CHALMERS
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Natural gas in a sunny place

Evaluation of the planned fuel switch for the electricity system of Baja California Sur.

Master's thesis in the Master's Programme Sustainable Energy Systems

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Department of Energy and Environment
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2015

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Abstract

In parallel to Mexico's major energy reform, the peninsular state of Baja California Sur (BCS) is planned to go through a fuel switch from heavy fuel oil to natural gas. This study investigates the impact of the fuel switch on the costs and emissions of the BCS electricity system as well as if there is an alternative where instead of the fuel switch more renewable power is being injected.

The study is done by modeling different scenarios including the switch to natural gas and alternative scenarios with combinations of diesel, photovoltaics (PVs) and concentrating solar power (CSP). The study also includes interviews with key actors of the system and the energy sector of Mexico and is complemented with literature studies. Results show that the planned fuel switch will provide a fast reduction of electricity generation costs but in the long run the solar alternatives have greater potential to lower them even further. Minimum possible emissions of $CO_{2equivalents}$ per scenario until 2026 are 384.94 kg/MWh for natural gas, 96.83 kg/MWh for PV/diesel and 137.01 kg/MWh for PV/CSP/diesel systems. However natural gas remains the least expensive investment.

The study analyzes the current policies promoting a sustainable electricity system in Mexico and if there is a risk of a lock-in to natural gas in the area. Finally it analyzes what the transformation of the Baja California Sur system, and the challenges for the alternatives, may say about what will happen in the electricity system of the rest of the country.

At the moment the high electricity price in Baja California Sur is the key motivator for investments in renewables, since they must cover high investment costs. Natural gas fuelled technologies in Baja California Sur, and the entire country, will decrease the marginal price of electricity, due to the lower fuel costs. Nonetheless, by injecting more renewables in the system the marginal price of electricity will decrease even further, attempting against their own profitability. The study shows that if there is no financial mechanisms to aid only renewable power investments, these technologies won't be able to compete with fossil fuelled technologies classified as clean energy in the new Energy industry law of Mexico.

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Acronyms

BCS	Baja California Sur
GAMS	General Algebraic Modeling System
NREL	National Renewable Energy Laboratory
SAM	System Advisor Model
LAERFTE	Law of Harnessing Renewable Energy and Financing the Energy Transition
LIE	Electricity Industry Law
LGCC	General Law of Climate Change
CEL	Clean Energy Certificates
SIN	National Interconnected System
POISE	Program of Construction and Investments in the Electricity Sector
IPP	Individual Pension Plan
COPAR	Cost and Reference Parameters for the Formulation of Investment Projects of the Electricity Sector
TG	"Turbo gas", open cycle gas turbine
CT	"Conventional Thermoelectric", Steam Turbine
DTG	"Diesel Turbo gas", Diesel operated open cycle gas turbine
IC	Internal Combustion engine
CC	Combined Cycle
PV	Photovoltaic
CSP	Concentrating Solar Power
CCS	Carbon Capture and Storage
SENER	Secretary of Energy
CRE	Regulating Commission of Energy
CENACE	National Control Centre of Energy
CFE	Federal Electricity Commission
PEMEX	Petróleos Mexicanos
SERMANAT	Secretary for Environment and Natural Resources
CENAGAS	National Gas Control Centre
CONAGUA	National Water Commission
ISO	Independent System Operator
TSO	Transmission System Operator
SPE	Special Purpose Entity
EUA	European Emission Allowance
DNI	Direct Normal Irradiation
FLH	Full Load Hours
PM	Particle Matter
GHG	Green House Gas
IEA	International Energy Agency
EPA	Environmental Protection Agency
IRENA	International Renewable Energy Agency

1
Introduction

The world stands in front of a huge challenge. The climate change requires major changes in many areas, the electricity supply sector being one of them. The demand of electricity is likely going to increase in the future in pace with the world's growing population and therefore the sector has to move away from fossil fuel dependency to be able to provide electricity in a sustainable way. More renewable electricity generation is needed not only to cover the current demand but also provide for developing nations future expansions. Developing countries are also the ones which climate change is going to hit hardest, both due to the living situation poverty entails (like weak constructions of homes), food requirements and due to that many developing countries are situated in risk zones for natural disasters [1]. Therefore it is very important for the developed world to start to mitigate the effects of climate change as well as bring their a-game when it comes to developing new technologies and solutions which can be deployed also in the developing world. It is also important for less developed countries to make as good and as sustainable choices as possible when expanding and developing. This master thesis is a study of a developing country, Mexico, on it's highway towards a a new energy sector, providing electricity access to an affordable price for its people, electricity security and to choose the right path towards a sustainable electricity generation.

1.1 Background

Since the administration of former president Felipe Calderón (2006-2012), Mexico has been making an effort to become a leader in sustainable development among developing nations. In 2010 Mexico hosted the UN Conference of the Parties (COP16) and in 2012 Mexico was the first developing country to publish a Climate Change Law (the first country was UK). In the adjustments made to the Law of Harnessing Renewable Energy and Financing the Energy Transition (LAERFTE) in 2011, a limit was set on the amount of fossil fuels to be used in the years 2024, 2035 and 2050 of 65%, 60% and 50% respectively (Transitory article 2).

Moreover with the approval of a major Energy Reform on December 20th 2013, that acknowledges the importance of investments towards sustainability, and opens up the sector for private sector participation, more interesting changes are bound to follow. Some of the recent changes in Mexican Law that could have an influence on sustainable energy production in Mexico, besides the growing openness for the private sector, are the implementation of carbon taxes on fuels and the establishment of Clean Energy Quotas, and thus Clean Energy Certificates. However the carbon tax is quite small and exempts natural gas.

Baja California Sur (BCS) is a State situated in the southern half of the Baja Peninsula in the north west of Mexico, Figure 1.1, and is an isolated generation system, which makes it an interesting study subject, since it's not connected to the north of the peninsula nor to the National Interconnected System (SIN for its acronym in Spanish). All the fuels used in BCS for residential, transportation, industrial, commercial consumption and for electricity power generation arrive by sea. The Mexican electricity system is divided in nine areas, of which BCS has the fastest growing demand; while the SIN has an expected growth of 4.0% from 2013 to 2028 the BCS interconnected system has an expected growth of 6.1% [2, p. 32]. Official government documentation (Program of Constructions and Investments in the Electricity Sector 2014-2028, POISE for its acronym in Spanish) states that due to the growing energy demands and the fact that fuels used in BCS are highly contaminating and expensive, a fuel switch from heavy fuel oil and diesel to natural gas has been planned (along with improvements on the BCS interconnecting grid). The change would considerably reduce CO_2, NOx, SOx and particulate matter emissions [2].

Figure 1.1: Where is Baja California Sur?

The new natural gas supply should be ready by June 2018 and should supply natural gas for all existing and new power plants in the system; existing power plants will be adapted to use this fuel [3]. The tender document [3] does not state which will be the connecting points for the gas transport, nor the type of technology to be used. The carrier can therefore decide weather to liquefy or compress the gas. However in the POISE 2012-2026 [4] it is mentioned that natural gas will be transported in compressed state (CNG) (thus a compression station must be installed) on boats from Puerto Libertad or Topolobampo Figure 1.2 and then by gas pipeline.

Figure 1.2: Proposed gas routes

1.2 Aim

The aim of the project is to evaluate the impact of a fuel switch from heavy fuel oil and diesel to natural gas in the electricity system of the peninsular state Baja California Sur in Mexico. To do this, a model of the system will be programmed in GAMS (General Algebraic Modeling System). The modeled scenarios are: the current scenario, the system in 2019 after the fuel switch has taken place and the system in 2026, which is the latest date mentioned in the POISE 2012-2026, which was the latest POISE publication by the time the thesis work began. Additionally, these results are compared with scenarios with more renewable energy sources implemented to evaluate if there is an alternative path to the switch to natural gas. The goal of the project is to analyze the effects of the fuel switch and with this the change of emissions and its environmental impact, economics and the electricity supply system's overall suitability for the peninsular system.

In order to better understand the current operation of the system, the government plans for the BCS electricity system and the effects of the energy reform interviews with key actors are carried out.

1.3 Limitations

The project only considers the south part of the state of Baja California Sur, that is the interconnected electricity system of the state. This does not include the two isolated systems Santa Rosalía and Guerrero Negro, it's electricity generation and distribution networks, situated further north in the state and that are not interconnected to the state's electricity system. Fossil fuel extraction is not considered.

1.4 Research questions

- What would be the environmental and economic effects of the switch of fuel in an optimally operated system?
- What could be a renewable alternative to the fuel switch? How does it compare in economic and environmental terms?
- Is the fuel switch risking a lock-in of natural gas in the area? What incites or prevent this?
- How can the transformation of the BCS system be used to understand the effects of the energy reform on the Mexican electricity system?

2

Theory

The theory chapter is divided in smaller section to get a information base about the project and Mexico's energy sector. First the system is described to get a good overview of what kind of electricity system that is modeled. Thereafter the actors of the Mexican electricity sector are presented as well as a description of the sector today and what the energy reform will change. The chapter is ended with a section about solar resources in Mexico.

2.1 The system

The state of BCS is divided in five municipalities; Mulegé, Comondó, La Paz, Los Cabos and Loreto, where the electricity generation takes place mainly around the cities; San Carlos, Ciudad Constitución, Punta Prieta, Cabo San Lucas and La Paz, the capital of the state. The distribution of the power plants can be seen in Figure 2.1. All power plants in the system besides a 30MW solar, Aura, is own by the state owned utility comapny, CFE (Regulating Commission of Energy for its acronym in Spanish).

Figure 2.1: The distribution of power plants in BCS

The transmission lines go through all the generation sites besides the Guerrero Negro and Santa Rosalia units which are isolated systems only providing for their surroundings. Table 2.1 shows the units that are connected and thereby the ones modeled in this project. The table also shows the sizes of the units, the fuels used and the technology of the plant. All this is of the year 2014. The abbreviation of the technologies stands for:

TG: Open cycle gas turbine, referred to by CFE as "Turbogas"
CT: Steam turbine, referred to by CFE as "Conventional Thermoelectric"
DTG: Diesel operated open cycle gas turbine "Diesel turbo gas" [1]
IC: Internal combustion engine
CC: Combined cycle
PV: Photovoltaic

A further explanation of these technologies can be found in Appendix A.1 along with additional information on solar generation technologies and energy storage options relevant for this project.

Table 2.1: The power plants and sizes of units in 2014

Site	Unit	Size [MW]	Fuel	Technologies
Ciudad Constitución	VIO U1	30	Diesel	DTG
Punta Prieta	PUP U1	37.5	Fuel oil	CT
	PUP U2	37.5	Fuel oil	CT
	PUP U3	37.5	Fuel oil	CT
	PUP U4	18	Diesel	DTG
	PUP U5	25	Diesel	DTG
San Carlos	GAO U1	31.5	Fuel mix	IC
	GAO U2	31.5	Fuel mix	IC
	GAO U3	41.125	Fuel oil	IC
Corumel	BCS U1	37	Fuel mix	IC
	BCS U2	41.9	Fuel oil	IC
	BCS U3	41.9	Fuel oil	IC
	BCS U4	41.9	Fuel oil	IC
La Paz	LP U1	43	Diesel	DTG
Los Cabos	LC U1	30	Diesel	DTG
	LC U2	23.7	Diesel	DTG
	LC U3	27	Diesel	DTG
Aura	Aura	30	Sun	PV
Total		606.025		

Fuel mix: 85% fuel oil, 15% diesel

[1] In the CFE future plans this systems will be now run on natural gas, however in the present report they will still be referred to as DTG to establish that it is the same unit that has been adapted to now operate with gas.

The system is planned to be changed during 2018. Some of the power plant will be shut down, some will be adapted to work with natural gas and some new plants will be built as the demand grows and some power plant's technical lifetime is over. Currently all of CFE's power plants run on heavy fuel oil and diesel, but this will change so that they all run on natural gas [4] [5]. In 2019 the three units in Los Cabos will be removed, two new units will be added in Corumel, a new CC power plant near Todos los Santos will also be built and another in La Paz, as well as a new 30MW PV solar plant [2]. By 2026 the CT units at Punta Prieta will be retired, the DTG at Ciudad Constitución will be replaced by a CC unit, and the DTG at La Paz will also be retired and substituted by a CC unit [2]. Another unit will be added in Todos los Santos as well as two new TG units in Los Cabos [2]. Table 2.2 and Table 2.3 show the plans of the new systems at these years, new units are marked with a star.

Table 2.2: The power plants and sizes of units in 2019

Site	Unit	Size [MW]	Fuel	Technologies
Ciudad Constitución	VIO U1	30	Natural gas	DTG
Punta Prieta	PUP U1	37.5	Natural gas	CT
	PUP U2	37.5	Natural gas	CT
	PUP U3	37.5	Natural gas	CT
	PUP U4	18	Natural gas	DTG
	PUP U5	25	Natural gas	DTG
San Carlos	GAO U1	31.5	Natural gas	IC
	GAO U2	31.5	Natural gas	IC
	GAO U3	41.125	Natural gas	IC
Corumel	BCS U1	37	Natural gas	IC
	BCS U2	41.9	Natural gas	IC
	BCS U3	41.9	Natural gas	IC
	BCS U4	41.9	Natural gas	IC
	BCS U5*	43	Natural gas	IC
	BCS U6*	43	Natural gas	IC
Todos Santos	TS UI*	137	Natural gas	CC
La Paz	LP U1	43	Natural gas	DTG
	LP UI*	117	Natural gas	CC
Aura	Aura	30	Sun	PV
New Solar	Solar*	30	Sun	PV
Total		895.325		

Table 2.3: The power plants and sizes of units in 2026

Site	Unit	Size [MW]	Fuel	Technologies
Ciudad Constitución	VIO UI*	137	Natural gas	CC
Punta Prieta	PUP U4	18	Natural gas	DTG
	PUP U5	25	Natural gas	DTG
San Carlos	GAO U1	31.5	Natural gas	IC
	GAO U2	31.5	Natural gas	IC
	GAO U3	41.125	Natural gas	IC
Corumel	BCS U1	37	Natural gas	IC
	BCS U2	41.9	Natural gas	IC
	BCS U3	41.9	Natural gas	IC
	BCS U4	41.9	Natural gas	IC
	BCS U5	43	Natural gas	IC
	BCS U6	43	Natural gas	IC
Todos Santos	TS UI	137	Natural gas	CC
	TS UII*	123	Natural gas	CC
La Paz	LP UI	117	Natural gas	CC
	LP UII*	117	Natural gas	CC
Los Cabos	LC UI*	94	Natural gas	TG
	LC UII*	94	Natural gas	TG
Aura	Aura	30	Sun	PV
New Solar	Solar	30	Sun	PV
Total		1'274.825		

The system is run in a cost minimization way, which determines the dispatch order of the system's power plants so that the system is as cheap as possible to run [6]. In the running costs the fuel prices, fuel taxes and costs of operation and maintenance are included. The fuel taxes are only on fuel oil and diesel and are included in the price when PEMEX (Petróleos Mexicanos) sells the fuels to larger utility companies or consumers [7]. Since 2014 external costs should be considered when establishing the merit order of power plants, however this cost is not passed on to the consumers [2]. In order to do this, when the dispatch of the plants are cost optimized, the external costs are included in the total system cost to decide the dispatch order. The external costs are defined as the $CO_{2equivalents}$ produced multiplied with the present price of the EUA, the EU Emission Allowances (this to get an estimation of the cost of the emissions). The external costs are then subtracted from the marginal cost of electricity and thereby not paid by the final consumer [2] [8].

2.2 Actors of the system

The Mexican electricity sector has many actors, but up until now, it has been dominated by the public sector utility, CFE. It is expected, however, that with the Energy

Reform recently approved, and the deregulation of the electricity market brought by it, this will change and the participation from the private sector will grow in the years to come. When the energy reform is finished and all the laws required are passed and put in practice, the sector will still be regulated by the state but more private parties will be included in the generation, transmission and distribution services.

The main participants in the sector are:

- SENER: Sectretaría de Energía, Sectretary of Energy, is the head of the energy sector.
- CRE: Comisión Reguladora de Energía, Regulating Commission of Energy, is the regulating entity of the energy sector of the Mexican state.
- CENACE: Centro Nacional de Control de Energía, National Control Centre of Energy, is the transmission system operator (TSO) of the Mexican electricity system.
- CFE: Comisión Federal de Electricidad, Federal Electricity Commission, is the state owned utility company of Mexico.
- PEMEX: Petróleos Mexicanos, the state owned oil company.

More information about the system actors can be found in Appendix A.2.

2.3 The energy panorama of Mexico

The Mexican electricity sector is based on three statutes which will have an influence on the transition: The Law of Harnessing Renewable Energy and Financing the Energy Transition (LAERFTE), the Electricity Industry law (LIE) that will with the reform substitute the Electricity Public Service Law (LSPEE) and the General Law of Climate Change (LGCC). The LGCC changes the "non fossil energy" goal mentioned in the LAERFTE from a "non fossil energy" goal to a "clean energy target" of 35% clean energy generation in 2024.[9]. The LIE law includes a definition of what clean energy is.

The definition of clean energy in the LIE law includes the following sources and technologies [10]:

- Wind
- Solar (any type)
- Ocean energy (any type)
- Geothermal
- Bio-energy (according to bio-energy law)

- Energy from the use of methane and other gases associated to waste disposal sites, farms, and water treatment facilities
- Energy generated by the use of hydrogen (provided that its production meets quality requirements by government)
- Hydro plants
- Nuclear plants
- Energy from agricultural waste and urban solid waste (provided that production don't generate harmful by-products)
- Energy from certified "efficient co-generation" (according to CRE and SEMARNAT, the Secretary for Environment and Natural Resources, for its acronym in Spanish, specifications)
- Energy produced in sugar farms that follows CRE specifications
- thermal units with CCS (carbon capture and storage)
- Technologies considered low on carbon emissions according to international standards
- Other technologies that the SEMARNAT considers clean.

At the same time, strong investments on natural gas infrastructure are being made, and it is expected that this fuel will soon be the dominating fuel for electricity generation in Mexico, as can be seen in Figure 2.2 [2].

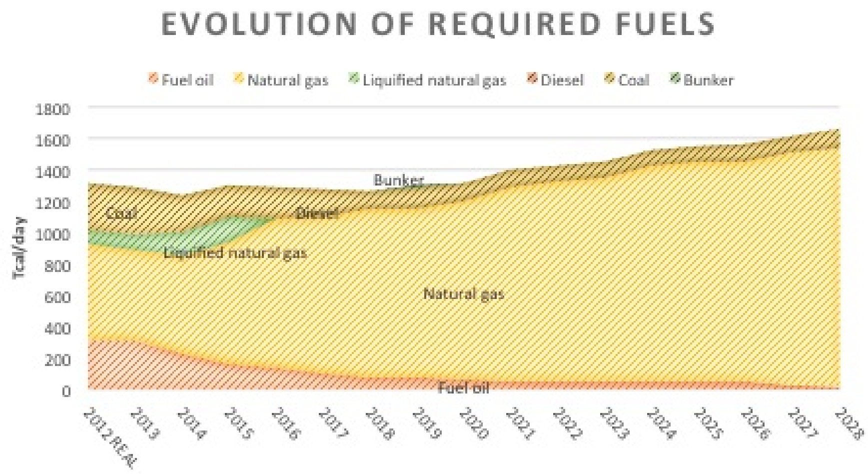

Figure 2.2: Evolution of fuel requirement for electricity generation in Mexico. [2]

2.3.1 The electricity market today

Before the transition started, the energy market in Mexico was state controlled by the SENER which had control over CRE, CFE and PEMEX. Most of the power in Mexico is generated in power plants owned by CFE, except for a few power plants that are privately owned, and in co-generation installations owned by PEMEX and private industry that sell their excess power to CFE (within a certain limit). The CFE has control over CENACE, the TSO. Figure 2.3 shows how the energy sector was structured until the energy reform started. [11]

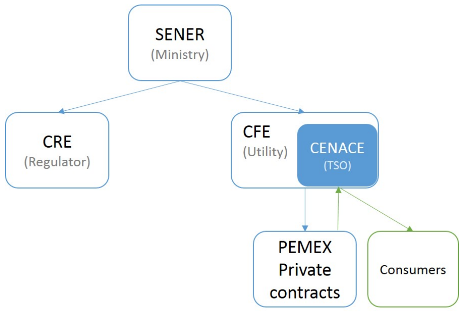

Figure 2.3: Previous Electricity Sector Scheme [11] [16]

2.3.2 The new electricity market

SENER will still be on the top of the hierarchy but the wholesale market that now is created will be operated by CENACE, the ISO (Independent System Operator)[14], and controlled and regulated by CRE [15]. CFE, PEMEX and private actors can then participate in the market, now without limitations on power output, and sell their electricity to utility companies which in their turn sell it to the final users, or they can sell it to qualified users, all to spot market prices. CFE, as well as PEMEX, will be transformed into SPEs (Special Purpose Entities) which means that it will still be a state-owned companies but will be more commercially oriented than before [14]. Figure 2.4 shows how the electricity sector will be structured when the transition is finished.

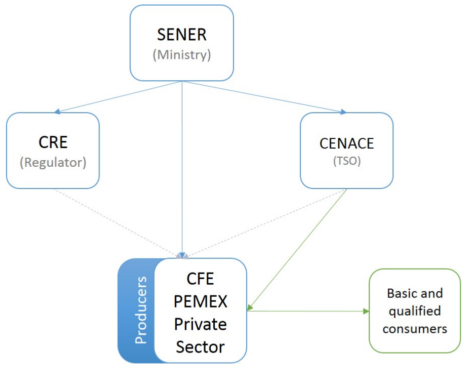

Figure 2.4: New Electricity Sector Scheme [11]

More information about the current and future operation of the electricity market can be found in Appendix A.3.

2.4 Solar Resource in Mexico

The north west of Mexico has the advantage of having high direct normal solar irradiation (DNI), with values above 6kWh/m2/day, as can be seen in in Figure 2.5, which is the minimum values required for Concentrated Solar Power (CSP) production [18]. However in the particular case of CSP technologies, what is more important than the direct irradiation is the variation of it during the day this makes the state of BCS ideal for CSP and PV operation since there is very little rain in the area. The map below (Figure 2.6) shows the climate regions in Mexico. As can be seen BCS has dry and very dry climate.

The Tropic of Cancer passes through the state of BCS, this means a low variability in the daily sun hours during the year and a hot and dry climate with two mains seasons, dry and rain season, where rains peak in September [19]. This type of conditions are expected to yield a high and stable power output from solar installations during the year.

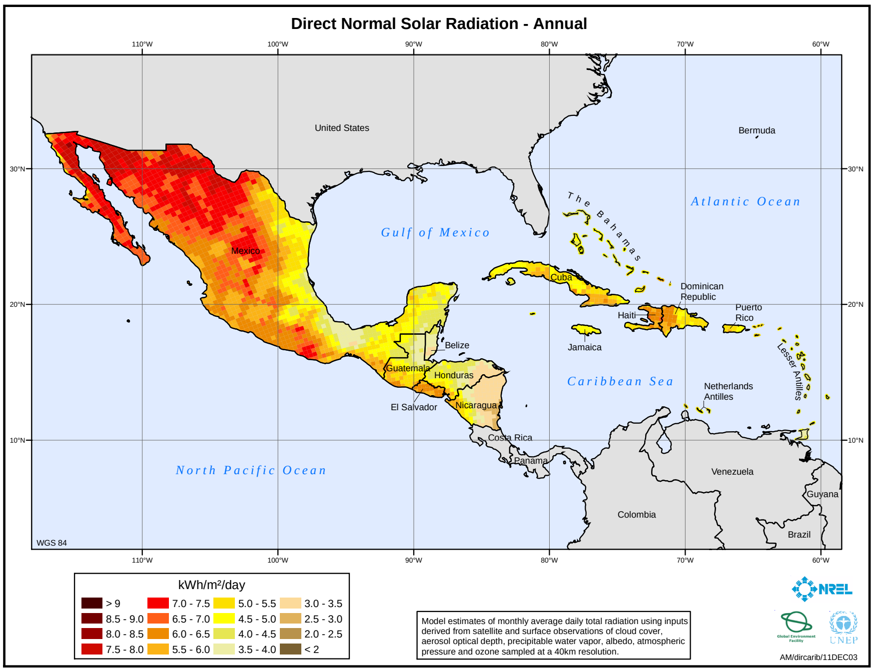

Figure 2.5: Annual Direct Normal Solar Radiation for Mexico and Caribbean

Figure 2.6: Climate regions of Mexico

3
Methodology

In order to carry out the project and thereby evaluate the fuel switch of BCS a model of the electricity system was created. The model was performed in the system of GAMS (General Algebraic Modeling System) which enables to build a specific mathematical model of the system and optimize it to a certain criteria such as system cost or emissions. To include the effects of the fuel switch, scenarios were modeled before the fuel switch in 2014 (the 2014 reference scenario), after the fuel switch in 2019 (the 2019 CFE scenario) and later on after the fuel switch in 2026 (the 2026 CFE scenario). In addition to these three scenarios, one alternative scenario of the year 2019 was created (the 2019 PV scenario) and two alternative ones for the year 2026 (The 2026 PV scenario and the 2026 PV/CSP scenario). In these alternative scenarios the fuel switch is assumed not to happen and instead more renewable electricity generation will be invested in. The model will be described in details further on in this chapter.

The CFE scenarios are based on plans published in POISE 2012-2026 and POISE 2014-2028 (the latest document was published during the project was running so the affected data was updated but the time scenarios up until 2026 was kept), as it is the governments plan for investment, for the private and public sector in the following years for electricity generation. This document states which power stations will be built by the government and which are to be put on a tender for the private sector to build. The later group has more flexibility in what type of technologies could be used and its size. There is however a clear statement that fuel oil and diesel are to be phased out and natural gas will be the fuel supplied to the area [2].

The environmental effects of the system that are analysed are the power plants emissions of flue gases. Amount of CO_2, CH_4, N_2O, and thereby the total $CO_{2equivalents}$ by using the global warming potentials is calculated as well as amount of CO, NO_x, SO_2, SO_3, filterable PM (particle matter) and condensable PM. Filterable PM are larger particles than can be trapped by a glass fiber filter which is 0.3 microns. Condensable PM is particles that is emitted in vapor state but which later will condense to aerosol particles, homogeneous and/or heterogeneous [20]. The calculation of $CO_{2equivalents}$ make it possible to compare the climate effects of the different scenarios. The CH_4 from natural gas leakage of the infrastructure is not taken into consideration in the model, just from incomplete combustion. The emissions that have local environment effects are also studied and compared between the different scenarios.

The data needed for the models was gathered on a field study in Mexico. Due to the fact that all the actors of the system have their administration centres in Mexico city, the most time of the field study was spent there, to collect data, information and have interviews with key actors of the system.

3.1 Modeling in GAMS

To evaluate the fuel switch of BCS, a model was created in GAMS. The model is built to optimize the electricity production of all the units to the lowest system cost and, alternately, to optimize the amount of emissions in terms of $CO_{2equivalents}$ in some scenarios. The system cost is defined as the sum of the running costs of the power plants and the start-up costs for plants starting up during the year, the 8760 hours, that the model is designed for. The running costs include the variable costs in terms of fuel costs, fuel taxes and fixed costs of the plants in terms of maintenance and operation. As mentioned in the theory chapter the external costs are added to the total system cost when deciding the dispatch order of the power plants but is subtracted again when calculating the average electricity generation cost. The model is therefore including the external costs in the objective function (when it's used to minimize the total system cost) and subtracted again when calculating the average generation cost, see equation 3.1.

$$Total\_system\_cost[USD] = \sum_{plants} \sum_{t=1}^{8760} X \times P_{rc} + C_{start} + E_c \tag{3.1}$$

Where X is the MWh produced of each power plants, P_{rc} is the running cost of each power plant, C_{start} is the start-up cost and E_c is the external costs. The variables are defined as:

X = MWh produced by each power plant [MWh]
P_{rc} = Fuel cost + O&M cost [USD/MWh]
C_{start} [USD] = Start-up time [h] × Fuel cost [USD/MWh] × Min load for the power plant [MW] × ON
(ON is the binary variable that tells if the power plant is starting up)
E_c [USD] = EUA price [USD/tonne CO_{2eq}] × $CO_{2equivalents}$ [tonne $CO_{2equivalent}$]

The model will minimize total system cost in a way that the demand for electricity is met while accounting for all technical constrains. These constrains generate a solution that reflects the technical properties of the power plants in the system. It have logic constrains so that the generated electricity always exceeds or is equal to zero and that the power plants can't use more capacity than what's installed. It is also constrained to reach the demand of the system in every time step. The models are required to fill the reserve criteria of the system. The first reserve, the spinning reserve, which is the reserve that can kick in instantly is set to 9% of the demand [6], also in every time step. The units included in this reserve are the ones already spinning and producing electricity but don't use their full capacity, which make it easy to increase the power output from them when the reserve is required. The second reserve, defined as spinning power supply and power supply that could be started within 15 minutes, is set to 5% of the demand in every time step [6] [5]. In this model units not including a steam cycle is assumed to be able to start up within this time. This includes turbo gas units, diesel turbo gas units, internal combustion engines and solar power which is combined with electricity or thermal storage due to that the thermal storage is considered to be a steam turbine which is already warm. The reserves are important for the system in case any unit suddenly stops working or fast have to be taken out of production for any reason.

The plants in the model are divided in slow and fast plants. The fast plants are the plant having a start-up time less than an hour, in this model the turbo gas, diesel turbo gas internal combustion and solar power combined with electricity or thermal storage as mentioned before. The slow plants, defined as plants including a steam cycle, are then including the combined cycle plants and conventional thermoelectric plants. The slow plants have to reach a specific capacity before generating electricity, a minimum load, which is also constrained in the model and which in turn will cause an start-up cost. To model this a binary variable is used so that this slow plant can't be in the start-up phase and generate electricity at the same time. This way of modelling it is taken from a paper of Lisa Göransson and Filip Johansson that have based their concept on the work of Schaffer and Cherene [21].

The renewable electricity generation that is included in the three alternative scenarios is different types of solar power. For the peninsula, solar power generation is the best choices based on information from several of the interviews [22], [23], [6]. Due to that the peninsula's largest income is the tourist industry, the general attitude towards wind power in the state is negative due to that it "affects" the view. There are also seasonal hurricanes that may have a negative impact on wind power due to the fact that too strong wind may force the wind turbines to shut down to not be damaged. Geothermal power generation is developed in the north of the peninsula, but in the south geothermal is still under research. Other renewable power sources such as wave power and tidal power would be a possibility for the peninsula, but the technologies are not mature enough and thereby very expensive to be a good choice for Mexico [22].

The models include solar power generation of different types, considering existent and currently planned photovoltaic (polycrystalline) as well as additional power plants of both photovoltaic and CSP technologies. Different scenarios with different types of solar power are created to evaluate which technology is the most suitable one for the state both in terms of economy and generation performance. To compliment the PVs, lithium ion batteries are modeled to handle the intermittent generation and off sun hours. The CSP type chosen for the model is a CSP plants with a molten salt thermal storage, due to its good thermal storage properties [18]. For all the different solar technologies, specific solar curves is used for the capacity factors in every time step over a year. The curves are created in NREL's (National Renewable Energy

Laboratory) software SAM (System Advisor Model). The solar curves used are geographically scattered to minimize overall intermittent problems and to "escape" the cloud effect. The solar curves used are from solar generation sites in California, The United States, which were the most suitable available production curves found due to lack of data of the Mexican region of the Baja California peninsula. Nine different sites for PV were then selected and modeled for PV plants and then used as generation profiles with an hourly resolution in the model. Two additional sites from California were here selected to model solar curves of a direct steam CSP (a CSP without any storage) which is used in the same way as the PV curves in the model, as generation profiles. The suitability of the curves is further discussed in section 5.4. When the thermal storage was added to CSP plants in the model, it was implemented as a general storage but the capacity and energy limitations were done in a way to correspond the CSP plants operation characteristics.

All assumptions used in the modeling process and data selection is included in Appendix B.

3.1.1 Scenarios

The system was modeled by three different times, in 2014, 2019 and 2026. The 2014 scenario is called "2014 reference" and is the current system of the peninsula. During the year 2018 the fuel is planned to be switched, therefore the year 2019 is selected for the second scenario so the change of the system and thereby changes in emissions and effects on the environment can be evaluated, this scenario will be called "2019 CFE". A following scenario in 2026 is selected to see what happens when the system expands even more and more power plants with better efficiencies, and thereby have better environmental properties, as combined cycle power plants, have been built, referred to as "2026 CFE". This scenario is also optimized in terms of minimize the system total $CO_{2equivalents}$ to see how low it's possible for the system to reach with the fuel switch. The configuration of these three scenarios could be seen in Table 2.1, 2.2 and 2.3 in the theory chapter where the changes of the system from 2014 to 2026 is described.

Then an alternative scenario was investigated under the assumption that the fuel switch did not take place. Instead investments were made on solar technologies and diesel remained as the only fossil fuel in the system for the already existing power plants. When building these alternative scenarios, it was selected to install renewable energy in a way that would gradually substitutes the capacity that must be retired, because the power plants technical lifetime has ended. Here all programed new energy technologies are substituted by solar PV aided by batteries to cover the demand at when the sun is out and to be able to fill up the reserve criteria. The further evolution of the system until 2026 was modeled in two alternative paths, one that just used PV technology and one that complimented the PV technology with CSP combined with a molten salt thermal storage of 14 hours to be able to supply the demand during off sun hours. These scenarios are referred to as "2019 PV", "2026 PV" and "2026 PV/CSP", see Figure 3.1.

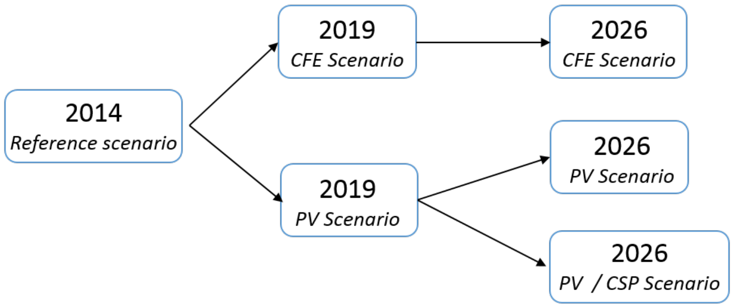

Figure 3.1: Scenarios modeled.

The system properties of the scenarios PV 2019, PV 2026 and 2026 PV/CSP are shown in Table 3.1, 3.2 and 3.3. The new units added are marked with stars.

Table 3.1: The power plants and sizes of units in the scenario PV 2019

Site	Unit	Size [MW]	Fuel	Technologies
CiudadConstitución	VIO U1	30	Diesel	DTG
Punta Prieta	PUP U1	37.5	Diesel	CT
	PUP U2	37.5	Diesel	CT
	PUP U3	37.5	Diesel	CT
	PUP U4	18	Diesel	DTG
	PUP U5	25	Diesel	DTG
San Carlos	GAO U1	31.5	Diesel	IC
	GAO U2	31.5	Diesel	IC
	GAO U3	41.125	Diesel	IC
Corumel	BCS U1	37	Diesel	IC
	BCS U2	41.9	Diesel	IC
	BCS U3	41.9	Diesel	IC
	BCS U4	41.9	Diesel	IC
La Paz	LP U1	43	Diesel	DTG
Aura	Aura	30	Sun	PV
SOL 2	Solar*	30	Sun	PV
SOL PV 1	Solar*	30	Sun	PV
SOL PV 2	Solar*	30	Sun	PV
SOL PV 3	Solar*	30	Sun	PV
SOL PV 4	Solar*	30	Sun	PV
SOL PV 5	Solar*	40	Sun	PV
SOL PV 6	Solar*	50	Sun	PV
SOL PV 7	Solar*	50	Sun	PV
SOL PV 8	Solar*	183	Sun	PV
Total		998.33		

Table 3.2: The power plants and sizes of units in the scenario PV 2026

Site	Unit	Size [MW]	Fuel	Technologies
Punta Prieta	PUP U4	18	Diesel	DTG
	PUP U5	25	Diesel	DTG
San Carlos	GAO U1	31.5	Diesel	IC
	GAO U2	31.5	Diesel	IC
	GAO U3	41.125	Diesel	IC
Corumel	BCS U1	37	Diesel	IC
	BCS U2	41.9	Diesel	IC
	BCS U3	41.9	Diesel	IC
	BCS U4	41.9	Diesel	IC
Aura	Aura	30	Sun	PV
SOL 2	Solar*	30	Sun	PV
SOL PV 1	Solar*	230	Sun	PV
SOL PV 2	Solar*	230	Sun	PV
SOL PV 3	Solar*	230	Sun	PV
SOL PV 4	Solar*	230	Sun	PV
SOL PV 5	Solar*	240	Sun	PV
SOL PV 6	Solar*	300	Sun	PV
SOL PV 7	Solar*	400	Sun	PV
SOL PV 8	Solar*	400	Sun	PV
SOL PV 9	Solar*	400	Sun	PV
Total		3029.83		

Table 3.3: The power plants and sizes of units in the scenario 2026 PV/CSP

Site	Unit	Size [MW]	Fuel	Technologies
Punta Prieta	PUP U4	18	Diesel	DTG
	PUP U5	25	Diesel	DTG
San Carlos	GAO U1	31.5	Diesel	IC
	GAO U2	31.5	Diesel	IC
	GAO U3	41.125	Diesel	IC
Corumel	BCS U1	37	Diesel	IC
	BCS U2	41.9	Diesel	IC
	BCS U3	41.9	Diesel	IC
	BCS U4	41.9	Diesel	IC
Aura	Aura	30	Sun	PV
SOL 2	Solar*	30	Sun	PV
SOL PV 1	Solar*	30	Sun	PV
SOL PV 2	Solar*	30	Sun	PV
SOL PV 3	Solar*	30	Sun	PV
SOL PV 4	Solar*	30	Sun	PV
SOL PV 5	Solar*	40	Sun	PV
SOL PV 6	Solar*	50	Sun	PV
SOL PV 7	Solar*	50	Sun	PV
SOL PV 8	Solar*	283	Sun	PV
SOL PV 9	Solar*	144	Sun	PV
Sol conc 1	Solar*	500	Sun	CSP
Sol conc 2	Solar*	500	Sun	CSP
Total		2056.83		

3.2 Investment calculations

To further understand the feasibility and advantages of the different ways of operating the system, investment costs for each scenario was considered. The investment cost includes installation of the power plants, batteries and natural gas infrastructure, according to what's included in the different scenarios. The grid investments were not considered, since the power plant locations were not specified, this applies for CFE plans and for alternative scenarios.

Costs for the base scenario were calculated with documents from the Mexican government: for the natural gas supply infrastructure the price on the bid announcement was used, for the costs of the power plants data from COPAR [24] (table 2.1) was used. As for the alternative scenarios data from IEA's World Energy Outlook investment costs [25] for USA was used for all solar PV and solar CSP plants, for electricity storage the cost of Tesla's Powerwall [26] was the one used, since its considered the best available technology. Heat storage costs were obtained from the document "Power Tower Technology Roadmap and Cost Reduction Plan" [27] prepared by Sandia National Laboratories for the U.S. Department of Energy's National Nuclear Security Administration.

The expected technical lifetime of the power plants along with a discount rate of 5% was used to calculate the annuity. The discount rate of 5% was chosen taking into account that this value is used by IEA in its studies for electricity costs [28]. Expected lifetimes were obtained, as with the costs, from NREL, COPAR, IEA and Tesla. In the case of natural gas infrastructure, some components have very long technical lives, however it was recommended to use the value of 30 years, as after that sustaining capital for the compressors would be required [29]. By choosing technical lifetime, instead of economical lifetime, an a low discount rate, the calculations take a socioeconomic perspective.

3.3 Interviews

In order to better understand the operation of the national electricity system, the panorama for the BCS electricity system, the way it has been administered and planned and the implications of the changes on the regulations due to the Energy reform happening in Mexico, one hour interviews with key actors from the private and public sector were made.

As all the power plants in the BCS system today, besides the solar plant Aura, are owned by the state utility company CFE an introductory meeting with the director of modernization, Act. Guillermo Turrent, was held on the 20th of february 2015. However due to the fact that the CFE is about to hold a tender for the project much information was considered confidential and since the tender has been delayed, the data could not be collected from the CFE.

To understand the role of the government to promote a more sustainable electricity system interviews were made to the sub-secretary of Electricity from SENER, Dr. César Emiliano Hernández [30], and the Director of Electricity and Renewable Energy at CRE, Dr. Alejandro Peraza [23]. Dr. Hernandez talked about the achievability of the current national clean energy targets and the challenges for a sustainable electricity system in Mexico. Dr. Peraza talked about the maximum share of renewable energy the BCS system can take and what renewable sources he considers the most promising for the area.

In order to understand how the private electricity companies foresee the operation of the system and what would motivate them to continue investing in clean energy generation Dr. Hector Olea [22], CEO of Gausse the company that owns Aura, was interviewed. Dr. Olea talked about their plans for the future in BCS, the best renewable alternative for the BCS interconnected system and the maximum share of renewables in the system.

Finally meetings were held with Ing. Marcos Valenzuela [6] from CENACE and Dr. Antonio Souza [5] from Evercore, leading advisors in the structuring and financing of very large projects in the oil and gas and power sector, this to obtain a better understanding of the BCS system current and future operation. Ing. Valenzuela provided information about the demand, dispatch and reserve management in the system and gave recommendations on how he considered the share of renewable in the system could be increased. Dr. Souza talked about what is expected from the future operation of the BCS system, that is after the fuel switch.

The interviews together with literature studies of the Mexican laws and additional information about the system, provided by the interviewees, help understand the changes the county is going through and answer the research questions and analyze the model results. The interview questions are attached in Appendix C.

4
Validity of the model

A validity check of the model was performed to evaluate that the model works in the correct way. As a first step when the first scenario, the 2014 reference scenario, had been made the fuel prices were changed, this to see how the output changes and thereby evaluate if the model is working as it's expected it to work. The model thereby got validated that is works in the correct way. For the 2014 reference scenario the model also got validated by comparing the results of dispatch order of the power plants. Comparisons were made of the expected decrease in average electricity generation cost with the fuel switch from the government with what the model results showed. Also the solar curves used for the hourly capacity factor were compared with curves given by CENACE of the Aura solar plant.

4.1 The dispatch

The dispatch of the first scenario, the 2014 reference scenario, was compared to data from CENACE. This to compare the merit order and how much the different plants were running. Therefore the first day of May was selected for a comparison. Figure 4.1 shows that the dispatches are very similar. The difference is that the CENACE curve is a prospective curve, which can be seen at the installed capacity of solar power of 60MW which not is the case in 2014. The demand curve of the CENACE graph is also built on perspective data which is a little bit higher than the scaled up real demand of 2013 that the model is using. When looking at the merit order it is very similar besides that the CENACE also uses the power plants PUP 1-3 which the model doesn't. This could depend on experience of the TSO on how the power plants are usually run, for example the operator might run certain units on part load due to some particularities of the units. In the dispatch provided by CENACE the demand is slightly higher which could also affect the number of units running.

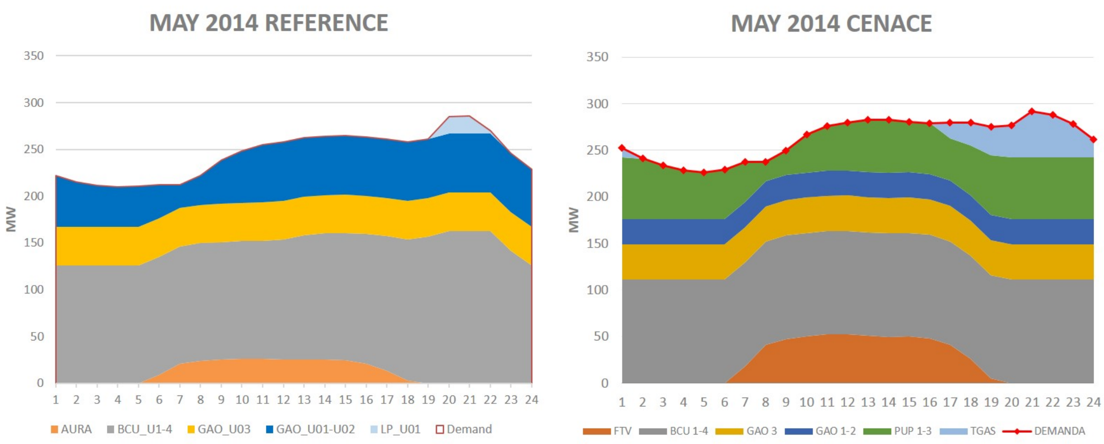

Figure 4.1: The dispatch of May 1st generated by the model of 2014 reference scenario (to the left) and the dispatch of the CENACE from year 2014 the same day.

4.2 Average electricity generation cost

The achieved price decrease from the 2014 reference scenario until the 2019 CFE scenario of approximately 60% is a reaffirmation that the model is working in a way that portrays the actual scenario and the most probable outcome after the fuel switch, since it coincides with the values given by Dr. Peraza (CRE) [23] and Dr. Souza (Evercore) [5].

4.3 The solar curves

Due to the fact that there were no solar curves available for BCS, the solar curves used to model all PV and CSP technologies in the different scenarios, except for Aura's, where obtained from NREL's program SAM. The curves were selected from areas that were approximate to Baja California Sur, that were close to the coastline and that were located on places with similar irradiation. For this reason locations in southern California and Arizona were picked. The seasonal patterns and average capacity factors were compared with the ones of the sun curve given by CENACE [6] for Aura to justify its appropriateness to be used in the area, Figure 4.2. The curves received from CENACE were both based on real data from the Aura solar plant and one of the monthly average data, which both were used for the comparison.

What can be seen here is that in some days the correlation between the real Aura curve and the California site is good and a good approximation. In some days the correlation is not so good but if considering that the solar plants would be spread out over the peninsula at different sites there will be places that sometimes are cloudy

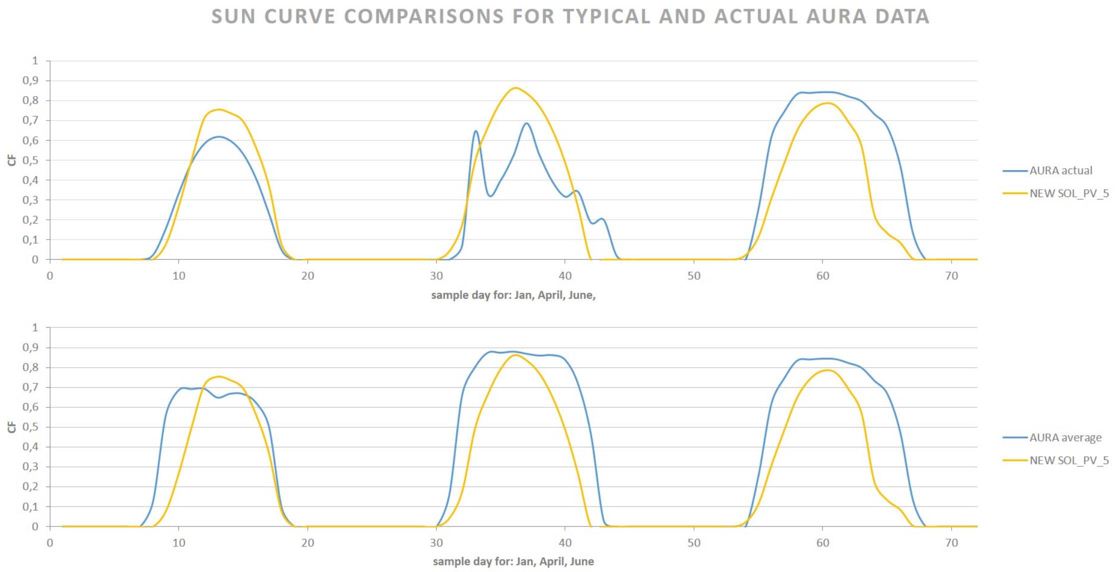

Figure 4.2: A comparison of the production curve of Aura with one good and one less good curve from California that was used in the model.

when some are not which is an advantage of spreading the solar plants out. What is important is to see that they reach approximately the same capacity factor during the days and that the sun stays up approximately the same amount of time, which it does. When comparing the average data with the sun curves used in the model it can be seen that they reach approximately the same height and last approximately during the same time span. With this targets the solar curves is considered a good approximation.

PV's using sun curves for typical daily behaviour in California and Arizona have average full load hours of 1750 hours. Furthermore, when calculating the full load hours of Aura in the 2014 with data provided by CENACE a relatively high value is obtained, 2263 hours, this is due to the fact that Aura's production curve was calculated with the average monthly data provided by CENACE [6]. These values were considered another form of validation of the appropriateness of the data from SAM for the BCS system.

5

Results

The results chapter is divided in three sections, the two first are Results from the modeling and results from the interviews. A third one, overall results is ending the chapter where results from the two first sections are combined.

5.1 Results from the modeling

The modeling results are divided in results of the fuel switch and results of the alternative scenarios. The results from all the scenarios is then included in the last section where the results of the investment calculations are presented.

5.1.1 Results of the fuel switch

The actual fuel switch is planned for 2018 which is modeled as the difference in the scenarios 2014 reference and 2019 CFE. When looking at the average electicity generation cost in the CFE scenarios it can bee seen that the fuel switch will lower it with approximately 60%, from 134.3 USD/MWh to 53.9 USD/MWh. The cost will then increase a bit until 2026, to 65.8 USD/MWh (which still is a decrease of about 51% compared with the 2014 reference scenario) due to that many DTG and CT power plants are phased out which makes the model use the IC ones more which have slightly higher running costs, see Figure 5.1.

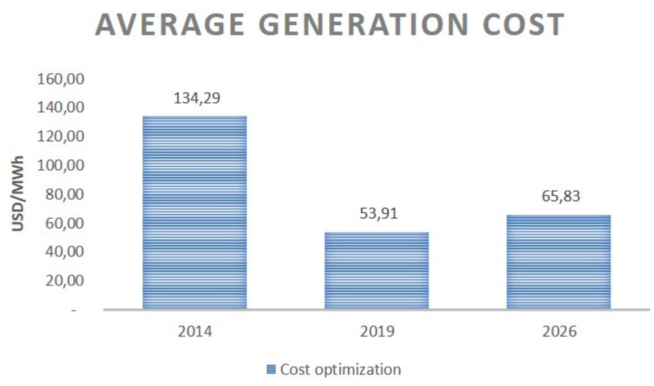

Figure 5.1: The evolution of the average generation cost of electricity of the CFE scenarios, when optimizing for cost and emissions in form of $CO_{2_{equivalents}}$.

As can be seen in Figure 5.2 the switch to natural gas in the system will lower the greenhouse gases in terms of $CO_{2equivalents}$ with 27.5% until 2019 and 30.6% until 2026 compared with 2014. The change from 2019, when the switch is done, until 2026 the amount of $CO_{2equivalents}$ have additionally decreased with 4.4% which is mainly due to that more combined cycle power plants running on natural gas are invested in which have a higher total efficiency than the conventional thermoelectric power plants, internal combustion engines and the turbines running on gas or diesel. Both these results are generated when the model is minimizing the total system cost of the scenarios. The variation in the amount of emissions do not change significantly when optimizing for cost or emissions, Figure 5.2. What can be seen is though that the lowest possible level of $CO_{2equivalents}$ in the 2026 CFE scenario is 384.94 kg/MWh for the new system run on natural gas.

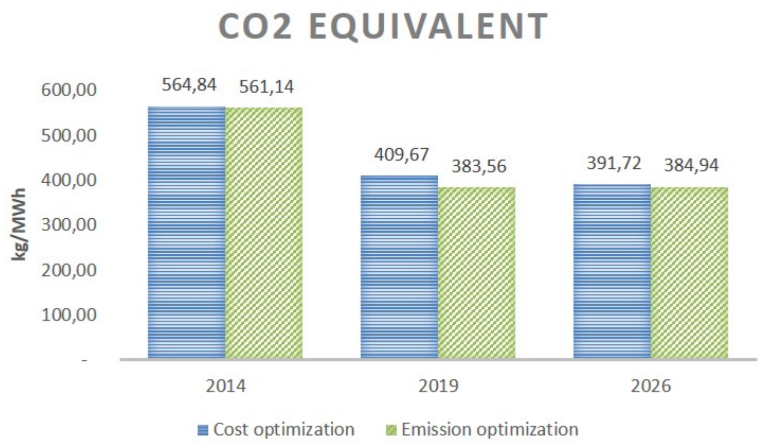

Figure 5.2: The difference on CO_{2eq} emissions of the CFE scenarios, when optimizing for cost and emissions [kg $CO_{2_{eq}}$/MWh].

When dividing the $CO_{2equivalents}$ in it's consisting parts, which in this model are CO_2, CH_4 and N_2O, it can be seen that the amount of CO_2 decreases a lot with the fuel switch from 561.02 kg/MWh to 407.20 kg/MWh in 2019 and further to 389.35 kg/MWh in 2026. The CH_4 on the other hand is increasing from 6.18 g/MWh to 7.80 g/MWh in 2019 to then decrease a little to 7.46 g/MWh in 2026, due to that natural gas now is used instead. The amounts of N_2O are also decreasing with the fuel switch from 11.91 g/MWh in 2019 to 7.47 g/MWh in 2019 and 7.14 g/MWh in 2026. The results presented are from the model that minimizes the total system cost. Figure 5.3.

Figure 5.3: Emissions of CO_2, CH_4 and N_2O per MWh for the different CFE scenarios, when optimizing for cost and emissions [kg/MWh].

The results of the changes in the CFE scenarios for PM show that filterable PM, that is the larger particulate matter, is practically gone when using natural gas instead of fuel oil and diesel, while the condensable PM decrease to half when using natural gas, Figure 5.4 and 5.5.

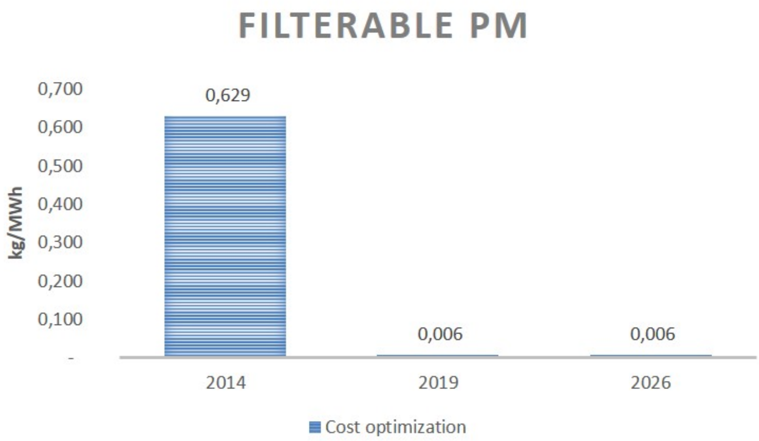

Figure 5.4: The difference on filterable particulate matter emissions between the different CFE scenarios [kg filtered PM/MWh].

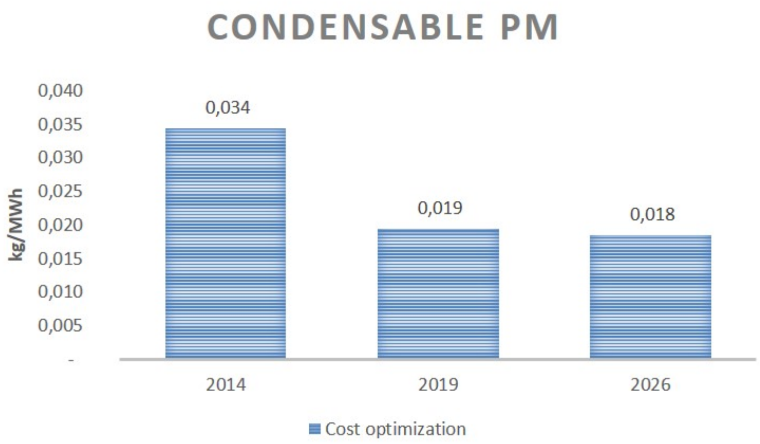

Figure 5.5: The difference on condensable particulate matter emissions between the different CFE scenarios [kg condensate PM/MWh].

The changes in SO_2 before and after the fuel switch will change drastically from 9.50 kg/MWh in 2014 to 2.04 g/MWh and 1.95 g/MWh in 2019 and 2026 respectively. The amount of SO_3 decreases from 0.35 kg/MWh in 2014 to 0 in both 2019 and 2026. Figure 5.6 and Figure 5.7.

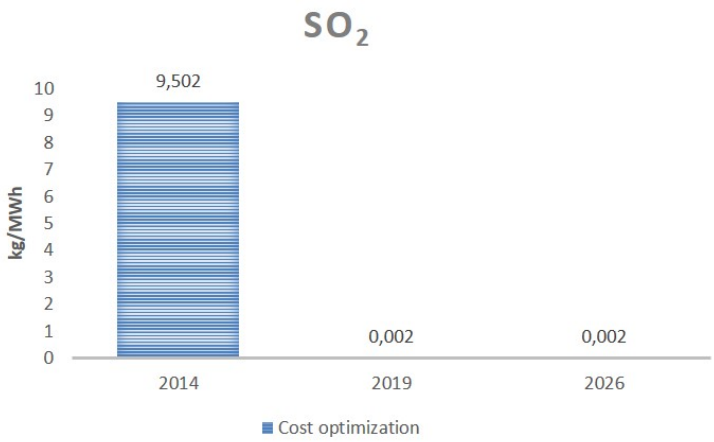

Figure 5.6: The difference on SO_2 emissions of the CFE scenarios, when optimizing for cost and emissions [kg SO_2/MWh].

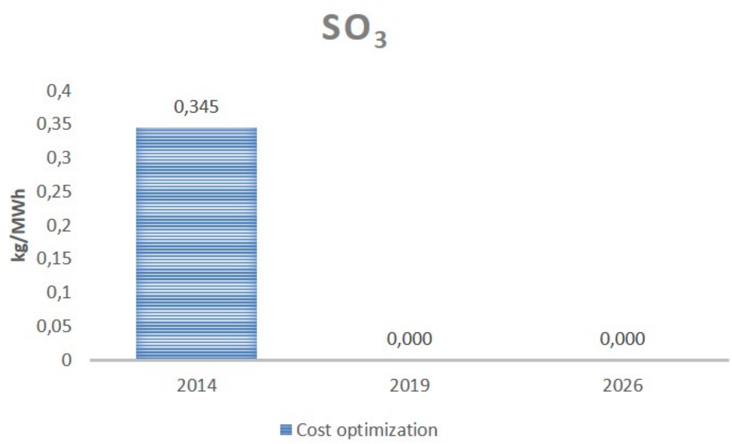

Figure 5.7: The difference on SO_3 emissions of the CFE scenarios, when optimizing for cost and emissions [kg SO_3/MWh].

However emissions of carbon monoxide increase with the change to natural gas from 0.115kg/MWh to 0.285 and 0.273 kg/MWh in 2019 and 2026 respectively, see Figure 5.8.

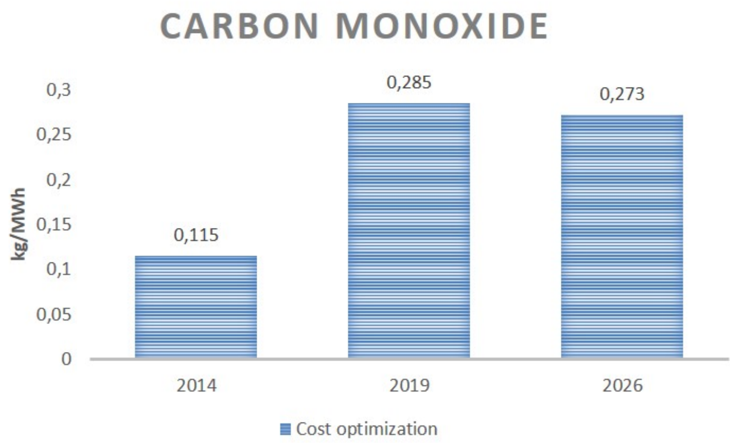

Figure 5.8: The difference on CO emissions of the CFE scenarios, when optimizing for cost and emissions [kg CO/MWh].

5.1.1.1 The dispatch of the CFE scenarios

The dispatch of the power plants in the 2014 reference scenario can be seen in Figure 5.9 below. The power plants BCS U02-U04, GAO U01-U02, GAO U03 and AURA work as base load, due to that these have the lowest fuel prices. BCS U01, PUP U01 and PUP U02 as mid load, while the rest of the power plants work as peak load.

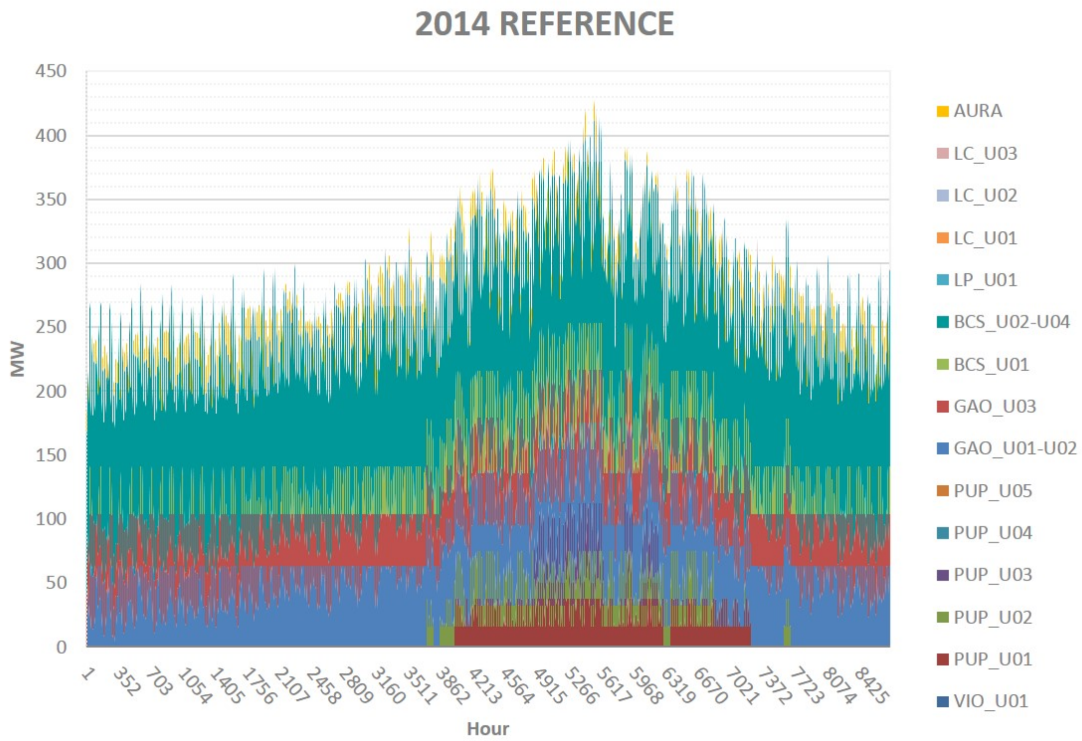

Figure 5.9: Hourly dispatch of 2014 Reference scenario for the BCS electricity system.

When comparing this dispatch to the dispatch of the CFE 2019 scenario (Figure 5.10) the dispatch changes a bit. The plants are now fueled by natural gas and have therefore the same fuel cost. This means that it's now the fixed costs and the efficiencies of the technologies that steers the dispatch. This means that turbo gas and combined cycles is running the base load which includes the power plants VIO U01, PUP U04, PUP U05, TS UI, LP U01 and LP UI together with the solar PV plants AURA and SOL 2. The mid and peak load is then generated by the internal combustion plants as well as the conventional thermoelectric. In this scenario the base load combined cycles TS UI and LP UI are the newly invested power plants together with the internal combustion plants BCS U04-U05, which runs as peak load.

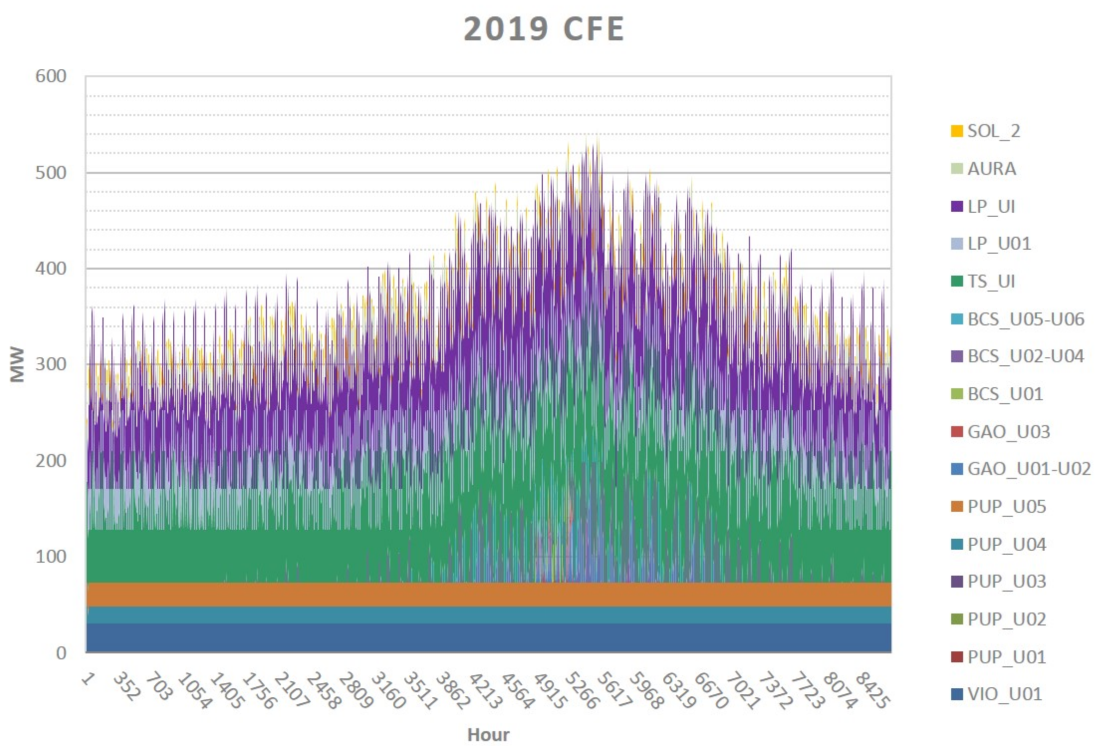

Figure 5.10: Hourly dispatch of 2019 CFE scenario for the BCS electricity system.

The dispatch order of the power plants in the CFE 2026 scenario is also decided out of the fixed prices of the different technologies, see Figure 5.11. The two additional invested combined cycles, TS UII and LP UII, generates the base load together with the same plants as in the 2019 CFE scenario due to the increased demand. The VIO U1 plant has also been replaced in this scenario with a new combined cycle, VIO UI, that also provides to the base load. Besides the internal combustion plants in the 2019 CFE scenario used as mid and peak load two turbo gas plants have been build, LC UI and LC UII, as peak load. These plants are not used in the model. This is due to their lower efficiency than the internal combustion ones which makes them use more fuel and thereby become more expensive, even if their fixed costs are lower than the internal combustion ones.

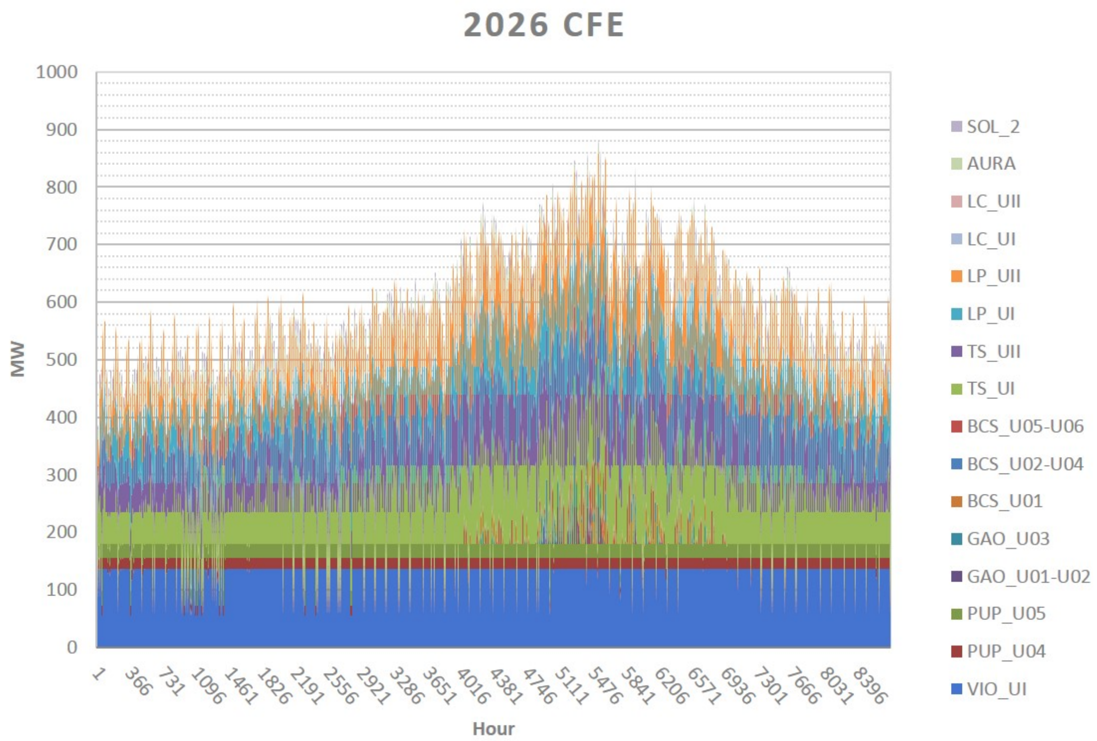

Figure 5.11: Hourly dispatch of 2026 CFE scenario for the BCS electricity system.

5.1.2 Results of the alternative scenarios

The alternative scenarios for the years 2019 and 2026 without the fuel switch to natural gas (assuming that the existing plants are all run on diesel) and with solar power that replaces the new investments show a different result. To make the system be able to fill up the demand in every time step in 2019, a total of 443MW of PVs is needed additional to the AURA and SOL 2 plants. These PVs would cover an area of 2.53km^2, that is 354 football fields or 2% of the area of the Cerralvo Island, outside La Paz, Figure 5.12. Also a battery is needed of 47MW and 148MWh. For the 2026 PV scenario an amount of 2660MW of PVs have to be installed additional to the Aura and SOL 2 plant and the battery size increase to 665 MW and 7964 MWh. The PVs now covering an area of 11.69 km^2, that would be 9% of the area of the Cerralvo Island. In the 2026 PV/CSP scenario the amount of PVs can be decreased to 687MW additional to the AURA and SOL 2 plants and instead two CSP plants with thermal storage can be used to cover the demand. The CSP plants needed are then of the size 500 MW each with a thermal storage of the same capacity and an 95% round trip efficiency [31], the solar installations would require a total area of 15.28 km^2, equivalent to 11% of the area of the Cerralvo island. The storage time needed is 14 hours to cover the demand during night. All the alternative scenario results that are presented further on is modeled to minimize the total system cost if not something else is stated.

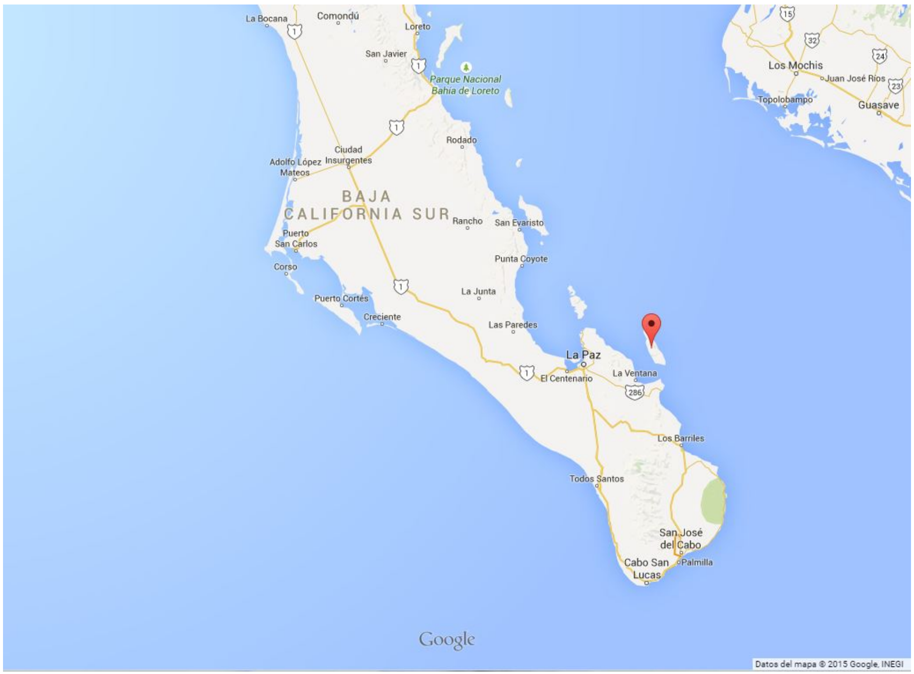

Figure 5.12: Island Cerralvo, BCS.

The effects of the different scenarios system composition on the average electricity generation cost can be seen on Figure 5.13. When comparing the 2019 PV scenario with the 2014 reference scenario the cost still goes down but not as much as for the 2019 CFE scenario, which decreased with approximately 60%. The average price still decreases from 134.3 USD/MWh to 77.9 USD/MWh, a decrease of about 42%. The average generation cost continues to decrease a lot as more PVs are injected in the system and the 2026 PV scenario gives an electricity generation cost of 34.6 USD/MWh, a decrease of approximately 74% compared to the 2014 reference scenario. If instead the 2026 PV/CSP scenario is selected the cost decreases to 47.9 USD/MWh, a decrease of about 64% compared to the 2014 reference scenario. This is a larger decrease than the 2026 CFE scenario of 51%.

The difference in emissions of the system in terms of $CO_{2equivalents}$ (Figure 5.14) between the different scenarios is a surprise when the amount increases when comparing the 2019 CFE scenario with 409.67 kg/MWh and 2019 PV scenario with 425.25 kg/MWh. This is due to that diesel which the system is using in the 2019 PV scenario is more polluting than natural gas which is used in the 2019 CFE scenario. When further comparing what happens between the 2026 CFE and 2026 PV scenario the PV scenario has a lot lower emissions, 120.78 kg/MWh compared to 391.72 kg/MWh. For the 2026 PV/CSP scenario the $CO_{2equivalents}$ are 143.66 kg/MWh. When comparing these numbers for the alternative scenarios of 2026 with the 2026 CFE scenario when the model is minimizing total $CO_{2equivalents}$ it can be seen that the lowest possible level of emissions technology wise that can be reached by the 2026 CFE scenario is of 384.94 kg/MWh, which is a lot higher than the solar power alternatives.

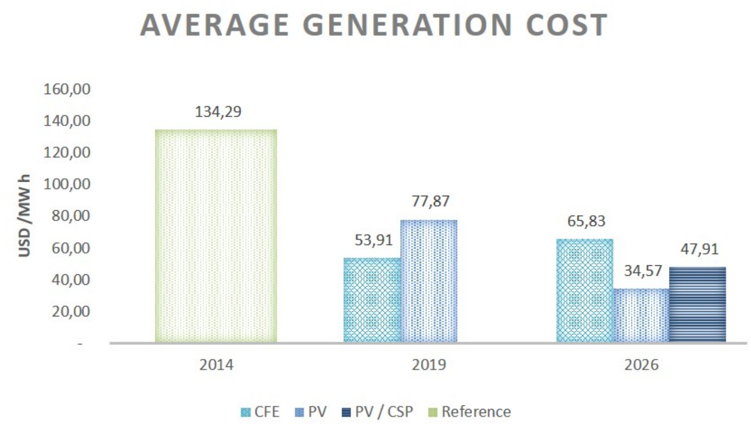

Figure 5.13: Average electricity generation cost for all scenarios [USD/MWh].

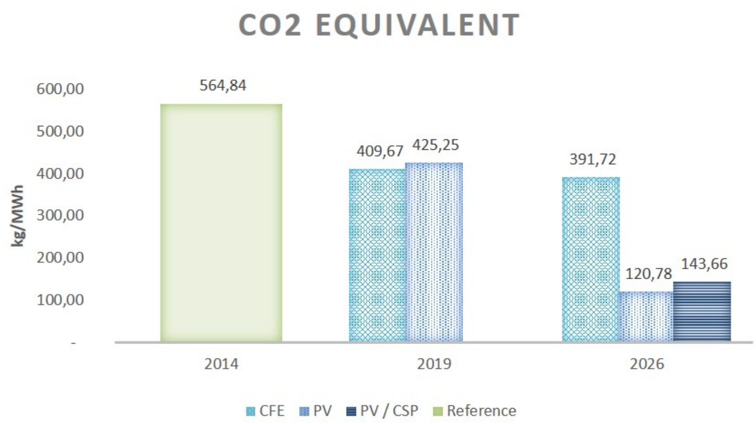

Figure 5.14: The evolution changes on CO_2 emissions of all the scenarios, when optimizing for cost [kg $CO_{2_{eq}}$/MWh].

When separating the GHG in its components, CO_2, CH_4 and N_2O, it can be seen that they all decrease in the 2019 PV and 2026 PV scenario as well as the 2026 PV/CSP scenario. What changes the most is the amount of CH_4 in the alternative scenarios due to the fact that there is no natural gas in the system anymore. The amount of CH_4 decreases from 6.19 g/MWh in the 2014 reference scenario to 0.99 g/MWH and 0.28 g/MWh in the 2019 PV and 2026 PV scenarios respectively. The 2026 PV/CSP scenario emit an amount of 0.33 g/MWh. Compared to the 2019 CFE and 2026 CFE scenarios with 7.80 g/MWh and 7.46 g/MMWh respectively, this is a large decrease. The N_2O decreases to 4.94, 1.40 and 1.67 g/MWh in the scenarios 2019 PV, 2026 PV and 2026 PV/CSP, which also is an improvement from the CFE scenarios. The amount of CO_2 in the 2019 PV scenario decreases compared to the 2014 reference sceanrio but is higher than the 2019 CFE scenario with 423.70 kg/MWh compared to 407.20 kg/MWh which is the reason that the total

$CO_{2equivalents}$ also increases in this scenario. Comparing the CO_2 emissions in the 2026 PV and 2026 PV/CSP with the 2026 CFE scenario it decreases though. This to 120.34 kg/MWh and 143.13 kg/MWh compared to 389.35 kg/MWh (Figure 5.3). The different GHG ars shown in Figure 5.15.

Figure 5.15: Emissions of CO_2, CH_4 and N_2O per MWh for the different alternative scenarios, when optimizing for cost [kg/MWh].

The amount of filterable PM (Figure 5.16) decreases compared to the 2014 reference scenario but is higher than the CFE scenarios in all of the alternative scenarios. The amount of condensable PM in the 2019 PV scenario is a little bit higher than the 2019 CFE scenario when it's in the 2026 PV scenario is lower than the 2026 CFE scenario, as can be seen in Figure 5.17. The 2026 PV/CSP scenario has lower amount of condensable PM than the 2026 CFE scenario but a bit higher than the 2026 PV scenario. The higher levels of filterable and condensable PM is due to that the diesel that is used in the already existing power plants is more polluting than natural gas that is used in the CFE scenarios. It's therefore dependent on how much the alternative scenarios use the diesel power plants to fill up the supply the solar power can't supply.

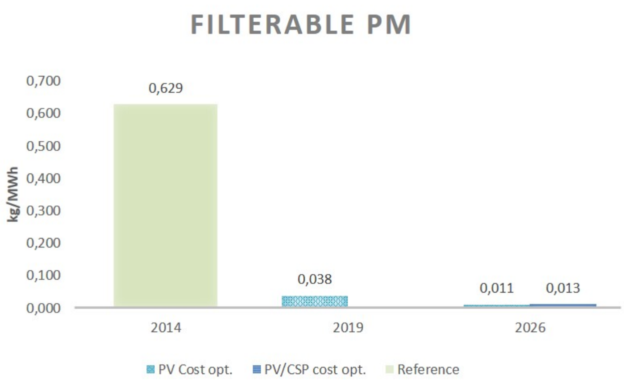

Figure 5.16: The difference on filtered particulate matter emissions between the different alternative scenarios, when optimizing for cost [kg filtered PM/MWh].

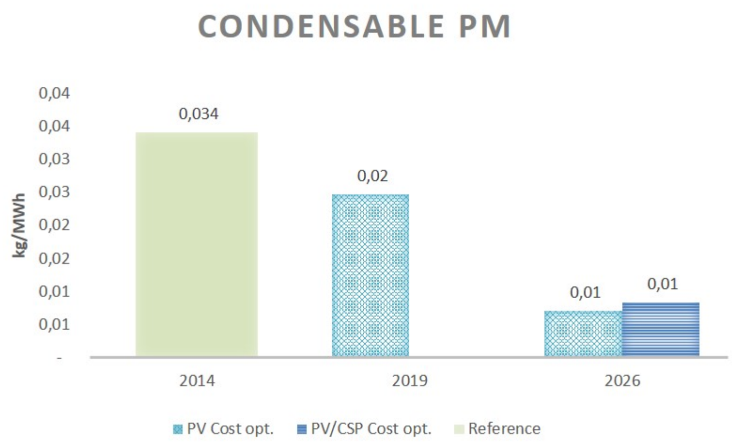

Figure 5.17: The difference on condensable particulate matter emissions between the different alternative scenarios, when optimizing for cost [kg condensate PM/MWh].

When looking at SO_2 (Figure 5.18) and SO_3 (Figure 5.19) in the PV scenarios of 2019 and 2026 they are all higher compared to the CFE scenarios for the same years, this due to that diesel is a more polluting fuel than natural gas. In the case of SO_3 it still decreases from the 2014 reference scenario a lot in the scenarios of 2019 PV and 2026 PV and 2026 PV/CSP but compared to the 2019 CFE and 2026 CFE scenarios where is goes down to zero, the emissions of SO_3 in the solar scenarios higher. This due to that these scenarios still uses diesel compared to the CFE 2019 and 2026 scenarios that uses natural gas.

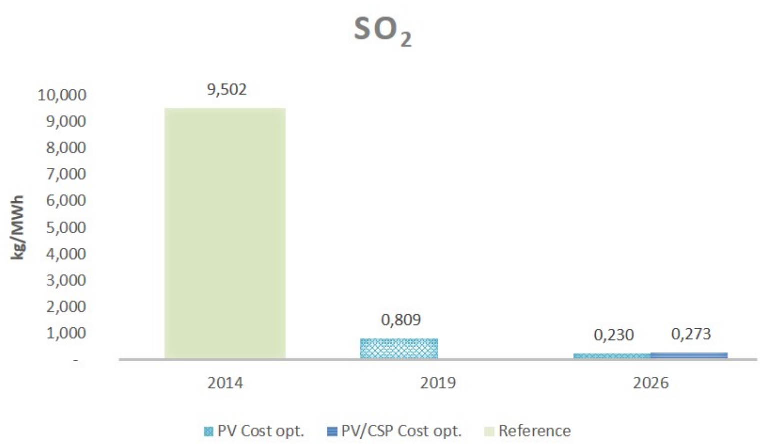

Figure 5.18: The difference on SO_2 emissions of the alternative scenarios, when optimizing for cost [kg SO_2/MWh].

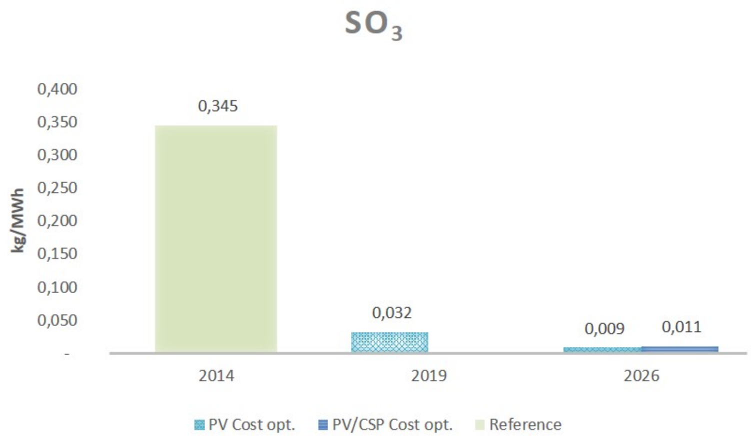

Figure 5.19: The difference on SO_3 emissions of the alternative scenarios, when optimizing for cost [kg SO_3/MWh].

The amount of emitted CO is decreasing if comparing the alternative scenarios with the 2014 reference scenario and also compared the the CFE scenarios. Figure 5.20 shows how the alternative scenarios decrease the carbon monoxide from 0.115 kg/MWh to 0.027 kg/MWh for the 2026 PV scenario and 0.032 kg/MWh for the 2026 PV/CSP scenario.

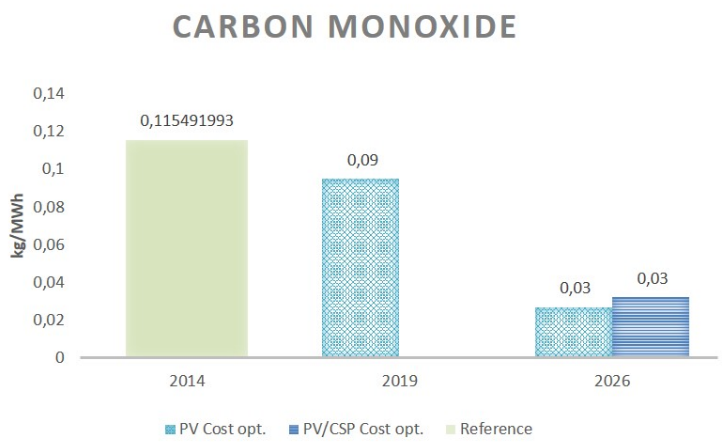

Figure 5.20: The difference on CO emissions of the CFE scenarios, when optimizing for cost [kg CO/MWh].

5.1.2.1 The dispatch of the alternative scenarios

The dispatch of the power plants in the 2019 PV scenario is very different from the 2019 CFE scenario Figure 5.21. Due to the high penetration of solar power which in this scenario is 29.58% of the generated electricity, a large battery is used to handle reserves and the demand during off sun hours. It can be seen in Figure 5.22 how the battery is loading up electricity during the peak generation of solar to use later when the sun is out.

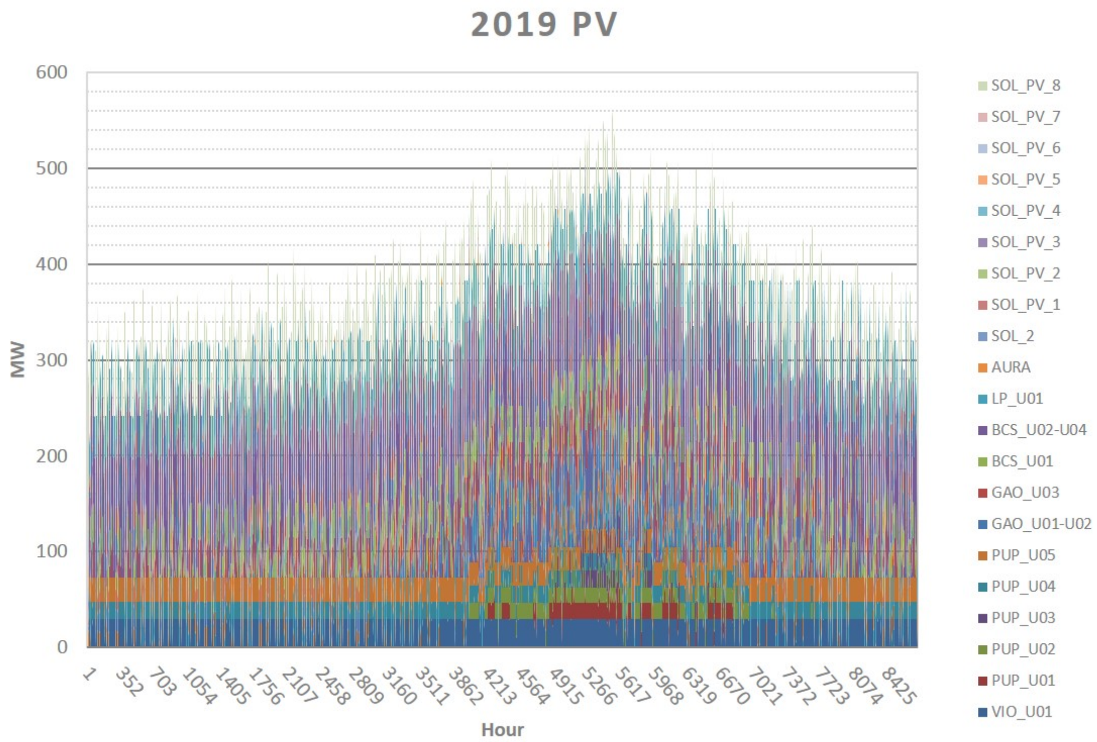

Figure 5.21: Hourly dispatch of 2019 PV scenario for the BCS electricity system.

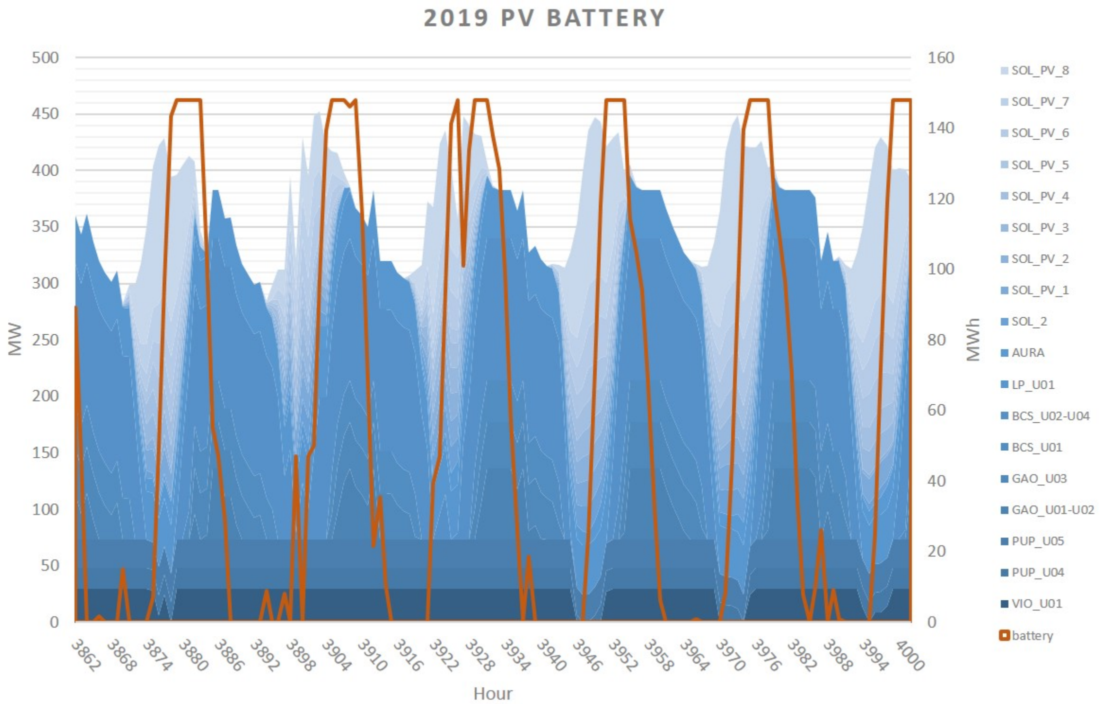

Figure 5.22: Hourly dispatch of 2019 PV scenario during a week and behaviour of the battery.

For the 2026 PV scenario the share of PVs are increased even further with a total share of 79.38% of the generated electricity, see Figure 5.23. Therefore a very large battery in terms of both energy and capacity is needed to handle the intermittent power generation of the solar plants. PVs will generate more energy than the required demand during the sun hours and store it, as can be seen by the demand line in blue below the actual hourly production pattern. In Figure 5.24 it can be seen how the battery working with the dispatch of the power plants over one week of the year.

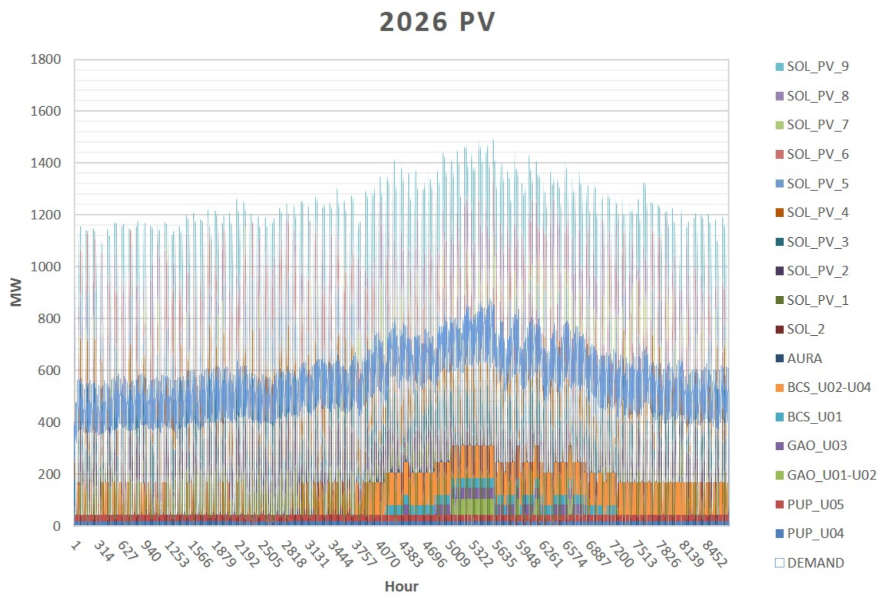

Figure 5.23: Hourly dispatch of 2026 PV scenario for the BCS electricity system.

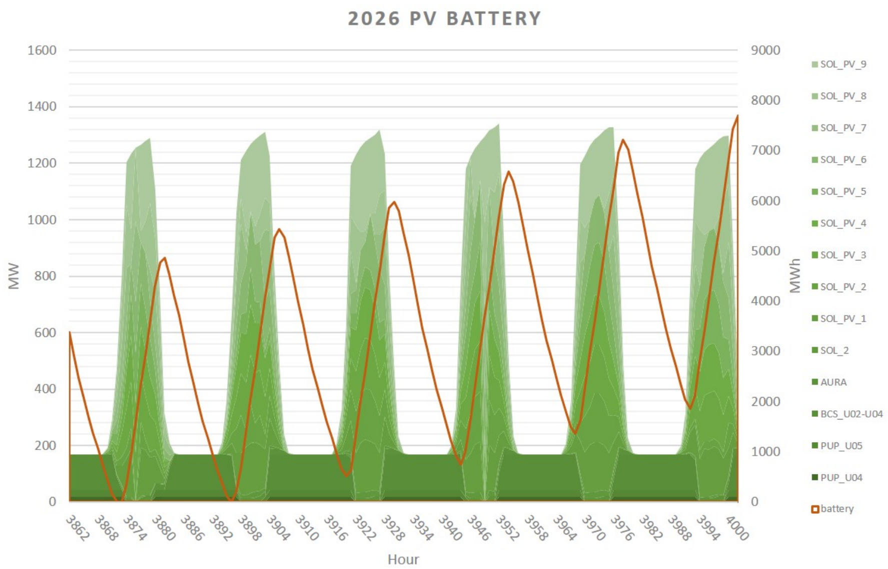

Figure 5.24: Hourly dispatch of 2026 PV scenario during a week and behaviour of the battery.

The 2026 PV/CSP scenario has a combination of PV and CSP power generation that amounts to 75.74% of the generated electricity. In this scenario a thermal storage of molten salt connected to the CSP is used for thermal storage to handle the load when the sun is down. As can be seen in the dispatch graph, Figure 5.25 where the blue line representing the demand, the solar energy is maximized during sun hours and stored. Figure 5.26 shows how the thermal storage is working with stored energy for later use during one week of the year. There is a couple of hours in the year in which the system can run purely on solar. A detailed graph on a week when the system is running purely on solar power can be seen in Figure 5.27.

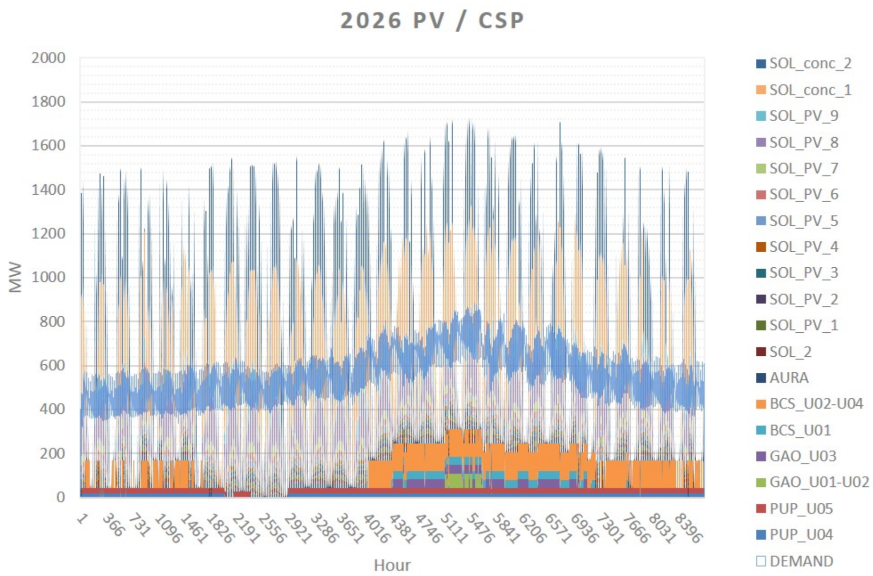

Figure 5.25: Hourly dispatch of 2026 PV/CSP scenario for the BCS electricity system.

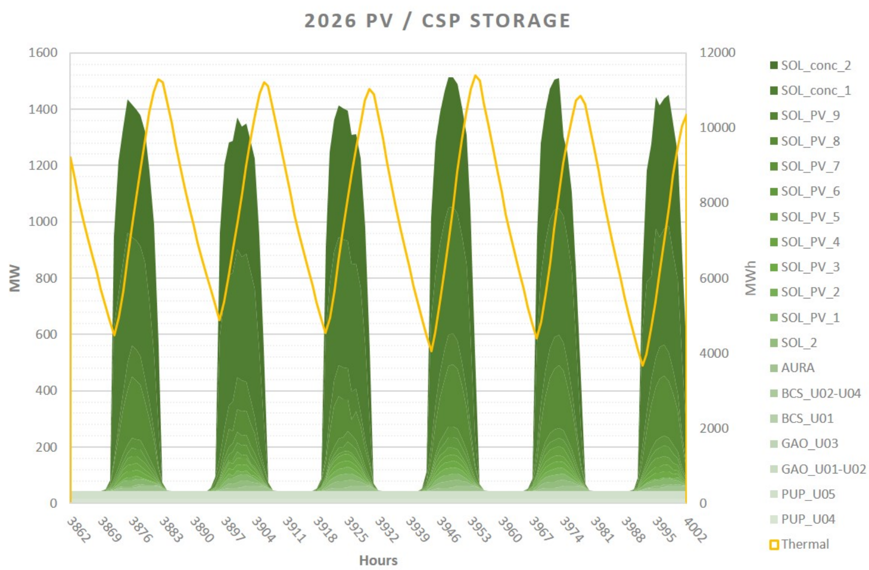

Figure 5.26: Hourly dispatch of 2026 PV/CSP scenario during a week and behaviour of the storage.

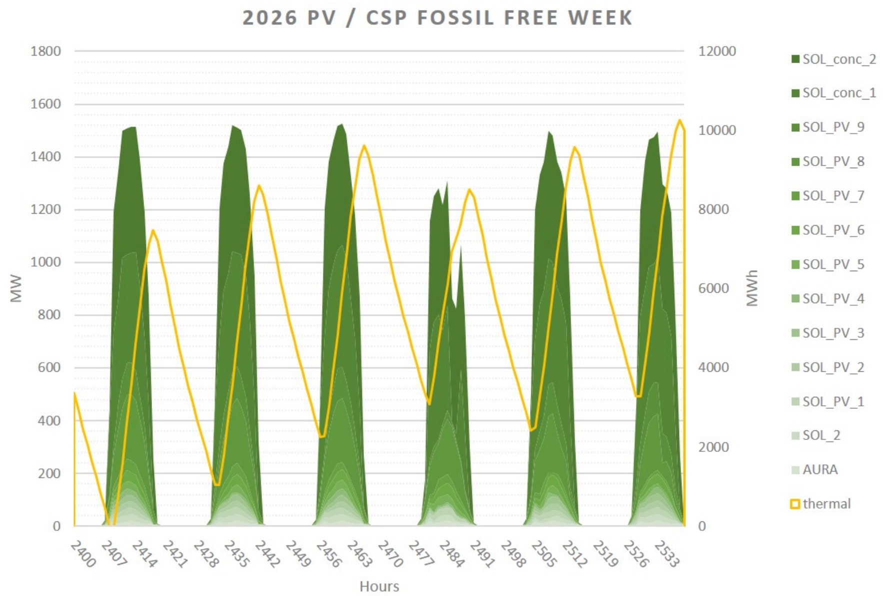

Figure 5.27: Hourly dispatch of 2026 PV/CSP scenario during a fossil free week and behaviour of storage

5.1.3 Investment calculations

The investment costs per scenario calculated include all necessary procurements from the point in which the tender expenses would begin until the investments required in order for the power plants in the 2026 scenarios (CFE, PV and PV/CSP) to be operating is done, Figure 5.28. The CFE planned scenario is the one that requires the smallest investment, and the PV scenario the highest one, due to the large amount of PVs and batteries required in order to fulfill the yearly power demand. The investment for the CFE scenario calculated is of 1490 million USD from the installation of the gas infrastructure onwards, for scenario PV the investment is of 8771 million USD, and for the PV/CSP scenario the total investment is of 7506 million USD.

The system costs calculated per scenario can be seen in Figure 5.29, where scenarios 2026 PV and 2026 PV/CSP part from the same scenario 2019 PV. The sum of annualized investment cost and total system running costs can be seen in Figure 5.30. When comparing the total yearly system cost of the scenarios 2026 PV/CSP and 2026 CFE it can be seen that the CFE scenario has much lower investment cost but also much higher operating costs, even when CSP technologies have higher running costs than PV technologies and that diesel has a higher price than gas. The total scenarios costs in 2019 are 238.18 million USD for the CFE scenario and 318.14 million USD for the PV scenario, and costs in 2026 are 350.36 million USD for the CFE scenario, 847.99 million USD for the PV scenario and 651.45 million USD for the PV/CSP scenario.

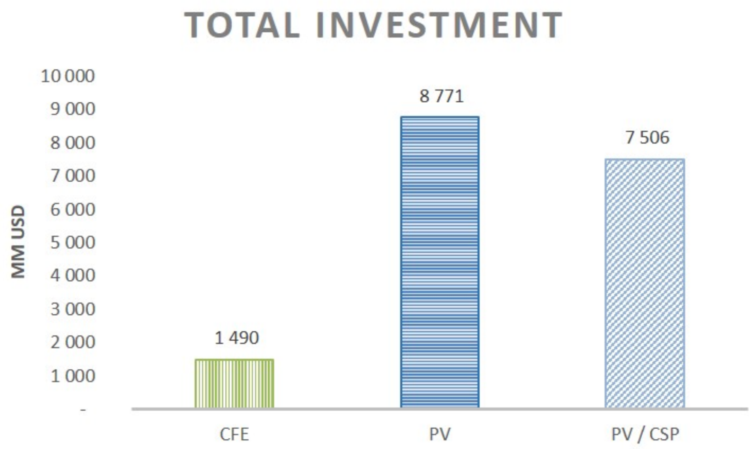

Figure 5.28: Total investment required per scenario in MMUSD.

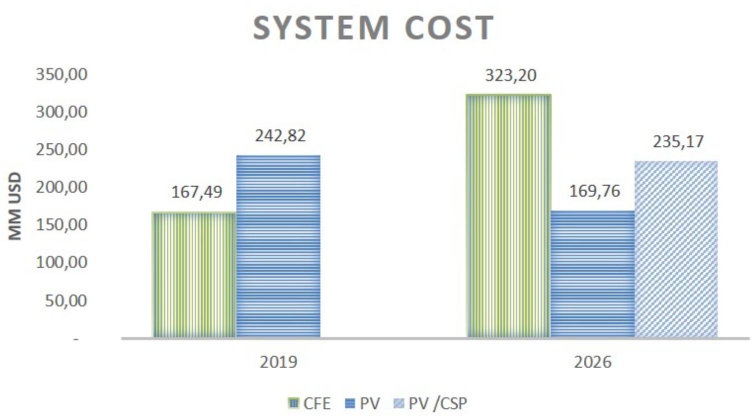

Figure 5.29: Yearly system operation cost per scenario.

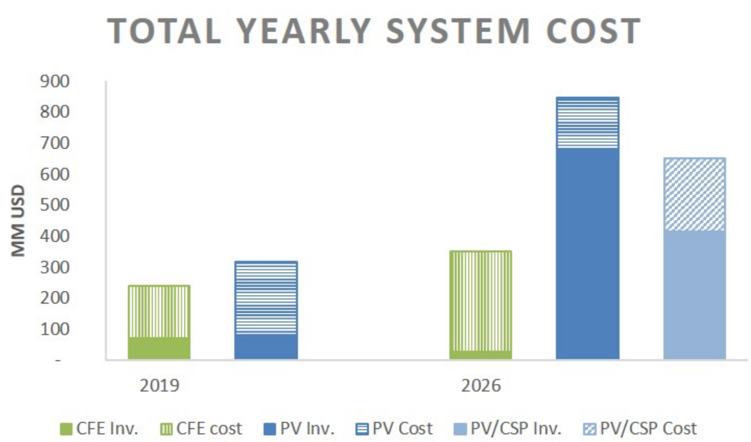

Figure 5.30: Total yearly system cost per scenario in MMUSD.

5.2 Results from the interviews

Dr. Peraza and Dr. Souza talked about the changes about to take place in the BCS system and the effects on the electricity price. Dr. Peraza stated that the prices are expected to decrease by about 60%. Dr. Souza explained how, once the infrastructure for natural gas will be ready, the change in all power plant fuel consumption will be practically simultaneous and how the boilers will be adjusted and the power plant's heat rate will decrease by about 5% due to this. Dr. Souza also mentioned that an estimate of 4 USD per MMBTU should be added to the natural gas price to account for transportation. Additionally, Ing. Valenzuela stated that the system is run based on merit order set by cost optimization.

Dr. Olea from Gauss, Dr. Peraza from CFE and Ing. Valenzuela from CENACE were asked what they considered to be the best renewable energy alternative in the BCS system. The general consensus was that solar is the best alternative for the area, and was therefore the source used to model the alternative scenarios for this study. As for other alternatives, the answers didn't coincide, Dr. Peraza considered low enthalpy geothermal to be an option, while Ing. Valenzuela and Dr. Olea stated that it was too little and far from the transmission system. Ing. Valenzuela stated that there could be a small percentage of wind in the southern part but on the other hand Dr. Olea stated that wind is not attractive to invest in because of the limited availability of it in BCS.

Dr. Olea, Dr. Peraza, Ing. Valenzuela and Dr. Hernandez all talked about the current considered limit on solar penetration in the area, the cause for this and how it could change. At the moment it has been stated that the maximum amount of solar power the system can take is 60MW, and it will soon be met since Aura has 30MW and another project of another 30MW has been approved. The sizes of the solar plants are due to the fact that previous regulation limited private power production to 30MW, under permissions label as "Small Producers". Ing. Valenzuela commented that in order to increase the solar capacity that can fit in the system smaller and scattered projects would be better, this, along with storage technologies, would considerably decrease the costs on the reserve required for frequency control and thus the willingness of the administrator of the system to inject more solar power in the system. Combined with policy incentives could increase renewable participation in BCS and the whole country. According to Dr. Peraza, advances expected in the next 5 years for solar technologies in Mexico are expected to be mainly with storage, and CFE has began exploring CSP technologies with a pilot project in the state of Baja California.

From the point of view of the government, the new incentives for sustainable electricity generation that emerged from the energy reform are expected to be efficient. Dr. Hernandez and Dr. Peraza were very positive when stating that the clean energy targets for 2024 will be met and that it will be with the help of the clean energy quotas, attached to clean energy certificates and costly penalties, that will incite the private sector to invest in clean technologies. Dr. Peraza stated that clean energy certificates should double earnings of solar energy in Mexico.

In contrast to what Dr. Peraza and Dr. Hernandez stated, Dr. Olea said to have little faith in the impact of clean energy certificates to promote investment in renewable technologies, and stated that more support to renewables was required in Mexico. A reason for this could be the definition of clean energy technologies in the Electricity Industry Law, though Dr. Hernandez stated that this measure was taken in order to not jeopardize foreign investment in different industrial sectors due to possible high electricity prices.

According to Dr. Hernández, the broad definition on clean energy will help the country to avoid lock-ins of any technology and make the country open to new developing technologies. The target should also be realistic and achievable for Mexico, and this definition of clean energy generation is the only way Mexico may reach the goals in an economic way. Every year, in March, there is a meeting where the next goal (a percentage) of clean energy is established and that should be reached within 2 years time. These goals are mandatory for basic electricity producers and qualified users. In this way short term goals are set towards the clean energy target of 2024 of 35% clean energy.

5.3 Overall results

While both 2019 scenarios show almost equal improvement on average generation costs and emissions, the model results show that if the government aims to achieve the cheapest generation costs with the least emissions the renewable scenarios can achieve this to a greater extent in the long run (Figure 5.14 and 5.13). However a larger investments are required both for the 2026 PV scenario and the 2026 PV/CSP scenario than the 2026 CFE, Figure 5.30.

Considering that willingness to invest in renewables and particularly in solar, depends on the high enough electricity prices in order to recover the investment, the 2026 PV and 2026 PV/CSP would be even less attractive for investors than the 2019 CFE and 2019 PV scenarios. Dr. Olea stated that the opportunity the private sector had seen on investing in solar technology in the BCS was due to the high short term cost of power in the area, which at the moment is on average three times higher than the one of the national interconnected system. Aura was the first and biggest solar plant to be built in Mexico as a Small Producer, and it was done so without any subsidy support thanks to the high local electricity prices [32]. This opportunity was unique in the country and will be gone with the switch to natural gas, due to the lower marginal costs of electricity. Dr. Olea stated that the current positive view of natural gas from the government could cause a natural gas lock-in in BCS.

Keeping in mind that the new definition of clean energy in the law includes energy from certified "efficient co-generation" and technologies considered low on carbon emissions according to international standards, some power plants running on fossil fuels will also receive clean energy certificates. The price of natural gas is at the moment very low and the fuel is also excluded from the fossil fuel taxes. For this reason, renewables have a risk of being left behind in the competition with natural gas, as the certificates, investments and running costs make natural gas powered co-generation sites the most attractive investment alternative. While co-generation is not used in BCS, due to a small industry, this could be a problem in the rest of the country.

By decreasing the marginal price of electricity as renewable participation increases, they, in a sense, attempt against their own profitability. Clean Energy Certificates, or a similar financial policy instruments, must therefore help cover the investment costs of renewables apart from other clean technologies. In off sun hours, when fossil fuelled clean technologies would be running, they would get their marginal costs covered, plus the earnings from the clean energy certificates, which should correspond to solar power investment costs.

The possibility of interconnecting BCS with the northern state or the mainland of Mexico was very briefly addressed in the interviews and current literature. The general perception is that it is not currently financially attractive since the perceived cost effective alternative goes through sensitive ecosystems, and environmentally safer alternatives are perceived as non viable [4], [2], [5]. The stated limit of 60 MW of renewable power in the BCS interconnected system, that is affected by the non feasible interconnection strategies mentioned above, can be increased when adding storage and scattering solar power sites.

6
Discussion

The discussion is divided in two parts, The scenarios and The energy reform. In the first part, the scenarios discusses assumptions, choices and results from the modeled scenario while the energy reform discusses current policies and possible implications of the development of the scenarios.

6.1 The scenarios

When choosing scenarios the 2014 reference, 2019 CFE and 2026 CFE were given due to the governmental plans for the system. The alternative scenarios though were modeled the way they were so as to evaluate the impact of operating the system with more than 60MW of renewable power generation in it when also combining it with storage technologies, something that was discussed in the interviews with Dr. Peraza, Dr. Olea and Ing. Valenzuela [23] [22] [6].

When scaling solar plants for the 2019 PV, 2026 PV and the 2026 PV/CSP scenarios the amount of installed capacity of solar power was decided in order to satisfy the demand of electricity for the years 2019 and 2026. It was therefore not substituting the exact same amount of energy that is planned in the 2029 CFE and 2026 CFE scenarios. It is instead enough to satisfy the demand in every time step and the system constrains. This could therefore result in a lower maximum power output than that of the CFE scenarios and therefore also make the investment cost lower for the alternatives.

The high level of renewable power generation is also aided by the fact that most of the slow plants should be retired by 2019, leaving fast plants that can better interact with renewable power generation. While a more realistic scenario might include less renewable power generation than the ones in the 2019 PV, 2026 PV and 2026 PV/CSP scenarios, the results should be encouraging for the private and public sector in Mexico to invest more in renewable power in BCS, and in the national electricity system in general, as it is shown that the system can stand a fair amount of variable power if it's correctly planned. The state can further encourage investment on renewable sources with the implementation of clean energy certificates and other environmental financial incentives (such as research and development incentives). Still, the scenarios of 2019 PV, 2026 PV and 2026 PV/CSP require a lot of storage to get the model running. This is due to that it needs to save the electricity to use during the off sun hours. If BCS would have an interconnection with

Mexico across the bay or interconnect with Baja California, the state in the north which in its turn is interconnected with the US, that also has a bit of wind power, it would probably allow more renewable participation with less need of storage. The state has considered the option of interconnecting the BCS system with the mainland, however economical and environmental aspects discarded this option [4] [2] [5].

The model uses the batteries and the thermal storage a lot in the alternative scenarios. Due to the fact that the storage units are not connected to any costs besides their investment costs it's the most cost optimal solution. In reality this would maybe not be the case. The thermal storage has a round trip efficiency of 95% [31] but this is the only loss considered. Due to the fact that the storage unit is using the stored energy every night, there will be no long term storage losses. For the Tesla Power Wall batteries used for the PV scenarios, a round trip efficiency of 100% was assumed. At Tesla's web page a efficiency of 92% [26] is stated which would increase the amount of battery capacity needed. However the batteries in the investment cost calculations are a bit over scaled due to that the Power Wall batteries have a fixed capacity combined with a fixed energy storage which means that the investment cost for the scenarios is still not too low even if the model uses a higher efficiency.

When analyzing the results it is important to keep in mind that the data used for costs is based mostly on national and international statistics. When it comes to prices and costs extracted from COPAR, the data is based on current technologies used in Mexico and not state of the art ones. Also the emission factors used from EPA are for technologies without any advanced flue gas cleaning. When it comes to cost data there is uncertainty on what is included for the fixed operation and maintenance cost in terms of insurances, when comparing the COPAR data and the IEA data for the CSP solar power.

The investment costs considered in the model is the up front investment costs. The model is not an investment model so pay back time and other factors are not considered. The investment costs are instead calculated to annual investments costs and added together with the total system cost of the year to be able to compare the different scenarios. The investment calculations of the PVs and CSPs scenarios have considered the fact that solar technologies will be less expensive in the future according to the S-curve that technologies usually follows when maturing. What is not included in the model is a similar price decrease of the batteries and thermal storage. Due to the fact that a large part of the investment costs of these scenarios consists of the investment costs of the storage, this could have a large impact on the result. It has been reported that prices on thermal technologies could decrease by more than half between 2020 to 2025 [36] and that lithium- ion batteries costs could also decrease to 150 USD per kWh [37] in order to be competitive with natural gas turbine regulating power [38]. With these price decreases of energy storage, system cost of the 2026 PV and 2026 PV/CSP scenarios for BCS could prove to be substantially lower.

What also would have an effect on the results of the calculations is that the calculations do not consider any possible financial incentives. The clean energy certificates that will be phased in with the energy reform are not considered to make any impact on the result in BCS and is therefore not included in the model, due to the uncertainties of how the market will operate and therefore the resulting prices. There is a possibility that there will be more policies such as subsidies in the future that would favour investments of renewable power generation.

6.2 The energy reform

The energy reform Mexico is going through is intended to improve energy security, enable efficiency improvements all along the production chain, thus achieving lower prices, and promote a more sustainable power generation. In the case of the electricity sector, this should be achieved by allowing greater participation of the private sector both in generation technologies and on research and development, promoting energy generation with different policies and by planning the development of the electricity system with reliability, sustainability and costs in mind. A key factor that will greatly influence the way the system evolution is planned is the fact that the planning will now be done by the TSO, and approved by SENER, and not by the state owned utility company, CFE. As was learnt from the interviews, the TSO might be more inclined to plan the system in a way that allows more renewable penetration in the system.

With the energy reform a strong push is given to clean energy generation with the creation of clean energy certificates associated to quotas. If the government manages to maintain high enough and stable prices on the certificates and the penalization for non compliance, as stated by Dr. Peraza and Dr. Hernandez, it could be a great advantage for cleaner technologies that have seemingly higher investment costs. Also, by promoting different renewable technologies to be developed, the net variability from them will decrease, making the system easier to operate. However we believe that the sometimes lax definition of clean energy in the Electricity Industry Law could have a negative effect on renewables, since co-generation investments, for example, that are included are less expensive than CSP power plants, and would also receive the certificates (not to mention the fact that natural gas is exempt form paying a carbon tax).

In order to truly incite fossil free energy generation, as was stated originally in the LAERFTE, renewables must be prioritized in the evolution of the electricity system in Mexico. The new electricity market and energy panorama in Mexico will anyway incite the development of more co-generation units as there is no longer a limit on the power they can sell to the state after the industries internal demand has been satisfied.

Regarding the concern stated by the sub-secretary of electricity Dr. Hernandez, that the electricity prices in Mexico must be kept low in order to attract foreign investment in the industry, the PV and PV/CSP scenarios show that though the upfront investment for renewables was higher than that of the CFE scenario to switch for natural gas, in the long run cheaper electricity generation costs were achieved. It is often a problem that decisions are made considering what is the most cost optimal decision for the moment, without considering long run advantages or disadvantages. This should be kept in mind in the policies implemented to promote a more sustainable energy system in developing countries like Mexico.

The CFE scenarios have the lowest investments cost. What is not considered today is that this scenario of 2026, the 2026 CFE scenario, has a lowest possible level of emissions in $CO_{2equivalents}$ of 384.94 kg/MWh when the system combination is running on natural gas. With future development in policies and international negotiations, this could be very high. If there would be a cap of emissions in the future the system might be forced to not use the power plants fully due to too high emissions and will then have to invest in renewable power generation anyway. According to the EU energy trends to 2030, as a result of policies implemented by 2009, $CO_{2equivalents}$ emissions from the power industry should be of 236 kg per MWh, and 179 kg/MWh by 2030 [33] and should go down further as negotiations advance to 80 kg of $CO_{2equivalents}$ per MWh by 2050 [34].

A problem with renewable technologies is that due to the fact that their running costs are so low, as greater participation is achieved, the marginal price of electricity goes down, reducing their earnings and their attractiveness for investors. This is why clean energy certificates play a key role in supporting renewables. An important question is what should set the price for this certificates? The external costs or the annualized investment costs?

It is a fair question to ask what chances do renewables stand when competing against traditional technologies? Investors are more likely to choose the project with the larger and more stable cash returns. Policy makers around the world have noticed this vulnerability of solar power production, some policy measures that have taken place are solar quotas besides renewable quotas, this happens for example in some states of the U.S. [35].

7

Conclusions

The results show that the planned fuel switch to natural gas, as well as a strategy replacing retired units with solar power, provide a fast reduction of short term electricity generation cost. In 2026 the solar alternatives achieve a lower average electricity generation cost than the fuel switch scenario. Looking at the total yearly system cost (including the annualized investment cost) the natural gas alternative has about 40% of the cost of the 2026 PV scenario, which is the most expensive alternative. When comparing with the 2026 PV/CSP scenario, the natural gas alternative has about 50% of the former. The solar alternatives use storage costs at present level and due to this the differences in investment costs for the scenarios could be smaller if the future decrease in prices of batteries and thermal storage would be considered. The prices of storage technologies are expected to half in the following decades. Likewise, since solar power is a developing technology prices are likely to decrease as well as they become a more established alternative, while prices of fossil fuel technologies are more stable.

The natural gas scenarios has been stated by CFE [4] and all the interviewees as a more sustainable alternative to the current electricity generation in the state of BCS. However, there is a lowest limit of greenhouse gases you can achieve with natural gas technologies, while the solar technologies presented in this paper have no emissions. This study shows that with proper incentives, the electricity system of BCS could achieve much lower emissions if investments were made on solar technologies and the required adjustments to maximize its integration (even when the fossil fuel used is diesel).

The model results show a decrease of emissions in terms of $CO_{2equivalents}$ for all 2019 and 2026 scenarios, compared to the 2014 reference scenario. The switch to natural gas could reach a level of 391.72 kg/MWh in 2026, when minimizing total system cost. When minimizing total $CO_{2equivalents}$ the lowest emission level of 384.94 kg/MWh in 2026 can be reached. These levels of emissions could turn out to be too high for international standards in the future. The European level for 2030 is of 179 kg/MWh and should decrease to 80 kg/MWh in 2050. If looking at the solar alternatives, that are combined with diesel powered generation units, when minimizing total system costs, the 2026 PV scenario results in a decrease to 120.78 kg/MWh and for the 2026 PV/CSP scenario a decrease to 143.66 kg/MWh is achieved. The lowest emissions level for the BCS system would be achieved when combining natural gas and solar power, however it would require adding up the investments.

Island systems are more sensitive to the variability of wind and solar power generation. Interactions between different renewable sources can aid to decrease the variability, and thus increase the penetration level. The interviewees stated that the best renewable source for the BCS interconnected electricity system is solar power and that the maximum amount of renewable capacity considered to date is 60MW, this amount was set by the CFE considering traditional electricity system operation codes and could be expected to increase with the help of storage. In the alternative scenarios, the model was pushed to operate with as much solar as possible, and this amount was found to be much higher than the 60MW that CFE has stated. This is achieved with the help of batteries, and eventually integrating CSP technologies with thermal storage, which gives the system better reliability.

The 2019 PV scenario operated with a capacity of 503MW PV installed, that produced 29.58% of the total electricity generated. In the case of the 2026 PV scenario, it had 2690 MW of PVs installed, producing 79.38% of the MWh consumed in the year, and the 2026 PV/CSP scenario had 717MW of PV and 1000 MW of CSP, supplying together 75.74% of the electricity demand.

This study confirms that the planned fuel switch to natural gas risks a possible lock-in to gas technologies in the area. The fuel switch would imply a strong reduction in marginal costs which would make the area unattractive to investors in renewable power generation. This risk was also expressed by both Dr. Olea [22] and Dr. Souza [5]. At the same time investors in natural gas infrastructure will prefer gas projects in order to pay off the investment (which has an economical lifetime of 30 years [29]).

By injecting more renewables in the system, the marginal cost of electricity generation has the possibility to decrease even more in the long run than with natural gas due to that there is no need of fuel for these units. Then, the renewables, in a way, attempt against their own profitability if electricity prices are set on marginal prices. For this reason it is important to set financial mechanisms to help renewable power cover its investment costs. For the BSC system, the prices of the clean energy certificates need to cover the high investment costs of PV and CSP installations in order to make it competitive. In the case of the rest of the country, certificates must also have a clear preference to renewable power generation to achieve a fair competition between renewable and fossil electricity generation.

Finally, the reader could keep in mind that the state of BCS today has the highest electricity price in Mexico, sometimes 3 times higher than that of the national average [22] [23]. The particularly high solar profiles in the area could make it a niche for solar power investment and development in Mexico, helping break technical and economical barriers to further implement these systems in the whole Mexican system. The high penetration of solar could also be an added value to the current eco-turism businesses in the area, where the 80% solar supplied system could be part of a selling argument and a show case. The high investments required by the solar technologies could be more easily paid off in a place where people have been able to pay higher prices than the rest of the country, and eventually lower prices would be achieved; in 2026 PV/CSP scenario the system could run purely on solar for weeks in a row.

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A

Supplementary Theory

A.1 Technologies

In the following section the power generation technologies relevant for the study of the Baja California Sur interconnected electricity system will be reviewed. The terminology used is the one used by the Mexican authorities in order to familiarize the reader with them. The BCS interconnected electricity system is composed at the moment of 7 different power generation sites, the technologies used currently and mentioned in the future scenarios are: turbogas, conventional thermoelectric, diesel turbogas, internal combustion, combined cycle and solar PV. These technologies will be reviewed along with Concentrated Solar Power (CSP) alternatives as well as energy storage technologies.

A.1.1 Conventional Thermoelectric

Conventional Thermoelectric technologies are based on the ideal Rankine cycle [24] and are composed of a steam turbine connected to a generator, a condenser and a feed pump.

In the case of CFE, conventional thermoelectric power plants usually work with heavy fuel oil as a fuel [24], however it is expected that fuel oil and diesel will be displaced by natural gas due to its lower price and reduced environmental effects , at least for the BCS system [2].

A.1.2 Turbogas

A turbo gas power plant is an open cycle gas turbine, composed of a compressor, a combustion chamber and an expansion turbine connected to a generator [24]. Some of its advantages are low investment cost and fast installation, short start-up and full load times and that it doesn't require water for cooling. However the compressor uses up about 60% of the energy generated by the turbine.[24].

A.1.3 Combined cycle

Combined cycles are the most efficient type of power plants using a gas turbine, and a steam turbine working together with the help of a heat recovery steam generator (HRSG), which uses the exhaust gases from the gas turbine to generate steam, sometimes with the help of auxiliary burners [39]. Some of the advantages of combined cycles along with the high thermal efficiency are low investment costs, less space than a conventional power plant is required for the same installed capacity and they can be built by stages. They usually use gaseous fuels, and in case of solid fuels, a gasification plant would be required, which would lower the net efficiency of the power station [24].

A.1.4 Internal combustion

Internal combustion power plants are based on a motor that works by pressurizing air so that high temperatures are reached and the fuel is spontaneously combusted. These type of engines were originally designed to operate with a light liquid fuel, diesel, but recent models can be operated with different fuels like gaseous fuels or fuel oil [24].

A.1.5 Solar PV

Photovoltaic cells are composed by a thin semiconductor material that transforms light into direct current of 1 to 8 Ampere and 0.6 Volts. By interconnecting 36-72 cells per module, a voltage of 20 to 40 Volts can be reached. The modules can be set on series (adding up voltage) or parallel (adding up current) formation, and are finally connected to a power inverter to convert direct current into alternate current.

A.1.6 Solar CSP

Concentrating solar power (CSP) systems generate thermal energy using high reflecting mirrors. The thermal energy is carried by steam or hot air and is used in steam or gas turbines generating power at utility scale. There are four main technologies available at the moment: parabolic troughs, tower systems, parabolic dish concentrators (also known simply as dishes), and linear Fresnel systems. [18]

CSP technology is a more complex and expensive technology than solar PV, however, heat generated can be stored for some hours allowing the system to provide power for longer hours and decreasing intermittency problems. Intermittency can be further reduced with fossil fuel hybridization.

Since diffuse energy cannot be optically focused, CSP technologies relay on direct normal solar irradiance (DNI). In order for CSP power plants to operate a minimum level of of 6 kWh/m^2/day (or 2000 kWh/m^2/year) is required. Another important consideration is that, unlike solar PV, under a certain threshold of direct sunlight no power is produced as the technology has constant heat losses, this happens usually when the irradiation is not enough for example in cloudy days. For this reason not all locations are fitted for this technology. Optimal conditions are found in arid and semi-arid areas [18].

A.1.7 Storage technologies

Because of the intermittent nature of renewable sources, storage technologies are key elements to achieve a greater participation of renewable energy in electricity systems. This is specially the case for isolated systems.

There are many different types of energy storage technologies, with different efficiencies, life cycles, capacities, discharge times, costs and market availability. According to the resources available in the area and the energy management requirements different types of energy storage are better suited. In the case of solar power generation in BCS two basic technologies are best suitable, electricity storage (for PV) and thermal storage (for CSP).

A.1.7.1 Electricity storage technologies

The technologies suitable for storage of electricity in a system like the BCS are mainly batteries, Figure A.1 .The different technologies in the figure are used for different purposes such as power quality, uninterrupted power supply (UPS), load shifting and grid support.

The model is investigating the hourly dispatch, for which load shifting and bulk power management technologies could play a central role. Due to geographical properties of the area pumped hydro and compressed air are not options. Therefore, lithium ion battery, a type of flow battery, is a good choice thanks to its properties of load shifting and proximity to bulk power management.

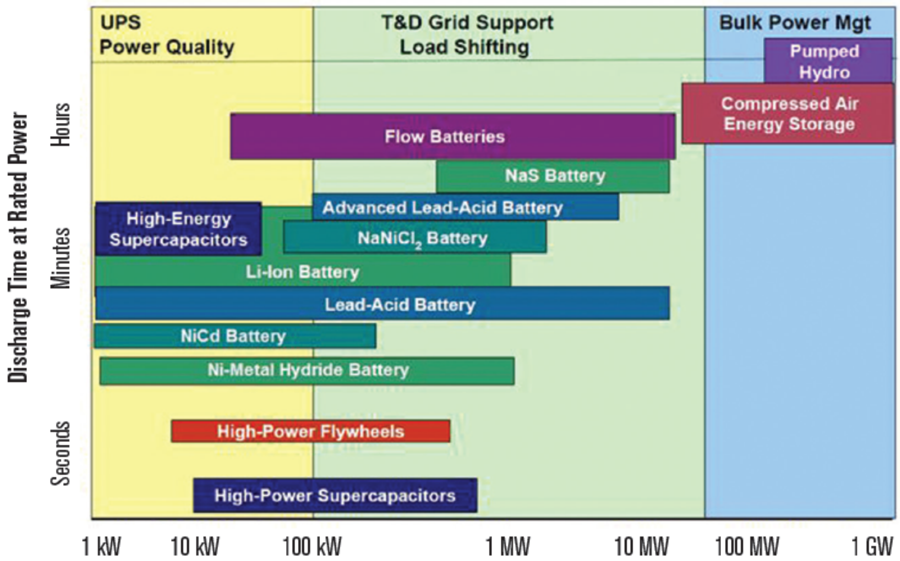

Figure A.1: Energy technologies storages. [40]

A.1.7.2 Thermal storage technologies

Additional to electricity storage technologies there are also thermal storage technologies. There is two types of thermal storage, thermophysical and thermochemical [18]. The type of thermophysical storage is divided into the different materials that are possible to use for the storage. Available material are molten salt, mineral oil, water/steam or air. The molten salt usually have a working temperature between 260-565 degrees Celsius. Mineral oil that is used should not me flammable or toxic, which makes this alternative more costly. Air is very cheap and easy to handle. Water/steam is for direct transfer to a steam turbine (if not consider thermal storage with water for district heating but the purpose is to use the storage for electricity production) which makes the storage time shorter than for example molten salt (when comparing the same storage volumes).The thermopsysical storage is using the sensible heat, latent heat or both when the physical state is changed of the material. Thermochemical storage is based on chemical reactions that is reversible. This technology is today not used widely.

A.2 Actors of the system

In the following sections a more detail description of the actors of the BCS system and the Mexican energy sector is presented. The actors described are SENER, CRE, CENACE, CFE and PEMEX.

A.2.1 SENER

SENER (Sectretaría de Energía, Sectretary of Energy) is the head of the energy sector. It establishes, conducts and coordinates the electricity sector. SENER also perform national developing plans and from that also sectoral programs. The growth of demand will be predicted and a plan to install or decommission power plants over the time is prepared. When the Clean Energy Certificates will be phased in with the energy reform, the SENER will establish the qualifications that is required to be defined as clean energy generation. The SENER also prepare and coordinate strategic projects in infrastructure, like gas pipelines and transmission grids extensions, needed in the country.

A.2.2 CRE

CRE (Comisión Reguladora de Energía, Regulating Commission of Energy) is the regulating entity of the energy sector of the Mexican state. It regulates the electricity market after what SENER decides. The CRE is providing conditions for the electricity supply, transmission services and the rules for promotion of clean electricity generation. It's also the entity that gives permits for new capacity installations and in the future going to handle the Clean Energy Certificates.

A.2.3 CENACE

CENACE (Centro Nacional de Control de Energía, National Control Centre of Energy) is the transmission system operator (TSO) of the Mexican electricity system.

A.2.4 CFE

CFE (Comisión Federal de Electricidad, Federal Electricity Commission) is the state owned utility company of Mexico. Before the energy reform, the CFE is in charge of generating electricity and to transmit and distribute it all around Mexico. CFE also today owns most of the power plants in Mexico [12]. With the energy reform CFE, while still being a state owned company, passes to be a company that will participate in electricity generation on the same conditions as private companies. Every second year CFE publishes the Plan of investments and constructions of the electricity sector (POISE for its acronym in Spanish). The POISE has a prospective scenario for energy consumption and supply, in order to see what must be built for the Mexican electricity system. Some of the things taken into account when making their future scenarios are: electricity consumption, maximum demand evolution and historical pattern, patterns of energy losses as well as specific requests for more energy and energy savings that could be achieved.

A.2.5 PEMEX

PEMEX (Petróleos Mexicanos) is the state owned oil company that today controls and make plans for Mexico's entire hydrocarbon industry. It is divided in four parts; PEMEX-Refinación (PEMEX Refining), PEMEX-Gas y Petroquímica Basica (PEMEX Gas and Basic Petrochemicals or PGBP), PEMEX-Petroquímica (PPQ) and PEMEX-Exploración y Producción (PEMEX Exploration and Production or PEP) [12]. The reserves of gas and oil is belonging to the state so when the energy sector opens up with the energy reform, other companies will also have the chance to provide services that today only PEMEX is permitted to do at the moment such as apply to explore new reserves.

A.3 The energy panorama of Mexico

This section is divided in two parts. First the electricity market of today is described, followed by a explanation of how the new electricity market will work after the energy reform.

A.3.1 The electricity market today

Today, most of the power in Mexico is generated in power plants owned by CFE, the sate owned utility. Mexico's electricity prices for customers in the residential and agricultural sector are today set below the actual cost which thereby works as a subsidy to make electricity more affordable. In 2006, an estimation of a total net subsidy of 6 billion USD was calculated. Due to that the prices are subsidized, the sector will have problems with attracting private investors in the future. The price setting today is not transparent enough to secure larger investments in for example renewable or alternative electricity generation. [12]

SENER and CFE are the ones today planning the future of the energy sector both in terms of investments and changes in infrastructure and energy generation. They publish a plan every year for the coming 15 years, called the POISE (Program of Constructions and Investments in the Electricity Sector), and are also responsible for estimating demand growth of energy in the country. To invest in new capacity, Mexico has three different investment modes; public works, financed public works and IPPs (Individual Pension Plans). Public works are paid out of public budget directly from the government. The financed public works are paid with revenues of services by the invested infrastructure but are still a part of the budget and is approved by the congress. IPPs are paid by the private sector. [13]

A.3.2 The new electricity market

The cornerstone of the new electricity industry will be a wholesale electricity market. SENER will still be on the top of the hierarchy but the wholesale market will be operated by CENACE, the ISO (Independent System Operator)[14], and controlled and regulated by CRE [15]. CFE, PEMEX and private actors can then participate in the market and sell their electricity to utility companies which in their turn sell it to the final users, or they can sell it to qualified users, all to spot market prices. The electricity is sold through CENACE which now will be independent from CFE

[15] and will operate the wholesale market based on economic efficiency principles [14]. PEMEX and CFE will be transformed into SPEs (Special Purpose Entities) which means that they are still state-owned companies but are more commercially oriented than before [14].
The new electricity market will open up many possibilities for the private sector not only to generate electricity but also open up for agreements. The agreements with private companies could include financing, installation, maintenance, administration, operation or expansion of infrastructure, for example transmission grids. The process should be carried out through competition with free participation. The wholesale market will then make it possible for producers, suppliers, traders, non-supplier traders and qualified users buy and sell electricity. The rates of electricity will be decided by free competition rules through CENACE. The market can also be used to buy and sell related services as the ones mentioned above [17].

To enter the wholesale market the participants have to enter a market participation agreement with CENACE. The CRE is the authority handling the basis of the market. The CRE is also authorizing connections to the national grid and importation of electricity. Besides the units for self-supply in case of emergency of a power outage, an unit of any size represented by a generator or a unit larger than 0.5MW will require a permit from CFE to generate electricity. CRE will also have the responsibility of the registration of the clean energy certificates [17].

The wholesale market will include basis for coordination between the electricity market and the natural gas market. For example, the results of the day-ahead market (when all participants sends offers for buying and selling electricity etc. to the market operator) have to be in time to schedule the transportation and supply of natural gas throughout the country. It is also important that the dispatch of the power generating units will take into account information about access of natural gas provided from CENAGAS (The National Gas Control Center for its acronym in Spanish) to know about interruptions or changes in the supply.The wholesale market is expected to start its operation with a test period in the fall of 2015 to be finally implemented by 2018, when also the clean energy certificates are expected to start its operation [15].

B

Assumptions

B.1 Power plant and technology data

Today all power plants in BCS is owned and operated by the CFE. Due to confidential reasons, the CFE, couldn't provide the project with power plant specific data but instead some unit specific data was received from the TSO, CENACE. The additional data needed for the units was assumed to be technology specific and was then available trough the public document COPAR [24]. The "Costs and reference parameters for the formulation of investment projects of the electricity sector", or COPAR for its acronym in Spanish, is a document published by the CFE, it contains up-to-date technical and economical parameters used to calculate the levelized electricity costs in Mexico. The latest publicly available version is the 32nd edition and it was published on May 2012.

The data that was specific for the units and available from the CENACE was the different units and their location as well as the installed capacity, which technology was used and which fuel they are run on today. Additionally, minimum load for all the units in 2014 except LP U1, which was assumed to have a minimum load of 15% of its maximum capacity, was available in the documentation provided by CENACE. The assumption of the 15% was then used for all units with technology diesel turbo gas, turbo gas and internal combustion in the future scenarios, while an assumption of 40% of maximum capacity was used for combined cycles [6],[5]. The units highest load was assumed to be their installed capacity. In the scenario of 2014 the fuel costs data for all the units were available from the CENACE [6] which then included the fuel taxes and transportation and already taken the heat rate into consideration.

By assuming that the same technologies have the same properties, COPAR provides data of efficiencies, fixed cost, which includes operation and maintenance cost and water costs, and heat rates [24]. Assumption of typically start-up times for different technologies were taking in consultation of Dr. Souza in full hours due to that the model has the resolution of hours over a year [5]. For the solar power generation the efficiencies are not used but instead capacity factor curves which are discussed further on in this appendix. The heat rate for this technologies are not used either due to that they not using any fuel. The data used can be seen in the Table B.1.

Table B.1: Technology specific data

Technology	Efficiency [%]	Fixed cost [USD/MWh]	Heat rate [MJ/MWh]	Start-up time [h]
TC	0.3669	13.71	9321.4	12
DTG	0.3768	15.13	3376.3	0
CI	0.4430	18.06	7719.7	0
TG	0.3921	14.57	8721.95	0
CC	0.4645	6.58	7362.5	12
PV	-	7.63	-	0
CSP	-	25.00	-	0

For operation and maintenance and water costs for the different technologies, the data from COPAR is taken from table 4.6 in the document [24] due to that the fuel use in BCS is different from the rest of Mexico. The table is divided in different sizes of the units, where the closest one to the real one is used. This means for the DTGs 39.9MW, the CCs 109MW, the CIs 44MW, the TCs 80MW and for solar PV 60MW which is the only available one. The fixed cost for the CSP is based on the possible future price from IRENA [41]. Data of heat rate and efficiency is used for the same sizes but from the table 1.7 in COPAR [24].

B.2 Solar curves

The solar capacity factor curves were, as mentioned in the methodology chapter, created in NREL's software SAM. Thirteen different sites were chosen in the south west of the U.S. due to that Mexican sites in BCS were not available. Besides geographical proximity, the average irradiation on the sites were compared with the irradiation in BCS to get as good substitution sites as possible. The sites and their average irradiation can be seen in the table below. A maps from IRENA (International Renewable Energy Agency) "3TIER Global wind and solar data sets" was used to compare irradiation ranges in BCS and in the area selected to obtain the curves. In general direct normal irradiation values (DNI) in the US cites and BCS are between 5 and 7 kWh/m^2/day, this is also of importance when considering CSP technologies, as was reviewed in the theory chapter. The daily and average output of the sites were also compared with data provided from the CENACE over a typical day of irradiation in BCS as discussed in the validation chapter.

To build the sun curves for PV power plants first the technology and size was chosen, and then the curves were generated by the SAM program for 10 sites. Five sites were modeled to run with a 30MW nameplate capacity, one with 40MW and four with 50MW, Table B.2 Then the curves were converted to capacity factor values, as our model used the curves by capacity values. In the case of CSP stations curves for three different technologies were made for the three sites with the highest DNI values, as CSP needs high DNI values, and a benchmark size of 100MW [27]. The technology modeled was a direct steam tower (therefore without storage). A thermal storage of 14 hours was then directly added in the model.

Table B.2: Solar curve sites

Site	DNI [kWh/m^2/day]	Technology
Chula Vista Brown Field Naas, CA	5.75	PV
San Diego Noth Island Nas, CA	5.46	PV
San Diego Montgomer, CA	5.52	PV
San Diego Miramar Nas, CA	5.75	PV
Camp Pendleton Mcas, CA	5.10	PV
San Diego, CA	5.38	PV
Carlsbad Palomar, CA	5.22	PV
Yuma Mcas, AZ	6.22	PV
Tucson International Ap, AZ	6.98	PV
Tucson, AZ	7.22	PV
Imperial, CA	7.23	CSP
Yuma Intl Arpt, AZ	6.35	CSP
Douglas Bisbee-Douglas Intl A, AZ	7.03	CSP

B.3 Storage

The storage used in the models are electricity storage in form of lithium ion batteries. Tesla's power wall batteries is used as a reference when looking at investment costs, which is assumed to be 350 USD/kWh [26].

Thermal storage for the CSP plants are assumed to be using molten salt and has a storage of 14 hours and capacity according to the plants.

B.4 Fuel prices and external costs

For the scenario 2014 the CENACE provided data that includes both fuel taxes and takes the heat rates into consideration as mentioned before. For the future scenarios though the prospective price for natural gas and diesel in 2018 and 2026 is used from the PIRA Energy Group, Scenario Planning Guide 1st Q 2015 [42]. For the natural gas the Henry Hub, constant dollar value of 2013 in USD/MMBtu is used and for the diesel the USG No 2 Heating Oil, constant dollar value of 2013 in USD/Barrel is used.

For the mixed fuel of fuel oil and diesel, prices and other properties such as emissions and thereby external costs were calculated with the same proportions as the mixed fuel has, 85% fuel oil no 6 and 15% diesel.

For calculating the external costs as described in the methodology chapter the global warming potentials for CO_2, CH_4 and N_2O is used to get the total CO_2 equivalents. Here factor 1, 21 and 310 are used respectively [43]. The equivalents are thereafter multiplied with the EUA price that is assumed to be 7.5 USD/tonne $CO_{2equivalents}$ [44].

B.5 Demand and reserve criteria

The demand curve provided from the CENACE is the real demand curve for the state in 2013. To get the right proportion on the growth of the demand for later years a growth factor is used based on the expected growth of the peak demand from the POISE [2], table 2.7. From 2013 to 2014 a factor of 1.06 is used due to the increased peak demand from 403MW to 428MW. In 2019 a factor of 1.39 due to the expected increase to 561MW as peak demand. In 2026, the factor 2.19 is used when the peak demand is expected to increase to 884MW.

B.6 Emissions

For the emission factors for the different types of fuel used in the model, the EPA values are used, which are the values normally referenced by CENACE, CFE, SENER and other entities in Mexico. The values are used together with the heat value of the fuels from the same source to calculate the emissions for the different units. The sulphur content of the fuel oil 6 and 2 is assumed to be 3w% and 0.3w% respectively [5]. The emissions factors and heat values can be seen in Table B.3 and Table B.4 [45], [20].

Table B.3: Heat values and emission factors

Fuel	Heat value	CO	CO_2	NO_x	SO_2	SO_3
Diesel	140 MMBtu/10^3 gal	5	22300	24	42.6	1.71
Fuel oil	150 MMBtu/10^3 gal	5	24400	47	471	17.1
Natural gas	1020 MMBtu/10^6 scf	84	120000	190	0.6	0

Emission factors for fuel oil and diesel are in the unit Ib/10^3 gal
Emission factors for natural gas are in the unit Ib/10^6 scf

Table B.4: Emission factors

Fuel	Filterable PM	Condensable PM	N_2O	CH_4	TOC	VOC
Diesel	2	1.3	0.26	0.052	0.252	0
Fuel oil	30.79	1.5	0.53	0.28	1.04	0
Natural gas	1.9	5.7	2.2	2.3	11	5.5

Emission factors for fuel oil and diesel are in the unit Ib/10^3 gal
Emission factors for natural gas are in the unit Ib/10^6 scf

Mexico uses the higher heating value as the US instead of the lower heating value as most of Europe. It is then this value that is used in calculations done by the CENACE, CFE and SENER [24].

B.7 Other

Additional conversion factors used in the model can be seen in Table B.5.

Table B.5: Additional conversion factors

1 USD	13 pesos
1 MMBtu	1055.87 MJ
1 Ib	453.5924 grams

C

Interview questions

C.1 Interview with Dr. César Emiliano Hernández Ochoa Sub-secretary of Electricity, SENER

1. How does the energy reform promote sustainable energy generation from your point of view?

2. How do you make the definition of clean energy from the electricity industry law compatible with the non-fossil energy targets in the LAERFTE?

3. Do you think the target of 35% clean energy by 2024 is achievable? And do you think the clean energy certificates will play a key role to achieve the target?

4. There are different mechanisms to promote renewable electricity generation mentioned in the renewable energy prospective 2014-2028. Besides the clean energy certificates and clean energy targets, which one do you believe has the greatest potential and why?

5. What do you consider will be the biggest challenge in the transition to cleaner electricity generation?

6. In the road towards a more sustainable electricity system, what is the most useful participation of the private sector for the national system?

7. In previous interviews we have understood that CFE has set the limit for renewable energy capacity of 60MW in BCS. Do you think it's possible to inject more renewables in the system in the future?

8. We know that this probably is a question for CENACE, but maybe you can help us, how is the dispatch of electricity optimized in the BSC system, and in Mexico? In our model we optimize the dispatch to the minimum system cost, is that how it works?

C.2 Interview with Dr. Héctor Olea Hernandéz CEO of Gauss and president of ASOLMEX

1. Do you have plans to build more solar capacity in BCS or the rest of Mexico? Would you use the same technology or would you be interested on trying other types of solar technology?

2. How big do you think the renewables share could be in the BCS system? Are there any studies about the maximum share?

3. Do you consider solar the best choice of renewable electricity generation for BCS? Why? Did you study other types of renewable electricity generation?

4. When Aura was built the short term cost (CTCP) in BCS was very high, but it is expected to decrease with the fuel switch to natural gas. How does this affect future investments in solar plants in BCS?

5. How can the national clean energy targets support Aura and future solar plants?

6. Since Aura started operations before August 11th 2014 when the clean energy certificate (CEL) regulation was passed, we understand that it does not receive CEL's to trade in the new whole sale market. Is this true?

7. Do you consider that the CEL's incentivize the private sector to invest in new clean energy? Or is the CTCP enough motivation, due to renewable power's low running costs compared with fossil fuel technologies?

8. We heard that Aura´s installations were affected by the resent hurricane season, do you think solar PV is more vulnerable to these type of natural disasters or does this affected all power in the peninsula equally?

C.3 Interview with Dr. Alejandro Peraza García General Director of Electricity & Renewable Energies in CRE

1. What do you think is the maximum share of renewable capacity in the BCS system? And which technologies would you think is the best or what mix of them?

2. Are there any studies in this area?

3. Do you know how many electricity permits in BCS were asked for and how many have been approved the last year? How many of these were for renewable electricity capacity? How many after August 2014?

4. As CRE will administer the clean energy certificates, what do you think will be the key to make them work as an incentive to invest in clean energy?

5. What do you consider will be the key role of CRE in the BCS system in order to achieve a more sustainable electricity generation for that state?

6. Can you tell us about the particularities of electricity reserves in the market operation of the BCS system?

7. For a scenario with more renewables in BCS, what would be the effects on the requirements and sizes of the reserves?

C.4 Dr. Antonio Souza Saldivar Senior Managing Director, Evercore Partners México

1. What do you recommend us for the modeling of the future scenarios? (Look at table.) Which units will be phased out and which will be invested in?

2. Which units will be adapted to natural gas?

3. What are typically start-up times for different technologies?

4. What are Maximum and minimal power capacity for normal operation values for CC, DTG and TG?

5. Should we assume that the reserves increases with the same factor as the total demand?

6. We are using SENER's prospective for future prices, is this a good source or do you have a better one?

7. What do you think we should do with the fuel price in USD/MWh? CENACE's data is higher than COPAR's data, should we adjust it somehow?

8. Do you have an idea of what is the sulphur content in the diesel and fuel oil used?

9. How do you think the electricity prices will be affected by the use of natural gas instead of diesel and fuel oil?

10. What kind of investment is the BCS project? Public work, financed public work or PPI?

11. What are these different investment options, can you please explain it for us?

C.5 Ing. Marcos Valenzuela Ortiz Assistant to the General Director, CENACE

1. How is the dispatch of electricity optimized in the BSC system, and in Mexico? In our model we optimize the dispatch to the minimum system cost, is that how it works?

2. Do you know if the dispatch of the BCS system is public and if we can have access to it for the year of 2014?

3. Do you have the average operation hours of the power plants in BCS?

4. Which power plants have a long start-up time in the BCS system?

5. Can you tell us about the particularities of electricity reserves in the market operation of the BCS system? Are there more than one reserve?

The constrains we have considered are:
a. Generation=demand
b. Hourly generation should be lower than the capacity
c. Plants with a long start-up time are limited to have an hourly generation between its minimum and maximum power output?
d. The solar plant is limited by its capacity factor
e. Reserve 1 that is spinning PP that has extra capacity that is not used.
f. Reserve 2 that is spinning PP that has extra capacity that is not used and PP with a short start-up time.

Anything else we should consider?

6. Do you have the integrated hourly demand of the BCS interconnected system for the year 2014? And do you have any studies about the growth of the demand until 2026? So far we have been using the data in POISE and multiplying it by the factor of the peak demand growth.

7. In previous interviews we have understood that CFE has set the limit for renewable energy capacity of 60MW in BCS. Do you think it's possible to inject more renewables in the system in the future? What would be required of the system for this to be possible?

As we have understood, the fuel switch to natural gas will provide a reserve that can be used more instantaneous than for example diesel and fuel oil and compensate the variable generation of renewables.

8. Do you have Auras hourly generation curve of 2014?