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Analysis of regulation and economic incentives of the hybrid CSP HYSOL

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Publication date:
2016

Analysis of regulation and economic incentives

Deliverable nº: 6.4

July 2016

EC-GA nº: 308912
Project full title: Innovative Configuration for a Fully Renewable Hybrid CSP Plant
WP: 6
Responsible partner: DTU-ME
Authors: Mattia Baldini and Cristian Cabrera
Dissemination level: Public

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Abbreviations

CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CDECs	Economic Load Dispatching Centres (Centro de Despacho Económico de Carga)
CEL	Clean Energy Certificate (Certificado de Energía Limpia)
CEL	Chile's Renewable Energy Center
CENACE	National Center of Energy Control (Centro Nacional de Control de la Energía)
CFE	Federal Commission of Electricity (Comisión Federal de Electricidad)
COD	Commercial Date of Operation
COP	Copenhagen Conference of Parties
CORFO	Corporación de Fomento de la Producción de Chile
CRE	Regulating Commission of Energy (Comisión Reguladora de Energía)
CSP	Concentrated Solar Power
DAM	Day Ahead Market
DFIs	Development Finance Institutions
DNI	Direct Normal Irradiance
DOE	US Department of Energy
EAF	Energy Availability Factor
ECRA	Electricity and Cogeneration Authority
EHV	Extra High Voltage
FIT	Feed-in Tariff
GDP	Gross Domestic Product
GHI	Global Horizontal Irradiance
GT	Gas Turbine
HV	High Voltage
IPPs	Independent Power Producers
IRENA	International Renewable Energy Association
IRP	Integrated Resources Plan
IRR	Internal Rate of Return
K.A. CARE	King Abdullah City for Atomic and Renewable Energy
KSA	Kingdom of Saudi Arabia
LAERFTE	Law for the Development of Renewable Energy and Energy Transition Financing
LCOE	Levelized Cost of Energy
MEM	Mexican Wholesale Market (Mercado Eléctrico Mayorista Mexicano)
NCRE	Non-Conventional Renewable Energy
NERSA	National Energy Regulator of South Africa
NMD	Nominated Maximum Demand
NPV	Net Present Value
NREL	US National Renewable Energy Laboratory
O&M	Operation and Maintenance
OECD	The Organization for Economic Cooperation and Development
OPEX	Operational Expenditure
PEMEX	Mexican Petroleum Company (Petróleos Mexicanos)
PPAs	Power Purchase Agreements

PV	Photovoltaic
RE	Renewable Energy (Renewables)
REIPPPP	Renewable Energy Independent Power Procurement Program
RES	Renewable Energy Sources
RFP	Request for Proposals
RPS	Renewable Portfolio Standards
RSAN	Republic of South Africa North
RSAS	Republic of South Africa South
SA	South Africa
SAPP	South African Power Pool
SEA	Aysén Electric System (Sistema Interconectado de Aysén)
SEC	Saudi Electricity Company
SEM	Magellan Electric System (Sistema Interconectado de Magallanes)
SEN	National Electricity System (Sistema Eléctrico Nacional)
SENER	Mexican Energy Bureau (Secretaria de Energía de México)
SIC	Central Interconnected System (Sistema Interconectado Central)
SIN	National Interconnected System (Sistema Interconectado Nacional)
SING	Northern Interconnected System (Sistema Interconectado del Norte Grande)
SSPPs	Self-Supply Power Projects
TDP	Transmission Development Plan

Acknowledgments

Within the Seventh Framework Programme, the deliverable D6.4 "*Analysis of regulation and economic incentives*" is a collaborative work among the System Analysis division of the Management Engineering Department of DTU, ACS Cobra, and PSA-CIEMAT

Special thanks go to Simone la Greca, Alberto Santos, Francesca Bona, Klaus Skytte, and Lise-Lotte Pade from DTU-ME, who have been supporting forces behind this work.

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1 Executive Summary

The aim of HYSOL Project is to become the European reference in competition to initiatives ongoing in the CSP/biomass global market. The HYSOL Project focusses on overcoming the CSP technology limitations to increase its contribution in the global electric market, hybridising with biomass energy to achieve 100 % renewable and sustainable energy, and providing a stable and reliable power independently of meteorological circumstances.

The purpose of this report is to investigate the market setup and the economic feasibility of the HYSOL technology in four selected countries: Kingdom of Saudi Arabia, Chile, Mexico and South Africa. By assessing the regulatory and policy framework regarding renewable energies it is possible to identify how the construction and operation of hybrid CSP-biomass power plants could be affected by the country-specific regulation framework.. Power market reforms, Renewable Energy (RE) targets, CO2 emissions trading system among others are key elements that can influence the future uptake of HYSOL. This analysis complements the corporate-economic assessment for the decision making process. The latest underlines the level of economic support required to make this technology economically viable and attractive to investors while considering present and estimated future prices on conventional fuels and electricity.

Market assessment

The market assessment performed aimed at identify key policies, power market reforms and targets for supporting renewable energy deployment in the Kingdom of Saudi Arabia (KSA), Mexico, Chile and South Africa. The market analysis serves as a framework condition for the take-off of HYSOL in the mid and long-terms. The most important findings/per country are hereby listed.

Key Findings from the market assessment

Kingdom of Saudi Arabia

- *Implementation of KSA's power market reform "Development of the Electricity Industry Restructuring Plan" by the Electricity and Cogeneration Authority (ECRA);*
- *Participation in the "Pan-Arab Strategy for the Development of Renewable Energy Applications: 2010 – 2030", adopted in 2013 (75% of installed capacity in the Arab region by 2030);*
- *Establishment of the "King Abdullah City for Atomic and Renewable Energy" (K.A.CARE) in 2010, aiming at 19% of CSP installed capacity in the energy system by 2032; in addition to its "Value Chain Activation Plan" seeking the development of the solar industry;*
- *Implementation of public competitive bidding for RE projects on municipal and national level.*

Mexico:

- *Implementation of the wholesale power market (MEM) reform, promulgated by the government in 2013. The most relevant features are:*
  - *A daily electricity trade: market scheme that allow to purchase and sale electricity in a real time and in a day-ahead basis;*

- *Clean energy certificates: policy that will help to promote the deployment of "clean technologies" imposing the suppliers to generate 25% of clean energy by 2018;*
- *Promulgation of the Law for the Development of Renewable Energy and Energy Transition Financing (LAERFTE). The government decision sets as a target that 35% of the total energy produced should come from renewable sources by 2024, 40% by 2035 and 50% by 2050.*

Chile:

- *Development of "National Energy Strategy 2012-2030", which includes the "Interconnection of Independent Electric Systems Law" (interconnection between the SIC and SING), approved by the parliament in 2013;*
- *Promulgation of the "RE law 20/25" approved by the parliament in 2013. The law aims at 20% of renewable energy produced in Chile by 2025;*
- *Tender process introduced for Renewable Energy (RE). The process resulted in financing one of the largest CSP plant in Latin America (Cerro Dominador), with 110 MW of installed capacity. The state played a key role with financing of USD 20 million (subsidies) through CORFO and creating a consortium for funding USD 350 million in soft loans offered by the European Union, the Inter-American Development Bank and the German Development Bank.*

South Africa:

- *Development of the Integrated Resources Plan (IRP) in 2010-2030 which leaded to:*
  - *Establishment of research work on Long-Term Mitigation Strategies. According to these strategies South Africa will reduce CO_2 emissions 34% below a business-as-usual scenario by 2020, and below 42% by 2025;*
  - *Setting of effective emissions cap at approximately 275 Mt/year CO2 equivalent for the power sector.*
- *Development of a feed-in tariff scheme. The support scheme was launched in 2009, however, afterwards it was cancelled in 2011. Nevertheless, it paved the way for the successful implementation of the Renewable Energy Independent Power Procurement Program (REIPPPP) in 2011;*
- *The development of the REIPPPP was rolled out in four phases from 2010 to2014. The REIPPPP program led to 64 new renewable energy projects of different sizes at different sites. The plants were subsequently introduced in the system as grid-connected renewable energy Independent Power Producers (IPPs). USD 14 billion investments has been committed for the construction of 3 922 MW[1] total capacity in RE technologies. Among these there are grid-connected wind farms, PV, CSP plants, smaller hydro power based units, landfill gas and biomass energy powered plants.*
- *Besides South Africa, the investigation of the power markets in the countries revealed a lack of regulating instruments, such as feed-in tariffs (FIT), for supporting RE projects. This comes as a surprise, because FIT has proven to be an effective way for supporting the take-off of CSP plants (and other RES projects) at their initial phase in Europe. To some extent, the lack of "feed-in support" is compensated with other support mechanisms for RE projects, e.g. Tenders, renewables quotes, and green certificates.*

[1] This is the total after financial close of bid windows in phase 1 and 2. The total request for proposals is slightly lower at 3 915 MW.

Private-economic feasibility assessment

In order to investigate the economic feasibility of the HYSOL CSP technology in the countries under analysis, a financial model is implemented. The aim is to prove whether the new CSP technology can fit within the frame of the power market in the Kingdom of Saudi Arabia, Chile, Mexico and South Africa. The Financial Model considers all the relevant input parameters for the technology (e.g. investment costs, revenues, taxes, construction time, overhaul among others) to assess the investment with three economic indicators: Net Present Value (NPV), Internal Rate of Return (IRR) and Levelized Cost of Energy (LCOE).

Key Findings from the corporate economic analysis

- *The outcomes show that, with the current values of the average power prices, the project is not profitable in the studied countries, meaning that it needs financial support. The high initial costs related with the investments were found to be the main cause for the non-profitability.*
- *A further sensitivity analysis performed over different values of IRR highlights an exponential-increasing relation between the IRRs and the power prices. For the NPV and LCOE, the relation was found to be almost linear. Therefore, the higher is the profit expected (i.e. higher IRR), the higher need to be the average power prices in the energy systems analysed.*
- *The highest profitability of the investment was found for South African. Indeed, in a hypothetical case in which all the systems would have the same average power price (assumption considered in order to compare the four markets on the same base), South Africa is the market where the HYSOL investment would perform the best, providing the highest NPV, the highest IRR and a LCOE competitive with the market price. Mexico, Kingdom of Saudi Arabia and Chile then follow as promising markets for the investment in HYSOL.*
- *Inspecting the outcomes, a major gap was identified between the current and the necessary average power prices. The result thus arise the need to focus on the subsidies. The conclusion of the study points out that, with an appropriate support, the HYSOL project would be profitable. Policy makers in Kingdom of Saudi Arabia, Chile, Mexico and South Africa thus have rooms for improvement concerning renewable energy technologies support, since insufficient support schemes are currently available.*
- *The suggestion for the investing company is thus to continue with the commitment in the project, once contextualized forms of renewables support will be proven to be effective, realise the HYSOL technology as a new renewable source of power for the energy systems under study.*

2 Introduction

CSP is in its infancy in terms of deployment compared to the other renewable power generation technologies, with only 5 GW of CSP installed worldwide at the end of 2014; of this capacity, the CSP market is dominated by parabolic trough technologies (around 85% of cumulative installed capacity). Nevertheless, an increasing numbers of solar towers are being built and offer the promise of lower electricity costs. CSP can integrate low-cost thermal energy storage in order to provide dispatchable electricity to the grid and capture peak market prices (IRENA, 2014b).

The weighted average LCOE of CSP by region varies from 0.20 USD/kWh in Asia to 0.25 USD /kWh in Europe. The LCOE of individual projects varies significantly depending on location and level of storage (IRENA, 2014b). As recently costs are falling, new projects are being built with LCOEs of 0.17 USD/kWh (IRENA, 2014b). Moreover, power purchase agreements are being signed at even lower values where low-cost financing is available. Future cost reductions can be expected if deployment in the solar industry accelerates, but policy uncertainties and market readiness are reducing the growth rate of prospects.

Under this framework the objectives of the study are:

1. To carry out a market assessment in the countries under analysis, highlighting the potential for the HYSOL project (by comparing, for example, the HYSOL with the generation costs relative to conventional power technologies);
2. To analyse country-specific RE policies and regulations, and to assess the necessary economic incentives for economic viability of HYSOL performing a feasibility study for the Kingdom of Saudi Arabia, Mexico, Chile and South Africa.

The market assessment characterises the key elements involved in the electricity supply and demand in KSA, Mexico, Chile and South Africa. Furthermore, it identifies the key policies, regulations and milestones which support the deployment of renewable energies, in particular concerning the CSP technologies. One of the main remarks from the market assessment is the lack of regulating instruments such as FITs, even though this could be an effective way for supporting CSP take-off at its initial phase. To some degree this compensates with tender, renewables quotes, and green certificates among others support mechanisms.

The private-economic feasibility assessment analyses the profitability of HYSOL using a Financial Model based on an input output approach. Three main economic indicators will prove the financial feasibility of the project: the Net Present Value (NPV), the Internal Rate of Return (IRR) and the Levelized Cost of Energy (LCOE). Additionally, to decrease the uncertainties in future power prices, four scenarios are considered:

- No support mechanism: this scenario is based on the hypothesis that no support mechanism will be issued for renewable technologies;
- Minimum subsidies: the scenario is used in order to evaluate the power price that would guarantee a Net Present Value equal to zero at the end of the project lifetime;

- Artificial subsidies: this scenario considers artificial subsidies provided for the renewable power generation in the different countries based on the hypothesis that for the entire HYSOL lifetime is eligible for a fixed subsidy throughout the whole lifetime of the plant. The support is considered as a "feed-in tariff";
- LCOE break-even: this scenario investigates which are the critical input parameters required for HYSOL to be competitive.

A country-specific sensitivity analysis is also performed on the values of average power prices, because of their high influence on the economic indicators. Afterwards, a comparison among the countries is carried out. Finally, conclusions and recommendations based on both market and private-economic assessments are drawn for decision makers.

3 Market assessment

3.1 The Kingdom of Saudi Arabia

For the Kingdom of Saudi Arabia (KSA), the market conditions are determined by:

1. High level of oil exports: KSA is the word's larger producer and exporter of oil;
2. Growing electricity demand: with an annual rate of 7.5%, this demand is conditioned by the increase in demand in the oil industry, desalinations plants, and rise in population (about 70% rise from 1990 to 2010);
3. Low electricity price.

3.1.1 Market description

With an average production of 11.84 MMBL[2]/day and export of 6.25 MMBL /day, Saudi Arabia was the world's largest producer and exporter of petroleum and other liquid fuels in 2012. With an estimated 267 BBO[3] proved reserves, it was also the country owning the world's largest oil reserves, accounting alone for roughly one-fifth of the global total (IEA, 2014).

Contrary to its neighbouring countries and despite the international strong demand, the KSA has never exported gas. Its 288 TCFG[4] of reserves have long been used to fuel Saudi Arabia's power generation (IEA, 2014). In 2013, gas provided 46% of Saudi electricity, with fuel oil and diesel providing the remaining (ECRA, 2015).

Although currently leading the world oil exports, the Kingdom's future potential is threatened by the fast growing domestic consumption. At present growth rates, Saudi Arabia's energy demand of 3.4 MBOE[5]/per day (2010), it is expected to reach the level of 8.3 MBOE/ day by the year 2028 (KA-CARE, 2016), (IEA, 2014). At that point, an average of 3 MBOE/day of oil might require to be drifted to the power sector (IEA, 2014), potentially cutting down the exports revenue and weakening the kingdom's role in the world market.

The growth in energy demand is due to Saudi Arabia's 70% rise in population from 1990 to 2010 (more than double the global trend) and its expected rise of 30% from 2010 to 2030, greater than China's expected increase of 7% and India's 23%, according to the United Nations Population Division (UN, 2015) In addition, the real gross domestic product is expected to grow by 3% in 2015, according to the International Monetary Fund (IMF, 2015).

One of the main causes of the growth in energy demand are the very low end-users prices, which 1) have attracted large investments in energy-intensive industries over the past decades, 2) encouraged wasteful consumption and 3) deterred investment in energy

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[2] Million barrels of petroleum liquids; includes crude oil, condensate, and natural gas liquids.
[3] Billion barrels of crude oil.
[4] Trillion cubic feet of natural gas.
[5] Million barrels of oil-equivalent.
https://pubs.usgs.gov/dds/dds-069/dds-069-d/REPORTS/69_D_CH_26.pdf

efficiency. Electricity tariffs do no exceed 0.07 USD/kWh in any sector and the industrial tariff is 0.032 USD/kWh independently of the electricity consumption (Dynamic-ews, n.d.).

Moreover, the extreme aridity of the Arabian Peninsula sustains the enormous desalination programme, processing more than 3.5 million cubic meters of seawater per day. The process considerably contributes to Saudi Arabia's high energy intensity (UN, 2015). In 2011, the country's rising energy intensity reached the level of 23 Btu[6]/1 000 USD (2005 dollars) of GDP, almost triple compared to the United States, where it has been declining, like in most of the world (EIA, 2016).

The KSA's electricity use is increasing with annual rate of about 7.5% and the country's fossil-fuel based power generation system is reaching its saturation point (IEA, 2014). The growth in demand is putting to the wringer the installed capacity of about 70 GW in 2013 (ECRA, 2015), by challenging the gas and fuel oil sector in supplying the power stations. In recent year, initiatives to integrate renewable energy technologies and to improve end-use energy efficiency have thus become necessary.

3.1.2 Electricity sector

The electricity system in KSA is the largest in the Arab world, with a licensed installed capacity of 69 761 MW, and a peak load of 53 864 MW in 2013, according to the Electricity and Cogeneration Authority (ECRA) (ECRA, 2015). The capacities of generation units of licensed entities are illustrated in Table 3.1.

Table 3.1: Capacities of generation units of licensed entities

Producing Entity	No. of plants	Capacity [MW]
Saudi Electricity Company (SEC)	46	51 525
Saline Water Conversion Corporation (SWCC)	6	5 018
Jubail Water and Electricity Company	1	2 875
Shuaibah Water and Electricity Company	1	1 191
Saudi Aramco	6	1 189
Tihamah Power Generation Company	4	1 083
MARAFIQ - Yanbu	1	1 589
Shuqaiq Water and Electricity Company	1	1 020
Rabigh Electricity Company	1	1 320
Rabigh Water and Electricity Company	1	600
Saudi Cement Company	2	223

[6] British thermal units.

Jubail Power Company	1	250
Twairgi Power Company	1	63
Dharma Electricity Company	1	1 756
Aman Modern Energy Company	3	59
Total	76	69 761 [7]

Source: (ECRA, 2015).

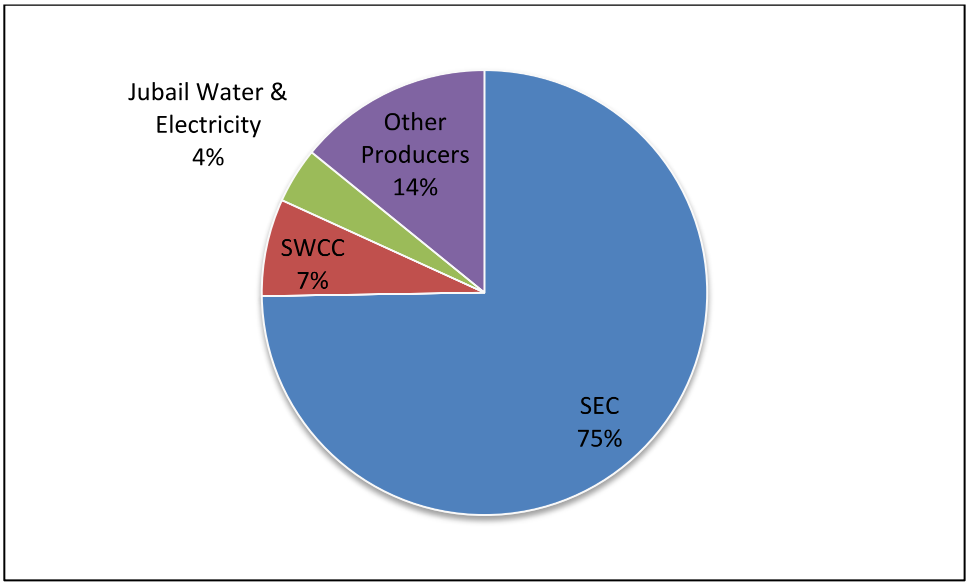


Figure 3.1: Distribution of generation capacities among producers

Source: Own figure based on (ECRA, 2015).

The Saudi Electricity Company (SEC) is the dominant player of this sector owing 74% of the total installed capacity as shown in Figure 3.1. It is a joint stock company whose shares are publicly traded on the market, and 81% of them are jointly owned by the Saudi Government and Saudi Aramco. A significant percentage of the electricity sold by the SEC is supplied to Saline Water Conversion Corporation, government agency leader of the kingdom water desalination industry.

The Saudi Electricity Company is not only engaged in electricity generation but also in transmission and distribution. It has the monopoly of the distribution to consumers with the exception of the two areas operated by MARAFIQ: Jubail and Yanbu. In 2013, the Saudi Electricity Company has delivered a total of 256 688 GWh of energy (SE, 2013), (ECRA, 2015), with an increase of 6.8% from the previous year, as illustrated in Table 3.2.

[7] The total capacity value represents the nominal installed capacities, while the available capacity was 58 462 MW.

Table 3.2: Energy production, sales and losses for the years 2012 and 2013 in KSA

	Energy 2012 [GWh]	Energy 2013 [GWh]
Energy generated at SEC plants	207 131	198 891
Energy sent from SEC plants	200 305	192 329
Energy imported from SWCC	14 102	14 597
Energy imported from other producers	50 432	70 520
Total energy carried by the transmission system	264 853	277 446
Total energy sold	240 288	256 688
Total energy loss in the transmission and distribution system	24 565	20 758
Percent of electricity consumed in SEC plants	3.3%	3.3 %
Loss in the entire SEC system	9.27%	7.48%

Source: (ECRA, 2015).

However, the Electricity and Cogeneration Authority in 2011 adopted a plan to restructure the electricity sector by unbundling the current vertically integrated structure in order to create a competitive environment, attractive for private sector investments. A simple diagram of the current vertically integrated structure is illustrated in Figure 3.2, while the final structure is illustrated in Figure 3.4.

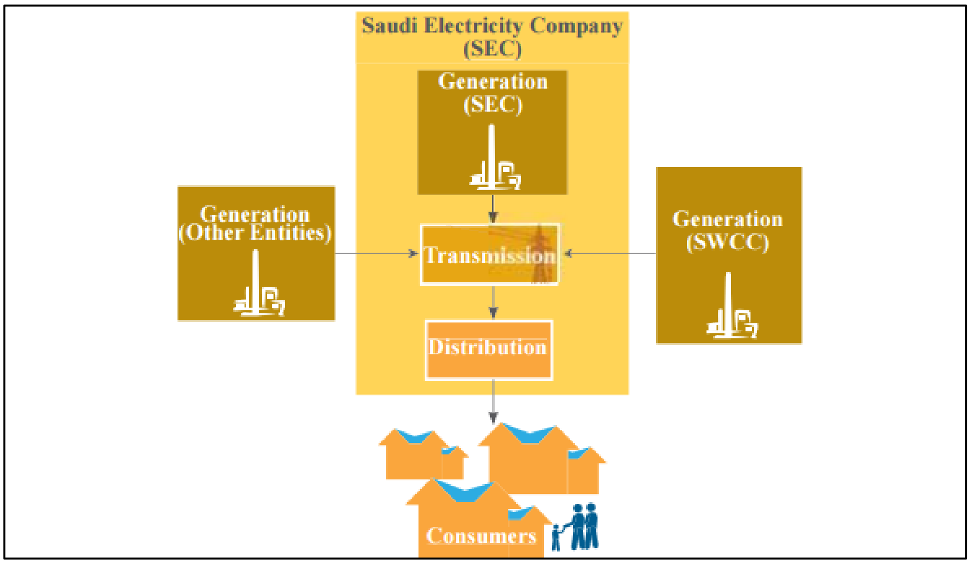


Figure 3.2: Current structure of the electricity industry

Source: (ECRA, 2015).

Note: The current organizational structure is considered a monopoly of the electricity industry (SEC monopoly).

3.1.2.1 Electricity Industry Restructuring Plan

The “Development of the Electricity Industry Restructuring Plan” approved by ECRA outlines the following major steps of the unbundling process:

- Creation of an independent transmission company, guaranteeing an indiscriminate access to the transmission system for all producers and large consumers;
- Creation of the “Principal Buyer” which manages the electricity industry income and stipulates contracts with services providers;
- Design of a clear, transparent and fair transmission tariff;
- Introduction of competition in wholesale electricity services to distribution companies and large consumers;
- Introduction of competition in distribution and service provision to consumers in the long run.

In 2012 the National Electricity Transmission Company (NETC) started to operate as a limited liability company entirely owned by SEC. Furthermore, in 2013 SEC agreed on the following milestones for the first phase of the restructuring plan:

- Establishment of an independent electricity system operator in 2014;
- Establishment of four generation companies entirely owned by SEC, which will sequentially begin to operate in 2014;
- Establishment of a distribution company, which will begin to operate in 2014, and develop a plan for its break up into several local distribution companies.

The implementation of these steps, which represent the first part of the restructuring plan, have been subjected to delays, but they are expected to be concluded in the near future. With the completion of these steps the activities unbundling would be completed and the electricity sector structure will be the one illustrated in Figure 3.3.

In the meantime, ECRA began a study aiming at developing a roadmap for the achievement of a competitive electricity market. The analysis involves the evaluation of the current status of the electricity sector and the establishment of the necessary requirements for the transition to the second phase of the plan. The final pre-requisites imply the introduction of competition in the wholesale market and the establishment of a parallel market for bilateral supply and trading of electricity (ECRA, 2015).

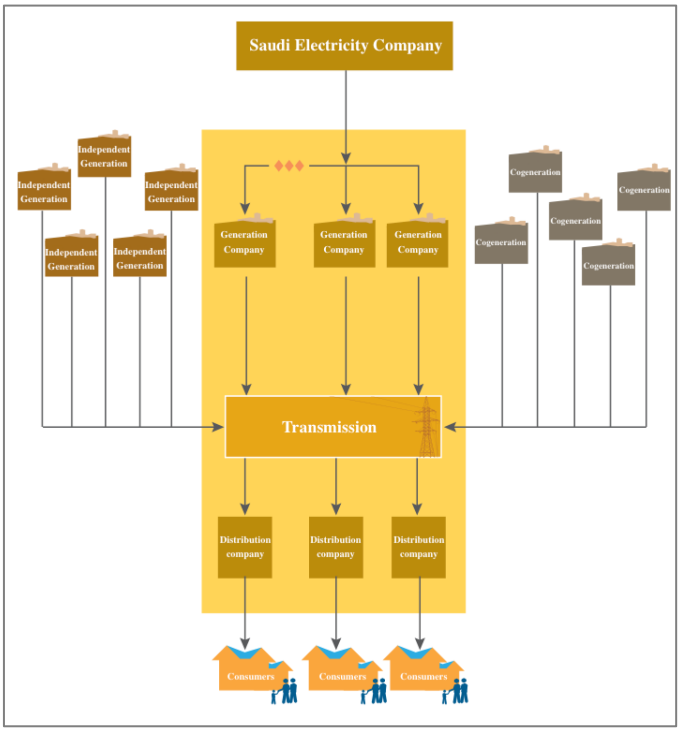


Figure 3.3: Structure of the electricity industry after Phase I of the restructuring plan

Source: (ECRA, 2015).

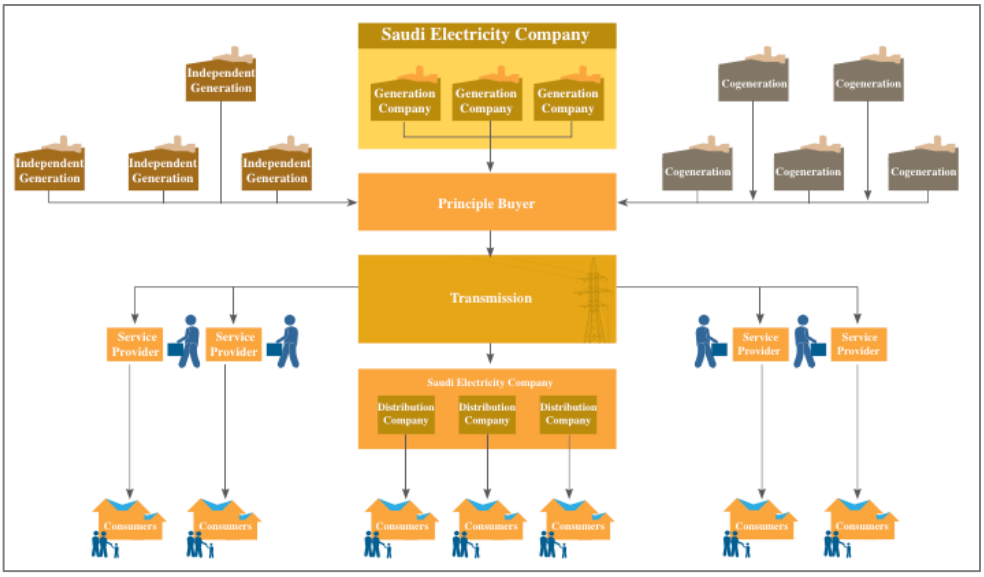


Figure 3.4: Electricity industry structure after the full implementation of the restructuring plan

Source: (ECRA, 2015).

3.1.3 Electricity supply

The technology mix is dominated by gas turbines with almost 40% of the total share, followed by steam turbines (32%) and combined cycles which reached up to 11% of the total mix generation in 2013 (Figure 3.5).

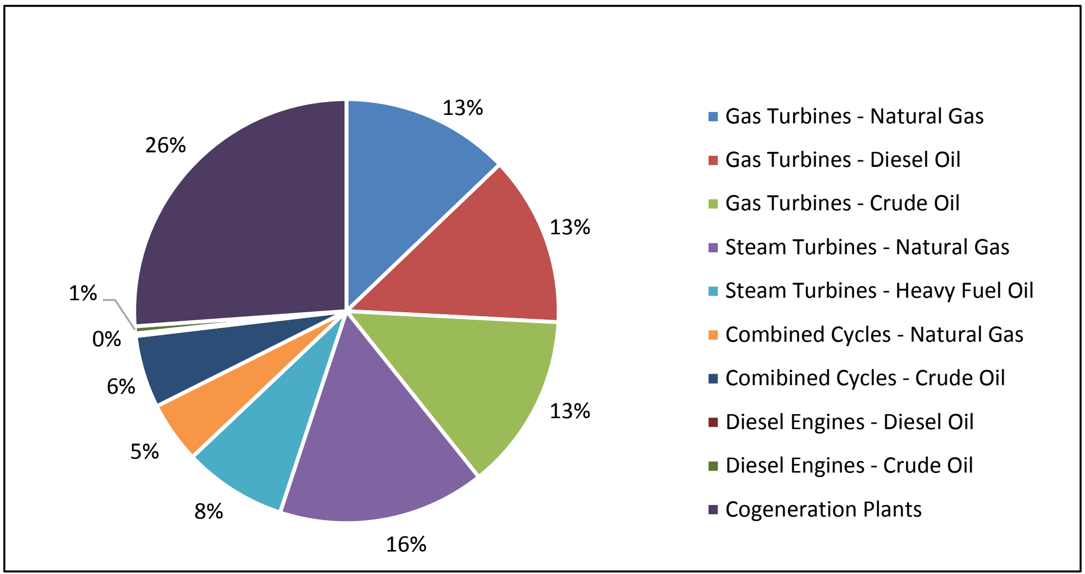


Figure 3.5: Technology mix of Saudi Arabia for the year 2013

Source: (ECRA, 2015)

The main parameters for the existing power plants are outlined in Table 3.3.

Table 3.3: Main parameters for each type of existing technology in 2013

Plant Type & Fuel	Efficiency	Capital Cost [SR/kW]	Fixed O&M [SR/kW-year]	Variable O&M [SR/MWh]	Load Factor	Sources
Gas Turbines (Natural Gas)	39%	2 138	36.34	12.75	46%	(Energinet.dk, 2010)
Gas Turbines (Diesel Oil)	38%	3 520	39.53	16.16	46%	(Energinet.dk, 2010)
Gas Turbines (Crude Oil)	40%	3 830	0	29.75	46%	(Energinet.dk, 2010)
Steam Turbines (Natural Gas)	45%	3 950	153	3.32	56%	(Energinet.dk, 2010)
Steam Turbines (Heavy Fuel Oil)	45%	3 950	153	3.32	56%	(Energinet.dk, 2010)
Combined Cycles (Natural Gas)	57%	2 445	0	17.85	82%	(Energinet.dk, 2010)
Combined Cycles (Crude Oil)	57%	2 445	0	17.85	82%	(Energinet.dk, 2010)

Diesel Engines (Diesel Oil)	40%	5 950	0	46.75	48%	(Energinet.dk, 2010)

Electricity generation based on oil dominates annual production representing almost 55% of the total electricity produced in 2013, while natural gas represented 46% as outlined in Table 3.4.

Table 3.4: Annual electricity production at SEC plants per fuel type in 2013

Fuel Type	Annual Electricity Produced [MWh]	Share of Total [%]
Natural Gas	97 976 227	46%
Crude Oil	61 601 245	29%
Diesel Oil	30 986 300	15%
Heavy Fuel Oil	22 341 837	10%
Total	212 905 609	100%

Source: (ECRA, 2015).

Note: Cogeneration plants excluded.

3.1.4 Electricity demand

Projections of KSA's energy demand envision a tremendous need of additional power capacity for the next two decades. If nowadays Saudi Arabia yearly energy demand is set to 60 GW, demographic and economic growth, as well as increasing urbanization, in the next 20 years will push that amount to nearly the double of the current level, i.e. 130 GW of power generation capacity by 2032 (KA-CARE, 2013).

3.1.5 RE Policies, regulations and milestones

At a regional level, an important milestone for the development of renewable energy pathways in the Arab region is represented by the "Pan-Arab Strategy for the Development of Renewable Energy Applications: 2010 – 2030", adopted by the Arab Economic and Social Development Summit in January 2013. The agreement points towards a consensus on key goals to improve the region's energy future. Based on approved national targets, it is forecasted that 75 GW of renewable energy sources will be added within the Arab countries by 2030 (IRENA, 2014).

At a national level, Saudi Arabia established a governmental agency on April 17th 2010, King Abdullah City for Atomic and Renewable Energy (K.A.CARE) by the Royal order A/35 of H.M. King Abdulaziz Al Saud. The aim is to create a sustainable future for the kingdom of Saudi Arabia through the development of an alternative energy capacity (KA-CARE, 2013). In order to ease the increasing pressure on the country's hydrocarbon resources, the Saudi government has thus decided to introduce alternative, sustainable and reliable energy sources for power generation and water desalination.

K.A.CARE declared that the introduction of alternative energy sources will produce a significant reduction of the amount of oil used for power generation and water desalination, ensuring a longer-term availability of hydrocarbons for exports and national industry utilization (KA-CARE, 2012). A balanced mix of conventional and alternative energy sources was found to be the strategically optimal solution to guarantee the Kingdom with long-term prosperity, energy security and a leading position in the international energy market.

3.1.5.1 Renewable energy targets

In the proposed Renewable Energy program it is projected that by 2032 more than half of the national energy generation will come from alternative (renewable plus nuclear) energy sources. The targets proposed by KA-CARE for 2032 (most likely postponed to 2040)[8] are broken down as presented in Figure 3.6.

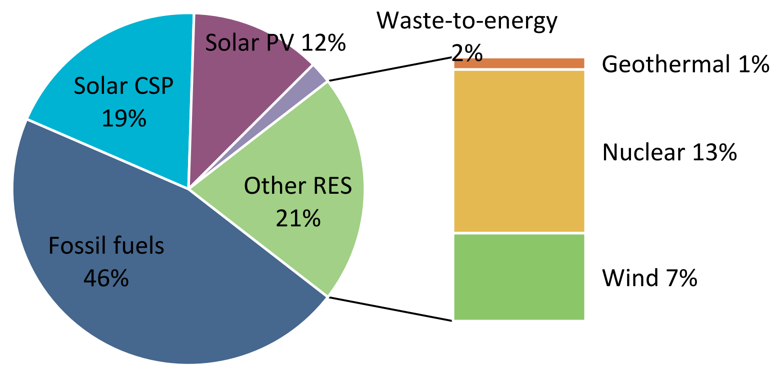


Figure 3.6: Projected KSA energy mix in 2032

Source: Own figure based on (KA-CARE, 2016).

In such a scenario, hydrocarbons will still be a prominent supplier of energy in Saudi Arabia, accounting for 60 GW of installed capacity. However, the plan is to supply only “remaining” energy demand with such conventional energy source. The additional 54 GW, needed to cover the growing energy demand at national level and freeing up oil resources for exports, will be covered by alternative energy sources. Base-load capacity will be provided by nuclear power (17 GW) with the addition of geothermal (1 GW) and waste-to-energy (3 GW) in order to form the base-load capacity “up to night-time demand during winter”. In addition, solar energy exploited through photovoltaics (16 GW) will meet the total daytime demand year round, whereas concentrated solar power with storage capacity (25 GW) will meet the maximum demand difference between photovoltaic and base load technologies. Finally, wind power (9

[8] http://www.reuters.com/article/2015/01/19/saudi-nuclear-energy-idUSL6N0UY2LS20150119

GW) will be entirely dedicated to desalination processes for tackling the water scarcity issue in the KSA. Figure 3.7 provides a graphical explanation, on a yearly scale. Area (1) represents the average annual load, area (2) the addition summer load and area (3) the daily summer peak loads. The Solar CSP technology with storage can contribute to the base load, in summer season and in peak loads.

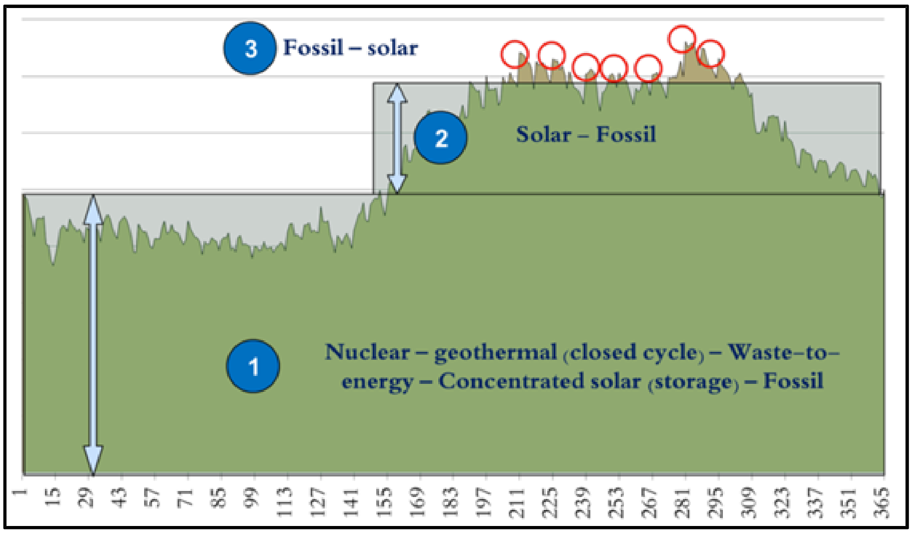


Figure 3.7: Proposed energy mix for the year 2032

Source: (KA-CARE, 2012).

Figure 3.8 depicts the deployment pathway proposed by KA-CARE for renewable energy technologies up to 2032.

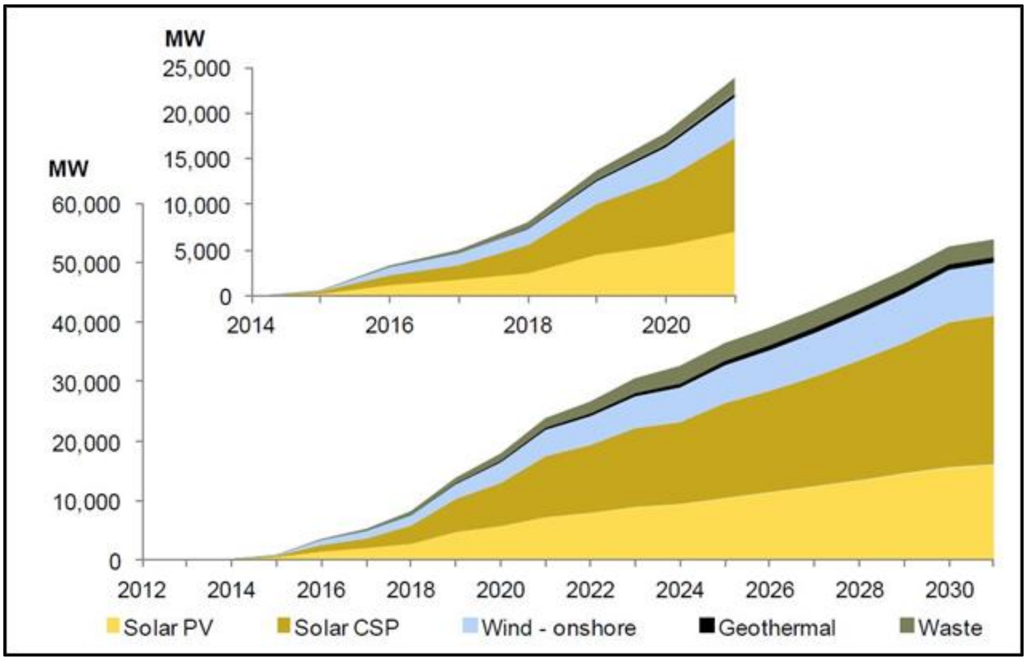


Figure 3.8: Long term Renewable Energy targets

Source: (KA-CARE, 2016).

A high penetration of solar energy (CSP and PV) is foreseen by 2032. Nevertheless the installed capacity based on fossil fuels will still play a key role in the summer season as illustrated in Figure 3.9.

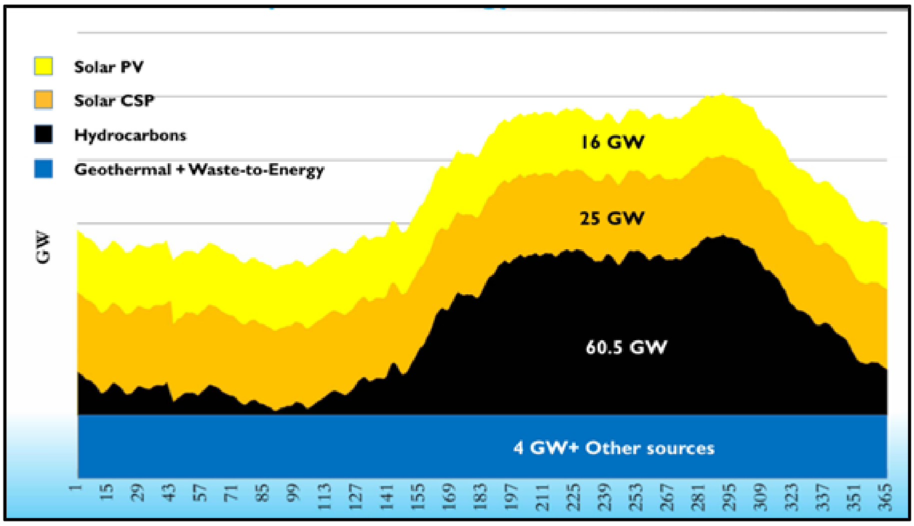


Figure 3.9: Proposed energy mix for the year 2032

Source: (KA-CARE, 2012).

3.1.5.2 Renewable energy policies

In terms of supporting policies for the implementation of the Renewable Energy program the following policies are in place (or are being considered):

- KSA has implemented public competitive bidding on municipal and national level. Public competitive bidding encourages private sector investment in large-scale RE projects;
- Additionally, it is considering a FIT (Feed-in Tariff) programme for small-scale RE power producers. FIT programmes would reward small power producers with premium prices for each unit of renewable energy electricity produced.

The implementation of FIT policies in KSA could be performed in two stages in order to promote investment and deployment of RE technologies. In the first stage, it is proposed the implementation of a market-independent FITs (e.g. fixed price FIT) in order to ensure a solid return on investments to investors while restructuring the energy market in KSA. Once market mechanisms/dynamics are in place and competition is introduced in the Saudi energy market, market-dependent FIT could be implemented in order to scale up and achieve full benefits of investments in RE supported by such a FIT policy scheme (Ramli A.M & Twaha S., 2015).

In terms of supporting financial and fiscal incentives at national level, several countries in the MENA[9] region have already established national renewable energy and energy efficiency funds, e.g. Algeria, Egypt, and Jordan. KSA is currently considering the establishment of such a fund in order to mobilise and facilitate financing of clean energy projects (IRENA, 2014b).

A prominent focus of KA-CARE, when promoting the development of the Saudi RE sector, lays on the aim of building a proper world-class renewable (mostly solar) energy sector in KSA. Hence, much attention is focusing on the value chain development of the solar energy sector, aiming at the creation of a manufacturing sector for the development of RE (solar) technologies. For such purpose, KA-CARE developed a "Value Chain Activation Plan" which encloses a 16-steps approach, as depicted in Figure 3.10.

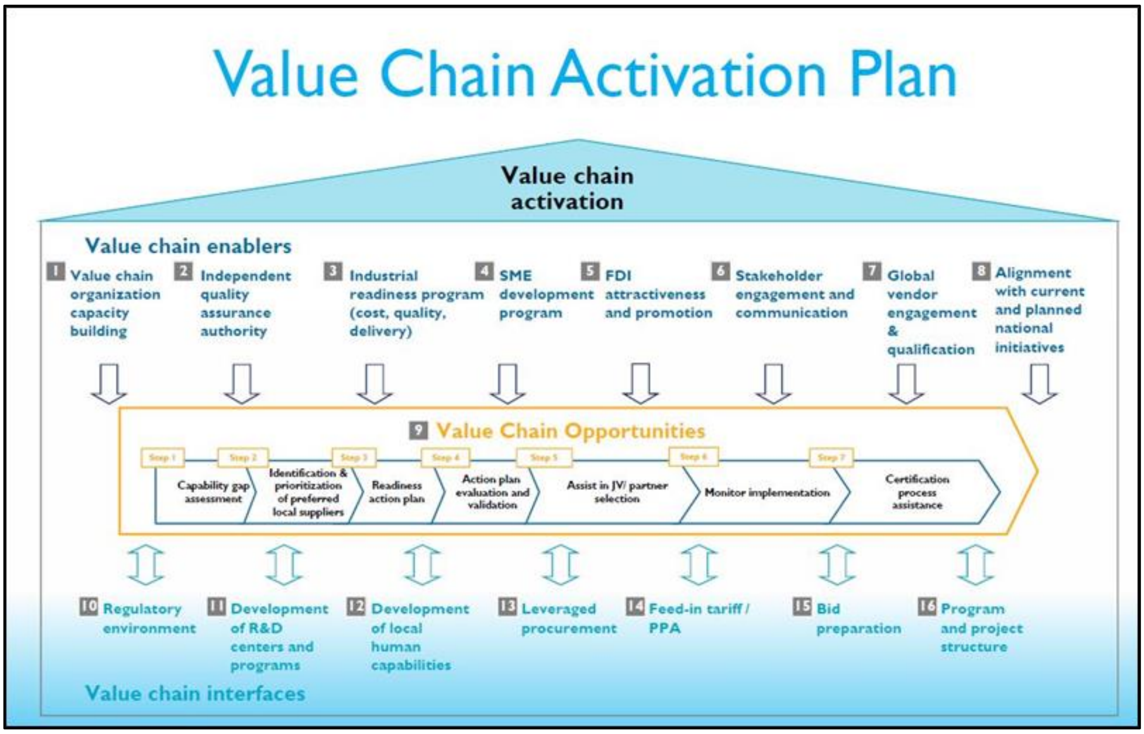


Figure 3.10: Value Chain Activation Plan

Source: (KA-CARE, 2012).

Ideally, such a development pathway will help in boosting the KSA's economy, opening up new job opportunities in the solar energy sector for the Saudi population.

3.1.6 Solar Potential

The Arabian Peninsula, mostly occupied by Saudi Arabia, has abundant solar potential. Every day remarkable quantities of sunshine fall on this region, on average enough to produce 12 425 TWh of electricity for approximately 50 years, given the current consumption rate,

[9] Middle East and North Africa region.

(Aljarboua, Z., 2009). The country large area, its close proximity to the equator and the plentiful availability of sunlight throughout the year qualifies KSA as a good candidate for the depletion of solar energy technology. Moreover, the KSA has one of the highest insolation rates of the world. As a consequence, a major plan of K.A.CARE plan for the introduction of renewable energy is the implementation of clean and cost-effective solar energy technologies.

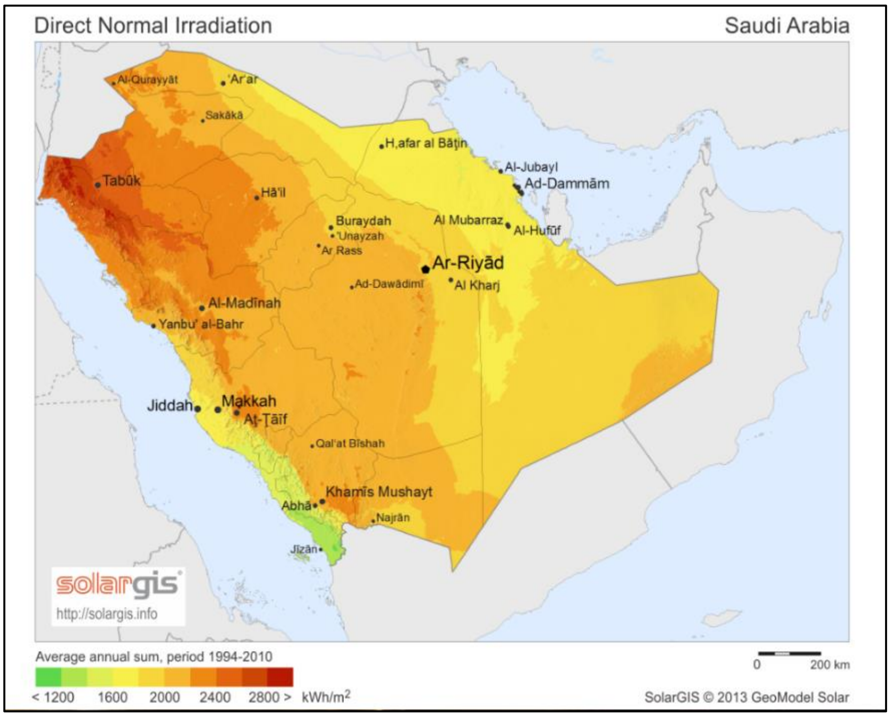


Figure 3.11: Direct Normal Irradiation map for Saudi Arabia

Source: (Saudi-sia, 2013).

Figure 3.11 and Figure 3.12 illustrate the long-term annual average of the Direct Normal Irradiation and the Global Horizontal Irradiation for Saudi Arabia. The data have been extrapolated from the SolarGIS database (Saudi-sia, 2013), a geographical information system designed for those areas receiving strong concentrations of solar irradiation. The SolarGIS data is validated with ground measurements from 12 different stations in Saudi Arabia, thus it can be considered quite accurate and it can be used to identify the best solar power sites but also to estimate the long-term power availability.

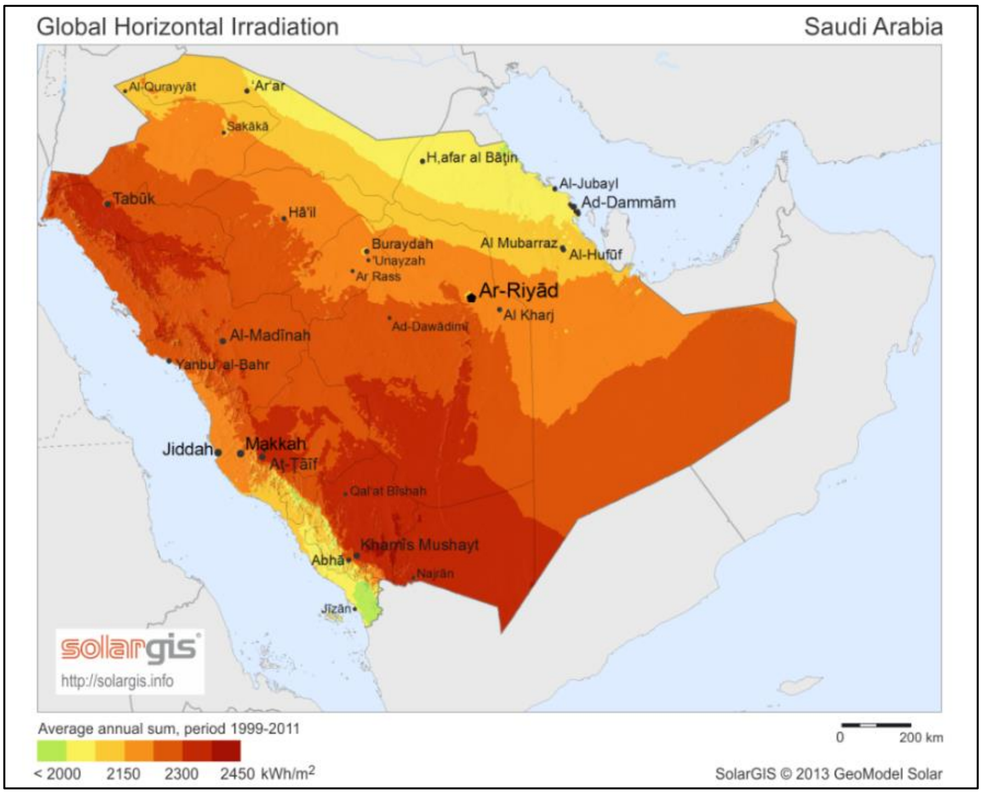


Figure 3.12: Global Horizontal Irradiation map for Saudi Arabia

Source: (Saudi-sia, 2013).

3.2 Mexico

For Mexico, the market conditions are defined by:

1. High oil production and exports: Mexico is one of the top ten oil exporters in the world;
2. Considerable high population: about 118 million inhabitants;
3. Significantly increase in electricity demand: approximately 90% from 2000 to 2015;
4. High electricity prices;
5. Three isolated interconnected systems: the National, the Baja California and the Baja California Sur systems.

3.2.1 Market description

Mexico is a federal republic located in North America whose population is estimated to be over 118 million (CONAPO, s.f.). The state is currently considered as a newly industrialized and emerging country. Mexico is one of the ten largest oil producers in the world, meaning that oil is a main component in the country's economy.

The oil and gas sector was in a 75-year monopoly of the state-owned PEMEX (Petroleos Mexicanos). In December 2013 the Mexican government enacted constitutional reforms to treat the decline of its domestic oil production, which leaded to direct impacts on the country's economy. The Mexican government broke the PEMEX's monopoly opening it to foreign investment, although PEMEX continued being state-owned. PEMEX now has more budgetary and administrative autonomy and will have to compete for bids with other firms on new projects (U.S. Energy Information Administration, 2014).

On the other side, the state-owned Comisión Federal de Electricidad (CFE) is the dominant player in the electricity generation sector, with more than 75% of the country's installed capacity. Moreover, CFE owns and operates all the electricity transmission and distribution (Anon., s.f.). The SENER (Secretaría de Energía), a government unit, and CRE (Comisión Reguladora de la Energía), an independent organization, have regulatory and supervisory authority over the wholesale power market. The CENACE (Centro Nacional de Control de la Energía) is the responsible party for guaranteeing open access to transmission and distribution. It also operates the dispatch of the system. CENACE was a unit within the CFE, but on December 2014 started to be the independent system operator for the entire grid.

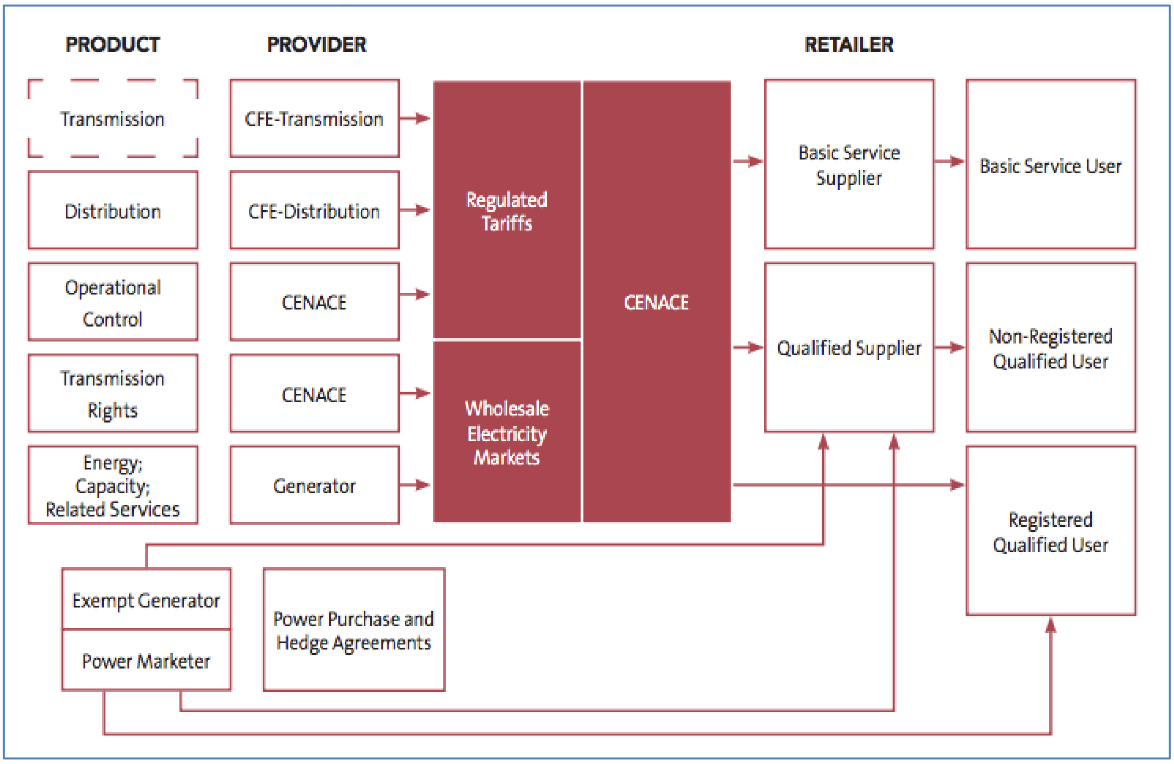


Figure 3.13: Mexican wholesale electricity market overview (Bierzwinsky, 2014)

Figure 3.13 provides an overview of the Mexican wholesale Electricity Market. For further clarification about the structure, refer to (Bierzwinsky, 2014).

3.2.1.1 Reform of the power market

In December 2013, the reform of the electricity market was promulgated by the Mexican government (Wikipedia, 2013). The objective was to increase supply competition in generation. In order to understand the reform it is necessary to analyse the role that the CFE plays in the market design. At the beginning of 2016, the market opened for all generators, including the CFE. The electricity market was divided into regulated and non-regulated market (Wholesales Electricity Market or MEM), thus limiting the monopoly of CFE.

The CFE can participate in both markets but is obliged to supply electricity into the regulated market (which demand is around 42% of the net electricity generation). The same market today is facing several challenges such as: 1) deregulation of electricity prices, 2) improvement in efficiency and 3) implementation of cost-effective incentives (Energiadebate, 2016).

The reform will not only liberalize the generation sector but also part of its commercialization. CENACE is the institution responsible for the commercialization of electricity. The regulated market will supply electricity into the residential, services and agriculture sectors while the non-regulated market will serve to the industrial sector (Energiadebate, 2016).

3.2.1.2 Market price

The electricity tariff for the end-user is equal to the sum of energy acquisition cost, access tariffs and commercialization cost. The marginal cost of generation, which is part of the energy acquisition cost, is the only element in the electricity tariff subject to free market. The remaining part of the cost is directly regulated, for example, through transmissions tariffs or indirectly regulated as capacity cost as a function of marginal reserves defined by the CRE.

The CRE defines short-term total cost (CTCP in Spanish) as "unit cost of electricity from a plant, during the period in question in the node considered (Mexico´s energy market is node based). It includes energy and all variable costs of operation & maintenance in which the plant incurred as a result of the activities of generation and transmission of energy to the interconnection point" (CRE, 2002).Therefore, the CTCP can be explained as the marginal cost of the variable cost in one specific node of interconnection. This is a key component of the non-regulated market.

3.2.1.3 Characteristics of the wholesale electricity market (MEM)

The MEM is characterized by four main features/products:

1. A daily electricity trade: market scheme that allows to purchase and sale electricity in a real time and in a day-ahead basis;
2. Power market: this product is designed to satisfy peak demand;
3. Clean energy certificates: this will help to promote the deployment of "clean technologies[10]" by imposing the suppliers to generate 25% of energy coming from this technologies by 2018;
4. Insurance against unforeseen: this product will protect suppliers from significant power variations in the electricity transmission.

3.2.1.3.1 Daily electricity trade

A division of the wholesale electricity market offer purchase and sale of electricity in a real time and in a day-ahead basis. Its purpose is to allow the players to choose the cheapest electricity at all times.

According to the SENER, the generators connected to the nodes provide energy in each of the 2 000 nodes and in each of the substations of the system. Each node will have a tariffs (price) related with the generation cost of the units available.

The CRE is responsible for defining the tariffs that the CFE will use for the start of the market. The tariffs are different according to the 16 different regions: three tariffs for the Valley of Mexico, and five depending on electricity demand - which are split into: two for households,

[10] Nuclear Energy is considered as a “Clean Energy” technology since it does not contribute to the CO_2 emissions.

two for low demand and one for high demand, thus reflecting part of this price differentiation (Expansion, 2016).

3.2.1.3.2 Power market (peak hours)

Power market is the second product in the wholesale electricity market. This market focuses on increasing supply in the about 100 peak that occur each year, and that the basic suppliers cannot attend. Therefore, there will be plants that will keep some capacity exclusively to meet this exceptional demand, and it will be paid a higher price, which allows these generation projects become profitable.

Within the wholesale electricity market there are auctions, in which the market operator (the CENACE) contracts energy and power. The auction concerns both long and medium-term (Expansion, 2016).

3.2.1.3.3 Clean energy certificates

The third product is the other auctions in the market, which monopolize the new clean energy certificates (CEL in Spanish). The certificates force the suppliers to provide an amount of energy (around 25%) from sources that do not generate greenhouse gases (GHGs) by 2018 (Expansion, 2016).

3.2.1.3.4 Insurance against unforeseen

The fourth product is a financial one, which will protect suppliers to abrupt changes in the price of electric power transmission. This kind of insurance will have a higher price in order to force participants to use them, to the point where they see more efficient increase and improve their capacity (Expansion, 2016).

3.2.2 Electricity sector

According to SENER, Mexico's total electricity generation increased around 25% in the last decade, reaching a value of 258 billion kWh in 2013 (U.S. Energy Information Administration, 2014), with a total effective generation capacity of 53.5 GW in the same year. This value has increased up to 54.9 GW in February 2015 (Anon., s.f.). It is worth noticing that Mexico exports electricity mainly to United States, but also small amounts to Belize and Guatemala. Electricity imports come mainly from the US.

Most of the electricity is generated by CFE, but private parties can also generate power in some limited circumstances, in these different ways (Practical Law, 2014):

- **Self-supply**: A private party generates power to satisfy its needs;
- **Self-supply Power Projects (SSPPs)**: A private party generates electricity and delivers it to its partners or shareholders;
- **Independent Power Producer (IPP)**: A private party generates electricity and sells it to the CFE, which will distribute and commercialise it;
- **Export**: A private party generates electricity for export.

Hence, the only entity that can sell electricity in the wholesale market is the CFE. The national electric system (SEN) includes three differentiated power systems:

- Sistema Interconectado Nacional-SIN (National Interconnected System);
- Baja California (expected to be connected to the SIN in 2018 (Secretaría de Energía, 2014);
- Baja California Sur

which currently are not interconnected. Figure 3.14 illustrates the situation.

Figure 3.14: National electricity system in Mexico 2009-2010

Source: (Diaz Bautista, A., 2011).

Note: The interconnected systems for both Baja California and Baja California Sur are outlined in Figure 3.14, while the rest corresponds to the National Interconnected System (SIN).

The power system of Baja California is interconnected to California (U.S), thus relying on the electricity imports from the U.S. However, it also has faced serious security of supply problems in the past. The U.S West Coast suffered one of the major North American blackouts in July and August 1996, lasting almost 9 hours in some areas. The power shortage thus affected not only the whole West Coast in the U.S but also Baja California in Mexico (OECD/IEA, 2005).

Figure 3.15: Interconnected systems in both Baja California and Baja California Sur 2009-2010

Source: (Diaz Bautista, A., 2011).

The Baja California Sur power system is isolated from the rest of the interconnected systems as illustrated in Figure 3.15. The lack of interconnections makes this system extremely vulnerable to blackouts, highlighting the low stability of the power system.

3.2.3 Electricity supply

Figure 3.16 shows Mexico's electricity generation evolution from 2004 until 2013 by source.

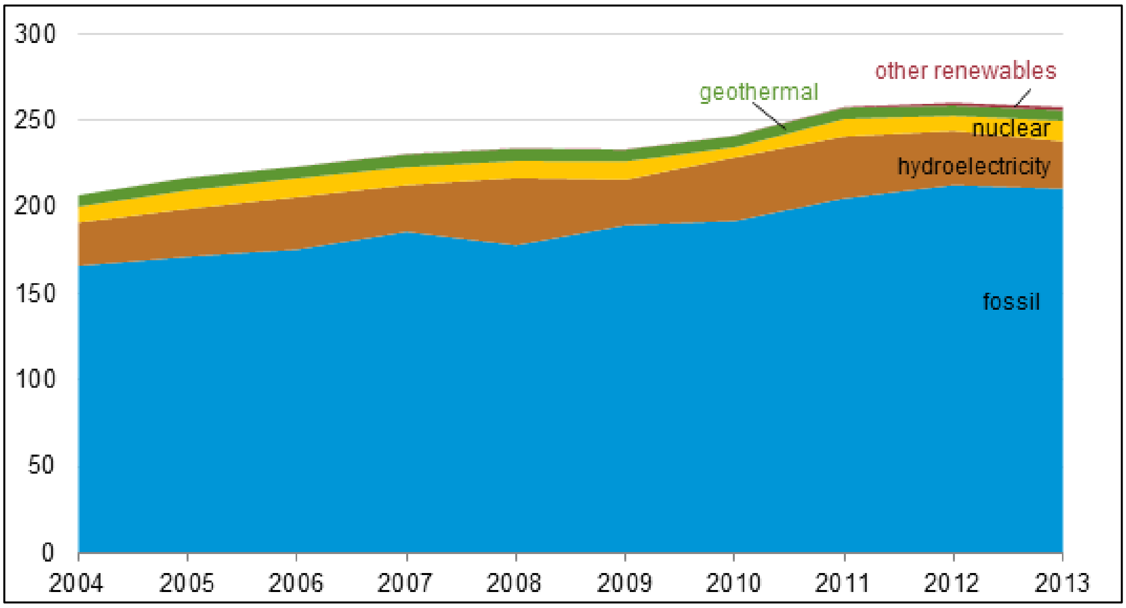


Figure 3.16: Mexico's electricity generation by source in billion kWh

Source: (U.S. Energy Information Administration, 2014).

As depicted from the graph, fossil-fuelled power plants provide most of the electricity generation, which increasingly uses natural gas as fuel source. Figure 3.17 shows the evolution of the consumption of each type of fossil fuel for electricity generation.

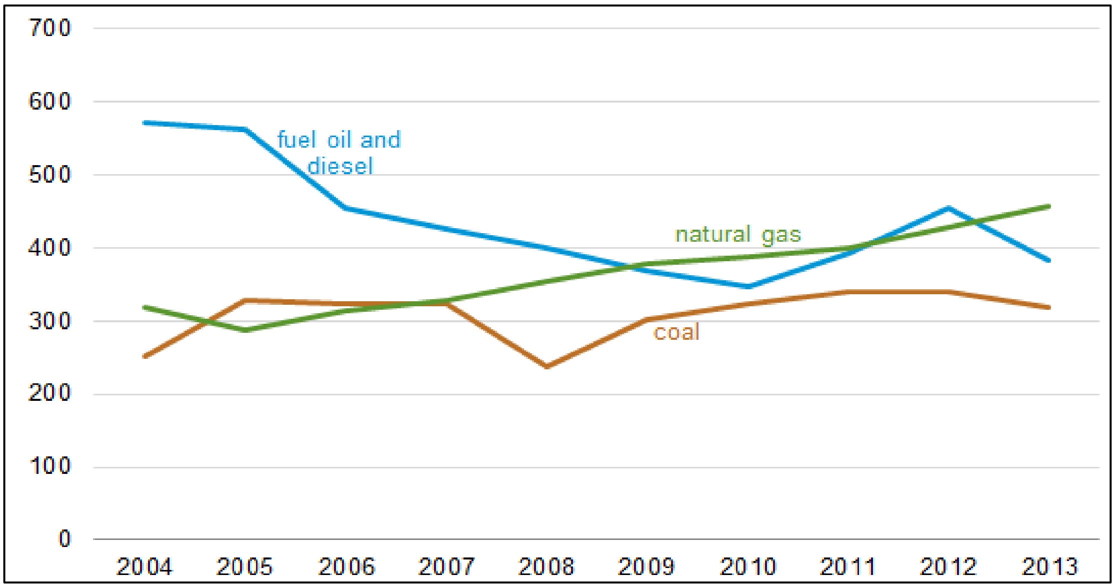


Figure 3.17: Consumption of fossil fuels for electricity generation in trillion Btu

Source: (U.S. Energy Information Administration, 2014).

Fossil fuels have a main role in the Mexican electricity generation sector, since conventional power plants hold a 75% of the total capacity.

Regarding nuclear power, there exists one nuclear power plant of 1 400 MW operated by CFE, which was modernized by Alstom in 2012.

Hydropower is the main source of RES, producing about 11% of Mexico's electricity generation in 2013. The rest of the renewable sources generated only the 3% of the total amount of electricity that year. Geothermal, along with biomass and waste are the most significant sources, followed by wind and solar energy. Nevertheless, Mexico is poised to become one of the world's fastest growing wind energy producers, with many recent wind projects in Baja California and southern Mexico. Specially, Oaxaca has very favourable wind resources and has been a focus of the government efforts within the renewable capacity development.

Figure 3.18 shows the installed capacity by technology in February 2015 in the national electric system.

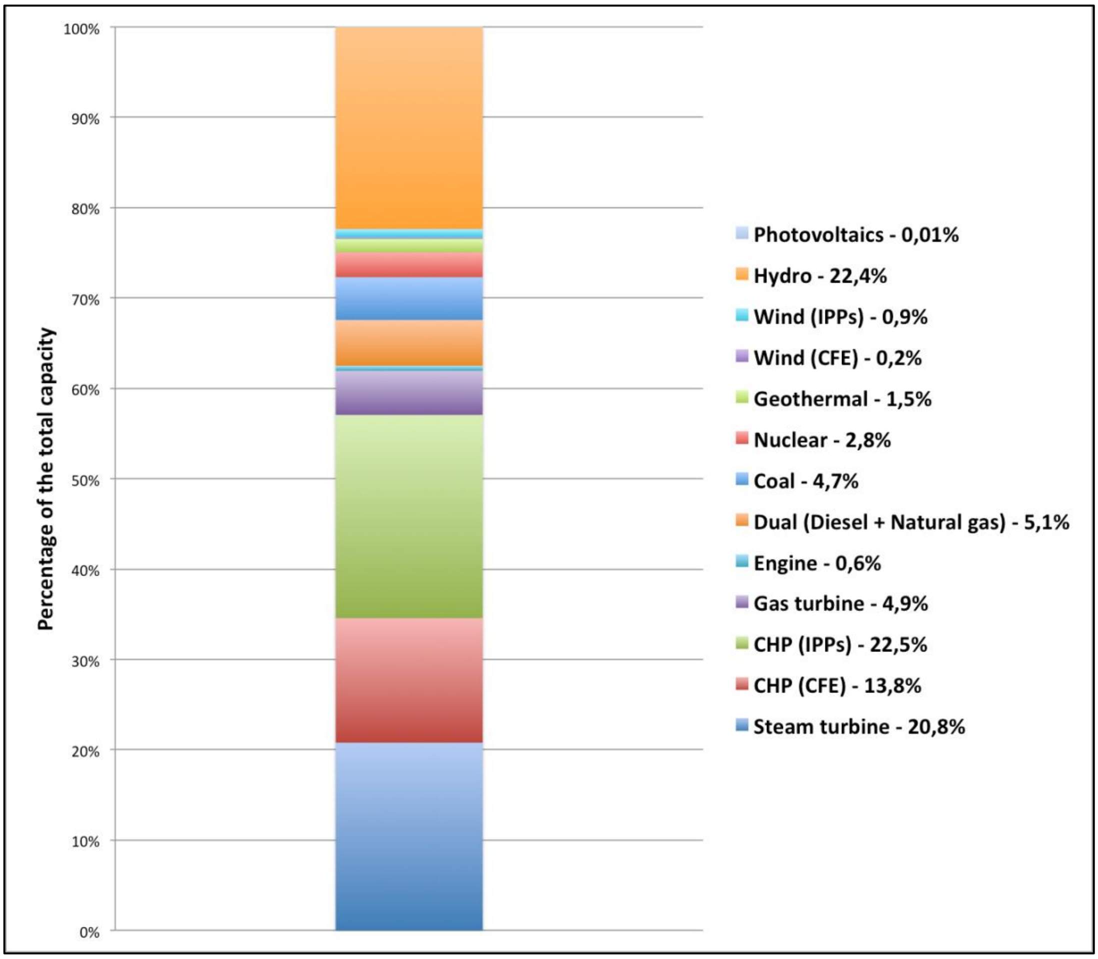


Figure 3.18: Current effective capacities in the Mexican power system (February 2015)

Source: (Anon., s.f.).

3.2.4 Electricity demand

In 2014, the total gross demand in Mexico was 284 382 GWh for the whole national electric system (SEN). Values for Baja California and Baja California Sur were 13 312 GWh and 2 369 GWh, respectively (Secretaría de Energía, 2014).

The maximum demand in 2014 was 39 000 MWh for the SIN, 2 360 MWh for Baja California and 454 MWh for Baja California Sur. Hourly profiles of the maximum demand for the SIN, Baja California and Baja California Sur can be found at (Centro Nacional de Control de Energía, s.f.).

Table 3.5 shows the annual gross demand forecast in GWh for the whole national electric system (SEN), national interconnected system (SIN), Baja California and Baja California Sur.

Table 3.5: Annual gross demand forecast on a national level and for Baja California in (GWh)

Year	SEN	SIN	Baja California	Baja California Sur
2015	291 931	275 593	13 667	2 488
2016	297 484	280 643	14 029	2 617
2017	302 948	285 491	14 498	2 760
2018	317 298	298 948	15 218	2 924
2019	330 742	311 449	15 959	3 118
2020	345 973	325 708	16 684	3 357
2021	361 582	340 358	17 387	3 603
2022	377 670	355 417	18 145	3 864
2023	394 725	371 334	18 986	4 150
2024	413 393	388 798	19 881	4 448
2025	434 320	408 436	20 824	4 781
2026	456 130	428 828	21 835	5 175
2027	479 093	450 247	22 927	5 613
2028	502 947	472 453	24 086	6 087

Source: (Secretaría de Energía, 2014).

3.2.5 RE Policies, regulations and milestones

On November 29, 2008 the Mexican Congress approved the Law for the Use of Renewable Energy and for the Financing of Energy Transition (Sasse, 2009) which sets as a target that 35% of the total energy produced should come from renewable sources by 2024, 40% by 2035 and 50% by 2050. Nevertheless, no sanctions or consequences will happen if targets are not met. Furthermore, on April 28, 2014 the Special Program for the exploitation of Renewable Energies (Anon., 28) was presented and on August 12, 2014 a package of nine laws covering the energy sector and amendments to 12 existing laws came into effect, trying to convert the Mexican energy system in a competitive market.

Currently, the new laws have no specific provisions for renewable energy projects. The law only defines RES as “clean energies” (defined as any type of energies not exceeding a given threshold of emissions). The law just fixes a minimum purchase requirement for clean energy certificates, which will be tied to the total electricity consumption (Bierzwinsky, 2014). There exist some incentives to encourage renewable energy projects. Nevertheless, these are not the often used European incentives as can be tax credits, feed-in tariffs or subsidies, but others. Examples are: funds to foster renewable projects, project financing, preferential transmission tariffs or regulation instruments diminishing the drawbacks of excess renewable energy production (Practical Law, 2014). Furthermore, the existing deficiencies in the transmission system avoid the larger introduction of renewables in the system.

Despite all this, the Mexican market is seeing an increase in renewable energy projects, which are mainly structured as SSPPs (Self-Supply Power Projects). This means that a company can generate electricity and deliver it to its shareholders or partners, but not distribute and commercialise it in the wholesale market.

Note that one of the main reasons for the energy reform in 2014 was the willingness to reduce electricity generation costs and at the same time reduce industrial rates (which are almost double than in US). This could be done only allowing cheaper generation (e.g. current renewable technologies) to enter the market. However, this is not happening as predicted. CFE owns a majority share of generating capacity in the country being in this way the price-setter in the system. Thus, CFE and existing IPPs take profit of the fact that marginal generating costs are below the power price. This imply that existing generators naturally cooperate against the entry of new units in the system, adding obstacles related to permitting, availability and prices of transmission/distribution that does not encourage the participation in the market. This situation highlights the need of an adequate regulation in order to help the reforms to improve the competitiveness in the energy system (Anon., s.f.).

3.2.6 Solar potential

The solar potential in Mexico is suitable for installing CSP plants, particularly in Baja California Sur where the annual average Global Horizontal Irradiance (GHI) is more than 2 300 kWh/m^2 as illustrated in Figure 3.19. In Mexico the DNI exceeds the minimum required of installing CSP plants ranging between 1 800 to 2 000 kWh/m^2 per year (Trieb et al., 2009). The power systems of Baja California and Baja California Sur are isolated from the rest of the interconnected system (SIN). Moreover both systems heavily rely on thermal power plants fuelled by coal and natural gas. Thus HYSOL project can thus contribute not only to balance the system when high penetration of RE will come into place in the future, but also to could contribute decarbonizing the interconnected system in both Baja California and Baja California Sur

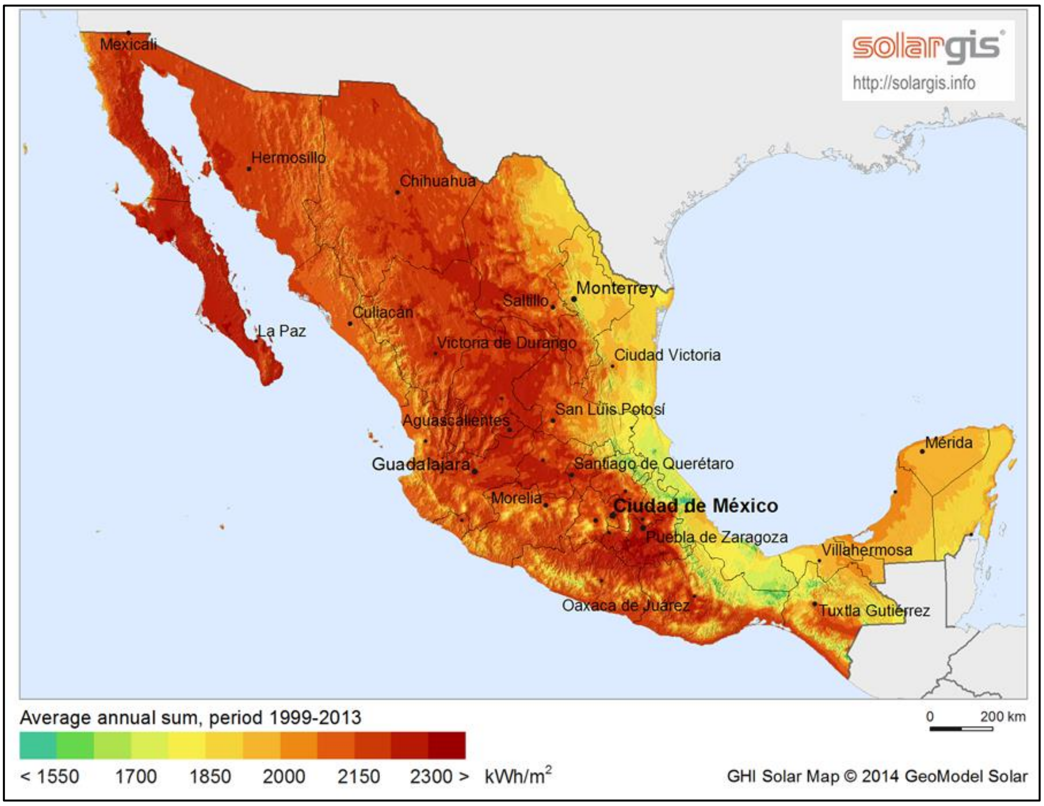


Figure 3.19: Average annual global horizontal irradiation (GHI) in Mexico

Source: (SolarGIS, 2014).

3.3 Chile

The Chilean market is characterised by:

1. An energy intensive copper mining industry: Chile is the top producer of copper in the world, accounting for 31% of the global production in 2014, this production is related to a 33% of all electricity demanded;
2. High electricity prices: the average electricity price is higher than the average OECD electricity price in 2011, however, the electricity prices are expected to decrease in the short-term;
3. Four isolated interconnected systems: the main interconnected systems, the Central (SIC) and the Northern (SIG), will be connected by 2018;
4. Completely privatized electricity market: controlled by a small number of companies though.

3.3.1 Market description

Chile's economy was expected to keep growing at a rate between 4% - 5% for the next fifteen years, based on the economic growth experienced in the last decade. However, the economy registered a slowdown with an increase of only in 1.9% of the national GDP in 2014, and an increase in GDP of 2.1% in 2015. This economic slowdown happened because of the decrease in both copper price and private consumption. A similar growth tendency is expected in the coming years (2016-2017) (World Bank, 2016).

The mining sector drives the Chilean economy. Today, the country is the most prominent producer of copper in the world, accounting for 31% of the global production in 2014 (Wikipedia, 2016).

However, in the recent years, the production cost of copper has decreased from an average price of 3.11 USD/pound in 2014 to 2.15 USD/pound in 2016. This is mainly due to a slowdown in the economic growth of China. Furthermore, it is envisaged that the copper price will be about 2 USD/pound until 2018 (Consejo Minero, 2016). Regardless the decreasing in the copper price along with the consequently decrease in mining investment, the mining sector is still a huge consumer of energy, in the form of both electricity and heat with 75% and 25% of the national industrial consumption respectively. The production of metals in Chile currently uses approximately 33% of all electricity generation. The largest part of this demand comes from the northern region and currently relies on fossil fuels as an energy carrier, despite the fact that the best solar resources are available in the same area (CSP Today, 2014).

Another important element which characterizes the Chilean electricity market is the high electricity prices. In both the industry and the households sector, the average electricity price is higher than the average OECD electricity price.

Chile has four interconnected system: Northern Interconnected System (SING in Spanish), the Central Interconnected System (SIC), the Aysén Electric System (SER) and the Magellan Electric System (SEM). However, the two main electric systems are the SIC and the Northern SING; none of the fourth systems are interconnected among them. With 78% of the total installed capacity the SIC is the most critical system since it serves approximately 92% of the population. On the other hand, the SING represents about 21% of the total installed capacity, and serves only 6% of the population, where most of the clients are heavy industries (approximately 90%).

3.3.2 Electricity sector

The Chilean power market is completely privatized. The current framework was established by the Electricity Act of 1983 and is composed of three segments (generation, transmission and distribution) operating in a completely independent manner. This system attracts investment from international players and leaves a minimal regulatory role to the state. The national electricity industry involves seventy companies. Of these, 40% operate in the generation segment, 7% in transmission, and 53% in distribution. Despite its liberalization, the electricity market is controlled by a small number of companies.

The generation sector in the SIC is dominated by three players: ENEL (former Endesa), Tractevel (Colbun) and AES Gener. Together these companies own approximately 90% of the total installed capacity. The SING market has six dominant players controlling over 99% of the installed capacity: E-CL (GDF-Suez), Electroandina, Gasatacama, Celta, Norgener and AES Gener as depicted in Figure 3.20.

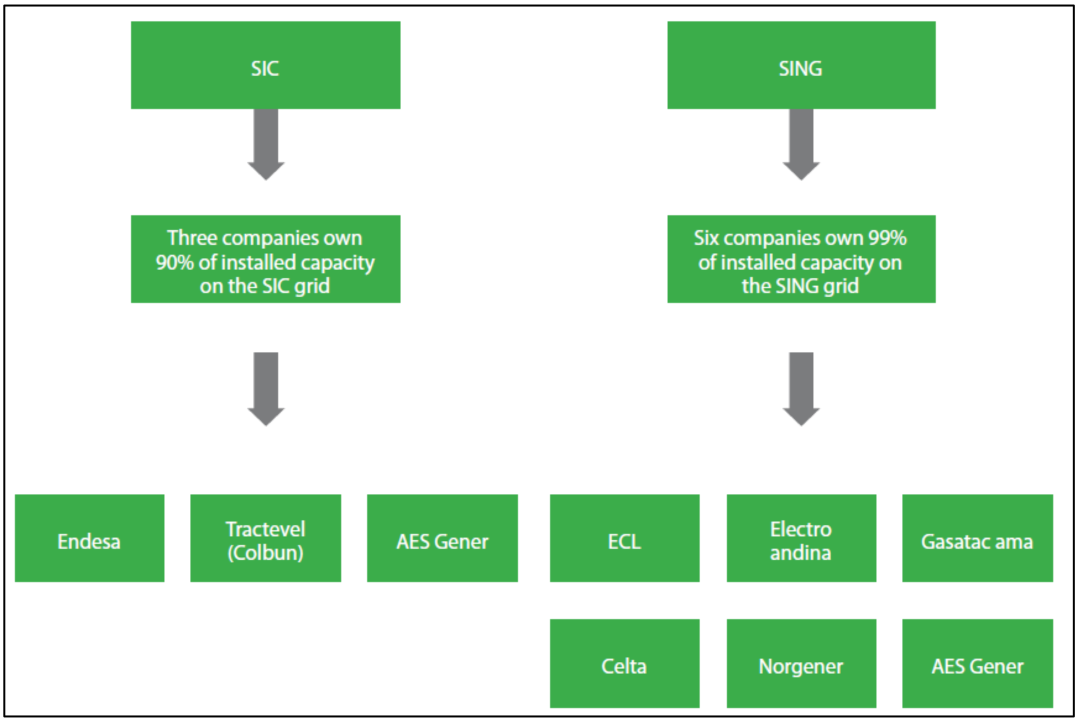


Figure 3.20: Chile's electricity generation market players

Source: (CSP Today, 2014).

A similar situation exists in the distribution sector, where few companies dominate the market: CGE Distribución S.A., Chilectra S.A., Chilquinta Energía S.A., and Inversiones Eléctricas del Sur S.A (Grupo SAESA).

3.3.2.1 Electricity trade

Generators sell the electricity to distribution companies within the wholesale market through public tenders at a fixed price determined by the "Centro de Despacho Económico de Carga" (Economic Load Dispatching Centres) or CDECs, and via long term Power Purchase Agreements (PPAs). PPAs are usually signed for a period of fifteen years. However, generators' owners can also negotiate financial contracts directly with free clients[11] or access the spot market to sell additional production outside of the PPA system. They also pay transmission fees, which can provide a 10% margin to transmission companies. Operators of this sector are classified according to the size of their systems. The large systems have an installed capacity greater than 200 MW, whereas small systems have a maximum capacity of 1.5 MW. Some large mining companies, or other heavy users of electricity, have their own generation. These are mainly developed to avoid the high operational costs of diesel generators and the cost of building transmission lines.

3.3.2.2 Electricity price

The Chilean power market is based on the concept of marginal cost (the last unit of electricity dispatched determines the price). Because of the use of diesel generators for the peak load (after hydro and coal), the price are usually very high.

Chile experiences high electricity prices for both industry and households. These prices were above the OECD average electricity prices in 2011, with 154 USD/MWh for industry and 212 USD/MWh for households as depicted in Figure 3.21. Moreover, Chile has the second-highest electricity prices in Latin America and Caribbean region, after Uruguay (CSP Today, 2014).

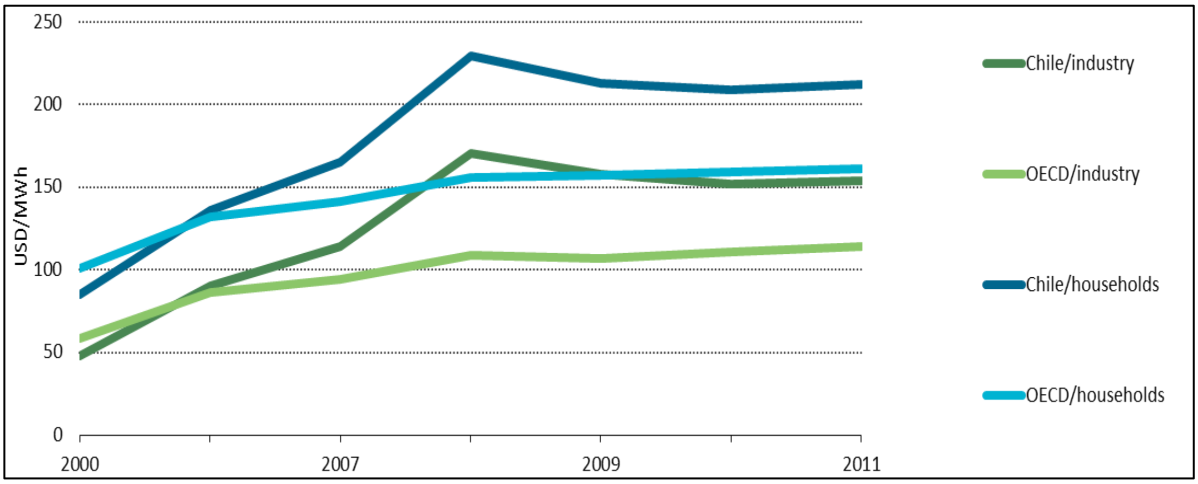


Figure 3.21: Historic electricity prices development in Chile and in the OECD countries

Source: Own figure based on statistics from (IEA, 2012).

[11] Clients with a connected capacity greater than 2 000 kW are considered free clients (mainly companies) while clients with a connected capacity less or equal to 2 000 kW are defined as regulated clients.
http://antiguo.cne.cl/cnewww/opencms/07_Tarificacion/01_Electricidad/

3.3.3 Electricity supply

3.3.3.1 Marginal cost of electricity in the SIC and SING

Since 2013 the average marginal cost of electricity is decreasing and this value is expected to decrease even more in the mid-term (2015-2021), with a range that will vary between 10 to 22 USD/MWh. This is forecast to happen because of four main reasons:

- First, a slowdown in the national economic growth[12] will have a direct impact on the electricity demand;
- Second, a series of unexpected delays in the development of industrial projects (mining), e.g. Pascua Lama, El Moro and Reilincho;
- Third, the decrease in fossil fuel prices, especially diesel and coal. The decrease is due to a reduction of demand for these commodities worldwide, and also because of the overproduction of oil;
- And finally, the incorporation of new actors in the market due to the tender process (2013/03, 2nd call) during December 2014 where 1 400 MW of non-RE installed capacity and more than 1 000 MW of RE installed capacity are expected by 2019.

The incorporation of these installed capacities will reduce marginal cost below the coal cost (currently varying between 80 to 86 USD/MWh (Systep, 2015)).

The future interconnection between the SIC and the SING will also lower the marginal cost in the SING between 14 to 25 USD/MWh with respect to 83 USD/MWh projected without connection between 2018-2021 (Systep, 2015).

In the SIC, the lowest marginal cost of electricity is set by coal power plants at an average 40 USD/MWh. It then follows LNG power plants at 80 USD/MWh, Hydro reservoir with more than 100 USD/MWh, and finally, diesel power plants with an average marginal cost between 140-150 USD/MWh (Systep, 2015). The supply curve is graphically reported in Figure 3.22.

Concerning the power market, the average marginal cost for the SIC was 117 USD/MWh (Alto Jahuel 220) in December 2014.

[12] The slowdown in the Chilean economy is mainly due to a slowdown in the Chinese economy.

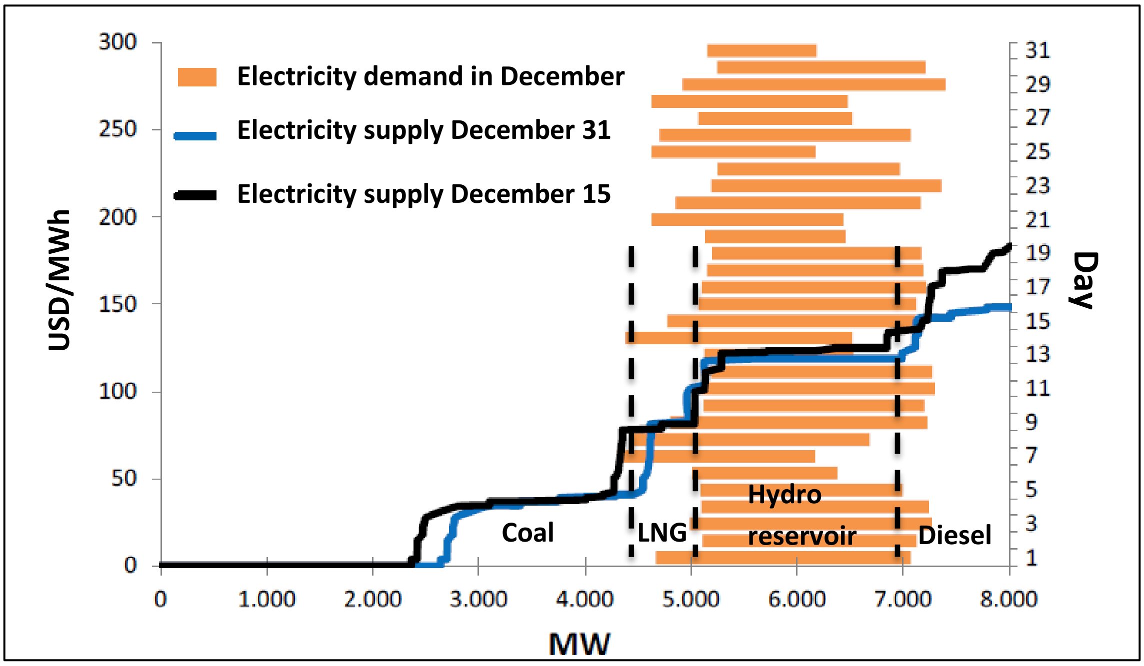


Figure 3.22: Merit order curve in the SIC during December 15 and 31, 2014

Source: (Systep, 2015) based on CDEC-SING data.

On the other hand, the power plants with the lowest average marginal cost in the SING system are the coal power plants (approximately 40 USD/MWh). LNG plants follows with more than 50 USD/MWh. Finally, diesel power plants are the most expensive with marginal cost varying between 150 to 170 USD/MWh as depicted in Figure 3.23.

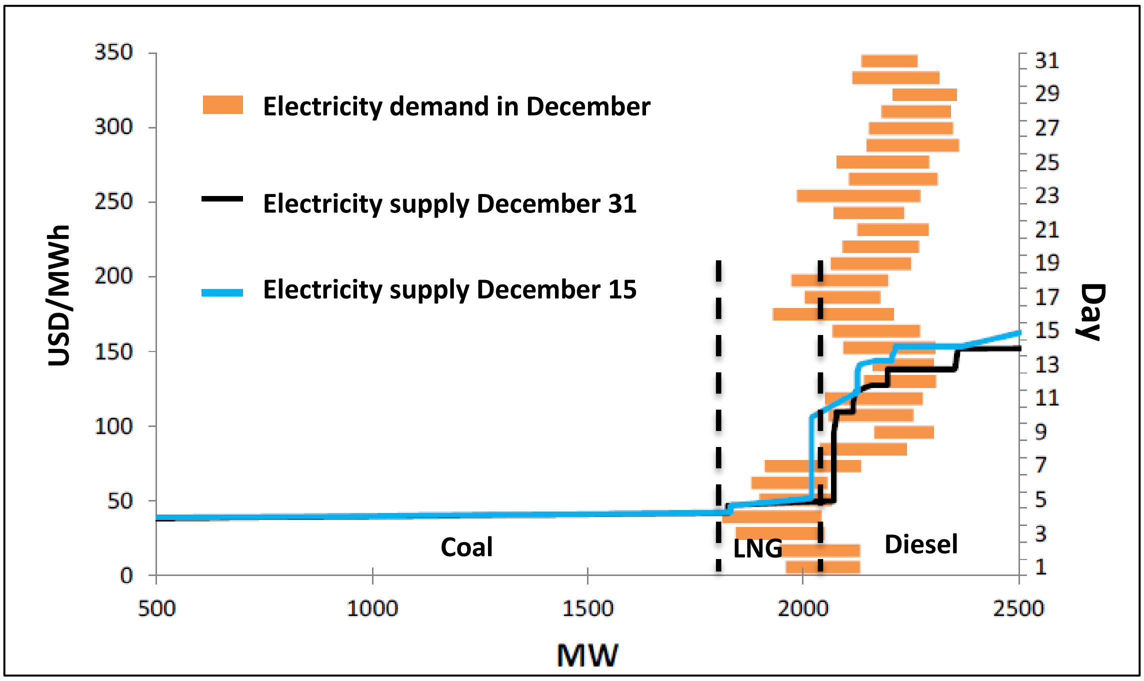


Figure 3.23: Merit order curve in the SING during December 15 and 31, 2014

Source: (Systep, 2015) based on CDEC-SING data.

3.3.3.2 Installed capacity

To understand the current energy context is necessary to go back in the history. Chile initially shifted its energy mix towards natural gas imported from Argentina. However, Argentina was forced to deal with its own domestic shortages due to the massive crisis in 2004 and, as a consequence, stopped natural gas exports. As a result, Chile's energy mix shifted toward diesel (20% of total installed capacity), and coal (about 24% of total installed capacity) power plants. The remaining capacity was covered by natural gas (21%), hydro reservoir power (20%) and biomass, hydro run of river, PV and wind power covering approximately 16%. Figure 3.24 provides a graphical illustration of the energy mix. On the side, Chile is also considering the option to import US shale-gas from 2016 (CSP Today, 2014).

With about 78% of the total installed capacity, the SIC is the most critical among the interconnected systems because it represented about 88% of the electricity sales in the residential sector in 2013. On the opposite, the SING (21% of the total capacity) represented about 11% of the electricity sales in the same period as illustrated in Figure 3.25. The SEA and SEM together represent the remaining 1% of the installed capacity in 2013. Figure 3.24 provides a graphical representation of the total installed capacity in Chile, according to the systems and the technologies.

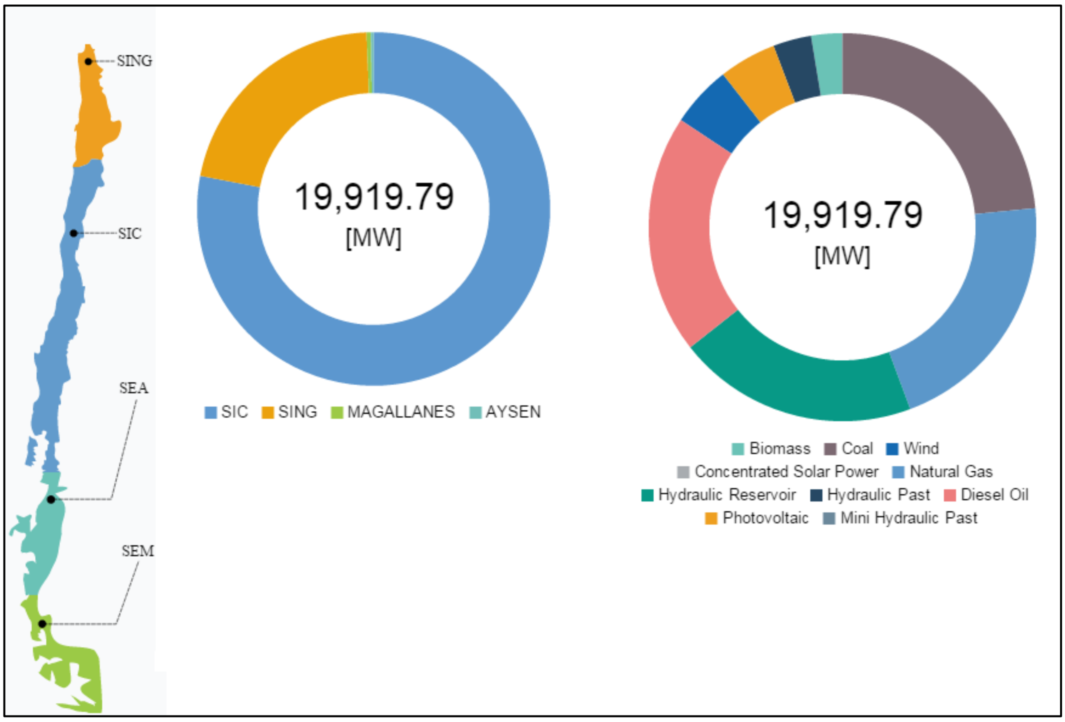


Figure 3.24: Installed capacity in Chile (SING, SIC, SEA and SEM) until 2013

Source: (CNE, 2016).

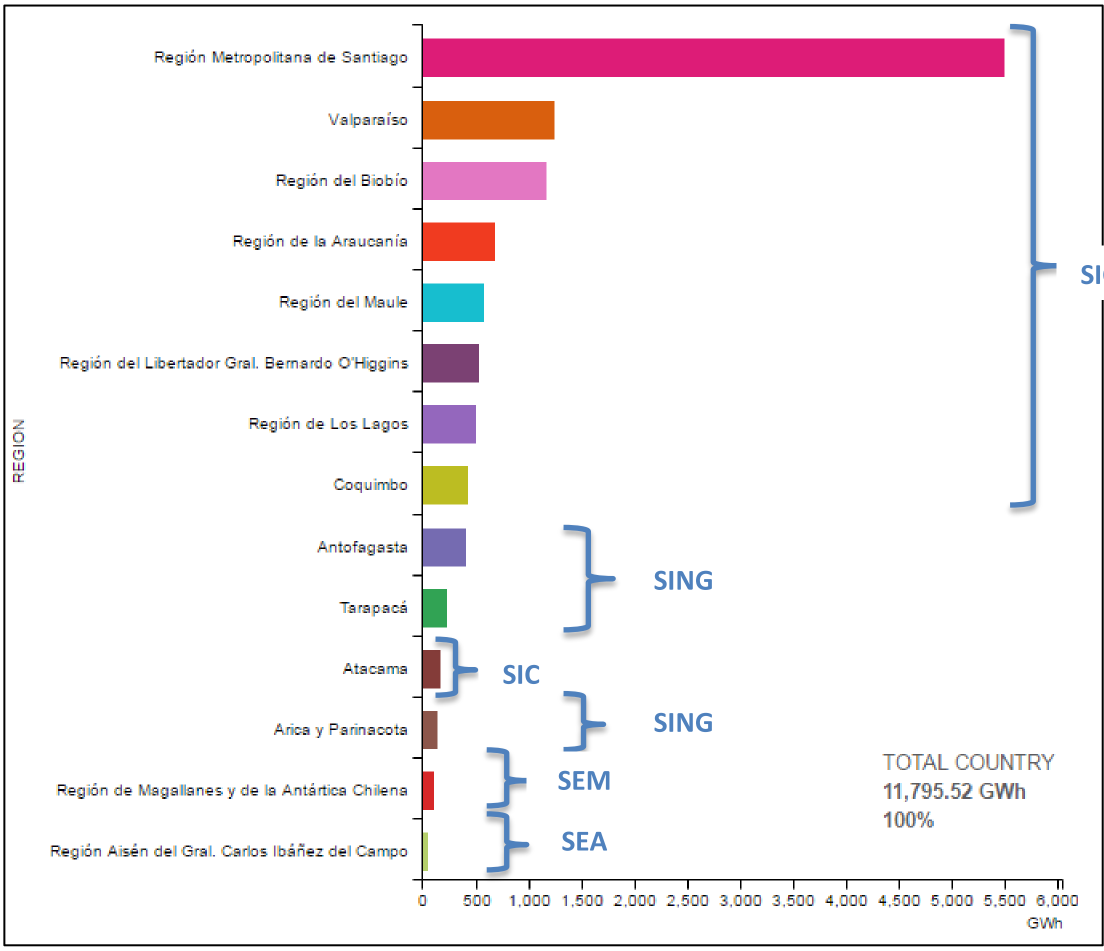


Figure 3.25: Electricity sales in the residential sector by regions in 2013

Source: (CNE, 2016).

Despite its great solar and wind potential in Northern Chile, the energy mix in the SING is mainly based on fossil fuels: coal power plants represent more than 46% of the installed capacity, natural gas about 43% and diesel around 4%. PV and wind power combined represent only about 6% of the total installed capacity (Figure 3.26).

The energy mix in the SIC is more diversified than the SING. In this system diesel oil, coal and natural gas combined represent more than 54% of the installed capacity, hydro reservoir about 29% and biomass, hydro run of river, PV and wind together 17%. Figure 3.26, right side, provides a sample of the capacity in 2015.

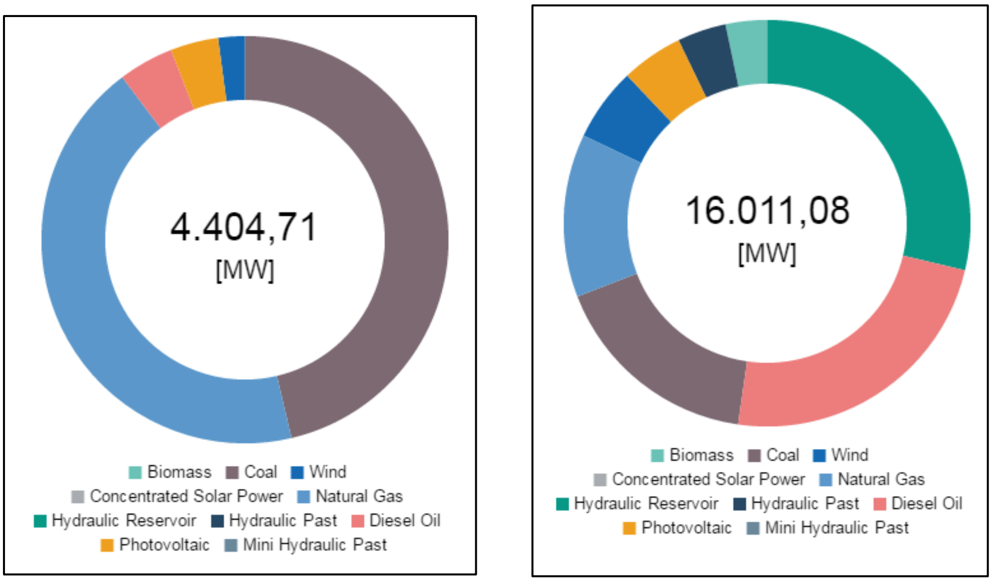


Figure 3.26: Installed capacity SING (left) and SIC (right) until 2015

Source: (CNE, 2016).

3.3.4 Electricity demand

In 2013, the industry sector represented 39% of the total final energy demand. The large consumption by the industry sector is attributed to energy intensive industries such as mining and pulp & paper industries. The transport sector was responsible for approximately 34% of the demand while commercial, public and residential sectors together accounted for 27% of the final energy demand as depicted in Figure 3.28.

Figure 3.27 also shows that from 2005 to 2015, the electricity generation increased by 42% mainly because of the increase in demand in the SIC (approximately 32% from 2005 to 2015).

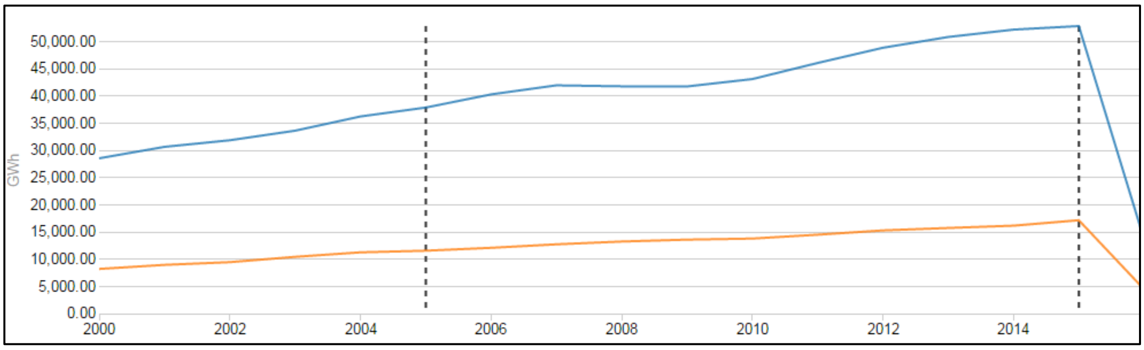


Figure 3.27: Historical electricity generation development in the SIC and SING between 2000-2015

Source: (CNE, 2016).

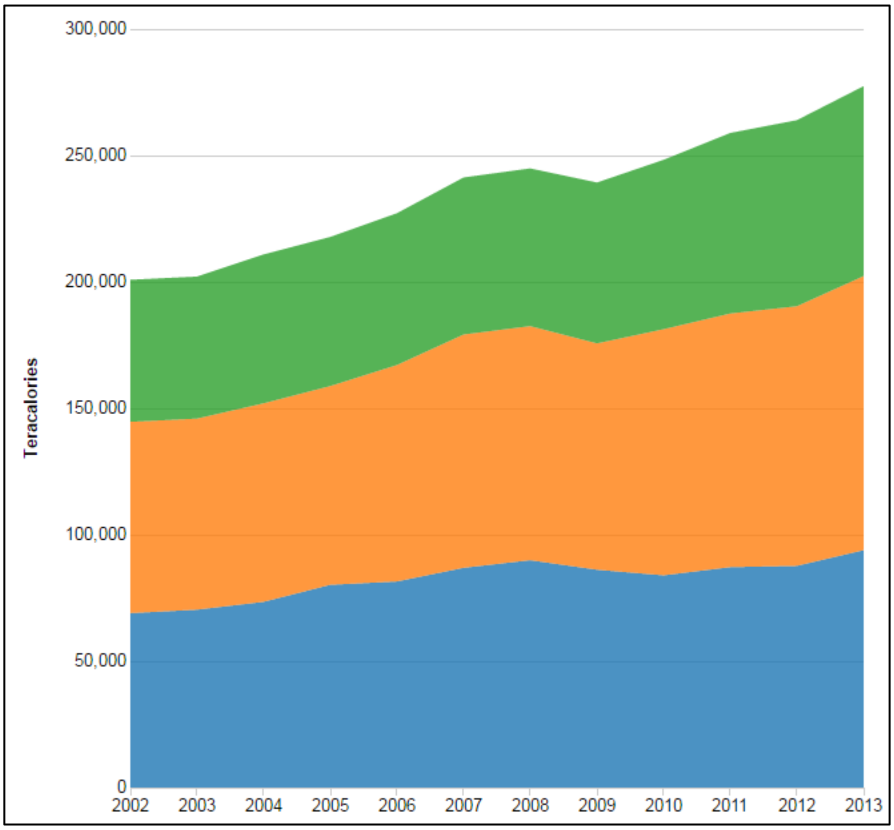


Figure 3.28: Historical final energy consumption by end-use sector between 2002-2013

Note: Green=Commercial, Public and Residential sectors. Orange=Industrial sector. Blue= Transport sector.

Source: (CNE, 2016).

3.3.5 CO_2 emissions factor development in the SING and the SIC

Due to fact that the energy mix in the SING mainly relies on fossil fuels the SING is more carbon intensive than the SIC with an average of 78 tCO_2eq[13]/MWh (against 37 tCO_2eq/MWh of the SIC), as illustrated in Figure 3.29. The lower carbon intensity of the SIC is due to the share of RE installed capacity which represents 46% of the total (including hydro reservoir).

[13] Tons equivalent of CO_2.

Figure 3.29: Historical emissions factor development in the SIC-SING between 2010-2014

Source: (CNE, 2016).

3.3.6 Grid transmission

The structure of Chile's grid has long posed a challenge to the role-out of the technology in the country. The transmission grid is spread unevenly throughout Chile, mainly because of the challenges related to the physical geography. The transmission and distribution grids serve almost all of the urban population and approximately 95% of the rural population. The transmission sector is divided into four separate power systems, which provide electricity to different geographic locations. The SING, supplies the north of the country – from Arica in the north to the town of Coloso in the south. The power production is entirely provided by fossil fuelled power plants and is mainly absorbed by the mining industry, which represents 90% of the total demand (all free customers). The SIC covers the central part of the country – from Taltal (Paposo) in the north down to the island of Chiloe in the southern region, including the capital city of Santiago (CDEC-SIC, 2016). The generation capacity of the SIC is represented by mainly fossil fuelled power generation (54% of total installed capacity), and by hydro power generation with 29% of the total installed capacity (25% hydro reservoir and approx. 4% of the total installed capacity corresponds to run of river).

The SEA corresponds to five medium systems located in the southern region: Palena, Hornopirén, Carrera, Cochamó and Aysén. Finally, the SEM covers four subsystems: Punta Arenas, Puerto Natales, Porvenir and Puerto Williams. It is located in the southeast part of Chile and supplies the cities of the same names. Additional information is provided in Table 3.6. In the past the country has suffered from the lack of a tailored policy and incentives to support the development of a suitable transmission grid able to accommodate renewable energy capacity. This is currently being adapted since renewables are gaining more importance in Chile. Among the most important current policies on the topic, the introduction of plans to connect the two major transmission networks in Chile is the most relevant.

Table 3.6: Transmission power system of Chile

	SING	SIC	SEA	SEM
Extended name	Northern Interconnected System	Central Interconnected System	Aysén Electric System	Magellan Electric System
Portion of the national generation capacity	28%	71%	0.4%	0.6%
Population served	6%	92%	<1%	<1%
Free clients	90%	35%	0%	0%
Regulated clients	10%	65%	100%	100%
Regions served	Arica/Parinacota, Tarapacá and Antofagasta	Atacama, Coquimbo, Valparaiso, Region Metropolitana (Santiago), Libertador General Bernardo O'Higgins, Maule, Bio Bío, Araucanía, Los Ríos and Los Lagos	Aysén	Magallanes

Source: Own table based on (CSP Today, 2014).

3.3.6.1 Interconnection between the SIC and the SING, (Interconnection of Independent Electric Systems Law)

In January 2014, a law to connect the two largest electricity systems was unanimously approved by the parliament (NME, 2016). The connecting of the SING and SIC systems will ultimately connect the north and the centre of the country. According to CNE it will consist of a 610 km line (1 500 MW capacity) at a total estimated cost of USD 850 million (CSP Today, 2014).

Currently SING only caters to 6% of the population located in the north of the country, which is regarded as a prime location for CSP due to good DNI conditions.

The interconnection of the system would require dispatchable energy throughout the north to provide for the different consumption and production patterns in Norte Grande (regions I, II and XV) and Norte Chico (regions III and IV). CSP with storage offers an efficient solution to this. The north is also home to the energy-intensive mining industries which could be either consumers or even self-generators of electricity.

Connecting the SING and SIC networks will increase the security and reliability of the overall Chilean system, and will facilitate the deployment of renewable energy sources. In March 2016 the Chilean company Transelec won the public tender for building part of the interconnection between the SIC and the SING with two transmission lines: one (2x500 kV) of 140km between Los Changos and Nueva Crucero-Encuentro, and another one (2x220 kV) of 3km between Los Changos and Kapatur. The company bid USD 174 million for this project. Transelec indicated that the shorter line will be working by the end of 2017, while the longer line will be operating by mid-2020 (Transelec, 2016).

3.3.7 RE Policies, regulations and milestones

3.3.7.1 2008: The introduction of Renewable Portfolio Standards (RPS), 10% of renewables by 2024

Approved by parliament in 2008 and amended in 2010, law 20.257 established the Renewable Portfolio Standards (RPS). The law created the obligation for generators with over 200 MW of installed capacity to implement at least 5% of electricity produced by RE sources within their energy mix. According to the regulatory framework, this threshold is bound to increase 0.5% per year starting from 2014 to become 10% by 2024.

Although in 2010 the renewable generation target was increased to an ambitious 20% by 2020, the goal was later abandoned on the basis of economic and fiscal grounds and on the fact that the transmission company would not be able to cope with the additional capacity. Nevertheless, in 2013 the target was again confirmed as the 2010 value, but this time extending the horizon: 20% by 2025. Ostensibly the planned improvements to the grid over the next few years have increased the government’s confidence that the transmission system will be able to cope with the additional capacity.

3.3.7.2 2010: Establishment of the Ministries of Energy and Environment and Chile’s Renewable Energy Centre

In 2010, the Ministry of Energy and the Ministry of the Environment were established with the aim of coordinating the energy market and related policies. In the same year the US Department of Energy (DOE) and the National Renewable Energy Laboratory (NREL) supported the development of Chile’s Renewable Energy Centre (CER), which was created to work under the guidelines of the Ministry of Energy and to ensure the optimal development of RE within the energy mix.

3.3.7.3 2012: Introduction to the National Energy Strategy

The "National Energy Strategy: 2012-2030: Energy for the Future" plan was announced in 2012. The plan concerns objectives to promote the deployment of non-conventional renewable energy sources into the Chilean electricity matrix.

Some of the highlights from the strategy include:

- The interconnection of the SIC and SING grids (promoted by a law passed in January 2014);
- Promoting international inter-connections. Chile aims to consolidate physical links with Argentina and explore any opportunities to connect with neighbouring countries (e.g. Peru and Bolivia);
- The introduction of a tender mechanism to encourage the development of RE sources;
- Specific incentives such as soft loans, tax incentives, and subsidies from the government to mitigate the risk for projects and achieve grid parity. As an example, the introduction of a guaranteed twelve year PPA scheme for renewable energy projects is under consideration;
- Increasing the deployment of hydropower to 45%-48% of the overall energy mix.

3.3.7.4 2013: Law 20.698 (RE law 20/25)

A new law, passed within Chile's National Energy Strategy in October 2013, has effectively doubled Chile's renewable energy targets. Experts are forecast that the strategy will result in 3.5 to 4 GW of clean energy being added to the grid within the next ten years. The new law, known as Law 20.698 and Law 20/25, aims at 20% of renewable energy produced in Chile by 2025. In terms of the target of 20% by 2025, all energy generation and distribution contracts have to include a 5% renewables contribution from 2014 onwards, increasing by 1% after each year until 2020 (with a total contribution of 12%), then increasing by a further 1.5% from 2021-2024 and 2% in 2024 (totalling 20% by 2025). This will doubles the Renewable Portfolio Standard of 2008 outlined earlier in this report.

Another law, 20.257, provided a good foundation for the introduction of Law 20/25. The introduction of a quota system under this mechanism leaded to 2 601 GWh of renewable generation between 2010 and 2013 (surpassing the minimum of 1 792 GWh). Together with the fact that renewable energy technologies have become more mature, the innovation has resulted in the Government's more aggressive NCRE targets. Companies that will fail to comply with the goal will be fined a penalty of 32 USD/MWh exceeding the minimum threshold. Furthermore, utilities that will not achieve the renewable energy quotas will be forced to buy renewable energy "credits" from other developers producing energy from RE over the limit contracted.

3.3.7.5 2013: New concessions law streamlining the permitting process

October 2013 also saw the Electrical Concessions Law published, which effectively streamlined the permitting process for a RES project from 700 to 150 days. The purpose is to standardize the paperwork required in submitting an electricity bid, thereby shortening the time it takes developers to gain approval for CSP plants.

3.3.7.6 2013: First CSP tender

The first tender for a CSP plant was published in February 2013. The Ministry of Energy, through the Corporación de Fomento de la Producción de Chile (CORFO) or the Chilean Economic Development Agency, agreed to provide a subsidy up to USD 20 million in addition to facilitating land access. Furthermore, the government negotiated a consortium of financing sources for a total amount of over USD 350 million in soft loans, with a below-market interest rate. Part of the funding were offered by other entities like: the European Union (USD 18.6 million), the Inter- American Development Bank (IDB, loans for at least USD 66 million), and the German Development Bank (KfW, loans for USD 135.2 million).

3.3.7.7 2014: Cerro Dominador – largest CSP plant in LATAM

The government tender resulted in a 110 MW tower project awarded to Abengoa Solar. The project is unique for a two main reasons: it will have the highest storage in the world lasting up to 17.5 hours, and will be the largest CSP project in LATAM. This will be Abengoa's third CSP project in LATAM where the developer already has two smaller-scale CSP projects: the 12 MW "Agua Prieta II" (project currently in construction in Mexico) and the 10 MW "Minera el Tesoro" (project now operational in Chile). Both of these projects are working according to the parabolic trough technology.

3.3.8 Solar potential

Recent researches regarding the potential of solar radiation in northern Chile indicates the Atacama Desert as one of the best worldwide regions for solar energy. According to these researches, the region presents a high number of clear days during the year, due to the aridity of the Atacama Desert, defined as a hyper acid region with annual average precipitations lower than 50 mm per year (Anrique, N. et al., 2012).

As illustrated in Table 3.7, Northern Chile has a higher solar irradiation compared to other locations. The higher potential implies a higher CSP with respect to other locations where the technology has already been implemented. Specifically, the locations with a high solar irradiation are: El Tatio, Calama, San Pedro de Atacama and Chuquicamata with more than 6 kWh per m^2day (in average). Moreover, the majority of the locations in northern Chile have a higher solar irradiation potential than Almeria in Spain (4.82 kWh/m^2 day) as outlined in Figure 3.30.

Table 3.7: Solar Irradiation of CSP plants and projects

Plant	Location	Radiation [kWh/m^2 day]
Plataforma Solar Almeria	Almeria, Spain	4.82
SEGS	California, USA	5.86
Abengoa ISCC project	Ain-Ben-Mathar, Moroco	4.84
Not developed yet	North Chile	≅6

Source: (Anrique, N. et al., 2012).

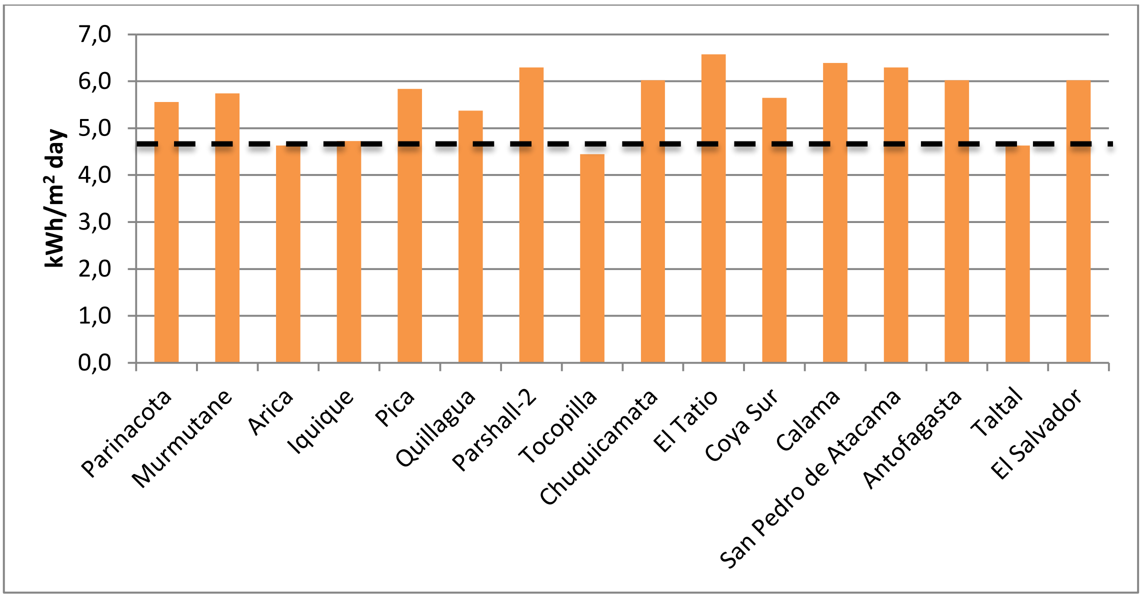


Figure 3.30: Average monthly global irradiation in Northern Chile

Source: Own figure based on (CNE/PNUD/UTFSM, 2008).

3.4 South Africa

South Africa (SA), also known as the Republic of South Africa, is the southernmost state in the African continent. With a population of almost 55 million people and with an extension of around 1.2 million squared km, it is the 25th most populated and extended country in the world. The inhabitants of SA are a mix of different ethnic groups. The cultural difference is highlighted by the number of languages officially spoken (and recognized). With 11 official languages, South Africa poses itself as a multicultural and multi-ethnic country (Statssa, 2016).

According to the World Bank, South Africa is classified as an upper-middle-income economy. Nowadays, with a nominal GDP of USD 326 541 billion, SA represents the second largest economy in Africa and ranks 35th in the world (Statssa, 2016). The energy business, directly related with growth and economy sustain, covers a key role in the South African context. In the period 2004 – 2012 the energy demand has been in average 1 600 TWh (IEA, 2013). Production and supply of electricity are covered entirely by Eskom, the government owned national power utility. The company owns 27 operational power plants and generates more than 95% of the country's electricity needs (Eskom, 2015a). Recent events in the past years have suggested that the utility have not been able to keep up with the recent economic and population growth. Due to a lack of investments, the SA grid experienced power shortages. The situation culminated with the decision of operating load-shedding in particular areas of the country, to improve the stability of the power grid and reduce the occasion of grid-failure (dailymaverick, 2012). It thus seems that the SA energy sector could benefit from a reinforcement of the national grid and an enhancement/increase of the energy generating plants in the system.

After this brief introduction to the South African context, a more specific and in-depth analysis of the energy sector will follow. The focus will be mainly on the power market, electricity demand and supply, concluding with availability of RES sources and investigation on the RE support's policies currently available.

3.4.1 Market description: The Southern African Power Pool (SAPP)

The energy market in the southern region of Africa is organized as a Power Pool, commonly known as Southern African Power Pool (SAPP) (sappmarket, 2016). Twelve countries play actively in the Pool, generating and exchanging energy through borders. The management of the operations is a duty of the power utility of each country. The list of the SAPP members along with the name of the competent power utility is (DOE, 2016):

- Angola (Empresa National de Electricidade);
- Botswana (Botswana Power Co-operation);
- DRC (Societe National d' Electricite);
- Lesotho (Lesotho Electricity Corporation);
- Mozambique (Electricidade de Mozambique, HCB, Motraco);
- Malawi (Electricity Supply Commission of Malawi);
- Namibia (Nam Power);
- South Africa (Eskom);

- Swaziland (Swaziland Electricity Board);
- Tanzania (Tanzania Electric Supply Company);
- Zambia (Zambia Electricity Supply Corporation);
- Zimbabwe (Zimbabwe Electricity Supply Authority).

The aim of the SAPP is to provide secure and economic electricity supply to all the members of the Pool, maximizing the efficient use of the natural resources available in every country. As participants of the Pool, all members have equal duties and commitments for the common sake of the group. As a result of the common collaborations, the members have agreed on creating a web platform where data like demand, planning outages, power prices and exchange flows are available to the public (sappmarket, 2016).

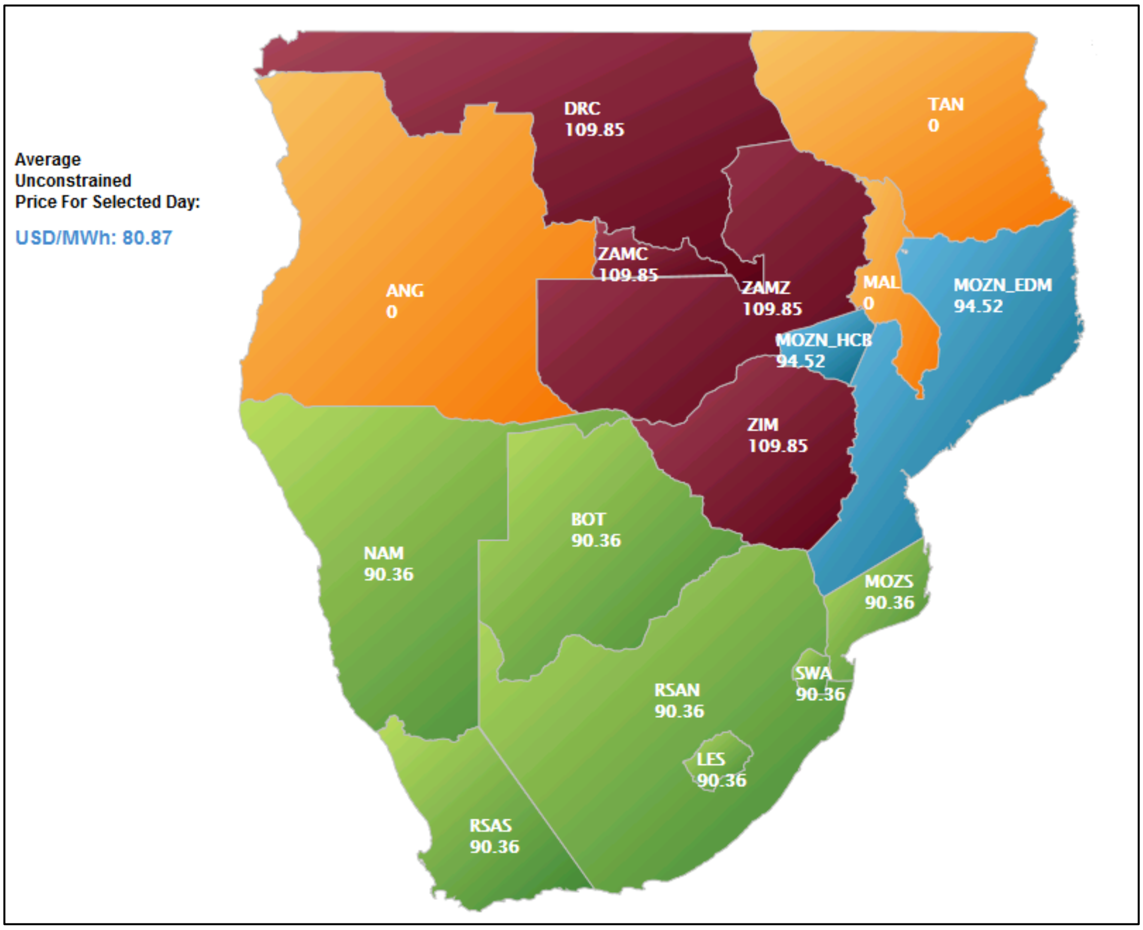


Figure 3.31: South African Power Pool, June 29th 2016

Figure 3.31 presents the geographical location of the zones of the Power Pool. The figure also reports the average power price for the selected day and the average unconstrained price[14]. South Africa is divided in two different zones: Republic of South Africa North (RSAN) and

[14] The average unconstrained price is the price that would occur in the SAPP if all the transmission capacities were neglected (i.e. copper plate).

Republic of South Africa South (RSAS). Besides for 24 hours, for the last two years the average power prices in the two regions have been the same. According to the latest market report (sappmarket, 2015), in March 2015 the energy volume traded in the day ahead market (DAM) was 25.3 GWh while in February 31.48 GWh. The results of the reports also highlight that, out of the value matched on the market, only 30.84 GWh were actually matched. The remaining 0.5 GWh were not traded due to lack of transmission between the zones.

The average power prices in South Africa are among the lowest in the SAPP. Figure 3.32 reports the development of the DAM prices (USD/MWh) for March 2016; no difference is observed between the values in the two regions, thus confirming the stability of the price within the same country.

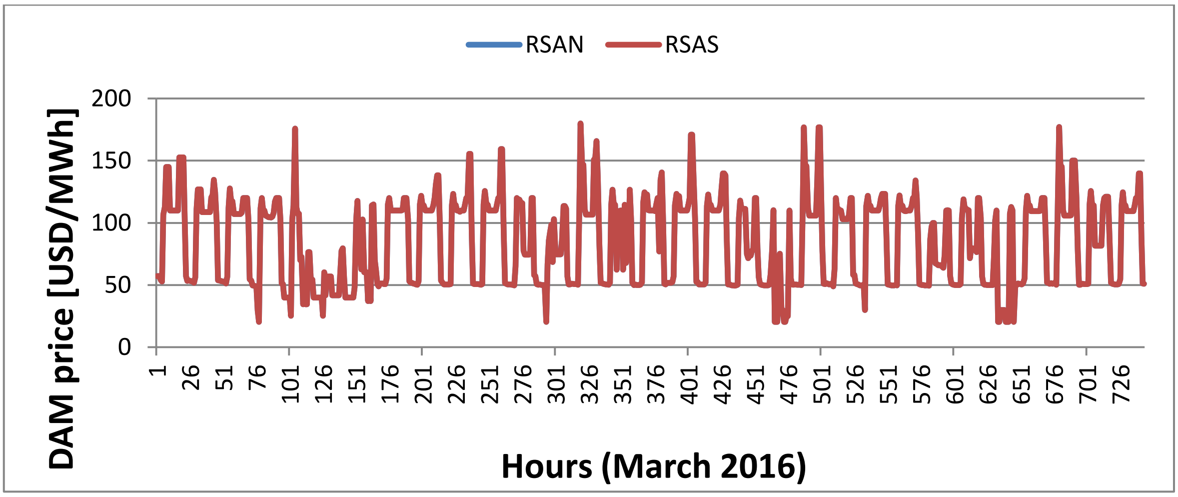


Figure 3.32: Day Ahead Market (DAM) prices in the North (RSAN) and South (RSAS) region of SA

Source: (sappmarket, 2016).

3.4.1.1 Major challenges of the SAPP: the South Africa case

The SAPP currently faces five major challenges (DOE, 2016):

1. Lack of transmission infrastructure;
2. Lack of maintenance of infrastructure;
3. Limited funds to finance new investments;
4. Insufficient generation and
5. High losses.

The list of challenges provides an idea about the situation of the power grid in the area of Southern Africa. The five points highlighted surely point towards circumstances where the grid stability is mined.

In the South Africa case, the situation degenerated when, in January 2008, Eskom introduced load shedding as a mean to stabilize the grid. The concept implies the disconnection of power supply in selected areas (i.e. planned blackouts) whenever the short power supply can compromise the integrity of the grid. The short power supply can be due to different causes.

Examples are: mistaken forecast of the energy demand and outages of power plants maintenance or refuelling (planned) and repairs or failure (un-planned).
The SA power utility pointed out that the planned blackouts were due to insufficient generation capacity in the system, thus leaning toward a refurbishment of the power mix.
From 2008, the planned outages happened more frequently. In November 2014, the Majuba power plant was lost due to a collapse in the coal storage silos. In the same month, other two power plants were shut down due to diesel shortages while other two hydro plants faced difficulties due to low level of water in the reservoirs. This combination of exceptional events forced the company to start “stage three load shedding”, the highest degree of load disconnection (Eskom, 2016a).

The blackouts, even though necessary in order to maintain the grid stability, had a negative impact on the SA economy. The mining industry is the sector that is affected the most, since the high demand of power for the metals’ processes is among the first to be shut down. Moreover, other companies dealing with food and refrigeration suffered the blackouts and had relevant losses. The counter action of the industry to the load shedding has been the secure of energy supply through back-up units. Most of the utilities thus secured their energy procurement with private generating units, to use in case of emergency.

Nevertheless, the unusual situation faced in the power sector in the recent years brought both the government and Eskom to improve the reliability of the power supply. Up to date (June 2016), Eskom increased the Energy Availability Factor (EAF) from 69% to 78% (Eskom, 2016b). The unplanned maintenance factor of the power plants has also been reduced, while the planned maintenance factor has been 11%. Some other achievement (e.g. satisfy the peak load with the available capacity and without the use of diesel generator/load shedding, greater use of Independent Power Producers) proved that the energy sector is improving, therefore enhancing the grid stability and power supply for the Republic of South Africa.

3.4.2 Electricity sector

As a part of the SAPP Power Pool, SA self-produce energy and, occasionally, exports it to the surrounding countries. The overall capacity installed in the SAPP is ≅55 GW and the only SA covers ≅44 GW. South Africa is connected, through power cables, with the neighbouring countries. The power lines present different capacities and voltages; the relevant technicalities are summarized in Figure 3.33. SA is connected in High Voltage (HV) with Lesotho with line capacity of 230 MW. Power exchanges also occur with Swaziland: the connections are both in HV and Extra High Voltage (EHV) with more than 1 450 MW line capacity. South Africa is also power connected with Mozambique, Botswana and Namibia with an overall capacity of 3 850 MW, 800 MW and 750 MW respectively.

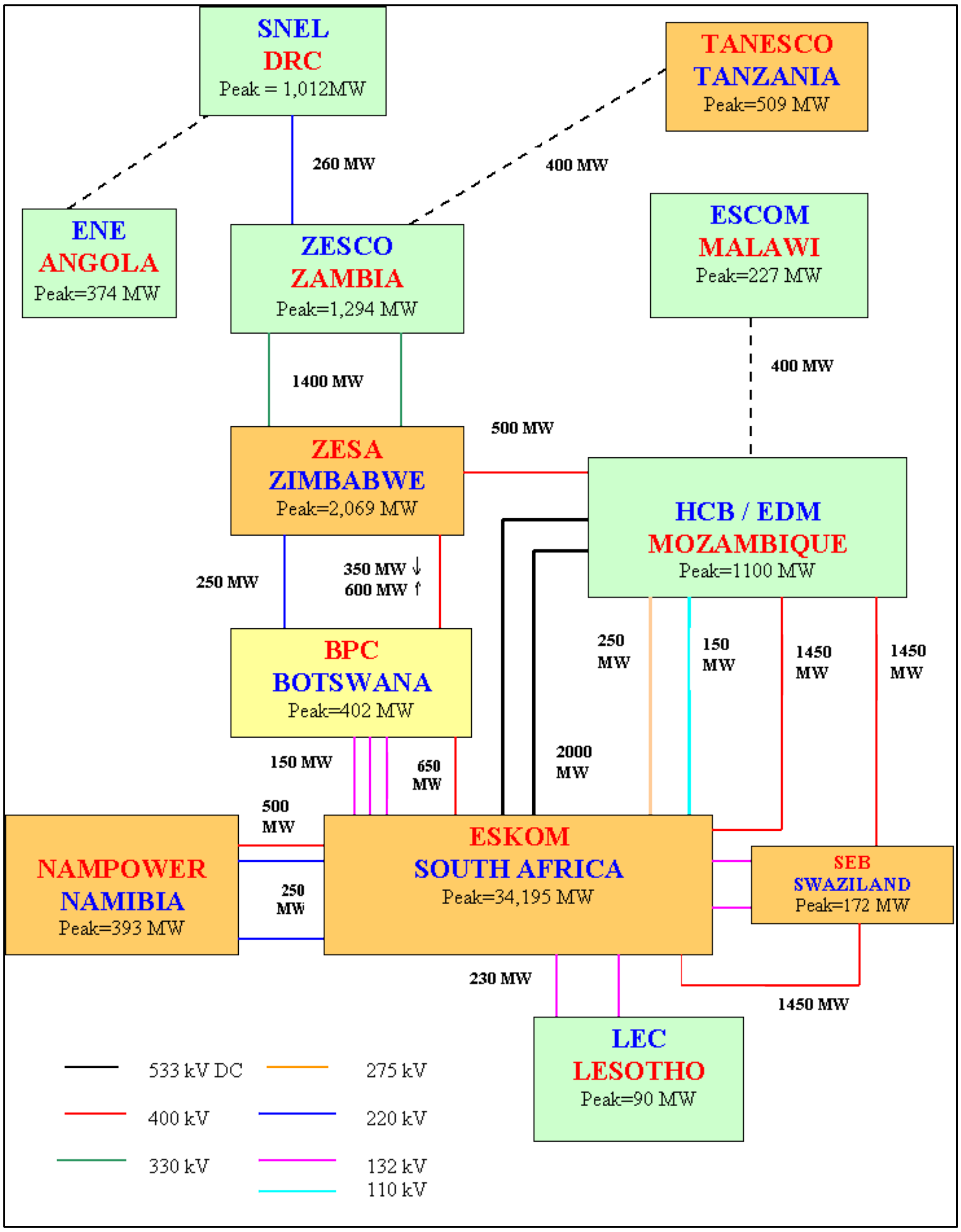


Figure 3.33: Transmission capacities and Power utilities in SAPP

Source: (sapp, 2016a).

Each of the SAPP country has an own power utility responsible for the energy sector. In South Africa, the electricity sector is almost entirely managed by the government owned national power utility Eskom. The company owns 96 % of the capacity installed in the system and has the right for the power generation and transmission in SA. The majority of the power plants are situated in the North-East and South-West regions, in correspondence of the big cities (Cape Town, Johannesburg and Pretoria). Other power generating plants (e.g. hydro and wind) are situated all around the country, in locations where the input energy potential is adequate.

Figure 3.34 provides the geographical location of the Eskom's plants along with a map of the high voltage national grid.

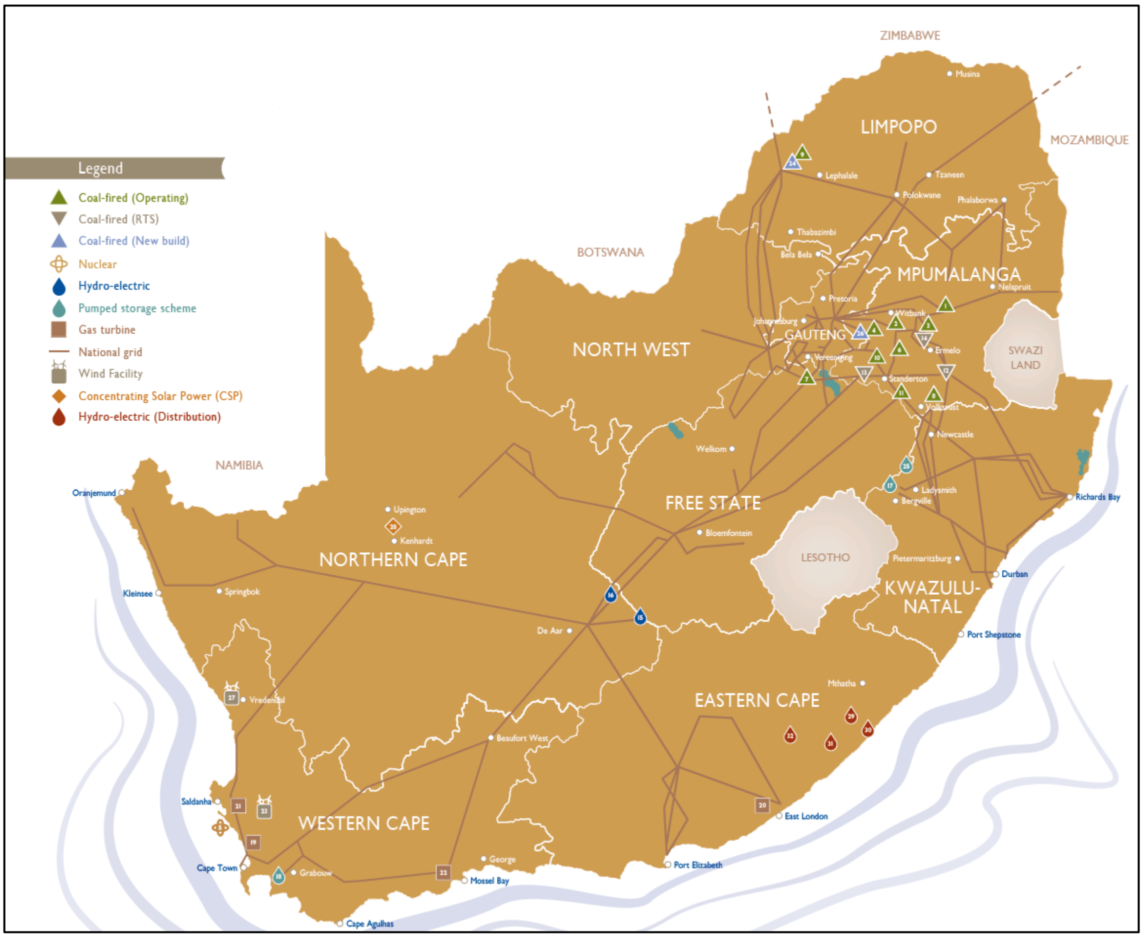


Figure 3.34: Eskom power stations

Source: (Eskom, 2016c).

3.4.3 Electricity supply

The electricity generation of South Africa is controlled by the state-owned power utility Eskom, which produces almost 96.7% of the power in the country (USEA, 2015). The remaining power is supplied by Independent Power Producers (IPP).

The power mix in South Africa is composed by Hydro power, Coal, Nuclear and Distillate-fuelled power plants (sapp, 2016b). Table 3.8 reports relevant info concerning the power mix of the SAPP members for the year 2015. With 86% of the installed capacity, Coal is the first source of energy for the SA system. It then follows Hydro and Distillate and finally Nuclear Power.

Table 3.8: SAPP Utility Generation Mix

Technology /Utility	Base hydro	Coal	Nuclear	CCGT	Distillate	Total
BPC	0 %	64 %	0 %	0 %	36 %	100 %
EDM	91 %	0 %	0 %	0 %	9 %	100 %
ENE	55 %	32 %	0 %	13 %	0 %	100 %
ESCOM	100 %	0 %	0 %	0 %	0 %	100 %
Eskom	**5 %**	**86 %**	**4 %**	**0 %**	**5 %**	**100 %**
LEC	100 %	0 %	0 %	0 %	0 %	100 %
NamPower	61 %	34 %	0 %	0 %	5 %	100 %
SEC	88 %	13 %	0 %	0 %	0 %	100 %
SNEL	100 %	0 %	0 %	0 %	0 %	100 %
TANESCO	50 %	0 %	0 %	43 %	7 %	100 %
ZESA	37 %	63 %	0 %	0 %	0 %	100 %
ZESCO	99 %	0 %	0 %	0 %	1 %	100 %
Total	17.4 %	72.9 %	3.5 %	1.2 %	5 %	100 %

Source: (sapp, 2016b).

The installed power capacity is expected to grow in the future since 44 GW of additional capacity are expected to be necessary by 2025 in order to sustain the growing economy and energy demand (USEA, 2015). Renewables energy is expected to contribute to the diversification of the energy mix with 18.2 GW, of which: 8.4 GW from Wind, 8.4 GW from Solar PV, 1 GW from CSP and the remaining 0.4 GW covered by other technologies (e.g. wave energy, geothermal among others).

In 2010, the Coal power plants satisfied almost completely (93%) the gross electricity generation with 240 TWh. The remaining production was covered by nuclear (14 TWh) and hydro (4 TWh). According to IRENA (and to the planned government vision), the future energy production mix will change. Table 3.9 reports the values according to two different scenarios: reference case (2030) and Remap (2030) (IRENA, 2016).

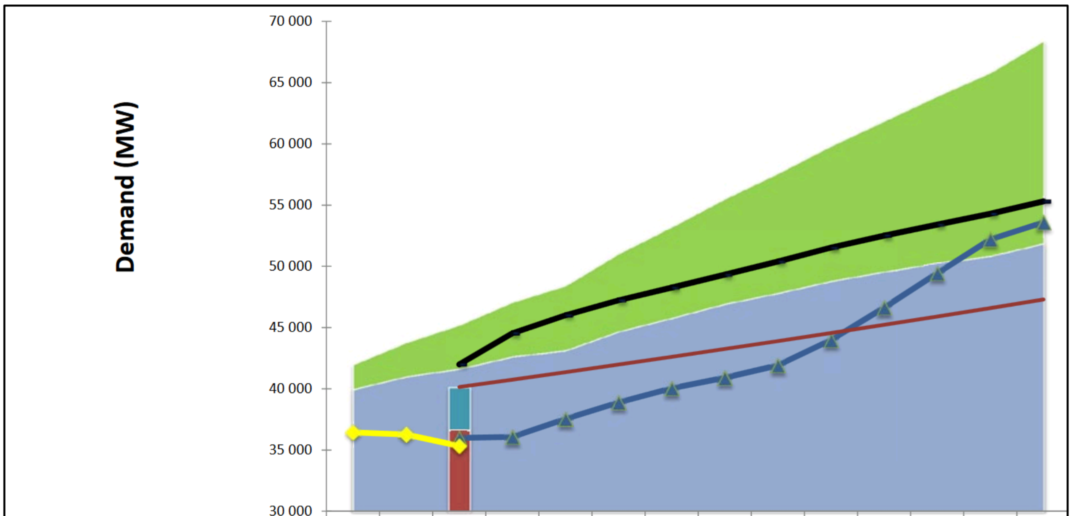
Table 3.9: Gross Electricity Generation in South Africa

Scenario	Base hydro	Coal	Nuclear	Natural gas	CSP	Bioenergy	Wind	Solar PV	Total
2010	2 %	93 %	5 %	0 %	0 %	0 %	0 %	0 %	100 %
Reference case (2030)	1 %	66 %	12 %	11 %	2 %	1 %	3 %	4 %	100 %
Remap 2030	1 %	57 %	10 %	11 %	4 %	3 %	5 %	9 %	100 %

Source: (IRENA, 2016).

3.4.4 Electricity demand

The energy demand in South Africa is related with three main sectors: 1) residential, 2) industry and 3) transport. IRENA reports that, for the year 2010, the consumption per sector was 795 PJ, 1 092 PJ and 753 PJ respectively for buildings, industry and transport (IRENA, 2016). For the same year, the peak demand was 35.85 GW. In the period 2010-2012, the peak demand followed different patterns, at first increasing from 35.85 GW to 36.54 GW (+1.9%) in 2010-2011, then decreasing to 35.89 GW (-1.8 %) (sapp, 2016b). Nevertheless, the future demand forecasted by Eskom points toward an increasing trend. Figure 3.35 provides a graphical representation of the forthcoming energy demand.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2010 IRP High Demand (MW)	42027	43839	45 255	47 124	48 479	51 090	53 276	55 573	57 649	59 885	61 932	63 955	65 870	68 458
2010 IRP Low Demand (MW)	40002	41040	41 669	42 666	43 157	44 710	45 815	46 952	47 848	48 828	49 596	50 299	50 872	51 903
Mid Size Customer NMD (MW)			3 472											
Top Customer NMD (MW)			36 676											
2015 TDP Demand (MW) - Constrained			36 000	36 065	37 536	38 885	40 036	40 904	41 921	43 990	46 629	49 427	52 193	53 600
2015 TDP Demand (MW) - Unconstrained			42 000	44 536	45 998	47 220	48 271	49 328	50 398	51 528	52 501	53 403	54 296	55 310
Actual Peak Demand (MW)	36437	36276	35 343											
NMD growth at 1.5%			40 148	40 750	41 361	41 982	42 612	43 251	43 900	44 558	45 226	45 905	46 593	47 292

Figure 3.35: Demand Forecast, Eskom

Source: (Eskom, 2015b).

The yellow line represents the peak demand with the data available up to date. Even though it shows a decreasing trend, the future forecasted demand (TDP demand constrained) points toward higher values for the future. The trend is based on the assumption of the constrained Transmission Development Plan (TDP) thus considering the physical limitation of the system. The black line, on the contrary, represents the unconstrained case (visibly higher), basing the load forecast on the contracted Nominated Maximum Demand (NMD) values that the SA power utility has agreed to supply. For more information on the demand forecast, the reader can refer to (Eskom, 2015b).

3.4.5 RE policies, regulations and milestones

South Africa occupies a central position in the global debate regarding the most effective policy instruments to accelerate and sustain private investment in renewable energy. In 2009, the government began exploring feed-in tariffs (FIT) for renewable energy, but these were later rejected in favour of competitive tenders. The resulting program, now known as the Renewable Energy Independent Power Producer Procurement Program (REIPPPP), has successfully channelled substantial private sector expertise and investment into grid-connected renewable energy in South Africa at competitive prices (PPIAF, 2014). As a result, a total of 64 projects have been awarded to the private sector, and the first projects are already on line in 2014. Private sector investment totalling USD 14 billion has been committed, and these projects will generate 3 922 MW of renewable power. Prices have dropped over the three bidding phases with average PV tariffs decreasing by 68% and wind dropping by 42%, in nominal terms. Most impressively, these achievements all occurred over a two-and-a-half year period (PPIAF, 2014).

3.4.5.1 Integrated Resources Plan (IRP) 2010-2030

The government began setting renewable energy targets in 2003, with the publication of a Renewable Energy Policy White Paper that envisioned reaching 10 000 GWh of renewable energy generation by 2013. The amount was split among bagasse 59%, landfill gas 6%, hydro 10%, solar water heaters 13%, other biomass 1%, and only 1% wind, no PV or concentrated solar power. Even these modest targets were not met by 2013 (PPIAF, 2014).

However, while the official renewable energy policy has not been very effective in applying practical implementation strategies, policies to mitigate climate change have had a much more profound impact. In several respects, this is surprising because as a country non-following the Kyoto Protocol, South Africa does not face any commitments to reduce greenhouse gas emissions. Nevertheless, the Department of Environmental Affairs commissioned research work on Long-Term Mitigation Strategies. These strategies provided the basis for the country to make a pledge at the Copenhagen Conference of Parties (COP) in 2009, that South Africa would reduce its CO2 emissions 34% below a business-as-usual scenario by 2020, and below 42% by 2025 (BBC, 2009), provided the international community supported South Africa with financial aid and the transfer of appropriate technology.

The peak, plateau, and decline scenarios for carbon emissions subsequently informed the development of the IRP 2010-2030. The power sector in South Africa contributes roughly half of the country's carbon emissions, and an effective emissions cap was set at approximately 275 $MtCO_2eq$/year. A subsequent National Climate Change Response White Paper, published in 2011 (PPIAF, 2014), provided a wider band for emission caps, but maintained the peak, plateau and decline trajectories. At the COP17 meeting in Durban in 2011, public and private sector stakeholder representatives agreed to 12 "commitments" aimed at achieving the government's goal of creating 300 000 new jobs in the "green economy" of South Africa by 2020 (PPIAF, 2014).

3.4.5.2 From Feed-in tariffs to Renewable Energy Independent Power Procurement Program (REIPPPP)

A renewable energy feed in tariffs policy was approved in 2009 by National Energy Regulator of South Africa (NERSA). Tariffs were designed to cover generation costs plus a real after tax return on equity of 17% and would be fully indexed for inflation (PPIAF, 2014). Initial published feed-in tariffs were generally regarded as generous by developers – 15.6 USD c/kWh for wind, 26 USD c/kWh for concentrated solar[15], and 49 USD c/kWh for photovoltaic[16]. But considerable uncertainty about the nature of the procurement and licensing process remained. The legality of feed-in tariffs within South Africa's public procurement framework was unclear, as was Eskom's intention to fully support the feed in tariffs program by allowing timely finalization of power purchase agreements and interconnection agreements (PPIAF, 2014).

In March 2011, NERSA introduced a new level of uncertainty with a surprise release of a consultation paper calling for lower feed-in tariffs, arguing that a number of parameters—such as exchange rates and the cost of debt—had changed. The new tariffs were 25% lower for wind, 13% lower for concentrated solar, and 41 % lower for photovoltaic. Moreover, the capital component of the tariffs would no longer be fully indexed for inflation. Importantly, in its revised financial assumptions, NERSA did not change the required real return for equity investors of 17 % (PPIAF, 2014).

In August 2011, the Department of Energy (DOE) announced that a competitive bidding process for renewable energy would be launched, known as the REIPPP. Subsequently, NERSA officially terminated the feed-in tariffs scheme. The abandonment of feed-in tariffs was met with dismay by a number of renewable energy project developers that had secured sites and initiated resource measurements and environmental impact assessments. However, it was these early developers who would later benefit from the first round of competitive bidding under the REIPPPP.

[15] Parabolic trough with 6 hours of thermal storage.
[16] These values are calculated at the exchange rate at the time of ZAR8/USD.

3.4.5.3 The bidding process and the results from the REIPPP

The result of a round of three bidding processes from 2011 till 2013 is indicated below:

- In August 2011, an initial Request for Proposals (RFP) was issued, and a compulsory bidder's conference was held with over 300 organizations attending. By November 2011, 53 bids for 2 128 MW of power generating capacity were received, in where 28 preferred bidders were selected offering 1 416 MW for a total investment of close to USD 6 billion. As a result, construction on all of these projects has commenced with the first project coming on line in November 2013.
- In November 2011, a second round of bidding was announced. The total amount of power to be acquired was reduced, and other changes were made to tighten the procurement process and increase competition. In March 2012, seventy-nine bids for 3 233 MW were received, and 19 bids were ultimately selected. Implementation, power purchase and direct agreements were signed for all 19 projects in May 2013.
- In May 2013, a third round of bidding commenced, and again, the total capacity offered was restricted. In August 2013, 93 bids were received totalling 6 023 MW. In October 2013, seventeen preferred bidders were notified totalling 1 456 MW. Prices fell further in round three. Local content again increased, and financial closure was expected in July 2014. A fourth round of bidding was set to commence in August 2014.

Banks, insurers, DFIs and even international utilities have financed the 64 projects within the REIPPPP framework. The most common financing structure has been project finance, although about a third of the projects in the third round used corporate financing arrangements. The majority of debt funding has been from commercial banks (USD 3.85 billion) with the balance from Development Finance Institutions (DFIs) (USD 1.88 billion), and pension and insurance funds (USD 0.32 billion). 86% of debt has been raised from within South Africa, and debt tenors typically extend 15 to 17 years from Commercial Date of Operation (COD).

3.4.6 Availability of solar resources

As depicted in Figure 3.36, South Africa has a significant solar potential to rollout CSP technologies, with areas in which the average annual DNI reach up to 3 200 kWh/m^2 (particularly in the north of Cape Town close to Upnington and Calvinia) and exceeds the minimum average annual DNI required for installing CSP plants (1 800 kWh/m^2) (Trieb et al., 2009). Furthermore, HYSOL can help to reduce coal fuelled power plants which represented 93% (240 TWh) of the total energy mix in 2010 (IRENA, 2010).

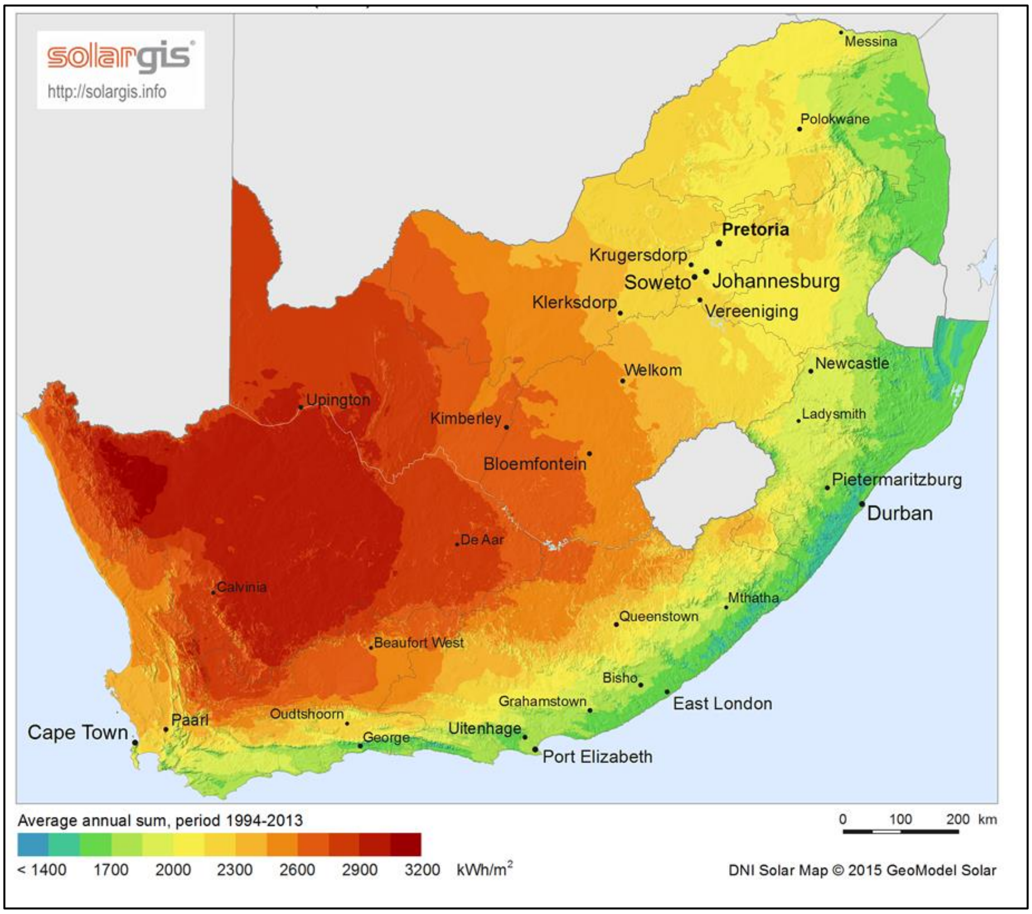


Figure 3.36: Direct Normal Irradiation (DNI) in South Africa

Source: (SolarGIS, 2015).

4 Corporate economic assessment for the HYSOL technology

4.1 Feasibility assessment of the HYSOL technology

The HYSOL technology bases its own energy generation on two basic concepts: gas turbine (GT) and concentrated solar power (CSP). The gas turbine is a well-known technology, already in use since years in the energy industry. As a result of the prior experience with the different plants in operation, costs, productions and revenues associated with these kinds of plants are usually easier to forecast. Nevertheless, some parameters (e.g. demand, plants faults,…) are still consider to be unpredictable, even if with a small range of error associated with the estimations. For the CSP plant the case is different compared to the gas turbine. Indeed, being the solar radiation the main (and only) input for the plant, the future revenues associated with the production of the plant are subject to uncertainties. From the investor point of view, a study on the future expenses and revenues from the plant operation is necessary, in order to assess the value of the investment in the long term. For this reasons, a private economic analysis has been undertaken to evaluate the project from the perspective of a private company purchasing the goal of determining if the project is worthwhile to invest on. Three different economic indicators have been chosen for the purpose of this analysis: Net Present Value (NPV), Internal Rate of Return (IRR) and Average Unit Cost (LCOE). All the indicators represent a tailored approach for the feasibility analysis of the HYSOL project, where a private company would like to investigate possible revenues for the selected investment.

The *NPV* is a central tool in investment analysis. The indicator is useful to compare different projects with different timings and distributions of cash flows over time. The calculations of the indicator consider the initial investment, the yearly cash flows and the discount rate. The choice of the discount rate to reflect the return from equivalent investment alternative in the market, leads to the natural selection of the NPV as decision criteria. A positive NPV indicates that the undertaking of the project is favourable. On the other hand, a negative NPV suggest that the investment should not be carried out.

The second economic indicator selected is the *IRR*. It represents the annual effective compounded return rate of a project or an investment option (i.e. the annual return a project is expected to yield). At this discount rate, the NPV would become zero. For any IRR greater than the discount rate, the undertaking of the project is favourable. In this case, the NPV is positive. In the opposite case (i.e. IRR lower than the discount rate) the project should be discontinued.

Last but not least, the *LCOE* represents the unit cost. It is equivalent to the average cost over the lifetime of a project, taking into account the cost of capital.

The next section presents the assumptions considered for the analysis. Moreover, the procedure of the interlinking between the different input and output will be explained in order to facilitate the understanding of the methodology followed.

4.2 Methodology

4.2.1 Structure of the financial model

The structure of the Financial Model used for the analysis follows a simple input-output block structure.

Figure 4.1 provides a graphical explanation. The input provided to the model are selected known data regarding electricity production, fuel consumption, utility prices, CAPEX, OPEX, future development of prices, lifetime, construction time, availability factors and many others. The output of the model consists on NPV, LCOE and IRR. Subsequently the setup of the model is adapted in order to calculate the power prices resulting from desired values of IRR.

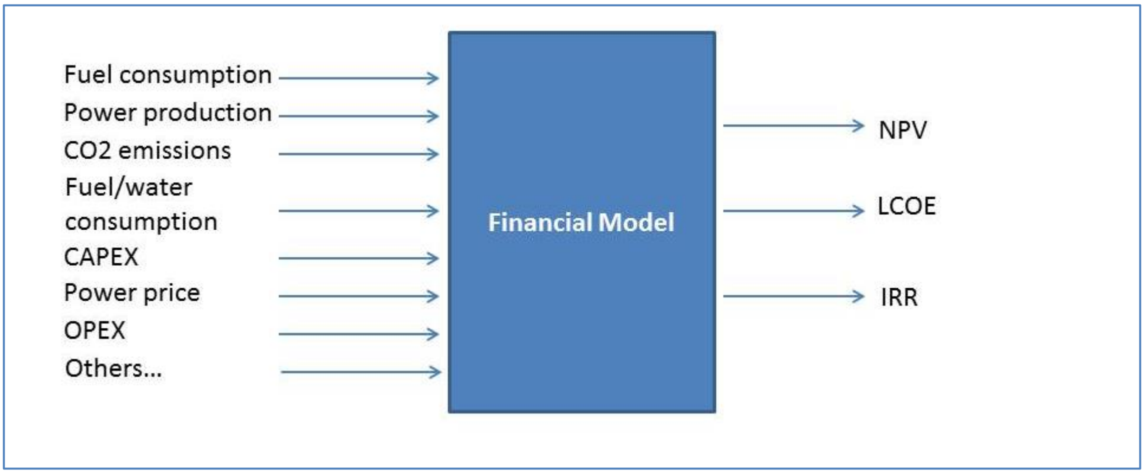


Figure 4.1: Structure of the Financial Model

The **NPV** considers cash outflows and inflows in subsequent years. The indicator is calculated according to:

$$NPV = -CF_0 + \sum_{t=1}^{T} \frac{CF_t}{(1+r)^t}$$

where CF_0 represent the initial investment at the year *t=0*, CF_t the positive cash flow for each year *t* during the lifetime *t=1,…,T* and *r* the discount rate. The positive cash flow is divided for the so called *discount factor* $\frac{1}{(1+r)^t}$ in order to account for the timing of the cash flows.

The **levelized cost of energy** can be calculated as the net present value of the negative cash flow of the project over the lifetime of the asset divided by the sum of the discounted electrical energy output of the technology. The LCOE is computed as:

$$\boldsymbol{LCOE} = \frac{\sum_{t=1}^{T} \frac{\boldsymbol{NC_t}}{(\boldsymbol{1+r})^t}}{\sum_{t=1}^{T} \frac{\boldsymbol{E_t}}{(\boldsymbol{1+r})^t}}$$

where *t = 1,…T* represents the lifetime considered (in years), *r* the discount rate, $\boldsymbol{NC_t}$ the negative cash flow for every year (e.g. OPEX, CAPEX and taxes) and $\boldsymbol{E_t}$ the electricity produced in the year *t*. In principle, when the LCOE is lower than the average power price of the electricity produced in the system, the project leads to profitability.

Last but not least the **IRR**, which represents the annual effective compounded return rate of a project, is obtained through:

$$\boldsymbol{0} = -\boldsymbol{CF_0} + \sum_{t=1}^{T} \frac{\boldsymbol{CF_t}}{(\boldsymbol{1+IRR})^t}$$

where $\boldsymbol{CF_0}$ represents the initial investment at the year t=0, $\boldsymbol{CF_t}$ the positive net cash flow for each year t. Observing the mathematical formulation, one can observe that the IRR represents the discount rate for which the NPV becomes zero. In principle, when the values of the IRR are greater than the discount rate, the project should be undertaken. The opposite works otherwise.

4.2.2 Assumptions

For the purpose of the analysis few assumptions are made. The goal is to represent as close as possible the real functioning of the plant and include parameters influencing the financial assessment of the HYSOL technology. The assumptions are here listed:

- The depreciation of the asset is applied as straight line depreciation throughout the whole lifetime of the project;
- The fuel (natural gas) and CO2 prices are assumed to increase during the lifetime according to steps (i.e. % increase respect to the previous year) predefined;
- An overhaul period is included in order to consider the renovation rate of the asset;
- For each of the year of the overhaul (and only for these), the O&M prices are increase of 25% (respect to the previous year);
- A degradation rate is included in order to consider the deterioration of the asset. Thus, each year the power production is decreased of 2%, until the end of the overhaul period. After the renovation, the power production gets back to the original value;
- The construction period is included in order to consider the availability of the different plants according to their completing date. According to these periods, gas turbine or CSP are producing/consuming only when they are fully completed;

- The offline consumption is included in order to consider the power consumption of devices related to the plant, while being offline;
- Water consumption and CO_2 emission, along with their costs, are also considered;
- The CAPEX includes the cost of the plant itself (both GT and CSP) and their auxiliaries (e.g. pumps, heliostat fields, air-cool condenser, etc…);
- The OPEX considers: water and gas consumption, CO_2 emissions, offline auxiliaries, insurance, spare parts of the plants, land rental, staff maintenance and taxes.

4.2.3 Base case

4.2.3.1 Input data

The input data for the base case in KSA, Mexico, Chile and South Africa are reported in Table 4.1.

Table 4.1: Input data for the base cases

Parameter	Country	Value	Reference
Lifetime	All	25 years	IDIE
Overhaul period	All	7 years	Grupo Cobra
O&M increase (overhaul)	All	25%	Grupo Cobra
Discount rate	All	10%[17]	IDIE
Inflation	All	2%	IDIE
Natural gas price	KSA	0,20 USD/kg	IDIE
	Mexico	0,20 USD/kg	IDIE
	Chile	0,66 USD/kg	IDIE
	South Africa	0,35 USD/kg	IDIE
Average annual power price 2014	KSA	41 USD/MWh	(ECRA, 2015)
	Mexico	27 USD/MWh	(CFE, 2014)
	Chile	131 USD/MWh	(CNE, 2014)
	South	85 USD/MWh	(sappmarket, 2016)

[17] The discount rate reflects the cost of capital of the project in question, assuming that equity is the only source of capital, thus it represents the minimum return that a shareholder would expect to receive when investing in the project.

	Africa		
Depreciation (straight line)	All	25	IDIE
Corporate tax rate	KSA Mexico Chile South Africa	20% 30% 23% 28%	(tradingeconomics, 2016a) (tradingeconomics, 2016b) (tradingeconomics, 2016c) (tradingeconomics, 2016d)
Water price	KSA, Mexico Chile South Africa	2.3 USD/m^3 2.3 USD/m^3 2.3 USD/m^3 2.3 USD/m^3	IDIE IDIE IDIE IDIE
CO_2 price	KSA Mexico Chile South Africa	0 USD/ton 0 USD/ton 0 USD/ton 0 USD/ton	IDIE IDIE IDIE IDIE

4.2.3.2 Support mechanisms for CSP in Kingdom of Saudi Arabia, Mexico, Chile and Saudi Arabia

Nowadays, the forms of support for the renewable energy technologies can occur in different ways. Examples are feed-in tariffs, feed-in premium, investments incentives and tax reduction/exemptions. Nonetheless, not many forms of support are implemented for the CSP plants in all the countries under study, as it is a relatively new technology still “young” in the energy market. For the sake of the analysis, in order to investigate the profitability of the HYSOL project under a “subsidy scenario”, assumptions are made in order to create hypothetical forms of support (FIT) for countries where this kind of support is not currently available. These artificial energy policies are calculated analysing the current support available on the energy sector of the countries considered both for renewables and for conventional generators.

4.2.3.2.1 Saudi Arabia

The hypothesis assumed for the Saudi Arabia case presumes that for the entire lifetime the hybrid plant under investigation is eligible for a *fixed subsidy*, equivalent to a “*feed-in tariff*”, for the whole time horizon of the project. The total subsidy per MWh is calculated based on the current average electricity unit cost calculated by ECRA using both international fuel prices and the fuel prices paid by the Kingdom's electricity producers (ECRA, 2015). Thereby, the total amount of subsidy per MWh received by the hybrid plant in this scenario is equivalent to the total amount of subsidy currently received by the conventional electricity generators of the Kingdom. Table 4.2 reports the values assumed.

Table 4.2: Current average electricity unit cost, Saudi Arabia

Currency[18]	Current avg.	Artificial subsidies[19]	Support
SR/MWh[20]	**154**	**800**	**646**
EUR/MWh	37	192	155
USD/MWh	41	213	172

Source: (ECRA, 2015).

The support is assumed to be paid on top of the average electricity price, which has been set once again equal to the average collected electricity price for the year 2014. The *artificial subsidies* values represent the "feed-in tariff" that will be implemented in the model. This scenario can be used to evaluate the economic feasibility of the HYSOL project in Saudi Arabia if a regulatory/policy framework, where the hybrid technology receives a subsidy per unit of electricity produced equals to the one currently received by the conventional generators, will be developed.

The assumption on the power price with subsidies is strong and uncertain, since the possibility of the development of such regulatory/policy framework in connection with the plan for the introduction of renewable technologies is not documented in the literature. Therefore a sensitivity analysis will be performed, evaluating the values of the economic indicators of the financial model for different average power prices.

4.2.3.2.2 Chile

The policy regulations concerning renewables support is different in Chile and no subsidies are currently available in form of feed in tariff or feed in premium for the Latin-American country. However, investments in RES technologies are usually subsidized with tax exemptions/reduction or through a financial help on the investment costs. As an example, the Chilean government supports RE uptake by directly subsidizing projects, where the first tender case for a CSP plant was published in February 2013. The Ministry of Energy, through the Corporación de Fomento de la Producción de Chile (CORFO) or the Chilean Economic

[18] Currency exchange rate according to (xe, 2016).
[19] The value correspond to the "feed-in tariff" value.
[20] Data available at (ECRA, 2015).

Development Agency, agreed to provide a subsidy of up to USD 20 million in addition to facilitating land access for the Cerro Dominator (Atacama 1) CSP plant (NREL, 2015); (Abengoa, 2015).

Furthermore, the government negotiated a consortium of financing sources for a total amount of over USD 350 million in soft loans, with a below-market interest rate. Some of this funding was offered by: the European Union (subsidy of up to USD 18.6 million), the Inter- American Development Bank (IDB, loans for at least USD 66 million), and the German Development Bank (KfW, loans for USD 135.2 million). For the sake of simplicity of the analysis, these schemes of support have been "converted" in a fixed amount of support per MWh (sort of feed-in-premium) paid on top of the current average electricity price. The final value is considered as "feed-in tariff". Considering the Cerro Dominator CSP plant as a case, the sum of the contribution to the investment and the lower taxes on the loan is spread on the total MWh produced during the lifetime of the plant. The values are reported in Table 4.3.

Table 4.3: Current average electricity unit cost, Chile

Currency[21]	Current avg.	Artificial subsidies	Support
EUR/MWh	117	127	10
USD/MWh	**131**[22]	142	11

Source: (Energia abierta, 2014).

In this way the support is shifted from the financing of the investment to the support of the energy production. Nevertheless, due to the uncertainties related with the amount of support for the CSP projects along with the "rough" assumption considered on the support level, a sensitivity analysis will be performed on the power prices in order to investigate the results with different amount of support.

4.2.3.2.3 Mexico

An approach similar to the one assumed for Chile has been used for the Mexican case. The Agua Prieta II CSP plant has been used as test case for the analysis, since it is the only CSP plant currently installed in Mexico (NREL, 2013). The World Bank financed the project on October 5, 2006 covering 100% of project cost (USD 49.35 million) under the Global Environment Facility (GEF) (World Bank, 2009). The project cost considered is for solar field only.

Similarly to Chile, the support received is shifted from the financing of the investment to the support of the energy production in order to calculate an artificial "feed-in-tariff" value (FIT). The values are reported in Table 4.4.

[21] Currency exchange rate according to (xe, 2016).
[22] Data available at (Energia abierta, 2014).

Further analyses will then investigate the change in the results according to different values of the average prices.

Table 4.4: Current average electricity unit cost, Mexico

Currency[23]	Current avg.	Artificial subsidies	Support
EUR/MWh	24	89	65
USD/MWh	27.27[24]	99	72

Source: (CFE, 2014).

4.2.3.2.4 South Africa

With almost 600 MW of capacity installed by 2018, South Africa is a front runner of the CSP technology in the Southern African Power Pool (SAPP) (NREL, 2016). Because of issues related with high initial investments and necessity of support, the CSP technology has been always included in the renewable support policies developed in South Africa. Under the Renewable Energy Feed-in Tariff (REFIT) program launched in March 2009, the tariffs concerning energy production through CSP technologies were definitely generous when compared to international feed-in tariffs. The FIT were set such that the RE generator could cover the cost of generating renewable energy plus an additional reasonable profit to encourage developers to invest in such projects. During the Phase I of the project, the FIT was set to 0.21 EUR/kWh for CSP with storage. On Phase II, the CSP without storages were eligible for 0.32 EUR/kWh (PPIAF, 2014). The support was intentionally designed high (compared to other countries) to take into account the higher risks associated with the development of such innovative projects in a new environment. However, during the year 2011 the REFIT program was substituted with the Renewable Energy Independent Power Procurement Program (REIPPP) establishing a competitive bidding process for renewable energy technologies. The REIPPPP program envisioned the procurement of 3 625 MW of RES power over a maximum of five tender rounds. With the new program the incentives for the CSP power production decreased. From round 1 to round 3[25], the support for CSP was in average 33.6 cUSD/kWh, 31.6 cUSD/kWh and 16.6 cUSD/kWh. Despite a decrease of almost 41.9% in the bids, 2 808 MW of RES capacity has still to be allocated (in the period 2010-2030). Further improvements can be expected in the bidding process, hopefully with a turn in the trend of the CSP support tariffs. For the sake of the analysis, the most recent (and worst) form of support was assumed (16.6 cUSD/kWh) in order to investigate the worst possible realization of the bidding offers.

Table 4.5 reports the values. More info about the tendering process and the resulting value is available at (PPIAF, 2014).

[23] Currency exchange rate according to (xe, 2016).
[24] Data available at (CFE, 2014).
[25] Results concerning round 4 and 5 were not available.

Table 4.5 Current average unit cost, South Africa

Currency[26]	Current avg.	Artificial subsidies	Support
EUR/MWh	76	91	15
USD/MWh	**85**[27]	101.6	16.6

Sources: (PPIAF, 2014) and (sappmarket, 2016).

4.2.4 Scenarios definition

Three main scenarios have been considered to test the Financial Model and investigate possible developments in the power prices. This was done in order to account for the current high uncertainties related with future power prices. The scenarios are:

- **No support mechanisms**: this scenario is based on the hypothesis that no support mechanism will be issued for renewable technologies. Thus the power price considered represents the average of the current power prices in the countries under investigation.

- **Minimum subsidies**: the scenario is used in order to evaluate the power price that would guarantee a Net Present Value equal to zero at the end of the project lifetime. The resulting value will thus show the minimum amount of subsidies required in order to reach the break-even.

- **Artificial subsidies**: in this scenario the analysis is performed considering artificial current subsidies provided for the renewable power generation in the different countries. The scenario is thus based on the hypothesis that for the entire lifetime the hybrid plant under investigation is eligible for a fixed subsidy. The support is assumed to be paid on top of the average electricity price. The final value represents an artificial "feed-in tariff" used to assess the project. This last scenario can be used to evaluate the economic feasibility of the HYSOL project if a regulatory/policy framework, where the hybrid technology receives a subsidy per unit of electricity produced equal to the one currently received by the conventional generators, will be developed.

- **LCOE break-even**: in order for the project to be competitive, the LCOE have to be smaller than the average power price in the market considered. Therefore, an investigation is performed for the project in the countries considered, in order to find the input data necessary to obtain the desired output.

[26] Currency exchange rate according to (xe, 2016).
[27] Data available at (sappmarket, 2016).

4.3 Results

4.3.1 Scenarios based analysis

The following tables report the results for the scenarios implemented in the countries considered.

Table 4.6: Results of the Financial Model, Kingdom of Saudi Arabia

Scenario	Power price [EUR/MWh]	NPV [MEUR]	IRR [%]	LCOE [EUR/kWh]
Current avg.	37	-551.4	-3.1	0.147
Minimum Subsidies	141	0	10%	0.173
Artificial Subsidies	192	270	14%	0.185
LCOE break-even	184	228.3	13%	0.183

Table 4.7: Results of the Financial Model, Chile

Scenario	Power price [EUR/MWh]	NPV [MEUR]	IRR [%]	LCOE [EUR/kWh]
Current avg.	117	-170.6	7%	0.173
Minimum Subsidies	148	0	10%	0.182
Artificial Subsidies	127	-115.8	8%	0.176
LCOE break-even	200	283.3	14%	0.196

Table 4.8: Results of the Financial Model, Mexico

Scenario	Power price [EUR/MWh]	NPV [MEUR]	IRR [%]	LCOE [EUR/kWh]
Current avg.	24	-606.6	-7%	0.124
Minimum Subsidies	135	0	10%	0.165
Artificial Subsidies	89	-252.7	6%	0.148
LCOE break-even	187	282.4	14%	0.184

Table 4.9: Results of the Financial Model, South Africa

Scenario	Power price [EUR/MWh]	NPV [MEUR]	IRR [%]	LCOE [EUR/kWh]
Current avg.	76	-313.6	4%	0.139
Minimum Subsidies	128	0	10%	0.157
Artificial Subsidies	91	-223.7	6%	0.144
LCOE break-even	176	286	14	0.173

4.3.1.1 Kingdom of Saudi Arabia

The results for the analysis performed on the KSA case showed that, given the current level of average power prices, the project would not be feasible. Both NPV and IRR, with negative values, confirm the non-profitability of the investment. The minimum value of power price required in the system in order to reach the break-even is ≅141 EUR/MWh. However, for this case, the LCOE is still greater than the power price, implying that the new technology would not be competitive in that market unless subsidized.

In order for the investment to be competitive (i.e. LCOE < average power price) the average power price in the KSA would need to be ≅184 EUR/MWh. With this value, both NPV (≅228 MEUR) and IRR (13%) assumes acceptable values and prove the financial feasibility of the investment.

Last but not least, with the assumption that the new renewable technology would receive the same amount of subsidies currently available for the conventional plants, the HYSOL project would yield to positive profit for the investing company (NPV ≅ 270 MEUR) along with an IRR of 14%. For this case, as the reader can notice in Table 4.6, the LCOE results to be smaller than the average power price, thus proving the competitivity and possible future exploit of the HYSOL technology in the Saudi Arabian energy market.

4.3.1.2 Chile

The results for Chile bring to similar considerations as for KSA. Given the current average power prices, the economic indicators suggest that the project should be discontinued.

The same result is found for average power prices that considers the artificial subsidies. Even for this case, the NPV assumes negative value; the IRR is also found to be smaller than the discount rate.

The minimum value of the average power prices to reach the break-even (i.e. NPV=0) is found to be ≅148 EUR/MWh. The resulting LCOE is greater than the power price, thus implying that additional subsidies would be necessary for the new technology to be competitive (≅34 EUR/MWh).

In order for the HYSOL technology to be competitive in the Chilean market, the average power prices should be ≅200 EUR/MWh. With this value, all the economic indicators point out that the investment would be profitable.

4.3.1.3 Mexico

The investment analysis performed with the financial model on the Mexican case shows results very similar to the case of Chile. With the current average power prices, the investment should be discarded, since the NPV assumes negative value, the IRR is lower than the discount rate and the LCOE is greater than the power price. A similar trend is found for the artificial subsidies case.

When calculating the minimum amount of subsidies necessary in order to reach NPV ≅0, the results shows that the average power price value should be ≅ 135 EUR/MWh. However, once again, the LCOE result to be higher than the average power price, thus implying the need for further subsidies.

The profitability for the HYSOL technology in the Chilean market is reached with average power prices ≅187 EUR/MWh. Given this value, the economic indicators show that the project should be undertaken.

4.3.1.4 South Africa

Table 4.9 reports the results of the simulations performed with the Financial Model. The outcomes show that for the South African case, the trend does not differ from the other countries previously analysed.

The HYSOL project would not be feasible considering the current average power price. Both IRR (value lower than the discount rate) and the negative NPV clearly identify the investment as non-profitable. The scenario performed considering the current (but worst case) amount of subsidies highlights that the support currently given to the CSP power producers is not enough.

Nonetheless, the power price required in order to reach the break-even for the project (i.e. NPV=0) lies "only" 37 EUR/MWh above the current power price (with support). For the LCOE break even, the quota is slightly higher (85 EUR/MWh) and would lead to an IRR of 14% and a NPV of 286 MEUR.

4.4 Sensitivity analysis

The results previously described are based on assumptions that try to represent the reality as close as possible. However, input data like lifetime, discount rate, inflation, natural gas/CO_2/water prices can have a great impact in the final results when their values are modified. The input data of greatest interest (and most influential on the results) is the average power price. A sensitivity analysis is therefore performed on the values of average power prices, in order to investigate the change in the economic indicators considered (i.e.

NPV, LCOE). The values of the power prices investigated are found fixing a desired IRR in the Financial Model and extracting the value of the power price necessary to get that IRR.

At first, the analysis will be performed for each country, focusing more on the economic indicator development. After, the analysis will target the comparison between countries.

4.4.1 Internal rate of return (IRR) VS Power prices

Figure 4.2, Figure 4.3, Figure 4.4 and Figure 4.5 show the results of the sensitivity analysis performed over the average power prices. The power prices-IRR relation is characterized by an increasing exponential function. The higher is the IRR desired by the investing company, the higher need to be the average power prices in the system. The break-even point for the LCOE is highlighted with a triangle. The equilibrium point is reached for an IRR of 14% for all the cases. The resulting power prices[28] are ≅196 EUR/MWh, 200 EUR/MWh, 187 EUR/MWh and 176 EUR/MWh respectively for KSA, Chile, Mexico and South Africa. The trend between IRR-power prices is found to be similar for all the countries under analysis (though, with different exponential functions).

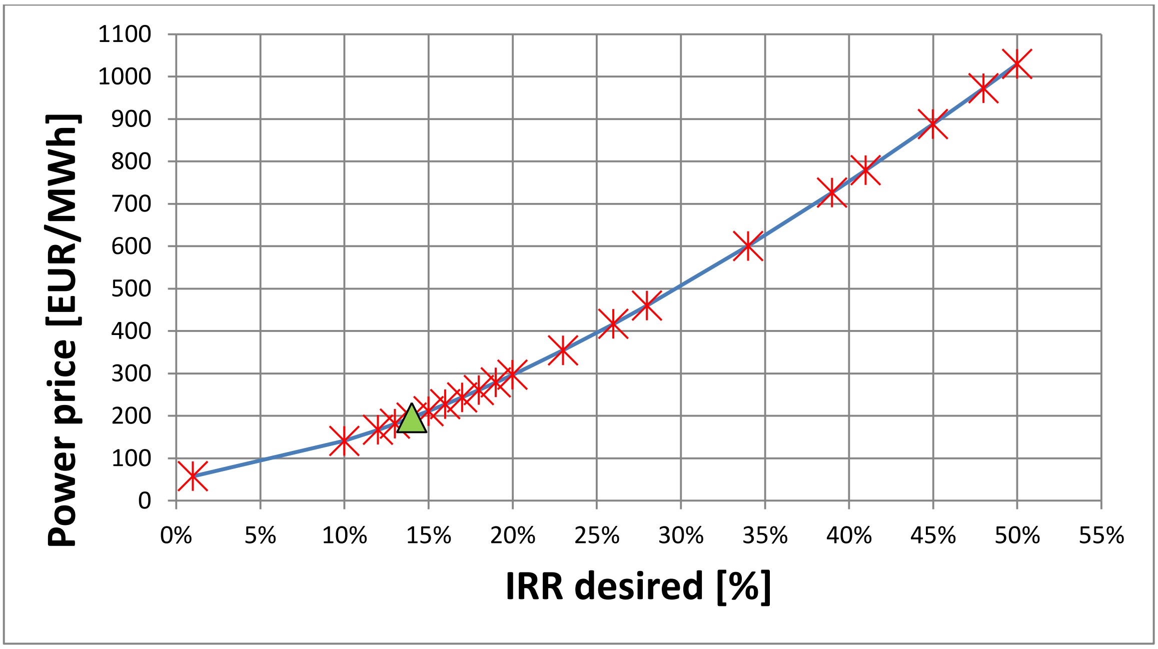


Figure 4.2: Resulting power prices for different IRR desired, Kingdom of Saudi Arabia

[28] The power price reported in the graphs represents the average power price in the energy system considered.

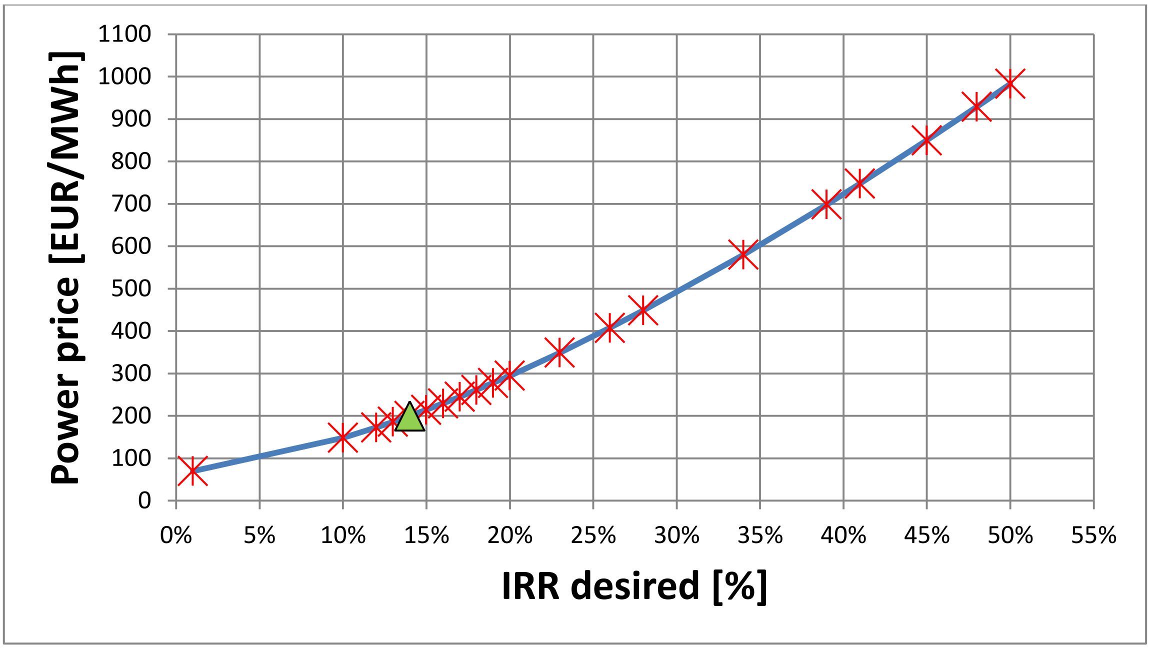


Figure 4.3: Resulting power prices for different IRR desired, Chile

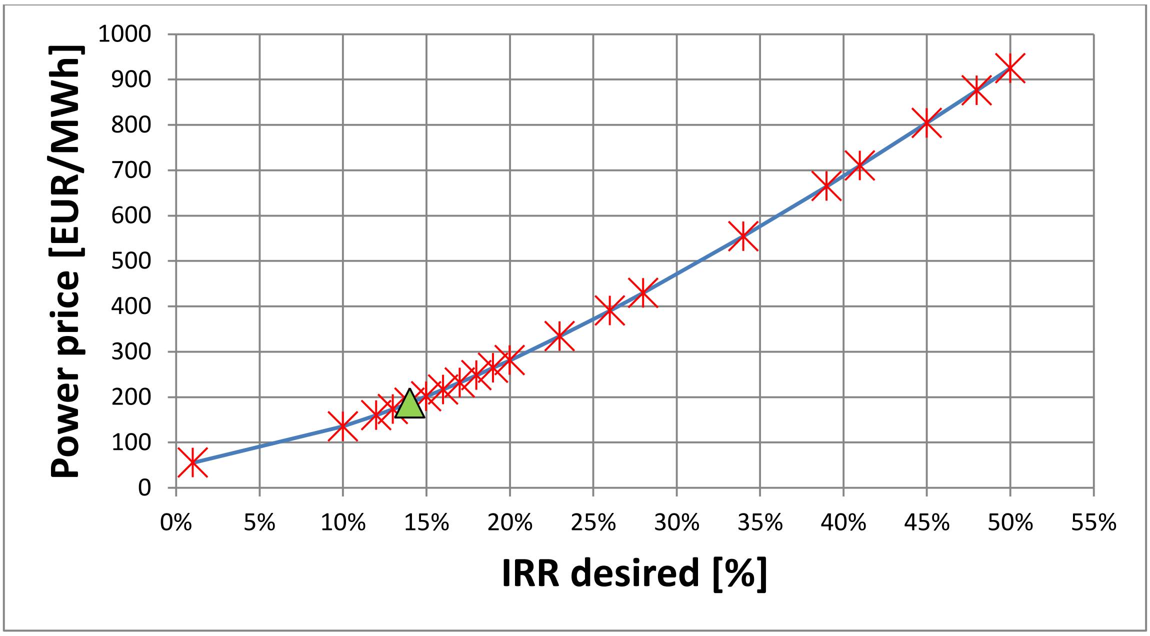


Figure 4.4: Resulting power prices for different IRR desired, Mexico

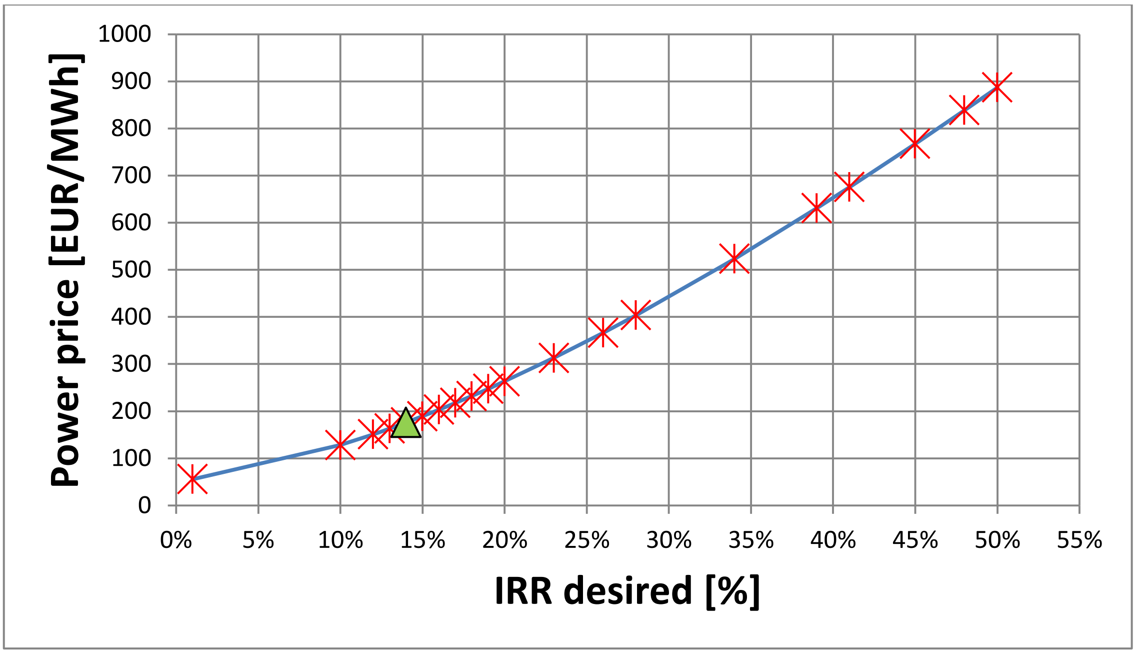


Figure 4.5: Resulting power prices for different IRR desired, South Africa

4.4.2 Power prices vs. Net present values (NPV) and LCOE

The resulting net present values (NPV) and the levelized cost of energy (LCOE) are plotted against the average power prices in Figure 4.6, Figure 4.7, Figure 4.8 and Figure 4.9. The NPV values can be read on the left axis, while the LCOE on the right. Differently from the IRR, the relation between the power prices and NPV/LCOE is characterized by linear functions, with different slopes. Meaning that an increase in the power prices result in a linear increase of the resulting NPV and final LCOE. A green triangle in the figures highlights the break-even point for the investment (i.e. power prices that leads to the LCOE break-even). For this power prices values, the NPV and the LCOE are ≅ 291 MEUR - 0.186 EUR/kWh, 283 MEUR - 0.196 EUR/kWh, 282 MEUR - 0.184 EUR/kWh and 286 MEUR - 0.173 EUR/kWh respectively for KSA, Chile, Mexico and South Africa.

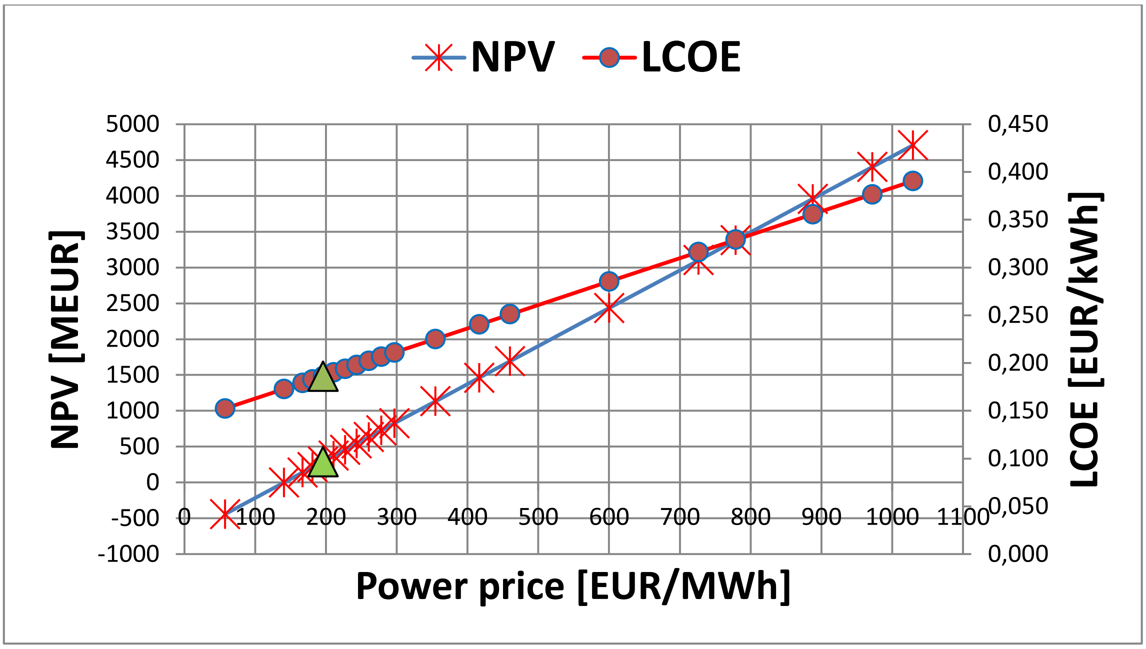


Figure 4.6: NPV and LCOE values for different power prices, Kingdom of Saudi Arabia

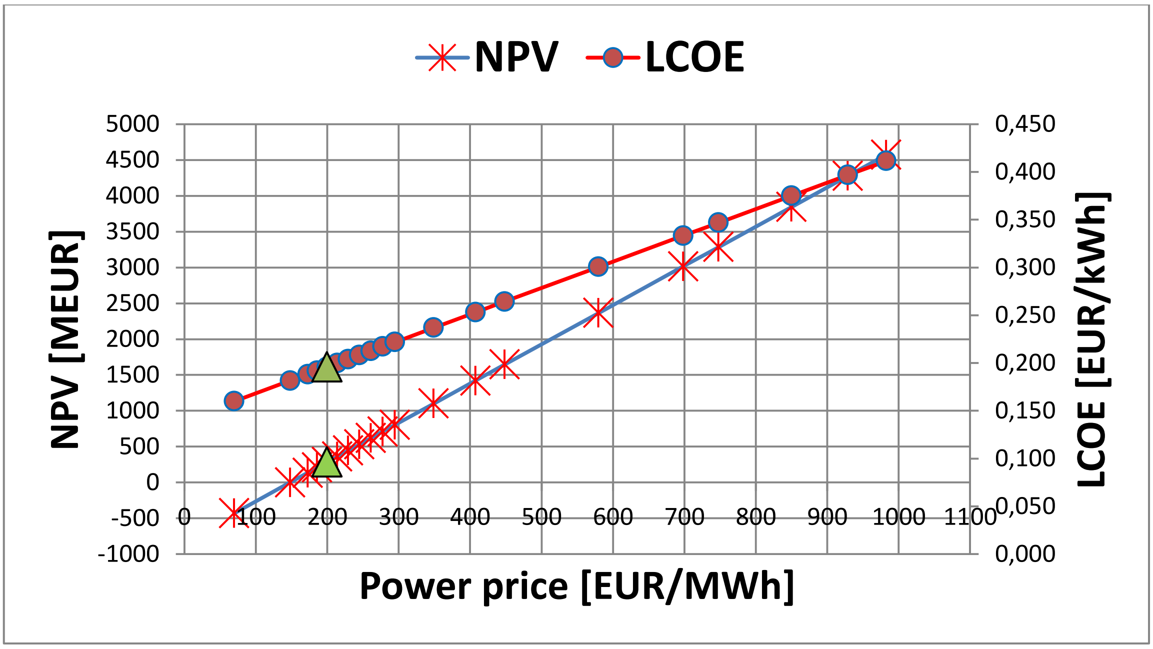


Figure 4.7: NPV and LCOE values for different power prices, Chile

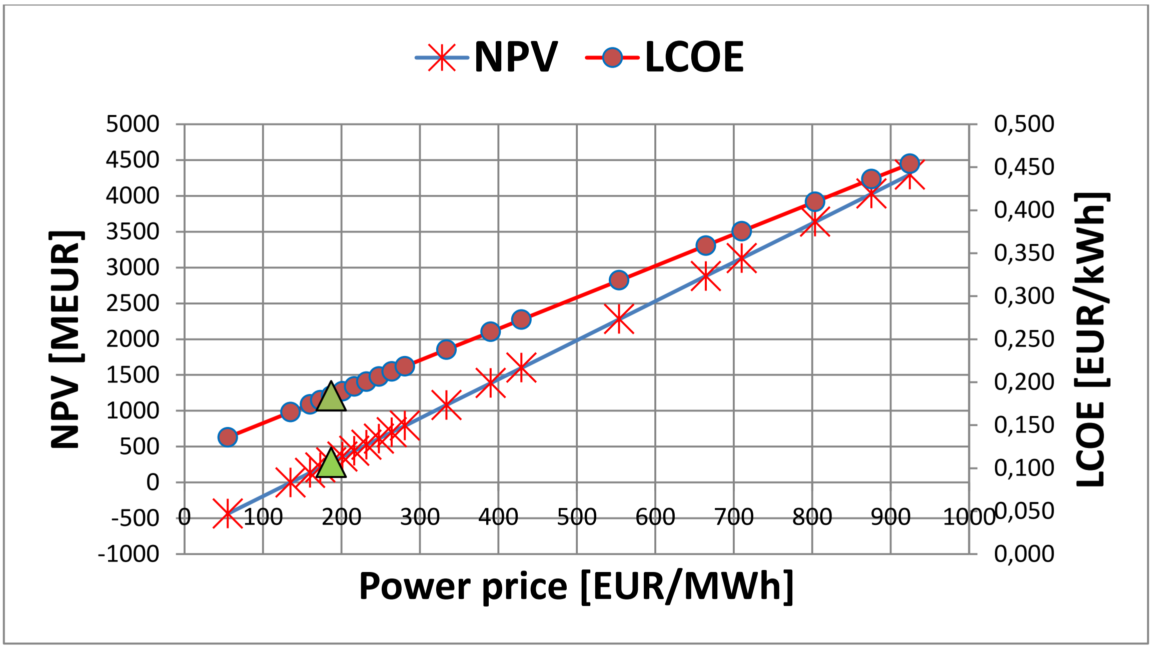


Figure 4.8: NPV and LCOE values for different power prices, Mexico

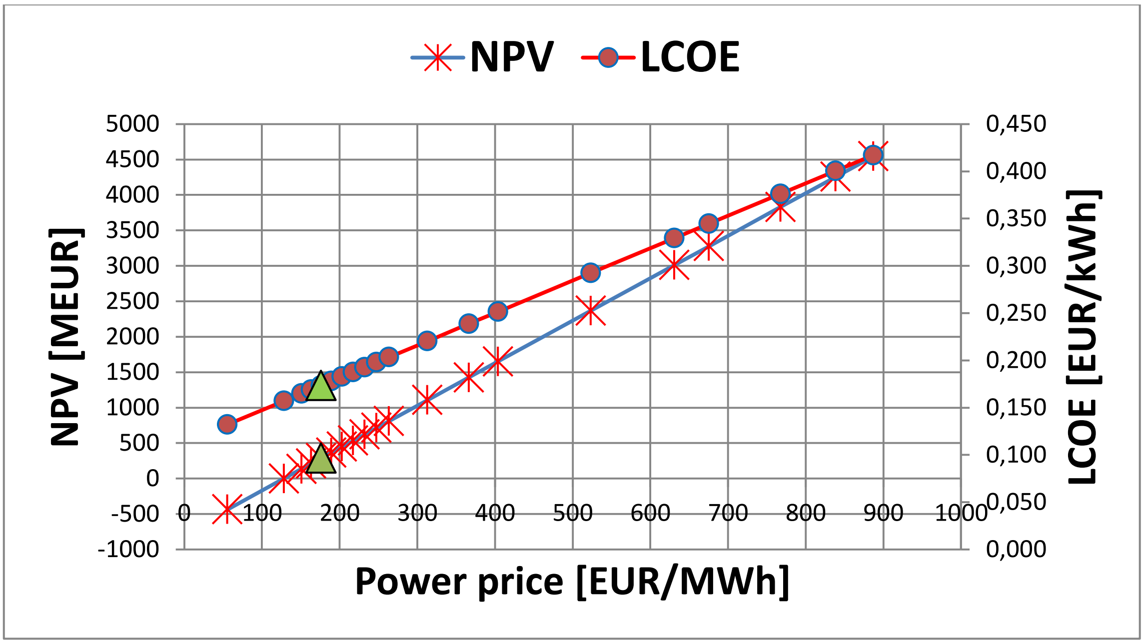


Figure 4.9: NPV and LCOE values for different power prices, South Africa

4.4.3 Countries comparison

When comparing the IRR values reported in Figure 4.10 one can notice that the curves are almost overlapping. The zoom reported in Figure 4.11 helps to discuss on the results and visualize better the findings. The outcomes of the Financial Model show that in order to reach the same IRR, the four countries necessitate different power prices. The country that can reach the IRR with the lowest value would then be the best for the investment. The results show that, in terms of IRR, the country where the HYSOL investment would lead to the best profit is South Africa. For all the series of prices considered, the IRR values for SA are always higher than the other countries. For example, if the average power price in the system is 175 EUR/MWh, the IRRs would be 14%, 13%, 12.5% and 12% respectively for SA, Mexico, KSA and Chile. The order of profitability thus sees SA as the most profitable country, followed by Mexico, KSA and Chile.

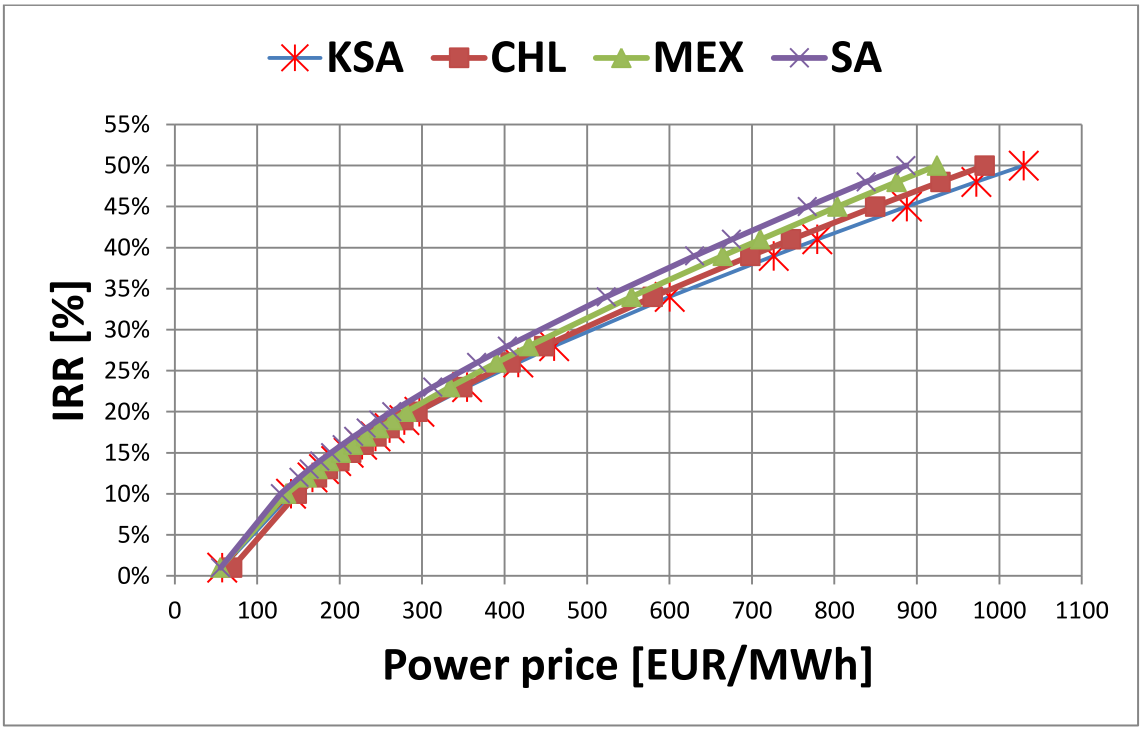


Figure 4.10: IRR values, countries comparison

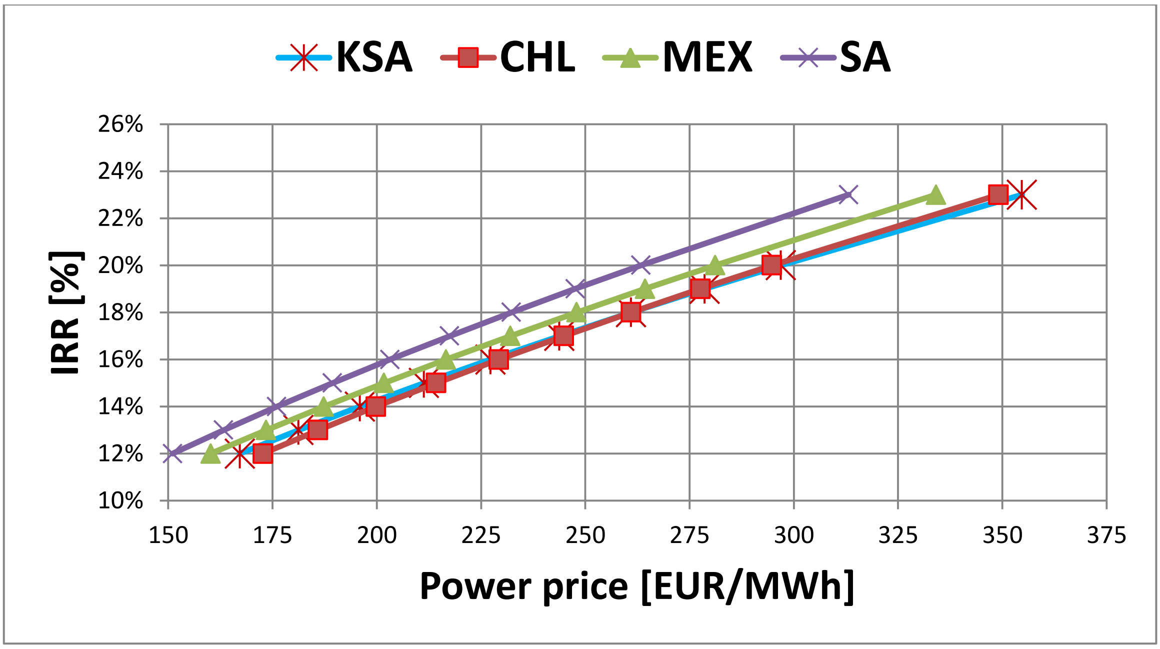


Figure 4.11: IRR values, countries comparison zoom

The same trend can be observed analysing the NPV values reported in Figure 4.12 and in the zoom in

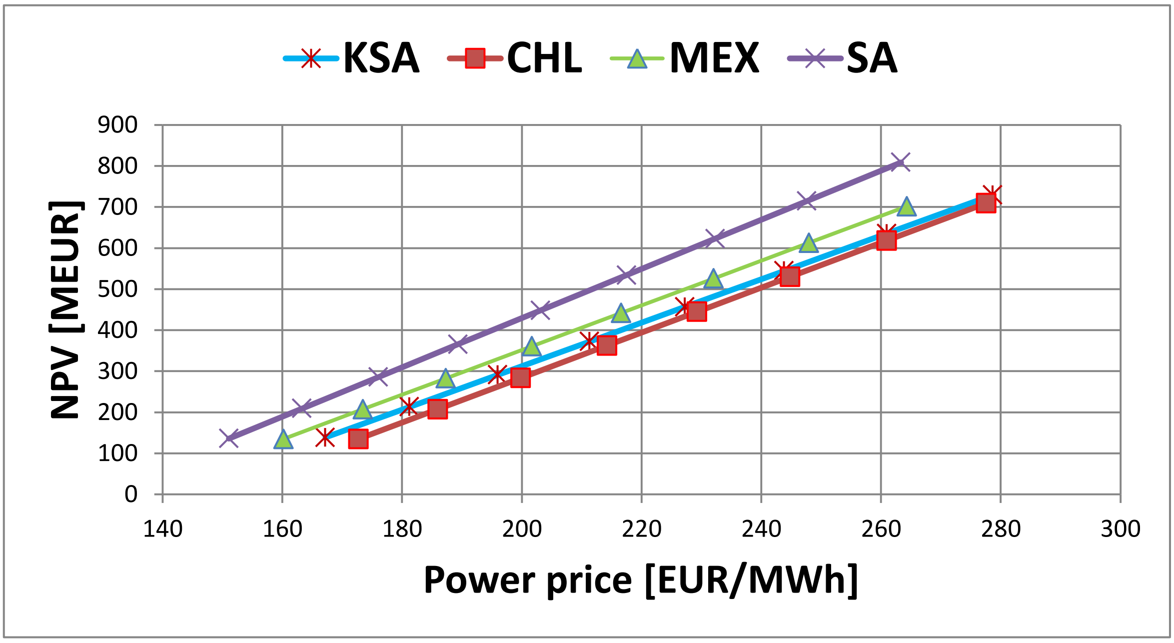


Figure 4.13. The reader can notice that, for the same power price (e.g. 200 EUR/MWh), the investment with the higher NPV is South Africa, followed by Mexico, KSA and Chile. For power price values greater than ≅280 EUR/MWh, the investment in Chile will be more profitable than KSA.

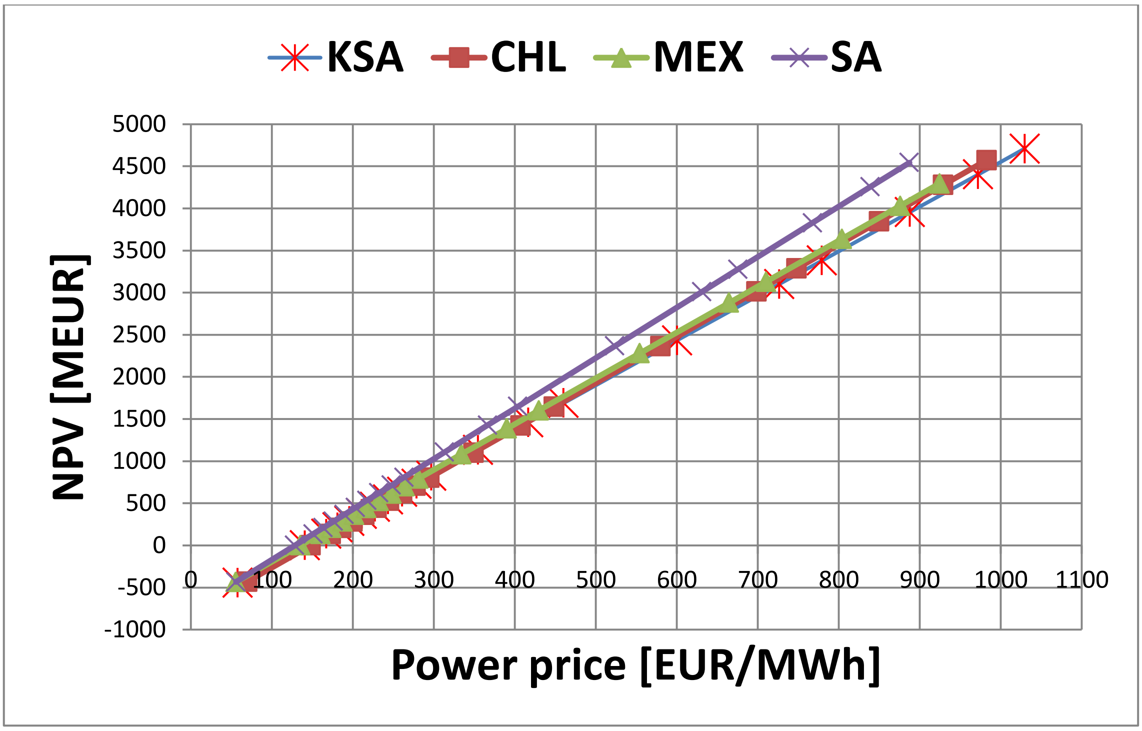


Figure 4.12: NPV values, countries comparison

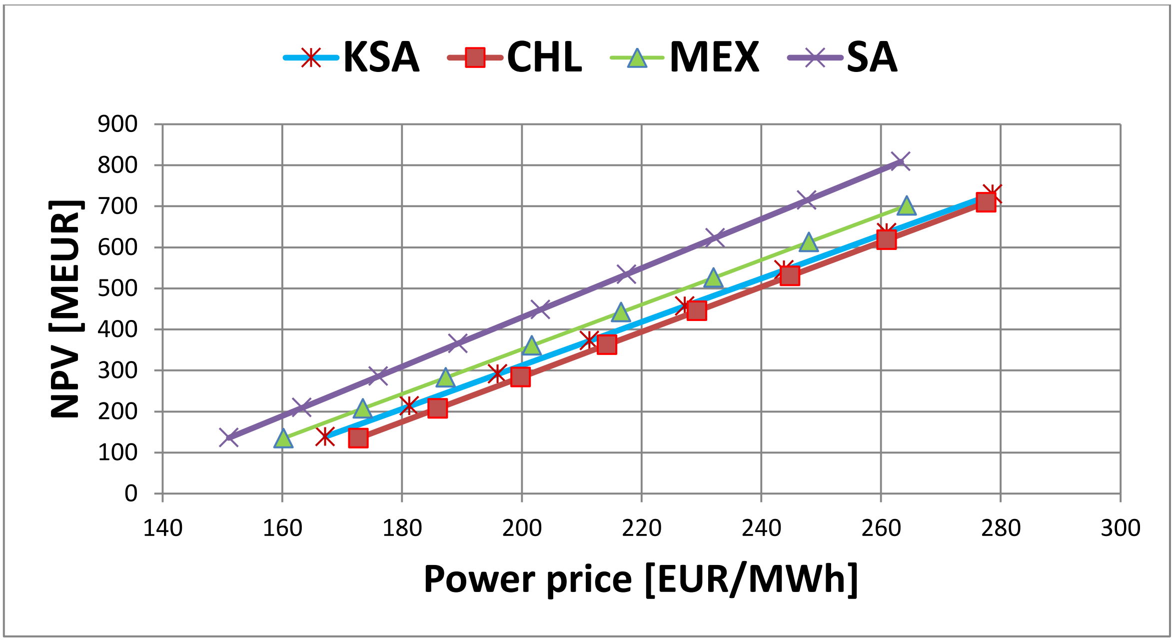


Figure 4.13: NPV values, countries comparison zoom

Concerning the LCOE, the results in Figure 4.14 and Figure 4.15 present a different trend. The reader now should analyse the graphs with a different approach: the lower is the LCOE, the better is the option. For average power prices lower than ≅180 EUR/MWh, the lowest LCOE is found in the investment in South Africa, followed by Mexico, KSA and Chile. However, when the power price lies between ≅180 EUR/MWh and ≅270 EUR/MWh the LCOE in KSA results to be lower than Mexico. The turning point is found to be at ≅270 EUR/MWh, where the order of profitability changes. Kingdom of Saudi Arabia results to be the most convenient option, followed by Chile, South Africa and Mexico.

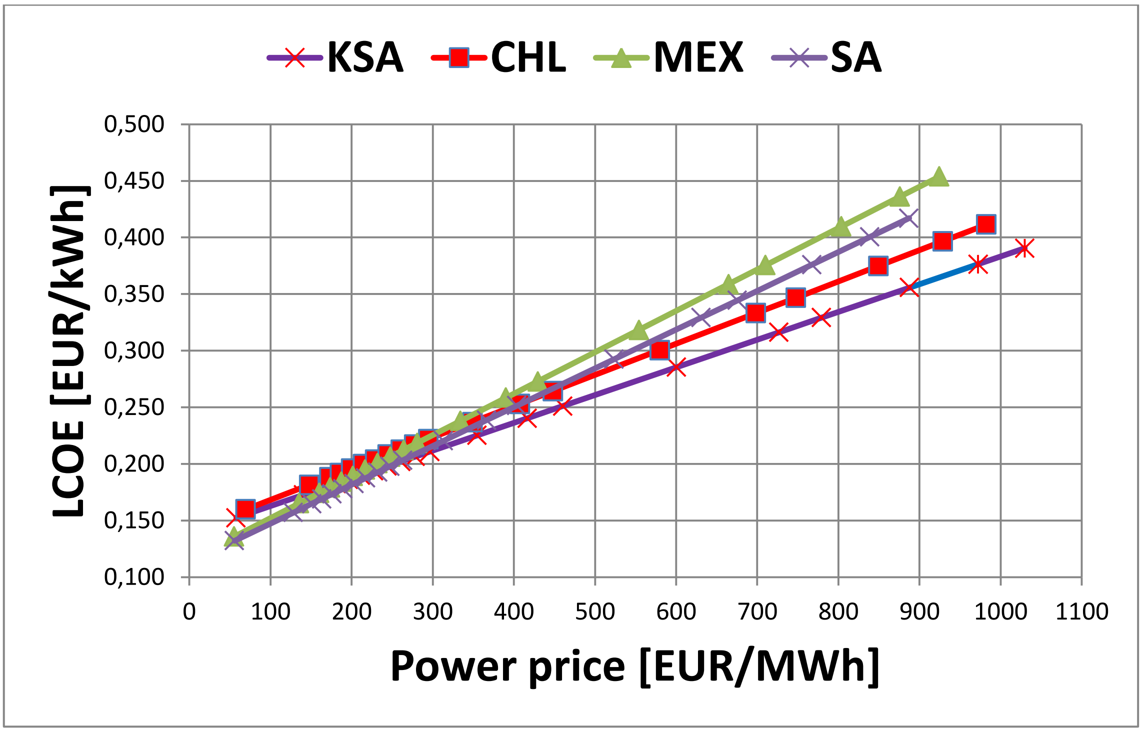


Figure 4.14: LCOE values, countries comparison

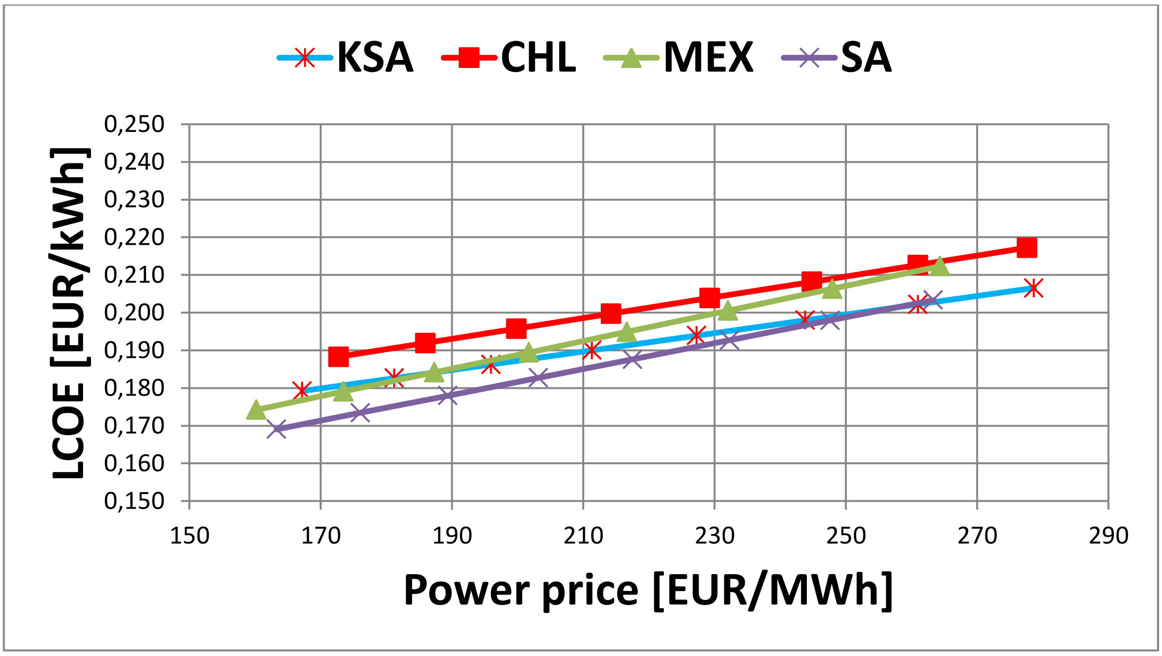


Figure 4.15: LCOE values, countries comparison zoom

4.5 Conclusions

The purpose of the Financial Model tailored to the investment analysis proposed, is to investigate the economic feasibility of the HYSOL technology in four selected countries: Kingdom of Saudi Arabia, Chile, Mexico and South Africa. Four scenarios are implemented to study possible development of the reality. The first scenario considered the current situation with no subsidies available for power produced from renewable sources (e.g. HYSOL technology). In the second scenario the Financial Model is used to calculate the minimum power price necessary in order to obtain a NPV equal to zero. The third scenario considers the case with hypothetical artificial subsidies available. The fourth scenario is used to calculate the necessary power price to reach the break-even with the HYSOL technology (from the LCOE point of view).

The results have shown that, without any subsidies, the HYSOL project should not be undertaken. In fact, the higher investments costs related with the project lead to negative NPV and IRR values lower than the discount rate. Both the indicators thus confirm the non-profitability of the investment.

When considering artificial subsidies, the outcomes of the analysis showed a mix situation. The investment in the HYSOL technology, in the KSA, results profitable with a NPV of ≅270 MEUR and an IRR of 14%. The opposite is observed for Chile, Mexico and South Africa since, with the input data implemented, the results shows negative NPV and low IRRs.

Through the results obtained in the "minimum subsidies" and "LCOE break-even" scenarios, it results clear that the minimum average power prices necessary are way above the current average power prices. These results highlight the need of a support tariff (e.g. feed-in tariff[29], feed-in premium, etc.) in order for the HYSOL technology to be competitive in the selected markets. Since no feed-in tariff is currently in place in the countries under investigation (or else: the kind of existing supports are not enough to guarantee the feasibility of the project), these results can be useful for decision makers when designing future energy policies on renewables.

The profitability of the investment through the investigation on the IRR is performed with a sensitivity analysis on the power prices according to desired IRR. The outcomes showed an increasing exponential relation between the IRR and the power prices. The findings thus allow the investors to understand (and forecast) which internal rate of return they will obtain considering the future development of the power prices in the energy systems under study. The calculated power prices are also used to analyse the relation with the NPV and the LCOE. For these economic indicators, the relation with the power prices is identified to be linear. Moreover it confirmed the increasing profit with the increase in the power prices.

[29] Support mechanism often used for the renewable energy technologies.

Last but not least, the comparison of the results within the countries shows that, with the selected assumptions, the investment in South Africa is the most profitable[30] (for low values of the average power prices). It then follows Mexico, the Kingdom of Saudi Arabia and Chile.

The results of the analysis are mainly influenced by the basic assumptions. One of the factors that impacts the most on the final results are the investments costs. As for most of the renewable energy technologies, the HYSOL project presents high investments costs mainly related with the components of the CSP technology. Equipment parts like mirrors, pipes, heat storages and turbines have a huge impact on the final cost of the project. However, the latest improvements in the manufacturing factories and on the technologies are reducing the production costs of components that used to be expensive. A clear example can be found in the photovoltaic (PV) solar systems both residential and commercial. Just as a case, a recent study reports that the prices of U.S. residential and commercial PV systems declined 5%–7% per year, on average, from 1998–2011, and by 11%–14% from 2010–2011, depending on system size (NREL, 2012). With the upcoming of the CSP technology, more and more factories will improve the performances of their processes thus reducing the costs of production of the same equipment/machineries that today are highly expensive. A reduction on the CSP systems costs, similar to the one that happen for the PV systems, is thus realistic. Once this will happen, the results of the financial analysis might be different, surely pointing towards a positive feasibility of the project (even with low average power prices).

In conclusion, the analysis performed with the Financial Model shows that with the current average power prices only, the HYSOL project should not be undertaken. However, the different scenarios implemented have shown the gap between the current and the necessary power prices in order to reach profitability for the investment. The results can be a useful suggestion for policy makers, when it will come the time to design support schemes for renewable energy technologies like HYSOL. Indeed, if properly supported, the HYSOL project can lead to high profitability and become a reality in these power markets characterized by a great use of fossil fuel based technologies. Being the HYSOL project based mainly on CSP technology, it would reduce the dependence on the fossil fuels and help the country to develop a clean energy system. The introduction of this new technology in the selected markets can thus bring large environmental benefit, reducing GHG emissions and, at the same time, provide clean and stable power production.

[30] Keep in mind that these results differ mostly because of the various set of assumptions considered for the different energy systems.

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