AMERICAN UNIVERSITY OF BEIRUT

DEVELOPMENT OF NATURAL GAS IN LEBANON: ASSESSMENT OF ITS IMPACT ON ELECTRIC POWER GENERATION

by
LEA MEHER BOUJIKIAN

A thesis
submitted in partial fulfillment of the requirements
for the degree of Master of Engineering
to the Department of Electrical and Computer Engineering
of the Faculty of Engineering and Architecture
at the American University of Beirut

Beirut, Lebanon
January 2019

AMERICAN UNIVERSITY OF BEIRUT

DEVELOPMENT OF NATURAL GAS IN LEBANON: ASSESSMENT OF ITS IMPACT ON ELECTRIC POWER GENERATION

by
LEA MEHER BOUJIKIAN

Approved by:

Dr. Riad Chedid, Professor — Advisor
Department of Electrical and Computer Engineering

Dr. Sami Karaki, Professor and Chairman — Member of Committee
Department of Electrical and Computer Engineering

Dr. Rabih Jabr, Professor — Member of Committee
Department of Electrical and Computer Engineering

Dr. Raymond Ghajar, Professor and Dean — Member of Committee
School of Engineering, LAU

Date of thesis defense: January 28, 2019

AMERICAN UNIVERSITY OF BEIRUT

THESIS, DISSERTATION, PROJECT RELEASE FORM

Student Name:

Boujikian Lea Meher

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.

February, 11 2019

Signature Date

ACKNOWLEDGMENTS

First and foremost, I thank God for giving me the strength, health, and patience to complete this thesis.

I would like to thank my advisor, Dr. Riad Chedid, for his continuous guidance and help at every step of my work. I thank him for his patience and constant encouragement, despite the difficulties that I was going through.

I would like to thank Dr. Sami Karaki, for providing me with the time, and guidance in every detail of my work. Without his continuous support and encouragement this thesis would not have been completed.

I am thankful to have had Dr. Rabih Jabr's constant supervision and instructive comments throughout my work.

I would also like to thank Dr. Raymond Ghajar for his ideas, instructive comments, and support that helped complete this thesis.

Last but not least, I would like to thank my family. My mother, Silva, who I wish would have been with us, I dedicate this work to her. I am thankful for her big heart and infinite love that inspire and motivate me every single day. I thank her for watching over me, and showering me with her prayers, as always.

I would like to thank my father, Meher, for his infinite support, encouragement, love, and patience.

I would like to also thank my sister, Angela, for her infinite love, support, and positivity.

AN ABSTRACT OF THE THESIS OF

Lea Meher Boujikian for Master of Engineering
Major: Power and Energy Systems

Title: Development of Natural Gas in Lebanon: Assessment of its Impact on Electric Power Generation

The increased reliance of modern societies on electricity urges the need for a reliable power system that provides uninterrupted power at a reasonable cost. Lebanon's power sector has been suffering since the civil war from various financial and technical problems. One of the main problems of the sector is the failure of the present generation capacity to satisfy the total demand, leading to frequent load shedding. A strategic expansion plan is necessary to increase the generation capacity according to the anticipated load growth. The generation expansion plan has to take into consideration the need for a shift to cleaner generation sources and fuels. This can be done by first, increasing the share of renewable energy sources (RES) in the energy mix. Furthermore, developed countries are trying to shift to natural gas (NG) for being a cheaper and cleaner alternative to oil or coal. Lebanon, likewise has the opportunity to add NG to its energy mix, especially with the claims of its presence offshore.

This thesis evaluates a proposed generation expansion plan and assesses several potential scenarios, in light of recent developments in renewable energy (RE) and explorations for NG. Reliability of the proposed system is assessed from energy and financial perspectives. Probabilistic production costing is used to calculate the Expected Energy Not Supplied (EENS), and evaluate the energy produced in addition to the costs of production and investments required. The assessment is done using a standard generation expansion planning (GEP) software available in the ECE department at AUB, which has been upgraded to incorporate RES using the residual load duration curve method (RLDC) and modified to serve the requirements of the study.

The program is applied to four scenarios. The first scenario is the baseline case, where the thermal units keep using heavy fuel oil (HFO) and diesel oil (DO) throughout the whole study. The second scenario assumes that local natural gas will be available for thermal plants starting from 2029. In the third scenario, Floating Storage Regasification Units (FSRU) are rented to provide thermal plants with liquid natural gas (LNG) starting from 2021, for 10 years, after which the power plants start using local natural gas assuming it becomes available. The last scenario considers the purchase of FSRU to provide thermal units with LNG starting from 2021, while local NG is sold in the international market.

CONTENTS

ACKNOWLEDGEMENTS V

ABSTRACT..VI

LIST OF ILLUSTRATIONS...X

LIST OF TABLES...XII

Chapter

I. INTRODUCTION...1

A. MOTIVATION AND OBJECTIVE..1

B. LITERATURE REVIEW...2

II. METHODOLOGY...9

A. GENERATION MODEL:...10

1. Recursive algorithm for building the COT:..........................12
2. Recursive Algorithm for unit removal:..................................13

B. LOAD MODEL:...14

III. MODELING AND OPERATION OF SYSTEM..........................17

A. GENERATION MODEL:...17

B. LOAD MODEL: 20

C. YEARLY COMPUTATIONS: 21

1. Solar Power: 21
2. Wind Power 22
3. Hydropower 22
4. Operating Costs: 23
5. Building the COT: 23

IV. NATURAL GAS IN LEBANON 25

V. THE GENERATION EXPANSION PLAN AND SCENARIOS 27

A. THE LEBANESE POWER SYSTEM: 27

B. THE SCENARIOS: 29

1. Scenario 1: 32
2. Scenario 2: 32
3. Scenario 3: 33
4. Scenario 4: 34

C. FSRU SIZE: 35

VI. RESULTS 38

A. DEMAND FORECAST: 38

B. RENEWABLE SOURCES: 39

C. ENERGY ASSESSMENT: 43

D. FINANCIAL ASSESSMENT: 47

E. RESULT CONCLUSION: 52

VII. CONCLUSION 54

APPENDIX A 56

APPENDIX B 57

REFERENCES 58

ILLUSTRATIONS

Figure Page

1. State space of a two-state system 11
2. Probability of capacity on outage 11
3. EENS due to outage O(k) 15
4. Equally Divided Hydropower Capacity 19
5. Peak of Hydropower at Peak of Load 19
6. Hydropower Model of the system 20
7. Wind Turbine Power Curve 30
8. Peak Load Forecast 31
9. World Bank Fuel Price Forecast 33
10. Peak Load and Total System Capacity 38
11. RE and the effect on Power Demand 39
12. Share of RES in 2020 40
13. Share of RES in 2030 40
14. Thermal and Renewable Capacities 41
15. LCD and RLDC in 2018 42
16. LDC and RLDC in 2020 42
17. LDC and RLDC in 2025 43
18. LDC and RLDC in 2030 43
19. Energy production and Energy Demand 45
20. Expected Energy Not Supplied 46

21. AVERAGE DAILY LOAD SHEDDING 46

22. GENERATION COST OF CONVENTIONAL UNITS FOR ALL SCENARIOS 48

23. LEVELIZED COST OF THERMAL PLANTS 49

24. SYSTEM FINANCIAL DEFICIT 51

TABLES

Table Page

1. CAPACITY OUTAGE TABLE OF A C MW UNIT 12

2. CURRENT THERMAL UNITS 28

3. AVAILABLE HYDROPOWER PLANTS 29

4. FUTURE PLAN FOR THERMAL PLANTS 31

5. PV PLAN 31

6. WIND PLAN 31

7. PEAK LOAD FORECAST 31

8. FSRU RENTAL COST 34

9. FSRU PURCHASE COST 35

10. NG AND LNG QUANTITIES 37

11. ANNUAL ENERGY PRODUCED AND DEMANDED 44

12. LEVELIZED COST OF THERMAL POWER PLANTS 50

13. SYSTEM FINANCIAL DEFICIT (M$) 52

CHAPTER I

INTRODUCTION

A. Motivation and Objective

Lebanon missed several chances to lift the power sector from its unlimited technical, financial, and administrative problems. The plans proposed for upgrading and rehabilitating the sector were either postponed or completed partially. Consequently, the sector accumulated problems in generation, transmission, and distribution of electricity. Nevertheless, the generation problem has been the main reason for the country's unbearable shortages in power supply. The problem is largely due to insufficient generation capacity that produces far less than the required energy demand. A generation expansion plan should be developed to save the current situation of continuous power outages and high electricity bills.

On the other hand, Lebanon has been going through an important phase of development by committing to change to cleaner energy sources and fuels. This is translated by the progress in Natural Gas (NG) explorations and renewable energy sources development. Prospects of natural gas availability date back to the 1920s, however, in the past two years, accelerated efforts were put to complete legislation and licensing activities, to prepare a solid base for the upcoming exploration phase. Exploration will start with the drilling stage, which should take place in 2019, and successful results from drilling can lead to production of NG in nearly ten years. Renewable energy incorporation in the power sector started with a commitment in 2009 to increase their share by 12% in 2020. The commitment was motivated by the available wind resources and suitable solar irradiance levels [1]. This was interpreted by encouraging public-private partnership (PPP), through agreement for projects by individual power producer (IPP) and signing for the first time power purchase agreements (PPA), to accelerate the addition of RES in the energy mix.

The objective of this thesis is to develop a generation expansion plan and assess several scenarios that can be realized, taking into consideration the current advancement in natural gas explorations and renewable energy sources development. Moreover, a generation expansion program is developed to perform the assessment from energy and financial perspectives.

B. Literature Review

A power system is required to provide customers with reliable electricity. The reliability constraint, however, is faced with the economic constraint. To solve this conflict deterministic techniques were used at the beginning. Due to the stochastic nature of the power system, design engineers developed probabilistic techniques for generation expansion planning, which unlike the deterministic techniques take into consideration the random behavior of the system. While reliability considers both adequacy and security assessment, adequacy is mostly considered in reliability evaluation [2].

Goel and Billinton [3] studied three analytical methods for reliability evaluation of generation capacity. The three methods, load modification technique, the cumulant method, and the segmentation procedure are compared based on accuracy and computational speed. The Roy Billinton Test System (RBTS) and the IEEE Reliability Test System (RTS) were used to compare the expected energy not supplied (EENS) and the system expected production cost (EPC) obtained by the three methods.

Billinton and Harrington [4] proposed an approach to calculate expected energy and expected energy not supplied for units with certain energy limitations. The approach is an extension of the Loss of Energy method which is used to calculate the EENS due to forced outages of units by convolving the capacity outage probability model of the units with the load duration curve. To model energy limitations, peak-shaving method was used whenever the type of limitation considered allowed the use of the method.

Generation expansion planning (GEP) is complex. To solve the problem of GEP, many optimization techniques were developed and proposed. Zhu and Chow [5] discussed and summarized many of these techniques, such as expert systems, fuzzy logic, artificial neural networks, network flow theory, analytic hierarchy process, simulated annealing, and genetic algorithm.

Many believe that using simulation methods allows the study of very complex situations in adequacy evaluation and reduce the need for assumptions used in analytical techniques. Ghajar and Billinton [6] described the Monte Carlo method for adequacy evaluation. The authors presented the simulation model used for modelling the power system, described the indices used for evaluation, and used the IEEE Reliability Test System to apply and assess the model.

Power system engineers and utility planners have to deal with the key problem of uncertainty in power system planning. Merrill and Wood [7] explained uncertainty and risk, and the difference between them. The authors presented the process for managing risk using trade-off analysis. Both, probabilistic and unknown but bounded models of uncertainty can be used in the method described.

Over the years, the methods used for GEP went through several changes and development phases. These changes were the results of constraints that power engineers where trying to solve at the time. Today new constraints appear to be present in many studies for generation expansion planning such as increasing the share of renewable energy sources, environmental constraints and many more. Many of these constraints urge the need for new techniques and methods to solve GEP and model the system. Sadeghi et al. [8] presented a review of the GEP problem from different perspectives, and highlighted the subjects that led to the development of the different optimization techniques hierarchically. Oree et al. [9] provided a review of how environmental policies and uncertainty led to developments in GEP techniques and evaluated the models that account these constraints. The authors also discussed the complications that arise from integrating RES of intermittent nature in the generation system.

In [10] Billinton et al. presented two time-series models for wind data. The two models were tested using the F-criterion and Q-test on two different wind data. The adequacy of the methods was compared and analyzed against actual observed wind data. The authors determined the significance of using additional wind data for a more accurate wind speed model that can be useful in reliability studies of generation systems having wind energy conversion systems (WECS).

Karaki et al. [11] presented a probabilistic model of a WECS which includes a wind farm that is connected to a load and a battery storage. The authors aimed at obtaining the joint probability distribution function of the total available wind power and the turbines' operating modes due to hardware failure. The wind velocity was considered to have a Weibull distribution. The model could also be used to find the upper limit of required battery size of several turbines for a specific EENS.

The authors in [11] extended their work in [12] using the same method but to model a hybrid solar-wind energy conversion system. The solar irradiance was assumed to have a β-distribution. The solar park model was then obtained from the joint probability distribution of the solar power and the capacity levels of hardware failures. The two models were then combined by convolution to have the solar-wind energy conversion system model.

The addition of RES in the power system cannot be completed without necessary modifications in traditional GEP methodologies. Tigas et al. [13] used probabilistic method to deal with the stochastic nature of RES. The residual load duration curve (RLDC) approach was used to account for the addition of large number of RES which will then be used to calculate the remaining residual load of conventional units and eventually, the necessary production costs. A forecast of the production of RES, the cumulative distribution function (CDF) and the probability density function of the RES are obtained to be used as input to calculate the RLDC, by convoluting the load with the generation of RES.

The usefulness of the RLDC method in systems having a large share of RES was further emphasized in [14] where Lyzwa and Wierzbowski presented a first approach to use the duration curves in MILP model. Case of the Polish power system was used to analyze the impact of RES on the operation of the power system using load duration curves. The authors addressed the advantages of the method, which allows the evaluation of many power system operation parameters such as reduction of annual peak load due to RES, decrease in the capacity of conventional units used and more.

In [15] Luz et al. described a multi-objective GEP model to assess the impact of increasing the share of RES. The objective functions of the model are minimizing total cost, increasing generation at peak load, maximizing capacity of non-hydro RES. The Brazilian case was used to apply the model. As a result, the share of solar power was mostly supported to address the need to meet the government's target and the peak demand objective.

Many authors addressed GEP in Lebanon, in their studies and research. Yehia et al. [16] presented a generation and transmission planning method, for the power system in Lebanon, to solve multiple conflicting objectives in the presence of high uncertainty. The authors took into account many power system planning problems in the study, such as, total demand growth, power plant locations, transmission system development and more. For the generation expansion planning the trade-off approach was used to analyze the supply. The LDC was derived to model the demand, where three scenarios of low, medium, and high growth were considered. Production costing was done using PC-Cum-L a production costing program developed at MIT.

Karaki et al. [17] presented a GEP model using tunnel dynamic programming (TDP). Probabilistic production costing was used to produce the risk model from which the adequacy index EENS was calculated to evaluate the reliability of the generation system. The objective of the GEP problem was to either minimize the cost or emissions, or a certain function of both objectives. The model was then applied to a case study of the Lebanese power system.

Hamdan et al. [18] proposed and evaluated an energy policy for the Lebanese power system based on energy modeling and financial modeling. The authors used probabilistic method to perform a reliability assessment for the existing Lebanese power system using a developed energy model based on the Load Modification Technique (LMT). The results of policy implementation were compared to a base line scenario considering 2009 as the base year and forecasting for the period of 2010 to 2015. It is concluded that implementing the policy fully would lead to a reliable and economical power sector.

Ibrahim et al. [19] presented a cost-environmental optimization and tariff optimization study where two generation plans are considered for the future of the Lebanese power system. The first was called the Gasoil scenario where the CCGT plants use gasoil except the Deir-Ammar plant which uses NG and the second called the Natural gas scenario where all old and new CCGT plants use NG. According to the obtained results the NG scenario was recommended in their study both economically and environmentally but the authors concluded that this option is difficult because NG cannot be available for the suggested capacity of CCGT plants.

Dagher and Ruble [20] considered two expansion scenarios for the future of the Lebanese power system. A baseline scenario (BS) was considered, where no climate change policy takes place, and the two alternative scenarios were compared against it. The first case is the renewable energy scenario (RES) and the second is the natural gas scenario. Long Range Alternatives Planning System (LEAP) was used to model the power system. Using LEAP, the scenarios were evaluated technically, economically, and environmentally. Based on the results obtained, the authors concluded that both alternatives yield attractive results compared to the baseline; the NG scenario had a lower capital cost and fuel cost than the BS while the RES had a lower fuel cost but higher capital cost than the BS. Comparing the two scenarios against each other, the authors noticed that the RES is favorable for having lower emissions, reduced dependence on fuel, and a price hike of NG to \$0.78/m^3 would make the NG scenario less attractive economically.

CHAPTER II

METHODOLOGY

The assessment of the generation system and suggested scenarios, that will be explained in the next chapter, are done on two levels: energy assessment and financial assessment. Probabilistic production costing is used to evaluate the production costs of the generation plan followed by an assessment of the energy produced by the units and the overall generation system.

Probabilistic production costing can be done using analytical method or simulation method. The first analytical methods were deterministic. However, as it was mentioned in the literature, many authors and researchers support the move towards probabilistic approach since, unlike the deterministic approach, it takes into consideration the stochastic nature of the system, the uncertainty in demand, and failure of units [2].

Baleriaux and Booth introduced a probabilistic production costing technique that was a starting point for many other approaches. Lin et. al studied several of these methods in [21]. The technique involves modifying the LDC using the conditional probability approach at every unit addition. The unit addition will give a capacity-modified LDC which will have less energy underneath it then the original LDC. This capacity-modified LDC will be considered as the equivalent load duration (ELDC) which will be seen by the next unit in the merit order unit list and from which the energy of the added unit can be calculated. This process is repeated for all units of the system.

Billinton [2,4] introduced another technique that uses the capacity outage probability table (COPT) and convolutes it with the LDC to calculate the expected energy not supplied (EENS). This technique, known as the Loss of Energy method, is used in this thesis to calculate the indices and production costs required.

A. Generation Model:

In the Loss of Energy method, the random availability of a unit, due to outages and technical problems, is represented by a two state model: unit is in service "up-state", or unit is in repair "down state", as shown in figure 1 where λ is the expected failure rate and μ is the expected repair rate. The probability of up-state or availability p is given by:

$$p = \frac{\sum t_f}{\sum t_f + \sum t_r} \quad (1)$$

The probability of down-state or unavailability q, which is also known as the forced outage rate (FOR) is given by:

$$q = \frac{\sum t_r}{\sum t_f + \sum t_r} \quad (2)$$

Where t_f is the up-time or time to failure, and t_r is the down-time or time to repair.

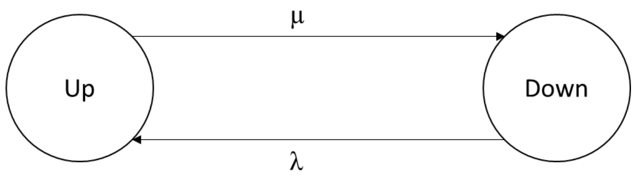


Figure 1: State space of a two-state system

For a unit of capacity C MW and FOR q, the probability density-function (PDF) of capacity on outage is represented as shown in figure 2. O_1 and O_2 are the outage states at 0 MW and C MW respectively.

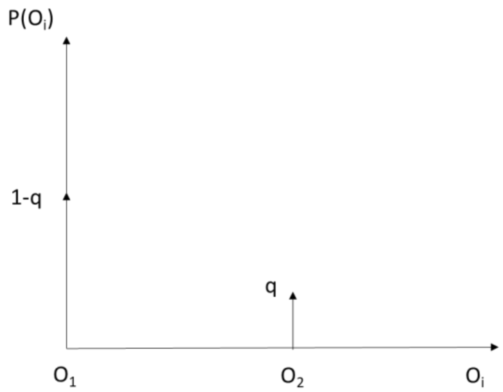


Figure 2: Probability of capacity on outage

A better representation of the PDF of capacity on outage is the Capacity Outage Table (COT). The COT is an array of capacity outage states and their associated probabilities as shown in Table 1.

Table 1: Capacity outage table of a C MW unit

State i	Outage O_i	Probability P(Oi)
1	0	1-q
2	C	q

The COT includes all states. However, to improve computational efficiency, a COT can be truncated to reduce the number of states by removing states with $P^*(O_i) \leq \varepsilon$, where, $P^*(O_i)$ is the cumulative probability of the state. Furthermore, unevenly spaced states can be rounded to states with equal increments to simplify the model.

To round a state O_i between states O_j and O_k, such that $O_k - O_j = r$, where $O_k > O_j$, the following expressions are used:

$$P'(O_j) = P(O_j) + \frac{O_k - O_i}{r} . P(O_i) \quad (3)$$

$$P'(O_k) = P(O_k) + \frac{O_i - O_j}{r} . P(O_i) \quad (4)$$

1. Recursive algorithm for building the COT:

An efficient method for building the COT when a large number of units are involved, is the recursive method. The algorithm is based on the idea of building the capacity outage table one unit at a time. The states of the added unit are combined to those of the COT using basic probability theorems. The unit to be added can have a two-state model or a multi-state model.

In the case of a two-state model unit addition, for a given capacity outage table $P_r(O_i)$ after adding r units, with O_i= 0…O_n, if an r+1 unit of capacity C and FOR q is added the updated probabilities are given as follows:

$$P_{r+1}(O_i) = P_r(O_i).p + P_r(O_i - C).q \tag{5}$$

Where, $P_r(O_i - C) = 0$ if $O_i - C \ni \{0 \dots O_n\}$.

In the case of a multi-state model unit addition, for a given capacity outage table $P_r(O_i)$ after adding r units, with O_i= 0…O_n, if an r+1 unit of outage capacities C_j and probabilities P_j respectively, for j=1…m, is added, the updated probabilities are given as follows:

$$P_{r+1}(O_i) = \sum_{j=1}^{m} P_r\left(O_i - C_j\right).P_j \tag{6}$$

Where, $P_r\left(O_i - C_j\right) = 0$ if $O_i - C_j \ni \{0 \dots O_n\}$.

2. *Recursive Algorithm for unit removal:*

The recursive algorithm can be used to also remove units, having a two-state model or a multi-state model. For a two-state model unit removal for a given capacity outage table $P_r(O_i)$ after adding r units, with $O_i = 0 \ldots O_n$, if an r+1 unit of capacity C and FOR q is removed the updated probabilities are given as follows:

$$P_{r-1}(O_i) = \frac{P_r\,(Oi\,) - P_{r-1}\,(Oi - C).q}{p} \tag{7}$$

Where, $P_{r-1}(O_i - C) = 0$ if $O_i - C \ \ni \{0 \ldots O_n\}$.

In the case of a multi-state model unit removal, for a given capacity outage table $P_r(O_i)$ after adding r units, with $O_i = 0 \ldots O_n$, if an r+1 unit of outage capacities C_j and probabilities P_j respectively, for j=1…m, is removed, the updated probabilities are given as follows:

$$P_{r-1}(O_i) = \frac{P_r(O_i) - \sum_{j=2}^{m} P_{r-1}(O_i - C_j).P_j}{P_1} \tag{8}$$

Where, $P_{r-1}(O_i - C) = 0$ if $O_i - C \ \ni \{0 \ldots O_n\}$.

B. Load Model:

The load duration curve (LDC) is used to model the load. The LDC shows the load levels and the duration of time during which the demand is equal or exceeds the load level. The area under the curve is the total energy demand of the system.

Loss of Energy Indices:

Combining the LDC with the COT, produces the expected energy not supplied (EENS). EENS, is a useful energy based index and preferred for providing a measure of shortage in capacity or amount of unmet demand, unlike the indices loss of load probability (LOLP) and loss of load expectation (LOLE). Furthermore, the expected energy supplied (EES) of a unit can be calculated, which eventually leads to the deduction of the operating costs of the units.

For a system with capacity C, outage states O(k) and corresponding probabilities P(k) for k=1…n, the energy curtailed or EENS due to O(k) is illustrated in figure 3. The expected energy not served due to O(k) is given by P(k). E(k), then the total EENS of the system is given by:

$$EENS = \sum_{k=1}^{n} P(k).E(k) \tag{9}$$

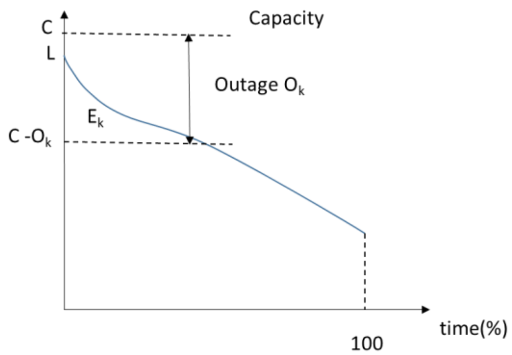


Figure 3: EENS due to outage O(k)

For a system of N units, and an LDC with total energy demand $E_{T,}$ initially, when no units are added:

$$EENS = E_T \tag{10}$$

The units are added by merit order; starting from units having least operating cost to highest operating cost. After adding first unit EENS is given as:

$$EENS = EENS_1 \tag{11}$$

And the energy supplied by the first unit is given by:

$$EES_1 = E_T - EENS_1 \tag{12}$$

And similarly the rest of the units are added and the respective EENS and EES are calculated. The energy supplied by the N^{th} unit is given by the general expression:

$$EES_N = EENS_{N-1} - EENS_N \tag{13}$$

CHAPTER III

MODELING AND OPERATION OF SYSTEM

The methods and techniques described in the methodology are translated in the simulation, to develop the generation and load model, and to calculate the outputs required for assessment, by combining both models. The modeling and assessment was done using a standard generation expansion planning (GEP) software, written using MATLAB, and available in the ECE department at AUB. The program was modified and upgraded to serve the requirements of this thesis. In the sections below the details of the simulation and the changes applied will be explained, going through the generation model, load model, and energy and cost outputs.

A. Generation Model:

The program used for modeling and assessment was initially developed for generation expansion planning. Both techniques, COT and ELDC, were available for use. In this work the COT method is used, to represent the failure of the units and the two-state generation model is used for modeling the units.

To begin with, the study period of the project must be specified. A generation plan should be provided to the program. Originally, the program was designed for thermal units only, however the current generation model incorporates conventional and renewable sources. The conventional units are given according to a specific plan of present units in the system, in addition to future plans. The details of the units must include, capacity, FOR, capital cost, lifetime, commissioning year, type of fuel used, and heat rate. For the provided study period a profile of fuel price forecast, and tariff profile are included.

The renewable units considered are photovoltaic (PV) system, wind, and hydropower. Each renewable source is considered as a bulk system having same type of pv modules, wind turbines, or hydro units. For the PV, module specifications should be provided to the program such as nominal operating cell temperature (NOCT), temperature coefficient of rated power, installation cost, operation and maintenance (OM) rate, interest rate, and lifetime. Furthermore, a PV plan should be provided specifying the capacity of PV to be added in each year.

Similarly, the wind turbine specifications should be provided including turbine hub height, installation cost, OM rate, interest rate, and lifetime. A wind plan should be provided, specifying the capacity of wind power to be added each year. The power curve of the turbine is required, and translated into an array containing the wind speed versus the power output. The power curve points have to include the cut-in, rated-output, and cut-out speeds versus there power output respectively.

In the hydropower plan, only the currently available capacity in the Lebanese power system is considered. Hydropower capacity in Lebanon is not very large compared to the thermal capacity, and only one reservoir is considerably large. For this reason, the model of the system was based on an averaging method; where an average of the available capacity of hydropower over a year will be divided over the base load. The representation of such a model is shown in figure 4. Another option to represent the hydropower is as shown in figure 5, where the peak of hydropower coincides with the peak load.

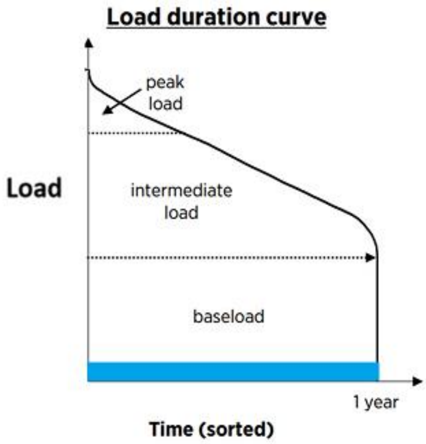


Figure 4: Equally Divided Hydropower Capacity

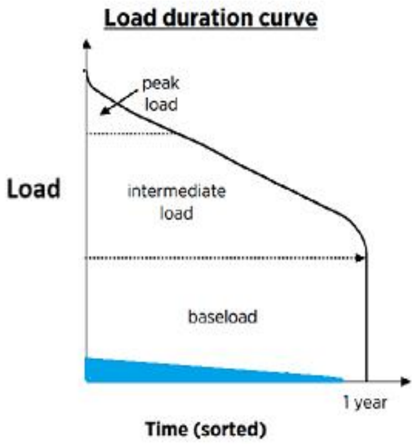


Figure 5: Peak of Hydropower at Peak of Load

However, these two cases are very optimistic. Therefore, the model in figure 6 is considered to represent the hydropower capacity, and consider a more pessimistic outlook.

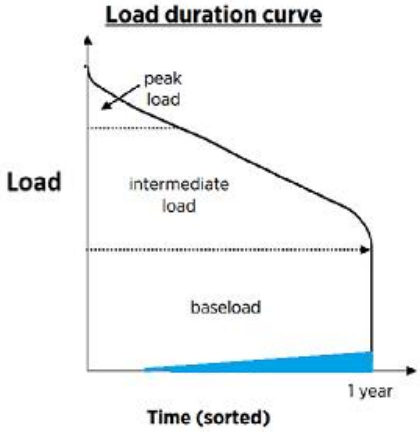


Figure 6: Hydropower Model of the system

B. Load Model:

The load model is represented by the LDC. To produce the yearly LDC, first an hourly load profile is developed by considering the loads of 12 typical days in the year given by EDL [22]. The given loads of the 12 days over 24 hours of each day, are assumed to be on the first day of the month, and interpolated to get the load for all days the months in a year. A weekly load profile is assumed, having a peak on Tuesday and lowest demand on Saturday and Sunday. This hourly load profile is loaded at the beginning of the simulation.

Also at the beginning, a weather profile is loaded, which contains hourly wind speed, ambient temperature, and solar irradiance over a year, measured at Qlayaat in Lebanon.

C. Yearly Computations:

1. Solar Power:

For every year of the study, the hourly load duration curve is modified according to the peak of that year. Also, the PV energy, cost, and hourly PV power are calculated each year. PV power is calculated using:

$$P_{PV} = \left(\frac{C_{cum} \cdot S}{S_0} . \left(1 + Temp_{Pmax} . (T_{cell} - T_S)\right)\right) . df_{pv} \qquad (14)$$

Where,

C_{cum}: PV capacity cumulated at present year

S: Solar insolation (W/m^2)

S_0: Irradiance (W/m2)

$Temp_{Pmax}$: Temperature coefficient of rated power

T_{cell}: Cell temperature (℃)

T_s: Standard Temperature (℃)

The cell temperature [23] is given by:

$$T_{cell} = T_{amb} + \left(\frac{NOCT - 20}{800}\right) . S \qquad (15)$$

Where,

T_{amb}: Ambient Temperature (℃)

NOCT: Nominal operating cell temperature (℃)

S: Solar insolation (W/m^2)

2. *Wind Power*

Similarly, for every year of the study, the total wind energy, cost, and hourly wind power are calculated. The wind power is calculated using the power curve and the hourly wind speed from a weather data file including the hourly wind speeds at a reference height. When a certain wind speed, from the data file, is not available in the power curve, the corresponding power is determined by interpolation. The final wind power is the product of the wind power and the equivalent efficiency of the turbine.

3. *Hydropower*

For the hydropower case, the model is based on the triangular shape illustrated in figure 6, as mentioned above. The area under the triangle is the total hydropower energy. Hourly hydro power is produced using:

$$p = \frac{P_W . t}{H} \tag{16}$$

Where,

p: Power at every time t of the year

P_W: Total Hydro power

t: Hours

H: Total hours in a year

After producing the hourly PV, wind, and hydro powers, each is deducted from the hourly load profile one at a time, generating at the end the residual hourly load curve. This residual load curve is the one that will be used with the conventional power plant's generation model to calculate the EENS, and the rest of the values required for energy and cost evaluation. The residual hourly load profile is then used to calculate the cumulants, and thus produce the LDC.

4. Operating Costs:

After producing the LDC, the operating costs (OC) are calculated and the units are sorted in ascending order of OC. The fuel costs (FC) of the units are given by:

$$Fuel\ cost\ of\ unit\ (\$/MWh)\ =\frac{Fuel\ price(\$/ton).HR(BTU/Kwh)\ .1000}{HV(MJ/ton).947.817} \tag{17}$$

And the operating costs are given by:

$$OC = FC + OM \tag{18}$$

5. Building the COT:

For each year of the study period, the unit in merit order is considered. If unit is not retired, it is added, and the COT is modified using the recursive technique described before. Therefore, it is built unit by unit, for all available units of the year. EENS and EES of the units are calculated. The total production cost of the system is produced and the total generation cost is given by the sum of operating cost (OC) and capital cost (CC):

$$Total\ Generation\ Cost = OC + CC \tag{19}$$

Then, the yearly total capacity, energy produced, system cost, levelized cost of energy are deduced for thermal units, renewable sources, and the total system. The average daily load shedding, for each year, is calculated using:

$$Average\ Daily\ Load\ Shedding\ (hrs/day) = \frac{EENS(KWh/yr)}{Total\ Energy\ Demand(KWh/yr)}.24 \tag{20}$$

The yearly financial deficit is calculated and given by:

$$Deficit\ \left(\frac{\$}{yr}\right) = EP_T.LCOE_s\ -\ EP_T.(1 - l_s).t.1000 \tag{21}$$

Where,

EP_T: Total energy produced of the system

$LCOE_S$: System levelized cost of energy

l_S: Technical and non-technical losses

t= Average Tariff

CHAPTER IV

NATURAL GAS IN LEBANON

The first explorations for oil and gas started onshore, as a result of a decision from the French High Commissioner, Henry de Jouvenel, in 1926, who assigned Louis Dubertret the task of exploration for the possibility of discovering oil and minerals [24].

During a search for Nickle-cobalt sulfide in the Lebanese village Yohmor, in 1947, new discoveries were made, indicating the presence of close petroleum fields. A company was put in charge to study the environment, and the result confirmed, that a rich petroleum area is present, however very high extraction cost is required. Since then many companies were put in charge for explorations, where between 1947 and 1967, seven wells were drilled onshore, in different locations and villages. The result of the drilling was the observation of bitumen and gas shows. The explorations and studies continued, and many companies were in charge of performing 2D and 3D seismic surveys, onshore and offshore. [24]

At the beginning of the seventies, geographical seismic surveying began offshore Tripoli. The progress was interrupted by the civil war, but continued at the beginning of the nineties. Several seismic surveys and interpretations were done since the nineties, but at a slow pace, due to maritime border negotiations, agreements, and disagreements. In 2012, Lebanon’s Council of Ministers approved the offshore Petroleum Resources Law and this was followed by announcing the first offshore licensing round, in 2012, and launching the licensing round in 2013, which was postponed afterwards [25].

The years 2017 and 2018 were full of legislative and preparatory works. In January 2017, the government passed two very important decrees that allow international oil companies to bid for the right to explore. The first is related to block delineation and the second is related to the Tender Protocol and Exploration and Production Agreement (EPA). It was announced that 51 companies were qualified to bid in the first offshore licensing round. In October 2017, the bidding was closed. In 2018 an EPA agreement was signed with the consortium of Total, ENI, and NOVATEK companies. The consortium had provided two bids for blocks 4 and 9 (Appendix A), which were approved by the government. [25]

At present time, preparations are on the way for a second offshore licensing round. Lebanon is waiting for the exploration stage, and drilling of two wells should take place in 2019. The upcoming steps of drilling and exploration, appraisal, and construction of the wells can take approximately 7 to 10 years [25]. That is, in approximately 10 years Lebanon may be a producer of oil and gas. Locally, this can have a good impact on the Lebanese power system. With its current situation of constant power cuts and consumers who pay two bills one for the government and the other for diesel generators, changing to a cheaper and cleaner type of fuel can be one of the corrective steps for a more reliable power system.

The effect of switching to natural gas, on the system, is studied in 3 possible scenarios, which are explained in more details below, and the effective changes are presented in the results.

CHAPTER V

THE GENERATION EXPANSION PLAN AND SCENARIOS

A. The Lebanese power system:

Electricity in Lebanon is mainly generated, transmitted, and distributed by Electricité du Liban (EDL), while the distribution network is operated and maintained by electricity utility companies. The consumer in Lebanon has been demanding for a reliable 24-hour electricity since the end of the civil war. The master plan that was done after the war for generation expansion and rehabilitation of the system, was insufficient [26]. Since then, the power sector is still suffering from technical and financial problems, besides constant political disagreements that led to delays or cancelations in proposed rehabilitation, expansion and modernization plans.

The problems of the sector are divided between generation, transmission and distribution. Since the scope of this thesis is limited to generation planning, we will consider the problems of the generation system in Lebanon. One of the major issues facing the generation system is the inability to cover the demand load. This is largely due to shortage in available generation capacity, aging of main thermal plants such as Zouk and Jieh, and using diesel oil to power the available combined cycle (CC) plants that are designed to use natural gas [26].

Currently, the available generation units are thermal and hydropower plants, as presented in table 2 and 3 [27,28]. The total generation capacity of both is unable to cover present demand, or future load growth. Lately, throughout the past few years, three major upgrading plans were presented by the ministers of energy and water in 2006, 2008 and 2010. The current Ministry of Energy and Water (MEW) [29] proposed many generation reformation plans that are mostly based on the policy paper of 2010 [30], with few updates to incorporate changes that took place since that year. The policy paper provides a framework for the Lebanese power sector, which includes ten strategic initiatives that cover the sector's generation, demand, infrastructure and legal aspects. The supply side plan includes capacity addition of economical and cleaner sources of energy; conventional units that use natural gas and renewable energy sources. The policy also includes the infrastructure requirements for natural gas, consisting of the coastal pipeline, and LNG terminal.

Table 2: Current Thermal Units

Power Plant (Existing)	Installed Capacity (MW)	Installed Technology	Fuel Type	Capable of Working on NG
Zouk	607	Steam Turbine	HFO	No
BWSC-Zouk	198	Reciprocating Engines	HFO	Yes
Jieh	346	Steam Turbine	HFO	No
BWSC Jieh	72	Reciprocating Engines	DO	Yes
Deir Ammar	465	Combined Cycle	DO	Yes
Zahrani	465	Combined Cycle	DO	Yes
Baalbek	70	Open Cycle	DO	Yes
Tyre	70	Open Cycle	DO	Yes
Hreyshe	75	Steam Turbine	HFO	No
Power Ships	370		HFO	Yes
Total Capacity	2738			

Table 3: Available Hydropower Plants

Hydropower Plant	Installed Capacity (MW)	Current Yearly Production (GWh)
Litani	199	680
Nahr Ibrahim	32	92
Kadisha	21	72
Bared	17	54
Richmaya	13	20
Total	282	918

B. The Scenarios:

The generation expansion plan to be considered in this thesis is composed of both conventional and renewable sources. Based on the policy paper of 2010 and the MEW, the expansion plan for conventional units is presented in table 4. To take into consideration the development of RES in Lebanon, the generation expansion plan considers a plan for renewable sources addition (pv and wind) as presented in tables 5 and 6 [30,31]. These plans are based on the commitment to increase the share of renewable energy sources (RES), to reach 12% in 2020 and 15% in 2030. In the case of PV addition, besides the 150, 50, and 100 MW additions in years 2020,2025, and 2030 respectively, an additional 100 MW of distributed PV (individual producers) is considered and divided throughout the study over the years 2018, 2020, 2025, and 2030.

To consider the recent advancement in NG explorations, three scenarios are developed to present possible cases through which NG can be added to the energy mix. Based on these developments, the work in this thesis was divided into two main parts:

- Assessing the proposed generation expansion plan (conventional and RE sources)
- Evaluating the impact of NG on electric power generation

The wind turbine considered in this study is Vestas V112-3.45-3.45 MW of 69 m hub height. The power curve [32] is provided below in figure 7. The PV module considered is from Yingli, YGE245 model having 46 °C NOCT, and -0.45 %/K temperature coefficient at P_{max}.

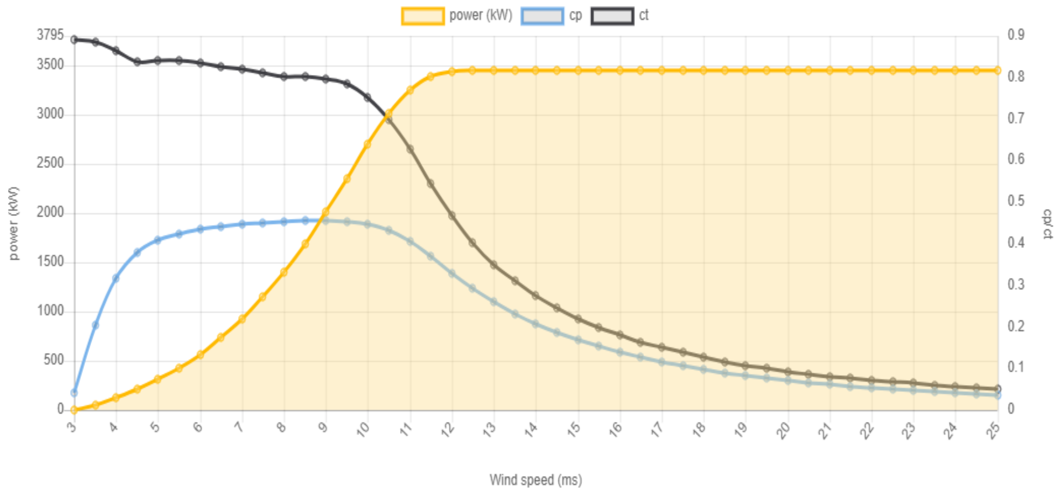


Figure 7: Wind Turbine Power Curve

The load growth rate is assumed to be 3% in all four cases, from the beginning of the study in 2018 to the end in 2032. Accordingly, the peak load growth is forecasted and illustrated in table 7 and figure 8.

Table 4: Future Plan for Thermal Plants

Power Plant (Expected)	Capacity to be Installed (MW)	Technology to be Installed	Fuel Type	Capable of Working on NG	Year of Completion
Zouk Rehabilitated	585	Steam Turbine	HFO	No	2022
Jieh-new	550	Combined Cycle	Diesel/ NG	Yes	2023
Baalbek-CC	110	Combined Cycle	Diesel/ NG	Yes	2022
Tyre-CC	110	Combined Cycle	Diesel/ NG	Yes	2022
Beddawi 2	530	Combined Cycle	Diesel/ NG	Yes	2021
Zahrani 2	600	Combined Cycle	Diesel/ NG	Yes	2023
Salaata 1	600	Combined Cycle	Diesel/ NG	Yes	2023
Salaata 2	600	Combined Cycle	Diesel/ NG	Yes	2023
New Power Ships	850		HFO/NG	Yes	2019

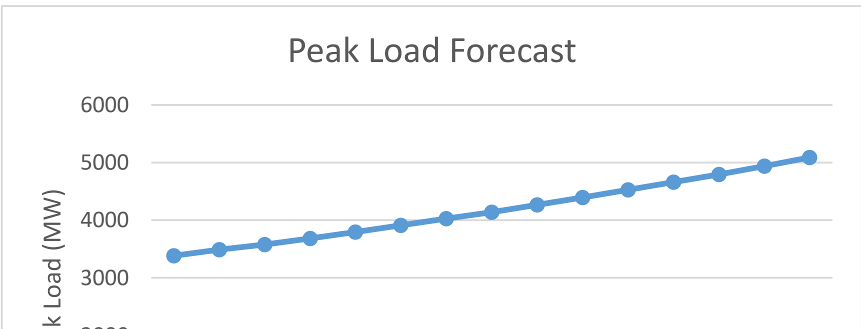
Table 5: PV Plan

PV Capacity (MW)	Commissioning Date
20	2018
150 + 20	2020
50 + 30	2025
100 + 30	2030
Total: 300 + 100 =400	

Table 6: Wind Plan

Wind Capacity (MW)	Commissioning Date
200	2020
150	2025
100	2030
Total: 450 MW	

Table 7: Peak Load Forecast



Year	Peak Load (MW)
2018	3383
2019	3485
2020	3577
2021	3685
2022	3796
2023	3910
2024	4028
2025	4140
2026	4265
2027	4393
2028	4526
2029	4662
2030	4796
2031	4941
2032	5090

1. ***Scenario 1:***

It is considered the baseline case. In this scenario it is assumed that development in local NG explorations does not take place, therefore all thermal power plants keep using HFO or DO throughout the whole study period. The World Banks's [33] forecasted cost of Crude oil was used to deduce the costs of HFO and DO for each year. Figure 9 shows the cost converted to $/ton.

2. ***Scenario 2:***

In this scenario it is assumed that development in local NG explorations takes place. However, since drilling does not start before 2019, it is assumed that NG becomes available in sufficient quantities after 10 years; in the year 2029. Therefore, thermal power plants; present and future, use HFO and DO from 2018 till year 2028. In

2029, the power plants that can use NG, are assumed to start working using local NG. The World Banks's [33] forecasted costs of NG was used as cost of fuel.

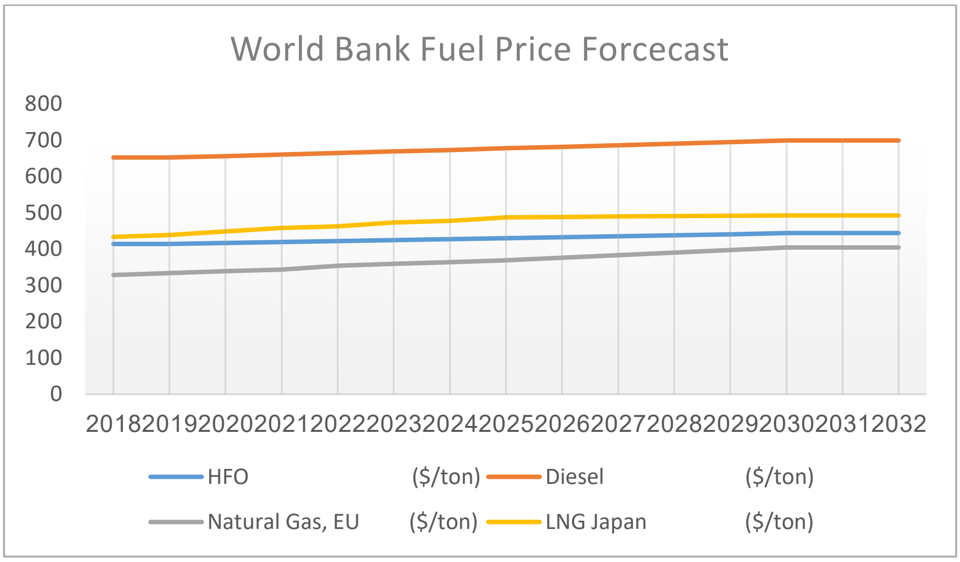


Figure 9: World Bank Fuel Price Forecast

3. Scenario 3:

In this scenario it is assumed that an intermediate plan for importing liquid natural gas (LNG), before local NG becomes available, takes place. Floating storage and regasification unit (FSRU) is needed to import LNG to Lebanon's coastline. The FSRU is a ship that stores LNG and also contains a regasification unit to turn LNG back to the gas state. If in 2019, the decision of importing is confirmed, it takes around 27-36 months to construct a new FSRU vessel and less for a converted vessel [34]. Therefore, it is assumed that within 2 years, in year 2021, the FSRU will be ready to provide LNG. The FSRU in this scenario is rented for 10 years (2021-2030), and power plants will be using LNG (converted to gas) from the vessel. According to Oxford Institute's outlook for FSRU [34] the lease cost of the unit is between $110-160,000/ day. Therefore, an average price of 135,000 $/day was considered. The OPEX of the FSRU is in the range of 20,000-45,000 $/day [34]. Consequently, an average price of 32,500 $/day was considered for the OPEX. Rental price is considered, as illustrated below in table 9, per year. Since local NG is assumed to be available starting from 2029, and after the leasing agreement ends in 2030, the power plants are assumed to start using local NG from year 2031 and on.

Table 8: FSRU Rental Cost

CAPEX($/day)	OPEX($/day)	Cost ($/year)
135000	32500	61137500

4. Scenario 4:

In this scenario, similar to scenario3, it is assumed that a plan for importing LNG takes place, starting from 2021, but in this case the FSRU is purchased. Therefore, LNG is the fuel used from 2021 and on, for all thermal power plants that can work using NG. According to Oxford Institute’s outlook for FSRU [34] the purchase cost of a 6 mtpa FSRU with 173,000 m^3 storage is in the range of 240-280 M$. The choice of an FSRU with 6mtpa send-out is the closest to the quantity required, and it is explained in the next section. Consequently, an average purchase cost of 260 M$ was considered. In addition to this cost, the capital cost of an FSRU terminal should include the cost of offshore infrastructure, which depends on locations and length of the offshore pipeline.

Since the cost of pipeline is in the order of 3-4 M$/km [34], an average value of 3.5M$/Km is assumed, with a 20 Km pipeline length.

This leads to a total of 70 M$ for infrastructure cost. The OPEX of the FSRU was considered to be 32,500 $/day, as in Scenario 3, to be consistent for the sake of comparison in the assessment part. This cost is equivalent to 11862500 $/year. Assuming the overall cost will be paid over the lifetime of the FSRU, the cost is amortized over 25 years at a 10% interest rate. The costs are presented in table 9. Finally, it is assumed that when local NG becomes available in 2029, it will be sold in the international market.

Table 9: FSRU Purchase Cost

CAPEX($)	260,000,000 + 70,000,000 = 330,000,000
OPEX($/year)	11862500
Yearly Payment ($/ year) (CAPEX Annuity ($/year) + OPEX($/year)	48,217,964

C. FSRU size:

To verify the size of FSRU needed, the quantity of NG required to power the available power plants was calculated. All present and future power plants that can work on NG, were considered. The formula used to calculate the gas quantity needed is given by:

$$Gas\ Quantity\ (MMBtu) = \frac{Capacity\ (MW).eff.8760.HR(Btu/KWh)}{1000} \tag{22}$$

Where,

Capacity: capacity of power plant in (MW)

Eff: efficiency of the plant

HR: heat rate of power plant in Btu/KW

The maximum quantity of NG needed, according to the power plant capacities considered, was estimated to be 6.88 Bm^3 which is equivalent to 11.72 Mm^3 of LNG ($LNG(Mm^3) = 1.71 * NG(Bm^3)$) corresponding to 5.33 mtpa as shown in table 10.

Table 10: NG and LNG Quantities

Power Plant	Capacity (MW)	efficiency	HR (BTU/Kwh)	NG quantity (mmbtu)	NG quantity (billion m3)	LNG quantity (million m3)
Zouk BWSC	198	0.915	9000	14283443	0.40	0.69
Jieh BWSC	72	0.915	10000	5771088	0.16	0.28
Zahrani 1 CT	160	0.8253	7180	8305397	0.23	0.40
Zahrani 2 CT	160	0.8253	7180	8305397	0.23	0.40
Zahrani 3 CT	145	0.8253	7180.1	7526871	0.21	0.36
Deir Ammar 1 CT	160	0.781	7180.2	7859803	0.22	0.38
Deir Ammar 2 CT	160	0.781	7180.2	7859803	0.22	0.38
Deir Ammar 3 CT	145	0.781	7180.3	7123046	0.20	0.34
Jieh New	550	0.9	7180	31133916	0.88	1.50
Baalbak CC	35	0.9	7640	2108182	0.06	0.10
Baalbak CC	35	0.9	7640	2108182	0.06	0.10
Baalbak CC	40	0.9	7640	2409350	0.07	0.12
Tyre- CC	35	0.9	7640	2108182	0.06	0.10
Tyre- CC	35	0.9	7640	2108182	0.06	0.10
Tyre- CC	40	0.9	7640	2409350	0.07	0.12
Beddawi 2 CC	530	0.9	7180	30001774	0.85	1.45
Zahrani 2 CC	600	0.9	7180	33964272	0.96	1.64
Salaata 1 CC	600	0.9	7180	33964272	0.96	1.64
Salaata 2 CC	600	0.9	7180	33964272	0.96	1.64
Total	4300			243314779	6.88	11.72

CHAPTER VI

RESULTS

A. Demand Forecast:

One of the main objectives of this thesis, is to assess the proposed generation expansion plan. Since the power system in Lebanon has insufficient capacity of units to cover the current demand, the task at this point is to check first if the addition of the planned capacities will cover the anticipated demand as it increases yearly. The plan for increasing production capacity is plotted against the peak load, with 3% yearly growth, in figure 10. The figure shows that starting from 2021 capacities to be added take into consideration the peak load forecasted till 2032.

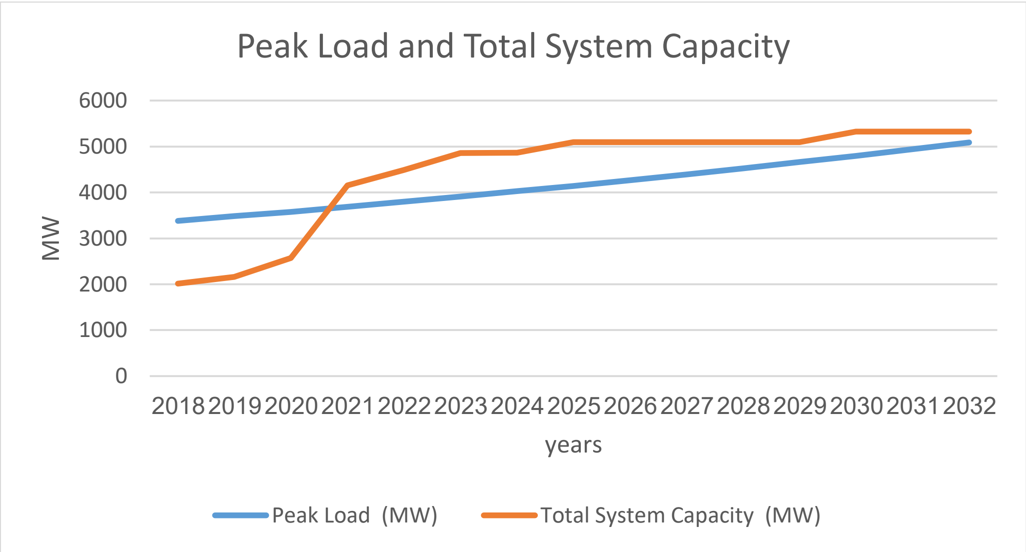


Figure 10: Peak Load and Total System Capacity

B. Renewable Sources:

The plan to reach a 12% target is based on the understanding that energy produced by RES will reach to 12% of the total energy to be produced in 2020. In figure 11 the effect on the demand by adding RE is illustrated. The figure shows the decrease in demand due to the addition of RE, for the adopted plan of RES described before.

The 12% target was tested, using the plan for RE capacity increase versus the total energy to be produced from thermal and renewable sources. It is deduced that in 2020, 1835 GWh of energy will be produced by RES, where total energy produced will be 15,265 GWh. Figure 12 illustrates the percentage of RES from the total energy produced. It shows that RES share is 12% of the total energy produced in 2020. In 2030, the energy produced by RES is considered to be 2,943 GWh according to the capacity available, where 23,636 GWh of total energy is produced in the same year. It is deduced that RES will produce 12.45% of the total energy to be produced as shown in figure 13.

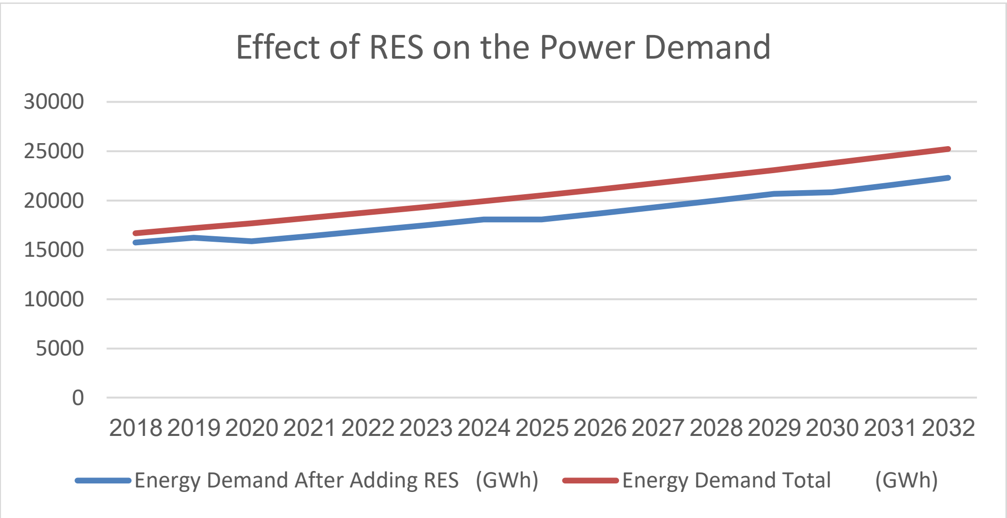


Figure 11: RE and the effect on Power Demand

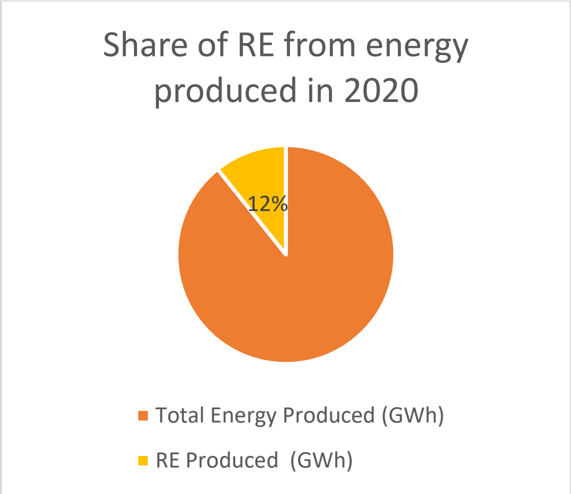


Figure 12:Share of RES in 2020

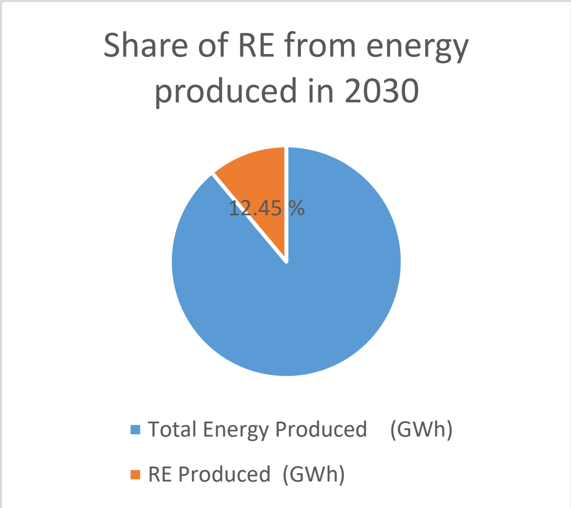


Figure 13: Share of RES in 2030

To further illustrate the increase in RES capacity through the years, figure 14 shows the actual capacity of thermal units against the capacity of total renewable sources.

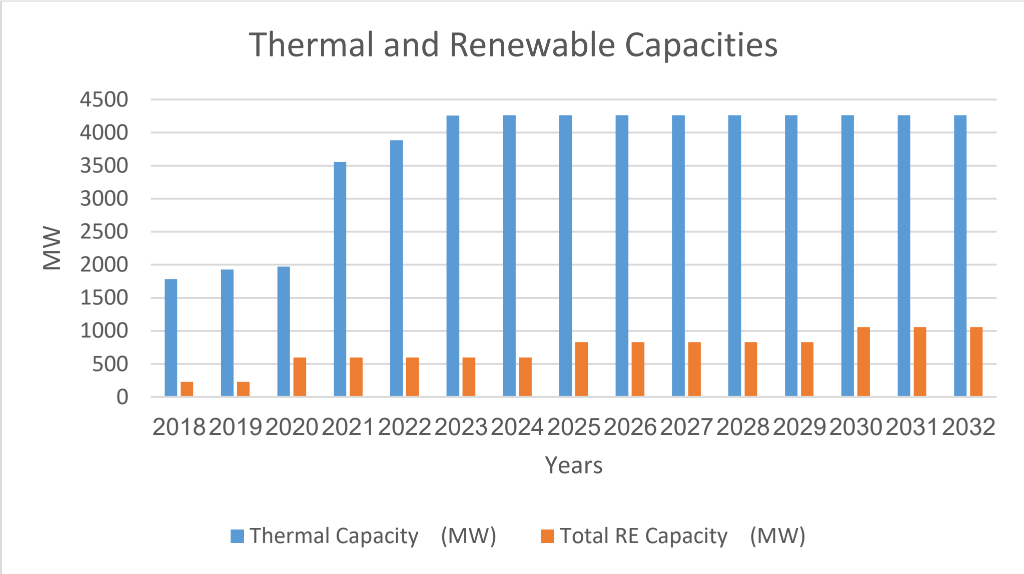


Figure 14: Thermal and Renewable Capacities

The developed program can provide the RLDC and compare it against the actual LDC for each year. Below in figures 15,16,17, and 18 the difference that RE addition does on the LDC is presented for the years 2018, 2020, 2025, and 2030 respectively. During these selected years an increase in PV and wind capacity takes place.

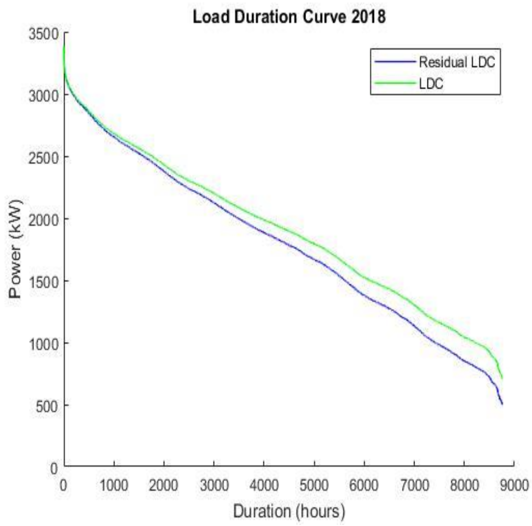


Figure 15: LCD and RLDC in 2018

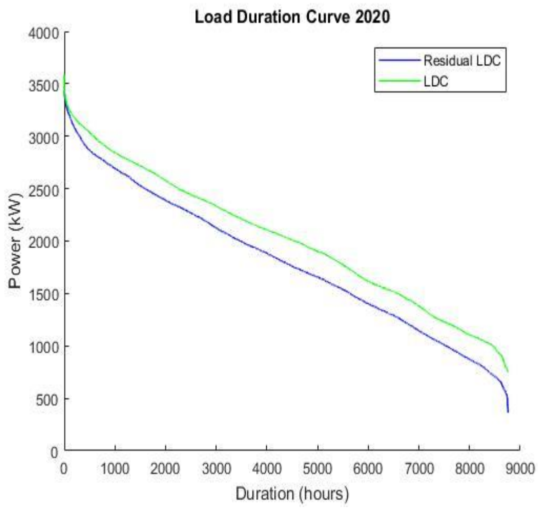


Figure 16: LDC and RLDC in 2020

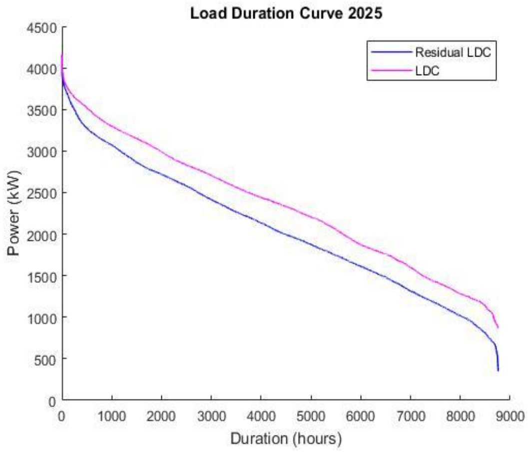


Figure 17: LDC and RLDC in 2025

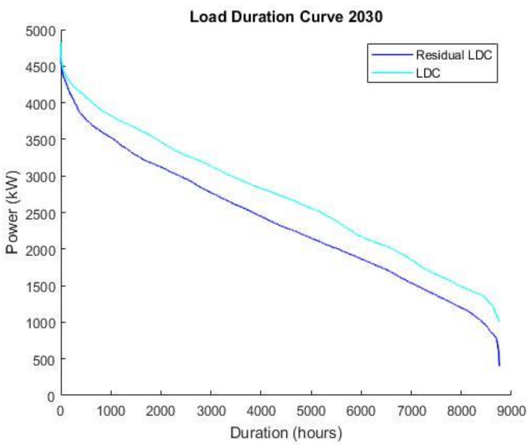


Figure 18: LDC and RLDC in 2030

C. Energy Assessment:

The plan for increasing the generation capacity, thermal and renewable, was mentioned in the section before. According to these additions, the energy produced from conventional and renewable units was calculated for every year of the study. Table

11 presents the energy produced, and figure 19 demonstrates these values graphically, compared to the total energy demand.

Table 11: Annual Energy Produced and Demanded

Years	Thermal Capacity (MW)	PV Capacity (MW)	Wind Capacity (MW)	Hydro Capacity (MW)	Thermal Energy Produced (GWh)	Solar Energy Produced (GWh)	Wind Energy Produced (GWh)	Hydro Energy Produced (GWh)	Total Energy Produced (GWh)	Energy Demand Total (GWh)
2018	1782	20	0	209	12593	29	0	918	13540	16682
2019	1931	20	0	209	13413	29	0	918	14360	17183
2020	1971	190	200	209	13430	273	644	918	15265	17698
2021	3554	190	200	209	16336	273	644	918	18171	18229
2022	3887	190	200	209	16918	273	644	918	18753	18776
2023	4256	190	200	209	17494	273	644	918	19329	19339
2024	4264	190	200	209	18066	273	644	918	19901	19919
2025	4264	270	350	209	18061	388	1127	918	20494	20517
2026	4264	270	350	209	18665	388	1127	918	21098	21133
2027	4264	270	350	209	19281	388	1127	918	21714	21766
2028	4264	270	350	209	19908	388	1127	918	22341	22419
2029	4264	270	350	209	20543	388	1127	918	22976	23092
2030	4264	400	450	209	20693	576	1449	918	23636	23785
2031	4264	400	450	209	21342	576	1449	918	24285	24498
2032	4264	400	450	209	21992	576	1449	918	24935	25233

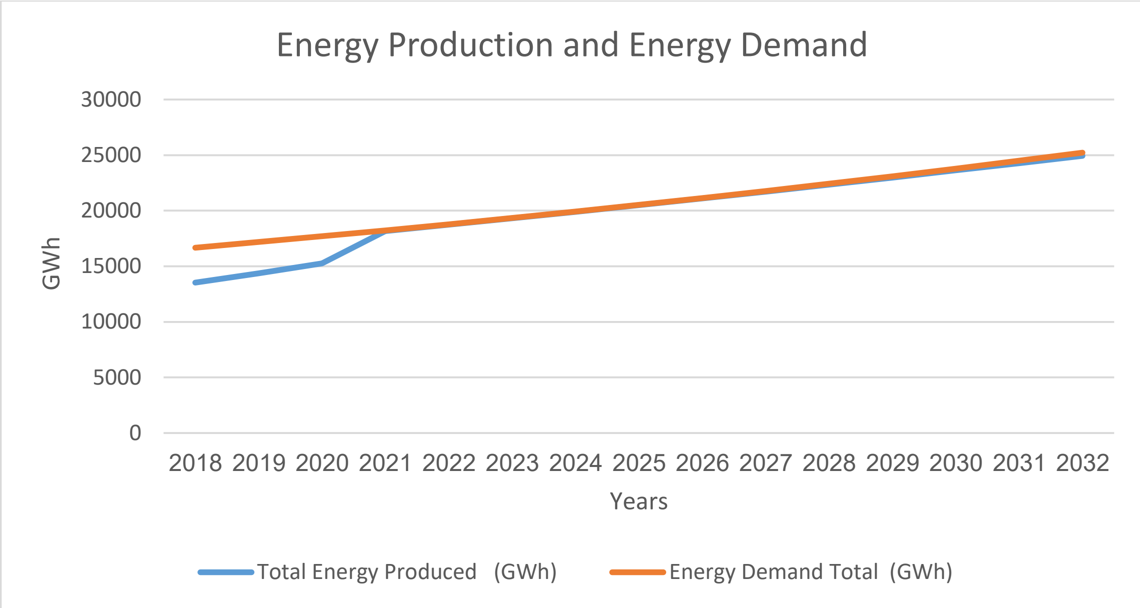


Figure 19: Energy production and Energy Demand

As clarified in figure 19, between 2018 and 2020 the energy produced is low compared to the demand. This is due to the absence of any new capacity addition during these years. Starting from 2021, the new units are added to the system, lifting energy production closer to the demand.

The program produced for every year, the EENS, presented in figure 20. For the study period considered, the addition of the new capacities, thermal and renewable, lead to the quick decrease in the EEN, starting from year 2021, confirming the effectiveness of the capacity to be added in the upcoming years. Near the end of the study, the EENS shows a noticeable increase which should be addressed by further increase in capacity at a second stage.

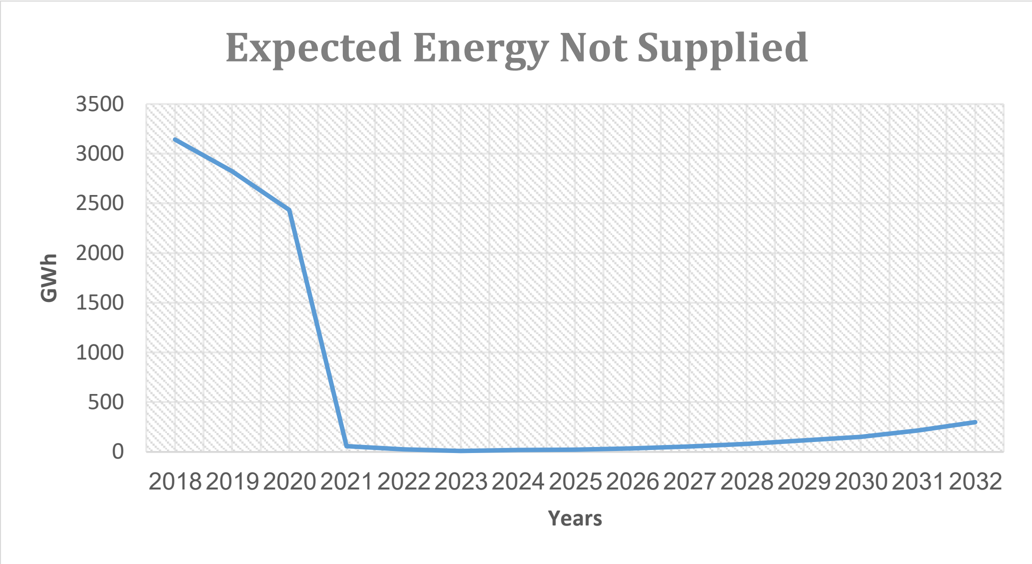


Figure 20: Expected Energy Not Supplied

Calculating the average daily load shedding, supported additionally the effectiveness and importance of the added generation capacity. Figure 21 shows the drop in number of hours from around 4.79 hours to around 0 hours after 2021.

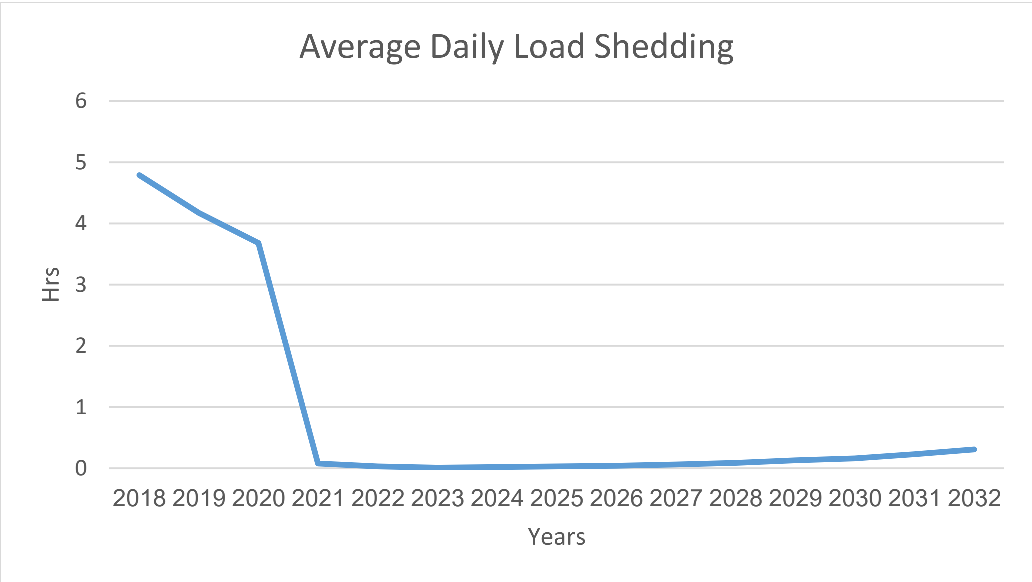


Figure 21: Average Daily Load Shedding

As explained before, this thesis used the program developed to assess four scenarios. Assessing the baseline scenario allows us to check the effectiveness of purely increasing the generation capacity, without any other support such as switch in type of fuel. Moreover, the baseline scenario allowed us to evaluate the program developed based on the results deduced, and compare it against actual present values. In this next section a financial assessment is done, comparing the baseline scenario and the other three scenarios that were explained before.

D. Financial Assessment:

The generation cost of the four scenarios is compared in figure 22. This cost is the sum of fuel cost, capital, OM in scenarios 1 and 2, while in scenario 3 additional cost of FSRU rental is added, and in scenario 4 additional cost of FSRU purchase, divided over the 25 years, is added as a yearly cost at a 10% interest rate. It appears that the cost in the baseline scenario, increases significantly in 2021 and eventually keeps increasing continuously as new units are added and run using HFO and DO.

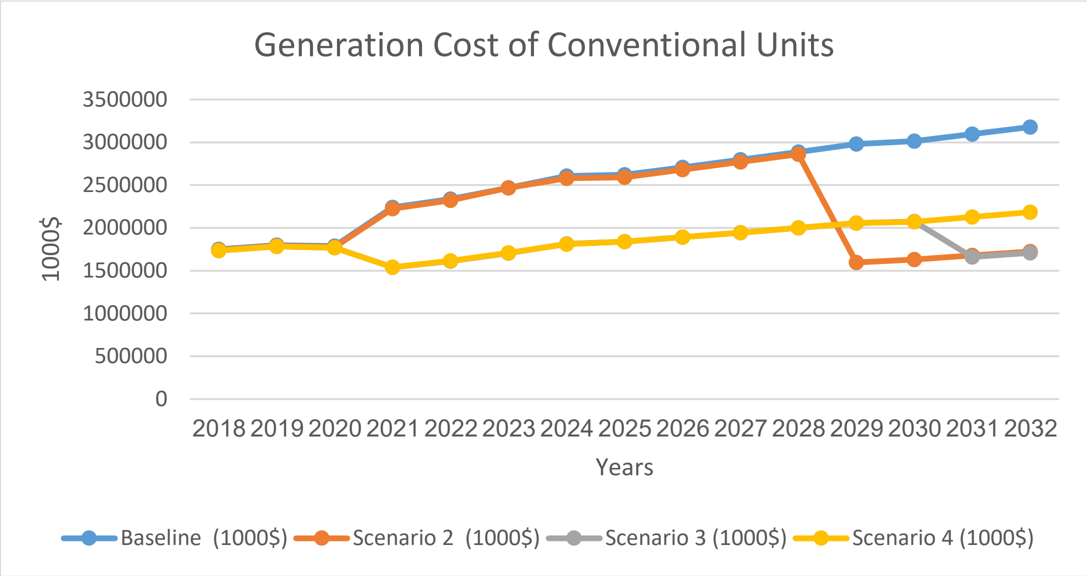


Figure 22:Generation Cost of Conventional Units for all Scenarios

Scenario 2 shows that once local NG starts being used in 2029 for most thermal power plants, a rapid drop in cost takes place. The generation cost in scenario 3 and 4 decreases considerably in 2021 as LNG becomes available and many of the thermal plants start using imported NG. In both scenarios generation cost keeps increasing continuously after the drop, as additional units are added, but at a significantly lower cost compared to scenarios 1 and 2.

Between 2021 and 2030, the cost in Scenario 3, where the FSRU is rented, is higher than scenario 4, based on the values of leasing and purchasing presented previously. The cost in scenario 3 drops to meet that of scenario 2 in 2031, when the power plants start using local NG in that year.

The changes in generation cost, are translated directly to the levelized cost of energy (LCOE) of thermal power plants. These changes are demonstrated in figures 23 and provided in table 12.

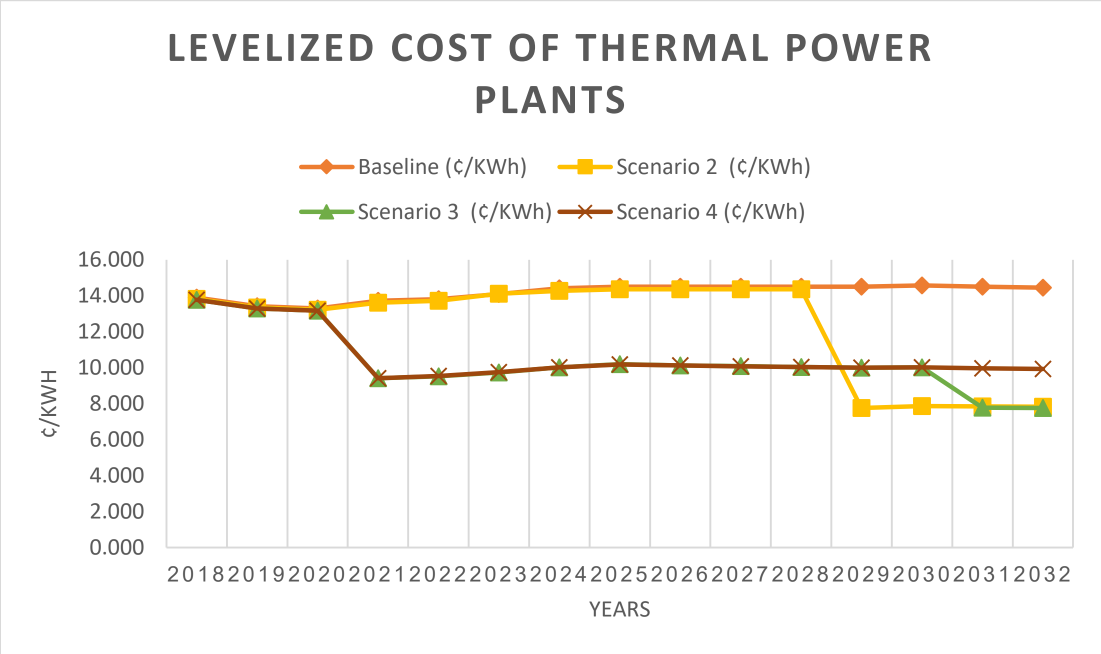


Figure 23: Levelized Cost of Thermal Plants

The LCOE of thermal power plants in the baseline scenario are in the range of 13-14 ¢/KWh between 2018 and 2032. In Scenario 2, when NG becomes available, starting from 2029 the LCOE decrease from values ranging between 13-14 ¢/KWh to approximately 7.8 ¢/KWh. Scenario 3 and 4 experience a drop in levelized cost in 2021, when LNG is imported, from values ranging 13-14 ¢/KWh to approximately 9-10 ¢/KWh. Scenario 3 experiences further drop, in 2031, when local natural gas is used to power most of the thermal plants, decreasing to approximately 7.8 ¢/KWh.

Table 12: Levelized Cost of Thermal Power Plants

Years	Baseline (¢/KWh)	Scenario 2 (¢/KWh)	Scenario 3 (¢/KWh)	Scenario 4 (¢/KWh)
2018	13.899	13.827	13.773	13.773
2019	13.412	13.345	13.295	13.295
2020	13.294	13.227	13.177	13.177
2021	13.716	13.620	9.422	9.422
2022	13.806	13.726	9.531	9.547
2023	14.100	14.114	9.733	9.761
2024	14.423	14.274	10.029	10.024
2025	14.504	14.355	10.190	10.184
2026	14.501	14.356	10.135	10.130
2027	14.500	14.360	10.088	10.082
2028	14.504	14.368	10.046	10.041
2029	14.511	7.762	10.010	10.005
2030	14.571	7.874	10.019	10.014
2031	14.508	7.853	7.776	9.966
2032	14.449	7.837	7.763	9.924

The system deficit of all four scenarios is calculated and presented in figure 25 and table 13. In Scenario 1, the deficit level increases continuously as generation capacity increases. Scenario 2, breaks the trend of continuous increase in deficit level, in the year 2029, when a rapid drop from 1788.49 M$ to 429 M$ is experienced due to shifting of most thermal plants to NG.

In scenario 3 and 4, a drop in deficit level is experienced in 2021 from approximately 1058.25 M$ to 626.48 M$. Scenario 3 experience a further drop in 2031 from a deficit level of 920.90 M$ to 450.71 M$. The financial deficit level in all scenarios, even after a rapid drop in scenarios 2, 3 and 4, continues increasing starting from a lower level of deficit. This is due to the steady and low tariff level that is not increased to match the increase in capacity followed by an increase in energy produced. The program contains a module ready to receive tariff profile, if it is available, to test how the change in tariff level would affect the yearly deficit.

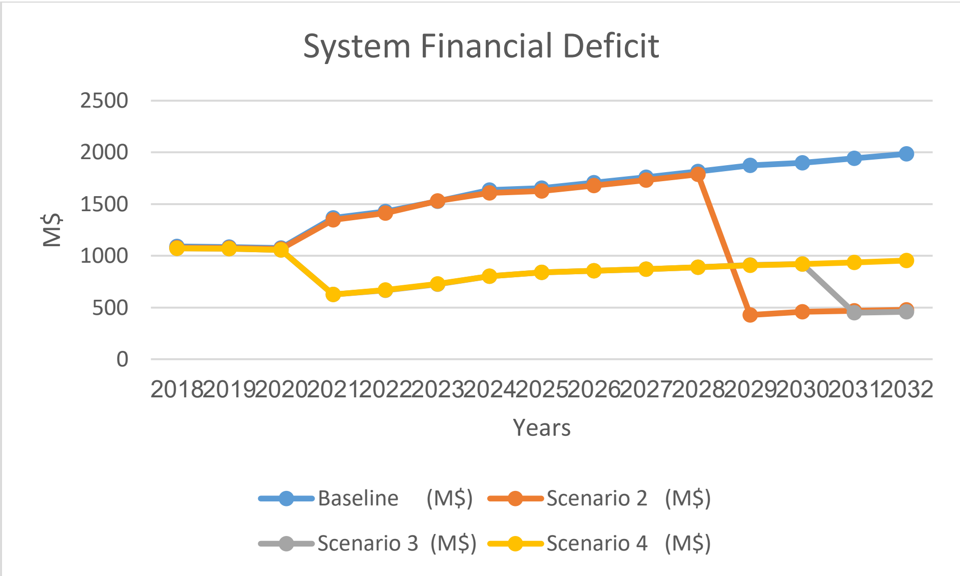


Figure 24: System Financial Deficit

Table 13: System Financial Deficit (M$)

Years	Baseline (M$)	Scenario 2 (M$)	Scenario 3 (M$)	Scenario 4 (M$)
2018	1089.92	1080.17	1072.99	1072.99
2019	1086.43	1076.73	1069.58	1069.58
2020	1075.04	1065.37	1058.25	1058.25
2021	1365.30	1348.73	626.48	626.38
2022	1427.29	1412.90	666.68	669.64
2023	1527.32	1529.89	725.23	730.41
2024	1635.94	1607.82	803.85	802.77
2025	1655.62	1627.56	840.03	838.94
2026	1707.54	1679.57	855.81	854.73
2027	1760.94	1733.07	872.84	871.76
2028	1816.25	1788.49	890.95	889.87
2029	1873.09	429.00	910.10	909.03
2030	1900.73	458.96	920.90	919.82
2031	1943.67	467.80	450.71	936.69
2032	1986.76	477.40	460.34	954.15

E. Result Conclusion:

Overall, according to the input data provided to the system from generation capacities of thermal plants and renewable sources, in addition to the load growth rate, and costs of plants and FSRU considered, the results obtained lead to the following conclusions:

Comparing thermal generation costs of scenarios 2, 3, and 4, when NG is used, against the baseline case that uses HFO and DO only, shows that increasing the share of

NG in the fuel mix decreases generation cost in addition to thermal LCOE, system LCOE, and system financial deficit.

Comparing Scenario 2 against scenarios 3 and 4 indicates that an intermediate or medium term solution, consisting the import of LNG, till the time when local NG is available, allows generation cost to drop at an earlier time, and save the country around 700 millions of dollars of additional losses every year.

Comparing Scenarios 3 and 4, shows that during the period 2021-2030, renting of FSRU, costs more than purchasing it, assuming a yearly payment as explained before. This leads to having in this period, generation cost, LCOE and system financial deficit of scenario 3 higher than that of scenario 4. However, this situation can be reversed if changes in FSRU leasing cost take place after some time, or a different FSRU provider is considered providing a higher purchasing cost, or if a different size of FSRU is assumed leading to changes in purchase and rental costs.

On the other hand, years 2031 and 2032, in scenario3, show that using local NG decreases the generation costs, LCOE, and financial deficit to levels lower than that of scenario 4, where imported LNG is still being used. This reassures that local NG should be part of the generation plan. However, the choice of whether FSRUs should be rented or purchased depends on what vision will be adopted for Lebanon’s anticipated natural gas resource. It should be noted that Lebanon currently lacks expertise and qualified engineers to operate FSRUs. Therefore, purchasing of FSRU, will require additional costs to provide high skilled expertise. This is an additional cost, which is not included in this thesis, because the exact value is not clear. Having this in mind, renting of the FSRU appears to be a better choice based on the current lack of operating skills.

CHAPTER VII

CONCLUSION

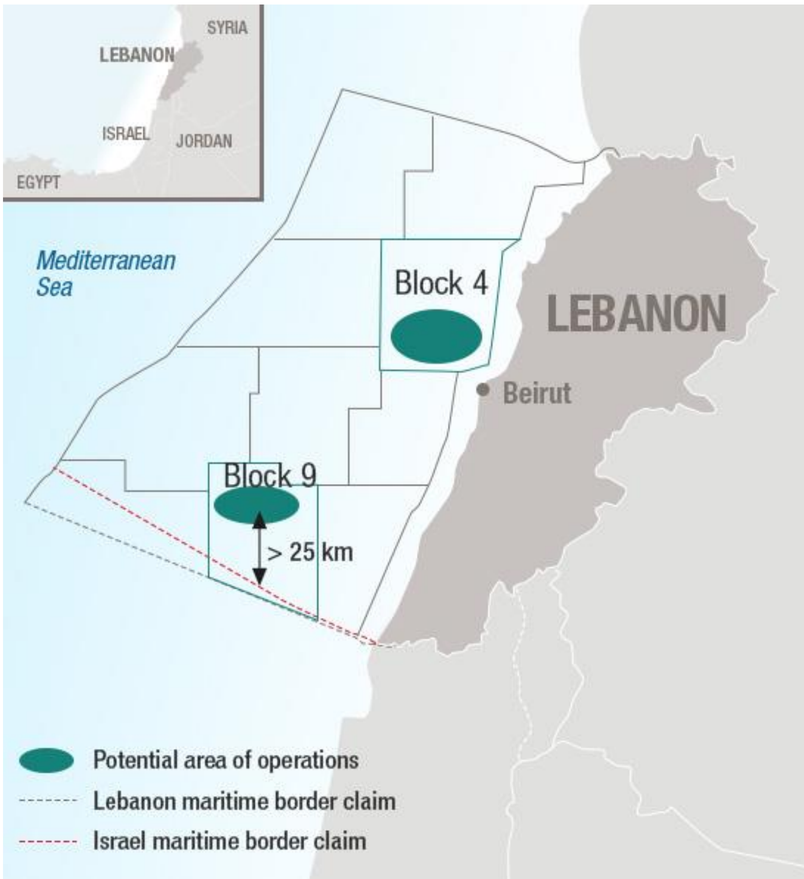
In this thesis, a generation expansion plan is proposed and four scenarios are developed in light of recent advancements in natural gas exploration and renewable energy development. The plan and the scenarios are assessed from a financial and energy perspective.

A generation expansion planning tool is developed to assess systems consisting of both conventional units that work on HFO and DO and later NG, and renewable energy sources. Using this tool, the expansion plan and scenarios are assessed. Probabilistic production costing is used to calculate the Expected Energy Not Supplied of the system and to evaluate the energy produced and production costs. The capacity outage probability table method is used to model the conventional units and the load duration curve (LDC) to model the load. To incorporate renewable energy, specifically wind, solar, and hydropower, the residual load duration curve (RLDC) method is used.

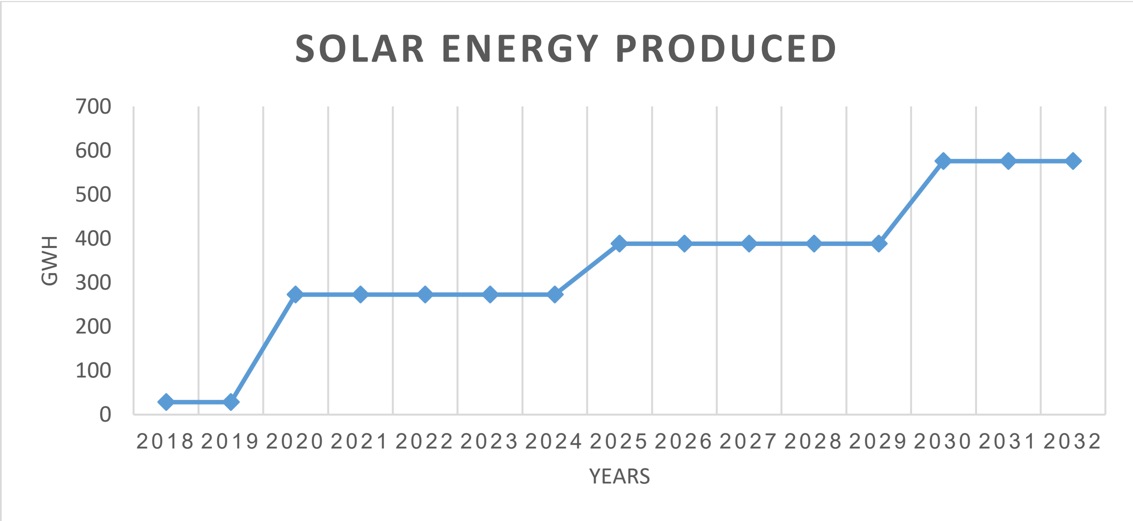
The production costs and energy evaluation of the system reassure the importance of strategic capacity addition to cover current and future demand. The results show the importance of using local natural gas for power generation, in terms of reduction in generation cost, levelized cost, and financial deficit. On the other hand, adopting an intermediate plan to import LNG, shows significant drop in generation cost, levelized cost, and financial deficit at an earlier stage, before local natural gas is available. FSRU rental is advised, till local NG is developed, due to the absence of expertise to operate an FSRU if it is purchased.

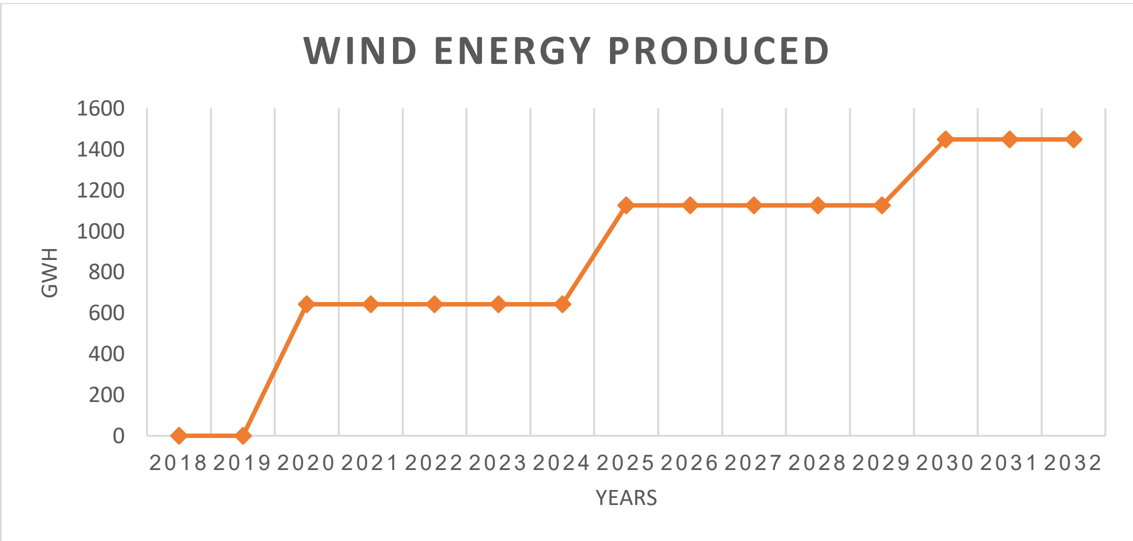
Although the plans incorporate economical conventional units, RES that reach 12% of total energy produced in 2020 and 12.45% at the end of the study, and cheaper fuel, the financial deficit persists. This calls for the need to match the tariff level with the planned increase in capacity and energy production. Finally, the study reveals the urgent need to apply a strategic generation expansion plan, without further delay.

APPENDIX A


SYRIA
LEBANON
ISRAEL
JORDAN
EGYPT
Mediterranean Sea
Block 4
LEBANON
Beirut
Block 9
> 25 km
Potential area of operations
Lebanon maritime border claim
Israel maritime border claim

APPENDIX B


SOLAR ENERGY PRODUCED
GWH
700
600
500
400
300
200
100
0
2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032
YEARS


WIND ENERGY PRODUCED
GWH
1600
1400
1200
1000
800
600
400
200
0
2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032
YEARS

REFERENCES

[1] *The National Renewable Energy Action Plan for the Republic of Lebanon 2016-2020*. Lebanese Center for Energy Conservation (LCEC), 2016 [Online]. Available: http://lcec.org.lb/Content/uploads/LCECOther/161214021429307~NREAP_DEC14.pdf [Accessed: Aug- 2018]

[2] R. Allan and R. Billinton, "Concepts of power system reliability evaluation", *International Journal of Electrical Power & Energy Systems*, vol. 10, no. 3, pp. 139-141, 1988.

[3] L. Goel and R. Billinton, "A comparison of three fundamentally different methods for generating capacity reliability evaluation", *Electric Power Systems Research*, vol. 29, no. 1, pp. 1-8, 1994.

[4] R. Billinton and P. Harrington, "Reliability Evaluation in Energy Limited Generating Capacity Studies", *IEEE Transactions on Power Apparatus and Systems*, vol. -97, no. 6, pp. 2076-2085, 1978.

[5] J. Zhu and M. Chow, "A review of emerging techniques on generation expansion planning", *IEEE Transactions on Power Systems*, vol. 12, no. 4, pp. 1722-1728, 1997.

[6] R. Ghajar and R. Billinton, "A Monte Carlo simulation model for the adequacy evaluation of generating systems", *Reliability Engineering & System Safety*, vol. 20, no. 3, pp. 173-186, 1988.

[7] H. Merrill and A. Wood, "Risk and uncertainty in power system planning", *International Journal of Electrical Power & Energy Systems*, vol. 13, no. 2, pp. 81-90, 1991.

[8] H. Sadeghi, M. Rashidinejad and A. Abdollahi, "A comprehensive sequential review study through the generation expansion planning", *Renewable and Sustainable Energy Reviews*, vol. 67, pp. 1369-1394, 2017.

[9] V. Oree, S. Sayed Hassen and P. Fleming, "Generation expansion planning optimization with renewable energy integration: A review", *Renewable and Sustainable Energy Reviews*, vol. 69, pp. 790-803, 2017.

[10] R. Billinton, H. Chen and R. Ghajar, "Time-series models for reliability evaluation of power systems including wind energy", *Microelectronics Reliability*, vol. 36, no. 9, pp. 1253-1261, 1996.

[11] S. Karaki, R. Chedid and R. Ramadan, "Probabilistic performance assessment of wind energy conversion systems", *IEEE Transactions on Energy Conversion*, vol. 14, no. 2, pp. 217-224, 1999.
[12] S. Karaki, R. Chedid and R. Ramadan, "Probabilistic performance assessment of autonomous solar-wind energy conversion systems", *IEEE Transactions on Energy Conversion*, vol. 14, no. 3, pp. 766-772, 1999.

[13] K. Tigas, J. Mantzaris, G. Giannakidis, C. Nakos, N. Sakellaridis, E. Pyrgioti and A. Alexandridis, "Generation Expansion Planning under Wide-Scale RES Energy Penetration", in *2012 International Conference on Renewable Energies for Developing Countries (REDEC)*, Beirut, Lebanon, 2012, pp. 1-7.

[14] W. Lyzwa and M. Wierzbowski, "Load duration curve in the long-term energy mix optimization", in *2016 13th International Conference on the European Energy Market (EEM)*, Porto, Portugal, 2016, pp. 1-5.

[15] T. Luz, P. Moura and A. de Almeida, "Multi-objective power generation expansion planning with high penetration of renewables", *Renewable and Sustainable Energy Reviews*, vol. 81, pp. 2637-2643, 2018.

[16] M. Yehia, R. Chedid, M. Ilic, A. Zobian, R. Tabors and J. Lacalle-Melero, "A global planning methodology for uncertain environments: application to the Lebanese power system", *IEEE Transactions on Power Systems*, vol. 10, no. 1, pp. 332-338, 1995.

[17] S. Karaki, F. Chaaban, N. Al-Nakhl and K. Tarhini, "Power generation expansion planning with environmental consideration for Lebanon", *International Journal of Electrical Power & Energy Systems*, vol. 24, no. 8, pp. 611-619, 2002.

[18] H. Hamdan, R. Ghajar and R. Chedid, "A simulation model for reliability-based appraisal of an energy policy: The case of Lebanon", *Energy Policy*, vol. 45, pp. 293-303, 2012.

[19] O. Ibrahim, F. Fardoun, R. Younes, H. Louahlia-Gualous and M. Ghandour, "Multi-variable optimization for future electricity-plan scenarios in Lebanon", *Energy Policy*, vol. 58, pp. 49-56, 2013.

[20] L. Dagher and I. Ruble, "Modeling Lebanon’s electricity sector: Alternative scenarios and their implications", *Energy*, vol. 36, no. 7, pp. 4315-4326, 2011.

[21] M. Lin, A. Breipohl and F. Lee, "Comparison of Probabilistic Production Cost Simulation Methods", *IEEE Power Engineering Review*, vol. 9, no. 11, pp. 31-31, 1989.
[22]"Electricity of Lebanon - Public Institution", *Edl.gov.lb*, 2019. [Online]. Available: http://www.edl.gov.lb/page.php?pid=37&lang=en.

[23] G. Masters, *Renewable and efficient electric power systems*, 2nd ed. Hoboken, NJ: John Wiley & Sons Inc., 2013, pp. 292-294, 327-329.
[24]"Lebanese Petroleum Administration", *Lpa.gov.lb*. [Online]. Available: http://www.lpa.gov.lb/index.php.

[25]"Lebanese Oil and Gas Initiative", *Logi-lebanon.org*, 2019. [Online]. Available: https://www.logi-lebanon.org/.

[26] O. Ibrahim, F. Fardoun, R. Younes and H. Louahlia-Gualous, "Energy status in Lebanon and electricity generation reform plan based on cost and pollution optimization", *Renewable and Sustainable Energy Reviews*, vol. 20, pp. 255-278, 2013.

[27] *Hydropower in Lebanon; History and Prospects*. 2013 [Online]. Available: http://www.cedro-undp.org/content/uploads/Publication/141009092113199~Exchange%204.pdf. [Accessed: Jun- 2018]

[28]"Electricity of Lebanon - Public Institution", *Edl.gov.lb*, 2019. [Online]. Available: http://www.edl.gov.lb/page.php?pid=37&lang=en.

[29] *Ministry of Energy and Water*, 2019. [Online]. Available: http://www.energyandwater.gov.lb/.

[30] *Policy Paper for the Electricity Sector*. 2010 [Online]. Available: https://data2.unhcr.org/en/documents/details/64585. [Accessed: 23- Apr- 2018]

[31] *The National Renewable Energy Action Plan for the Republic of Lebanon 2016-2020*. Lebanese Center for Energy Conservation (LCEC), 2016 [Online]. Available: http://lcec.org.lb/Content/uploads/LCECOther/161214021429307~NREAP_DEC14.pdf. [Accessed: Aug- 2018]

[32] L. Bauer and S. Matysik, "Vestas V112-3.45 - 3,45 MW - Wind turbine", *wind-turbine-models.com*. [Online]. Available: https://en.wind-turbine-models.com/turbines/1247-vestas-v112-3.45.

[33]"Commodity Markets", *World Bank*, 2018. [Online]. Available: http://www.worldbank.org/en/research/commodity-markets. [Accessed: Jun- 2018]

[34] B. Songhurst, *The Outlook for Floating Storage and Regasification Units (FSRUs)*. Oxford Institute for Energy Studies, 2017, pp. 1-54 [Online]. Available: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/07/The-Outlook-for-Floating-Storage-and-Regasification-Units-FSRUs-NG-123.pdf. [Accessed: Jan- 2019]