AMERICAN UNIVERSITY OF BEIRUT

UTILITY SCALE SOLAR PV FOR THE LEBANESE POWER SECTOR: INVESTIGATING THE OPPORTUNITIES OF UTILITY SCALE BATTERY STORAGE

by
AHMAD HUSSEIN DIAB

A thesis
submitted in partial fulfillment of the requirements
for the degree of Master of Science
to the Department of Mechanical Engineering
of the Maroun Semaan Faculty of Engineering and Architecture
at the American University of Beirut

Beirut, Lebanon
May 2018

AMERICAN UNIVERSITY OF BEIRUT

UTILITY SCALE SOLAR PV FOR THE LEBANESE POWER SECTOR: INVESTIGATING THE OPPORTUNITIES OF UTILITY SCALE BATTERY STORAGE

by
AHMAD HUSSEIN DIAB

Approved by:

Dr. Nesreen Gaddar, Professor Department of Mechanical Engineering	Advisor
Dr. Hassan Harajli, Lecturer Department of Economics	Member of Committee
Dr. Rabih Jabr, Professor Department of Electrical and Computer Engineering	Member of Committee
Dr. Saif Al-Qaisi, Assistant Professor Department of Industrial Engineering and Management	Member of Committee

Date of thesis/dissertation defense: May 2, 2018

AMERICAN UNIVERSITY OF BEIRUT

THESIS, DISSERTATION, PROJECT RELEASE FORM

Student Name: Diab Ahmad Hussein
Last First Middle

● Master's Thesis ○ Master's Project ○ Doctoral Dissertation

☑ I authorize the American University of Beirut to: (a) reproduce hard or electronic copies of my thesis, dissertation, or project; (b) include such copies in the archives and digital repositories of the University; and (c) make freely available such copies to third parties for research or educational purposes.

☐ I authorize the American University of Beirut, to: (a) reproduce hard or electronic copies of it; (b) include such copies in the archives and digital repositories of the University; and (c) make freely available such copies to third parties for research or educational purposes after :

One ---- year from the date of submission of my thesis, dissertation, or project.
Two ---- years from the date of submission of my thesis, dissertation, or project.
Three ---- years from the date of submission of my thesis, dissertation, or project.

May 11, 2018

Signature Date

This form is signed when submitting the thesis, dissertation, or project to the University Libraries

ACKNOWLEDGMENTS

I would like to express sincere gratitude to my professors that helped me to write this paper. Namely, Dr. Nesreen Ghaddar who supported me and believed in me, Dr. Saif Al-Qaisi who I have the privilege of calling a close friend and Dr. Rabih Jabr who was a motivation to complete this work.

I can fairly state that this work is a result of Dr. Hassan Harajli's values and morals which empowered me every day and set forth a path to follow. I also thank Nour Baalbaki for devoting the time and energy to support me.

AN ABSTRACT OF THE THESIS OF

Ahmad Hussein Diab for Master of Science
Major: Energy Studies

Title: Utility Scale Solar PV for the Lebanese Power Sector: Investigating the Opportunities of Utility Scale Battery Storage

Given the current status of the Lebanese power system, this paper assesses the opportunity to leapfrog directly to utility-scale solar PV farms, coupled with Li-ion battery storage, as compared to the current plans by the Government of Lebanon that rely mostly on conventional power generation. The continuing and structural supply-demand power deficit in Lebanon has considerable negative social, economic, and environmental implications. With the current decrease in the costs of utility-scale solar photovoltaic (PV) systems and lithium-ion batteries, an opportunity presents itself to fill this supply-demand deficit. In this paper, the Lebanese power system is studied, modeled and projected to the year 2020.

Different scenarios are built and compared in order to study the technical and economic feasibility of grid-connected PV systems coupled with large-scale lithium-ion battery energy storage systems to achieve an overall more reliable and adequate power system. Simulations are run using Homer pro to optimize for the lowest cost of electricity. Furthermore, additional benefits of the renewable energy system, such as its capacity value and impact on investment deferral are studied, calculated and discussed. A cost-benefit analysis is then applied to compare the different systems and incorporate benefits that are not captured by the levelized cost of electricity (LCOE) metric. The results show that incorporating grid-connected utility-scale solar PV plants coupled with battery energy storage systems can decrease the overall LCOE of the best-case conventional Lebanese power system (based on natural gas) from an average of $c9/kWh to $c8/kWh. Furthermore, an economic limit of approximately 30% solar PV penetration has been calculated due to the current load profile of the Lebanese economy, beyond which, any further solar PV penetration will yield excessive curtailment of solar PV, undermining the economics of the technology.

Sensitivity analysis is undertaken while adopting various values for the cost of natural gas and battery storage. Results confirmed the presence of the economic limit of solar penetration under the current Lebanese load profile. In addition, it was found that utilizing a battery energy storage system having a capacity of four hours of average load provides various technical benefits that should be quantified when undergoing capacity expansion planning. Enhanced grid flexibility was also seen as a limiting factor for increased penetration of variable generation.

Based on these results, the research strongly recommends the establishment of the National Regulatory Authority that can systematically model the power system and populate its generating sources in accordance with the greatest technical, economic, and environmental benefits, as well as regulate and optimize the power system's operation at any given time.

CONTENTS

ACKNOWLEDGMENTS iii

AN ABSTRACT OF THE THESIS OF vi

LIST OF ILLUSTRATIONS ix

LIST OF TABLES xi

Chapter

1. INTRODUCTION 1

2. THE CURRENT LEBANESE POWER SYSTEM AND LITERATURE REVIEW 3

2.1 Overview of The Power Sector 3

2.2 Economic and social impacts 6

2.3 Environmental impacts 9

2.4 Recent updates and future plans 11

3. SOLAR PV - BESS AS AN ALTERNATIVE AND LITERATURE REVIEW 16

3.1 Utility Scale PV Systems Review 16

3.1.1 Technology Overview and Description 16

3.1.2 Limitations and Intermittency Problem 20

3.1.3 Cost Study for Utility Scale Solar PV – International and Local 25

3.2 Utility Scale Battery Energy Storage Systems Review 31

3.2.1 Technology Overview and Description 31

3.2.2 Cost Study for Utility Scale Storage - International 36

3.3 Literature Review on PV-Battery Systems 43

3.4 Description of the Different Architectures of Grid Connected PV-Battery Storage 46

3.5 Main Benefits of PV Plus Storage 47

3.5.1 Provision of Ancillary Services 47

3.5.2 T&D Infrastructure Upgrade Investment Deferral 50
3.5.3 Capacity Value 53
4. METHODOLOGY 56
4.1 Method Statement 56
4.2 Simulation Software 57
4.3 Projecting the Lebanese electricity demand 57
5. SCENARIOS 59
5.1 Limitations 62
5.2 Scenario One 62
5.3 Scenario Two 63
5.4 Scenario Three 65
6. RESULTS AND DISCUSSIONS 67
6.1 Scenario One results 67
6.2 Scenario Two results 68
6.3 Scenario Three results 69
6.4 Summary of results 71
6.5 Discussion 72
7. B/C ANALYSIS 84
7.1 Calculating the Capacity Value 84
7.2 Energy Revenue 87
7.4 Sensitivity analysis 89
7.4.1 Varying the costs of natural gas and BESS 89
7.4.2 Designing for four hours of storage 92
8. CONCLUSIONS AND POLICY RECOMMENDATIONS 96
BIBLIOGRAPHY 101

LIST OF ILLUSTRATIONS

Figure Page

Figure 1: Schematic of the HV power lines and power plants in Lebanon (CDR, 2015) 4
Figure 2: Electricity rationing vs use of generators (Akkaya et al., 2009) 5
Figure 3: Energy consumption and GDP – Lebanon (Dagher & Yacoubian, 2012) 8
Figure 4: LCA results of 1 kWh of delivered energy from the Lebanese versus European electricity (El-Fadel et al., 2010) 10
Figure 5: Solar PV uptake in Lebanon 2010 – 2016 (DREG, 2017) 12
Figure 6: Summary of the 2020 targets by NREAP to reach 12% renewable energy integration – source: ((LCEC), 2016) 13
Figure 7: Global solar PV capacity and annual additions (Fraunhofer Institute for Solar Energy Systems, 2017) 17
Figure 8: The photelectric effect applied on a PV module (Stion, 2018) 17
Figure 9: Utility scale PV system architecture and components (Shiva Kumar & Sudhakar, 2015) 18
Figure 11: Potential of solar PV in Lebanon (MoE & UNDP, 2014) 20
Figure 10: GHI for Lebanon(Atlas) 20
Figure 13: Load profile and Solar PV generation profile on a typical day in May 21
Figure 14: Load profile and Solar PV generation profile on a typical day in January ... 22
Figure 15: Increased economic carrying capacity either by decrease cost of PV or increased flexibility (Paul Denholm et al., 2016) 24
Figure 16: Learning rate of the PV module 25
Figure 17: LCOE from utility-scale solar PV projects - global weighted average and range(IRENA, 2018) 27
Figure 18: Solar PV LCOE 2009-2017 (Lazard, 2017) 28
Figure 19: Components and operating principle of a Li-ion battery cell 32
Figure 20: Comparison of different Li-ion chemistries (IRENA, 2017) 32
Figure 21: Qualitative comparison of different Li-ion chemistries from literature (Hesse, Schimpe, Kucevic, & Jossen, 2017) 33
Figure 22: S-curve for energy storage technologies (IHS, 2016) 34
Figure 23: Schematic drawing of a Li-ion battery storage system (Hesse et al., 2017) . 36
Figure 24: Price forecast for Li-ion batteries based on market analysts 37
Figure 25: DC-coupled configuration for a solar PV plus BESS plant (Paul Denholm et al., 2017) 47
Figure 26: BESS ancillary service - peak shaving (Motors, 2016) 48
Figure 27: BESS ancillary service - frequency regulation (Motors, 2016) 49
Figure 28: T&D investment deferral due to installation of BESS (Motors, 2016)......... 51
Figure 29: Weighted average annual T&D avoided cost in California (Eyer, 2099) 52
Figure 30: Average daily load profile in 2020 58
Figure 31: Schematic of Scenario One in Homer 63

Figure 32: Schematic of Scenario Two in Homer 65
Figure 33: Schematic of Scenario Three in Homer 66
Figure 34: Scenario One - monthly average electric production 67
Figure 35: Scenario Two - monthly average electric production 68
Figure 36: Scenario Three - monthly average electric production 70
Figure 37: Scenario Three - BESS SOC per month... 71
Figure 38: Load duration curve in 2020 72
Figure 39: Scenario One - yearly load and generation profile....................................... 73
Figure 40: Scenario Two - January load and generation profile.................................... 75
Figure 41: Scenario Two - April load and generation profile.. 75
Figure 42: Scenario Two - August load and generation profile 76
Figure 43: Scenario Two - November load and generation profile 76
Figure 44: Scenario Two - load profile with conventional power generators 78
Figure 45: Scenario Three – load and generation profile of a typical week in 2020...... 79
Figure 46: Scenario Three - January load profile with solar PV and BESS.................. 80
Figure 47: Scenario Three - April load profile with solar PV and BESS....................... 81
Figure 48: Scenario Three - August load profile with solar PV and BESS.................... 81
Figure 49: Scenario Three - November load profile with solar PV and BESS 82
Figure 50: Load duration curves and ELCC for Scenario Two...................................... 85
Figure 51: Load duration curves and ELCC for Scenario Three................................... 86
Figure 52: B/C ratio of the systems in Scenarios Two and Three 89
Figure 53: Sensitivity case 4 load and generation profile.. 93
Figure 54: Load duration curves and ELCC for sensitivity case 4................................ 95

LIST OF TABLES

Table Page

Table 1: Global weighted average LCOE decline 2010-2017 (IRENA, 2018) 29
Table 2: Current and projected LCOEs for utility scale solar PV plants in Lebanon..... 31
Table 3: Characteristics of a general Li-ion battery 35
Table 4: Price forecast of utility scale L-ion battery energy storage systems 42
Table 5: The main configurations of grid-tied solar PV plus battery storage (Paul Denholm et al., 2017) 46
Table 6: Main grid services and benefits of grid connected BESS 49
Table 7: Main simulation and financial parameters and constraints 60
Table 8: CCGT operational parameters 61
Table 9: OCGT operational parameters 61
Table 10: Monthly GHI data 63
Table 11: Input parameters for the grid connected solar PV systems 64
Table 12: Input Parameters of BESS 66
Table 13: Summary of the results for the three simulations and scenarios 71
Table 14: Results comparison between Scenario Two and Scenario Three 83
Table 15: Sensitivity analysis cases 90
Table 16: Simulation results of sensitivity cases 90
Table 17: Simulation results of sensitivity case 4 92

CHAPTER 1
INTRODUCTION

Lebanon's energy use sector is in a drastic condition and has been unable to recover and make considerable advancement since the Lebanese civil war. The issue that vividly stands out first is the large gap between supply and demand in the electricity sector; the Lebanese electricity sector (LES) is facing aging infrastructure and running on outdated sources of supply and generation plants that are either not being supplied with their optimal primary energy resource or are running past their recommended design lifetime. Further, there are major delays and bottlenecks in development and legislative action hindering and preventing any chance of true advancement and reform (G. Bassil, 2010; Bouri & El Assad, 2016; Khodr & Uherova Hasbani, 2013).

In terms of sustainability, the energy sector is characterized by a weak performance originating from lack of competence and security mainly due to a low diversity index, poor operation and a deficit in supply (El-Fadel et al., 2010). Lebanon is a country rich in its renewable energy resources yet does not make good use of it. The country mainly relies on the import of oil and fossil fuels in order to generate its energy(Ibrahim, Fardoun, Younes, & Louahlia-Gualous, 2013).

A considerable bunch of the energy sector's legislative, institutional and infrastructure framework date back to the 1950's. The sector lacks applied policy measures to guide it and a solid independent institution that links research with policy formation (Khodr & Uherova Hasbani, 2013). Furthermore, there is an absence of a true political will for reformation and a lack of qualified and trained personnel at the state-owned utility EDL. Private diesel generators are being used under the control and intervention of private individuals and form an added cost on the Lebanese citizen who wishes a continuous supply of power.

Under the umbrella of sustainable energy transition, Lebanon should consider the current situation of its power sector as an opportunity for sustainable energy reform. Having a considerable solar resource and vast land areas that are unoccupied and unsuitable for vegetation and farming, the country can capitalize on its natural resources in order to expedite its sustainable development and transform its deteriorating power sector. In this paper, we study and model utility scale solar PV plants and grid connected battery energy storage systems as supporting technologies for the sustainable energy transition in Lebanon and simulate different configurations for the power system in order to undertake a comparative analysis.

Chapter 2 describes the current power system in detail while highlighting the subsequent economic, social and environmental impacts it poses on the country. Chapter 3 presents a review and description on utility scale solar PV plants and grid connected battery energy storage system (BESS) while forecasting their costs and describing their limitations and benefits when coupled together. Chapter 4 states the methodology and describes the simulation software used. Chapter 5 presents the modeled scenarios with the input parameters to the simulation software. In Chapter 6 the results of the simulations are stated and discussed with a comparative analysis. We undertake a benefit to cost analysis in Chapter 7 and run a sensitivity analysis to examine and compare our results. The conclusion along with policy recommendations are presented in chapter 8.

CHAPTER 2
THE CURRENT LEBANESE POWER SYSTEM AND LITERATURE REVIEW

2.1 Overview of The Power Sector

As of 2017, the maximum generation capacity available from the local generation plants was 1,800 MW with a total available capacity of 2,300 MW when considering the rented power ships that have a total power capacity of 385 MW and the power imported from the neighboring country having a 115 MW power capacity. The technical losses associated with the transmission and distribution network amount to 13% and result in a decrease in the maximum supplied power capacity to 2,000 MW. The power system also witnesses an outstanding 18% of non-technical losses mainly due to uncollected bills and illegal connections. The peak power demand is estimated to reach 3,450 MW in 2018 yielding a 1,450 MW of supply deficit (CoM, 2018).

The power generation units are split into HFO-fired steam turbines at Jieh, Zouk and Hraycheh, diesel-fired combined cycle gas turbines (CCGT) at Zahrani and Beddawi and diesel-fired open cycle gas turbines (OCGT) at Sour and Baalbek. Some of the power plants are running past their design life with the latest retirement date, without considering recent plant extensions, being in the year 2022 (EDF, 2008). The current average cost of generating one unit of energy and delivering it to the consumer through the T&D network is 16.5 US cents/kWh considering the price a fuel at 65 $/barrel (CoM, 2018).

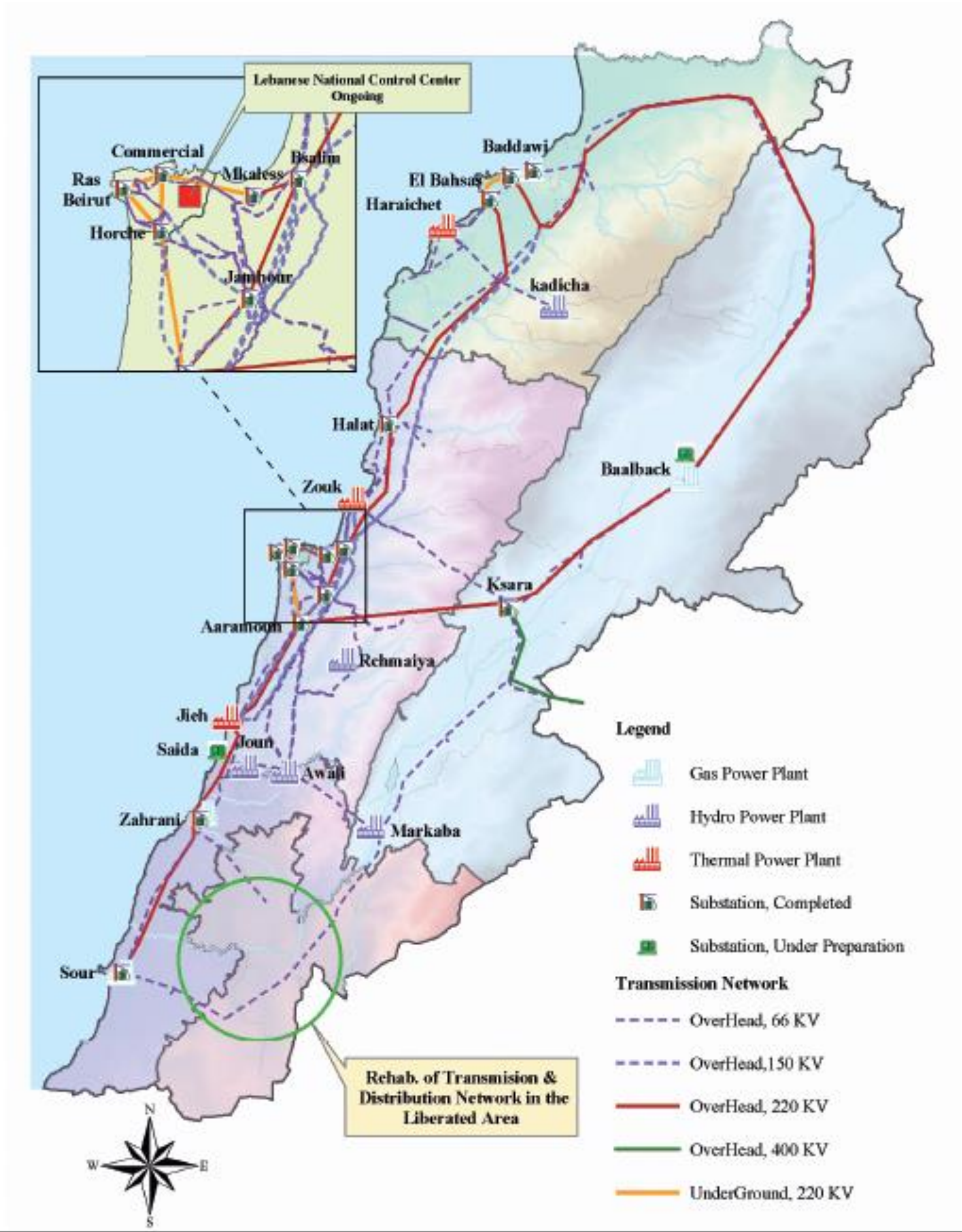

Figure 1: Schematic of the HV power lines and power plants in Lebanon (CDR, 2015)

The supply-demand power deficit drives people to make use of self or community owned diesel generators with an estimated ratio of one-third of all electricity produced coming from diesel generators leading to an incurred cost of diesel generators, oil and maintenance (Akkaya, Junge, & Mansour, 2009).

The lack of a reliable, affordable and secure energy source results in a decrease of the overall living quality. Access to energy is a basic need that should be easily attainable to any citizen. The establishment of independent generator companies that distribute electricity on their own grid operates in the so called “grey economy”, thus in order to attain 24 hours of electricity supply people are forced to connect to this grey grid. Being an unregulated establishment, the independent generator owners are free to set their own rules and pricing schemes which makes them prone to conflict between each other and the consumers.

It can be clearly seen in the below graph of the surveyed data by the World Bank in 2008 that there exists an inverse relationship between the number of hours of daily utility intermissions and the use of diesel generators (Akkaya et al., 2009):

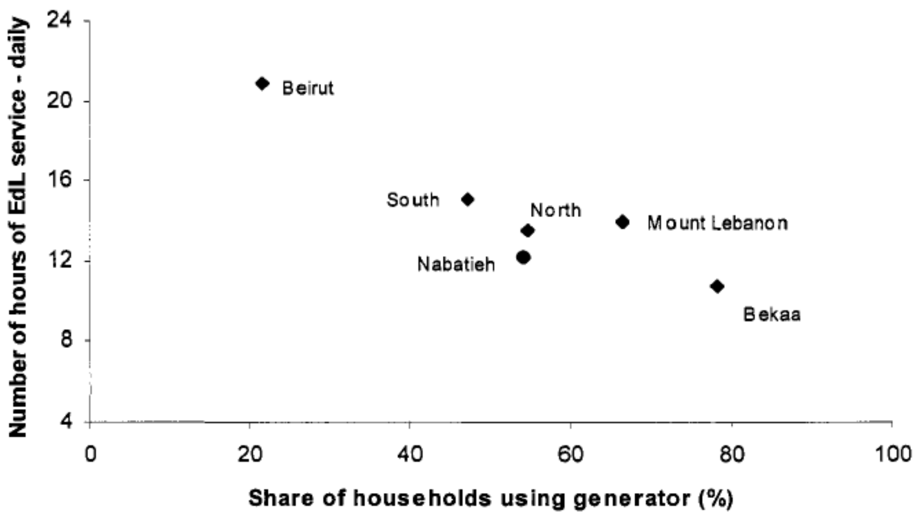

Figure 2: Electricity rationing vs use of generators (Akkaya et al., 2009)

2.2 Economic and social impacts

Due the large gap between the electricity tariff that is paid by the consumer and the generation, transmission and distribution costs that are incurred on the utility company, the government subsidizes the deficit of the utility company by adopting new loans and increasing the government debt. Since 1994, EDL has adopted a fixed tariff policy where domestic consumers pay an average tariff of 9.58 US cents per kWh and small industries pay a rate of 7.63 US cents per kWh (Bouri & El Assad, 2016). Over the period 1992 to 2017 the sum of the public debt including interest that went to subsidize the operation of the utility company is at USD 36 billion and forms approximately 45% of the gross public debt of the government (CoM, 2018). Given that Lebanon has one of the highest debt to GDP ratios in the world, the country cannot afford to continue to spend billions of dollars each year on subsidies for the utility company.

In order to quantify the economic impact of not meeting the electric load the term Value of Lost Load (VOLL) is usually defined and is represented by the cost in USD of not meeting one unit of energy demand. Due to the unavailability of in-depth data and surveys on the effects of grid cut-offs and the uniqueness of the Lebanese case when it comes to the wide adoption of distributed and costly diesel generators, several studies have tried to estimate the VOLL in Lebanon using empirical methods and found the value to be in the range of 200 $/MWh to 2,000 $/MWh with the average value being 700$/MWh (Bouri & El Assad, 2016). Using the average VOLL of 700 $/MWh, Bouri E. & El Assad J. (2016) calculated a total loss for the Lebanese economy over the period 2009 to 2014 that amounted to $23.23 billion (G. Bassil, 2010; Bouri & El Assad, 2016; EDF, 2008).

One of the most discussed topics in the energy-economics nexus field is the causal connections between economic growth and energy consumption. Lee (2005) uses the panel root test, heterogeneous panel co-integration and panel-based correction models on a set of data spanning from the period of 1975 to 2001 for 18 developing countries to study the causality relationship between energy consumption and GDP (economic growth). The study found that there is an evident long-term and short-term causal relationship between energy consumption and economic growth, however, this relationship is a unidirectional one. The finding that in developing countries energy conservation may harm economic growth was deduced (Lee, 2005).

On the other hand, Dagher & Yacoubian (2012) used series data from the period 1980 to 2009 to make use of a bivariate model and apply the Hsia, Granger and TY tests to examine the causality connections between energy consumption and economic growth in Lebanon. The study came to find that there exists a bi-directional relationship between energy consumption and economic growth in both the short term and long term diverging from the findings of Lee (2005) for developing countries. The authors stressed on advancing the security of supply and refuted government policies that advocate decrease in consumption from the demand side. Further, the findings elaborate on the need for increasing supply and its diversity whilst decreasing the dependency on primary energy import through focusing on and prioritizing the use of local energy supply and making use of renewable energy resources to fill the supply gap, thus, leading to the stimulation of economic growth. The work continues to state that the extensive losses in transmission and distribution and the inefficient production increases the viability of installing new local energy supplies as these sources have a double dividend effect by meeting the needed demand and reducing the existing losses and inefficient production. Nonetheless, it is stated that the use of and retrofit to energy efficient technologies and appliances imported from other countries can have a positive influence on economic growth as they can reduce demand without affecting the end user (Dagher & Yacoubian, 2012). The energy consumption – GDP causality for Lebanon is graphed below:

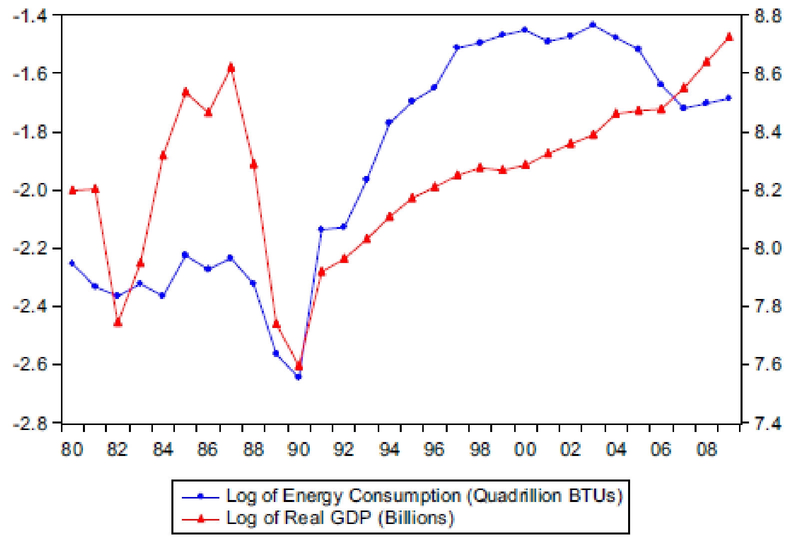

Figure 3: Energy consumption and GDP – Lebanon (Dagher & Yacoubian, 2012)

In the report “The Impact of the Syrian Crises on the Lebanese Power Sector and Priority Recommendations” the impact of the displaced Syrians on electricity consumption is evaluated. The study used different methodologies including gathering and analyzing data, completing site surveys, and calculating power and energy consumption. The main findings regarding the effects of the Syrian crises included the potential impairment of existing transmission cables and distribution stations, an additional 486 MW of additional load leading to further stress on the utility grid that is already operating under a shortage of generating capacity and an increase of damage to the distribution network caused by heretical connections. In congruence with Dagher &

Yacoubian (2012), the report recommends the use of the abundant renewable resources by utilizing technologies such as solar PV, wind and hydro plants and retrofitting old technologies and appliances with more efficient ones. The report also mentions the need to reinforce the current utility transmission and distribution network and to apply a net-metering scheme (AEMS & UNDP, 2017).

Kaygusuz (2012) states that a source of interruption of social development is the “lack of access to modern energy services” (Kaygusuz, 2012). El-Fadel, et al. (2010) advise that intermittent power supply has significant social impacts (El-Fadel et al., 2010). Ibrahim et al. (2013) state that electricity has become a necessity when it comes to social security (Ibrahim et al., 2013).

2.3 Environmental impacts

The most pressing environmental impacts and problems challenging the energy sector are related to climate change and the emittance of GHGs (Kaygusuz, 2012). As Lebanon imports most of its primary energy needs from oil resources, this, as a result, leads to anthropogenic harm done to the environment and the climate. In addition to using fossil fuels as a primary energy resource, the fuel is burnt in generation plants that are running past their design lifetime with high values of inefficiency due to the need of considerable retrofit and maintenance. As a result of the poor operation, an increased value of GHG emissions is witnessed.

In El-Fadel, et al. (2010), the environmental performance of the Lebanese electricity system was studied and investigated using the life cycle assessment method. The inputs to the study included the type of primary energy used, the type of power conversion and generation unit, the efficiency of the generation plants, the transmission and distribution losses and more. The study compares different scenarios for the

Lebanese electricity systems taking the current situation as the base case. For the current scenario (centralized generation by EDL and self-generation from distributed diesel generators) the following main environmental impacts and emissions were quantified per 1 kWh of electricity delivered: 0.0141 kg of SO_2 equivalent (acidification), 1.1 kg of CO_2 equivalent (global warming potential), $1.43e^{-7}$ kg of CFC-11 equivalent (ozone depletion potential (El-Fadel et al., 2010). The LCA for Lebanon is then compared to that of Europe and is graphed below:

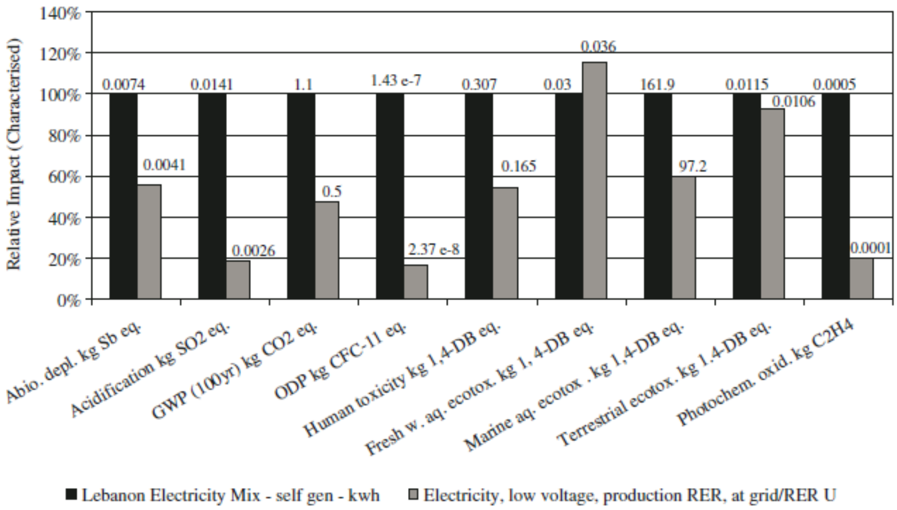

Figure 4: LCA results of 1 kWh of delivered energy from the Lebanese versus European electricity (El-Fadel et al., 2010)

It is evident that the Lebanese electricity system preforms poorly when it comes to environmental criteria having high levels of global warming potential, ozone depletion potential and human and water toxicity. These results can be explicated mainly by the high losses in the transmission and distribution network, the use of oil in electricity generation plants designed to operate on natural gas, the inefficient operation of the generation plants and the use of distributed diesel generators.

2.4 Recent updates and future plans

The 2010 policy paper issued by the Ministry of Energy and Water put forward an action plan to transform the Lebanese power sector into an adequate and reliable one. The paper stresses on the immediate intervention in terms of power generation capacity additions and the uptake of renewable energy technologies (G. Bassil, 2010).

In December 1994, Lebanon ratified the United Nations Framework Convention on Climate Change (UNFCCC) and in 2015 the country presented its Intended National Determined Contributions (INDCs) which consisted of unconditional contributions (without international support) and conditional contributions (with international support). Lebanon plans to meet 15% of the total power and heat demand by 2030 with renewable energy sources under the unconditional target and 20% of the total power and head demand by 2030 under the conditional target (Lebanon, 2015).

Although not in line with schedule of implementation of the 2010 policy paper, over the past 8 years, the country has been witnessing improvements and enhancements in the power system. An exponential uptake in solar PV projects is witnessed since 2010 where only 350 kWp of solar PV capacity was available compared to 23 MW in 2016. This uptake is partly due to technology improvements and cost declines and partly to government incentives in forms of soft loans issued by the central bank (DREG, 2017).

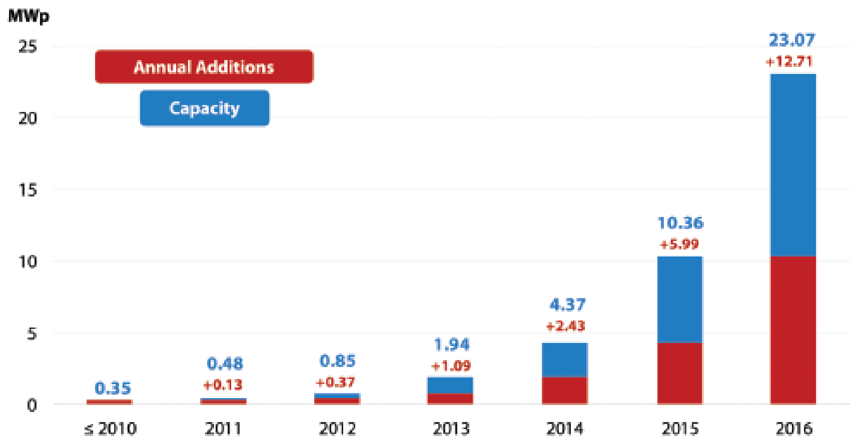

Figure 5: Solar PV uptake in Lebanon 2010 – 2016 (DREG, 2017)

In addition, the government has recently issued a bid for 180 MW of grid connected solar PV projects following a power purchase agreement scheme (Chehab, 2018; Saad, 2018), and signed the first public-private partnership agreement with three companies to procure, install and interconnect a 200 MW wind farm (Star, 2018).

The National Renewable Energy Action Plan (NREAP) set forth in 2016 was prepared by the Lebanese Center for Energy Conservation in order to develop a renewable energy adaptation strategy for the Ministry of Energy and Water so that to reach a renewable energy share of 12% of the total electric and thermal energy consumed in Lebanon by 2020. The technologies to adopt included wind energy, solar PV and concentrated PV (CPV), concentrated solar power (CSP), solar water heaters (SWH), hydroelectric power, geothermal energy and bioenergy ((LCEC), 2016). The distributed shares of each technology are presented in the below table:

Year	2010			2015			2020		
	MW	GWh	ktoe	MW	GWh	ktoe	MW	GWh	ktoe
Wind	-	-	-	-	-	-	200	595.7	128.7
PC, CPV	-	-	-	-	-	-	150.0	240.0	51.8
Distributed PV	-	-	-	-	-	-	100.0	160.0	34.6
CSP	-	-	-	-	-	-	50.0	170.6	36.8
SWH	211,988 m^2	137.8	12.72	413,988 m^2	269.3	58.2	1,053,988 m^2	685.5	148.1
Total hydro	190.0	836.5	181	190.0	836.5	181	331.5	961.9	207.8
Geothermal	-	-	-	-	-	-	1.3	6.0	1.3
Bioenergy	-	-	-	-	-	-	-	771.5	166.6
Total renewable energy	-	974.3	193.72	-	1,105.8	239.2	-	3,591.2	775.7
Total primary energy demand	-	15,934.0	3,438.5	-	22,324.1	4,822.0	-	29,578.7	6,389.0
Target	6.1			5.0			12.1		

Figure 6: Summary of the 2020 targets by NREAP to reach 12% renewable energy integration – source: ((LCEC), 2016)

Having in mind the recently announced utility scale solar PV, Wind and hydroelectric energy projects (LCEC, 2018), the witnessed exponential uptake in distributed solar PV and the 1.08 MW ground source heat pump being implemented (CEDRO, 2017), it can be deduced that Lebanon is on its way to meeting the announced target by 2020.

Recent updates to the power system also include renting power barges having a total capacity of 360 MW with a contract period that ends in 2018, adding to the grid 272 MW of reciprocating engines and a 63 MW combined upgrade for the power plants at Deir Ammar and Zahrani. Other updates that are still in the pipeline and are between the feasibility study phase and project award phase include the rehabilitation of the Zouk power plant and an addition of 235 MW generation capacity, implementing an independent power producer scheme at Salaata and Zahrani to add 500 to 700 MW of generation capacity each and installing floating gasification units along with a costal pipeline to import and distribute natural gas (Ouseiran, 2018).

According to an advisor to the Ministry of Energy and Water in Lebanon, in addition to the critical need of increased generation capacity, the transmission and distribution bottlenecks need to be addressed along with the enhancement of the technical capacity and the human resource skill set of Lebanese National Control Center responsible for the operation of the power system especially with the increased integration of variable renewable energy generation. Furthermore, and in order to reach a fully adequate and reliable power system, the advisor stated a best-case scenario timeline that extends over a period of 6 years in order to implement all the needed projects and rehabilitations that are in the pipeline (Ouseiran, 2018).

Dechezleprêtre, et al. (2009) stated "to catch up, developing countries must either develop the technology by their own means, or acquire it abroad – two costly options." When it comes to sustainability transitions, international transfer of knowledge and technology play a vital role in speeding up the transition process and building a base for utilizing new technology. Dechezleprêtre, et al. (2009) stressed on capacity building as it is a key cause of technology diffusion be it on the national or international level (Dechezleprêtre, Glachant, & Ménière, 2009).

Projects, organizations and international cooperation and agreements are key components in applying sustainable change to developing countries as such institutions have bilateral goals were the developing country is assisted in its sustainability transition and developed countries create new opportunities while satisfying their carbon credits. Projects and grants from the UNDP, soft loans from international finance institutions and specialized funds such as the Green Climate Fund (GCF) are examples of the various tools that could be utilized or adopted.

However, research done by Gaast, et al. (2009) suggests that projects and international interventions in developing countries should focus on the country's specific priorities and needs and take into consideration factors such as existing technology awareness, previous experiences, resistance to innovation and cost sensitivities. This, according to the authors, will ensure true technology transfer and will have a higher impact on the sustainable development of the country (Gaast, Begg, & Flamos, 2009). Furthermore, Markard, et al. (2012) state that building connections, refining methodological approaches and providing further empirical evidence are important issues to tackle when it comes to sustainable development (Markard, Raven, & Truffer, 2012).

It can be deduced that a major reform plan is crucially needed to be implemented encompassing the generation units, transmission and distribution networks and tariff schemes. Considerable research and a considerable number of studies have been done yet the results are not vividly reflected in the policy making process nor accurately applied in implementation procedures. This shows the week linkage and lack of collaboration between policy makers and scientific research and studies or the absence of political will.

CHAPTER 3

SOLAR PV - BESS AS AN ALTERNATIVE AND LITERATURE REVIEW

3.1 Utility Scale PV Systems Review

3.1.1 Technology Overview and Description

This study and research is based on several fundamental concepts, one of which is exquisitely stated in the IRENA's "Renewable Power Generation Costs in 2017" and goes as follows: "Falling renewable power costs signal a real paradigm shift in the competitiveness of different power generation options" (IRENA, 2018).

Utility scale solar PV refers to the generation of bulk power from a solar PV plant and the direct injection into the power grid (Wolfe, 2018). As of 2016, 303 GW of solar PV power were available worldwide with an addition of 75 GW of capacity in 2016 only. Solar PV power contributed to 1.3% of the world electricity consumption in 2016. Over the past decade, an exponential growth is witnessed in the installed capacity of solar PV plants ((Fraunhofer Institute for Solar Energy Systems, 2017; REN21, 2017).

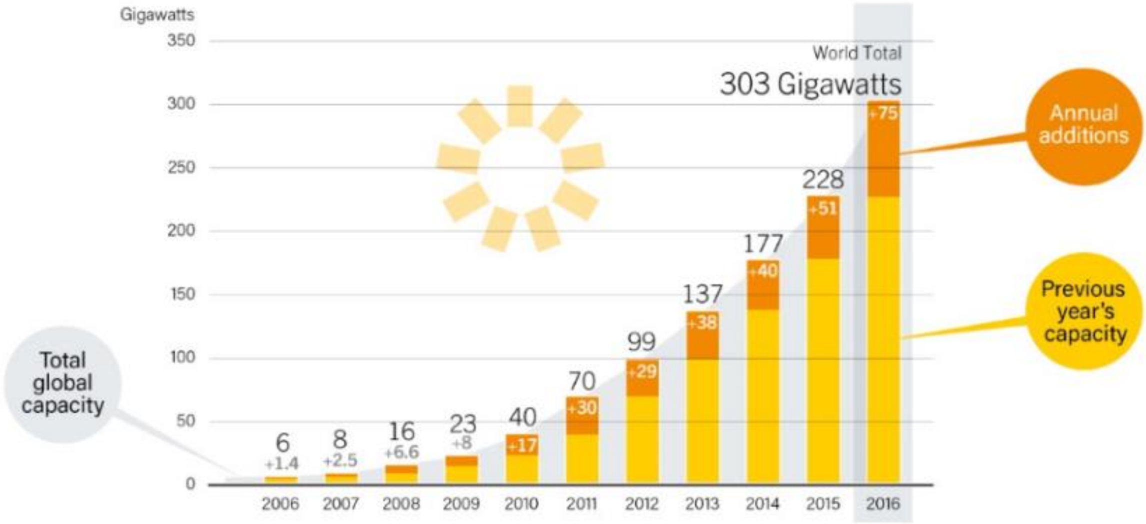

Figure 7: Global solar PV capacity and annual additions (Fraunhofer Institute for Solar Energy Systems, 2017)

The main components of a utility scale PV system include the PV module, the mounting structure, the inverter and power electronics, the transformer and grid interconnection components, electric safety and isolation equipment and the monitoring and control system. The PV module converts the solar irradiation into electric energy by utilizing the basic principles of the photoelectric effect.

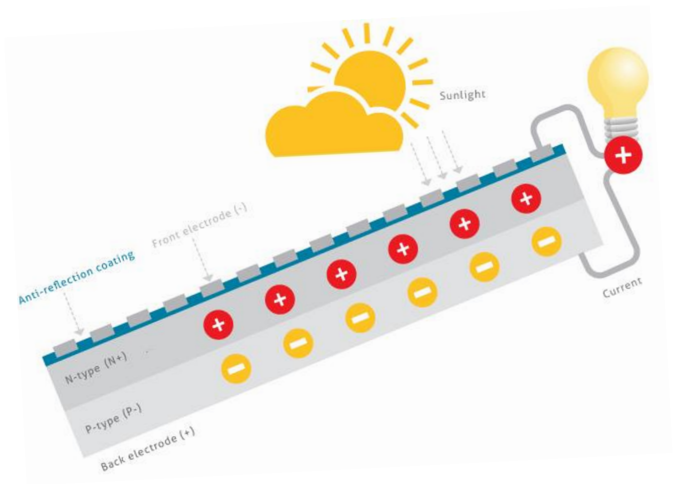

Figure 8: The photelectric effect applied on a PV module (Stion, 2018)

The electricity generated is of a DC nature and needs to be converted into AC in order to be coupled and match the grid electricity, thus strings of PV modules are first connected to safety equipment, such as fuses, surge protection devices and others, and then connected to inverters containing power electronics to operate the DC system on the maximum power point and convert the DC electricity into AC. The AC output lines are then connected to electrical safety and isolation components and then connected to a transformer to step-up the voltage to match that of the grid at the point of common coupling. The transformer is equipped with switch gears and protection devices to ensure safety in operation. A monitoring and control system allows the operator to monitor and maintain the system as well as control the level of power injected into the grid (Shiva Kumar & Sudhakar, 2015). The below figure shows a schematic of a common architecture for utility scale PV systems:

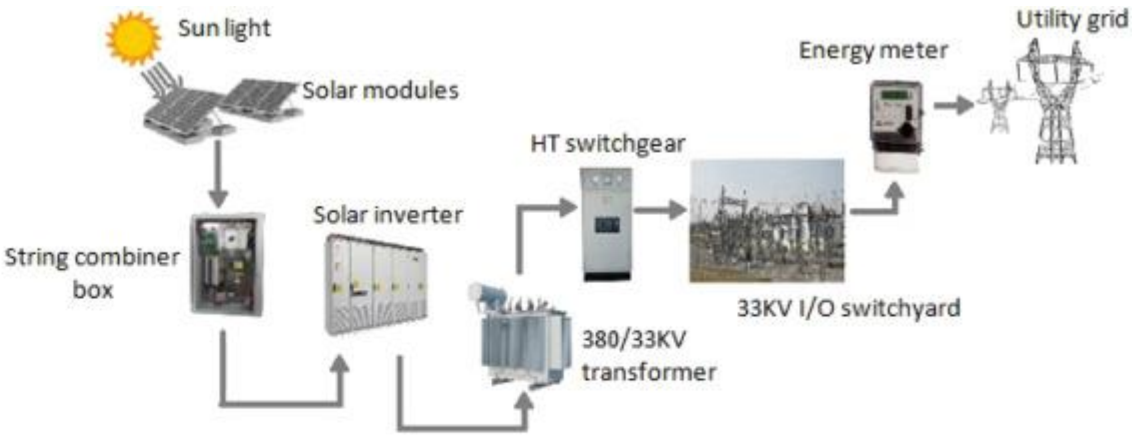

Figure 9: Utility scale PV system architecture and components (Shiva Kumar & Sudhakar, 2015)

The output of a solar PV plant depends on the local climatic and environmental conditions; mainly the intensity and amount of solar irradiation, the clearness index and the ambient temperature. In order to acquire an approximate figure on the potential of solar PV energy production in Lebanon, we look at the global horizontal irradiation (GHI) in Lebanon and the land availability. Data on the GHI for Lebanon is imported from the Global Solar Atlas and can be seen in the below figure which shows the average GHI over the period 1999 to 2015. It can be seen that based on the selected location, the GHI in Lebanon can vary from below 1,680 kWh/m2 to above 2,100 kWh/m2 with the average being around 1,900 kWh/m2 (Atlas). In a study done by the Lebanese Ministry of Environment and the UNDP to assess the renewable energy sector in Lebanon, it was shown that Lebanon has the potential to install and make use of 110 GW of solar PV plants in areas of high irradiance. 110 GW of solar PV plants in Lebanon are more than enough to cover the demand in terms of energy produced (see below Potential solar PV areas in Lebanon figure). The study excluded surface areas less than 8,000 m^2, slopes not facing south or inclined at more than 35 degrees, wet land and water bodies, historic sites, forest areas and agricultural land (MoE & UNDP, 2014).

The terms capacity factor and specific yield are often used to identify the amount of energy a solar PV plant installed in a specific location with a specific configuration produces per year. The capacity factor represents the ratio of a plant's actual output to its potential output if it were to operate at the nameplate capacity continuously. The specific yield represents the amount of energy generated per unit of power, usually as the amount of energy (kWh) generated per installed capacity (kWp) in a year. Other than the climatic conditions of a certain location, certain factors affect the yield such as the tilt angle of the PV panels, the ambient temperature and how well the mounting configuration allows cooling air to pass. In Lebanon, and considering a system installed in a high irradiation area, similar to the ones presented in (MoE &

UNDP, 2014), with the PV panels installed at an optimal tilt angle, the specific yield can reach values in excess of 1900 kWh/kWp (Atlas). In this study, we will consider a conservative value of 1680 kWh/kWp for the specific yield which is equivalent to a capacity factor of approximately 19.2%.

Figure 11: GHI for Lebanon(Atlas)

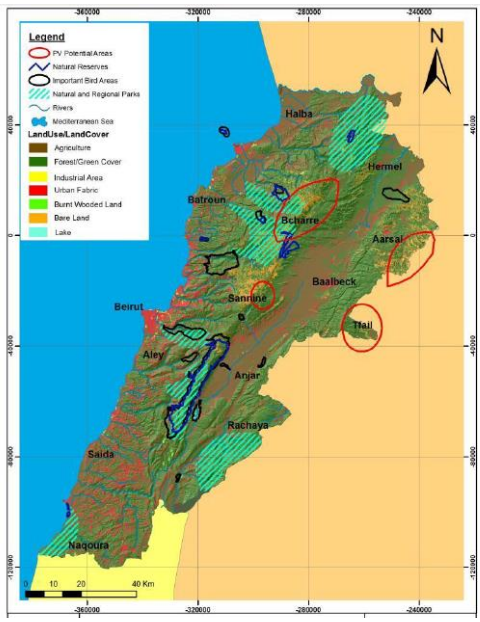

Figure 10: Potential of solar PV in Lebanon (MoE & UNDP, 2014)

3.1.2 Limitations and Intermittency Problem

A high penetration of solar PV energy comes with its limitations and drawbacks. The inherent nature of the technology renders it intermittent and variable with the instantaneous power output largely interlinked with the instantaneous irradiation, temperature and clearness index. Thus, the increased penetration of variable solar energy in an electric power system stipulates an increased need for greater flexibility and additional spinning reserve in the network. Furthermore, solar PV systems have limited to no dispatchability with the power output following the sun’s irradiation and not the energy demand with limited time coincidence of the solar resource with power demand (Chua, Lim, & Morris, 2015; Paul Denholm & Hand, 2011; Zou, Chen, Xia, He, & Kang, 2016).

The below two figures represent the typical load demand (for all of Lebanon) and the solar PV production (from a 130 kWp south oriented system) on two days, the first in May 2015 and the second in January 2015. The figures show the non-coincidence between solar power generation and the peak power demand:

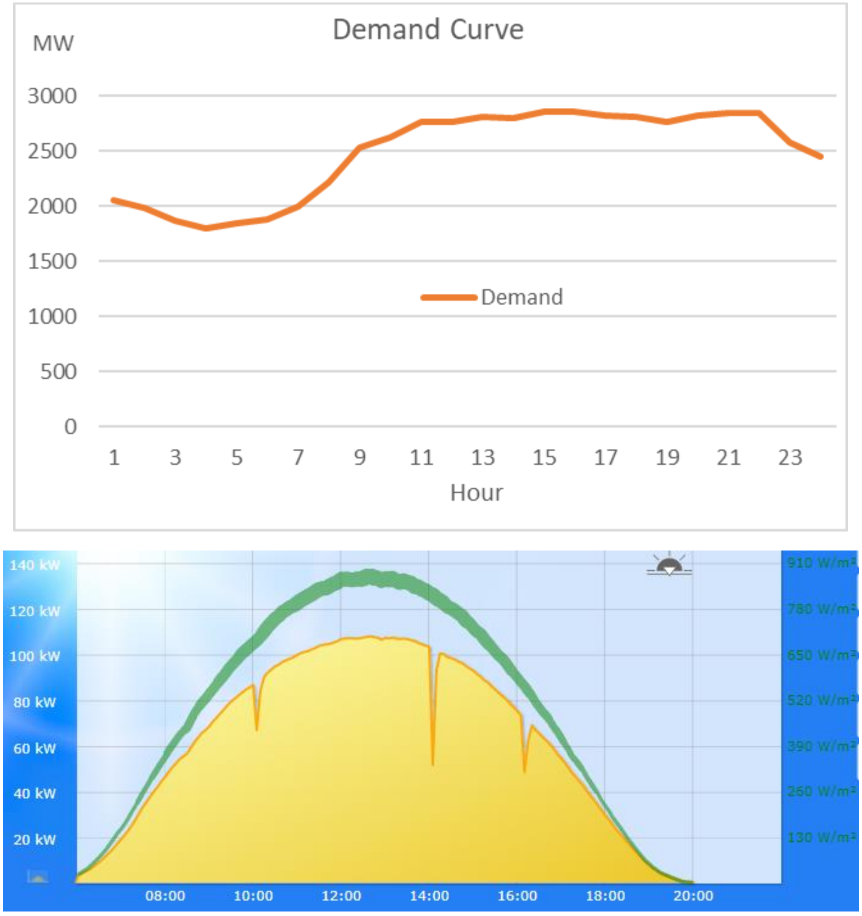

Figure 12: Load profile and Solar PV generation profile on a typical day in May

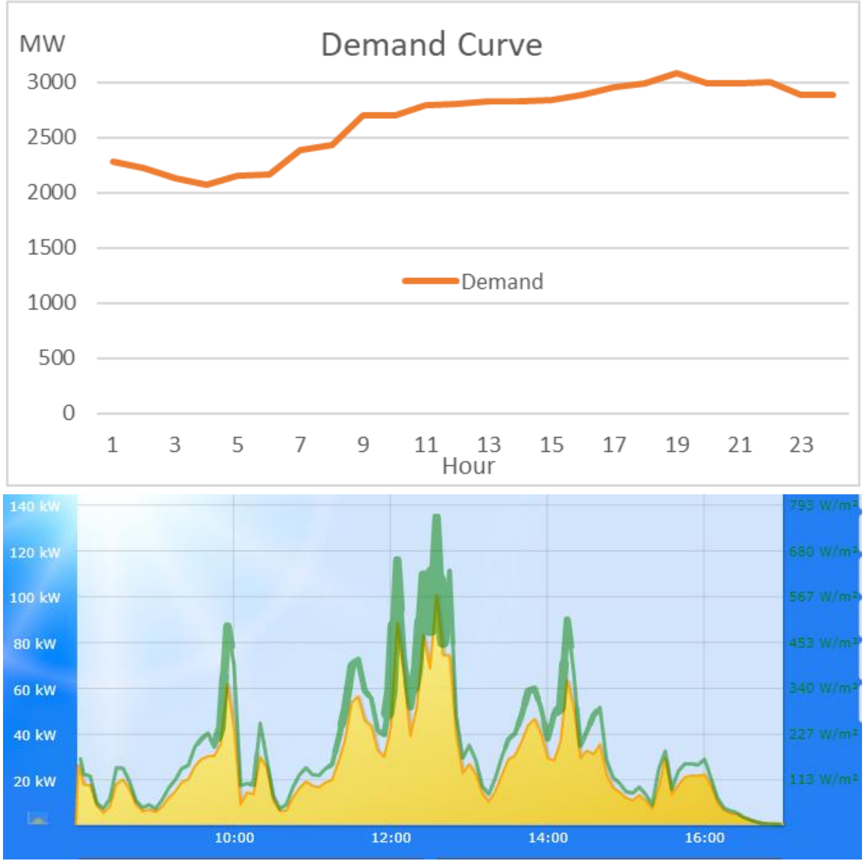

Figure 13: Load profile and Solar PV generation profile on a typical day in January

One may find consensus in literature about the diminishing returns of increasing the integration of variable power generation into an electric grid. Deploying variable generation technologies such as wind and solar with very high penetration levels (greater than the 50% mark) will make further capacity additions uneconomical due to increased curtailment and the subsequent decrease in the capacity factor of the variable generation systems (Bistline, 2017; Paul Denholm, Brinkman, & Mai, 2018; Paul Denholm & Hand, 2011; Paul Denholm & Margolis, 2007; Paul Denholm, Novacheck, Jorgenson, & O’Connell, 2016; Yekini Suberu, Wazir Mustafa, & Bashir, 2014)

Bistline J. (2017) built a model to show that the operational constraints and investments in dispatchable power such as minimum load levels, startup costs and ramping limits can negatively impact the economics of the integration of variable renewable energy. Conventional power generation units will have to undergo larger hourly ramp rates, more frequent starts and extended periods with lower utilization leading to increased operation and maintenance costs and negatively impacting the unit availability factor. Thus, oversizing variable generation systems comes with an increased operational and financial cost (Bistline, 2017).

Flexibility in a power system has been defined in many ways. Dnholm P. et al. (2016) define it as the ability of a power system to meet the load less the contribution of variable generation. The authors aimed at quantifying the benefits of enhanced grid flexibility and the subsequent effects on the economic carrying capacity, which is defined as the capacity limit of integrated variable generation with the benefits outweighing the costs, and the system cost. The study showed that increased flexibility can increase the economic carrying capacity and decrease system costs (Paul Denholm et al., 2016).

Denholm P. et al. (2011) use a dispatch model to quantify the curtailed variable generation under different flexibility options. The study defines the flexibility factor as the fraction below the yearly peak demand that the conventional power generators can cycle to. The simulations ran show that for a system having a flexibility factor of 100%, and using wind and load data for Texas, it is not possible to have a penetration of variable generation greater than 50% if the percentage of curtailed energy is to be limited to 10% of the energy produced. Furthermore, the work done shows a substantial increase in costs as the penetration of variable generation and the curtailment percentage increases due to increased ramping rate and ramping range, the increased need for frequency regulation (higher operational costs) and the decreased capacity factor of the variable generation units. It was also shown that utilizing a mix of wind and solar resources enhances the system performance by decreasing curtailment under all the modeled flexibility factors, however, this diversification in variable generation technologies does not resolve the problem of mismatch between the supply and demand. Thus, the conclusion that power systems with a high penetration of variable generation must include generating plants that are capable of starting, stopping and ramping quickly has been made while highlighting that electric energy storage provides a critical role in the large scale integration of variable generation (Paul Denholm & Hand, 2011).

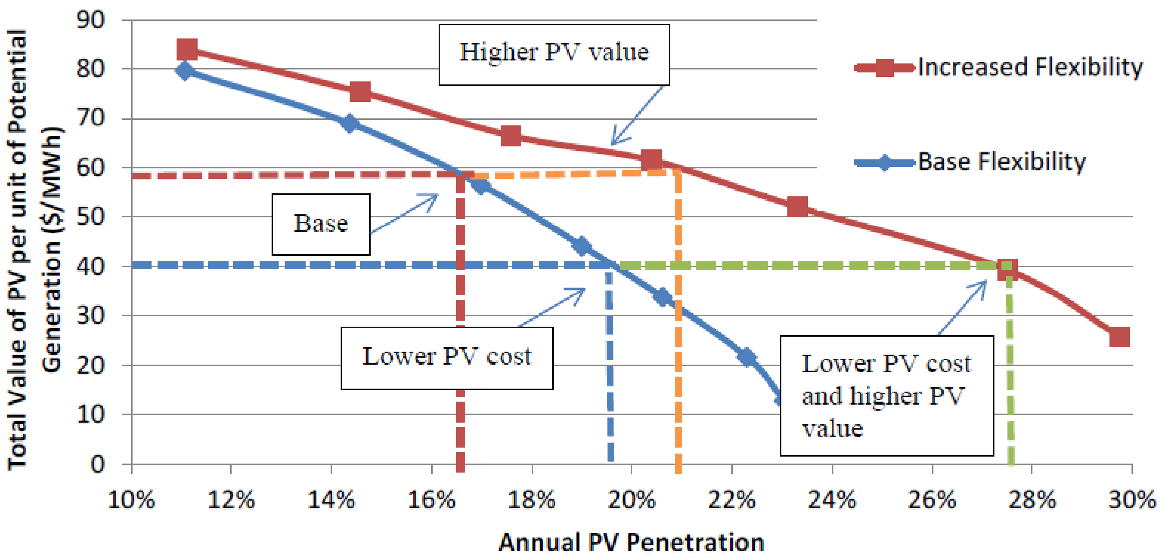

Figure 14: Increased economic carrying capacity either by decrease cost of PV or increased flexibility (Paul Denholm et al., 2016)

The figure above provides an illustration for the two main factors that could increase the economic carrying capacity and the penetration of variable generation plants. It could be seen that the cost of the technology has to decline, or the grid flexibility has to increase in order to for increased penetration to become economic.

3.1.3 Cost Study for Utility Scale Solar PV – International and Local

In order to get an accurate figure on the current and future costs of utility scale solar PV plants, data was collected from international analysts and local projects. It is well known that the PV modules make up the bulk of a PV systems balance of system (BOS) costs, therefore, a key term to analyze is the learning rate for the solar PV technology. The learning rate is defined as percentage decrease in the technology cost for every doubling of global installed capacity (IRENA, 2018). Data collected on the learning rate for the solar PV module from four different organizations is shown in the below graph (Feldman, Margolis, & Denholm, 2016; Fraunhofer Institute for Solar Energy Systems, 2017; IEA, 2017b; IRENA, 2018).

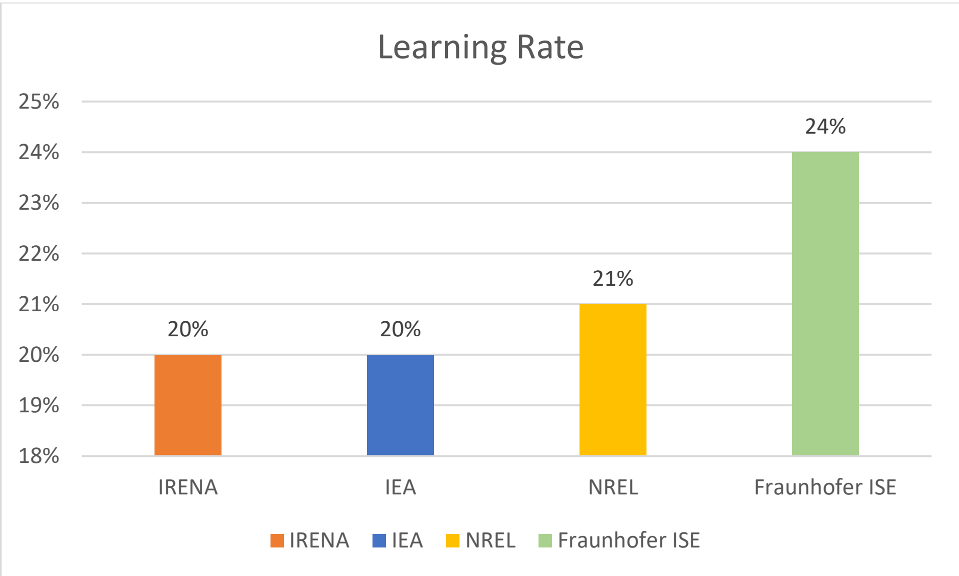

Figure 15: Learning rate of the PV module

From the collected data, an average learning rate for the PV module can be calculated to be 21.25 %.

Another term to look at, and which is commonly used to provide the capability of an economic comparison between projects of different technologies and capacities, is the levelized cost of electricity (LCOE). The LCOE can be defined as an economic valuation of the cost to build, operate and maintain a power generation asset over its lifetime divided by the total energy yield from that asset over the same lifetime (Lai & McCulloch, 2017).

There are two main methods to calculate the LCOE of a PV system, namely, the "discounting" method and the "annuitization" method. The former divides the sum of the present value of the lifetime costs of building and operating the PV plant with the sum of the present value of the energy produced each year and the former divides the annuitized system cost over the average energy generated in one year (Lai & McCulloch, 2017). It is generally argued that utilizing the discounting method gives more accurate results as it takes into consideration the derating of the PV plant over its lifetime.

According to the International Renewable Energy Agency (IRENA), the global weighted average of the LCOE for utility scale solar PV plants has fallen 73% from 2010 to 2017 reaching USD 0.1/kWh while the 5^{th} percentile of the data collected being at 0.07 $/kWh with the LCOE of systems having a high capacity factor being well below that figure. In addition, the average capital cost of utility scale PV systems was reported at 1,388 $/kW with the 5^{th} percentile of the data collected being below 1,000 $/kW. This price fall can be attributed to the 81% price decrease of PV modules since the end of 2009 along with the reduction in the balance of system costs. IRENA states that the price decline trend is likely to continue to 2020 and beyond and forecasts the global weighted average to reach a value between 0.5 and 0.6 USD per kWh by 2020 (IRENA, 2018).

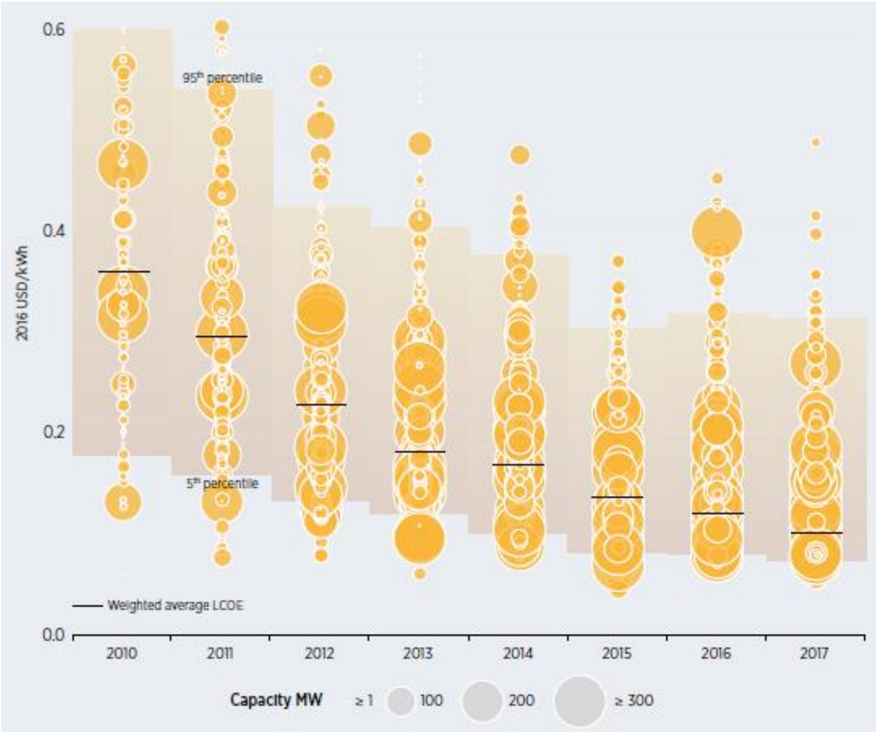

Figure 16: LCOE from utility-scale solar PV projects - global weighted average and range(IRENA, 2018)

Lazard's Levelized Cost of Energy Analysis report states that an 86% price decrease has been witnessed in the LCOE of utility scale solar PV plants between 2009 and 2017. Furthermore, the analysis presents the capital costs related to a crystalline utility scale PV plants to be in the range of 1,100 to 1,375 $/kW. For the Middle East region and for a utility scale PV plant with a capacity factor between 18% and 20% an LCOE of 0.056 USD/kWh is presented in the report (Lazard, 2017). The below figure shows the downward trend in the price decrease, however, the stated prices for utility scale solar PV plants represent systems that have a single axis tracking system.

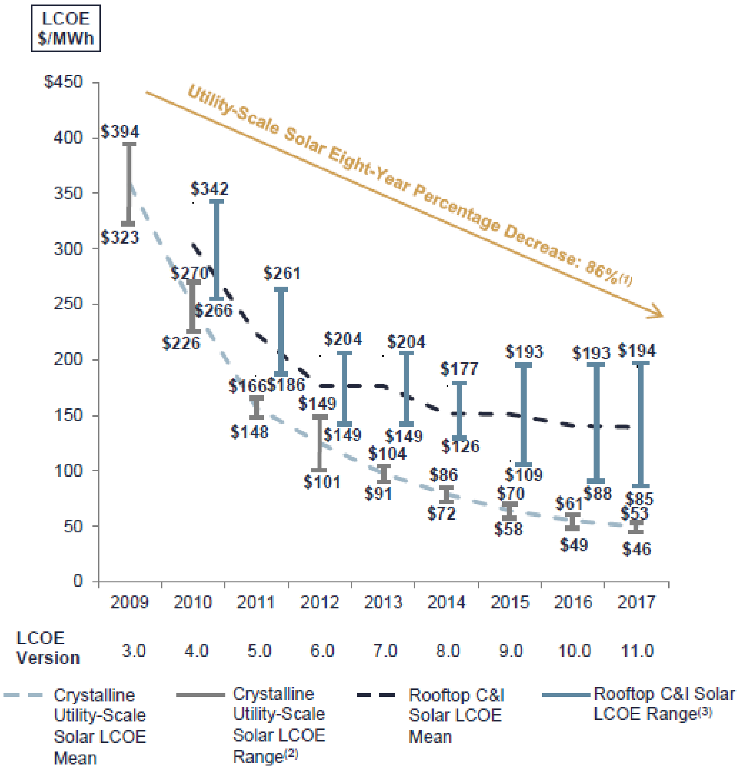

Figure 17: Solar PV LCOE 2009-2017 (Lazard, 2017)

In the Renewables 2017 report by the International Energy Agency (IEA), it is forecasted that the global average generation cost from utility scale PV plants will further decline by 25% over the period 2017-2022 with the global installed capacity reaching 740 GW in 2022 which is more than double the installed capacity at the beginning of 2017 (iea, 2017a).

Zheng C. and Kammen D. (2013) showed the importance of considering the effects of research, development and innovation measured by patent activity as a proxy on the price forecasting of a certain technology. The research developed a two-factor learning curve model based on the annual installed capacity and the number of patents issued and showed that innovation can have a major role in further decreasing the price of PV systems (Zheng & Kammen, 2014). This may explain the discrepancy in the price forecast of PV systems from different organization and analysts as some may not consider or may place less weight on the effects of research, development and innovation in the solar PV field. For instance, IRENA states that near future price reductions for solar PV plants can be attributed more to improvements in the production process and efficiency gains associated with newer PV cell designs, such as diamond wafer cutting and reactive ion etching methods, Passivated Emitter Rear Cell (PERC) architectures and Light Induced Regeneration (LIR) cell technologies and others, rather than the capacity deployment upsurge and economies of scale (IRENA, 2018).

The table below summarizes the decline in the global weighted average LCOE of solar PV plants in the period 2010-2017:

Year	Global weighted average LCOE decline
2010	20%
2011	20%
2012	20%
2013	20%
2014	8%
2015	20%
2016	11%
2017	15%

Table 1: Global weighted average LCOE decline 2010-2017 (IRENA, 2018)

The compound annual rate of decline can be estimated at approximately 14% between 2014 and 2017 which is within practical limits when the two factors of increased global installed capacity and innovation and development are factored in. If current trends continue while taking into account current auction prices for PV systems to be built in the near future, IRENA forecasts the global weighted average for the

LCOE of solar PV to fall to below 0.06 USD per kWh in 2019-2020 and to 0.03 USD per kWh beyond 2020 in some regions (IRENA, 2018).

A fall to 0.06 USD per kWh is equivalent to a 40% decrease in current prices equivalent to a 15.6% annual rate of decline in the three-year period between 2017-2020. For our study and in order to take a conservative estimate, we will consider an overall decrease of 33.3% in 2020 from current LCOE values thus an annual rate of decline in the LCOE of approximately 12% in the three-year period 2017-2020.

As a solar PV plant's balance of system costs are location-specific with a wide variation in soft costs, labor costs and comports costs from country to country (Feldman et al., 2016), it is required to get an accurate figure on the local prices and LCOE in Lebanon for solar PV plants. Therefore, data was collected on six different commercial solar PV sites in six different locations in Lebanon that were awarded during 2017 ranging from 60 to 600 kWp. The average capital cost to engineer, procure and build a plant was 955 $/kW which is below IRENA's and LAZARD's average capital cost. Furthermore, the largest project of a size of 600 kWp had a capital cost of 783 $/kWp and the lowest cost was 775$/kWp for a roof mounted 105 kWp system (CEDRO, 2018).

The above prices give an indication for the capital cost of commercial scale PV plants in Lebanon, however, no further information was provided on the cost of capital and the projected yearly energy yield. Recently, the Lebanese Ministry of Energy and Water has received bids for the building and operation of 12 utility scale solar PV plants in various areas of high irradiation across the country. The plants will operate under a power purchasing agreement (PPA) between the government and the investors and thus can give us a reassuring figure for the LCOE of utility scale PV systems in Lebanon. In areas of high irradiance and good climatic conditions, a fixed tilt PV system will have a PPA with a value less than 0.06 USD per kWh as the price of electricity (MoEW, 2018). Therefore, and to be conservative with the estimates, we will consider the LCOE for utility scale solar PV plants in Lebanon to be 0.06 USD per kWh in 2017 projected to drop to 0.04 USD per kWh in 2020 (33.33% decrease) and to 0.033 USD per kWh in 2022 and afterwards (17.5% decrease). The below table summarizes the price estimates:

Electricity price of utility scale solar PV plants	2017	2020	2022 and beyond
LCOE ($/kWh)	**0.06**	**0.04**	**0.033**

Table 2: Current and projected LCOEs for utility scale solar PV plants in Lebanon

3.2 Utility Scale Battery Energy Storage Systems Review

3.2.1 Technology Overview and Description

Lithium-ion (Li-ion) batteries where first introduced by Sony Corporation in the early 1990s and have become one of the most important technologies for mobile electronics. The basic principal of operation for Li-ion batteries is the exchange of lithium ions between the anode and the cathode electrode through an electrolyte. It is often the case that the cathode is made up of a lithium-ion oxide and the anode is made up of graphite (carbon). Compared to other types of batteries, Li-ion batteries provide a higher specific energy and a higher energy density (Wh/L). They also have a long lifetime (up to 20,000 cycles), a high round-trip efficiency (80% to 100%), a low self-discharge rate and a high-power discharge capability (IRENA, 2017). The below figure is a specific representation of one type of Li-ion battery cell and presents the operating principle of the battery:

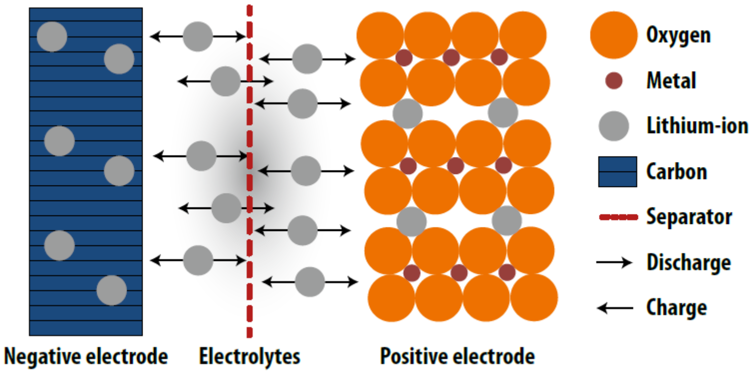

Figure 18: Components and operating principle of a Li-ion battery cell

Different types of lithium ion battery chemistries are commercially available with varying properties of safety, power density, energy density, lifetime and overall performance. The commercially available chemistries are compared in the below table from IRENA:

Key active material	lithium nickel manganese cobalt oxide	lithium manganese oxide	lithium nickel cobalt aluminium	lithium iron phosphate	lithium titanate
Technology short name	NMC	LMO	NCA	LFP	LTO
Cathode	$LiNi_xMn_yCo_{1-x-y}O_2$	$LiMn_2O_4$ (spinel)	$LiNiCoAlO_2$	$LiFePO_4$	variable
Anode	C (graphite)	C (graphite)	C (graphite)	C (graphite)	$Li_4Ti_5O_{12}$
Safety					
Power density					
Energy denisty					
Cell costs advantage					
Lifetime					
BES system performance					
Advantages	-good properties combination -can be tailored for high power or high energy -stable thermal profile -can operate at high voltages	-low cost due to manganese abundance -very good thermal stability -very good power capability	-very good energy and good power capability -good cycle life in newer systems -long storage calendar life	-very good thermal stability -very good cycle life -very good power capability -low costs	-very good thermal stability -long cycle lifetime -high rate discharge capability -no solid electrolyte interphase issues
Disadvantages	-patent issues in some countries	-moderate cycle life insufficient for some applications -low energy performance	-moderate charged state thermal stability which can reduce safety -capacity can fade at temperature 40-70°C	-lower energy density due to lower cell voltage	-high cost of titanium -reduced cell voltage -low energy density

Figure 19: Comparison of different Li-ion chemistries (IRENA, 2017)

Hesse H. et al. (2017) complete a review on stationery battery storage systems and compile data from various literature and present the below table which will be used as an additional resource to IRENA's data above:

Parameter	NMC:C	NCA:C	LFP:C	LFP:LTO
Cost per kWh	++	+	–	– –
Safety	–	– –	+	++
Maturity	Market	Market	Market	Research
Cycle Life	–	–	+	++
Calendar Life	+	+	+	++
Energy Density	+	++	–	– –
Power Density	++	+	–	– –

Figure 20: Qualitative comparison of different Li-ion chemistries from literature (Hesse, Schimpe, Kucevic, & Jossen, 2017)

Discrepancies in the data collected from the two sources can be witnessed especially in the power density and cost metrics, however, these differences are minor and can be attributed to collecting data from different time scales, locations and markets. Therefore, we deduce that lithium nickel manganese cobalt oxide (NMC), lithium nickel cobalt aluminum (NCA) and lithium iron phosphate (LFP) are currently available and mature li-ion cell technologies. In 2016, IHS Markit completed a market study on the available energy storage technologies and built the below S-curve showing that Li-ion battery storage was in the scaling up and approaching the maturity phase:

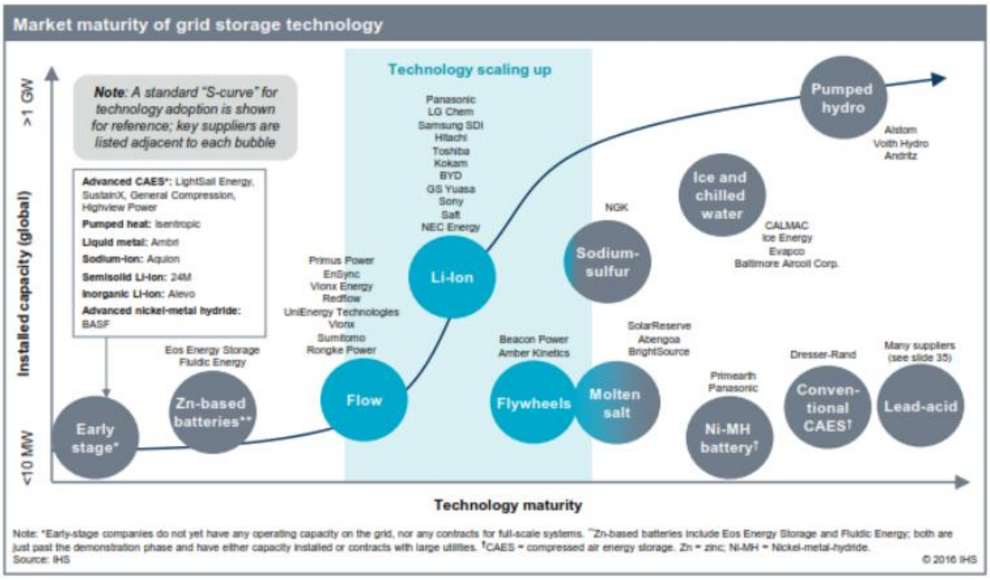

Figure 21: S-curve for energy storage technologies (IHS, 2016)

In regards safety, the main concern is the thermal stability of the Li-ion battery where the so called "thermal runaway" of a battery resulting from chemical reactions that release oxygen when lithium metal oxide cathodes overheat due to several factors including high external heat conditions and high rates of charging or discharging can cause leaks and eventually lead to the battery cell catching on fire (IRENA, 2017). Another important factor to consider is the degradation of the battery cell over its lifetime. Cell aging and degradation is an inevitable process caused by side reactions in all electrochemical devices. These side reactions ("electrolyte decomposition, passive fil formation, particle cracking, and active material dissolution") result in a significant change in the battery cell capacity and resistance characteristics over time (Hesse et al., 2017). Furthermore, the external temperature of a li-ion battery has considerable effects on the cycle lifetime, with the optimal temperature range falling between 20 and 30 degrees Celsius. To put the temperature effect in context, and as a rule of thumb, the battery calendar life drops by 50% for every temperature increase of approximately 10 degrees Celsius over the design operating temperature (IRENA, 2017). From the collected data, average qualitative values for the different characteristics of Li-ion battery technologies were considered to be used in this study and are presented in the below table (Hesse et al., 2017; IRENA, 2017; Lai & McCulloch, 2017; Müller et al., 2017; Zou et al., 2016):

Characteristics of a general Li-ion battery cell	Value
Round trip efficiency	90%
Design Lifetime (calendar life)	15 years
Number of cycles	10,000 cycles
Capacity degradation over lifetime	20%
Depth of discharge (DoD)	90%

Table 3: Characteristics of a general Li-ion battery

Connecting a group of Li-ion batteries in a series/parallel configuration and adding the necessary protection and power electronics will form a battery storage system. A stationery li-ion battery storage system connected to the grid generally includes the following main components: The li-ion battery packs connected in a specific configuration, the battery thermal management system and the overall system thermal management system (TMS), the energy management system (EMS), the power electronics mainly made up of inverter units (DC to AC) and a transformer to couple the system with the high-voltage grid lines if needed (Hesse et al., 2017). The bow figure gives a general idea of the configuration and components of a Li-ion battery storage system:

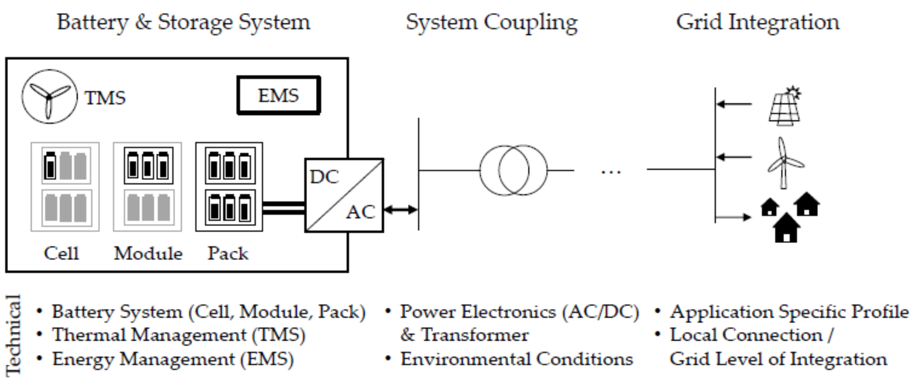

Figure 22: Schematic drawing of a Li-ion battery storage system (Hesse et al., 2017)

The following section will study the current and forecasted prices of lithium-ion battery storage systems.

3.2.2 Cost Study for Utility Scale Storage - International

To attain accurate values on current and projected prices for large scale Li-ion battery energy storage systems (BESS) we look at both the studies and projections of market analysts and the academic work done using scientific methodologies centered on learning rates. We subdivide the costs of a BESS into two main components that are the Li-ion battery modules and the balance of system (BoS) components that aggregate all software, hardware and soft components other than the battery itself. Therefore, the BoS components include the power conversion equipment with the inverters and safety electronics, thermal energy management system and HVAC, energy management system, electrical distribution and control, containers and housing, grid interconnection and engineering, procurement and construction (EPC) (Ardani et al., 2017; IRENA, 2017; Lazard, 2016; McLaren et al., 2016).

It was found that a lower contribution of the battery module to the overall system cost is witnessed as system size increases (Müller et al., 2017). Furthermore, from the data collected, the ratio of the cost of the battery module to the entire system cost was found to vary in the range of 35% for large systems and up to 60% for smaller systems (Ardani et al., 2017; Paul Denholm, Eichman, & Margolis, 2017; IRENA, 2017)

The main drivers of the cost decline in Li-ion battery storage systems are the uptake in electric vehicles that use these batteries and the increased penetration of variable renewable energy sources into power grids (Berckmans et al., 2017; Feldman et al., 2016; Müller et al., 2017; Zheng & Kammen, 2014). Bloomberg New Energy Finance reported a cost decrease of 73% between 2010-2016 for Li-ion battery packs with a learning rate of 19% attributed to technology improvement, economies of scale and fierce competition between manufacturers (Curry, 2017). In comparison, a learning rate of 9% was presented in 2014 by a study done by NREL(Paul Denholm et al., 2017). The below figure summarizes the current and projected prices for Li-ion battery packs imported from the different market analysts. The data is organized based on the date of analysis and projection:

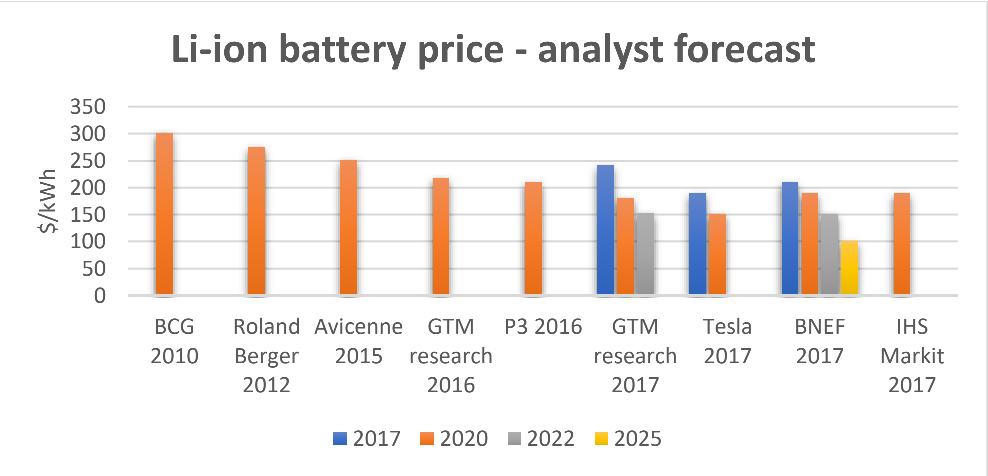

Figure 23: Price forecast for Li-ion batteries based on market analysts

From the above figure and data, it is noticed that price forecasts done at earlier stages tend to underestimate the price reduction which is a phenomenon previously witnessed in the solar PV industry. As an example, 2017 Li-ion battery prices are well below the 2020 price projections done by BCG, Roland Berger and Avicenne done in 2012, 2010 and 2015 respectively. Furthermore, in 2016, GTM research projected a price of 217 $/kWh for 2020 and in 2017 it re-adjusted that projection to 180$/kWh. Consequently, we will place more weight on more recent forecasts. This expedited decline in prices comes from several reasons that will be discussed in upcoming sections. We calculate the mean projected value for 2020 by averaging the forecasts of GTM research, Tesla, BNEF and IHS Markit which turns out to be 177.5 $/kWh[1]. For 2022, the mean projected value is calculated by averaging the projections of GTM Research and BNEF and found to be 151 $/kWh which yield a 15% price decrease between 2020 and 2020.

From literature and academic work that is concerned with projecting the future prices of Li-ion batteries, a common figure which is described as a turning point threshold or sales barrier of 100$/kWh for the price of Li-ion batteries can be found (Berckmans et al., 2017; Kittner, Lill, & Kammen, 2017; Schmidt, Hawkes, Gambhir, & Staffell, 2017).

One of the main methodologies applied to project the prices of Li-ion batteries is the learning curve. Schmidt O. et al. (2017) derive an experience curve based on Wright's law while using historic product pricing and cumulative installed capacities as inputs. The work done showed that independent of the technology used for energy

[1] IHS Markit forecasted the price of Li-ion batteries to be less than 200 $/kWh by 2019. A price of 190 $/kWh was considered for 2020

storage, the technology that brings the most installed capacity to the global market is the one likely to be the most cost competitive. Particularly, once 1 TWh of stationery energy storage capacity is installed the price of such systems reduces to the range of 280 $/kWh to 400 $/kWh for the entire system and to the range of 150 $/kWh to 200$/kWh for the battery packs only. The study identifies a price range of 290 $/kWh to 520 $/kWh for stationery energy storage systems by 2030, however, it notes that the price of the Tesla Powerwall 2 is already within that range at 500 $/kWh in 2017. To explain this, the authors resort to the synergetic learning effects of the stationery energy storage technology across different applications which led to cost reductions that were not accounted for. In addition, the authors state that increased competition and the price reductions witnesses since 2014 are not in line with the experience curves derived (Schmidt et al., 2017). This happening is in congruence with the learning rate gap that was found above with a learning rate value of 9% in 2014 (Feldman et al., 2016) and 19% in 2016 (Curry, 2017).

Berkmans G. et al. (2017) built a model to forecast the price of a Li-ion battery packs for electric vehicles while considering the aspects of increased research and the commercialization of new chemistries and the mass manufacturing and production cost optimization that come with increased uptake and the maturing of the market. The study found that for current chemistry of Li-ion batteries, NMC specifically, prices are expected to drop to 195 $/kWh by 2020 and reach the 100$/kWh threshold in the period 2025-2030 which is in line with the data imported from the analysts' projections above. And for new chemistries, specifically silicon based li-ion batteries, prices are expected to drop to 131 $/kWh by 2020 and reach the 100 $/kWh threshold in the period 2020-

2025. However, the authors state that silicon-based Li-ion batteries are unlikely to be commercially available by 2020, rather more likely by 2025 (Berckmans et al., 2017).

Similar to the study referenced above on utilizing a two-factor model-based experience curve to forecast the price of PV modules (Zheng & Kammen, 2014), Kittner N. et al. (2017) utilize an empirical dataset that analyzes technology deployment and innovation to build a two-factor model and project the prices of Li-ion battery storage systems. Using patent activity as a proxy for innovation, the authors present a solid argument and reasoning on why forecasting and utilizing experience curves solely based on technology deployment tend to underestimate the future price decline of a technology as the synergies between deployment and innovation are overlooked. To that end, the two-factor model built showed a learning rate of 16.9% for economies of scale and deployment and a price decrease of 2% for every 100 patents issued. Furthermore, it was able to explain and support the recent plunge in battery prices better than the conventional single-factor experience curve approach. Assuming that the patent activity stays on a similar level to that found between 2011 and 2015, the Authors forecast the price of a Li-ion battery for energy storage to drop to 124.24 $/kWh by the year 2020 and the price of Li-ion cell for consumers to drop to 85.55 $/kWh by 2019 in line with what was stated by IHS Markit above. The authors discussed the impact of Gigawatt-scale grid storage and the uptake of electric vehicles on the price decline and stressed on the importance of continued R&D spending on the technology in order to reach the projected figures (Kittner et al., 2017).

Thus, in order to attain a price figure in 2020 for Li-ion batteries for large scale energy storage, we will aggregate and average out the projections from the market analysts and scientific mthods found in academic articles. The mean value of is calculated to be 171.54 $/kWh as a price for Li-ion batteries for energy storage in 2020. The below formula shows the averaging calculation:

$$\frac{190 + 190 + 180 + 150 + 195 + 124.4}{6} = 171.54\ \$/kWh$$

In regards the BoS costs for utility scale Li-ion battery energy storage applications, the cost figure is determined by the peak power capacity of the system rather than the energy capacity. Data on the BoS costs is not as widely available as that for Li-ion batteries. However, a study done by GTM research in 2016 shows that a learning rate of 18.8% for the BoS costs was witnessed over the period 2012-2015 (Feldman et al., 2016). Furthermore, several components are included in the balance of system rendering the price forecasting to be more difficult. Therefore, in order to attain an accurate figure for large scale Li-ion based energy storage systems we will again revert to analyst projections while incorporating the projected price of the Li-ion battery calculated above and validating that it is within an acceptable range.

IRENA states that in 2017, the average price of a turnkey NCA based Li-ion battery storage system is at 350 $/kWh and is projected to drop to 145 $/kWh in 2030 (IRENA, 2017). Navigant Research states that in 2017, the price of a Li-ion battery storage system was at approximately 500 $/kWh and is projected to drop to approximately 400 $/kWh in 2020 and to 350 $/kWh in 2022 (Eller & Dehamna, 2017). Lazard states that the average price of a grid-connected Li-ion battery storage system will drop from approximately 650 $/kWh in 2016 to approximately 400 $/kWh in 2020, with the low end dropping from 386 $/kWh to 239 $/kWh (Lazard, 2016). Therefore, the price forecast range in 2020 is between 239 $/kWh as the lowest forecast to 400 $/kWh as the highest forecast.

Having in mind the reported 129 MWh grid connected Li-ion battery project completed by Tesla in south Australia in 2017 that had an estimated cost of 388 $/kWh (Dent, 2017; Roberts, 2017; Spector, 2017), and the data collected on the forecasted price range and Li-ion battery prices, we shall consider the price of 380$/kWh for a turnkey grid connected Li-ion battery storage systems in 2020. Given that (1) the local climatic conditions in Lebanon yield an approximate average temperature that falls in the range of 20 degrees Celsius to 30 degrees Celsius which is within the optimal operating temperature range of a li-ion battery system and thus will save costs related to the thermal management system and (2) that considering a battery price of 171.54 $/kWh will result in the battery pack component representing 45% of the 380 $/kWh turnkey price which is within the range found above and (3) that the 380 $/kWh price of the battery storage system is in the high region of the 239 $/kWh to 400 $/kWh range then we can state that the forecasted price of 380 $/kWh in 2020 is considered as a conservative estimate.

To remain conservative and in accordance with (Gupta, 2017), we will consider a compound annual growth rate of -9% between 2020 and 2025 yielding an estimated price of approximately 315 $/kWh in 2022 and approximately 240 $/kWh in 2025.

Price forecast of utility scale Li-ion BESS	2020	2022	2025
Price ($/kWh)	**380**	**315**	**240**

Table 4: Price forecast of utility scale L-ion battery energy storage systems

3.3 Literature Review on PV-Battery Systems

In recent years, academic work on utility scale solar PV systems with battery storage has showed a noticeable increase due to the declining costs of batteries and the increased penetration of intermittent and renewable energy sources into electric grids. When large scale battery storage coupled with utility scale PV plants are studied, the dominant applications considered are usually one or a combination of the following: improved dispatchability, renewables curtailment minimization, ancillary services (voltage and frequency regulation), transmission management, and transmission losses reduction (Castillo & Gayme, 2014; Evans, Strezov, & Evans, 2012; Lai et al., 2017; Subburaj, Pushpakaran, & Bayne, 2015; Wright, 2015).

Evans, A. et al. (2012) present a comparative study of the different options for grid connected energy storage solutions and state that when large amounts of energy need to be provided, combining different types of energy storage shall be necessary (Evans et al., 2012). Subburaj, A. et al. (2015) provide a review on grid-connected battery storage projects in the US and state that battery storage systems are a necessity when it comes to intermittent renewable energy integration and that, when compared to other forms of storage, batteries have the benefit of compactness and convenience in terms of distributed installation (Subburaj et al., 2015). Castillo, A. & Gayme, D. (2014) study grid-scale energy storage solutions and focus on the potential and barriers of the different technologies used while presenting the main challenges faced with large-scale adoption of grid-scale storage that include economic, technical and regulatory aspects (Castillo & Gayme, 2014). Wright, J. (2016) develop a simulation model in order to examine the technical benefits of grid-connected battery storage systems in scenarios where large-scale integration of intermittent renewable energy is present. The main application of the modeled battery system was to obtain dispatchability for the intermittent energy sources, further, the needed amount of storage capacity was shown to be reliably calculated based on confidence intervals for day-ahead forecasts of solar PV and wind energy (Wright, 2015).

In comparison with the above literature, academic research and studies have been done for utility scale solar PV plants with grid connected storage systems while having the functionality of a power plant rather than a grid supporting unit. One may find such studies for island systems where distributed renewable energy plants offer an added benefit when considering the transmission, distribution and interconnection of conventional power plants. For instance, several studies have been done regarding the renewable energy integration into the Portuguese islands located in the Atlantic sea. Stenzel, P. et al. (2017) perform a life cycle assessment study to compare powering up the Graciosa Island with a diesel combustion only system or with a renewable energy-storage hybrid system. The results show a reduction of environmental impacts of approximately 43 % when running on the hybrid system (Stenzal et al., 2017). Miguel, M. et al. (2017) show the need to integrate grid-connected energy storage for the island of Madeira after developing a simulation tool showing that the best solution for the island would be to connect a large-scale battery that will reduce power curtailment, increase dispatchability and increase frequency and voltage control (Miguel, Nogueira, & Martins, 2017). Rodrigues, A. et al. (2017) present the case that installing pumped-hydro as a storage system for the island of Terceira would be more cost effective than grid-connected battery systems for a certain range of power capacity due to the high replacement costs, high operation and maintenance costs and loss of efficiency of the batteries over time (Rodrigues, Machado, & Dentinho, 2017).

Yang, Y. et al. (2017) and Beltran, H. et al. (2013) present a new way of observing utility scale solar PV systems coupled with large battery storage systems when they design a hybrid system to have a constant power output. Beltran, H. et al. (2013) mention that the benefits of such systems include power generation, hence, not treating such systems as solely grid supporting as can be witnessed in the previously discussed literature. Yang, Y. et al. (2017) propose an energy management strategy for utility scale solar PV with battery storage systems in order to achieve a constant power output while calculating the minimum energy capacity needed of the battery system. (Yang, Y. et al., 2017; Beltran, H. et al., 2013)

Denholm, P. et al. (2017) study the technical and economic performance of grid connected solar PV and storage systems and find that when comparing such systems with conventional power systems, it is essential to consider the added value presented by the capacity credit of the PV-battery system. Further, the study shows that the decline in capacity value of PV systems as their penetration level increases can be mitigated by grid-connected storage systems (Paul Denholm et al., 2017).

The literature presented so far considers the addition of a solar PV plant with battery storage to a power system that can adequately and reliably meet the power demand. Lebanon presents a unique case when studying the addition and integration of utility scale PV systems coupled with battery storage as such systems will have to be accounted for as independent power generation units. Given the inherent dispatchability of battery systems and the abundance of solar energy that Lebanon has, modelling and studying the integration of such systems into the Lebanese grid will be a pilot case especially when quantifying the benefits of adding such systems in comparison with adding conventional power generation units.

3.4 Description of the Different Architectures of Grid Connected PV-Battery Storage

Different architectures can be used when installing grid-tied solar PV plus battery storage plants each having different technical and economic benefits. The different architectures can be narrowed down to four main configurations, namely, (1) independent systems where the solar PV plant and the battery energy storage system are not co-located and do not share a point of common coupling, (2) AC-coupled systems where the solar PV plant and the battery energy storage system are co-located but do not share the main power electronics and have a point of common coupling at the transmission of feeder point, (3) DC-coupled systems where the solar PV plant and the battery energy storage system are co-located with the point of common coupling on the DC side of the shared inverter and power electronics and (4) DC tightly coupled systems where the same configuration of a DC-coupled system exists with the only difference being in that the battery energy storage system can only charge from the solar PV plant and not from the grid (Paul Denholm et al., 2017). The table below summarizes the four main configurations:

Type of Coupling	Co-Located?	Point of Common Coupling	Energy Stored
Independent	No	None	Grid (could include PV via market)[a]
AC-coupled	Yes	Transmission/feeder	Grid or PV
DC-coupled	Yes	DC side of inverter	Grid or PV
DC tightly coupled	Yes	DC side of inverter	Only PV

Table 5: The main configurations of grid-tied solar PV plus battery storage (Paul Denholm et al., 2017)

For our study, and in order to utilize a configuration that best suits the Lebanese power system, we will be considering a DC-coupled system due the added benefits it presents when it comes to the decreased capital cost resulting from fewer power electronics to connect the system (combining the PV plant and the BESS to one main bi-directional inverter), the provision of charging the batteries from the grid during times of low load, and co-locating the system and connecting it to feeders and substations having high congestion and thus de-loading the transmission system during peak demand. The below figure represents a simple schematic on the DC-coupled configuration:

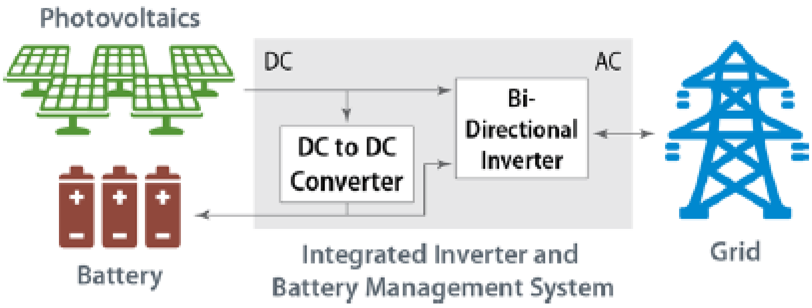

Figure 24: DC-coupled configuration for a solar PV plus BESS plant (Paul Denholm et al., 2017)

3.5 Main Benefits of PV Plus Storage

3.5.1 Provision of Ancillary Services

As the integration and penetration of variable renewable energy sources increase in a power system, the need for enhanced control and reaction times on the grid level increase. Several literature studies have identified key services that a grid connected BESS can provide for the utility operator that become increasingly important as high levels of renewable are integrated into the power grid. Muller M. et al. (2017) report the main applications of a grid connected BESS to include the provision of emergency energy units or uninterrupted power supply connected to crucial nodes in the grid, the provision of black-start capabilities, the provision of primary, secondary and tertiary control reserves to ensure synchronized and matched generation and consumption, the provision of grid support with the instant injection of active or reactive power as well as peak shaving, shifting and managing (Müller et al., 2017) (see Figures 26 and 27).

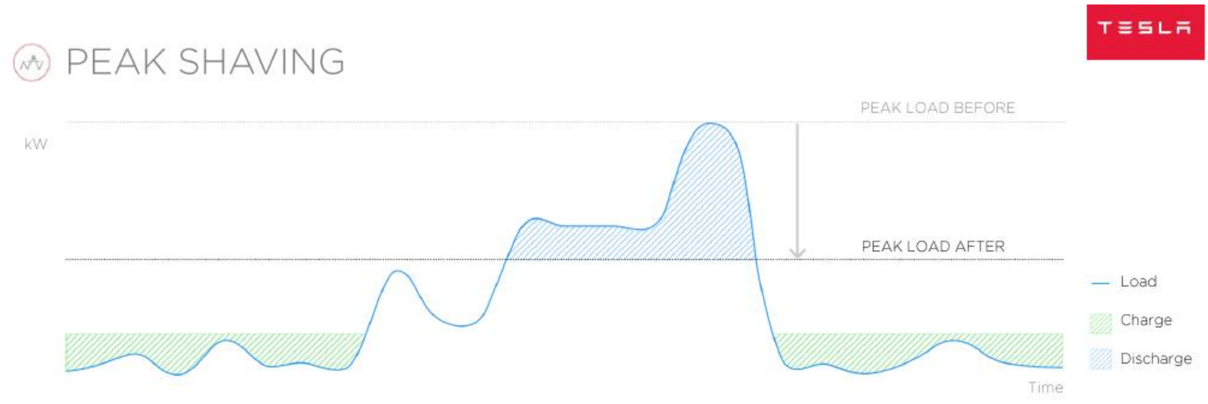

Figure 25: BESS ancillary service - peak shaving (Motors, 2016)

Due to the intermittent nature of renewables and the decreasing amounts of spinning reserve and inertia in power systems and grids (Liserre, Sauter, & Hung, 2010), installing and utilizing grid connected BESS generates the capability of reacting to grid fluctuations on a millisecond timescale (Lawder et al., 2014). In regards frequency control and primary control reserves, Li-ion based BESS have been shown to be technically mature and to be economically competitive with conventional power plant dispatch plans and applications for primary reserve control (Stroe, Knap, Swierczynski, Stroe, & Teodorescu, 2017) (see Figure 27).

Giorgio A. et al. (2017) study the utilization of energy storage systems and their provision of an optimal solution for black starts in electricity grids after events resulting in the interruption of the main power supply (Giorgio, Giuseppi, Liberati, & Pietrabissa, 2017). Zeh A. et al. (2016) present a sizing optimization for battery energy storage systems such that to maximize the profitability resulting from the utilization of battery storage systems for primary reserve control (Zeh et al., 2016).

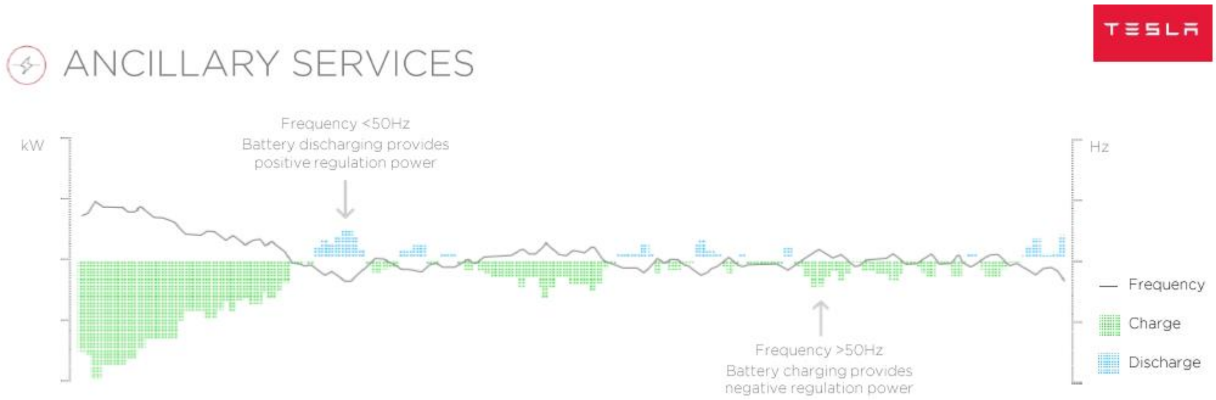

Figure 26: BESS ancillary service - frequency regulation (Motors, 2016)

For simplicity and given that different market systems for the electricity sector exist worldwide with the primary control reserve demand often auctioned out and supervised by an independent system operators (Hesse et al., 2017), and due to the limited available data, we shall not account for the economic benefits provided by the enhanced ancillary services when considering grid connected BESS in Lebanon. The below table summarize the main services provided by grid connected BESS:

Service	Benefit or value
Peak shaving and load shifting	Lower peak charges decreased stress on the grid and reduces energy costs
Renewable energy self-consumption	Decreased energy and grid connection costs and increased sustainability
Enhanced demand response	Improves grid stability and supports renewable energy development
Primary control and frequency reserves (ancillary services)	Improves grid stability and reliability and avoids the activation of large energy assets
Renewable energy firming	Avoids renewables curtailment and smooths out the intermittent output
Backup power and UPS	Supplies instant power during grid outages and reduces O&M costs

Table 6: Main grid services and benefits of grid connected BESS

3.5.2 T&D Infrastructure Upgrade Investment Deferral

As the load demand increases and the transmission and distribution (T&D) network reaches its operation capacity, utilities and distribution service providers are required to enhance, reinforce and upgrade the existing T&D network in order to be capable of accommodating the increased load. Therefore, the reinforcement of the T&D infrastructure mainly depends on the growth of the load as well as the aging of the infrastructure. Strategically installed energy storage systems can supply power during peak load times and hence reduce the amount of power needed to be transmitted over the existing transmission lines (Chua et al., 2015). Utilizing battery storage as a distributed energy source by installing it downstream of the T&D infrastructure presents two related value propositions that are (1) deferring the upgrade of the infrastructure and (2) extending the life of that infrastructure by allowing it to operate at lower temperatures and decreasing the occurrence of ground faults (see Figure 28).

Wannasut C. & Hongesombut K. (2013) studies the installation of battery energy storage system in distribution networks to defer the investment upgrade needed for the rehabilitation of the T&D network to incorporate the increased load. The study found that the construction of a new distribution line would be a more expensive solution than a BESS that would postpone the construction of line (Wannasut & Hongesombut, 2013). Dasgupta K. et al. shows that when considering and quantifying the added benefits of a BESS, one of which is the deferral of the T&D investments, BESS become more economically feasible and competitive. The simulations done in the study show that storage systems can be effective when it comes to T&D network congestion and upgrade deferral (Dasgupta, Hazra, Rongali, & Padmanaban, 2015). Spiliotis K. et al. (2016) built an optimization model to show that with the increasing number of distributed generation and the uptake of EVs, an increased grid flexibility will be needed to meet the peak loads of congested nodes. Furthermore, the study showed that distribution system operates will incur considerable cost reductions if local BESS units are utilized (Spiliotis, Ramos Gutierrez, & Belmans, 2016).

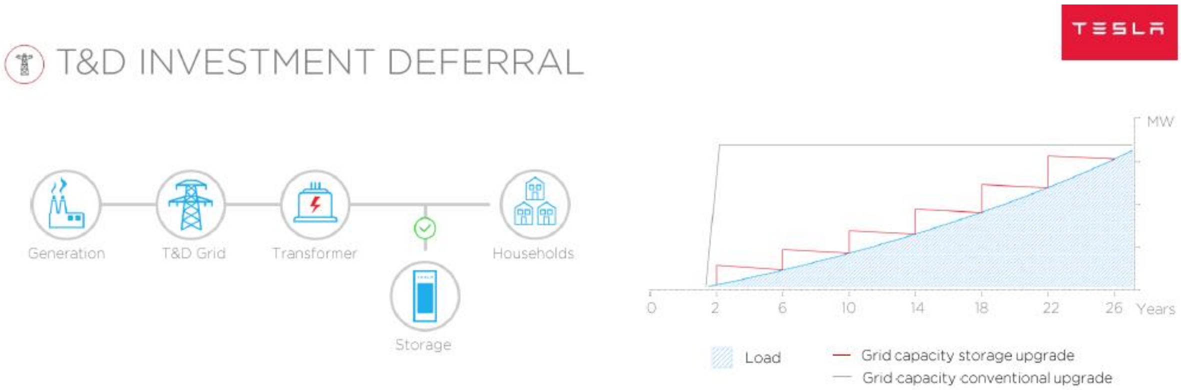

Figure 27: T&D investment deferral due to installation of BESS (Motors, 2016)

Go R. et al. utilized a two-stage stochastic mixed-integer linear program optimization model in order to study the impact of co-optimizing generation, transmission and bulk ESS and reached a finding that T&D investment deferral was the major benefit of the co-optimization resulting in $180 million cost saving per year. Furthermore, the study shows that if the two assets of generation and transmission are optimized and planed for first and optimization for ESS is done at a later stage, the cost savings drastically drop to $3 million per year. In addition, the results show that utilizing BESS having a power to energy ratio of 1:6.3 allows the power system to integrate more renewable energy capacity (Go, Munoz, & Watson, 2016).

In order to get an avoided cost figure for deferring the investment in T&D, one can divide the capacity related T&D investment over a period of time and divide it by the load growth over the same period and then annuitize to get a cost per kW-year estimate. However, due to the lack of historic and current local data on the costs associated with upgrading the T&D network and the proportional relationship with the increased demand, quantifying the investment costs for T&D upgrade or rehabilitation on a per kW of load increase basis has proven to be a difficult task especially while considering the variations in power cable lengths, type of installation (aerial or underground) and the climate zone for different regions.

Referring to the US experience with the costs of T&D upgrade and investment deferral, estimates imported from multiple utilities in California and the Pacific Northwest provide an average avoided cost for T&D investment deferral of 50 $/kW-year with a range spanning between 30 $/kW-year to 105 $/kW-year which excludes investments related to rehabilitation of aging infrastructure (Neme & Sedano, 2012). Furthermore, the below figure imported from the California Public Utilities Commission shows the weighted average annual T&D avoided cost for large investor-owned utilities in 13 climate zones in California (Eyer, 2099):

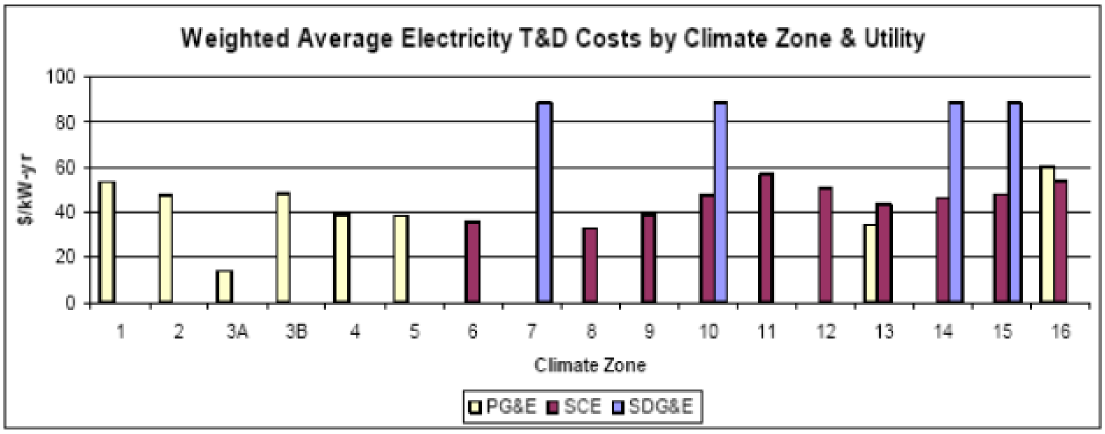

Figure 28: Weighted average annual T&D avoided cost in California (Eyer, 2099)

3.5.3 Capacity Value

In order to acquire a power figure for intermittent renewable energy sources that matches a reliable and readily available energy source, the term capacity credit or capacity value is defined and is often presented as a percentage of the rated capacity of the renewable energy source or in units of power (W).

Capacity credit or value has been defined in several ways. IEA describes it as the difference between peak demand and peak residual demand, which is the demand met by conventional power generation, as a percentage of variable renewable capacity installed in a system (IEA, 2011). NREL defines it as the percentage or fraction of the variable renewable energy source that can be established to reliably meet demand (Kirby, Ma, & O'Malley, 2013). Mills and Wiser state that the capacity value of a solar plant reflects the avoided cost of building traditional power plants to reliably meet peak demand (Mills & Wiser, 2012). Therefore, it can be established that the capacity value or credit of a variable renewable energy plant represents the capacity of the plant when it is equated to a non-renewable power generation plant that can meet the demand with an ensured reliability.

The importance of capacity credit and its value is manifested when modeling a power system having renewable and fossil fuel-based power generation units connected to the same grid. In addition, it is essential to define and calculate its value when studying the reliability of a power system in meeting the load and peak demand.

Methods to calculate the capacity value of variable renewable energy generation sources are numerous with a considerable amount of literature for the different methods available. Different utilities in different parts of the world use different models and approximations to calculate the capacity value so that to incorporate it into their capacity expansion models and to calculate the expected loss of load probability.

Getting an accurate figure for the capacity value has proven to be a difficult task as estimates must be made and the accuracy of calculations is affected by the resolution of data for the demand and power generation used. That is why, estimation techniques are used which can be divided into two main criteria: reliability-based approaches that principally use the loss of load probability (LOLP) as a standard reliability metric; and approximation methods that focus on a subset of hours where there is high risk of the system experiencing a loss of load.

One of the most common reliability approaches used and found in literature is the LOLP probabilistic approach that makes use of the Effective Load Carrying Capability (ELCC) method. The ELCC is defined as the value by which the system load can increase after adding the variable energy source and without changing or affecting the original LOLP of the system. To calculate the ELCC, first the original LOLP or loss of load expectation (LOLE) of the system is calculated by taking into consideration the equivalent forced outage rates (EFOR) of the different generators. Second, the variable energy source (PV, wind, ect.) is added to the generation mix and a fixed controllable load is added to the system. Third, the LOLE of the new system is iteratively calculated by varying the fixed controllable load until the new LOLE value is equal to the previous LOLE value. The added fixed load that made the two LOLEs equal is equivalent to the ELCC of the added variable energy source.

Other reliability methods that use a similar approach to the ELCC are the Equivalent Conventional Power (EPC) approach and the Equivalent Firm Capacity (EFC) approach.

As reliability-based methods require considerable computational effort and generation and consumption data that span over a period of several years and have a sub-hourly resolution, approximation methods are widely used that focus on a subset of hours where the load is the highest. These approximations methods include the Capacity Factor Based Approximations, Graver Approximation Based Method and the Z-Method.

NREL's "8760-Based Method for Representing Variable Generation Capacity Value in Capacity Expansion Models" well suits the Lebanese case as an approximation method for calculating the capacity credit of variable renewable energy plants as it offers a more refined and accurate version of capacity value approximations and combines parts of the Capacity Factor Based Approach with the ELCC method and is similar to the method used in the IEA World Energy Model. The main differences between NREL's method and other approximation methods is that it uses load duration curves to estimate the contribution of the added variable renewable energy source. Load duration curves reflect the total load sorted from hours of highest load to hours of lowest load. Further, the model considers time-synchronous hourly generation and consumption values across the 8760 hours of the year enabling the localization of all high load durations. The method also provides a self-consistent framework that can be mapped and extrapolated correctly while using the 8760-hourly data of a single year (Paul Denholm et al., 2016).

CHAPTER 4

METHODOLOGY

4.1 Method Statement

In order to acquire a solid understanding on and quantify the economic feasibility of grid connected solar PV plants coupled with battery energy storage systems in Lebanon, we shall revert to the LCOE metric and complete a benefit to cost (B/C) study to accommodate and quantify benefits and criteria that the LCOE metric calculation process does not incorporate.

To that end, three different models and scenarios, discussed in detail in the next sections, shall be built for the Lebanese power system in 2020. The first scenario utilizes conventional power generation units to fill in the supply-demand gap, the second incorporates utility scale solar PV plants and the third incorporates utility scale solar PV plants coupled with battery energy storage systems. The load data shall be projected to 2020 in order to attain an accurate representation for the load profile and demand. An energy dispatch model is developed in Homer Pro for the three scenarios in order to calculate the optimal system configuration while optimizing for the lowest levelized cost of electricity and output the optimal capacity and penetration of each technology and generation source so that to meet the constraints defined by the user. In order to account for the added benefits that include the capacity value, a benefit to cost study is completed to compare two modeled scenarios and assist in estimating the opportunity cost faced.

4.2 Simulation Software

Homer (Hybrid Optimization of Multiple Energy Resources) Pro software will be used and utilized in order to run the different scenarios and complete the simulations of the power system. The software is originally developed by NREL and is mainly used as an optimization tool to calculate the lowest levelized cost of electricity of a power system given different power generation units, system constraints and user inputs. The software is also capable of running sensitivity analyses to evaluate different configurations while varying factors that have a large impact on the operation of the system. It incorporates conventional generation units, renewable energy plants, energy storage, load management and other functionalities (Chua et al., 2015; Hesse et al., 2017; Lai & McCulloch, 2017).

Being that Homer Pro provides the capabilities of (1) inputting hourly load data, (2) defining the operational parameters for conventional power plants, the utility grid, solar PV plants and Li-ion battery storage systems, (3) specifying the dispatch strategy, (4) specifying the financing parameters, (5) running sensitivity analyses and (6) outputting the technical performance and economic data for each system component separately, it is an optimal platform to simulate the developed scenarios and compare them in a controlled and scientific manner.

4.3 Projecting the Lebanese electricity demand

The demand data for the year 2020 will be forecasted by adopting the collected load data for the year 2015 and considering an average yearly demand growth of 7% as mentioned in the Policy Paper and action plan reports ((LCEC), 2016; G. Bassil, 2010). An average annual growth rate of 5.81% is considered post 2020.

The total load demand for 2015 was 21,207 GWh and is forecasted to grow to 29,744 GWh in 2020 with an average demand of 3,395 MW having a forecasted average daily load profile as shown in the below figure:

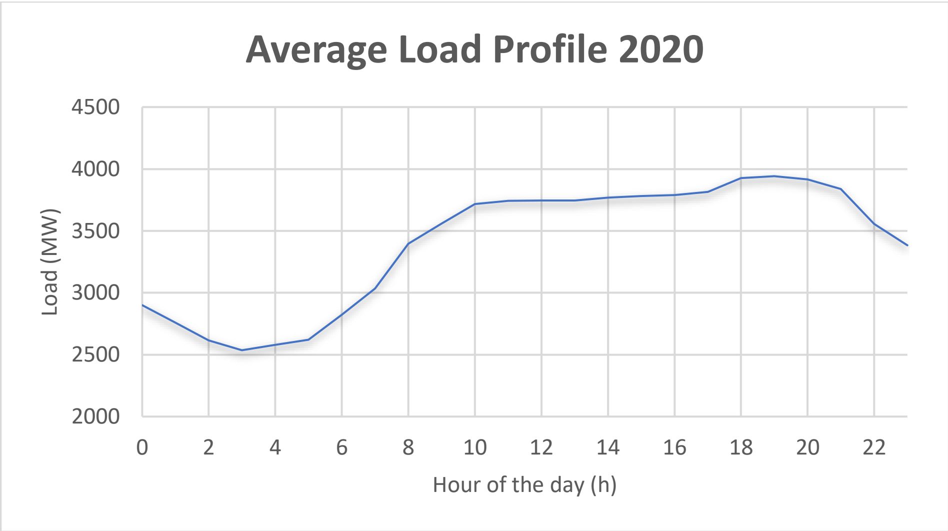

Figure 29: Average daily load profile in 2020

The hourly load data for the year 2020 will be inputted into the simulation software in order to represent an accurate model of the total load. Utilizing an accurate load profile in the simulation is critical so that to correctly model the effects of the variable generation on the power system and take into account the impacts of the non-coincidence of power generation and power consumption. It can be witnessed from the graphed average daily load profile that the average peak demand occurs between approximately 5 pm and 9 pm.

CHAPTER 5
SCENARIOS

Three scenarios shall be developed in order to study the impact of utilizing utility scale solar PV plants and battery energy storage systems and compare the conventional case with the case of leapfrogging to new technologies in the year 2020. Scenario One models an adaptation plan that uses one of the most efficient conventional generation technologies in order to fill in the supply deficit. Combined cycle gas turbines and open cycle gas turbines are utilized in order to build a best-case scenario where only conventional power generation is used. Scenario Two builds on the same model of Scenario One while optimizing for the optimal capacity integration of utility scale solar PV plants to reach the lowest overall cost of electricity. Scenario three builds on the model of Scenario Two while optimizing for the optimal capacity integration of utility scale solar PV plants coupled with Li-ion battery energy storage systems to reach the lowest overall cost of electricity. The projected electric load in 2020 with an hourly resolution is inputted as the primary load for each simulation and scenario.

The components and parameters that are constant for all three scenarios include the existing utility grid, the combined cycle gas turbines (CCGT), the open cycle gas turbines (OCGT), the financial parameters, the value of lost load and the minimum spinning reserve ratios.

The utility grid is modelled as a grid power source having a maximum power output of 2,000 MW, i.e. no upgrades to the current grid are made, with a fixed rate equal to 16.5 US cents per kWh generated for simplification purposes. A price for natural gas of 9 $/MMBtu is imported from a study done for Lebanon that incorporates the needed infrastructure to gasify and distribute the gas (C. N. Bassil, 2018). However, to take future price increase into consideration and considering the price projections of natural gas by the IEA and the world bank, an average conservative price of 9.5 $/MMBtu was considered (*Commodity Markets Outlook*, 2017; IEA, 2017b). The price of natural gas and the BESS is then considered as a sensitivity variable in order to study the effect of different price variations on the power system and the simulation results through a sensitivity analysis.

The main simulation and financial parameters and constraints are defined in the below table:

Parameter	Value
Project lifetime	30 years
Effective interest rate (adjusted for inflation)	12% per year
Inflation rate	2% per year
Percentage of unmet load	0%
Value of lost load	0.7 $/kWh
Dispatch strategy	Load following or cycle charging
Optimization objective	Economic minimization
Minimum spinning reserve	10% of current load value plus 40% of

Table 7: Main simulation and financial parameters and constraints

The input parameters for the CCGT power generation unit are summarized in the below table. Average values were calculated from different sources for the different parameters:

Parameter	Value
Lifetime[2]	30 years
Capital expenditure[3]	1080 $/kW
Fixed operation costs[3]	17.7 $/kW-year
Variable operation costs[3]	2.6 $/MWh
Installation time[3]	31.75 months
Heat rate[3]	6,591 BTU/kWh
Minimum load[4]	50%

Table 8: CCGT operational parameters

The input parameters for the OCGT power generation unit are summarized in the below table. Average values were calculated from different sources for the different parameters:

Parameter	Value
Lifetime[2]	30 years
Capital expenditure[5]	835 $/kW
Fixed operation costs[5]	11.81 $/kW-year
Variable operation costs[5]	13.6 $/MWh
Installation time[5]	27 months
Heat rate[5]	9,697 BTU/kWh
Minimum load	10%

Table 9: OCGT operational parameters

[2] Value imported from (*Projected Costs of Generating Electricity*, 2015)
[3] Average of the values imported from ((NREL), 2012; Commission, 2014; eia, 2018; Lazard, 2017; *Projected Costs of Generating Electricity*, 2015)
[4] Value imported from ((NREL), 2012)
[5] Average of the values imported from ((NREL), 2012; eia, 2018; Lazard, 2017)

5.1 Limitations

Due to the non-availability of sub-hourly load data and the limitations of the simulation software when it comes to defining the ramp rates and startup times of conventional power plants, the outputted levelized costs of electricity assumes a highly flexible system. However, and since our aim is to complete a comparative study between different scenarios, the results prove to be sufficient and represent electricity cost figures that are close to accurate figures found in real power systems.

5.2 Scenario One

Scenario One utilizes combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT) to fill in the supply-demand deficit in 2020. In this scenario Homer optimizes for the lowest cost of electricity and outputs the optimal capacity for the OCGT and CCGT units and the usage percentage for each of the utility grid, CCGT unit and OCGT unit given the above parameters and constraints. To be able to complete a comparative analysis, this scenario considers that it is feasible to construct and commission the needed conventional power generation plants by 2020, furthermore, and since both CCGT and OCGT technologies are at a mature stage, no future price declines are considered to occur between the period 2018-2020 ((NREL), 2012; *Projected Costs of Generating Electricity*, 2015). The below figure shows a schematic of the system:

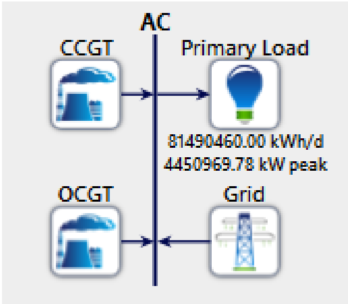

Figure 30: Schematic of Scenario One in Homer

5.3 Scenario Two

In Scenario Two the model of Scenario One is adopted while adding grid connected solar PV plants (see Figure 32). Homer optimizes for the best system configuration in terms of energy penetration and capacity of each technology while meeting the defined constraints in order to output the lowest possible overall cost of electricity. The global horizontal irradiance (GHI) and temperature data were imported from NASA Surface Meteorology and Solar Energy Database with the GHI scaled to have an annual average value of 5.38 kWh/m^2/day.

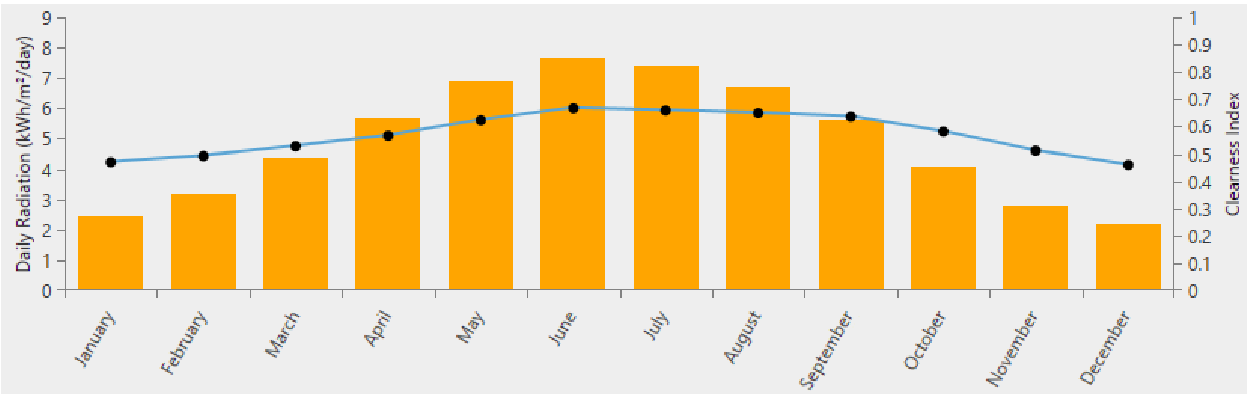

Table 10: Monthly GHI data

The solar PV system will act as a negative load in the system, thus, decreasing the operational capacity of the conventional generation units and their overall capacity and load factors. A spinning reserve of 40% of the instantaneous solar PV power is assumed in order to remain within reliability limits. This spinning reserve is attained from the rotating mass and inertia of the different conventional power plants. The optimal tilt and azimuth angle were selected in order to maximize the yield of the fixed tilt solar PV system. The below table gives the parameters and constraints defined for the solar PV system:

Parameter	Value
Lifetime	30 years
Capital expenditure[6]	570 $/kW
Fixed operation costs[7]	9 $/kW
Installation time[7]	9 months
Capacity factor	19.2%
Specific yield	1,680 kWh/kWp
Inverter efficiency	98%
Derating factor[8]	82%
Temperature effect on power	-0.39 %/°C

Table 11: Input parameters for the grid connected solar PV systems

[6] This represents the overall price of the system including EPC costs, power electronics and interconnection
[7] Value imported from (Lazard, 2017)
[8] Nominal derating factor is 88% after 25 years. A derating factor of 82% was considered for 30 years

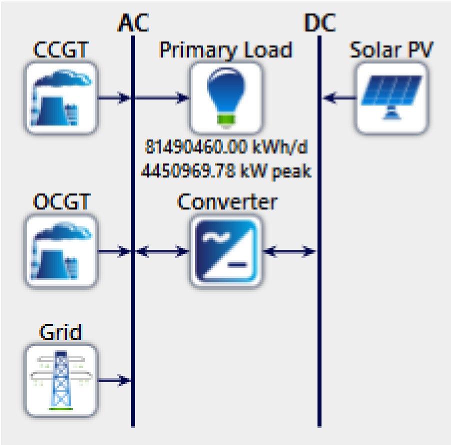

Figure 31: Schematic of Scenario Two in Homer

5.4 Scenario Three

In Scenario Three the model of Scenario Two is adopted while coupling the solar PV plants with Li-ion battery energy storage systems (see Figure 33). As stated earlier, a DC-coupled architecture shall be considered as it provides the added benefits of utilizing less power electronics and provides the capability of installing distributed systems. The cost of the power electronics and battery system BOS are incorporated into the cost of the battery bank without reducing the BOS costs of the PV system to remain extra conservative when considering cost estimates. Homer then optimizes for the best system configuration in terms of energy penetration and capacity of each technology while meeting the defined constraints in order to output the lowest possible overall cost of electricity. No specific Li-ion technology was selected, rather the average operational parameters of the different technologies along with an average price were imported from the data collected above. The below table presents the input parameters and constraints for the Li-ion BESS:

Parameter	Value
Lifetime	15 years
Capital expenditure	380 $/kWh
Fixed operation costs[9]	1% of Capex
Replacement cost[10]	145 $/kWh
Minimum State of Charge	10%
Roundtrip efficiency	90%
Rectifier efficiency	98%
Derating limit	30% of initial capacity

Table 12: Input Parameters of BESS

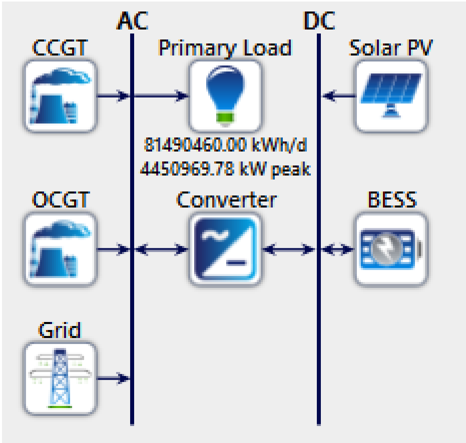

Figure 32: Schematic of Scenario Three in Homer

[9] Value imported from (Lazard, 2017)
[10] Value imported from (IRENA, 2017) and based on a battery price of 73 $/kWh beyond 2030

CHAPTER 6

RESULTS AND DISCUSSIONS

6.1 Scenario One results

The optimal configuration was found to consist of 4 GW of CCGT plants operating with the 2 GW utility grid. The electricity produced from the CCGT plants made up more than 99% of the consumed electricity with the utility grid supplying less than 1% of the energy only during peak hours. The overall levelized cost of electricity was found to be 8.6 US cents per kWh with the cost of grid electricity at 16.5 US cents per kWh and the marginal cost of electricity from the CCGT plants at 6.12 US cents per kWh. The needed initial capital is USD 4.32 billion which represents the capital cost of the CCGT power plants. Furthermore, the mean electrical efficiency of the CCGT plants was found to be 53.4% while operating 8,760 hours per year and having a capacity factor of 84.3%.

The optimal dispatch strategy was the cycle charging (CC) strategy where whenever a generator needs to operate, it operates at full rated power to serve the primary load first and then feeds surplus electric power to lower priority loads such as charging an energy storage bank.

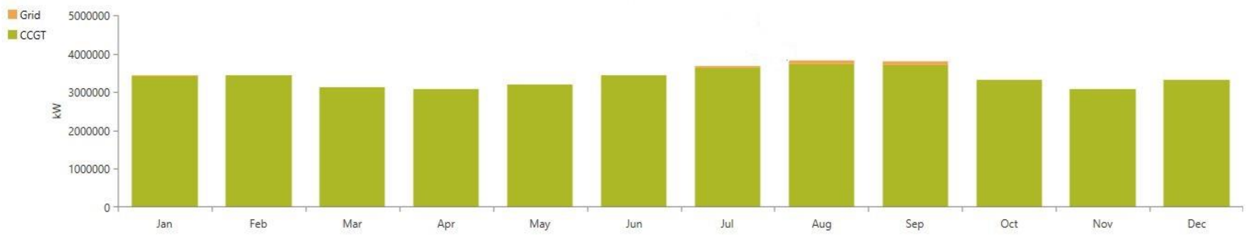

Figure 33: Scenario One - monthly average electric production

Running the simulation without considering the existing utility will result in an optimal configuration having a CCGT capacity of 4 GW and an OCGT capacity of 500 MW with an overall levelized cost of electricity of 9.03 US cents per kWh and an initial capital of USD 5.28 billion. However, in this configuration an OCGT plant was considered due to its low minimum load ratio of 10% and not due to its faster ramp rate and startup time that enable it to meet the fluctuating peak load.

6.2 Scenario Two results

The optimal system configuration consisted of 2.5 GW of CCGT power plants, 100 MW of OCGT power plants, the existing 2 GW utility grid and 6.11 GW of solar PV plants connected to a 4.45 GW grid-tied inverter. The overall levelized cost of electricity was found to be 8.54 US cents per kWh with solar PV energy forming 30% of the total energy supply and having a levelized cost of electricity 4.07 US cents per kWh. Furthermore, an initial investment of USD 6.27 billion dollars is needed to purchase and implement the new conventional and renewable power plants.

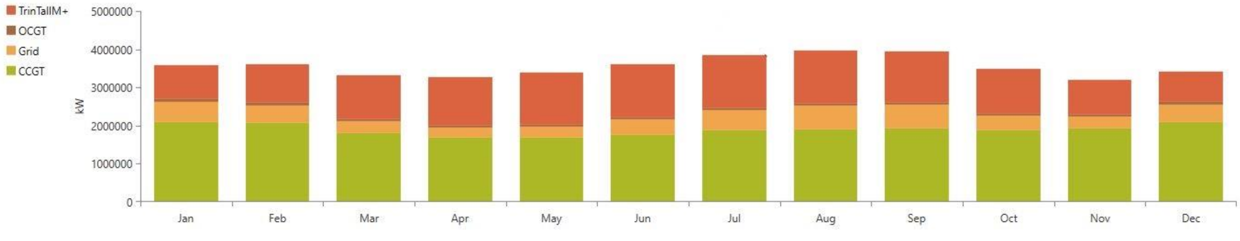

Figure 34: Scenario Two - monthly average electric production

Energy from the CCGT units formed 53.2% of the total supply with the OCGT plants and the grid supplying 1.55% and 12.2% respectively. Excess electricity from the renewable energy plant formed 3.82% of the total annual energy demand and 11.6% of the total energy produced from the renewable energy plant.

The CCGT plants operated with a marginal cost of electricity of 6.12 US cents per kWh and presented a capacity factor of 75.6% while operating for 7,302 hours per year and experienced 331 start-ups. The OCGT plants operated with a marginal cost of electricity of 9 US cents per kWh and presented a capacity factor of 55.2% while operating for 4,942 hours per year and experienced 783 start-ups. The operation of the OCGT plant can be attributed to its increased flexibility having a minimum loading ratio of 10% when operating with the variable renewable energy source with an optimal dispatch strategy of cycle charging selected.

6.3 Scenario Three results

In Scenario Three, the OCGT plants were neglected and replaced by a Li-ion BESS connected to the grid and coupled to the renewable energy PV plants. The battery bank will be take the role of the OCGT plants to meet the load during peak demand hours.

The optimal system configuration consisted of 3.5 GW of CCGT power plants, the existing 2 GW utility grid, 5.98 GW of solar PV plants coupled to a 951.2 MWh battery bank having a maximum power capacity of approximately 464 MW. A 6.6 GW converter is utilized and is common for the PV plants and the BESS while being responsible to feed power to the grid and charge the BESS from the PV plants and the CCGT plants. The overall levelized cost of electricity was found to be 8.06 US cents per kWh with solar PV energy forming 30.4% of the total energy supply and having a levelized cost of electricity of 4.07 US cents per kWh. Furthermore, an initial investment of USD 7.55 billion dollars is needed to purchase and implement the new conventional and renewable power plants coupled with the BESS.

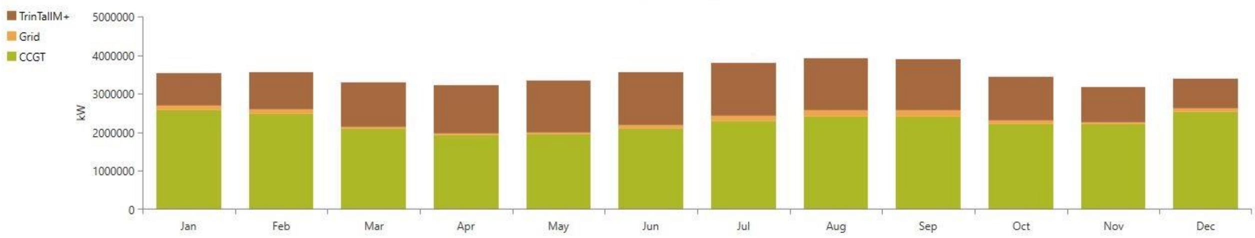

Figure 35: Scenario Three - monthly average electric production

Energy from the CCGT units formed 64.4% of the total supply with the PV plants and the grid supplying 30.4% and 2.9% respectively. Excess electricity from the renewable energy plant formed 2.64% of the total annual energy demand and 8% from the total energy produced from the renewable energy plant.

The CCGT plants operated with a marginal cost of electricity of 6.12 US cents per kWh and presented a capacity factor of 64.6% while operating for 7,063 hours per year and experienced 382 start-ups.

The BESS annual energy throughput was 393 GWh having a mean state of charge of 22% in December and approximately 33% in August. Given that the average load demand is approximately 3.4 GW and the usable nominal capacity of the BESS is 0.86 GWh, the battery bank autonomy is calculated to be approximately 0.252 hours when considering the annual average power demand as the load.

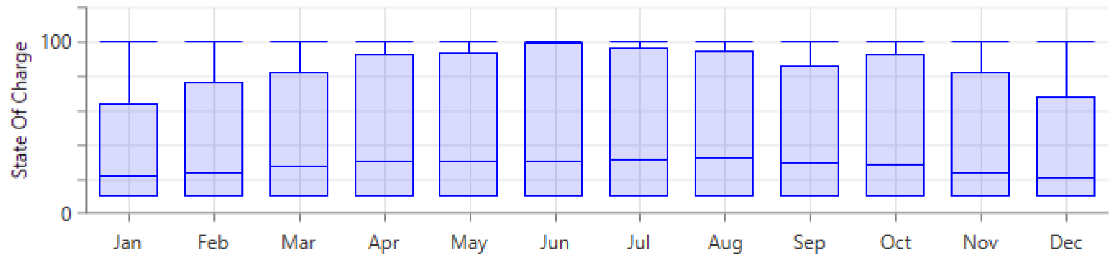

Figure 36: Scenario Three - BESS SOC per month

The optimal dispatch strategy selected was the load following (LF) strategy where the conventional generation plants ramp up only to meet the primary load demand and the charging of the battery bank is left to the renewable energy resource.

6.4 Summary of results

	Utility (GW)	CCGT (GW)	OCGT (MW)	PV (GW)	BESS (MWh/MW)	LCOE ($/kWh)	Excess Elec. (%)	Initial Capital (b$)	Dispatch Strategy
Scenario One[11]	**2**	**4**	**0**	**0**	**0**	**0.0861**	**0**	**4.32**	**CC**
Scenario One[11] (OCGT)	**0**	**4**	**500**	**0**	**0**	**0.0903**	**0**	**5.28**	**CC**
Scenario Two	**2**	**2.5**	**100**	**6.11**	**0**	**0.0854**	**3.82**	**6.27**	**CC**
Scenario Three	**2**	**3.5**	**0**	**5.98**	**951.2/464**	**0.0806**	**2.64**	**7.55**	**LF**

Table 13: Summary of the results for the three simulations and scenarios

[11] Due to limitations of Homer Pro, specifically the unavailability of limiting factors such as the ramp rate and startup time, Scenario One was modeled twice while considering the utility grid in one scenario and OCGT in the other. In the Scenario without OCGT, the CCGT plants are considered to have a very high flexibility allowing them to have a theoretical high ramp rate and startup time to meet the peak demand and fluctuations in the load which is a non-realistic assumption.

6.5 Discussion

In order to characterize the power demand and categorize the base load, intermediate load and peak load, a load duration curve for the power demand in 2020 is completed which graphs the hourly power demand organized in descending order.

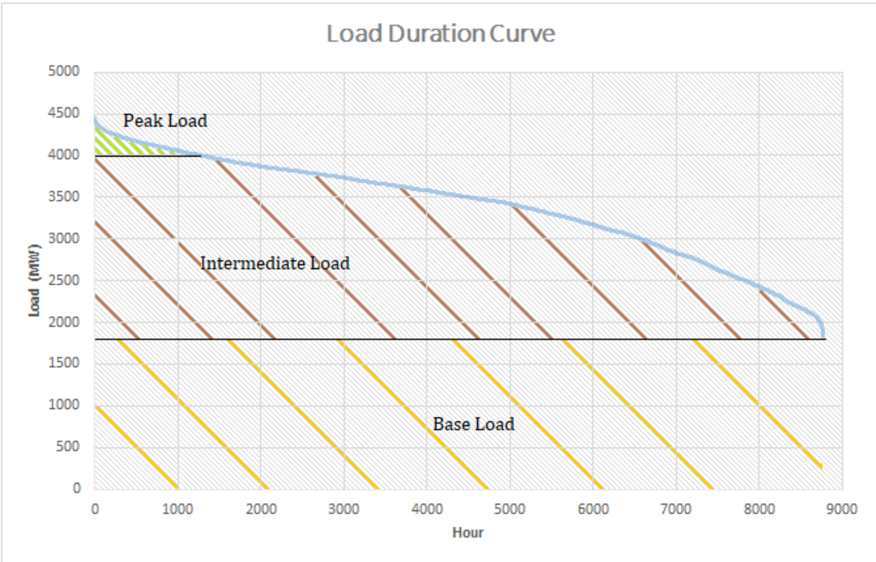

Figure 37: Load duration curve in 2020

From the load duration graph, we assign the base load to be the region between zero load and 1825 MW, the peak load to be region between 4,000 MW of load and 4,450 MW and the intermediate load region to be the region in between the base load and the peak load regions. A large slope value can be witnessed for the curve representing the nature of the highly variable load; the load factor can be calculated by dividing the average load of 3,395 MW by the peak load of 4,450 to get 76.3%.

For Scenario One and considering the option of adding only conventional power plants, 4 GW of CCGT plants were presented to be the most economical solution when it comes to filling in the supply-demand deficit. The CCGT plant supplied more than 99% of the total electric load with the existing utility power plants supplying all the load that is above 4 GW or below 2 GW. The CCGT plant had a high capacity factor of 84.3% and a mean electrical efficiency of 53.4%. The below figure shows the yearly load profile with an hourly resolution and presents the fraction supplied by the CCGT plants and the fraction supplied by the existing utility:

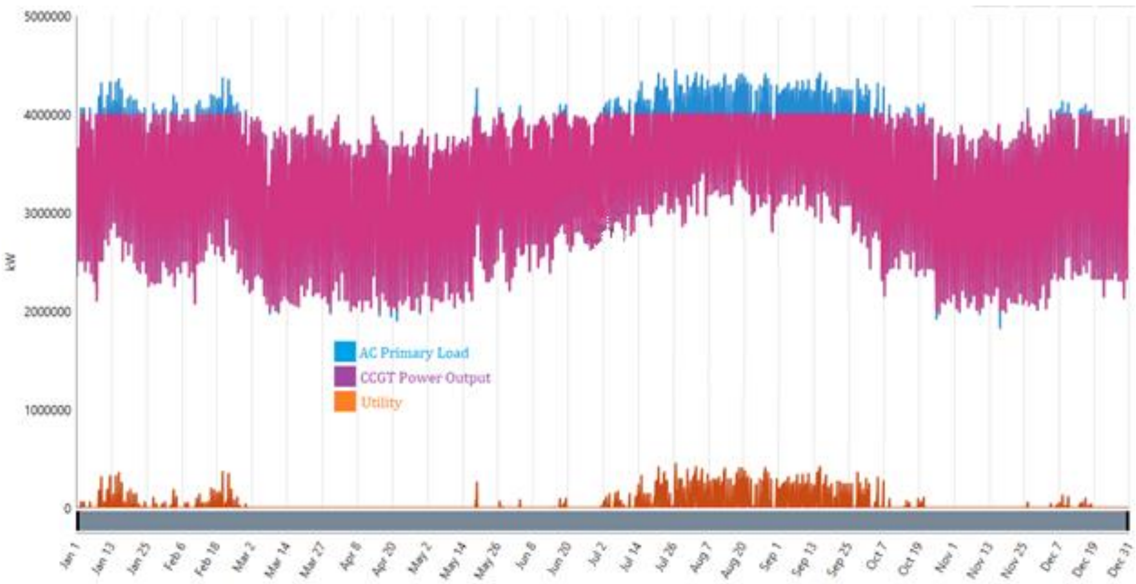

Figure 38: Scenario One - yearly load and generation profile

The existing utility generators were treated as the peaking power plants as no ramp rate nor startup time was factored in for the utility. Therefore, the LCOE of 8.61 US cents per kWh for this scenario is slightly underrated especially since an average electricity cost was selected for the utility electricity and not the cost of running the peaking power plants.

To that end, a simulation was run under the same conditions however the utility power plants were replaced by a 500 MW OCGT plant. A more realistic LCOE was computed at 9.03 US cents per kWh with the OCGT plant having a marginal generation cost of approximately 9 US cents per kWh. We can deduce from this scenario and simulation that under the premise of having an adequate and reliable transmission and distribution system, and while factoring in the costs associated with the infrastructure for natural gas gasification, transportation and distribution into the simulation, investing an initial capital of approximately USD 5.28 billion to purchase and install 4 GW of CCGT power plants and 500 MW of OCGT power plants both running on natural gas would result in a cost of electricity much less than that of the existing utility electricity cost and will allow the utility company and the government to remove all subsidies from the applied tariffs.

When adding the utility scale solar PV plants in Scenario Two, the CCGT capacity is reduced to 2.5 GW with an OCGT capacity of 100 MW. Due to the low LCOE of the 6.11 GW solar PV plant, the overall LCOE of the power system is reduced to 8.54 US cents per kWh having a renewable energy fraction of 30%. The below figures represent the load profile along with the power supply sources, excluding the OCGT plants, for seven days in January, April, August and November:

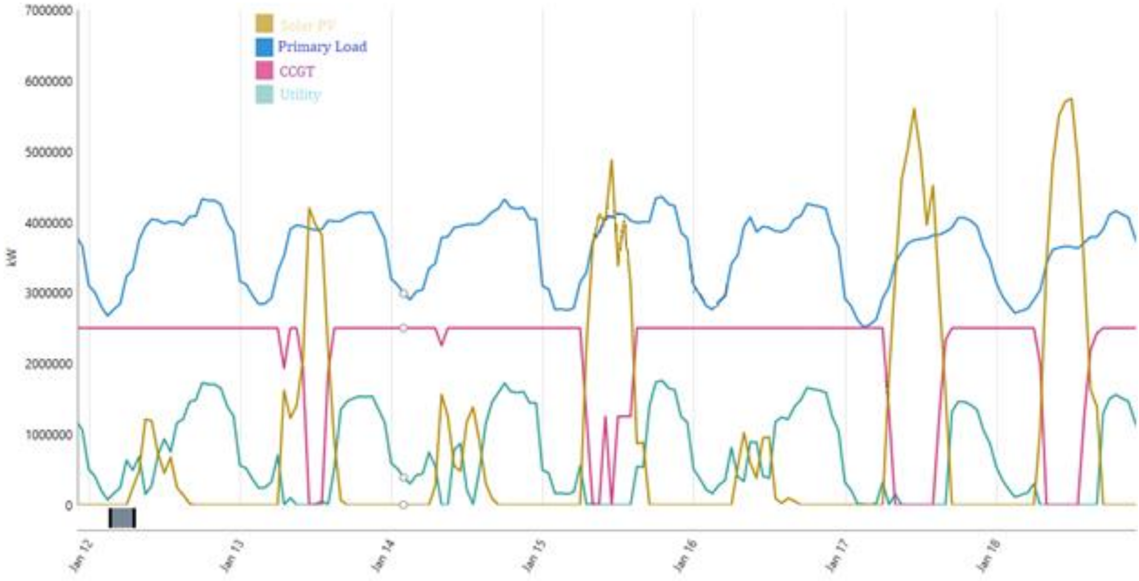

Figure 39: Scenario Two - January load and generation profile

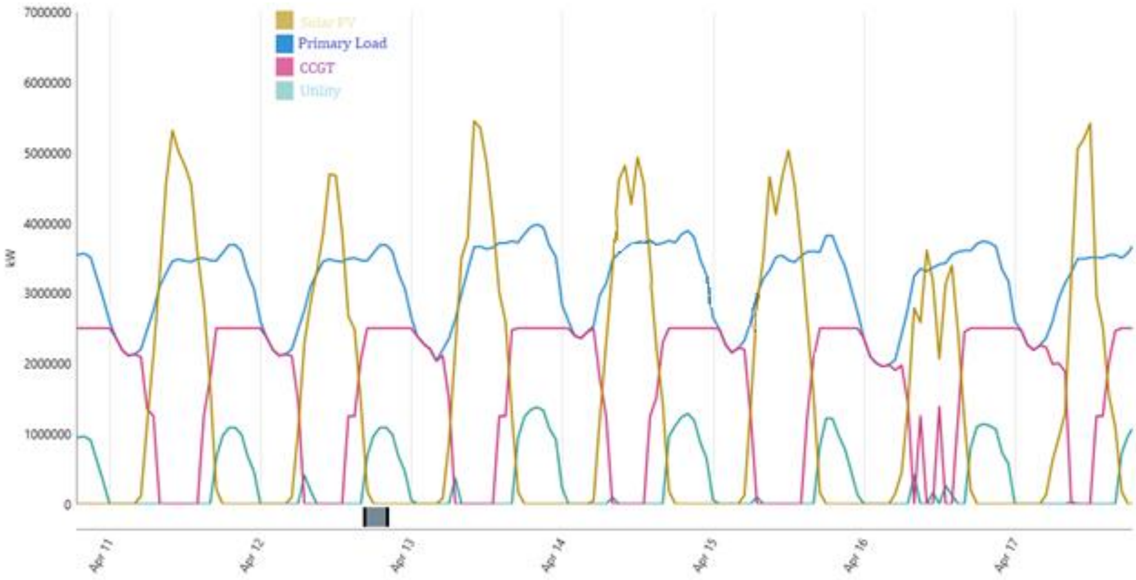

Figure 40: Scenario Two - April load and generation profile

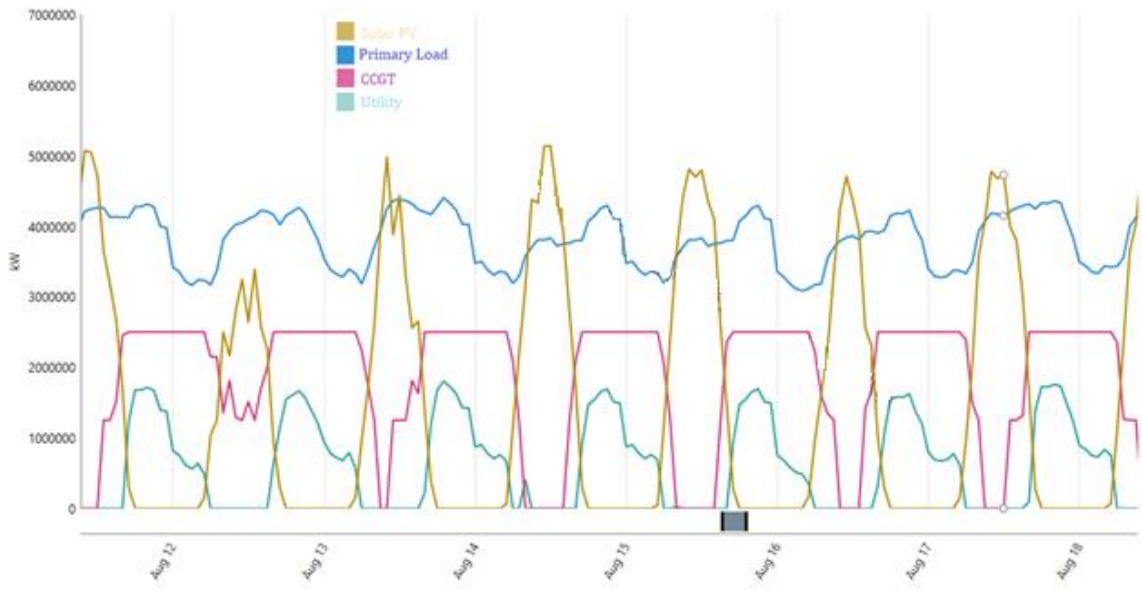

Figure 41: Scenario Two - August load and generation profile

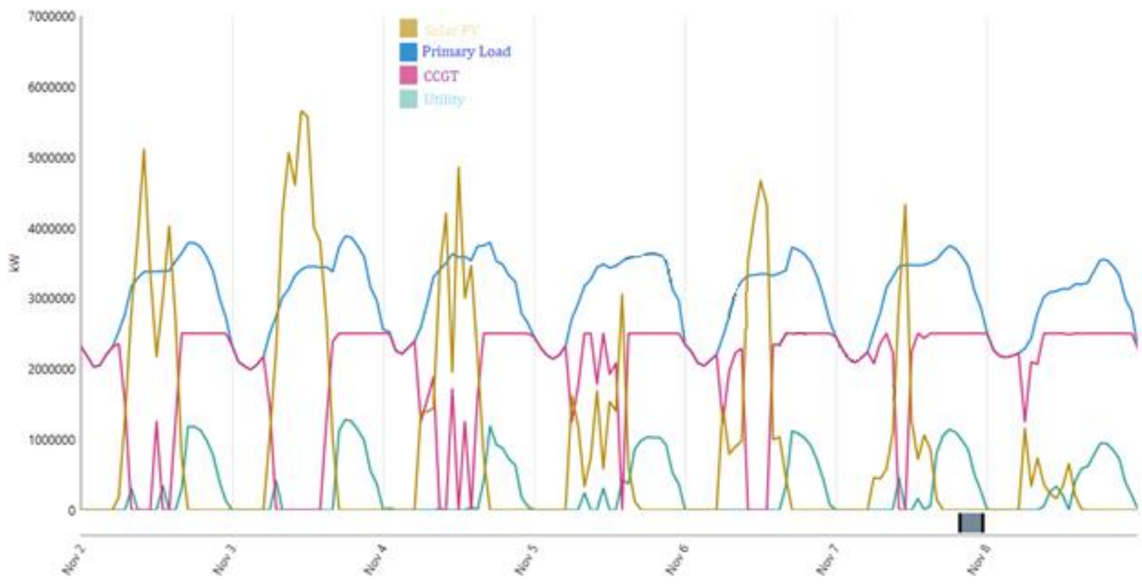

Figure 42: Scenario Two - November load and generation profile

From the graphs, one can witness the high variability of the solar resource in the Winter and Autumn months as compared to the Spring and Summer months. In addition, the non-coincidence between power generation from the solar PV plant and the hours of peak demand can be witnessed year-round. This is a critical factor that presents an economical and technical limit to the percentage penetration of solar PV plants into the Lebanese grid, especially when observing that the percentage of curtailed solar PV energy is 11.6% which is in line with the literature addressed when considering such high values of renewable penetration.

Furthermore, and even though operating reserve limits were set at 40% of the current solar PV power plus 10% of the current load power, the above modeled system assumes a highly flexible utility power generation and grid with the needed ancillary services and control. This can be seen mostly in the evening during peak hours where the utility power generation ramps up and down following the load demand and during day on cloudy days where the CCGT power plants respond in a very fast manner to the highly variable and intermittent renewable energy source.

In regards the 100 MW OCGT plant, and mainly due to the fact that its marginal cost of electricity is cheaper than that of the utility power plants and the fact that it can ramp down to 10% of its capacity, the plant starts and ramps up in the afternoon to cater for the gradual decrease in the solar resource and support in meeting the evening peak demand and continues to operate until early morning hours when the solar resource starts to inject power again. The below figure presents the load curve of a typical week and the generation profile of the conventional power plants:

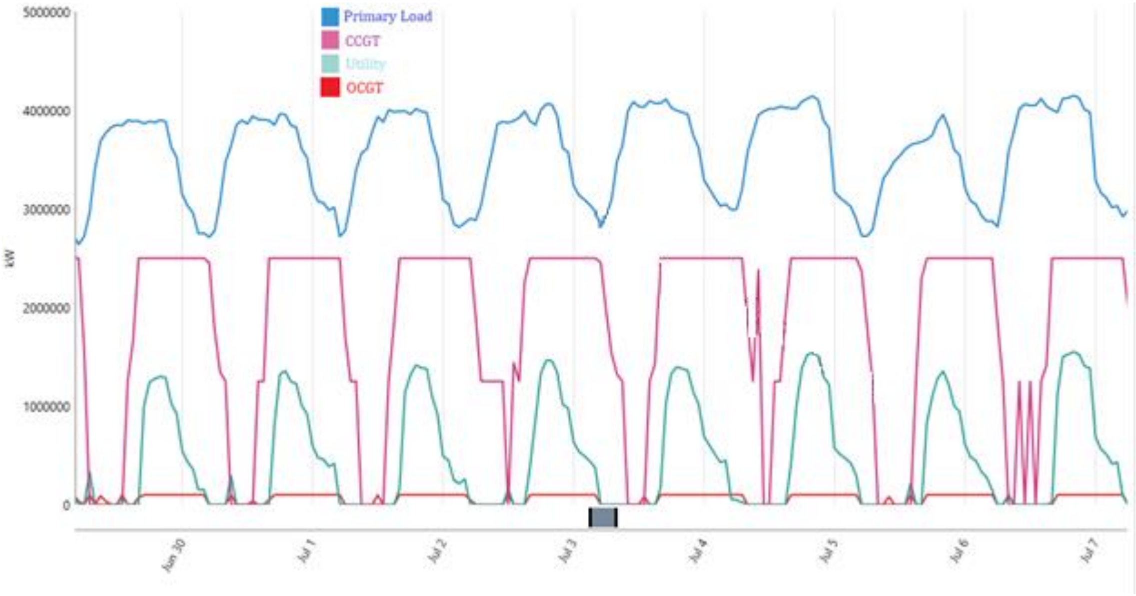

Figure 43: Scenario Two - load profile with conventional power generators

Flexibility of the conventional generation units and the existing utility power generators is of critical importance in Scenario Two due to the large penetration of the variable renewable energy source. To that end, the CCGT units experienced 331 starts and the OCGT units experienced 783 starts in one year, thus having an increased cycling and a subsequent increase in O&M costs and an expedited system deterioration that are not represented in the simulated LCOE. The finding of the direct correlation between increased cycling of the conventional power plants and the increase in the penetration of variable generation is in line with what is found in the addressed literature and imposes increased incidents of large thermal and pressure stresses on the conventional power plants (Paul Denholm et al., 2017; Paul Denholm et al., 2016).

Removing the OCGT power plant and adding a grid connected BESS results in Scenario Three where the system is simulated in order to optimize for the most economic configuration. The system resulted in a slight decrease in the solar PV capacity to 5.98 GW, an increase in the CCGT capacity to 3.5 GW and a grid connected

BESS having a power capacity of 464 MW and an energy capacity of approximately 951.2 MWh. The usable capacity of the BESS is 90% of the nominal capacity due to the minimum DoD constraint and is equal to 856 MWh. Considering the average load of 3.4 GW in 2020, the BESS will be able to provide an average autonomy of approximately 15 minutes. This finding suggests that the BESS is mainly used for renewable energy firming and can be used for the provision of ancillary services such as frequency and voltage control while having limited capabilities when it comes to load shifting. The below figure presents the load profile for a typical week in 2020 while showing the operation of the different power plants and the renewable energy firming phenomenon represented by the inverter output graph:

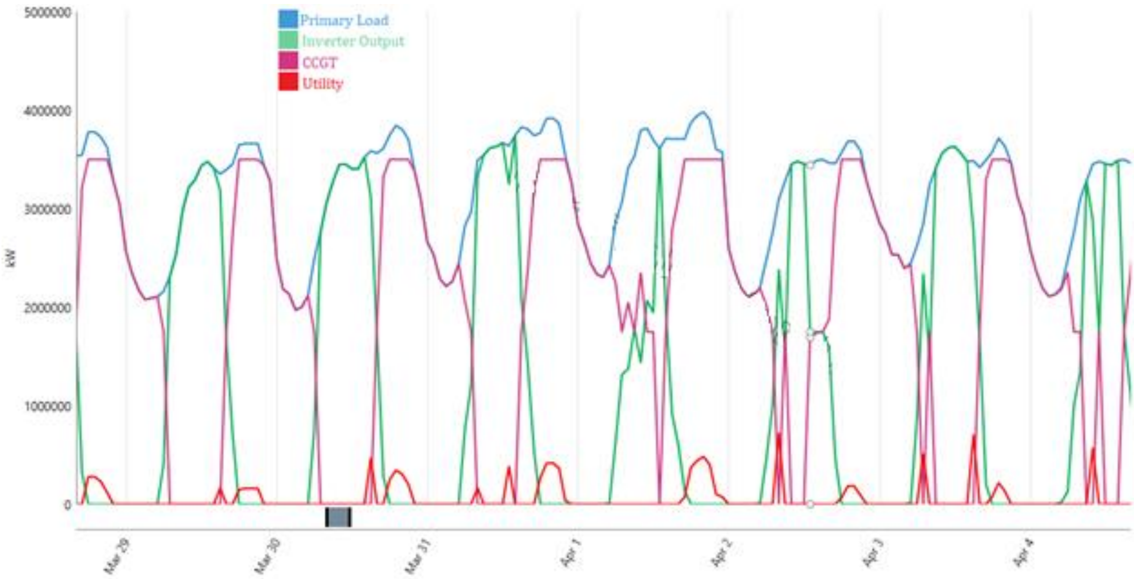

Figure 44: Scenario Three – load and generation profile of a typical week in 2020

In comparison with Scenario Two, the results of Scenario Three presented a lower LCOE at 8.05 US cents per kWh which is cheaper by approximately half a cent. Furthermore, utility supplied energy was reduced from 12.2% of the generation mix to 2.9% in Scenario Three. In addition, the renewable energy penetration was increased slightly from 30% to 30.4% with an increase also witnessed in CCGT penetration from 53.2% to 64.4%. The below figures present the load profile with solar PV generation and BESS output and input power for four different months:

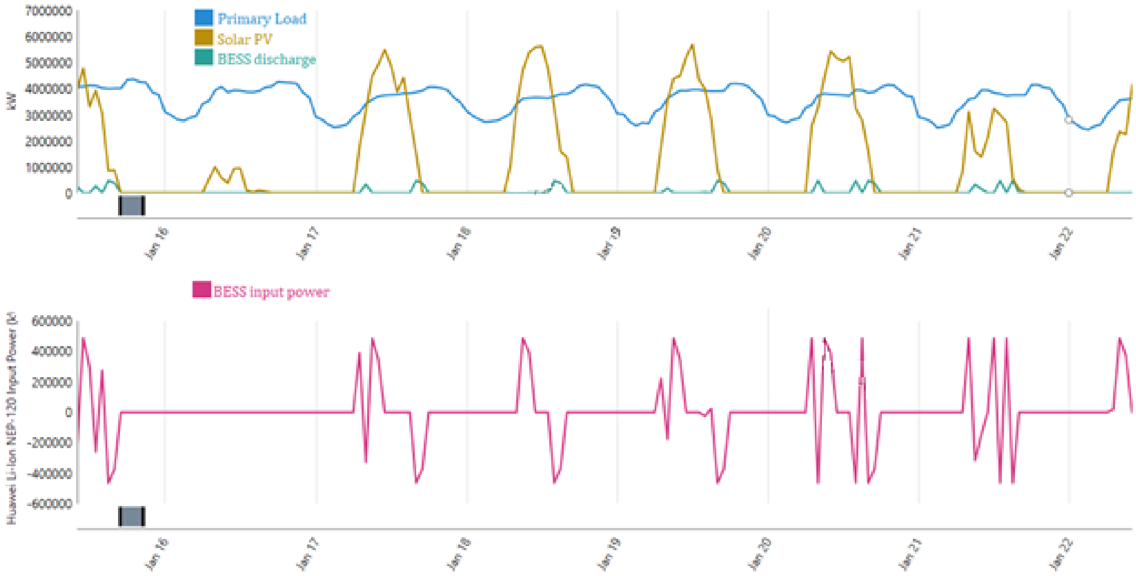

Figure 45: Scenario Three - January load profile with solar PV and BESS

Figure 46: Scenario Three - April load profile with solar PV and BESS

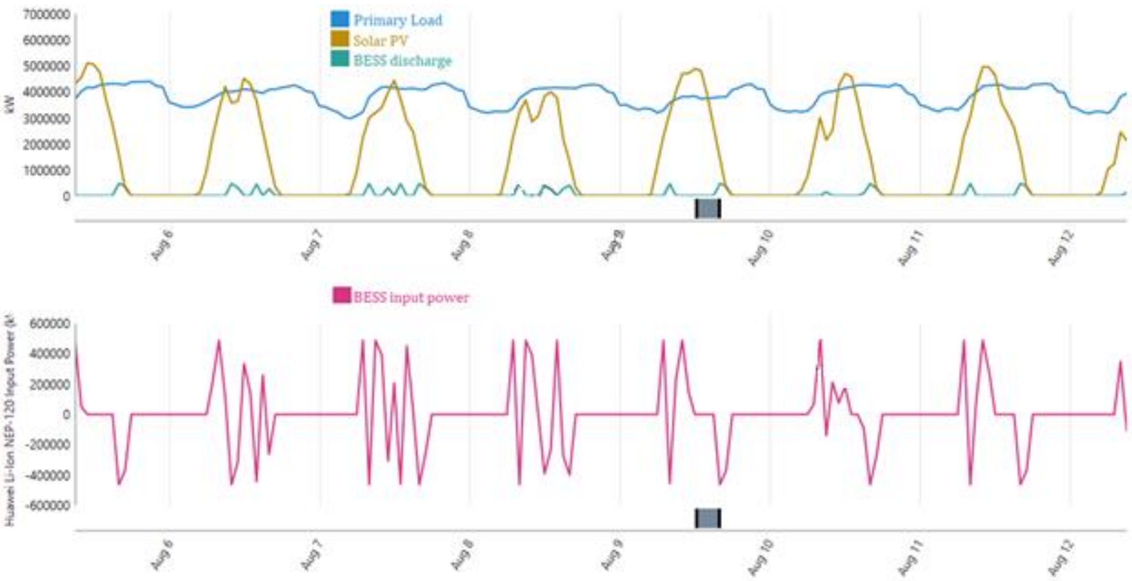

Figure 47: Scenario Three - August load profile with solar PV and BESS

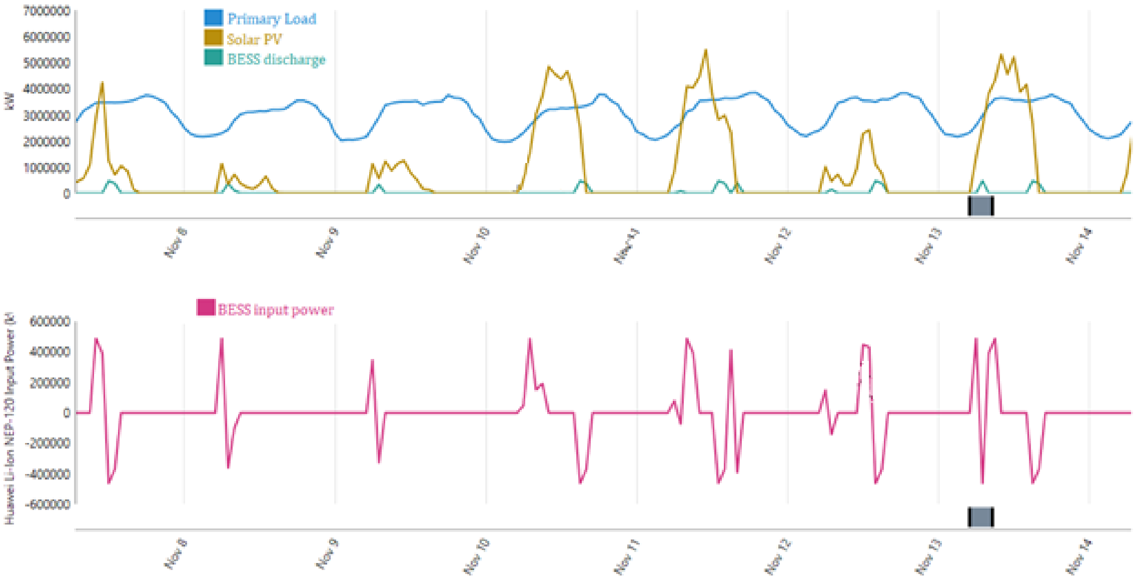

Figure 48: Scenario Three - November load profile with solar PV and BESS

Given the input parameters and costs assumed in 2020, we find that a DC-tightly coupled architecture is the most economical solution due to the load following dispatch strategy that was found to be optimal. The BESS only stores excess energy generated from the renewable energy plant and mainly discharges it during the day to smooth out the solar PV output and support in supplying the peak demand during the morning hours. An interesting finding is that the DC-tightly coupled BESS allowed for a slightly higher renewable energy penetration while the overall capacity of the solar PV plant decreased. This can be attributed to the renewable energy firming and smoothing phenomenon which decreased the amount of curtailed solar PV energy from 11.6% to 8%.

Therefore, it can be deduced that the increased renewable energy fraction, the decreased renewable energy curtailment and the decreased LCOE can be attributed to the renewable energy smoothing and firming feature of the added BESS having an average autonomy of 15 minutes. Here again, and based on the above graphs, we can perceive the crucial need of a flexible fleet of conventional power generation units. The below table summarizes and compares the results of Scenarios Two and Three:

	Solar PV (GW)	CCGT (GW)	OCGT (MW)	BESS (MWh)	Utility penetration (%)	RE penetration (%)	Curtailed RE energy (%)	LCOE (Cents/kWh)
Scenario Two	**6.11**	**2.5**	**100**	**0**	**12.2**	**30**	**11.6**	**8.54**
Scenario Three	**5.98**	**3.5**	**0**	**951.2**	**2.9**	**30.4**	**8**	**8.05**

Table 14: Results comparison between Scenario Two and Scenario

In order to calculate the levelized cost of electricity for the DC-tightly coupled solar PV plus BESS system we will utilize the annuity method to calculate the LCOE while considering a constant power output for simplification purposes. The LCOE annuitizing formula is presented below:

$$LCOE = \frac{Annualized\ costs\ for\ the\ DC\ tightly\ coupled\ system}{Annual\ Energy\ yield\ from\ the\ inveter}$$

Annualized costs are calculated at $ 409,611,253.68 for the solar PV system and $ 43,719,558.93 for the BESS giving a total annualized cost for the DC-tightly coupled system of $453,330,812.61. The annual energy yield is inputted as the annual energy output from the system inverter and is found to be 9,043,355,791 kWh. Therefore, the LCOE of the DC-tightly coupled solar PV system and BESS is calculated at 5.01 US cents per kWh which is approximately one cent greater than the LCOE of the solar PV system alone.

CHAPTER 7

B/C ANALYSIS

In order to quantify benefits that are not captured by the LCOE for the solar PV plant and the DC-coupled solar PV-BESS, the benefit to cost ratio (B/C ratio) is used and measured in our study by dividing the sum of the annual energy revenue and the capacity value by the annualized capital and operating cost. The ratio is calculated for both Scenario Two and Three to provide further comparative analysis.

7.1 Calculating the Capacity Value

NREL's "8760-Based Method for Representing Variable Generation Capacity Value in Capacity Expansion Models" approach is used to calculate the capacity value of the different systems. This method utilizes load duration curves in order to calculate the effective load carrying capacity (ELCC) of the variable generation plant during the "riskiest" hours or the hours of highest loss of load probability which are typically the first 100 hours of the load duration curve plot. The area between the load duration curve of the existing demand and the load duration curve of the existing demand less the variable generation output during the first 100 hours is considered to be the ELCC. After finding the ELCC, it is divided by the nominal capacity of the variable generator multiplied by 100 hours in order to attain the capacity value of the variable generator. The below formula represents the calculation of the capacity value:

$$Capacity\ Value = \frac{ELCC}{100 * Inverter\ capacity}$$

Afterwards, and in order to quantify the capacity value, it is multiplied by the annualized capital and running cost of a peaking power plant. This annualized cost is imported from Scenario One for the OCGT peaking plant at 128 $/kW-year and is in line with values found in the addressed literature (Paul Denholm et al., 2017).

The below two figures show the load duration curves for Scenarios Two and Three respectively with the ELCC for each scenario being the grey colored area between the two curves:

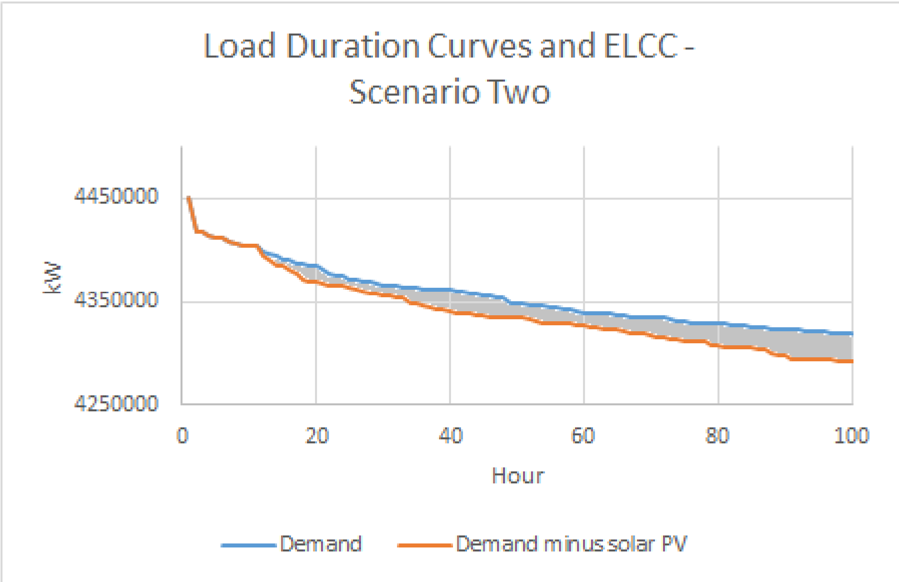

Figure 49: Load duration curves and ELCC for Scenario Two

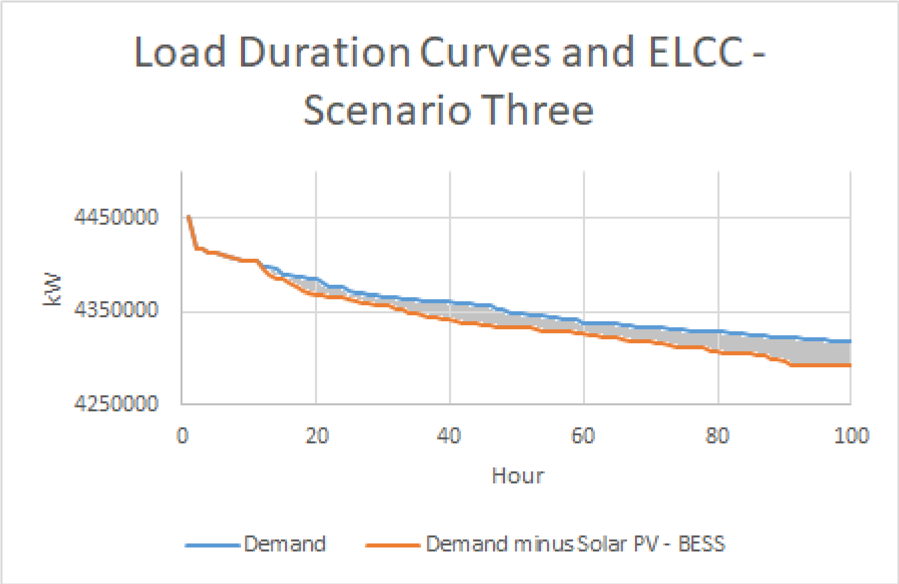

Figure 50: Load duration curves and ELCC for Scenario Three

The ELCC was found to be 1516 MWh for the solar PV system in Scenario Two and 1512 MWh for the DC tightly coupled solar PV – BESS system in Scenario Three. The capacity values of the two systems were found to be almost identical at 0.34% due to the small BESS system relative to the PV system.

It is critical to note that the capacity value of the BESS was not calculated separately due to the fact that it is a part of a tightly DC-coupled system and mostly functions as a renewable energy firming device with negligible impact on load shifting. Furthermore, and since both scenarios did not have any effect on the yearly peak demand supplied by conventional generation, it is assumed that no transmission upgrade investment deferral is incurred due to the addition of the solar PV plant and BESS. This phenomenon is mainly attributed to the load profile witnessed in Lebanon and the non-coincidence of the solar PV power generation with the evening peak demand which will be discussed in an upcoming section.

Therefore, the solar PV system in Scenario Two and the solar PV – BESS system in and Scenario Three can be equated to a 15,164 kW and a 15,119 kW of peaking power plants respectively. Multiplying these values by the annuitized cost of a peaking power plant imported from Scenario One results in a yearly benefit or avoided cost of \$ 1,940,992 for the solar PV system and \$ 1,935,232 for the solar PV – BESS system.

7.2 Energy Revenue

The second component of the benefits is the energy revenue generated from the two systems. To calculate the annual energy revenue from the solar PV plant and the solar PV – BESS plant we will multiply the annual energy produced by the marginal cost of conventional energy generation. For simplification purposes and since both systems mainly produce energy off-peak hours and the BESS does not result in any load shifting, we will utilize the marginal cost of operating the CCGT units of 6.12 US cents per kWh as our value for the generated energy. This yields a yearly energy revenue of \$553,453,374.4 for the solar PV – BESS system and \$545,240,206.3 for the solar PV system.

The benefits to cost ratio for each system is then calculated by aggregating the benefits and dividing by the annuitized capital and running costs. The total annualized benefits and costs for the PV system in Scenario Two are \$546,181,198.3 and \$418,525,141.78 respectively. The total annualized benefits and costs for the PV-BESS system in Scenario Three are \$555,388,604.4 and \$453,330,812.6 respectively. The below formula shows the calculation methodology:

$$\frac{B}{C} = \frac{capacity\ credit + energy\ revenue}{annualized\ system\ cost}$$

The B/C ratio for the solar PV system in Scenario Two is found to be equal to 1.307 and for the solar PV – BESS system of Scenario Three to be equal to 1.225. It is noted that the ratio is higher for the solar PV system alone due to the added costs of the BESS as compared to its energy revenue which is in line with the addressed literature (Paul Denholm et al., 2017). Furthermore, it can be witnessed that the capacity value of both systems forms a negligible percentage of the total benefits which can also be attributed to the load profile and the non-coincidence of the solar resource with hours of peak demand. This fact is one of the main causes of the economic and technical ceiling for the percentage penetration of a solar resource into the Lebanese grid.

Calculating the incremental B/C ratio to asses if the added benefits of the PV-BESS justify the added costs, we subtract the benefits of the PV system from the benefits of the PV-BESS system and divide by the subtraction of the costs of the PV system from the cost of the PV-BESS system (shown in the below formula). The incremental B/C ratio outputs a value of 0.24 which is less than 1, thus, not justifying the added costs of the PV-BESS system in comparison with its benefits.

$$\Delta\left(\frac{B}{C}\right) = \left(\frac{Benefits_{\ PV-BESS} - Benefits_{\ PV\ alone}}{Costs_{\ PV-BESS} - Costs_{\ PV\ alone}}\right)$$

The added benefits of the ancillary services provided by the BESS or the solar PV system and the costs associated with the enhanced flexibility and increased cycling of the conventional power plants, the information and communication technology (ICT) infrastructure needed and the dispatch platform to optimally control such high penetrations of variable generation were not included in the B/C study and were assumed to cancel each other out for simplification purposes.

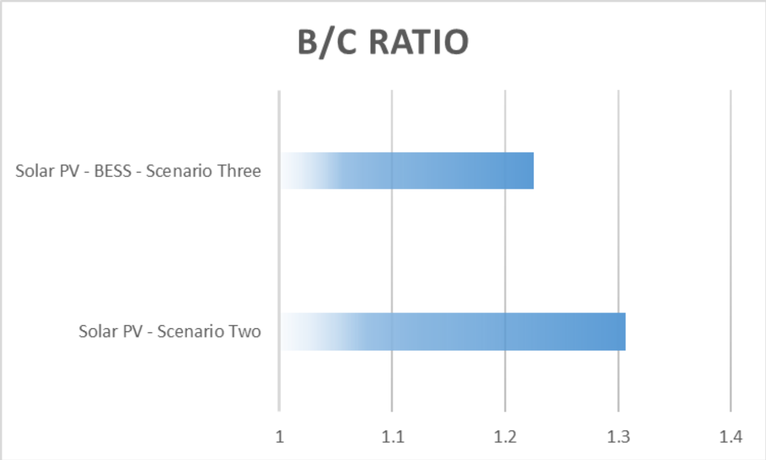

Figure 51: B/C ratio of the systems in Scenarios Two and Three

7.4 Sensitivity analysis

7.4.1 Varying the costs of natural gas and BESS

In order to study the impacts of the selected price of natural gas and the forecasted costs of grid-connected BESS, a sensitivity analysis is carried out by varying the price of natural gas to be either 9.5 $/MMBtu or 11.5 $/MMBtu and the capital cost of the BESS to be either 380 $/kWh or 240 $/kWh which represents the low end of our forecasted price range. The below table shows the input data for each sensitivity variable where three sensitivity cases are built:

	Natural gas price ($/MMBtu)	*BESS capital cost ($/kWh)*
Base case[12]	*9.5*	*380*
Sensitivity case 1	*9.5*	*240*
Sensitivity case 2	*11.5*	*240*
Sensitivity case 3	*11.5*	*380*

Table 15: Sensitivity analysis cases

A simulation is run for each sensitivity case and the resulting system configuration and LCOEs are presented in the below table:

	PV (GW)	BESS (GWh)	CCGT (GW)	RE fraction (%)	LCOE (₵/kWh)
Base case[12]	**5.98**	**0.95**	**3.5**	**30.4**	**8.06**
Sensitivity case 1	**6.22**	**1.29**	**3.5**	**31.6**	**8.01**
Sensitivity case 2	**6.72**	**1.24**	**3.5**	**32.9**	**8.85**
Sensitivity case 3	**6.46**	**0.89**	**3.5**	**31.7**	**8.91**

Table 16: Simulation results of sensitivity cases

Sensitivity case 1 presents the lowest LCOE having the lowest cost for natural gas and the BESS. In this case, the solar PV capacity increases slightly by 4% and the BESS capacity increased by 35%. However, these capacity increases have minimal effect on the renewable energy penetration increasing it by 1.2% and a minimal effect on the LCOE decreasing it by only 0.05 US cents per kWh. This small change in results

[12] Equivalent to Scenario Three

can be attributed to the decreasing marginal return with increased renewable energy penetration phenomena that can also be found in the addressed literature.

For sensitivity case 2, the increased price of natural gas and the decreased price of battery storage yielded the highest renewable energy penetration with a 6.72 GW system and supplying 32.9% of the total load, however, the LCOE increased drastically by approximately 0.8 US cents per kWh. This Increase in LCOE shows the larger weight attributed to the fluctuations in the natural gas price as the CCGT units are responsible for meeting the majority of the load demand.

Sensitivity case 3 showed the highest LCOE at 8.91 US cents per kWh due to the increased natural gas and BESS costs. The capacity of the battery bank dropped to 0.89 GWh, however, the solar PV capacity increased to 6.46 GW supplying 31.7% of the total load.

It can be witnessed that due to the discussed economic limit, and when modelling for the lowest LCOE, varying the price of natural gas and the forecasted price of storage has minimal effect on the contribution of solar PV energy to the Lebanese power system, even if the solar PV capacity increased by 12.4% and the BESS capacity is increased by 30.5%, as seen in sensitivity case 2, this will only yield a 2.5% increase in solar PV penetration.

Following the above findings, we model and present below a sensitivity case and model where a BESS having a fixed capacity of four hours of storage is simulated while optimizing the configuration for all other variables to reach the lowest LCOE.

7.4.2 Designing for four hours of storage

We consider sensitivity case 4 having the same input parameters of Scenario Three however while fixing the BESS capacity to 15.1 GWh (4 hours of average load demand) and removing the existing utility power generators from the power system.

The results of the simulation are shown in the below table:

	PV (GW)	BESS (GWh)	CCGT (GW)	RE fraction (%)	LCOE (₵/kWh)
Sensitivity case 4	**3.38**	**15.1**	**4**	**17.2**	**10.35**

Table 17: Simulation results of sensitivity case 4

The optimization results from the simulation give further insight on the attractiveness and feasibility of utility scale battery energy storage coupled with solar PV plants. When considering a BESS having a capacity of 4 hours of average demand in 2020 to meet the peak demand hours, the forecasted costs associated with the BESS are reflected in the overall LCOE of the system at 10.35 US cents per kWh having an initial overall capital of $12 billion. The optimal system configuration comprised 4 GW of CCGT power plants responsible of meeting the base and intermediate loads, 3.38 GW of solar PV plants that feed power directly to the base and intermediate load with the CCGT units and utilize any excess solar energy to charge the battery bank and a 15.1 GWh BESS that charges from both the solar PV excess energy and the CCGT units during low load times in order to support in meeting the peak load. The optimal dispatch strategy was found to be the cycle charging strategy allowing the CCGT units to operate at full load to meet the demand and charge the BESS.

Contrary to what is stated in literature, the increased battery size from 15 minutes of storage capacity to 4 hours of storage capacity resulted in a 43% decrease in the solar PV capacity with the RE fraction of the supplied energy decreasing from 30.4% to 17.2%. The total energy outputted from the shared system converter was 8,687 GWh forming approximately 30% of the total AC primary load. Furthermore, the amount of CCGT energy that went to charging the battery bank was approximately 3,000 GWh. Even though the LCOE of the solar PV plant at 4.07 US cents per kWh is cheaper than the marginal cost of running the CCGT unit at 6.12 US cents per kWh, due to the seasonal variability of the solar resource and the non-coincidence of the solar PV output with the peak demand hours, it is found that limiting the solar PV capacity to 3.38 GW and utilizing a CC dispatch strategy to charge the batteries from the CCGT units will result in the lowest LCOE for the system. The below figure presents the typical operation of the system over three consecutive days in August:

Figure 52: Sensitivity case 4 load and generation profile

From the B/C analysis carried out for Scenarios Two and Three, it can be deduced that the LCOE metric cannot be solely utilized to design an optimal system configuration since it does not capture all the added benefits of the different systems. Building a B/C analysis for sensitivity case 4 after acquiring accurate local figures on power generation, transmission and distribution in order to help in quantifying the benefits of load shifting, peak shaving, enhanced demand response, T&D investment deferral and the provision of ancillary services for the Lebanese case is a crucial step for an effective and efficient power system planning and is considered as critical future work to be completed due to the current non-availability of the needed data.

In addition to the mentioned benefits that were not accounted for, one can also consider the social cost of carbon while modeling the power system and study the effects of different pricing mechanisms on the optimal system configuration.

For speculative purposes, we calculated the capacity value of the DC-coupled solar PV – BESS system in sensitivity case 4 and came to find that the system is equivalent to a 326 MW peaking power plant when considering its effects on the loss of load probability (LOLP). Furthermore, the system was able to reduce the overall peak power demand.

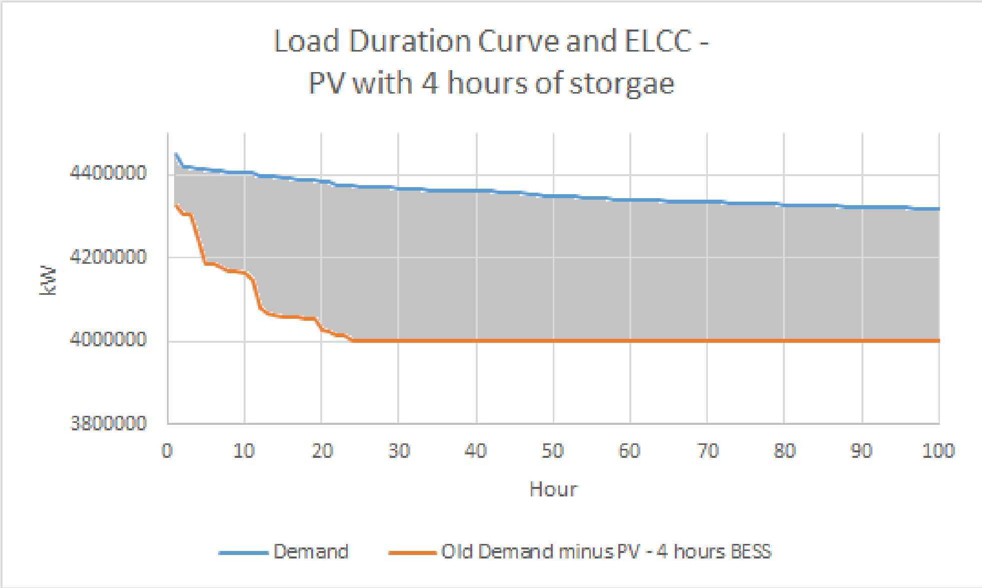

Figure 53: Load duration curves and ELCC for sensitivity case 4

CHAPTER 8

CONCLUSIONS AND POLICY RECOMMENDATIONS

The modeled and simulated scenarios and sensitivity analysis show that solar PV plants coupled with battery energy storage systems have a major role to play in the transitioning of the Lebanese power system. The price estimates and forecasts adopted in our study are considered to be conservative enabling us to remove biases towards new technologies. When we consider the recent power purchase agreements (PPAs) for utility scale solar PV plants in countries having a similar solar GHI to Lebanon, such as the 37 $/MWh, 24.2 $/MWh, 23.6 $/MWh and 21.48 $/MWh PPAs in India, UAE, Saudi Arabia and Chile respectively (Clover, 2018), we are reassured of our conservative price forecast of solar PV energy in Lebanon in 2020.

Under a general and comparative approach, our simulations and models of the different possible configurations of the Lebanese power system in 2020 provided insight on the importance of solar energy and battery storage in decreasing the overall cost of electricity and providing the added benefits that accompany grid connected storage. We found that natural gas based CCGT and OCGT units are of critical importance as they supplied most of the annual load demand. Furthermore, and based on the LCOE metric, utilizing grid connected utility scale solar PV plants coupled to a BESS having an energy capacity of 15 minutes of average load is the most economical option while providing the main benefits of renewable energy firming and decreasing the amount of curtailed solar energy. Our B/C analysis showed that due to the high incurred cost of the BESS as compared to its benefits, installing utility scale solar PV plants alone has a higher B/C ratio than a DC-coupled solar PV plant with a 15 minutes energy capacity

BESS. When considering a 4-hour BESS, the LCOE metric proved to be the highest among all models due to the large capital investment, however, the modeled system provides benefits including load shifting, peak shaving, enhanced demand response, ancillary services and T&D investment deferral that were not accounted for nor quantified due to the unavailability of real-life data.

A major finding is that when utilizing solar energy as the only renewable energy power source, an economic limit of 30% renewable energy fraction is presented mainly due to the nature of the Lebanese load profile and the subsequent non-coincidence of the solar energy resource with the peak demand. Furthermore, when high renewable energy penetrations are modeled, the conventional power generation units need to have enhanced flexibility to cater for the intermittency and fluctuations of the solar resource. Although the scenarios and simulations ignore important features such as unit ramping limits, unit commitment and cycling costs, our comparative approach enables us to present the opportunity costs between different options. Our results, specifically the sensitivity case having a 4-hour grid connected BESS highlight the necessity to develop a co-optimization model and run simulations that accurately and simultaneously consider the limitations and operational parameters of all convention generation, RE, transmission and BESS assets in the system as variables in order to appropriately assess the full economic value which compromises the benefits of grid connected BESS.

While our study focuses on solar PV as the only RE source, it is highly recommended to include other RE resources to allow increased renewable energy penetration beyond the economic limit that was found. Wind energy is a highly valuable option due to the nature of wind power and how it complements the solar resource by increased wind power output during night times as compared to day times and increased power output during the winter season as compared to the summer season.

Further work can encompasses collecting accurate data on the Lebanese generation, transmission and distribution assets and building a stochastic modeling framework in a high computing power environment where components, costs and benefits such as ramp rates, cycling costs, ancillary services and load shifting can be incorporated.

For speculative purposes, when aggregating the yearly subsidies that the government pays for the power sector (approximately $1.4 - $2 billion), and the economic impact of the grid cutoffs measured by the value of lost load metric ($4 - $5 billion), one can find that the annual economic burden of the current power system and its operation on the Lebanese economy exceeds or equates to the initial investment required for all of the modeled scenarios which are capable of transforming the Lebanese power system into an adequate, reliable and sustainable one while keeping the current tariff structure.

It is of high importance to consider the current conditions of the Lebanese power sector as an opportunity enabling Lebanon to leapfrog to a sustainable power sector utilizing renewable energy and energy storage solutions. This opportunity must be strategically developed into a set of action plans, research centers and projects to further push Lebanon beyond meeting its INDCs to become a model country for the region in the near-term future.

Based on our findings, we present the below policy recommendations in order of priority:

- Forming a public regulatory body, agency or authority employing skilled and experienced personnel that regulates the power sector, issues permits and licenses and supervises the generation, transmission, distribution, sale, export, and importation of electrical energy and primary energy sources. Furthermore, this government body will also be responsible for tightening the link between academic research and public policy.
- Hiring international consultants and multinationals, operating with or under the regulatory authority for a nation-specific and bespoke stochastic modelling framework while co-optimizing all assets and possible solutions to build an energy reform plan leading to the sustainable development of the power sector. The international body will also be responsible for knowledge transfer and technology diffusion.
- Empowering the Lebanese National Control Center through in depth technical trainings for its employees and international knowledge transfer.
- Adopting a national grid code and building an information and communication technology (ICT) infrastructure under the control of the national control center while utilizing the requires smart grid devices.
- De-monopolizing EDL and increasing the involvement of the private sector in electricity production and supply to the national grid.
- De-risking the renewable energy sector through public instruments related to policy de-risking and financial de-risking. The de-risking instruments may include the adoption of a feed in tariff scheme, power purchase agreements, public private partnerships, streamlining the process of RE permit issuance, awareness raising campaigns and issuing government guarantees and political

insurance for RE investments. Selecting the optimal de-risking measures will be part of the joint work to be done by the regulatory agency and the international body when building and energy reform plan.

BIBLIOGRAPHY

(LCEC), L. C. f. E. C. (2016). *The National Renewable Energy Action Plan for the Republic of Lebanon 2016-2020*. Retrieved from

(NREL), N. R. E. L. (2012). *COST AND PERFORMANCE DATA FOR POWER GENERATION TECHNOLOGIES*. Retrieved from

AEMS, & UNDP. (2017). *The Impact of the Syrian Crisis on the Lebanese Power Sector and Priority Recommendations*. Retrieved from

Akkaya, S., Junge, N., & Mansour, W. (2009). LEBANON: Social Impact Analysis For the Electricity and Water Sectors. Open Knowledge Repository, from World Bank https://openknowledge.worldbank.org/bitstream/handle/10986/10960/518030BRI0MENA10Box342050B01PUBLIC1.pdf?sequence=1&isAllowed=y

Ardani, K., O'Shaughnessy, E., Fu, R., McClurg, C., Huneycutt, J., & Margolis, R. (2017). *Installed Cost Benchmarks and Deployment Barriers for Residential Solar Photovoltaics with Energy Storage: Q1 2016*. Retrieved from

Atlas, G. S. Retrieved from http://globalsolaratlas.info/downloads/lebanon

Bassil, C. N. (2018). *Pilot study to further assess the applicability of switching from conventional fuels to natural gas in the industrial sector in Lebanon, particularly in the industrial zones of Chekka and Zouk Mosbeh*. Retrieved from

Bassil, G. (2010). *Policy Paper for the Electricity Sector*.

Berckmans, G., Messagie, M., Smekens, J., Omar, N., Vanhaverbeke, L., & Van Mierlo, J. (2017). Cost Projection of State of the Art Lithium-Ion Batteries for Electric Vehicles Up to 2030. *Energies, 10*(12), 1314. doi:10.3390/en10091314

Bistline, J. E. (2017). Economic and technical challenges of flexible operations under large-scale variable renewable deployment. *Energy Economics, 64*, 363-372. doi:10.1016/j.eneco.2017.04.012

Bouri, E., & El Assad, J. (2016). The Lebanese Electricity Woes: An Estimation of the Economical Costs of Power Interruptions. *Energies, 9*(12), 583. doi:10.3390/en9080583

Castillo, A., & Gayme, D. F. (2014). Grid-scale energy storage applications in renewable energy integration: A survey. *Energy Conversion and Management, 87*, 885-894. doi:10.1016/j.enconman.2014.07.063

CDR. (2015). Electricity.

CEDRO. (2017). Retrieved from http://www.cedro-undp.org/Projects/details/152

CEDRO (2018, 3-4-2018).

Chehab, F. (2018). Retrieved from http://www.businessnews.com.lb/cms/Story/StoryDetails.aspx?ItemID=6296

Chua, K. H., Lim, Y. S., & Morris, S. (2015). Cost-benefit assessment of energy storage for utility and customers: A case study in Malaysia. *Energy Conversion and Management, 106*, 1071-1081. doi:10.1016/j.enconman.2015.10.041

Clover, I. (2018). Webinar Q&A: Calculating large-scale PV costs. Retrieved from https://www.pv-magazine.com/2018/04/18/webinar-qa-calculating-large-scale-pv-costs/

CoM. (2018). *Summary of the ELectricity Sector in Lebanon*

Retrieved from

Commission, C. E. (2014). *ESTIMATED COST OF NEW RENEWABLE AND FOSSIL GENERATION IN CALIFORNIA*. Retrieved from

Commodity Markets Outlook. (2017). Retrieved from

Curry, C. (2017). *Lithium-ion Battery Cost and Market*. Retrieved from

Dagher, L., & Yacoubian, T. (2012). The causal relationship between energy consumption and economic growth in Lebanon. *Energy Policy, 50*, 795-801. doi:10.1016/j.enpol.2012.08.034

Dasgupta, K., Hazra, J., Rongali, S., & Padmanaban, M. (2015). *Estimating Return on Investment for Grid Scale Storage within the Economic Dispatch Framework*. IBM India Research Lab.

Dechezleprêtre, A., Glachant, M., & Ménière, Y. (2009). Technology transfer by CDM projects: A comparison of Brazil, China, India and Mexico. *Energy Policy*, 703-711.

Denholm, P., Brinkman, G., & Mai, T. (2018). How low can you go? The importance of quantifying minimum generation levels for renewable integration. *Energy Policy, 115*, 249-257. doi:10.1016/j.enpol.2018.01.023

Denholm, P., Eichman, J., & Margolis, R. (2017). *Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants*. Retrieved from

Denholm, P., & Hand, M. (2011). Grid flexibility and storage required to achieve very high penetration of variable renewable electricity. *Energy Policy, 39*(3), 1817-1830. doi:10.1016/j.enpol.2011.01.019

Denholm, P., & Margolis, R. M. (2007). Evaluating the limits of solar photovoltaics (PV) in traditional electric power systems. *Energy Policy, 35*(5), 2852-2861. doi:10.1016/j.enpol.2006.10.014

Denholm, P., Novacheck, J., Jorgenson, J., & O'Connell, M. (2016). *Impact of Flexibility Options on Grid Economic Carrying Capacity of Solar and Wind: Three Case Studies*. Retrieved from

Dent, S. (2017). Tesla completes its giant Australian Powerpack battery on time.   Retrieved from https://www.engadget.com/2017/11/23/tesla-australia-powerpack-100-day-bet/

DREG, U.-. (2017). *2016 Solar PV Status Report for Lebanon*. Retrieved from

EDF. (2008). *Generartion and Transmission Master Plan for the ELectricity Sector - Generation Master Plan Report*. Retrieved from

eia. (2018). *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2018*. Retrieved from

El-Fadel, R. H., Hammond, G. P., Harajli, H. A., Jones, C. I., Kabakian, V. K., & Winnett, A. B. (2010). The Lebanese electricity system in the context of sustainable development. *Energy Policy, 38*(2), 751-761. doi:10.1016/j.enpol.2009.10.020

Eller, A., & Dehamna, A. (2017). *Country Forecasts for Utility-Scale Energy Storage Utility-Scale Energy Storage System Capacity and Revenue Forecasts for Leading Countries*. Retrieved from

Evans, A., Strezov, V., & Evans, T. J. (2012). Assessment of utility energy storage options for increased renewable energy penetration. *Renewable and Sustainable Energy Reviews, 16*(6), 4141-4147. doi:10.1016/j.rser.2012.03.048

Eyer, J. (2099). *Electric Utility Transmission and Distribution Upgrade Deferral Benefits from Modular Electricity Storage*. Retrieved from

Feldman, D., Margolis, R., & Denholm, P. (2016). *Exploring the Potential Competitiveness of Utility-Scale Photovoltaics plus Batteries with Concentrating Solar Power, 2015–2030*. Retrieved from

Fraunhofer Institute for Solar Energy Systems, I. (2017). *PHOTOVOLTAICS REPORT*. Retrieved from

Gaast, W. v. d., Begg, K., & Flamos, A. (2009). Promorting sustainable energy technology transfers to developing countires through CDM. *Applied Energy*, 230-236.

Giorgio, A. D., Giuseppi, A., Liberati, F., & Pietrabissa, A. (2017). *Controlled Electricity Distribution Network Black Start with Energy Storage System Support* Paper presented at the 2017 25th Mediterranean Conference on Control and Automation (MED), Valletta, Malta.

Go, R. S., Munoz, F. D., & Watson, J.-P. (2016). Assessing the economic value of co-optimized grid-scale energy storage investments in supporting high renewable portfolio standards. *Applied Energy, 183*, 902-913. doi:10.1016/j.apenergy.2016.08.134

Gupta, M. (2017). *Large-Scale Energy Storage System Price Trends: 2012 – 2022*. Retrieved from

Hesse, H., Schimpe, M., Kucevic, D., & Jossen, A. (2017). Lithium-Ion Battery Storage for the Grid—A Review of Stationary Battery Storage System Design Tailored for Applications in Modern Power Grids. *Energies, 10*(12), 2107. doi:10.3390/en10122107

Ibrahim, O., Fardoun, F., Younes, R., & Louahlia-Gualous, H. (2013). Energy status in Lebanon and electricity generation reform plan based on cost and pollution optimization. *Renewable and Sustainable Energy Reviews, 20*, 255-278. doi:10.1016/j.rser.2012.11.014

IEA. (2011). *Modelling the capacity credit of renewable energy sources*. Retrieved from

iea. (2017a). *Renewables 2017 - Analysis and Forecasts to 2022*. Retrieved from

IEA. (2017b). *World Energy Outlook 2017*. Retrieved from

IHS. (2016). Retrieved from https://technology.ihs.com/Categories/450477/smart-grid-energy-storage

IRENA. (2017). ELECTRICITY STORAGE AND RENEWABLES: COSTS AND MARKETS TO 2030.

IRENA. (2018). *Renewable Power Generation Costs in 2017*. Retrieved from

Kaygusuz, K. (2012). Energy for sustainable development: A case of developing countires. *Renewable and Sustainable energy Reviews*, 1116-1126.

Khodr, H., & Uherova Hasbani, K. (2013). The dynamics of energy policy in Lebanon when research, politics, and policy fail to intersect. *Energy Policy, 60*, 629-642. doi:10.1016/j.enpol.2013.05.080

Kirby, B., Ma, O., & O'Malley, M. (2013). *The Value of Energy Storage for Grid Applications*. Retrieved from

Kittner, N., Lill, F., & Kammen, D. M. (2017). Energy storage deployment and innovation for the clean energy transition. *Nature Energy, 2*(9), 17125. doi:10.1038/nenergy.2017.125

Lai, C. S., Jia, Y., Lai, L. L., Xu, Z., McCulloch, M. D., & Wong, K. P. (2017). A comprehensive review on large-scale photovoltaic system with applications of electrical energy storage. *Renewable and Sustainable Energy Reviews, 78*, 439-451. doi:10.1016/j.rser.2017.04.078

Lai, C. S., & McCulloch, M. D. (2017). Levelized cost of electricity for solar photovoltaic and electrical energy storage. *Applied Energy, 190*, 191-203. doi:10.1016/j.apenergy.2016.12.153

Lawder, M. T., Suthar, B., Northrop, P. W. C., De, S., Hoff, C. M., Leitermann, O., . . . Subramanian, V. R. (2014). Battery Energy Storage System (BESS) and Battery Management System (BMS) for Grid-Scale Applications. *Proceedings of the IEEE, 102*(6), 1014-1030. doi:10.1109/jproc.2014.2317451

Lazard. (2016). Lazard's Levelized Cost of Storgae - Version 2.0.

Lazard. (2017). *Lazard's Levelized Cost of Electricty - Version 11.0*. Retrieved from

LCEC. (2018). Retrieved from http://www.lcec.org.lb/en/LCEC/DownloadCenter/Others#page=1

Lebanon, R. o. (2015). *Lebanon’s Intended Nationally Determined Contribution under the United Nations Framework Convention on Climate Change*. Retrieved from

Lee, C.-C. (2005). Energy consumption and GDP in developing countries: A cointegrated panel analysis. *Energy Economics, 27*(3), 415-427. doi:10.1016/j.eneco.2005.03.003

Liserre, M., Sauter, T., & Hung, J. (2010). Future Energy Systems: Integrating Renewable Energy Sources into the Smart Power Grid Through Industrial Electronics. *IEEE Industrial Electronics Magazine, 4*(1), 18-37. doi:10.1109/mie.2010.935861

Markard, J., Raven, R., & Truffer, B. (2012). Sustainability transitions: An emerging field of research and its prospects. *Research Policy*, 955-967.

McLaren, J., Gagnon, P., Anderson, K., Elgqvist, E., Fu, R., & Remo, T. (2016). *Battery Energy Storage Market: Commercial Scale, Lithium-ion Projects in the U.S.* Retrieved from

Miguel, M., Nogueira, T., & Martins, F. (2017). Energy storage for renewable energy integration The case of Madeira Island, Portugal. *Energy Procedia*.

Mills, A., & Wiser, R. (2012). *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California*. Retrieved from http://eetd.lbl.gov/EA/EMP

MoE, & UNDP. (2014). *Strategic Environmental Assessment of Lebanon's Renewable Energy Sector*. Retrieved from

MoEW (2018, 5-4-2018).

Motors, T. (2016). *POWERPACK APPLICATIONS*. Retrieved from

Müller, M., Viernstein, L., Truong, C. N., Eiting, A., Hesse, H. C., Witzmann, R., & Jossen, A. (2017). Evaluation of grid-level adaptability for stationary battery energy storage system applications in Europe. *Journal of Energy Storage, 9*, 1-11. doi:10.1016/j.est.2016.11.005

Neme, C., & Sedano, R. (2012). *US Experience with Efficiency As a Transmission and Distribution System Resource*. Retrieved from

Ouseiran, K. (2018, March, 2018) */Interviewer: A. Diab*.

Projected Costs of Generating Electricity. (2015). Retrieved from

REN21. (2017). *Renewables 2017 Global Status Report*. Retrieved from

Roberts, D. (2017). Elon Musk bet that Tesla could build the world's biggest battery in 100 days. He won.

. Retrieved from https://www.vox.com/energy-and-environment/2017/11/28/16709036/elon-musk-biggest-battery-100-days

Rodrigues, A., Machado, D., & Dentinho, T. (2017). Electrical Energy Storage Systems Feasibility; the Case of Terceira Island. *Sustainability, 9*(12), 1276. doi:10.3390/su9071276

Saad, P. (2018). Lebanon issues RfP for 180 MW of solar. Retrieved from https://www.pv-magazine.com/2017/05/31/lebanon-issues-rfp-for-180-mw-of-solar/

Schmidt, O., Hawkes, A., Gambhir, A., & Staffell, I. (2017). The future cost of electrical energy storage based on experience rates. *Nature Energy, 2*(8), 17110. doi:10.1038/nenergy.2017.110

Shiva Kumar, B., & Sudhakar, K. (2015). Performance evaluation of 10 MW grid connected solar photovoltaic power plant in India. *Energy Reports, 1*, 184-192. doi:10.1016/j.egyr.2015.10.001

Spector, J. (2017). Tesla Fulfilled Its 100-Day Australia Battery Bet. What's That Mean for the Industry? Retrieved from https://www.greentechmedia.com/articles/read/tesla-fulfills-australia-battery-bet-whats-that-mean-industry#gs.KGhHkfQ

Spiliotis, K., Ramos Gutierrez, A. I., & Belmans, R. (2016). Demand flexibility versus physical network expansions in distribution grids. *Applied Energy, 182*, 613-624. doi:10.1016/j.apenergy.2016.08.145

Star, T. D. (2018). Wind farms on the way: Energy minister inks contracts. Retrieved from http://www.dailystar.com.lb/News/Lebanon-News/2018/Feb-03/436708-wind-farms-on-the-way-energy-minister-inks-contracts.ashx

Stenzal, P., Schrieber, A., Marx, J., Wulf, C., Schreieder, M., & Stephan, L. (2017). Renewable energies for Graciosa Island, Azores – Life Cycle Assessment of electricity generation. *Energy Procedia*.

Stion. (2018). Retrieved from http://www.stion.com/technology/photovoltaic-effect/

Stroe, D.-I., Knap, V., Swierczynski, M., Stroe, A.-I., & Teodorescu, R. (2017). Operation of a Grid-Connected Lithium-Ion Battery Energy Storage System for Primary Frequency Regulation: A Battery Lifetime Perspective. *IEEE Transactions on Industry Applications, 53*(1), 430-438. doi:10.1109/tia.2016.2616319

Subburaj, A. S., Pushpakaran, B. N., & Bayne, S. B. (2015). Overview of grid connected renewable energy based battery projects in USA. *Renewable and Sustainable Energy Reviews, 45*, 219-234. doi:10.1016/j.rser.2015.01.052

Wannasut, C., & Hongesombut, K. (2013). Evaluation of the Requirements for Battery Energy Storage System to Postpone the Investment of Distribution System. *IEEE*.

Wolfe, P. R. (2018). Utility-Scale Solar Power. 1073-1093. doi:10.1016/b978-0-12-809921-6.00030-6

Wright, J. (2015). Electrical energy storage to make wind and solar PV resources disptatchable. *Energy Exemplar*.

Yekini Suberu, M., Wazir Mustafa, M., & Bashir, N. (2014). Energy storage systems for renewable energy power sector integration and mitigation of intermittency. *Renewable and Sustainable Energy Reviews, 35*, 499-514. doi:10.1016/j.rser.2014.04.009

Zeh, A., Müller, M., Naumann, M., Hesse, H., Jossen, A., & Witzmann, R. (2016). Fundamentals of Using Battery Energy Storage Systems to Provide Primary Control Reserves in Germany. *Batteries, 2*(3), 29. doi:10.3390/batteries2030029

Zheng, C., & Kammen, D. M. (2014). An innovation-focused roadmap for a sustainable global photovoltaic industry. *Energy Policy, 67*, 159-169. doi:10.1016/j.enpol.2013.12.006

Zou, P., Chen, Q., Xia, Q., He, G., & Kang, C. (2016). Evaluating the Contribution of Energy Storages to Support Large-Scale Renewable Generation in Joint Energy and Ancillary Service Markets. *IEEE Transactions on Sustainable Energy, 7*(2), 808-818. doi:10.1109/tste.2015.2497283