Technical Feasibility and Economical Viability of Remote Hybrid Power Systems in Northern Ontario

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Abstract

As of 1996 there were 302 remote communities with a total population of 205,041 in Canada. These communities are not connected to the Bulk Electric System (BES) and as such are responsible for maintaining their own power systems to meet their energy requirements. As of 2010, 43 of the 302 remote communities were located in the province of Ontario. These remote communities are primarily powered with diesel generators which are a proven technology that are not limited by external environmental constraints. However this begets a dependency upon hydrocarbon based fuels which are: costly to purchase and transport, subject to volatility in the market, and diminishing in supply. These trends indicate that fuel prices will continue to escalate. Due to the relative isolation and cost of expanding the BES it is assumed that these communities will continue to operate as remote power systems for the foreseeable future. As such, this thesis focuses on increasing self-sufficiency within these communities to positively impact community welfare and the Canadian presence in the North. This is achieved through a technical feasibility and economical viability analysis of the application of remote hybrid power systems in Northern Ontario.

To facilitate this research a model of a typical remote power system, located within Northern Ontario, is developed. This model may be employed for multitudinous tasks including the technical feasibility and economical viability analysis of this thesis. Using this model a base case representing the existing diesel based generation is performed. The technologies investigated for hybrid system implementation include: methods of energy storage, solar energy conversion systems, wind energy conversion systems, and fuel cells. The proposed hybrid power systems are compared to the base case to determine their relative viability. The investigated technologies are also analyzed to determine their technical feasibility in the North. This investigation was completed to aid with: the reduction of fossil fuel dependencies and of the net cost of power generation, the creation of localized employment opportunities, and the promotion of better planning and infrastructure development to increase community self sufficiency.

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Acronym Index

A	
ACC	Annualized Capital Cost
AETP	Alternative Energy Technologies Programme
AFC	Alkaline Fuel Cell
Ah	Ampere Hours
AL-TES	Aquiferious Low-Temperature Thermal Energy Storage
APA	Alaska Power Association
ARC	Annualized Replacement Cost
AVEC	Alaska Village Electric Cooperative
AW	Annual Worth
B	
BES	Bulk Electric System
BESS	Battery Energy Storage System
BHB	Brake Horse Power
Bill 150	See GEGEA
C	
CAAP	Clean Air Action Plan 2004
CAD	Canadian Dollars
CAES	Compressed Air Energy Storage
CARS	Canadian Aviation Regulations
CBC	Canadian Broadcasting Corporation
CC	Capital Cost
CDD	Cooling Degree-Day
CDF	Cumulative Distribution Function
CEAA	Canadian Environmental Assessment Agency
CES	Cryogenic Energy Storage
CETC-Ottawa	CANMET Energy Technology Centre-Ottawa
CHP	Combined Heat and Power
CI	Clearness Index
COE	Cost of Energy
CPI	Consumer Price Index
CRF	Capital Recovery Factor
CWEEDS	Canadian Weather Energy and Engineering Datasets
D	
D	Diesel
DC	Duration Curve
DER	Distributed Energy Resource
DFO	Department of Fisheries and Oceans Canada
DG	Diesel Generator
DGS	Diesel Generator System

Dmap	Data Map
DMFC	Direct Methanol Fuel Cell
DOE	Department of Energy (American)
DX	Distribution
E	
EES	Electrical Energy Storage
EPA	Environmental Protection Act (American)
ET	Extraterrestrial
F	
FOF	Field Output Factor
FV	Future Value
G	
G	Gasoline/Petroleum
GEGEA	Green Energy and Green Economy Act 2009
H	
H.S.	High Speed (3600 RPM)
HDD	Heating Degree-Day
HOMER	Microprocessor Optimization Tool
HST	Harmonized Sales Tax
I	
IC	Internal Combustion
ICG	IESO Controlled Grid
IESO	Independent Electricity System Operator
INAC	Indian and Northern Affairs Canada
INT()	Integer Function
IPPI	Industrial Product Price Index
IRR	Internal Rate of Return
ITSOFC	Intermediate Temperature Solid Oxide Fuel Cell
K	
KEA	Kotzebuse Electric Association (Alaska)
L	
L.S.	Low Speed (1800 RPM)
LDC	Local Distribution Company
Li-ion	Lithium Ion
LP	Liquid Propane
M	
MCFC	Molten Carbonate Fuel Cell
MOE	Ministry of Energy
MOE	Ministry of the Environment
MPPT	Maximum Power Point Tracker

N

NaS	Sodium Sulphur
NCMH	Normal Cubic Metres per Hour
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NiCd	Nickel Cadmium
Ni-MH	Nickel-Metal Hydride
NOCT	Nominal Operating Cell Temperature
NTPC	Northwest Territories Power Corporation
NP	Nunavut Power
NPCC	Northeast Power Coordinating Council Inc.
NPV	Net Present Value
NRCAN	Natural Resources Canada
NREL	National Renewable Energy Laboratory
NU	Nunavut
NWT	Northwest Territories

O

O&M	Operation and Maintenance Costs
OEB	Ontario Energy Board
OEFC	Ontario Electricity Financial Corporation
ON	Ontario
OPA	Ontario Power Authority
OPG	Ontario Power Generation

P

PAFC	Phosphoric Acid Fuel Cell
PCM	Phase Change Materials
PCU	Power Conditioning Unit
PEMC	Polymer Electrolyte Membrane Fuel Cell
PHS	Pumped Hydroelectric Storage
PM	Particulate Matter
PPNiCd	Pocket Plated Nickel Cadmium
PSB	Polysulphide Bromide (Battery)
PV	Photovoltaic
PW	Present Worth

Q

QEC	Quilliq Energy Corporation (Utility)
QC	Québec

R

RA	Right Ascension
RC	Replacement Cost
REA	Renewable Energy Approval Act
RETs	Renewable-energy and Energy-efficient Technologies
ROI	Return on Investment

ROR	Rate of Return
RTIL	Room Temperature Ionic Liquids

S

SARA	Species At Risk Act
SCMH	Standard Cubic Metres per Hour
S-D	Solar Diesel System
S-D-S	Solar Diesel Storage System
SECA	Solid State Energy Conversion Alliance
SECS	Solar Energy Conversion System
SFF	Sinking Fund Factor
SG	Solar Generator
SMES	Superconducting Magnetic Energy Storage
SOFC	Solid Oxide Fuel Cell
STC	Standard Test Conditions
SV	Salvage Value
S-W-D	Solar Wind Diesel System
S-W-D-S	Solar Wind Diesel Storage System

T

TAC	Total Annualized Cost
TC	Transport Canada
TES	Thermal Energy Storage
TSOFC	Tubular Solid Oxide Fuel Cell
TX	Transmission

U

UFLS	Under Frequency Load Shedding
UL	Underwriters Laboratories Inc.
USD	US Dollars

V

VRB	Vanadium Redox (Battery)
VRLA	Valve Regulated Lead-Acid

W

W-D	Wind Diesel System
W-D-S	Wind Diesel Storage System
WECS	Wind Energy Conversion System
WG	Wind Generator

Y

YEC	Yukon Energy Company (Utility)
YT	Yukon Territory

Z

ZEBRA	Sodium Nickel Chloride
ZnBr	Zinc Bromine (Battery)

Chapter 1

Introduction

Chapter 1 introduces the layout of the thesis as well as fundamental terms and background information that will allow for the development of the appropriate essentials in the subject area. This will in turn be utilized by the subsequently developed research. Section 1.1 provides an overview of power systems, Section 1.2 introduces the concept of a remote community, Sections 1.3 and 1.4 develop the motivations and contributions of this thesis respectively, and Section 1.5 provides a brief outline of the thesis in its entirety.

1.1 Power Systems

A power system is a collection of equipment and materials that allows for the generation, transmission, transforming, and distribution of electrical energy. The majority of Ontario is connected to a centralized power transmission network, which is also referred to as the grid, Bulk Electric System (BES), or the Independent Electricity

System Operator Controlled Grid (ICG), with a small number of remote communities being both independent and responsible for maintaining their own local power system.

Ontario Power Generation (OPG) is the crown corporation responsible for roughly 70% of the power generation for the grid connected portion of Ontario. This power is primarily generated through the use of nuclear, hydro, gas, coal, and wind sources. Overall there are more than 20 generators in Ontario which includes other large scale generators such as Bruce Nuclear, Brookfield Power, and Portlands Energy. Hydro One is the crown corporation that owns and operates approximately 97% of the transmission network, a large telecommunications network, and approximately 70% of the distribution network across Ontario. The remaining ~3% of the transmission network is controlled by Great Lakes Power, 5 Nations Power Inc., Canadian Niagara Power Inc., and Cat Lake Power Utility Limited. Hydro One Networks operates at the distribution level and serves many rural and commercial based customers along with the Local Distribution Companies (LDCs) that operate in urban or populated centres. The only urban centre that is controlled by Hydro One is Hydro One Brampton which operates within the city of Brampton [1]. The majority of the distribution network across Ontario is controlled by the 91 LDCs and Provincial Lines. A full list of LDCs can be obtained from the Independent Electricity System Operator (IESO) [2]. Table 1.1 demonstrates the approximate total amount of installed capacity for existing grid connected renewable generators as of April 2011 within the province of Ontario. The existing renewable generators are classified as either hydraulic, wind, solar, or biogas and the total installed capacity of the respective generators connected to the transmission (TX) and distribution (DX) systems are also indicated.

Table 1.1: BES Connected Renewable Electricty Generation in Ontario

Generation Type	**Installed Capacity (MW)**		
	TX	**DX**	**Total**
Hydraulic	7,311	314	7,625
Wind	1,282	283	1,565
Solar	-	173	173
Biogas	-	105	105

The IESO is responsible for the operation of the Ontario grid connected power system with direction from the Ontario Power Authority (OPA), the Ontario Ministry of Energy (MOE), the Ontario Energy Board (OEB), the North American Electric Reliability Corporation (NERC), and the Northeast Power Coordinating Council Inc. (NPCC). The OPA is responsible for the medium to long term system planning to ensure that the power requirements of the province can be met. The IESO is responsible for the short term planning of the system and ensuring that the power system is operated within the guidelines set by NERC and the NPCC. The OEB regulates all non-commodity electricity licences from all participants in the Ontario market. The ON MOE establishes the energy policies for Ontario and ensures that the Ontario grid remains robust. The Ontario Electricity Financial Corporation (OEFC) manages liabilities from the former provincial utility of Ontario Hydro prior to the development of the free market. Hydro One Remote Networks, a division of Hydro One, is responsible for the entire power system in a number Ontario's remote communities. The other remote communities that are not under the jurisdiction of Hydro One Remote Networks are maintained by the local populace. The transmission network also connects through interconnections to neighbouring states and provinces which include Minnesota, Michigan, New York, Manitoba, and Quebec which supports up to 4,000 MW of electricity imports [2].

These interconnections combined with the availability of various power generation means provide greater flexibility for the operation of the grid which is not possible in remote power systems. Residences in Ontario are supplied with a split-phase 240 volts ($\pm$ 5%) with a 100 to 200 ampere service which is provided by the LDC, Provincial Lines, or Hydro One. The commercial supply varies based on local requirements.

1.2 Remote Communities

In order for a Canadian community to be classified as a remote community two requirements must be met. The first is that the community must not be presently connected to the North-American centralized power distribution network or natural gas network. The second is that the community must be a permanent or long term settlement with at least ten permanent residences where long term is defined as greater than or equal to five years. As such a remote community is responsible for maintaining its own power system to satisfy local demand. As of 1996 there were 302 remote communities across Canada with a total population of around 205,041. The majority of these remote communities are located across Northern Canada and they do not include several other types of communities such as outpost camps or some fishing camps as these communities do not meet the two aforementioned requirements. Some of these remote communities are connected to localized grids, many use independent power systems, and some official remote communities have no associated power system. Between the years of 1984 and 1996 the total number of remote communities decreased from approximately 380 to 302. This decrease in the number of remote communities is primarily a result of the extension of the electrical grid. However, during the period between 1984 and 1996 the overall population located within the remote communities across Canada has remained relatively constant which indicates that the population levels in the remaining remote communities has increased to compensate [3].

A community in general can be defined as a residential district that supports a local population. The community is primarily constructed of private residences but commercial and governmental facilities are normally present in smaller quantities. A remote community is typically removed from other communities and public services. They also do not typically have any form of public water, natural gas or propane connections, or sewer systems. Many of the remote communities in Ontario are populated by first nation members and located across Northern Ontario. Tables 1.2 and 1.3 provide a cumulative list of the remote communities in Ontario along with their means of accessibility. Table 1.2 contains a list of communities that are studied further in depth and Table 1.3 contains the additional communities for completeness. Most of the remote communities do not have regular road service that can be used year round and typically the only way to transport materials, including food, fuel, and building materials, to these locations is either on an ice road or by air transportation. Transportation by air is significantly more expensive than any other form of transportation and is minimized whenever possible [4]. For fields in Table 1.2 that include a question mark it is assumed that the metric is as shown, however some of the information is difficult to acquire. For the other types of accessibility on the ground N denotes none, W denotes water, and T denotes train [3, 5].

Ontario has a total of 43 remote communities that vary in both size and location. Five of the remote communities in Ontario are accessible via the coast. There are 10 remote communities in Ontario that are connected via rail service and they are primarily located across central Ontario. The remaining 26 remote communities in Ontario are accessible only by ice road or air and are considered to be located in the interior of Northern Ontario [3]. The '?' indicates values that were not obtainable and Kashechewan is connected to the generators at Albany to form a localized mini-grid as indicated by the '*' in Table 1.3.

Table 1.2: Accessibility Distribution in Ontario - Studied Communities

Name	Air Code	Band Number	Accessibility			
			Roads		Other	
			Regular	Ice	Air	Ground
Armstrong Station	YYW	190	N	Y	Y	T
Bearskin Lake	XBE	207	Y	-	Y	N
Big Trout Lake	YTL	209	N	Y	Y	N
Biscotasing	Float	226	Y	-	Y	T
Deer Lake	YVZ	237	N?	N?	Y	N
Fort Hope	YFH	183	N	Y	Y	N
Fort Severn	YER	215	N?	Y	Y	N
Gull Bay	-	188	N?	N?	-	N
Kasabonika	XKS	210	N	N	Y	N
Kee-way-win	KEW	325	N?	N?	Y	N
Kingfisher Lake	KIF	212	N	Y	Y	N
Lansdowne House	YLH	239	N	Y	Y	N
Muskrat Dam Lake	MSA	213	N?	N?	Y	N
North Caribou Lake	ZRJ	204	N?	N?	Y	N
North Spirit Lake	YNO	238	N	Y	Y	N
Ogoki Post/Marten Falls	YOG	186	N	Y	Y	N
Peawanuck (Winisk)	YPO	146	N	Y	Y	W
Pikangikum 14	YPM	208	N	Y	Y	N
Poplar Hill	YHP	236	N	Y	Y	N
Sachigo Lake	ZPB	214	N?	N?	Y	N
Sandy Lake	ZSJ	211	N	Y	Y	N
Sultan	-	228	Y	-	?	T
Summer Beaver	SUR	241	N	Y	Y	N
Wapekeka (Angling Lake)	YAX	206	N	N?	Y	N
Webequie	YWP	240	N	Y	Y	N
Wunnumin Lake	WNN	217	N	Y	Y	N

Table 1.3: Accessibility Distribution in Ontario - Additional Communities

Name	Air Code	Band Number	Accessibility			
			Roads		Other	
			Regular	Ice	Air	Ground
Albany	?	?	N	Y	Y	W
Allan Water	?	?	?	?	?	T
Attawapiskat	CYAT	?	N	Y	Y	W
Auden	?	?	?	?	?	T
Cat Lake	CYAC	?	N	Y	Y	N
Collins	?	?	N	N	Y	T
Ferland	?	?	N	N	N	T
Graham	?	?	?	?	?	T
Hillsport	?	?	N	N	N	T
Kashechewan*	?	?	N	Y	Y	W
Lac Seul	28	-	?	?	?	N
MacDowell	?	?	N	N	Y	N
Moose River Crossing	?	?	N	N	N	T
Oba	?	?	N	N	N	T
Ponask	?	?	?	?	?	N
Ramsey	?	?	N	N	N	T
Wawakapewin	?	?	N	Y	N	N

As opposed to Ontario the three territories only operate remote power systems as the small population and vast distances dictate that a centralized power transmission network is highly impractical. There are 34 official communities in the Northwest Territories [6], 26 in Nunavut [7], and 23 in the Yukon [8]. The number of remote communities located in the Northwest Territories and Nunavut between 1984 and 1996 remained constant however the overall population increased by approximately 25% due primarily to a high birth rate. The number of remote communities in the Yukon also remained relatively constant between 1984 and 1996 however the overall population increased by about 30% due primarily to migration [3, 5]. Remote communities will continue to be responsible for their own power generation for the foreseeable future. As such research focusing on how to create a more self-sufficient community may have a tremendous impact on the welfare of these communities and the Canadian presence in the North.

1.3 Motivation

Presently the majority of the remote communities in Canada are powered with diesel generators and heated using oil. Diesel generation is employed as it is cost effective, is not dependent upon external environmental constraints, and has been successfully used in a variety of climates for a long period of time. This indicates that diesel generation it as a mature technology. The required fuels are normally transported via ice road, ship, or in rare circumstances by air [3, 4]. In select locations, where both the resources exist and the system is cost effective to implement, hydroelectric facilities have been installed in the form of mini-hydro turbines. However the availability of mini-hydro is limited. A small number of electric utilities have also installed a limited quantity of small scale trial wind turbines in both the near North (Northern Ontario) and the far North (arctic region encompassed by the three territories).

The harsh climate, extreme temperatures, small populations, and isolated manner in which the remote communities can be found pose a unique conundrum for energy production. Due to their energy production portfolio the majority of these remote communities are dependent upon hydrocarbon based fuels which are costly to both purchase and transport due to the isolation of the communities and vast distances. The ever increasing cost of fuel and the decrease in availability indicates that the net cost of the required fuels will likely continue to escalate [5]. The ice roads, which are used for primary fuel transportation during short periods in the winter months, have been operational for shorter periods than ever before due to the change in global climate [4, 9]. It is projected that this shortening of the usable season will continue into the future.

The motivation of this thesis is to investigate the communities located across Northern Ontario, with regards to power production, to determine if there is a cost effective method that can be used to decrease the dependency on hydrocarbon based fuels. This would potentially allow for cheaper energy production both presently and in the future, the remote communities to become self sufficient, provide new job and training opportunities within the remote communities, and decreases the funding required by both the communities and the federal government.

1.4 Thesis Contributions

The contributions of this thesis are twofold. The first contribution of the thesis is with the development of a system model for Northern Ontario. Due to the large geographical area of Northern Ontario it was vital to develop a system model that exhibits the typical or average conditions that can be expected within the boundaries of Northern Ontario. However at present little information is publicly available for the remote communities located within the bounds of Northern Ontario. The system model created in this thesis investigates multiple parameters, including population, housing, climatic, and power system data, which encompass the entire expanse of the territory contained within Northern Ontario. These parameters were refined and manipulated to create a functioning model that can be employed for multitudinous future tasks.

The second contribution is an in-depth technical feasibility and economical viability analysis of various power generating technologies as applied to a power system described by the developed system model at a Northern latitude. Presently few alternative sources of power generation have been investigated for remote communities particularly in the North. The aim of this thesis is to determine which technologies are feasible to: reduce fossil fuel dependencies, decrease cost, promote better planning and infrastructure development, and increase community self sufficiency in Canadian remote communities located across Northern Ontario.

1.5 Organization of the Thesis

This thesis consists of eight Chapters including the Introduction and nine Appendices. The Chapters are outlined below:

Chapter 2: System Model

This Chapter investigates population, housing, climatic, and power system data when available across Northern Ontario, Nunavut, the Northwest Territories, and the Yukon. Using the available data a system model is created to model a typical location in Northern Ontario. The system model includes population, power system, diesel consumption, and climatic variables. This model will be used in subsequent chapters to complete the analysis of various technologies and power system options.

Chapter 3: Introduction to Simulation Methodologies

This Chapter introduces the simulation concepts and methods, community load profile, and economic dispatch methodology used throughout this thesis. The converter components that will be used for a number of the simulations in the proceeding Chapters are also introduced in this Chapter.

Chapter 4: Storage Technologies

This Chapter begins with a brief overview to electrical energy storage technologies. Energy management storage medians are investigated in-depth with a focus on pumped hydroelectric storage, compressed air energy storage, large-scale batteries, solar fuels, and thermal energy storage. The various electrical energy storage technologies are compared and analyzed for implementation in conjunction with the system model. The energy storage technologies that are selected for implementation will be introduced in this Chapter.

Chapter 5: Diesel Generator Systems

This Chapter begins with a brief introduction to Diesel Generator Systems (DGS). The architecture or construction of the DGS is explored so that a fundamental knowledge is obtained. Using the knowledge developed from the introduction and architecture of the DGSs implementable systems are developed. These DGS conform to the system model and are accompanied by a detailed economical and technical analysis obtained from simulation.

Chapter 6: Solar Energy Conversion Systems

This Chapter begins with a brief introduction to Solar Energy Conversion Systems (SECS). The climatic data associated with the system model that pertains to solar Photovoltaic (PV) is introduced and explained. The architecture or construction of the SECS is explored so that a fundamental knowledge is obtained. Using the knowledge developed from the introduction and architecture of the SECS, along with the applicable climatic data, implementable systems are developed. These SECSs conform to the system model and are accompanied by a detailed economical and technical analysis obtained from simulation.

Chapter 7: Wind Energy Conversion Systems

This Chapter begins with a brief introduction to Wind Energy Conversion Systems (WECS). The climatic data associated with the system model that pertains to wind is introduced and explained. The architecture or construction of the WECS is explored so that a fundamental knowledge is obtained. Using the knowledge developed from the introduction and architecture of the WECS, along with the applicable climatic data, implementable systems are developed. These WECSs conform to the system model and are accompanied by a detailed economical and technical analysis obtained from simulation.

Chapter 8: Conclusion

This Chapter is subdivided into two Sections. The first Section includes the author's views on future work emanating from the results and work found within this thesis. The second Section provides a summary of the results determined throughout this thesis as well as an overview of the thesis through concluding thoughts.

Appendices A and B

Appendices A and B are virtual appendices that contain raw data, additional Tables and Figures, and other related information applicable to this thesis. The appendices contain an index of the data found on the accompanying compact disc.

Appendix C

Appendix C contains additional Figures relating to the community load approximation as introduced in Chapter 3.

Appendix D

Appendix D contains additional Figures and data relating to the Battery Energy Storage System (BESS) employed by the power system as introduced in Chapter 4.

This includes additional component detail, source information, and the component capacity and lifetime curves along with the associated tabular data. The capital cost of various BESS enclosures are also investigated.

Appendix E

Appendix E introduces additional information on the Diesel Generator Systems (DGS) introduced in Chapter 5. Various definitions of DG operation will be introduced followed by common and specific technical specifications. The common technical specifications include derating curves, start-up curves, and efficiency curves. The specific technical specifications include individual DG unit loading specifics, advanced unit details, source information, and the related fuel and efficiency curves.

Appendix F

Appendix F provides additional information on the Solar Energy Conversion Systems (SECS) introduced in Chapter 6. The first Section of this Appendix includes the scaled solar resources experienced by the system model. The second Section includes the extraterrestrial radiation experienced at the community location. The third and final Section introduces additional information with respect to the Solar Generators (SG) that were studied in this thesis. The additional SG information includes unit specific: technical data, source and manufacturer information, efficiency of the SGs under STC conditions and the related variables, and the related temperature coefficients, optimum operating characteristics, open circuit values, temperature range, all associated costs, and unit life expectancy.

Appendix G

Appendix G provides additional information on the Wind Energy Conversion Systems (WECS) introduced in Chapter 7. This includes information and data related to the wind rose and frequency distribution, system model wind resources, system model wind resources at upper air levels, wind power generation and system loading, and Wind Generator (WG) unit specific: general technical and source information, the power curve data points, power curves, and cost curves.

Appendix H

This Appendix begins with an introduction to various fuel cell technologies. The molten carbonate and solid oxide fuel cells are studied individually and in-depth. The various fuel cell technologies are compared and an analysis for implementation of a fuel cell based power system is completed. This fuel cell based power system conforms to the system model and is accompanied by a detailed economical and technical analysis. This material was placed in the Appendix as it was not deemed feasible for implementation within the system model constraints and as such was removed from the body of the thesis.

Appendix I

Appendix I provides additional information as it relates to the SECS introduced in both Chapter 6 and Appendix F with a focus on solar energy and astronomical terminology.

Chapter 2

System Model

To achieve the objectives as outlined in Section 1.4 a general system model that exhibits characteristics representative of the desired geographical locations must be developed. At present there is no readily available alternative which resulted in an extensive analysis of Northern Ontario (ON) and of the Canadian federal territories which consist of the Northwest Territories (NWT), Nunavut (NU), and the Yukon (YT). The system model, which is the term used here on in, must exhibit all aspects of a typical community in Northern Ontario which can be broadly summarized by the following classifications: population and housing data, power system data, and climatic data. The desired data that would be used to produce the system model was not publicly available so all available relevant data for the desired province and territories was collected and analyzed. The collected data was then used to infer logical estimations of the typical conditions that the modelled system would experience in Northern Ontario. Natural Resources Canada (NRCAN) published a summary of Canadian remote communities in 1996 through RETScreen International which is the most extensive relevant database in existence [3]. However due to the age of this database its use was limited in the development of the current system model. All the raw data that was collected regarding population, housing, and power systems can be found in Appendix A and the raw climatic data can be found in Appendix B. A summary of the applicable results can be found in the remainder of this Chapter.

2.1 Population and Housing Data

Population and housing data was obtained for locations across the territories and Northern Ontario. The population and housing information was obtained from Statistics Canada's 1991, 1996, 2001, and 2006 census results, Indian and Northern Affairs Canada (INAC) community databases, and from some of the remote communities' individual websites where applicable. The percentage change in population was calculated between the census years to determine the overall population trends when the required information was present. Due to the size, type, and location of the communities some of the population data was not collected for all locations during the census periods. The collected data, graphs, and some preliminary results can be found in Appendix A.

2.1.1 Northern Ontario

In 1996 there were a total of 43 remote communities located across Northern Ontario with a combined population of 29,296. Ontario contained 14.10 % of the Canadian remote communities and 14.29 % of the total population that resides within the Canadian remote communities. These figures have changed slightly in the following years and the overall values are not available after 1996. The remote communities in Ontario can be divided into three different regions that are used to separate the remote communities based on their geographical situation. These regions are coastline, interior, and rail. There are 5 remote communities that are classified as coastline communities which held a combined population of 6,059 in 1996. Twelve locations are classified as rail communities which held a combined population of 6,267 in 1996. The remaining 26 communities, which are the majority of the communities of interest in the system model analysis, are considered interior communities and held a combined population of 16,970 in 1996 [3]. Table 2.1 contains the list of studied remote communities in Ontario along with their respective populations from the 1991, 1996, 2001, and 2006 census results [5]. The periods for which the desired data was not obtainable are denoted by a '-' in the table. The Canadian remote community database from RETScreen does represent all 43 remote communities in Ontario however due to the size, limited nature of published data, and the fact that not all 43 of these locations have an installed power system only the 28 communities listed in Table 2.1 were studied.

Table 2.1: Population Distribution in Ontario [5]

Location	Population				% Change		
	1991	**1996**	**2001**	**2006**	**91-96**	**96-01**	**01-06**
Armstrong Station	-	115	-	247	-	-	-
Bearskin Lake	344	428	363	459	24.4	-15.2	26.4
Big Trout Lake	-	-	-	-	-	-	-
Biscotasing	137	-	165	-	-	-	-3.0
Deer Lake	611	630	755	681	2.8	19.8	-9.9
Fort Severn	335	365	400	-	8.1	9.6	-
Gull Bay	240	160	252	206	-33.8	57.5	-18.3
Kasabonika	536	520	740	681	-3.0	42.3	-8.0
Kingfisher Lake	365	305	368	415	-16.4	20.7	12.8
Neskantaga	226	235	270	265	4.0	14.9	-1.9
Sachigo Lake	276	305	443	450	10.5	45.2	1.6
Sandy Lake	1352	1610	1705	1843	19.2	5.9	8.2
Sultan	179	100	105	-	-44.1	5.0	-
Wapekeka FN	287	210	330	350	-26.8	57.1	6.4
Weagamow Lake 87	506	475	697	700	-6.1	46.7	0.4
Webequie	564	445	600	614	-21.5	34.8	2.3
Fort Hope	453	800	1000	1144	76.8	25.0	14.3
Kee-way-win	-	235	265	318	-	12.8	20.0
Muskrat Dam Lake	166	217	61	252	30.7	-71.9	313.1
North Spirit Lake	-	160	231	259	-	44.4	12.1
Ogoki Post	187	205	-	221	9.1	-	-
Peawanuck	150	240	193	221	59.3	-19.6	14.5
Pikangikum 14	1303	1170	-	2100	-10.2	-	-
Poplar Hill	271	290	373	457	7.0	28.6	22.5
Summer Beaver	307	317	276	362	3.3	-12.9	32.2
Wunnumin Lake	368	455	407	487	23.6	-10.5	19.7

Table 2.2 contains the location of the remote communities, number of private dwellings during the 1996, 2001, and 2006 census results, and what corporation or organization is responsible for the power generation at the provided remote communities [3, 5].

Hydro One Remote Networks is responsible for the power generation in 23 communities of which 16 are listed in Table 2.2 [1]. The remaining locations operated by Hydro One Remote Networks are relatively small and it is difficult to find applicable data. The remaining 10 communities listed in Table 2.2 are provided power through local band operated utilities. The additional 10 locations in Ontario do not have an installed power system [3].

Table 2.2: Dwelling Distribution in Ontario

Location			# Dwellings			
Name	**Lat.**	**Long.**	**1996**	**2001**	**2006**	**Operator**
Armstrong Station	50.18	89.02	115	-	90	Hydro One
Bearskin Lake	53.55	90.58	-	-	147	Hydro One
Big Trout Lake	53.82	89.87	-	-	-	Hydro One
Biscotasing	47.18	82.06	-	60	-	Hydro One
Deer Lake	52.62	94.07	140	175	213	Hydro One
Fort Severn	56.01	87.35	85	95	-	Hydro One
Gull Bay	49.49	89.06	55	-	86	Hydro One
Kasabonika	53.35	88.39	115	-	210	Hydro One
Kingfisher Lake	53.01	89.51	80	-	113	Hydro One
Lansdowne House	52.14	87.53	145	80	96	Hydro One
Sachigo Lake	53.53	92.09	75	-	154	Hydro One
Sandy Lake	53.04	93.19	390	450	549	Hydro One
Sultan	47.35	82.46	30	35	-	Hydro One
Wapekeka	53.43	89.32	50	80	114	Hydro One
Weagamow Lake 87	52.57	91.16	150	-	232	Hydro One
Webequie	52.59	87.16	105	140	174	Hydro One
Fort Hope	51.33	87.59	200	240	286	Band
Kee-way-win	52.60	92.48	50	65	100	Band
Muskrat Dam Lake	53.21	91.51	70	-	105	Band
North Spirit Lake	52.20	93.01	40	-	74	Band
Ogoki Post	51.39	85.54	55	-	79	Band
Peawanuck	55.00	85.25	60	70	66	Band
Pikangikum 14	51.49	94.00	235	-	387	Band
Poplar Hill	52.05	94.18	65	90	117	Band
Summer Beaver	52.48	88.27	-	-	114	Band
Wunnumin Lake	52.51	89.17	110	-	137	Band

The infrastructure in the remote communities is supported by INAC in conjunction with the federal government. Due to the nature of the operations in the remote communities in Northern Ontario more specific data is not publicly available. Figure

2.1 shows the population trends for the communities in Northern Ontario that have population data available for at least two years collected in Table 2.1 not including site 25 or Pikangikum 14 First Nations as the population there is significantly higher than the other communities. It can be seen that overall the population has either remained relatively constant or increased slightly between 1991 and 2006. However, the population in Fort Severn and Fort Hope have increased and decreased significantly over the studied period respectively.

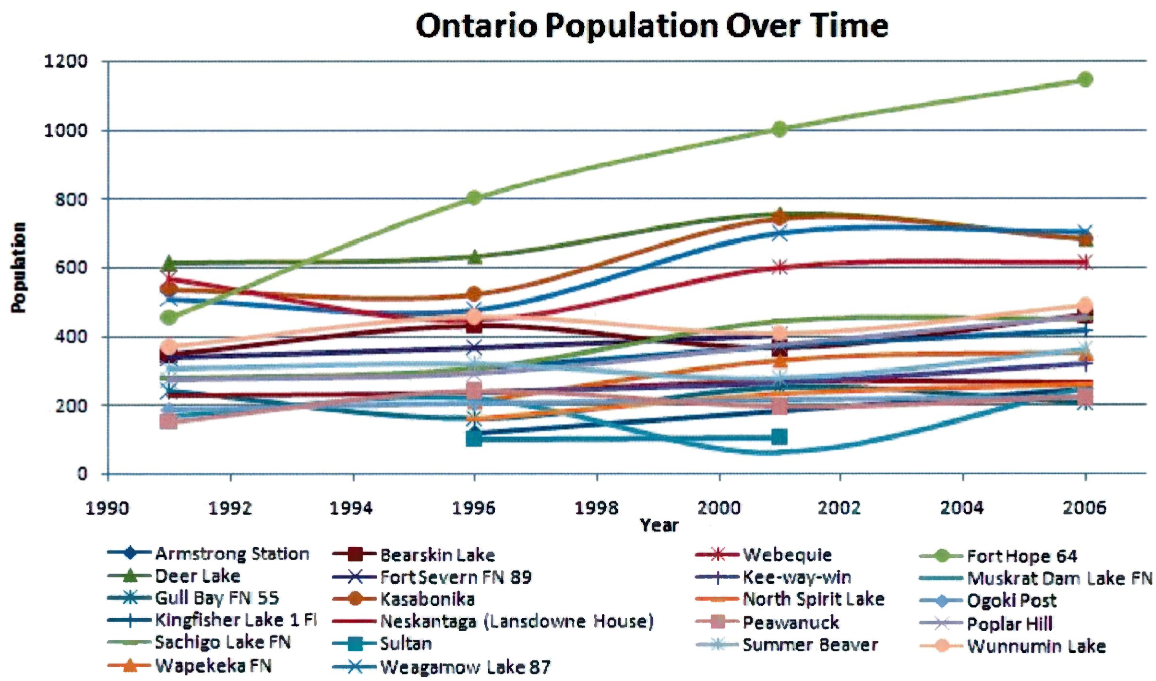

Figure 2.1: ON Population Over Time

2.1.2 Northwest Territories

On April 1, 1999 the Canadian federal government approved the subdivision of the existing territory known as the Northwest Territories into two territories. The new federal territory created was named Nunavut and the remaining land was still governed under the name of the Northwest Territories. The census data from 1991 and 1996 as well as the data provided by the 1996 RETScreen Canadian remote community summary use the definition of the Northwest Territories prior to April 1, 1999. During the data collection and analysis the combined data from this period in time was manually separated with respect to the current definitions of the federal territories. Over the past 20 years many locations found across the territories have also had official name changes which create logistical issues when researching statistics for various communities in conjunction with a change in federal jurisdiction. The names of the communities explored here on in should represent the current names of the locations but many sources will still list information under obsolete naming conventions. In the rare cases where the obsolete name is still extensively used an effort has been made to include both naming conventions.

In 1996 there were a total of 34 remote communities located across what is now known as the Northwest Territories with a combined population of 34,167. The NWT contained 11.26 % of the Canadian remote communities and 17.81 % of the total population that resides within the Canadian remote communities [3]. In 2010 there are still a total of 34 official communities in the Northwest Territories all of which utilize remote power systems. A total of 19 communities were studied in depth as they are all powered with only diesel generators. In 1996 these 19 communities had a combined population of 7,825. The remaining 15 communities are powered with an assortment of hydro, diesel-hydro hybrid, and limited natural gas installations [6]. Table 2.3 lists the 19 studied communities along with their corresponding population based on the 1991, 1996, 2001 and 2006 census results, location, and the number of private dwellings in 2001 and 2006 [5].

Table 2.3: Population Distribution in the Northwest Territories

	Population				**% Change**		
Location	**1991**	**1996**	**2001**	**2006**	**91-96**	**96-01**	**01-06**
Aklavik	801	727	632	594	-9.2	-13.1	-6.0
Colville Lake	69	90	102	126	30.4	13.3	23.5
Deline	551	616	536	525	11.8	13.0	-2.1
Fort Liard	485	512	530	583	5.6	3.5	10.0
Fort Good Hope	602	644	549	557	7.0	-14.8	1.5
Fort McPherson	759	878	761	761	15.7	-13.3	0.4
Fort Simpson	1142	1257	1163	1216	10.1	-7.5	4.6
Gameti	-	256	274	283	-	7.0	3.3
Jean Marie River	49	53	50	81	8.2	-5.7	62.0
Lutselk'e	286	304	248	318	6.3	-18.4	-1.2
Nahanni Butte	85	75	107	115	-11.8	42.7	7.5
Paulatuk	255	277	286	294	8.6	3.2	2.8
Sachs Harbour	125	135	114	122	8.0	-15.6	7.0
Tsiigehtchic	144	162	195	175	12.5	20.4	-10.3
Tuktoyaktuk	918	943	930	870	2.7	-1.4	-6.5
Tulita	375	450	473	505	20.0	5.1	6.8
Ulukhaktok	361	423	398	398	17.2	-5.9	0.0
Wha Ti	392	418	453	460	6.6	8.4	1.5
Wrigley	174	167	165	122	-4.0	-1.2	-33.0

Table 2.4 contains the locations of the remote communities, number of private

dwellings during the 2001 and 2006 census results, and the number of dwellings that were occupied by regular residents in 2006 throughout the NWT.

Table 2.4: Dwelling Distribution in the NWT

Location			**Private Dwelling**		**Usual Residents**
Name	**Lat.**	**Long.**	**2001**	**2006**	**2006**
Aklavik	68.13	135.00	261	254	218
Colville Lake	67.02	126.05	37	43	35
Deline	65.19	123.42	208	222	173
Fort Liard	60.14	123.28	180	211	175
Fort Good Hope	66.15	128.37	204	209	176
Fort McPherson	67.26	134.52	335	293	265
Fort Simpson	61.45	121.14	489	531	434
Gameti	64.06	117.21	99	99	71
Jean Marie River	61.31	120.37	22	28	23
Lutselk'e	62.41	110.74	75	144	111
Nahanni Butte	61.02	123.23	39	46	35
Paulatuk	69.21	124.04	72	87	75
Sachs Harbour	72.00	125.16	48	54	45
Tsiigehtchic	67.26	133.44	72	77	60
Tuktoyaktuk	69.27	133.00	343	348	274
Tulita	64.54	125.34	159	170	144
Ulukhaktok	70.45	117.48	144	152	134
Wha Ti	63.08	117.16	118	154	113
Wrigley	63.13	123.28	55	63	43

Figure 2.2 shows the population trends for the communities in the Northwest Territories as summarized by Table 2.3. It can be seen that overall between 1996 and 2006 that the population levels remain fairly constant in the selected communities.

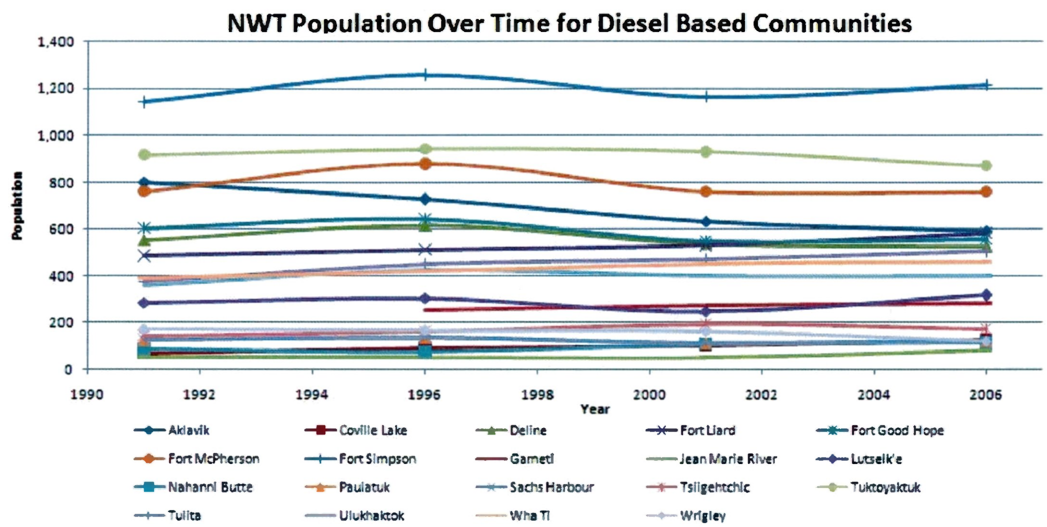

Figure 2.2: NWT Population Over Time for Diesel Based Communities

2.1.3 Nunavut

In 1996 there were a total of 26 remote communities located across what is now known as Nunavut with a combined population of 20,636. Nunavut contained 8.61 % of the Canadian remote communities and 10.16 % of the total population that resides within the Canadian remote communities [3]. Table 2.5 contains a complete list of the remote communities in Nunavut [7] along with their respective populations during the 1991, 1996, 2001, and 2006 census results [5]. All of the communities located within Nunavut were studied as they are all diesel powered remote power systems. The periods for which the desired data was not available are denoted by a '-' in the Table.

Table 2.5: Population Distribution in Nunavut

Location	Population				% Change		
	1991	**1996**	**2001**	**2006**	**91-96**	**96-01**	**01-06**
Arctic Bay	543	639	646	690	17.7	1.1	6.8
Arviat	1323	1559	1899	2060	17.8	21.8	8.5
Baker Lake	1186	1385	1507	1728	16.8	8.8	14.7
Bathurst Inlet	18	18	5	0	0.0	-72.2	-100.0
Cambridge Bay	1116	1351	1309	1325	21.1	-3.1	1.22
Cape Dorset	961	1117	1148	1236	16.3	2.7	7.7
Chesterfield Inlet	316	337	345	322	6.6	2.4	-3.8
Clyde River	565	708	785	820	25.3	10.9	4.5
Coral Harbour	578	669	712	769	15.7	6.4	8.0
Gjoa Haven	783	879	960	1064	12.3	9.2	10.8
Grise Fiord	130	148	163	141	13.8	10.1	-13.5
Hall Beach	526	543	609	254	3.2	12.2	-58.0
Igloolike	936	1174	1286	1538	25.4	9.5	19.6
Iqaluit	3552	4220	5236	6184	18.8	24.1	18.1
Kimmirut	365	397	433	411	8.8	9.1	-5.1
Kugaaruk	-	496	605	688	-	22.0	13.7
Kugluktuk	1059	1201	1212	1302	13.4	0.9	7.4
Pangnirtung	1135	1243	1276	1325	9.5	2.7	3.8
Pond Inlet	974	1154	1220	1315	18.5	5.7	7.8
Qikiqtarjuaq	-	488	519	473	-	6.4	-8.9
Rankin Inlet	1706	2058	2177	2358	20.6	5.8	8.3
Repulse Bay	488	559	612	748	14.5	9.5	22.2
Resolute Bay	171	198	215	229	15.8	8.6	6.51
Taloyoak	580	648	720	809	11.7	11.1	12.4
Whale Cove	235	301	305	353	28.1	1.3	15.7

Table 2.6 contains the locations of the remote communities, number of private dwellings during the 2001 and 2006 census results, and the number of dwellings that were occupied by regular residents in 2006 throughout Nunavut [5].

Table 2.6: Dwelling Distribution in Nunavut

Location			Private Dwelling		Usual Residents
Name	**Lat.**	**Long.**	**2001**	**2006**	**2006**
Arctic Bay	73.02	85.10	170	190	161
Arviat	61.06	94.03	456	497	453
Baker Lake	64.17	96.04	464	478	450
Bathurst Inlet	67.34	108.30	20	0	0
Cambridge Bay	69.06	105.08	457	524	449
Cape Dorset	64.13	76.31	333	356	321
Chesterfield Inlet	63.32	91.04	103	120	100
Clyde River	70.29	68.31	160	183	173
Coral Harbour	64.11	83.21	194	242	195
Gjoa Haven	68.37	95.52	249	246	237
Grise Fiord	76.25	82.53	49	55	48
Hall Beach	68.46	81.13	134	154	146
Igloolike	69.23	81.48	324	370	329
Iqaluit	63.45	63.45	2105	2460	2074
Kimmirut	62.50	62.50	108	116	113
Kugaaruk	68.31	67.49	120	137	134
Kugluktuk	67.49	67.49	392	407	359
Pangnirtung	66.08	66.09	403	433	365
Pond Inlet	72.41	72.41	308	335	311
Qikiqtarjuaq	67.33	67.33	150	156	136
Rankin Inlet	62.49	62.49	744	776	655
Repulse Bay	66.31	66.31	130	153	136
Resolute Bay	74.43	74.43	85	83	67
Taloyoak	69.32	69.32	192	205	185
Whale Cove	62.10	62.10	91	93	91

Figure 2.3 shows the population trends for the communities in Nunavut as summarized by Table 2.6 for the communities where the census population results were available for all four years not including Iqaluit. Iqaluit was not included as the population in the capital city of Nunavut is significantly higher than any other location

and it has seen significant growth over the 15 year period. It can be seen that overall the trend in population is that it is increasing slightly for the majority of the communities over the studied 15 year period. The only communities that experienced a significant decrease in population were Bathurst Inlet and Hall Beach. Due to the small initial population of Bathurst Inlet in 1991 the population change in Figure 2.3 is difficult to read. However in 2006 the community had population is zero which translates to a -100% change in population over the studied period [3, 5].

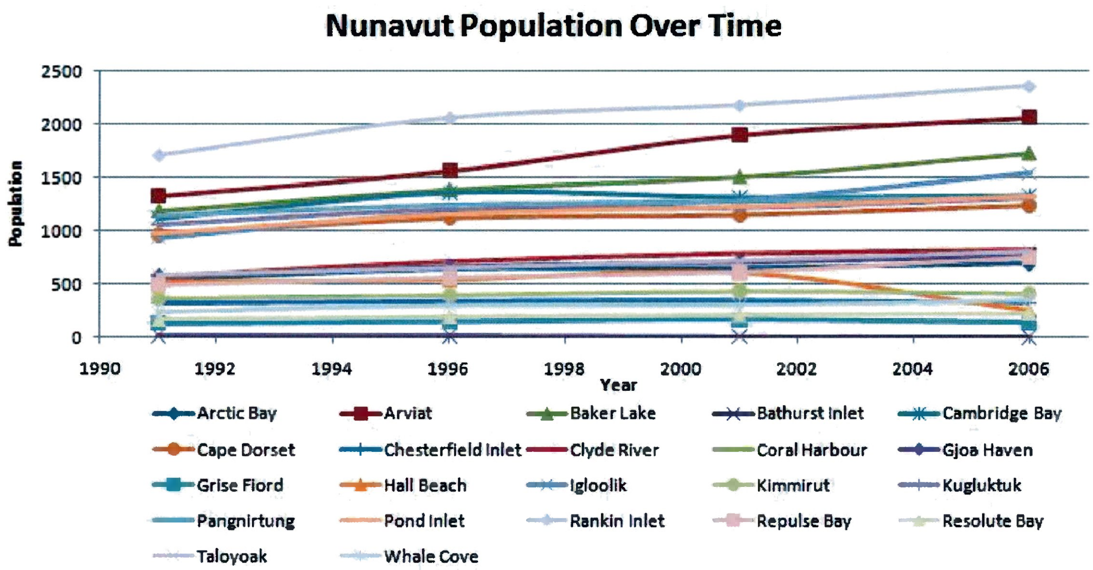

Figure 2.3: NU Population Over Time

2.1.4 Yukon

In 1996 there were a total of 23 remote communities located across the Yukon with a combined population of 33,326. The Yukon contained 7.62 % of the Canadian remote communities and 16.41 % of the total population that resides within the Canadian remote communities [3]. Table 2.7 contains a complete list of the studied remote communities in the Yukon along with their respective populations during the 1991, 1996, 2001, and 2006 census results [5]. The Yukon has 10 communities which are solely powered by diesel generators with a combined population of 4,881 in 1996. These 10 communities are subdivided by large and small diesel operations. The 7 small diesel communities had a combined population of 905 in 1996 and the 3 large diesel communities had a population of 3,981 in 1996. The remaining 13 communities are hydro based power systems which form localized grids with a combined population of 28,440 in 1996. Liard Post, BC (Lower Post) is also included within this analysis as the utility that operates there is the same as that within the Yukon. Burwash Landing is connected to the power system located in Destruction Bay [3, 8]. The periods for which the desired data was not available are denoted by a '-' in the Table.

Table 2.7: Population Distribution in the Yukon

Location	**Population**				**% Change**		
	1991	**1996**	**2001**	**2006**	**91-96**	**96-01**	**01-06**
Beaver Creek	104	131	88	112	26.0	-32.8	27.3
Burwash Landing	77	58	68	73	-24.7	17.2	7.4
Destruction Bay	32	34	43	55	6.3	26.5	27.9
Dawson City	2,026	1,287	1,251	1,327	-36.5	-2.8	6.1
Liard Post, BC	124	125	28	113	0.8	-77.6	303.6
Old Crow	256	278	299	253	8.6	7.6	-15.4
Pelly Crossing	216	238	328	296	10.2	37.8	-9.8
Stewart Crossing	42	42	40	35	0.0	-4.8	-12.5
Swift River	14	15	15	10	7.1	0.0	-33.3
Upper Liard	162	111	159	178	-31.5	43.2	11.9
Watson Lake	912	993	912	846	8.9	-8.2	-7.2

Table 2.8 contains the locations of the remote communities, number of private dwellings during the 2001 and 2006 census results, and the number of dwellings that were occupied by regular residents in 2006 throughout the Yukon [5].

Table 2.8: Dwelling Distribution in the Yukon

Location			**Private Dwelling**		**Usual Residents**
Name	**Lat.**	**Long.**	**2001**	**2006**	**2006**
Beaver Creek	62.24	140.52	58	72	58
Burwash Landing	61.22	139.03	53	53	41
Destruction Bay	61.51	138.48	20	30	24
Dawson City	64.06	139.41	675	768	599
Liard Post, BC	59.56	128.30	22	69	48
Old Crow	67.34	139.50	148	153	118
Pelly Crossing	62.49	137.22	124	126	115
Stewart Crossing	63.32	139.43	18	19	16
Swift River	60.00	131.18	9	18	5
Upper Liard	63.03	128.54	94	96	79
Watson Lake	60.06	128.49	422	424	337

Figure 2.4 shows the population trends for the communities in the Yukon as summarized by Table 2.8 for the communities not including Dawson City and Watson Lake. Dawson City and Watson Lake were not included as the population in these locations are significantly higher than the other locations in the Yukon. It can be seen that the population in the Yukon varies greatly over the examined years. Overall population levels were slightly higher in 2006 as compared to the starting period of 1991.

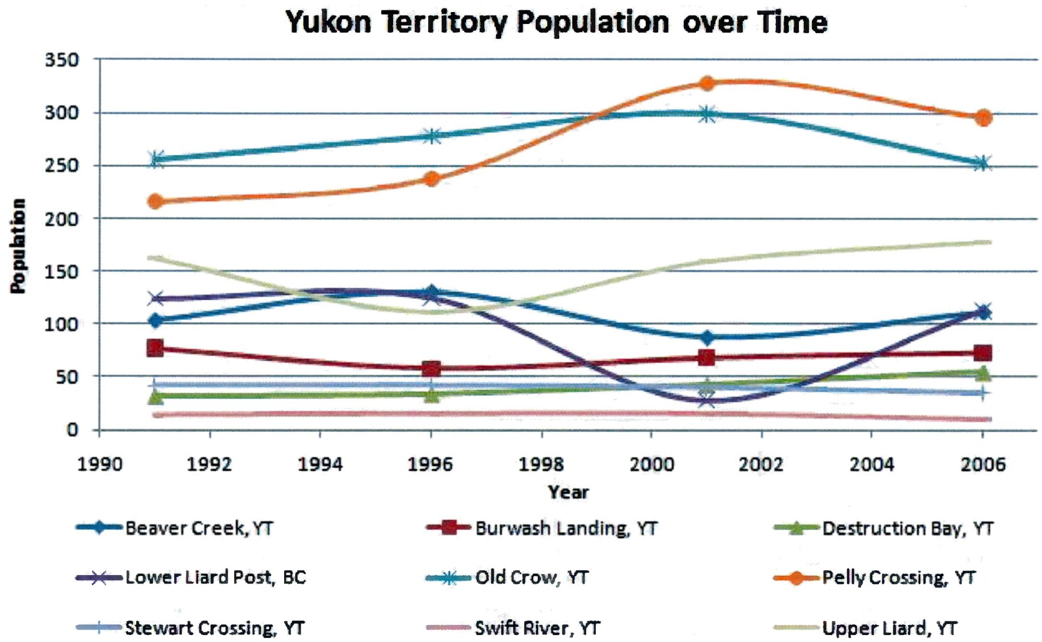

Figure 2.4: YT Population Over Time

2.2 Power System Data

Unfortunately power system data is not publicly available for remote locations within Ontario operated by either Hydro One Remote Networks or independently through the resident native band. The Yukon Electrical Company (YEC) and Quilliq Energy Corporation (QEC), which operate as utilities in the Yukon Territory and Nunavut respectively, also do not make information on their power systems publicly available. QEC does however have information for four locations available to the public through a study performed by [10]. The Northwest Territories Power Corporation (NTPC), the public utility in the Northwest Territories, publishes a significant amount of their power system information which is available to the public. The RETScreen Canadian remote community summary from 1996 contains significant data but is dated [3]. The available present day data from QEC and NTPC along with applicable data from the 1996 RETScreen summary is analyzed in this section so that the results can be translated to a potential remote system in present day Northern Ontario to further develop the system model. Power system information from within Alaska is also briefly introduced being as there are many similarities between Alaska and the targeted focus areas. There has been substantially more research performed in Alaska in the field of remote power systems and Alaska boasts a larger population for development [11, 12, 13]. Although Alaska is not a major focus of this thesis an introduction is provided. The collected data, graphs, and some preliminary results can be found in Appendix A.

2.2.1 Northwest Territories

Table 2.9 lists the 19 communities in the Northwest Territories that utilize power systems that produce electricity from 100% local diesel generators. Table 2.9 also provides a corresponding location identification number, present quantity and size of the diesel generators, and the total size of the installed power system for the 19 diesel locations both at present day and in 1996 [3, 6].

Table 2.9: Power System Installed Capacity in the NWT

Location		Generator (kW)		Installed Capacity (kW)	
Name	**#**	**Quantity**	**Size**	**2010**	**1996**
Aklavik	1	4	320	1,280.00	1,350
Colville Lake	2	3	75-90	255.00	140
Deline	3	1	500	-	-
		2	320	1,140.00	1,240
Fort Liard	4	1	1320	1,320	1,135
Fort Good Hope	5	1	1230	1,230	1,230
Fort McPherson	6	1	1825	1,825	1,805
Fort Simpson	7	1	3210	3,210	4,325
Gameti	8	1	100	-	-
(Rea Lakes)		1	212	-	-
		1	300	612.00	550
Jean Marie River	9	1	230	230.00	180
Lutselk'e	10	1	180	-	-
(Snowdrift)		2	320	820.00	740
Nahanni Butte	11	1	245	245.00	185
Paulatuk	12	1	840	840.00	750
Sachs Harbour	13	1	795	795.00	745
Tsiigehtchic	14	1	500	500.00	400
Tuktoyaktuk	15	1	2205	2,205.00	3,085
Tulita	16	1	1100	1,100.00	880
Ulukhaktok	17	1	1160	1,160.00	1,140
Wha Ti	18	1	175	-	-
(Lac la Martre)		1	480	-	-
		1	320	975.00	1,015
Wrigley	19	1	781	781.00	465

Table 2.10 provides the peak demand of the installed power system in 1996 as well as the annual demand for 1996/97, 2006/07, 2007/08. These metrics will be utilized for the parameter derivation of the system model later in this Chapter.

Table 2.10: Power System Peak and Annual Demand in the NWT

Location		**Peak Demand**	**Annual Demand (MWh)**		
Name	**#**	**(kW) 1996**	**1996/97**	**2006/07**	**2007/08**
Aklavik	1	721	3,408	3004	2996
Colville Lake	2	81	319	357	395
Deline	3	633	2,930	2721	2724
Fort Liard	4	530	2,368	2717	2786
Fort Good Hope	5	700	2,579	2867	2944
Fort McPherson	6	830	4,032	3546	3583
Fort Simpson	7	1,703	4,032	8103	8419
Gameti	8	342	1,265	999	1011
Jean Marie River	9	103	354	303	322
Lutselk'e	10	358	1,565	1604	1647
Nahanni Butte	11	130	412	416	432
Paulatuk	12	264	1,394	1338	1492
Sachs Harbour	13	272	1,215	944	1063
Tsiigehtchic	14	223	698	737	765
Tuktoyaktuk	15	1,057	5,416	4458	4450
Tulita	16	498	2,257	2458	2700
Ulukhaktok	17	499	2,146	1918	2070
Wha Ti	18	466	1,869	1680	1624
Wrigley	19	254	1,012	728	727

Figures 2.5 and 2.6 demonstrate the allocation of the generated power by community for the 2006/07 and 2007/08 periods respectively. The generated power is allocated, represented from top to bottom for the 19 communities represented by the columns, to either street lighting services, general services, or residential services. The related community name to reference number (independent variable representing the 19 communities) for both Figures can be found in Table 2.9 or Table 2.10.

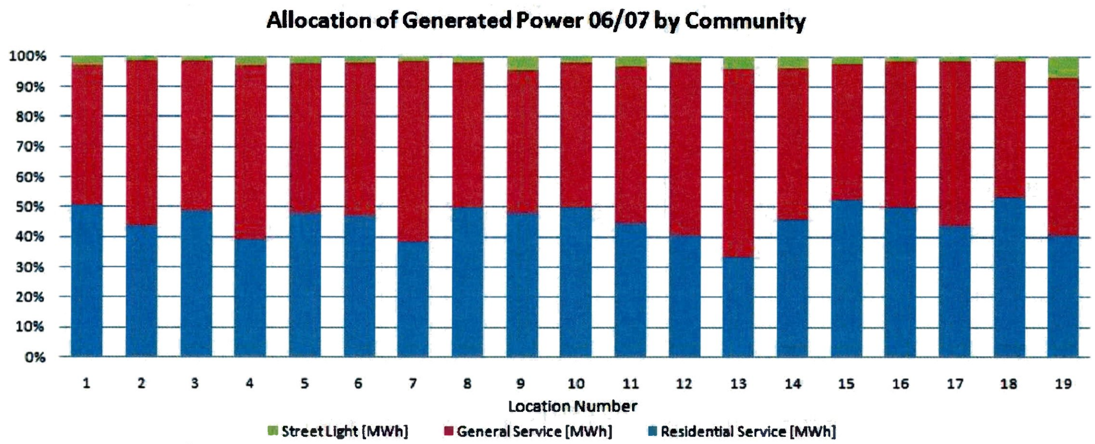

Figure 2.5: NWT - Allocation of Generated Power by Community for 2006/07 [6]

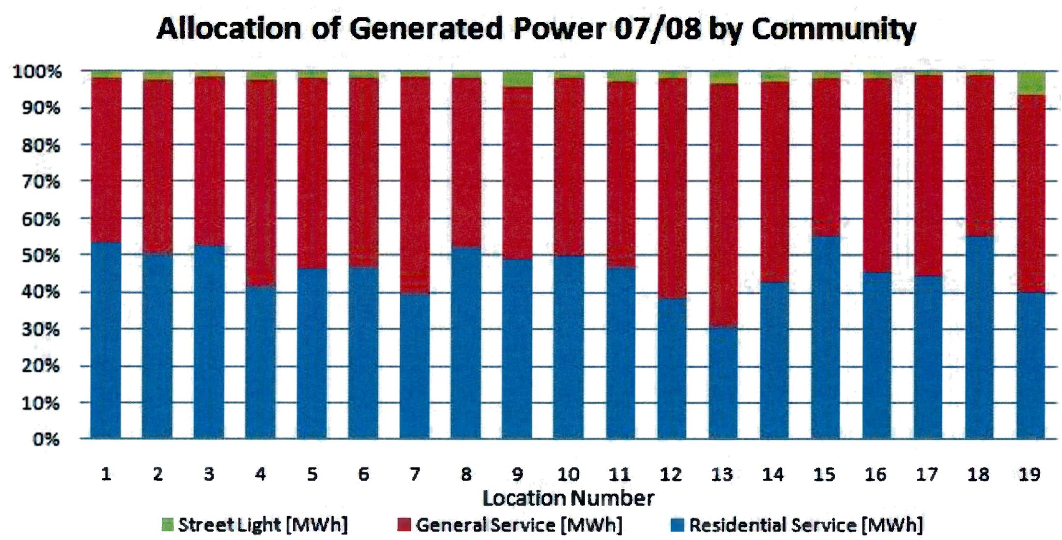

Figure 2.6: NWT - Allocation of Generated Power by Community for 2007/08 [6]

Overall the allocation of generated power remains relatively constant between the two periods and generally the 19 communities have a similar percentage of allocation between the three service sectors. Jean Marie River, Sachs Harbour, and Wrigley do use significantly more power for street lighting services than the other fifteen locations and Sachs Harbour uses the most power for residential services. Table 2.11 consists of the median and mean of the allocation of generated power as a percentage for both 2007 and 2008. The raw data used for developing the figures and tables for the allocation of generated power can be found in Appendix A. It can be seen that on average general services consume approximately 51.5% of the generated power. Residential services consume approximately 46% and street lighting consumes approximately 2.5% of the generated power.

Table 2.11: Allocation of Generated Power Statistics in the NWT (2007/08)

	% Street Lighting		**% General**		**% Residential**	
Statistic	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**
Median	2.131	1.992	50.635	51.290	47.068	46.929
Mean	2.579	2.359	51.655	51.251	45.758	46.400

Average of the Above 2007/2008 Percentages			
Median	2.062	50.962	46.998
Mean	2.469	51.453	46.079

The number of NTPC customers also remains relatively constant over the two year period. By comparing the difference between the sold and generated diesel power statistics it was found that among the 19 communities there was approximately an 11.5% loss between the generator and end user. Figure 2.7 demonstrates the diesel generator size versus the diesel power generated at each of the 19 communities over the two year period. It can be seen that the energy generated between 2006/07 and 2007/08 remained relatively constant. The energy generated in 1996/97 is lower than the other two later years but is still a strong linear relationship. It can be seen that over the 14 year period that the annual energy produced per person increases. Regardless of the year in question the size of the power system is linearly proportional to the total power generated for the year at any given location as all three demonstrate a strong linear relationship. The majority of the power systems have a generation capability of less than 1,500 kW. It can be interpolated from Figure 2.7 that for a power system with an installed capacity of around 1,144 kW that the total diesel power generated per year is approximately 2,326 MWh.

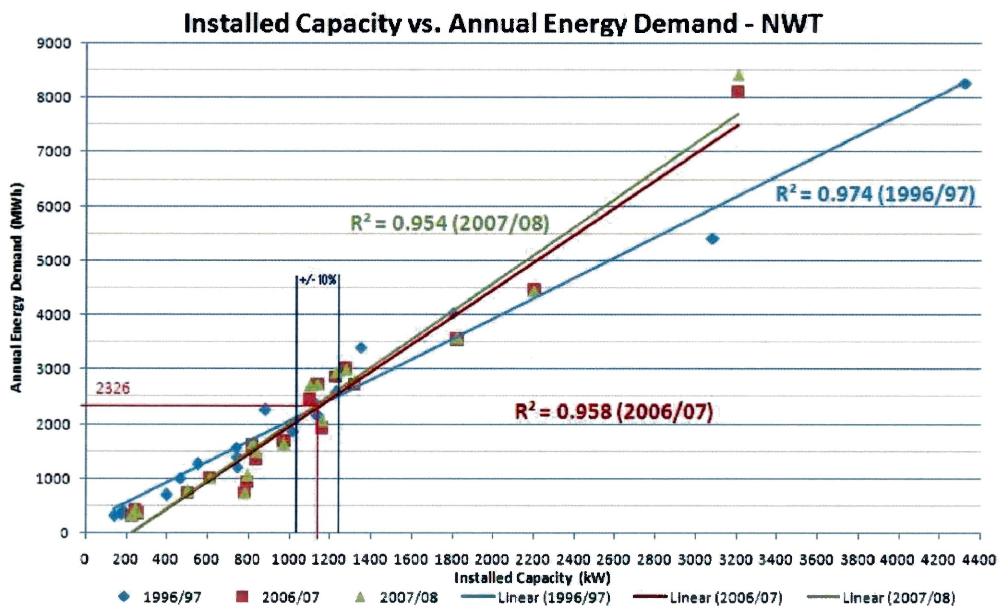

Figure 2.7: NWT - Installed Capacity vs. Annual Energy Demand [6]

Figure 2.8 demonstrates the overall sales versus customers for the 19 communities. It can be seen that Fort Simpson (top right point) is an extreme outlier which should probably be ignored during analysis. The quantity of customers versus installed capacity is not available for 1996. The majority of the communities serve between 100 and 250 customers in 2006 with net sales being typically between 1 to 3 GWh. It can be interpolated from Figure 2.8 that for a power system with approximately 242 customers that the total diesel power generated per year is almost 2,326 MWh.

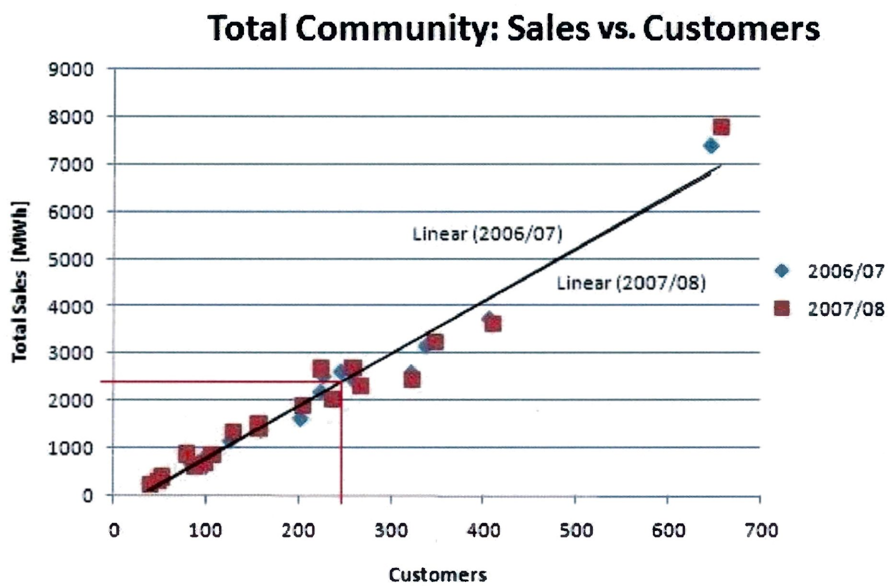

Figure 2.8: NWT - Total Community Sales vs. Customers [6]

2.2.2 Nunavut

In [10] data for four locations across Nunavut is available and was used to obtain the power information below in Table 2.12. The diesel usage in Table 2.12 indicates the volume of diesel used in 2006/07 for electricity generation purposes only. These communities consist of Cambridge Bay, Iqaluit, Rankin Inlet, and Resolute Bay and their respective peak demand, total kWh used, total diesel usage, and total electrical power generated for the 2006/07 year were provided. The peak demand, annual demand, and installed capacity for all locations in Nunavut during 1996 can be found in Appendix A.

Table 2.12: Power System Sizes in Nunavut

Location	2006 Peak Demand (kW)	Total kWh Used 06/07	Diesel Usage 06/07 (L)	Electrical Generation (MWh/yr)
Cambridge Bay	1,400	6,253,712	1,679,111	7,692
Iqaluit	10,000	50,546,130	13,273,102	-
Rankin Inlet	3,000	14,501,716	3,936,378	14,016
Resolute Bay	700	3,861,979	1,110,019	3,872

Figure 2.9 demonstrates the total amount of diesel in litres that was used in the four communities during 2007 on a monthly basis. As expected consumption is lowest during the summer months but overall the usage does not vary significantly.

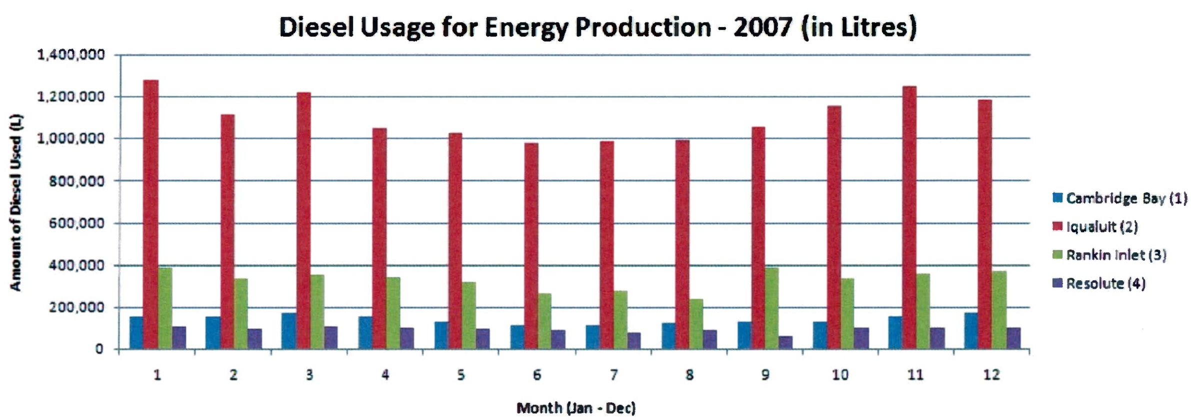

Figure 2.9: NU - Diesel Usage for Energy Production in 2007

Figures 2.10 and 2.11 demonstrate the annual energy distribution between five services for two of the four locations. Both Figures start with the 1994/95 year and project the expected levels until 2013/14. It can be seen that for both locations that energy requirements have already increased significantly since the mid 1990's and they are expected to continue to rise. Similar to locations in the Northwest Territories the commercial and domestic applications are roughly equal in consumption and constitute the majority of power needs. As with most power system applications it can be expected that future requirements will continue to tax the existing systems and the installed systems should be able to handle some increase in demand.

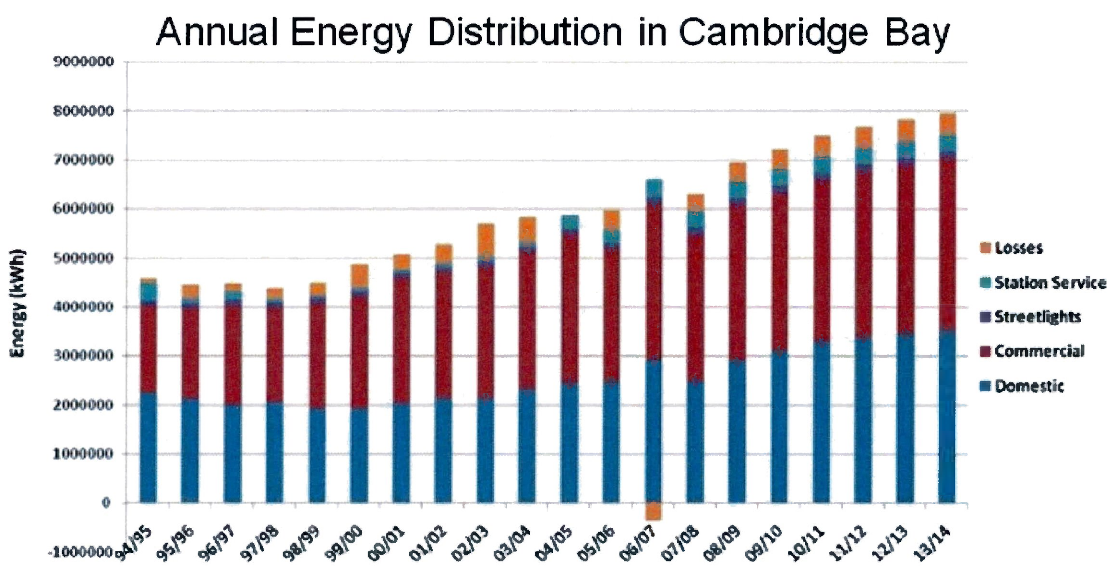

Figure 2.10: NU - Annual Energy Distribution in Cambridge Bay [10]

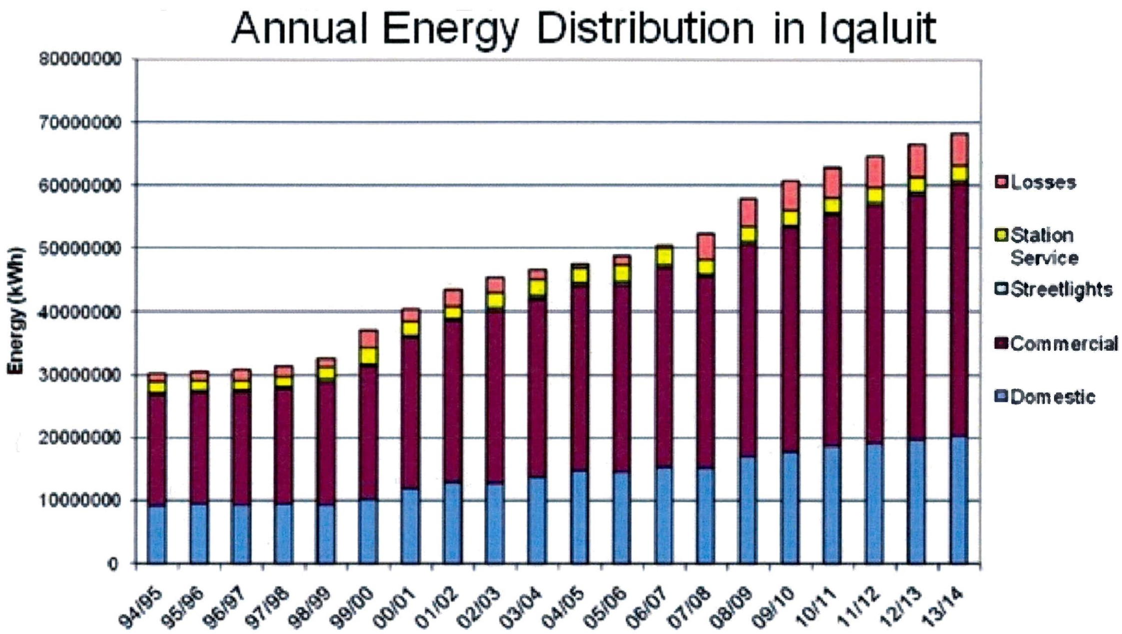

Figure 2.11: NU - Annual Energy Distribution in Iqaluit [10]

Figure 2.12 demonstrates the peak demand of Cambridge Bay between the years of 1994/95 and projects the peak demand until 2013/14. It can be seen that although the peak demand is not always increasing the overall trend does. The peak demand is expected to increase significantly between 2006/07 and 2013/14. Appendix A contains the raw data, supporting material, and additional information on the power systems in 1996 across NU.

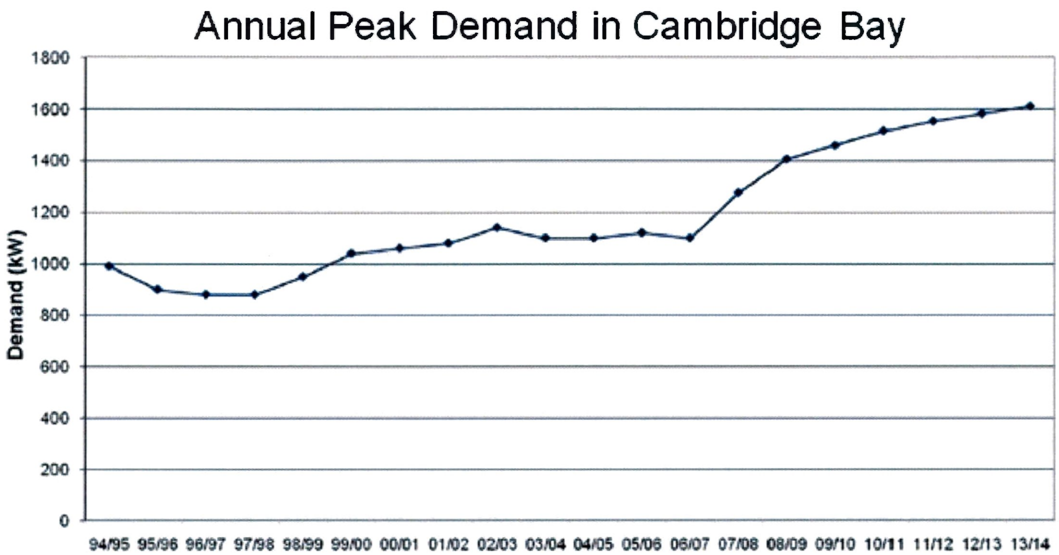

Figure 2.12: NU - Annual Peak Demand in Cambridge Bay [10]

2.2.3 Alaska

Within the state of Alaska there are approximately 175 remote communities with a combined population of around 620,000. The Alaska Power Association (APA) is the state-wide governing trade association for the majority of the LDCs located across Alaska. More than 90% of the population of Alaska obtains their power from either a cooperative or one of the 118 independent LDCs. The two large cooperatives located in Alaska are the Alaska Village Electric Cooperative (AVEC) and the Kotzebuse Electric Association (KEA). As with the remote communities located across Northern Canada the remote communities can also be accessed via plane, barge, rail, or ice road dependent upon location within the state. The AVEC represents remote communities with populations ranging from 100 - 1,100 across 51 remote communities with a total population of around 20,000. These communities typically have three to five diesel generators and experience temperatures ranging from -54 to 34ºC. Some of the larger communities within the AVEC service area connect to smaller nearby communities to supply the base load for the community. It is common for the smaller community to have a small diesel generator located on hand for peaking and some redundancy. In 2002 the average rate of electricity was 39.9 ¢/kWh (USD) with fuel rates being between 1.02 to 2.88 $/US Gallon. Depending upon the location it is typical to store 9 to 13 months of fuel on site. The AVEC publishes some power system data that includes the installed capacity and population in 2010 and the population, annual energy use, average daily use, average load, peak load, and storage capacity in 2002. The associated graphs can be found in Appendix A and generally the results obtained from the AVEC graphs are comparable to that obtained from their Canadian counterparts [11, 12, 13].

2.3 Climatic Data

Environment Canada was utilized for data acquisition from their climate data online, climate normals and averages, and Canadian Weather Energy and Engineering Datasets (CWEEDS) data collections. The climate data online and climate normals and averages data collections provide both climate averages and extremes for various locations across Canada that have at least fifteen years of data available between the years of 1971 and 2000. CWEEDS was created to track long term weather patterns to aid in the development of urban environments and in the design of efficient buildings. CWEEDS provides raw hourly data for twenty one different weather metrics for a collection of locations ranging between the years of 1953 and 2005. Some of the metrics provided by CWEEDS are estimated through various prediction algorithms when measured data is unobtainable at the given station. More information on these algorithms and their implementation can be found in the CWEEDS supporting documentation [9]. An interface was developed to determine the monthly averages for the eight solar related metrics and six wind related metrics during the periods provided for the individual stations so that the raw hourly data could be summarized. The source code along with the raw data text files and their respective summarized '.out' files can be found in Appendix B.

The Ministry of Natural Resources was utilized for data acquisition from their Renewable-energy and Energy-efficient Technologies (RETs) RETScreen clean energy project analysis software. RETScreen provides information to evaluate the energy production and savings, costs, emission reductions, financial viability and risks associated with renewable power implementations through the use of product, project, hydrology, and climate databases [3]. Table 2.13 provides a comprehensive list of the various locations within Northern Ontario that were examined during the climatic analysis along with their respective period of study and data source information. The period of study provided is only relevant to data obtained from Environment Canada as RETScreen only provides overall, non period specific averages. The data collection labelled as other includes both the climate data online and climate normals and averages data collections from Environment Canada and the coordinates provided are those of the weather recording stations. This data from Environment Canada's climate data online and climate normals and averages databases includes data related to precipitation, wind chill factors, and maximums and minimums of various weather metrics in conjunction with additional weather station locations both of which were not available through the CWEEDS or RETScreen databases.

Table 2.13: Northern ON Climatic Location and Data Summary

Location			**Period**		**Data Collection [3, 9]**		
Name	**Lat.**	**Long.**	**Start**	**End**	**CWEEDS**	**RETs**	**Other**
Armstrong	50.28	88.90	1953	1967	Yes	Yes	No
Atikokan	48.75	91.62	1967	1988	Yes	Yes	Yes
Big Trout Lake	53.83	89.87	1967	1990	Yes	Yes	Yes
Geraldton	94.70	86.95	1968	2000	Yes	Yes	Yes
Graham	49.27	90.58	1953	1966	Yes	No	No
Lansdowne House	52.14	87.53	1971	2000	No	Yes	Yes
Kapuskasing	49.42	82.47	1953	2005	Yes	Yes	Yes
Kenora	49.80	94.37	1953	2005	Yes	Yes	Yes
Moosonee	51.27	80.65	1957	1993	Yes	Yes	Yes
Nakina	50.18	86.70	1953	1966	Yes	No	No
Pickel Lake	51.26	90.13	1971	2000	No	Yes	Yes
Red Lake	51.04	93.47	1971	2000	No	Yes	Yes
Sioux Lookout	50.12	91.90	1953	2005	Yes	Yes	Yes
Thunder Bay	48.37	89.32	1953	2005	Yes	Yes	Yes

Overall climatic data was collected for 12 locations in Northern Ontario, 5 in the Northwest Territories, 9 in Nunavut, and 5 in the Yukon. Only the climatic data relevant to Northern Ontario was studied in depth and it was used to provide the climatic analysis of the system model. Table 2.14 provides a comprehensive list of the additional locations that were investigated. The period for all locations is from

1971 to 2000. The CWEEDS data set is available for many of the locations but since the climate data was not studied in depth for the various territories it was not utilized. A summary of the weather station data from the territories can be found in Appendix B.

Table 2.14: Territory Climatic Location and Data Summary

Location			**Data Collection [3, 9]**		
Name	**Lat.**	**Long.**	**CWEEDS**	**RETs**	**Other**
Fort Liard, NWT	60.14	123.28	None	No	Yes
Fort Simpson, NWT	61.45	121.14	Available	Yes	Yes
Sachs Harbour, NWT	72.00	125.16	Available	Yes	Yes
Tuktoyaktuk, NWT	69.27	133.00	None	Yes	Yes
Ulukhaktok, NWT	70.45	117.48	None	No	Yes
Baker Lake, NU	64.17	96.04	Available	Yes	Yes
Cambridge Bay, NU	69.06	105.08	Available	Yes	Yes
Cape Dorset, NU	64.13	76.31	None	Yes	Yes
Clyde River, NU	70.29	68.31	Available	Yes	Yes
Coral Harbour, NU	64.11	83.21	Available	Yes	Yes
Hall Beach, NU	68.46	81.14	Available	Yes	Yes
Iqaluit, NU	63.45	68.33	Available	Yes	Yes
Rankin Inlet, NU	62.49	92.07	Available	Yes	Yes
Resolute Bay, NU	74.43	94.59	Available	Yes	Yes
Beaver Creek, YT	62.24	140.52	None	No	Yes
Burwash Landing, YT	61.22	139.03	Available	Yes	Yes
Old Crow, YT	67.34	139.50	None	No	Yes
Pelly Crossing, YT	62.49	137.22	None	No	Yes
Watson Lake, YT	60.06	128.49	Available	Yes	Yes

2.4 Development of a Northern ON System Model

The system model was developed using the population and housing, power system, and climatic data for the available locations as previously explored. Due to the fact that power system information is difficult to obtain, a comparison was done between the available population, housing, and power system data in the territories and the available population and housing data from Northern Ontario. The climatic data was acquired for the territories and Northern Ontario. However since it was later determined that the heating in the territories and Northern Ontario is typically oil or wood and thus not electric the difference in climate between Northern Ontario and the territories was neglected for power system sizing. Being as the territories do not rely on electric heat it was assumed that the power requirements would remain similar between Northern Ontario and the territories. As such only the climatic data from Northern Ontario from the available applicable weather stations was analyzed in depth. The power system data available for the territories was translated to Northern Ontario and used to form the basis of the model. Additional population concerns will be addressed in the following Section. From an analysis of the various weather stations in Ontario the average latitude and longitude were found to be 50.39 and 88.89 degrees respectively. The average elevation was found to be 297.9 metres.

2.4.1 Population and Housing Parameters

As seen from Figure 2.1 the population trends for the communities in Northern Ontario that have population data available for all four collection years has either remained the same or increased slightly between 1991 and 2006. When comparing the population of a remote community with the number of private dwellings in Northern Ontario it is found that the number of private dwellings is about 25% of the entire population. Using the population values from Table 2.1 the mean population from all of the remote systems in Ontario, regardless of utility, was determined as well as the utility specific maximum, minimum, mean, and median populations over the studied period. The results are displayed in Table 2.15. The overall mean population across Ontario during the 1991, 1996, 2001, and 2006 census periods is 469.84. The increase between 1991 and 2006 is evident from Table 2.15.

Table 2.15: Population Statistics Across Ontario

Utility Independent Statistics - Across Ontario								
Statistic	**2006**		**2001**		**1996**		**1991**	
Mean	578.73		454.50		416.33		429.81	
Overall Mean Population from 1991 to 2006:					469.84			
Statistics Based Upon Utility								
Statistics (Pop.)	**Hydro One**				**Band Operated**			
	2006	**2001**	**1996**	**1991**	**2006**	**2001**	**1996**	**1991**
Min.	206	105	100	179	221	61	160	150
Max.	1843	1705	1610	1352	2100	1000	1170	1303
Mean	575.92	513.79	421.64	447.77	582.10	350.75	408.90	400.63
Median	454.50	384.00	335.00	344.00	340.00	270.50	265.00	289.00

Figure 2.13 graphically demonstrates the change in the mean population during the provided census periods. The projected change in the overall mean between the 2006 census period and present day is also indicated. This projected figure was derived from independent community specific population sources and through current INAC publications. The projected mean in population during 2010 across ON is 614.12

as determined from the available total band population data in 2010. When this projected 2010 mean population is averaged with the existing mean population of 469.84 from the provided census periods the resulting mean population between 1991 and 2010 is found to be 498.70.

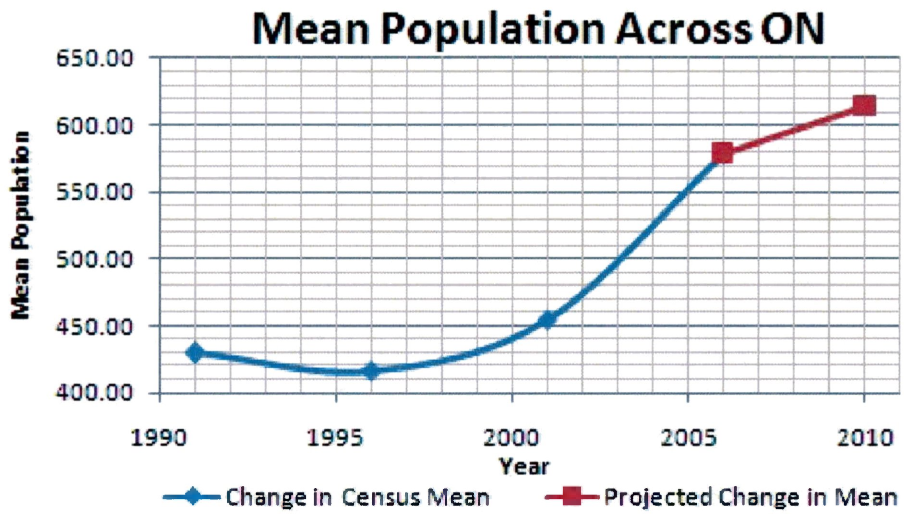

Figure 2.13: Projected Change in ON population by 2010

Using the results from Table 2.15 and Figure 2.13 it is determined that an appropriate population range for the remote system was between 300 to 700 people. This range will be used to aid in the development of the power system specific parameters. The model will use a population value of 500 as the total population size. This value was chosen as it is both close to the overall mean of 498.70 during the 19 year period and it is midway between the desired population range of 300 to 700. Using the supplied acceptable range of population for a given remote community Table 2.16 summarizes the communities that fall within the acceptable range. There are 6 communities located within NU, 8 within the NWT, and 13 within ON. It should be noted that there are no communities within the acceptable population range located within the YT. The system model is designed for present day however since the last census was in 2006 the population values used represent those of 2006 even though some of the power system data from the NWT is representative of present day installations.

Table 2.16: Cummulative List of Acceptable Locations Based on Population

	Location	**Pop. 06**		**Location**	**Pop. 06**
Nunavut			**Ontario**		
1	Arctic Bay	690	2	Bearskin Lake	459
7	Chesterfield Inlet	322	5	Deer Lake	681
15	Kimmirut	411	6	Fort Severn	445
16	Kugaaruk (Pelly Bay)	688	9	Kasabonika	681
20	Qikiqtarjuarq	473	20	Kee-way-win	318
25	Whale Cove	353	10	Kingfisher	415
North West Territories			26	Poplar Hill	457
1	Aklavik	594	13	Sachigo Lake FN	450
3	Deline	525	27	Summer Beaver	362
4	Fort Liard	583	16	Wapekeka FN	350
5	Fort Good Hope	557	17	Weagamow Lake 87	700
10	Lutselk‘e	318	18	Webequie	614
16	Tulita	505	28	Wunnummin Lake	487
17	Ulukhaktok	398			
18	Wha Ti	460			

It is clear from the previous population analysis across the territories and Northern Ontario that in general the population in the NWT is relatively constant and the population in Northern ON has continued to increase. The power system is being designed from a combination of aspects from the 1996 and present day data and as such it is important to also consider the change in the community population for system sizing information. The average population across ON during 1996 and

2006 for the remote communities with a population between 300 and 700 was 424.50 and 497.83 respectively. This yields a 73.33 person or 14.74 % difference between 1996 and 2006. In the NWT the average population during 1996 and 2006 for the remote communities with a population between 300 and 700 was 481.00 and 492.50 respectively. This yields an 11.50 or 2.34 % difference between 1996 and 2006. This general trend was also verified in Section 2.1 during the full population analysis. This also demonstrates that between 1996 and 2006 that there was an overall difference of 12.40 % in the rate of population growth between the NWT and N ON. From the population analysis it was found that there is a difference in the increase of population over the 14 year period and that there is a faster rate of increase in population across N ON when compared to the NWT. However, given that remote power systems are already designed to allow for moderate population growth over time and that the installed capacity was investigated across a 10 year span there is a sufficient margin to allow for the aforementioned differences in population growth. In the future additional installed capacity will be provided as required alongside the current infrastructure.

2.4.2 Power System Parameters

Figure 2.14 demonstrates the population versus the installed capacity for the locations of accepted population within the NWT as listed in Table 2.16. Numbers 1 through 18 in Figure 2.14 represent locations in the Northwest Territories as described in Table 2.9. The line of best fit in Figure 2.14 has an r-squared value of approximately 0.575 in 1996 and 0.738 in 2006 which denotes an acceptable mid-range linear relationship to aid in the development of the power system model. Location 17, or Ulukhaktok, is an outlier which does negatively skew the results of the line of best fit. A possible explanation for this is that in Ulukhaktok there is only one diesel generator. In order for a diesel generator to be operational it must have a minimum load ranging from typically 30-50% and to operate at an optimal level it should be loaded at around 70-80%. With only one diesel generator it is very possible that more power was created by the system than was required to meet these constraints. Through interpolation it is found from Figure 2.14 that for a population of 500 the resulting installed power system size is approximately 1,144 kW. Although the installed capacity does change during the 10 year period for the two provided data sets when interpolating for a population of 500 the installed capacity is virtually identical between 1996 and 2006. Since the installed capacity is derived from the latest published values from NTCP in 2008 it is assumed that the derived approximation of 1,144 kW installed capacity is valid in the present day as well. The reason being that the above analysis was performed under the guise of 2006 when NTCP made information available for the 2006-2008 period and since census population data is available for 2006 it is the de facto year for the provided data set.

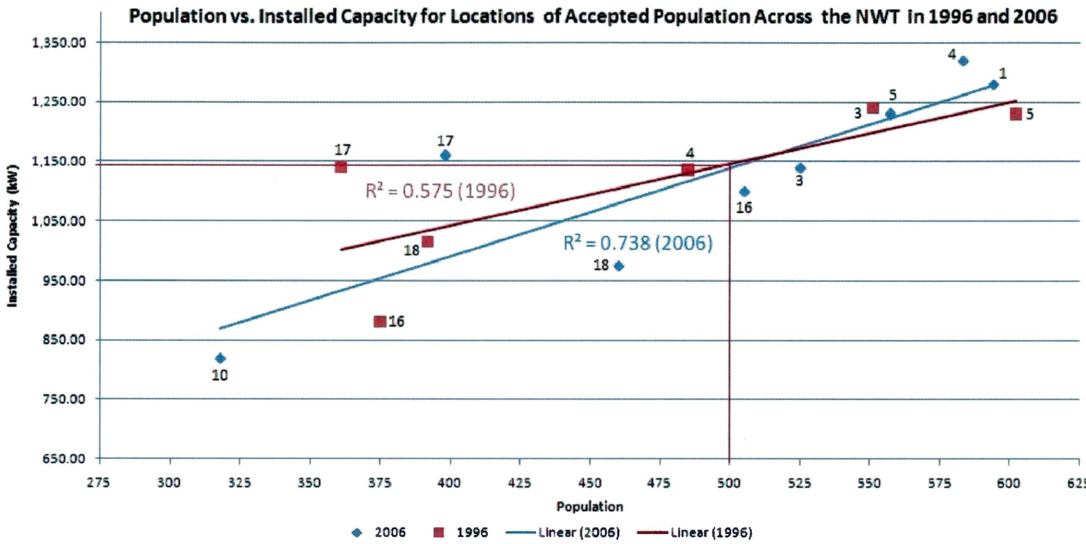

Figure 2.14: Population vs. Installed Capacity for Locations of Accepted Population across the NWT in 1996 and 2006

Figure 2.15 demonstrates the population versus the peak demand for the locations of accepted population within the NWT as listed in Table 2.16. Numbers 1 through 18 in Figure 2.15 represent locations in the Northwest Territories as described in Table 2.9. The line of best fit in Figure 2.15 has an r-squared value of approximately 0.887 in 1996 which denotes a strong linear relationship to aid in the development of the power system model. Through interpolation it is found from Figure 2.14 that for a population of 500 in 1996 that the resulting peak demand of the power system is approximately 588 kW. The mean population of the selected communities in 1996 was 461 and 493 in 2006. The peak demand is dependent upon many variables one which includes the population of the given power system. The mean population increased by 6.8% between 1996 and 2006. For simplicity it is assumed that the peak demand increased proportionally which produces an approximate peak demand of

628 kW.

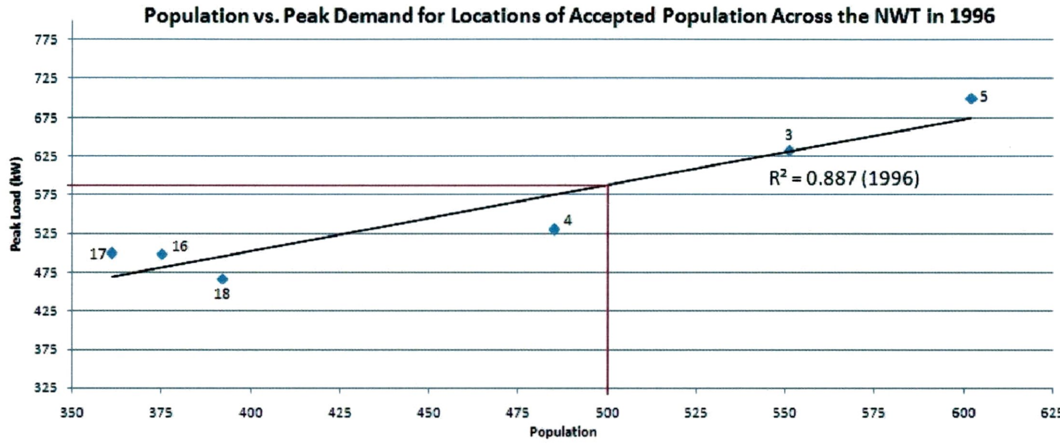

Figure 2.15: Population vs. Peak Demand for Locations of Accepted Population Across the NWT in 1996

For the eight locations in the NWT that have the appropriate population and power system sizing information the size of the installed capacity required (in Watts) per dwelling in 2001, person in 2001, customer in 2006/07, and person in 2006 were calculated. Figure 2.16 demonstrates the amount of installed capacity required for the metrics listed above. The sites 1 through 18 represent locations in the Northwest Territories as described in Table 2.9. Location 10, or Lutselk'e, does not include variables for 2001 as the population during the census was below that of the determined appropriate population range. It was assumed for the dwellings and person 2001 (noted by the *) that the installed capacity of the power system in 2001 was the same as 2006.

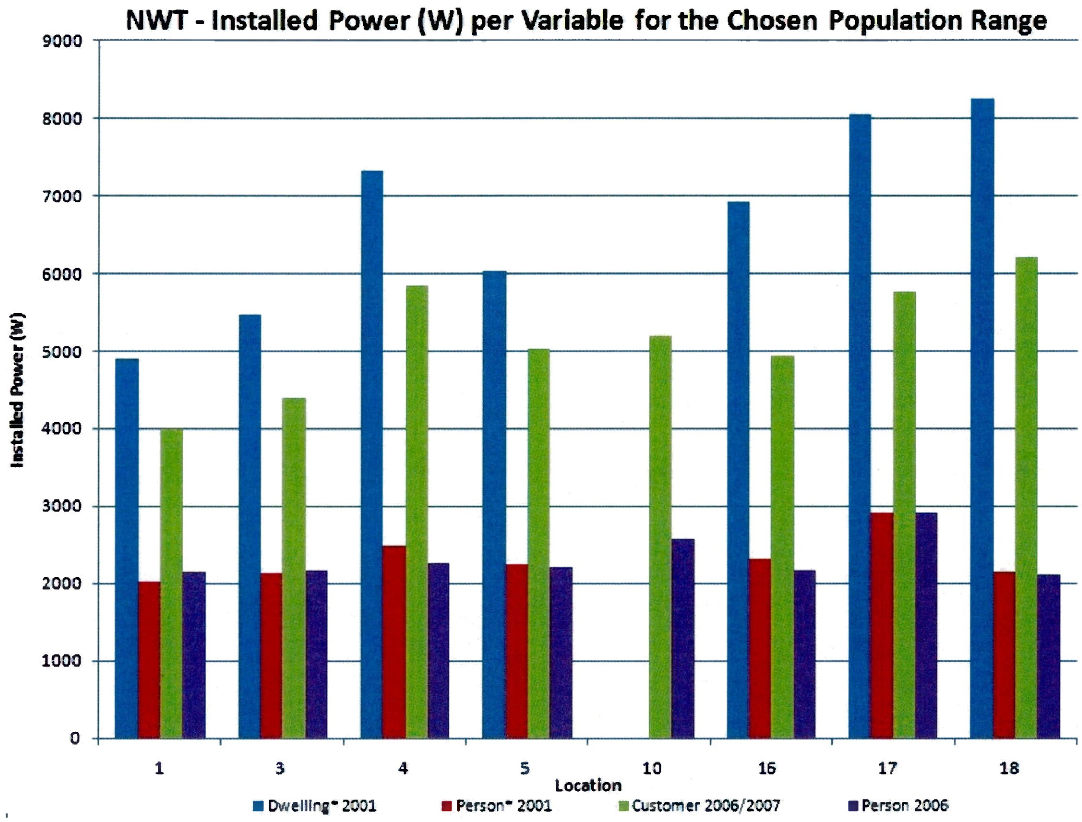

Figure 2.16: Installed Power per Variable for the Chosen Population Range

It can be seen from Figure 2.16 that the installed capacity per person in 2001 is very similar to that in 2006 with Wha Ti being the most extreme case. The installed capacity per customer and dwelling are also closely related. Table 2.17 provides the calculated mean and median for the data graphed in Figure 2.16.

Table 2.17: Installed Power (W) per Variable Statistics

Statistic	Dwelling 2001	Person 2001	Costumer 2006/2007	Person 2006
Mean	6712.034 W	2325.094 W	5169.268 W	2323.712 W
Median	6918.239 W	2240.437 W	5105.141 W	2193.238 W

Assuming that the installed power per a person in 2006 is 2,300 W then a community with 500 people would require 1,150 kW of installed power which is comparable to the 1,144 kW obtained from Figure 2.14.

Figure 2.17 represents the 19 communities in the NWT and the quantity of Wh generated by 1 L of Diesel over the course of the two years. It can be seen that many locations are similar across the two year period. The ability for diesel to generate power varies from location to location but is relatively consistent within 2400 and 3800 Wh.

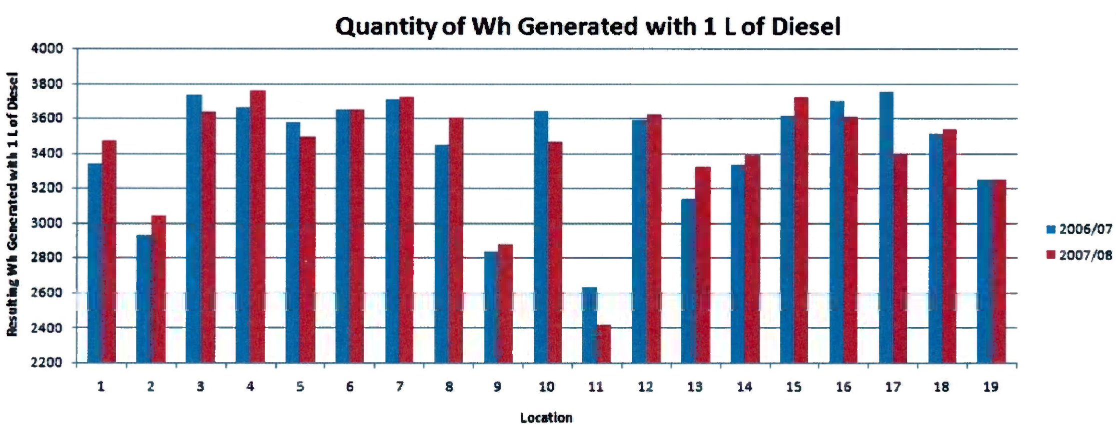

Figure 2.17: Quantity of Wh Generated with 1 L of Diesel

Table 2.18 contains the means and medians that were calculated from the raw data over the course of the two years for the quantity of Wh generated by 1 L of diesel. It can be concluded that 1 L of diesel will produce about 3,400 Wh of power.

Table 2.18: Quantity of Wh Generated by 1 L of Diesel Statistics

Statistic	**2006/07**	**2007/08**
Mean	3421.521	3417.525
Median	3574.813	3492.289

Using the data provided by [10] in Table 2.12 for Resolute Bay the above assumption that 1 L yields roughly 3,400 Wh can be verified. The total kWh used in 2006/07 divided by the factor of 3,400 Wh/L yields 1,135,876 L of diesel which is only 2.33% more than the actual consumed quantity of 1,110,019 L in 2006/07. Thus the assumed factor also works with the power system information obtained for Nunavut as well for similar communities. Figure 2.18 demonstrates the percentage of fuel used per month for the overall diesel energy production in 2007 at the four NU locations. It can be seen that the usage is highest during the winter months and that the four locations in NU are closely related.

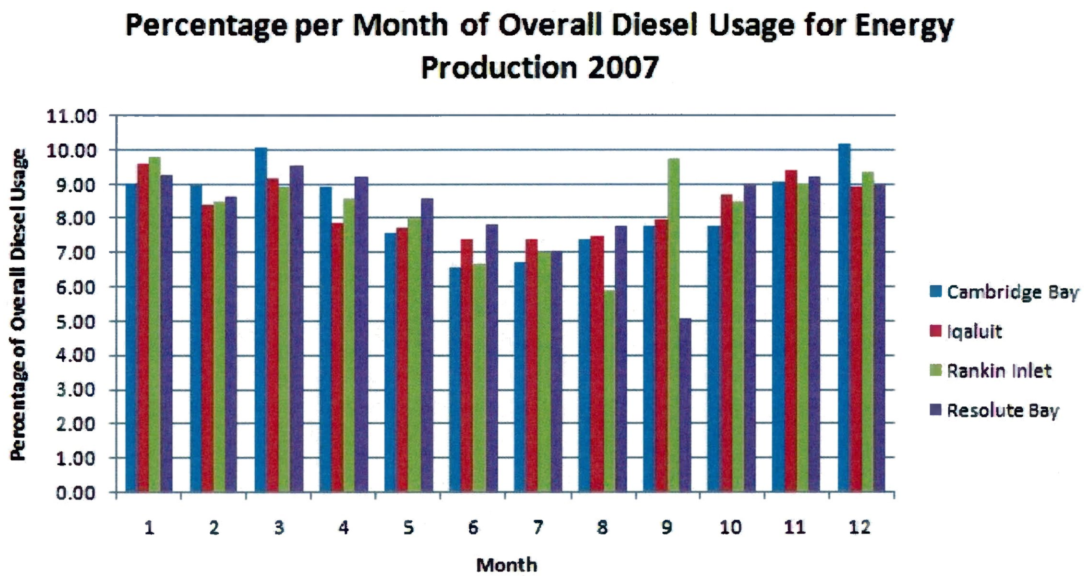

Figure 2.18: NU - Percentage per Month of Diesel Used for Generation in 2007

Table 2.19 displays the average percentage per month of the overall diesel usage for energy production in NU during 2007 for the locations in Figure 2.18. This analysis of the monthly fuel utilization will be used within the thesis to demonstrate operational costs and to demonstrate the potential decrease of hydrocarbon fuel dependencies in remote communities upon a technical and economical analysis of the various technologies. Due to the limited nature of publicly available data the percentage of diesel consumed per a month in NU is used as a basis for the consumption archetype in Northern ON.

Table 2.19: Average Percentage of Diesel Used per Month in NU for 2007

Month	Percentage	Month	Percentage
Jan.	9.41	July	7.03
Feb.	8.63	Aug.	7.13
Mar.	9.43	Sept.	7.63
Apr.	8.65	Oct.	8.48
May	7.98	Nov.	9.17
June	7.11	Dec.	9.36

2.4.3 Power System Overview

NU and the NWT were previously studied in-depth as both territories had the 1996 RETScreen Canadian remote power system data and recent utility data available for analysis. The overall trends of the installed capacity, peak demand, and annual demand for Northern ON, NU, and the NWT were studied for the desired population range of 300 to 700 people which were primarily based off of the 1996 data set as indicated. Figure 2.19 provides an overview of the population versus the installed capacity. The only data set with an acceptable r-squared value is that of the NWT in 2006 at 0.738. ON exhibits a very poor relationship between population and installed capacity with an r-squared value of 0.004. This indicates that in 1996, for the population range that includes the average population of a remote community in the province of Ontario, that there appears to be a minimal amount of effort expended on the sizing of the remote systems.

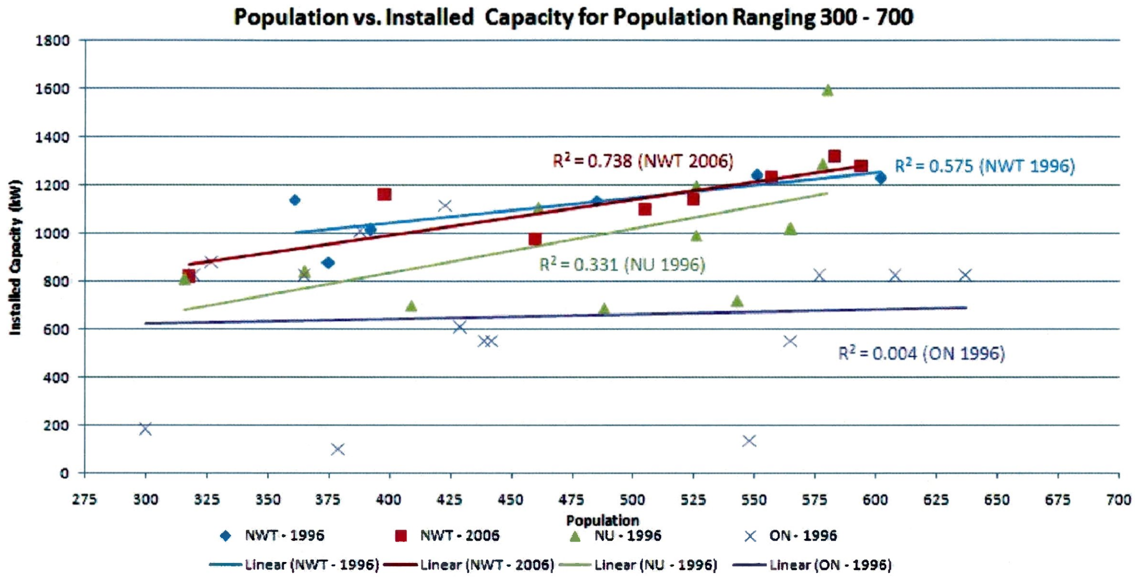

Figure 2.19: Overview of Installed Capacity for the Population Ranging 300 to 700

Figure 2.20 provides an overview of the population versus the peak demand. Both the data sets from the NWT and NU for 1996 provide a strong linear relationship between the population and the peak demand. Once again ON suffers from relatively poor characteristics when compared to the territories within the desired population range.

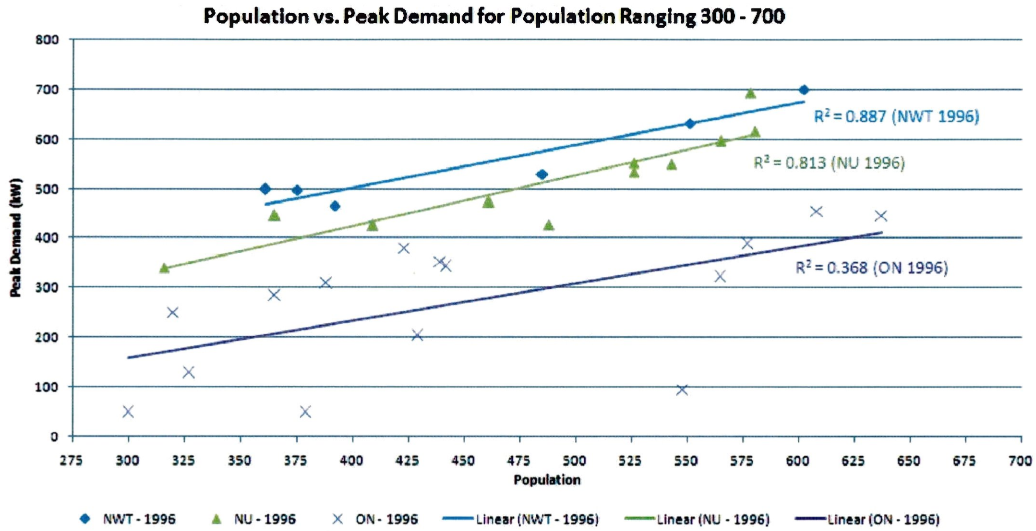

Figure 2.20: Overview of Peak Demand for the Population Ranging 300 to 700

Figure 2.21 provides an overview of the population versus the annual demand. The provided data sets from the NWT in 1996/97, 2006/07, and 2007/08 and NU in 1996/97 all provide a mid to strong linear relationship between the population and the annual demand. Once again ON suffers from relatively poor characteristics when compared to the territories within the desired population range.

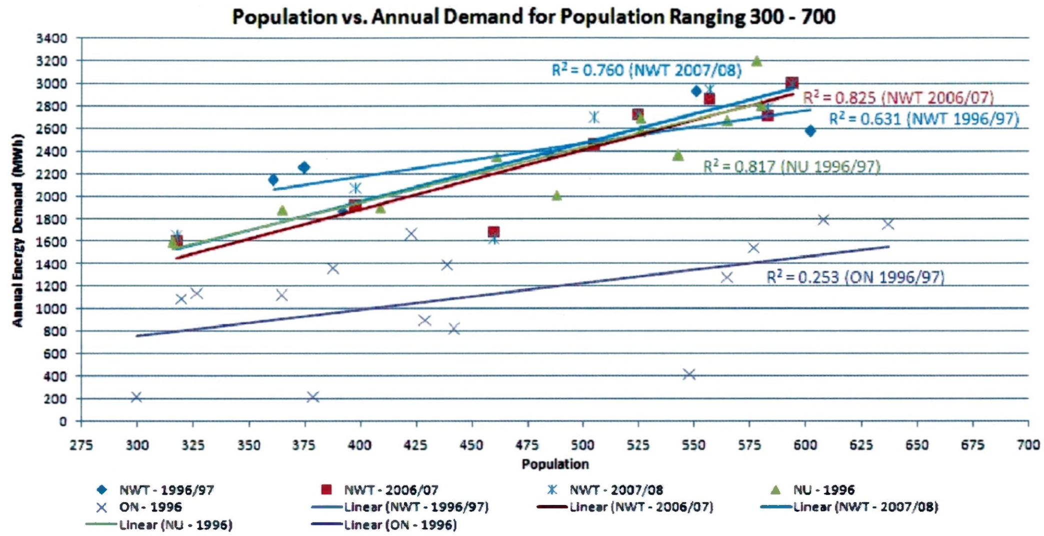

Figure 2.21: Overview of Annual Demand for the Population Ranging 300 to 700

Table 2.20 demonstrates the available data's related r-squared values for both the desired population range of 300 to 700 and an overall analysis of the province or territory. The desired population range of 300 to 700 derivations can be seen from Figures 2.19, 2.20, and 2.21 and the overall view r-squared values can be found in Appendix B. Only communities that rely on diesel power generation were explored in Table 2.20.

Table 2.20: Summary of Power System Overview Results

Location	Year	R Squared Value - Overall View Peak Load	Installed Capacity	Annual Demand	Number of Locations
NWT	1996	0.923	0.848	0.917	19
NWT	2006/07	-	0.928	0.946	19
NWT	2007/08	-	0.928	0.935	19
NU	1996	0.774	0.505	0.740	25
NU	1996*	0.873	0.749	0.886	23
YT	1996	0.967	0.933	0.994	8
ON	1996	0.830	0.667	0.833	32
R Squared Value - Selected Population (300 to 700)					
NWT	1996	0.887	0.575	0.631	6
NWT	2006/07	-	0.738	0.825	8
NWT	2007/08	-	0.738	0.760	8
NU	1996	0.813	0.331	0.817	11
ON	1996	0.368	0.004	0.253	15

The overall community summary for NU in 1996 does not include the capital of Iqaluit in the calculations. In the initial NU entry for 1996 there are two additional outliers which consist of Rankin Inlet, NU and Resolute Bay, NU. With these two additional data points removed from the analysis the results obtained during the NU year titled "1996*" the corresponding r-square value is significantly improved upon. The YT summary does not include Upper Liard, BC. It can be seen from the overall r-squared value overview that the relationship between population and the three studied metrics yield predominantly strong linear relationships. However, when the r-squared value is compared across the various locations and years for the community of a population between 300 and 700 the results are significantly different.

It can be seen that most of the resulting r-squared values result in mid range linear relationships however ON performs significantly poorer than the territories. From this analysis it becomes evident that one of the applications of this thesis is to develop practical alternatives to the existing infrastructure within Ontario in the hope to improve the economics when compared to the existing power systems.

2.4.4 Climatic Parameters

As seen from Table 2.13 the most Northern weather station is Big Trout Lake, the most Eastern weather station is Moosonee, the most Western weather station is Kenora, and the most Southern weather station is Thunder Bay. These fourteen weather stations are located across the majority of Northern Ontario and are thus able to provide a sufficient collection of data from which to extrapolate solar and wind energy information for the climatic analysis. The only two remote communities that are further North than Big Trout Lake are Fort Severn and Peawanuck. Figure 2.22 demonstrates the climate zones that apply in Ontario which includes three of the four that occur throughout Canada. The majority of Northern Ontario is zone C, with the exception of the area surrounding Fort Severn and Peawanuck, which are zone D. Being as zone D is the same zone as the arctic or far North and that there are only two communities located within this zone in Ontario they are neglected in the climate analysis making Big Trout Lake the upper limit of the analysis [14].

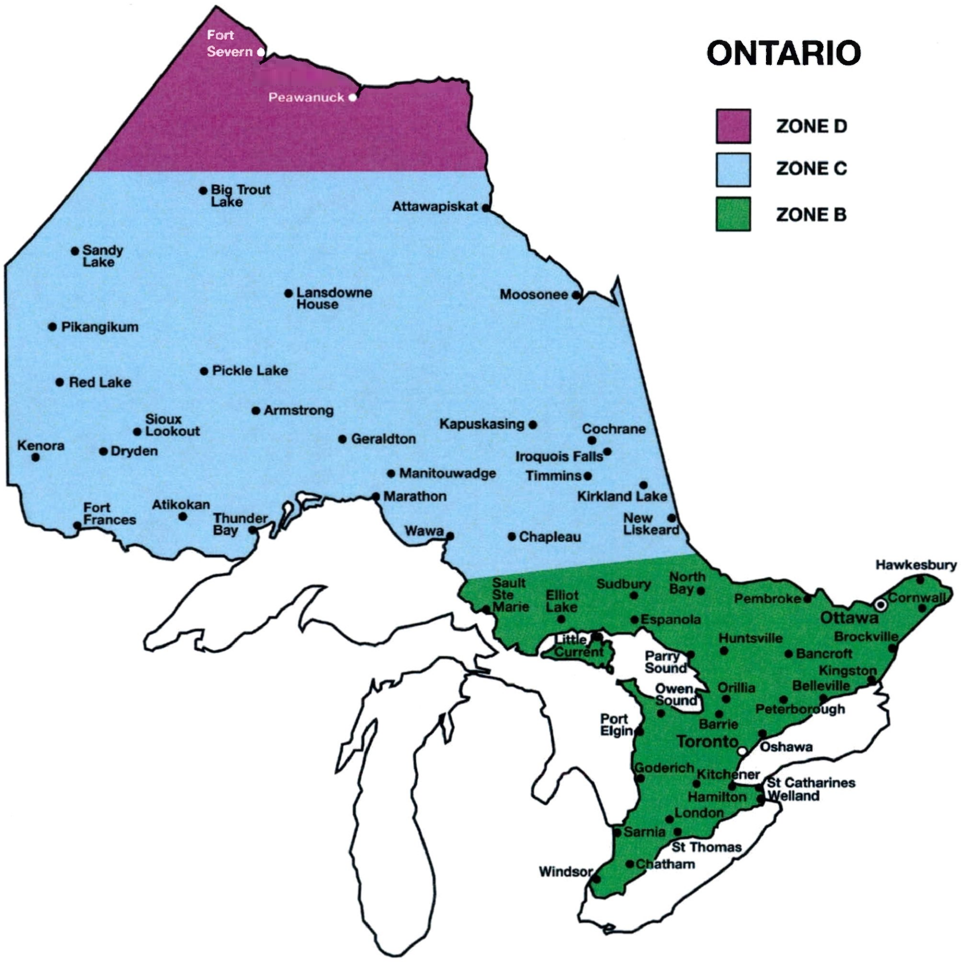

Figure 2.22: Climate Map of Ontario

Table 2.22 summarizes the rainfall, snowfall, heating degree-days, and cooling degree-days as the median of the monthly averages at the stations listed in 2.13. The climatic variables used to construct the model relating specifically to solar energy are located in Section 6.2, wind energy in Section 7.2, and the remaining variables in Table 2.22.

Heating Degree-Days (HDD) is a measurement produced by Natural Resources Canada that indicates the amount of energy required to heat a building. The HDD measurement is derived from the daily temperature requirement and the specific heating requirements for the given building, which is very dependent upon location. The Cooling Degree-Day (CDD) is the inverse of HDD. The CDD and HDD parameters are considered when designing facilities and are particularly important in Northern climates. The climate zones A through D found in Figure 2.22 indicate the average number of HDDs for a given location as defined by Table 2.21 [14].

Zone	**Range**
Zone D	> 8000 HDDs
Zone C	> 5500 to <= 8000 HDDs
Zone B	> 3500 to <= 5500 HDDs
Zone A	<= 3500 HDDs

Table 2.21: Climate Zone Definitions

For the summarized snowfall values the monthly averages recorded in Kapuskasing were neglected as the snowfall was significantly higher at the station compared to any other location for January, March, and December as shown on the monthly average snowfall across Northern Ontario graph. The graphs demonstrating the monthly averages of the variables denoted by Table 2.22 across Northern Ontario can be found in Appendix B. It should be noted that all graphs related to the climatic variables list the relevant locations from the lowest latitude to the highest latitude value or from the most Southerly to the most Northerly location.

Table 2.22: Various Climatic Variables [3, 9]

Month	Climatic Parameter			
	Rainfall (mm)	Snowfall (cm)	Degree-Days (ºC-d)	
			Heating	Cooling
Jan.	0.40	39.40	1139.35	0.00
Feb.	1.00	26.70	945.00	0.00
Mar.	6.50	27.95	813.80	0.00
Apr.	21.70	18.50	519.00	0.00
May	57.00	5.15	285.00	0.00
June	86.00	0.30	115.50	124.50
July	97.90	0.00	29.45	218.55
Aug.	87.50	0.00	62.00	186.00
Sept.	88.70	2.45	246.00	0.00
Oct.	57.00	17.45	444.85	0.00
Nov.	14.10	41.80	724.50	0.00
Dec.	2.20	38.50	1029.20	0.00
Avg.	43.3	18.2	529.5	44.1

2.5 Fuel Prices

To successfully complete an economical analysis of the proposed power systems it is vital to include the price of diesel fuel for the purpose of power generation. RETScreen International provided the cost of bulk diesel oil to remote electrical utilities in Ontario during 1996. Table 2.23 demonstrates the bulk diesel oil price to utilities in dollars per a Litre in 1996 and the available location specifics for the same period. Being as the majority of the studied communities in Ontario are from the native interior region the typical price of fuel for the desired community in 1996 ranged between 0.24 and 1.39 \$/L. In 1996, using all the available community data, the price of diesel ranged between 0.64 and 1.26 $/L. However, since the native interior locations are of primary interest the price of diesel ranged between 0.64 and 0.91 $/L with an average price of 0.75 $/L [3].

RETScreen Remote Communities (1996)		**Bulk Diesel Oil**
Region	**Mode of Transport**	**Price to Utilities ($/L)**
Rail	Railway/Road	0.24 to 0.28
Native Coastal	Barge/Winter Road	0.24 to 0.63
Native Interior	Air/Winter Road	0.24 to 1.39
Location		**Price ($/L)**
19	Ebanetoong (Fort Hope)	0.68
20	Kee Way Win	0.72
21	Muskrat Dam	0.75
22	North Spirit Lake	0.77
23	Ogoki/Marten Falls	0.85
24	Peawanuck (Winisk)	1.26
26	Poplar Hill	0.64
27	Summer Beaver	0.69
-	Wawakapewin	0.91
28	Wunnummin Lake	0.72

Table 2.23: 1996 Cost of Bulk Diesel to Utilities in ON

An extensive analysis of fuel pricing was undertaken to determine the present day price of fuels for the remote community. A combination of wholesale and retail diesel, oil, and gasoline of various octane levels were studied and the related information can be found in Appendix B. Being as the primary fuel of interest is diesel it is the only fuel that will be investigated in-depth in this Chapter. Statistics Canada was used to determine the long term variations in the price of diesel across ON. Figure 2.23 provides the Industrial Product Price Index (IPPI) of diesel fuel in Ontario between the years of 1980 and 2010. The IPPI is used by Statistics Canada to demonstrate the relative change, as compared to an index value, in the price of a commodity over a time period without detailing the physical cost per unit. The index of the provided IPPI occurs in the year 1997 which has an IPPI value of 100. This means that the provided variation in diesel price is comparable to the market prices in 1997. It can be seen that the IPPI and hence prices of diesel fuel were relatively consistent during the 1990s which is also the time period from which the prices in Table 2.23 were valid. However, the IPPI of diesel fuel increased drastically between the years of 1999 and 2000 and continued to do so until it hit a recent peak IPPI in 2008 [5]. This demonstrates the need to modify the prices provided in 1996 from Table 2.23 to reflect current prices in diesel fuel.

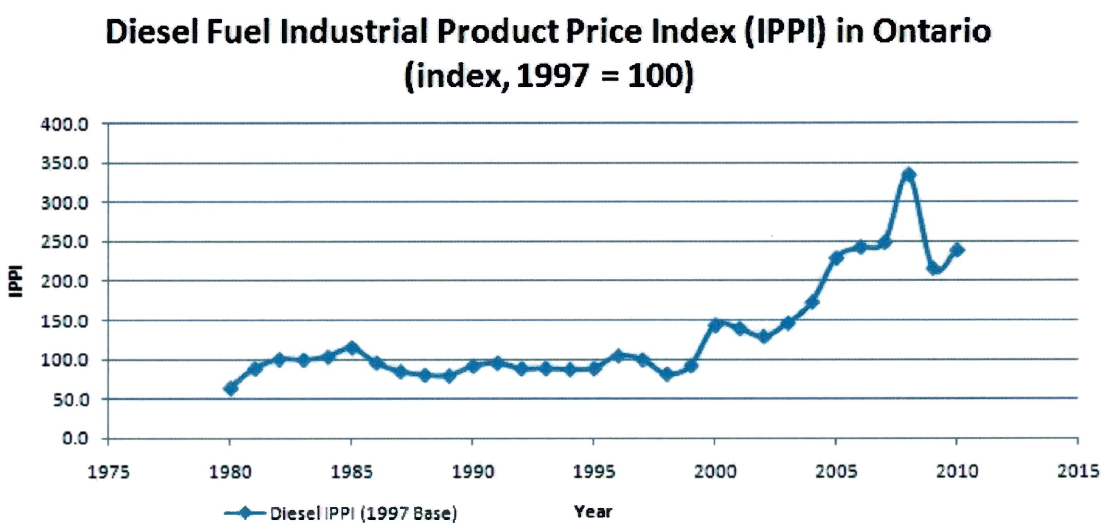

Figure 2.23: Diesel Fuel Industrial Product Price Index in Ontario

Figure 2.24 demonstrates the physical price of diesel fuel between the years of 2001 and 2010 as recorded by Natural Resources Canada [14]. This value represents the cost of wholesale diesel prices across all of Canada during the provided period in cents per Litre. Figure 2.24 does indicate that there has been substantial price increases since 2001 however it fails to provide pricing data as far back as 1996 and as seen from the IPPI value in Figure 2.23 that a drastic price change occurred between 1999 and 2001 hence the applicability of Figure 2.24 is lessened. Figure 2.24 also only demonstrates diesel prices across Canada and the data is not available on the provincial level.

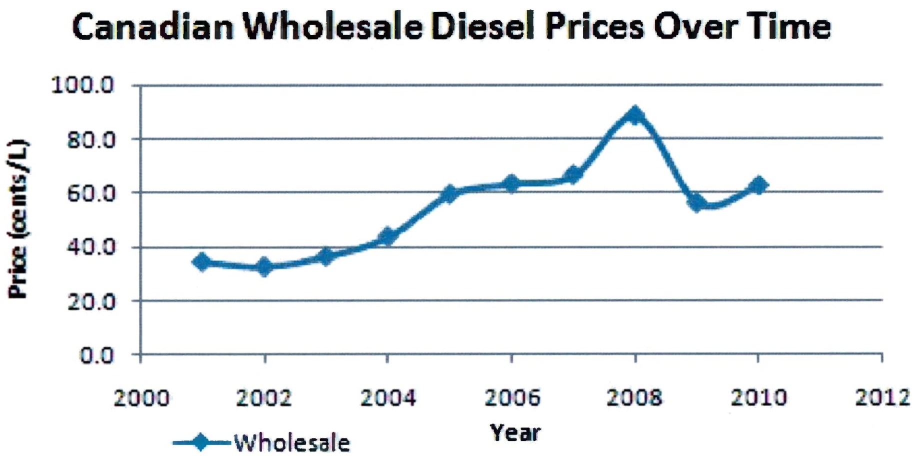

Figure 2.24: Canadian Wholesale Diesel Prices Over Time

During the extensive fuel analysis the current taxation practises on fuels were also investigated as set forth by the federal and provincial governments. At present there is a 4 c/L federal and 14.3 c/L provincial fuel tax and a 10 c/L federal excise tax on diesel sold within Ontario. However, there are no fuel taxes applied to fuels that are used for electrical generation applications. Diesel fuel is also subject to the 13% Harmonized Sales Tax (HST) that was implemented in the province of Ontario on July 1, 2010. However, Native American reserves and bands, as defined under the Canadian Indian Act, are not charged the associated HST for fuels that are used on their reserves. Being as the remote communities in Northern Ontario are almost exclusively native reserves this form of taxation is also discarded for the net price calculation of diesel fuel.

It was found from Figure 2.23 that the average IPPI during the 1990s was 92.1. Being as the IPPI increased during the 1999 to 2001 period from the average of 92.1 to 139.6 the difference in IPPI between this period was 44.5 or 51.55%. The net percent change between the wholesale price of diesel as displayed in Figure 2.24 between 2001 and 2010 was 182.7%. Combining the percentage change between the average 1990s value and 2001 with the percentage change between 2001 and 2010 the overall percentage change was 234.25%. Assuming that the bulk price for diesel fuel for a utility in 1996 for a typical community was 0.75 $/L and by applying the derived 234.25% increase to the price of fuel after 14 years the current price of diesel fuel in 2010 for a remote interior community will cost approximately 1.76 $/L.

2.6 Summary of System Model

Table 2.24 provides a summary of the various metrics associated with the system model that was created for Northern Ontario as explored in the previous sections. The population of 500 was selected based on the analysis found in Table 2.15, Figure 2.13, and it is the mean population for the selected population range of 300 to 700. The private dwellings and customer values were obtained using the approximations found in Table 2.17. The installed capacity was determined through the average of the values obtained from Figure 2.14 and through the use of the factor located in Table 2.17 in conjunction with the data found in Table 2.24. The peak demand was assumed to be approximately 55% of the installed capacity at 628 kW as determined by Figure 2.15 and the subsequent derivations. The total energy generated per a year was determined from Figure 2.8 and Figure 2.7. The amount of diesel used per year can be determined by applying the factors found in Table 2.17 to the total energy generated per year value. The energy delivered to the end user can be determined by either using the 11.5% loss factor or through interpolation of Figure 2.8 using the number of customers determined above. The allocation of power section of Table 2.24 was determined from the amount of energy delivered to the end user after being applied to the allocation percentages developed in Table 2.11.

Table 2.24: Summary of the System Model

Summary of Northern Ontario System Model			
Location Parameters			
Metric	**Value**	**Unit**	
Latitude	50.39	degrees (N)	
Longitude	88.89	degrees (W)	
Elevation	297.9	metres	
Population and Housing Parameters			
Metric	**Value**		
Population	500		
Private Dwellings	170		
Costumers	243		
Power System Parameters			
Metric	**Value**	**Unit**	
Installed Capacity	1,144	kW	
Peak Demand	628	kW	
Annual Energy Generated (1)	2,326	MWh/y	
Amount of Diesel Used	684,118	L/y	
Allocation of Power System Parameters			
Metric	**% of Allocation**	**Value**	**Unit**
Percentage Diesel Generation	100% of (1) and (2)	100	%
Energy Delivered to End User (2)	88.5% of (1)	2,058.5	MWh/y
General Service Allocation	51.5% of (2)	1,060.13	MWh/y
Residential Service Allocation	46% of (2)	946.91	MWh/y
Lighting Service Allocation	2.5% of (2)	51.46	MWh/y

Table 2.25 displays the average percentage per month of the overall diesel usage for energy production from Table 2.19 which were used in conjunction with the total volume of diesel used per year to determine the volume of diesel used per month. This volume of diesel used per a month was used along with the factor found in Table 2.18 to determine the amount of energy generated on a monthly basis.

Table 2.25: Model Diesel Usage per Month

Month	%	Diesel Volume (L)	Generated Energy (MWh)
Jan.	9.41	64,375.50	218.88
Feb.	8.63	59.039.38	200.73
Mar.	9.43	64,512.33	219.34
Apr.	8.65	59,176.21	201.20
May	7.98	54,592.62	185.62
June	7.11	48,640.79	165.38
July	7.03	48,093.50	163.52
Aug.	7.13	48,777.61	165.84
Sept.	7.63	52,198.20	177.47
Oct.	8.48	58,013.21	197.25
Nov.	9.17	62,733.62	213.29
Dec.	9.36	64,033.44	217.71
Total	**100**	**684,186.41**	**2,326.23**

The bulk price of fuel to a utility for a remote community located in the interior of Northern Ontario is at present projected to be 1.76 $/L. The climatic summaries can be found in Table 2.22 and Sections 6.2 and 7.2.

Chapter 3

Introduction to Simulation Methodologies

Initially several modeling, design, and simulation concepts and methodologies were researched extensively for the simulation of the system model introduced in Section 2.6. Both in-house designs and third party software suites were reviewed and considered however after extensive preliminary research it was decided to utilize an external software suite to model and simulate both the components and the various system configurations that are to be studied in this thesis. The software suite chosen for this task was HOMER from HOMER Energy which was until recently developed and supported by the National Renewable Energy Laboratory (NREL) with funding from the US Department of Energy (DOE) [15].

Section 3.1 provides an overview of HOMER, Section 3.2 introduces the community load profile which was developed in part in Chapter 2, Section 3.3 introduces the economics used to determine system viability, Section 3.4 discusses renewable penetration, and Section 3.5 introduces the converter component that will be used for a number of the simulations in the proceeding Chapters.

3.1 HOMER

HOMER was developed by the NREL in 1992 and was specifically developed to be used in the optimization of hybrid renewable energy systems to model on or off-grid systems on a sub-utility scale. HOMER has been used in 193 countries over the past 17 years for both academic research and viability and feasibility based industry applications. In 2009 HOMER became an enterprise of HOMER Energy with the NREL maintaining the rights to the suite [15].

HOMER was selected for use in this thesis due to the extensive flexibility that it exhibits with the design of hybrid micropower systems. These power system configurations are very complex in nature due to the intermittency of the supply, variances in the localized climates, and additional ever-changing metrics such as fuel prices and technology. HOMER allows for a desired system to be compared between multiple configurations over the effective designed lifetime of a system by investigating the net costs of the system while maintaining the required load. Multiple electricity generating sources can be considered during the design and simulation of power systems that include: photovoltaics, biomass, diesel engines, microturbines, fuel cells, wind turbines, hydraulic, cogeneration, batteries, electrolyzers, and flywheels. The technical information for these components can be manually entered into HOMER or selected from an existing database. Additional storage options are also available for simulation as well as multiple types of loads. The local climatic variables and diesel fuel information must also be supplied. Once HOMER is provided with the required system components and information it analyzes the system in a three step process comprised of simulation, optimization, and sensitivity modules.

To complete the simulation module of the analysis HOMER models the operation of the defined power system for every hour of the year using the provided component and supply data sets. HOMER also simulates various dispatch methods in an attempt to reduce the storage requirements on the system while maximizing equipment life [16]. After the simulation of all of the possible system configurations is complete HOMER uses the optimization module of the analysis to determine what simulated configurations meet the load requirements. The sensitivity analysis allows the resulting system to be fine tuned using variables that are inherently unpredictable. These variables can include diesel fuel prices, wind speeds, and solar irradiance. Using the sensitivity analysis HOMER uses a user defined range for a given variable that indicates potential occurrences which the system simulation results include. For example the economic dispatch of an existing system may not be feasible but if diesel prices increase by 20% the system would become viable [15].

Due to the wide selection of power system components available, varying operational specific characterizations, and costs of these components the selection of one component over another could potentially dictate the difference between a feasible and un-feasible system design. To minimize the effect of different component sizes and models the analysis using HOMER will utilize multiple different components from various venders that exhibit different operating characteristics. All studied technologies will be able to operate in the climate zone as described in Chapter 2. The components used will include solar PV panels, wind turbines, batteries, converters, and diesel generators. The solar, wind, and diesel related information files will be provided to HOMER along with the load information. The above information will be introduced as it becomes relevant in the remainder of this thesis.

It should also be noted that a system operating solely on diesel generators will be explored as the base condition. Various hybrid-diesel implementations will be studied and a comparison will be made between them and the base case. The renewable energy based generators will not be explored for stand-alone operation as the communities of interest already have existing diesel generators installed.

3.2 Community Load Profile

HOMER requires the community load profile to include hourly load data for every day of the year for simulation. The load profile used to represent the system model was established with aid of a pre-determined daily profile for a remote community. This daily profile accounts for the AC load of a general remote community for every hour of the year accounting for variances between weekdays and weekends on a monthly basis. The provided daily profile is similar to the prediction methods used by the Independent Electrical System Operator (IESO) for the Ontario bulk energy system. Figure 3.1 demonstrates the changes in energy use by sector in remote Northern locations between the period of 1969 to 2002. It can be seen that the majority of the typical load is residential, government, and schools. Both the commercial and residential sectors grew during this time period with the government and school sector experiencing a decline in energy use.

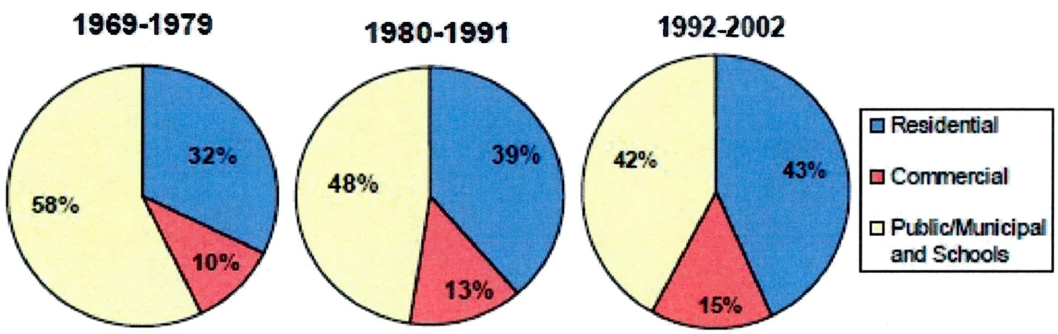

Figure 3.1: Changes in Remote Community Energy Use by Sector [11, 13]

The aforementioned sectors can be further refined to better indicate the energy use in the remote community. Figure 3.2 demonstrates the relative load consumption by facility type in a typical remote community. This method is used by the Alaskan Load Calculator to approximate community load profiles in a Northern remote environment. Since community information is not readily accessible in Ontario this method was not used within this thesis however the community breakdown is indicative of a typical community in a Northern remote environment.

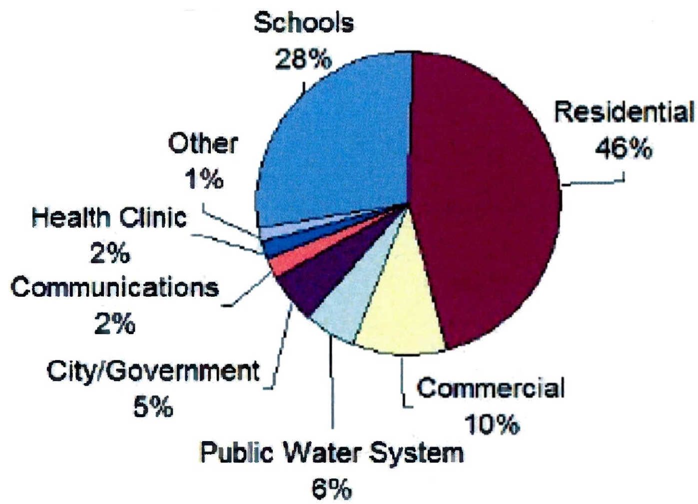

Figure 3.2: Relative Load Consumption by Facility Type in Typical Remote Community [11, 13]

Table 3.2 demonstrates the average energy and power used, the peak demand, and the load factor for the pre-determined profile referred to as the baseline condition. Table 3.1 uses the data provided in Chapter 2 to determine the average energy consumed per a day in the community represented by the system model which was found to be 5,645 kWh/day. This community is referred to as 'the community' or 'the community load' from here on in.

Table 3.1: Determining Load Average kWh/day

Month	**%**	**Consumed Energy (kWh)**	**Days in Month**	**kWh/day**
Jan.	9.41	193704.85	31	6248.54
Feb.	8.63	177648.55	28	6344.59
Mar.	9.43	194116.55	31	6261.82
Apr.	8.65	178060.25	30	5935.34
May	7.98	164268.3	31	5298.98
June	7.11	146359.35	30	4878.65
July	7.03	144712.55	31	4668.15
Aug.	7.13	146771.05	31	4734.55
Sept.	7.63	157063.55	30	5235.45
Oct.	8.48	174560.8	31	5630.99
Nov.	9.17	188764.45	30	6292.15
Dec.	9.63	192675.6	31	6215.34
Total	**100**	**2058500**	**365**	**5639.73**
			Average kWh/day	**5644.95**

HOMER allows for the entry of the average annual daily energy requirements of the community which is in turn used to scale the baseline information to represent that as required by the community. From the provided monthly and weekday/weekend data for the baseline system a standard deviation of 7.9% and 7.8% was used to account for random variability with respect to the difference between the hourly and daily profile data respectively. Using the average annual energy consumed per a day of 5,645 kWh/day as the scaling factor and the above standard deviation values which yields a peak of 628 KW the baseline system is scaled to model the required community. Table 3.2 demonstrates the baseline and scaled data summary. The load factor represents the average load divided by the peak load which results in a dimensionless value.

Table 3.2: Community Load Profile Summary

Metric	Baseline	Scaled
Average (kWh/day)	84.7	5,645
Average (kW)	3.53	235
Peak (kW)	9.42	628
Load Factor (%)	0.375	0.375

Figure 3.3 demonstrates the maximum, daily high, mean, daily low, and minimum average load of the community on a monthly basis. It can be seen that the system model experiences the peak demand during the month of August closely followed by April. The right most column indicates an annual representation of the load model.

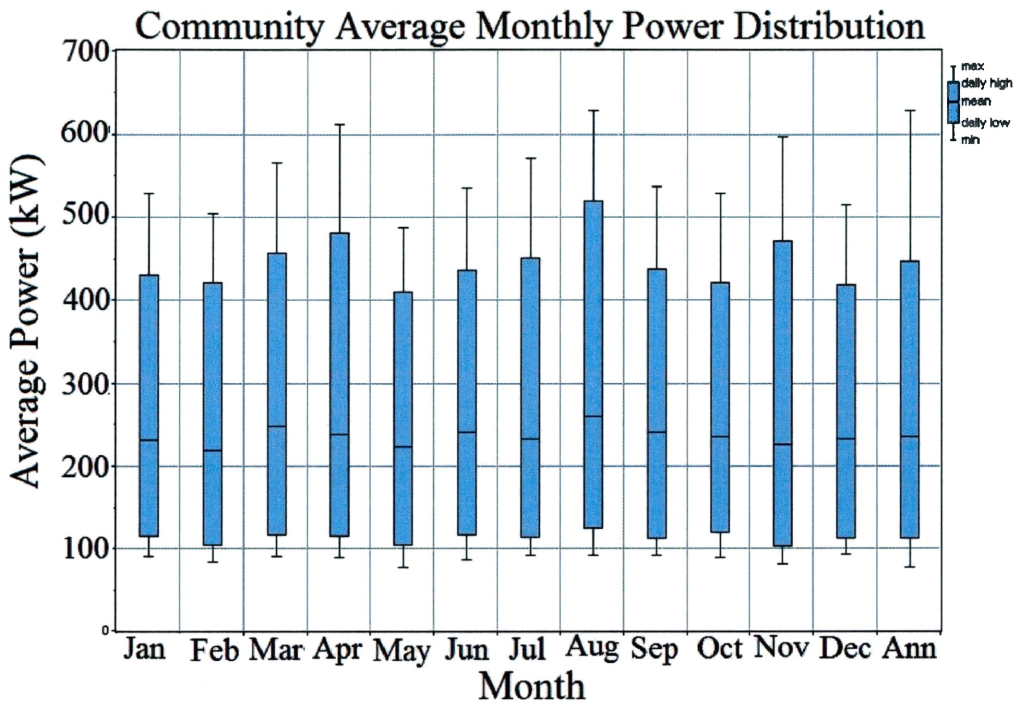

Figure 3.3: Community Average Monthly Power Distribution

Figure 3.4 demonstrates the average daily profile distribution on a monthly basis for the entire year. It can be seen that although there is variance from month to month that the changes are not extensive in the remote community. The daily peak demand typically occurs shortly after 18hr00 and the average required power is higher during the summer months. It should be noted that this daily profile distribution is not comparable to that of the Ontario bulk energy system. Communities connected to the bulk energy system experience a single peak period during the summer months in the early evening and two peak periods during the winter months in the late morning and early evening. This is contrasted by the remote community monthly profiles as it can be clearly seen that there is one peak in the early evening regardless of the time of year. The absence of extremely hot temperatures and alternative methods of winter heating helps curb the energy use in the remote communities to produce a more uniform distribution.

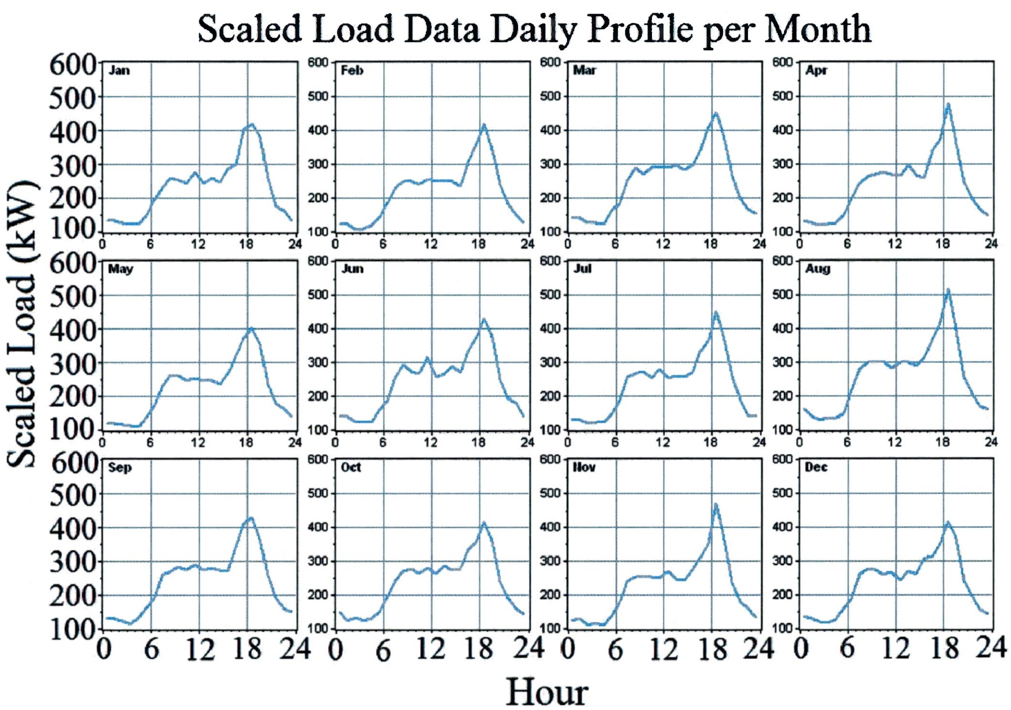

Figure 3.4: Community Average Daily Profile Distribution

The distribution map is a colour blend that indicates a given parameter over a defined period of time. The parameters studied could include, but are not limited to, solar resources, wind resources, and community loading. The shade of colour used at any point in the blend indicates the frequency of occurrence. Figure 3.5 demonstrates the distribution map of the community load profile. It can be seen from the distribution map that daily peaks occur around 18hr00 and that the peak demand occurs during the April and August time period. This can be observed by bar of darker shading around the 17 to 20 hour mark with the darkest points occurring during the summer months.

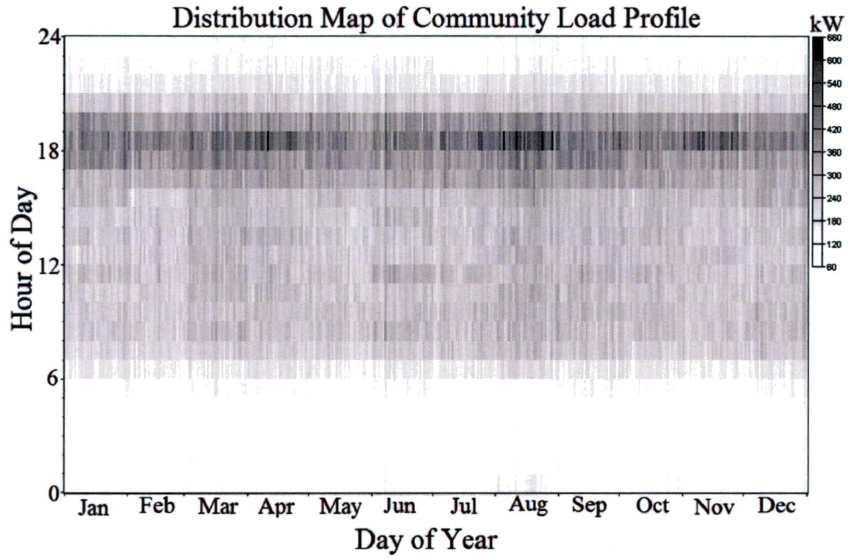

Figure 3.5: Distribution Map of Community Load Profile

See Appendix C for the community hourly data distribution, the duration curve, PDF, and cumulative frequency distribution Figures that represent the system load data.

3.3 Economics

The economics affecting the viability of the system are introduced here. First, the costs associated with the components and the overall system are introduced. Second, the methods used to determine the determinative viability through simulation are explored. Third and final, a summary of the economics is detailed.

3.3.1 Component and System Definitions

In order to complete the feasibility analysis for the various system configurations it is required to obtain the costs associated with the individual components that constitute any given system. This sub-Section introduces the fundamental topics required for the component cost analysis which will be used throughout the remainder of this thesis.

The net Capital Cost (CC) is the overall costs of the power system infrastructure that includes the overall capital and installation costs associated with the purchase and installation of the equipment and infrastructure required for operation. The CC varies significantly based on externalities however Table 3.3 demonstrates common CC values per installed kW that could be found in an urban location in North America. It should be noted that although the CC can vary significantly based upon the individual component models selected for installation that the CC is typically expressed in dollars per kW of installed capacity [15, 17]. To calculate the net cost of the power system the overall desired size or installed capacity and lifetime of the entire system must be known. The lifetime of most components are provided in years however the diesel generator lifetime is based upon number of operating hours. The project lifetime (R_{proj}) is defined as the length of time, in years, over which the costs of the system are incurred. The project lifetime is used to calculate the annualized replacement and capital costs of the individual components along with the total Net Present Value (NPV) of the system [18].

Table 3.3: Sample CC of Various Power System Installations

System Type	CC ($/kW) [USD]
Microturbine	700 - 1,100
Combustion Turbine	300 - 1,000
IC Engine	300 - 800
Stirling Engine	2,000 - 50,000
Fuel Cell	3,500 - 10,000
Photovoltaic	4,500 - 6,000
Wind Turbine	800 - 3,500

The CC can vary based upon multiple metrics which include the size of the installation, the power output, the unit performance, fuel type, and location of the installation. Combustion turbines are considered a mature technology that experiences large volume production. Typically the larger the combustion turbine is the lower the associated cost is per a kW of installed capacity. Photovoltaic technology is also considered a relatively mature technology however the CC varies significantly due to various technologies used in the solar cell production process and the installed system sizes. Large scale wind turbines typically have a lower CC which is representative of large scale wind farms. The wind turbines used in common residential projects are typically more expensive. Due to installation limitations in remote communities the typical modern large wind turbines cannot be installed as with more accessible locations. Overall the installation costs typically vary less for mature technologies and often represent roughly 30% of the CC. However this does depend on local variables which could drive the installation cost to be close to 100% of the CC. The total installed cost may include the power generation module, the power conditioning unit (PCU), installation, facilities, access points, engineering fees, taxes, design fees, and owner costs. The CC for installations in the North will vary significantly from the aforementioned values due to the increased cost of transportation of goods, the requirement of cold weather materials, alternative required installation techniques, construction of roads and alternative access points, limited construction seasons, increased labour costs, difficulties obtaining installation devices, higher associated costs, and increased costs required for site selection. Depending on the location and date of installation it may be possible to receive stimulus funding or rebates from various levels of government to help offset the CC of new projects. The annualized capital cost is explored in the proceeding sub-Section.

The Replacement Cost (RC) is the cost of replacing the component at the end of its lifetime. In some cases the entire unit must be replaced so the RC may be equal to the initial CC of the unit however this is not always the case. For example components within the wind turbine gear box may require replacing however the structure may not. The replacement of these components would be significantly cheaper than the entire initial investment of the wind turbine which includes the foundation and structure. There are often lower labour costs associated with the replacement of components which often decreases cost significantly. There may be a reduction in component costs over time as the technology becomes more mature and production is increased. The RC does not account for inflation and all calculations done during simulation represent real costs or constant dollars [15, 18].

The Salvage Value (SV) is the value retained by the component at the end of the systems project lifetime. The salvage value calculations are based upon linear depreciation and are based upon the replacement costs rather than the initial capital costs. Equation 3.1 demonstrates the SV of the system [15, 18]. The SV is required to calculate the annualized replacement cost which is explored in the proceeding sub-Section. It should be noted that the integer function, INT(), returns the unrounded integer portion of the real value.

$$SV = \frac{C_{rep}\left[R_{comp}\left(1 + INT(\frac{R_{proj}}{R_{comp}}\right) - R_{proj}\right]}{R_{comp}} \tag{3.1}$$

Variable	Description	Unit
C_{rep}	Replacement Cost	\$
R_{comp}	Component Lifetime	years
R_{proj}	Project Lifetime	years

The annual Operation and Maintenance costs (O&M) indicates the total cost of fuel, annualized replacement costs less the annualized salvage value, and additional general costs of operation and maintenance. The O&M costs are provided for the individual components in the given system. The net O&M cost of the overall power system is the sum of the individual component O&M costs. These system fixed O&M costs reoccur on an annual basis regardless of the size or type of power system. The miscellaneous annual costs such as: system fixed O&M costs, emission penalties, and capacity shortage penalties are for the purposes of this thesis, classified as other O&M costs and are discussed in the proceeding sub-Section [15, 18].

Examples of general costs include periodic inspections, replacement and repair of system components (ie. filters), and consumption of consumables (i.e. fuels, water, oil). Operating costs can be composed of both fixed and variable costs. Short and long term contracts for fuel and servicing, for example, can help the local generator compensate for some volatility in the market which could be considered as temporarily fixed costs. In order to promote the projects to the communities' local involvement is vital. This involvement can also be used to produce a small number of long term employment positions that after completion of the initial training would help reduce costs by maintaining a full time, long term staff on site. The O&M costs are normally denoted in dollars per a year, are based on the number of hours of unit operation, and indicated by the total operating costs ($C_{oper,tot}$). Table 3.4 indicates typical O&M costs of various power system installations that could be found in an urban area in North America [15, 17]. Similar to the previously discussed CC the O&M for installations in the North will be higher than the sample rates presently discussed.

Table 3.4: Sample O&M of Various Power System Installations

Unit Type	Time Until Maintenance Required (hours of operation)	Costs [USD] (¢/kWh)
Microturbine	5,000 - 8,000	~ 0.5 - 1.6
Combustion Turb.	4,000 - 8,000	0.4 - 0.5
IC Engine	750 - 1,000 -> Change oil and filter	0.7 - 1.5 (NG)
	8,000 -> Rebuild engine head	0.5 - 1.0 (D)
	16,000 -> Rebuild engine block	-
Fuel Cell	Yearly -> Fuel supply system check	~0.5 - 1.0
	Yearly -> Reformer system check	-
	40,000 -> Replace cell stack	-
Photovoltaic	Bi-yearly	1% of CC/year
Wind Turbine	Bi-yearly	1.5 - 2% of CC/year

3.3.2 Simulation and Calculation Methods

The economic aspects of the system simulations utilize the annual real interest rate which is denoted by i_r. This is the discount rate used to convert between one-time costs and annualized costs and can be found using Equation 3.2 [15, 18]. Annualized cost is defined as the sum of the component's annualized capital cost, annualized replacement cost, and annual O&M cost which are converted to equal yearly cash flows (annualized) over the project lifetime. The real interest rate also allows for inflation to be factored into the economic analysis as it is important over the project lifetime [18]. This allows for all costs to be stated as real costs in terms of constant dollars. To simplify the analysis it is assumed that the rate of inflation is the same for all costs [15].

$$i_r = \frac{i' - f}{1 + f} \tag{3.2}$$

Variable	Description	Unit
i’	Nominal Interest Rate	%
f	Annual Inflation Rate	%

The Annualized Capital Cost (ACC) is determined during the simulation of the desired system. In order to obtain the ACC the initial capital of each component in the power system is taken over the project lifetime and then annualized [18]. Equation 3.3 demonstrates the method used to determine the ACC for each of the components within the desired system [15].

$$ACC = C_{acap} = C_{cap} * CRF(i_r, R_{proj}) \tag{3.3}$$

Variable	Description	Unit
C_{cap}	Initial Component Capital Costs	$
CRF()	Capital Recovery Costs	?
i_r	Interest Rate	%
R_{proj}	Project Lifetime	years

The Capital Recovery Factor (CRF) is the ratio used to calculate the Present Value (PV) of an annuity. The PV is the present equivalent value of a set of future cash flows which considers the effects of inflation and interest over the period of study. The discount factor is the ratio, expressed in Equation 3.4, that is used to calculate the PV of a cash flow that occurs in any given year of the project life cycle [15, 18]. The variable N is the number of years over the course of a project lifetime.

$$f_d = \frac{1}{(1+i_r)^N} \tag{3.4}$$

Using the discount factor from Equation 3.4 above, Equation 3.5 is modelled to determine the Capital Recovery Factor (CRF) [15, 18].

$$CRF(i_r, N) = \frac{i_r\,(1+i_r)^N}{(1+i_r)^N - 1} \tag{3.5}$$

Other capital costs consist of the system fixed CC and the CC associated with the load efficiency measures which are both in dollars. The other Annualized Capital Cost ($\mathbf{ACC_{other}}$) is the annualization of the other capital cost which is achieved in a manner similar to the component CC as seen with the ACC and denoted by Equation 3.6 [15].

$$ACC_{other} = (C_{cap,fixed} + C_{eff,load}) * CFR(i_r, R_{proj}) \tag{3.6}$$

The Sinking Fund Factor (SFF) is the ratio used to calculate the Future Value (FV) of a series of equal annual cash flows. Equation 3.7 denotes the calculation used to determine the SFF where N is the number of years [15, 18].

$$SFF(i_r, N) = \frac{i_r}{(1+i)^N - 1} \tag{3.7}$$

The Annualized Replacement Cost (ARC) is determined during the simulation of the desired system. In order to obtain the ARC of the individual system components the annualized value of all the replacement costs that occur during the project lifetime less the SV must be determined on a component to component basis. The ARC could potentially be found to be a negative cost as it is dependent upon the annualized SV of the component [15, 18]. Equation 3.8 demonstrates the method used to determine the ARC for each of the components within the desired system [15]. The SV can be found from Equation 3.1 [15]. The f_{rep} variable is the factor that arises due to the fact that the component lifetime can alter from the project lifetime and is expressed as the conditional statement in Equation 3.9 [15]. It should be noted that the integer function, INT(), returns the unrounded integer portion of the real value.

$$ARC = C_{arep} = C_{rep} * f_{rep} * SFF(i_r, R_{comp}) - SV * SFF(i_r, R_{proj}) \tag{3.8}$$

$$f_{rep} = \begin{cases} \frac{CRF(i_r, R_{proj})}{CRF\left(i_r, R_{comp} * INT\left(\frac{R_{proj}}{R_{comp}}\right)\right)} & , \; R_{comp} * INT\left(\frac{R_{proj}}{R_{comp}}\right) > 0 \\ 0 & , \; R_{comp} * INT\left(\frac{R_{proj}}{R_{comp}}\right) = 0 \end{cases} \tag{3.9}$$

The other Annualized Replacement Cost (ARC_{other}) is the replacement costs associated with the primary load efficiency measure. This measure of efficiency is of the various strategies that can be employed to reduce the electrical demand of the load. The ARC_{other} is the only replacement cost that isn't associated with a system component and is modelled by Equation 3.10 [15]. The f_{rep} variable in Equation 3.10 is also defined by Equation 3.9.

$$ARC_{other} = C_{eff}[f_{rep} * SFF(i_r, R_{eff}) - \left(\frac{R_{comp}\left(1+INT\left(\frac{R_{proj}}{R_{comp}}\right)\right)-R_{proj}}{R_{eff}}\right) * SFF(i_r, R_{proj})] \tag{3.10}$$

Variable	Description	Unit
C_{eff}	CC of the efficiency measures	$
R_{eff}	Lifetime of the efficiency measures	years

The other O&M cost is the sum of the system fixed O&M cost, the penalty for capacity shortage, and penalties for the emission of pollutants. The capacity shortage penalty is the cost applied against the system for any capacity shortage that occurs during the year. The total capacity shortage (or annual capacity shortage) is the net capacity shortage that occurs during the year. Due to the remote nature of the investigated power systems they exhibit significantly different capacity shortage costs than the IESO Controlled Grid (ICG). In general, the cost of capacity shortage in a remote system results in a temporary loss of service. At year end the total capacity shortage is used to determine the capacity shortage fraction. The system fixed operation and maintenance cost is the recurring annual cost that occurs regardless of the size of the power system. It is used to determine the other annualized capital costs which dictates that it affects the total net present value of each system [15, 18]. Equation 3.11 demonstrates the other O&M cost calculation [15].

$$C_{O\&M,other} = C_{O\&M,fixed} + c_{CS} * E_{CS} + C_{emissions} \tag{3.11}$$

Variable	Description	Unit
$C_{O\&M,fixed}$	System Fixed O&M Costs	$/year
c_{CS}	Capacity Shortage Penalty	$/kWh
E_{CS}	Total Capacity Shortage	kWh/year
$C_{emissions}$	Emmisions Penalty	$/year

The cost of emissions can be calculated by Equation 3.12 and the six emission types can be summarized by the proceeding Table [15]. The penalty for emissions is determined as a value of $/tonne. It should be recalled that 1 tonne (t) is 1000 kg. This cost has significant future implications on the annual O&M costs as all levels of government continue to review their emissions policies in an attempt to reduce emissions to meet both local and international obligations. Many Canadian utilities and LDCs have begun reviewing the impact of renewable generation on the reduction of emissions.

$$C_{emissions} = \frac{\sum_{i=1}^{6}(c_i * M_i)}{1000} \tag{3.12}$$

i	Emission Type		i	Emission Type	
1	$CO2$	Carbon Dioxide	4	PM	Particulate Matter
2	CO	Carbon Oxide	5	$SO2$	Sulphur Dioxide
3	UHC	Unburned Hydrocarbons	6	NOx	Nitrogen Oxide
c_i		Penalty for Emissions ($/tonne)			
M_i		Annual Emissions (kg/year)			

The Total Annualized Cost (TAC), represented by Equation 3.13 in $/year, is the sum of the annualized costs of each system component and the other annualized cost

[15]. It is used to calculate both the levelized cost of energy and the total Net Present Value (NPV) which is also commonly referred to as the lifecycle cost.

$$\begin{aligned} TAC &= (Annualized\,Costs)_{individual\,component} + (Annualized\,Costs)_{other} \\ TAC &= (ACC + ARC + O\&M) + (ACC_{other} + ARC_{other} + C_{O\&M,other}) \end{aligned} \tag{3.13}$$

The TAC metric is useful for comparing the costs of different components when a direct comparison can not be easily made. This is done as a means of measuring the component's relative contribution to the total NPV. This allows for a fair economic comparison between components with low CC and high O&M and the inverse. As a practical example the NPV allows for a comparison to be drawn between the following two systems. The first is system that is comprised a diesel generator (low CC and high O&M) and the second is comprised of solar photovoltaic arrays or wind turbines (high CC and low O&M) [17]. Due to the significant differences in the system costs it is difficult to fairly compare them without the use of the NPV [15].

The levelized Cost of Energy (COE), measured in \$/kWh, is the average cost/kWh of useful electrical energy that is produced by the power system. Equation 3.14 demonstrates the methodology to calculate the COE which can be summarized, by the first line of the Equation, as dividing the annualized cost of energy production by the total useful electrical energy production [15]. However, since there is only a primary AC load in the system model, there is no grid connection, and there is no thermal load at present the equation can be simplified as seen in the second line of

Equation 3.14.

$$COE = \frac{TAC-(c_{boiler}*E_{thermal})}{E_{prim,AC}+E_{prim,DC}+E_{def}+E_{grid,sales}} \qquad (3.14)$$
$$COE = \frac{TAC}{E_{prim,AC}}$$

Variable	Description	Unit
c_{boiler}	Bioler Marginal Cost	\$/yr
$E_{thermal}$	Total Thermal Load Served	\$/kWh
$E_{prim,AC}$	AC Primary Load Served	kWh/yr
$E_{prim,DC}$	DC Primary Load Served	kWh/yr
E_{def}	Deferrable Load Served	kWh/yr
$E_{grid,sales}$	Total Grid Sales	kWh/yr

The COE is a metric that can be used to determine the difference in feasibility between multiple projects. However, there are multiple concerns that arise through the use of the COE as a comparative metric that dictate that it may not be an ideal comparison tool. These may include but are not limited to: the complexity of systems serving both electric and thermal loads and attempting to separate the load sources, if the system fails to serve 100% of the electrical demand during the year is the cost to be calculated per kWh of demand or of load actually supplied, et cetera. Due to the complexity and resulting simplifications of the COE calculations the simulations will use the NPV to determine the final economic applicability of a given system design. The NPV is the present value of all costs associated with a given project that it is expected to incur during the project lifetime less the PV of all the revenue that it will earn during the same period. As previously discussed the costs associated with the NPV include the CC, RC, O&M, and emission penalties.

The revenues associated with the NPV include the SV [15, 18]. As introduced in Equation 3.13 the TAC encompasses all of the cost and revenue metrics required to calculate the NPV. Equation 3.15 demonstrates the NPV formula [15].

$$NPV = \frac{TAC}{CRF(i_r, R_{proj})} \tag{3.15}$$

The NPV represents an accurate metric that is not subjected to the same difficulties as the COE which dictates that it will be used as the primary economic figure of merit for the simulations performed throughout this thesis.

3.3.3 Summary of Economics

Using the definitions and methodologies introduced in this Section Table 3.5 was formed to initialize the economical input variables that remain constant throughout the simulation process. Using the nominal interest and annual inflation rates in conjunction with Equation 3.2 the annual real interest rate was determined. The project lifetime was selected based on other common project lengths that share a common scope. The capacity shortage penalty is assumed to be non-existent in the remote community, although power quality is a concern, there is no significant legal responsibilities similar to those associated with the grid connected power system as dictated by the OEM, OPA, IESO, NERC and the NPCC. The fixed CC and O&M costs were determined to be 0.00 at this point in time.

Table 3.5: Economic Inputs

Variable	Description	Value	Unit
i'	Nominal Interest Rate	4.75	%
f	Annual Inflation Rate	1.9	%
i_r	Annual Real Interest Rate	0.983	%
R_{proj}	Project Lifetime	25	years
$C_{cap,fixed}$	System Fixed CC	0.00	$
$C_{O\&M,fixed}$	System Fixed O&M cost	0.00	$/year
c_{cs}	Capacity Shortage Penalty	0.00	$/kWh

The Bank of Canada and the Canadian federal government attempt to contain the annual inflation which is a measure of the rate of change in the overall Consumer Price Index (CPI). At present the inflation control target is set to be within the range of 1 and 3% with the ideal inflation control target being 2%. As of September 2010 the inflation as set by the total CPI was 1.9%. Due to recent events in the global economy the prime interest rate as set by the Bank of Canada in October 2010 was 1.25%. However, due to the extremely low interest rates of the past 2 years in an attempt of economy management by the Bank of Canada, it is unrealistic to assume that the long term nominal interest rate will remain at the low present rates [19]. TD Securities forecasts that the long term nominal interest rate will maintain 4.75% [20]. Although it is realistic to assume that these rates will change, at present, the aforementioned rates provide realistic targets. As such the subsequent calculations in this thesis will be modelled upon these rates which were accurate as of the end of October 2010. It should be noted that for the writing of this thesis it is assumed that the Canadian Dollar and United States Dollar are at parity as denoted by the exchange rates at the time of writing [19]. Any monetary values not originally expressed in CAD or USD will be converted to reflect current value in CAD.

It is also assumed at this point in time that there are no emission penalties in the province of Ontario. However with the current political climate in Ontario, Canada, and within the global community this variable will likely become more important in future analysis work. At present British Columbia has a form of a carbon tax and it is projected that other provinces will follow suit. With the conception of Ontario Bill 150 and the Green Energy and Green Economy Act (GEGEA) 2009, which was legislated on May 14, 2009, Ontario became one of the leaders in green energy across the globe [21]. However, at present there is no existing carbon tax associated with the bill. It is believed that with a green energy economy and focus within the province that future additional legislation will be proposed. Ontario's Clean Air Action Plan (CAAP), which was passed in 2004, focuses on emission reduction. However, regarding the emission costs for diesel based energy production and the scope of this thesis, the emission costs are presently considered marginal and neglected as it is assumed that the existing generation has been retrofitted with emission minimizing features [22].

The Ontario Regulation 419 entitled air pollution - local air quality (O. Reg. 419) is a directive set by the MOE and enforced by the OPA with respect to the emission limits for non-emergency power generation from combustion engines. O. Reg. 419 has been tabled to ensure the protection of air quality within ON and aid in a seamless transition between traditional thermal generation sources to new sources with lower emission outputs. The designed target of O. Reg. 419 was to allow for the internal combustion engines that use diesel, bio-diesel, NG, or bi-fuel to obtain similar emission output levels as that realized from the use of a NG combustion turbine. Table 3.6 demonstrates the emission limits as set within ON. It should be noted that the nitrogen oxide metric is expressed as a nitrogen dioxide equivalent [23].

Table 3.6: ON Regulated Emission Limits [23]

Type	**2007-2010**	**2011 Onwards**	**Units**
Carbon Oxide	3.5	3.5	kg/MWh
Unburned Hydrocarbons	1.3	0.19	kg/MWh
Particulate Matter	0.2	0.02	kg/MWh
Sulphur Dioxide	15	15	ppm
Nitrogen Oxide	1.0	0.40	kg/MWh

The emission limits regarding the unburned hydrocarbons, particulate matter, sulphur dioxide, and nitrogen oxide were designed for generator sets ranging from 130 to 560 kW which was based off of the new source performance standards for non-road and stationary emissions in the USA. The generators are also regulated to utilize ultra low sulphur diesel or an equivalent emission level for regular use. However, at this point in time these emission limits do not effect remote community power generation [23].

In order to compare the simulated power systems and determine which is the most economical to meet the requirements of the power system it is required to compare the simulated results with a base case scenario. For the purpose of this thesis the base case will be a power system that operates strictly off of diesel generators as it is representative of the existing community generation portfolio and is a mature technology that has been used successfully for decades in the North. This base case will be used to calculate the payback of possible alternatives with respect to itself. When comparing the two systems together there are a number of economic metrics that facilitate the economic comparison provided post-simulation which include:

- Present Worth (PW)
- Annual Worth (AW)
- Return on Investment (ROI) or Rate of Return (ROR)
- Internal Rate of Return (IRR)
- and Payback Period

The PW is the total amount of money from the entire project lifespan of the project at present day in today's dollars. The AW is the PW multiplied by the CRF which demonstrates an equivalent uniform AW of the total costs associated with the project during the project lifetime. The ROI or ROR is the ratio of capital that is either gained or lost over the project lifetime. To be classified as an attractive project the ROR must be greater than zero. The IRR determines the ROR without accounting for external variables such as interest and inflation. The payback period is the number of years that will be required to recover the initial investment and obtain a stated ROR or yield a specified level of return. Each method of analysis has its own strengths and weaknesses which will not be explored in this thesis. The simulated results will be compared to the base case using the above methods as deemed appropriate to determine the overall economic feasibility of the project [15, 18].

3.4 Renewable Penetration

The level of renewable penetration must be factored into system design as it directly impacts the complexity and costs of the system. Table 3.7 demonstrates the operating characteristics of low, medium, and high renewable penetration classifications along with their related instantaneous and average penetration levels. With low penetration systems the renewable generators are treated as additional sources of generation which require very little control. As the penetration level increases the ability to reduce the number or size of DG operated in conjunction with the renewable generators increases. However due to the intermittent and varying output power levels of renewable generators it can be seen that the installed capacity must be much higher to meet community requirements. If a high penetration renewable-diesel system was used the additional energy could also be used for heating applications which could be of particular interest in the North through offsetting hydrocarbon based fuel use [13].

Table 3.7: Renewable Penetration Levels

Penetration Level	Operating Characteristics	Penetration (%) Instant.	Average
Low	- DG(s) operate full-time - Renewable power reduces net load on diesel - All renewable energy goes to primary load - No supervisory control system	< 50	< 20
Medium	- DG (s) operate full-time - At high renewable power levels, secondary loads are dispatched to ensure sufficient DG loading or renewable gen. is curtailed - Requires a relatively simple control system	50 - 100	20 - 50
High	- DG(s) may be shut down during periods of high renewable availability - Auxiliary components required to regulate V and frequency - Requires a sophisticated control system	100 - 400	50 - 150

In general either storage or a dispatchable generator is required in conjunction with renewable generation. It is common in low and medium penetration systems that at least one Diesl Generator (DG) is operating to provide reactive power and maintain system voltage. Electrical Energy Storage (EES) can be of particular use in high penetration renewable hybrid systems as it can increase the fuel savings and reduce the DG operating hours and number of starts required [13, 24]. This effectively decreases the amount of wear and tear on the DG which translates to decreased O&M costs. In systems with no EES a dump load is used to absorb excess energy and maintain stability.

At present there is no standard guideline that denotes the appropriate level of EES penetration that should be installed to optimize its use in a renewable system. Storage in a remote community application would typically be utilized to provide start up time for the DG or enough time for the DG to operate at full load. In general, low penetration renewable systems do not benefit from EES since the DGS is still operating in parallel. EES is considered to be economically justifiable if the average renewable penetration and instantaneous penetration is 50% and 80% respectively.

These approximated CCs associated with DGS expansion for renewable implementation can be seen in Table 3.8 which are dependent upon the level of renewable penetration in the local energy portfolio [13].

Table 3.8: Costs Associated with the DGS Expansion for Renewable Implementation

Description	**Low**	**Medium**	**High**
Diesel Controls	\$20,000	\$45,000	\$45,000
Line Extensions (/100 m)	15,000	15,000	15,000
Insulated Container Shelter	25,000	25,000	25,000
Dump Load with Controller	-	20,000	30,000
Supervisory Control	-	-	50,000
Battery Bank and Rotary Converter or AC Synchronous Condenser	-	-	95,000
Installation and Shipping	25,000	35,000	45,000
Total (in USD)	**\$85,000**	**\$140,000**	**\$305,000**

3.5 Converter

The converter is used in various implementations of the simulated system model for conversion between the AC and DC buses. The inverter is comprised of two subsystems which include the inverter and rectifier. The inverter converts DC to AC and the rectifier converts AC to DC. HOMER uses the cost curve of the input values for the converter to determine the optimal system configuration. The Sunny Boy, Sunny Tripower, and Sunny Central series from SMA Solar Technologies were investigated as well as models from ABB, Effekta, Fronius, Power One Aurora, Studer, and Victron Phoenix MultiPlus.

The cost curve also demonstrates the rated capacity of the rectifier relative to the inverters rated capacity and the efficiency of the rectifier with respect to its ability to convert AC to DC. For simulation purposes it is possible to select an inverter that is capable of operating in conjunction with one or more AC generators. The inverter can also operate in switched inverter mode where it can't run in conjunction with other AC generators. For the purpose of simulation within this thesis it will be assumed that the inverter can operate in conjunction with one or more AC generators. The lifetime of the inverter is set to be 15 years and the maximum efficiency at 96% [25, 26]. The rectifier relative capacity is set to be 100% and the efficiency of the unit is set at 85% based on the suggested value from NREL and information available from ABB and other vendors [15, 27, 28]. Both efficiencies were taken as an average of multiple product options. .

After investigating various options it was decided to use a cost function that was developed. The simulation will investigate converters sized from 1 kW through 25 kW in 1 kW steps and starting at 50kW in 25 kW step sizes up to 1,000 kW. All systems that utilize a DC bus will use the above methodology for simulation application. These hybrid systems can be summarized by the following: solar-diesel, solar-storage-diesel, wind-storage-diesel, wind-solar-diesel, and wind-solar-storage-diesel. Chapter 4 introduces the storage utilized which will be connected on the DC bus for the applicable configurations. Chapter 6 introduces the solar energy conversion systems that inherently require a converter unit for operation. And Chapter 7 demonstrates wind energy conversion systems that use storage and/or solar resources. For the purpose of this thesis DC generating wind turbines are not considered for implementation hence no converter is required for a wind-diesel hybrid system.

Chapter 4

Storage Technologies

This Chapter introduces various electrical energy storage technologies. The technologies that are potentially appropriate for the community requirements are further explored and compared. As a result the technology type that will be used for simulation is selected. The components are determined based upon the type of technology chosen and are introduced in depth as they will be used in subsequent Chapters for simulation purposes.

4.1 Electrical Energy Storage Technologies

Electrical Energy Storage (EES) consists of a process that converts electrical energy to another form so that it can be stored for use at a later time as required. EES system development and use has steadily increased in recent years and currently EES technology is implemented in conjunction with portable devices, vehicles, and stationary applications such as power generation and distribution networks. These stationary power related EES systems are being developed to aid with the implementation of renewable resources in the power system portfolio to help compensate for intermittency, to allow the system to meet peak demand, and to offset the cost of generation [24]. EES are also utilized as they allow the power system to remain stable or aid in stabilization of the system when disturbances do occur and as such are important in maintaining and enhancing system reliability, aid in power transfer, and improve power quality [29]. EES is primarily utilized for power applications that are part of Distributed Energy Resource (DER) system, remote power and communication systems, and within substations [24, 29, 30]. Being as electricity cannot be easily or cheaply stored directly as electrical energy it must be converted to another form for storage purposes. The various underlying storage technologies can be summarized by the following: electrical energy storage, mechanical energy storage, chemical energy storage, and thermal energy storage. For stationary power applications EES systems are utilized to ensure typically either power quality and reliability or energy management [24, 29]. Figure 4.1 demonstrates the common EES techniques and how these techniques relate to their respective applications.

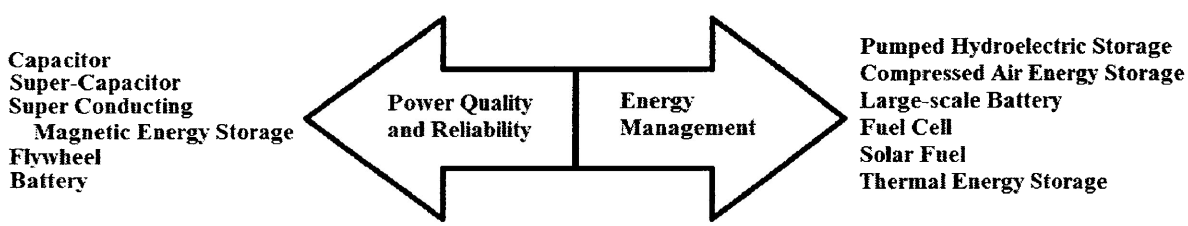

Figure 4.1: Energy Storage Systems and their Related Functions [24]

For remote systems similar to that of the modelled case both applications of EES are beneficial. However the primary desired application is the ability to perform effective energy management. As such Section 4.2 will briefly outline the various techniques to enable this outcome [24] with the exception of fuel cells which are covered in detail in Appendix H. The application of the studied EES systems will be completed in Section 6.8 and Section 7.8 for the respective sizing analysis of the selected systems.

4.2 Energy Management EES Technologies

4.2.1 Pumped Hydroelectric Storage

Pumped Hydroelectric Storage (PHS) is the most commonly used technology to implement large scale EES around the globe. PHS is common due to both its simplicity and that it is one of the two EES systems that allow for large scale storage. A PHS system normally consists of the following three components:

1. Two water reservoirs located at different heights
2. A pumping system that enables water to be pumped from the reservoir of lower elevation to that of higher elevation for storage
3. A turbine to convert the kinetic energy of the water into electricity as it travels from the reservoir of higher elevation to that of lower elevation

Typically during non-peak periods the excess energy produced is used to pump water from the lower reservoir to the higher reservoir. When the energy is later required the water is allowed to return to the lower reservoir through a turbine that converts the kinetic energy of the water back into electricity. The amount of electricity generated is dependent upon the difference in height between the reservoirs similar to a hydro electric station. The efficiency of PHS is typically around 71-85% and PHS is rated for systems that range between 100 MW to 3,000 MW with an average system size rated for 1,000 MW. The PHS technology is mature and involves a low capital cost for the net benefits yielded. PHS can store excess energy for extensive time periods very cheaply with minimal losses that are generally associated with long term storage. PHS does however require two reservoirs and a dam to be implemented which increases overall costs when natural locations are scarce and the construction has a negative effect on the local ecosystem. PHS systems are typically located at existing hydro electric dams, within mine shafts or other underground cavities that can be flooded, or along the sea shore allowing the sea to be the lower reservoir. All of these natural or pre-existing locations allow for a lower capital cost which allows PHS to become a feasible solution for EES.

As such PHS is not an appropriate EES median for Northern Ontario as it is site dependant and very expensive to install if the desired geographical attributes are not naturally available. As well as the required location specifications for the climate of Northern Ontario would not allow for efficient use of water as a storage medium during the majority of the winter months which severely decreases the applicability of this technology.

4.2.2 Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) is the other EES system that allows for large scale storage. A CAES system normally consists of the following five components:

1. A motor/generator that can be interfaced with either a compressor or turbine as required through the utilization of clutches

2. An air compressor

3. A turbine train consisting of both low and high pressure turbines

4. An air tight cavity to store the compressed air

5. Controlling infrastructure, fuel storage, and heat exchanger units

CAES allows for the storage of compressed air during periods of low demand in an air tight cavity for later use. This compressed air is typically 4.0 - 8.0 MPa and the air tight cavity is generally comprised of underground rock caverns, salt caverns, or depleted gas/oil fields. The capital cost of the system is dependent upon the type of storage cavity utilized but typically ranges between \$400 - 800 /kW. When power is required the compressed air is released from the storage cavity, heated, and expanded with a high pressure turbine. The expanded air is mixed with a hydrocarbon based fuel, combusted, and the exhaust is expanded with a low pressure turbine. Both of the turbines are connected to the generator which produces the resulting power. Some heat co-factoring can also be utilized within the CAES system to increase net efficiency. The CAES system is designed to operate during partial load conditions on a daily basis. Thus, due to its design, the CAES allows for long storage periods of the compressed air and low capital costs. CAES has a lower ecological impact than PHS. CAES has a rated output typically between 50 to 300 MW with a storage efficiency of 70-89% for up to over a year.

As CAES requires an air tight storage location for the compressed air the capital cost of the system is greatly dependent upon location and it is only economically feasible to implement CAES if the system is located near rock mines, salt caverns, or depleted gas fields. CAES must also be operated alongside a gas turbine plant which creates a dependency upon hydrocarbons for power production. As such CAES is not an appropriate storage median for Northern Ontario as it is site dependant and requires large scale gas turbines which do not exist in the North. The geography of Northern Ontario does not provide access to salt caverns or depleted gas fields and although there is minimal mining in Northern ON it is not present within the remote communities under investigation. A CAES system could be investigated further if a suitable site was located but for the generalized model it is not an applicable storage method.

4.2.3 Large-Scale Battery

Batteries are the oldest form of energy storage and they operate by converting electrical energy to chemical energy. The battery consists of multiple cells where an individual cell is created by two electrodes separated by an electrolyte. These cells are connected together in parallel or series to meet the desired electrical characteristics of the battery [24, 29]. When a battery is charged the cells are subjected to an internal chemical reaction and a potential is applied to the electrodes. Since the internal chemical reactions within the battery are reversible when the cell discharges the stored energy it does so via a reversed electrochemical reaction that occurs at the two electrodes [24, 29]. This reverse reaction creates a flow of electrons through the connected circuit. Batteries are ideal for energy storage as they are a mature technology, they allow for fuel flexibility with respect to power generation, can be recharged as the reaction that occurs is reversible, when operating they have minimal effect on the local environment, they can be used to quickly compensate to changes in required power loads, and the efficiency of batteries ranges from 60-95%. BESS are one of the most promising near-term EES technologies and have been implemented to aid with load levelling, stabilizing, and load frequency control applications. Typically medium performance general purpose BESS are used rather than high performance units as the conditions of operation require a more rugged unit. Reliability is achieved with medium performance units as the internal plates and construction of the high performance units tends to be smaller and thinner which decreases the life expectancy [31]. Batteries can be made from a multitude of materials which change their operational characteristics and capabilities. The batteries that will be investigated for utility scale Battery Energy Storage Systems (BESS) include: lead-acid, valve regulated lead-acid, nickel cadmium, nickel-metal hydride, sodium sulphur, sodium nickel chloride, lithium ion, and lithium polymer batteries [24, 29, 31, 32].

Lead-Acid Batteries

The lead-acid battery is popular for EES and is a mature technology as it is the oldest and most widely used type of rechargeable device in existence [24, 29]. As such the lead-acid battery is a reliable cost effective EES option. The charged lead-acid battery consists of electrodes made of lead and an electrolyte of lead oxide containing 37% or 5.99 moles of sulphuric acid. The discharged lead-acid battery consists of lead sulphate electrodes and the electrolyte loses the dissolved sulphuric acid which results in water. The chemical reactions existing within the cell are:

- Anode Reaction: $Pb + SO_4^{2-} <==> PbSO_4 + 2e^-$
- Cathode Reaction: $PbO_2 + SO_4^{2-} + 4H^+ + 2e^- <==> PbSO_4 + 2H_2O$
- Net Reaction: $PbO_2 + Pb + 2H_2SO_4 <==> 2PbSO_4 + 2H_2O$

The lead-acid battery has a low cost that ranges from $300 - 600/kWh and its efficiency ranges from 70-90% [24, 29]. The energy density of the lead-acid battery ranges between 30-50 Wh/Kg and the power density ranges between 75-300 W/Kg. The vented lead-acid batteries require regular maintenance to replenish the distilled water and for specific gravity measurements to be taken [24, 31]. This maintenance increases the cost, specialized training required of the personnel, and the handling of hazardous materials.

Lead-acid batteries normally require maintenance of the electrolyte through regular water refills over the lifetime of the battery and measuring the specific gravity [24, 31]. The specific gravity is measured to determine the actual charge of the lead-acid battery. If the battery is cycled very deeply and then recharged quickly the specific gravity will be lower than it should be. This is due to the fact that the electrolyte at the top of the battery may not have fully mixed with the already existing charged electrolyte. The battery manufacturer provides information that relates the specific gravity to the actual state of charge in percentage. The specific gravity measurement has to be taken every couple months for each cell by inserting a hydrometer to remove acid for measuring. This process requires the handling of hazardous materials which is a negative aspect of lead-acid use. The specific gravity measurement and addition of water is required to ensure that the lead-acid battery operates at both maximum efficiency and so that the life of the battery is not prematurely shortened.

The Valve Regulated Lead-Acid (VRLA) batteries and the sealed maintenance free lead-acid batteries are maintenance free with respect to the electrolyte. The sealed maintenance free lead-acid battery is constructed using a gelled or absorbed electrolyte. The electrolyte of the VRLA is immobilized which means that none of the electrolyte can spill out of the battery making it safer and requires less training of personnel than the vented lead-acid battery. The VRLA has better cost and performance characteristics for stationary power applications and perform much better in extreme temperatures than the vented lead-acid BESS with relatively few system failures [29, 31]. For large scale power applications the battery efficiency decreases rapidly as the discharge time approaches zero. This affects the sizing of the BESS along with aging factors, load expansion possibilities, and a low temperature operation margin [31]. The IEEE recommends that the VRLA BESS undergo regular internal ohmic measurements and annual discharge tests. The VRLA has an expected life of 10 years but with testing it has been found that failures have tended to occur from 5 - 7 years of continuous favourable operation. The VRLA has been marketed as a 20 year BESS which when combined with the fact that the unit is prone to failure has hampered sizable results. The VRLA must continue to be developed but presently it is not a viable EES solution [31].

However, the lead-acid battery has a short cycle life ranging from 500-1000 cycles and a low energy density ranging from 30-50 Wh/kg since lead has a high density. Lead-acid batteries exhibit poor performance at low temperatures and require extensive thermal management [24, 29]. If used in Northern latitudes the lead-acid batteries would need to be housed within a heated environment with environmental controls.

Nickel Cadmium Batteries

Nickel Cadmium (NiCd) batteries are also a popular and mature technology. The NiCd battery is constructed with a nickel hydroxide positive electrode plate, a cadmium hydroxide negative electrode plate, a separator, and an alkaline electrolyte [24]. These materials are normally rolled together in a spiral shape and housed within a metal case with a sealing plate that creates a safety seal. The chemical reaction existing within the cell during discharge is:

- Anode Reaction: $Cd + 2OH^- <==> Cd(OH)_2 + 2e^-$
- Cathode Reaction: $2NiO(OH) + 2H_2O + 2e^- <==> 2Ni(OH)_2 + 2OH^-$

- Net Reaction: $2NiO(OH) + Cd + 2H_2O <==> 2Ni(OH)_2 + Cd(OH)_2$

The NiCd has a high energy density ranging from 50-75 Wh/kg, a power density ranging from 150-300 W/kg, a robust reliability, and requires little regular maintenance.

However, the NiCd still has a low cycle life ranging from 2,000 to 2,500 cycles and has a cost of about $1,000 / kWh. The cycle life of the NiCd is better than the lead-acid but is still considered to be relatively low. Cadmium is a toxic heavy metal which poses potential negative environmental impact. NiCd batteries experience poor retention of electrical charge over time due to memory effect which decreases the effectiveness of the battery. This effect may be reduced using proper battery management and care.

In the mid 1980's Pocket Plated Nickel Cadmium (PPNiCd) batteries and solar panels were installed in more than 68 remote telecommunication systems located throughout Sweden's arctic region. [30] provided an introduction and analysis to the installed systems after 6 years of continuous operation. The size of these installations varied depending on time of installation and application. Table 4.1 demonstrates the quantity and use of the various telecommunication installations along with their respective capacity.

Table 4.1: Remote Swedish Telecommunication Storage Capacities [30]

Organization	**Number of Units**	**Use**	**NiCd BESS Capacity (Ah)**
Swedish National Administration of Shipping and Navigation	40	Navigation	320
Swedish National Telecommunication Administration	18	Microwave Repeaters	220
Swedish National Road Administration	Numerous	Roadside Telephone	350
Swedish National Telecommunication Administration	27	Emergency Phones for Hikers	400

The 40 navigational aides were typically designed to consist of two solar panels connected in parallel rated at 12 volts along with the NiCd BESS that allowed for 90 days of autonomy and the 18 microwave repeaters were installed in the far north.

It was found that after the 6 years that the installed BESSs listed in Table 4.1 performed at a satisfactorily level with no malfunctions. The PPNiCds are able to operate satisfactory in climates of extreme temperatures [31] ranging from -50 to 50 ^{o}C [30]. The PPNiCd is not damaged if the temperature drops below -50^{o}C and ice crystals form on the electrolyte freezing the unit. Upon warmer temperatures the battery operates with normal characteristics. The PPNiCd is operable at the extremely low temperatures as the alkaline electrolyte doesn't alter in density while charging or discharging. This in turn allows the ions to be transferred between cell plates even in cold temperatures regardless of the charge level of the battery. The PPNiCd also remains undamaged if the battery is operated or remains dormant when it is only partially charged. The PPNiCds are expected to operate for 10 years before any form of maintenance is required.

The photovoltaic system implemented in [30] had a theoretical charging efficiency of 90-95% when operated at 25°C. It was found that with physical implementation that the charging efficiency dropped to 85-90% at -20°C which is considered the standard temperature of operation. Thus, even if there is a decrease in efficiency, the PPNiCd still operates exceptionally well in cold temperatures. The characteristics of the PPNiCd suffer when the operating temperature reaches -40°C as the efficiency drops to 55%. This efficiency is obviously not ideal but the unit is able to function with no other ill effects. As a result of these characteristics the BESS were not over sized for the telecommunication systems explored by [30]. The power systems required in the remote communities of Northern Ontario are significantly larger than the aforementioned telecommunication systems that were installed in Sweden. The common characteristics between the two applications are the extreme temperatures and remote nature. This significant difference in scale may have a negative impact on the operation of the PPNiCd BESS if it is installed for use in larger systems such as those located in Northern Ontario.

The Nickel-Metal Hydride (Ni-MH) has a similar chemical composition as the NiCd except the Ni-MH has a much higher energy density than the NiCd. The Ni-MH is also maintenance free but is significantly more sensitive to high temperatures and costly when compared to the NiCd [31]. The Ni-MH is a developing technology that promises to be a competitive EES system in the remote Northern applications when both the cost is decreased and it has matured. The NiCd based EES systems do have some negative aspects but they could potentially be utilized to meet the requirements of the system model.

Sodium Sulphur Batteries

Sodium sulphur (NaS) batteries are constructed using molten sulphur as a positive electrode and molten sodium at the negative electrode. The electrolyte is a solid beta alumina ceramic which allows only the Na^+ ions to pass through (similar to a membrane) which then combines with sulphur to form sodium polysulphides. The chemical reaction existing within the cell during discharge is:

- Anode Reaction: $2Na <==> 2Na^+ + 2e^-$
- Cathode Reaction: $xS + 2e^- <==> S_x^{2-}$
- Net Reaction: $2Na + xS <==> Na_2S_x$

Each cell produces around 2.0 volts and the chemical process is reversible as charging the cell causes sodium polysulphides to release the Na^+ ions which recombine as sulphur at positive electrode.

The NaS battery is typically used for power quality applications. The NaS battery has a typical cycle life of around 2,500 cycles, an energy density ranging between 150-240 Wh/kg, a power density ranging between 150-230 W/kg, and an efficiency between 75 to 90%. The NaS battery needs to operate between 300 and 350 °C which requires a separate heat source and the cost of the NaS battery is high with an average around \$2,000 / kW and \$350/kWh. Due to the high cost and high operational temperature the NaS battery is not an applicable EES for a remote Northern community.

Sodium Nickel Chloride Batteries

The sodium nickel chloride (ZEBRA) battery is also a high temperature operated battery that operates around 300 °C. The ZEBRA battery also has the ability to operate between -40 to 70 °C without additional cooling. The chemical reaction existing within the cell is:

- Anode Reaction: $NiCl_2 + 2Na^+ + 2e^- <==> Ni + 2NaCl$
- Cathode Reaction: $Na <==> Na^+ + e^-$
- Net Reaction: $2NaCl + Ni <==> NiCl_2 + 2Na$

The ZEBRA battery is similar to the NaS battery with some notable expectations. The ZEBRA battery is of a safer design, has a higher cell voltage of 2.58 volts, and is able to withstand some overcharge/discharge occurrences. The ZEBRA has a lower energy density ranging from 100 to 120 Wh/kg and a lower power density ranging from 150 to 200 W/kg when compared to the NaS battery. Due to the limited accessibility of the relatively new ZEBRA battery and high operational temperature the ZEBRA battery is currently not an applicable EES for a remote Northern community.

Lithium Ion Batteries

Lithium ion (Li-ion) batteries were first commercially available in 1990 and are yet an unproven technology for large-scale applications. The Li-ion is constructed with an electrolyte that is composed of lithium salts (Ex. $LiPF_6$) dissolved in organic carbonates. The anode consists of a graphitic carbon with a layering structure and the cathode is a lithiated metal oxide (Ex. $LiCoO_2$, $LiMO_2$, $LiNiO_2$, et cetera). When the Li-ion battery is being charged, the lithium atoms in the cathode become ions and transfer to the anode where they are then combined with external electrons that are deposited between the carbon layers of the anode as lithium atoms. The Li-ion battery is hermetically sealed which dictates that the electrolyte is maintenance free over the lifetime of the battery [31].

The energy density of the Li-ion battery is 200 Wh/kg [24] which is significantly higher than the lead-acid battery [31]. The life cycle of the Li-ion is as high as 10,000 cycles, the efficiency is almost 100% [24, 31], and the expected life time is in the range of 15 years [31]. The cost of the Li-ion battery ranges from \$1,200 to 4,000 /kWh since the Li-ion battery requires special packaging and internal circuitry to provide overcharge protection. The current operational temperature for the Li-ion ranges from -10 to 60 °C. The Li-ion will operate outside of this temperature range but the battery experiences rapidly declining performance. The Li-ion has similar characteristics and life cycle expectancy when operating at 25 °C or 60 °C which makes it well suited for high temperature applications [31]. Research is currently being performed that allows for the Li-ion to operate with high discharge rates within a temperature range of -50 to 80 °C using alternative composition methods. One possible solution to solve operational temperature ranges is to design the Li-ion battery specifically for the task required [33]. For example in the remote system or space applications designing a battery that operates optimally at low temperatures would be ideal. However, at present the Li-ion has similar temperature requirements as the lead-acid battery and if used in an extreme environment the Li-ion would have be kept in a heated facility. The Li-ion has primarily been tested and designed for cyclic operations of charges and discharges. The implementation of the Li-ion into a system that provides continuous float charging requires significant development [31].

The Lithium polymer (Li-polymer) battery is designed using a similar chemical composition except that the organic electrolyte of the Li-ion is replaced with a solid polymer that encapsulates the electrodes [31]. The solid polymer encapsulation creates a safer battery that reduces the flammability compared to the Li-ion. The battery must be operated at high temperatures, ranging from 60 - 80 ºC, to achieve suitable conductivity of the electrolyte. The Li-polymer is still under development and it is doubtful that it will yield a cost effective EES system for large scale applications [31].

The Li-ion battery is not currently a mature enough technology for implementation in the required system and presently it is being further researched and developed. There have been limited functioning large scale units built but the long term applicability of these have yet to be studied [31]. At present the cost of the Li-ion battery is slightly larger than that of competing technologies and large-scale Li-ion batteries have yet to be produced on a large-scale. When the Li-ion has been further developed and becomes a viable alternative for large-scale applications it is quite possible that it will be the EES system of choice for implementation in remote Northern communities.

4.2.4 Solar Fuels

Solar fuels are a developing technology that consists of focusing sunlight over a small area and capturing the resulting radiated energy. The radiated energy from this process is used to create high heating temperatures that produce endothermic reactions to yield fuel that can be later used for power production. Traditional use of heat to produce power via a steam Rankine cycle has a very low efficiency. The virtual efficiency of a solar fuel system is close to 100%. This is due to key benefit of solar fuels that enables storage to become integrated into the system. The storage is integrated into the system as the fuel is expected to be stored in its natural state unlike electrical energy that is required to be converted to chemical energy in BESS. This reduction in conversion requirements and system components reduce the loses throughout the process which allows for the high efficiency. Figure 4.2 demonstrates the process of creating solar fuels.

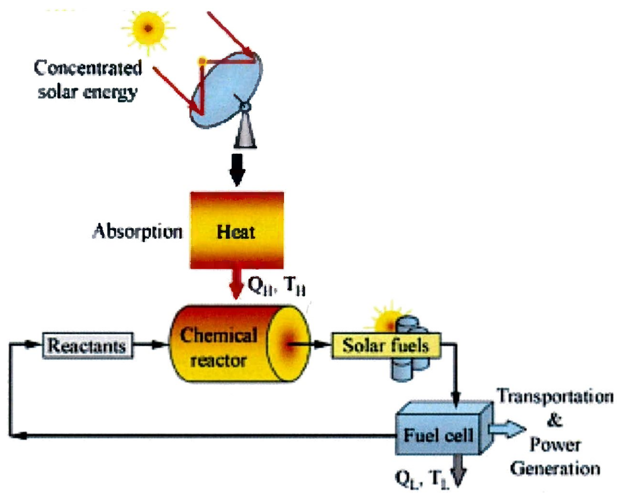

Figure 4.2: Solar Energy Conversion into Solar Fuels [24]

Variable	Definition
T_H	Isothermal heat addition (high temp.)
Q_H	Heat energy entering the system (high heat)
T_L	Isothermal heat rejection (low temp.)
Q_L	Heat energy leaving the system (low heat)

There are a few variations of fuels that can be produced from the process outlined in Figure 4.2 which include:

- Solar hydrogen
- Solar metal
- Solar chemical heat pipe

Due to the developing technology maturity of solar fuels and the variations in local climatology solar fuels are not currently applicable EES for a remote Northern community.

4.2.5 Thermal Energy Storage

Thermal Energy Storage (TES) is an EES technology that utilizes various materials that can be maintained at high or low temperatures from within the confines of an insulated space. This stored heat/cold can be used by a heat engine to produce electricity. The overall efficiency is within the range of 30-60% and the heat cycle efficiency ranges from 70-90%. The ecological impact of TES systems is negligible which may offset a lower overall efficiency. TES is normally subdivided into two sub categories: low-temperature TES and high-temperature TES. The differentiation is dependent upon the operating temperature of the energy storage material when compared to ambient temperature. TES can be subdivided into the following classifications:

- Industrial cooling ($<$ -18 °C)
- Building cooling (0 to 12 °C)
- Building heating (25 to 50 °C)
- Industrial heat storage ($>$ 175 °C)

Low-temperature TES technologies consist of Aquiferious Low-temperature TES (AL-TES) which cools or ices water during non-peak hours so that cooling requirements can be partially met using this stored cooling energy during peak hours and Cryogenic Energy Storage (CES) which achieves similar results as AL-TES using liquid nitrogen or liquid air in lieu of water. High-temperature TES technologies consist of Molten salt storage and Room Temperature Ionic Liquids (RTILs), concrete storage, and Phase Change Materials (PCMs). The RTILs system uses molten salts which are able to store temperatures in the range of 100s of degrees without decomposing which is used to aid in heating applications to offset overall energy requirements. Concrete storage uses heat transferring fluids, chiefly oil, to transfer excess high temperatures from power production facilities into concrete storage facilities for later heating use. PCMs are a new technology that is being investigated that requires the use of phase changes to match the temperature of the thermal input source so that latent heat can be stored.

Both low and high TES systems have been implemented and are currently subject of extensive research. TES systems, as explored above, are not applicable to Northern Ontario due to local climatology. The regions under investigation do not require cooling during the summer months which eliminates the applicability of low-temperature TESs. Due to the small penetration of high temperature producing facilities, difficulties of transmitting stored heat throughout the community, and considering that it is a developing technology high-temperature TESs are also not feasible in Northern Ontario. There is room for future applicability of TES systems to supplement small scale power systems in the North but due to localized variables it will likely also remain infeasible in the near future.

4.2.6 Hydrogen Storage

In December 2008 the first and only wind-hydrogen-diesel hybrid power system in Canada, which is located in Ramea Newfoundland, was brought in service after four years of construction as a proof of concept to retrofit an existing wind-diesel hybrid power system. Ramea is one of the 28 remote communities in NFLD that rely on diesel generators and is situated on a coastal island accessible by barge. The project was sponsored by CANMET Energy Technology Centre-Ottawa (CETC-Ottawa), the Ministry of Natural Resources, Newfoundland and Labrador Hydro, Frontier Power Systems, University of New Brunswick, and Memorial University with the objective to demonstrate the wind-hydrogen-diesel integrated control system to demonstrate that wind energy can be used to supplement diesel generation efficiently in a remote community while maintaining reliability through the use of hydrogen storage. The control system required for this is complex and of unique design which attempts to optimize the individual component outputs so that an overall higher level of wind penetration is available. The project was also conducted to gain experience in the sizing and design of wind-hydrogen-diesel hybrid power systems [34].

The Ramean power system serves approximately 350 customers and experiences a peak winter load of 1,078 kW. The existing wind-diesel system consisted of six 65 kW Windmatic turbines with a capacity factor of 0.33 and three 925 kW diesel generators. In 2005 the system produced a total of 4.2 GWh of which 90% was from DG and 10% from WG. It was found that normally only one DG was operating at around 300 kW during the year. After 12 months of the wind-diesel system operation it was found to have: produced 1 MWh of wind energy a year, saved 10% of the community diesel requirements, reduced GHG emissions by 750 tonnes per year, and improved air quality. The retrofit project, which included hydrogen storage, was implemented to increase the wind penetration capabilities of the community and to ensure that excess wind energy would not have to be dumped [34]. Figure 4.3 demonstrates the hydrogen integration project to the existing wind-diesel system.

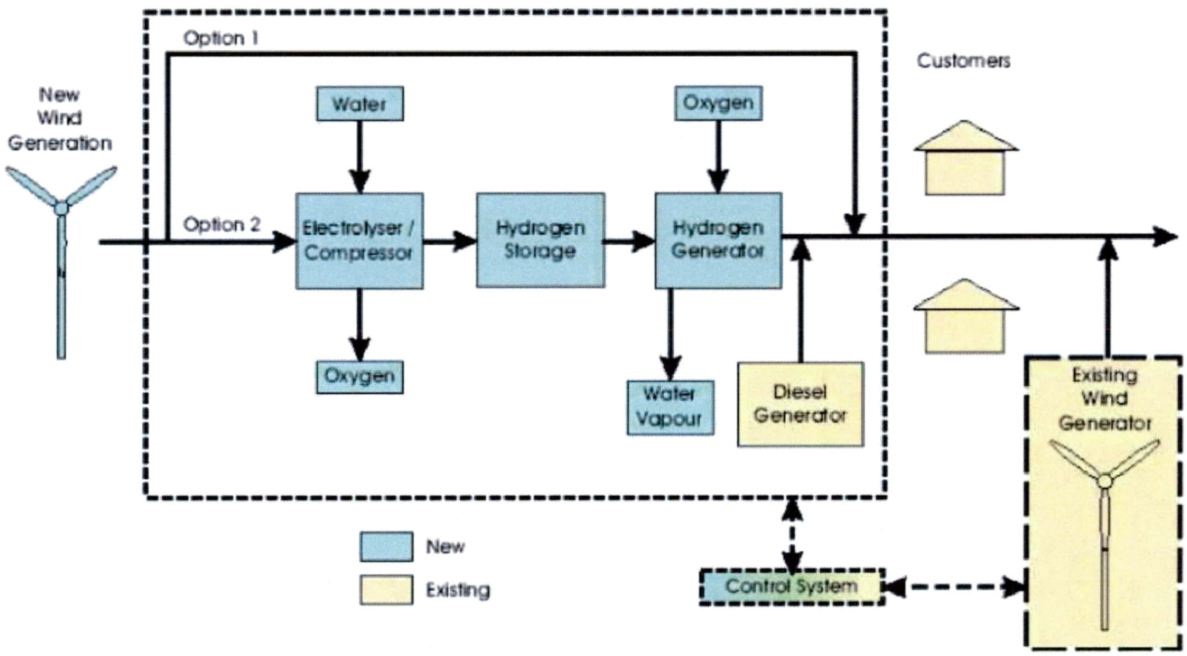

Figure 4.3: Hydrogen Integration at Ramea, Newfoundland [34]

The hydrogen generator uses existing reliable internal combustion technology from which previous operating experience has been obtained, they are more cost effective than a fuel cell, and are significantly more mature than existing fuel cell options. The

Ramea project uses four 62.5 kW hydrogen engines, based on the 4.9 L Ford engine, supplied by Hydrogen Engine Centre Canada for an installed capacity of 250 kW [34].

Conventional hydrogen storage systems are more environmentally friendly than batteries and could help develop a hydrogen based society. The hydrogen storage and compression system requirements at Ramea were derived from the hydrogen engine generator sizing. The utilized hydrogen engines consume 250 Nm^3/hour and the power system was developed to provide system autonomy for a total of eight hours. In order to achieve this 2,000 Nm^3 of hydrogen storage capacity was required.

The Nm^3/hour unit represents the Normal Cubic Metres per Hour (NCMH) which is a common measure of flow rate in industries that use gaseous materials. The NCMH is equivalent to one cubic metre under normal conditions which are defined to be 0 °C and 101.3 kPa (or 1 atm). The difference between the Standard Cubic Metres per Hour (SCMH) and NCMH is that the standard conditions occur at 15 °C and 101.3 kPa.

To facilitate the 2,000 Nm^3 storage requirement a volume equivalent to 6,837 L of H_2O is required. This translates to 9 x 19-ft cylinders that store the hydrogen at 6,700 psi. Based upon the storage requirements of the system a minimum size of the hydrogen electrolyzer was determined. In Ramea it was determined that the maximum amount of time to fill the hydrogen storage was 24 hours. As such to fill 2,000 $Nm^3$of storage in 24 hours a rate of 79 Nm^3/hr plus additional capacity would have to be met. The electrolyzer selected in Ramea was 90 Nm^3/hr. Using the electrolyzer sizing, the assumed capacity factor of 0.33, and Figure 4.4 the planned wind capacity for the wind-hydrogen-diesel retrofit project was determined to be 1,500 kW which includes a margin for error. The hydrogen storage at Ramea allowed for an additional 1,110 kW of installed wind capacity [34].

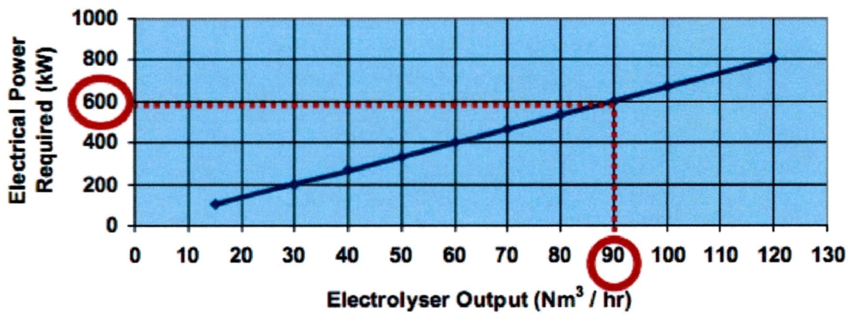

Figure 4.4: Determining Wind Capacity at Ramea, Newfoundland [34]

As denoted in Figure 4.3 when wind energy is available and required by the load it will be used directly via option 1. When available wind energy is greater than the required load the electrolyzer is used to produce hydrogen which is then stored as seen by option 2. This technique is used to mitigate intermittency concerns and utilize renewable resources, such as wind, to their potential by storing unneeded and unused energy (such as during the night for wind) in the form of hydrogen generated by electrolysis as opposed to dumping the excess energy.

Table 4.2: Expected Performance of the Hydrogen System [34]

Component and Process	**Approximate Efficiency**
Electrolysis + Compression	80%
Storage + Decompression	90%
Hydrogen Internal Combustion	35%
Approximate Round Trip Efficiency	**25%**

As shown in Table 4.2 the round trip efficiency of the hydrogen system is expected to be approximately 25%. As such results are still preliminary and the technology is not mature enough to be considered for use in this thesis. This technology should be revisited once additional operating experience is obtained [34].

4.3 Comparison of EES Technologies

As seen in Section 4.2 there are many available technologies to perform EES for energy management applications. Figure 4.5 demonstrates the technical maturity levels of the various EES technologies. It can be see that PHS and lead-acid batteries are mature technologies [24, 29]. The fuel cell, solar fuels, and CES are developing energy management technologies that are not yet commercially mature. The remaining energy management technologies are developed but lack the wide spread implementation that the mature technologies exhibit.

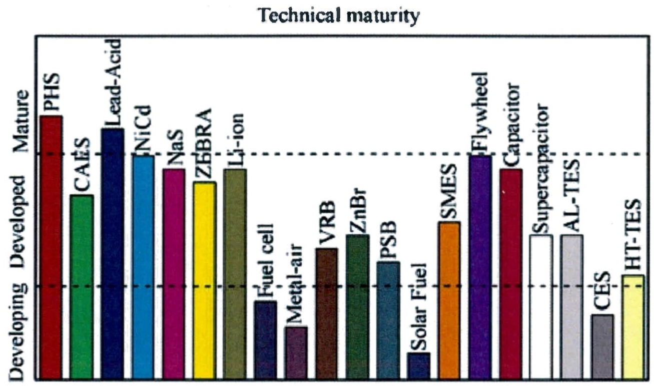

Figure 4.5: Technical Maturity of EES Systems [24]

Tables 4.3 and 4.4 demonstrate system parameters of the various EES technologies for both energy management and energy quality and reliability applications. The Metal-Air is a special type of fuel cell that uses metal as the fuel and air as the oxidant. A flow battery is a battery where the electrolyte contains one or more dissolved electro-active species flowing through the cell where the chemical energy is converted to electricity. The Vanadium Redox Battery (VRB), Zinc Bromine (ZnBr) Battery, and Polysulphide Bromide Battery (PSB) are all different types of flow batteries. The Superconducting Magnetic Energy Storage (SMES) system stores electrical energy directly as electric current. This is achieved by passing the electric current through a circular inductor made from superconducting materials. This inductor enables the current to circulate almost indefinitely with minimal loses. The flywheel stores energy in the angular momentum of a spinning mass. The capacitive storage system, which consists of either the capacitor or super-capacitor, is the most direct method of storing electrical energy. The simplistic form of the capacitor is constructed with two metal plates separated by a dielectric [24].

Table 4.3: EES system parameters - 1 [24]

System	Typical Application	Power Rating	Discharge Time	Self Discharge/Day	Suitable Storage Duration	Life: Time (years)	Life: Cycle (cycles)
PHS	Management	100-5000 MW	1 – 24 hr+	Very Small	Hr-months	40-60	-
CAES	Management	5 – 300 MW	1 – 24 hr+	Small	Hr-months	20-40	-
Fuel Cells	Management	0 – 50 MW	Sec – 24 hr+	Almost Zero	Hr-months	5-15	1000+
Metal-Air	Management	0 – 10 kW	Sec – 24 hr+	Very Small	Hr-months	-	100-300
Solar Fuel	Management	0 – 10 MW	1 – 24 hr+	Almost Zero	Hr-months	-	-
AL-TES	Management	0 – 5 MW	1 – 8 hr	0.50%	Min – days	10-20	-
HT-TES	Management	0 – 60 MW	1 – 24 hr+	0.05-1.0%	Min – months	5-15	-
Lead-acid	Varies	0 – 20 MW	Sec – Hr	0.1-0.3%	Min-days	5-15	500-1000
NiCd	Varies	0 – 40 MW	Sec – Hr	0.2-0.6%	Min – days	10-20	2000-2500
NaS	Varies	50 kW – 8 MW	Sec – Hr	~20%	Sec – hr	10-15	2500
ZEBRA	Varies	0 – 300 kW	Sec – Hr	~15%	Sec – hr	10-14	2500+
Li-ion	Varies	0 – 100 kW	Min – Hr	0.1-0.3%	Min – days	5-15	1000-10000+
VRB	Varies	30 kW – 3 MW	Sec – 10 hr	Small	Hr-months	5-10	12000+
ZnBr	Varies	50 kW – 2 MW	Sec – 10 hr	Small	Hr-months	5-10	2000+
PSB	Varies	1 – 15 MW	Sec – 10 hr	Small	Hr-months	10-15	-
CES	Varies	100 kW – 300 MW	1 – 8 hr	0.5-1.0%	Min – days	20-40	-
SMES	Quality/Reliability	100 kW – 10 MW	mSec – 8 sec	10-15%	Min – hr	20+	100000+
Flywheel	Quality/Reliability	0 – 250 kW	mSec – 15 min	100.00%	Sec – min	~15	20000+
Capacitor	Quality/Reliability	0 – 50 kW	mSec – 60 min	40.00%	Sec – hr	20+	100000+
Super-Capacitor	Quality/Reliability	0 – 300 kW	mSec – 60 min	20-40%	Sec – hr	~5	50000+

The power density is determined by dividing the rated output power by the volume of the storage device. The power density in Table 4.4 is given by Watt-hours per Kilogram or Watt-hours per Litre. The energy density is determined by dividing the stored energy by the volume. The energy density in Table 4.4 is given by Watts per Kilogram or Watts per Litre. The volume of the storage device is the overall volume of the system. This includes the volume of the storage element, accessories, system inverter, and the supporting structure of the system [24].

Table 4.4: EES system parameters - 2 [24]

System	Capital Cost			Energy and Power Density				Influence on Environment
	$/kW	$/kWh	¢/kWh/Cycle	Wh/kg	W/kg	Wh/L	W/L	
PHS	600-2000	5-100	0.1-1.4	0.5-1.5	-	0.5-1.5	-	Negative
CAES	400-800	2-50	2-4	30-60	-	3-6	0.5-2.0	Negative
Fuel Cells	10000+	-	6000-20000	800-100000	500+	500-3000	500+	Negative
Metal-Air	100-250	10-60	-	150-3000	-	500-10000	-	Small
Solar Fuel	-	-	-	800-100000	-	500-10000	-	Benign
AL-TES	-	20-50	-	80-120	-	80-120	-	Small
HT-TES	-	30-60	-	80-200	-	120-500	-	Small
Lead-acid	300-600	200-400	20-100	30-50	75-300	50-80	40-100	Negative
NiCd	500-1500	800-1500	20-100	50-75	150-300	60-150	-	Negative
NaS	1000-3000	300-500	8-20	150-240	150-230	150-250	-	Negative
ZEBRA	150-300	100-200	5-10	100-120	150-200	150-180	220-300	Negative
Li-ion	1200-4000	600-2500	15-100	75-200	150-315	200-500	-	Negative
VRB	600-1500	150-1000	5-80	10-30	-	16-33	-	Negative
ZnBr	700-2500	150-1000	5-80	30-50	-	30-60	-	Negative
PSB	700-2500	150-1000	5-80	-	-	-	-	Negative
CES	200-300	3-30	2-4	150-250	10-30	120-200	-	Positive
SMES	200-300	1000-10000	-	0.5-5	500-2000	0.2-2.5	1000-4000	Negative
Flywheel	250-350	1000-5000	3-25	10-30	400-1500	20-80	1000-2000	~None
Capacitor	200-400	500-1000	-	2.5-15	500-5000	10-30	100000+	Small
Super-Capacitor	100-300	300-2000	2-20	0.05-5	~100000	2-10	100000+	Small

It can be seen from Table 4.3 that the EES utilized for energy management applications typically boast larger power ratings and significant larger discharge times. Almost all of the energy management EES systems exhibit small self discharge characteristics which translate into long periods of storage capabilities. The lead-acid, NiCd, Li-ion batteries, TESs and CES are suitable for storage periods lasting up to around 10s of days due to medium self-discharge ratios. The NaS and ZEBRA batteries exhibit poor storage capabilities which when coupled with the high temperature requirements deem them inappropriate to meet the required energy management criteria.

The PHS, CAES, and CES EES systems are suitable for applications that require a rated power of over 100 MW with hourly to daily output durations. The large-scale batteries, flow batteries, fuel cells, CES, TES, and solar fuels EES systems are suitable for medium scale energy management systems with a rated capacity ranging from 10 - 100 MW.

Table 4.4 demonstrate the capital cost for the various EES systems along with the related energy and power density ranges. Of the various energy management technologies at present date only NiCd and lead-acid batteries provide an affordable capital cost. Of these two EES systems the NiCd battery provides superior energy and power density performance for a modest increase in capital cost. The capital costs of the major BESS can be demonstrated by: Li-polymer > Li-ion > Ni-MH > NiCd > lead-acid [31]. Figure 4.6 demonstrates the cycle efficiency of the various EES technologies that corresponds to Table 4.4 which contains life cycle and life time expectancies of the EES systems.

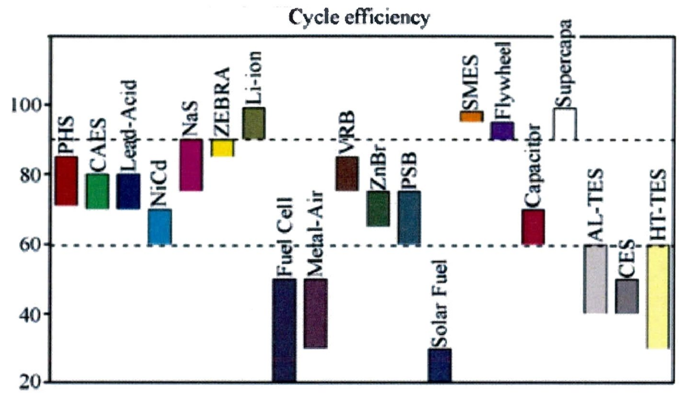

Figure 4.6: Cycle Efficiency of Various EES Technologies [24]

The Li-ion is the only energy management technology that possesses a high efficiency of over 90%. The majority of energy management technologies have high efficiencies that range from 60-90%. The NiCd battery out performs the lead-acid battery significantly when comparing the expected life time and cycle life of the units. The downside of using BESS is the typically low cycle life when compared with other EES technologies due to chemical deterioration over time. This is also enhanced since BESS cannot operate at high power levels for long periods of time. The rapid and deep discharges that many BESS exhibit also contribute to a shortened life span of the BESS due to additional heating that occurs [29]. The batteries are constructed with toxic materials that could heavily impact the local ecological system if handled or disposed of improperly [24, 29]. Proper training and facilities are required when utilizing batteries for any application but the difficulty of ensuring or regulating procedures in the North is difficult to guarantee.

The NiCd EES system is also beneficial when comparing high temperature ranges as they offer an inherent resistance. Generally the lead-acid's operational life is reduced by 50% for every 8ºC above 25ºC whereas the NiCd only decreases by 20%. Meanwhile the EES system employed at the Northern latitude will not normally operate in this temperature range it does demonstrates that the NiCd is more versatile. The NiCd is also built using thin plates of steel with no ill effect whereas the lead-acid battery experiences corrosion of the positive plates over time [31].

After analyzing the various EES technologies the only energy management capable technologies that are presently feasible in Northern latitudes are lead-acid and NiCd batteries. In mild environments the lead-acid battery will likely remain the battery of choice in the near future however in the extreme Northern climate there are many benefits and drawbacks of both the vented lead-acid and NiCd batteries [31]. The NiCd may prove to be ineffective due to the memory effect. In the near future it is also foreseeable that Li-ion will become a viable and preferred alternative as its operating characteristics are superior to both lead-acid and NiCd batteries but it must be further developed for large scale applications and is not a mature technology at this time. For the purpose of this thesis only lead-acid batteries will be considered for implementation at this time due to the complexity of component selection and the availability, viability, and feasibility of lead-acid batteries. HOMER uses the lead acid battery storage model for hybrid energy systems developed by [35] for modelling purposes however the simulation methodology of the lead acid battery will not be studied in depth in this thesis.

4.4 BESS Component Selection

As determined in Section 4.3 the vented lead-acid batteries will be utilized for the simulation of the system model. This Section investigates in detail the BESS selected and the requirements of these components for simulation. Appendix D contains additional information regarding the BESS used for simulation along with their respective lifetime and capacity curves and sourcing documentation.

For the purpose of simulation of this thesis a total of ten different battery models will be considered to constitute the BESS. These units were selected based on past experiences in Arctic conditions, Arctic weather ratings, accessibility, and to allow for some variance with respect to rated capacity selection. Table 4.5 introduces the studied units and their respective reference ID, manufacturer, and model information. The reference ID will be used here on in to indicate the selected unit. Additional information regarding the selected BESS can be found in Appendix D. When it was both possible and feasible Canadian manufacturers were selected [36].

Table 4.5: List of BESS Suppliers and Models

Reference	Company	Model	Reference	Company	Model
B1	Surrette	S460	B6	Surrette	4KS25P
B2	Surrette	S530	B7	Surrette	6CS17P
B3	Surrette	S600	B8	Surrette	6CS21P
B4	Surrette	4CS17P	B9	Surrette	6CS25P
B5	Surrette	4KS21P	B10	Surrette	8CS25P

Table 4.6 highlights technical information of the selected BESS components. More

in depth information can be found in Appendix D or the associated unit's datasheet. For all ten units the round trip efficiency was selected to be 80%, the minimum state of charge was selected to be 40%, and the set point state of charge is 80%. The round trip efficiency indicates the efficiency of the BESS energy transformations between the electrical energy to chemical energy to electrical energy or the fraction of energy put into the battery that can be retrieved. It is also assumed that the BESS charge and discharge efficiencies are both equal to the square root of the round trip efficiency. The minimum state of charge is the relative state of charge allowable for the specific BESS. This represents the minimum relative level of discharge that is observed to mitigate damage to the BESS due to excessive discharge. The set point state of charge is used to configure the cycle charging strategy. Once the system starts to charge the BESS it will not stop until the set point state of charge is reached. This is done to reduce the amount of time the BESS spends with a low state of charge and to reduce the quantity of generator start-ups and the number of battery charge-discharge cycles over time [15, 36].

The battery throughput is the amount of energy that cycles through the BESS over the course of a year. It is defined as the change in energy level of the BESS and is measured after charging losses but before discharging losses. The maximum or theoretical capacity of the BESS is a calculated parameter and indicates the total amount of energy it contains when fully charged. The nominal or rated capacity of the BESS is the amount of energy that may be withdrawn from the BESS at a particular constant current assuming that the BESS is initially fully charged. The manufacturer provides the various times and current levels on the respective data sheets at the 1-6, 8, 10, 12, 15,20, 24, 50, 72, 100 hour rates. The commonly utilized rated capacity is taken at 20 hours, which denotes that the sustained current would cause the BESS to be drained after 20 hours. These rated capacity values are indicated in Table 4.6 as the nominal capacity. The maximum charge current sets the upper limit on the allowable charge current regardless of the respective BESS state of charge. This is done to prevent damages to the BESS and extend unit life. The capacity ratio c is the ratio of the size of the available charged energy capacity to the nominal capacity. The rate constant k is the rate at which available chemical energy can be converted to available electrical energy [15, 36].

Table 4.6: BESS Component General Technical Information

Ref. #	Nominal Cap. (Ah)	Nominal Volt. (V)	Max. Charge Current (A)	Lifetime Throughput (kW)	Max. Capacity (Ah)	Capacity Ratio c -	Rate Constant k (1/hr)
B1	446	6	17.5	1536	454	0.279	0.520
B2	532	6	20.0	1812	535	0.280	0.462
B3	599	6	22.5	2001	604	0.304	0.414
B4	770	4	27.3	4479	797	0.272	0.335
B5	1557	4	55.2	9016	1605	0.277	0.322
B6	1904	4	67.5	10935	1947	0.272	0.347
B7	770	6	27.3	6593	783	0.263	0.370
B8	963	6	34.2	8354	992	0.278	0.324
B9	1156	6	41.0	10048	1193	0.272	0.334
B10	1156	8	41.0	13450	1197	0.276	0.324

Table 4.7 indicates the DC bus voltage and the associated costs of the selected BESS.

The Net CC is comprised of the unit cost, enclosure cost (Encl Costs), labour, and transportation costs. The minimum unit life is seven years for B1 - B3 and ten years for B4 - B10. The float life, which is defined as the maximum length of time the BESS can last prior to required replacement regardless to unit usage, is ten years for B1 - B3 and twenty years for B4 - B10. The float life is commonly associated with BESS corrosion and is strongly affected by temperature. If the BESS is installed in a ventilated and controlled environment the float life can be significantly extended [15, 30]. The enclosure costs are assumed to be the costs associated per a single battery that is to be housed in a chest style insulated unit. The common size of 2x6 for a total of 12 batteries was considered when determining the pricing as found in Appendix D. The miscellaneous costs account additional components such as cables and connectors along with installation costs. It is assumed that the installation cost related with the BESS will be relatively minimal and that the RC consists of new units with their respective shipping. The O&M is assumed to be 5% of the CC [11].

Table 4.7: BESS Component Cost Information

Ref. #	Unit CC	Encl. Costs	Ship Costs	Misc. Costs	Net CC	RC	O&M	Batteries per String
	($/unit)						($/yr)	(480 V Bus)
B1	454.00	227	98	9	789	552	22.70	80
B2	499.00	227	108	10	844	607	24.95	80
B3	610.00	227	132	12	982	742	30.50	80
B4	858.00	292	186	17	1353	1044	42.90	120
B5	1501.00	292	326	30	2149	1827	75.05	120
B6	1874.00	292	407	37	2610	2281	93.70	120
B7	1224.00	377	266	24	1891	1490	61.20	80
B8	1453.00	377	315	29	2174	1768	72.65	80
B9	1678.00	377	364	34	2452	2042	83.90	80
B10	2236.00	338	485	45	3104	2721	111.80	60

These costs and technical parameters will be utilized during the system simulations to determine the feasibility of the systems in question. For simulation purposes the number of batteries per string will be determined based upon the desired DC bus voltage, the various generators connected to the DC bus, and the inverter(s) utilized. The simulations will model as a minimum the number of batteries required to obtain the DC bus voltage, based upon their respective nominal voltages, so that the inverter can function. For each iterative simulation the same quantity of BESS will be simulated along with combinations consisting of BESSs selected from all 10 models listed in Table 4.5. The CC will be adjusted depending upon the number and type of BESS units being simulated at any given time based upon bulk buy options (where available), enclosure limitations, and other variability in the unit cost approximations. It is generally found, as denoted by NREL, that the difference between theoretical and actual battery throughput is typically less than 5% [15].

Chapter 5

Diesel Generator Systems

This Chapter introduces the Diesel Generator Systems (DGS) and Diesel Generators (DG) used in this thesis. All of the existing communities within Ontario utilize diesel generation as the primary means to meet their energy requirements and as such it is assumed that the system model currently operates a DGS. Since the DGS is integral to the existing functionality of the community and any subsequent analysis, this Chapter introduces a number of fundamental technical concepts surrounding the DGS, the base case simulation that is used for system comparison, and the simulation aspects of said case. Section 5.1 introduces DGS technical considerations. Section 5.2 provides an overview of the various installation considerations. Section 5.3 introduces the units selected for simulation. The DGS components selected in this Chapter are introduced in depth as they will be used in subsequent Chapters and Sections for simulation purposes. Section 5.4 contains the system diagram. Section 5.5 introduces the simulation methodology and Section 5.6 demonstrates the results of the base case simulation which will be used in subsequent Chapters as a reference case. Appendix E introduces additional information related to the DGS including various definitions of DG operation, common technical specifications including minimum percentage loading, derating factors, short circuit decrement curve, and specific technical specifications which include fuel and efficiency curves along with additional unit specific technical information.

5.1 Technical Considerations

To account for unit degradation and operating characteristics the lifetime of the diesel generator must be known for unit simulation. The DG's lifetime is not critically related to the age of the unit but rather it is dependent upon the number of hours of generator operation. Hence not only does the operation of the unit incur costs associated with fuel and routine maintenance but it also strongly affects the depreciation of the unit and increases the annualized costs over time. When renewable resources and storage are used in the system the associated costs of the DGS, including O&M and depreciation, are considered when determining the most cost effective generator dispatch schedule [16]. It is therefore a possibility to increase the longevity of the DGS by using alternative generation methods.

There are many variables that effect the lifetime of the unit which include the operating conditions, maintenance frequency, and fuel quality. Since these variables are often difficult to predict the engine classification is the best indicator of engine longevity. Table 5.1 demonstrates various generator classifications along with their respective estimated lifetimes. The lifetime of the DGS is conventionally provided in hours as opposed to years [15, 37, 38].

Table 5.1: Diesel Generator Lifetime [15]

Generator Type	**Size Range (kW)**	**Estimated Lifetime (hrs)**
H.S. air-cooled G, NG, or LP	1 - 10	250 - 1,000
H.S. air-cooled D	4 - 20	6,000 - 10,000
L.S. liquid-cooled NG or LP	15 - 50	6,000 - 10,000
Prime power liquid-cooled D	7 - 10,000	20,000 - 80,000
NG microturbine	25 - 500	50,000 - 80,000
Abbreviations - Speeds		
H.S.	High Speed	3600 RPM
L.S.	Low Speed	1800 RPM
Abbreviations - Fuels		
G	Gasoline/Petroleum	
D	Diesel	
NG	Natural Gas	
LP	Liquid Propane	

The reciprocating internal combustion engine is the most common generator type in use. It can be seen that overall the compression-ignition (diesel) engine tend to last significantly longer than the spark-ignition engine (G, LP, and NG). For longevity purposes, Low Speed (L.S.) is superior to High Speed (H.S.), liquid cooling is superior to air cooling, and pressurized oil lubrication is superior to splash lubrication. However, when accounting for the net cost of the DGS it is vital to perform a cost benefit analysis of the aforementioned technological factors that directly impact system longevity. For the purpose of this thesis it is assumed that the DGS used is of the prime power liquid-cooled diesel classification and that the generator lifetime, or $R_{gen,h}$, is 30,000 hours. Due to the increased lifetime of the compression-ignition engine, density of diesel fuel, existing DGS infrastructure, and difficulties of fuel transportation only engines that operate using diesel fuel (DGS) are investigated [15, 17].

Using the assumed generator lifetime in hours, as previously approximated, Equation 5.1 can be used to determine the lifetime of the DGS in terms of operating years [15]. However, the lifetime of the DGS may be misleading since it is dependent upon the dispatch method, size, and type of generators installed on the system. The number of hours that the generator operates during one year can vary significantly which in turn is inversely proportional to the generator operational lifetime [15].

$$R_{gen} = \frac{R_{gen,h}}{N_{gen}} \tag{5.1}$$

Table 5.2: R_{gen} Calculation Variables

Variable	**Description**	**Unit**
R_{gen}	Generator Operational Life	years
$R_{gen,h}$	Generator Lifetime	hours
N_{gen}	Number of Hours the Generator Operates During One Year	hours/year

The dispatch strategy is the methodology employed to determine when to operate the DGS and when to operate another form of generation or EES. For the purposes of simulation both cycle charging and load following dispatch methods will be investigated. Determining the form of generation to utilize is dependent upon a multitude of factors which includes the installed capacity, if the generator is dispatchable, cost of diesel fuel, depreciation through use, and O&M costs. The load following strategy dictates that the generator produces only enough electricity to supply the demand. Load following tends to be optimal in systems with large amounts of renewable generation when the renewable sources produce more power than required. The cycle charging strategy dictates that the DGS will only operate at full capacity and all power that is not required by the load is used to charge an EES. It is possible to constrain the system so that the EES will constantly be charged until a set point before the DGS cuts out. Cycle charging tends to be optimal in systems with minimal renewable penetration [15].

The DGS has a rated design value that indicates the minimum allowable load, denoted as $f_{gen,min}$, which is expressed as a percentage of its rated capacity. The generator dispatch will not terminate the generator service if the load requirements drop below this value however the generator will not follow the load to operate at too low of a capacity. The minimum allowable load is typically 30% of the installed capacity however the unit specific minimum load will be presented upon component selection [15, 37, 38]. This dictates that the community base load, while operating a DGS as in the base case, can never fall below the minimum allowable load even if the demand during non-peak periods (ie. overnight) is lower than this value. The excess generation has to be used to service a deferrable load, charge EES if applicable, or be dumped. It is assumed during DGS selection that cogeneration systems or combined-heat-and-power systems (CHP) are not considered. It is reasonable to assume that the community will never experience a no load condition and that the diesel generator will always be operational, even if minimally so, unless dispatch dictates that the community load is serviceable from EES devices and/or from renewable sources.

All power systems must be able to provide some form of operating reserve. This reserve is the surplus operating capacity that can be used to meet the instantaneous changes in system demand if generation is lost of disrupted. This allows the community to provide a safety margin that allows for both the reliable service of electricity for its consumers and the integration of renewable generation within the system [2]. This reserve could be met, in part, by a DGS with a larger installed capacity, smaller DGSs installed in parallel to allow for peak shaving and redundancy, and EES technologies. It should be noted however that the EES options are typically limited by the capabilities of the inverter to convert between the DC and AC buses and overall storage capacity. Due to the limited number of generators, small size of the power system, and control provided to the remote LDC, Under Frequency Load Shedding (UFLS) and relaying schemes are not considered.

5.2 Installation Considerations

Figure 5.1 demonstrates the overall population in 2002 versus the fuel storage capacity for 46 of the AVEC communities in Alaska. Typically enough fuel is stored in the remote communities to last 6 to 13 months depending upon location and associated circumstances. Overall 10 different metrics were investigated to determine the suitability of obtaining the overall fuel storage capability however it was found that using the overall population was the best metric [11, 12, 13]. The additional graphs and data can be found in Appendix A.

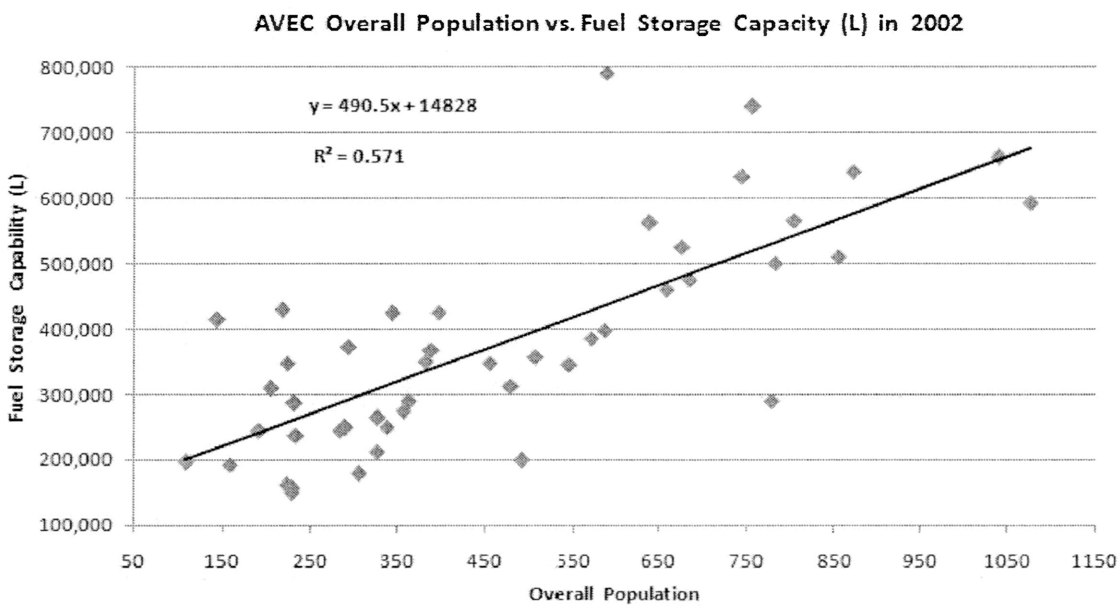

Figure 5.1: AVEC Fuel Storage Capacity

It can be seen that the r-squared value of the linear trend line is 0.571 and the relationship can be denoted as Fuel Storage Capability = 490.5 * Community Population + 14,828. Using the system model population of 500 the fuel storage capability of the system model can be estimated at 393,552 L. Using the additional available metrics for approximation it was determined that the target fuel storage capability of the system model will be 400,000 L. It was projected that the annual diesel consumption of the community will be 684,118 L/year for electricity generation which indicates that the fuel storage capability of the system will be approximately 58.5% of the yearly requirement or seven months. For practical consideration two types of bulk fuel storage tanks were considered which included the single wall remote fuel tank and the UL-142 double wall base mounted fuel tank. The available sizes investigated ranged from 60 gallons to 5000 gallons and it was concluded that the size of the diesel fuel tank was linearly proportional to the cost as seen in Figure 5.2. Figure 5.2 demonstrates the cost of the base mounted fuel tanks only. The result of the remote fuel tanks cost analysis is also linear but they weren't studied in-depth as the base mounted fuel tanks were the preferred model type. Typically the larger the storage tank the lower the CC however the difference was considered minute and the desired fuel tank was selected based on other metrics.

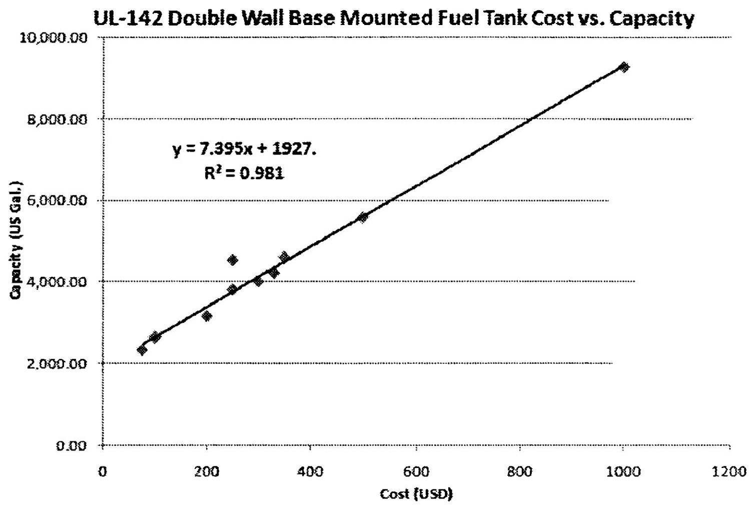

Figure 5.2: Fuel Tank Cost vs. Capacity

The UL-142 double wall base mounted fuel tanks were chosen for the DGS to minimize effects of the extreme conditions and space requirements for the installed system. The size of the DG selected dictates what size and model of storage tank can be used in the system. Due to the linear cost and size requirements within the DGS the following two fuel tanks, listed in Table 5.3 from Americas, were primarily considered from the 28 models investigated. Both models are generic and allow for connection to any DG that fits within the size criteria and the price provided is the base cost without transportation or applicable taxes [39]. Both units are also outfitted with numerous safety and environmental features which are also highly desirable. The fuel tank size selected is dependent upon the size of the DG selected in following Sections and the overall capacity of the DGS will be close to the 400,000 L target.

Table 5.3: Fuel Tanks of Primary Interest

Metric	Model A	Model B
Capacity (US Gal.)	500	1000
Price (USD)	5,589.00	9,279.00
Max. Dimensions (LxW)	154"x47.5"	216.5"x59"
Min. Dimensions (LxW)	60"x40"	80"x50"

The DGS proximity to the community is vital to consider due to the continuous operation and sound attenuation. As a result the DGS is typically located outside of the community proper. The studied DGS include the selection of a sound attenuated weatherproof enclosure for all of the selected DG models which is absorbed by the fixed CC. The sound reduction using these enclosures is typically 70 dB at 7 meters. Additional industrial soundproofing options are also available with 1/2" or 1" foam absorber faced sound barrier. It is constructed of a fire retardant fibreglass reinforced aluminized Mylar design, in 1 lb per square foot sections, for $79.99 and $99.99 USD respectively [39]. For the purposes of this thesis only the standard enclosure is utilized and additional soundproofing may be considered on a case by case basis as required. These enclosures also afford protection to the DGS from both physical and environmental occurrences and can improve the life of the units. Due to the limited distances only a low voltage distribution system will be used within the community. The design of the distribution system will not be explored here due to the individual requirements of the community and the potential difference in industrial/commercial loads and their requirements.

The system model dictates that the installed capacity of the power system is 1,144 kW. A 10% margin was calculated thus the installed capacity range used for DG selection was between 1,030 and 1,258 kW as seen by Figure 2.7. Ninety DGs were considered that ranged between 11 kW to 2,000 kW. A total of 227 combinations consisting of DGs ranging from 100 kW to 1250 kW, were studied to meet the installed capacity requirements within the 10% margin. Figure 5.3 demonstrates the DG size versus cost for the 90 units. It can be seen that the size versus cost relationship is a strong linear relationship. From these 90 DG units, 19 units consisting of primarily manufactured by Cummins and Perkins were used to form the 227 combinations, of which each unit is a unique size while meeting similar operational characteristics. In general the DG units at and below 250 kW can only be installed with the 500 US Gallon base mounted fuel tank and the larger DG units are to be installed with the 1000 US Gallon base mounted fuel tank. Some of the selected DG units meet the American Environmental Protection Act (EPA) and/or UL-2200 requirements and others can be retrofitted to meet these restrictions [39]. The UL-2200 specifications are safety specifications for stationary engine generator assemblies. Being as emission targets are not the focus of this thesis nor expressly required in Northern Canadian remote communities it is assumed that units selected meeting these requirements are desired but not required.

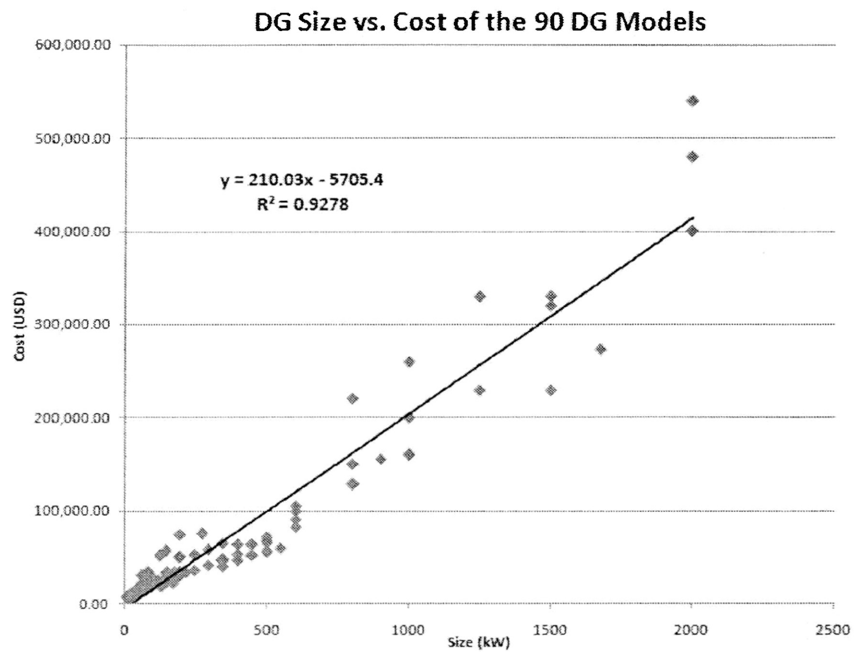

Figure 5.3: DG Size vs. Cost for the 90 DG Models

Since the studied remote communities are located in North America, even if they are not connected to the grid, they operate at 60 Hz with a 3Φ AC supply. The selected DGSs operate at a Low Speed (L.S.) or 1800 RPM with a power factor of 0.8 lagging. The absolute minimum load ratio of the studied DG units is ~25% however the minimum load ratio is taken to be 30% to provide a safety margin as the performance across the 5% drops significantly and it is a suggested practise by the DG manufacturers [37, 38]. Being the sole source of generation in the power system the DG units are used to provide base load and peaking capabilities. The dispatch model and simulation constraints will determine if it is feasible to use larger generators for both power generation aspects or to use mid size generators for base load and smaller DG units for peaking application [16]. The additional controls, filters, gauges, and associated incidental costs will be absorbed by the CC of the DGS.

5.3 System Diagram

The DG system overview can be seen in Figure 5.4, the one line diagram of the power system, and is representative of the existing infrastructure in the vast majority of the studied communities. All proceeding system diagrams of the studied systems will provide high level overview and will be used to understand the system interconnections. The labelling performed on these diagrams are done in accordance to the component section introductions. The various individual components modelled for system simulation are not denoted on these diagrams however this information can be found in tabular form in the respective component detailing sections. For example in Figure 5.4 the diesel generator, shown as DG, can be DG1 through DG6 as shown in Table 5.4. The bus bars used in these Figures denote whether the specific connection is DC or AC and does not indicate the physical number of bus bars. The voltage levels of these buses vary depending upon what components used during the simulation. The load on the system diagrams remains the same for all simulated cases and represents the load developed in Section 3.2. The system demonstrated in Figure 5.4 includes a DG connected to the community via an AC bus bar.

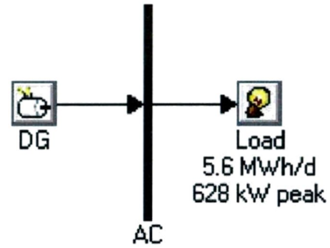

Figure 5.4: DGS Circuit Diagram

5.4 Unit Selection for Simulation

The 19 DG units chosen for simulation are listed in Table 5.4. Each DG unit is provided with a reference identification code, manufacturer name, and model number. The identification code will be used here on in within this thesis to refer to the respective DG. When selecting the provided DGs from the 90 investigated a combination of cost, size, and technical parameters were considered.

Table 5.4: List of DG Manufacturers and Models

ID	Manuf.	Model	ID	Manuf.	Model
DG1	Perkins	TP-P100-T3-60	DG11	Perkins	TP-P400-T3-60
DG2	Cummins	T150	DG12	Cummins	T450
DG3	John Deer	155-Kw554072-3B	DG13	Volvo	MV500 SAE
DG4	Perkins	TP-P175-T3-60	DG14	Perkins	TP-P550-T1-60
DG5	Perkins	HP180	DG15	Perkins	TP-P600-T2-60-UL
DG6	Cummins	T200	DG16	Cummins	QSK23G7
DG7	Perkins	TP-P220-T1-60	DG17	Cummins	TC900
DG8	Cummins	T250	DG18	Cummins	QST30G5
DG9	Perkins	TP-P300-T1-60	DG19	Cummins	OC1250
DG10	Perkins	TP-P360-T3-60	-	-	-

Table 5.5 demonstrates the rated power of the DG, the dimensions in inches of the DG unit, and if the unit is Environmental Protection Act (EPA) or UL-2200 certified. It should be noted that the dimensions are approximated from the available specification sets and where possible refer to the size of the DG itself and not the combination of the DG and enclosure set. However, due to some of the available unit specifications, some units have the enclosure dimensions built into the DG information. The rated voltage for the provided DGs is assumed to be 480 V [37, 38].

Table 5.5: DGS Component Output Information

Ref. #	Rated Power (kW)	Dimensions (LxWxH)	EPA	UL 2200
DG1	100	110"x40"x54"	Yes	Yes
DG2	150	128.35"x42.91"x74.8"	No	No
DG3	155	139.8"x45.7"x70.9"	Yes	No
DG4	175	128.70"x45.99"x73.69"	Yes	Yes
DG5	180	130"x47.2"x72.8"	Yes	Yes
DG6	200	129.92"x47.24"x70.86"	No	No
DG7	220	143.70"x51.70"x80.12"	No	No
DG8	250	113.10"x48.36"x67.47"	No	No
DG9	300	177.17"x57.60"x84.66"	No	No
DG10	350	128.23"x45.28"x83.62"	Yes	Yes
DG11	400	128.23"x45.28"x83.62"	Yes	Yes
DG12	450	198.65"x68.90"x104.33"	No	No
DG13	500	150.39"x49.02"x85.24"	Yes	No
DG14	550	196.85"x69.98"x104.33"	No	No
DG15	600	151"x47.2"x86"	No	Yes
DG16	800	177"x59"x72"	Yes	No
DG17	900	165.35"x66.93"x86.61"	No	No
DG18	1000	177.16"x76"x96.46"	Yes	No
DG19	1250	194"x84"x89"	No	No

Table 5.6 demonstrates the prime unlimited time running power fuel consumption at 25%, 50%, 75%, and 100% of the rated capacity where available in L/hr. Table 5.6 also demonstrates the displacement of the engine, the intercept coefficient, and slope of the fuel curve. The prime unlimited time running power is defined as prime power being available for an unlimited number of hours over the course of a year in a variable load application. Being as the load requirements are constantly altering in the community, and the DG is in this case the sole source of power, the variable load application is required. This variable load should not exceed 70% of the prime power capacity during any operating period of 250 hours. The DG can operate at 100% prime power but the unit should not operate in this mode more than 500 hours per year. There is also a 10% overload capability associated with the DG which is available for a period of 1 hour within a 12-hour period of operation. The DG should not be run in the 10% overload state for more than 25 hours per year [37, 38].

Table 5.6: DGS Component General Technical Information

Ref. #	Prime Unlimited Time Running Power Fuel Consumption @ % Capacity (L/hr)				Engine Fuel Displacement (L)	Intercept Coefficient ($L/hr/kW_{rated}$)	Slope ($L/hr/kW_{o/p}$)
	25	50	75	100			
DG1	-	16	22	27.7	4.4	.04350	0.2340
DG2	14	24	35	48	8.3	0.01333	0.3013
DG3	-	23.4	32	41.3	6.8	0.03473	0.2310
DG4	-	26	37	49	6.6	0.01619	0.2629
DG5	20.1	32.6	41.2	51	6.6	0.06056	0.2251
DG6	15	28	41	56	8.3	0.00500	0.2720
DG7	-	27.9	40.3	54.4	8.7	0.005076	0.2409
DG8	21	41	58	70	8.8	0.02600	0.2624
DG9	-	48	67	87	12.5	0.02944	0.2600
DG10	-	48	67	87	12.5	0.02524	0.2229
DG11	-	48	69	94	12.5	0.003333	0.2300
DG12	35.5	60.8	84.5	108	15.0	0.02644	0.2144
DG13	-	60	90	122	16.12	-0.00080	0.2432
DG14	-	79	124	146	15.2	0.02879	0.2436
DG15	-	79	112	145	15.2	0.02167	0.2200
DG16	58	102	145	186	23.15	0.02000	0.2135
DG17	-	-	151	202	30.48	-0.00085	0.2243
DG18	66	119	177	240	30.48	0.0055	0.2320
DG19	89	157	222	291	50.3	0.01760	0.2147

Table 5.7 demonstrates the cost of the unit, fuel tank, enclosure, shipping, miscellaneous, net CC, RC, and the O&M for the respective DG units on a per unit basis.

Table 5.7: DGS Component Cost Information

Ref. #	CC ($)	Fuel Tank ($)*	Encl. Cost ($)	Ship Costs ($)	Misc. Costs ($)	Net CC ($)	RC ($)	O&M ($/hr)
DG1	18,599	4.0	5,589	4035	7440	39662	22555	1.20
DG2	25,999	7.5	5,589	5640	10400	55128	31529	1.80
DG3	34,999	6.0	5,589	7593	14000	68180	42443	1.86
DG4	25,999	6.0	5,589	5640	10400	53628	31529	2.10
DG5	35,000	inc.	5,589	7593	14000	62182	42445	2.16
DG6	34,299	6.0	5,589	7441	13720	67048	41595	2.40
DG7	32,999	6.0	9,279	7159	13200	68636	40018	2.64
DG8	35,699	7.0	5,589	7745	14280	70312	43292	3.00
DG9	40,999	6.0	9,279	8894	16400	81572	49720	3.60
DG10	46,999	11.0	9,279	10196	18800	96274	56996	4.20
DG11	62,999	11.0	9,279	13667	25200	122145	76399	4.80
DG12	62,999	12.0	9,279	13667	25200	123145	76399	5.40
DG13	71,999	16.0	9,279	15619	28800	141697	87314	6.00
DG14	59,999	16.0	9,279	13016	24000	122294	72761	6.60
DG15	99,999	21.0	9,279	21694	40000	191971	121269	7.20
DG16	149,999	20.0	9,279	32541	60000	271818	181904	9.60
DG17	154,999	20.0	9,279	33625	62000	279903	187968	10.80
DG18	199,999	30.0	9,279	43388	80000	362665	242540	12.00
DG19	229,999	40.0	9,279	49896	92000	421173	278921	15.00

5.5 Simulation Methodology

The quantity of DGs utilized per simulation varies depending upon their rated capacity. Each DG utilized in a given simulation will include cases that represent: no units, 1 unit, and then multiple units until the maximum capacity of 1,258 kW is met. These selected DGs, of various rated capacities, will then be combined and simulated to determine the ideal system.

The specific fuel consumption calculation performed by HOMER, which demonstrates the average amount of fuel consumed by the generator per the kWh of electricity that it generates, is demonstrated by Equation 5.2 [15].

$$F_{spec} = \frac{F_{total}}{E_{gen}} \tag{5.2}$$

Metric	Description	Units
F_{spec}	Specific fuel consumption	L/kWh
F_{total}	Total annual DG fuel consumption	L/yr
E_{gen}	Total annual DG electrical production	kWh/yr

The annual cost of fuel required to operate the DGS is determined by multiplying the price of fuel ($/L) by the amount of fuel (L) used in a calendar year. The DGS is the only generator type that requires an external fuel source studied in this thesis. This factor also contributes towards higher unit O&M costs. The diesel fuel used for the purpose of power generation in this thesis is characterized by the fuel properties listed in Table 5.8. The price of fuel for the purpose of simulation is 1.76 $/L as derived in Section 2.5.

Table 5.8: Diesel Fuel Properties

Description	Value	Unit
Lower Heating Value	43.2	MJ/kg
Density	820	kg/m^3
Carbon Content	88	%
Sulfur Content	0.33	%

The fuel curve demonstrates the marginal fuel consumption of the generator as a linear function of the output power versus the fuel consumption in L/hr. The fuel consumption data is modelled using the linear least-squares method and the resulting linear function is the line of best fit. This linear function is deemed valid as it represents the majority of constant-speed internal combustion generators. The fuel curve intercept coefficient is the no-load or idling fuel consumption rate of the generator divided by the rated capacity and is representative of the y-intercept of the slope of the fuel curve divided by the rated output. For example if a 650 kW DG consumes 10 L/hr when generating an output of 260 kW and 20 L/hr at its rated output, the fuel curve slope is .0256 L/hr/kW ([20 L/hr - 10 L/hr]/[650 kW - 260 kW] = [10 L/hr]/[390 kW] = .0256 L/hr/kW) as per a linear function. The fuel curve intercept coefficient of 0.0256 L/hr/kW is 0.005114 L/hr/kW. Equation 5.3 demonstrates the fuel consumption of the DGS for a given hour of operation provided that the DGS is operational [15].

$$F = F_0 * Y_{gen} + F_1 * P_{gen} \tag{5.3}$$

Metric	Description	Unit
F	Fuel consumption this hour	L
F_0	Generator fuel curve intercept coefficient	$L/(h*kW_{rated})$
F_1	Generator fuel curve slope	L/(h*kW)
Y_{gen}	Rated capacity of the generator	kW
P_{gen}	Output of the generator in this hour	kW

Equation 5.4 demonstrates the electrical efficiency of the DG using the fuel consumption calculation as described by Equation 5.3 [15]. The co-efficient of 3,600 represents the conversion of 1 kWh being equal to 3.6 MJ and the calculation is done in Litres.

$$\eta_{gen} = \frac{3,600 * P_{gen}}{\rho_{fuel} * F * LHV_{fuel}} \tag{5.4}$$

Metric	Variable	Unit
η_{gen}	Generator efficiency	%
ρ_{fuel}	Fuel density	kg/m^3
LHV_{fuel}	Lower Heating Value	MJ/kg

HOMER's synthetic or mathematical DG model was formulated from the results of Equations 5.1, 5.2, 5.3, and 5.4. This synthetic model was verified from field or actual results upon its development. It was found by NREL that the synthetic data representing the fuel consumption and generator run time is typically within a 5% tolerance range when compared to actual data. The margin between synthetic and actual costs is typically less than 2%. This indicates that the simulated results are within an acceptable margin of error [15].

5.6 Simulation Results

Using the 19 selected DGs a total of 227 DGS were simulated as per the one line diagram in Section 5.3. A complete list of simulation results is available in Appendix A. Table 5.9 summarizes the variables that were selected for the simulation process. All of the studied systems in this Section were investigated over a 25 year period which is reflected by the NPV.

Table 5.9: DGS Simulation Variable Summary

Variable	**Value**	**Units**
Target Capacity:	1144	kW
Capacity Range:	1030 - 1258	kW
Number of DG in DGS:	2 or 3	-
DG Lifetime:	30,000	hours
Diesel Price:	1.76	$/L
Annual Interest Rate:	0.983	%
Overall System Life:	25	years

The number of DGs selected was based upon results from other remote communities across Northern Canada. In the NWT it was found that the average community DGS was operated from 3 DG and as such the same value was chosen in this simulation. Two unit DGS were also considered and in both cases the installed capacity met the required total. The three unit DGS is also preferred to allow for a first contingency and redundancy within the system energy portfolio. The dispatch schedule for all of the selected DGS was set to optimized and to allow for load following [16]. The simulation allows for systems with multiple generators and allows for multiple generators to operate simultaneously. The generator capacity must be greater than peak load which is also enforced due to the installed capacity criterion. Table 5.10 demonstrates the selected optimal result of the 227 simulated DGS cases. This selected case was chosen based upon all available metrics and is the base case that will be used throughout the remainder of this thesis. The base case is case 188 and consists of 500 kW, 400 kW, and 220 kW DGs which operate for 125, 5,245, and 4,110 hours per year respectively.

Table 5.10: Optimal Simulated Results for DGS

System Type	**Initial Capital** ($)	**O&M** ($/yr)	**Total NPV** ($)	**COE** ($/kWh)	**Ren. Frac.** (%)	**Diesel Cons.** (L)
D	332,478	913,856	20,500,828	0.451	0.00	491,813
System Type	**Unit Ref. #**	**Quan.**	**Size (kW)**	**Time (hr)**	**kWh/yr**	**% Gen.**
D	DG7	1	220	4,110	532,899	26
	DG11	1	400	5,245	1,483,744	72
	DG13	1	500	125	43,768	2

Over the 25 year life cycle chosen for the project DG7 and DG11 will need to be replaced 3 and 4 times respectively. DG13 will not require replacement during the simulated period. Fuel costs remain the highest yearly expenditure of the system and these costs are the main component of yearly operational costs. Both fuel costs and O&M costs are remain relatively consistent over the life of the project. It should be noted that depending on the type of contract procured by the community as well as the global markets the price of fuel may fluctuate during the 25 year period in all cases running DG units. Table 5.11 indicates the economic summary of the system in both NPV and annualized cash flows. The O&M defined in Table 5.10 is calculated from the annualized cash flows as RC+O&M+Fuel-SV. The COE is calculated, as per Equation 3.14, to be: COE = (928,921/2,060,416) = 0.451 \$/kWh.

Table 5.11: System Economic Summary

Cost Type	**CC (\$)**	**RC (\$)**	**O&M (\$)**	**Fuel (\$)**	**SV (\$)**	**Total (\$)**
NPV	332,478	370,480	811,637	19,103,144	116,908	**20,500,830**
Annualized	15,065	16,787	36,776	865,590	5,297	**928,921**
AC Primary Load Consumption:			2,060,416		kWh/year	

Table 5.12 summarizes the operational, electrical, and fuel variables for the optimal D system.

Table 5.12: Additional Generator Results for Optimal Case

Metric	Quantity	Unit	Metric	Quantity	Unit
D System: DG7					
Operational Variables			**Electrical Variables**		
Hours of Op.	4,110	hr/yr	Mean Elec. o/p	130	kW
Number of Starts	751	#/yr	Min. Elec. o/p	66.0	kW
Operational Life	7.30	yr	Max. Elec. o/p	196	kW
Capacity Factor	27.7	%	**Fuel Variables**		
Fixed Gen. Cost	5.94	$/hr	Fuel Consumption	132,965	L/yr
Marg. Gen. Cost	0.424	$/kWh	Specific Fuel Cons.	0.250	LWh/y
Electrical Variables			Fuel Energy i/p	1,308,372	kWh/y
Elec. Production	532,899	kWh/y	Mean Elec. Effic.	40.7	%
D System: DG11					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	5,245	hr/yr	Mean Elec. o/p	283	kW
Number of Starts	499	#/yr	Min. Elec. o/p	196	kW
Operational Life	5.72	yr	Max. Elec. o/p	400	kW
Capacity Factor	42.3	%	**Fuel Variables**		
Fixed Gen. Cost	9.69	$/hr	Fuel Consumption	348,254	L/yr
Marg. Gen. Cost	0.405	$/kWh	Specific Fuel Cons.	0.325	LWh/y
Electrical Variables			Fuel Energy i/p	3,426,813	kWh/y
Elec. Production	1,483,744	kWh/y	Mean Elec. Effic.	43.3	%
D System: DG13					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	125	hr/yr	Mean Elec. o/p	350	kW
Number of Starts	116	#/yr	Min. Elec. o/p	164	kW
Operational Life	240	yr	Max. Elec. o/p	374	kW
Capacity Factor	0.999	%	**Fuel Variables**		
Fixed Gen. Cost	8.21	$/hr	Fuel Consumption	10,594	L/yr
Marg. Gen. Cost	0.428	$/kWh	Specific Fuel Cons.	0.242	LWh/y
Electrical Variables			Fuel Energy i/p	104,248	kWh/y
Elec. Production	43,768	kWh/y	Mean Elec. Effic.	42.0	%

Chapter 6

Solar Energy Conversion Systems

This Chapter begins with a brief introduction to the topic of Solar Energy Conversion Systems (SECS) in Section 6.1. The climatic data associated with the system model that pertains to solar energy is introduced and explained in Section 6.2. The architecture of the SECS is explored so that a fundamental knowledge is obtained in Sections 6.3 and 6.4. Using the knowledge developed from the introduction and architecture of the SECSs, along with the applicable climatic data, multiple implementable systems are designed and detailed in Sections 6.5 and 6.6 which conform to the system model. These systems are simulated using the methodologies introduced in Section 7.7 and the Chapter is concluded by an economical and technical analysis derived from the simulation results in Section 6.8. Appendix F contains additional climatic information that includes a more detailed look at the system model's solar resources and experienced extraterrestrial radiation. Appendix F also includes additional solar generator technical specifications for the individual units, summaries, and costing information. Appendix I provides additional information as it relates to the SECS with a focus on solar energy and astronomical terminology.

6.1 Solar Energy Conversion Systems (SECS)

Solar and solar based energies are created by the sun and how it interacts with the earth. To have a complete understanding of how the earth interacts with the sun a few fundamental astronomical principles are introduced. These topics can be summarized by two commonly used co-ordinate systems which consist of the equatorial and horizon co-ordinate systems. Both of these co-ordinate systems are used to explore the earths' position with respect to the solar system around it which is beneficial for a fundamental understanding of solar energy. These concepts are explored in Appendix I.

Northern Ontario and the majority of communities studied are far removed from the North celestial pole and are not affected by the long periods of constant daylight or darkness. As demonstrated in Appendix I the optimal location on the earth's surface to capture solar radiation is near the equator. However, since the analysis is being performed at a Northern latitude the Solar Energy Conversion System (SECS) will have lower potential than a more Southern location. The peak months for solar radiation occur during the summer months which translates into a higher power output potential during this time. It can be seen from Table 2.25 that during the winter months the community consumes more electrical energy than during the summer. At present there are few solar installations located in Northern Canada in part due to the seemingly unsuitability of the Northern latitude and the typically high capital costs associated with all aspects of the SECS. Some applicable literature is reviewed in Section 6.3 regarding a comparison of solar panels installed at various azimuths in Japan and an overview of one of the only existing solar projects in the North located in Nunavut. This Chapter explores the implementation of a SECS within the community both with and without a storage median when determining the economical viability of the SECS project. Due to the complexity associated with SECSs the studied case assumes that solar tracking is not applicable at present, the solar panels are directed towards a constant Southern azimuth, and the pitch of the solar panels are both constant and directly related to the latitude. These simplifications are typical of installations at a Northern latitude due to the relative proximity to the North celestial pole. The panels are installed on an angle to maximize solar capabilities and minimize snow and ice build-up.

Section 6.2 introduces solar energy climatic values that were determined and presented as part of the system model. In addition to the climatic variables presented in Table 6.3 detailed in Section 6.2 the concept of albedo effect is important to consider and can have a relatively significant impact on the functionality of the system. The albedo effect is defined as the ability of an object, typically the ground, to reflect light. The albedo is a unitless value that ranges between 0 to 1 or dark to bright. Some common albedo values for typically encountered surfaces are listed in Table 6.1. It can be seen that the best reflective surface is fresh snow fall with an albedo ranging between 0.80 to 0.90. With the exception of ocean ice the albedo of fresh snow fall is significantly higher than any other surface. Due to the climate of Northern Ontario the albedo effect could have a significant impact on solar photovoltaic generation and the optimal placement of the solar panels.

Table 6.1: Common Albedo Values [9]

Surface Type	Albedo Value	Surface Type	Albedo Value
New Asphalt	0.04	Green Grass	0.25
Old Asphalt	0.12	Desert Sand	0.40
Conifer Forest	0.08 to 0.15	New Concrete	0.55
Deciduous Forest	0.15 to 0.18	Ocean Ice	0.50 to 0.70
Soil	0.17	Fresh Snow	0.80 to 0.90

Both SECS and WECS are also subject to provincial legislation including initiatives introduced in the 2009 Green Energy and Green Economy Act (GEGEA) also known as Bill 150 and the 2009 Renewable Energy Approval Act (REA). The GEGEA repealed the 2006 Energy Conservation Leadership Act and the Energy Efficiency Act and amended numerous other provincial regulations. The purpose of the GEGEA was to promote renewable resources in ON, to produce quicker development of renewable energy projects in ON, and to promote a green economy within ON. The REA provides the framework developed by the Ministry of the Environment that incorporates the requirements set out by the MOE and the Municipal Planning Act to provide a consistent methodology for renewable energy project analysis. The REA is utilized by the province of ON as the current method to determine the approval framework for renewable projects. This process is used by the provincial ministries of interest to determine potential impacts of the proposed renewable energy project to the environment, public safety, and public health [21, 40, 41].

In accordance with the REA SECS can be classified as facilities categorized as class 1 through class 3. It should be noted that all SECS mounted to a structure may be subject to local or municipal building permits. Table 6.2 summarizes the REA classes for SECS. For Class 3 SECS a noise study is required to demonstrate that the proposed SECS does not exceed 40 dB and that it does not impact nearby infrastructure due to electrical noise. The acceptable installation distance for the SECS will be determined based upon the noise study and the nearest residence or other existing infrastructure [40, 41].

Table 6.2: SECS REA Classifications

Metric	Class 1	Class 2	Class 3
Size	> 10 kW	≤ 10 kW	> 10 kW
Installation	Roof or Wall	Any	Ground
REA Required	No	No	Yes
Certificate of Approval Required	No	No	N/A
Other	N/A	N/A	Noise Study

In conjunction with provincial requirements proposed SECS must also abide by federal regulations. Some additional organizations that should be considered during the planning stages include [40, 41]:

- Environment Canada - An assessment of the potential impact to migratory birds and their natural habitat

- Parks Canada - If the SECS is to be built on federal land owned by Parks Canada, or if it has the potential to affect a national park, national park reserve, national historic site, or historic canal or national marine conservation areas.

- Canadian Environmental Assessment Agency (CEAA) - May be required if the federal government provided financial assistance, crown lands are involved, additional permits/licences are required, the federal government is a stake holder in the SECS, et cetera.

- Natural Resources Canada

- The local conservation authority or the Ministry of Natural Resources if there is no local conservation authority. SECS installations that may affect fish and fish habitats are to be reported to the conservation authority.

- Fisheries and Oceans Canada (DFO) - SECS that require additional study of fish and fish habitats under the Fisheries Act, Canadian Environmental Assessment Agency (CEAA), or Species at Risk Act (SARA) are investigated by the DFO.

The above organizations and ministries provide an outline as to the requirements of SECS installations under the existing REA and GEGEA however additional research should be done during the planning stages of SECS development. In addition to the provincial and federal guidelines there may be municipal bylaws that must also be considered. Installations on cultural or natural heritage sites must also be assessed separately. In accordance to the Endangered Species Act, 2007 all renewable energy projects must be assessed to determine if they endanger or potentially could endanger any protected species or their habitats. The MNR should be consulted if there are potential negative effects. All renewable projects must meet a minimum setback distance of 120 m from any nearby water of body, such as lakes, streams, and seepage areas. If the proposed installation location is less than 120 m from the body of water a water report must be completed addressing any negative environmental effects. Renewable energy projects cannot generally be located on shoreline areas subject to hazards from flooding, erosion, dynamic beach action, or on hazardous sites. Generally new renewable projects are not permitted in provincial parks or conservation areas however for use in the remote communities it is allowable provided that it can be demonstrated to the MNR that there are no reasonable alternatives, all reasonable measures will be undertaken to minimize harm to the environment, and ecological integrity will be protected. Additionally, there may be additional considerations or requirements in place for installations in the far north as dictated by the MNR under the Far North Land Use Planning Initiative depending on the project specifics [9, 14, 21, 40, 41].

6.2 Climatic Data Analysis

A climatic data analysis is required due to the vast area and localized climatic differences across Northern Ontario. The following information was obtained in the form of monthly averages to perform the climatic data analysis with respect to solar energy: heating and cooling degree-days, extraterrestrial irradiance, global horizontal irradiance, direct normal irradiance, diffused horizontal irradiance, global horizontal illuminance, direct normal illuminance, diffused horizontal illuminance, minutes of sunshine, rainfall, and snowfall for a collection of locations across Northern Ontario. The analysis was conducted using data made publicly available from Environment Canada and the Ministry of Natural Resources.

Irradiance is the measure of intensity of solar energy as it propagates towards the earth. The extraterrestrial irradiance, measured in kJ/m^2, indicates the amount of solar energy that is received at the top of the atmosphere during the indicated solar hour. The value provided is based on the solar constant of 1367 W/m^2 and during the night there is no significant extraterrestrial irradiance. The monthly averages that were calculated for all provided data sets was calculated used all 24 hours to find a true daily average which were then averaged for the total period to find the overall monthly average. The monthly average daily total and hourly extraterrestrial solar radiation received on a horizontal surface is denoted as $\overline{H}_o$ and $\overline{I}_o$ respectively. The global horizontal irradiance, measured in kJ/m^2, indicates the total of both the direct and diffused radiant energy that is received on a horizontal surface during the indicated time period. The values provided in the data were converted from local apparent time (solar time) to local standard time. On average about 30% of the original extraterrestrial irradiance is reflected or dissipated as it passes through the atmosphere. The global horizontal irradiances is primarily dependent upon cloud cover at any given time and the thickness of the atmosphere over an area. The equator has a much higher global horizontal irradiance value when compared with locations closer to the celestial poles. Direct normal irradiance, measured in kJ/m^2, is the amount of radiant energy that is received directly from the sun during the indicated period. The values in the raw data were estimated from the solar global horizontal irradiance. The diffused horizontal irradiance, measured in kJ/m^2, is the amount of radiant energy received on a horizontal surface indirectly from the sky. The values provided in the data were also converted from local apparent time (solar time) to local standard time. The radiation reflected from the ground is dependent upon the albedo effect. To summarize the total solar radiation received on a surface is a combination the direct, diffused, and ground reflected radiation and can be denoted as G_o. The above variables measured in kJ/m^2 indicate data that was integrated over an hourly period per unit area. The monthly average daily total and hourly radiation on a horizontal surface is denoted as $\overline{H}$ and $\overline{I}$ respectively. These variables can also be provided in the form of kWh/m^2 where the ratio of 1 Wh is equal to 3.6 kJ can be applied. The instantaneous irradiance is typically denoted by 'G' and is measured in W/m^2.

Illuminance is the total amount of light incident on a surface of a given size. The units of illuminance are lux or $\frac{lumens}{m^2}$. The global horizontal, direct normal, and diffused horizontal illuminance values are measured in klux and relate to their respective irradiance value. The minutes of sunshine are also converted from local apparent time (solar time) to local standard time. The raw data provided the minutes of sunshine per an hour and the calculated average is the average number of minutes per an hour during the given month.

Table 6.4 summarizes the variables listed in Table 6.3. The variables labelled as 101 through 110 are the median of the monthly averages of the CWEEDS data for the available communities listed in Table 2.13. The variable labelled R101 is provided as a daily average for the available stations listed in Table 2.13 under the heading of RETs. The clearness index is a calculated variable which is described in more detail below. All related graphs, summarized data, and raw data are available in Appendicies A and B.

These summarized values were used to represent the system model's solar energy variables. For the summarized extraterrestrial irradiance values the monthly averages recorded in Atikokan were neglected as the extraterrestrial irradiance was significantly higher at the station compared to any other location for November and December as shown on the monthly average extraterrestrial irradiance across Northern Ontario graph. The graphs demonstrating the monthly averages of the variables denoted by Table 6.3 across Northern Ontario can be found in Appendix B.

The Clearness Index (CI) is a dimensionless measure that ranges from 0 to 1 and indicates the clearness of the atmosphere. The monthly average CI typically ranges between 0.25 and 0.75 which can occur as an example during a cloudy month such as December in London, UK and a sunny month such as June in Arizona, USA respectively. The CI is the fraction of the solar irradiance that is transmitted through the atmosphere that reaches the Earth's surface and can be calculated by dividing the total extraterrestrial radiation by the total surface radiation. The CI approaches 1 when clear, sunny conditions are prevalent and conversely approaches zero under cloudy conditions. Table 6.3 demonstrates the monthly average CI, denoted by the variable K_t, as experienced by the system model. The CI is calculated based upon the daily horizontal solar radiation and the respective community co-ordinates [15].

Table 6.3: Climatic Data Variables [3, 9]

Field	Description	Unit
101 [9]	Extraterrestrial Irradiance	kJ/m^2
102 [9]	Global Horizontal Irradiance	kJ/m^2
103 [9]	Direct Normal Irradiance	kJ/m^2
104 [9]	Diffused Horizontal Irradiance	kJ/m^2
105 [9]	Global Horizontal Illuminance	klux
106 [9]	Direct Normal Illuminance	klux
107 [9]	Diffused Horizontal Illuminance	klux
110 [9]	Minutes of Sunshine per Day	min
R101 [3]	Daily Horizontal Solar Radiation	$kWh/m^2/day$
K_t [15]	Clearness Index	Dimensionless

Table 6.4: Solar Energy Climatic Variables [3, 9]

	Climate Parameter									
	101	102	103	104	105	106	107	110	R101	K_t
Jan.	383.14	211.6	421.63	112.12	64.60	106.17	38.19	7.77	1.31	.539
Feb.	612.39	370.0	589.06	183.19	114.64	155.97	61.97	10.90	2.28	.587
Mar.	955.16	601.7	734.60	294.29	188.07	201.36	98.16	12.80	3.59	.583
Apr.	1320.76	764.2	807.32	361.16	239.88	235.92	116.46	14.09	4.82	.555
May	1601.76	84.8	82.48	34.82	26.50	24.86	11.62	1.63	5.47	.513
June	1728.63	87.2	83.67	37.51	27.33	23.96	12.47	1.92	5.64	.489
July	1666.35	84.5	84.34	36.04	26.46	23.67	12.03	1.89	5.55	.501
Aug.	1434.00	689.6	741.56	300.10	216.24	213.07	100.06	16.06	4.62	.491
Sept.	1098.94	478.4	516.40	231.10	150.42	138.94	77.07	10.44	3.14	.448
Oct.	750.86	309.4	379.75	161.77	96.46	106.89	53.70	7.89	1.99	.438
Nov.	465.00	177.7	238.42	116.10	55.26	57.62	38.43	4.31	1.25	.455
Dec.	317.34	156.0	323.43	88.95	47.29	77.59	30.27	5.88	0.99	.490
Avg.	1027.86	334.6	414.96	163.10	104.43	113.84	54.20	7.97	3.39	.507

6.3 Technical Considerations

Solar energy is converted to electrical energy through the photovoltaic effect within the solar cell. The solar cell is typically constructed of an ultra-thin layer of phosphorous doped or n-type silicon which is separated from a thicker layer of boron-doped or p-type silicon by a p-n junction. These layers of silicon are placed on a metal base and inter-connections are made to connect solar cells together and to provide external connections. The solar cells are inter-connected to form a module. These modules are in turn inter-connected to form a panel which are then inter-connected to form a solar array [42]. Table 6.5 demonstrates various characteristics of the different components in the SECS.

Component	Voltage (V)	Current (A)	Power (W)	Size
Cell	0.5	5-6	2-3	about 10 cm
Module	20-30	5-6	100-200	about 1 m
Array	200-300	50-200	10-50kW	about 30 m

Table 6.5: Typical SECS Architecture

The use of solar energy to date has been minimal across Northern Ontario and the far North. There has been small scale development in the YT and NU of SECS and nothing of significance in the NWT and N ON.

In the Yukon the YEC has begun investigating solar photovoltaic hybrid systems as green energy replacements in remote communities. The initial project funded by YEC in 1999, entitled The Yukon Energy Portable Solar-Hybrid Project, has continued to be used to provide a proof of concept to Yukoners that solar energy is a viable option for power generation. This project was developed for small-scale residential use for non heat related loads to help offset the power required for an individual household. The general installation of this system is that it is to be placed in a southerly facing shade free level area which minimizes the low level maintenance required throughout the year. Solar energy is also used at the Wind Energy Conversion Systems (WECS) sites near Whitehorse, YT to provide energy to the control and heating systems of the turbines. Although there has been some exposure to SECS across the YT it has only been small scale implementations to date which serve a different purpose than the SECS studied in this thesis. Long term results of installed systems are also not available from which feasibility analysis could be derived.

In NU there have been two solar projects that have been implemented to date [7]. The first project was the Solarwall Demonstration Project which was installed near Rankin Inlet in 2001. This project was funded by the government of Nunavut and NRCan and is comprised of solar technology that pre-heats air before it is drawn into the building's heating and ventilation systems. This form of passive solar energy use is promising to reduce energy consumption however being as the scope of study of this thesis is electrical power generation this project was not investigated in depth. The second project was comprised of two solar photovoltaic (PV) panels that were installed at the Arctic College located in Iqaluit, NU in 1995. This project was conceived in 1993 and installation was completed in the summer of 1995. It was sponsored by NRCan, the Arctic College, the government of Nunavut, and local partners and it was designed to offset the power required by the college which is connected to the local power system. The objective of the project was to gain experience with solar PV in the far North, decrease the power required to operate the college campus, and to determine if it is a realistic future alternative to diesel based power generation in the North.

The research team in [4] explore the College's system operation in 2000 after five years of service. The solar panels were installed on vertical surface facing W 30° S at 63.4° N. The 3.2 kWp (kWp is rated power or peak kilowatt output measured under standard test conditions) array is made from two sub-arrays connected in parallel. These sub-arrays, denoted by SO and SS, are provided by different manufacturers and are both of a mono-crystalline Si construction. Table 6.6 demonstrates the individual characteristics of the sub-arrays at nominal conditions.

Table 6.6: Characteristics of the Two PV Modules at Nominal Conditions [4] (T = 25ºC and P=1000 W/m²)

Module	Rating (W)	Area (m^2)	V_{MPP} (V)	I_{MPP} (A)	V_{OC} (V)	I_{SC} (A)
SS	53	0.4267	17.4	3.05	21.7	3.4
SO	53	0.4225	17.1	3.1	20.3	3.4

The overall size of the 3.2 kWp array is 25.62 m^2 and the associated dispatch schedule dictates that whenever possible the solar array is used to displace diesel generation and that there is no storage available on the system. Multiple environmental variables were recorded on site however these devises were negatively impacted by extreme temperatures experienced. The original recording instruments were also questioned due to the materials used internally to sense solar irradiance as a result of the lower angles of penetration and an altered spectral composition of the solar irradiance. It was also found that one of the sensors constantly overestimated the monthly solar irradiance. Over the five year period additional sensors were installed to verify existing results and periodic maintenance and calibration was performed. The installed system at Arctic College is explored more in-depth later in this Section.

Due to the relatively extreme Northern latitudes of both the proposed and existing SECS in Canada the tilt angle and composition of various solar arrays were investigated as demonstrated at Shiga, Japan in an installed 80 kWp experimental development. Typically solar cells are installed facing a Southerly azimuth as the highest annual solar irradiation is experienced in this direction. However due to an increasing interest in solar PV an attempt to provide more viable surface area for larger scale SECS additional azimuths of installation are considered. The 80 kWp trial project installed on the roof of the ROHM plaza at Ritsumeikan University in February 2000 (N 34°58', E 135°57') consisted of four different solar arrays located on three different surfaces as studied between April 2002 and March 2003. Table 6.7 indicates the direction, size, tilt, and Field Output Factor (FOF) of the four installed solar arrays. The FOF is defined as the percentage of normalized accumulated output divided by the accumulated irradiation. The types of solar arrays are denoted as: single crystalline silicon (c-Si), amorphous silicon (a-Si), and polycrystalline silicon (poly-Si). The DC output from each of the four arrays is converted into AC and connected to the local utility. Similar to the SECS installed at the Arctic College, NU the application of the small scale SECS is to both provide the local building with electrical energy to operate required services while offsetting the amount of electricity required from the utility and to provide technical insight into the application of SECS. The installed system at Shiga, Japan is explored more in-depth later in this Section with only the raw output being examined and not the overall system response.

Table 6.7: Summary of Different Si Based Solar Cells Installed at Different Azimuths [43]

Direction	Type	Size (kW)	Tilt (º)	FOF (%)
North	poly-Si	30	26.5	84.8
	a-Si	5	26.5	103.2
South	c-Si	40	26.5	86.3
Horizontal	a-Si	5	5 (due W)	96.7

Figure 6.1 demonstrates the mean daily irradiance and temperatures exhibited at the Arctic College SECS installation from April 1995 to August 2000. It can be seen that the solar irradiance and temperature follows a reoccurring yearly trend with the maximum irradiance and temperature occurring in April and July to August respectively. The temperature ranges between -30°C and 10°C and the annual solar irradiance experienced by the panel varies between 26.1 and 28.7 MWh/year. The solar irradiance is negligible in December and the solar irradiation exhibits the strong seasonal variations due to the proximity to the Northern celestial pole. The indicated LiCor label indicates the Li-Cor pyranometers sensor units that were installed for system monitoring purposes. It should be noted that initially in 1996 there were a few new construction issues that slightly skewed the cumulative data results. It was found that the LiCor units over estimated the irradiance particularly in low light level conditions (winters in particular) and as a solution an eppley pyranometer was installed. It was determined that the average annual over-estimation was approximately 25%.

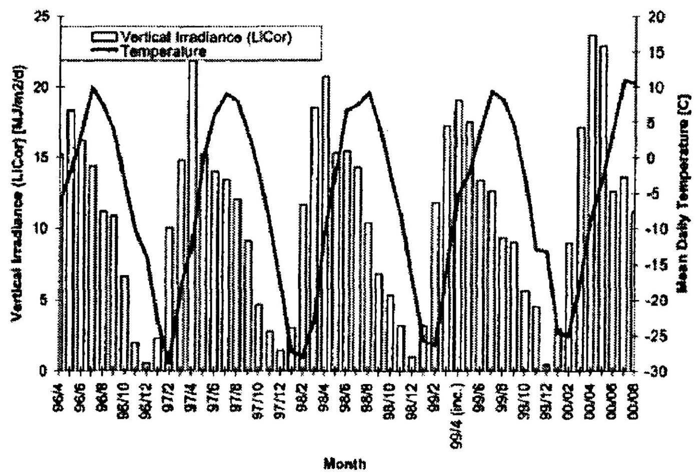

Figure 6.1: Arctic College Mean Daily Irradiance and Temperature [4]

Figure 6.2 demonstrates the DC output and efficiency of the array over the four year period. As expected the array output follows the seasonal patterns as previously introduced. The monthly array output varied between 513 kWh in April 1997 to 3.4 kWh in December 1999. However, on a yearly basis the array's output can be considered constant at 2.6 ± 0.2 MWh. The maximum efficiency of the array occurs between February and April. This is due to the increased availability of the solar irradiance and the relatively low temperatures as seen in Figure 6.1 which produces optimal operational conditions. The efficiency of the array decreases between June and November primarily due to the increased temperatures of operation. Due to the significant decrease of efficiency in the month of December it is considered negligible for energy production. The efficiency of the array averages between 7.4 and 11.2% from January to November. It can be seen from Figure 6.2 that the overall efficiency of the array decreases slightly over time as the array ages. It is believed that this decrease in yearly efficiency was possibly due to drifting of the sensors and the increased age of the cells.

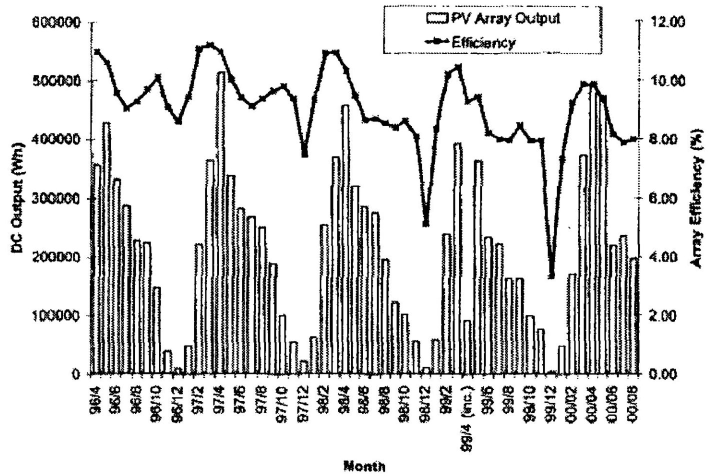

Figure 6.2: Arctic College PV Array DC Output and Efficiency [4]

Figure 6.3 demonstrates the efficiency of the two sub-arrays. Both the SO and SS sub-arrays exhibited similar nominal module efficiencies as seen in Table 6.6. However, as can be seen from Figure 6.3 in practise that the efficiency of SS is consistently about 2 to 3% more efficient than SO. After extensive investigation it was determined that SO fails to perform as expected in accordance to the manufacturers provided data and that there were no calibration or installation errors. This re-affirms that not only may technical devices experience lower operational efficiencies in the North but that they may also fail to operate at the expected capacity. Due to the high capital costs involved and the relatively small demand in the North it is important to ensure that the devices operate as expected.

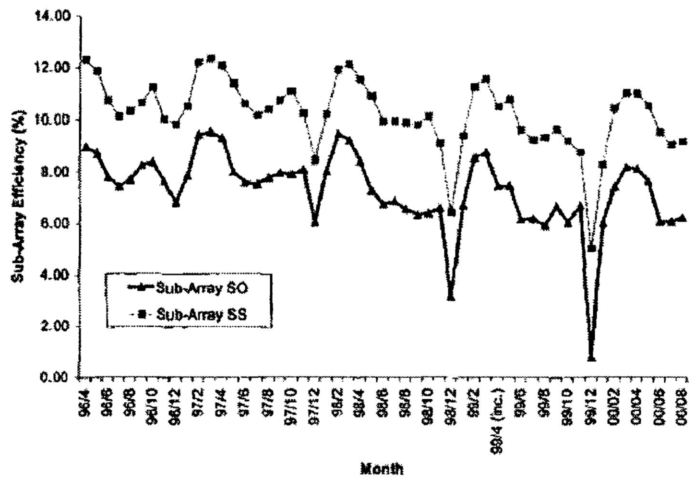

Figure 6.3: Arctic College Sub-Array Efficiency [4]

The inverting unit was found to behave as predicted and experienced a maximum efficiency of roughly 90% when the input power was 2 kW DC. The annual average efficiency of the inverter was 81%. When the input power drops below 500 W DC the efficiency of the unit decreases significantly. The efficiency metrics determined in Section 3.5 from current utility grade rectifiers and inverters suggest similar responses as those found in the Arctic College installation which was installed 16 years ago. The notable difference is between the documented inverter efficiency metrics and the experienced maximum efficiency found above. The studied utility inverters have a maximum documented efficiency ranging from 94% to 98% depending on the unit size and manufacturer. A maximum inverter efficiency of 96% was selected for the purpose of simulation as it was determined to be the average value of the studied products. The inverter was optimized for the designed range of the array and is obviously poor in low power conditions. There is also power drawn by the inverter that is required for operation which offsets the relative DC power and efficiency relationship by roughly 35 W. However this does explain the significant decrease in the unit efficiency during the month of December. There were advanced dispatch techniques used to enhance the efficiency of the inverter which are out of the scope of this thesis. Figure 6.4 demonstrates the monthly system AC output and efficiency when the system when considered in its entirety. The system delivered between 1.943 and 2.131 MWh on a yearly basis and the peak production period occurring in April 1997 at 429.2 MWh. During the winter months the production becomes very small or as seen in Figure 6.4 the AC output in December of 1999 was -5.7 kWh. The AC output was negative in December of 1999 as the inverter required more energy to operate than generated by the DC solar array. As such the array consumed more energy than it fed back into the power system. The effects of this would be considerably minimized in an installation located in Northern Ontario due to the increase in distance from the Northern celestial pole. However the winter period output in Northern Ontario will also suffer due to poor operational conditions.

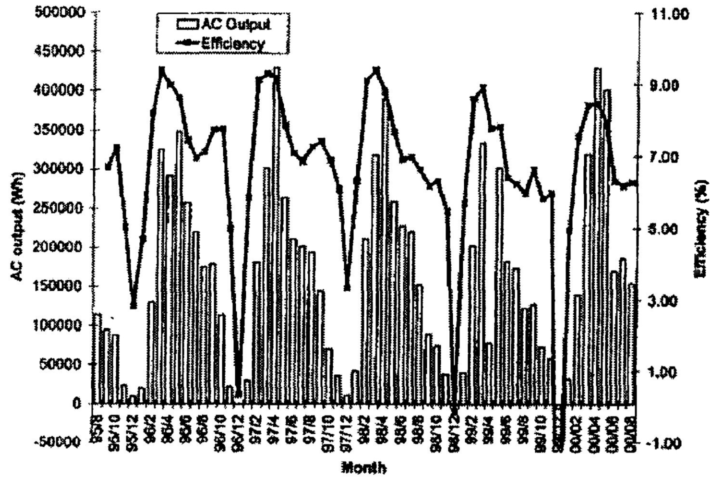

Figure 6.4: Arctic College Monthly System AC Output and Efficiency [4]

Figure 6.5 demonstrates the hourly system output versus the incident radiation from January to August 2000 when solar irradiance levels were greater than 60 W/m^2. The system output is virtually linear with an r-squared value of 0.98 which can be demonstrated by $AC_{output} = 0.094$ x Incident Radiation - 150, where both the AC output and incident radiation are expressed in Wh. The outliers seen on Figure 6.5 are due to the AC feed into the building being out of operation.

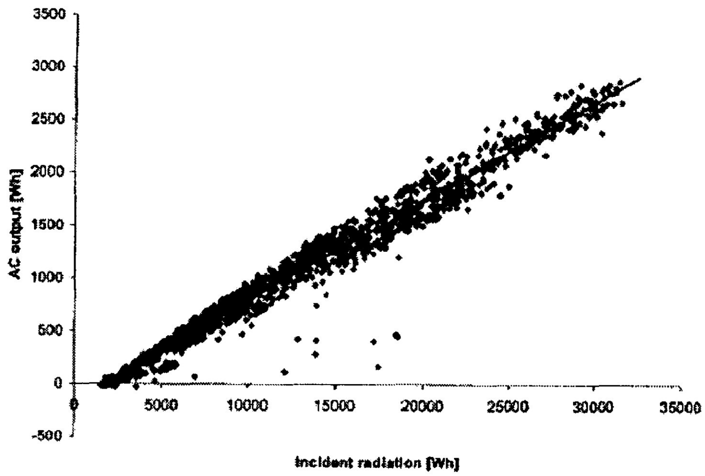

Figure 6.5: Arctic College Hourly System Output vs. Incident Radiation [4]

Table 6.8 demonstrates the annual system energy production of the SECS installed at the Arctic College during the first five years of operation between 1995 and 2000. It can be seen that overall the annual average AC output remains relatively constant with an average of 2,044.2 kWh. The array was reliable during the first five years of operation and the annual power generation can be modelled by 2.03 $\pm$ 0.09 MWh. There were no interruptions in operation except when the building was experiencing power outages. The efficiency ranged between 7.4 and 11.2% dependent upon the season with an annual average efficiency of 9.4%. This demonstrates that solar PV is able to operate even in the far North where less than ideal conditions may be exhibited and that accurate long term forecasting of energy outputs may also be possible.

Table 6.8: Arctic College Annual System Energy Production [4]

Period	AC Energy Delivered (kWh)
Sept. 1995 to Aug. 1996	1,982
Sept. 1996 to Aug. 1997	2,131
Sept. 1997 to Aug. 1998	2,079
Sept. 1998 to Aug. 1999	1,943
Sept. 1999 to Aug. 2000	2,086

Figure 6.6 demonstrates the monthly accumulated output energy normalized to 1 kWp for each of the four solar arrays installed in Shiga, Japan between April 2002 and March 2003. The bracketed letter behind the array material type indicates the direction of installation as previously denoted in Table 6.7. It can be seen from Figure 6.6 that generally, regardless of the azimuth of installation that the peak output occurs in July and the output of the arrays are higher during the summer than during the winter. During the winter the panel fabricated with c-Si cells has the highest output because the South side receives the highest irradiance and the unit experiences the lowest module temperature.

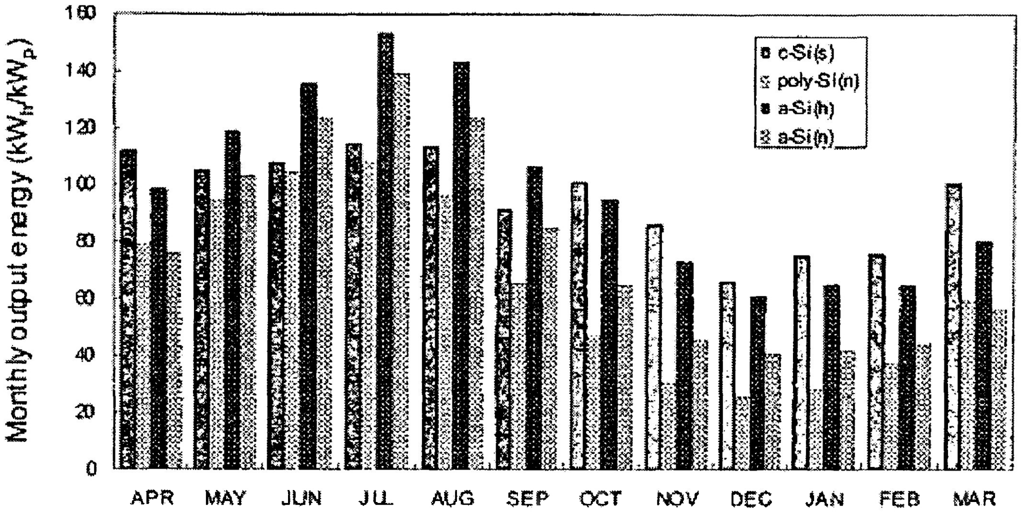

Figure 6.6: Shiga Monthly Accumlated Output Energy Normalized to 1kWp of Each Array From April 2002 to March 2003 [43]

It was found, as demonstrated in Table 6.7, that the FOF of the a-Si solar cell exceeds 90% with the horizontal and North facing units having an FOF of 96.7% and 103.2% respectively. The a-Si solar cells performed significantly better than the c-Si and poly-Si units which operated at 86.3% and 84.8% respectively. This demonstrated that the a-Si solar cells produced the most efficient outputs even on the North side of the structure which receives less solar irradiance than the South side. This was also demonstrated by the horizontal surface which used a-Si cells which outperformed the c-Si cells on the South side by 10.4%. Figure 6.7 demonstrates the monthly accumulated solar irradiance on each azimuth form April 2002 to March 2003 along with the average temperature.

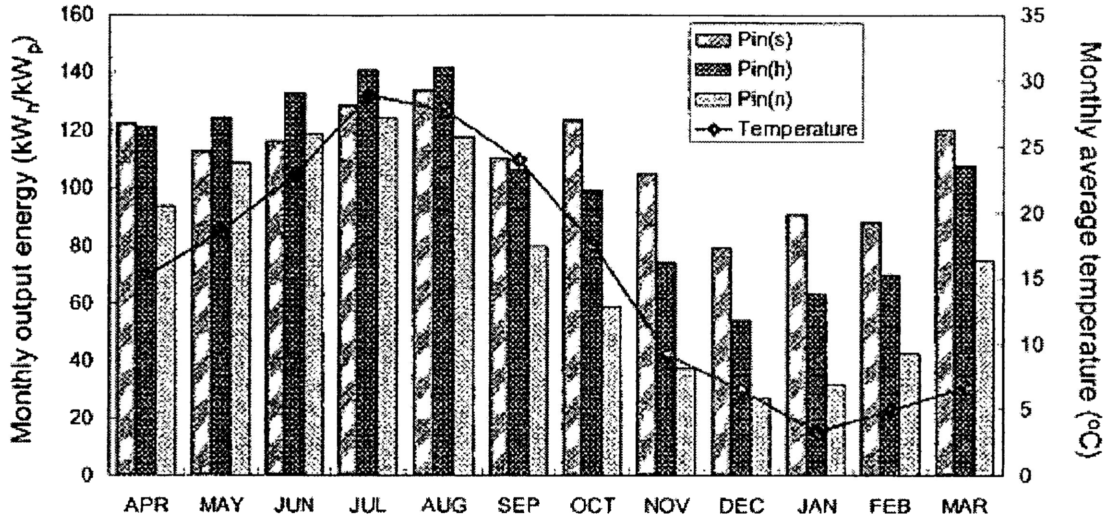

Figure 6.7: Shiga Monthly Accumulated Solar Irradiance on Each Azimuth From April 2002 to March 2003 [43]

It was found that the c-Si cells outperformed the a-Si cells during the winter and that the converse held true during the summer. During the summer there is a positive temperature coefficient due to the high temperature conditions which results in thermal recovery effects that affect the solar cells. The a-Si(n) cells performed better than the c-Si(s) cells in the mid-summer due to the high solar irradiation and high temperatures. It can be seen from the previous Figures and Table 6.7 that the c-Si(s) cells performed relatively poorly even during the summer months. The a-Si cells performed better than the poly-Si cells during the winter on the North side due to a high spectral response in short wavelength light which is the main composition of the incident light entering the North facing cells during this period. Overall the a-Si cells performed relatively poorly during the summer months when compared to the other cell technologies. However, it was found that the a-Si cells exhibit superior annual output characteristics on both the horizontal and North faces even when compared with the South facing panels. These results indicate that it may be a possibility in the future to have larger solar constructions on non South facing surfaces even at a latitude far removed from the equatorial plane.

6.4 Installation Considerations

There are many considerations to be taken with the design and installation of SECS across Northern Ontario. The majority of buildings in the remote communities are private dwellings and the remainder can be classified as governmental, commercial, and industrial. Due to the typically close proximity of the community infrastructure, relatively low profile of the buildings, small surface area of dwelling roof tops, and aging buildings it is reasonable to assume that any large scale solar PV installation would be located outside of the community proper. There is a possibility that the more modern governmental buildings and enterprising private locations, that could possibly afford the capital costs of such installations, could benefit from SECS mounted on site similar to those installed at the Arctic College in NU. These NUGS could result in a decrease of the required electricity and reduce operational costs. Due to the smaller sizes of the remote communities and probable lower quantity of SECS installations distributed generation may potentially be easier to administer in the remote communities if both the public demand and investment was present. In addition to technical considerations for installation it is also very important for the local community to be very involved in the planning process so as to respect their land use desires, culture, and customs. These variables will vary from site to site and there is very little the system model can do to predict the physical site locations and externalities. The physical land characteristics surrounding the communities also vary from location to location which will also affect the installation capabilities and costs of the local operator. Due to the negligible audible and visual impacts and low profile of SECS there is some additional flexibility afforded during site selection.

As previously introduced, the azimuth or direction of which the array faces denoted by γ, has a direct impact on the potential output power. It is common in the northern hemisphere to install fixed-azimuth arrays at an azimuth of $0°$ or due south so that the array is oriented towards the equator for maximum solar radiation penetration [15, 40]. When the array is mounted horizontally the affects of azimuth are negligible. The slope angle, denoted by β, is the angle at which the panels are mounted relative to the horizontal where $0°$ is horizontal and $90°$ is vertical. With fixed-slope arrays it is common that the slope reflects the latitude in magnitude as this position typically maximizes the solar resources on site [15]. It is generally assumed that SECS in S ON should have a tilt of approximately $45°$ [40].

Tracking options also exist that allow the SG to change azimuth and/or slope to obtain better solar resources however they are not studied in this thesis to both contain the scope and due to the Northern latitude. Tracking options available for future study are tracking along the horizontal axis with either continuous, daily, weekly, or monthly adjustments, continuous adjustments on the vertical axis, or two axis tracking. For the daily, weekly, or monthly adjustments along the horizontal axis movement is about the east to west axis, β is ignored, and the tracking system adjusts to allow the sun's rays to be perpendicular to the array surface at noon. For the horizontal continuous tracking option the movement is about the east to west axis and β is constantly adjusted to minimize the angle of incidence. For the vertical continuous tracking option the movement is about the vertical axis, β is fixed, and γ is constantly adjusted to minimize the angle of incidence. For tracking long both axis the arrays are rotated so that the sun's rays are always perpendicular to the array surface. This tracking method allows for the best solar resources to be utilized but increases cost and complexity of the SECS.

The PV derating factor is used to account for differences between the rated and actual performance of the SG. The output power of the SG is lower than the rated capacity due to external influences such as array aging, snow cover, shading, temperature differences et cetera. This factor is used to scale the system modelled results to provide a tolerance band around the output power. The ground reflectance or albedo effect is considered when using tilted SGs however the effects from albedo on output power are marginal. Table 6.9 indicates the SECS installation parameters used within this thesis unless otherwise stated. The slope of the array is set to the latitude of the system model and the azimuth directs the arrays due South.

Table 6.9: SECS Installation Parameters

Metric	Value	Unit
Derating Factor	76	%
Slope	50.65	º
Azimuth	0	º W of S
Ground Reflectance	20	%

6.5 System Diagram

The SECS modelled for simulation can be seen by the system diagram in Figure 6.8. These system configurations can be summarized as either solar-diesel hybrid systems as seen on the left or solar-diesel hybrid system with storage as seen on the right. The SG unit must be connected to a DC bus and the CV unit is required to supply the AC load attached to the AC bus.

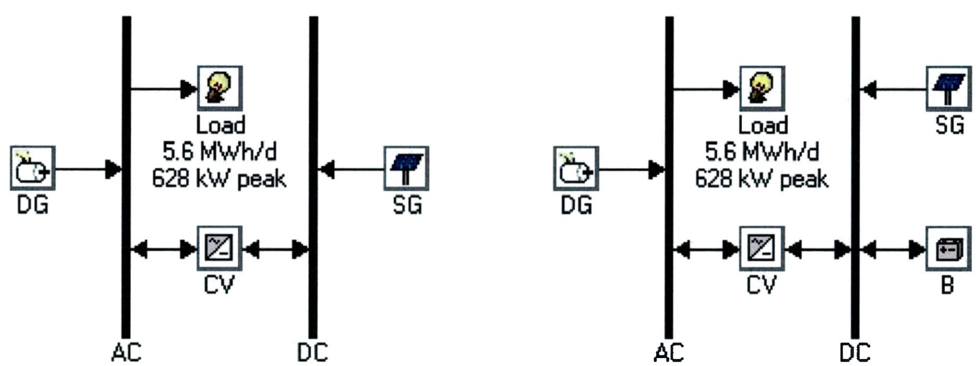

Figure 6.8: SECS Circuit Diagrams

6.6 Unit Selection for Simulation

For the purpose of simulation of this thesis a total of thirty nine different SGs will be considered to constitute the SECS. These units were selected based on past experiences in Arctic conditions, Arctic weather ratings, accessibility, and to allow for some variance with respect to manufacturer and rated capacity selection. Table 6.10 introduces the studied units and their respective reference ID, manufacturer, and model information. The reference or unit ID will be used here on in to indicate the selected unit and additional information regarding the selected SGs can be found in Appendix F. When it was both possible and feasible Canadian manufacturers were selected.

Table 6.10: List of SECS Suppliers and Models

Unit	Manufacturer	Model	P_{max} (W)	Unit	Manufacturer	Model	P_{max} (W)
SG1	DuPont	DA100-A2	100	SG21	REC	REC210AE-US	210
SG2	Mitsubishi Electric	PV-AE115MF5N	115	SG22	REC	REC215AE-US	215
SG3	Mitsubishi Electric	PV-AE120MF5N	120	SG23	Canadian Solar	CS6X-220M	220
SG4	Mitsubishi Electric	PV-MF125UE4N	125	SG24	REC	REC225AE-US	225
SG5	Mitsubishi Electric	PV-AE130MF5N	130	SG25	Canadian Solar	CS6X-230P	230
SG6	Kyocera	KD135GX-LPU	135	SG26	Canadian Solar	CS6X-235M	235
SG7	Canadian Solar	CS5T-140M	140	SG27	Solar World	SW240M	240
SG8	Canadian Solar	CS5T-145M	145	SG28	Solar World	SW245M	245
SG9	Canadian Solar	CS5T-150M	150	SG29	Canadian Solar	CS6X-250P	250
SG10	ecoSolargy	TWES-(155)72M	155	SG30	ET Solar Group	ET-P672255	255
SG11	Canadian Solar	CS6X-160P	160	SG31	Canadian Solar	CS6X-260M	260
SG12	Canadian Solar	CS6X-165M	165	SG32	Canadian Solar	CS6X-265P	265
SG13	Sharp	NE-170UC1	170	SG33	Canadian Solar	CS6X-270M	270
SG14	Solar World	SW175M	175	SG34	Canadian Solar	CS6X-275P	275
SG15	Canadian Solar	CS6X-180M	180	SG35	Canadian Solar	CS6X-280M	280
SG16	Mitsubishi Electric	UD185MF5	185	SG36	Canadian Solar	CS6X-285P	285
SG17	Canadian Solar	CS6X-190M	190	SG37	Canadian Solar	CS6X-290M	290
SG18	BP Solar	SX3195B	195	SG38	Canadian Solar	CS6X-295P	295
SG19	Sanyo	HIP-200BA19	200	SG39	Canadian Solar	CS6X-300M	300
SG20	REC	REC205AE-US	205				

The Tables located in Section F.3 introduce technical parameters of the SG units which include the temperature coefficient, nominal operating cell temperature, and the SG efficiency at Standard Test Conditions (STC). These parameters were all considered to account for the effect of temperature on the SGs. For additional parameters refer to Appendix F or the respective SG datasheet(s). It is assumed that all SGs considered in this thesis have a DC output and that all inversion will be done by a central inverter unit as per Chapter 3 unless otherwise stated.

The temperature coefficient indicates the relationship strength between output power and cell temperature. The rated capacities of the SG are based upon the array performance at STC. These STC are characterized by: a solar radiation of 1 kW/m^2 , a cell temperature of 25°C, and no wind. For simulation purposes it is required to account for the difference between these ideal rated capacity values and the real world application which includes accounting for different solar resources, temperatures, and presence of wind resources at the installation location. The nominal operating cell temperature, $T_{C,NOCT}$, is the cell temperature when the following conditions are met: a solar radiation of 0.8 kW/m^2, an ambient temperature of 20°C, and a wind speed of 1 m/s which provide a more realistic view of practical SG capabilities. This temperature is defined as the methodology that is used to determine the PV cell temperature as it varies with the ambient temperature and the solar radiation. The efficiency at STC is the measure of the maximum power point efficiency under STC and will be introduced under simulation methodology [15, 42].

Since the SGs are being installed along side an existing DGS there will be some modifications required to allow for the implementation of the SECS. This effects the CC of the SECS since the infrastructure does not currently exist as part of the DGS installation and these modifications are required. Section F.4 demonstrates the CC, RC, O&M, lifetime, and net CC of the SECS including an approximated value of transmission line extension costs. Other related modifications required, such as protection schemes or relaying, are subject to local system variability and would need to be studied on a case by case basis.

For simulation purposes it is assumed that the cost curve for quantity of SGs versus net CC is a linear function. The varying costs associated with penetration level and DGS expansion costs as indicated in Table 3.8 will be accounted for by altering the linear approximations as required when the number of investigated SGs is sufficient for an increase in penetration level. It is also assumed that the output power of the SG is linearly related to the solar radiation incident on the array and independent of the DC bus voltage. This assumption dictates that the SG has a maximum power point tracker as introduced in Section 6.3. The base case net CC for any given SECS studied will have the associated expansion costs for a low penetration system included. These costs will be utilized during the unit simulation to determine the feasibility of the system in question.

6.7 Simulation Methodology

This Section introduces the simulation methodology used to implement the various system designs as seen in Section 6.5 using the components introduced in Section 6.6 and Appendix F. SGs 1 though 39 will be simulated to a maximum of 600 kW per individual SG. The first 1 through 100 units of a particular SG will be modelled in 5 unit increments. After 100 units this quantity increases in increments of 10 until the maximum simulated capacity is obtained. This allows for small and medium solar power penetration levels in the simulated systems.

The simulation process utilizes the monthly average solar radiation from the system model for data acquisition purposes. However, to model the system model for simulation hourly data is required. Being as the system model covers a large geographical area with fluctuating hourly solar penetration the simulation tool approximates the model's hourly solar resources. If hourly data exists for a site it may be used for simulation purposes. However, it is common that the required hourly solar radiation data is seldom available so synthetic data is normally generated on a monthly basis as per the methodology introduced by [44]. The synthetic data is formed from the 12 average monthly solar radiation values and the latitude of the installation site to generate the required 8,760 average hourly solar radiation values. Appendix F provides the distribution map associated with the generated synthetic data. It can be seen from the data map (DMap) that the synthetic data exhibits characteristics that accounts for realistic day to day, hour to hour, and seasonal patterns [15]. For example if it is cloudy during hour 9 it is reasonable to assume that it will be cloudy during hour 10 as well. The algorithm used to create the synthetic solar data uses statistical analysis representative of global averages to generate data for a given location [44]. The synthetic model developed by [44] was verified from field or actual results upon its implementation by NREL. It was found that the synthetic solar resources varied from the actual resources within a tolerance of less than 5%. This indicates that the simulated results are within an acceptable margin of error [15].

To generate the synthetic data required by the system model either monthly average solar radiation data or clearness index data is required [44]. The Clearness Index (CI), as introduced in Section 6.2, is calculated from the provided monthly average solar radiation from the system model climatic data analysis. Equation 6.1 is used to calculate the monthly average CI from the available solar radiation data for the system model [15]. The monthly average horizontal radiation is provided to the system model and the desired result is the monthly average clearness index. To achieve this, the monthly average extraterrestrial (ET) horizontal radiation must be calculated which is based upon the month of the year and the latitude of the system model.

$$K_T = \frac{H_{ave}}{H_{o,ave}} = \frac{\bar{G}}{\bar{G}_o} \tag{6.1}$$

Metric	Parameter	Unit
K_T	Monthly Average Clearness Index	Dimensionless
H_{ave}	Monthly Average Horizontal Radiation	$(kWh/m^2/day)$
$H_{o,ave}$	Monthly Average ET Horizontal Radiation	$(kWh/m^2/day)$
G	Global Horizontal Radiation on the Earth's Surface Averaged Over the Time Step	(kW/m^2)
G_o	ET Horizontal Radiation Avgd. Over the Time Step	(kW/m^2)

To obtain the monthly average extraterrestrial horizontal radiation the following process is used to determine the solar radiation incident on the PV array. Equation 6.2 is used to calculate the ET radiation on a surface normal to the Sun's rays or the intensity of solar radiation at the top of the Earth's atmosphere [15].

$$G_{on} = G_{sc}\left(1 + 0.033\cos\frac{360n}{365}\right) \tag{6.2}$$

Metric	Parameter	Unit
G_{on}	ET Radiation on a Surface Normal to the Sun's Rays	(kW/m^2)
G_{sc}	Solar Constant	$1.367\ kW/m^2$
n	Day of the Year	1 to 365

The ET radiation on the horizontal surface can be calculated by Equation 6.4 using the zenith angle as demonstrated by Equation 6.3 [15].

$$\cos\theta_z = \cos\phi\cos\delta\cos\omega + \sin\phi\sin\delta \tag{6.3}$$

$$G_o = G_{on}\cos\theta_z \tag{6.4}$$

Metric	Parameter	Unit
ϑ_z	Zenith Angle	(°)
Φ	Latitude	(°)
δ	Solar Declination	(°)
ω	Hour Angle	(°)
G_o	ET Radiation on the Horizontal Surface	(kW/m^2)

The solar declination can be calculated from Equation 6.5 where as in Equation 6.2 n represents the day of the year where, during a standard year, January 1 corresponds to 1 and December 31 corresponds to 365 [15].

$$\delta = 23.45^\circ \sin\left(360^\circ \frac{284 + n}{365}\right) \tag{6.5}$$

The total daily ET radiation per square meter can be calculated by Equation 6.4 which is achieved by integrating Equation 6.4 between the daily sunrise and sunset times [15]. The sunset hour angle can be found using Equation 6.3 [15].

$$\cos \omega_s = -\tan \phi \tan \delta \tag{6.6}$$

$$H_o = \frac{24}{\pi} G_{on} \left[\cos \phi \cos \delta \cos \omega_s + \frac{\pi \omega_s}{180^\circ} \sin \phi \sin \delta\right] \tag{6.7}$$

Metric	Parameter	Unit
H_o	Average Daily ET Horizonal Radiation	(kW/m^2)
ω_s	Sunset Hour Angle	(°)

Once Equation 6.4 is used to find the average daily ET horizontal radiation Equation

6.8 is used to find the monthly average ET horizontal radiation as desired [15]. N is used to denote the number of days in the particular month and after $H_{o,ave}$ is determined the CI can be calculated.

$$H_{o,ave} = \frac{\sum_{n=1}^{N} H_o}{N} \tag{6.8}$$

It is assumed that the simulated system includes a Maximum Power Point Tracker (MPPT). The model developed for PV output power is relatively simplistic and assumes that the output power of the array is linearly proportional to the amount of solar radiation striking it. It has been determined that this output power assumption is reasonably accurate only if MPPT is considered during modelling. As such the MPPT efficiency must be modelled and is typically done so using the derating factor of the PV array. The battery charge controller is not modelled as a separate component during simulation. To simulate the associated cost and efficiency of the charge controller other metrics must be modified to compensate. This was compensated by adjusting the CC of the SG to include the CC of the charge controller and by reducing the derating factor to account for the efficiency of the charge controller. The derating factor introduced in Section 6.4 was obtained by using a charge controller efficiency of 0.95 and an original derating factor of 0.80 to obtain the utilized derating factor of 0.760 from 80 % * 95 % = 76.0 % [15, 42, 45].

It is common to have the global horizontal radiation available during the climatic analysis. However, for the majority of SG installations the PV array is not installed on a horizontal surface. Being as the output power of the array is dependent upon the amount of solar radiation striking the surface of the array this difference must be accounted for. For the purpose of simulation in this thesis the radiation incident on the PV array is calculated hourly using the methodology presented by [46]. This is done using the slope and azimuth of the array as introduced in Section 6.4. To account for location specific geometric parameters the latitude, time of year, and time of day must be considered. As introduced in Appendix I the time of year affects the solar declination, which is modelled by Equation 6.5, and represents the latitude at which the Sun's rays are perpendicular to the Earth's surface at solar noon. The time of day, or hour angle, is defined as the location of the Sun in the sky and demonstrated by Equation 6.9. The simulation methodology assumes that the HA is 0 at solar noon, negative before solar noon, and positive after solar noon. Equation 6.9 accounts for the Sun moving across the sky at 15 degrees per an hour [15].

$$\omega = (t_s - 12\,hours) * 15^\circ/hr \tag{6.9}$$

It is assumed that all time-dependent data used for simulation is provided in local time. To convert from local time to solar time Equation 6.10 is utilized. By convention it is assumed that Western longitudes and time zones West of GMT are both negative [15].

$$t_s = t_l + \frac{\lambda}{15^\circ/hr} - Z_l + E \tag{6.10}$$

Metric	Parameter	Unit
t_s	Solar Time (Corresponding to the Midpoint of Time Step)	(hr)
t_l	Local Time (Corresponding to the Midpoint of Time Step)	(hr)
λ	Longitude	(°)
Z_l	Time Zone in Hours East of GMT	(hr)
E	Equation of Time	(hr)

Equations 6.11 and 6.12 are both used to determine the time experienced at the installation location and the related effects of the Earth's obliquity or the tilt of the axis of rotation relative to the ecliptic and eccentricity of orbit [15]. The variable n once again corresponds to the day of the year.

$$\begin{aligned} E &= 3.82(0.000075 + 0.001868\cos B - 0.032077\sin 2B \\ &\quad -0.014615\cos 2B - 0.04089\sin 2B) \end{aligned} \tag{6.11}$$

$$B = 360^\circ\frac{(n-1)}{365} \tag{6.12}$$

The angle of incidence is defined as the angle between the Sun's beam radiation and the normal to the surface. Equation 6.13 can be used to determine the angle of incidence for an array at any orientation which is particularly important to account for. The zenith angle of a horizontally installed PV array can be found by substituting a surface slope of 0° into Equation 6.13 which yields Equation 6.3 [15].

$$\begin{aligned} \cos\theta = \; & \sin\delta\sin\phi\cos\beta - \sin\delta\cos\phi\sin\beta\cos\gamma + \cos\delta\cos\phi\cos\beta\cos\omega \\ & + \cos\delta\sin\phi\sin\beta\cos\gamma\cos\omega + \sin\delta\sin\beta\sin\gamma\sin\omega \end{aligned} \tag{6.13}$$

Metric	Variable	Unit
ϑ	Angle of Incidence	(°)
β	Slope of the Surface	(°)
γ	Azimuth of the Surface	(°)
φ	Latitude	(°)
δ	Solar Declination	(°)
ω	Hour Angle	(°)

Integrating the ET horizontal radiation from Equation 6.4 to find the average ET horizontal radiation over a time step results in Equation 6.14 [15]. This is the average amount of solar radiation striking a horizontal surface at the top of the atmosphere during the desired time step.

$$\bar{G}_o = \frac{12}{\pi} G_{on} \left[\cos\phi \cos\delta \left(\sin\omega_2 - \sin\omega_1 \right) + \frac{\pi \left(\omega_2 - \omega_1 \right)}{180^\circ} \sin\phi \sin\delta \right] \tag{6.14}$$

Metric	Parameter	Metric
$\bar{G}_o$	ET Horizontal Radiation Averaged Over the Time Step	(kW/m^2)
G_{on}	ET Normal Radiation	(kW/m^2)
ω_1	HA at the Beginning of the Time Step	(°)
ω_2	HA at the End of the Time Step	(°)

As introduced in Section 6.2 the global horizontal radiation on the Earth's surface can be subdivided into beam radiation and diffused radiation. Beam radiation is analogous with direct radiation and casts a shadow whereas diffused radiation does not cast a shadow. The ability to differentiate between beam and diffused radiation is important since the orientation of the array greatly affects the amount of possible beam radiation that occurs on the unit whereas the diffused radiation is relatively constant regardless of orientation. Equation 6.15 models the global horizontal radiation on the Earth's surface averaged over the time step as a sum of its components [15].

$$\bar{G} = \bar{G}_b + \bar{G}_d \tag{6.15}$$

Metric	Parameter	Unit
$\bar{G}$	Global Horizontal Radiation on the Earth's Surface Averaged Over the Time Step	(kW/m^2)
$\bar{G}_b$	Beam Radiation	(kW/m^2)
$\bar{G}_d$	Diffuse Radiation	(kW/m^2)

However, normally only the global horizontal radiation is available as a climatic variable. As such, during each simulated time step the global horizontal radiation must be divided into its respective beam and diffused radiation components to find the radiation incident on the PV array. Equation 6.16 [15] provides the diffused fraction as a function of the CI using the correlation methodology presented by [46]. In summary, for each of the simulated time steps, the following are calculated individually in sequence: average global horizontal radiation is used to calculate the CI, diffused radiation, and the beam radiation by rearranging and solving Equation 6.15.

$$\frac{\bar{G}_d}{\bar{G}} = \begin{cases} 1.0 - 0.09K_T & K_T \leq 0.22 \\ 0.9511 - 0.1604K_T^2 - 16.638K_T^3 + 12.336K_T^4 & 0.22 < K_T \leq 0.80 \\ 0.165 & K_T > 0.8 \end{cases} \tag{6.16}$$

It is assumed by the model in [46], which is used to simulate the SECS with respect to estimations of the diffused radiation fraction for various global radiation parameters, that there are three components that combine to form the total diffused solar radiation. These are the isotropic, circumsolar, and horizon brightening components which are defined and introduced by the following three Equations. These components are required to simulate the global radiation experienced on the tilted surface of the PV array. The isotropic component is the component which is experienced by all octants of the sky equally. This component is represented by Equation 6.17 which is the ratio of the beam radiation on the tilted surface to the beam radiation on the horizontal surface [15].

$$R_b = \frac{\cos\theta}{\cos\theta_z} \tag{6.17}$$

The circumsolar component of the total diffused solar radiation is that which emanates from the direction of the sun. The circumsolar component can be represented by the anisotropy index which indicates the atmospheric transmittance of beam radiation. Equation 6.18 represents the estimated amount of circumsolar diffused radiation or forward scattered radiation [15].

$$A_i = \frac{\bar{G}_b}{\bar{G}_o} \tag{6.18}$$

The horizon brightening component of the total diffused solar radiation is that which emanates from the horizon. This component represents the majority of the diffused radiation and as such is heavily dependent upon the cloud cover experienced at the installation location during the given period. Equation 6.19 represents the horizon brightening component [15].

$$f = \sqrt{\frac{\bar{G}_b}{\bar{G}}} \tag{6.19}$$

Using the above components of the total diffused solar radiation, slope of the panel surface, albedo, beam radiation, diffused radiation, and the global horizontal radiation on the Earth's surface averaged over the desired hour the [46] model can calculate the global radiation incident on the PV array from Equation 6.20 [15]. The global radiation incident on the PV array is then used to calculate the cell temperature and the power output of the array.

$$\bar{G}_T = \left(\bar{G}_b + \bar{G}_d A_i\right) R_b + \bar{G}_d \left(1 - A_i\right) \left(\frac{1 + cos\beta}{2}\right) \left[1 + f \sin^3\left(\frac{\beta}{2}\right)\right] + \bar{G}\rho_g \left(\frac{1 - \cos\beta}{2}\right) \tag{6.20}$$

As introduced in Section 6.6 the efficiency at STC is the measure of the maximum power point efficiency under STC of the SG. Equation 6.21 is used to determine the efficiency at which the SG converts solar radiation into electricity at its maximum power point under STC as found above [15]. This metric is used to calculate the PV cell temperature and is modelled as an approximation since manufacturer data is often difficult to obtain.

$$\eta_{mp,STC} = \frac{Y_{PV}}{A_{PV} G_{T,STC}} \tag{6.21}$$

Variable	**Description**	**Unit**
$\eta_{mp,STC}$	Efficiency of the PV Module Under STC	(%)
Y_{PV}	Rated Power Output of the PV Module Under STC	(kW)
A_{PV}	Surface Area of the PV Module	(m^2)
$G_{T,STC}$	Radiation at STC	(1 kW/m^2)

Practical testing of some commonly available SG units was performed by NREL to determine average efficiency values at STC [15, 47]. The results of this practical SG testing are denoted in Table 6.11. These average efficiency values are similar in magnitude to those found in Section 6.1 during regular operation at various locations. The temperature coefficient of power, indicated by αP, demonstrates the strength of the power output versus the cell or surface temperature of the array. The temperature coefficient of power is also indicated in Table 6.11 and assumes a negative magnitude as the power output decreases with an increase in cell temperature. Of the sampled SG units in Table 6.11 it was found that approximately 60% of their respective datasheets provide NOCT values which vary over a narrow range from 45 °C to 48°C.

Table 6.11: Results of Practical SG Testing

SG Module Type	Sample Size For:		Average Efficiency at STC (%)	Average Value of αP (%/°C)
	η	αP		
Polycrystalline Silicon	10	7	13.0	-0.48
Monocrystalline Silicon	8	4	13.5	-0.46
Monocrystalline and Amorphous Silicon Hybrid	1	1	16.4	-0.30
Thin Film Amorphous Silicon	4	4	5.5	-0.20
Thin Film CIS	1	1	8.2	-0.60

If the temperature coefficient of power is not provided it can commonly be derived from the slope of the function that represents the normalized performance versus cell temperature. The temperature coefficient of power can also be approximated Equation 6.22 [15].

$$\alpha_P \approxeq \frac{\mu_{Voc}}{V_{mp}} \tag{6.22}$$

Variable	Description	Unit
α_P	Temperature Coefficient of Power	%/°C
μ_{Voc}	Temperature Coefficient of the Open-Circuit Voltage	V/°C
V_{mp}	Voltage at the Maximum Power Point Under STC	V

The open-circuit voltage can be directly supplied from the SG datasheet or it can be determined from IV curves that are provided for multiple common cell temperature values. To find the temperature coefficient of the open-circuit voltage the slope of the function that represents the voltage at the bottom of the IV curve versus cell temperature is determined.

The solar absorbance of a surface is the fraction of the sun's radiation that the surface absorbs. The solar transmittance of a surface is the fraction of the sun's radiation that is transmitted through the surface. It is assumed that the product of the solar absorbance and the solar transmittance is 90% and is used to calculate the array temperature.

The PV cell or surface temperature is used in part to calculate the SG output power. During the night the cell temperature is equal to the ambient temperature however at solar noon the cell temperature can exceed the ambient temperature by more than 30°C. The cell temperature is calculated during each hour or time step and uses the ambient temperature and solar radiation during this period to calculate the power output of the SG. Equation 6.23 [15] defines the energy balance for the PV array as introduced by [48].

$$\tau \alpha G_T = \eta_c G_T + U_L \left(T_c - T_a \right) \tag{6.23}$$

Variable	**Description**	**Unit**
τ	solar transmittance of any cover over the PV array	(%)
α	solar absorptance of the PV array	(%)
G_T	solar radiation striking the PV array	(kW/m^2)
η_c	Electrical Conversion Efficiency	(%)
U_L	Coefficient of Heat Transfer to the Surroundings	(kW/m^2°C)
T_c	Cell Temperature	(°C)
T_a	Ambient Temperature	(°C)

From the energy balance equation represented by Equation 6.23 it can be seen that there is a relationship between the solar radiation absorbed by the PV array on the LHS and the electrical output and heat transfer to the surroundings on the RHS. Re-arranging the energy balance equation to solve for the cell or surface temperature of the array results in Equation 6.24 [15].

$$T_c = T_a + G_T \left(\frac{\tau\alpha}{U_L}\right)\left(1 - \frac{\eta_c}{\tau\alpha}\right) \tag{6.24}$$

The variable represented by $\frac{\tau\alpha}{U_L}$ is difficult to measure directly and as such is modelled by Equation 6.25 which uses the NOCT as introduced in Section 6.6 assuming no load operation ($\eta_c = 0$). Assuming that the expression in Equation 6.25 is constant the approximation is substituted into the cell temperature equation modelled by Equation 6.24 which results in a simplified expression denoted by Equation 6.26. [15]

$$\frac{\tau\alpha}{U_L} = \frac{T_{c,NOCT} - T_{a,NOCT}}{G_{T,NOCT}} \tag{6.25}$$

$$T_c = T_a + G_T \left(\frac{T_{c,NOCT} - T_{a,NOCT}}{G_{T,NOCT}}\right)\left(1 - \frac{\eta_c}{\tau\alpha}\right) \tag{6.26}$$

Variable	**Description**	**Unit**
$T_{c,NOCT}$	Nominal Operating Cell Temperature (NOCT)	(°C)
$T_{a,NOCT}$	Ambient Temperature at Which the NOCT is Defined	(20°C)
$G_{t,NOCT}$	Solar Radiation at Which the NOCT is Defined	(0.8 kW/m^2)

[48] suggest that the relationship between solar absorbance and transmittance ($\tau * \alpha$) result in an approximation of 0.9. Since the effects of this relationship are small on the $\frac{\eta_c}{\tau\alpha}$ term it is assumed that the PV array always operates at its maximum power point which leads to the assumption that the cell efficiency is always equal to the maximum power point efficiency. However, the maximum power point efficiency is dependent upon the cell temperature. It is assumed that the relationship between the maximum power point efficiency and cell temperature can be modelled by a linear function as denoted by Equation 6.27. As demonstrated by Table 6.11 the temperature coefficient of power (α_P) is normally of a negative magnitude which dictates that the efficiency of the PV array decreases with an increase in cell temperature as modelled by Equation 6.27 [15].

$$\eta_{mp} = \eta_{mp,STC}\left[1 + \alpha_p\left(T_c - T_{c,STC}\right)\right] \tag{6.27}$$

Variable	Description	Unit
η_{mp}	Maximum Power Point Efficiency	(%)
$\eta_{mp,STC}$	Maximum Power Point Efficiency Under STC	(%)
α_P	Temperature Coefficient of Power	(%/°C)
$T_{c,STC}$	Cell Temperature Under STC	(25°C)

Substituting the maximum power point efficiency approximation of the PV array in Equation 6.27 in lieu of the cell efficiency into the cell temperature Equation modelled by Equation 6.26 results in Equation 6.28 [15]. Equation 6.28 represents the cell or surface temperature of the array in degrees Kelvin in its final form which is used on an hourly basis for the entire data set.

$$T_c = \frac{T_a + \left(T_{c,NOCT} - T_{a,NOCT}\right)\left(\frac{G_T}{G_{T,NOCT}}\right)\left[1 - \frac{\eta_{mp,STC}\left(1-\alpha_p T_{c,STC}\right)}{\tau\alpha}\right]}{1 + \left(T_{c,NOCT} - T_{a,NOCT}\right)\left(\frac{G_T}{G_{T,NOCT}}\right)\left(\frac{\alpha_p \eta_{mp,STC}}{\tau\alpha}\right)} \tag{6.28}$$

The output power of the SG is dependent upon the rated capacity, the derating factor, the availability of solar resources, and the temperature experienced on the PV array as previously introduced. In some cases the temperature can be neglected however due to the expansive temperature range experienced at the system model it is considered to determine the array output power. After the available solar resources and temperature have been determined for a given hour Equation 6.29 is used to model the PV array's output power during this time [15].

$$P_{PV} = Y_{PV} f_{PV} \left(\frac{\bar{G}_T}{\bar{G}_{T,STC}}\right)\left[1 + \alpha_p \left(T_c - T_{c,STC}\right)\right] \tag{6.29}$$

Variable	**Description**	**Unit**
P_{PV}	Output of PV Array	(kW)
Y_{PV}	Rated PV Array Capacity at STC	(kW)
f_{PV}	PV Derating Factor	(%)
$\bar{G}_T$	Solar Radiation Incident on the PV Array in the Current Time Step	(kW/m^2)
$G_{T,STC}$	Incident Radation at STC	(1 kW/m^2)
α_P	Temperature Coefficient of Power	(%/°C)
T_C	PV Cell Temperature in the Current Time Step	(°C)
$T_{C,STC}$	PV Cell Temperature Under STC	(25°C)

STC = Standard Test Conditions

Once the above process is complete and the output power of the array is determined for a given period it is repeated for the entire time series of hourly solar resources at the system model location. Using the resulting output power from Equation 6.29 over the available time period the minimum, maximum, and average output power of the SG can be determined. With these metrics the solar penetration and capacity factor, which are defined as the average output of the SG divided by the primary load and rated power respectively, can also be calculated for the SECS. The determined output power results are then applied towards the simulation of the proposed systems from Section 6.5 and the results are discussed in Section 6.8.

6.8 Simulation Results

Table 6.12 demonstrates the top 8 optimal results of the simulated S-D systems. There is little variance between the COE between the various system configurations. All variables represented in Table 6.12 are comprised of the composite DG and SECS system as a sum of the associated costs of both systems. All of the studied systems in this Section were investigated over a 25 year period which is reflected by the NPV. The favoured system is reference simulation 11 due to the best economics and mid-sized SG dimensions in an attempt to minimize surface area required when possible. The renewable fraction of the short listed installations are relatively consistent at 0.33% and the SECS size is comparable within these optimal systems. The optimal configuration requires an area 4,875 m^2 (approx. 1.2 acres or 0.5 hectares), for the panels alone, which may make SECS un-viable for the community depending on the available space for installation.

Table 6.12: Top 8 Optimal S-D Results

Ref. Sim. #	SG Size (kW)	Initial Capital ($)	O&M ($/yr)	Total NPV ($)	COE ($/kWh)	Ren. Frac. (%)	Diesel Consump. (L)
11	**600**	**2,016,913**	**749,352**	**18,554,738**	**0.408**	**0.33**	**364,588**
7	596.4	2,188,985	752,948	18,806,178	0.414	0.33	364,899
5	598	2,303,701	752,939	18,920,692	0.416	0.33	364,805
4	578.75	2,313,822	755,297	18,982,848	0.417	0.32	367,097
15	601.2	2,417,535	748,650	18,939,862	0.417	0.34	364,134
23	556.6	2,328,337	755,695	19,006,150	0.418	0.32	369,492
1	569	2,162,302	765,861	19,064,462	0.419	0.31	370,344
3	562.8	2,334,066	757,329	19,047,934	0.419	0.32	369,014
2	448.5	1,997,754	775,437	19,111,248	0.420	0.26	385,937

For the S-D-S system both load following and cycle charging dispatch methods were simulated. The set point utilized was set to 80% state of charge. Although results varied relative to the simulated system and both methods indicated merit it was found that the selected S-D-S system provided better results with a load following dispatch methodology. Two methodologies were used for simulation of the S-D-S system. The first was to find the optimal system configuration as used by the D and S-D systems. The second was utilizing the optimal system found by the S-D system and modelling the S-D-S system with similar components to facilitate comparison metrics. The second choice was used in this section with additional information available in Appendix B. The resulting S-D-S system results can be found in Table 6.13. As expected the storage allows for systems with a higher renewable penetration however there is an increased initial CC to consider. Table 6.13 also provides a summary of the DG, SG, CV, and B units used in the selected hybrid systems which include: which units were used, their respective quantity, installed capacity, percentage of generator contribution to overall system, operating time, and the energy generated per year of the applicable generator units. The simulation was modelled to allow for multiple generators to operate simultaneously which includes various renewable generators and the base case's diesel generators. The selected results for the solar-diesel and solar-diesel-storage hybrid systems are found in Table 6.13 along with the base case D system from Chapter 5 for comparison.

Table 6.13: Optimal Simulated Results for SECS

System Type	**Initial Capital** ($)	**O&M** ($/yr)	**Total NPV** ($)	**COE** ($/kWh)	**Ren. Frac.** (%)	**Diesel Consump.** (L)
D	332,478	913,856	20,500,828	0.451	0.00	491,813
S-D	2,016,913	749,352	18,554,738	0.408	0.33	364,588
S-D-S	2,538,209	712,052	18,252,848	0.401	0.41	331,822
System Type	**Unit Ref. #**	**Quan.**	**Size (kW)**	**Time (hr)**	**kWh/yr**	**% Gen.**
D	DG7:	1	220	4,110	532,899	26
	DG11:	1	400	5,245	1,483,744	72
	DG13:	1	500	125	43,768	2
S-D	DG7:	1	220	5,837	687,274	30
	DG11:	1	400	2,942	771,577	34
	DG13:	1	500	130	45,942	2
	SG11[1]:	3,750	600	4,384	757,347	33
	CV:	300 kW	[1]SG11 are 160W panels			
S-D-S	DG7:	1	220	4,758	639,575	28
	DG11:	1	400	2,582	734,752	32
	DG13:	1	500	0	0	0
	SG11[2]:	4,688	750	4,384	940,133	41
	B3[3]:	160	575 kWh	-	27,475	N/A
	CV:	350 kW	[2]SG11 are 160W panels [3]B3 are 6V 599 Ah			

It can be seen from Table 6.13 that the S-D and S-D-S systems reduce diesel consumption by 127,225 L and 159,991 L or -25.9% or -32.5% respectively from the D case. The diesel fuel saved from the S-D system is roughly equivalent to 2 winter months or 3 summer months which reflect relatively substantial savings in fuel with the medium penetration installation. The initial CC of the systems utilizing SGs are substantially higher than the D system with lower yearly O&M costs. Although SG systems do inherently have very low O&M costs, as can be seen from Table 6.13, diesel generators are still required to service the community. The modelled S-D system utilizes a load following dispatch which requires constant DG utilization as a base load. SGs are used, when possible, to decrease the size of the DG units required for operation. The DGs are also used to mitigate the intermittent nature of SECS and to offset marginal SG output. This required use of DGs increases the O&M of the S-D-(S) systems. To decrease the required use of DG units a high penetration system would need to be installed as introduced in Chapter 3 which is not viable at this point in time. A system with a high renewable fraction would have a significantly higher CC with a significantly lower O&M cost. The total number of DG running hours, calculated from the combined use of all 3 DG units, are 9,480, 8,909, and 7,340 for the D, S-D, and S-D-S systems respectively. It can be seen that although the DG units are still required to provide the functionality listed above that the overall number of hours is decreased and the size of the generator required to be operating decreases. This can be seen between the D and S-D systems where DG11 decreases from 5,245 to 2,942 hours of operation and DG7 increases from 4,110 to 5,837 hours of operation. DG13 was not required with the higher level of penetration exhibited by the S-D-S system. The smaller the DG unit is, the cheaper it is to operate, which impacts the O&M and COE. To maximize the use of the system generation and increase the longevity of the EES units cycle charging is also employed within the S-D-S system.

Over the 25 year life cycle chosen for the S-D system DG7 will require replacement four times, DG11 twice, and the CV will requirement replacement once. For the S-D-

S system the following components will need to be replaced over the 25 year period: DG7 three times, DG11 twice, the batteries twice, and the CV once. DG13 and the SG units will not require replacement during the simulated period for either system configuration. Fuel costs remain the highest yearly expenditure of the systems and these costs are the main component of yearly operational costs. Both fuel costs and O&M costs are remain relatively consistent over the life of the project. It should be noted that depending on the type of contract procured by the community as well as the global markets the price of fuel may fluctuate during the 25 year period in all cases running DG units.

SG unit replacement was considered and accounted for during the simulation process for all system configurations that utilize SGs. It was assumed that SG life is 25 years based on the following considerations. The manufacturer information and technical specifications provided in Appendix F demonstrate that SG11 has a 6 year product warranty and a 25 year module power output warranty. The simulated model accounts for the effect of temperatures and a general derating factor of the unit over its lifetime. This derating factor, as introduced in Sections 6.4 and 6.7, was selected to be 76%. This derating factor is used in part to account for aging of the unit as well as other limiting factors such as wiring losses, shading, snow cover, and panel soiling. Skypower Limited, the corporation with the majority of the large scale SECS projects in the Province of Ontario, designed many of their projects with a 25 year expected life. One such location is the 13th Side Rd., Simcoe, ON which is a 9.47 MW installation in Norfolk County. The arrays are constructed using a 168 W SG model from the same manufacturer that is very similar to SG11 (160 W). The life time estimations will be reassessed by Skypower as additional practical experience is obtained in Ontario. Annual maintenance is also performed on the SG to ensure unit performance and longevity. Additional simulations can be performed using HOMER or Hyrbid2 to account for variations if additional information is made available regarding unit life time and performance.

Table 6.14 indicates the economic summary of both systems in both NPV and annualized cash flows. The O&M defined in Table 6.13 for the S-D system is calculated from the annualized cash flows as RC+O&M+Fuel-SV. The COE is calculated, as per Equation 3.14, to be: COE = (840,741)/(2,060,416) = 0.408 \$/kWh for the S-D system.

Table 6.14: System Economic Summary

Cost Type	CC ($)	RC ($)	O&M ($)	Fuel ($)	SV ($)	Total ($)
S-D System Summary						
NPV	2,016,913	491,589	2,048,850	14,161,447	-164,003	**18,554,740**
Annualized	91,389	22,275	92,836	641,675	-7,434	**840,741**
AC Primary Load Consumption			2,060,416		kWh/year	
Excess Electricity			190,391 kWh/year or 8.42%			
Unmet Electric Load			0.00749		kWh/year	
S-D-S System Summary						
NPV	2,538,209	695,478	2,372,456	12,888,764	-242,037	**18,252,848**
Annualized	115,010	31,513	107,499	584,007	-10,967	**827,062**
AC Primary Load Consumption:			2,060,416		kWh/year	
Excess Electricity			219,567 kWh/year or 9.49%			
Unmet Electric Load			0.00696		kWh/year	

Tables 6.15 and 6.16 summarize the operational, electrical, and fuel variables for the optimal S-D and S-D-S systems.

Table 6.15: Additional Generator Results for Optimal S-D Case

Metric	Quantity	Unit	Metric	Quantity	Unit
S-D System: DG7					
Operational Variables			**Electrical Variables**		
Hours of Op.	5,837	hr/yr	Mean Elec. o/p	118	kW
Number of Starts	1,204	#/yr	Min. Elec. o/p	66.0	kW
Operational Life	5.14	yr	Max. Elec. o/p	196	kW
Capacity Factor	35.7	%	**Fuel Variables**		
Fixed Gen. Cost	5.94	\$/hr	Fuel Consumption	172,082	L/yr
Marg. Gen. Cost	0.424	\$/kWh	Specific Fuel Cons.	0.250	LWh/y
Electrical Variables			Fuel Energy i/p	1,693,292	kWh/y
Elec. Production	687,274	kWh/y	Mean Elec. Effic.	40.6	%
S-D System: DG11					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	2,942	hr/yr	Mean Elec. o/p	262	kW
Number of Starts	848	#/yr	Min. Elec. o/p	120	kW
Operational Life	10.2	yr	Max. Elec. o/p	400	kW
Capacity Factor	22.0	%	**Fuel Variables**		
Fixed Gen. Cost	9.69	\$/hr	Fuel Consumption	181,385	L/yr
Marg. Gen. Cost	0.405	\$/kWh	Specific Fuel Cons.	0.235	LWh/y
Electrical Variables			Fuel Energy i/p	1,784,825	kWh/y
Elec. Production	771,577	kWh/y	Mean Elec. Effic.	43.2	%
S-D System: DG13					
Hours of Op.	130	hr/yr	Mean Elec. o/p	353	kW
Number of Starts	121	#/yr	Min. Elec. o/p	153	kW
Operational Life	231	yr	Max. Elec. o/p	374	kW
Capacity Factor	1.05	%	Fuel Consumption	11,121	L/yr
Fixed Gen. Cost	8.21	\$/hr	Specific Fuel Cons.	0.242	LWh/y
Marg. Gen. Cost	0.428	\$/kWh	Fuel Energy i/p	109,430	kWh/y
Elec. Production	45,942	kWh/y	Mean Elec. Effic.	42.0	%
S-D System: SG11					
Rated Capacity	600	kW	Min. o/p	0	kW
Mean o/p	86	kW	Max. o/p	586	kW
Mean o/p	2,075	kWh/d	PV penetration	36.8	%
Capacity Factor	14.4	%	Hours of Operation	4,384	hr/y
Total Production	757,347	kWh/y	Levelized Cost	0.158	\$/kWh

Table 6.16: Additional Generator Results for S-D-S Case

Metric	Quantity	Unit	Metric	Quantity	Unit
S-D-S System: DG7					
Operational Variables			**Electrical Variables**		
Hours of Op.	4,758	hr/yr	Mean Elec. o/p	134	kW
Number of Starts	1,202	#/yr	Min. Elec. o/p	66.0	kW
Operational Life	6.31	yr	Max. Elec. o/p	197	kW
Capacity Factor	33.2	%	**Fuel Variables**		
Fixed Gen. Cost	5.94	$/hr	Fuel Consump.	159,387	L/yr
Marg. Gen. Cost	0.424	$/kWh	Spec. Fuel Cons.	0.249	LWh/y
Electrical Variables			Fuel Energy i/p	1,568,369	kWh/y
Elec. Prod.	639,575	kWh/y	Mean Elec. Effic.	40.8	%
S-D System: DG11					
Hours of Op.	2,582	hr/yr	Mean Elec. o/p	285	kW
Number of Starts	703	#/yr	Min. Elec. o/p	196	kW
Operational Life	11.6	yr	Max. Elec. o/p	400	kW
Capacity Factor	21.0	%	Fuel Consump.	172,435	L/yr
Fixed Gen. Cost	9.69	$/hr	Spec. Fuel Cons.	0.235	LWh/y
Marg. Gen. Cost	0.405	$/kWh	Fuel Energy i/p	1,696,762	kWh/y
Elec. Prod.	734,752	kWh/y	Mean Elec. Effic.	43.3	%
S-D-S System: SG11					
Rated Capacity	750	kW	Min. o/p	0	kW
Mean o/p	107	kW	Max. o/p	771	kW
Mean o/p	2,576	kWh/d	PV penetration	45.6	%
Capacity Factor	14.3	%	Hours of Op.	4,384	hr/y
Total Prod.	940,133	kWh/y	Levelized Cost	0.158	$/kWh
S-D-S System: CV - Inverter					
Capacity	350	kW	Capacity Factor	22.4	%
Mean o/p	78	kW	Energy In	714,671	kWh/y
Max. o/p	345	kW	Losses	28,588	kWh/y
S-D-S System: B3					
Nominal Cap.	575	kWh	Energy In	30,471	kWh/y
Usable Nom. Cap.	345	kWh	Storage Dep.	222	kWh/y
Autonomy	1.47	hr	Losses	5,675	kWh/y
Lifet Through.	321,579	kWh	Ann. Through.	27,475	kWh/y
Batt. Wear Cost	0.413	$/kWh	Expected Life	10.0	yr

Chapter 7

Wind Energy Conversion Systems

This Chapter begins with a brief introduction to the topic of Wind Energy Conversion Systems (WECS) in Section 7.1. The climatic data associated with the system model that pertains to wind energy is introduced and explained in Section 7.2. The architecture of the WECS is explored so that a required knowledge is obtained in Section 7.3. Using the knowledge developed from the introduction and architecture of the WECSs, along with the applicable climatic data, multiple implementable systems are designed and detailed in Sections 7.5 through 7.6, which conform to the system model. The simulation methodology is explored in Section 7.7 and the associated simulation results are provided in Section 7.8. Appendix G provides additional climatic analysis through wind roses and wind frequency distribution charts for selected communities as well as a more detailed look at the system model's wind resources. Appendix G also introduces practical considerations required concerning wind power generation and system loading as well as wind generator unit details that include additional technical specifications and power curve data.

7.1 Wind Energy Conversion Systems (WECS)

In recent years there has been a growing interest in wind energy and its application from communities, governments, and utilities around the globe. This technology is of particular interest in remote communities across Canada as it could potentially allow for communities to become more self sufficient, reduce the costs of energy production, enable communities to have less of a negative environmental impact, and allow communities to partake in government subsidies to improve the local economy and future prospects. With the increased exposure and interest in wind energy conversion systems in the early 1980s many communities and utilities studied the possibilities of combining new technology with their existing infrastructure to take advantage of the potential benefits yielded by the use of WECS [47]. In general the capital costs associated with WECS are significantly higher than other forms of electricity generation. However, the regular operation and maintenance costs associated with installed WECS systems are typically low. When the lower operational costs are coupled with the increasing costs of diesel fuel and increasing costs of carbon and GHG producing technologies the economics of a WECS may prove to have net positive rate of return [6, 7, 49, 50]. Over the past 30 years a number of wind-diesel systems have been installed in many remote Canadian communities which includes those listed in Table 7.1 [49].

Table 7.1: Remote Canadian Communities with Wind-Diesel Hybrid Systems [49]

ON	**NWT**	**NU**
Big Trout Lake	Igloolik	Cambridge Bay
Fort Severn	Omingmaktok	Ellesmere Island
Kasabonika Lake	Sachs Harbour	Iqaluit
Peawanuck		Kugkluktuk
		Rankin Inlet
PQ	**NFLD**	
Kuujjuaq	Ramea Island	

Of the WECS installed in the aforementioned communities most encountered various technical and economical problems during their initial trial periods between 1980 and 2000. This resulted in relatively poor results and only the WECS in Cambridge Bay, NU and Kuujjuaq, NU operated for more than eight years. The majority of the other WECS listed in Table 7.1 were operational for approximately two years or less [7]. The installed WECS were all considered low-penetration projects with the exception of Ramea, NFLD which is scheduled to be completed in 2010 [7, 14]. A low-penetration WECS can be defined as a system where the maximum rated capacity of the installed turbines does not exceed the minimum load of the community and where the WECS typically contributes roughly 20 to 35% of the average annual output to the community. Additionally, in a more practical sense a low-penetration system is a system where the combined installed capacity of all available wind turbines does not interfere with the diesel generators ability to set the voltage and frequency of the local power system. Due to the scarcity of information regarding operational wind-diesel systems, the small quantity of wind-diesel hybrid systems in existence across Canada, and that many remote communities' exhibit similar characteristics a brief analysis of the WECS projects outlined in Table 7.1 were explored to learn from past experiences of practical cold climate installations in Northern Canada [7, 12, 14, 49, 51]. As of 2006 the only wind-diesel systems operational in Canada were Cambridge Bay and Kuujjuaq in NU [7, 49].

In 1996 the Qulliq Energy Corporation (QEC), which is the crown utility of Nunavut and provides electricity through its subsidiary Nunavut Power (NP), launched a wind power programme in hopes to harness additional energy production from wind to offset the costs of diesel generation. Upon the formation of the programme it was assumed that the return on the WECS would be poor. However, the programme was formed to provide practical experience in the area of WECS. This was done so that at a future date, when large scale implementations are economically feasible, QEC has the experience required to make a seamless and cost-effective transition [49].

To date, QEC has operated three WECS using turbines rated less than 100 kW across NU. These WECS were implemented alongside the existing diesel generators in Cambridge Bay, Kugluktuk, and Rankin Inlet. Table 7.2 demonstrates the models and sizes of the turbines used along with the related installation and in-service dates for the three communities. Limited information is publicly available regarding the continued operation of the WECS in these three communities and the QEC has had limited success with their installed WECS [7, 49].

Table 7.2: Existing ADC WECS Installations [7]

Location	Turbine Type	Quantity	Size (kW)	Total (kW)	Date	
					Install	Service
Cambridge Bay, NU	Lagerwey LW18/80	1	80	80	-	1994
Kuluktuk, NU	Lagerwey LW18/80	2	80	160	Oct. 1996	Apr. 1997
Rankin Inlet, NU	Atlantic Orient AOC15/50	1	66	66	Sept. 2000	Nov. 2000

QEC had some difficulties with the procurement of viable turbine options during the mid-1990s. It was also found that while the annual operating and maintenance costs for the turbines was relatively low the costs of transporting materials, obtaining prompt service from the turbine suppliers, and importing trained labour significantly increased the costs of the WECS. It was found that to make WECS viable that locally trained and staffed labour would be required to optimize the operational periods of the turbines. QEC also experienced difficulties with two of the communities with respect to the placement of the turbines. Two of the locations had to be altered after the initial construction had been commenced with greatly increased the CC of the projects. QEC found that although they had consulted with the local populace during the prefeasibility assessment that in the future additional and more extensive planning procedures would be required. Of the two turbines installed in Kugluktuk one became inoperable on July 19, 2000 only 40 months after it became in-service. This failure was due to the turbine falling to the ground after the bolts that held the turbine to the lattice broke. This damaged the turbine beyond repair. Shortly thereafter the second turbine was struck by lightning which caused significant damage to the control circuitry. The second turbine was repaired however these occurrences coupled with regular required maintenance and the time required to obtain service significantly decrease the generating capabilities of the WECS. As of August 1999 a total of 254,080 kWh was generated which displaced 68,670 L of fuel which translated into savings of $41,298 from diesel fuel [7]. QEC provided the annualized CC (ACC) of the WG over the unit project life for comparison purposes. Table 7.3 demonstrates the economic analysis of the installed turbine in Cambridge Bay between 1994 and 1999.

Table 7.3: Cambridge Bay, NU Short Term WECS Results [7]

Year	Production (kWh)	ACC ($)	Fuel Displaced (L)	Fuel Displaced ($)	Price of Fuel ($/L)
1994	57,080	11,416	15,385	8,097	0.5263
1995	155,364	31,073	41,877	22,040	0.5263
1996	150,538	30,108	40,576	21,355	0.5263
1998	122,610	24,522	33,048	19,435	0.5881
1999	72,067	19,425	19,425	12,191	0.6276
2000	-	-	-	-	0.7644
Total	**557659**	**116,544**	**150,311**	**83,118**	-

It was also found that although the turbine was rated for extreme temperatures that energy production was significantly decreased when the temperature decreased lower than -35°C. Cambridge Bay, NU also experienced detrimental delays in service which negatively impacted the bottom line of the turbine. However, with advances in technology and a warmer climate in Northern Ontario the past deficiencies of turbines at extremely cold temperatures should be minimized [7]. It can be seen from Table

7.3 that overall the impact of the WECS resulted in a net positive economic dispatch.

The WECS in Rankin Inlet, NU has an estimated annual generation of 152,000 kWh and is expected to displace 41,100 L of diesel fuel which translates to annual savings of $24,000 (based on diesel prices in 2000). Aside from the initial concerns regarding placement of the turbines additional mechanical issues resulted in extensive downtime during the first year of operation. It was found that between November 23, 2000 and December 1, 2001 that the turbine operated for a total of 3,250 of the 8,952 available hours which translates to an availability of 36.3%. The turbine generated 80,000 kWh during this period of slightly more than one calendar year. The information available for Rankin Inlet demonstrates that the turbine was operational during this period and that net savings on diesel fuel did occur. However more current data is not available to determine a more extensive short term analysis which would be required to determine if the installed turbine was overall cost effective. It is foreseeable that with the rather limited availability during the studied period that this would have a negative impact on the system economics [7].

Meanwhile there has been some interest in WECS in the YT by the Yukon Electrical Company (YEC) but at present there are no wind-diesel hybrid systems installed. There are two wind farms located in Whitehorse, YT which are part of a mid-sized hydro electric based grid that interconnects many communities in the YT [8, 49]. From the remaining communities within Nunavut, as listed in Table 7.1, the WECS installed on Ellesmere Island support local small scale research facilities and the city of Iqaluit is significantly larger than the communities of interest – both of which are independent of QEC operations [7, 49, 51]. In both cases public information is limited and the WECS data would be of limited use. Very little information is available for the low-density wind-diesel hybrid systems located in ON, PQ, and the NWT as indicated in Table 7.1. The Northwest Territories Power Corporation (NTPC), the crown utility in the NWT, has commenced prefeasibility studies for renewable sources of electricity generation. The NTPC has also launched the Alternative Energy Technologies Program (AETP) to promote renewable resources to their service communities. However, at present there are no community scale WECS operated by the NTPC [6, 49]. As previously mentioned these WECS were not operational for longer than two years prior to 2000 which makes any data that is available both dated and sparse.

The WECS located on Ramea Island, NFLD is a developmental research project which commenced in 2004 and is led by Newfoundland and Labrador Hydro in partnership with Natural Resources Canada (NRCan), Memorial University, the University of New Brunswick, and Frontier Power Systems. It is comprised of six 65 kW wind turbines, a 250 kW hydrogen powered generator, a hydrogen electrolyzer and storage facilities, diesel generators, and advanced control systems. It is projected that the Ramea Island WECS will produce 1,000 MWh/year in electricity and is scheduled to be completed in 2010 [14, 49]. Due to the lack of operating experience, technical maturity of the utilized technology, and scope of this thesis Ramea Island is not explored in depth.

Section 7.2 introduces the climatic variables that were developed as part of the system model that relate to the topic of WECS. Section 7.3 introduces the architectures of the wind-diesel hybrid systems that are explored in this thesis including practical design considerations taken into account with the component selection. The Chapter is concluded with a technical and economical analysis of the architectures introduced in Sections 7.3 through 7.7.

In accordance with the REA WECS can be classified as facilities categorized as class 1 through class 5. It should be noted that for both free standing and building mounted WECS local or municipal building permits may be required. Table 7.4 summarizes the REA classes for WECS. The additional notes classified as other will be introduced in Section 7.4. As of February 2011 all offshore renewable projects have been suspended by the government of Ontario until further notice [21].

Table 7.4: WECS REA Classifications

Metric	Class 1	Class 2	Class 3	Class 4	Class 5
Size	≤ 3 kW	> 3 kW and < 50 kW	> 50 kW	> 50 kW	Any
Installation	Any Land Based Location				Offshore
REA Required	No	Yes	Yes	Yes	Yes
Other:					
Class 2	Simplified REA requirements and no mandatory setback.				
Class 3	Quite operation units (< 102 dB) which result in streamlined requirements. Must meet property and road setbacks but not noise setbacks.				
Class 4	Subject to all REA requirements including property, road, and noise setbacks. Noise setbacks for units rated ≥ 102 dB.				
Class 5	Class 4 requirements and additional coastal and natural studies required.				

7.2 Climatic Data Analysis

A climatic data analysis is required due to the vast area and localized climatic differences across Northern Ontario. The following information was collected in the form of monthly averages to perform the climatic data analysis with respect to wind energy: wind speed, wind direction, atmospheric pressure, daily pressure, dry bulb temperature, dew point temperature, and air density was calculated for a collection of locations across Northern Ontario. The analysis was conducted using data made publicly available from Environment Canada and the Ministry of Natural Resources [9, 14].

Table 7.5 summarizes the pressure, temperature, and the mean wind velocity ($\overline{V}_w$) as the median of the monthly averages at the stations listed in Table 2.13. These summarized values were used to represent the system model's wind energy variables. For the summarized pressure values the monthly averages recorded in Moosonee were neglected as it was seen from the monthly average pressure across Northern Ontario graph that the pressure measured in Moosonee was significantly higher compared to any other station for every month. For the summarized wind speed values the monthly averages recorded in Atikokan were neglected as the wind speed was significantly higher at the station compared to any other location for June through December as shown on the monthly average wind speed across Northern Ontario graph. The graphs demonstrating the monthly average wind speed, pressure, and temperature across Northern Ontario can be found in Appendix B. Wind resources are typically superior during the winter months and the later hours of the day. This can be seen from the power generation data for grid connected WECS across ON between Jan. 2007 and Jan. 2010 and the total wind power generated in ON measured on an hourly basis between Mar. 1 to 9 2010 Figures in Appendix G. Additional Figures demonstrating the system model scaled wind resources with respect to: monthly averages, daily profiles, duration curve, CDF, PDF, and DMap are included in Appendix G.

Table 7.5: Wind Energy Climatic Variables [3, 9]

Month	Climate Parameter		
	Pressure (kPa)	Temperature (ºC)	Wind Velocity (m/s)
Jan.	97.66	-19.0	3.31
Feb.	97.60	-15.5	3.42
Mar.	97.71	-8.8	3.60
Apr.	97.53	0.5	3.90
May	97.56	8.8	3.85
June	97.43	14.3	3.64
July	97.48	17.2	3.40
Aug.	97.55	15.8	3.24
Sept.	97.58	9.7	3.60
Oct.	97.50	3.8	3.77
Nov.	97.38	-5.5	3.73
Dec.	97.55	-15.0	3.22
Avg.	97.54	0.5	3.56

It should be noted that the majority of the weather stations used an anemometer height (z_{anem}) of 10 m AGL for the readings as found in the CWEEDS dataset. As a result the average wind speeds provided in Table 7.5 are assumed to be at 10 m above ground. These weather stations are also typically located at the community airfield which is normally sheltered from the elements when possible. These two aspects lead to an overall conservative estimation of the community wind resources. A number of Environment Canada weather stations have incomplete information regarding the anemometer location regarding both height and installation site. As previously mentioned measuring equipment error must also be considered and having trained staff on location is vital for accurate data collection.

7.3 Technical Considerations

Wind is an intermittent and non-dispatchable supply which creates additional challenges when operating WECS for power generation. The WG will have a name plate capacity which indicates the rated output power of the turbine. Wind penetration is the average power output of the WG divided by the average primary load and the capacity factor is the average power output of the WG divided by the total WG capacity. The performance of the WG is based upon the nameplate capacity and the power curve. The power curve is used to indicate various output powers for their corresponding wind speed. The cut-in wind speed is the speed at which the WG will start to produce electricity. The rated wind speed is the wind speed required to obtain maximum power output which can be seen as a peak on the power curve. Increasing wind speeds that surpass the rated wind speed typically result in minimal changes to the output power however when wind speeds become too high the WG will disengage at the speed known as the cut-out speed. Damage to the WG may be experienced if the wind speed reaches the extreme wind speed threshold. The power curves and additional information regarding the WGs investigated in this thesis can be seen in Appendix G.

The height of the community above sea level also affects the WECS as the air density changes with height and the available output power capacity of the WG varies with the change in air density. The elevation of the system model is 297.9 metres ASL and the effects of altitude will be explored later in this Section. In order to investigate the difference in altitude the wind shear or wind gradient must be explored. The wind shear is the difference in wind speed and direction over a relatively short distance and account for differences in both vertical and horizontal directions. Wind shear accounts for the difference in wind speeds at coastal locations and changes in low altitude wind speeds.

7.4 Installation Considerations

The installation location and orientation of the WG will vary significantly from location to location. However, using the available data from the climatic analysis a general rule of thumb orientation can be derived. Being as nearly 50% of the remote communities within ON are located in the same immediate region as Big Trout Lake and that the only available weather station in this region is located there it will be explored in-depth as the typical interior remote community. All other communities, with the exception of Moosonee, were also analyzed in the same manner and the respective results are located in Appendix B. Moosonee was neglected as the data availability was not ideal, it is connected to the bulk electrical grid via a 115 kV line with no nearby remote communities, and it is a coastal community which typically receive better wind penetration. Big Trout Lake was explored with respect to wind resources between 1984 and 1990 inclusively. During this 7 year period a total of 61,368 hours of wind data was recorded with an average wind speed of 4.52 m/s. It was found that there were 2,133 calm hours (or data entries as it is hourly) which translates to calm conditions 3.48 % of the time. There were a total of 42 missing or incomplete records during the 7 year period which translates to a data availability of

99.93% and a total of 61,326 hourly entries. Figure 7.1 demonstrates the wind rose for Big Trout Lake during this period. The wind rose demonstrates the direction of the prevailing wind, the wind speed, and the distribution of the given speed in the corresponding direction. This particular wind rose was subdivided into 36 directions and the simplified model using 16 directions is available in Appendix B. It can be seen from Figure 7.1 that the strongest winds occur in the NWN and the most frequent direction for wind penetration is from the WNW. In this situation there is a trade off between the most frequent direction and direction of strongest penetration however it is clear from the figure that the turbine should be orientated in the NW direction and in this case between NWN and WNW. Reviewing the associated locations available in Appendix B and Appendix G it can be seen that as a general rule of thumb the WG should be installed in a Westerly orientation as the prevailing wind is commonly available from the West.

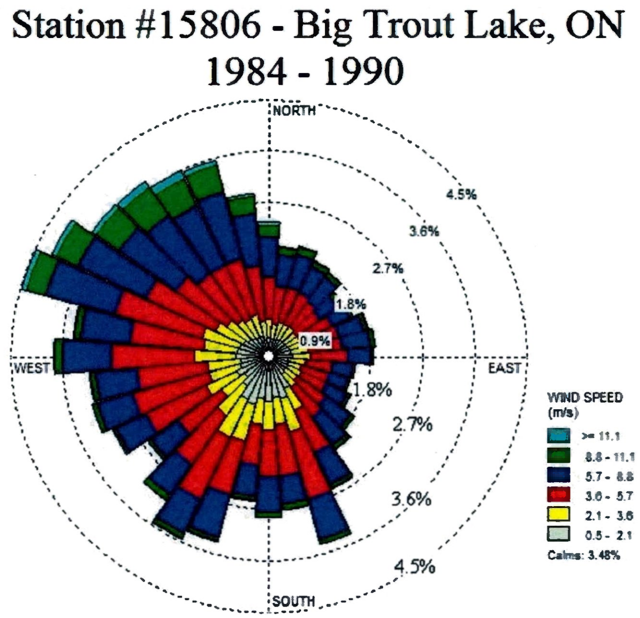

Figure 7.1: Big Trout Lake Wind Rose

Figure 7.2 demonstrates the frequency distribution of wind speed in Big Trout Lake. For the analysis of the raw data used in the creation of Figures 7.1 and 7.2 6 classes were used as seen in Figure 7.2. The highest percentage of distribution occurs in the class that ranges from 3.6 to 5.7 m/s which also coincides with the projected wind speeds of the system model.

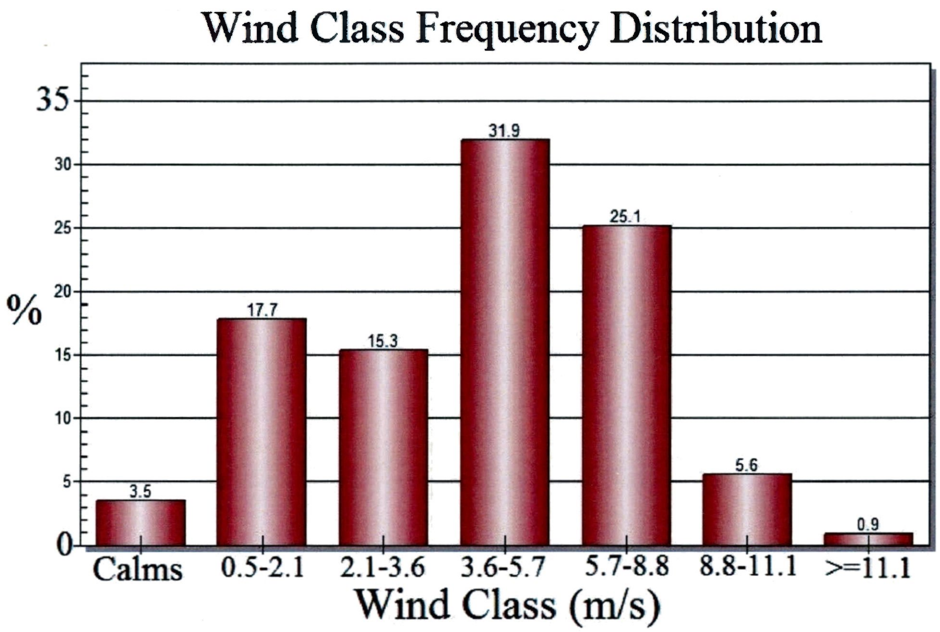

Figure 7.2: Big Trout Lake Wind Speed Frequency Distribution

The wind resources provided were measured at 10 m off the ground. However, the hub height (z_{hub}) of various WG models typically varies between 25 to 30 m above ground level. Wind speeds are typically improved as height increases mainly due to less ground resistance. This increase of wind penetration at higher altitudes is analyzed in Appendix G. Air density and temperature decrease with height. Thus it can be assumed that the WG will experience better wind resources than provided by the climatic analysis however the climatic analysis results are used to provide a conservative case for feasibility. For the purpose of simulation it is assumed that a WG with a hub height of 30 m will experience approximately 1.3667 m/s better wind speed when compared to the 10 m anemometer height. This is based on Equation 7.7 in Section 7.7 using a terrain consisting of forest and woodland. It is common for WG with a name plate capacity of 50 kW or less to have a hub height of around 25 meters whereas large multi-megawatt WGs typically have a hub height of around 100 meters.

Additional aspects beyond wind resources must be considered for WECS installation which includes accessibility, cost of providing accessibility and unit transportation, terrain suitability for: the installation crews and their equipment, the transmission network installation and right of way, and WG base installation. Ontario laws must also be considered concerning the placement of WGs and population located nearby. Community social and political concerns must also be addressed though extensive community consultation and involvement during the pre-feasibility analysis. This should be addressed during this stage to manage costs, time, and to foster community involvement the support of the residents in remote communities is vital.

Under the GEGEA and REA public consultation for renewable projects are required for all projects classified as class 3 - 5. Initially all nearby property owners (within the 120 m range) must be notified and advertisements published in local media resources. At least two community consultations must be held by law with additional consultations being considered ideal. During the application process all related studies must be made publicly available and upon completion project planning a final public consultation must be performed. Aboriginal consultations are mandatory and a list of all Aboriginal communities of interest for any given location can be obtained from the MOE which outlines both communities and treaty rights that may be affected by development [21, 41].

WECS that require a noise study or noise setback must ensure that the noise level does not exceed 40 dB. This is done by ensuring a minimum of 550 m clearance is provided or through a noise study and analysis to determine a more accurate position requirement. All WECS with a nameplate capacity equal to or greater than 50 kW must be set back at least the height of the WG from adjacent properties where the adjacent properties land owner is not involved in a contractual agreement to lessen this distance or involved with the WECS project itself. This distance may be reduced where there are no surrounding land use concerns are present to allow for a distance equal to the blade length plus 10 metres. WECS must also be set back from roads and railways right of way by at least the blade length plus 10 metres. As an additional criterion, WECS must maintain conditions for approval, which include procedures to ensure safe operation of the WECS and the requirement to maintain the equipment [21, 41].

In addition to the federal government requirements for SECS, which also apply for WECS, it is advised to consider the following organizations for WECS. For WECS located within 80 km of a national weather radar station, either land based or offshore, Environment Canada must be contacted due to the potential interference with weather radar signals and their ability to detect severe weather pattern. The only weather stations in NW ON are located near Dryden and outside of Thunder Bay so in remote communities this will not have an impact. Environment Canada must also be contacted if offshore WECS can potentially affect water quality in any way. The

Royal Canadian Mounted Police require all proposed WECS applicants to contact their mobile communication services division. The Canadian Broadcasting Corporation (CBC) requires WECS applicants to comply with the Radio Advisory Board of Canada and CanWEA guidelines and to notify the CBC of any proposed WECS projects. Transport Canada (TC) requires all obstacles to be installed in accordance to the Canadian Aviation Regulations (CARS). In addition to the CARS requirements, the Aeronautical Obstruction Clearance Form must be completed, and any WECS installed near aerodromes must be brought to the attention of TC due to possible alterations in bird patterns near the WECS site. This is required in addition to the Canadian Environmental Assessment Act. Due to the small size of most of the remote communities and the importance of aviation in the remote communities the TC requirements are particularly important to consider. The above organizations and ministries provide an outline as to the requirements of WECS installations under the existing REA and GEGEA however additional research should be done during the planning stages of WECS development. In addition to the provincial and federal guidelines there may be municipal bylaws that must also be considered. The installation requirements for renewable projects as outlined in Chapter 6 regarding cultural and natural heritage sites, endangered species, water ways, shoreline areas, provincial parks, and in the far North are also considered for WECS [14, 21, 41].

Of particular importance when considering the installation of WECS are bats and bat habitats. As previously introduced, for class 3 - 5 installations, environmental assessments must be considered when planning renewable energy projects. These assessments are done both during the planning stages and post construction. It has been found that bat migratory paths follow natural corridors such as escarpments, ridges, and shorelines. Abandoned mines and caves are commonly used as nesting sites and bat levels are commonly higher around bodies of water and wetlands. Bat mortality rates have been found to be the highest along forested ridge tops and along the shore of large bodies of water [9, 14, 21, 40].

7.5 System Diagram

The WECS modelled for simulation can be seen by the system diagrams in Figures 7.3 and 7.4. These system configurations can be summarized as either wind-diesel hybrid systems as seen on the left or wind-diesel hybrid system with storage as seen on the right. Figure 7.3 and 7.4 represent the system using an AC WG and DC WG respectively. As with the SG unit if the DC WG unit is used it must also be connected to a DC bus and the CV unit is required to supply the AC load attached to the AC bus.

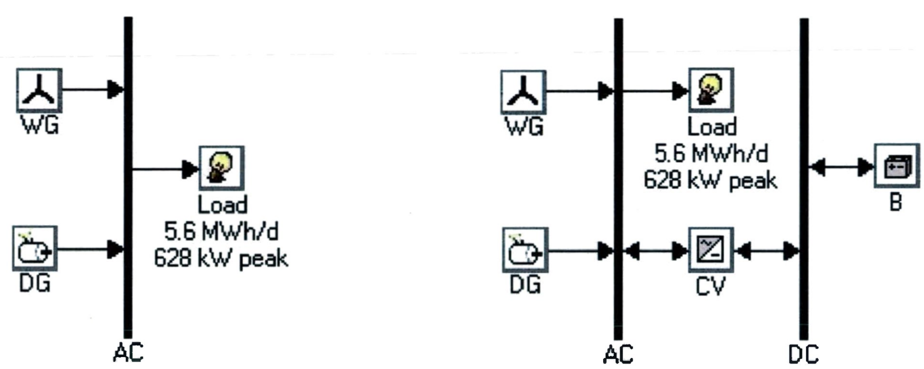

Figure 7.3: WECS AC Circuit Diagrams

Figure 7.4: WECS DC Circuit Diagrams

In addition to the WECS configurations explored above a wind-solar-diesel system is simulated both with and without storage as seen in Figure 7.5 and with DC WG options as seen in Figure 7.6. At this point in time only the AC WECS will be considered in this thesis.

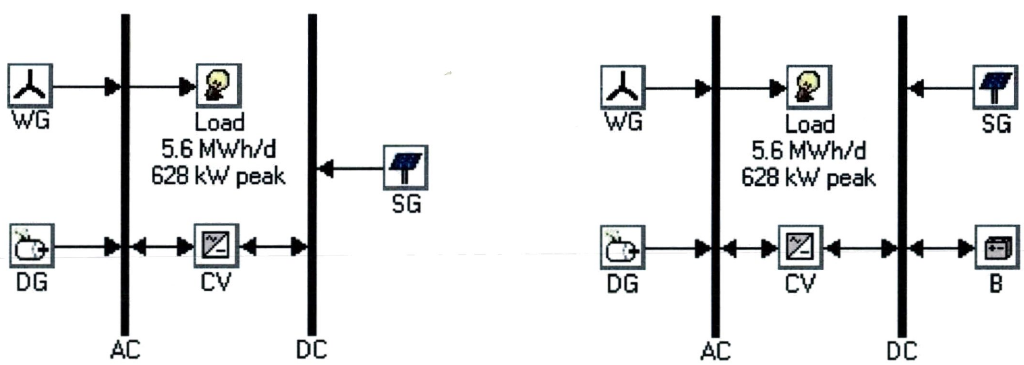

Figure 7.5: Combined SECS and AC WECS Circuit Diagrams

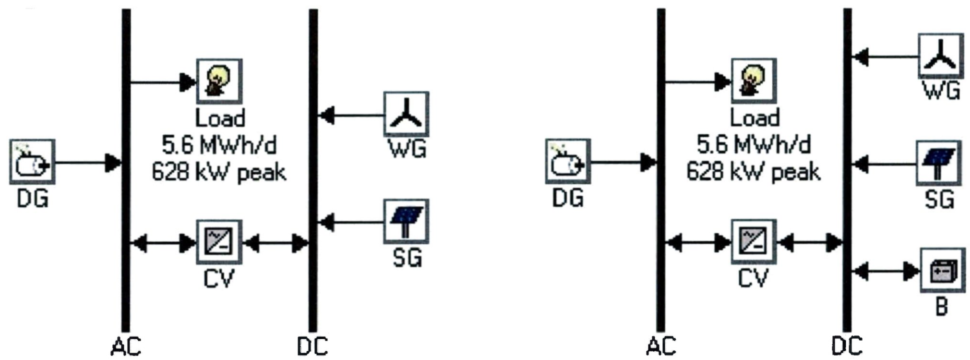

Figure 7.6: Combined SECS and DC WECS Circuit Diagrams

7.6 Unit Selection for Simulation

For the purpose of simulation of this thesis a total of ten different WGs will be considered to constitute the WECS. These units were selected based on past experiences in Arctic conditions, Arctic weather ratings, accessibility, and to allow for some variance with respect to manufacturer and rated capacity selection. Table 7.6 introduces the studied units and their respective reference ID, manufacturer, and model information. The reference ID will be used here on in to indicate the selected unit and additional information regarding the selected WGs can be found in Appendix G.

Table 7.6: List of WECS Suppliers and Models

Reference	Manufacturer	Model	Pmax (kW)	Country
WG1	Furlander	FL30	30	DE
WG2	Furlander	FL100	100	DE
WG3	Furlander	FL250	250	DE
WG4	Vestas	V27	225	DK
WG5	Northern Power	NW100/19	100	USA
WG6	Northern Power	NW100A	100	USA
WG7	Atlantic Orient Corperation	AOC 15/50	50	CA
WG8	Endurance	G-3120	35	CA
WG9	Endurance	E-3120	55	CA
WG10	Bergey	Excel-S	10	CA

Table 7.7 introduces additional technical parameters of the WG units including key parameters such as rated output, rotor diameter, hub height, and associated speeds. For additional parameters refer to Appendix G and/or the respective WG datasheet(s).

Table 7.7: WECS Component General Technical Information

Ref. #	Rated Output (kW)	Rotor Diameter (m)	Hub Height (m)	Cut-in Speed (m/s)	Cut-out Speed (m/s)	Max Speed (m/s)
WG1	30	13	27	2.5	25	55
WG2	100	21	35	2.5	25	67
WG3	250	29.5	42	2.5	25	67
WG4	225	27	30	3.6	25	53.6
WG5	100	21	37	3.5	25	59.5
WG6	100	21	37	3.5	25	56
WG7	50	15	24.4	4.6	22.4	59.5
WG8	35	19.2	42.7	3.5	25	52
WG9	55	19.2	42.7	3.5	25	52
WG10	10	7	43	2.2	-	60

Since the WGs are being installed along side an existing DGS there will be some modifications required to said DGS to allow for the implementation of the WECS. This affects the CC of the WECS since the infrastructure does not currently exist as part of the DGS installation and these modifications are required. Table 7.8 demonstrates the CC, shipment costs, installation costs, and foundation costs per unit which form the WECS Net CC. Table 7.8 also includes the RC and O&M of the WECS. Exact values and their sources can be found in Appendix A.

Table 7.8: WECS Component Cost Information

Ref. #	Unit CC ($)*	Shipping Costs ($)*	Installation Costs ($)*	Foundation Costs ($)*	Net CC ($)*	RC ($)*	O&M ($/yr)
WG1	90	20	40	37.5	187.5	90	4691
WG2	232	38.5	54.5	90	415	195	5401
WG3	451	71	111	132	765	379.8	6496
WG4	230	75	120	150	575	255	5391
WG5	230	35	75	100	440	204	5391
WG6	245	35	75	100	455	213	5466
WG7	90	25	50	100	265	99	4691
WG8	76.5	16.6	29.7	33.4	156.2	73.7	4624
WG9	94.5	20.5	36.7	41.2	193	91	4714
WG10	61	13.2	23.7	26.6	124.6	58.7	4546

**Note: In '000s of dollars*

For simulation purposes it is assumed that the cost curve for quantity of WGs versus net CC is a linear function. The varying costs associated with penetration level and DGS expansion costs as indicated in Table 3.8 will be accounted for on separate linear approximations as required when the number of investigated WGs is sufficient for an increase in penetration level. The base case net CC for any given WECS studied will have the associated expansion costs for a low penetration system included. These costs will be utilized during the unit simulation to determine the feasibility of the system in question.

7.7 Simulation Methodology

This Section introduces the simulation methodology for the WECS only. The SECS simulation methodology was previously discussed and only the dispatch methods require altering for the combined systems composed of the wind-solar-diesel hybrid system and its derivatives as described in Figures 7.5 and 7.6. Table 7.9 introduce the WG quantities that will be simulated for this thesis. These units were introduced in a technical manner in both Section 7.3 and Appendix G. As per the penetration ranges in Table 3.7 the minimum and maximum quantity of WGs are denoted if the proposed WECS consisted of only the singular WG model. For costing applications, due to penetration levels, the maximum quantity of units to be simulated for some models may be artificially high. The number of units that may be physically installed at a given location is dependent upon circumstances out of control and scope of this thesis. During the analysis of the simulation results the number of units that could reasonably be installed will be considered.

Table 7.9: WECS Simulation Metrics for Consideration

Ref. #	Low		Med.		High		# Units Simulated
	Min.	Max.	Min.	Max.	Min.	Max.	
WG1	0	20	21	40	41	162	0 - 20
WG2	0	6	7	12	13	48	0 - 12
WG3	0	2	3	4	5	19	0 - 19
WG4	0	2	3	5	6	21	0 - 21
WG5	0	6	7	12	13	48	0 - 12
WG6	0	6	7	12	13	48	0 - 12
WG7	0	12	13	24	25	97	0 - 24
WG8	0	17	18	34	35	139	0 - 34
WG9	0	11	12	22	23	88	0 - 22
WG10	0	61	62	122	123	488	0 - 25

The simulation process utilizes the monthly average wind speed of the system model for data acquisition purposes. However, to model the system model for simulation hourly data is required. Being as the system model covers a large geographical area with fluctuating hourly wind penetration the simulation tool approximates the model's hourly wind resources using a statistical method. If hourly data exists for a site it may be used for simulation purposes however synthetic data is normally generated on a monthly basis from the 12 average monthly wind speed values to generate the 8,760 average hourly wind speeds. The statistical variables used to populate the model are developed by contributions from [52, 53], and the typical parameter values, are provided in Table 7.10. The method of implementing these variables and their significance are explained below.

Table 7.10: Advanced Wind Resource Parameters

Metric	Value	
	Utilized	Typical
Weibull k	2	1.5 - 2.5
Autocorrelation Factor	0.85	0.8 - 0.95
Diurnal Pattern Strength	0.25	0.0 - 0.4
Hours of Peak Windspeed	15	14-16

Wind resources are commonly modelled using a Weibull distribution which is what was used to generate the synthetic wind resources in this thesis. The two-parameter Weibull distribution, represented by the probability density function in Equation 7.1, is often used to characterize wind resources [15, 54, 52]. This is used as the result of extensive research in the area of wind analysis as it provides a well fitting wind resource profile when compared to measured historic wind data [52].

$$f(v) = \frac{k}{c}\left(\frac{v}{c}\right)^{k-1} * \exp\left[-\left(\frac{v}{c}\right)^{k}\right] \tag{7.1}$$

Equation 7.2 indicates the Cumulative Distribution Function (CDF) of the wind resources at the given community [15]. The system model's wind resource CDF can be found in Appendix G.

$$F(v) = 1 - \exp\left[-\left(\frac{v}{c}\right)^{k}\right] \tag{7.2}$$

Equation 7.3 indicates a function that relates the two Weibull parameters from Equation 7.1 and the average wind speed as a simplified expression [15].

$$\bar{v} = c\Gamma\left(\frac{1}{k} + 1\right) \tag{7.3}$$

Variable	Description	Unit
v	Wind Speed	m/s
k	Weibull Shape Factor	-
c	Weibull Scale Parameter	m/s

The Weibull distribution can be described by the use of the Weibull k value and average wind speeds. This Weibull k value is a measure of the long-term distribution of wind speeds and it represents the shape factor of the Weibull curve that demonstrates the breadth of the distribution of wind speeds over the course of a year. The lower the k value the broader the resulting Weibull probability distribution function. This broader wind speed distribution results in a wider range of wind speeds over the given period. The higher the k value the narrower the range of the resulting Weibull probability distribution. A high k value is uncommon in areas with relatively standard wind resources and a k value of 2 is defaulted as it indicates most community wind resources relatively accurately. There is a moderate correlation between the Weibull k value and the average wind speed. In general, the lower average wind speeds correspond to a lower Weibull k value [52].

Wind speeds at a specific location typically exhibit a dependency upon the preceding hour's wind speed. This dependency is known as autocorrelation and is represented by r_1 which is denoted by a value between 0.0 and 1.0. When no autocorrelation is considered, or $r_1 = 0$, while generating synthetic data each hourly average is completely independent of the previous hour's speeds and the resulting data points increase and decrease at random. When a moderate autocorrelation is considered, or $r_1 = 0.5$, the synthetic wind speed time series demonstrates some correlation including the past hour's wind speed however there are still significant volatility expressed in the time series. When a strong autocorrelation is considered, or $r_1 = 0.96$, the resulting time series is much smoother and more practical when considering physical wind resources [53]. This can be explained by an example case. If a sustained wind speed of 3 m/s is experienced in hour 1 it is logical to assume that in hour 2 the sustained wind speed would be similar both in magnitude and direction [15]. The value of the ideal and accurate autocorrelation value varies from location to location. Equation 7.4 represents the autocorrelation coefficient r_k [15, 53].

$$r_k = \frac{\sum_{i=1}^{n-k} (z_i - \bar{z})(z_{i+k} - \bar{z})}{\sum_{i=1}^{n} (z_i - \bar{z})^2} \tag{7.4}$$

The variable r_k represents the autocorrelation between any two time series values separated by a lag of k time units. The autocorrelation value for r_0 is by default 1. Some communities have a very strong autocorrelation during short lags and exhibit weak autocorrelation during longer lags. This indicates that there is little daily pattern exhibited at the site with respect to wind resources. In contrast, other locations may exhibit distinct daily patterns in their wind resources where the afternoons are typically windier than the morning periods. This recurring pattern in the wind speed causes the autocorrelation function to oscillate over the 24 hour period. This indicates that the wind speed during hour 1 on one day is going to be similar to the wind speed during hour 1 on another day. The autocorrelation factor, demonstrated by Equation 7.5, is the measure of how strongly the wind speed in the current hour is dependent upon the wind speed during the previous hour as an average [15, 53]. It is a single number that is used to represent the autocorrelation characteristics as demonstrated by Equation 7.4 in a simplified manner.

$$r_k = r_1^k \tag{7.5}$$

Variable	Description	Unit
r_k	Autocorrelation Between any 2 Time Series	-
k	Seperation or Lag Between 2 Time Series	time units
i	Hour Number	-
z	Wind Speed	m/s
n	Iteration Number	-

To simplify the autocorrelation characteristics the effects of the diurnal pattern is removed. This is done by using an average diurnal profile which is subtracted from the wind resource profile being used to generate the synthetic wind speed data. This is achieved by creating an average time series of 0 m/s where the resulting pattern indicates only the change in wind speed which is normally not represented as oscillation as there is no reoccurring pattern. Equation 7.5 models a damped exponential function which represents the resulting wind resource profile. Thus, a single parameter indicated by r_1 describes the degree of autocorrelation experienced at the community. Communities surrounded by a variety of different types of topography tend to have low (0.70 - 0.80) autocorrelation factors whereas communities surrounded by uniform topography tend to have high (0.90 - 0.97) autocorrelation factors. Uniform topography may commonly be represented as plains or open water that surrounds a community. The autocorrelation is independent of the Weibull k parameter as it reflects how randomly the wind speeds vary from hour to hour at a given location [15, 53].

The diurnal pattern strength (δ) is the measure of how strongly the wind speed depends upon the time of day. δ is assigned a value between 0 and 1. Since wind energy is in part affected by solar radiation there is a varying effect due to the diurnal cycle on localized wind speeds [15, 54]. This effect is introduced in Appendix I. Due to the diurnal cycle it is common that the afternoon period experiences higher wind speeds than during the morning. It is also possible to see that wind energy is better during the winter months than summer months which is also in part attributed to the diurnal cycle. Appendix G demonstrates both of these characteristics. The diurnal pattern strength indicates the dependency of wind speed on the time of day. A high diurnal pattern strength indicates a strong dependence and vice versa. The diurnal pattern strength, commonly demonstrated on a distribution map (DMap) as in Appendix G, is calculated from the average diurnal profile on an hourly basis using the respective hours' annual average wind speed [15, 54]. To determine the strength of the diurnal pattern the average diurnal profile, as calculated by Equation 7.6, is used to calculate the average wind speed for each hour of the day [15]. These results are then fitted to a cosine function indicated in which results in the ratio of the amplitude of the cosine wave to the average wind speed (diurnal pattern strength vs. frequency) [15].

$$v_i = \bar{v}\left\{1 + \left\{\delta \cos\left[\left(\frac{2\pi}{24}\right)(i - \Phi)\right]\right\}\right\} \tag{7.6}$$

Variable	Description	Unit
i	Hour Number	1 - 24
δ	Diurnal Pattern Strength	0.0 - 1.0
Φ	Hour of Peak Windspeed	1 - 24

The hour of peak wind speed (Ø) is the period during which the average highest wind speeds are generally obtained. This hour normally also represents the period of the daily peak wind speed [15, 54].

Figure 7.7 demonstrates the range, average, maximum, and minimum wind speeds as predicted for the system model with respect to WECS simulation. These variables were calculated from the system model's climatic values as per Section 7.2 and the aforementioned statistical method modeling variables as listed in Table 7.10. After the hourly wind data is approximated from both the aforementioned processes and the system model's climatic data a three step process is used to determine the specific WG's output power during a particular hour at the installation location.

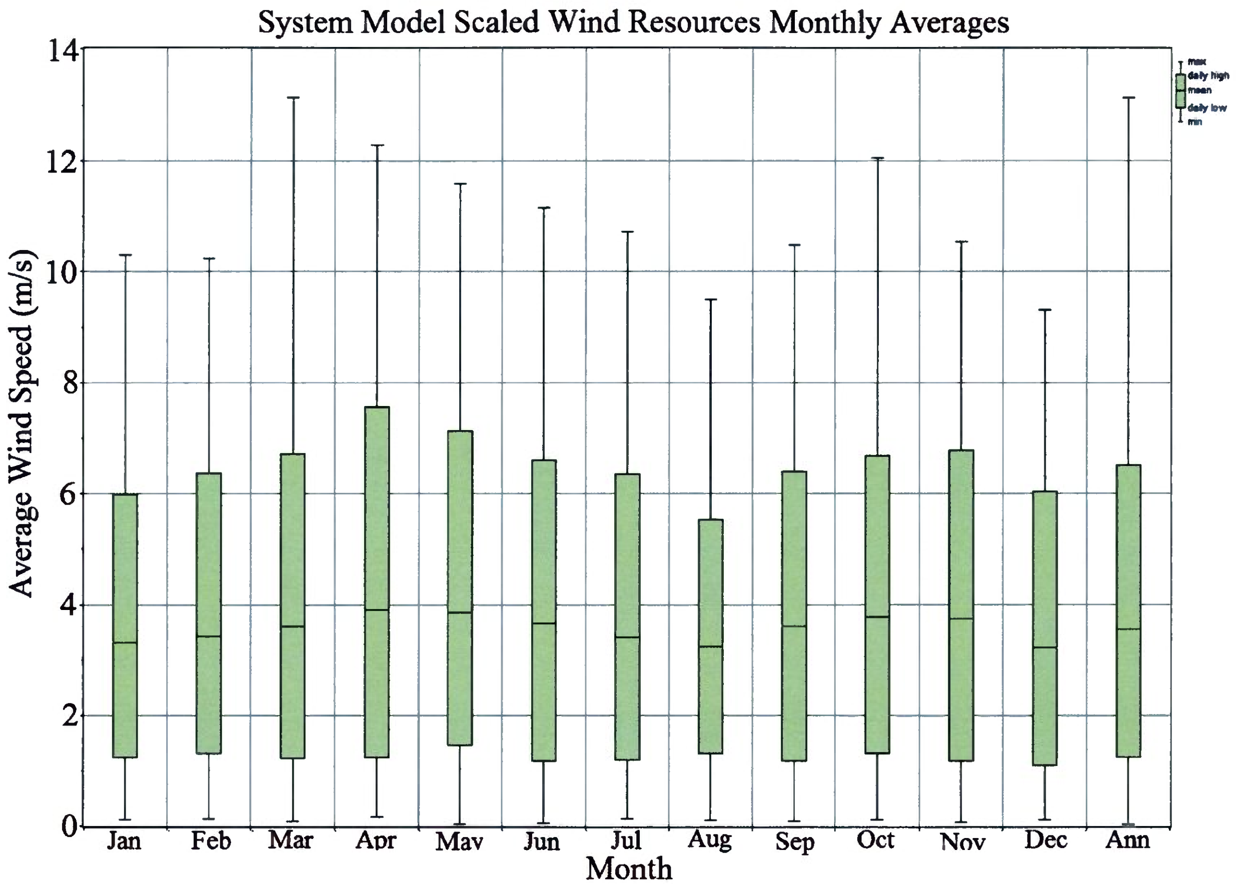

Figure 7.7: Monthly Wind Speed Distribution of the System Model

First, the resulting hourly wind speed for the model is adjusted from the provided anemometer height to the WG hub height as introduced in Section 7.6 [15, 54]. As introduced in Section 7.3 wind shear is used to approximate the wind resources available at the WG hub height. Wind resources do improve with altitude as seen in Appendix G. However, when accounting for the change between the 10 m anemometer height and the WG hub height the wind shear is primarily experienced due to ground level obstacles and local topographic features. Equation 7.7 is used to correct for this change in altitude by assuming that the wind speed is proportional to the logarithm of the height above ground [15]. This is done by providing the wind speed at hub height with respect to wind speed at anemometer height.

$$\frac{v\left(z_{hub}\right)}{v\left(z_{anem}\right)} = \frac{ln\left(\frac{z_{hub}}{z_0}\right)}{ln\left(\frac{z_{anem}}{z_0}\right)} \tag{7.7}$$

Variable	Description	Unit
z_{hub}	Hub Height	m
z_{anem}	Anemometer Height	m
z_0	Surface Roughness Length	m
$v(z_{hub})$	Wind Speed at the Hub Height	m/s
$v(z_{anem})$	Wind Speed at the Anemometer Height	m/s

The surface roughness length used by Equation 7.7 characterizes the roughness of the terrain surrounding the WG. Table 7.11 includes common surface roughness lengths.

Table 7.11: Surface Roughness Length

Terrain Type	z_0 (m)	Terrain Type	z_0 (m)
Very smooth, ice or mud	0.00001	Crops	0.05
Calm open sea	0.0002	Few trees	0.10
Blown sea	0.0005	Many trees, few buildings	0.25
Snow surface	0.003	Forest and woodlands	0.5
Lawn grass	0.008	Suburbs	1.5
Rough pasture	0.010	City centre, tall buildings	3.0
Fallow field	0.03	-	

Second, the particular WG's power curve is used to calculate the power output under

STP conditions [15, 53]. Appendix G contains the power curve information used for simulation purposes for the investigated WGs. Third, the air density ratio is applied against the resulting output power level found from the power curve to account for the system model's elevation ASL as introduced in Section 7.3 [15, 54]. Equation 7.8 is the air density ratio equation, which is a function of altitude, and used in the WG output power calculation process [15]. Equation 7.8 is derived from the ideal gas law which is used to model the air density ratio and also accounts for the change in temperature and pressure due to a change in altitude [15, 55]. It is assumed using STP conditions that for an altitude of up to 11,000 m that temperature decreases linearly with altitude which is modelled as a relationship between the lapse rate and altitude. As such as the altitude of the WG installation location increases the air density decreases as compared to STP conditions. This decrease in air density leads to degradation in the performance of the WECS. Air density is also impacted by the cold temperatures associated with weather patterns and cold weather extremes may lead to air density levels significantly higher than at STP conditions. For the system model the air density ratio should have minimal impact from the affects of altitude however cold winter weather may have more of an impact on air density.

$$\frac{\rho}{\rho_0} = \left(1 - \frac{Bz}{T_0}\right)^{\frac{g}{RB}} \left(\frac{T_0}{T_0 - Bz}\right) \tag{7.8}$$

Variable	Description	Unit/Value
ρ	Air Density	kg/m^3
ρ_0	Standard Pressure	101.325 kPa
B	Lapse Rate	0.00650 K/m
z	Altitude	m
T_0	Standard Temperature	288.16 K
g	Gravitational Acceleration	$9.81 m/s^2$
R	Gas Constant	287 J/(kg*K)

Once the above process is complete for a given period it is repeated for the entire time series of hourly wind resources at the system model location. This is applied towards the simulation of the proposed systems from Section 7.5 and the results are discussed in Section 7.8. The synthetic model developed by [52] and [53] was verified from field or actual results upon its implementation by NREL. It was found that the synthetic solar resources varied from the actual resources within a tolerance of less than 5%. This indicates that the simulated results are within an acceptable margin of error [15].

7.8 Simulation Results

Table 7.12 demonstrates the top 5 optimal results of the simulated W-D systems. The difference between simulation 3 and 9 are considered negligible however only 3 WGs are required for the optimal system in simulation 3 as opposed to 9. The optimal response for simulation 8 is removed from selection even though it is the best optimal result in favour of a 3 WG system as opposed to 12. The remaining 2 systems demonstrate significantly poorer results when compared to the above. All variables represented in this Section are comprised of the composite DG and related renewable generator as a sum of the associated costs of both systems. All of the studied systems in this Section were investigated over a 25 year period which is reflected by the NPV.

Table 7.12: Top 5 Optimal W-D Results

Ref. Sim. #	# **WG**	**Initial Capital** ($)	**O&M** ($/yr)	**Total NPV** ($)	**COE** ($/kWh)	**Ren. Frac.** (%)	**Diesel Consump.** (L)
8	12	2,475,303	708,911	18,120,612	0.398	0.39	351,487
9	9	2,301,640	750,424	18,863,128	0.415	0.28	380,835
3	**3**	**2,797,478**	**732,473**	**18,962,798**	**0.417**	**0.29**	**380,901**
4	3	2,227,478	780,670	19,456,480	0.428	0.20	409,218
5	4	2,122,478	804,571	19,878,948	0.437	0.17	419,428

For the W-D-S system both load following and cycle charging dispatch methods were simulated. The set point utilized was set to 80% state of charge. Although results varied relative to the simulated system it was found that the cycle charging dispatch was superior to the load following dispatch methodology. Two methodologies were used for simulation of the W-D-S system. The first was to find the optimal system configuration as used by the D, S-D, and W-D systems. The second was utilizing the optimal system found by the W-D system and modelling the W-D-S system with similar components to facilitate comparison metrics. The second choice was used in this section with additional information available in Appendix B. The resulting W-D-S system results can be found in Table 7.13. As expected the storage allows for systems with a higher renewable penetration however there is an increased initial

CC to consider. Table 7.13 also provides a summary of the DG, WG, CV, and B units used in the selected hybrid systems which include: which units were used, their respective quantity, installed capacity, percentage of generator contribution to overall system, operating time, and the energy generated per year of the applicable generator units. The simulation was modelled to allow for multiple generators to operate simultaneously which includes various renewable generators and the base case's diesel generators. The selected results for the wind-diesel and wind-diesel-storage hybrid systems are found in Table 7.13.

Table 7.13: Selected Results for WECS

System Type	**Initial Capital** ($)	**O&M** ($/yr)	**Total NPV** ($)	**COE** ($/kWh)	**Ren. Frac.** (%)	**Diesel Consump.** (L)
W-D	2,797,478	732,473	18,962,798	0.417	0.29	380,901
W-D-S	3,960,698	676,471	18,890,084	0.415	0.37	340,322
System Type	**Unit Ref. #**	**Quan.**	**Size (kW)**	**Time (hr)**	**kWh/yr**	**% Gen.**
W-D	DG7	1	220	4,787	525,397	24
	DG11	1	400	4,028	990,273	45
	DG13	1	500	195	65,513	3
	WG3	3	750	7,375	631,825	29
W-D-S	DG7:	1	220	4,591	568,970	25
	DG11:	1	400	3,058	842,970	37
	DG13:	1	500	2	706	< 1
	WG3[1]:	4	1,000	7,375	842,433	37
	B3[2]:	160	575 kWh	-	23,269	N/A
	CV:	150 kW	[1]WG3 are 250 kW each [2]B3 are 6V 599 Ah			

It can be seen from Table 7.13 that the W-D and W-D-S systems reduce diesel consumption by 110,912 L and 151,491 L or -25.6% or -30.8% respectively when compared to the D case. The diesel fuel saved from the W-D system is roughly equivalent to 2 winter months or 3 summer months which reflect relatively substantial savings in fuel with the medium penetration installation. The initial CC of the systems utilizing WGs are substantially higher than the D system with lower yearly O&M costs. Although WG systems do inherently have very low O&M costs, as can be seen from Table 7.13, diesel generators are still required to service the community. The modelled W-D system utilizes a load following dispatch which requires constant DG utilization as a base load. WGs are used, when possible, to decrease the size of the DG units required for operation. The DGs are also used to mitigate the intermittent nature of WECS and to offset marginal WG output. This required use of DGs increases the O&M of the W-D-(S) systems. To decrease the required use of DG units a high penetration system would need to be installed as introduced in Chapter 3 which is not viable at this point in time. A system with a high renewable fraction would have a significantly higher CC with a significantly lower O&M cost. The total number of DG running hours, calculated from the combined use of all 3 DG units, are 9,480, 9,010, and 7,651 for the D, W-D, and W-D-S systems respectively. It can be seen that although the DG units are still required to provide the functionality listed above that the overall number of hours is decreased and the size of the generator required to be operating decreases. This can be seen between the D and W-D systems where DG11 decreases from 5,245 to 4,028 hours of operation and DG7 increases from 4,110 to 4,787 hours of operation. DG13 was only required for 2 hours with the higher level of penetration exhibited by the W-D-S system. The smaller the DG unit is, the cheaper it is to operate, which impacts the O&M and

COE. To maximize the use of the system generation and increase the longevity of the EES units cycle charging is also employed within the W-D-S system.

Over the 25 year life cycle chosen for the W-D system DG7 and DG11 will need to be replaced twice each. For the W-D-S system chosen DG11 and the batteries will all have to be replaced twice, DG7 will be replaced three times, and the CV will need to be replaced once. DG13 and the WG units will not require replacement during the simulated period for either system configuration. Fuel costs remain the highest yearly expenditure of the systems and these costs are the main component of yearly operational costs. Both fuel costs and O&M costs are remain relatively consistent over the life of the project. It should be noted that depending on the type of contract procured by the community as well as the global markets the price of fuel may fluctuate during the 25 year period in all cases running DG units.

WG unit replacement was considered and accounted for during the simulation process for all system configurations that utilize WGs. It was assumed that WG life is 25 years based on the following considerations. The manufacturer information and technical specifications provided by the wind energy sector in Appendix G demonstrate that WG3 has an expected life time of 25 years. Annual maintenance is also performed on the WG to ensure unit performance and longevity so that the 25 year life is attainable. Additional simulations can be performed using HOMER or Hyrbid2 to account for variations if additional information is made available regarding unit life time and performance.

Table 7.14 indicates the economic summary of both the W-D and W-D-S systems in both NPV and annualized cash flows. The O&M defined in Table 7.13 for the W-D system is calculated from the annualized cash flows as RC+O&M+Fuel-SV. The COE is calculated, as per Equation 3.14, to be: COE = (859,231)/(2,060,416) = 0.417 \$/kWh for the W-D system.

Table 7.14: System Economic Summary

Cost Type	**CC (\$)**	**RC (\$)**	**O&M (\$)**	**Fuel (\$)**	**SV (\$)**	**Total (\$)**
W-D System Summary						
NPV	2,797,478	304,805	1,161,519	14,795,085	-96,088	**18,962,798**
Annualized	126,758	13,811	52,630	670,386	-4,354	**859,231**
AC Primary Load Consumption			2,060,416		kWh/year	
Excess Electricity			152,597 kWh/year or 6.90%			
Unmet Electric Load			0.0130		kWh/year	
W-D-S System Summary						
NPV	3,960,698	55,773	1,337,965	13,218,895	-180,238	**18,890,082**
Annualized	179,465	25,047	60,625	598,967	-8,167	**855,936**
AC Primary Load Consumption:			2,060,416		kWh/year	
Excess Electricity			184,361 kWh/year or 8.18%			
Unmet Electric Load			0.0111		kWh/year	

Tables 7.15 and 7.16 summarize the operational, electrical, and fuel variables for the optimal W-D system and W-D-S systems.

Table 7.15: Additional Generator Results for Optimal W-D Case

Metric	Quantity	Unit	Metric	Quantity	Unit
W-D System: DG7					
Operational Variables			**Electrical Variables**		
Hours of Op.	4,787	hr/yr	Mean Elec. o/p	110	kW
Number of Starts	924	#/yr	Min. Elec. o/p	66.0	kW
Operational Life	6.27	yr	Max. Elec. o/p	196	kW
Capacity Factor	27.3	%	**Fuel Variables**		
Fixed Gen. Cost	5.94	$/hr	Fuel Consump.	131,913	L/yr
Marg. Gen. Cost	0.424	$/kWh	Spec. Fuel Cons.	0.251	LWh/y
Electrical Variables			Fuel Energy i/p	1,298,026	kWh/y
Elec. Production	525,397	kWh/y	Mean Elec. Effic.	40.5	%
W-D System: DG11					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	4,028	hr/yr	Mean Elec. o/p	246	kW
Number of Starts	799	#/yr	Min. Elec. o/p	120	kW
Operational Life	7.45	yr	Max. Elec. o/p	400	kW
Capacity Factor	28.3	%	**Fuel Variables**		
Fixed Gen. Cost	9.69	$/hr	Fuel Consump.	233,133	L/yr
Marg. Gen. Cost	0.405	$/kWh	Spec. Fuel Cons.	0.235	LWh/y
Electrical Variables			Fuel Energy i/p	2,294,031	kWh/y
Elec. Production	990,273	kWh/y	Mean Elec. Effic.	43.2	%
W-D System: DG13					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	195	hr/yr	Mean Elec. o/p	336	kW
Number of Starts	159	#/yr	Min. Elec. o/p	150	kW
Operational Life	154	yr	Max. Elec. o/p	374	kW
Capacity Factor	1.50	%	**Fuel Variables**		
Fixed Gen. Cost	8.21	$/hr	Fuel Consump.	15,855	L/yr
Marg. Gen. Cost	0.428	$/kWh	Spec. Fuel Cons.	0.242	LWh/y
Electrical Variables			Fuel Energy i/p	156,011	kWh/y
Elec. Production	65,513	kWh/y	Mean Elec. Effic.	42.0	%
W-D System: WG3					
Total Rated Cap.	750	kW	Min/Max. o/p	0/741	kW
Mean o/p	72	kW	Wind Pen.	30.7	%
Capacity Factor	631,825	%	Hours of Op.	7,375	hr/y
Total Production	631,825	kWh/y	Levelized Cost	0.208	$/kWh

Table 7.16: Additional Generator Results for W-D-S Case

Metric	Quantity	Unit	Metric	Quantity	Unit
W-D-S System: DG7					
Operational Variables			**Electrical Variables**		
Hours of Op.	4,591	hr/yr	Mean Elec. o/p	124	kW
Number of Starts	1,149	#/yr	Min. Elec. o/p	66.0	kW
Operational Life	6.53	yr	Max. Elec. o/p	198	kW
Capacity Factor	29.5	%	**Fuel Variables**		
Fixed Gen. Cost	5.94	$/hr	Fuel Consump.	142,191	L/yr
Marg. Gen. Cost	0.424	$/kWh	Spec. Fuel Cons.	0.250	LWh/y
Electrical Variables			Fuel Energy i/p	1,399,164	kWh/y
Elec. Prod.	568,970	kWh/y	Mean Elec. Effic.	40.7	%
W-D-S System: DG11					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	3,058	hr/yr	Mean Elec. o/p	276	kW
Number of Starts	644	#/yr	Min. Elec. o/p	120	kW
Operational Life	9.81	yr	Max. Elec. o/p	400	kW
Capacity Factor	24.1	%	**Fuel Variables**		
Fixed Gen. Cost	9.69	$/hr	Fuel Consump.	197,960	L/yr
Marg. Gen. Cost	0.405	$/kWh	Spec. Fuel Cons.	0.235	LWh/y
Electrical Variables			Fuel Energy i/p	1,947,925	kWh/y
Elec. Prod.	842,970	kWh/y	Mean Elec. Effic.	43.3	%
W-D-S System: DG13					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	2	hr/yr	Mean Elec. o/p	353	kW
Number of Starts	2	#/yr	Min. Elec. o/p	334	kW
Operational Life	15,000	yr	Max. Elec. o/p	372	kW
Capacity Factor	0.0161	%	**Fuel Variables**		
Fixed Gen. Cost	8.21	$/hr	Fuel Consump.	171	L/yr
Marg. Gen. Cost	0.428	$/kWh	Spec. Fuel Cons.	0.242	LWh/y
Electrical Variables			Fuel Energy i/p	1,681	kWh/y
Elec. Prod.	706	kWh/y	Mean Elec. Effic.	42.0	%

Table 7.17: Table 7.16 Continued

W-D-S System: WG3					
Total Rated Cap.	1,000	kW	Min. o/p	0	kW
Mean o/p	96	kW	Max. o/p	988	kW
Capacity Factor	9.62	%	Wind Pen.	40.9	%
Total Production	842,433	kWh/y	Hours of Op.	7,375	hr/y
-			Levelized Cost	0.210	$/kWh
W-D-S System: CV - Inverter/Rectifier					
Capacity	150/150	kW	Capacity Factor	1.5/2.0	%
Mean o/p	2/3	kW	Energy In	20812/30286	kWh/y
Max. o/p	136/22	kW	Losses	832/4,543	kWh/y
W-D-S System: B3					
Nominal Cap.	575	kWh	Energy In	25,743	kWh/y
Usable Nom. Cap.	345	kWh	Storage Dep.	245	kWh/y
Autonomy	1.47	hr	Losses	4,686	kWh/y
Lifetime Through.	321,579	kWh	Ann. Through.	23,269	kWh/y
Batt. Wear Cost	0.413	$/kWh	Expected Life	10.0	yr

The same selection criterion as used for the W-D-S system was used for the S-W-D and S-W-D-S systems. The selected results for the solar-wind-diesel and solar-wind-diesel-storage hybrid systems are found in Table 7.18.

Table 7.18: Selected Results for WECS and SECS Combination

System Type	Initial Capital ($)	O&M ($/yr)	Total NPV ($)	COE ($/kWh)	Ren. Frac. (%)	Diesel Consump. (L)
S-W-D	3,084,936	682,672	18,151,156	0.399	0.40	333,596
S-W-D-S	4,550,915	585,428	17,471,020	0.384	0.55	262,585
System Type	**Unit Ref. #**	**Quan.**	**Size (kW)**	**Time (hr)**	**kWh/yr**	**% Gen.**
S-W-D	DG7	1	220	6,001	643,867	28
	DG11	1	400	2,735	661,033	29
	DG13	1	500	195	66,537	3
	WG3[1]	2	500	7,375	421,216	19
	SG11[2]	2,388	382	4,384	479,343	21
	CV	200 kW	[1]WG3 are [2]SG11 @ 250 kW, 160W each			
S-W-D-S	DG7:	1	220	4,626	573,372	24
	DG11:	1	400	1,827	507,696	21
	DG13:	1	500	1	364	< 1
	WG3[1]:	3	750	7,375	631,825	26
	SG11[2]	3,360	537.6	4,384	673,888	28
	B3[3]:	160	575 kWh	-	37,378	N/A
	CV:	350 kW	[3]B3 are 6V 599 Ah			

It can be seen from Table 7.18 that the S-W-D and S-W-D-S systems reduce diesel consumption by 158,217 L and 229,228 L or -32.2% or -46.6% respectively when compared to the D case. This demonstrates that the amount of fuel saved by these configurations is significantly higher than other system configurations with the S-W-D-S being the optimal choice. The S-W-D and S-W-D-S systems exhibit similar analysis results as the W-D and W-D-S systems with the exception that the renewable fraction is significantly higher while still maintaining a viable system. Storage is used to enable a 15% difference in the renewable fraction. Although both solar and wind are intermittent sources which still require DGs to be operating they are complimentary to each other. Wind energy produces its best results during the night and solar energy produces its best results during the day. By using both forms of generation in the system renewables are used more frequently which allows for better optimization of the installed capacity. The size of the solar system installed in the S-W-D-S system is smaller than the optimal option for the S-D and S-D-S options which is also a benefit to the community. This decrease in TAC denotes the decrease in the COE and although the CC of the S-W-D and S-W-D-S systems are significantly higher the resulting NPV is lower which makes these system configurations viable. This is due to the aforementioned decrease in fuel costs and O&M which leads to the lower TAC.

Over the 25 year life cycle chosen for the S-W-D system DG7 and DG11 will need to be replaced four and two times respectively and the CV will need to be replaced once. For the S-W-D-S system chosen DG7 must be replaced three times, DG11 and the CV once, and the batteries will have to be replaced twice. DG11 and the SG and WG units do not require replacement during the simulated period for either system configuration. Fuel costs remain the highest yearly expenditure of the systems and these costs are the main component of yearly operational costs. Both fuel costs and O&M costs are remain relatively consistent over the life of the project. It should be noted that depending on the type of contract procured by the community as well as the global markets the price of fuel may fluctuate during the 25 year period in all cases running DG units.

Table 7.19 indicates the economic summary of both the S-W-D and S-W-D-S systems in both NPV and annualized cash flows. The O&M defined in Table 7.19 for the S-W-D-S system is calculated from the annualized cash flows as RC+O&M+Fuel-SV. The COE is calculated, as per Equation 3.14, to be: COE = (791,637)/(2,060,416) = 0.384 \$/kWh for the W-D system.

Table 7.19: System Economic Summary

Cost Type	**CC (\$)**	**RC (\$)**	**O&M (\$)**	**Fuel (\$)**	**SV (\$)**	**Total (\$)**
S-W-D System Summary						
NPV	3,084,936	417,781	1,835,189	12,957,633	-144,384	18,151,152
Annualized	139,783	18,930	83,155	587,129	-6,542	822,454
AC Primary Load Consumption			2,060,416		kWh/year	
Excess Electricity			198,178 kWh/year or 8.72%			
Unmet Electric Load			0.0149		kWh/year	
S-W-D-S System Summary						
NPV	4,550,915	635,304	2,272,619	10,199,406	-187,225	17,471,022
Annualized	206,208	28,787	102,976	462,149	-8,483	791,637
AC Primary Load Consumption:			2,060,416		kWh/year	
Excess Electricity			298,775 kWh/year or 12.5%			
Unmet Electric Load			0.0113		kWh/year	

Tables 7.20 and 7.21 summarize the operational, electrical, and fuel variables for the S-W-D and S-W-D-S systems.

Table 7.20: Additional Generator Results for S-W-D Case

Metric	Quantity	Unit	Metric	Quantity	Unit
S-W-D System: DG7					
Operational Variables			**Electrical Variables**		
Hours of Op.	6,001	hr/yr	Mean Elec. o/p	107	kW
Number of Starts	996	#/yr	Min. Elec. o/p	66.0	kW
Operational Life	5.00	yr	Max. Elec. o/p	196	kW
Capacity Factor	33.4	%	**Fuel Variables**		
Fixed Gen. Cost	5.94	$/hr	Fuel Consump.	161,808	L/yr
Marg. Gen. Cost	0.424	$/kWh	Spec. Fuel Cons.	0.251	LWh/y
Electrical Variables			Fuel Energy i/p	1,592,192	kWh/y
Elec. Production	643,867	kWh/y	Mean Elec. Effic.	40.4	%
S-W-D System: DG11					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	2,735	hr/yr	Mean Elec. o/p	242	kW
Number of Starts	881	#/yr	Min. Elec. o/p	120	kW
Operational Life	11.0	yr	Max. Elec. o/p	400	kW
Capacity Factor	18.9	%	**Fuel Variables**		
Fixed Gen. Cost	9.69	$/hr	Fuel Consump.	155,684	L/yr
Marg. Gen. Cost	0.405	$/kWh	Spec. Fuel Cons.	0.236	LWh/y
Electrical Variables			Fuel Energy i/p	1,531,929	kWh/y
Elec. Production	661,033	kWh/y	Mean Elec. Effic.	43.2	%
S-W-D System: DG13					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	195	hr/yr	Mean Elec. o/p	341	kW
Number of Starts	167	#/yr	Min. Elec. o/p	150	kW
Operational Life	154	yr	Max. Elec. o/p	374	kW
Capacity Factor	1.52	%	**Fuel Variables**		
Fixed Gen. Cost	8.21	$/hr	Fuel Consump.	16,104	L/yr
Marg. Gen. Cost	0.428	$/kWh	Spec. Fuel Cons.	0.242	LWh/y
Electrical Variables			Fuel Energy i/p	158,462	kWh/y
Elec. Production	66,537	kWh/y	Mean Elec. Effic.	42.0	%

Table 7.20 Continued					
S-W-D System: WG3					
Total Rated Cap.	500	kW	Min. o/p	0	kW
Mean o/p	48	kW	Max. o/p	494	kW
Capacity Factor	9.62	%	Wind Pen.	20.4	%
Total Production	421,216	kWh/y	Hours of Operation	7,375	hr/y
-			Levelized Cost	0.209	$/kWh
S-W-D System: SG11					
Rated Capacity	382	kW	Min. o/p	0	kW
Mean o/p	55	kW	Max. o/p	393	kW
Mean o/p	1,313	kWh/d	PV penetration	23.3	%
Capacity Factor	14.3	%	Hours of Op.	4,384	hr/y
Total Prod.	479,343	kWh/y	Levelized Cost	0.161	$/kWh
S-W-D System: CV - Inverter					
Capacity	200	kW	Capacity Factor	18.4	%
Mean o/p	37	kW	Energy In	335,189	kWh/y
Max. o/p	200	kW	Losses	13,408	kWh/y

Table 7.21: Additional Generator Results for S-W-D-S Case

Metric	Quantity	Unit	Metric	Quantity	Unit
S-W-D-S System: DG7					
Operational Variables			**Electrical Variables**		
Hours of Op.	4,626	hr/yr	Mean Elec. o/p	124	kW
Number of Starts	1,294	#/yr	Min. Elec. o/p	66.0	kW
Operational Life	6.49	yr	Max. Elec. o/p	196	kW
Capacity Factor	29.8	%	**Fuel Variables**		
Fixed Gen. Cost	5.94	$/hr	Fuel Consump.	143,291	L/yr
Marg. Gen. Cost	0.424	$/kWh	Spec. Fuel Cons.	0.250	LWh/y
Electrical Variables			Fuel Energy i/p	1,409,982	kWh/y
Elec. Production	573,372	kWh/y	Mean Elec. Effic.	40.7	%
S-W-D-S System: DG11					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	1,827	hr/yr	Mean Elec. o/p	278	kW
Number of Starts	596	#/yr	Min. Elec. o/p	158	kW
Operational Life	16.4	yr	Max. Elec. o/p	400	kW
Capacity Factor	14.5	%	**Fuel Variables**		
Fixed Gen. Cost	9.69	$/hr	Fuel Consump.	119,206	L/yr
Marg. Gen. Cost	0.405	$/kWh	Spec. Fuel Cons.	0.235	LWh/y
Electrical Variables			Fuel Energy i/p	1,172,987	kWh/y
Elec. Production	507,696	kWh/y	Mean Elec. Effic.	43.3	%
S-W-D-S System: DG13					
Operational Variables			**Electrical Variables Continued**		
Hours of Op.	1	hr/yr	Mean Elec. o/p	364	kW
Number of Starts	1	#/yr	Min. Elec. o/p	364	kW
Operational Life	30,000	yr	Max. Elec. o/p	364	kW
Capacity Factor	0.00830	%	**Fuel Variables**		
Fixed Gen. Cost	8.21	$/hr	Fuel Consump.	88.1	L/yr
Marg. Gen. Cost	0.428	$/kWh	Spec. Fuel Cons.	0.242	LWh/y
Electrical Variables			Fuel Energy i/p	867	kWh/y
Elec. Production	364	kWh/y	Mean Elec. Effic.	42.0	%

Table 7.21 Continued					
S-W-D-S System: WG3					
Total Rated Cap.	750	kW	Min. o/p	0	kW
Mean o/p	72	kW	Max. o/p	741	kW
Capacity Factor	9.62	%	Wind Pen.	30.7	%
Total Production	631,825	kWh/y	Hours of Operation	7,375	hr/y
-			Levelized Cost	0.208	\$/kWh
S-W-D-S System: SG11					
Rated Capacity	538	kW	Min. o/p	0	kW
Mean o/p	77	kW	Max. o/p	553	kW
Mean o/p	1,846	kWh/d	PV penetration	32.7	%
Capacity Factor	14.3	%	Hours of Op.	4,384	hr/y
Total Prod.	673,888	kWh/y	Levelized Cost	0.160	\$/kWh
S-W-D-S System: CV - Inverter/Rectifier					
Capacity	350	kW	Capacity Factor	14.5	%
Mean o/p	51	kW	Energy In	464,340	kWh/y
Max. o/p	317	kW	Losses	18,573	kWh/y
S-W-D-S System: B3					
Nominal Cap.	575	kWh	Energy In	41,616	kWh/y
Usable Nom. Cap.	345	kWh	Storage Dep.	157	kWh/y
Autonomy	1.47	hr	Losses	8,027	kWh/y
Lifet Through.	321,579	kWh	Ann. Through.	37,378	kWh/y
Batt. Wear Cost	0.413	\$/kWh	Expected Life	8.60	yr

Chapter 8

Conclusion

This Chapter is subdivided into two Sections. Section 8.1 includes the author's views on future work emanating from the results and work found within this thesis. Section 8.2 provides a summary of the results determined throughout this thesis as well as an overview of the thesis through concluding thoughts.

8.1 Future Work

Although it was attempted to encompass all relevant subject materials in this thesis it is inevitable that there are multiple facets that can be further explored and developed. If the technical information appurtenant to the system model and existing diesel infrastructure becomes publicly available the system model can be verified. Although HOMER was found to be an acceptable simulation suite additional fine tuning simulations utilizing Hybrid2 could be performed to further define economic viability. All simulated components can be further explored with additional unit types both with present technologies and future developments. Technology will continue to advance and mature making new technologies feasible. As utilities continue to explore renewable options in the North additional practical experience data may be collected for analysis. The ever changing political climate must also be continuously monitored as changes in policy may affect the viability of renewable projects.

Due to a lack of operating experience and technical maturity of the utilized technology, the electrolyzer based system as used on Ramea Island, NFLD, is not presently studied. This technology may be considered for future application in Ontario. At present fuel cells were not deemed viable for utility grade power however they should be revisited for future analysis. The analysis in this thesis neglected to consider the results of the leap year as the alterations in results were considered negligible. However, to increase numerical validity this could be considered in future analysis. At present emission costs and output levels were not considered in this thesis and future analysis may be performed to include these metrics. The debate of creating a carbon based taxation system in Canada is currently being addressed, in part by the 2011 federal elections, and there is a possibility it will become a reality in the near future. As renewables continue to become integrated with existing generation techniques regarding generator dispatch should be periodically reviewed.

SECS can be modelled to include tracking options which include tracking along the horizontal axis with continuous, daily, weekly, or monthly adjustments, continuous adjustments on the vertical axis, or two axis tracking. Passive solar energy use can also be explored to reduce the energy consumption of the load. The application of cogeneration, biomass, flywheels, other EES, and an increased awareness towards energy efficiency should be considered for future analysis.

WECS installations allowing for higher hub heights should be researched which will require a viability analysis of installation equipment. There are currently tethered floating WGs being developed which may be feasible during non winter months in the North. This would effectively make use of the upper air wind as explored in Appendix G and decrease wind shear.

After the initial economic viability and technical feasibility study is completed a specific study based on specific remote communities should be explored since many local geographical constraints (that may allow for hydraulic, PHS, CAES, and suitable locations for renewable installations) are difficult to predict with the system model.

8.2 Conclusions

To aid with the reduction of fossil fuel dependencies and the net cost of power generation, to create localized employment opportunities, and to promote better planning and infrastructure development to increase community self sufficiency this thesis investigated various technologies that can be applied to the operation of remote power systems. This analysis took form of an economic viability and technical feasibility of remote systems consisting of diesel and wind-diesel, wind-diesel-storage, solar-diesel, solar-diesel-storage, wind-solar-diesel, and wind-solar-diesel-storage hybrid generators. To facilitate this research a model of a typical remote power system located within Northern Ontario was developed.

In general the capital costs associated with renewable hybrid systems are significantly higher than other forms of electricity generation. However, the regular operation and maintenance costs associated with the installed systems are typically low. When the lower operational costs are coupled with the increasing costs of diesel fuel and increasing costs of operating carbon and GHG producing technologies the economics of renewable hybrid systems may prove to have net positive ROR. Diesel generators are a proven technology that aren't limited by external environmental constraints. Since the existing infrastructure is diesel based and a mature technology it is used as the base case for analysis. Ninety DG units were investigated and 19 were selected for simulation application. The DGS was assumed to operate with either 2 or 3 DG units in accordance to the system model. Using an optimized dispatch schedule, which allowed for load following and multiple DG capable of operating simultaneously, 227 cases were simulated. The base case DGS (D) consists of three DG sized 500 kW, 400 kW, and 220 kW and is seen in Table 8.1. Over the 25 year life cycle chosen for the project DG7 and DG11 will need to be replaced 3 and 4 times respectively. DG13 will not require replacement during the simulated period for the D system configuration. All of the studied systems in this Section were investigated over a 25 year period which is reflected by the NPV. All other replacement schedules and life time considerations can be found in the respective Chapter concluding Sections for the respective configurations along with detailed simulation results.

Table 8.1: Optimal Simulated Results for DGS

System Type	**Initial Capital** ($)	**O&M** ($/yr)	**Total NPV** ($)	**COE** ($/kWh)	**Ren. Frac.** (%)	**Diesel Consumption** (L)
D	332,478	913,856	20,500,828	0.451	0.00	491,813

At this point in time only BESS was deemed feasible for EES as fuel cells, solar fuels, and CES are not mature and the other forms of EES are developed but lack wide spread implementation that the mature technologies exhibit. It was found that lead acid and NiCd BESS were presently applicable with Li-Ion BESS exhibiting promising characteristics. As other EES technologies continue to advance and mature they should be considered for system implementation once they become technically feasible. For the purpose of simulation 10 different lead acid batteries were considered to constitute the BESS.

There has been very limited exposure to solar generation in the North to date. In 1999 YEC installed a solar hybrid system under the Yukon Energy Portable Solar-Hybrid Project. However long term results of the installed system is not currently available. In 1995 two solar PV panels were installed at the Arctic College located in Iqaluit, NU. It was found that the efficiency of the Arctic College panels ranged between 7.4 to 11.2% depending on the season with an annual average efficiency of 9.4%. It was found that the solar irradiance is negligible in December and that solar irradiation in the North exhibits very strong seasonal variations due to the proximity to the Northern celestial pole. An 80 kWp trail project was installed on the roof of the ROHM plaza at Ritsumeikan University located in Shiga, Japan in February 2000. This SECS consisted of 4 different solar arrays installed on 3 different surfaces studied between April 2002 and March 2003. Overall the a-Si cells performed relatively poorly during the summer months when compared to the other cell technologies. However, it was found that the a-Si cells exhibit superior annual output characteristics on both the horizontal and North faces even when compared with the South facing panels. These results indicate that it may be a possibility in the future to have larger solar constructions on none South facing surfaces even at a latitude far removed from the equatorial plane.

Thirty nine SGs, consisting of panels with a rated output and efficiencies ranging from 100 – 300 W and 6.39% to 17.23% respectively, were investigated for implementation in the SECS. The 39 SECS were assumed to operate at a low penetration level. The derating factor was set at 76%, a slope of 50.56°, an azimuth of 0°, and ground reflectance of 20%. The optimal simulated results of the Solar-Diesel (S-D) and Solar-Diesel-Storage (S-D-S) hybrid systems are as follows in Table 8.2. The S-D-S system is the better option of the two with a lower NPV and COE. An explanation detailing the variables involved with this comparison are discussed following the results of the WECS below.

Table 8.2: Simulated Results for SECS

System Type	**Initial Capital** ($)	**O&M** ($/yr)	**Total NPV** ($)	**COE** ($/kWh)	**Ren. Frac.** (%)	**Diesel Consumption** (L)
S-D	2,016,913	749,352	18,554,738	0.408	0.33	364,588
S-D-S	2,538,209	712,052	18,252,848	0.401	0.41	331,822

Since the 1980s there have been a number of wind-diesel systems installed in 4 ON, 3 NWT, 5 NU, 1 PQ, and 1 NFLD locations. There were also 2 WGs installed in YT connected to the local hydraulic based grid. Of the WECS installed in the aforementioned communities most encountered various technical and economical problems during their initial trial periods between 1980 and 2000. This resulted in relatively poor results and only the WECS in Cambridge Bay, NU and Kuujjuaq, NU operated for more than eight years. The limited information available about these WECS indicates that current technologies should perform better.

Ten AC 3Φ WGs with a rated output ranging from 10 – 250 kW and a hub height ranging from 7 to 42.7 m were investigated for implementation in the WECS. DC WGs were not simulated at this time. For 8 of the simulated WECS low to medium renewable penetrations were considered. For the remaining 2 WECS low to high renewable penetrations were considered containing WGs of rated capacities 225 and 250 kW. The simulated results of the Wind-Diesel (W-D), Wind-Diesel-Storage (W-D-S), Solar-Wind-Diesel (S-W-D), and Solar-Wind-Diesel-Storage (S-W-D-S) hybrid systems are as follows in Table 8.3.

Table 8.3: Simulated Results for WECS and WECS/SECS

System Type	Initial CC ($)	O&M ($/yr)	Total NPV ($)	COE ($/kWh)	Ren. Frac. (%)	Diesel Consumption (L)
W-D	2,797,478	732,473	18,962,798	0.417	0.29	380,901
W-D-S	3,960,698	676,471	18,890,084	0.415	0.37	340,322
S-W-D	3,084,936	682,672	18,151,156	0.399	0.40	333,596
S-W-D-S	4,550,915	585,428	17,471,020	0.384	0.55	262,585

As seen in Table 8.3 the CC of the four systems increases as the system complexity increases. All four systems have the same CC of DG units and the addition of renewable generators (SG and WG) along with the applicable storage increase the net CC. The S-W-D-S has the highest CC which accounts for the SG, WG, DG, B, and CV unit(s). Renewable generators typically have high CC but low annual O&M costs. Since the implementation of renewable generators reduces the electricity generated from DG units while achieving a lower O&M cost the net O&M per year decreases as additional renewable generators are used. As renewable generators are used the size of the DG dispatched decreases which translates to a lower O&M for DG operation and alters the replacement costs of the units. This can be seen as the difference between the D, W-D, and S-W-D systems. With the implementation of storage to the system the renewable fraction of the system is increased which allows for higher levels of renewable penetration which decreases the net O&M while increasing the net CC (due to more renewable generators and storage systems). This change can be identified between the W-D/W-D-S and S-W-D/S-W-D-S systems. This change in generators, from DG to a combination of DG and renewables, accounts for the decrease in yearly diesel consumption required. Again with the increased renewable fraction due to storage the amount of diesel required decreases. This decrease in fuel consumption lowers the COE as per Equations 3.13 and 3.14 as part of the total annualized costs (TAC). It should be noted that in a given system configuration the amount of fuel required per year remains relatively consistent over time as does the annual AC energy requirement which is used to determine the COE. The total NPV of the system decreases since, as indicated by Equation 3.15, the NPV is a function of the TAC. As discussed, the TAC decreases due to the decrease in fuel costs which account for a significant cost in the system, that when corrected using the real interest rate significantly impact the NPV of the system. It should also be noted that due to the 25 year life cycle of the project that the salvage value also modifies the TAC.

Although past renewable energy experiences in the North have been wrought with disappointment recent technological developments have made some renewable penetration technically feasible. During periods of particularly harsh winter weather, lower winter irradiation levels, and seasonal variations in wind resources, the electricity from renewable sources may become temporarily unavailable or generate under their regular levels. The intermittent aspect of renewable generators is mitigated by the diesel generators in low to medium penetration hybrid systems. It was found that in order to achieve a hybrid system that consistently meets the system load requirements that between 6.9% to 12.5% of the system's electricity would be generated in excess on an annual basis.

Even though it was determined that there is no existing carbon penalty system in place within the province of Ontario a positive by-product of renewable hybrid systems is a potential reduction in pollutants produced. Table 8.4 summarizes the projected pollutants created by the studied selected systems which include carbon dioxide, carbon monoxide, unburned hydrocarbons, particulate matter, sulphur dioxide, and nitrogen oxides.

Table 8.4: Projected Pollution from System Operation

System Config.	**Emissions of Pollutant (kg/yr)**					
	CO_2	CO	Unburned Hydrocarbons	Particulate Matter (PM)	SO_2	NO_x
D	1,295,105	3,197	354	241	2,601	28,525
S-D	960,081	2,370	263	179	1,928	21,146
S-D-S	873,797	2,157	239	163	1,755	19,246
W-D	1,003,038	2,476	274	187	2,014	22,092
W-D-S	896,180	2,212	245	167	1,800	19,739
S-W-D	878,467	2,168	240	163	1,764	19,349
S-W-D-S	**691,473**	**1,707**	**189**	**129**	**1,389**	**15,230**
	1,295,105	3,197	354	241	2,601	28,525
Difference Between D and S-W-D-S Pollution Production:						
Net:	603,632	1,490	165	112	1,212	13,295

All of the renewable hybrid systems experience less pollution than the base case however the best case is the S-W-D-S system. The difference, or amount of pollution not produced, between the base D case and the S-W-D-S can be seen in Table 8.4. There is approximately a savings of 46% between the two configurations which translates to a significant impact on community pollution production. Although no monetary value was placed upon this reduction in pollutant production at this time, it is another benefit of the hybrid system, and may play an increasingly important role with respect to future policy.

Although practical experience with diesel hybrid power systems to date has been limited in the Canadian North this thesis found that renewable hybrid diesel power systems are both viable and feasible in Northern Ontario given existing technology and market conditions. These existing conditions must be continuously re-assed as both existing and developing technologies continue to mature and economic climates continue to change. This will aid in the determination of the viability and feasibility of future developments. The most economically viable system at this time, and furthermore the system with the lowest projected pollution creation, is the S-W-D-S. The S-W-D-S system has: the highest CC of the studied systems but consumes the least amount of diesel per year, the lowest cost of energy, and the highest level of renewable penetration from a combination of wind and solar generators. Providing that sufficient capital can be procured prior to system installation the S-W-D-S is the optimal system. However, due to the high CC an alternative configuration may have to be considered depending upon financial circumstances even though the NPV is lower. Although the future of renewable systems, technology, and the political climate of the province of Ontario are unknown it is believed that interests in renewable hybrid power systems will continue to grow.

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Appendix A - Virtual 1

Appendix A includes the following as part of the accompanying compact disc:

- An excel file called "Population and Power Statistics.xls"

  This file includes:

  - Northern Ontario

    * Remote community names, locations, and elevations, accessibility information, population, and dwelling information. The dwelling information is subdivided into eight categories for the two periods
    * Power system and fuel price data from the 1996 RETs remote community package
    * Building code zone, climate zone, and operator breakdown - along with zone definitions and related ON building code information (2009 update)
    * An analysis of the population (mean, minimums, maximums, median) for various datasets
    * Number of dwellings versus total population calculations

    * Insulation calculations and conversion ratios
    * Overall population graph
- Northwest Territories
    * Full list of communities, locations, elevations, sources of power generation, amount of power generated for residential, general service, and street lighting applications by total sales and number of costumers, consumption of diesel, and a breakdown of total generated power for a two year period
    * Power system and fuel price data from the 1996 RETs remote community package
    * Summarized list detailing diesel only operations
    * Population and dwelling information
    * Analysis to determine: loss between total generated and total sold, installed power per dwelling/person (01 and 06)/costumer, mean and median calculations of the installed power calculations, and how many Wh of power is created from 1 L of diesel
    * Graphs including: diesel generator size vs. diesel power generated per year, total community sales vs. customers, allocation of generated power by community (06/07 and 07/08), 1 L of diesel yields how many Wh generated, installed power for systems in the NWT within the chosen population range per, and overall population over time
- Nunavut

    * List of communities, locations, elevations, population, and dwelling information
    * Power system and fuel price data from the 1996 RETs remote community package
    * Detailed information on four locations including: peak demand, peak demand per capita, total kWh used 06/07, kWh per capita, Diesel/Gen usage 06/07 (L), Diesel/Gen per capita, overall electrical generation, average wind speed, and wind resource levels
    * Monthly diesel usage for energy production in 2007 for the four locations
    * Calculations to determine power per person and dwelling 2006
    * Graphs including: population vs. diesel usage for energy production 2007, year vs. population of the four communities, annual peak demand of Cambridge Bay, diesel usage for energy production 2007 for the four communities, annual energy usage in Cambridge Bay and Iqaluit (1994-2014 projected), and overall population over time
  - Yukon
    * Locations, elevations, population, and dwelling information
    * Power system and fuel price data from the 1996 RETs remote community package
  - Alaska
    * Raw data for 45 communities consisting of population in 2002 and

2010, number of customers in 2010, installed capacity in 2010, energy use in 2002, average kWh and load per day in 2002, peak load in 2002, and fuel storage capacity in 2002

  * Graphs that represent: desired population range found from the list of the 45 communities (300-700) versus installed capacity 2010, fuel storage 2002, peak demand 2002, average load 2002, average kWh per day 2002, energy usage 2002, and customer 2010
  * Graphs that represent: overall population of the 45 communities versus installed capacity 2010, fuel storage 2002, peak demand 2002, average load 2002, average kWh per day 2002, energy usage 2002, and customer 2010
  * Equations indicating fuel consumption for various metrics and the determination of the ideal storage size in the system model

- Technical Considerations (In "NWT" tab)
  * Raw data indicating:
    - DG sizes, prices, possible installation combinations etc. for new projects
    - Analysis of existing NTCP DG usage
    - Breakdown of fuel usage per month, usage required per season, and size of storage required to supply 25, 50, 75, 100% of required fuel
  * Graphs indicating size vs cost of DG units,

  - DG Summary
    * Summary of existing available DG installations
    * Graphs of various storage tanks vs cost
    * Raw data demonstrating costs, dimensions, safety, intercept coefficient, slope (fuel), fuel consumption with respective loading, available enviromental information for new DGs, available combinations of DG units
  - Simulation components, costs, and additional related information.
  - Some Conclusions
    * Data that was compiled, considered, and reviewed for the model of approximation from the above location data files
    * Graphs including: population vs. total power system size in the NWT for 2006, and all related graphs for NU, NWT, and ON within the desired population range for applicable raw data values

- A Microsoft Streets and Trips map file called "RemoteCommunities.est" that maps the various remote communities studied in the territories and Northern Ontario and related .JPEG files

- The associated graphs created from the various location specific raw data collections.

Appendix B - Virtual 2

Appendix B includes the following as part of the accompanying compact disc:

- An excel file called "ECData.xlsx"

  This file includes:

  - The summary of the monthly averages of the CWEEDS stations
  - Multiple graphs comparing fields 101 to 104, 110, and 209 of the summarized CWEEDS data for both overall analysis and extreme cases
  - A summary of the selected station data from Environment Canada's climate data online and climate normals and averages collections for: 12 ON, 5 NWT, 9 NU, and 5 YT locations for a total of 31 locations
  - A monthly summary of the means and medians of the daily average temperatures for all 31 station locations
  - Graphs comparing daily average temperatures by province or territory both individually and overall
  - A summary of the relevent RETScreen station and parameters data

  - Tables comparing solar and wind parameters for all relevent stations in Ontario combining information from RETScreen, CWEEDS, and Environment Canada's climate data online and climate normals and averages data collections
  - A summary of information found while doing wind rose conversions

- A Microsoft Streets and Trips map file called "ECData.est" that maps the various stations in Ontario for which weather data was collected and related .JPEG files

- The source code and executable for EnvrioCanReader. The custom application developed to summarize the CWEEDS data

- The raw hourly station data from CWEEDS as both .TXT and .WY2 file formats

- The raw hourly station data used for wind rose and frequency development saved as .SAM file formats

- Graphs demonstrating the wind rose (16 and 36 points) and frequency distribution along with text files demonstrating the statistics summary of the resulting analysis for both 16 and 36 points (5 files for each of the 10 communities)

- The raw hourly station data used for wind rose and frequency distribution save as Excel format for the last available seven years. These files were converted to the .SAM files.

- The monthly average station data from CWEEDS as .OUT files that were generated by EnvrioCanReader
- Climatic graphs produced using the monthly averages to provide an overall summary of the condensed data
- An excel file called "Dwellings.xlsx" which contains various statistics from StatsCan regarding dwellings across the North
- An excel file called "Fuels.xlsx"
  - NWT fuel rates for residential and general services
  - StatsCan IPPI data and related graphs for motor gasoline (3 sets), diesel fuel, stove and light fuel oils, stove oil, light fuel oil, and heavy fuel oil which were all available from 1980 to 2010 for Ontario
  - StatsCan retail information and related graphs for regular and premium gasoline, and diesel at full and self serve stations. Household heating oil is also available. All locations are in Ontario typically Toronto and Thunder Bay were selected and period ranges from 1985 - 2010.
  - NRCan pricing for various wholesale gasoline types (2001 to 2010) and Canadian taxation laws on fuel
  - Furnace oil prices from NRCan between 2001 and 2010
  - NRCan diesel oil prices from 2001 to 2010 along with the summary used to determine the rate of increase between information periods

- An excel file called "Temp Loading.xlsx"
  - Includes information used for scaling of the community load
- Canadian Wind Energy Association (CanWEA) windspeed distribution maps of four sectors (Q42, Q43, Q52, Q53) which include winspeeds at 30 m, 50 m, and 80 m during the Spring, Summer, Fall, and Winter, and yearly average. A general Canadian overview map is also supplied. Raw data for the four sectors is also provided.
- CanWEA wind roses, histograms, and wind speed values for the system model as based off provided latitude and longitude values per season and annually at 30 m, 50 m, and 80 m.
- An excel file called "Simulation Components.xlsx"
  - Includes information regarding all simulated components as part of this thesis as well as tables of life time approximations, and summary of results from Alaska simulations.

Appendix C - Load Profile

Appendix C contains additional Figures and data relating to the community load approximation as introduced in Chapter 3.

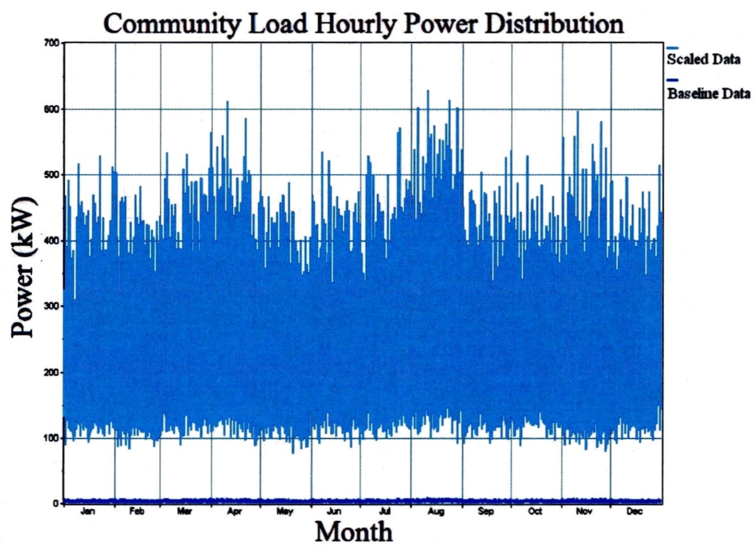


Figure C.1: Community Load Hourly Power Distribution

System Model Hourly Load Profile (kW)													
Hour	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**June**	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**Avg**
0	133.199	122.125	143.254	134.573	121.703	142.173	133.380	164.170	134.542	150.658	120.602	136.362	**136.395**
1	132.367	122.019	139.595	127.989	118.412	139.490	129.392	141.394	128.334	125.809	128.042	126.210	**129.921**
2	126.921	107.836	127.192	120.441	117.070	122.165	119.568	130.859	124.354	132.162	108.779	119.459	**121.401**
3	123.659	110.536	127.748	124.597	115.022	126.016	122.113	136.279	111.266	126.790	116.472	113.588	**121.174**
4	123.323	119.009	121.718	126.521	132.267	139.393	113.549	174.575	126.235	150.372	123.153	132.619	**131.894**
5	148.385	142.548	162.024	131.458	121.114	145.371	110.827	139.565	116.718	125.564	138.057	132.176	**134.484**
6	197.792	187.001	184.680	117.739	118.802	128.427	107.944	134.744	121.368	133.452	109.555	113.696	**137.933**
7	231.784	229.894	252.117	122.086	120.259	125.346	111.736	141.356	102.321	130.333	129.145	113.558	**150.828**
8	258.571	249.639	290.606	128.151	110.111	134.896	112.432	126.855	126.750	133.122	121.413	120.960	**159.459**
9	253.278	249.136	269.124	144.190	145.996	164.749	138.496	149.899	149.375	151.140	134.232	146.882	**174.708**
10	242.438	241.518	290.217	213.386	189.634	178.913	159.064	215.918	163.801	202.507	176.530	168.121	**203.504**
11	276.051	256.720	294.640	247.091	231.807	266.578	224.611	292.174	255.408	260.672	247.075	247.433	**258.355**
12	242.894	249.548	291.362	255.293	266.923	304.493	256.697	322.739	281.962	257.487	238.666	284.614	**271.056**
13	261.401	253.250	298.297	270.917	265.838	280.885	249.604	308.236	277.146	280.027	252.765	262.796	**271.763**
14	248.004	249.265	283.377	252.950	254.712	265.059	219.136	315.032	242.379	250.058	255.425	245.643	**256.753**
15	287.893	234.746	295.485	252.612	265.097	327.213	252.164	268.593	263.337	275.475	248.722	254.594	**268.828**
16	298.418	308.089	340.544	256.157	259.436	275.969	227.907	314.052	254.250	263.674	253.102	226.291	**273.157**
17	402.425	359.360	409.823	283.260	246.662	268.477	243.190	305.209	265.413	312.752	238.280	261.362	**299.684**
18	418.947	418.433	451.736	265.584	258.136	296.913	237.700	296.885	261.842	270.443	266.871	247.776	**307.605**
19	382.090	342.639	371.707	255.987	258.140	271.738	245.756	296.986	267.844	288.681	269.089	283.404	**294.505**
20	261.229	239.313	265.562	333.183	316.192	308.837	296.257	375.305	325.571	335.446	313.861	287.000	**304.813**
21	176.675	184.509	197.745	374.245	378.475	384.890	327.281	420.609	414.410	371.891	364.783	348.332	**328.654**
22	164.480	150.055	165.306	478.911	417.029	438.862	386.070	509.601	397.376	441.953	456.795	404.507	**367.579**
23	132.446	128.157	153.582	348.005	379.368	383.392	331.643	394.707	355.109	374.184	370.136	341.885	**307.718**
Avg	**230.195**	**218.973**	**246.977**	**223.555**	**217.008**	**234.177**	**202.355**	**253.156**	**219.463**	**231.027**	**215.898**	**213.303**	225.507
Sum (kWh)	**92.078**	**87.589**	**98.791**	**89.422**	**86.803**	**93.671**	**80.942**	**101.262**	**87.785**	**92.411**	**86.359**	**85.321**	-

Figure C.2: Community Load Hourly Load Profile

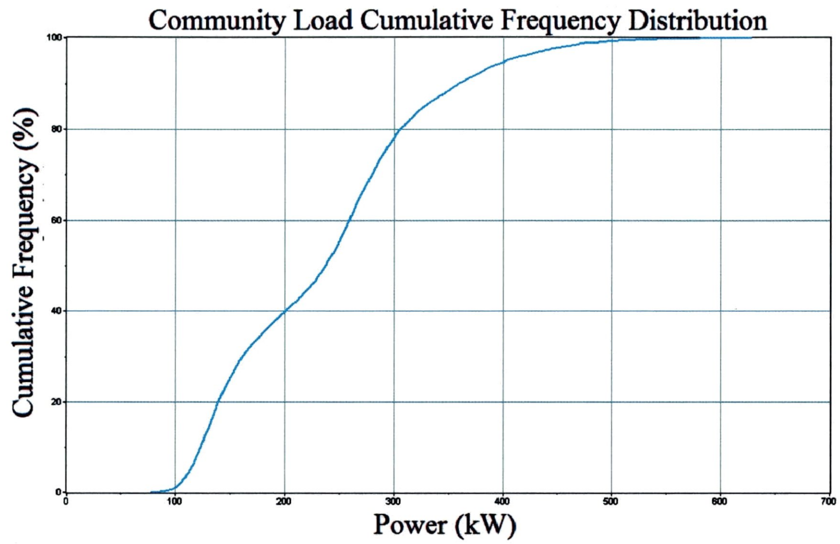


Figure C.3: Community Load Cumulative Frequency Distribution

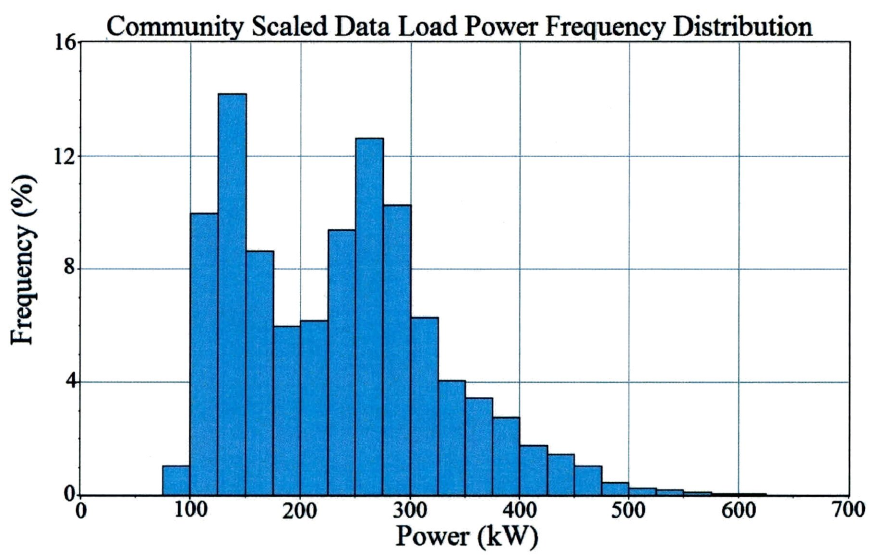


Figure C.4: Community Load Power Frequency Distribution

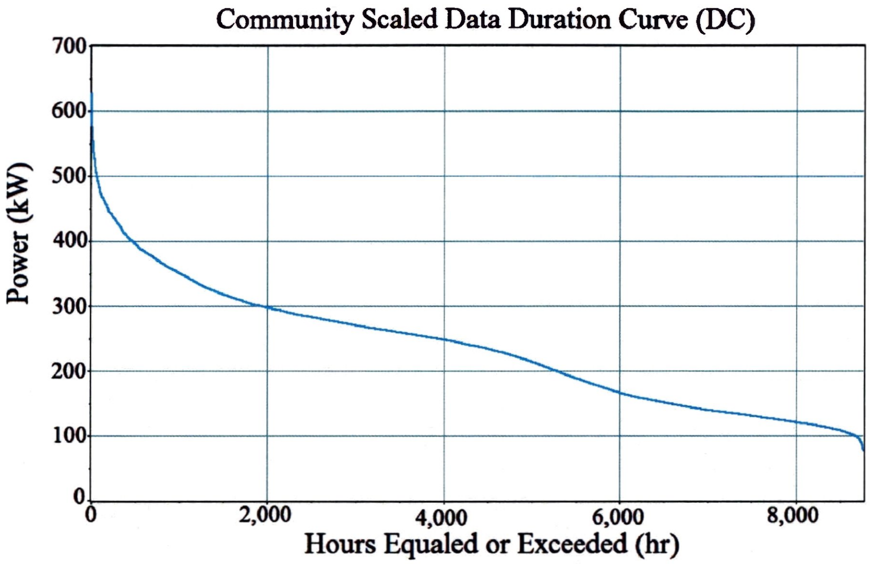


Figure C.5: Community Load Duration Curve

Appendix D - BESS Specification

Appendix D contains additional Figures and data relating to the Battery Energy Storage System (BESS) employed by the power system as introduced in Chapter 4. The battery's lifetime curve is plotted as a function of the lifetime throughput. The yellow data points represent the values plotted from the cycles-to-failure verses depth-of-discharge. For each of these data points the lifetime throughput is calculated from the following Equation and plotted as the corresponding black data point [15].

$$Q_{lifetime,i} = f_i d_i \left(\frac{q_{max} V_{nom}}{1000W/kW} \right)$$

Metric	Description	Unit
$Q_{lifetime,i}$	Lifetime Throughput	kWh
f_i	Number of Cycles to Failure	-
d_i	Depth of Discharge	%
q_{max}	Maximum Capacity of Battery	Ah
V_{nom}	Nominal Voltage of Battery	V

The thick black horizontal line indicates the lifetime throughput using the y-axis on the right hand side of the graph. Ideally this lifetime throughput should occur between the cycles-to-failure verses depth-of-discharge and the calculated lifetime throughput curves.

Unit:	**B1**		**Manufacturer:**		
Model:	S460		Surrette/Rolls Battery		
Series:	4000		**Section:**	B	
Link: http://www.rollsbattery.com/					
Unit Parameters:					
Nominal Capacity:	446	Ah	Float Life:	10	yrs
Nominal Voltage:	6	V	Max. Charge Current:	17.5	A
Round Trip Efficiency:	80	%	Lifetime Throughput:	1536	kWh
Min. State of Charge:	40	%			
Calculated Parameters:					
Maximum Capacity:	454	Ah	Capacity Ratio, c:	0.279	
Rate Constant, k:	0.520	1/hr			

Capacity Curve				**Lifetime Curve**	
B1				Depth of	Cycles to
Current (A)	Capacity (Ah)	Current (A)	Capacity (Ah)	Discharge (%)	Failure -
4.66	446	43.20	259	20	2000
6.13	441	49.00	245	30	1707
8.33	417	57.00	228	40	1493
15.00	361	69.00	207	50	1280
17.50	350	89.00	179	60	1120
21.90	329	126.00	126	70	960
26.00	312	-	-	80	800
29.80	298	-	-	90	700
35.00	280	-	-	100	590

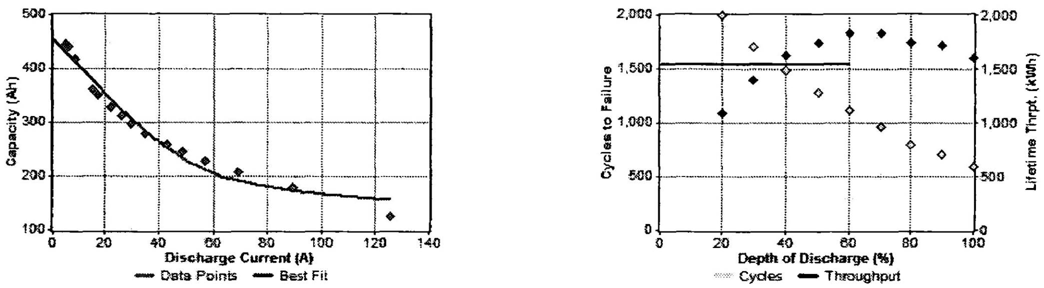


Figure D.1: B1 Capacity (L) and Lifetime (R) Curves

Unit:	**B2**		**Manufacturer:**			
Model:	S530		Surrette/Rolls Battery			
Series:	4000		**Section:**	B		

Link: http://www.rollsbattery.com/

Unit Parameters:

Nominal Capacity:	532	Ah	Float Life:	10	yrs
Nominal Voltage:	6	V	Max. Charge Current:	20.0	A
Round Trip Efficiency:	80	%	Lifetime Throughput:	1812	kWh
Min. State of Charge:	40	%			

Calculated Parameters:

Maximum Capacity:	535	Ah	Capacity Ratio, c:	0.280
Rate Constant, k:	0.462	1/hr		

Capacity Curve				Lifetime Curve	
B2				Depth of Discharge (%)	Cycles to Failure -
Current (A)	Capacity (Ah)	Current (A)	Capacity (Ah)		
5.32	532	49.30	296	20	2000
7.00	504	56.00	280	30	1707
9.52	476	65.00	260	40	1493
17.20	412	79.00	236	50	1280
20.00	400	102.00	204	60	1120
25.10	376	144.00	144	70	960
29.70	356	-	-	80	800
34.00	340	-	-	90	700
40.00	320	-	-	100	590

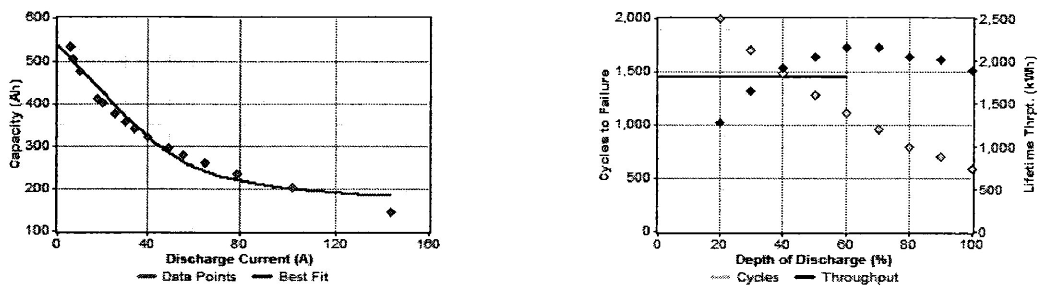


Figure D.2: B2 Capacity (L) and Lifetime (R) Curves

Unit:	**B3**	**Manufacturer:**	
Model:	S600	Surrette/Rolls Battery	
Series:	4000	**Section:**	B

Link: http://www.rollsbattery.com/

Unit Parameters:

Nominal Capacity:	599	Ah	Float Life:	10	yrs
Nominal Voltage:	6	V	Max. Charge Current:	22.5	A
Round Trip Efficiency:	80	%	Lifetime Throughput:	2001	kWh
Min. State of Charge:	40	%			

Calculated Parameters:

Maximum Capacity:	591	Ah	Capacity Ratio, c:	0.304
Rate Constant, k:	0.414	1/hr		

Capacity Curve				**Lifetime Curve**	
B3				Depth of Discharge (%)	Cycles to Failure -
Current (A)	Capacity (Ah)	Current (A)	Capacity (Ah)		
5.99	599	55.50	333	20	2000
7.88	567	63.00	315	30	1707
10.71	536	73.00	293	40	1493
19.30	464	89.00	266	50	1280
22.50	450	115.00	230	60	1120
28.20	423	162.00	162	70	960
33.40	401	-	-	80	800
38.30	383	-	-	90	700
45.00	360	-	-	100	590

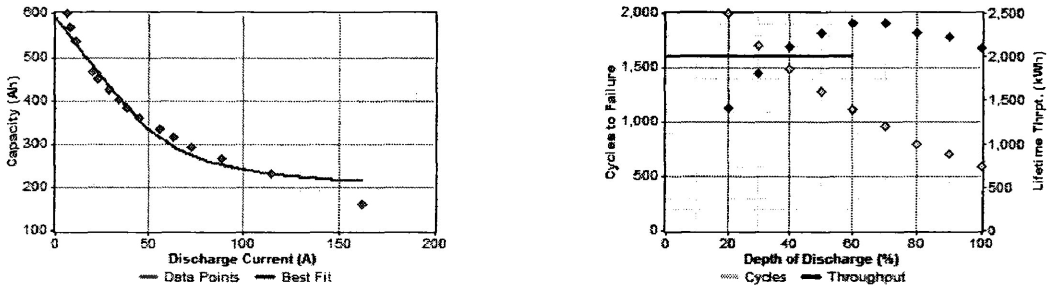


Figure D.3: B3 Capacity (L) and Lifetime (R) Curves

Unit:	**B4**		**Manufacturer:**		
Model:	4CS17P		Surrette/Rolls Battery		
Series:	5000		**Section:**	E	

Link: http://www.rollsbattery.com/

Unit Parameters:

Nominal Capacity:	770	Ah	Float Life:	20	yrs
Nominal Voltage:	4	V	Max. Charge Current:	27.3	A
Round Trip Efficiency:	80	%	Lifetime Throughput:	4479	kWh
Min. State of Charge:	40	%			

Calculated Parameters:

Maximum Capacity:	797	Ah	Capacity Ratio, c:	0.272
Rate Constant, k:	0.335	1/hr		

Capacity Curve				Lifetime Curve	
B4				Depth of Discharge (%)	Cycles to Failure -
Current (A)	Capacity (Ah)	Current (A)	Capacity (Ah)		
7.70	770	64.60	388	20	5000
10.09	726	73.00	366	30	4200
13.43	672	85.00	339	40	3700
23.70	568	102.00	306	50	3200
27.30	546	131.00	262	60	2800
33.90	508	186.00	186	70	2400
39.60	475	-	-	80	2100
45.30	453	-	-	90	1800
53.20	426	-	-	100	1500

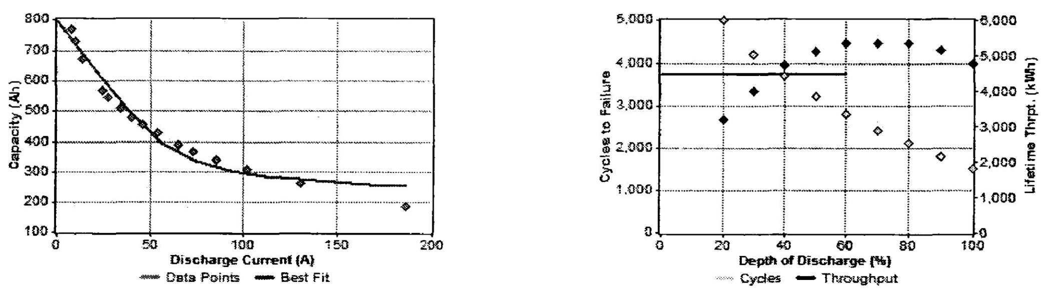


Figure D.4: B4 Capacity (L) and Lifetime (R) Curves

Unit:	**B5**		**Manufacturer:**		
Model:	4KS21P		Surrette/Rolls Battery		
Series:	5000		**Section:**	E	

Link: http://www.rollsbattery.com/

Unit Parameters:

Nominal Capacity:	1557	Ah	Float Life:	20	yrs
Nominal Voltage:	4	V	Max. Charge Current:	55.2	A
Round Trip Efficiency:	80	%	Lifetime Throughput:	9016	kWh
Min. State of Charge:	40	%			

Calculated Parameters:

Maximum Capacity:	1605	Ah	Capacity Ratio, c:	0.277
Rate Constant, k:	0.322	1/hr		

Capacity Curve				**Lifetime Curve**	
B5				Depth of Discharge (%)	Cycles to Failure -
Current (A)	Capacity (Ah)	Current (A)	Capacity (Ah)		
15.57	1557	130.60	784	20	5000
20.39	1468	148.00	740	30	4200
27.16	1358	171.00	684	40	3700
47.80	1148	206.00	618	50	3200
55.20	1104	265.00	530	60	2800
68.40	1027	375.00	375	70	2400
80.00	960	-	-	80	2100
91.60	916	-	-	90	1800
107.60	861	-	-	100	1500

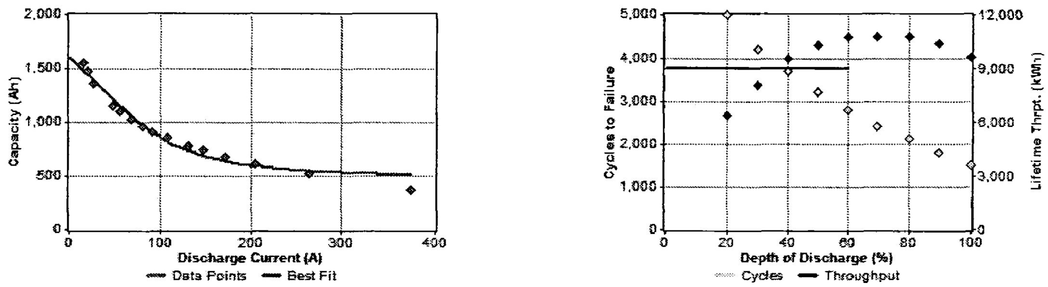


Figure D.5: B5 Capacity (L) and Lifetime (R) Curves

Unit:	**B6**	**Manufacturer:**	
Model:	4KS25P	Surrette/Rolls Battery	
Series:	5000	**Section:**	E

Link: http://www.rollsbattery.com/

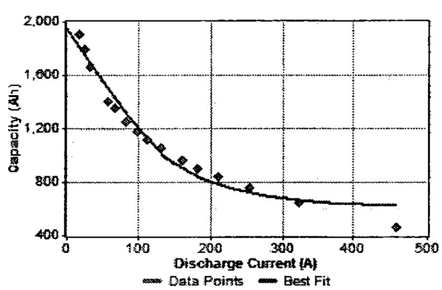
Unit Parameters:

Nominal Capacity:	1904	Ah	Float Life:	20	yrs
Nominal Voltage:	4	V	Max. Charge Current:	67.5	A
Round Trip Efficiency:	80	%	Lifetime Throughput:	10935	kWh
Min. State of Charge:	40	%			

Calculated Parameters:

Maximum Capacity:	1947	Ah	Capacity Ratio, c:	0.272
Rate Constant, k:	0.347	1/hr		

Capacity Curve				Lifetime Curve	
B6				Depth of Discharge (%)	Cycles to Failure -
Current (A)	Capacity (Ah)	Current (A)	Capacity (Ah)		
19.04	1904	159.80	959	20	5000
24.94	1796	181.00	905	30	4200
33.21	1661	209.00	837	40	3700
58.50	1404	252.00	756	50	3200
67.50	1350	324.00	648	60	2800
83.70	1256	459.00	459	70	2400
97.90	1175	-	-	80	2100
112.10	1121	-	-	90	1800
131.60	1053	-	-	100	1500



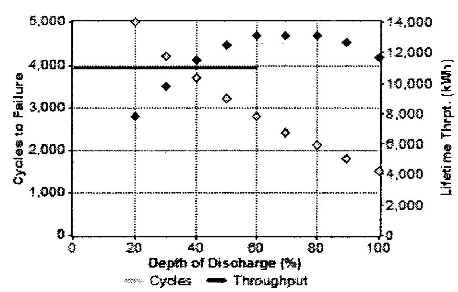


Figure D.6: B6 Capacity (L) and Lifetime (R) Curves

Unit:	**B7**	**Manufacturer:**	
Model:	6CS17P	Surrette/Rolls Battery	
Series:	5000	**Section:**	F

Link: http://www.rollsbattery.com/

Unit Parameters:

Nominal Capacity:	770	Ah	Float Life:	20	yrs
Nominal Voltage:	6	V	Max. Charge Current:	27.3	A
Round Trip Efficiency:	80	%	Lifetime Throughput:	6593	kWh
Min. State of Charge:	40	%			

Calculated Parameters:

Maximum Capacity:	783	Ah	Capacity Ratio, c:	0.263
Rate Constant, k:	0.370	1/hr		

Capacity Curve				**Lifetime Curve**	
B7				Depth of Discharge (%)	Cycles to Failure -
Current (A)	Capacity (Ah)	Current (A)	Capacity (Ah)		
7.70	770	64.60	388	20	5000
10.09	726	73.00	366	30	4200
13.43	672	85.00	339	40	3700
23.70	568	102.00	306	50	3200
27.30	546	131.00	262	60	2800
33.90	508	186.00	186	70	2400
39.60	475	-	-	80	2100
45.30	453	-	-	90	1800
53.20	426	-	-	100	1500

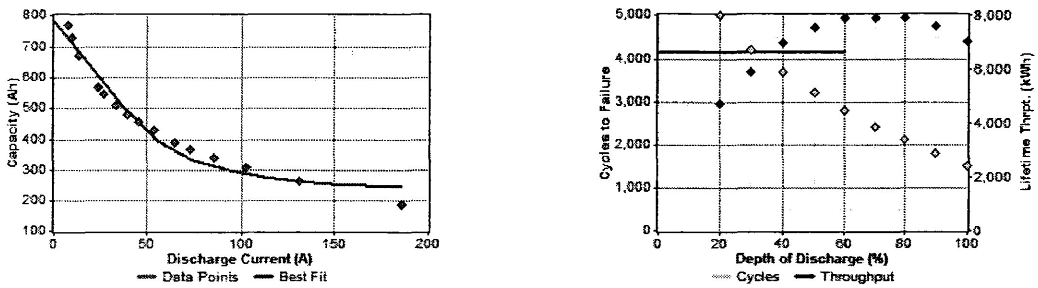


Figure D.7: B7 Capacity (L) and Lifetime (R) Curves

Unit:	**B8**	**Manufacturer:**	
Model:	6CS21P	Surrette/Rolls Battery	
Series:	5000	**Section:**	F

Link: http://www.rollsbattery.com/

Unit Parameters:

Nominal Capacity:	963	Ah	Float Life:	20	yrs
Nominal Voltage:	6	V	Max. Charge Current:	34.2	A
Round Trip Efficiency:	80	%	Lifetime Throughput:	8354	kWh
Min. State of Charge:	40	%			

Calculated Parameters:

Maximum Capacity:	992	Ah	Capacity Ratio, c:	0.278
Rate Constant, k:	0.324	1/hr		

Capacity Curve				Lifetime Curve	
B8				Depth of Discharge (%)	Cycles to Failure -
Current (A)	Capacity (Ah)	Current (A)	Capacity (Ah)		
9.63	963	80.80	485	20	5000
12.62	908	92.00	458	30	4200
16.80	840	106.00	423	40	3700
29.60	710	127.00	382	50	3200
34.20	683	164.00	328	60	2800
42.30	635	232.00	232	70	2400
49.50	594	-	-	80	2100
56.70	567	-	-	90	1800
66.60	533	-	-	100	1500

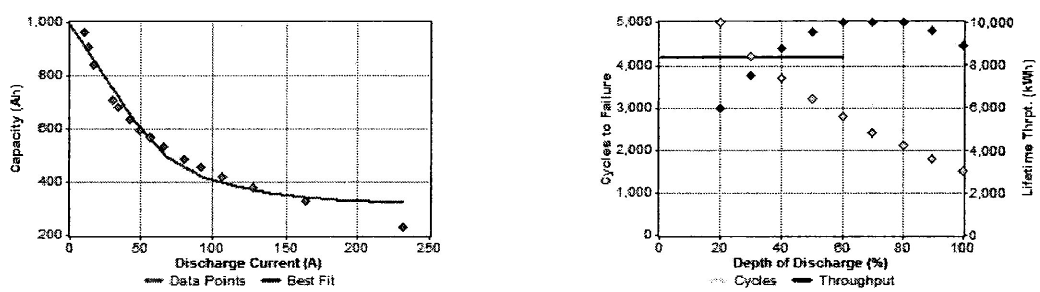


Figure D.8: B8 Capacity (L) and Lifetime (R) Curves

Unit:	**B9**		**Manufacturer:**		
Model:	6CS25P		Surrette/Rolls Battery		
Series:	5000		**Section:**	F	

Link: http://www.rollsbattery.com/

Unit Parameters:

Nominal Capacity:	1156	Ah	Float Life:	20	yrs
Nominal Voltage:	6	V	Max. Charge Current:	41.0	A
Round Trip Efficiency:	80	%	Lifetime Throughput:	10048	kWh
Min. State of Charge:	40	%			

Calculated Parameters:

Maximum Capacity:	1193	Ah	Capacity Ratio, c:	0.272
Rate Constant, k:	0.334	1/hr		

Capacity Curve				**Lifetime Curve**	
B9				Depth of Discharge	Cycles to Failure
Current (A)	Capacity (Ah)	Current (A)	Capacity (Ah)	(%)	-
11.56	1156	97.00	582	20	5000
15.15	1091	110.00	549	30	4200
20.17	1009	127.00	508	40	3700
35.50	853	153.00	459	50	3200
41.00	820	197.00	394	60	2800
50.80	763	279.00	279	70	2400
59.50	713	-	-	80	2100
68.10	681	-	-	90	1800
80.00	640	-	-	100	1500

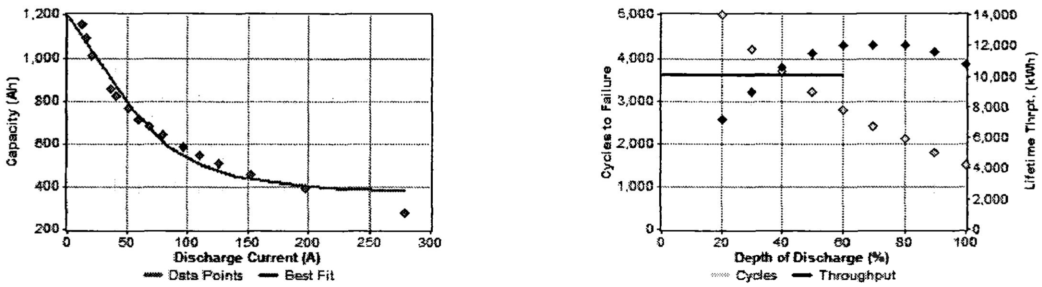


Figure D.9: B9 Capacity (L) and Lifetime (R) Curves

Unit:	**B10**	**Manufacturer:**	
Model:	8CS25P	Surrette/Rolls Battery	
Series:	5000	**Section:**	G

Link: http://www.rollsbattery.com/

Unit Parameters:

Nominal Capacity:	1156	Ah	Float Life:	20	yrs
Nominal Voltage:	8	V	Max. Charge Current:	41.0	A
Round Trip Efficiency:	80	%	Lifetime Throughput:	13450	kWh
Min. State of Charge:	40	%			

Calculated Parameters:

Maximum Capacity:	1197	Ah	Capacity Ratio, c:	0.276
Rate Constant, k:	0.324	1/hr		

Capacity Curve				Lifetime Curve	
B10				Depth of Discharge (%)	Cycles to Failure -
Current (A)	Capacity (Ah)	Current (A)	Capacity (Ah)		
11.56	1156	97.00	582	20	5000
15.15	1091	110.00	549	30	4200
20.17	1009	127.00	508	40	3700
35.50	853	153.00	459	50	3200
41.00	820	197.00	394	60	2800
50.80	763	279.00	279	70	2400
59.50	713	-	-	80	2100
68.10	681	-	-	90	1800
80.00	640	-	-	100	1500

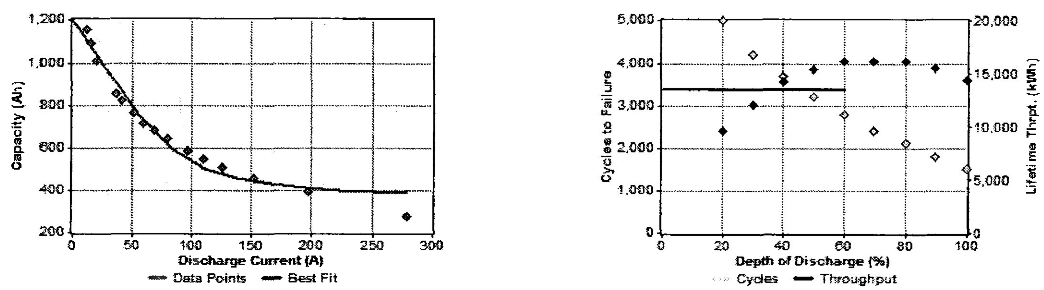


Figure D.10: B10 Capacity (L) and Lifetime (R) Curves

The following Table demonstrates the cost of the BESS enclosures for the selected battery units. NIP indicates the non-insulated chest enclosure price and IP indicates the insulated chest enclosure price.

Table D.1: Surrette/Rolls Battery Enclosure Prices

Num. of Batt.	Layout	B1/B2/B3		B4/B5/B6		B7/B8/B9		B10	
		NIP ($)	IP ($)	NIP ($)	IP ($)	NIP ($)	IP ($)	NIP ($)	IP ($)
2	2x1	955	1275	1190	1560	1385	1785	1530	1955
4	2x2	1225	1595	1580	2020	1930	2435	2205	2760
4	1x4	1270	1660	1625	2080	1960	2475	2180	2725
6	2x3	1465	1900	1900	2412	2390	2980	2725	3370
8	2x4	1670	2140	5190	2750	2820	3475	3225	3945
10	2x5	1870	2390	2470	3090	3220	3955	3720	4545
12	2x6	2070	2725	2750	3505	3625	4520	3230	4060
12	4x3	2045	2690	2720	3470	2510	4500	4210	-
14	2x7	2285	2965	3040	3830	-	-	4665	-
16	2x8	2485	3220	3315	4180	-	-	-	-
16	4x4	2415	3130	3245	4090	-	-	-	-

Appendix E - DGS

Appendix E introduces additional information as it relates to the DGS introduced in Chapter 5. Various definitions of DG operation will be introduced followed by common and specific technical specifications.

Standby Power Rating is used for emergency power applications. The DG cannot be overloaded or operated in parallel with other utility generation. The DG should be sized to allow for generation of 80% of the average load and able to operate up to 200 hours a year with a maximum of 25 hours at the standby power rating. The standby power rating must only be used under absolute emergency conditions. The Continuous Power Rating is used to represent the generator‘s ability to supply utility power, at a constant 100% load, for an unlimited period of yearly operation with no overload capabilities. Both the standby power and continuous power ratings are not applicable in the remote community. Prime Power Rating is used to supply power locally as opposed to commercially purchased power. Prime Power Rating is subdivided into two sub-ratings which include limited and unlimited time running prime power. Unlimited Time Running Prime Power is prime power that is available to supply varying loads for an unlimited number of hours a year and shall be governed by the following Table [37].

Loading	Duration
Variable load <= 70% average prime power rating	250 hours/operating period
Operating time at 100% prime power rating	<500 hours/yr
Operating at 10% overload capability	1 hr within 12 hr operation period
Operating time at 10% overload power	< 25 hr/yr

Limited Time Running Prime Power is prime power that is available for a limited number of hours in conjunction with a non-variable load. It is used to provide power during planned outages and may operate in parallel with additional generation for up to 750 hours/yr provided that the generated power level is lower than the prime power rating. If generation is required in parallel for more than 750 hours/yr Continuous Power Rating generation should be used. Due to the non-variable load constraint the limited time running prime power rating is not appropriate for the remote community. Therefore the DGs used in this thesis should be operated within the confines of the unlimited time running prime power rating [37].

E.1 DG Common Technical Specifications

The information contained within this Section was obtained from the datasheet and other technical documentation of the 250 kW DG unit. Most of the DG units explored exhibit very similar characteristics however for unit specifics it is suggested to refer to the unit datasheet which will be sourced in the following Section. Figure E.1

demonstrates the 3Φ efficiency curves for the DG with a rated output voltage of 416 and 480 Volts. There are four voltages available which are 416, 440, 460, and 480 V however the maximum and minimum are investigated here. All DGs investigated for this thesis are 60 Hz. Even though the communities and their generation sources are not connected to the Bulk Electric System, they are still located within North America, and due to standardization 60 Hz is the only feasible option. It can be seen that there is a slight increase in efficiency as the rated output voltage increases and the units are commonly operated at 480 V. As previously stated the minimum loading assumed for simulation in this thesis is 30% which is indicated in Figure E.1. As seen in Figure E.1 the DGs may be operated with a lower loading, however the efficiency decreases rather significantly when lower than 30% and the optimal operation of the DG is around 70% loaded. Selecting 30% as the minimum load factor also introduces a tolerance to the DG operation. These general trends remain valid for all rated output voltages [37, 38].

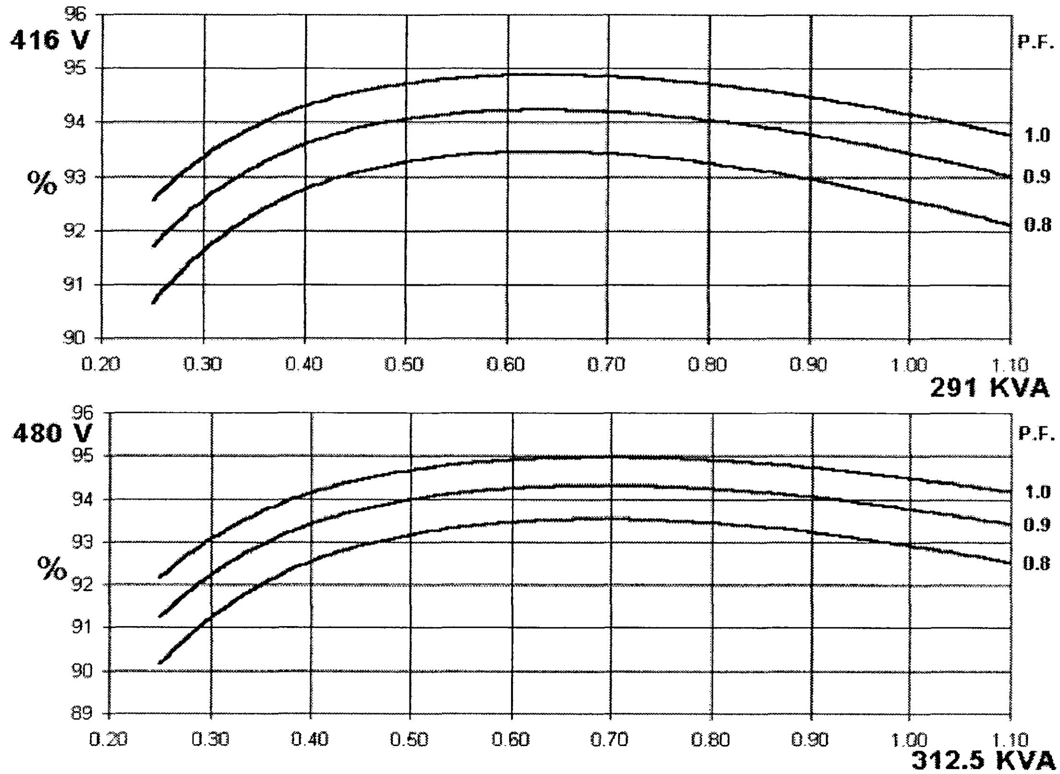


Figure E.1: DG 3Φ Efficiency Curves

Figure E.2 demonstrates the derating curves of the DG when operating at 1800 RPM as done in this thesis. The Figure on the left demonstrates the derating curve at standby or prime power and the Figure on the right at continuous power. As the altitude and/or temperature of the DG increases the rated power or rated output of the DG is derated as a percentage as demonstrated. The system model is situated 297.9 m or 977.36' ASL with an average ambient temperature of 0.5 °C. Even with the variance of the DG operation due to altitude and ambient temperature, from both constant location based variables and year to year temperature variance, it is expected that the DG output will not be derated above any standard operational tolerances. For standby and prime operation above the temperature or altitude conditions provided in Figure E.2 operation is derated by an additional 5.0% per 300 m or 1000' and 15% per 10ºC or 18ºF [38].

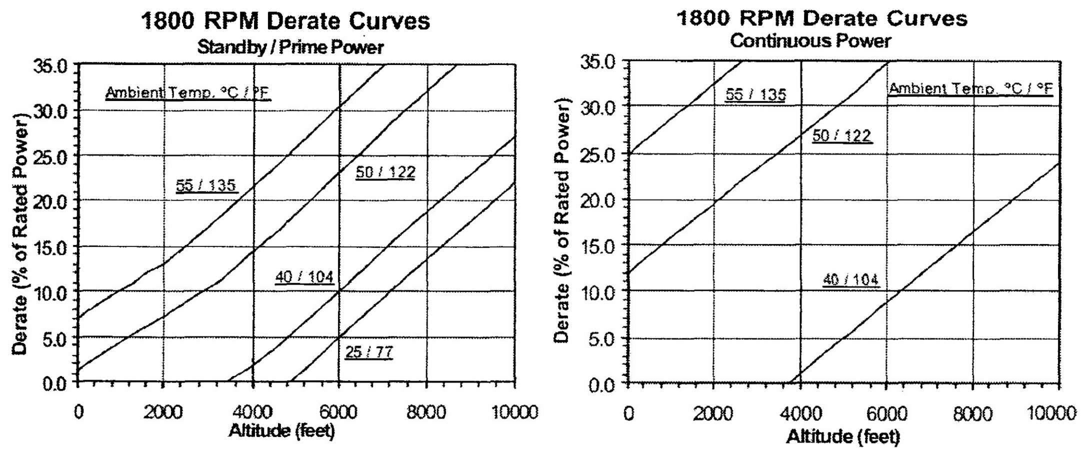


Figure E.2: DG Derating Curves at 1800 RPM

Figure E.3 demonstrates the locked rotor motor starting curve of the DG. This is done by plotting the locked rotor kVA vs. the percent voltage transient dip for the four rated output voltages. The higher the locked rotor kVA the higher the rated output voltage experienced for the same percent voltage transient dip [38].

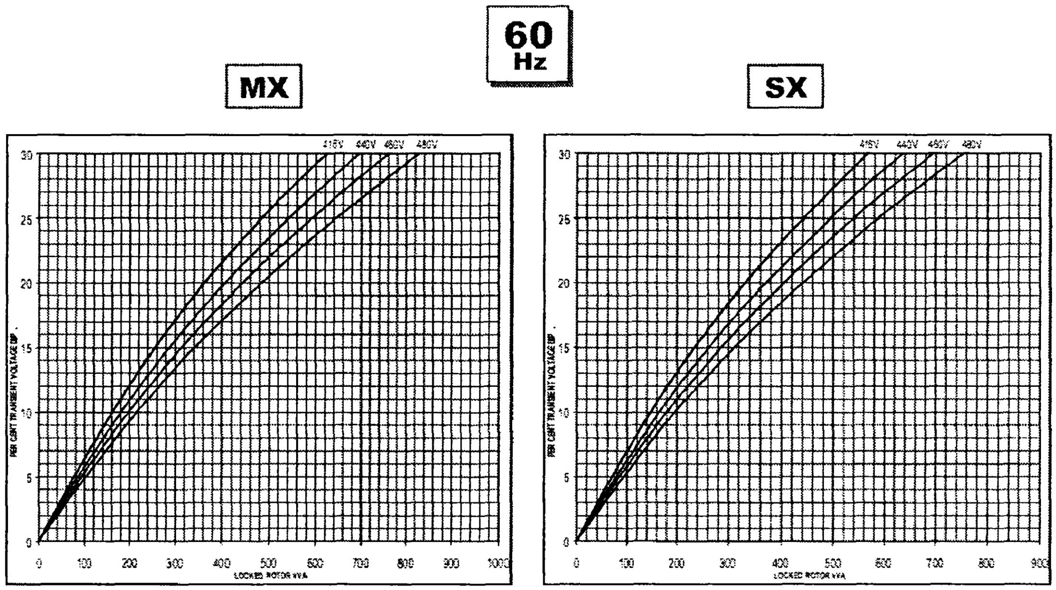
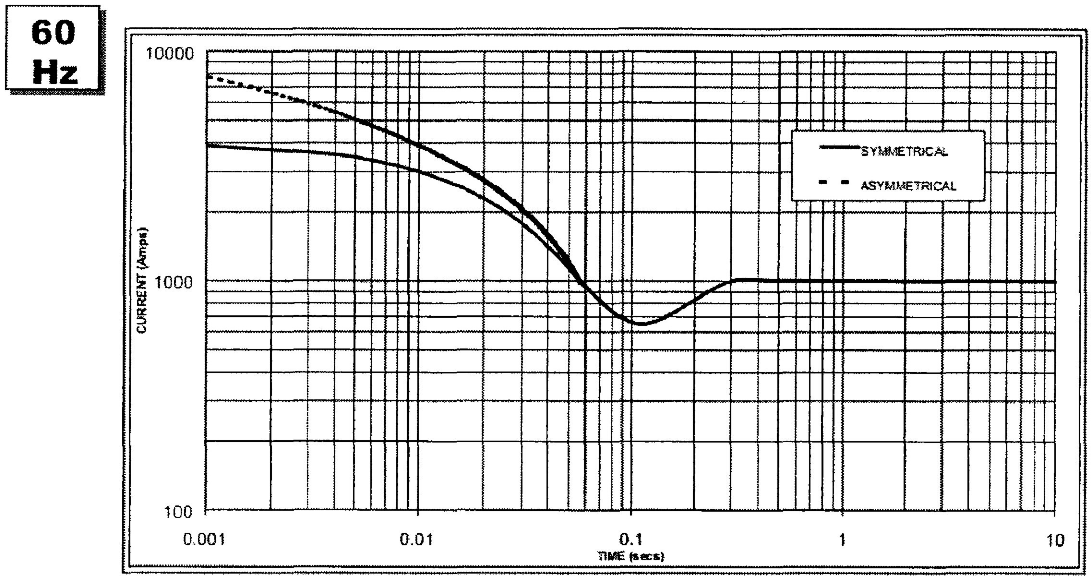


Figure E.3: DG Locked Rotor Motor Starting Curve

Figure E.4 demonstrates the 3Φ short circuit decrement curve. This decrement curve is provided at a no-load excitation at rated speed based on a wye connection. Additional information is provided in the data sheet that allows for the conversion of the data located in Figure E.4 to be transformed or adjusted to: adjust the values of the curve between .001 s and the minimum current point with respect of the nominal operating voltage, to convert the minimum current point value to various short circuit conditions (instantaneous, minimum, sustained, and maximum sustained duration for 3Φ, 2Φ L-L, and 1Φ L-N faults), and to adjust for parallel star or series delta connections as opposed to the existing wye connection [38].



Sustained Short Circuit = 1,000 Amps

Figure E.4: DG 3Φ Short Circuit Decrement Curve

Figure E.5 demonstrates the DG ratings while operating at a 0.8 PF. The Figure demonstrates the three connection types at the four available voltages for various outputs with their respective efficiencies and input relationships. The datasheet also includes the rated voltages for the various modes of operation [38].

60 Hz																
Series Star (V)	416	440	460	480	416	440	460	480	416	440	460	480	416	440	460	480
Parallel Star (V)	208	220	230	240	208	220	230	240	208	220	230	240	208	220	230	240
Series Delta (V)	240	254	266	277	240	254	266	277	240	254	266	277	240	254	266	277
kVA	267.0	275.0	286.5	286.5	291.0	299.0	312.5	312.5	304.0	312.5	331.3	331.3	312.0	320.0	343.8	343.8
kW	213.6	220.0	229.2	229.2	232.8	239.2	250.0	250.0	243.2	250.0	265.0	265.0	249.6	256.0	275.0	275.0
Efficiency (%)	92.9	93.0	93.1	93.2	92.6	92.7	92.8	92.9	92.4	92.6	92.5	92.7	92.2	92.4	92.3	92.5
kW Input	229.9	236.6	246.2	245.9	251.4	258.0	269.4	269.1	263.2	270.0	286.5	285.9	270.7	277.1	296.0	297.3

Figure E.5: DG Ratings with 0.8 PF

E.2 DG Specific Technical Specifications

The following Figures demonstrate the fuel and efficiency curves of the DG investigated in Chapter 5. The efficiency curve was calculated from the fuel curve which in turn was created from unit specific data entry regarding the unit's fuel consumption (L/hr) at specific outputs (kW). Each unit entry will consist of the aforementioned Figures as well as a reiteration of the appropriate intercept, slope, size, and model characteristics. Table E.1 includes some common conversion ratios that are used for the DG specific technical specifications. BHP is the Brake Horse Power and is measured at the maximum operating RPM of the engine. The mechanical kilowatt output of the engine (kWm) is the output power of the engine that does not account for efficiency losses in the generator or other losses such as cooling fans et cetera before the generator's electrical output is measured. The generator's electrical output is measured in electrical kilowatts (kWe) and is the amount of power available at the generator terminals.

Table E.1: Common Conversions

Unit	**Conversion**
Litres	U.S. Gal x 3.785
kWm	BHP x 0.746
U.S. Gal	Litres x 0.2642
BHP	kWm x 1.34

For the majority of the 19 DG below the specifications were obtained with system parameters of 100 kPa, at an altitude of 100 m, an air inlet temperature of 25 °C, at a relative humidity of 30%, and while operating with No. 2 diesel fuel. The fuel consumption data was based on No. 2 diesel fuel with a weight of 0.85 kg/litre. In general for an engine speed of 1800 RMP the DG will operate up to an altitude of 1,525 m and 40°C with no power degradation. If conditions are sustained above this the DG output is derated by approximately 4% per 300 m and 1% per 10°C. Due to the location of the system model and the general landscape of N ON it is reasonable to assume that the DG will not experience output power degradation.

Table E.2 demonstrates the loading specific parameters of the DG units which will be used below.

Table E.2: DG Loading Specific Metrics

#	**Metric Description**	**Unit**
1	Prime Unlimited Time Running Power Fuel Consumption	L/hr
2	Prime Unlimited Time Output Power	kWm
3	Standby Power Output and Fuel Consumption	L/hr
4	Cont. Power Output and Fuel Consumption	L/hr
5	Percentage of Rated Power	kW

Unit:	**DG1**	**Manufacturer:**
Model:	**TP-P100-T3-60**	**Perkins**

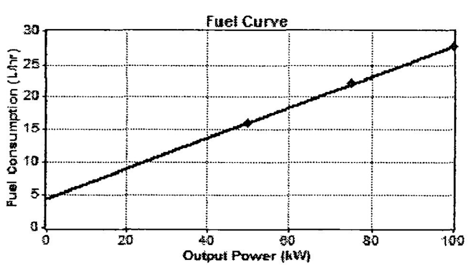
Link: http://www.gopower.com/documents/docs/1287410230.pdf

Unit Parameters:

Rated Power:	100	kW
Standby Power:	125	kVA
	100	kW
Prime Power:	112.5	kVA
	90	kW
Engine Speed:	1800	RPM
Engine Fuel Displacement:	4.4	L
Intercept Coefficient:	.04350	$L/hr/kW_{rated}$
Slope:	0.2340	$L/hr/kW_{o/p}$

DG1 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1		16	22	27.7	L/hr
2	-	-	-	111	kWm
5	25	50	75	100	kW



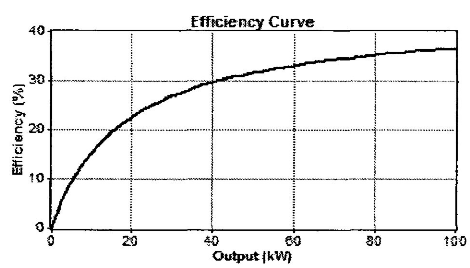


Figure E.6: DG1 Fuel and Efficiency Curves

Unit:	**DG2**	**Manufacturer:**
Model:	**T150**	**Cummins**

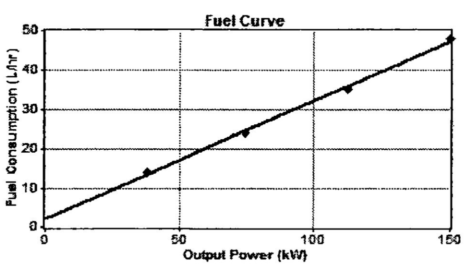
Link: http://www.gopower.com/documents/docs/1247172897.pdf

Unit Parameters:

Rated Power:	150	kW
Standby Power:	207	kWm
Prime Power:	188	kWm
Continuous Power:	159	kWm
Engine Speed:	1800	RPM
Engine Fuel Displacement:	8.3	L
Intercept Coefficient:	0.01333	$L/hr/kW_{rated}$
Slope:	0.3013	$L/hr/kW_{o/p}$

DG2 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1	14	24	35	48	L/hr
2	47	94	141	188	kWm
3	100%	207	kWm	53	L/hr
4	100%	159	kWm	40	L/hr
5	37.5	75	112.5	150	kW



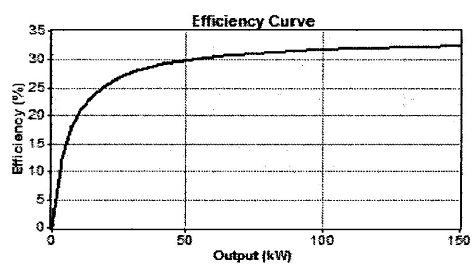


Figure E.7: DG2 Fuel and Efficiency Curves

Unit:	**D3**	**Manufacturer:**
Model:	**155-Kw554072-3B**	**John Deer**

Link: http://www.gopower.com/documents/docs/1267130290.pdf

Unit Parameters:

Rated Power:	155	kW
Standby Power (LTP):	155	kWe
Prime Power:	140	kWe
Engine Speed:	1800	RPM
Engine Fuel Displacement:	6.8	L
Intercept Coefficient:	0.03473	$L/hr/kW_{rated}$
Slope:	0.2310	$L/hr/kW_{o/p}$

DG3 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1		23.4	32	41.3	L/hr
2		-	-	161	kWm
3	-	25.2	34.6	44.5	L/hr
5	38.75	77.5	116.25	155	kW

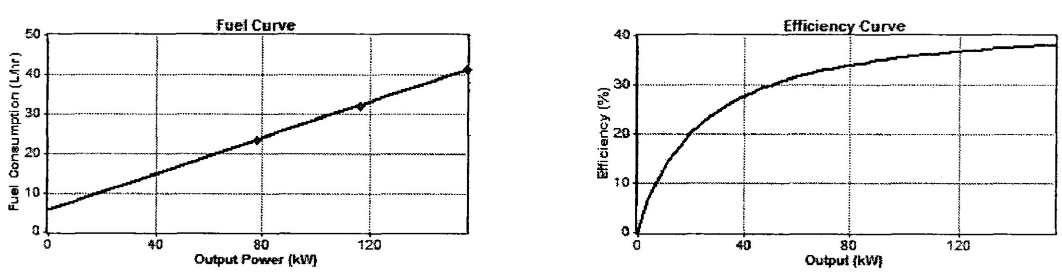


Figure E.8: DG3 Fuel and Efficiency Curves

Unit:	DG4	Manufacturer:
Model:	**TP-P175-T3-60**	**Perkins**

Link: http://www.gopower.com/documents/docs/1287413516.pdf

Unit Parameters:

Rated Power:	175	kW
Standby Power:	220	kVA
	175	kW
Prime Power:	200	kVA
	160	kW
Engine Speed:	1800	RPM
Engine Fuel Displacement:	6.6	L
Intercept Coefficient:	0.01619	$L/hr/kW_{rated}$
Slope:	0.2629	$L/hr/kW_{o/p}$

DG4 Loading Specifics

Metric	% Load				Unit
	25	50	75	100	
1	-	26	37	49	L/hr
2	-	-	-	193	kWm
5	43.75	87.5	131.25	175	kW

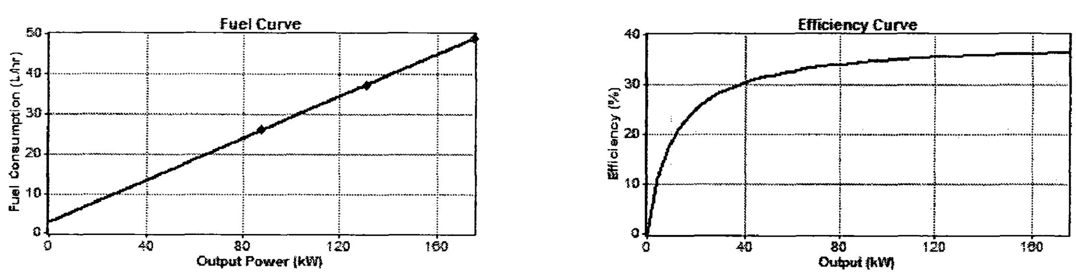


Figure E.9: DG4 Fuel and Efficiency Curves

Unit:	DG5	Manufacturer:
Model:	**HP180**	**Perkins**

Link: http://www.gopower.com/documents/docs/1207929468.pdf

Unit Parameters:

Rated Power:	180	kW
Standby Power:	212.5-222.5	kVA
	170-178	kW
Prime Power:	200-201	kVA
	160-161	kW
Engine Speed:	1800	RPM
Engine Fuel Displacement:	6.6	L
Intercept Coefficient:	0.06056	$L/hr/kW_{rated}$
Slope:	0.2251	$L/hr/kW_{o/p}$

DG5 Loading Specifics

Metric	% Load				Unit
	25	**50**	**75**	**100**	
1	20.1	32.6	41.2	51.0	L/hr
2	-	-	-	204.3	kWm
3	21.0	32.7	42.6	54.3	L/hr
5	45	90	135	180	kW

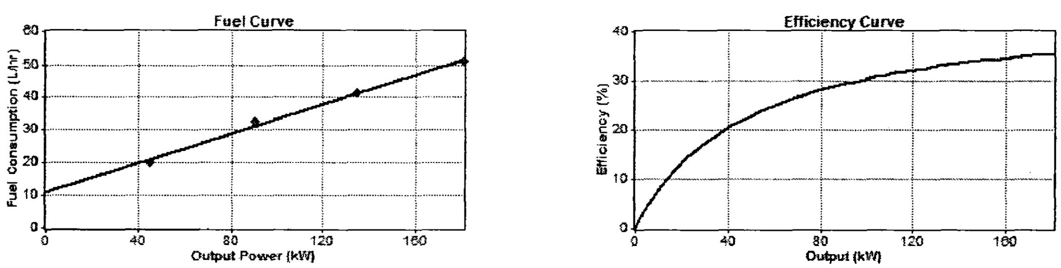


Figure E.10: DG5 Fuel and Efficiency Curves

Unit:	**DG6**	**Manufacturer:**
Model:	**T200**	**Cummins**

Link: http://www.gopower.com/documents/docs/1245952048.pdf

Unit Parameters:

Rated Power:	200	kW
Standby Power:	237	kWm
Prime Power:	213	kWm
Continuous Power:	175	kWm
Engine Speed:	1800	RPM
Engine Fuel Displacement:	8.3	L
Intercept Coefficient:	0.00500	$L/hr/kW_{rated}$
Slope:	0.2720	$L/hr/kW_{o/p}$

DG6 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1	15	28	41	56	L/hr
2	53	106	160	213	kWm
3	100%	237	kWm	64	L/hr
4	100%	175	kWm	44	L/hr
5	50	100	150	200	kW

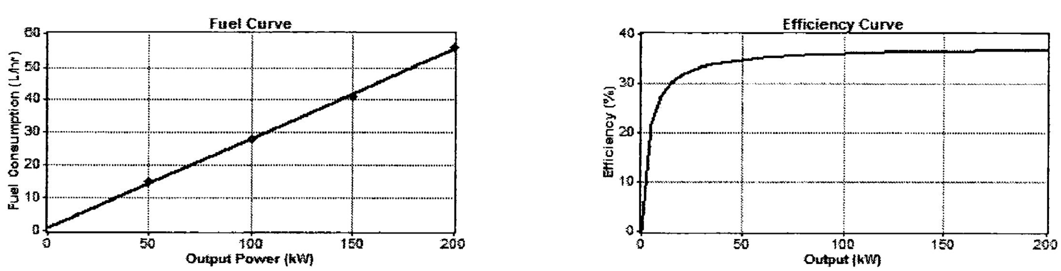


Figure E.11: DG6 Fuel and Efficiency Curves

Unit:	**DG7**	**Manufacturer:**
Model:	**TP-P220-T1-60**	**Perkins**

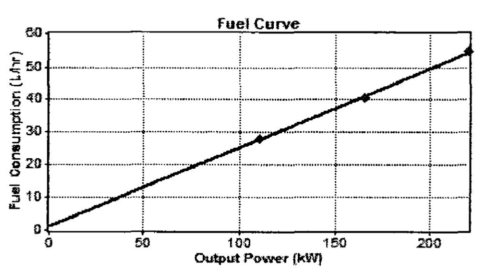
Link: http://www.gopower.com/documents/docs/1275684267.pdf

Unit Parameters:

Rated Power:	220	kW
Standby Power:	275	kVA
	220	kW
Prime Power:	250	kVA
	200	kW
Engine Speed:	1800	RPM
Engine Fuel Displacement:	8.7	L
Intercept Coefficient:	0.005076	$L/hr/kW_{rated}$
Slope:	0.2409	$L/hr/kW_{o/p}$

DG7 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1	-	27.9	40.3	54.4	L/hr
2	-	-	-	235	kWm
5	55	110	165	220	kW



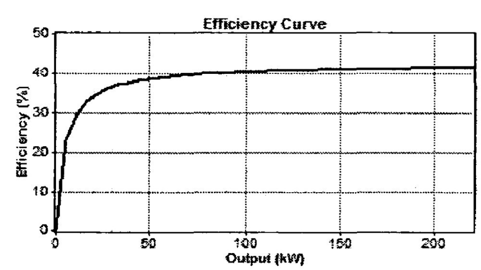


Figure E.12: DG7 Fuel and Efficiency Curves

Unit:	**DG8**	**Manufacturer:**
Model:	**T250**	**Cummins**

Link: http://www.gopower.com/documents/docs/1245955591.pdf

Unit Parameters:

Rated Power:	250	kW
Standby Power:	297	kWm
Prime Power:	262	kWm
Continuous Power:	223	kWm
Engine Speed:	1800	RPM
Engine Fuel Displacement:	8.8	L
Intercept Coefficient:	0.02600	$L/hr/kW_{rated}$
Slope:	0.2624	$L/hr/kW_{o/p}$

DG8 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1	21	41	58	70	L/hr
2	66	131	197	262	kWm
3	100%	297	kWm	77	L/hr
4	100%	223	kWm	63	L/hr
5	62.5	125	187.5	250	kW

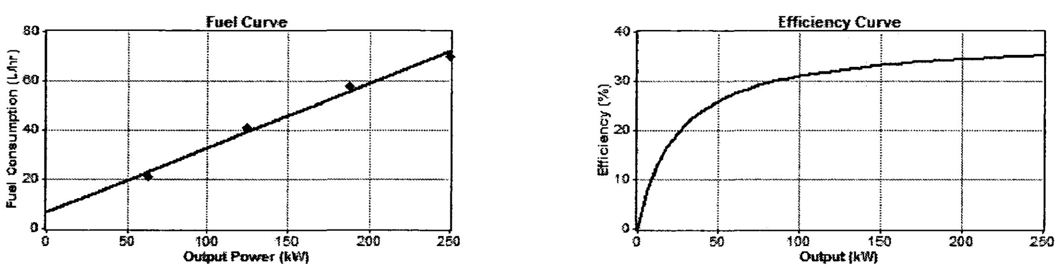


Figure E.13: DG8 Fuel and Efficiency Curves

Unit:	DG9	Manufacturer:
Model:	TP-P300-T1-60	Perkins

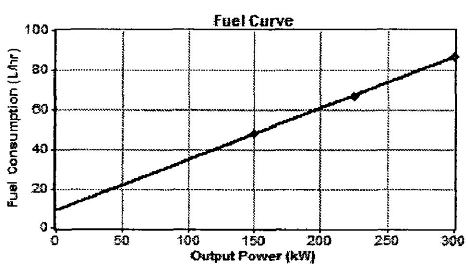
Link: http://www.gopower.com/documents/docs/1275684322.pdf

Unit Parameters:

Rated Power:	300	kW
Standby Power:	385	kVA
	300	kW
Prime Power:	350	kVA
	280	kW
Engine Speed:	1800	RPM
Engine Fuel Displacement:	12.5	L
Intercept Coefficient:	0.02944	$L/hr/kW_{rated}$
Slope:	0.2600	$L/hr/kW_{o/p}$

DG9 Loading Specifics

Metric	% Load				Unit
	25	**50**	**75**	**100**	
1	-	48	67	87	L/hr
2	-	-	-	381	kWm
5	75	150	225	300	kW



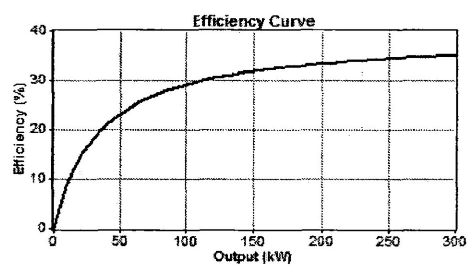


Figure E.14: DG9 Fuel and Efficiency Curves

Unit:	**DG10**	**Manufacturer:**
Model:	**TP-P360-T3-60**	**Perkins**

Link: http://www.gopower.com/documents/docs/1287415179.pdf

Unit Parameters:

Rated Power:	350	kW
Standby Power:	440	kVA
	350	kW
Prime Power:	400	kVA
	320	kW
Engine Speed:	1800	RPM
Engine Fuel Displacement:	12.5	L
Intercept Coefficient:	0.02524	$L/hr/kW_{rated}$
Slope:	0.2229	$L/hr/kW_{o/p}$

DG10 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1	-	48	67	87	L/hr
2	-	-	-	407	kWm
5	87.5	175	262.5	350	kW

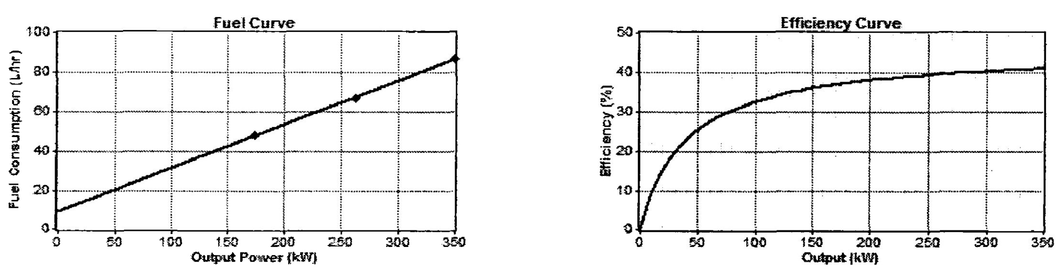


Figure E.15: DG10 Fuel and Efficiency Curves

Unit:	DG11	Manufacturer:
Model:	TP-P400-T3-60	Perkins

Link: http://www.gopower.com/documents/docs/1287434340.pdf

Unit Parameters:

Rated Power:	400	kW
Standby Power:	500	kVA
	400	kW
Prime Power:	438	kVA
	350	kW
Engine Speed:	1800	RPM
Engine Fuel Displacement:	12.5	L
Intercept Coefficient:	0.003333	$L/hr/kW_{rated}$
Slope:	0.2300	$L/hr/kW_{o/p}$

DG11 Loading Specifics

Metric	% Load				Unit
	25	50	75	100	
1	-	48	69	94	L/hr
2	-	-	-	435	kWm
5	100	200	300	400	kW

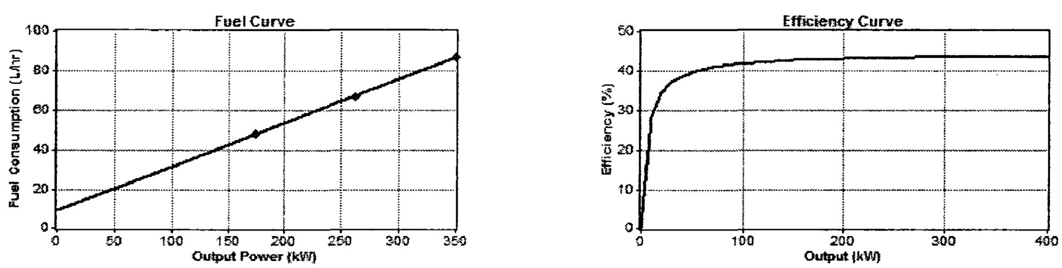


Figure E.16: DG11 Fuel and Efficiency Curves

Unit:	**DG12**	**Manufacturer:**
Model:	**T450**	**Cummins**

Link: http://www.gopower.com/documents/docs/1249332202.pdf

Unit Parameters:

Rated Power:	450	kW
Standby Power:	511	kWm
Prime Power:	463	kWm
Continuous Power:	325	kWm
Engine Speed:	1800	RPM
Engine Fuel Displacement:	15.0	L
Intercept Coefficient:	0.02644	$L/hr/kW_{rated}$
Slope:	0.2144	$L/hr/kW_{o/p}$

DG12 Loading Specifics

Metric		**% Load**			**Unit**
	25	**50**	**75**	**100**	
1	35.5	60.8	84.5	108	L/hr
2	116	231	347	463	kWm
3	100%	511	kWm	120	L/hr
4	100%	325	kWm	79.1	L/hr
5	112.5	225	337.5	450	kW

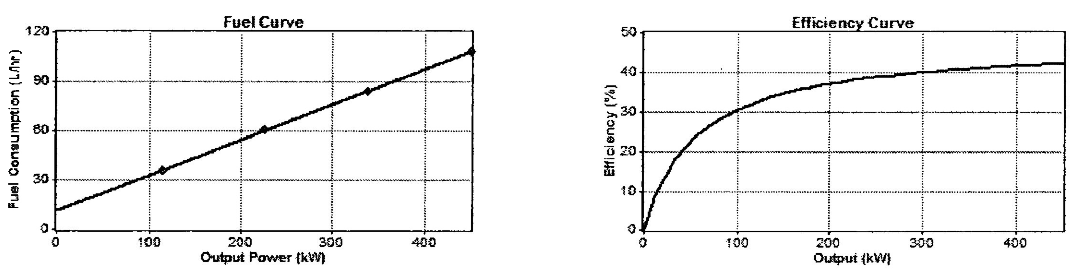


Figure E.17: DG12 Fuel and Efficiency Curves

Unit:	**DG13**	**Manufacturer:**
Model:	**MV500 SAE**	**Volvo**

Link: http://www.gopower.com/documents/docs/1287776893.pdf

Unit Parameters:

Rated Power:	500	kW
Standby Power:	625	kVA
	500	kW
Prime Power:	563	kVA
	450	kW
Engine Speed:	1800	RPM
Engine Fuel Displacement:	16.12	L
Intercept Coefficient:	-0.00080	$L/hr/kW_{rated}$
Slope:	0.2432	$L/hr/kW_{o/p}$

DG13 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1	-	60	90	122	L/hr
2	-	-	-	565	kWm
5	125	250	375	500	kW

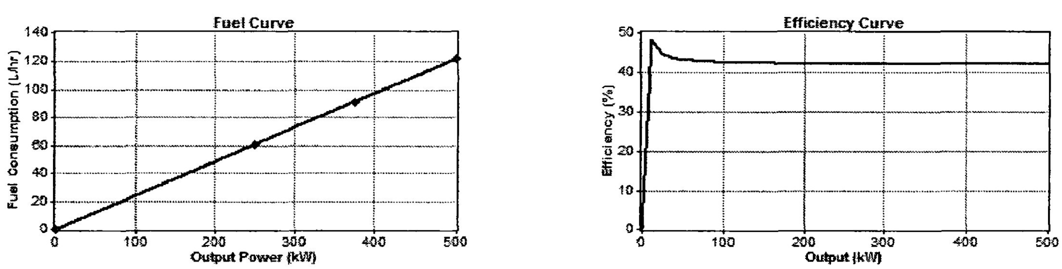


Figure E.18: DG13 Fuel and Efficiency Curves

Unit:	**DG14**	**Manufacturer:**
Model:	**TP-P550-T1-60**	**Perkins**

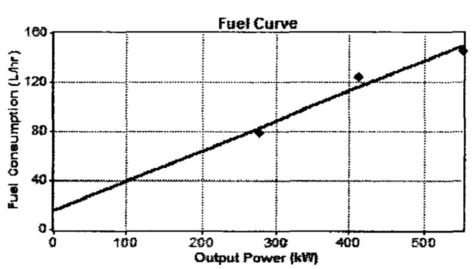
Link: http://www.gopower.com/documents/docs/1275924396.pdf

Unit Parameters:

Rated Power:	550	kW
Standby Power:	688	kVA
	550	kW
Prime Power:	Standby Only	
Engine Speed:	1800	RPM
Engine Fuel Displacement:	15.2	L
Intercept Coefficient:	0.02879	$L/hr/kW_{rated}$
Slope:	0.2436	$L/hr/kW_{o/p}$

DG14 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1	-	79	124	146	L/hr
2	-	-	-	597	kWm
5	137.5	275	412.5	550	kW



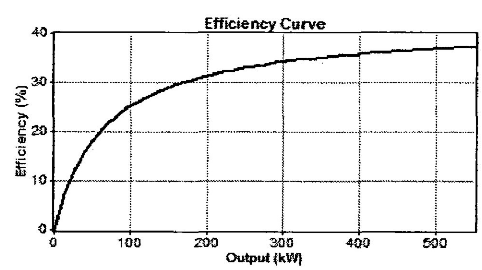


Figure E.19: DG14 Fuel and Efficiency Curves

Unit:	DG15	Manufacturer:
Model:	**TP-P600-T2-60-UL**	**Perkins**

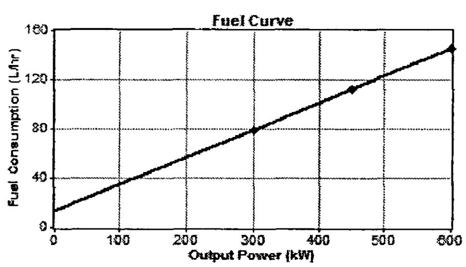
Link: http://www.gopower.com/documents/docs/1288023127.pdf

Unit Parameters:

Rated Power:	600	kW
Standby Power:	750	kVA
	600	kW
Prime Power:	675	kVA
	540	kW
Engine Speed:	1800	RPM
Engine Fuel Displacement:	15.2	L
Intercept Coefficient:	0.02167	$L/hr/kW_{rated}$
Slope:	0.2200	$L/hr/kW_{o/p}$

DG15 Loading Specifics

Metric	% Load				Unit
	25	**50**	**75**	**100**	
1	-	79	112	145	L/hr
2	-	-	-	652	kWm
5	150	300	450	600	kW



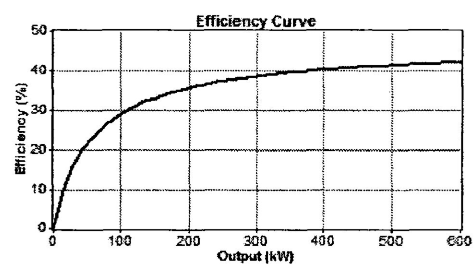


Figure E.20: DG15 Fuel and Efficiency Curves

Unit:	DG16	Manufacturer:
Model:	QSK23G7	Cummins

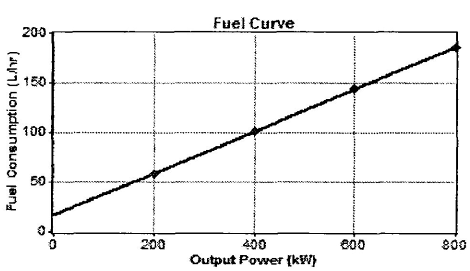
Link: http://www.gopower.com/documents/docs/1201019820.pdf

Unit Parameters:

Rated Power:	800	kW
Standby Power:	910	kWm
Prime Power:	809	kWm
Continuous Power:	653	kWm
Engine Speed:	1800	RPM
Engine Fuel Displacement:	23.15	L
Intercept Coefficient:	0.02000	$L/hr/kW_{rated}$
Slope:	0.2135	$L/hr/kW_{o/p}$

DG16 Loading Specifics

Metric	% Load				Unit
	25	50	75	100	
1	58	102	145	186	L/hr
2	202	405	607	809	kWm
3	100%	910	kWm	209	L/hr
4	100%	653	kWm	155	L/hr
5	200	400	600	800	kW



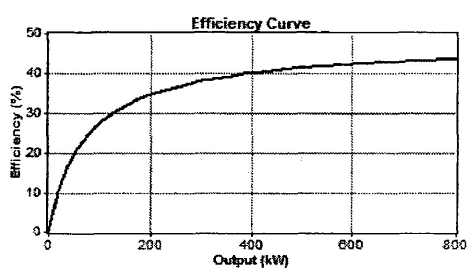


Figure E.21: DG16 Fuel and Efficiency Curves

Unit:	DG17	Manufacturer:
Model:	**TC900**	**Cummins**

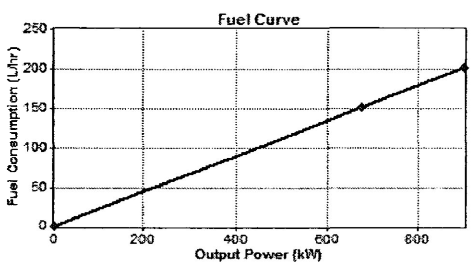
Link: http://www.gopower.com/documents/docs/1271176143.pdf

Unit Parameters:

Rated Power:	900	kW
Prime Power:	880	kWm
Engine Speed:	1800	RPM
Engine Fuel Displacement:	30.48	L
Intercept Coefficient:	-0.00085	$L/hr/kW_{rated}$
Slope:	0.2243	$L/hr/kW_{o/p}$

DG17 Loading Specifics

Metric	% Load				Unit
	25	50	75	100	
1		-	151	202	L/hr
2	-	-	-	-	kWm
5	225	450	675	900	kW



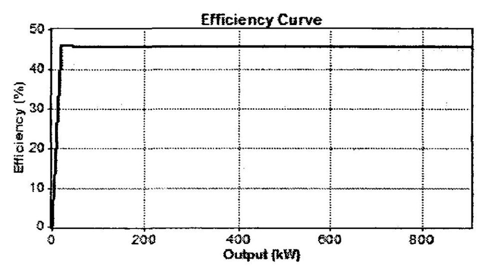


Figure E.22: DG17 Fuel and Efficiency Curves

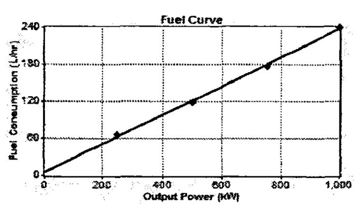
Unit:	**DG18**	**Manufacturer:**
Model:	**QST30G5**	**Cummins**

Link: http://www.gopower.com/documents/docs/1192556013.pdf

Unit Parameters:		
Rated Power:	1000	kW
Standby Power:	1111	kWm
Prime Power:	1007	kWm
Continuous Power:	832	kWm
Engine Speed:	1800	RPM
Engine Fuel Displacement:	30.48	L
Intercept Coefficient:	0.0055	$L/hr/kW_{rated}$
Slope:	0.232	$L/hr/kW_{o/p}$

DG18 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1	66	119	177	240	L/hr
2	252	504	756	1007	kWm
3	100%	1112	kWm	267	L/hr
4	100%	832	kWm	194	L/hr
5	250	500	750	1000	kW



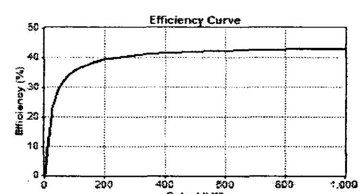


Figure E.23: DG18 Fuel and Efficiency Curves

Unit:	**DG19**	**Manufacturer:**
Model:	**OC1250**	**Cummins**

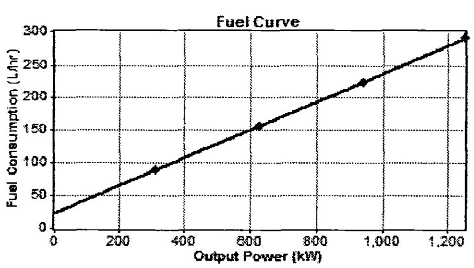
Link: http://www.gopower.com/documents/docs/1213026982.pdf

Unit Parameters:

Rated Power:	1250	kW
Standby Power:	1380	kWm
Prime Power Limited:	1300	kWm
Prime Power Unlimited:	1220	kWm
Continuous Power:	1000	kWm
Engine Speed:	1800	RPM
Engine Fuel Displacement:	50.3	L
Intercept Coefficient:	0.01760	$L/hr/kW_{rated}$
Slope:	0.2147	$L/hr/kW_{o/p}$

DG19 Loading Specifics

Metric	**% Load**				**Unit**
	25	**50**	**75**	**100**	
1	89	157	222	291	L/hr
2	305	610	915	1220	kWm
3	-	-	-	310	L/hr
5	312.5	625	937.5	1250	kW



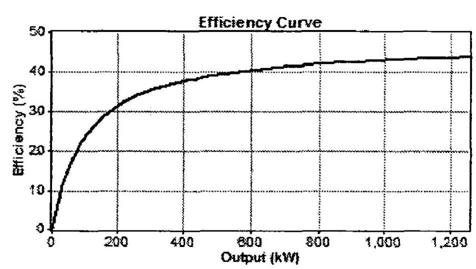


Figure E.24: DG19 Fuel and Efficiency Curves

Appendix F - SECS

Appendix F provides additional information as it relates to the Solar Energy Conversion Systems (SECS) introduced in Chapter 6. The first Section of this Appendix includes the scaled solar resources experienced by the system model. The second Section includes the extraterrestrial radiation experienced at the community location. The third and final Section introduces additional information with respect to the Solar Generators (SG) that were studied in this thesis. Appendix I contains additional SECS information which focuses on terminology associated with solar generation. The following Figure provides an overview of the global horizontal radiation and clearness index on a monthly basis which was derived from the climatic variables in Chapter 6.

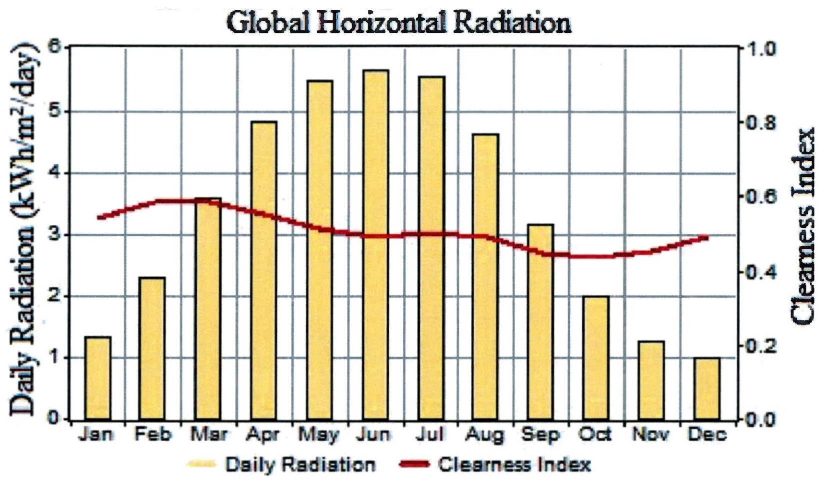


Figure F.1: System Model Global Horizontal Radiation and Clearness Index

F.1 Climatic - System Model Scaled Solar Resources

This Section contains additional Figures relating to the system model solar resources as introduced in Chapter 6. The solar daily radiation average was 3.939 $kWh/m^2/day$ from the climatic variables found by analysis of Environment Canada data. As such a scaled annual average of 3.939 $kWh/m^2/day$ was used which is the base for the following Figures. The baseline data was scaled for simulation purposes.

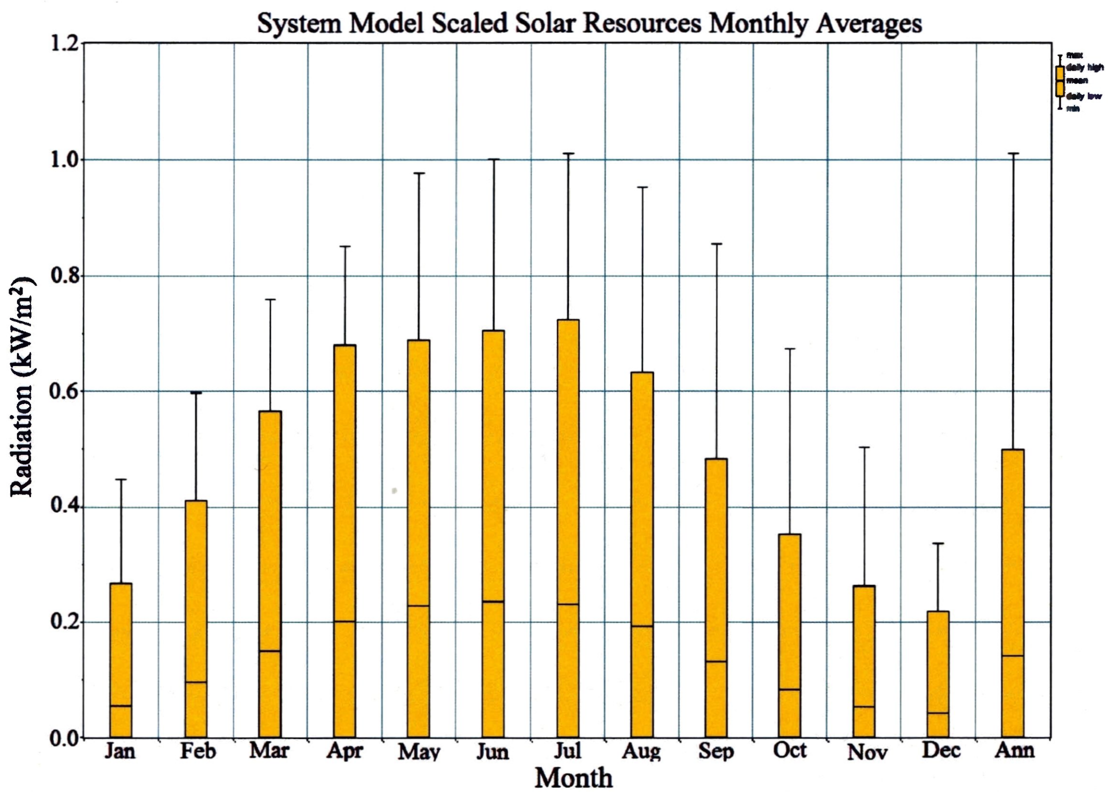


Figure F.2: System Model Scaled Solar Resources Monthly Averages

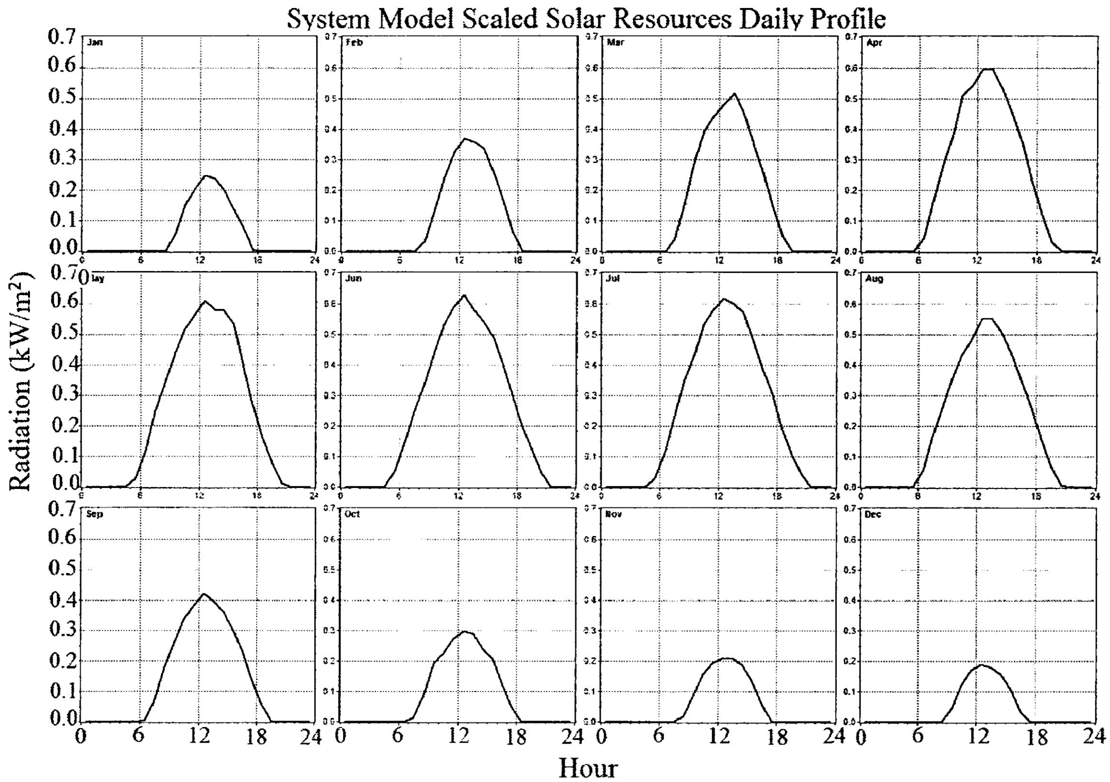


Figure F.3: System Model Scaled Solar Resources Daily Profile

System Model Hourly Solar Radiation (kWh/m2)													
Hour	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**June**	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**Avg**
0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
4	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
5	0.000	0.000	0.000	0.001	0.026	0.051	0.029	0.002	0.000	0.000	0.000	0.000	**0.009**
6	0.000	0.000	0.001	0.043	0.120	0.145	0.114	0.056	0.006	0.000	0.000	0.000	**0.040**
7	0.000	0.000	0.038	0.159	0.249	0.245	0.223	0.164	0.070	0.014	0.000	0.000	**0.097**
8	0.001	0.032	0.158	0.281	0.339	0.335	0.348	0.259	0.178	0.086	0.019	0.000	**0.170**
9	0.059	0.136	0.300	0.380	0.438	0.439	0.430	0.356	0.263	0.191	0.090	0.044	**0.261**
10	0.151	0.241	0.395	0.509	0.516	0.532	0.532	0.432	0.337	0.224	0.157	0.119	**0.345**
11	0.205	0.326	0.445	0.543	0.563	0.591	0.581	0.483	0.383	0.271	0.195	0.169	**0.396**
12	0.249	0.369	0.483	0.594	0.609	0.629	0.618	0.549	0.421	0.296	0.211	0.188	**0.435**
13	0.236	0.355	0.517	0.592	0.579	0.576	0.598	0.550	0.395	0.287	0.208	0.178	**0.423**
14	0.197	0.338	0.454	0.534	0.576	0.541	0.572	0.507	0.360	0.241	0.185	0.157	**0.388**
15	0.134	0.257	0.351	0.449	0.534	0.491	0.479	0.434	0.301	0.207	0.129	0.105	**0.323**
16	0.073	0.161	0.253	0.352	0.390	0.398	0.382	0.342	0.227	0.121	0.054	0.029	**0.232**
17	0.005	0.062	0.147	0.232	0.272	0.301	0.308	0.262	0.136	0.049	0.001	0.000	**0.148**
18	0.000	0.002	0.048	0.122	0.165	0.199	0.190	0.155	0.058	0.001	0.000	0.000	**0.078**
19	0.000	0.000	0.001	0.029	0.081	0.122	0.106	0.064	0.004	0.000	0.000	0.000	**0.034**
20	0.000	0.000	0.000	0.000	0.014	0.046	0.040	0.004	0.000	0.000	0.000	0.000	**0.009**
21	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
23	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
Avg	**0.055**	**0.095**	**0.150**	**0.201**	**0.228**	**0.235**	**0.231**	**0.192**	**0.131**	**0.083**	**0.052**	**0.041**	**0.141**
Sum	**1.310**	**2.280**	**3.590**	**4.820**	**5.470**	**5.640**	**5.550**	**4.620**	**3.140**	**1.990**	**1.250**	**0.990**	-

Figure F.4: System Model Solar Resources Daily Profile

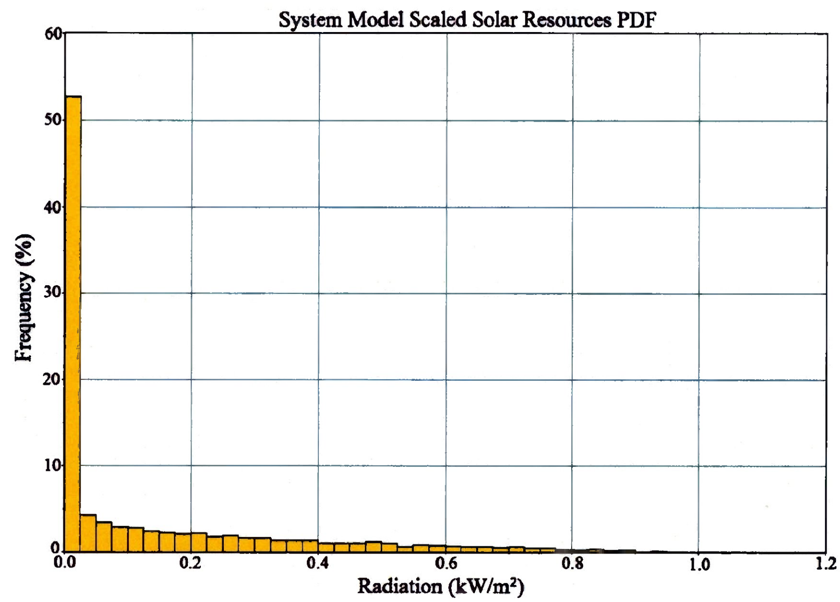


Figure F.5: System Model Scaled Solar Resources PDF

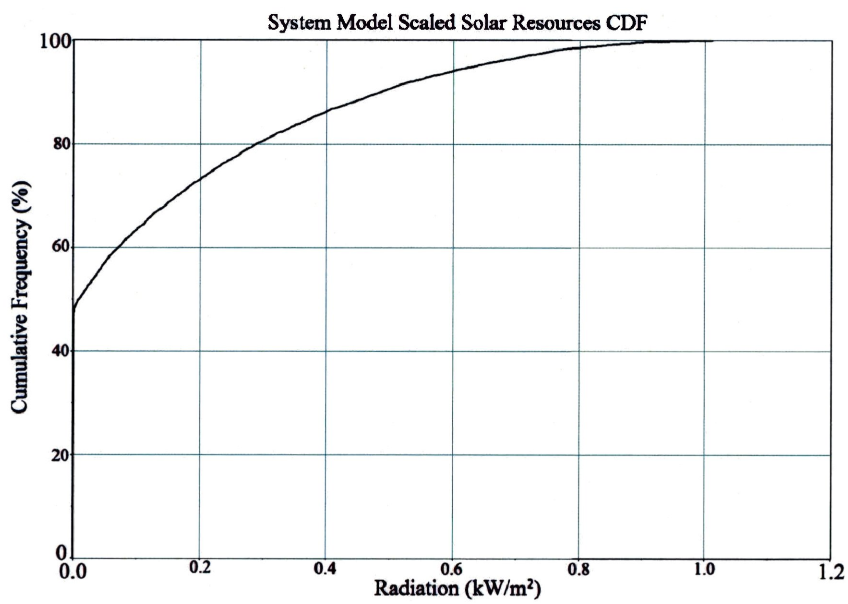


Figure F.6: System Model Scaled Solar Resources CDF

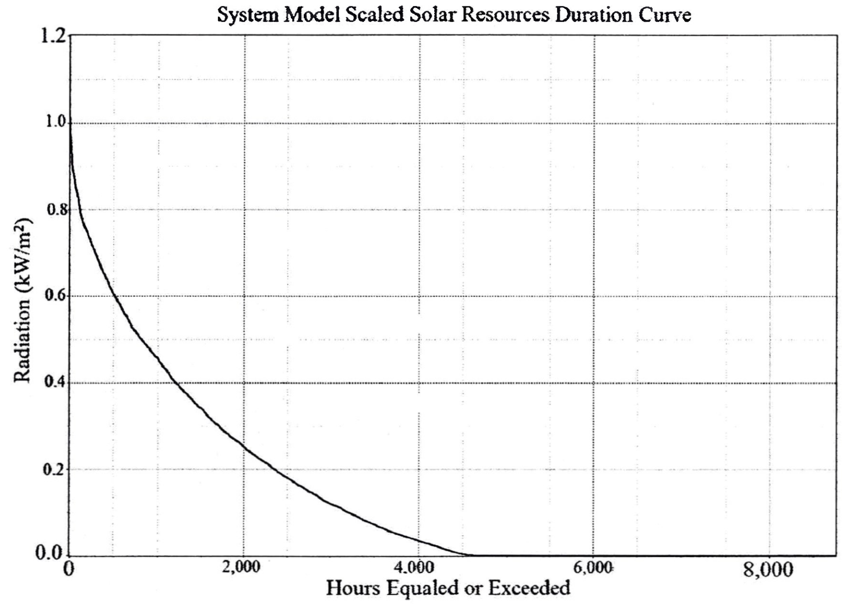


Figure F.7: System Model Scaled Solar Resources Duration Curve (DC)

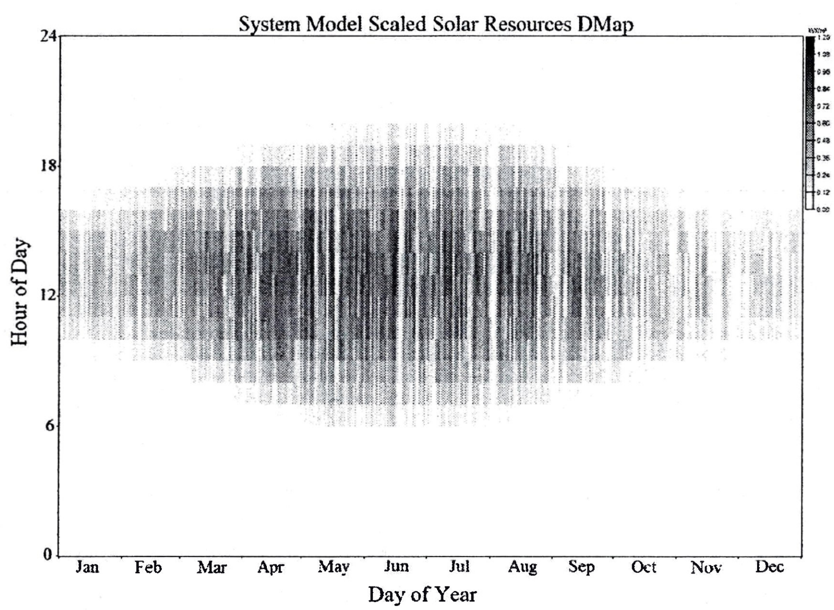


Figure F.8: System Model Scaled Solar Resources DMap

F.2 Climatic - System Model ET Solar Resources

This Section contains additional Figures relating to the system model solar resources as introduced in Chapter 6 with respect to the Extraterrestrial (ET) radiation experienced at the system model site.

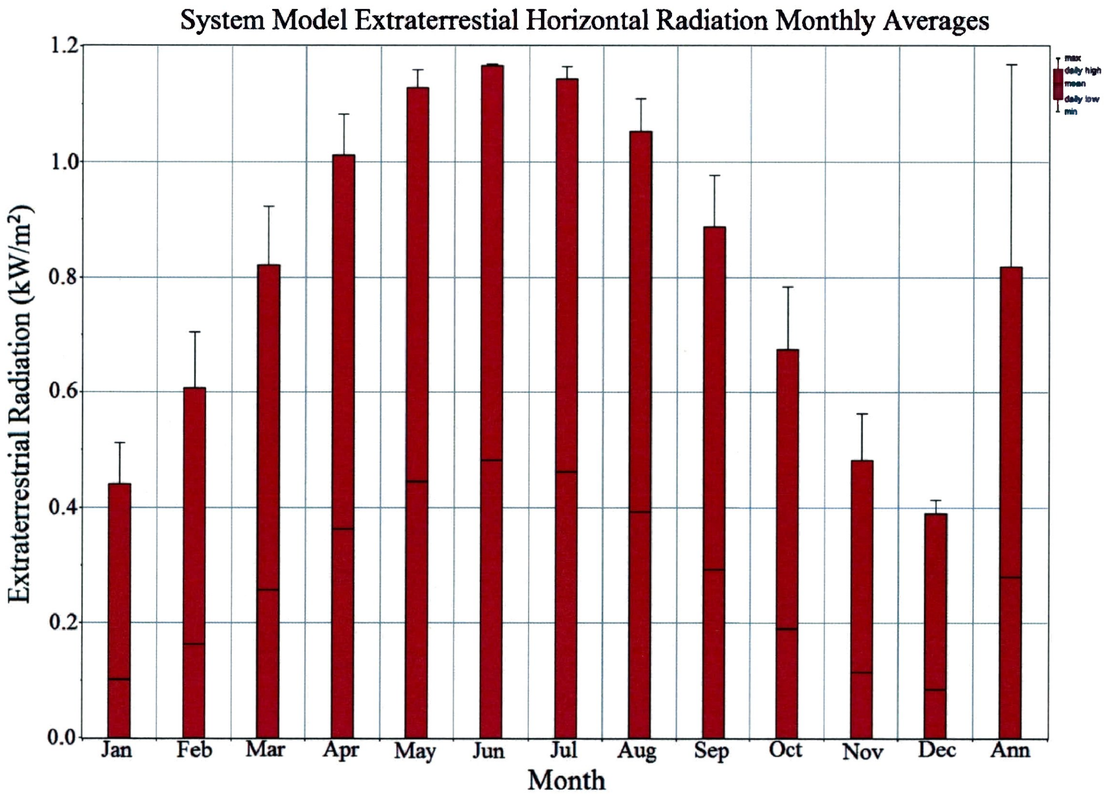


Figure F.9: System Model Extraterrestrial Horizontal Radiation Monthly Averages

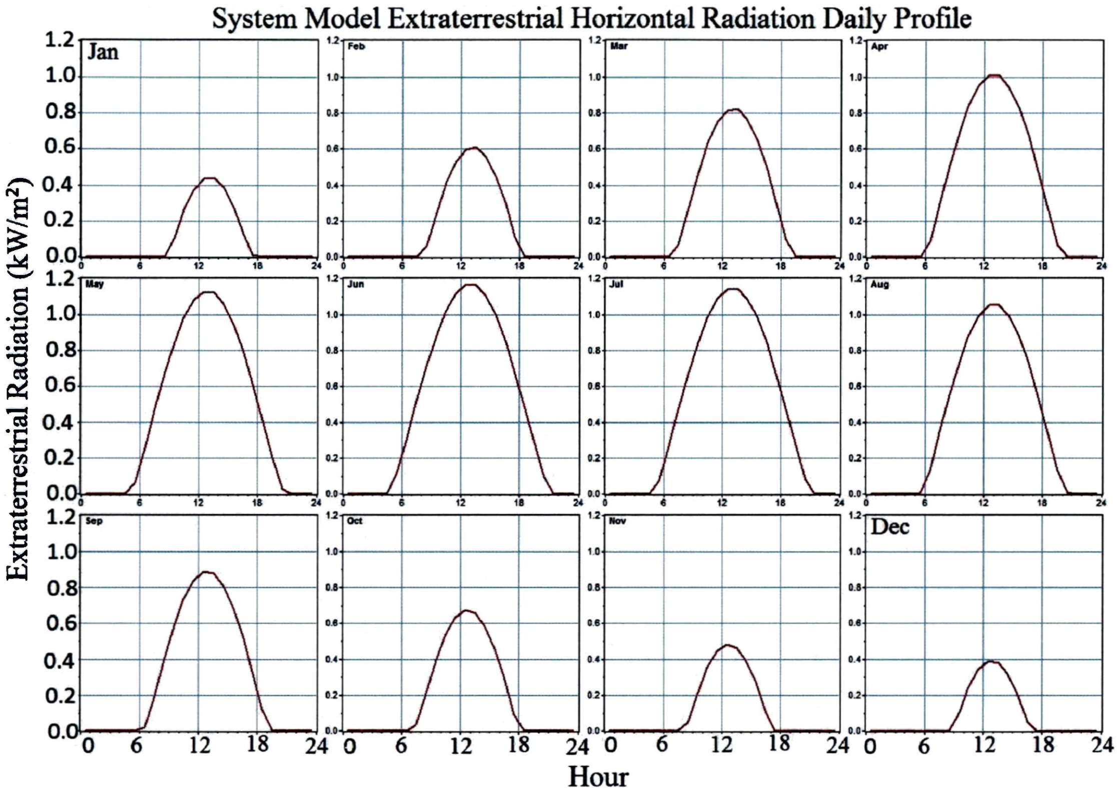


Figure F.10: System Model Extraterrestrial Horizontal Radiation Daily Profile

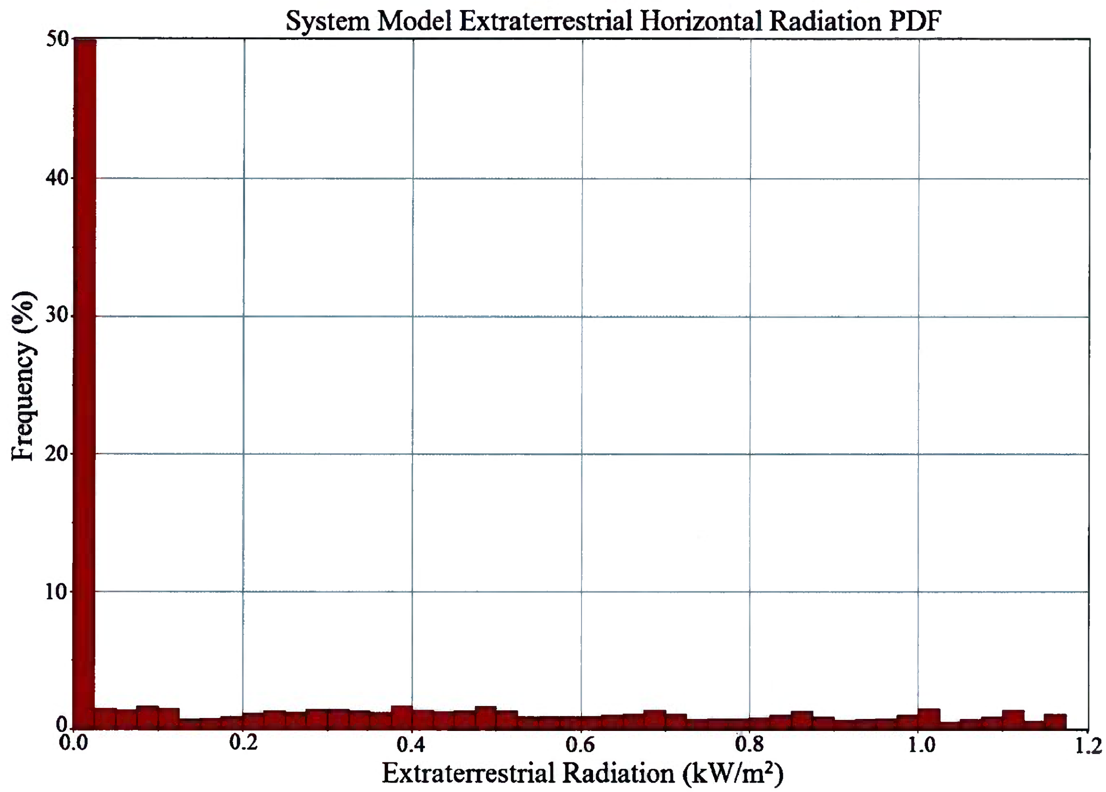


Figure F.11: System Model Extraterrestrial Horizontal Radiation PDF

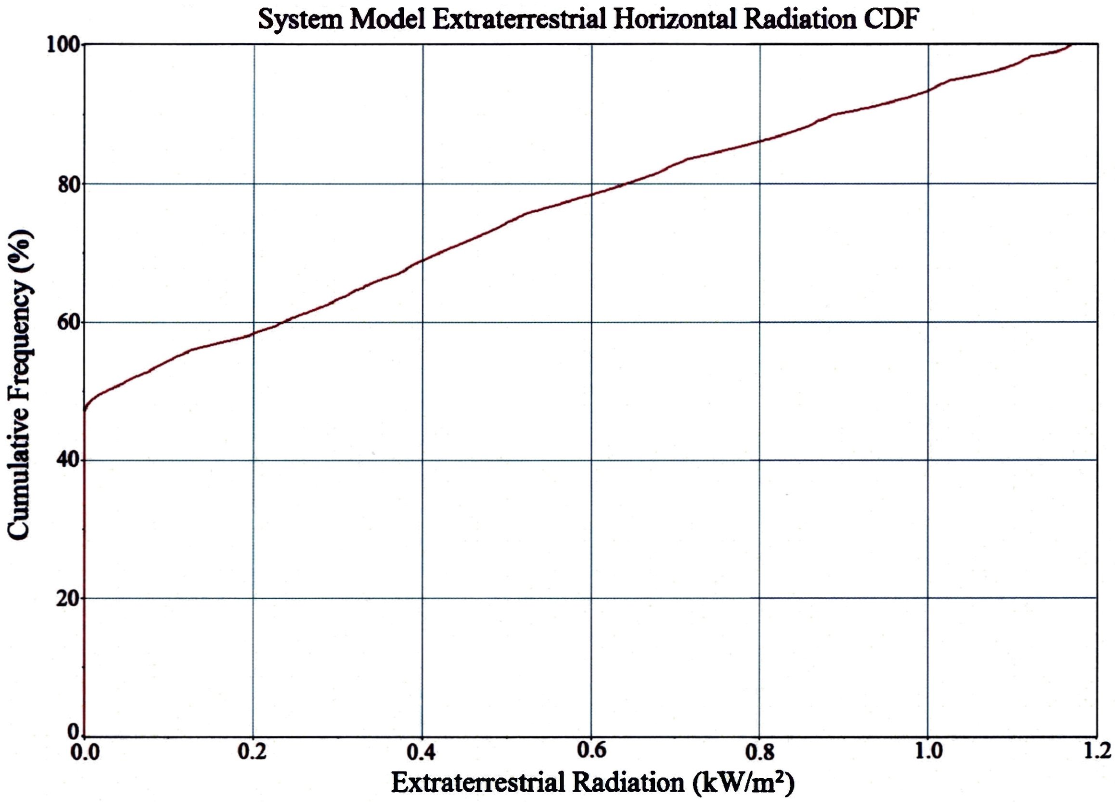


Figure F.12: System Model Extraterrestrial Horizontal Radiation CDF

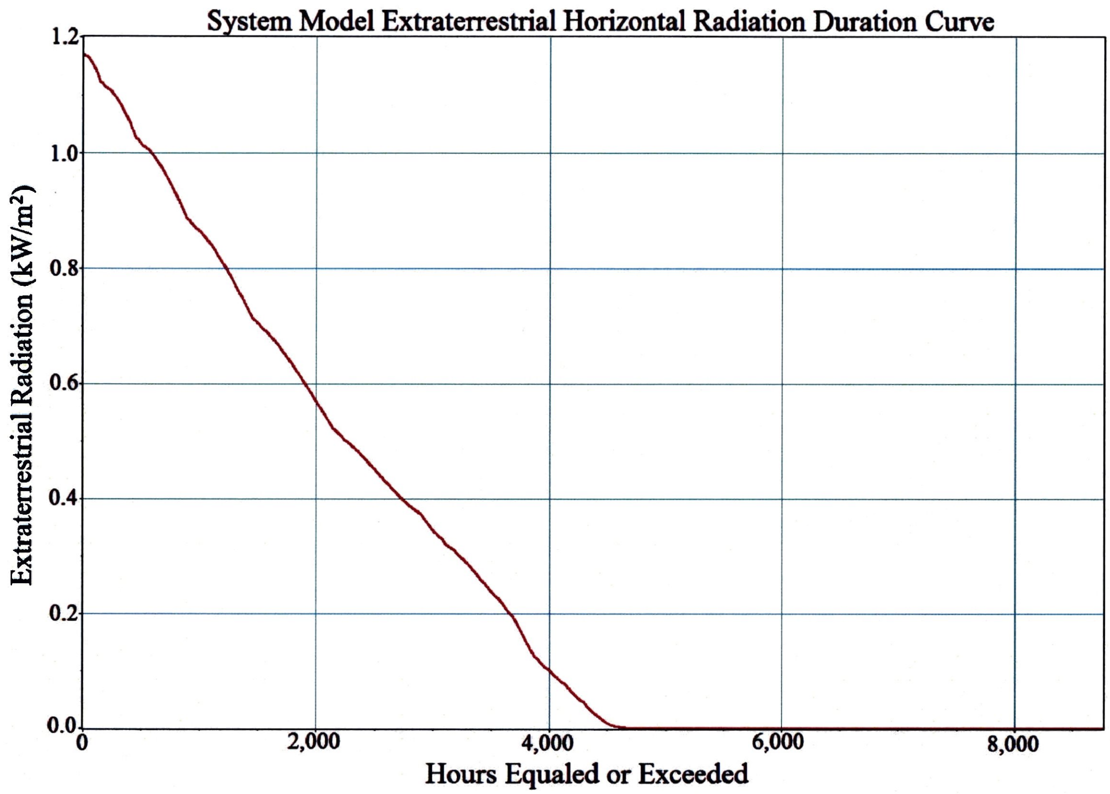


Figure F.13: System Model Extraterrestrial Horizontal Radiation Duration Curve (DC)

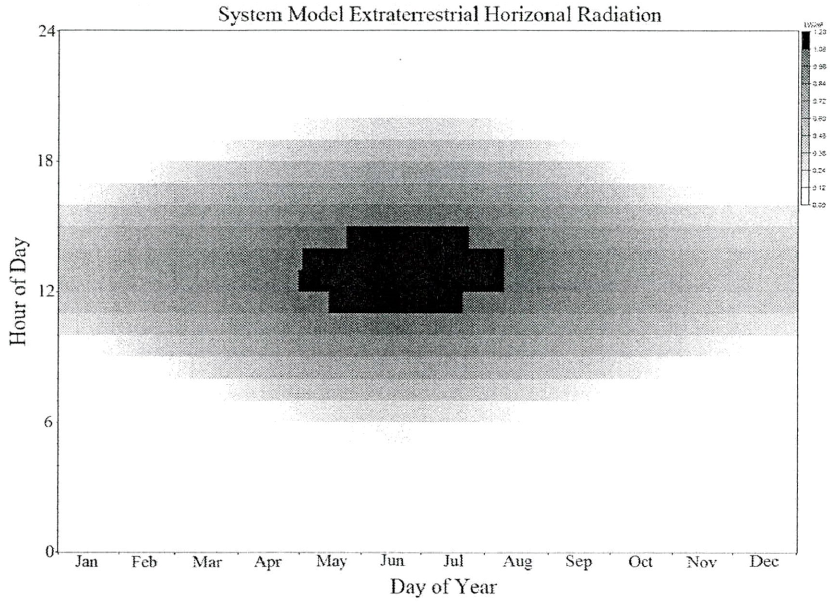


Figure F.14: System Model Extraterrestrial Horizontal Radiation DMap

F.3 SG Unit Technical Specifications

The following Tables and Figures represent additional information, including general technical information and the curst curves, regarding the SGs studied in this thesis. For additional information refer to the product datasheets which are also listed below. Following the SG unit specific introduction, in Section 8.2, will be additional bulk sets of information. Modern SG typically have a derating value of 0.75 to 0.80 where 0.80 was selected to represent all of the simulated SGs [15, 42, 45].

Unit:	**SG1**		**Manufacturer:**		
Model:	DA100-A2		DuPont		

Link: http://sunelec.com/Specs/DuPont/DuPont%20DA100-A2.pdf

Unit Parameters:

Output Current:	DC		Rated Power:	100	W
Lifetime:	20	Years	Derating Factor:	80.0	%
A_{pv}:	1.564	m^2	P_{max}:	-0.250	%/ºC
NOTC:	47.0	ºC	η_{STD}:	6.39	%

Unit:	**SG2**		**Manufacturer:**		
Model:	PV-AE115MF5N		Mitsubishi Electric		

Link: http://global.mitsubishielectric.com/products/energy/

Unit Parameters:

Output Current:	DC		Rated Power:	115	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.008	m^2	P_{max}:	-0.452	%/ºC
NOTC:	47.5	ºC	η_{STD}:	11.41	%

Unit:	**SG3**		**Manufacturer:**		
Model:	PV-AE120MF5N		Mitsubishi Electric		

Link: http://global.mitsubishielectric.com/products/energy/

Unit Parameters:

Output Current:	DC		Rated Power:	120	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.008	m^2	P_{max}:	-0.452	%/ºC
NOTC:	47.5	ºC	η_{STD}:	11.91	%

Unit:	**SG4**		**Manufacturer:**		
Model:	PV-MF125UE4N		Mitsubishi Electric		

Link: http://global.mitsubishielectric.com/products/energy/

Unit Parameters:

Output Current:	DC		Rated Power:	125	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.008	m^2	P_{max}:	-0.452	%/ºC
NOTC:	47.5	ºC	η_{STD}:	12.41	%

Unit:	**SG5**		**Manufacturer:**		
Model:	PV-AE130MF5N		Mitsubishi Electric		

Link: http://global.mitsubishielectric.com/products/energy/

Unit Parameters:

Output Current:	DC		Rated Power:	130	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.008	m^2	P_{max}:	-0.452	%/ºC
NOTC:	47.5	ºC	η_{STD}:	12.90	%

Unit:	**SG6**		**Manufacturer:**		
Model:	KD135GX-LPU		Kyocera		

Link: http://www.solar-electric.com/kyso130wa12v.html

Unit Parameters:

Output Current:	DC		Rated Power:	135	W
Lifetime:	20	Years	Derating Factor:	80.0	%
A_{pv}:	1.002	m^2	P_{max}:	-0.451	%/ºC
NOTC:	47.9	ºC	η_{STD}:	13.47	%

Unit:	**SG7**		**Manufacturer:**		
Model:	CS5T-140M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	140	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.609	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	8.70	%

Unit:	**SG8**		**Manufacturer:**		
Model:	CS5T-145M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	145	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.609	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	9.01	%

Unit:	**SG9**		**Manufacturer:**		
Model:	CS5T-150M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	150	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.609	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	9.33	%

Unit:	**SG10**		**Manufacturer:**		
Model:	TWES-(155)72M		ecoSolargy		

Link: http://www.ecosolargy.com/products

Unit Parameters:

Output Current:	DC		Rated Power:	155	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.277	m^2	P_{max}:	-0.480	%/ºC
NOTC:	47.0	ºC	η_{STD}:	12.14	%

Unit:	**SG11**		**Manufacturer:**		
Model:	CS6X-160P		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	160	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.300	m^2	P_{max}:	-0.430	%/ºC
NOTC:	45.0	ºC	η_{STD}:	12.31	%

Unit:	**SG12**		**Manufacturer:**		
Model:	CS6X-165M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	165	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.300	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	12.69	%

Unit:	**SG13**		**Manufacturer:**		
Model:	NE-170UC1		Sharp		

Link: http://www.infinigi.com/sharp-ne170uc1-170-watt-solar-module-p-3061.html

Unit Parameters:

Output Current:	DC		Rated Power:	170	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.301	m^2	P_{max}:	-0.485	%/ºC
NOTC:	47.5	ºC	η_{STD}:	13.07	%

Unit:	**SG14**		**Manufacturer:**		
Model:	SW175M		Solar World		

Link: http://www.wholesalesolar.com

Unit Parameters:

Output Current:	DC		Rated Power:	175	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.304	m^2	P_{max}:	-0.450	%/ºC
NOTC:	46.0	ºC	η_{STD}:	13.42	%

Unit:	**SG15**		**Manufacturer:**		
Model:	CS6X-180M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	180	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.300	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	13.84	%

Unit:	**SG16**		**Manufacturer:**		
Model:	UD185MF5		Mitsubishi Electric		

Link: http://global.mitsubishielectric.com/products/energy/

Unit Parameters:

Output Current:	DC		Rated Power:	185	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.383	m^2	P_{max}:	-0.452	%/ºC
NOTC:	47.5	ºC	η_{STD}:	13.38	%

Unit:	**SG17**		**Manufacturer:**		
Model:	CS6X-190M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	190	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.300	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	14.61	%

Unit:	**SG18**		**Manufacturer:**		
Model:	SX3195B		BP Solar		

Link: http://www.bp.com/modularhome.do?categoryId=8050&contentId=7035481

Unit Parameters:

Output Current:	DC		Rated Power:	195	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.407	m^2	P_{max}:	-0.482	%/ºC
NOTC:	49.4	ºC	η_{STD}:	13.86	%

Unit:	**SG19**		**Manufacturer:**		
Model:	HIP-200BA19		Sanyo		

Link: http:\\www.ca.sanyo.com/HIT-Power

Unit Parameters:

Output Current:	DC		Rated Power:	200	W
Lifetime:	20	Years	Derating Factor:	80.0	%
A_{pv}:	1.161	m^2	P_{max}:	-0.290	%/ºC
NOTC:	46.9	ºC	η_{STD}:	17.23	%

Unit:	**SG20**		**Manufacturer:**		
Model:	REC205AE-US		Renewable Energy Corporation		

Link: http://www.recgroup.com/en/products/

Unit Parameters:

Output Current:	DC		Rated Power:	205	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.650	m^2	P_{max}:	-0.452	%/ºC
NOTC:	47.5	ºC	η_{STD}:	12.42	%

Unit:	**SG21**		**Manufacturer:**		
Model:	REC210AE-US		Renewable Energy Corporation		

Link: http://www.recgroup.com/en/products/

Unit Parameters:

Output Current:	DC		Rated Power:	210	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.650	m^2	P_{max}:	-0.452	%/ºC
NOTC:	47.5	ºC	η_{STD}:	12.73	%

Unit:	**SG22**		**Manufacturer:**		
Model:	REC215AE-US		Renewable Energy Corporation		

Link: http://www.recgroup.com/en/products/

Unit Parameters:

Output Current:	DC		Rated Power:	215	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.650	m^2	P_{max}:	-0.452	%/ºC
NOTC:	47.5	ºC	η_{STD}:	13.03	%

Unit:	**SG23**		**Manufacturer:**		
Model:	CS6X-220M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	220	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.609	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	13.68	%

Unit:	**SG24**		**Manufacturer:**		
Model:	REC225AE-US		Renewable Energy Corporation		

Link: http://www.recgroup.com/en/products/

Unit Parameters:

Output Current:	DC		Rated Power:	225	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.650	m^2	P_{max}:	-0.452	%/ºC
NOTC:	47.5	ºC	η_{STD}:	13.64	%

Unit:	**SG25**	**Manufacturer:**	
Model:	CS6X-230P	Canadian Solar	

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	230	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.609	m^2	P_{max}:	-0.430	%/ºC
NOTC:	45.0	ºC	η_{STD}:	14.30	%

Unit:	**SG26**	**Manufacturer:**	
Model:	CS6X-235M	Canadian Solar	

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	235	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.609	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	14.61	%

Unit:	**SG27**	**Manufacturer:**	
Model:	SW240M	Solar World	

Link: http://www.wholesalesolar.com/

Unit Parameters:

Output Current:	DC		Rated Power:	240	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.677	m^2	P_{max}:	-0.450	%/ºC
NOTC:	47.0	ºC	η_{STD}:	14.31	%

Unit:	SG28	Manufacturer:
Model:	SW245M	Solar World

Link: http://www.wholesalesolar.com/

Unit Parameters:

Output Current:	DC		Rated Power:	245	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.677	m^2	P_{max}:	-0.450	%/ºC
NOTC:	47.0	ºC	η_{STD}:	14.61	%

Unit:	SG29	Manufacturer:
Model:	CS6X-250P	Canadian Solar

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	250	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.609	m^2	P_{max}:	-0.430	%/ºC
NOTC:	45.0	ºC	η_{STD}:	15.54	%

Unit:	SG30	Manufacturer:
Model:	ET-P672255	ET Solar Group

Link: http://www.etsolar.com/De/Products/Modules/

Unit Parameters:

Output Current:	DC		Rated Power:	255	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.940	m^2	P_{max}:	-0.460	%/ºC
NOTC:	45.3	ºC	η_{STD}:	13.14	%

Unit:	**SG31**		**Manufacturer:**		
Model:	CS6X-260M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	260	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.919	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	13.55	%

Unit:	**SG32**		**Manufacturer:**		
Model:	CS6X-265P		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	265	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.919	m^2	P_{max}:	-0.430	%/ºC
NOTC:	45.0	ºC	η_{STD}:	13.81	%

Unit:	**SG33**		**Manufacturer:**		
Model:	CS6X-270M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	270	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.919	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	14.07	%

Unit:	**SG34**		**Manufacturer:**		
Model:	CS6X-275P		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	275	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.919	m^2	P_{max}:	-0.430	%/ºC
NOTC:	45.0	ºC	η_{STD}:	14.33	%

Unit:	**SG35**		**Manufacturer:**		
Model:	CS6X-280M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	280	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.919	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	14.59	%

Unit:	**SG36**		**Manufacturer:**		
Model:	CS6X-285P		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	285	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.919	m^2	P_{max}:	-0.430	%/ºC
NOTC:	45.0	ºC	η_{STD}:	14.85	%

Unit:	**SG37**		**Manufacturer:**		
Model:	CS6X-290M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	290	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.919	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	15.11	%

Unit:	**SG38**		**Manufacturer:**		
Model:	CS6X-295P		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	295	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.919	m^2	P_{max}:	-0.430	%/ºC
NOTC:	45.0	ºC	η_{STD}:	15.37	%

Unit:	**SG39**		**Manufacturer:**		
Model:	CS6X-300M		Canadian Solar		

Link: http://www.canadian-solar.com/en/products/standard-modules/

Unit Parameters:

Output Current:	DC		Rated Power:	300	W
Lifetime:	25	Years	Derating Factor:	80.0	%
A_{pv}:	1.919	m^2	P_{max}:	-0.450	%/ºC
NOTC:	45.0	ºC	η_{STD}:	15.63	%

F.4 Summary of SG parameters

Ref. #	Pmax	Optimum Operating		Open Circuit		Temp		Temp Coefficient				Life Time	Cell Type
	(W)	Vmp (V)	Imp (A)	Voc (V)	Isc (A)	Min (°C)	Max (°C)	Pmax (%/°C)	Voc (%/°C)	Isc (%/°C)	NOCT (°C)	(yrs)	
SG1	100	77.00	1.34	99.30	1.55	-40	85	-0.250	-0.300	0.090	***47.0***	***20***	P
SG2	115	17.10	6.75	21.50	7.60	-25	80	-0.452	-0.343	0.054	47.5	25	P
SG3	120	17.20	6.99	21.60	7.75	-25	80	-0.452	-0.343	0.054	47.5	25	P
SG4	125	17.30	7.23	21.80	7.90	-25	80	-0.452	-0.343	0.054	47.5	25	P
SG5	130	17.40	7.47	21.90	8.05	-25	80	-0.452	-0.343	0.054	47.5	25	P
SG6	135	17.70	7.63	22.10	8.37	-40	90	*-0.451*	-0.362	0.060	47.9	20	M
SG7	140	29.50	4.74	36.80	5.08	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG8	145	29.8	4.87	37.00	5.21	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG9	150	30.10	4.99	37.10	5.34	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG10	155	34.50	4.49	41.40	5.03	-40	85	-0.480	-0.341	0.038	47.0	25	M
SG11	160	23.10	6.93	28.90	7.67	-40	85	-0.430	-0.340	0.065	45.0	25	P
SG12	165	23.40	7.06	29.20	7.71	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG13	170	34.80	4.90	43.20	5.47	-40	90	-0.485	-0.360	0.053	47.5	25	P
SG14	175	35.30	4.70	44.10	5.20	-	-	-0.450	-0.350	0.060	46.0	25	M
SG15	180	23.80	7.58	29.60	8.07	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG16	185	24.70	7.71	30.60	8.13	-25	80	-0.452	-0.343	0.054	47.5	25	P
SG17	190	24.10	7.87	29.80	8.38	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG18	195	24.40	7.96	30.70	8.60	-40	80	-0.482	-0.330	0.100	49.4	25	P
SG19	200	55.80	3.59	68.70	3.84	-20	46	-0.290	-0.251	0.023	46.9	20	M
SG20	205	28.10	7.30	36.10	7.90	-40	80	-0.452	-0.340	0.074	47.5	25	M
SG21	210	28.20	7.50	36.10	8.10	-40	80	-0.452	-0.340	0.074	47.5	25	M
SG22	215	28.30	7.60	36.30	8.10	-40	80	-0.452	-0.340	0.074	47.5	25	M
SG23	220	29.50	7.45	36.90	7.97	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG24	225	29.10	7.70	36.80	8.20	-40	80	-0.452	-0.340	0.074	47.5	25	M
SG25	230	29.60	7.78	36.80	8.34	-40	85	-0.430	-0.340	0.065	45.0	25	P
SG26	235	30.20	7.95	37.30	8.46	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG27	240	30.60	7.87	37.60	8.22	-	-	-0.450	-0.330	0.042	47.0	25	M
SG28	245	30.10	8.78	37.30	8.78	-	-	-0.450	-0.330	0.042	47.0	25	M
SG29	250	30.10	8.30	37.20	8.87	-40	85	-0.430	-0.340	0.065	45.0	25	P
SG30	255	35.20	7.23	43.90	7.85	-25	80	-0.460	-0.346	0.065	45.3	25	P
SG31	260	35.30	7.37	44.10	7.92	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG32	265	35.10	7.55	43.90	8.10	-40	85	-0.430	-0.340	0.065	45.0	25	P
SG33	270	35.60	8.11	44.40	8.11	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG34	275	35.50	7.76	44.10	8.31	-40	85	-0.430	-0.340	0.065	45.0	25	P
SG35	280	36.00	7.78	44.60	8.30	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG36	285	35.80	7.96	44.30	8.64	-40	85	-0.430	-0.340	0.065	45.0	25	P
SG37	290	36.30	8.00	44.70	8.51	-40	85	-0.450	-0.350	0.060	45.0	25	M
SG38	295	36.00	8.19	44.50	8.76	-40	85	-0.430	-0.340	0.065	45.0	25	P
SG39	300	36.50	8.22	45.00	8.74	-40	85	-0.450	-0.350	0.060	45.0	25	M

Ref. #	P max (W)	Y_{pv} Rated Output Under STC (kW)	$G_{t,stc}$ Radiation at STC (1 kW/m2)	Dimensions L (m)	W (m)	H (m)	Apv Surface Area of PV module (m2)	Cell Temp at STC (C)	Weight (kg)	η_{stc} * Efficiency of under STC (%)
SG1	100	0.100	1	1.409	1.110	0.035	1.564	25	20	6.39
SG2	115	0.115	1	1.495	0.674	0.046	1.008	25	13.5	11.41
SG3	120	0.120	1	1.495	0.674	0.046	1.008	25	13.5	11.91
SG4	125	0.125	1	1.495	0.674	0.046	1.008	25	13.5	12.41
SG5	130	0.130	1	1.495	0.674	0.046	1.008	25	13.5	12.90
SG6	135	0.135	1	1.500	0.668	0.046	1.002	25	12.5	13.47
SG7	140	0.140	1	1.638	0.982	0.040	1.609	25	20	8.70
SG8	145	0.145	1	1.638	0.982	0.040	1.609	25	20	9.01
SG9	150	0.150	1	1.638	0.982	0.040	1.609	25	20	9.33
SG10	155	0.155	1	1.580	0.808	0.035	1.277	25	15.5	12.14
SG11	160	0.160	1	1.324	0.982	0.040	1.300	25	16	12.31
SG12	165	0.165	1	1.324	0.982	0.040	1.300	25	16	12.69
SG13	170	0.170	1	0.826	1.575	0.046	1.301	25	16	13.07
SG14	175	0.175	1	1.610	0.810	0.034	1.304	25	15	13.42
SG15	180	0.180	1	1.324	0.982	0.040	1.300	25	16	13.84
SG16	185	0.185	1	1.658	0.834	0.046	1.383	25	17	13.38
SG17	190	0.190	1	1.324	0.982	0.040	1.300	25	16	14.61
SG18	195	0.195	1	1.679	0.838	0.050	1.407	25	15.4	13.86
SG19	200	0.200	1	1.319	0.880	0.046	1.161	25	15	17.23
SG20	205	0.205	1	1.665	0.991	0.043	1.650	25	22	12.42
SG21	210	0.210	1	1.665	0.991	0.043	1.650	25	22	12.73
SG22	215	0.215	1	1.665	0.991	0.043	1.650	25	22	13.03
SG23	220	0.220	1	1.638	0.982	0.040	1.609	25	20	13.68
SG24	225	0.225	1	1.665	0.991	0.043	1.650	25	22	13.64
SG25	230	0.230	1	1.638	0.982	0.040	1.609	25	20	14.30
SG26	235	0.235	1	1.638	0.982	0.040	1.609	25	20	14.61
SG27	240	0.240	1	1.675	1.001	0.034	1.677	25	22	14.31
SG28	245	0.245	1	1.675	1.001	0.034	1.677	25	22	14.61
SG29	250	0.250	1	1.638	0.982	0.040	1.609	25	20	15.54
SG30	255	0.255	1	1.956	0.992	0.050	1.940	25	23	13.14
SG31	260	0.260	1	1.954	0.982	0.040	1.919	25	27	13.55
SG32	265	0.265	1	1.954	0.982	0.040	1.919	25	27	13.81
SG33	270	0.270	1	1.954	0.982	0.040	1.919	25	27	14.07
SG34	275	0.275	1	1.954	0.982	0.040	1.919	25	27	14.33
SG35	280	0.280	1	1.954	0.982	0.040	1.919	25	27	14.59
SG36	285	0.285	1	1.954	0.982	0.040	1.919	25	27	14.85
SG37	290	0.290	1	1.954	0.982	0.040	1.919	25	27	15.11
SG38	295	0.295	1	1.954	0.982	0.040	1.919	25	27	15.37
SG39	300	0.300	1	1.954	0.982	0.040	1.919	25	27	15.63

* ***Recall:*** $\eta_{STC}* = (Y_{pv})/(A_{pv} * G_{tSTC})$

Ref. #	Manufacturer	Model	P max (W)	CC ($)	Ship Costs ($)	Install Costs ($)	Misc. Costs ($)	Net CC ($)	RC ($)	O&M ($/yr)
SG1	DuPont	DA100-A2	100	169.00	36.66	33.80	8.45	247.91	236.08	8.45
SG2	Mitsubishi Ele	PV-AE115MF5N	115	230.00	49.90	46.00	11.50	337.40	321.30	11.50
SG3	Mitsubishi Ele	PV-AE120MF5N	120	240.00	52.07	48.00	12.00	352.07	335.27	12.00
SG4	Mitsubishi Ele	PV-MF125UE4N	125	250.00	54.23	50.00	12.50	366.73	349.23	12.50
SG5	Mitsubishi Ele	PV-AE130MF5N	130	260.00	56.40	52.00	13.00	381.40	363.20	13.00
SG6	Kyocera	KD135GX-LPU	135	354.00	76.80	70.80	17.70	519.30	494.52	17.70
SG7	Canadian Solar	CS5T-140M	140	280.00	60.74	56.00	14.00	410.74	391.14	14.00
SG8	Canadian Solar	CS5T-145M	145	420.50	91.22	84.10	21.03	616.85	587.41	21.03
SG9	Canadian Solar	CS5T-150M	150	435.00	94.37	87.00	21.75	638.12	607.67	21.75
SG10	ecoSolargy	TWES-(155)72M	155	449.50	97.51	89.90	22.48	659.39	627.92	22.48
SG11	Canadian Solar	CS6X-160P	160	302.00	65.52	60.40	15.10	443.02	421.88	15.10
SG12	Canadian Solar	CS6X-165M	165	478.50	103.81	95.70	23.93	701.93	668.44	23.93
SG13	Sharp	NE-170UC1	170	556.75	120.78	111.35	27.84	816.72	777.75	27.84
SG14	Solar World	SW175M	175	490.00	106.30	98.00	24.50	718.80	684.50	24.50
SG15	Canadian Solar	CS6X-180M	180	340.00	73.76	68.00	17.00	498.76	474.96	17.00
SG16	Mitsubishi Ele	UD185MF5	185	390.00	84.61	78.00	19.50	572.11	544.81	19.50
SG17	Canadian Solar	CS6X-190M	190	359.00	77.88	71.80	17.95	526.63	501.50	17.95
SG18	BP Solar	SX3195B	195	600.00	130.16	120.00	30.00	880.16	838.16	30.00
SG19	Sanyo	HIP-200BA19	200	494.00	107.17	98.80	24.70	724.67	690.09	24.70
SG20	REC	REC205AE-US	205	507.00	109.99	101.40	25.35	743.74	708.25	25.35
SG21	REC	REC210AE-US	210	511.00	110.86	102.20	25.55	749.61	713.84	25.55
SG22	REC	REC215AE-US	215	525.00	113.89	105.00	26.25	770.14	733.39	26.25
SG23	Canadian Solar	CS6X-220M	220	425.00	92.20	85.00	21.25	623.45	593.70	21.25
SG24	REC	REC225AE-US	225	528.75	114.71	105.75	26.44	775.64	738.63	26.44
SG25	Canadian Solar	CS6X-230P	230	585.00	126.91	117.00	29.25	858.16	817.21	29.25
SG26	Canadian Solar	CS6X-235M	235	610.00	132.33	122.00	30.50	894.83	852.13	30.50
SG27	Solar World	SW240M	240	667.00	144.70	133.40	33.35	978.45	931.76	33.35
SG28	Solar World	SW245M	245	700.00	151.86	140.00	35.00	1,026.86	977.86	35.00
SG29	Canadian Solar	CS6X-250P	250	680.00	147.52	136.00	34.00	997.52	949.92	34.00
SG30	ET Solar Group	ET-P672255	255	740.00	160.54	148.00	37.00	1,085.54	1,033.74	37.00
SG31	Canadian Solar	CS6X-260M	260	754.00	163.57	150.80	37.70	1,106.07	1,053.29	37.70
SG32	Canadian Solar	CS6X-265P	265	768.50	166.72	153.70	38.43	1,127.34	1,073.55	38.43
SG33	Canadian Solar	CS6X-270M	270	783.00	169.86	156.60	39.15	1,148.61	1,093.80	39.15
SG34	Canadian Solar	CS6X-275P	275	797.50	173.01	159.50	39.88	1,169.88	1,114.06	39.88
SG35	Canadian Solar	CS6X-280M	280	812.00	176.15	162.40	40.60	1,191.15	1,134.31	40.60
SG36	Canadian Solar	CS6X-285P	285	826.50	179.30	165.30	41.33	1,212.43	1,154.57	41.33
SG37	Canadian Solar	CS6X-290M	290	841.00	182.45	168.20	42.05	1,233.70	1,174.83	42.05
SG38	Canadian Solar	CS6X-295P	295	855.50	185.59	171.10	42.78	1,254.97	1,195.08	42.78
SG39	Canadian Solar	CS6X-300M	300	870.00	188.74	174.00	43.50	1,276.24	1,215.34	43.50

Appendix G - WECS

Appendix G provides additional information as it relates to WECS introduced in Chapter 7.

G.1 Climatic - Wind Rose and Frequency Distribution

Appendix B has full digital records of the 16 and 36 point Wind Rose, frequency charts, statistical data, and raw data formats for the available communities. Environment Canada was able to provide the desired information for the communities listed in Table G.1 which were analyzed during the indicated periods. A sample size of the latest 7 years was selected due to the ease of analysis and it was determined that this period provided the desired outlook. The raw data is available such that future analysis can be performed for the periods indicated in Chapter 2 Table 2.13. NW Ontario was sub-divided into four zones for regional analysis as seen in Figure G.1. Since communities located on the shore of a large body of water experience higher wind speeds and due to the large geographic area of N ON a community at large was selected per each zone to indicate the normal localized wind resources. This Appendix includes related information for the communities that were selected in the related zones to indicate a normal community. These communities are demonstrated by bolded text in Table G.1 and the remaining communities are presented in Appendix B. It should also be noted that Big Trout Lake was discussed in Section 7.2 and thus will be neglected here. The reference numbers used in the following Table are only used as such in this Appendix.

Table G.1: Available Communities for Detailed Wind Climatic Data

Ref. #	**Community**	**Duration**		**Zone**
		Start	**End**	
1	Armstrong	1961	1967	2
2	Atikokan	1961	1967	2
3	**Big Trout Lake**	**1984**	**1990**	**1**
4	**Geraldton**	**1970**	**1976**	**3**
5	Graham	1960	1966	3
6	Kapuskasing	1999	2005	3
7	Kenora	1999	2005	2
8	Nakina	1960	1966	2
9	**Sioux Lookout**	**1999**	**2005**	**2**
10	Thunder Bay	1987	1993	2/Shore

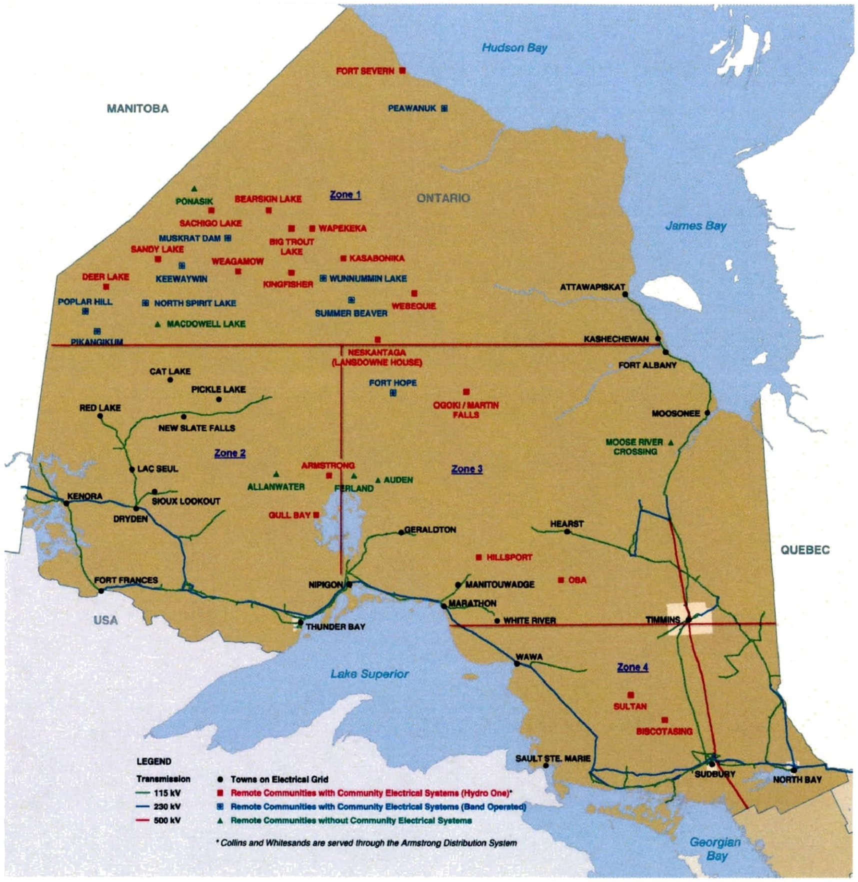


Figure G.1: Northern Ontario Sub-Divided into Zones

For the 10 available communities a brief summary is provided to demonstrate data integrity. This demonstrates the total number of available hours for the 7 year duration, which at 8,736 available hours a year, results in an average of 216 hours shy of a complete sample period. Leap years were not considered in this calculation but regardless the maximum difference would be 48 hours depending on the years selected. If further detail were required leap years would be considered but for the scope of this analysis the alterations in results is negligible and only effect the total number of available hours. The number of calm records, or no wind speed records, is recorded along with the average wind speed of the community. The data availability is provided along with the corresponding number of invalid entries in the raw hourly data. The total number of records used is the total number of hours less the incomplete/missing records. In the raw data sets this missing or incomplete data is represented as a series of 9's or a flag depending on the metric of study.

Table G.2: Data Integrity for Communities with Detailed Wind Climatic Data

Metric	**1**	**2**	**3**	**4**	**5**
Total # of Hours	61,344	61,368	61,368	61,368	61,368
Avg. Wind Speed (m/s)	3.5	2.27	4.52	3.43	3.95
Calm Records	4,506	14,333	2,133	6,859	4,344
Calm Winds Frq. (%)	7.35	23.36	3.48	11.22	7.08
Data Availability (%)	100	100	99.93	99.62	100
Incomplete/Missing Records	0	0	42	232	0
Total Records Used	61,344	61,369	61,326	61,136	61,368
Metric	**6**	**7**	**8**	**9**	**10**
Total # of Hours	61,368	61,368	61,368	61,368	61,368
Avg. Wind Speed (m/s)	3.62	3.97	3.37	3.71	3.02
Calm Records	5,316	1,823	3,460	5,196	9,172
Calm Winds Frq. (%)	8.67	2.97	5.64	8.47	14.95
Data Availability (%)	99.91	99.97	100	99.95	99.99
Incomplete/Missing Records	55	16	0	28	4
Total Records Used	61,313	61,362	61,368	61,340	61,364

The chosen community for Zone 2 is Sioux Lookout due to its centralized and inland location. Figures G.2 and G.3 demonstrate the 36 point Wind Rose and wind speed frequency distribution for Sioux Lookout respectively.

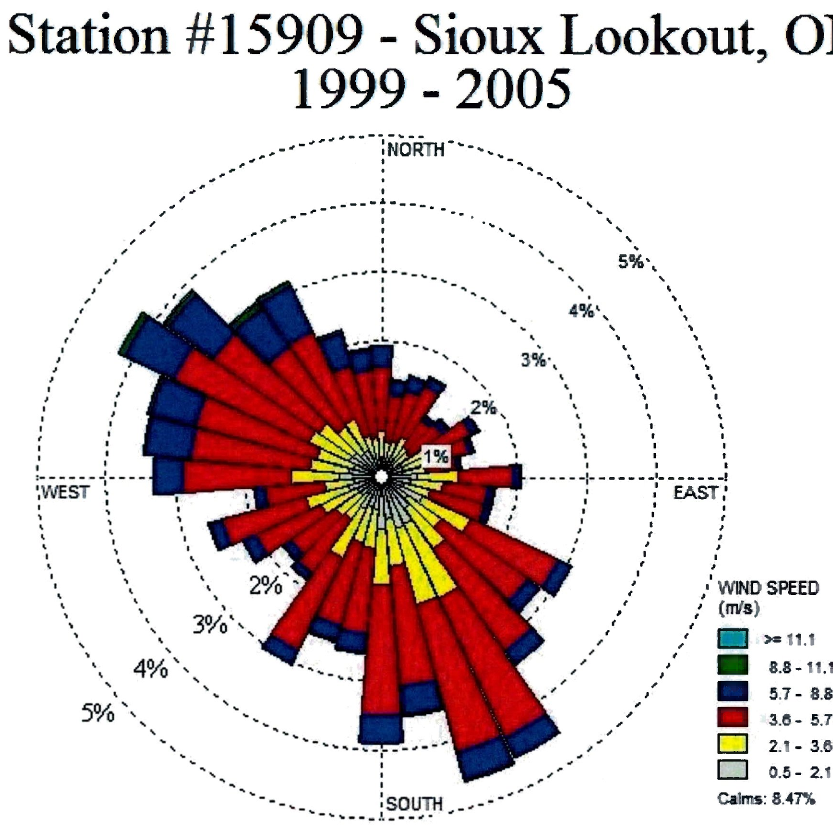


Figure G.2: Sioux Lookout 36 Point Wind Rose

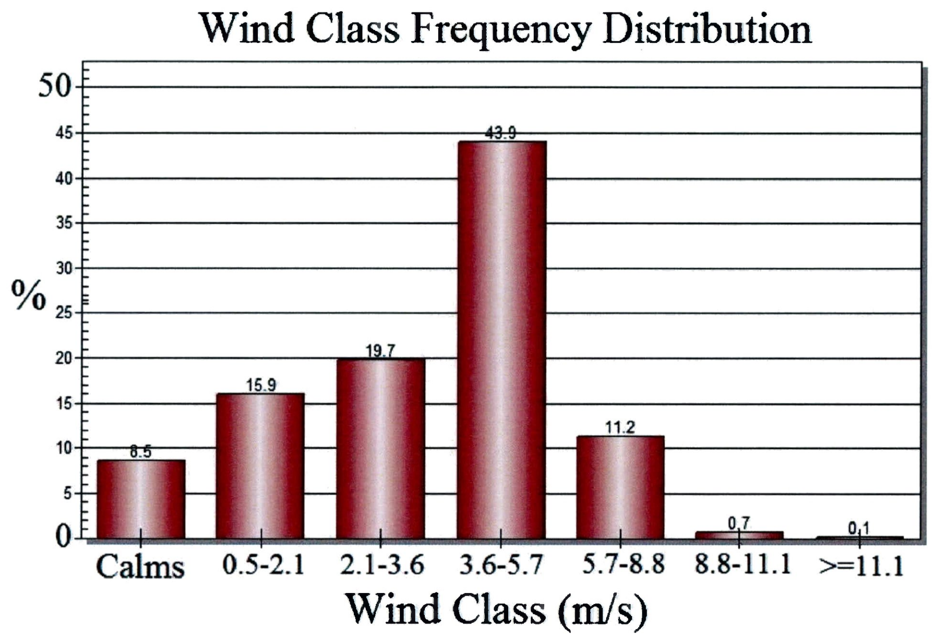


Figure G.3: Sioux Lookout Wind Speed Frequency Distribution

The chosen community for Zone 3 is Geraldton due to its relative proximity to other Northern remote communities. Figures G.4 and G.5 demonstrate the 36 point Wind Rose and wind speed frequency distribution for Geraldton respectively. It can be seen that Geraldton predominantly experiences the prevailing wind from the West as does Big Trout Lake and the stronger winds in Sioux Lookout. All three locations experience a significant percentage of their wind speeds within the 3.6 to 5.7 m/s class as denoted by the system model and Big Trout Lake experiences the highest percentage of strong wind speeds.

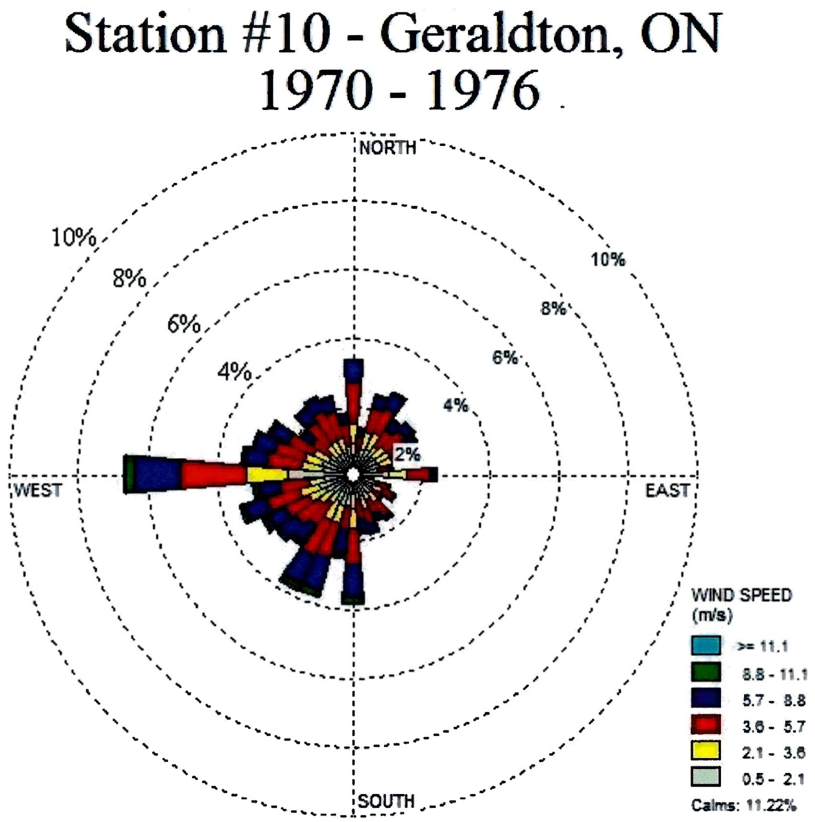


Figure G.4: Geraldton 36 Point Wind Rose

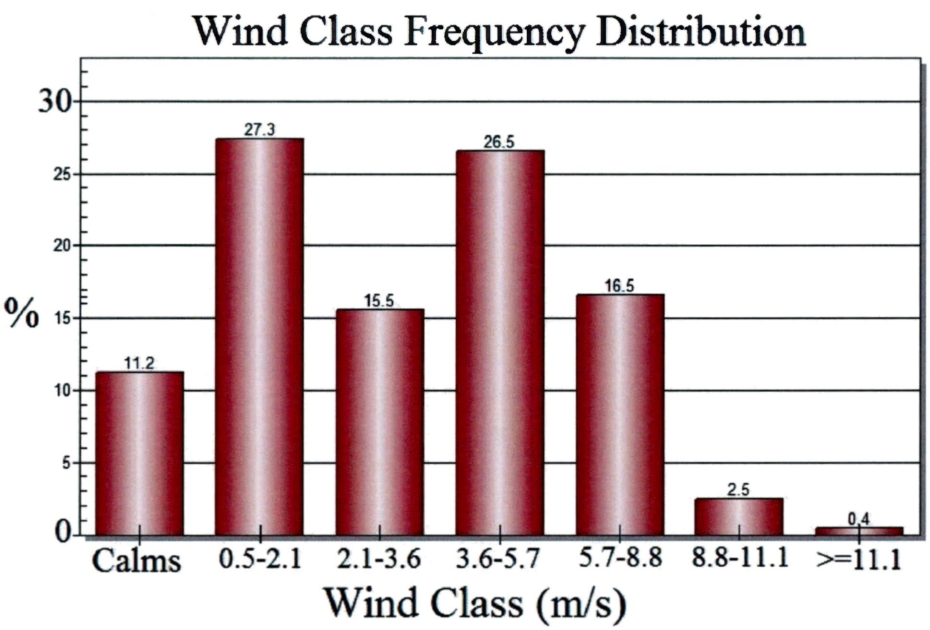


Figure G.5: Geraldton Wind Speed Frequency Distribution

G.2 Climatic - System Model Wind Resources

This Section contains additional Figures relating to the system model wind resources as introduced in Chapter 7. The wind resource average was 3.557 m/s from the climatic variables found by analysis of Environment Canada data [9]. As such a scaled annual average of 3.56 m/s was used as the base for the results in the following Figures. The baseline data was scaled for simulation purposes.

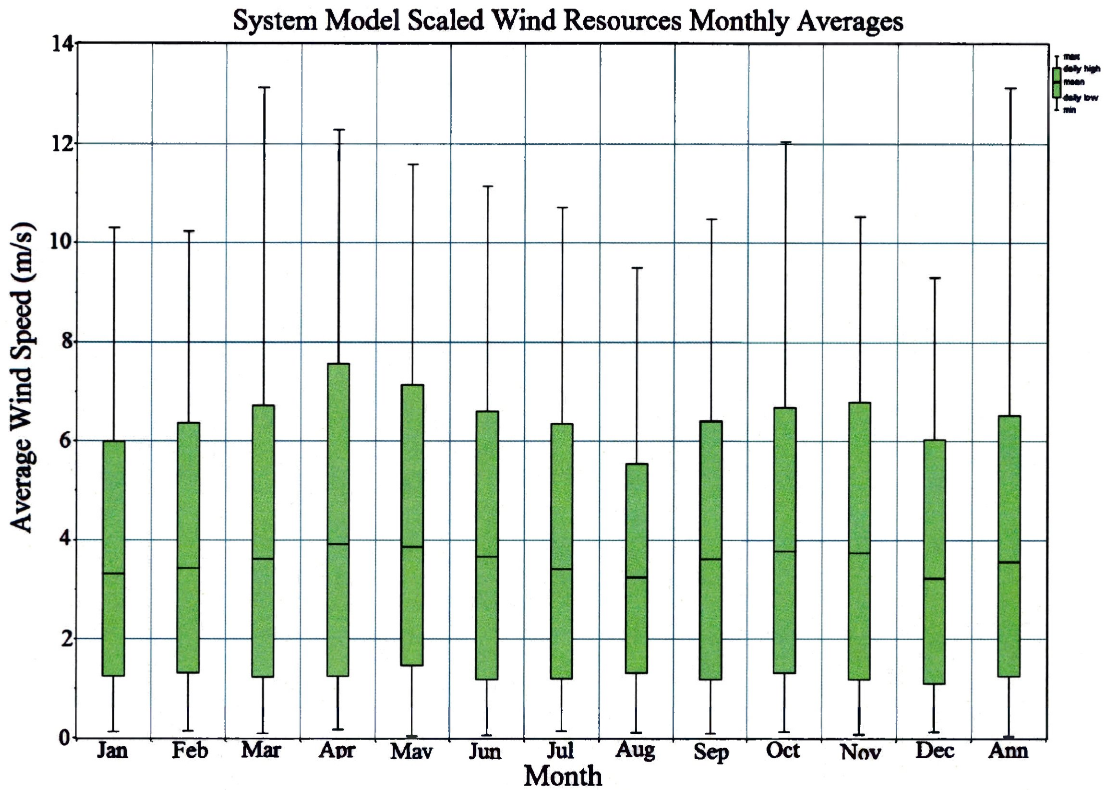


Figure G.6: System Model Scaled Wind Resources Monthly Averages

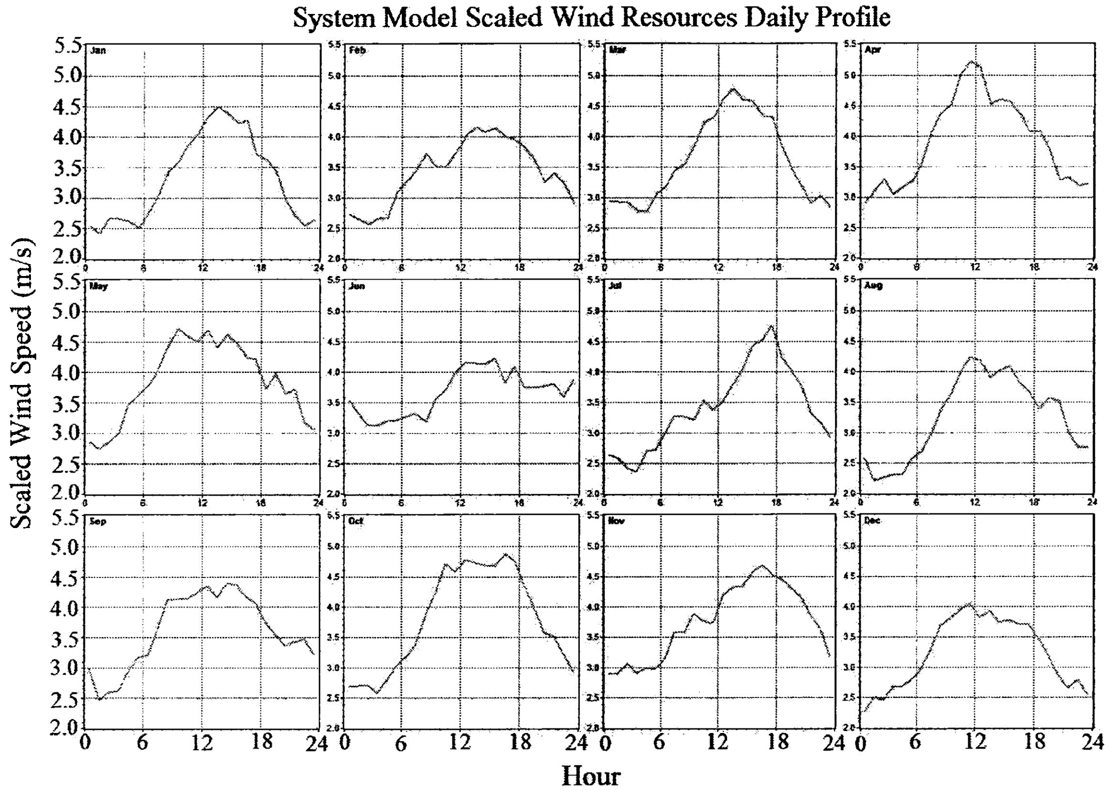


Figure G.7: System Model Scaled Wind Resources Daily Profile

System Model Hourly Wind Speed (m/s)													
Hour	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg
0	2.54471	2.731446	2.927423	2.90574	2.859716	3.539223	2.650565	2.578629	2.99891	2.692548	2.88908	2.26829	**2.798857**
1	2.414048	2.650879	2.928994	3.106547	2.743087	3.316457	2.583177	2.203081	2.471487	2.705719	2.898423	2.513403	**2.711275**
2	2.671529	2.562454	2.918187	3.303487	2.850387	3.121883	2.419935	2.274761	2.601007	2.720987	3.069013	2.463658	**2.748107**
3	2.667016	2.665011	2.783297	3.055387	2.99991	3.114373	2.366594	2.305229	2.624683	2.57679	2.904487	2.681929	**2.728725**
4	2.619642	2.667618	2.776016	3.16389	3.467116	3.204307	2.697958	2.3094	2.934803	2.794606	2.997193	2.694252	**2.860567**
5	2.495484	3.087746	3.048929	3.26394	3.634829	3.218253	2.727348	2.582581	3.1688	3.042365	2.965847	2.80011	**3.003019**
6	2.774816	3.284396	3.190913	3.57356	3.778961	3.286097	3.008129	2.706803	3.21277	3.189726	3.155567	2.988448	**3.179182**
7	3.041639	3.44995	3.444577	4.05165	4.030994	3.328563	3.28249	2.971106	3.646857	3.394323	3.574427	3.294897	**3.459289**
8	3.436265	3.733104	3.553303	4.371087	4.416623	3.191897	3.27109	3.361297	4.120783	3.8834	3.579963	3.679335	**3.716512**
9	3.5895	3.497746	3.851529	4.51677	4.713523	3.56775	3.2147[illegible]3	3.63569	4.127463	4.234574	3.88371	3.806835	**3.88665**
10	3.855035	3.50985	4.230955	4.99547	4.584074	3.703913	3.5367[illegible]5	3.967745	4.129483	4.707974	3.76683	3.941939	**4.077502**
11	4.052045	3.732954	4.307203	5.2245	4.490426	3.996437	3.3730[illegible]7	4.243552	4.23279	4.573839	3.7267	4.052252	**4.167149**
12	4.334174	4.006054	4.622258	5.11522	4.689455	4.158923	3.5201[illegible]6	4.182055	4.350683	4.77241	4.18721	3.823755	**4.313525**
13	4.4924	4.157893	4.789971	4.525707	4.401758	4.14397	3.79611	3.901252	4.153417	4.723952	4.32331	3.932894	**4.278553**
14	4.392019	4.082868	4.597906	4.60308	4.617329	4.13211	4.0425[illegible]9	4.026997	4.380683	4.678971	4.325523	3.743513	**4.301961**
15	4.218552	4.146939	4.580871	4.56717	4.461016	4.223337	4.4334[illegible]2	4.096416	4.355603	4.672671	4.558873	3.784648	**4.341628**
16	4.261932	3.993632	4.336613	4.355783	4.231652	3.822677	4.5249[illegible]1	3.809774	4.154413	4.867294	4.683917	3.701648	**4.228691**
17	3.713165	3.954846	4.317639	4.08162	4.215642	4.092397	4.7627[illegible]3	3.672677	4.060033	4.762074	4.529013	3.70301	**4.155402**
18	3.634581	3.822536	3.8477	4.086137	3.730445	3.74077	4.2426[illegible]4	3.391148	3.737093	4.362681	4.452197	3.456303	**3.875355**
19	3.447742	3.622696	3.458223	3.78234	3.972465	3.733737	4.0139[illegible]5	3.573229	3.540243	3.974561	4.28926	3.178845	**3.715607**
20	2.958971	3.2555	3.188397	3.2831	3.64259	3.766443	3.768497	3.510319	3.36606	3.578403	4.160477	2.833023	**3.442648**
21	2.718542	3.401818	2.900477	3.329467	3.707003	3.81388	3.336632	3.006365	3.41189	3.514603	3.85639	2.667677	**3.305395**
22	2.535903	3.241939	3.034697	3.19288	3.173623	3.589377	3.173577	2.753003	3.46562	3.224348	3.650817	2.791784	**3.152297**
23	2.640526	2.892768	2.840406	3.22838	3.069152	3.870777	2.925152	2.765745	3.230933	2.911219	3.170953	2.545932	**3.007662**
Avg	**3.312926**	**3.423027**	**3.603187**	**3.903455**	**3.853407**	**3.653231**	**3.403008**	**3.242869**	**3.603188**	**3.773335**	**3.733299**	**3.222849**	**3.560648**

Figure G.8: System Model Scaled Wind Resources Daily Profile

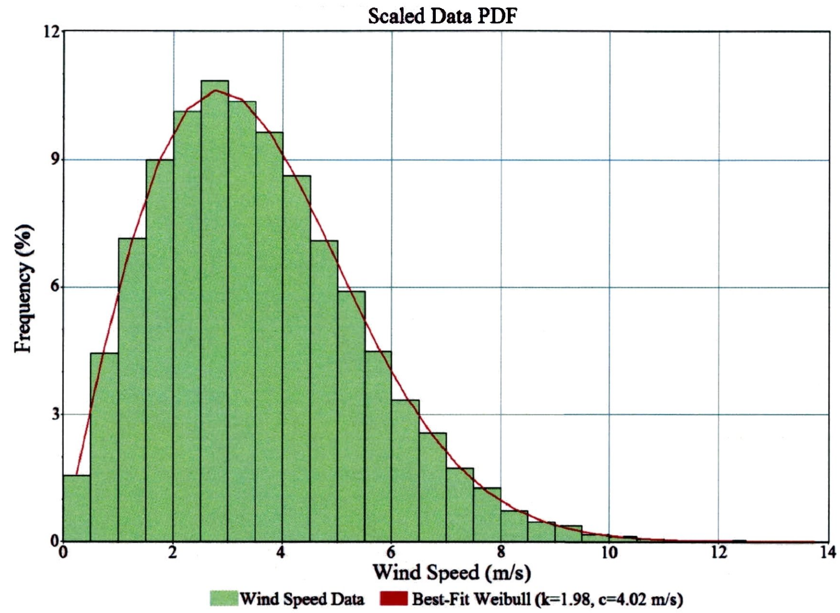


Figure G.9: System Model Scaled Wind Resources PDF

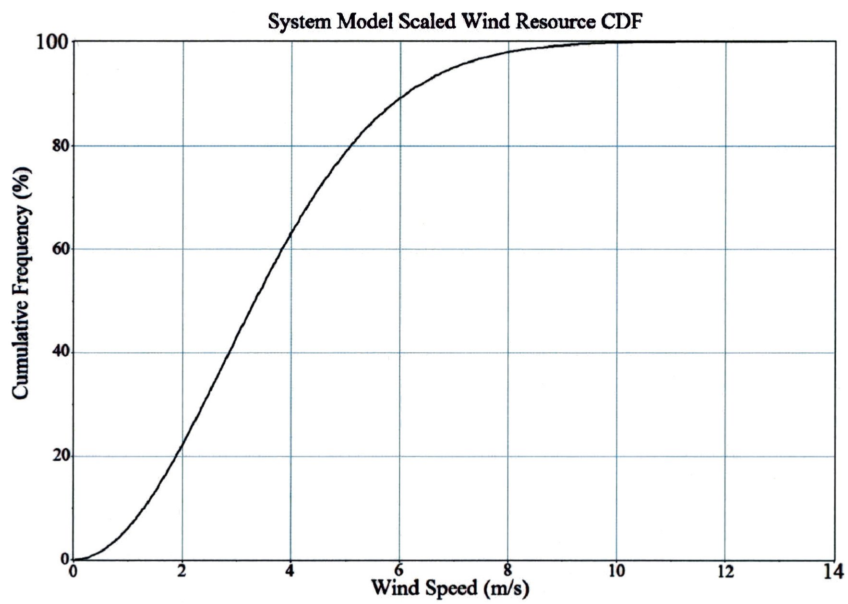


Figure G.10: System Model Scaled Wind Resources CDF

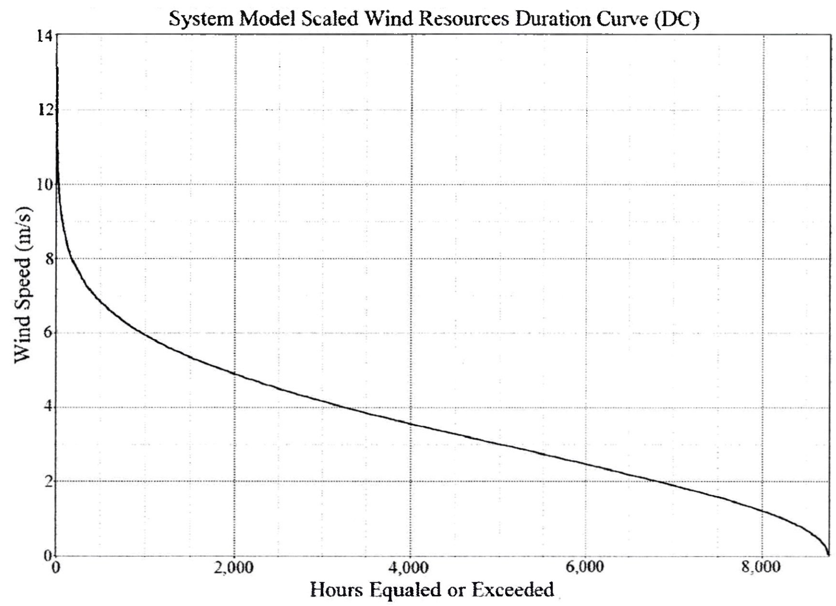


Figure G.11: System Model Scaled Wind Resources DC

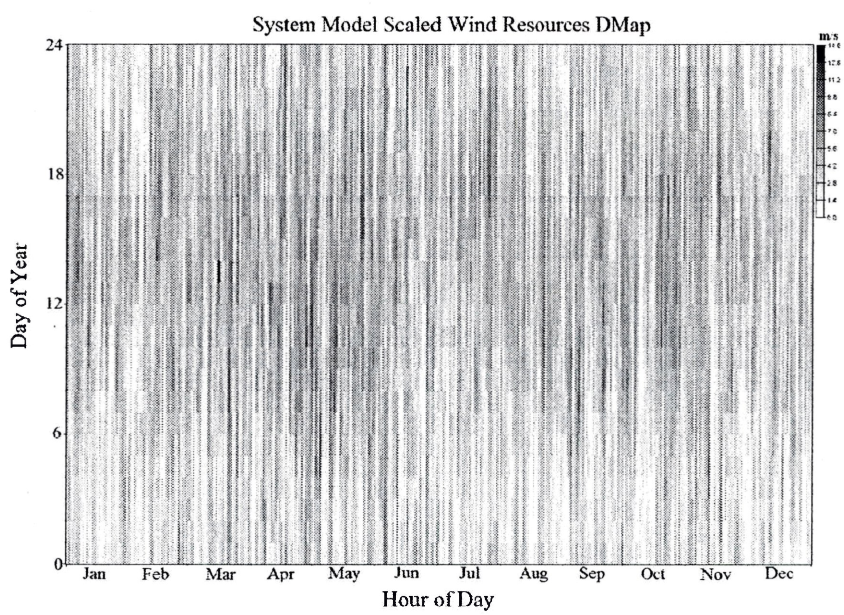


Figure G.12: System Model Scaled Wind Resources DMap

G.3 Climatic - System Model Wind Resources at Upper Air Levels

As introduced in Appendix B this Section introduces the wind roses, histograms, and wind values seasonally and as a yearly average at the location of the system model as denoted by the co-ordinates provided in Chapter 2 at 30 m, 50 m, and 80 m altitudes [56]. The following are approximated for a latitude of 50.387 (N) and a longitude of -88.924 (W).

G.3.1 30 meters

Table G.3: Numerical Analysis at 30 m

Period	Mean Wind		Weibull Parameter	
	Speed (m/s)	Energy (W/m^2)	Shape (k)	Scale (A) [m/s]
Annual	4.49	80.38	2.16	5.07
Winter	4.91	98.75	2.33	5.54
Spring	4.22	68.00	2.11	4.76
Summer	3.92	52.44	2.21	4.43
Fall	4.81	96.25	2.23	5.44

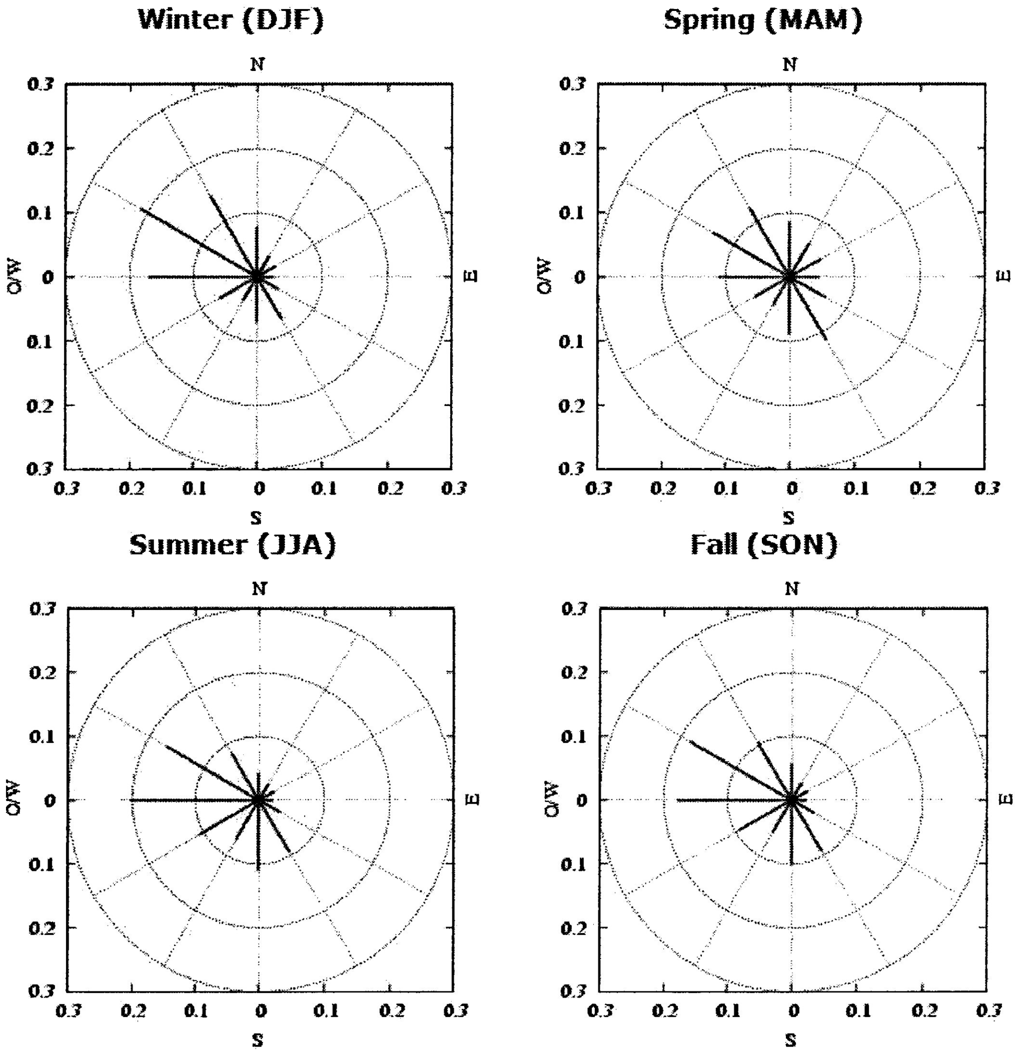


Figure G.13: Seasonal Wind Roses at 30 m

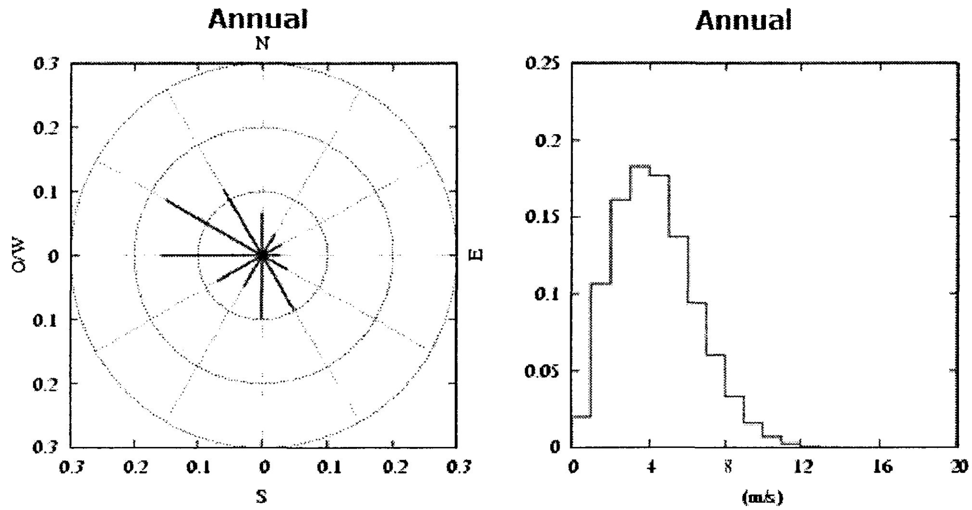


Figure G.14: Annual Wind Rose and Histogram at 30 m

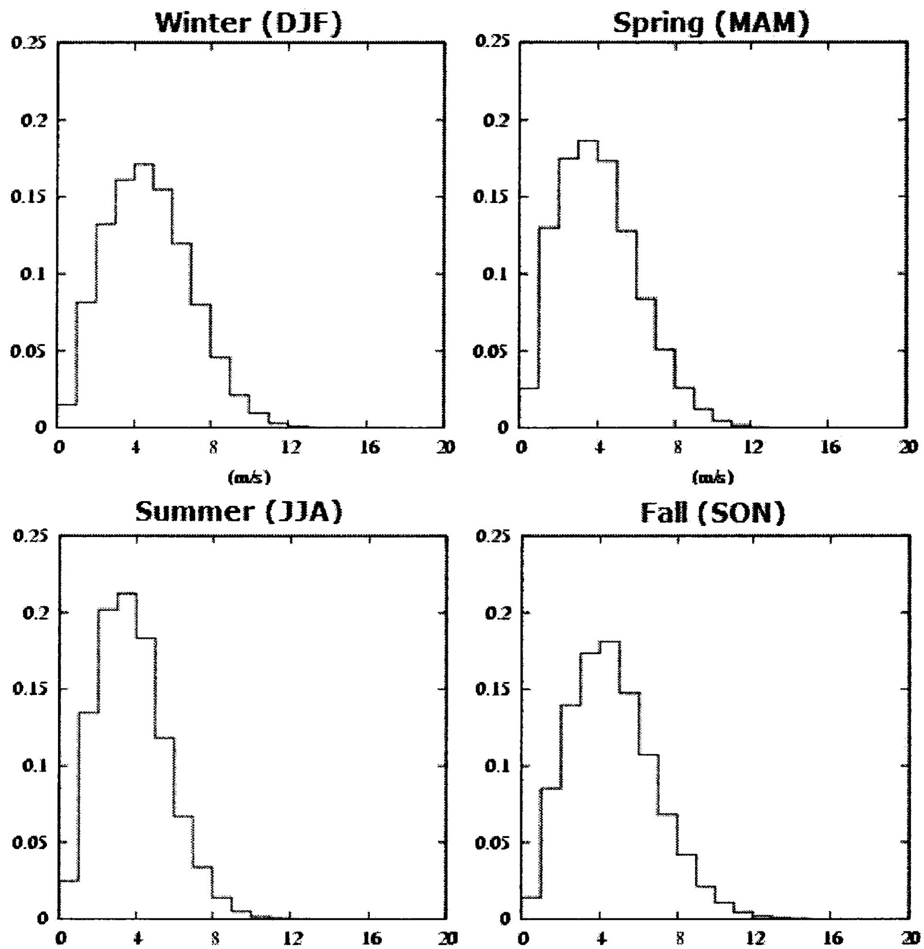


Figure G.15: Seasonal Histograms at 30 m

G.3.2 50 meters

Table G.4: Numerical Analysis at 50 m

Period	Mean Wind		Weibull Parameter	
	Speed (m/s)	Energy (W/m^2)	Shape (k)	Scale (A) [m/s]
Annual	5.23	126.75	2.16	5.90
Winter	5.72	155.75	2.33	6.45
Spring	4.91	107.13	2.11	5.54
Summer	4.56	82.63	2.21	5.15
Fall	5.60	151.63	2.23	6.33

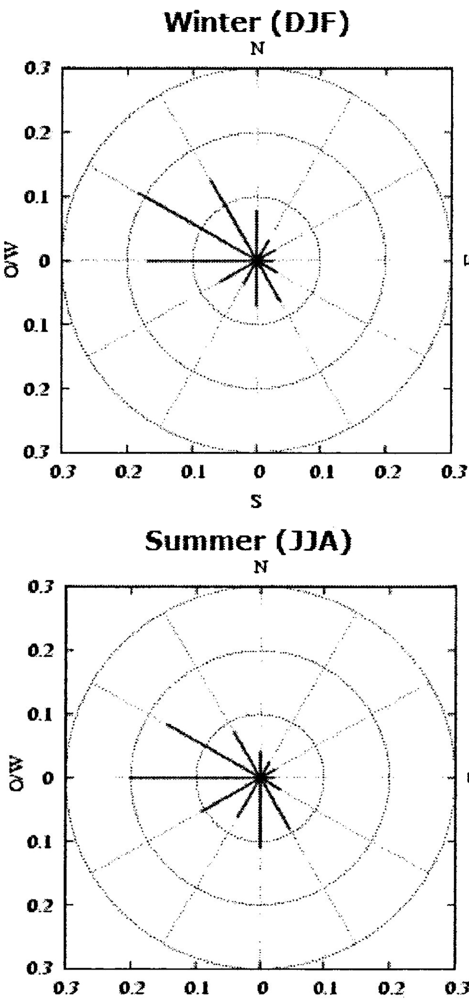


Figure G.16: Seasonal Wind Roses at 50 m

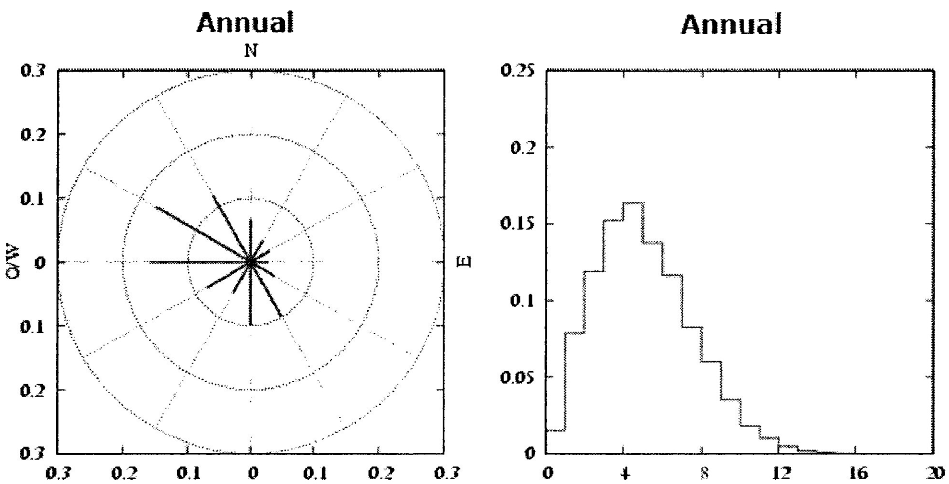


Figure G.17: Annual Wind Rose and Histogram at 50 m

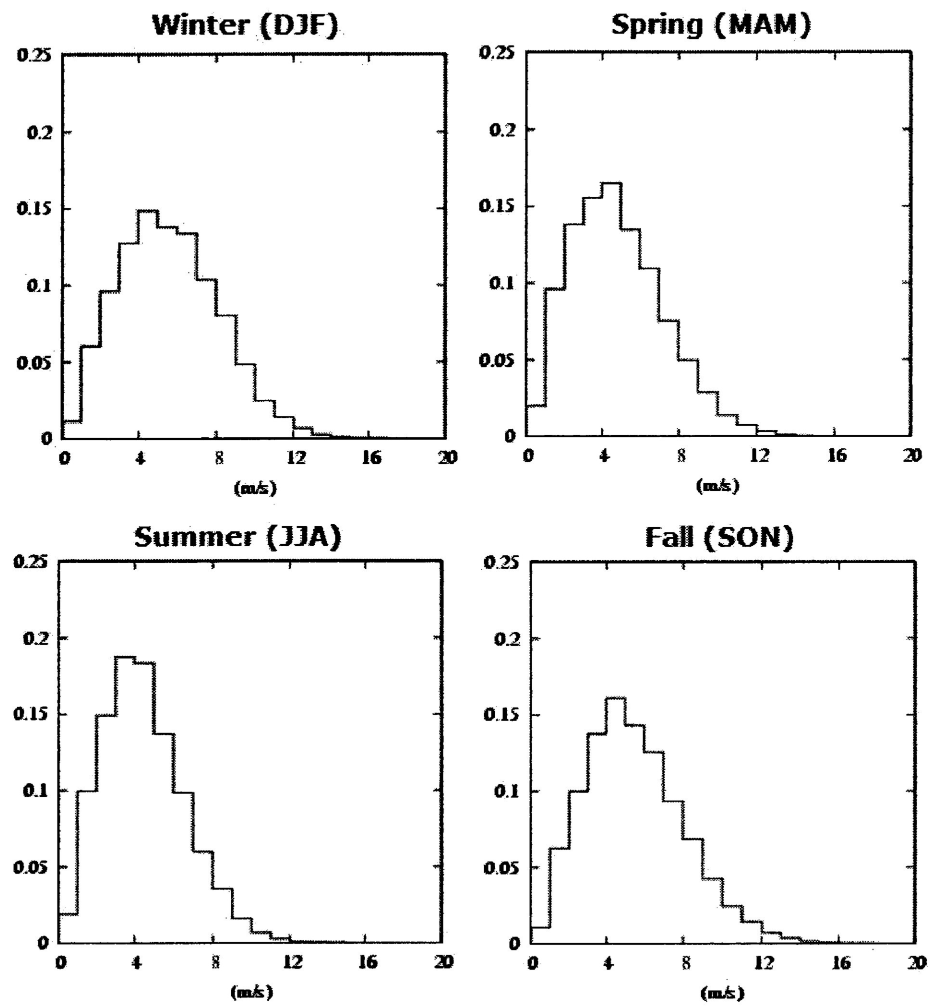


Figure G.18: Seasonal Histograms at 50 m

G.3.3 80 meters

Table G.5: Numerical Analysis at 80 m

Period	Mean Wind		Weibull Parameter	
	Speed (m/s)	Energy (W/m^2)	Shape (k)	scale (A)
Annual	6.14	201.50	2.21	6.94
Winter	6.69	245.00	2.38	7.54
Spring	5.76	170.38	2.15	6.50
Summer	5.39	134.56	2.25	6.09
Fall	6.60	242.13	2.29	7.45

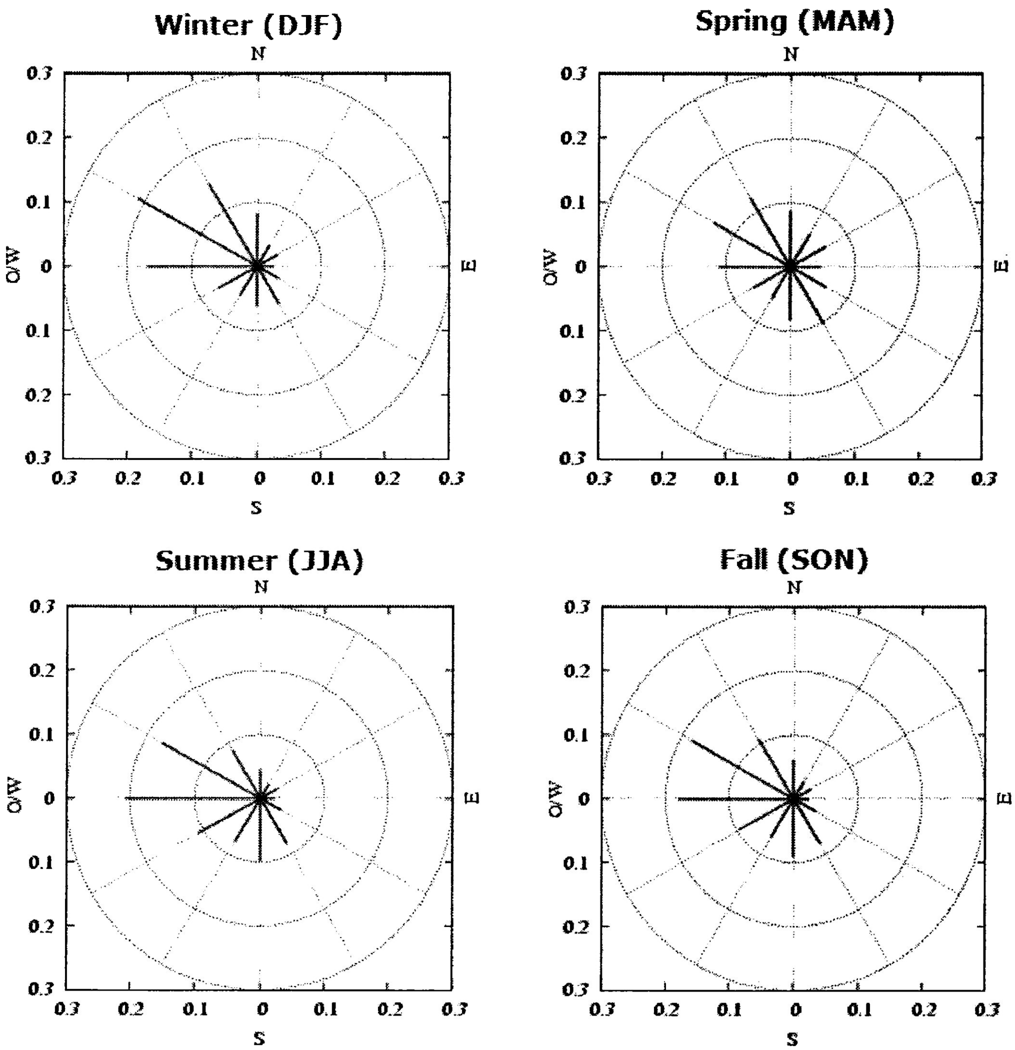


Figure G.19: Seasonal Wind Roses at 80 m

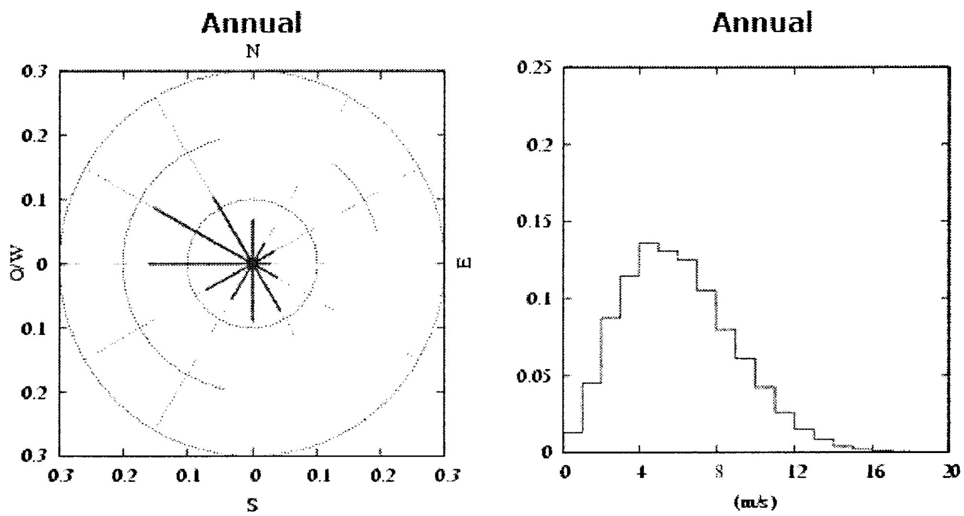


Figure G.20: Annual Wind Rose and Histogram at 80 m

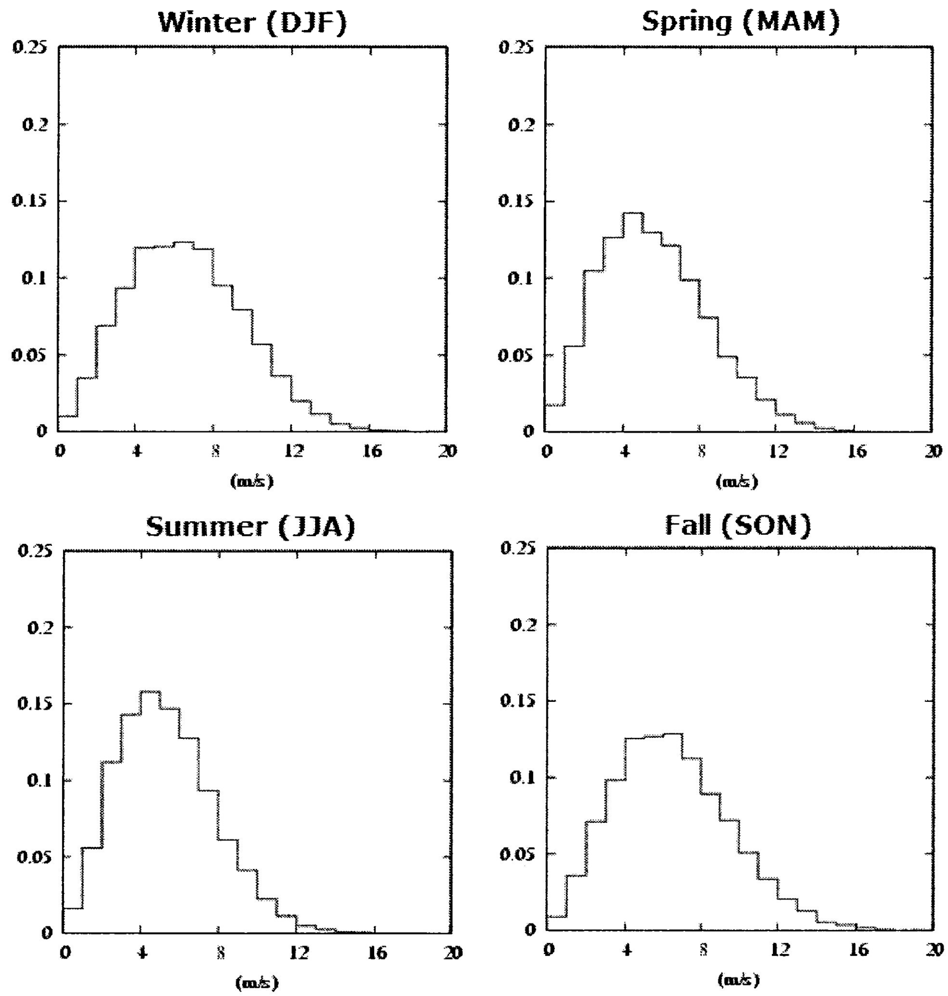


Figure G.21: Seasonal Histograms at 80 m

G.4 Wind Power Generation and System Loading

Due to the climatic nature of wind resources within ON the following situations are experienced. Figure G.22 shows the total wind power produced in Ontario on the IESO connected grid as measured on an hourly basis from 1 March 2010 to 9 March

2010 [2]. One of the key data trends from Figure G.22 is that over the course of the 9 days the total wind power in Ontario fluctuated significantly day to day. It can also be seen that the most wind power was produced around 19hr00 to 06hr00.

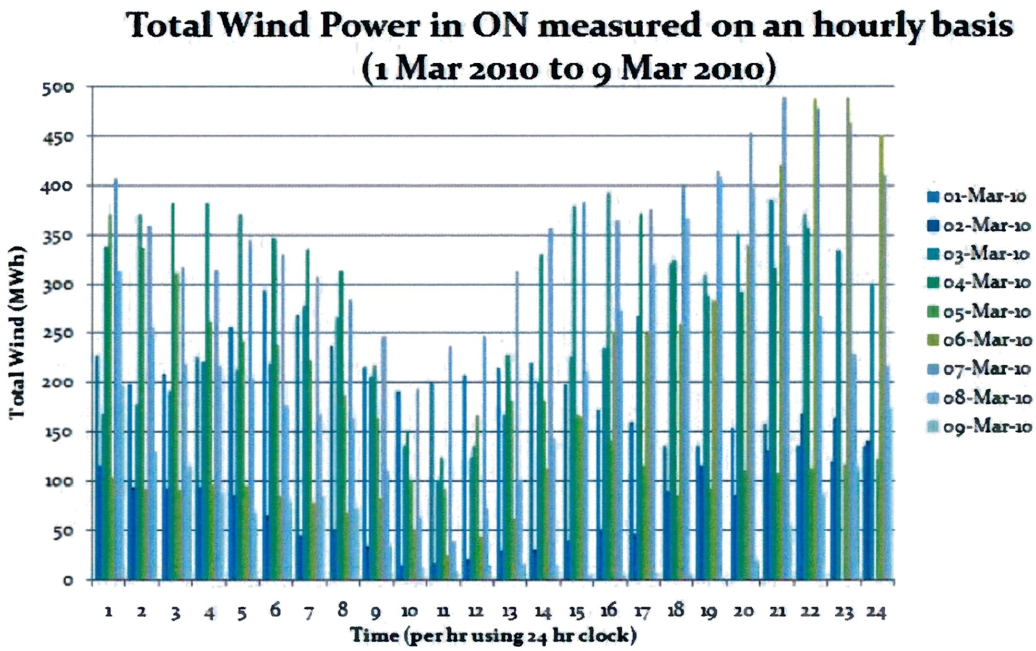


Figure G.22: Total Wind Power in Ontario Measured on an Hourly Basis

Within ON the peak demand generally occurs between 16hr00 and 19hr00 and the lowest daily demand typically occurs during the middle of the night. Thus it can be seen that most wind power is produced when the electrical grid does not overly require it based on a day to day hourly basis which means that this energy cannot be used to its full potential. This may cause surplus base generation on the grid that is a complex issue for energy management. Figure G.23 shows the total wind power generation in Ontario between January 2007 and January 2010. It can be seen that fist the total power generation has drastically increased since January 2007. Second, the wind production per hour and week both really vary over time. The pink boxes on the x-axis indicate a winter season and the x-axis alternates between winter and summer. It can be seen that the majority of wind power is produced during the winter months by following the red per week trend line.

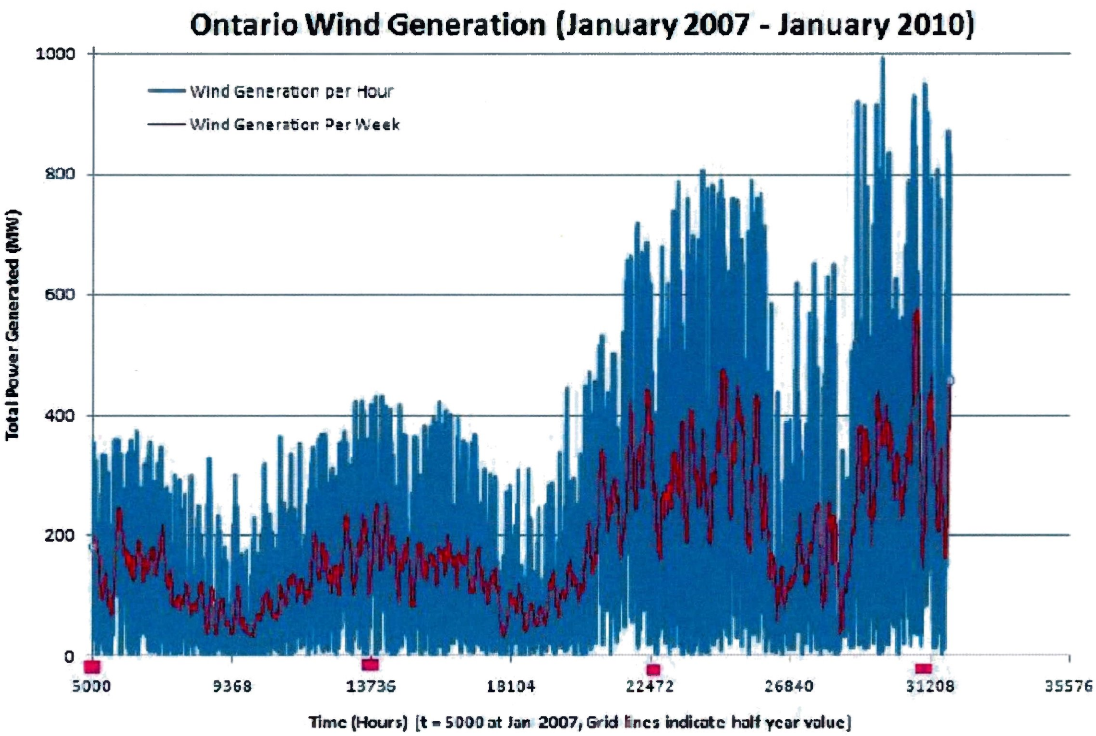


Figure G.23: Ontario Wind Generation (January 2007 to January 2010)

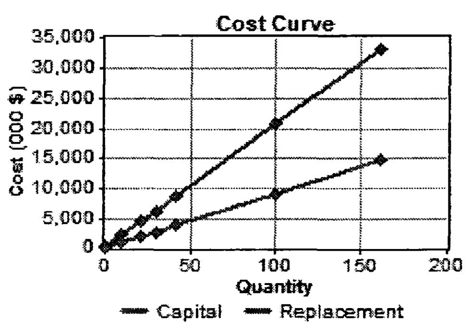
This also demonstrates that wind energy is intermittent and cannot be used to meet the peak demand in any sizable capacity either on a daily or seasonal basis and that the produced wind energy cannot be used to its full potential. The IESO published a report in 2007 that stated "typically, the wind does not blow on the hottest days of the year, so the wind generation production is usually less than 10% of its nameplate capacity at the time of summer peak load". Although the above information relates to the IESO controlled grid and its respective demands WECS installed in remote locations across ON will exhibit similar characteristics both with respect to climate and load demands as seen by the community load profile.

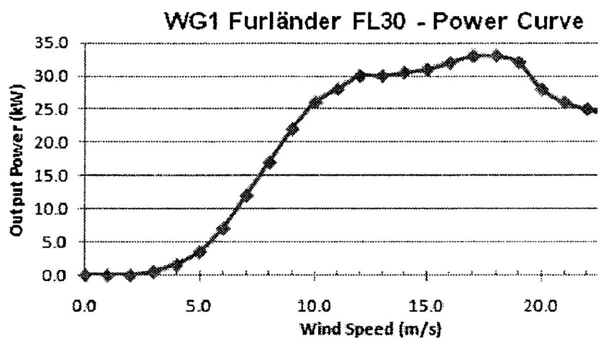
G.5 WG Technical Specifications

The following Tables and Figures represent additional information regarding the WGs studied in this thesis. For additional information refer to the product datasheets which are also listed below. General technical information, the power curve data points, power curve, and cost curve are provided below.

Unit:	**WG1**	**Manufacturer:**		
Model:	**FL30**	**Furländer**		
Link: http://fuhrlaender.de/produkte/downloads/fl30_de_neu.pdf				
Unit Parameters:				
RPM:	22.0	Rated Power:	30	kW
Orientation:	Upwind	Rotor Diameter:	13	m
Power Regulation:	Fixed Pitch, stall	Hub Height:	27	m
Tower Type:	Lattice	Tower Weight:	1360	kg
Temp. Range (°C):	-	Top Weight:	3000	kg
Cut In Speed:	2.5	Cut Out Speed:	25	m/s
Peak Speed:	12	Do Not Exceed:	55	m/s

WG1	Standard Conditions @ STP				
Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Annual Energy (MWh)
0.0	0.0	13.0	30.0	8.5	129.0
1.0	0.0	14.0	30.5	8.0	121.0
2.0	0.0	15.0	31.0	7.5	111.0
3.0	0.5	16.0	32.0	7.0	101.0
4.0	1.6	17.0	33.0	6.5	89.0
5.0	3.5	18.0	33.0	6.0	77.0
6.0	7.0	19.0	32.0	5.5	64.0
7.0	12.0	20.0	28.0	5.0	52.0
8.0	17.0	21.0	26.0	-	-
9.0	22.0	22.0	25.0	-	-
10.0	26.0	23.0	24.4	-	-
11.0	28.0	24.0	25.0	-	-
12.0	30.0	25.0	0.0	-	-





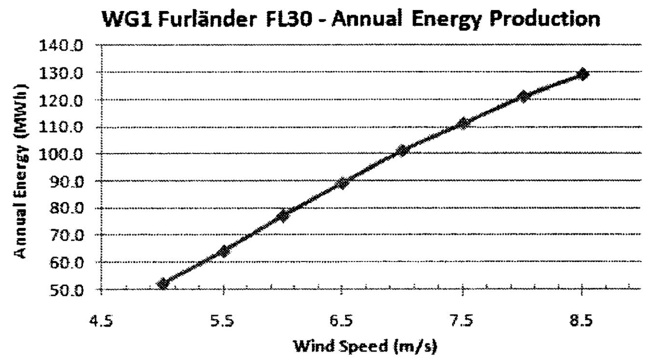


Figure G.24: WG1 Cost, Power, and Annual Energy Curves

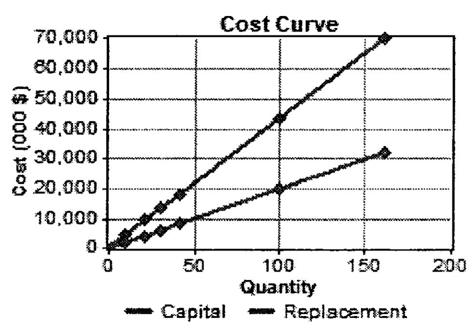
Unit:	**WG2**	**Manufacturer:**	
Model:	**FL100**	**Furländer**	

Link: http://fuhrlaender.de/produkte/downloads/fl100_de.pdf

Unit Parameters:

RPM:	-	Rated Power:	100	kW
Orientation:	Upwind	Rotor Diameter:	21	m
Power Regulation:	Stall	Hub Height:	35	m
Tower Type:	Tubular	Tower Weight:	9000	kg
Temp. Range (°C):	-	Top Weight:	18000	kg
Cut In Speed:	2.5	Cut Out Speed:	25	m/s
Peak Speed:	13	Do Not Exceed:	67	m/s

WG2	Standard Conditions @ STP				
Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Annual Energy (MWh)
0.0	0.0	13.0	119.0	8.5	396.0
1.0	0.0	14.0	125.0	8.0	370.0
2.0	0.0	15.0	122.0	7.5	340.0
3.0	1.0	16.0	120.0	7.0	306.0
4.0	2.0	17.0	112.0	6.5	267.0
5.0	8.0	18.0	107.0	6.0	226.0
6.0	17.0	19.0	101.0	5.5	183.0
7.0	30.0	20.0	97.0	5.0	144.0
8.0	45.0	21.0	96.0	-	-
9.0	63.0	22.0	95.0	-	-
10.0	79.0	23.0	94.0	-	-
11.0	94.0	24.0	97.0	-	-
12.0	108.0	25.0	101.0	-	-



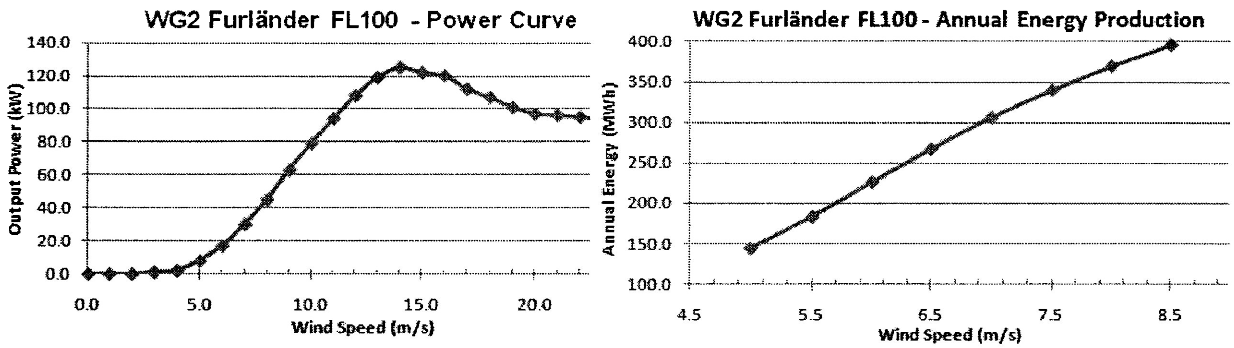


Figure G.25: WG2 Cost, Power, and Annual Energy Curves

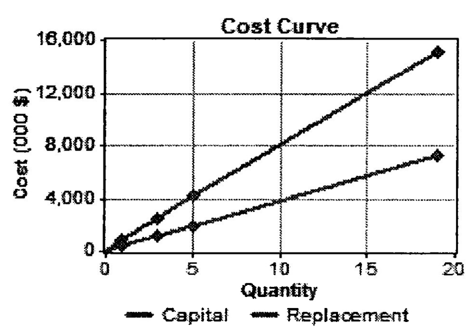
Unit:	**WG3**	**Manufacturer:**	
Model:	**FL250**	**Furländer**	

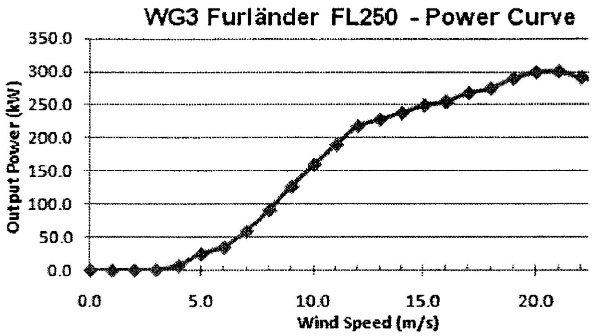
Link: http://www.fuhrlaender.de/produkte/downloads/fl250_de.pdf
Life: http://www.wind-industry-germany.com/en/companies/manufacturers/fuhrlaender-ag/

Unit Parameters:

RPM:	-	Rated Power:	250	kW
Orientation:	Upwind	Rotor Diameter:	29.5	m
Power Regulation:	Stall	Hub Height:	42	m
Tower Type:	Tubular	Tower Weight:	14700	kg
Temp. Range (°C):	-	Top Weight:	26500	kg
Cut In Speed:	2.5	Cut Out Speed:	25	m/s
Peak Speed:	15	Do Not Exceed:	67	m/s

WG3	Standard Conditions @ STP				
Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Annual Energy (MWh)
0.0	0.0	13.0	228.0	8.5	857.0
1.0	0.0	14.0	238.0	8.0	791.0
2.0	0.0	15.0	249.0	7.5	717.0
3.0	1.0	16.0	255.0	7.0	638.0
4.0	7.0	17.0	268.0	6.5	554.0
5.0	25.0	18.0	275.0	6.0	468.0
6.0	35.0	19.0	290.0	5.5	380.0
7.0	59.0	20.0	299.0	5.0	302.0
8.0	91.0	21.0	300.0	-	-
9.0	127.0	22.0	291.0	-	-
10.0	160.0	23.0	284.0	-	-
11.0	190.0	24.0	278.0	-	-
12.0	218.0	25.0	272.0	-	-





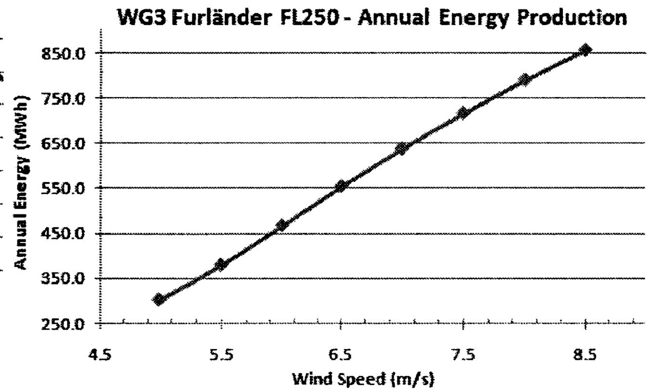


Figure G.26: WG3 Cost, Power, and Annual Energy Curves

Unit:	**WG4**	**Manufacturer:**		
Model:	**V27**	**Vestas**		

Link: http://www.windturbinewarehouse.com/pdfs/vestas

Unit Parameters:

RPM:	43.1	Rated Power:	225	kW
Orientation:	Upwind	Rotor Diameter:	27	m
Power Regulation:	Pitch	Hub Height:	30	m
Tower Type:	Tubular	Tower Weight:	11974	kg
Temp. Range (°C):	-	Top Weight:	10877	kg
Cut In Speed:	3.6	Cut Out Speed:	25	m/s
Peak Speed:		Do Not Exceed:	53.6	m/s

WG4	Standard Conditions @ STP		
Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Power Output (kW)
0.0	0.0	14.0	217.0
1.0	0.0	16.0	225.0
2.0	0.0	18.0	225.0
4.0	3.2	20.0	225.0
6.0	28.6	22.0	225.0
8.0	72.4	24.0	225.0
10.0	125.4	26.0	76.0
12.0	190.1	28.0	0.0

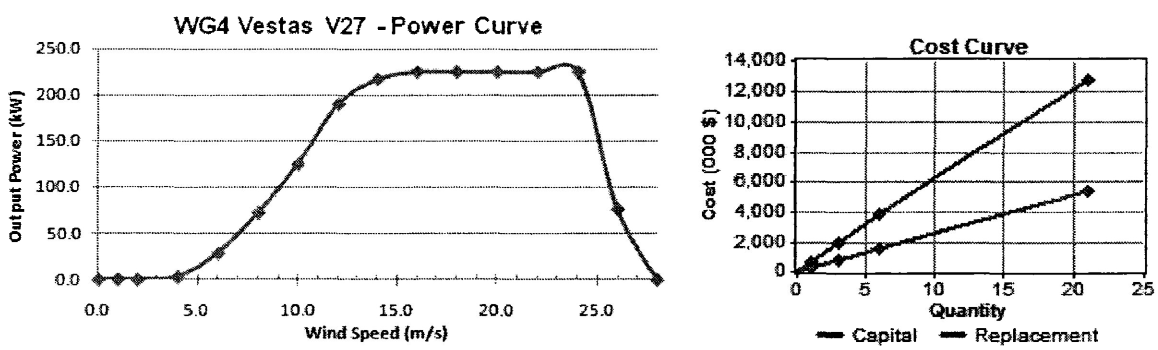
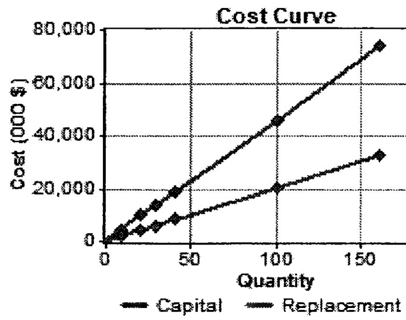
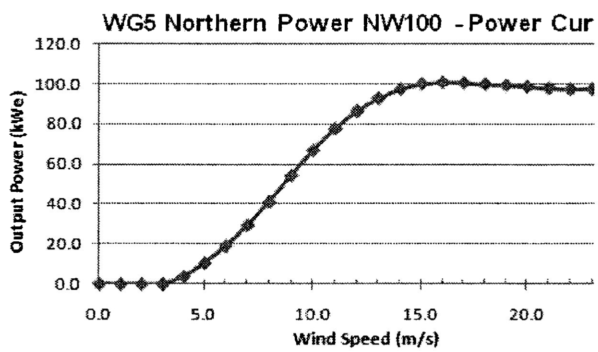


Figure G.27: WG4 Power and Cost Curves

Unit:	**WG5**	**Manufacturer:**			
Model:	**NW100/19**	**Northern Power Systems**			
Link:	http://www.northernpower.com				
	Unit Parameters:				
RPM:	59	Rated Power:	100	kW	
Orientation:	Upwind	Rotor Diameter:	21	m	
Power Regulation:	Stall	Hub Height:	37	m	
Tower Type:	Tubular	Tower Weight:	13800	kg	
Temp. Range (°C):	-20 to 50	Top Weight:	7200	kg	
Cut In Speed:	3.5	Cut Out Speed:	25	m/s	
Rated Wind Speed:	14.5	Do Not Exceed:	59.5	m/s	
		Lifetime:	20	yrs	

WG5	Standard Conditions @ STP				
Wind Speed (m/s)	Power Output (kWe)	Wind Speed (m/s)	Power Output (kWe)	Wind Speed (m/s)	Annual Energy Output (MWh)
0.0	0.0	13.0	92.8	3.5	-
1.0	0.0	14.0	97.3	4.0	77
2.0	0.0	15.0	100.0	4.5	110
3.0	0.0	16.0	100.8	5.0	145
4.0	3.7	17.0	100.6	5.5	183
5.0	10.5	18.0	99.8	6.0	222
6.0	19.0	19.0	99.4	6.5	260
7.0	29.4	20.0	98.6	7.0	298
8.0	41.0	21.0	97.8	7.5	334
9.0	54.3	22.0	97.3	8.0	368
10.0	66.8	23.0	97.3	8.5	400
11.0	77.7	24.0	98.0	9.0	-
12.0	86.4	25.0	99.7	9.5	-





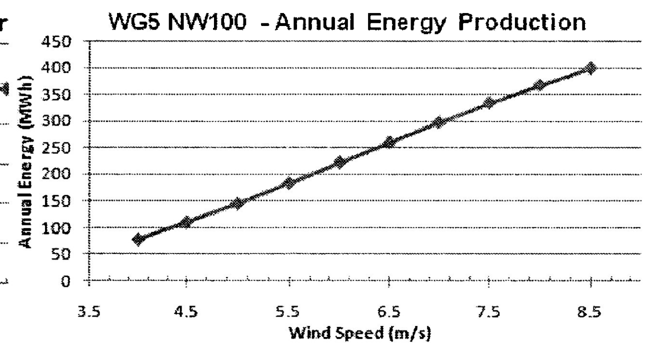
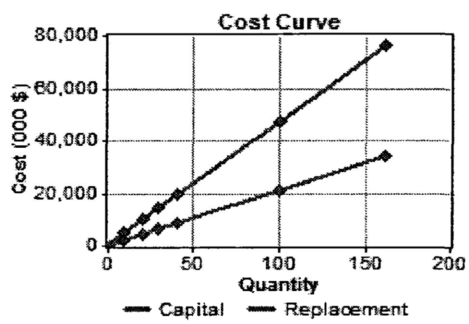


Figure G.28: WG5 Cost, Power, and Annual Energy Curves

Unit:	**WG6**	**Manufacturer:**		
Model:	**NW100A**	**Northern Power Systems**		
Link: http:\\www.northernpower.com				
	Unit Parameters:			
RPM:	59	Rated Power:	100	kW
Orientation:	Upwind	Rotor Diameter:	21	m
Power Regulation:	Stall	Hub Height:	37	m
Tower Type:	Tubular	Tower Weight:	13800	kg
Temp. Range (°C):	-40 to 50	Top Weight:	7200	kg
Cut In Speed:	3.5	Cut Out Speed:	25	m/s
Rated Wind Speed:	14.5	Do Not Exceed:	56	m/s
		Lifetime:	20	yrs

WG6	Standard Conditions @ STP				
Wind Speed (m/s)	Power Output (kWe)	Wind Speed (m/s)	Power Output (kWe)	Wind Speed (m/s)	Annual Energy Output (MWh)
0.0	0.0	13.0	92.8	3.5	-
1.0	0.0	14.0	97.3	4.0	77
2.0	0.0	15.0	100.0	4.5	110
3.0	0.0	16.0	100.8	5.0	145
4.0	3.7	17.0	100.6	5.5	183
5.0	10.5	18.0	99.8	6.0	222
6.0	19.0	19.0	99.4	6.5	260
7.0	29.4	20.0	98.6	7.0	298
8.0	41.0	21.0	97.8	7.5	334
9.0	54.3	22.0	97.3	8.0	368
10.0	66.8	23.0	97.3	8.5	400
11.0	77.7	24.0	98.0	9.0	-
12.0	86.4	25.0	99.7	9.5	-



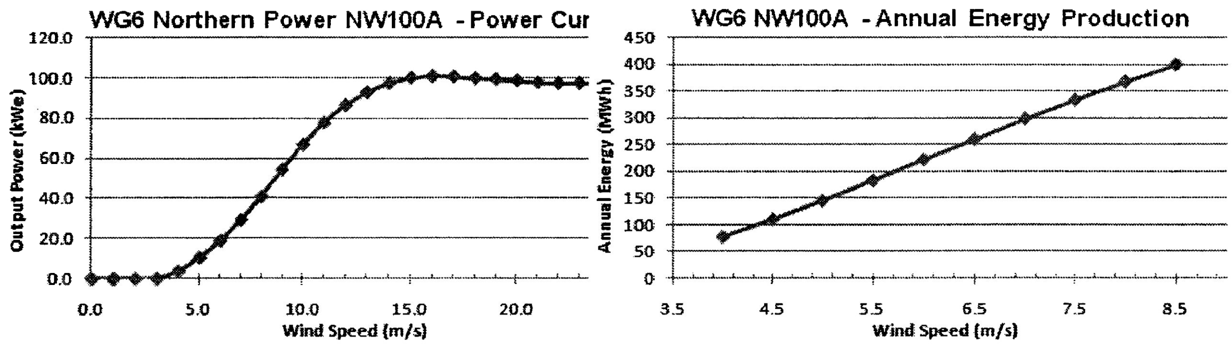


Figure G.29: WG6 Cost, Power, and Annual Energy Curves

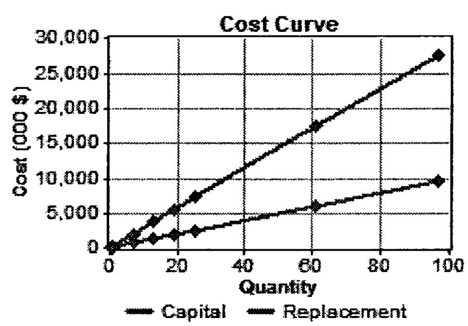
Unit:	**WG7**	**Manufacturer:**		
Model:	**AOC 15/50**	**Atlantic Orient Corporation**		

Link: http://www.atlanticorientcanada.ca/aoc1550.htm

Unit Parameters:

RPM:	-	Rated Power:	50	kW
Orientation:	Downwind	Rotor Diameter:	15	m
Power Regulation:	Pitch/Stall	Hub Height:	24.4	m
Tower Type:	Lattice	Tower Weight:	3210	kg
Temp. Range (°C):	-	Top Weight:	2420	kg
Cut In Speed:	4.6	Cut Out Speed:	22.4	m/s
Rated Speed:	11.3	Do Not Exceed:	59.5	m/s

WG7	Standard Conditions @ STP				
Wind Speed (m/s)	Power Output (kWe)	Wind Speed (m/s)	Power Output (kWe)	Wind Speed (m/s)	Annual Energy Output (MWh)
0.0	0.0	12.0	54.0	3.5	-
1.0	0.0	13.0	59.0	4.0	30
2.0	0.0	14.0	62.0	5.4	87
3.0	0.0	15.0	64.0	6.7	153
4.0	0.0	16.0	64.7	8.0	215
5.0	2.0	17.0	65.2	9.0	250
6.0	7.8	18.0	64.5	11.0	300
7.0	15.2	19.0	64.3	12.0	-
8.0	24.0	20.0	64.2	-	-
9.0	32.5	21.0	63.9	-	-
10.0	41.75	22.4	0.0	-	-
11.0	48.0	-	-	-	-



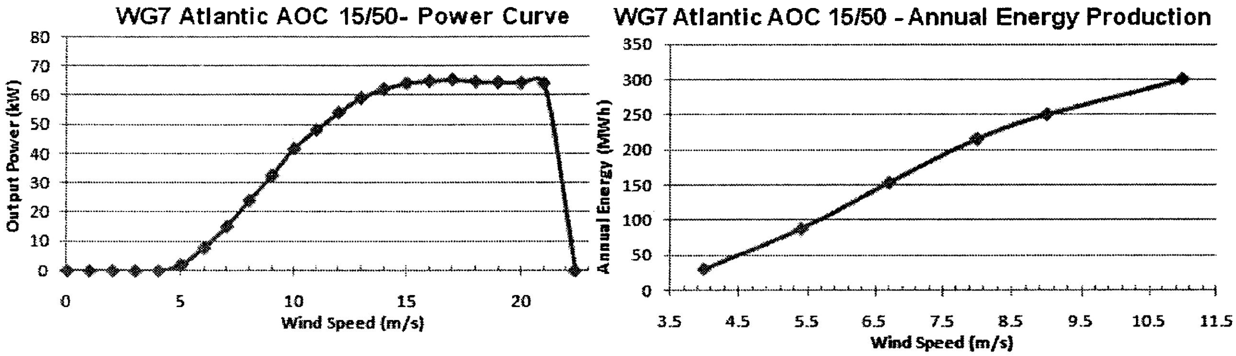


Figure G.30: WG7 Cost, Power, and Annual Energy Curves

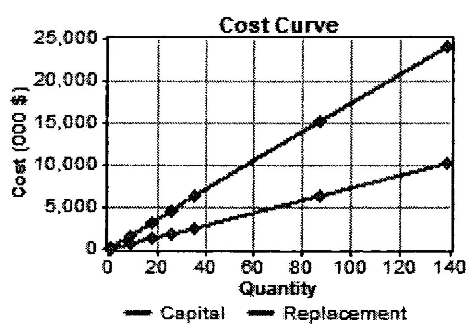
Unit:	**WG8**	**Manufacturer:**		
Model:	**G-3120**	**Endurance**		

Link: http://www.endurancewindpower.com/e3120.html

Unit Parameters:

RPM:	42	Rated Power:	35	kW
Orientation:	Downwind	Rotor Diameter:	19.2	m
Power Regulation:	Stall	Hub Height:	42.7	m
Tower Type:	Lattice	Lifetime:	30	yrs
Cut In Speed:	3.5	Cut Out Speed:	25	m/s
Peak Speed:	-	Do Not Exceed:	52	m/s

WG8	Standard Conditions @ STP				
Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Annual Energy Output (MWh)
0.0	0.0	10.0	50.9	3.5	40.064
1.0	0.0	11.0	54.8	4.0	62.526
2.0	0.0	12.0	57.3	4.5	87.951
3.0	0.0	13.0	59.3	5.0	114.927
4.0	2.2	14.0	59.3	5.5	142.24
5.0	8.1	15.0	58.6	6.0	168.927
6.0	15.2	16.0	57.1	6.5	194.253
7.0	24.8	17.0	54.9	7.0	217.664
8.0	35.8	18.0	51.3	7.5	238.751
9.0	43.8	19.0	-	8.0	257.234



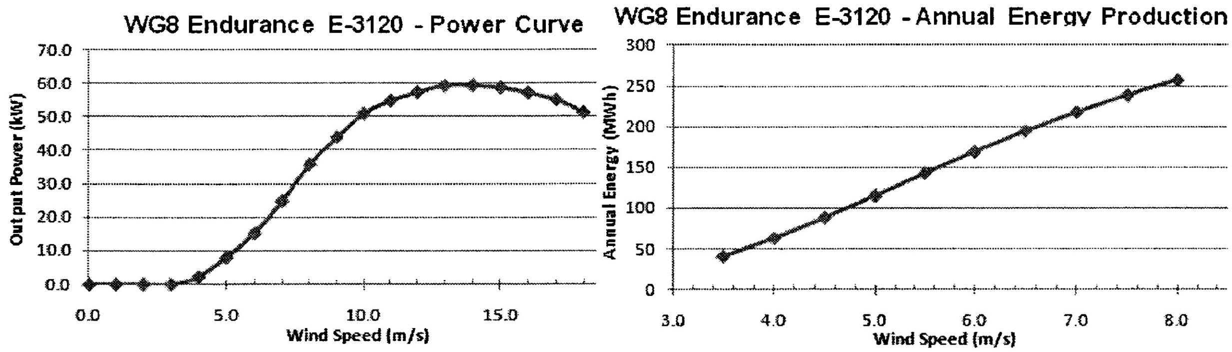


Figure G.31: WG8 Cost, Power, and Annual Energy Curves

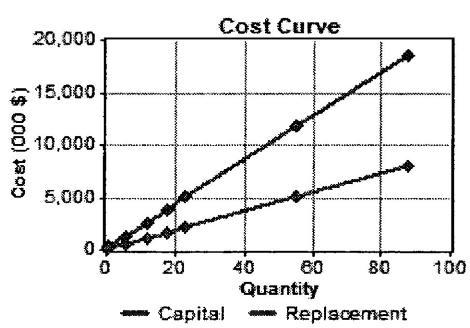
Unit:	**WG9**	**Manufacturer:**		
Model:	**E-3120**	**Endurance**		

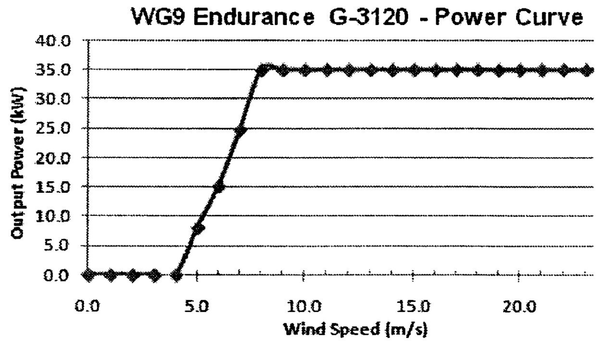
Link: http://www.endurancewindpower.com/g3120.html

Unit Parameters:

RPM:	42	Rated Power:	55	kW
Orientation:	Downwind	Rotor Diameter:	19.2	m
Power Regulation:	Stall	Hub Height:	42.7	m
Tower Type:	Lattice	Lifetime:	30	yrs
Cut In Speed:	3.5	Cut Out Speed:	25	m/s
Peak Speed:		Do Not Exceed:	52	m/s

WG9	Standard Conditions @ STP				
Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Annual Energy Output (MWh)
0.0	0.0	13.0	35.0	3.0	-
1.0	0.0	14.0	35.0	3.5	38.927
2.0	0.0	15.0	35.0	4.0	59.137
3.0	0.0	16.0	35.0	4.5	80.401
4.0	0.0	17.0	35.0	5.0	101.335
5.0	8.1	18.0	35.0	5.5	121.055
6.0	15.2	19.0	35.0	6.0	139.102
7.0	24.8	20.0	35.0	6.5	155.28
8.0	35.0	21.0	35.0	7.0	169.528
9.0	35.0	22.0	35.0	7.5	181.838
10.0	35.0	23.0	35.0	8.0	192.23
11.0	35.0	24.0	35.0	8.5	-
12.0	35.0	25.0	35.0	9.0	-





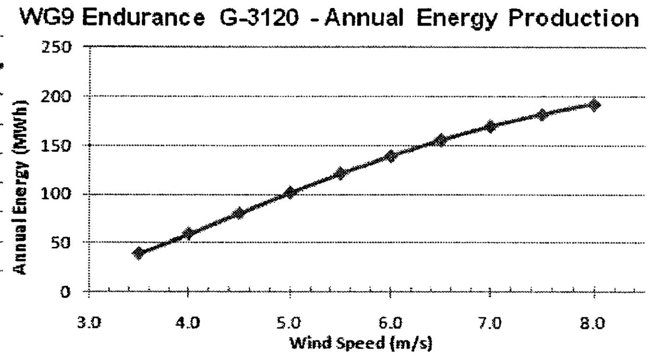


Figure G.32: WG9 Cost, Power, and Annual Energy Curves

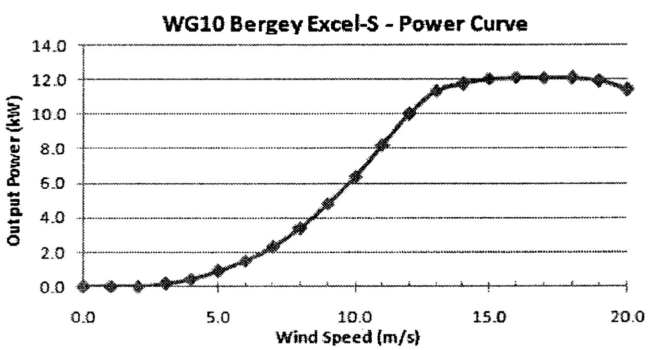
Unit:	**WG10**	**Manufacturer:**		
Model:	**Excel-S**	**Bergey**		

Link: http://www.bergey.com/pages/technical

Unit Parameters:

RPM:		Rated Power:	10	kW
Orientation:	-	Rotor Diameter:	7	m
Power Regulation:	Fixed Pitch	Temp. Range:	-40 to 60	°C
Tower Type:	Latice	Hub Height:	18-43	m
Tower Type:	Tubular	Hub Height:	37	m
Cut In Speed:	2.5	Cut Out Speed:	-	m/s
Start-up Speed:	3.4	Furling Speed:	15.6	m/s
Rated Speed:	12.0	Do Not Exceed:	60.0	m/s

WG10	Standard Conditions @ STP		
Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Power Output (kW)
0.0	0.00	11.0	8.21
1.0	0.00	12.0	10.02
2.0	0.00	13.0	11.37
3.0	0.14	14.0	11.76
4.0	0.43	15.0	12.06
5.0	0.88	16.0	12.14
6.0	1.51	17.0	12.15
7.0	2.35	18.0	12.10
8.0	3.43	19.0	11.92
9.0	4.80	20.0	11.44
10.0	6.42	-	-



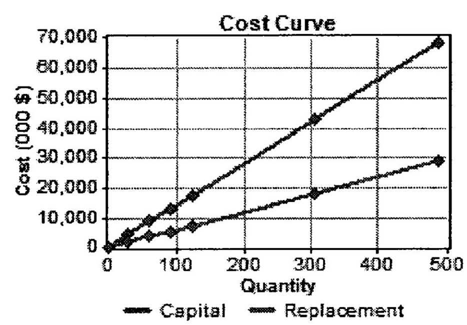


Figure G.33: WG10 Power and Cost Curves

Note: WG11 and WG12 are DC generators. They are included as a provision if DC simulations and case studies are considered if time allows. Also note that WG11 is the same unit as WG10 however it is meant to charge batteries or provide a DC output for a rated power of 7.5 kW. WG12 is currently available only as a 24 VDC battery-charging system.

Unit:	**WG11**	**Manufacturer:**			
Model:	**Excel-R**	**Bergey**			

Link: http://www.bergey.com/pages/technical

Unit Parameters:

RPM:		Rated Power:	7.5	kW
Orientation:	-	Rotor Diameter:	7	m
Power Regulation:	Fixed Pitch	Temp. Range:	-40 to 60	°C
Tower Type:	Latice	Hub Height:	18-43	m
Tower Type:	Tubular	Hub Height:	37	m
Cut In Speed:	2.5	Cut Out Speed:	-	m/s
Start-up Speed:	3.4	Furling Speed:	15.6	m/s
Rated Speed:	12.0	Do Not Exceed:	60.0	m/s

WG11	Standard Conditions @ STP		
Wind Speed (m/s)	Power Output (kW)	Wind Speed (m/s)	Power Output (kW)
0.0	0.00	11.0	6.58
1.0	0.00	12.0	7.02
2.0	0.00	13.0	7.02
3.0	0.00	14.0	7.02
4.0	0.22	15.0	6.14
5.0	0.70	16.0	4.39
6.0	1.45	17.0	2.37
7.0	2.24	18.0	2.63
8.0	3.20	19.0	2.63
9.0	4.26	20.0	2.63
10.0	5.40	-	-

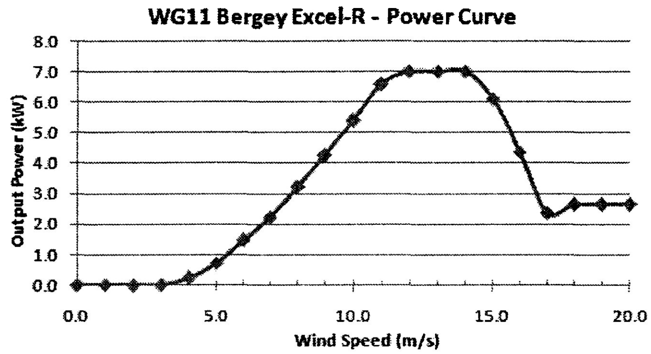


Figure G.34: WG11 Power Curve

Unit:	**WG12**	**Manufacturer:**		
Model:	**XL1R**	**Bergey**		
Link: http://www.bergey.com/pages/technical				
Unit Parameters:				
RPM:		Rated Power:	1	kW
Orientation:	-	Rotor Diameter:	2.5	m
Power Regulation:	Fixed Pitch	Temp. Range:	-40 to 60	°C
Tower Type:	Tubular	Hub Height:	18-29	m
Cut In Speed:	2.5	Cut Out Speed:	-	m/s
Start-up Speed:	3.0	Furling Speed:	13.0	m/s
Rated Speed:	11.0	Do Not Exceed:	54.0	m/s

WG12	Standard Conditions @ STP		
Wind Speed (m/s)	Power Output (W)	Wind Speed (m/s)	Power Output (W)
0.0	0.00	11.0	1040.53
1.0	0.00	12.0	1166.95
2.0	1.94	13.0	1196.13
3.0	21.39	14.0	1166.95
4.0	58.35	15.0	1118.33
5.0	121.56	16.0	1064.84
6.0	223.67	17.0	1011.36
7.0	364.67	18.0	962.74
8.0	515.40	19.0	914.11
9.0	680.72	20.0	865.49
10.0	855.76	-	-

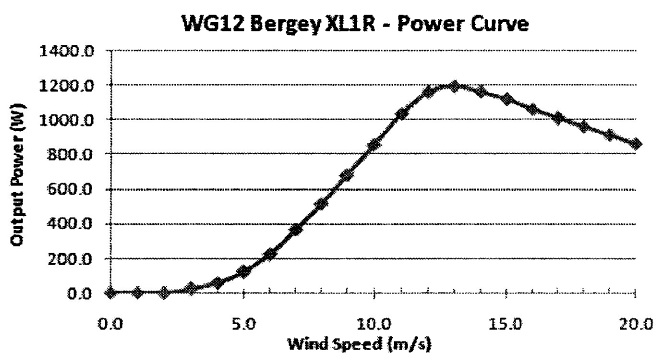


Figure G.35: WG12 Power Curve

Appendix H - Fuel Cells

Appendix H provides a background on fuel cell technologies. This was removed from the body of the thesis as it was determined that the following analysis was not applicable for the given community parameters as outlined in Chapters 2 and 3.

H.1 Introduction to Fuel Cell Technology

The fuel cell is a steady-flow system that converts chemical energy to electrical energy. Fuel cells are currently being researched and implemented as they promise to be enviromentally clean, quite in operation, and highly efficient for power generation [57]. There are currently multiple fuel cell technologies that are being employed and researched for both low voltage and power generation applications. The major technologies consist of the following fuel cell architectures:

- Alkaline Fuel Cell (AFC)
- Direct Methanol Fuel Cell (DMFC)
- Molten Carbonate Fuel Cell (MCFC)

- Phosphoric Acid Fuel Cell (PAFC)

- Polymer Electrolyte Membrane Fuel Cell (PEMC)

- Solid Oxide Fuel Cell (SOFC)

  - Tubular Solid Oxide Fuel Cell (TSOFC)

  - Intermediate Temperature Solid Oxide Fuel Cell (ITSOFC)

Many fuel cells commonly utilize hydrogen as fuel which emits water and heat as byproducts since the chemical reaction is exothermic. Modern hydrogen fuel cells can have an efficiency of up to 80%. The current capability of the fuel cell is dependent upon the rate of reaction between the anode and cathode. In order to increase the the rate of reaction it is possible to: raise the operational temperature, increase the surface area of the electrode, and introduce a catalyst. The voltage of the individual cells tends to be low at around 0.7 V. These cells are combined in series to create fuel stacks of higher voltages. These fuel stacks are typically internally connected using bipolar plates which allows for the individual cells to be connected across the entire surface area of one cathode to the next anode. The use of bipolar plates allows for less resistance between connections and easier access for intake and exhaust lines. These fuel stacks are enclosed in an external manifold that typically provides cooling through narrow channels that allow cooling water and air to flow between the plates. The AFC, DMFC, and PEMC are typically used in low power applications, the PAFC is used in mid range power applications, and the MCFC and SOFC are used for high power applications. The SOFC consists of two common configurations which are the TSOFC and ITSOFC. The TSOFC is a tubular cell and the ITSOFC is an electrode or anode supported fuel cell that is considered to be an intermediate temperature SOFC with a flat-plate design [58]. The MCFC and SOFC will be investigated more in depth as they are applicable to large power generation as required in remote communities.

H.2 Molten Carbonate Fuel Cells

The MCFC is considered a high temperature operating fuel cell and has been successfully utilized in small scale power generation applications. Figure H.1 demonstrates the chemical composition of the fuel cell when the fuel source is hydrogen. The MCFC is of planar construction and constructed through a tape-casting process. This design decreases the voltage drop between the cells in the stack and allows for easier access for the fuel intake lines.

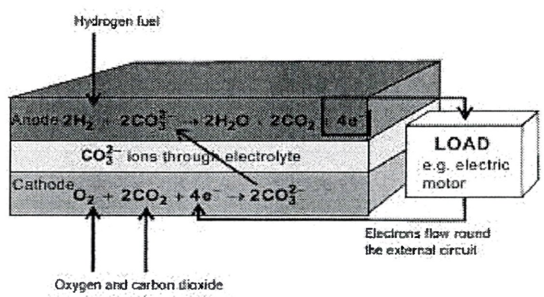


Figure H.1: Operational Principle of the MCFC Showing Anode and Cathode Reactions When Hydrogen is Used as Fuel [59]

These construction practises have allowed for cells of up to 1 m^2 to be constructed. The MCFC is normally operated between 600 to 700^{o}C and the fuel stacks are housed inside of a stainless steel chassis. The construction of the MCFC allows for the cost of materials to be lower compared to other fuel cell technologies. However there must be a gas tight seal around each cell within the stack. The MCFC utilizes liquid molten carbonate to form this seal against the metal cell housing. This liquid molten carbonate is highly corrosive which requires the metal to have a protective coating which is normally alumina. To effectively produce the gas tight seal the operational temperature of the MCFC must be kept above 500ºC in order to keep the electrolyte in a liquid state [58]. The composition of the sealant leaves the MCFC prone to degradation through corrosion which both decreases the life time of the MCFC and increases the cost of operation due to the alumina coating and increased maintenance costs [59].

The MCFC is typically constructed with the anode being produced of a porous sintered Ni-Cr/Ni-Al alloy and the cathode of NiO. The electrolyte is usually a binary mixture of lithium/potassium carbonates or lithium/sodium carbonates which is retained in a ceramic matrix of $LiAlO_2$. For regular operation the MCFC can use CO-containing gases as a fuel and the MCFC requires CO_2 for the cathode reactions. This requirement of CO_2 makes the MCFC unique when compared to other fuel cell technologies and MCFC generators are equipped with a CO_2 transfer device to facilitate this. The MCFC generator also contains extensive temperature monitoring and control instrumentation. While utilizing hydrogen fuel $H_2O_{(vapour)}$ is produced at the anode due to the hydrogen oxidation. This production of water creates an increase of pressure within the cell that decreases the voltage and overall efficiency of the MCFC.

H.3 Solid Oxide Fuel Cells

The SOFC technology is contrived by creating a multilayer structure consisting of both ceramic and metallic materials that utilize chemical reactions produce electricity. The SOFC is considered a high temperature fuel cell and typically operates between 600 to 1000°C [57]. The TSOFC typically operates at 1000°C and the IT-SOFC has an operational temperature between 600-800°C [58]. [60] demonstrates that the SOFC used in small stationary power generation applications, ranging from 1 to 100 kW, is capable of obtaining a net electrical efficiency of up to 50%. When the thermal byproduct of power generation is also utilized the net efficiency increases to between 70 and 90%. The SOFC technology is beneficial for operation in a remote environment as the technology provides long term stability, thermal cycling capabilities, short start-up time, and operation using different fuels with a high fuel utilization factor. This wide range of fuel sources allows remote applications to process a wider range of more readily available resources and if the SOFCs were implemented as part of a hybrid system the short start-up times are particularly beneficial. Table H.1 from [60] demonstrates target parameters for stationary SOFC generating systems.

Table H.1: Stationary SOFC System Target Parameters [60]

Parameter Type	Parameter Value
Operation Temperature	700-1000ºC
Power Density	> 0.25 W/cm^2
Operation Lifetime	$> 40{,}000$ h
Degradation Rate	< 1 µV/h
Fuel Utilization	$> 80\%$
Thermal Cycles	> 100 *
Heating Rates	> 1 K/min
Fuel Utilization	Natural gas, fuel oil
Oxidant	Air
System Cost	$<$ $500/kW

Note: * denotes approximate value

The electrolyte in the SOFC is solid and consists of Zirconia (ZrO_2) doped with 8-10 mol% Yittria (Y_2O_3) which is also known as YSZ. The anode is typically a metallic nickel supported on a porous YSZ and the cathode is made of Strontium-doped Lanthanum Manganite $(La_{0.84}Sr_{0.16})/MnO_3$.

Figure H.2 demonstrates the chemical reactions at the anode and cathode for the SOFC and the mobile ion in the electrolyte. The SOFC is capable of utilizing various fuel sources such as natural gas (NG), fuel oil, petrol, liquid propane, or diesel provided that the internal reforming temperature is sufficiently high enough [57, 60]. Figure H.2 includes the SOFC composition using hydrogen and carbon monoxide as fuels.

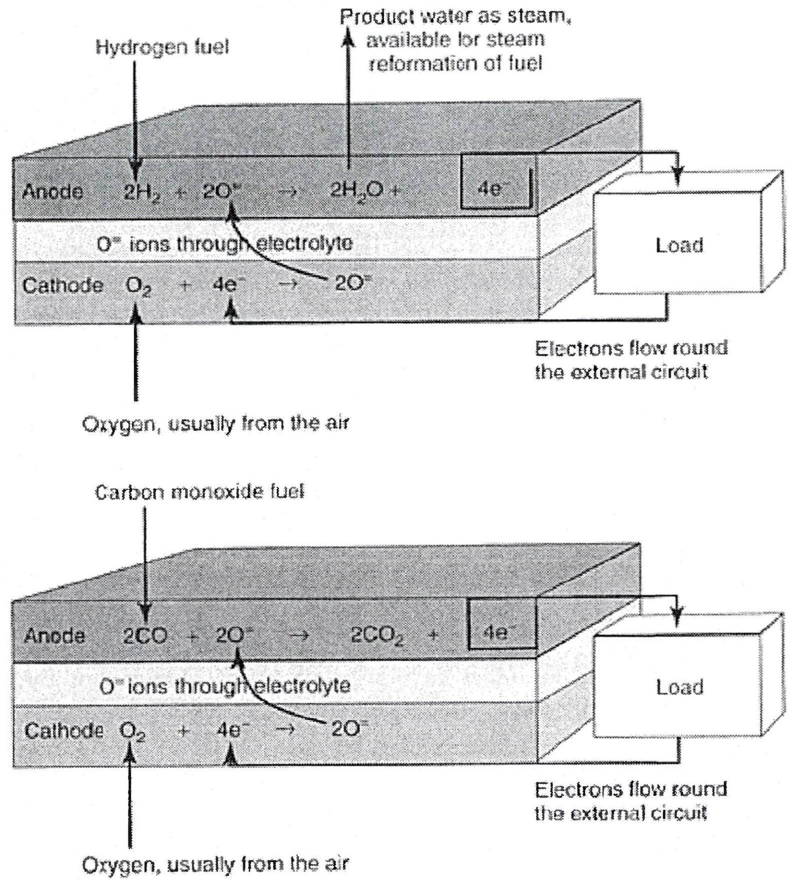


Figure H.2: SOFC Composition [60]

H.4 Fuel Cell Technology Comparison

Table H.2 demonstrates the various fuel cells and their normal operating temperature ranges.

Table H.2: Fuel Cell Temperature Comparison [58, 59, 60]

Fuel Cell Type	Mobile Ion	Operating Temperature
Alkaline Fuel Cell (AFC)	OH^-	50 - 200ºC
Direct Methanol Fuel Cell (DMFC)	H^+	20 - 90ºC
Molten Carbonate Fuel Cell (MCFC)	CO_3^{2-}	600 - 700ºC
Phosphoric Acid Fuel Cell (PAFC)	H^+	220ºC *
Polymer Electrolyte Membrane Fuel Cell (PEMC)	H^+	30 - 100ºC
Solid Oxide Fuel Cell (SOFC)	O^{2-}	700 - 1000ºC
Tabular Solid Oxide Fuel Cell (TSOFC)	O^{2-}	1000ºC
Intermediate Temperature SOFC (ITSOFC)	O^{2-}	600-800°C

Note: * denotes approximate value

It can be seen that the SOFC derivatives and the MCFC have the highest range of operating temperatures which is why they are commonly referred to as high temperature fuel cells. This higher temperature allows the high temperature fuel cells to increase the rate of reaction without the use of a catalyst. The remaining fuel cells are known as low temperature fuel cells which commonly employ expensive catalysts for optimal operation. Figures H.3 and H.4 demonstrate typical performance criteria of the various fuel cells for comparison.

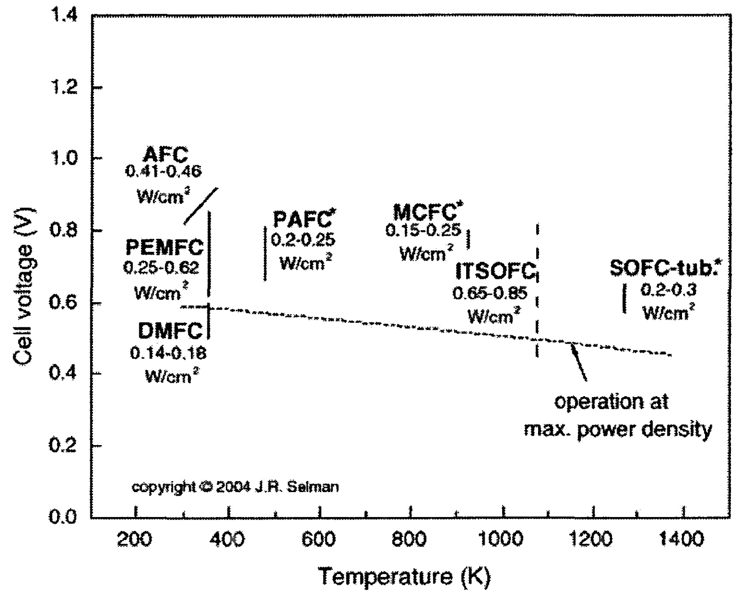


Figure H.3: Typical Performance Ranges of Different Types of Fuel Cells [61]

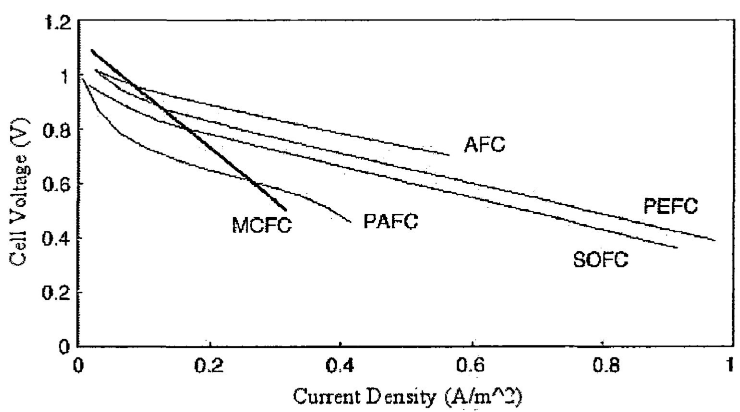


Figure H.4: Polarization Curves for Various H-O Fuel Cells [58]

Figure H.4 demonstrates a polarization curve for multiple H-O fuel cells as explored in Section 8.2. This polarization curve demonstrates the averaged performance of the fuel cells while operating within the threshold of normal operation. The MCFC demonstrates a linear dependency between current density and voltage and the polarization curve also has the steepest slope. Figure H.4 indicates that the MCFC has the lowest current densities for high power ranges and that the MCFC cell has a high efficiency while operating within the limited range of low current densities (up to 150 $\frac{mA}{cm^2}$). Figure H.3 shows the range of electrical efficiency and power densities for the various types of fuel cells as a function of operating temperature [61]. Figure H.3 demonstrates for the individually labeled fuel cell types the correstponding output voltage range for a given operational temperature. The voltage under load is not overly dependent on the operating temperature and thus fuel cell type independent. The high temperature SOFC and MCFCs operate closer to their ideal potential due to the lower ohmic resistance unlike the PAFC, AFC, PEMFC, and DMFC. The high temperature fuel cells also operate with more rapid kinetic reactions. These provide the high temperature fuel cells with a higher electrical efficiency compared to the lower temperature fuel cells. The PEMFC and ITSOFC both have high power densities which denotes future commercial promise. The MCFC lacks in power density as it is significantly below its competitors. The MCFC has a potential to have a much higher power density which has been shown by recent testing and internal restructuring [61].

Figure H.5 demonstrates the thickness of the electrodes and electrolytes for multiple hydrogen-oxygen fuel cells from Section 8.2.

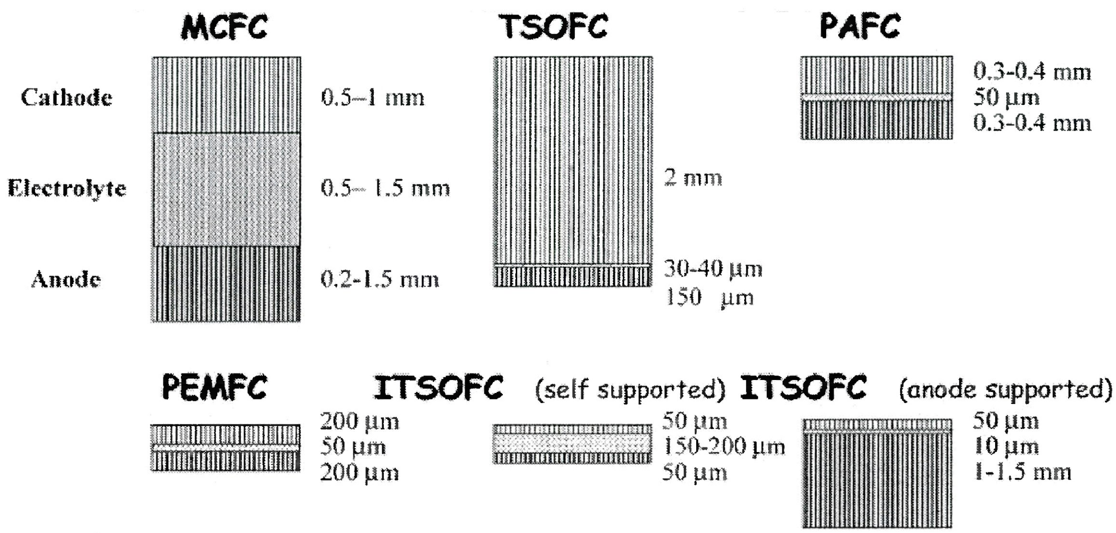


Figure H.5: Thickness of Electrodes and Electrolytes for Various H-O Fuel Cells [58]

In the MCFC a thick electrolyte has the capability to neutralize the phenomenon of NiO cathode dissolution in molten carbonates. This NiO cathode dissolution may lead to short circuiting between the electrodes. Even though the electrolyte is thicker the ohmic drop in the MCFC remains acceptable as the molten salts used exhibit a high level of conductance. Due to these factors the MCFC has the thickets electrolyte and one of the thickets electrodes-electrolyte assemblies. Due to the low power densities, thick electrodes-electrolyte assembly, and precise temperature and CO_2 control the MCFC is almost exclusively designed for stationary power generators [58]. These larger electrodes also allow the chemical reactions to exhibit increased rates of reaction which increases current capabilities. Currently the SOFC is the main competitor in stationary generation fuel cell market. The MCFC faces competition from both the SOFC and traditional power generating plants. The most attractive application of the MCFC is a medium scale stationary unit in the range of 100 kW to 10 MW. Figure H.6 demonstrates the voltage loss contribution for the various fuel cells being investigated.

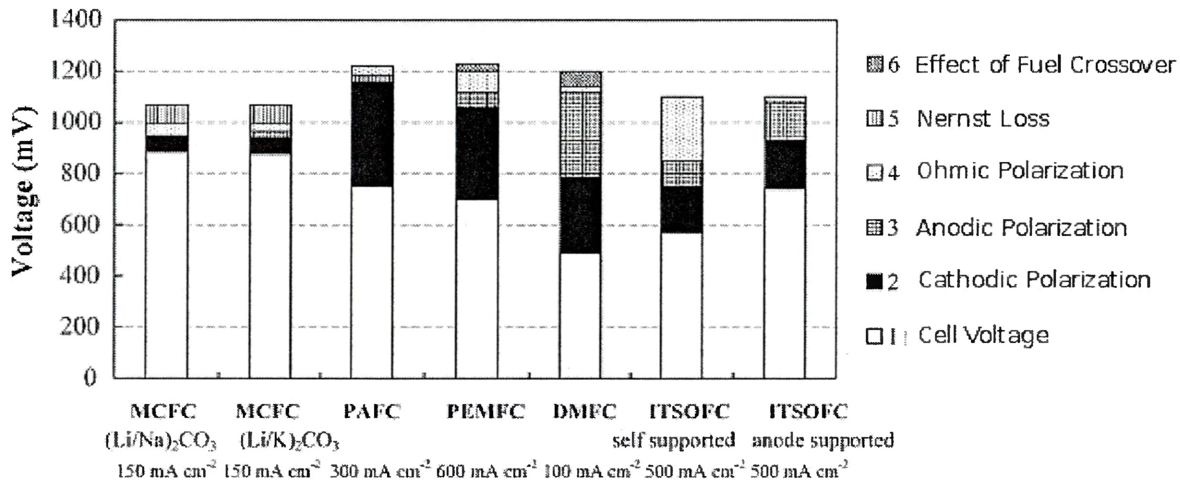


Figure H.6: Voltage Loss Contributions for Various Fuel Cells [58]

The fuel cells shown in Figure H.6 suffer from sluggish kinetics of oxygen reduction. The cathode operation in the PAFC, PEMFC, and SOFC are better than that of the MCFC due to construction techniques that are not possible with a molten carbonate electrolyte. Overall the voltage losses of the MCFC are minimal compared to the other fuel cell types.

Although the MCFC does require some further development it already has some benefits over the PEMFC and SOFC. These benefits are outlined by the following:

- The MCFC's operating temperature is optimal for internal reforming and utilizing the heat produced for other purposes. The PEMFC operates at too low of a temperature to allow this and the SOFC operates at too high of a temperature to do so in a cost effective manner

- The PEMFC requires the use of a noble catalyst that the MCFC and SOFC do not require
- The MCFC utilizes a CO based fuel type which is readily accesssible
- The PEMFC utilizes a rare earth metal Pt catalyst which drastically increases the cost of the unit
- The PEMFC has an electrical efficiency 36-38% whereas the MCFC is 45-50% (without heat reuse)
- The underlying technology of the MCFC is more advanced than the SOFC
- The MCFC currently has poor current density. As a result the cell voltage drops quickly as the current density increases. MCFC's are currently being furthur researched and developed in an attempt to eleviate this concern
- The liquid molten carbonate in the MCFC allows for a lower contact resistance and gas sealing abilities when compared to the SOFC
- MCFC and SOFCs could be utilized alongside with CO_2 separation from other energy production sources

There are many design trade offs between the MCFC, SOFC, and PEMFC. The MCFC is currently becoming the optimal fuel cell for stationary power and heat co-generation units. The SOFC and PMFC have the potential to be developed using different and cheaper material and design innovations.

H.5 Analysis for Implementation

For the implementation of the fuel cell in a power system the AFC, DMFC, PAFC, and PEMC are not applicable as they do not have a high enough power density. The high temperature fuel cells have many advantages in applications in a power system. The electrode reactions occur faster when the fuel cell is operated at higher temperatures and these fuel cells do not typically require noble metal catalysts which significantly decreases the cost of production. To compensate for a lower operational efficiency the high-temperature exit gasses can be used for localized heating or electrical generation through heat engines. The high temperature fuel cells also have the benefit of being able to operate on a larger variety of fuel sources and are able to out produce the other fuel cell types for large scale implementation. The MCFC requires CO_2 which could possibly be sequestered from hydrocarbon facilities in a hybrid power system. Current SOFC and MCFC technologies could potentially be utilized in remote systems or for distributed generation to run in parallel with existing grid infrastructure. Table H.3 compares some commercial values for various fuel cell developments. Acumentrics and FuelCell Energy are both members of the United States Department of Energy (DOE) Solid State Energy Conversion Alliance (SECA) programme which focuses on researching cost effective alternatives to power generation via fuel cell technology. The 2010 Phase III target goals of SECA are to increase the general electrical efficiency of fuel cells from 40 to 45%.

Table H.3: Commercial Fuel Cell Development [62, 63, 64, 65]

Company	Model	Fuel Cell Type	Rated Output	Electrical Efficiency	Environ-mental Temp.	Lifetime (years)	Stack Replacement	Cost (USD)
Bloom Energy	ES-5000 [62]	SOFC	100 kW	> 50%	0ºC to 40ºC	10	twice over lifetime	$750,000*
Ceramic Fuel Cells Ltd.	BlueGEN [63]	SOFC	0 - 2 kW	60% *	1ºC to 45ºC	15	[illegible]	$8,000*
Acumentrics	CP-SOFC-5000 [64]	TSOFC	5kW peak 3kW nom.	30-50%	-20ºC to 50ºC	10-15		$175,000*
FuelCell Energy	DFC3000 [65]	MCFC	2.8 kW to 50 MW	47%				

Note: * denotes approximate value

Determining the cost benefit analysis of a remote power system utilizing fuel cells as the primary means of power generation is difficult as there is significant variance of ambient temperature, elevation, means of accessibility, size of power requirements, and fuel prices from location to location. The commercial fuel cells of today typically operate from near sub zero to 45ºC. This temperature range dictates that fuel cells cannot be implemented in a Northern latitude without significant efficiency loss due to room heating requirements for general operation. Typical distributed generation infrastructure is reliant upon a direct connection to a natural gas line which is unobtainable in a remote or northern community which negatively affects the cost of power generation without this median. To make use of possible local fuel sources to decrease transportation costs of hydrocarbons (such as bio-fuel) significant capital must be expended to produce these alternative fuels on site. Due to the variance in localized capabilities it is not possible to ascertain the amount of capital required develop this so the analysis will utilize an approximate cost of diesel that includes the cost of transportation and that of the raw fuel. The present day worth of diesel is difficult to develop and due to the volatility of the hydrocarbon based markets the future worth is equally difficult to predict. Of the 26 remote communities in Ontario (ON), 23 are accessible year round by air, 3 by permanent roads, and roughly 22 via ice roads for roughly six to eight weeks during the peak of the winter season. However, with the changing climate the availability of these ice roads has greatly decreased which creates costly difficulties. Only one remote community in ON has large scale shipping capabilities.

[57] performed an economical evaluation of a 5 kW SOFC power system implementation. As the majority of commercial readily implementable fuel cell systems for large scale power generation are SOFC at present day the cost benefit analysis will be performed using the methodology outlined by [57]. Overall most SOFC applications are still in the experimental stages of development which make commercial data unavailable and approximate at best [57]. The fundamental formula used to calculate total cost from [57] is given by Equation 1.

$$C_t = C_c + C_m + C_f \tag{1}$$

Variable	Variable Description
C_t	Total Cost
C_c	Capital Cost (Cost of Investment)
C_m	Cost of Maintenance
C_f	Cost of Operation

After extensive simplification of the derivations provided by [57] the resulting formula for total annual cost is modelled by Equation 2.

$$C_t = \frac{\left[\frac{C_{fc} i_r (1+i_r)^n}{((1+i_r)^n - 1)} + C_m\right]}{\left[1 - \frac{E_{ep}}{\eta(E_{ec}+E_{es}+E_{th})}\right]} \tag{2}$$

Variable	Variable Description	Variable	Variable Description
C_{fc}	Annual Investment Cost	E_{es}	Electrical Energy Sold
C_m	Cost of Maintenance	E_{th}	Electrical Energy Thermal
C_t	Total Annual Cost	i_r	Annual Interest Rate (%)
E_{ec}	Electrical Energy Consumed	n	Lifetime (years)
E_{ep}	Electrical Energy Produced	η	Electrical Efficiency

In the economic analysis by [57] two financial metrics, Net Present Value (NPV) and Internal Rate of Return (IRR), were used to determine the feasibility of the fuel cell implementation. The NPV is determined by the net yearly present value of the future cash flows returned by a project less the capital cost [57]. The yearly benefit is modelled by Equation 3 and the NPV is modelled by Equation 4.

$$B = E_{es}\left(\gamma_{es} - \gamma_p\right) + E_{ec}\left(\gamma_{ec} - \gamma_p\right) + E_{th}\left(\gamma_{th} - \gamma_p\right) \tag{3}$$

Variable	Variable Description
γ_{ec}	Electrical Buying Price
γ_{es}	Electrical Selling Price
γ_{th}	Thermal Buying Price
γ_{p}	Unit Cost of Produced Energy
B	Yearly Benefit

$$NPV = \left(\sum_{t=1}^{n} \frac{B}{(1+i_r)^t} \right) \qquad \begin{cases} \text{NPV} > 0 & \textit{Accept} \\ \text{Else} & \textit{Reject} \end{cases} \tag{4}$$

[57] found that for the 5 kW SOFC power system considering the current state of technology and data from Table H.4 that the NPV was less than 0. This meant that according to the analysis of the system that the implementation of the 5 kW fuel cell was impractical.

Table H.4: Fuel Cell Economic Data [57]

Reference Data				Model Data			
Economic Data		Technical Data		Economic Data		Technical Data	
C_{fc}($)	4000	P_e (kW)	3.3	C_{fc}($)		P_e (kW)	
C_c($)	923.9	P_{th} (kW)	2.7	C_c($)		P_e (kW)	
C_f($)	4845	E_{ec} (kWh)	6338	C_f($)		E_{ec} (kWh)	
C_m($)	400	E_{es} (kWh)	21,988	C_m($)		E_{es} (kWh)	
γ_{ng}($/kWh)	0.065	E_{th} (kWh)	16,957	γ_{diesel}($/kWh)		E_{th} (kWh)	
γ_{p}($/kWh)	0.136	E_{ep} (kWh)	28,327	γ_{p}($/kWh)		E_{ep} (kWh)	
γ_{th}($/kWh)	0.05	E_p (kWh)	45,284	γ_{th}($/kWh)		E_p (kWh)	
γ_{es}($/kWh)	0.16	n (year)	5	γ_{es}($/kWh)		n (year)	
γ_{ec}($/kWh)	0.13			γ_{ec}($/kWh)			
i_r	5%			i_r			
NPV ($)-4239				NPV ($)			

At this moment in time the analysis of fuel cell implementation into the energy portfolio of the community was not completed. This was due to poor results in technical feasibility both due to the colder climate and general large scale implementation, lack of time to complete the analysis, lack of commercial data, and relative immaturity of the fuel cell technology. It is believed that in the future fuel cells may be a viable option for utility grade power however at this time in the scope of this thesis it is deemed not technically feasible.
[57] provided a percentage range for the maintence cost (C_m) of the system to be between 4 and 10%. Due to circumstances it is assumed that for the remote applications that 10% would be a valid The analysis using the developed model does not take into account the reliability of the generating fuel cell units. The only criteria that is met is the rated output of the community. Depending on the community size and power requirements the stacks may be organized and controlled in subunits to account for various power levels such as peak load and hourly base load to increase system reliability and operational efficiency.

Due to the poor IRR and NPV of the modelled system coupled with poor operational capabilities within the localized ambient temperature ranges the fuel cell is presently not a valid technology to produce power on a remote system in Northern Ontario. The research currently being done in the field of fuel cell technology, with a particular interest on an implementable MCFC design, dictates that the fuel cell may one day be used for large scale power generation in remote communities. Gradual changes in regulatory policies, market energy prices, and improved efficiency of fuel cell technologies will affect how and if the fuel cell can be implemented in a remote community in Northern ON in the future.

Appendix I - Solar Terminology

Appendix I provides additional information as it relates to the SECS introduced in Chapter 6 with a focus on solar energy and astronomical terminology.

Solar and solar based energies are created by the sun and how it interacts with the earth. To have a complete understanding of how the earth interacts with the sun a few fundamental astronomical principles are introduced. These topics can be summarized by two commonly used co-ordinate systems which consist of the equatorial and horizon co-ordinate systems. Both of these co-ordinate systems are used to explore the earths' position with respect to the solar system around it which is beneficial for a fundamental understanding of solar energy.

The equatorial co-ordinate system allows a viewer on earth to locate other celestial bodies by utilizing standardized definitions for a reference point which has an associated relative direction. The equatorial co-ordinate system is defined by the celestial sphere, celestial poles, celestial equator, declination, and right ascension. The celestial sphere is a concept in which the earth is the centre of a giant sphere and that all the objects in the night sky are located around the Earth. These objects can be found in a similar manner as with the latitudinal and longitudinal system commonly used for locations on Earth. The celestial poles are the points about which the celestial sphere is rotating and are a projection of the Earth's poles into the celestial sphere. In the Northern hemisphere the North Star, named Polaris, is relatively stationary above the North celestial pole and is used as a reference point. The celestial equator is an imaginary line in the sky that is a projection of the Earth's equator onto the celestial sphere. Declination is the celestial sphere's equivalent of latitude and is the angle above the celestial equator. When the declination is being measured in the direction of the North celestial pole the angle is positive. Conversely, when declination is being measured for locations to the celestial south they are negative angles. The lines of declination are used to determine the position of the Earth with respect to the diurnal circle which is the daily paths taken by celestial objects in the sky. These diurnal paths determine the rising and setting times of various points on the celestial sphere which is dependent upon the declination and latitude. The Right Ascension (RA) is the equivalent to longitude for the celestial sphere. The RA is measured in hours, minutes, seconds and increments in a counter clockwise fashion using the North celestial pole as a reference.

The horizon co-ordinate system allows a viewer on earth to locate other celestial bodies by specifying the direction from the earth to the star. The horizon co-ordinate system is defined by the horizon, zenith, azimuth, and altitude. The horizon is the line or great circle at which the earth would meet the sky if there were no obstructions. The zenith is the point directly overhead the observer and the nadir is the point directly opposite the zenith. The stars at the horizon and at zenith are constantly changing due to the rotation of the earth and the only locations on earth that remain constant are located above the two celestial poles. The direction of the star is determined by the azimuth and altitude. The azimuth angle is the compass heading of the point where an imaginary line connecting the zenith and the star meets the horizon. Similar to a magnetic compass a Northerly azimuth is denoted as zero degrees and increments in a clockwise manner. An imaginary line connects locations of constant azimuth between the zenith and nadir and is analogous to a line of longitude on the earth. Every line of constant azimuth is half of a great circle and the lines of azimuth equal to 0 and 180 degrees form the boundary between the visible and invisible hemispheres which is known as the prime meridian. The celestial poles have no associated azimuth value similar to the magnetic compass. The altitude is the vertical angle of elevation from the horizon to a point on the celestial sphere where the zenith is a reference point of 90 degrees. All locations above the horizon have a positive altitude and are considered to be part of the visible hemisphere. Conversely, all locations that have a negative altitude are considered to be part of the invisible hemisphere.

The ecliptic is a great circle on the celestial sphere that defines the path of the sun over the course of the year. There are four points of importance along the ecliptic which include the solstices and equinoxes. The solstices are the two points on the celestial sphere at which the sun attains its most extreme declinations. The sun obtains its most positive declination at the summer solstice (the first day of summer) and the most negative declination at the winter solstice (the first day of winter). The equinoxes are the two points on the celestial sphere at which the sun crosses the celestial equator. When the sun crosses the celestial equator heading from a negative to positive declination is the vernal equinox (the first day of spring) and the converse is the autumnal equinox (the first day of autumn).

The Earth in constantly rotating about an imaginary axis that passes through the celestial poles. A sidereal day is one complete rotation of the Earth which occurs in 23 hours and 56 minutes. The rotational speed is decreased slightly due to the gravitational effects of the moon on the Earth. Sunrise occurs when the given location on the surface of the Earth passes from the Earth's shadow into the sunlight. The time of the sunrise depends on the latitude of the location and there is no sunrise at the celestial poles during the winter and summer seasons. Noon occurs when the sun crosses the meridian, which happens once per a day, and is consistent between all locations that share the same longitude. The concept of a day is also known as a solar day which is the amount of time between two successive noons. A solar day is 24 hours, or slightly longer than a sidereal day, due to the fact that the earth revolves through about one degree per day relative to the sun (or 4 minutes longer for the 1 degree difference). The solar irradiance at any given location is highest during solar noon which is due to the varying location of the Earth on the ecliptic and durian cycle. The sidereal time at solar noon varies based on the current month.

The seasons on Earth are caused by the Earth being tilted by 23.5 degrees with respect to the orbital plane. When the Northern tip of the pivotal axis is pointed towards the sun there are more than 12 hours of daylight which occurs in the summer. The longest day of the year occurs on the summer solstice, around June 21, which also indicates that with longer hours of sunlight that solar PV will be more efficient during the summer. As a consequence solar irradiation is higher during the summer months. The ability for light and heat to obtain their maximum intensity occurs during the summer as the Sun's rays hit the surface of the earth at an angle of 90 degrees and no shadows are cast. During the summer less of the solar rays are dissipated in the atmosphere due to the angle of entry and the concentrated intensity on a smaller surface area creates more intense heat by products. This is more evident closer to the equator which dictates that solar installations located closer to the equator or at a more Southerly latitude will outperform those in the North. The shortest day of the year occurs on the winter solstice and due to the shortened days during the winter months solar penetration is considerably lower. During the winter months precipitation accumulation and icing is also a concern on solar installations which result from the weather patterns due to the tilt of the Earth's axis.