{NS}\sum_{t}^{NT}\sqrt{PG_{gtsy}^{2} + QG_{gtsy}^{2}} \quad \forall g \in \{G\}, \forall y. \quad (31)$$

$$k1_{gy} \cdot \sum_{s}^{NS}\sum_{t}^{NT}\left(\sqrt{PG_{gtsy}^{2} + QG_{gtsy}^{2}} + EG_{gtsy}\right) = \sum_{s}^{NS}\sum_{t}^{NT}\left(\sqrt{PG_{gtsy}^{2} + QG_{gtsy}^{2}} + EG_{gtsy}\right) \ \forall g \in \{ES\}, \forall y. \quad (32)$$

where $k1_{gy}$ is one for the years that the generator or ES is operated and zero for the years it is not operated. The investment period for installation of generator or ES required can be found $k2_{gy}$. The value $k2_{gy}$ of can be found by subtracting $k1_{gy}$ as presented in (33). The computation of the net present value factor for the investment period is given in (34).

$$k2_{g\,y+1} = k1_{g\,y+1} - k1_{gy} \text{ and } k2_{g1} = k1_{g1} \quad \forall g \in \{G, ES\}. \quad (33)$$

$$NPV_y = (1/(1+r)^{y*NYP+1}) \quad \forall y. \quad (34)$$

3.2 Benchmark Microgrid System

A benchmark microgrid [16] was used for testing the developed algorithm. The microgrid has twelve buses. It is assumed that all power demands are constant power type nodal loads. Details of the connected loads and distribution lines are proved in Table 4 and Table 5. Appropriate power factor values were assumed (Table 5) to compute real and reactive power values at each bus. There is no DER connected to the original network. Five renewable generators and seven energy storage candidate options were considered as candidate DER for this sizing and siting study. Information on these candidate options is given in Table 6 and Table 7. In order to investigate the competitive DER selection, it is taken that grid power capacity is higher than the total microgrid load. The transmission grid connection is at bus 101. Fig. 4 shows the single line diagram of the benchmark microgrid system.

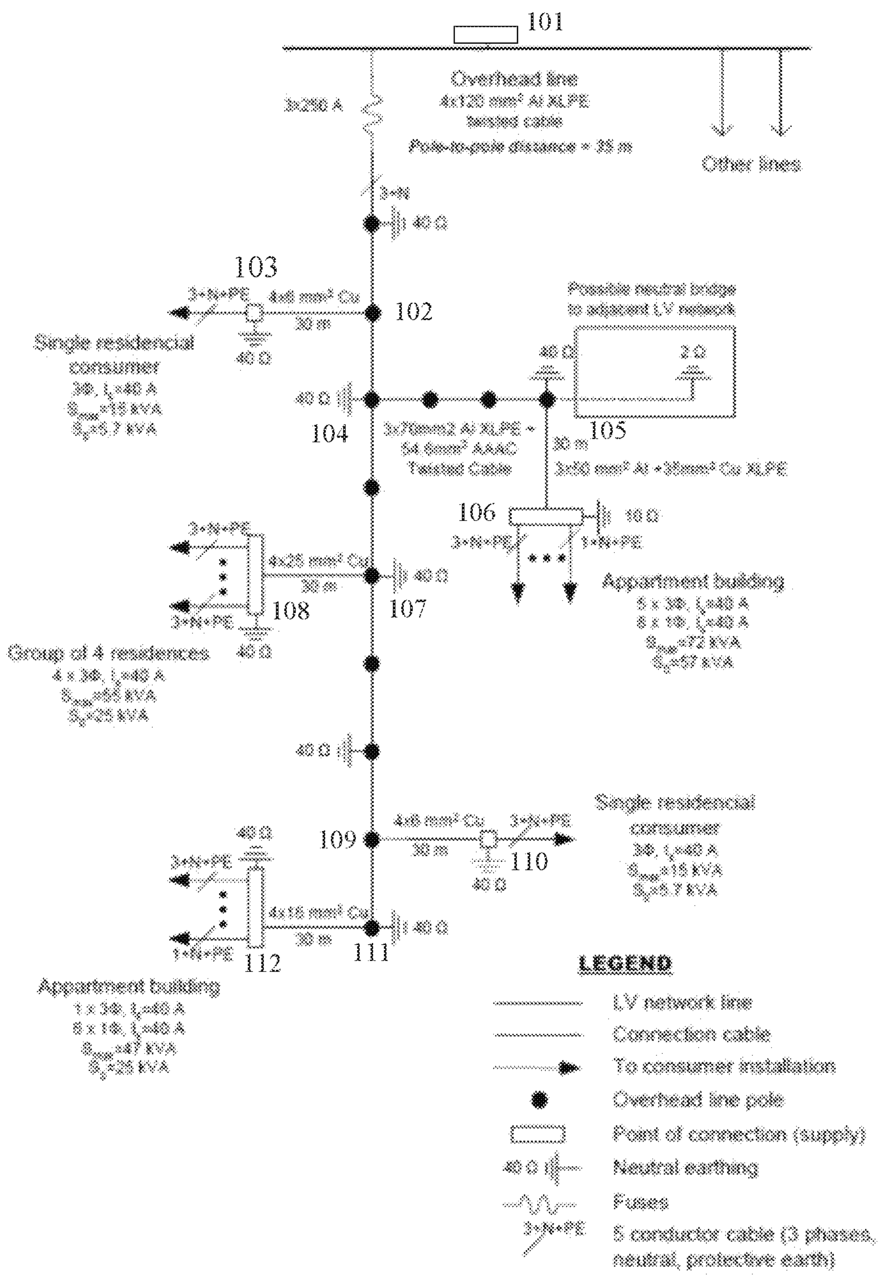

Figure 4 – Benchmark Microgrid System

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Table 4 – Bus Power Demand of the Microgrid

Node	Load Model	Ph-1 kW	Ph-1 kVAr	KVA	PF
103	Y-PQ	12	9	15	0.8
106	Y-PQ	70.6	14.3	72	0.98
108	Y-PQ	44	33	55	0.8
110	Y-PQ	12	9	15	0.8
112	Y-PQ	46.1	9.4	47	0.98

Table 5 – Network Data of the Microgrid

Node A	Node B	Length(m)	R (Ω/km)	X(Ω/km)	Vbase
101	102	70	0.284	0.083	0.4
102	103	30	3.690	0.094	0.4
102	104	35	0.284	0.083	0.4
104	105	105	0.497	0.086	0.4
105	106	30	0.822	0.077	0.4
104	107	70	0.284	0.083	0.4
107	108	30	0.871	0.081	0.4
107	109	105	0.284	0.083	0.4
109	110	30	3.690	0.094	0.4
109	111	35	0.284	0.083	0.4
111	112	30	1.380	0.082	0.4

Table 6 – Microgrid Renewable Generator Data

Node	Source	Maximum Real Power (kW)	Maximum React. Power (kVAr)	Capital Cost ($/kW)	O&M Cost ($/kWh)
101	Grid	300	200	0	0.000
112	Solar	50	40	4183	0.008
105	Solar	10	10	3873	0.008
104	Wind	50	0	2213	0.010
102	solar	5	5	3873	0.007
107	CHP	40	40	1023	0.014

Table 7 – Microgrid Energy Storage Data

Node	Technology	Maximum Real Power (kW)	Maximum React. Power (kVAr)	Maximum Energy (kWh)	Capital Cost for Power ($/kW)	Capital Cost for Energy ($/kWh)	O&M Cost ($/kW-yr)	Charge/ Discharge loss (%)
105	Lead Acid	25	20	100	930	831	20.76	8.0
109	NaNiCl	20	20	150	869	722	20.77	8.0
110	Li-Ion	40	40	200	651	1236	34.69	8.0
111	Flywheel	10	8	2	2159	8638	7.90	6.0
107	Li-Ion	5	5	50	651	1236	34.69	7.0
102	NaS	4	4	20	559	386	9.38	8.0
104	Li-Ion	8	8	40	651	1236	34.69	9.0

3.3 Energy Storage Siting and Sizing for Microgrids

Daily load variation creates an opportunity to store energy during low demand hours and release energy during peak demand hours. Furthermore, excess generation or deficit of generation in the network is also a deciding factor of the storage requirement in the network. In general, solar and wind generation varies with the time of the day and time of the year. In addition to these ES sizing factor, the price of electricity of the transmission system gives the economic benefit for the ES function. Therefore, all of these chronological variations have to be considered for a proper ES sizing and siting study. Table 8 provides the chronological variations considered in this study. Three periods of equal length were considered for each day and two seasons with different daily variations were considered for the analysis. Ontario time-of-use tariff was taken as the price of electricity from the transmission grid.

Table 8 – Energy Storage Data of the Microgrid

	Time Period	Wind Power (%)	Solar power (%)	Load profile (%)	Price $/kWh
Winter day	11 pm – 7 am	1	0	0.4	0.087
	7 am – 3 pm	0.5	0.5	0.6	0.132
	3 pm – 11 pm	0.7	0	1	0.18
Summer day	11 pm – 7 am	0.8	0	0.4	0.087
	7 am – 3 pm	0.3	1	0.6	0.132
	3 pm – 11 pm	0.5	0	0.95	0.18

If the Ontario current time of day prices are considered as the price of electricity supplied to the microgrid from the transmission system, wind and CHP generation technologies are selected for investments at the first investment period. This includes the 40 kW of CHP plant at bus 107 and the 35 kW of wind turbine at bus 104. The generation capacity selection is shown in Fig. 5. None of the ES technologies are selected for the long-term minimum cost plan. This is due to the high price of ES cost.

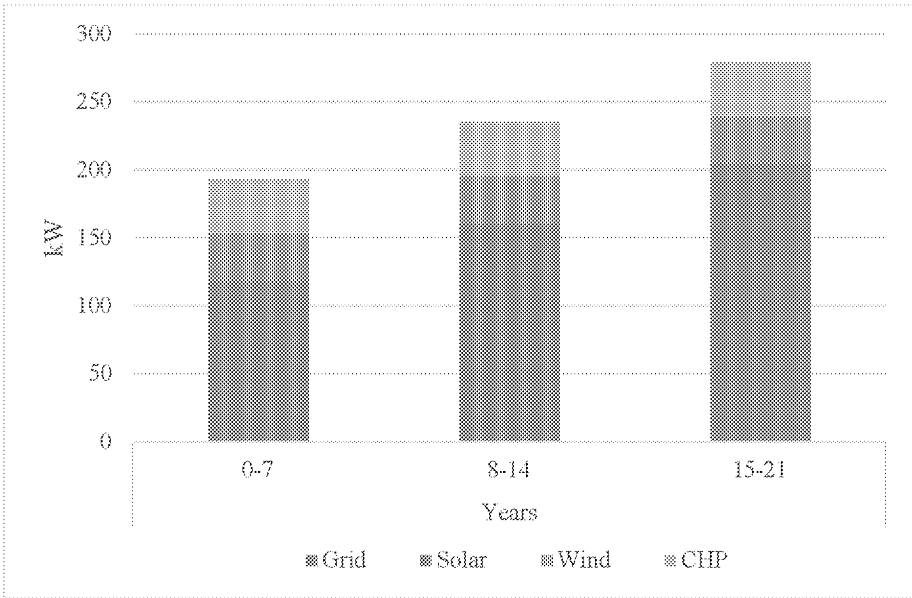

Figure 5 – Capacity Selection Generation Sources –Time-Of-Use Electricity Prices

If the microgrid has been designed to electrify a remote community, the transmission connection is replaced by a conventional thermal generator, and it is fair to assume a very high price for the electricity supplied to the microgrid. This assumption reflects the high generation cost due to fuel transportation costs to the remote community. Tenfold higher rates for the electricity from the transmission grid were taken for the rest of the study. Generation capacity selection under this high electricity price scenario is shown in Fig. 6. Comparing Fig. 5 and Fig. 6, it is noted that power supply from the costly conventional generators/transmission grid is reduced considerably. The wind generation capacity was increased from 35 kW to 50 kW at bus 104. Even with high prices, electricity generated with solar PV is not economical compared to the electricity from the conventional sources. Wind and CHP are fully utilized in this least-cost plan. The locations of these generators in the microgrid are shown in Fig. 9.

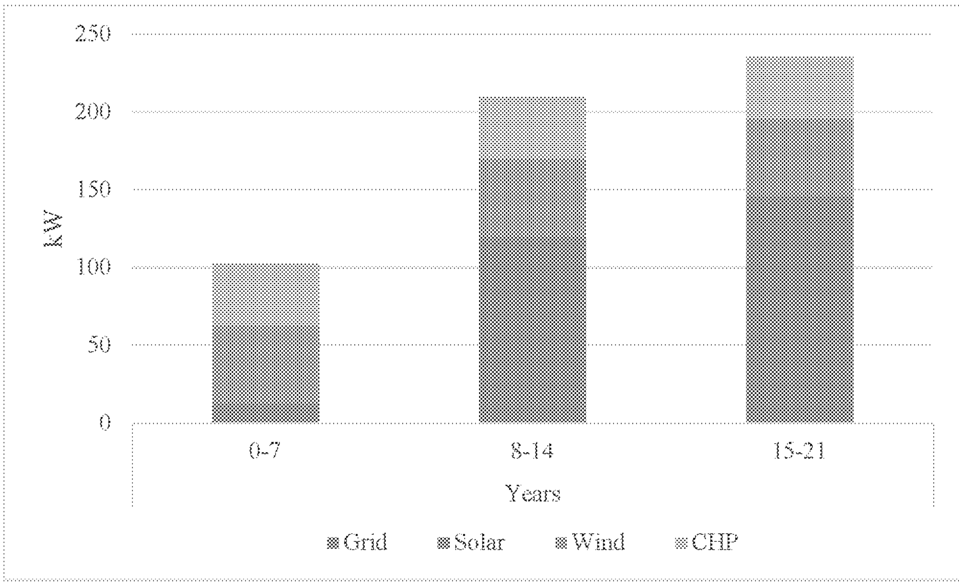

Figure 6 – Capacity Selection Generation Sources – Tenfold Electricity Prices

Energy storage power and energy capacity selection for different investment periods are presented in Fig. 7 and Fig. 8. Except for flywheels, all energy storage technologies are selected with different capacities across investment periods. ES technologies help to store power from renewable sources and minimize the power supply from the transmission grid. The sites of these ES in the microgrid are shown in Fig. 9.

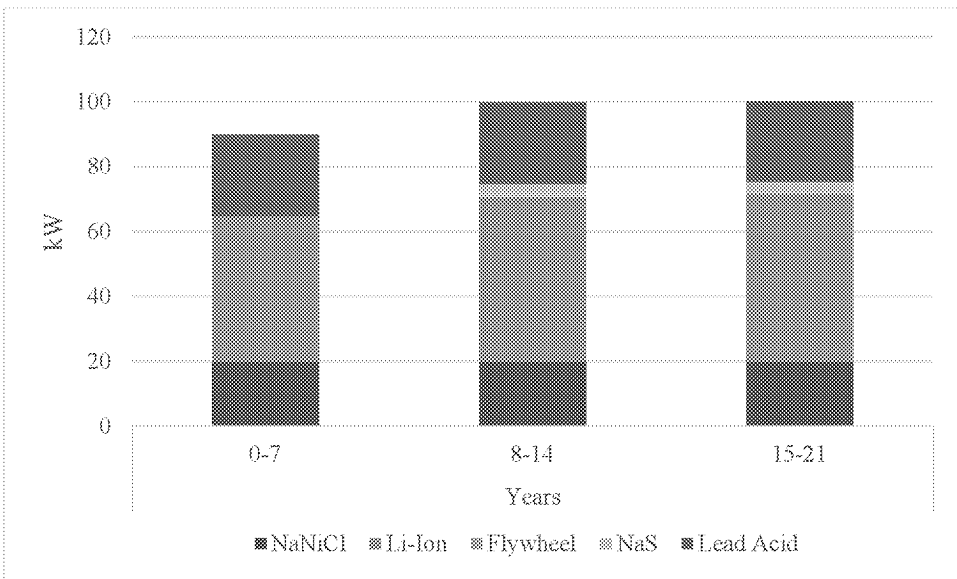

Figure 7 – Power Capacity of Selected Generation Sources

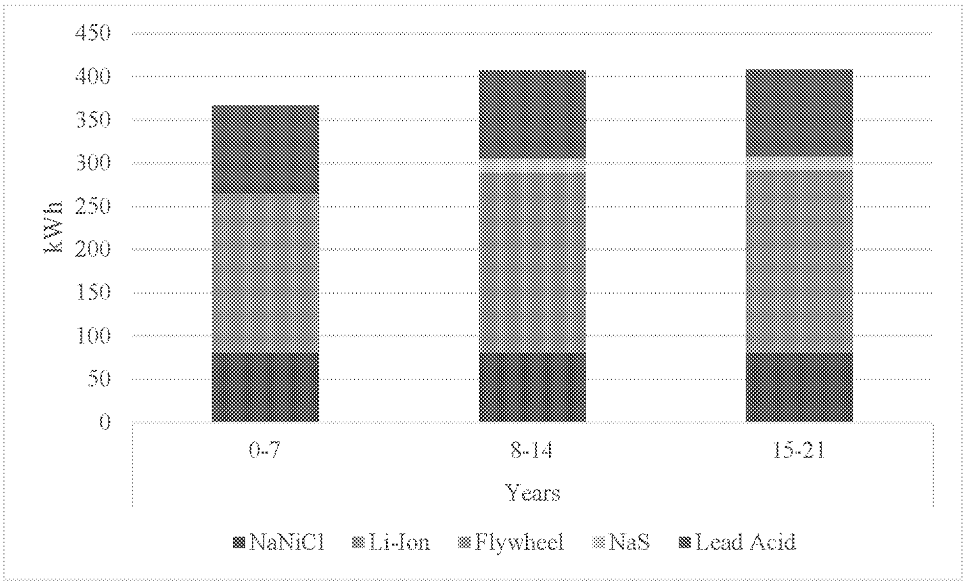

Figure 8 – Power Capacity of Selected Energy Storage

It is fair to expect that ES technologies are improving and the prices are declining gradually. To investigate the effect of ES prices on the least-cost investment plan, two different ES planning studies were conducted by reducing the ES price by 20% and 40%. It is observed that even with the price of ES reduced, the selection of ES is the same. This is due to the lack of cheap electricity from renewable electricity resources to store in ES. The main deciding factor for ES selection is the price of electricity from the transmission grid or conventional sources.

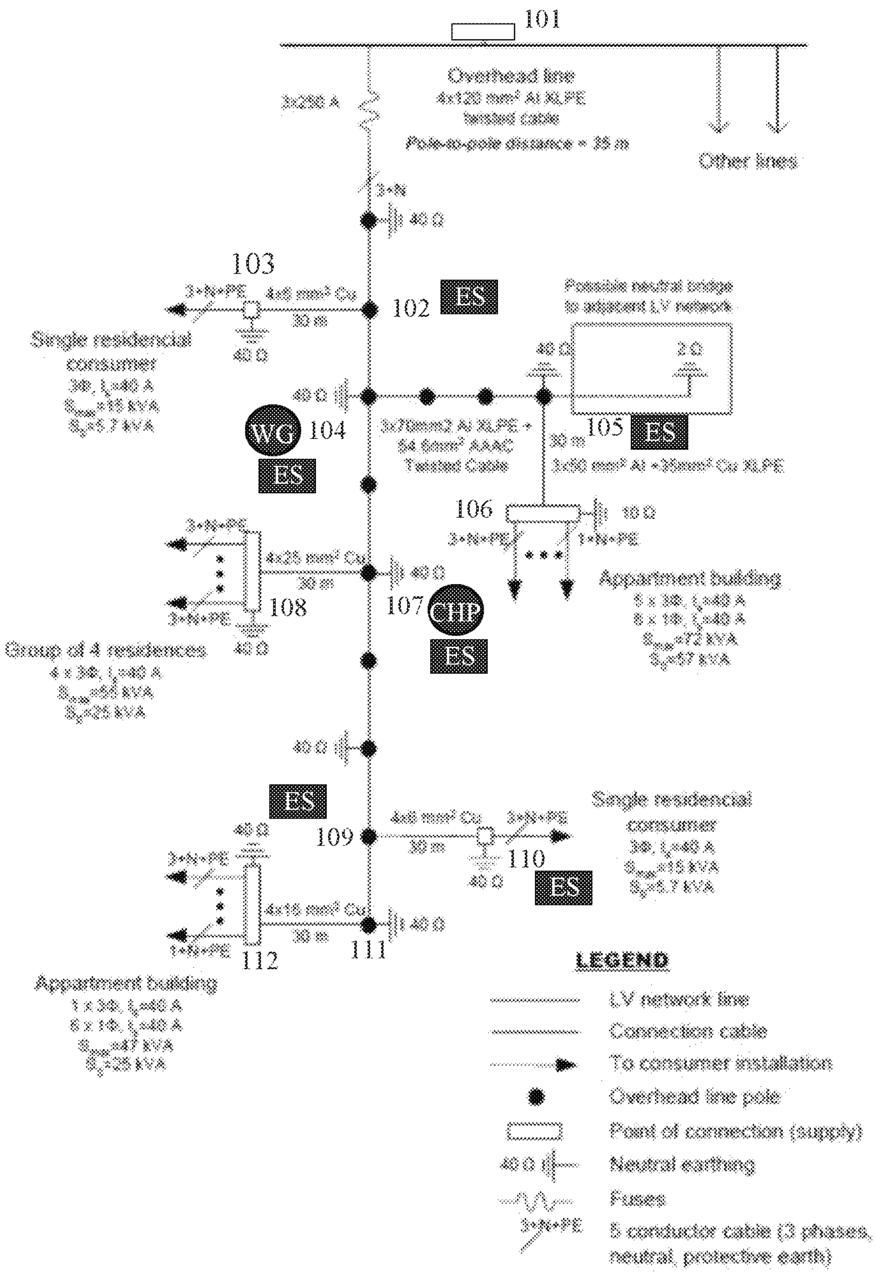

Figure 9 – DER Locations in the Microgrid

3.4 Key Conclusions

1. From our extensive studies, we found that renewable generators or ES are not economically attractive with the current time of day electricity prices in Ontario. Due to the economic nature of our studies, we did not consider any financial incentives provided for renewable generators.
2. In the case of remote communities, with a tenfold higher price of electricity from conventional fuel based sources, Wind and CHP generators are economical to operate in parallel with the conventional sources.
3. Except for flywheels, other ES technologies such as batteries are economical to install in the remote microgrids. The main deciding factor of ES installation is the price of electricity from the grid or conventional sources.

4 Summary

This paper presents an ES sizing and siting study carried out for power distribution systems. Mathematical models for two different ES sizing and siting strategies were presented with detailed explanations. The first mathematical formulation (Strategy 1) allows distribution system planners to consider ES for distribution line deferral. It minimizes total long-term system cost including customer interruption cost. A case study was conducted considering a distribution feeder in Ontario. From the case study, it is found that PV penetration is one of the main factors which decide the requirement for ES. The case studies show that ES is a good option to minimize the system cost and to avoid expensive feeder circuit investments. The developed Strategy 1 siting and sizing algorithm can be executed for any feeder considering different ES locations. It looks at the total economic benefits in the long run to evaluate the economic cost of ES against the cost of feeder circuits. The algorithm takes different life spans of ES and feeders and considers annualized cost for the computation.

The paper also presents a detailed mathematical formulation for energy storage sizing and siting for microgrid applications (Strategy 2). The formulation minimizes the total cost of the microgrid investment, operation and maintenance. A case study was carried out using a benchmark microgrid. According to the results of the case study, with the current price levels of ES and retail price levels of electricity from the grid, it is not beneficial to use ES for managing power mismatches of microgrids. However, if the microgrid is built for a remote community, where electricity from the transmission grid or conventional generation sources are expensive, ES are economical to use with renewable energy sources. Most battery ES technologies are economical at their current price levels.

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