Measuring Efficiency Gains of Fuel Substitution in Thermal Power Generation

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ABSTRACT

As the global population and affluence increase, electricity demand will increase accordingly. Although pressure from the international community due to increased environmental awareness has led to a surge in the use of clean and renewable sources for electricity generation over the past decade (especially in developed countries), over half of the world's electrical energy used today is from steam turbine generators burning fossil fuels, with large scale fossil-fueled plants providing most of the world's baseload generating capacity.

Meanwhile, many thermal power plants worldwide- mostly in undeveloped countries - are inefficient and can be optimized financially and economically and minimize their environmental impact. Fuel flexibility and choosing the correct type of thermal plant appropriate to the forecast load can be considered in maintaining power generation efficiency.

This study aims to undertake a Cost-Effectiveness analysis (CEA) of two different power generating technologies - Internal Combustion (Diesel) and combined cycle gas turbines – in the Turkish Republic of North Cyprus (TRNC) by analyzing the appropriateness of using heavy fuel oil (HFO) and liquefied natural gas (LNG) to ascertain an economically optimum combination, nonetheless, could be extended to any other place with the appropriateness of these types of plants.

Keywords: Electricity generation, efficiency, CEA, fuel flexibility, thermal power generation, diesel, TRNC, CCGT, HFO, LNG.

ÖZ

Küresel nüfus ve refah arttıkça, elektrik talebi de buna bağlı olarak artacaktır. Artan çevre bilincine bağlı olarak uluslararası toplumdan gelen baskı, geçtiğimiz on yılda (özellikle gelişmiş ülkelerde) elektrik üretimi için temiz ve yenilenebilir kaynakların kullanımında bir artışa yol açsa da, bugün kullanılan dünya elektrik enerjisinin yarısından fazlası buhardan sağlanmaktadır. fosil yakıtları yakan türbin jeneratörleri ve dünyanın temel yük üretme kapasitesinin çoğunu sağlayan büyük ölçekli fosil yakıtlı tesisler.

Oesnada, dünyanın her yerinde, çoğu gelişmemiş ülkelerde çalışan birçok termik santral verimsizdir ve finansal, ekonomik ve çevresel etkilerini en aza indirgemek için optimize edilebilir. Yakıt esnekliği ve tahmini yüke uygun doğru termik santral tipinin seçilmesi, enerji üretim verimliliğinin korunmasında düşünülebilir.

Bu çalışma, Kuzey Kıbrıs Türk Cumhuriyeti'nde (KKTC) iki farklı güç üretim teknolojisinin - İçten Yanmalı (Dizel) ve kombine çevrim gaz türbinlerinin - Maliyet-Etkililik analizini (CEA), ağır akaryakıt kullanımının uygunluğunu analiz ederek gerçekleştirmeyi amaçlamaktadır. HFO) ve sıvılaştırılmış doğal gaz (LNG), ekonomik olarak optimum bir kombinasyonu belirlemek için, yine de, bu tür tesislerin uygunluğuyla başka herhangi bir yere genişletilebilir.

Anahtar Kelimeler: Elektrik üretimi, KKTC, verimlilik, CEA, yakıt esnekliği, termik enerji üretimi, dizel, CCGT, HFO, LNG.

DEDICATION

To My Family

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LIST OF ABBREVIATIONS

BBL	Oil Barrel
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CE	Cost-Effectiveness
CEA	Cost-Effectiveness Analysis
CER	Cost-Effectiveness Ratio
CO2	Carbon Dioxide
EIA	The US Energy Information Administration
EDF	Électricité de France
EOCK	Economic Opportunity Cost of Capital
GDP	Gross Domestic Product
GWh	Gigawatt Hour
HFO	Heavy Fuel Oil
IC	Internal Combustion
IEA	The International Energy Agency
IIA	Integrated Investment Approach
ILCOE	Incremental Levelized Cost of Energy
IPP	Independent Power Producer
Kg	Kilogram
KIB-TEK	Kibris Turk Elektrik Kurumu
KW	Kilowatt
KWh	Kilowatt Hour

LCOC	Levelized Cost of Capital
LCOE	Levelized Cost of Energy
LNG	Liquified Natural Gas
MJ	Megajoule
MMBTU	Million British Thermal Units
MW	Megawatt
MWh	Megawatt Hour
NOx	Nitrogen Oxides
OECD	Organisation for Economic Co-operation and Development
OPEX	Operational Expenditure
PM	Particulate Matter
PPA	Power Purchase Agreement
PV	Present Value
SDR	Social Discount Rate
SO2	Sulfur Dioxide
TON	Tonne
TRNC	Turkish Republic of North Cyprus
TVM	Time Value of the Money
USD	United States Dollar
USD’M	Million United States Dollar

Chapter 1

INTRODUCTION

1.1 Background

As the global population and affluence increase, electricity demand will increase accordingly. Although pressure from the international community due to increased environmental awareness has led to a surge in the use of clean and renewable sources for electricity generation over the past decade (especially in advanced countries), more than half of the world's electrical energy used today is from steam turbine generators burning fossil fuels, with large scale fossil-fueled plants providing most of the world's baseload generating capacity. Meanwhile, many thermal power plants worldwide- mostly in developing nations - are inefficient and can be optimized financially, economically and minimize their environmental impact.

Economic systems planning addresses the problem of choosing the correct type of thermal plants appropriate to supply the forecasted demand so that overall production costs are minimized. Unlike nuclear and coal power generations, combined-cycle or single-cycle plants can have a built-in fuel flexibility system to work with either liquid fuels such as HFO or natural gas to increase fuel efficiency. In terms of safety and environmental impact, they are one step ahead of the other types of thermal power generations and have become the technology of choice for supplying baseload electricity demand (Kehlhofer, Rukes, Hannemann, & Stirnimann, 2009; Roques, 2008).

What are the advantages of using natural gas over other fossil fuels? To answer this question, we must first bear in mind that liquid fuel and natural gas can be delivered through the pipeline or via carriers both onshore and offshore. Where natural gas pipelines are not possible or do not exist, liquefying natural gas can transport natural gas from production areas to markets. In addition, the volume of natural gas in its liquid state is approximately 600 times less than its volume in gaseous form. Consequently, to make LNG, natural gas is cooled down to -162 Celsius and compressed for transportation and storage (EIA, 2020).

LNG is the cleanest fossil fuel. Therefore, in the current energy transfer field that the European Commission is looking for, this is an excellent alternative to reducing PM emission, especially in economies dependent on tourism such as the TRNC.

The flexibility value of LNG is increasing market liquidity and enhancing the security of supply. Technology cost reductions in finding LNG and reduced cost of sea transportation resulted in a decrease in the marginal cost of production and tremendous growth in the global LNG market, tripling in size since 2000 (International Gas Union, 2019). With the development of gas hubs, gas trade, and LNG imports and trade over the past decade, the share of gas supply to indexed oil in Europe had dropped to below 30% in 2018 from some 80% in 2005 (Tsvetana Paraskova, Bloomberg, 2018), Figure 1 shows oil (Crude oil) and gas price correlation from 1997 to 2020 (Macrotrends.net).

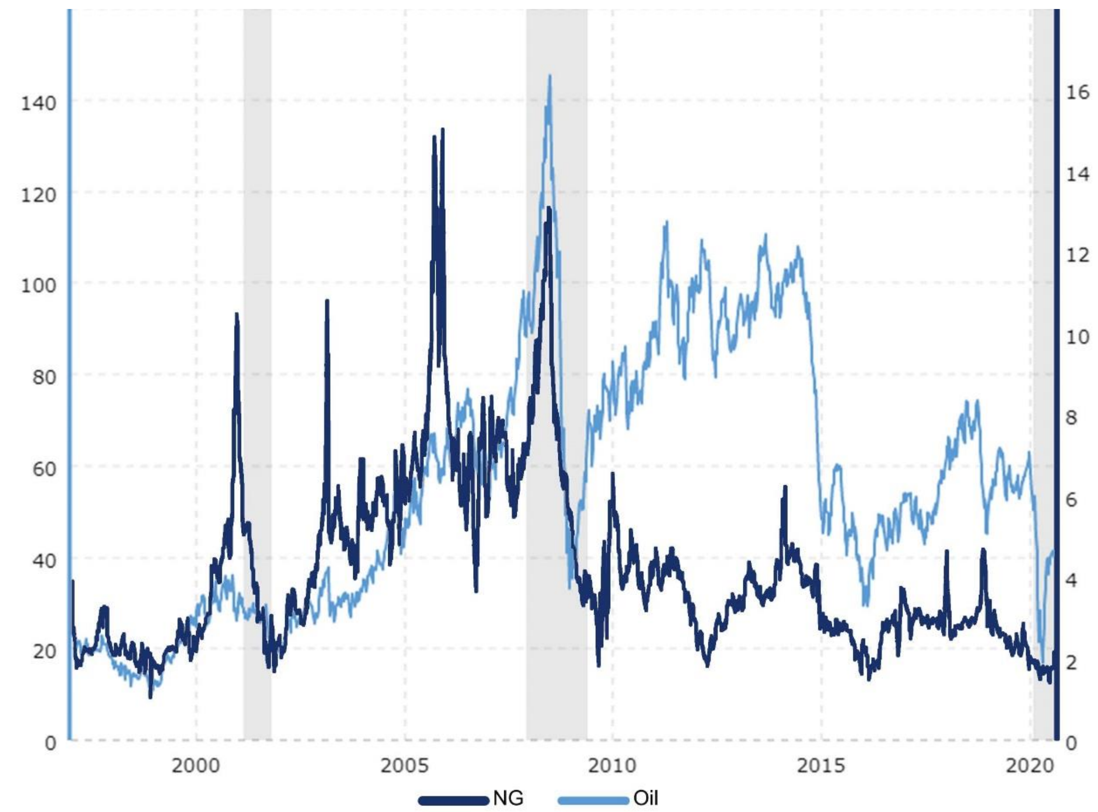

Figure 1: Crude Oil vs Natural Gas - 23 Year Daily Chart

EIA data shows a direct relationship between crude oil and natural gas between 2003 and 2008; however, there was little correlation between 2009 and 2019 (EIA, 2020). Since 2007, shale oil and gas in the United States have disrupted global energy markets and turned natural gas from a scarce commodity into an important energy source globally. According to the EIA, US natural gas production poured by more than 51% and has gone from being an importer to a net exporter of natural gas in 2017 for most of its history. This has accelerated global trade in LNG, with global LNG exports increasing by almost 90% from 2007 to 2018, representing more than 45% of the global gas trade (Ruhe, 2019). In addition, increased shale production in the US explains the delinking of crude oil and natural gas prices because natural gas is a regionalized product (EIA, 2020).

Natural gas provides an economical, efficient, and stable option to generate electricity. Therefore, it is particularly suitable for developing economies, which require significant new capacity investments (EIA, 2020). In addition to the clean air benefits, natural gas provides high system capacity and reliability, helping to mitigate integration costs of variable renewables (International Gas Union, 2019).

The price of oil and gas highly depends on supply and demand in the market. According to offshore technology analysis, after the COVID-19 pandemic, oil demand decreased by 23.1 million barrels per day (Ruth Starchan, 2020), thus causing a sudden drop in the oil price (WTI Crude) from 63.05 USD/bbl on January 3rd, 2020, to 10.30 USD/bbl on April 28th, 2020, and now to the date August 10^{th,} 2020 as might be expected increased to 42 USD/bbl (Oilprice.com).

Figure 2 shows the expected new global liquefaction capacity pre/post-COVID-19 situation. The sudden decline in gas demand will affect the financing of new capitalization projects and lead to delays in bringing new supply to the market. On the other hand, the low price of LNG motivates most countries to start importing LNG and not only drives the growth of the LNG industry in the future but also reduces production costs through technological improvements and makes it more beneficial than other liquid fuels.

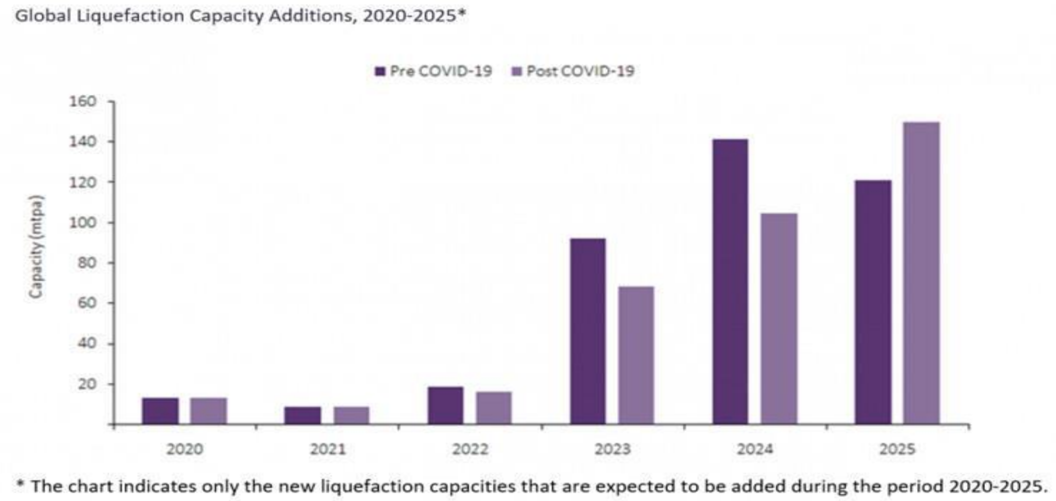

Figure 2: Expected New Global Liquefaction Capacity pre/post-COVID-19.

LNG historical prices confirm a long-run decline in price due to the economy of scale in extraction, new reservoir discoveries, and technological improvement; as mentioned before, Figure 3 depicted LNG daily rates (USD/MMBTU) from 2010 to 2020 in the Mediterranean region (S&P Global, Platts).

Figure 3: Daily LNG Price in Mediterranean Region 2010-2020

Gains of fuel substitution from liquid fuel to natural gas as a primary fuel in thermal power generators come from the price difference and higher heat-rate of natural gas. As a result, it reduces fuel consumption compared to other competitors like heavy fuel oil. All these benefits and being the top environmentally friendly fossil fuel have caused LNG to be more frequently selected as the primary fuel for liquid fossil fuel-based thermal power generations.

1.2 Importance and Objectives

This study aims to undertake a CEA of two different power generating technologies - Internal Combustion (Diesel) and combined-cycle gas turbines (CCGT) – in the Turkish Republic of North Cyprus (TRNC) by analyzing the appropriateness of using heavy fuel oil (HFO) and liquefied natural gas (LNG) to ascertain an economically optimum combination; nonetheless, it could be extended to any other region with the same structural base power system.

1.3 Study Framework

This dissertation is structured as follows below:

i. Chapter 2: A Literature review of the existing electricity production system
ii. Chapter 3: Overview of the proposed scenarios to improve the current system
iii. Chapter 4: Detailed review of the methodology used to assess the proposal
iv. Chapter 5: Cost-effectiveness Analysis of proposal
v. Chapter 6: Risk analysis of the proposal
vi. Chapter 7: Conclusion and Recommendation

Chapter 2

LITERATURE REVIEW OF THE EXISTING ELECTRICITY PRODUCTION SYSTEM

2.1 Introduction

The electricity production system depends on different factors (e.g., technology, availability of energy resources, location, budget, regulations, etc.). As a result, it inevitably has changed over time; Figure 3 shows world gross electricity production by source (IEA,2018).

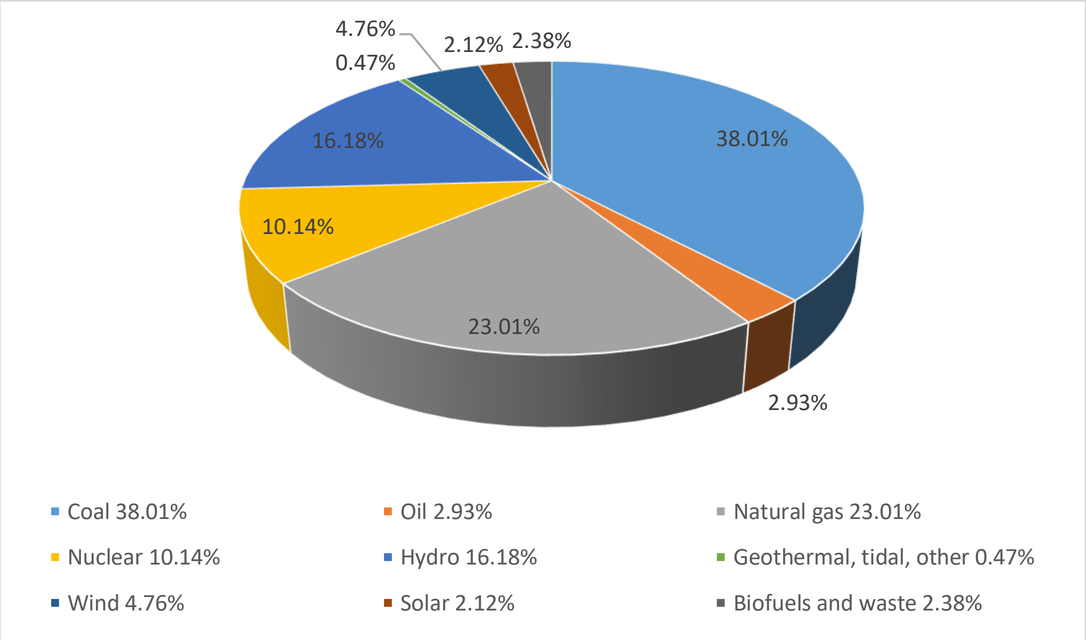

Figure 4: World Gross Electricity Production, by source, 2018

As shown above, 38.8% of the world's primary source of electricity is coal. Although due to technological improvement, emissions of coal-fired power generations reduce significantly, still pressure from the international community has led to a surge in the use of clean sources (Jerram, 1996). In total, 76% of fossil fuel sources use to feed thermal power generations, and only 24% are from renewable sources (e.g., hydro, solar, wind, and geothermal). The type of thermal power plant is versatile and, due to its suitability for use, is designed in various capacities and classes (Sharma & Singh, 2020).

Statistics show the importance of thermal power plants in electricity generation systems worldwide (US Energy Information Administration, 2020). This study focuses primarily on two different thermal power generation technologies and evaluates the correctness of using HFO and LNG to determine an environmentally and economically efficient combination.

2.2 TRNC Electricity Sector

The electricity production system in TRNC consists of the public sector Kibris Turk Elektrik Kurumu (KIP-TEK), and an independent power producer (IPP) AKSA (private electricity generation company) from Turkey with 42% share of annual electricity production, and the rest provided by the public sector (KIP-TEK) from thermal power plants, solar, and the power grid connection to the south side of the island.

2.3 Existing Thermal Power Generation System

The total thermal installed capacity is 404 MW, and the breakdown of this capacity to the date 2020 is reflected in Table 1.

Table 1: Total Thermal Installed Capacity Breakdown, 2020

Plant Specification			
Owner	Technology	Number of Units	Capacity (MW)
KIB-TEK	Steam Turbine	2	120
	Intenal Combustion	8	136
AKSA	Intenal Combustion	8	140
	Waste	1	8

2.4 Power Purchase Agreement With AKSA

AKSA has a long-term power purchase agreement (PPA) in the form of the Take-and-Pay contract [1], which includes a 700 GWh annual purchase guarantee, with the rental price of 0.037 USD/KWh given by KIB-TEK. However, the contract is expected to expire at the end of 2023. Therefore, the proposed project would be implemented after the termination of the contract in 2024.

2.5 Proposed Project

Electricity is an inseparable part of economic growth (Adom, 2011). The objective of the proposed project is to ensure the best thermal technology replaces the old and obsolete ones in the baseload, and also, by providing the required infrastructure for using LNG as the primary fuel, make sure full productivity delivery and benefit comes to the TRNC's economy. However, following the project's capital cost (CAPEX), as will be seen in the following sections, the fuel cost imposes a heavy burden on its total expense over its lifetime.

[1] A contract obligating the buyer of the project's output to take delivery and pay for the output only if the project is able to deliver them. No payment is required unless the project is able to make deliveries

Besides fuel type, the heat-rate of the plant [2] or the plant's power generation efficiency[3] has a noticeable impact on the fuel consumption of the system and is characteristically defined as the amount of energy used by an electrical generator/power plant to generate one kilowatt-hour (kWh) of electricity (Bellman et al., 2007). The EIA expresses heat rates in British thermal units (Btu) per net kWh generated. Net Generation is the amount of electricity a power plant supplies to the power transmission line connected to the power plant. Net generation accounts for all the electricity that the power plant consumes to operate the plant's generator(s) and other equipment, such as fuel feeding systems, boiler water pumps, cooling equipment, and pollution control devices.

[2] Heat rate is one measure of the efficiency of electrical generators/power plants that convert a fuel into heat and into electricity.

[3] To express the efficiency of a generator or power plant as a percentage, divide the equivalent Btu content of a kWh of electricity (3,412 Btu) by the heat rate

Chapter 3

OVERVIEW OF THE PROPOSED SCENARIOS TO IMPROVE THE EXISTING SYSTEM

3.1 Introduction

Although this project was proposed for the existing TRNC electricity generation system, it could be extended elsewhere. The primary aim is to demonstrate the benefit of fuel substitution to the economy; therefore, solar and grid connections to the south side are excluded from the system. Under the economic recession, CCGT uses natural gas to express a competitive superiority over other conventional thermal plants (Weron & Przybylowicz, 2000).

As electricity demand increases, combined cycle technologies will play a vital role in the future of the electricity market (Poullikkas, 2004). Advance combined cycle efficiency has increased to 58% (Sharma & Singh, 2020), and the French company EDF recently developed a new model of CCGT called Bouchain with an efficiency of 62.22%, and it has begun to dominate the CCGT market. Therefore, as market power increases, the salient features of combined cycle power plants become more attractive.

3.2 Electricity Generation System “Without” The Project

Demand for electricity in terms of peak hour (MW) and total energy (GWh) in 2019 shows in Table 2 below:

Table 2: TRNC Electricity Demand, 2019.

Electricity Demand		
Year	Peak hour (MW)	Total Energy (Gwh)
2019	319	1,664

The current electricity generation system provides electricity demand in the following orders: Table 3 shows installed operational capacity and Table 4 energy generation by sector (KIP-TEK and AKSA), type, and share.

Table 3: Installed Operational Capacity, 2019.

Plant Specification			
Owner	Technology	Number of Units	Total Capacity (MW)
KIB-TEK	Steam Turbine	2	110
	Intenal Combustion	8	140
AKSA	Intenal Combustion	8	136
	Heat-Waste	1	8

Table 4: Energy Generation by Share and Sector, 2019.

Production (GWh)							
KIP-TEK						Aksa	
Steam Turbine	% Steam Turbine	Diesel	% Diesel	Solar	% Solar	Diesel	% Diesel
170	10%	734	44%	60	4%	700	42%

3.3 Electricity Generation System "With" The Project

The proposed project is expected to start in 2024 and continue to operate for the next 20 years. Therefore, the economic life of the power plants is assumed to be 25 years. By the commencement of the project, the life of the existing steam turbine will end, and it will be decommissioned, thus as the termination of the AKSA's contract, the operational installed capacity will be 140 MW in 2024. According to the demand forecasted and 140 MW of operational installed capacity in 2024, the proposed installed capacity to meet the demand shows in Table 5.

Table 5: Annual Proposed Capacity by Type, 2024-2043.

Installed Capacity Forecast (MW)										
Year	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
CCGT	150	0	0	0	0	100	0	0	0	0
IC	175	35	35	17.5	0	0	0		35	35
Year	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
CCGT	0	0	150	0	0	0	0	0	0	150
IC	0	0	0	0	0	0	105	0	0	0

The table above shows that in 2043, the TRNC needs a total capacity of 550 MW for CCGT as the baseload power plant and 577.5 MW capacity of diesel for the mid-range and peak hours.

Chapter 4

DETAILED REVIEW OF THE METHODOLOGY USED TO ASSESS THE PROPOSAL

4.1 Introduction

The proposed project was modelled based on the integrated investment appraisal (IIA) [4] and structured in the format of FAST [5] modelling standard. According to the nature of the project, IIA could be implemented either financially or economically. Cost-benefit analysis (CBA) becomes handy when the project can be evaluated in monetary terms, and CEA when there is no financial benefit which assigns a monetary value to the measure of effect. The proposed project was analyzed based on the CEA method. First, the appropriateness of the thermal power generation technology of the baseload was analyzed. Then, the appropriateness of using HFO and LNG as the primary fuel, Levelized cost of energy (LCOE), was examined [6]; In the end, an incremental LCOE (ILCOE) was obtained to demonstrate the effectiveness of the project.

4.2 Cost-Effectiveness Analysis

The CEA emphasizes comparative analysis of alternatives in terms of costs and results (Drummond, 2015). As mentioned above, the CEA method is used to evaluate the

[4] Method of project appraisal, in the form of financial, economic, stakeholder, and risk analysis.

[5] An Organization who built up the excel coding standard based on: Flexibility, accuaracy, well structured and transparency of spreadsheets https://www.fast-standard.org/about-fso/.

[6] Is a measure of the average net present cost of electricity generation for a generating plant over its lifetime and calculated as follows: $\mathrm{LCOE}\frac{\text{PV of Total Cost}}{\text{PV of Totan Net Energy Generation}}$

effectiveness of the project when there is a policy commitment to supply the services produced (i.e., commitment to supply sufficient electricity to meet the electricity demand), so the relevant financial or economic questions are to determine how to supply the given quantities of the service, with a specified quality, at the least cost. The government mostly does these types of projects to increase the quality of life in society (Adom, 2011), in other words, account for the socio-economic benefits of the project, which improves the whole economy and, thus, in the long run, leads to increase the GDP of the country.

The CEA method is mainly used in medical and healthcare projects when the monetary evaluation of the service is complex. At the same time, the quantitative measures of the service (i.e., the number of life-years saved) are relatively easy to measure. CEA is applicable in any other project (e.g., public schools, prisons, etc.) where public commitment is to supply a service at a given quality. Despite the CEA method having a specific structure according to the nature of the project, there are standard preliminary considerations and essential steps that all projects should consider. (Manaf et al., 2017).

4.2.1 Initial Contemplations

There are four initial considerations in any CEA methodology to be considered as detailed below (Manaf et al., 2017):

i. Baseline determination: Specify the basis of an alternative project for comparison.
ii. Choose the right outcome: It depends on the objective of the evaluation.
iii. Cost determination: Which costs should be included and attributed to the outcomes.

iv. Timeframe: The specified period in which evaluation takes place (systematic horizon).

4.2.2 CEA Conduction

Necessary steps to be taken for conducting the CEA are as follows:

i. Raising of a research question
ii. Cost and outcome determination
iii. CEA ratio (CER) and incremental CEA ratio (CERI) calculation
iv. Testing for uncertainty (Sensitivity analysis)

Raising of the Research Question

What is the objective of the CEA? In the proposed project, the primary purpose is the calculation of fuel cost-saving and to compare four scenarios of producing electricity, as shown below:

i. Diesel power generation using HFO
ii. Diesel power generation using LNG
iii. Combined cycle gas turbine using HFO
iv. Combined cycle gas turbine using LNG

Cost and Outcome Determination

Cost measurement depends on the characteristic of the cost and can be calculated from a financial or economic perspective view. Since the project is evaluated economically, the economic discount rate [7] is used for calculation (Gift et al., 2007). Cost estimation has two significant elements to consider:

i. Type of cost (Categorization)

[7] Opportunity costs denote the gains an investor, business, or individual lose when selecting one alternative over another.

ii. Cost estimation (Actual expenditure).

Depends on the project type, there are different outcome determination methods (e.g., direct estimation of health effects by counting the number of patients cured in the specified group and compared with the other group) (Gift et al., 2007).

In the proposed project, the outcome of the CEA is LCOE and represents the cost of producing each kilowatt of electricity, which, as mentioned in part 4.2.2, is the CER of the project. However, the incremental ratio (ICER) is more critical than the CER, representing the gain of the most cost-effective alternative (Manaf et al., 2017). Hence, the proposed project ICER is the incremental Levelized cost of energy (ILCOE).

4.3 Notion of Discounting

As the project is evaluated today (project commencement year), it is crucial to apply the discount rate to all the costs and benefits. It is all about the time value of the money (TVM), which means the money you have now is worth more than what it should be in the future. This principle holds that the money can earn interest, or in other words, in order to receive money tomorrow instead of today, the person asks for more money to compensate for the time lost (Cellini & Kee, 2015).

Depends on the type of evaluation, we should use either the economic discount rate in economic analysis or the financial discount rate in financial analysis. The proposed project in this study is based on economic evaluation, and thus the discount rate used is the economic opportunity cost of capital (EOCK).

4.4 Testing For Uncertainty

Life is full of uncertainty foresee; no matter how accurate the inputs and calculations will be, it is impossible to have an impeccable outcome due to either macroeconomic or the project's factors (Saltelli et al., 2004). Therefore, this type of analysis focuses on quantifying the uncertainty of the output. Figure 5 depicted the parametric bootstrap of uncertainty and sensitivity analysis (Global Sensitivity Analysis: The Primer, 2008).

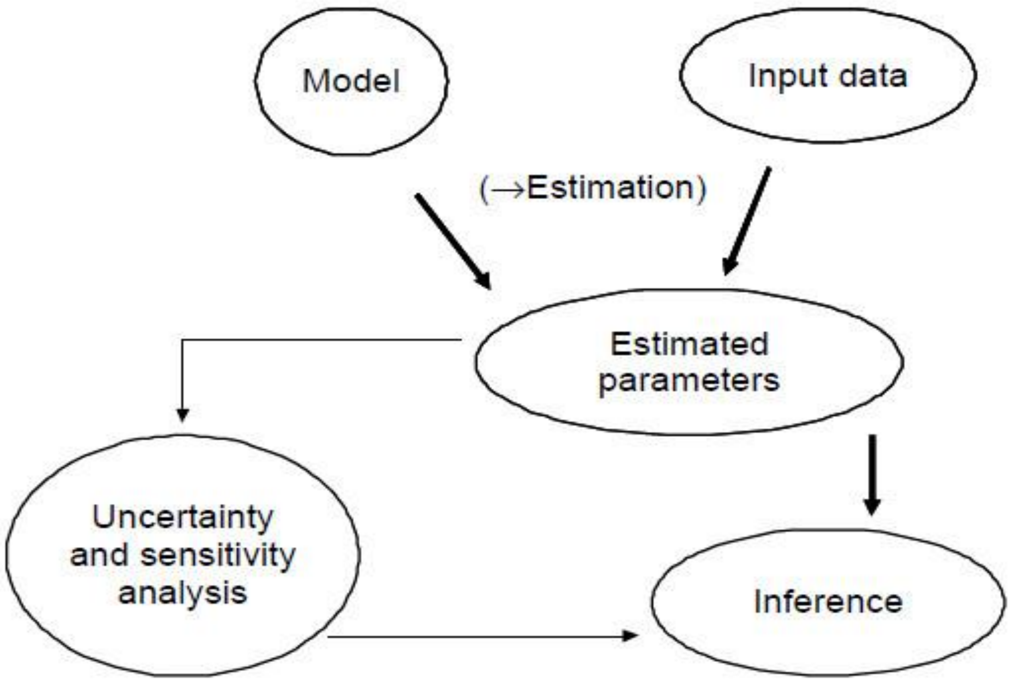

Figure 5: Parametric bootstrap of uncertainty and sensitivity analysis.

The proposed project was developed with Microsoft Excel and modelled on the FAST standard to be flexible and dynamic in handling any changes in input factors over time. In every model, variable elements are testable in three different ways (Walker et al., 2010):

1. One-way (variables only varied once at a time)
2. Two-way (variables varied twice at a time)
3. Versatile (variables varied more than twice at a time).

The one-way method is the basic form and examines the impact of the change in the value of one parameter on the output. This method is proper when the researcher or analyzer would like to assess the effect of the specific parameter on the model (Taylor, 2009).

On the other hand, the two-way process would be used when there is a correlation between two factors, where varying one independently could mislead the analyst and thus be used to measured results. Finally, the last method is proper when the analyst examines the relationships among more than two factors while changing them simultaneously.

Chapter 5

COST-EFFECTIVENESS ANALYSIS OF THE PROPOSAL

5.1 Introduction

Economic analysis is one of the essential parts of the IIA, and the CEA method is a form of economic study that evaluates alternative scenarios with the same objectives in finding the most cost-effective (CE) one. Compared to the financial analysis that focuses on calculating the benefits accrued to a few beneficiaries with a financial interest in the project, the economic analysis measures the distribution of benefits to the economy.

Optimizing energy efficiency is one of the most CE and efficient ways of tackling the problems of rising energy costs, energy security and reliability, emissions, and global climate change. Estimating energy efficiency's CE is vital to determine how much of the country's energy efficiency resource capacity should be captured. Studies show that the savings from energy efficiency will reach over 50% of the expected load growth by 2025. In addition, identifying CE allows energy efficiency to compete with a wide variety of other resource choices to get the necessary support and funding to be widespread in its adoption (Efficiency National Action Plan for Energy, 2008).

In the proposed project, the efficiency gains of fuel substitution (LNG over HFO) are fuel cost-saving and environmental benefits of emissions and pollutant particles savings compared to the current fuel (HFO) being used in the system.

5.2 Model's Inputs and Presumptions

This project was modelled dynamically based on data provided by KIB-TEK and the S&P Global Platts database for the Mediterranean region specific for the TRNC. However, it could be extended to any other place by updating the inputs.

5.2.1 Time Scope

The proposed project is assumed to start after completing AKSA's contract in 2024 and with a 20-year concession but excludes any extension limitations.

5.2.2 Demand for Electricity

The demand for electricity in the TRNC is assumed to increase by 5% per year. Figure 6 shows the hourly load duration curve for electricity demand (MW) in 2019.

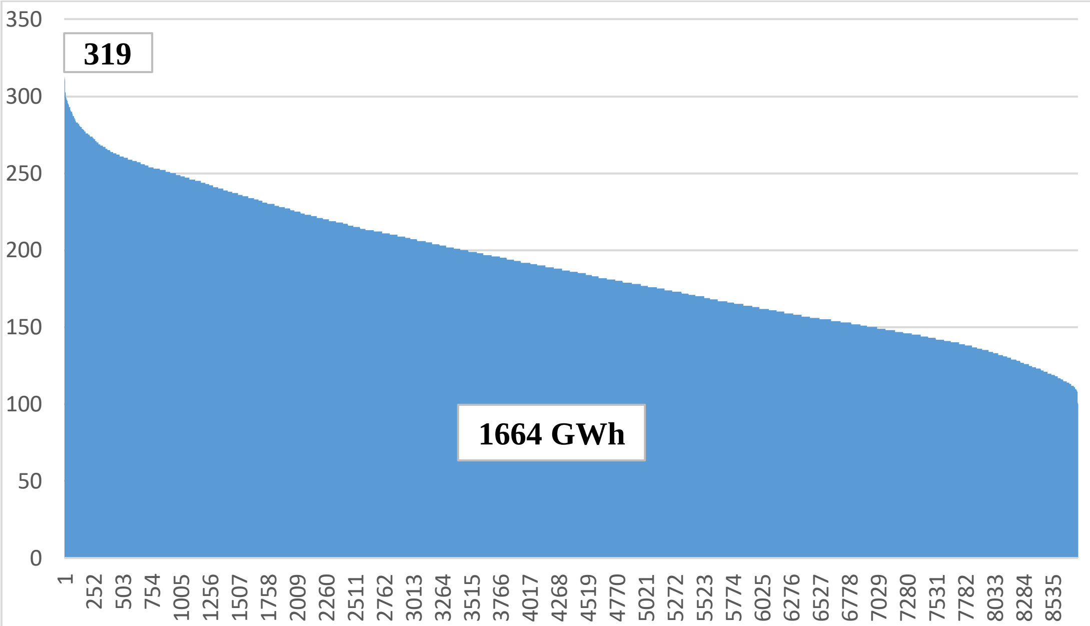

Figure 6: TRNC load duration curve for electricity demand, 2019.

As shown in Figure 6 above, the peak hour demand for electricity generation capacity in 2019 is 319 MW, and the total electricity demand is about 16,664 GWh. Therefore, the minimum installed operational capacity should be equal to the maximum peak hour demand if one is to have a reliable electricity generation system without interruptions and blackouts. On the other hand, estimations are not 100% certain, so the net operational capacity of a 20-year forecasted supply should be 15-20% more than the maximum peak hour demand in case of emergencies and unexpected events. Figure 7 shows the duration load demand curve in 2024, which is forecasted based on a 5% increase in the 2019 demand provided by KIB-TEK.

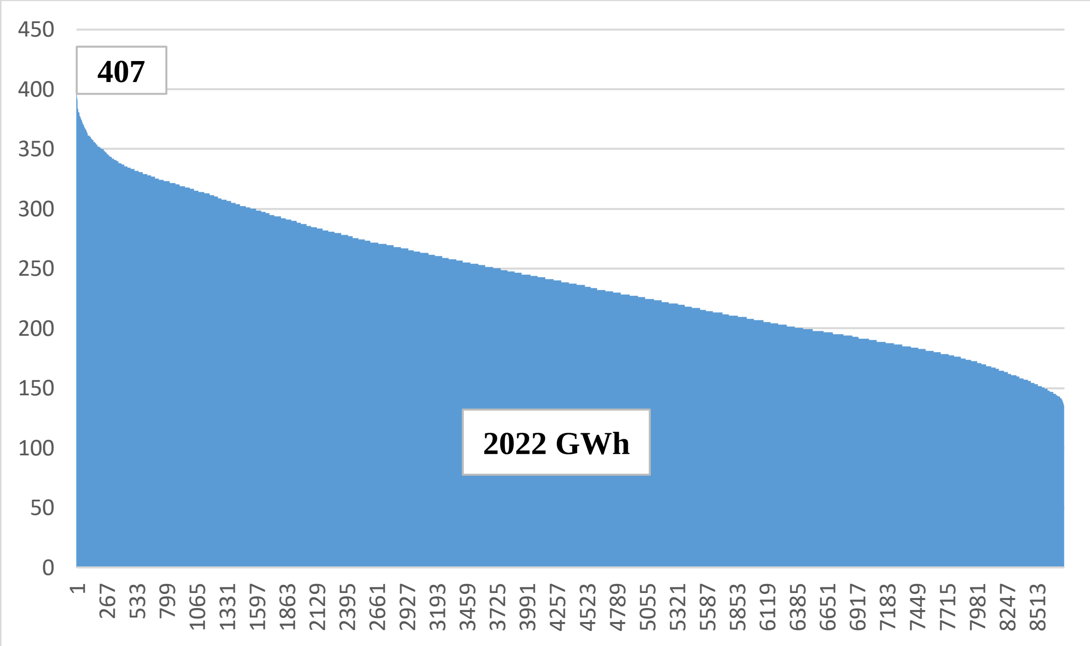

Figure 7:TRNC load duration curve forecast for electricity demand, 2024.

The peak hour demand for the base period of the project is estimated at 407 MW, and the total electricity demand is 2022 GWh. Therefore, annual electricity demand and the peak hour forecast for the project's lifespan are estimated and shown in Table 6 below:

Table 6: Annual Electricity Demand and Peak Hour Forecast, 2024-2042.

Demand Forecast for Electricity										
year	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Electricity (GWh)	2,022	2,124	2,230	2,341	2,458	2,581	2,710	2,846	2,988	3,138
Peak Hour (MW)	407	427	449	471	495	520	546	573	602	632
year	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Electricity (GWh)	3,294	3,459	3,632	3,814	4,004	4,205	4,415	4,636	4,867	5,111
Peak Hour (MW)	663	696	731	768	806	846	889	933	980	1,029

The electricity rows in Table 6 show the total electricity the project needs to generate each year. According to the duration load curve of each year, the total capacity of the baseload and peak load plant can be derived. For instance, the annual peak hour demand in Table 6 shows the maximum capacity requirement over the 8760 hours of each year; in other words, if the net installed capacity of the power generations in the system is smaller than this number, most likely, people will experience blackouts throughout the year.

5.2.3 Technical Parameters

Technical details of power plants and fuels used in the proposed model are provided in this section.

Plant capacity and distribution plan

The diesel plants in the system have a rated capacity of 17.5 MW with the availability of 15 MW (to decrease the maintenance cost). Therefore, the load factor would be 78% of the rated capacity (17.5 MW). Alternatively, the CCGT plant consists of two 60 MW internal combustion with a 30 MW steam turbine offering a 150 MW rated capacity, with a load factor of 76% as the baseload plant. Table 7 shows the installed capacity available in the base year (2024) and the capacity required to offset the increase in electricity demand.

Table 7: Installed Operational Capacity Distribution Plan, 2024-2043.

Annual Capacity Distribution Plan (MW)										
Year	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
CCGT	150	0	0	0	0	100	0	0	0	0
IC	175	35	35	17.5	0	0	0		35	35
Year	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
CCGT	0	0	150	0	0	0	0	0	0	150
IC	0	0	0	0	0	0	105	0	0	0

As shown in Table 7, the total installed capacity of diesel and CCGT (baseload plant) is estimated as 550 MW and 577.5 MW, respectively, and the total available installed capacity of the project's horizon at 2043 is 1127.5 MW.

General parameters

The proposed project has two important parameters. First, the type of thermal technology (diesel and CCGT) and the type of fuel (HFO and LNG) used in the system and each has necessary specifications that are shown in Tables 8 and 9, respectively:

Table 8: Plant Efficiency (%) by type.

Type	Energy Efficiency (%)
CCGT	57
IC	46

Table 9: Fuel Heat-Content (KJ/Kg) by Type.

Fuel Type	Heat Content (KJ/Kg)
HFO	40,160
LNG	48,000-52,000

Tables 8 and 9 represent the most critical inputs of the proposed project, with the economic gain being derived from the differences between these factors in each table. The calculations will be shown in detail in aforementioned part.

5.2.4 Investment Cost (CAPEX)

There are three types of investments in the project:

i. Investment cost of the power plant
ii. Investment cost of a regasification plant
iii. The conversion cost of the existing diesel plants.

Among the three costs mentioned above, only the investment cost [8] of power plants is considered in this category, with the rest being included in the operation expenditure section (OPEX). Table 10 shows the investment cost of power plants per kilowatt of capacity by type.

Table 10: Plant Investment Cost (USD/KW) by Technology.

Type	Investment Cost (USD/kW)
CCGT	800
IC	714

5.2.5 Operation Expenditure (OPEX)

The operation cost of the project is divided into two categories of fixed and variable expenses, as shown in Table 11 below:

Table 11: Categorized Fixed and Variable Cost of the Project.

<table>
<tr><th colspan="3">Fixed Cost</th><th colspan="4">Variable Cost</th></tr>
<tr><th rowspan="2">Labor Cost (USD'M)</th><th rowspan="2">Regasification Plant (USD'M)</th><th rowspan="2">Conversion Cost of Existing Plants (USD'M)</th><th colspan="2">Variable Operation and maintenance (USD/MWh)</th><th colspan="2">Fuel Cost (USD/TON)</th></tr>
<tr><th>IC</th><th>CCGT</th><th>HFO (USD/TON)</th><th>LNG (USD/MMBtu)</th></tr>
<tr><td>9.45</td><td>288</td><td>20</td><td>9</td><td>6</td><td>424</td><td>8.23</td></tr>
</table>

All data in Table 11 are provided by KIB-TEK and viable only in the TRNC.

[8] Investment cost of power plant included fixed operation and maintenance (O&M) cost and labor cost.

5.2.6 Social Discount Rate (SDR)

The evaluation of the proposed project is based on the economic point of view. Therefore, the discount rate used in the model is the opportunity cost of capital (ECOK) and is considered to be 8% in the CEA calculations.

5.3 Model's Calculation

5.3.1 Available Capacity and Energy Generation Forecast

CCGT is used as the baseload plant with a roughly 80% load factor, so to avoid the restarting costs associated with the load duration curve, the time to increase the plant's capacity to meet the baseload demand must be carefully considered. Out of 8760 hours of the year, CCGT operates approximately 7000 hours per year, which means that the annual energy generation of one CCGT (150 MW) is equal to 1,032 GWh. Therefore, given the load duration curve each year, the TRNC power grid needs three CCGTs (150 MW) and one 100 MW to meet the electricity demand as it grows over time during the next 25 years. Figures 8 and 9 show the acceptable load duration curve to employ two other CCGTs.

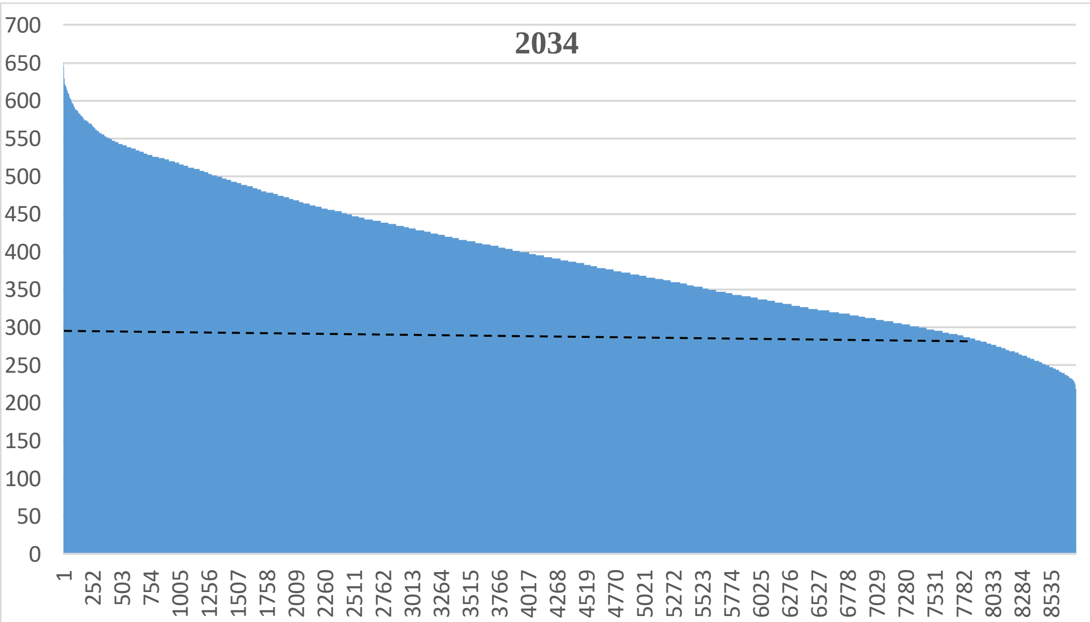

Figure 8: Load duration curve for electricity demand in TRNC, 2034.

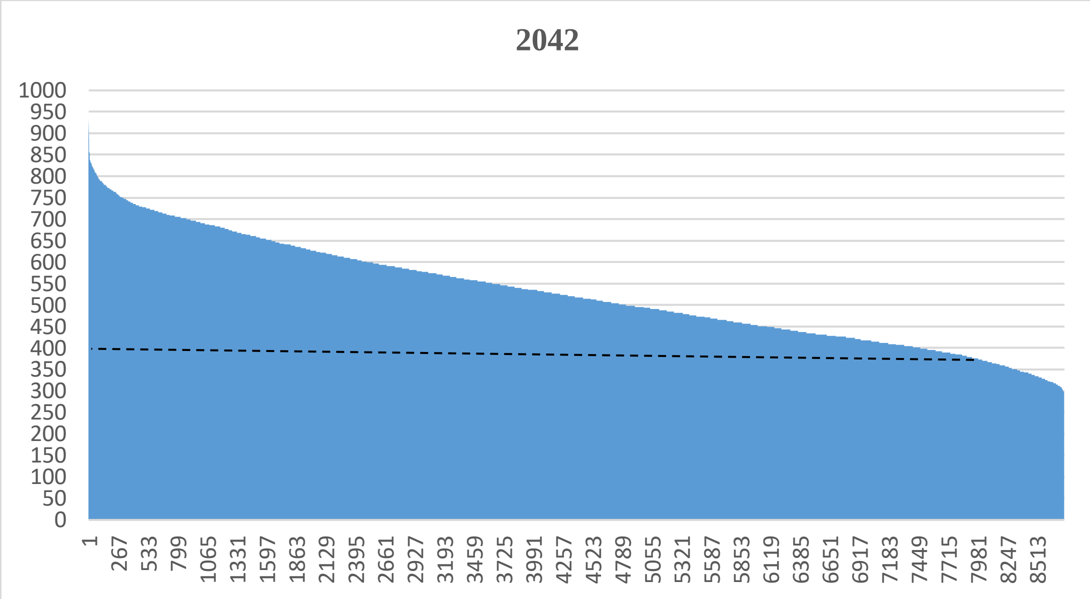

Figure 9: Load duration curve for electricity demand in TRNC, 2042.

The area inside the dotted lines is produced by the baseload plant (CCGT) and the outer area by the diesel technology. For example, figure 8 shows that in 2034, the power grid needs two CCGTs, and from Figure 9, it can be seen that the third CCGT must be installed into the system to meet the electricity demand. Table 12 represents the share of each technology from the total energy generation.

Table 12: Total Energy Generation by Type (2024-2043).

Type	Total Energy Generation (GWh)
CCGT	50,736
IC	16,139

According to Table 12, the total electricity demand during the project's lifespan (2024-2043) is estimated at 66,875 GWh, with the TRNC requiring 4 CCGTs and 27 diesel electricity generators to generate this amount of electricity.

5.3.2 Investment Schedule of Power Plants (CAPEX)

To calculate the total CAPEX of the project, both the investment costs of the new plants added to the system and the existing ones should be considered. The investment cost of each existing diesel plant is 5 USD’M for 15MW of capacity. After annualizing[9] all the CAPEX, the present value of the total investment cost was calculated and represented in Table 13.

Table 13: Total Investment Cost of Power Plants by Type, 2024.

Type	PV of Total Investment Cost (USD'M)
CCGT	223
IC	430

According to Table 13, the total new investment cost PV was estimated at 653 USD’M, and the existing one, which is 43 USD’M, gives us 696 USD’M.

5.3.3 Operation Expenditures (OPEX)

Project operating costs are divided into two main categories:

1. Fixed Costs
2. Variable Costs.

Fixed costs do not change during the project’s lifespan, such as O&M long term contracts, regasification costs, and conversion costs of the existing plants to LNG. On

[9] Equivalent annuity value over the project lifespan, and calculated as: $C = \frac{(r \times NPV)}{(1-(1+r)^{-n})}$

Where:
C = equivalent annuity value
r = interest rate per period
NPV = net present value
n = number of periods

the other hand, the variable costs depend on the amount of energy generated, such as fuel cost and variable O&M costs (e.g., chemicals, lubrication, etc.).

Cost of Regasification Plant

According to data provided by KIB-TEK, the cost of the off shore regasification plant is 288 USD'M. This cost is incurred when LNG comes into the equation; in other words, to run the whole grid with LNG, the system needs a regasification plant to transform the LNG from the liquid phase to the gas. Table 14 shows the equivalent annual cost (ECA)[10] of the regasification plant over the project's lifespan. The ECA helps assess alternative projects of unequal costs (where only the lifespans are relevant) to address any built-in bias favouring the longer-term investment.

Table 14: Annual Regasification Cost.

Annual Regasification Cost										
year	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Annual Regasification Cost	4.48	4.77	5.06	5.35	5.64	5.78	6.22	6.37	6.66	6.95
year	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Annual Regasification Cost	8.09	8.09	8.09	8.38	8.81	9.25	9.97	10.26	11.40	11.40

Conversion Cost of Plant to LNG

This cost was imposed on only eight existing diesel plants. All other plants in the system are fuel flexible. According to KIB-TEK, the conversion cost of the existing plants is about 20 USD'M, and the annualized cost over 20 years of the operation with 8% ECOCK was calculated at 2.037 USD'M.

[10] In finance, the equivalent annual cost is the cost per year of owning and operating an asset over its entire lifespan. It is calculated by dividing the NPV of a project by the present value of annuity factors.

Variable O&M Costs

Variable operation and maintenance costs are production-based costs that vary according to the amount of electricity generated. These expenses include water consumption, wastewater disposal, chemicals such as selective catalytic ammonia minimizer, and consumables, including lubricants and calibration gas (US Energy Information Administration, 2020).

As presented in Table 7, the variable O&M cost for diesel and CCGT are 9 and 6 USD/MWh, respectively. Therefore, to calculate the annual variable O&M for each type, we simply multiply each factor by its annual energy generation.

Fuel Requirement

In order to determine the fuel cost, the amount of energy produced must be calculated and converted from watts to Joules [11]. The amount of fuel required for each type of power plant varies according to the following essential factors:

1. Plant Efficiency
2. Fuel heat-content (calorific value) [12].

From parameters represented in Tables 8 and 9, the fuel requirement of each type of plant, and thus fuel consumption, were calculated. Finally, Table 15 shows the fuel requirement and fuel consumption by plant and fuel type (2024-2043).

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[11] 1 Kilowatt in Mega joules : 3,694.71 MJ

[12] The amount of energy produced when substance is burnt.

Table 15: The Total Quantity and Fuel Consumption by Type (2024-2043).

Type	PV of Quantity of Fuel Required		Fuel Consumption	
	HFO (TON)	LNG (MMBtu)	HFO (gr/kWh)	LNG (Btu/kWh)
CCGT	3,631,214	138,220	157	5,976
IC	1,613,659	64,870	196	7,879

Table 15 provides the most critical data used to calculate the efficiency gains of fuel substitution and the effectiveness of different thermal power plant technologies. If the system works with HFO, the total fuel required from 2024 to 2043 is 5,244,873 tonnes and 203,090 MMBtu for LNG, representing approximately one million tonnes of fuel-saving using LNG as a primary fuel.

Fuel Cost

Despite the fuel price constantly changing over time, the average price over a long period (historical data) is the most reliable metric to consider. In this study, the historical LNG and HFO prices for the Mediterranean region were provided from S&P Global Platts over the past decade. Table 16 shows the average LNG and HFO (including freight cost) from 2010 to 2020 in the Mediterranean region.

Table 16: Fuel Price in the Mediterranean Region by Type.

Type	Fuel Price
HFO (1% Sulphur)	424 (USD/TON)
LNG (Regional)	8.24 (USD/MMBtu)

According to the data provided in Tables 15 and 16, the total fuel cost of each type of plant using HFO and LNG was calculated and illustrated in Table 17 below:

Table 17: Total Fuel Cost by Type (2024-2043).

Type	PV of Total Fuel Cost (USD'M)		Fuel Cost (USD/kWh)	
	HFO	LNG	HFO	LNG
CCGT	3,433	2,540	0.067	0.049
IC	1,271	993	0.083	0.065

The PV of total fuel cost if the entire system operated with LNG or HFO over its lifespan (2024-2043) is 3,533 and 4,703 USD’M, respectively. Consequently, the fuel cost saving of using LNG as the primary fuel is 550 USD’M.

Fuel Emissions

The transition from HFO to LNG would reduce emissions such as NOx and SOx and conform to tighter regulations. In addition, lower fuel consumption through improved engine efficiency or a change to less carbon-intensive natural gas would also minimize CO2 emissions from electricity generation. Nevertheless, a fuel’s environmental effect is related to the engine’s combustion and the fuel’s entire life cycle starting at the well. This means that fuel, which appears favourable in the combustion process, can have significant environmental effects in the upstream cycle or vice versa (Bengtsson et al., 2013). Table 18 shows the emission reduction percentage by switching from HFO to LNG (Sharafian et al., 2019).

Table 18: Emission Reduction by Switching From HFO to LNG.

Air pollutant	The percentage of emissions reduction by using LNG
SOx	Over 90%
NOx	Up to 35%
PM	Over 85%
CO2	Up to 29%

5.3.4 Fuel Cost Saving

Fuel cost savings vary according to the type of fuel and technology of the power plant and are classified into three different scenarios:

1. Diesel using LNG (Diesel/HFO – Diesel/LNG)
2. CCGT using HFO (Diesel/HFO – CCGT/HFO)
3. CCGT using LNG (CCGT/HFO – CCGT/LNG).

In the first scenario, the fuel cost saving is the difference between using HFO and LNG with the same diesel technology in both cases. In the second scenario, the fuel cost saving comes from the efficiency of the technology (CCGT vs diesel) instead of the fuel type. Finally, in the third scenario, similar to the first, the benefit comes from the fuel cost and not the technology. Table 19 shows the fuel cost saving per kW of production by scenario.

Table 19: Fuel Cost Saving by Scenario.

Type	Fuel Type	Fuel Cost Saving (USD/kWh)
IC	NG	0.0182
CCGT	HFO	0.0165
CCGT	NG	0.0338

The proposed project consists of two techniques; hence the total fuel cost of the system must be calculated for both scenarios using different fuels (HFO and LNG). The fuel cost saving is obtained from the difference between the two numbers (Incremental cost of LNG vs HFO). Table 20 represents the total fuel cost saving of the proposed project.

Table 20: PV of the Total Fuel Cost Saving of the Proposed Project (2024-2043).

Fuel Type	PV of Total Fuel Cost (USD'M)	PV of Total Fuel Cost Saving (USD'M)
HFO	4,703	1,170
LNG	3,553	

5.4 CEA

In the case of the LNG as the base fuel, all additional costs incurred in the system must be considered (e.g., the conversion cost of the existing plants, regasification plant). In other words, the gross benefit of this project is fuel cost-saving, while the net benefit is the deduction of LNG costs from the gross benefit. Thus, according to Table 13, the PV of the total investment cost of power plants (including the existing ones) is 696 USD’M, and the PV of the total cost using HFO and LNG is illustrated in Table 21.

Table 21: PV of the Total Cost by Source.

PV of CAPEX (USD’M)	PV of OPEX - LNG (Including Regasification unit) (USD'B)	PV OPEX - HFO (USD'B)
696	2.373	2.536

From Table 21, the PV of the total cost of the proposed project using HFO and LNG is 2,536 and 2,373 USD’M, respectively. In the CEA method, as mentioned in previous parts, the gain to the economy is the difference between the cost of two alternatives with the same goal. Therefore, the cost of each alternative is the LCOE of HFO and LNG and represented in Table 22 as follows:

Table 22: Levelized Cost of Energy by Scenario and Incremental LCOE.

LCOE (USD/kWh)		ILCOE (USD/kWh)	PV of Total Cost Saving (USD’M)	PV of Annualized Cost Saving (USD’M)
HFO	LNG			
0.1031	0.0978	0.0052	163.46	16.65

According to Table 22, the ILCOE is 0.0052 USD/kWh, and the PV of the net gain from undertaking the proposed project is 163.46 USD’M. The annuity value of these saving over the lifespan of the proposed project (2024-2043) is 16.65 USD’M; in other words, this number shows the annualized value over the next 20 years that the TRNC would receive if they made this policy change.

Chapter 6

SENSITIVITY ANALYSIS

6.1 Introduction

The fundamental approach and another chief pillar of the IIA in overcoming uncertainty is sensitivity analysis. This is a method for testing the robustness of economic evaluation and includes a systematic evaluation of the impact of changes in the assumptions made (Byford et al., 2003). In other words, some variables (e.g., fuel cost, investment cost, operation cost, etc.) change over time, and with this method, CEA is reassessed according to the new values.

This study was analyzed uses the one-way and two-way methods. In the one-way method, the uncertain factor of the assessment is varied independently, while the other contains the base-case conditions to create an independent impact on the outputs by each variable. The other factor that might change over time and might have a negative impact on the project is CAPEX and should be considered in the sensitivity analysis. Since the highest cost of the project after CAPEX is the fuel cost with a high level of volatility, evaluation of fuel price change on the project outcomes is the priority.

The sensitivity analysis results help decision-makers evaluate the riskiness of the factors in the project and enable them to find solutions to mitigate the risks to prevent interruption or any inconvenience over the project’s lifetime. The risky variables whose impacts in the proposed project are to be evaluated includes:

1. Investment cost over-run
2. Fuel price.

6.2 Investment Cost Over-run

Investment cost over-run implies the unforeseen costs that exceed the initial budget estimates at each stage over the project implementation. To find whether the project is affected by the change in the investment cost, the relationship between the measured factors must be added to the model's formulas to ensure the sensitivity analysis is carried out correctly. In addition, the interval changes from positive to negative should be subsequently set up to observe the impact of the positive and negative change on the outputs.

Sensitivity results on variable outputs such as the total cost of the project, LCOE, LCOC, ILCOE show that even when the investment cost increased from 0% to 25%, the ILCOE decreased only by 3.45%, indicates that this parameter is insignificant, and has a minor impact on the project's output.

6.3 Change in Fuel Price

The most important factor of the sensitivity analysis is the fuel price; Figure 10 illustrates the price correlation between HFO and LNG (2010-2020) based on the data provided by S&P Global Platts.

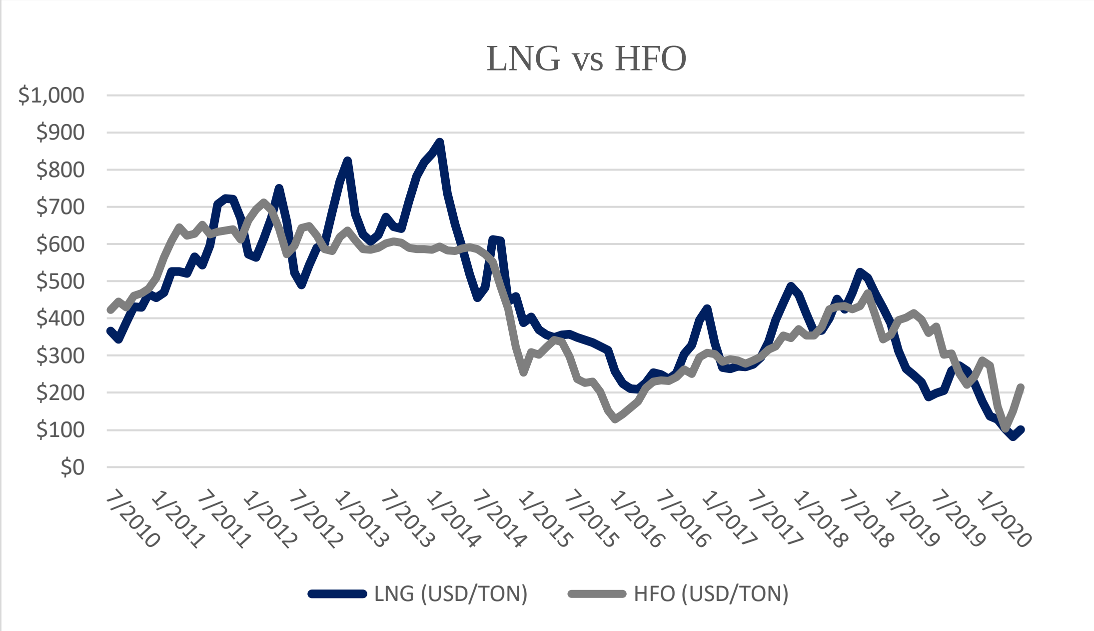

Figure 10: Price Correlation Between HFO and LNG (2010-2020)

The general trend implies the relationship between prices, but the degree of correlation varied over time. Table 23 presents the HFO and LNG price [13] correlation in detail.

Table 23: Price Correlation Between HFO and LNG (2010-2018).

Price Correlation					
Year	Average LNG Price (USD/MMBTU)	Chane in Price (LNG)	Average HFO Price (USD/MMBTU)	Chane in Price (HFO)	Increment of Change in Prices
2010	7.57		11.10		
2011	10.96	30.97%	14.98	25.88%	5.09%
2012	11.34	3.34%	15.28	2.00%	1.34%
2013	13.14	13.65%	14.78	-3.38%	17.02%
2014	11.36	-15.63%	13.20	-12.00%	3.63%
2015	6.63	-71.39%	6.77	-95.08%	23.68%
2016	4.91	-34.85%	5.46	-23.90%	10.95%
2017	6.35	22.60%	8.03	32.00%	9.39%
2018	8.22	22.74%	10.38	22.64%	0.10%

[13] 1 MMBTU is equal to 0.02522 tonne of oil. https://www.unitjuggler.com/convert-energy-from-MMBtu-to-toe.html - 1 TON of LNG is equivalent of 53.38 MMBtu – However, this number is an approximation, and it varies by the nature of fuel (calorific value) being used.

Data are shown in Table 23 that LNG price in 2013 increased by 13.65% compared to the previous year, but the HFO price decreased by 3.38%, which implied a 17.02% change in the difference between the LNG and HFO prices. Similarly, 2015 shows a significant increment of 23.68% between the price change of these two fuels compared to their previous years.

Consequently, LNG price decreased by 10.9% more than HFO in 2016 compared to its previous year's price, and, while the 2017 HFO price increased by 32%, LNG price increased by 22.6%, which is 9.39% less than the HFO price and shows that the rate of the increase in LNG prices decreased compared to that of HFO.

Fluctuations in fuel prices over the past ten years indicate the need for sensitivity analysis on the change in the price of these two fuels. In addition, due to the price correlation in the long-term trend, both the one-way and the two-way sensitivity analysis must be undertaken.

The one-way sensitivity analysis of HFO and LNG prices was performed to demonstrate and comprehend the impact of "change in fuel price" on different project outputs one at a time. Tables 24 and 25 show the one-way sensitivity analysis of HFO and LNG, respectively.

Table 24: The One-way Sensitivity Analysis for Change in HFO.

Heavy Fuel Oil						
Change in Price (%)	PV of Total Cost (USD'M)	LCOE (USD/KWh)	LCOC (USD/KW)	PV of Fuel Cost (USD/KWh)	PV of Fuel Cost Saving (USD/KWh)	PV of Total Cost Saving (USD'M)
	2800.7322	**0.0745**	**0.0148**	**0.6940**	**0.0211**	**660.8420**
-25%	2184.9836	0.0581	0.0148	0.5205	0.0148	464.5815
-20%	2308.1334	0.0614	0.0148	0.5552	0.0161	503.8336
-15%	2431.2831	0.0646	0.0148	0.5899	0.0173	543.0857
-10%	2554.4328	0.0679	0.0148	0.6246	0.0186	582.3378
-5%	2677.5825	0.0712	0.0148	0.6593	0.0198	621.5899
0%	**2800.7322**	**0.0745**	**0.0148**	**0.6940**	**0.0211**	**660.8420**
5%	2923.8820	0.0777	0.0148	0.7287	0.0223	700.0941
10%	3047.0317	0.0810	0.0148	0.7634	0.0236	739.3462
15%	3170.1814	0.0843	0.0148	0.7982	0.0248	778.5983
20%	3293.3311	0.0875	0.0148	0.8329	0.0261	817.8504
25%	3416.4809	0.0908	0.0148	0.8676	0.0273	857.1025

The change in fuel price in the base case scenario was set to 0%, and by increasing the fuel price in 5% increments, the PV of the total cost of the project using HFO and LNG increased by 4.36% 4.01%, respectively. Furthermore, the LCOE of HFO and LNG increased by 3.56% and 3.08%, respectively, but the impact of change in fuel prices is not reflected in the ILCOE of the project.

Table 25: The One-way Sensitivity Analysis for Change in LNG Price.

Liquified Natural Gas						
Change in Price (%)	PV of Total Cost (USD'M)	LCOE (USD/KWh)	LCOC (USD/KW)	PV of Fuel Cost (USD/KWh)	PV of Fuel Cost Saving (USD/KWh)	PV of Total Cost Saving (USD'M)
	2800.7322	**0.0675**	**0.0148**	**0.4728**	**0.0211**	**660.8420**
-25%	2184.9836	0.0541	0.0148	0.3546	0.0148	464.5815
-20%	2308.1334	0.0568	0.0148	0.3783	0.0161	503.8336
-15%	2431.2831	0.0595	0.0148	0.4019	0.0173	543.0857
-10%	2554.4328	0.0622	0.0148	0.4255	0.0186	582.3378
-5%	2677.5825	0.0648	0.0148	0.4492	0.0198	621.5899
0%	**2800.7322**	**0.0675**	**0.0148**	**0.4728**	**0.0211**	**660.8420**
5%	2923.8820	0.0702	0.0148	0.4965	0.0223	700.0941
10%	3047.0317	0.0729	0.0148	0.5201	0.0236	739.3462
15%	3170.1814	0.0755	0.0148	0.5438	0.0248	778.5983
20%	3293.3311	0.0782	0.0148	0.5674	0.0261	817.8504
25%	3416.4809	0.0809	0.0148	0.5910	0.0273	857.1025

The results relation in Tables 24 and 25 show that the one-way method is not suitable in examining the impact of change in fuel price on the final output (ILCOE), with only certain components of the project being investigatable and showing the two-way method should be used.

Table 26 illustrates all the possible effects of changes in fuel prices separately on the ILCOE. In the base case scenario, a 0% change in fuel prices was considered. For instance, if the HFO price increased by 6% and LNG price remained unchanged, efficiency saving increased from 0.0138(USD/KWh) to 0.0188 (USD/KWh), showing that project gains increased by 36%, and cementing that the most important factor of the project is the fuel price.

Table 26: The Two-ways Sensitivity Analysis for Change in Fuel Price on ILCOE.

ILCOE (USD/kWh)											
Change in LNG	Change in HFO Price										
	-6%	-5%	-4%	-3%	-2%	**0%**	2%	3%	4%	5%	6%
-6%	0.0042	0.0049	0.0056	0.0063	0.0070	0.0084	0.0098	0.0105	0.0112	0.0120	0.0127
-5%	0.0036	0.0043	0.0050	0.0058	0.0065	0.0079	0.0093	0.0100	0.0107	0.0114	0.0121
-4%	0.0031	0.0038	0.0045	0.0052	0.0059	0.0073	0.0088	0.0095	0.0102	0.0109	0.0116
-3%	0.0026	0.0033	0.0040	0.0047	0.0054	0.0068	0.0082	0.0089	0.0096	0.0104	0.0111
-2%	0.0020	0.0027	0.0034	0.0042	0.0049	0.0063	0.0077	0.0084	0.0091	0.0098	0.0105
0%	0.0010	0.0017	0.0024	0.0031	0.0038	**0.0052**	0.0066	0.0073	0.0080	0.0088	0.0095
2%	(0.0001)	0.0006	0.0013	0.0020	0.0027	0.0041	0.0056	0.0063	0.0070	0.0077	0.0084
3%	(0.0006)	0.0001	0.0008	0.0015	0.0022	0.0036	0.0050	0.0057	0.0064	0.0072	0.0079
4%	(0.0012)	(0.0005)	0.0002	0.0010	0.0017	0.0031	0.0045	0.0052	0.0059	0.0066	0.0073
5%	(0.0017)	(0.0010)	(0.0003)	0.0004	0.0011	0.0025	0.0040	0.0047	0.0054	0.0061	0.0068
6%	(0.0022)	(0.0015)	(0.0008)	(0.0001)	0.0006	0.0020	0.0034	0.0041	0.0048	0.0056	0.0063

Chapter 7

CONCLUSION AND RECOMMENDATION

Advanced developed economies depend on restoring and replacing their ageing infrastructures. Although roads are arteries throughout the country to feed the economy, this process will be disrupted without electricity infrastructure. The source of electricity production is the heart of this infrastructure, which is the most critical part of the electricity generation system.

This study focuses on the electricity generation source, and with two alternatives, tried to increase the efficiency of the existing system:

A. Fuel Substitution (HFO to LNG).

B. Efficient Technology (CCGT as a baseload power generation).

Fuel substitution could be applied to every existing liquid fuel-burn power generation (e.g., internal combustion, single cycle, steam turbine, etc.). Another way of increasing efficiency is choosing the best power generation technology that can be applied in a new project, expanding or replacing an old power plant in the system and varied according to the resources and availability. Table 27 shows the abridged CEA results:

Table 27: CEA Outputs.

CEA Outputs				
PV of Total Energy Generation (GWh)	ILCOE (USD/kWh)	PV of Total Cost Saving (USD'M)	LCOE (USD/kWh)	
			HFO	LNG
31,362	0.0052	163.46	0.1031	0.0978

The gains of fuel substitution and using CCGT as the baseload power generation, over 20 years of operation, is about 0.0052 USD per KW of electricity produced, and it is the difference between the two LCOE in the table above. Thus, the total gain of the TRNC from 31,362 GWh of electricity production is about 163.46 USD'M. On the other hand, Tables 28 and 29 present the fuel costs and LCOE of the project separately in detail.

Table 28: Fuel Cost of Alternatives.

Fuel Cost (USD/kWh)			
IC_HFO	IC_NG	CCGT_HFO	CCGT_NG
0.083	0.067	0.065	0.049

According to Table 28, the most efficient combination is the CCGT using LNG as a primary fuel and 69% less than what TRNC pays in the base case scenario (Diesel-HFO) in the system.

Table 29: LCOE of Alternatives.

Levelized Cost of Energy (USD/KWh)			
Diesel-HFO	Diesel-LNG	CCGT-HFO	CCGT-LNG
0.096	0.073	0.074	0.060

Results of Table 29 show that the CCGT using LNG has reduced the LCOE of the project by 38% compared to the base case scenario.

To sum it all up, the CEA results implied that fuel substitution and the right choice of thermal generation technology could significantly reduce the cost of electricity generation in the TRNC, and decision-makers must consider all the alternatives before making the final decision.

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APPENDICES

Appendix 1: Electricity Demand, Available Capacity, Energy Generation Forecast, CAPEX, OPEX & Fuel Saving

Table 30: Demand for Electricity Forecast (2024-2043)

YEARS			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Demand for Electricity Off-Peak (2024)	2,022	GWh																				
Demand for Electricity Peak (2024)	407	MW																				
Expected Increase in Electricity Demand (per year)	5%	%																				
Thousand	1,000	#																				
Hours per Year (With)	8,760	Hours																				
Annual Demant for Electricity		GWh	2,022	2,124	2,230	2,341	2,458	2,581	2,710	2,846	2,988	3,138	3,294	3,459	3,632	3,814	4,004	4,205	4,415	4,636	4,867	5,111
Annual Demant for Electricity Peak		MW	407.13	427.49	448.87	471.31	494.87	519.62	545.60	572.88	601.52	631.60	663.18	696.34	731.15	767.71	806.10	846.40	888.72	933.16	979.82	1,028.81

Table 31:Avaiable Capacity Schedule (2024-2043)

2. Available Capacity & Energy Generation Forecast																						
Available Capacity																						
Plant Capacity - CCGT	150	MW																				
Plant Capacity - Diesel (available capacity)	18	MW																				
Plant Capacity - Diesel	100	MW																				
Number of Plant																						
Number of Plant Diesel (With)	2	#																				
Number of Plant Diesel (15MW) (With)	10	#																				
Number of Plant CCGT (With)	1	#																				
Maximum Plant Availability	98%	%																				
Auxillary Usage - CCGT	2%	%																				
Net Available Capacity - Diesel	86%	0%																				
CCGT																						
Annual Demant for Electricity Peak	-	MW	407	427	449	471	495	520	546	573	602	632	663	696	731	768	806	846	889	933	980	1,029
New Available Capacity (With) - CCGT		MW	150	-	-	-	100	-	-	-	-	-	-	-	150	-	-	-	-	-	150	-
Annual Number of New Plant		#	1	-	-	-	1	-	-	-	-	-	-	-	1	-	-	-	-	-	1	-
Annual Available Capacity - CCGT		MW	150	150	150	150	250	250	250	250	250	250	250	250	400	400	400	400	400	400	550	550
Maximum Available Capacity		MW	147.00	147.00	147.00	147.00	245.00	245.00	245.00	245.00	245.00	245.00	245.00	245.00	392.00	392.00	392.00	392.00	392.00	392.00	539.00	539.00
Gross Capacity Available		MW	144.80	144.80	144.80	144.80	241.33	241.33	241.33	241.33	241.33	241.33	241.33	241.33	386.12	386.12	386.12	386.12	386.12	386.12	530.92	530.92
Auxillary Usage		MW	2.21	2.21	2.21	2.21	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	5.88	5.88	5.88	5.88	5.88	5.88	8.09	8.09
Net Available Capacity for Sale - CCGT		MW	**144.80**	**144.80**	**144.80**	**144.80**	**241.33**	**241.33**	**241.33**	**241.33**	**241.33**	**241.33**	**241.33**	**241.33**	**386.12**	**386.12**	**386.12**	**386.12**	**386.12**	**386.12**	**530.92**	**530.92**
Annual Demant for Electricity Peak		MW	407	427	449	471	495	520	546	573	602	632	663	696	731	768	806	846	889	933	980	1,029
Available Capacity Need for Diesel (Including 15% reserve back-up)		MW	321	326	349	356	356	356	367	379	410	443	477	496	499	538	545	537	548	547	542	560
Diesel																						
Annual Number of Plants - Diesel		#	18.0	19.0	20.0	20.0	20.0	20.0	21.0	22.0	23.0	25.0	27.0	28.0	28.0	31.0	31.0	31.0	31.0	31.0	31.0	32.0
Installed Capacity		MW	315.0	332.5	350.0	350.0	350.0	350.0	367.5	385.0	402.5	437.5	472.5	490.0	490.0	542.5	542.5	542.5	542.5	542.5	542.5	560.0
Maximum Available Capacity		MW	511	533	550	550	550	550	568	585	603	638	673	690	690	743	743	743	743	743	743	760
Net Available Capacity for Sale - Diesel		MW	**438**	**456**	**471**	**471**	**471**	**471**	**486**	**501**	**516**	**546**	**576**	**591**	**591**	**636**	**636**	**636**	**636**	**636**	**636**	**651**

Table 32: Energy Generation Forecast (2024-2043)

Energy Generation																						
Hours per Year (With)	8,760	Hours																				
Thousand	1,000	#																				
CCGT																						
Annual Demant for Electricity		GWh	2,022	2,124	2,230	2,341	2,458	2,581	2,710	2,846	2,988	3,138	3,294	3,459	3,632	3,814	4,004	4,205	4,415	4,636	4,867	5,111
Net Available Capacity for Sale - CCGT		MW	145	145	145	145	241	241	241	241	241	241	241	241	386	386	386	386	386	386	531	531
Net Energy Generation		GWh	1,268	1,268	1,268	1,268	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	3,382	3,382	3,382	3,382	3,382	3,382	4,651	4,651
Annual Load Factor -CCGT			62.72%	59.73%	56.88%	54.18%	85.99%	81.90%	78.00%	74.28%	70.75%	67.38%	64.17%	61.11%	93.13%	88.69%	84.47%	80.45%	76.62%	72.97%	95.55%	91.00%
Annual Energy Generation - CCGT		GWh	**1,268**	**1,268**	**1,268**	**1,268**	**2,114**	**2,114**	**2,114**	**2,114**	**2,114**	**2,114**	**2,114**	**2,114**	**3,382**	**3,382**	**3,382**	**3,382**	**3,382**	**3,382**	**4,651**	**4,651**
Diesel																						
Annual Demant for Electricity		GWh	2,022	2,124	2,230	2,341	2,458	2,581	2,710	2,846	2,988	3,138	3,294	3,459	3,632	3,814	4,004	4,205	4,415	4,636	4,867	5,111
Annual Energy Generation - Diesel		GWh	**754**	**855**	**961**	**1,073**	**344**	**467**	**596**	**732**	**874**	**1,024**	**1,180**	**1,345**	**250**	**431**	**622**	**822**	**1,032**	**1,253**	**217**	**460**
Annual Energy Generation - CCGT		GWh	1,268	1,268	1,268	1,268	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	3,382	3,382	3,382	3,382	3,382	3,382	4,651	4,651
Annual Energy Generation - Diesel		GWh	754	855	961	1,073	344	467	596	732	874	1,024	1,180	1,345	250	431	622	822	1,032	1,253	217	460
Total Annual Energy Generation		GWh	**2,022**	**2,124**	**2,230**	**2,341**	**2,458**	**2,581**	**2,710**	**2,846**	**2,988**	**3,138**	**3,294**	**3,459**	**3,632**	**3,814**	**4,004**	**4,205**	**4,415**	**4,636**	**4,867**	**5,111**
Total Demand for Electricity (2024-2043)	66,875	GWh																				
Total Energy Generation (2024-2043)	66,875	GWh																				

Table 33: Investment Schedule of Power Plants- CAPEX(2024-2043)

YEARS			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Investment Cost																						
Plant Capacity - Diesel (rated capacity)	18	MW																				
Number of Plant Diesel (15MW) (With)	10	#																				
Number of Plant CCGT (With)	1	#																				
Number of Plant Diesel (Without)	8	#																				
Investment Cost Overrun Factor	0%	%																				
Million	1,000,000																					
Thousand	1,000	#																				
Investment Cost (Including Fixed O&M) - CCGT	800	USD/KW																				
Investment Cost (Including Fixed O&M) - Diesel	714	USD/KW																				
Investment Cost (Including Fixed O&M) per Plant - Diesel (existing)	5	USD'M																				
Economic Opportunity Cost of Capital (EOCK)	8%	%																				
Operation Duration	20	Year																				
Million	1,000,000	#																				
Thousand	1,000	#																				
Annualized Cost of Capital (Including Fixed O&M) - CCGT	81,482	USD/KW																				
Annualized Cost of Capital (Including Fixed O&M) - Diesel	72,752	USD/KW																				
Annualized Cost of Capital (Including Fixed O&M) - Diesel (existing)	29,100.6	USD/KW																				
Diesel Vs CCGT																						
Plant Capacity (existing)	140	MW																				
Annual Capital Cost (Including Fixed O&M) – Diesel (existing)		USD'M	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07
CCGT																						
Annual Available Capacity – CCGT		MW	150	150	150	150	250	250	250	250	250	250	250	250	400	400	400	400	400	400	550	550
Annual Capital Cost (Including Fixed O&M) – CCGT		USD'M	12.22	12.22	12.22	12.22	20.37	20.37	20.37	20.37	20.37	20.37	20.37	20.37	32.59	32.59	32.59	32.59	32.59	32.59	44.81	44.81
Diesel																						
Annual Available Capacity – Diesel		MW	316.2	481.3	501.7	501.7	501.7	501.7	522.1	542.5	562.9	603.8	644.6	665.0	665.0	726.3	726.3	726.3	726.3	726.3	726.3	746.7
Annual Number of Plant – Diesel			18	28	29	29	29	29	30	31	32	35	37	38	38	42	42	42	42	42	42	43
Annual Number of New Plant – Diesel			10	9	1	-	-	-	1	1	1	2	2	1	-	4	-	-	-	-	-	1
Annual Capital Cost (Including Fixed O&M) – Diesel		USD'M	23.00	35.01	36.50	36.50	36.50	36.50	37.98	39.47	40.95	43.92	46.89	48.38	48.38	52.84	52.84	52.84	52.84	52.84	52.84	54.32
Diesel (existing)																						
Plant Capacity (Without) – Diesel	18	MW																				
Number of Plant	8	#																				
Annual Capital Cost (Including Fixed O&M) – CCGT		USD'M	12.22	12.22	12.22	12.22	20.37	20.37	20.37	20.37	20.37	20.37	20.37	20.37	32.59	32.59	32.59	32.59	32.59	32.59	44.81	44.81
Annual Capital Cost (Including Fixed O&M) – Diesel		USD'M	23.00	35.01	36.50	36.50	36.50	36.50	37.98	39.47	40.95	43.92	46.89	48.38	48.38	52.84	52.84	52.84	52.84	52.84	52.84	54.32
Annual Capital Cost (Including Fixed O&M) – Diesel (existing)		USD'M	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07
Total Investment Cost (Including existing Plants)		USD'M	39	51	53	53	61	61	62	64	65	68	71	73	85	90	90	90	90	90	102	103

Table 34: Annual Fuel Requirement and Annual Fuel Cost (2024-2043)

YEARS			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Variable Costs																						
Fuel Requirement																						
Energy Consumption-IC-HFO	0.1960	kg/MWh																				
Energy Consumption-CCGT-HFO	0.16	kg/MWh																				
Million	1,000,000	#																				
Thousand	1,000	#																				
HFO																						
Annual Energy Generation - Diesel		GWh	754	855	961	1,073	344	467	596	732	874	1,024	1,180	1,345	250	431	622	822	1,032	1,253	217	460
Quantity of Fuel Required (Diesel) - HFO		TON	**147,797**	**167,617**	**188,429**	**210,280**	**67,487**	**91,578**	**116,874**	**143,435**	**171,324**	**200,608**	**231,355**	**263,640**	**48,933**	**84,527**	**121,901**	**161,143**	**202,348**	**245,613**	**42,434**	**90,134**
Annual Energy Generation - CCGT		GWh	1,268	1,268	1,268	1,268	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	3,382	3,382	3,382	3,382	3,382	3,382	4,651	4,651
Quantity of Fuel Required (CCGT) - HFO		TON	**199,139**	**199,139**	**199,139**	**199,139**	**331,899**	**331,899**	**331,899**	**331,899**	**331,899**	**331,899**	**331,899**	**331,899**	**531,039**	**531,039**	**531,039**	**531,039**	**531,039**	**531,039**	**730,178**	**730,178**
Energy Consumption- Diesel -LNG	7.8793	MMBtu/MWh																				
Energy Consumption- LNG	5.9761	MMBtu/MWh																				
LNG																						
Annual Energy Generation - Diesel		GWh	754	855	961	1,073	344	467	596	732	874	1,024	1,180	1,345	250	431	622	822	1,032	1,253	217	460
Quantity of Fuel Required (Diesel) - LNG		MMBtu/k	**5,942**	**6,738**	**7,575**	**8,453**	**2,713**	**3,681**	**4,698**	**5,766**	**6,887**	**8,065**	**9,301**	**10,599**	**1,967**	**3,398**	**4,900**	**6,478**	**8,135**	**9,874**	**1,706**	**3,623**
Annual Energy Generation - CCGT		GWh	1,268	1,268	1,268	1,268	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	3,382	3,382	3,382	3,382	3,382	3,382	4,651	4,651
Quantity of Fuel Required (CCGT) - LNG		MMBtu/k	**7,580**	**7,580**	**7,580**	**7,580**	**12,634**	**12,634**	**12,634**	**12,634**	**12,634**	**12,634**	**12,634**	**12,634**	**20,214**	**20,214**	**20,214**	**20,214**	**20,214**	**20,214**	**27,794**	**27,794**
Fuel Price																						
Fuel Price (Base year) - HFO	424	USD/TON																				
Fuel Price (Base year) - LNG	8.2404	USD/Mmbtu																				
Change in Fuel Price	0%	%																				
Change in HFO Price	0%	%																				
Change in LNG Price	0%	%																				
Million	1,000,000	#																				
Fuel Cost - Diesel Vs CCGT																						
Quantity of Fuel Required (Diesel) - HFO		TON	147,797	167,617	188,429	210,280	67,487	91,578	116,874	143,435	171,324	200,608	231,355	263,640	48,933	84,527	121,901	161,143	202,348	245,613	42,434	90,134
Annual Fuel Cost - Diesel - HFO		USD'M	**63**	**71**	**80**	**89**	**29**	**39**	**50**	**61**	**73**	**85**	**98**	**112**	**21**	**36**	**52**	**68**	**86**	**104**	**18**	**38**
Fuel Cost of Diesel - HFO	**0.083**	USD/kWh																				
Quantity of Fuel Required (Diesel) - LNG		MMBtu/k	5,942	6,738	7,575	8,453	2,713	3,681	4,698	5,766	6,887	8,065	9,301	10,599	1,967	3,398	4,900	6,478	8,135	9,874	1,706	3,623
Annual Fuel Cost - Diesel - LNG		USD'M	**48.96**	**55.53**	**62.42**	**69.66**	**22.36**	**30.34**	**38.72**	**47.52**	**56.75**	**66.45**	**76.64**	**87.34**	**16.21**	**28.00**	**40.38**	**53.38**	**67.03**	**81.36**	**14.06**	**29.86**
Fuel Cost of Diesel - LNG	**0.065**	USD/kWh																				
Quantity of Fuel Required (CCGT) - HFO		TON	199,139	199,139	199,139	199,139	331,899	331,899	331,899	331,899	331,899	331,899	331,899	331,899	531,039	531,039	531,039	531,039	531,039	531,039	730,178	730,178
Annual Fuel Cost - CCGT - HFO		USD'M	**84**	**84**	**84**	**84**	**141**	**141**	**141**	**141**	**141**	**141**	**141**	**141**	**225**	**225**	**225**	**225**	**225**	**225**	**310**	**310**
Fuel Cost of CCGT - HFO	**0.0666**	USD/kWh																				
Quantity of Fuel Required (CCGT) - LNG		MMBtu/k	7,580	7,580	7,580	7,580	12,634	12,634	12,634	12,634	12,634	12,634	12,634	12,634	20,214	20,214	20,214	20,214	20,214	20,214	27,794	27,794
Annual Fuel Cost - CCGT - LNG		USD'M	**62.46**	**62.46**	**62.46**	**62.46**	**104.10**	**104.10**	**104.10**	**104.10**	**104.10**	**104.10**	**104.10**	**104.10**	**166.57**	**166.57**	**166.57**	**166.57**	**166.57**	**166.57**	**229.03**	**229.03**
Fuel Cost of CCGT - LNG	**0.0492**	USD/kWh																				
Total Fuel Cost																						
Annual Fuel Cost - Diesel - LNG		USD'M	49	56	62	70	22	30	39	48	57	66	77	87	16	28	40	53	67	81	14	30
Annual Fuel Cost - CCGT - LNG		USD'M	62	62	62	62	104	104	104	104	104	104	104	104	167	167	167	167	167	167	229	229
Total Fuel Cost - LNG		USD'M	**111**	**118**	**125**	**132**	**126**	**134**	**143**	**152**	**161**	**171**	**181**	**191**	**183**	**195**	**207**	**220**	**234**	**248**	**243**	**259**
Annual Fuel Cost - Diesel - HFO		USD'M	63	71	80	89	29	39	50	61	73	85	98	112	21	36	52	68	86	104	18	38
Annual Fuel Cost - CCGT - HFO		USD'M	84	84	84	84	141	141	141	141	141	141	141	141	225	225	225	225	225	225	310	310
Total Fuel Cost - HFO		USD'M	**147**	**155**	**164**	**174**	**169**	**180**	**190**	**201**	**213**	**226**	**239**	**252**	**246**	**261**	**277**	**293**	**311**	**329**	**328**	**348**

Table 35: O&M and Regasification Costs (2024-2043)

YEARS			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Fixed Cost																						
Regasification Cost																						
Regasification Plant Cost	288	USD'M																				
Operation Duration	20	Year																				
Change in Opex (excluding Fuel)	0%	%																				
LNG Regasification Cost	0.004	USD/KWh																				
Annualized Regasification Cost	**29,333**	USD/MW																				
Total Avaiable Capacity		MW	583	601	616	616	713	713	728	743	758	788	818	833	978	1,023	1,023	1,023	1,023	1,023	1,167	1,182
Annualized Regasification Cost		USD'M	**17.10**	**17.64**	**18.08**	**18.08**	**20.91**	**20.91**	**21.35**	**21.79**	**22.23**	**23.11**	**23.99**	**24.43**	**28.67**	**29.99**	**29.99**	**29.99**	**29.99**	**29.99**	**34.24**	**34.68**
Total Annual Energy Generation		GWh	2,022	2,124	2,230	2,341	2,458	2,581	2,710	2,846	2,988	3,138	3,294	3,459	3,632	3,814	4,004	4,205	4,415	4,636	4,867	5,111
Variable Cost of Regasification Plant		USD'M	**8.09**	**8.49**	**8.92**	**9.37**	**9.83**	**10.32**	**10.84**	**11.38**	**11.95**	**12.55**	**13.18**	**13.84**	**14.53**	**15.25**	**16.02**	**16.82**	**17.66**	**18.54**	**19.47**	**20.44**
Conversion Cost to LNG																						
Diesel + Filters	34	USD'M																				
Operation Duration	20	Year																				
Economic Opportunity Cost of Capital (EOCK)	8%	%																				
Annual Energy Generation - Diesel		GWh	402	456	513	572	184	249	318	390	466	546	630	717	133	230	332	438	551	668	115	245
Annual Conversion Cost to LNG (existing diesels)		USD'M	**3.46**	**3.463**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**	**3.46**
Labor Cost																						
Annual Labor Cost	9.5	USD'M																				
Total Avaiable Capacity		MW	583	601	616	616	713	713	728	743	758	788	818	833	978	1,023	1,023	1,023	1,023	1,023	1,167	1,182
Tota Anuual Labour Cost			**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**	**9.45**
Variable Cost																						
Base Load																						
Variable cost (excluding fuel) - CCGT	6	USD/MWh																				
Variable cost (excluding fuel) - Diesel	9	USD/MWh																				
Thousand	1,000	#																				
CCGT																						
Annual Energy Generation - CCGT		GWh	1,268	1,268	1,268	1,268	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	3,382	3,382	3,382	3,382	3,382	3,382	4,651	4,651
Annual Variable O&M - CCGT		USD'M	**7.61**	**7.61**	**7.61**	**7.61**	**12.68**	**12.68**	**12.68**	**12.68**	**12.68**	**12.68**	**12.68**	**12.68**	**20.29**	**20.29**	**20.29**	**20.29**	**20.29**	**20.29**	**27.90**	**27.90**
Diesel																						
Annual Energy Generation - Diesel		GWh	754	855	961	1,073	344	467	596	732	874	1,024	1,180	1,345	250	431	622	822	1,032	1,253	217	460
Annual Variable O&M - Diesel		USD'M	**6.8**	**7.7**	**8.7**	**9.7**	**3.1**	**4.2**	**5.4**	**6.6**	**7.9**	**9.2**	**10.6**	**12.1**	**2.2**	**3.9**	**5.6**	**7.4**	**9.3**	**11.3**	**1.9**	**4.1**
Annual Variable O&M - CCGT		USD'M	7.61	7.61	7.61	7.61	12.68	12.68	12.68	12.68	12.68	12.68	12.68	12.68	20.29	20.29	20.29	20.29	20.29	20.29	27.90	27.90
Annual Variable O&M - Diesel		USD'M	7	8	9	10	3	4	5	7	8	9	11	12	2	4	6	7	9	11	2	4
Total Variable O&M Cost		USD'M	**14.40**	**15.31**	**16.26**	**17.27**	**15.78**	**16.89**	**18.05**	**19.27**	**20.55**	**21.90**	**23.31**	**24.79**	**22.54**	**24.18**	**25.89**	**27.69**	**29.59**	**31.57**	**29.85**	**32.04**
Total Fixed Cost		USD'M	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45
Total Variable O&M Cost		USD'M	14.40	15.31	16.26	17.27	15.78	16.89	18.05	19.27	20.55	21.90	23.31	24.79	22.54	24.18	25.89	27.69	29.59	31.57	29.85	32.04
Total O&M Cost		USD'M	**23.85**	**24.76**	**25.71**	**26.72**	**25.23**	**26.34**	**27.50**	**28.72**	**30.00**	**31.35**	**32.76**	**34.24**	**31.99**	**33.63**	**35.34**	**37.14**	**39.04**	**41.02**	**39.30**	**41.49**

Table 36: Total OPEX by Scenario

YEARS		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Total Operating Expenditures																					
Total Fuel Cost - HFO	USD'M	147	155	164	174	169	180	190	201	213	226	239	252	246	261	277	293	311	329	328	348
Total O&M Cost	USD'M	23.85	24.76	25.71	26.72	25.23	26.34	27.50	28.72	30.00	31.35	32.76	34.24	31.99	33.63	35.34	37.14	39.04	41.02	39.30	41.49
Total Operation Expenditure - HFO	USD'M	**171**	**180**	**190**	**200**	**195**	**206**	**218**	**230**	**243**	**257**	**272**	**287**	**278**	**295**	**312**	**331**	**350**	**370**	**367**	**389**
Total Fuel Cost - LNG	USD'M	111.42	117.99	124.88	132.12	126.46	134.44	142.82	151.62	160.86	170.56	180.75	191.44	182.78	194.57	206.95	219.95	233.60	247.93	243.09	258.89
Total O&M Cost	USD'M	22.66	23.52	24.43	25.38	23.97	25.02	26.13	27.28	28.50	29.78	31.12	32.53	30.39	31.94	33.58	35.29	37.08	38.97	37.34	39.42
Annualized Regasification Cost	USD'M	17.10	17.64	18.08	18.08	20.91	20.91	21.35	21.79	22.23	23.11	23.99	24.43	28.67	29.99	29.99	29.99	29.99	29.99	34.24	34.68
Annual Conversion Cost to LNG (existing diesels)	USD'M	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46
Variable Cost of Regasification Plant	USD'M	8.09	8.49	8.92	9.37	9.83	10.32	10.84	11.38	11.95	12.55	13.18	13.84	14.53	15.25	16.02	16.82	17.66	18.54	19.47	20.44
Total Operation Expenditure - LNG	USD'M	**162.73**	**171.10**	**179.77**	**188.41**	**184.64**	**194.16**	**204.60**	**215.54**	**227.00**	**239.46**	**252.49**	**265.70**	**259.84**	**275.23**	**290.00**	**305.51**	**321.80**	**338.90**	**337.60**	**356.90**

Table 37: Fuel and Fuel Cost Saving by Scenario (2024-2043)

YEARS			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
5. Fuel Savings																						
Fuel Price (Including Freight) - LNG	8	USD/Mmbtu																				
Fuel Price (Including Freight) - HFO	424	USD/TON																				
Change in Fuel Price	0%	%																				
Thousand	1,000	#																				
Diesel Vs CCGT																						
Diesel - LNG																						
Annual Fuel Cost - Diesel - HFO		USD'M	63	71	80	89	29	39	50	61	73	85	98	112	21	36	52	68	86	104	18	38
Annual Fuel Cost - Diesel - LNG		USD'M	49	56	62	70	22	30	39	48	57	66	77	87	16	28	40	53	67	81	14	30
Annual Fuel Cost Saving - Diesel (LNG)		USD/KW	**14**	**16**	**17**	**19**	**6**	**8**	**11**	**13**	**16**	**19**	**21**	**24**	**5**	**8**	**11**	**15**	**19**	**23**	**4**	**8**
CCGT - LNG																						
Annual Fuel Cost - CCGT - HFO		USD'M	84	84	84	84	141	141	141	141	141	141	141	141	225	225	225	225	225	225	310	310
Annual Fuel Cost - CCGT - LNG		USD'M	62	62	62	62	104	104	104	104	104	104	104	104	167	167	167	167	167	167	229	229
Annual Fuel Cost Saving - CCGT (LNG)		USD'M	**22.0**	**22.0**	**22.0**	**22.0**	**36.6**	**36.6**	**36.6**	**36.6**	**36.6**	**36.6**	**36.6**	**36.6**	**58.5**	**58.5**	**58.5**	**58.5**	**58.5**	**58.5**	**80.5**	**80.5**
Total																						
Annual Fuel Cost - HFO		USD'M	147	155	164	174	169	180	190	201	213	226	239	252	246	261	277	293	311	329	328	348
Annual Fuel Cost - LNG		USD'M	111	118	125	132	126	134	143	152	161	171	181	191	183	195	207	220	234	248	243	259
Total Fuel Cost Saving		USD'M	**36**	**37**	**39**	**41**	**43**	**45**	**47**	**50**	**52**	**55**	**58**	**61**	**63**	**66**	**70**	**73**	**77**	**81**	**84**	**89**
Fuel Cost of Diesel - HFO	0.083	USD/kWh																				
Fuel Cost of CCGT - HFO	0.067	USD/kWh																				
Fuel Cost of Diesel - LNG	0.065	USD/kWh																				
Fuel Cost of CCGT - LNG	0.049	USD/kWh																				
Fuel Cost Saving - Diesel - HFO to LNG	**0.0182**	USD/kWh																				
Fuel Cost Saving - Diesel to CCGT- HFO	**0.0165**	USD/kWh																				
Fuel Cost Saving - Diesel to CCGT - HFO to LNG	**0.0338**	USD/kWh																				

Appendix 2: CEA

Table 38: LCOE, ILCOE, LCOC of the Project (2024-2043)

YEARS			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Cost-Effectiveness Comparison of Four Alternatives																						
1. Levelized Cost of Energy																						
Diesel Vs CCGT																						
Annual Energy Generation - CCGT		GWh	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032
Economic Opportunity Cost of Capital (EOCK)	8%	%																				
Operation Duration	20	Year																				
Million	1,000,000	#																				
Thousand	1,000	#																				
PV of Total Net Energy Generation	10,946	GWh																				
Total Operation Expenditure - LNG		USD'M	60	60	60	61	61	61	62	62	62	62	63	63	63	64	64	65	65	66	67	67
PV of Total Cost (Excluding Investment Cost)	657	USD'M																				
Levelized Cost of Energy (LCOE)	**0.060**	USD/KWh																				
Total																						
Total Capital Cost		USD'M	38.4	41.0	43.5	46.1	48.6	49.9	53.7	55.0	57.5	60.1	75.4	75.4	75.4	77.9	81.7	85.6	91.9	94.5	109.7	109.7
PV of Total Capaital Cost	**633**	USD'M																				
Total Annual Energy Generation		GWh	2,022	2,124	2,230	2,341	2,458	2,581	2,710	2,846	2,988	3,138	3,294	3,459	3,632	3,814	4,004	4,205	4,415	4,636	4,867	5,111
PV of Total Net Energy Generation	**31,362**	GWh																				
Total Operation Expenditure - HFO		USD'M	172	182	193	204	215	228	241	254	268	283	270	286	303	321	340	360	381	403	397	421
Total Operation Expenditure - LNG		USD'M	129	136	144	152	161	169	179	189	199	210	201	213	225	238	252	267	282	298	295	312
Economic Opportunity Cost of Capital (EOCK)	8%	%																				
Million	1,000,000	#																				
Thousand	1,000	#																				
PV of Total Cost (excluding Capital) - HFO	**2,701**	USD'M																				
PV of Total Cost (excluding Capital) - LNG	**2,008**																					
Levelized Cost of Energy - HFO	**0.10629**	USD/KWh																				
Levelized Cost of Energy - LNG	**0.08421**																					
Levelized Cost of Energy (Including Capital Cost) - HFO	0.10629	USD/KWh																				
Levelized Cost of Energy (Including Capital Cost) - LNG	0.08421	USD/KWh																				
ILCOE	**0.0221**	USD/KWh																				
Total Annual Energy Generation		GWh	2,022	2,124	2,230	2,341	2,458	2,581	2,710	2,846	2,988	3,138	3,294	3,459	3,632	3,814	4,004	4,205	4,415	4,636	4,867	5,111
Annual Cost Saving		USD'M	45	47	49	52	54	57	60	63	66	69	73	76	80	84	88	93	97	102	107	113
PV of Total Cost Saving	**692.58**	USD'M																				
Annualized PV of Cost Saving	**70.54**	USD'M																				
2. Levelized Cost of Capital																						
Total Annual Energy Generation		GWh	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	1,032	2,065	2,065	2,065	2,065	2,065	2,065	2,065	2,065	3,097	3,097
Economic Opportunity Cost of Capital (EOCK)	8.00%	%																				
Thousand	1000	#																				
PV of Total Energy Generation of One Plant - CCGT	14,909	GWh																				
Annual Capital Cost (Including Fixed O&M) - CCGT		USD'M	15	15	15	15	15	15	15	15	15	15	31	31	31	31	31	31	31	31	46	46
PV of Capital Cost - CCGT	**221**																					
Annual Capital Cost (Including Fixed O&M) - Diesel		USD'M	19	22	24	27	29	31	34	36	38	41	41	41	41	43	47	51	57	60	60	60
PV of Capital Cost - Diesel	**369**																					
Annual Capital Cost (Including Fixed O&M) - Diesel (existing)		USD'M	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
PV of Capital Cost - Diesel (existing)	**43**																					
PV of Total Capaital Cost	221	USD'M																				
Levelized Cost of Capital (excluding fuel) (LCOE) -	**0.0148**	USD/KW																				

Appendix 3: Sensitivity Analysis

Table 36: Total CAPEX Sensitivity – Diesel Using HFO

	PV of Total Cost of HFO	LCOE of Diesel-HFO	LCOC of CCGT	PV of Fuel Cost of Diesel-HFO	ILCOE	PV of Total Cost Saving
	Heavy Fuel Oil					
	2,700.524	0.0964	0.025	0.9584	0.0221	692.578
-25%	2,700.5243	0.0964	0.0188	0.9584	0.0228	715.6937
-20%	2,700.5243	0.0964	0.0201	0.9584	0.0227	711.0705
-15%	2,700.5243	0.0964	0.0213	0.9584	0.0225	706.4473
-10%	2,700.5243	0.0964	0.0226	0.9584	0.0224	701.8241
-5%	2,700.5243	0.0964	0.0238	0.9584	0.0222	697.2008
0%	2,700.5243	0.0964	0.0251	0.9584	0.0221	692.5776
5%	2,700.5243	0.0964	0.0263	0.9584	0.0219	687.9544
10%	2,700.5243	0.0964	0.0276	0.9584	0.0218	683.3312
15%	2,700.5243	0.0964	0.0288	0.9584	0.0216	678.7080
20%	2,700.5243	0.0964	0.0301	0.9584	0.0215	674.0848
25%	2,700.5243	0.0964	0.0313	0.9584	0.0213	669.4615

Table 37: Total CAPEX Sensitivity – Diesel Using LNG

	PV of Total Cost of LNG	LCOE of Diesel-LNG	LCOC of CCGT	PV of Fuel Cost of Diesel-LNG	ILCOE	PV of Total Cost Saving
	Liquified Natural Gas					
	2,007.947	0.0732	0.025	0.6530	0.0221	692.578
-25%	1,984.8306	0.0718	0.0188	0.6530	0.0228	715.6937
-20%	1,989.4538	0.0720	0.0201	0.6530	0.0227	711.0705
-15%	1,994.0770	0.0723	0.0213	0.6530	0.0225	706.4473
-10%	1,998.7002	0.0726	0.0226	0.6530	0.0224	701.8241
-5%	2,003.3235	0.0729	0.0238	0.6530	0.0222	697.2008
0%	2,007.9467	0.0732	0.0251	0.6530	0.0221	692.5776
5%	2,012.5699	0.0734	0.0263	0.6530	0.0219	687.9544
10%	2,017.1931	0.0737	0.0276	0.6530	0.0218	683.3312
15%	2,021.8163	0.0740	0.0288	0.6530	0.0216	678.7080
20%	2,026.4395	0.0743	0.0301	0.6530	0.0215	674.0848
25%	2,031.0628	0.0746	0.0313	0.6530	0.0213	669.4615

Table 38: Total CAPEX Sensitivity – CCGT Using HFO

	PV of Total Cost of HFO	LCOE of CCGT-HFO	LCOC of CCGT	PV of Fuel Cost of CCGT-HFO	ILCOE	PV of Total Cost Saving
	Heavy Fuel Oil					
	2,700.524	0.0745	0.015	0.6940	0.0221	692.578
-25%	2,700.5243	0.0745	0.0111	0.6940	0.0228	715.6937
-20%	2,700.5243	0.0745	0.0118	0.6940	0.0227	711.0705
-15%	2,700.5243	0.0745	0.0126	0.6940	0.0225	706.4473
-10%	2,700.5243	0.0745	0.0133	0.6940	0.0224	701.8241
-5%	2,700.5243	0.0745	0.0141	0.6940	0.0222	697.2008
0%	2,700.5243	0.0745	0.0148	0.6940	0.0221	692.5776
5%	2,700.5243	0.0745	0.0155	0.6940	0.0219	687.9544
10%	2,700.5243	0.0745	0.0163	0.6940	0.0218	683.3312
15%	2,700.5243	0.0745	0.0170	0.6940	0.0216	678.7080
20%	2,700.5243	0.0745	0.0178	0.6940	0.0215	674.0848
25%	2,700.5243	0.0745	0.0185	0.6940	0.0213	669.4615

Table 39: Total CAPEX Sensitivity – CCGT Using LNG

	PV of Total Cost of LNG	LCOE of CCGT-LNG	LCOC of CCGT	PV of Fuel Cost of CCGT-LNG	ILCOE	PV of Total Cost Saving
	Liquified Natural Gas					
	2,007.947	0.0601	0.015	0.4728	0.0221	692.578
-25%	1,984.8306	0.0584	0.0111	0.4728	0.0228	715.6937
-20%	1,989.4538	0.0588	0.0118	0.4728	0.0227	711.0705
-15%	1,994.0770	0.0591	0.0126	0.4728	0.0225	706.4473
-10%	1,998.7002	0.0594	0.0133	0.4728	0.0224	701.8241
-5%	2,003.3235	0.0597	0.0141	0.4728	0.0222	697.2008
0%	2,007.9467	0.0601	0.0148	0.4728	0.0221	692.5776
5%	2,012.5699	0.0604	0.0155	0.4728	0.0219	687.9544
10%	2,017.1931	0.0607	0.0163	0.4728	0.0218	683.3312
15%	2,021.8163	0.0610	0.0170	0.4728	0.0216	678.7080
20%	2,026.4395	0.0614	0.0178	0.4728	0.0215	674.0848
25%	2,031.0628	0.0617	0.0185	0.4728	0.0213	669.4615

Table 40: Fuel Price – Diesel Using HFO

	PV of Total Cost of HFO	Levelized Cost of Energy - HFO	LCOC of Diesel	PV of Fuel Cost of Diesel-HFO	ILCOE	PV of Total Cost Saving
	Heavy Fuel Oil					
	2,700.524	0.1063	0.025	0.9584	0.0221	692.578
-25%	2,084.7757	0.0867	0.0251	0.7188	0.0158	496.3171
-20%	2,207.9254	0.0906	0.0251	0.7668	0.0171	535.5692
-15%	2,331.0751	0.0945	0.0251	0.8147	0.0183	574.8213
-10%	2,454.2249	0.0984	0.0251	0.8626	0.0196	614.0734
-5%	2,577.3746	0.1024	0.0251	0.9105	0.0208	653.3255
0%	2,700.5243	0.1063	0.0251	0.9584	0.0221	692.5776
5%	2,823.6740	0.1102	0.0251	1.0064	0.0233	731.8297
10%	2,946.8237	0.1141	0.0251	1.0543	0.0246	771.0818
15%	3,069.9735	0.1181	0.0251	1.1022	0.0258	810.3339
20%	3,193.1232	0.1220	0.0251	1.1501	0.0271	849.5860
25%	3,316.2729	0.1259	0.0251	1.1981	0.0283	888.8381

Table 41: Fuel Price – Diesel Using LNG

	PV of Total Cost of LNG	Levelized Cost of Energy - LNG	LCOC of Diesel	PV of Fuel Cost of Diesel-LNG	ILCOE	PV of Total Cost Saving
	Liquified Natural Gas					
	2,007.947	0.0842	0.025	0.6530	0.0221	692.578
-25%	1,588.4586	0.0708	0.0251	0.4897	0.0158	496.3171
-20%	1,672.3562	0.0735	0.0251	0.5224	0.0171	535.5692
-15%	1,756.2538	0.0762	0.0251	0.5550	0.0183	574.8213
-10%	1,840.1514	0.0789	0.0251	0.5877	0.0196	614.0734
-5%	1,924.0490	0.0815	0.0251	0.6203	0.0208	653.3255
0%	2,007.9467	0.0842	0.0251	0.6530	0.0221	692.5776
5%	2,091.8443	0.0869	0.0251	0.6856	0.0233	731.8297
10%	2,175.7419	0.0896	0.0251	0.7182	0.0246	771.0818
15%	2,259.6395	0.0922	0.0251	0.7509	0.0258	810.3339
20%	2,343.5372	0.0949	0.0251	0.7835	0.0271	849.5860
25%	2,427.4348	0.0976	0.0251	0.8162	0.0283	888.8381

Table 42: Fuel Price – CCGT Using HFO

	PV of Total Cost of HFO	Levelized Cost of Energy - HFO	LCOC of CCGT	PV of Fuel Cost of CCGT-HFO	ILCOE	PV of Total Cost Saving
	Heavy Fuel Oil					
	2,700.524	0.1063	0.015	0.6940	0.0221	692.578
-25%	**2,084.7757**	**0.0867**	**0.0148**	**0.5205**	**0.0158**	**496.3171**
-20%	**2,207.9254**	**0.0906**	**0.0148**	**0.5552**	**0.0171**	**535.5692**
-15%	**2,331.0751**	**0.0945**	**0.0148**	**0.5899**	**0.0183**	**574.8213**
-10%	**2,454.2249**	**0.0984**	**0.0148**	**0.6246**	**0.0196**	**614.0734**
-5%	**2,577.3746**	**0.1024**	**0.0148**	**0.6593**	**0.0208**	**653.3255**
0%	**2,700.5243**	**0.1063**	**0.0148**	**0.6940**	**0.0221**	**692.5776**
5%	**2,823.6740**	**0.1102**	**0.0148**	**0.7287**	**0.0233**	**731.8297**
10%	**2,946.8237**	**0.1141**	**0.0148**	**0.7634**	**0.0246**	**771.0818**
15%	**3,069.9735**	**0.1181**	**0.0148**	**0.7982**	**0.0258**	**810.3339**
20%	**3,193.1232**	**0.1220**	**0.0148**	**0.8329**	**0.0271**	**849.5860**
25%	**3,316.2729**	**0.1259**	**0.0148**	**0.8676**	**0.0283**	**888.8381**

Table 43: Fuel Price – CCGT Using LNG

	PV of Total Cost of LNG	Levelized Cost of Energy - LNG	LCOC of CCGT	PV of Fuel Cost of CCGT-LNG	ILCOE	PV of Total Cost Saving
	Liquified Natural Gas					
	2,007.947	0.0842	0.015	0.4728	0.0221	692.578
-25%	**1,588.4586**	**0.0708**	**0.0148**	**0.3546**	**0.0158**	**496.3171**
-20%	**1,672.3562**	**0.0735**	**0.0148**	**0.3783**	**0.0171**	**535.5692**
-15%	**1,756.2538**	**0.0762**	**0.0148**	**0.4019**	**0.0183**	**574.8213**
-10%	**1,840.1514**	**0.0789**	**0.0148**	**0.4255**	**0.0196**	**614.0734**
-5%	**1,924.0490**	**0.0815**	**0.0148**	**0.4492**	**0.0208**	**653.3255**
0%	**2,007.9467**	**0.0842**	**0.0148**	**0.4728**	**0.0221**	**692.5776**
5%	**2,091.8443**	**0.0869**	**0.0148**	**0.4965**	**0.0233**	**731.8297**
10%	**2,175.7419**	**0.0896**	**0.0148**	**0.5201**	**0.0246**	**771.0818**
15%	**2,259.6395**	**0.0922**	**0.0148**	**0.5438**	**0.0258**	**810.3339**
20%	**2,343.5372**	**0.0949**	**0.0148**	**0.5674**	**0.0271**	**849.5860**
25%	**2,427.4348**	**0.0976**	**0.0148**	**0.5910**	**0.0283**	**888.8381**