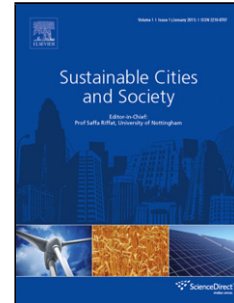


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Sustainable island power system – Scenario analysis for Crete under the energy trilemma index

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Highlights

- A techno-economic evaluation of different energy scenarios under the Energy Trilemma Index for the island of Crete
- A high spatio-temporal resolution analysis was performed
- No Business as Usual Scenario that relies on oil-fired generators could facilitate a future solution for Crete and similar small islands across Europe
- The optimum scenario incorporates interconnectors and energy storage systems
- It is possible for Crete to halve its total system costs and GHG emissions between 2020 and 2040

ABSTRACT

Sustainable energy supply is an essential part for economic and social development in every society. Islands as geographical isolated regions have to confront a number of challenges to secure a reliable and clean energy system. Currently, electricity demand on the Greek island of Crete is supplied by oil-fired engines imposed to new emissions restrictions applied from 2020. Thus, a capacity upgrade is necessary and new solutions driven by renewable energy, energy storage and interconnections. This study investigates three scenarios: Business as Usual (BAU); Natural Gas (NG); and the Interconnection of Crete with the National Grid System (Int.) to assess the potential techno-economic and environmental impact of the required transition under the Energy Trilemma Index. A capacity expansion and operation optimisation process has been applied through a high resolution spatio-temporal analysis performed with PLEXOS Integrated Energy Model. It was concluded that no BAU Scenario could facilitate a future plan for the electricity system of Crete or any European island imposed to such constrains. The optimum scenario incorporates interconnectors and energy storage systems that manage to deliver 52% reduction in the total system costs (2020-2040), 79% in electricity prices and 48% reduction in GHG emissions by 2040, compared to the BAU.

KEYWORDS

electricity, energy storage, energy trilemma, interconnections, islands, natural gas, renewable energy, scenarios

1 INTRODUCTION

More than 100,000 islands across the world (Richardson, n.d.) struggle to secure a reliable energy system with affordable energy prices and low carbon intensity. In particular, non-interconnected islands (NII) characterized by energy isolation, depend mostly on diesel and heavy fuel oil as their primary electricity source resulting in economic and environmental impediments. ‘Energy Islands’ can be considered beyond the geographical non-interconnected islands, any remote rural and weakly interconnected area in the world which strives for affordable and sustainable energy supply.

According to the report of the United Nations conference on Environment and Development in Rio in 1992, “islands are ecologically fragile and vulnerable” (United Nations, 1992). Two years later the ‘Programme of Action for the Sustainable Development of Small Island Developing States’ was established (United Nations, 1994). Although islands usually comprise small regions, possess a significant yet unexploited renewable energy potential making the electricity sector a driver towards decarbonization in the energy transition of islands’ economies (Eurelectric, 2012). Examples across the world from the Pacific to the Caribbean Islands and the Mediterranean Sea demonstrate as examples with abundant wind, solar and other natural energy resources. In the European context, several declarations have been recorded from the Canary islands - Palma de Mallorca declaration in 1999 and the Chania declaration in 2001 (Cipriano, 2015) to the latest one, in Malta for Clean Energy in EU islands (European Commission, 2017a). Key catalysts towards the overall improvement on islands have been initiatives such as the Covenant of Mayors, the Pact of Islands, the Smart Islands Initiative and recently the Clean Energy for EU Islands as part of the Clean Energy for All Europeans which addresses challenges related to islands prosperity and sustainability in Europe (European Commission, 2016c).

In that respect, Island System Operators (ISOs), producers and power suppliers on islands aim to transit towards a more robust and sustainable energy system. The European governments have approved that the target of the dominant framing of the low carbon energy transition problem is one of replacing old fossil fuel plants with zero carbon technologies. This barrier could be addressed by transforming islands and remote, energy isolated regions into test-beds and apply advanced technologies such as: interconnectors, smart energy systems such as demand response with increased energy efficiency, energy storage and electrification of the transport sector accompanied by target policies and incentives.

1.1 Overview of Crete’s electricity system

Europe counts 362 main islands with more than 50 permanent residents plus 286 with smaller population. Approximately 2% of Europe’s population currently is living on them (Eurelectric, 2012). The peculiar case of the Greek system consists of 80 principal islands from which 58 are non-interconnected. The island of Crete is the largest non-interconnected island in Greece, located in the southern part of the Aegean Sea. The capital of Crete, Heraklion, is the fourth largest city in Greece and the whole island utilizes more than 50% of the total power consumed in the Aegean Sea non-interconnected islanding region (Hellenic Electricity Distribution Network Operator, 2014). Crete is the only island in Greece considered a small isolated system since 2014, when the Non-Interconnected Islands (NIIs) Code was entered into force (Hellenic Republic, 2014d). All other Greek NIIs are qualified as isolated micro-systems compliant with Article 2(27) of Directive 2009/72/EC (European Commission, 2014).

Crete recorded annual electricity demand levels of 2.7 TWh (2,693 GWh) and a peak load of 634.3 MW in 2015 (Figure 1). Electricity demand is covered by three local thermal power plants with a total capacity of 823.46 MW (Table 1). Crete as the plethora of geographically isolated regions across the world, relies predominantly on heavy fuel oil (HFO) and secondly on diesel fuel, which is used to cover peak demand since it records considerably higher prices and increased tax rates. The steam turbines and the CCGT station are mainly used to cover the base load, on the basis of their slow response to demand fluctuations, while gas turbines and diesel engines provide power during the peak hours. Renewable

energy sources (RES) represent 23% of the total annual electricity generation, consisting of wind and solar energy (200.3 MW and 78.3 MW respectively) and a small hydropower station (0.3 MW). Other forms of energy such as bioenergy, solar thermal and hybrid technologies have not been exploited yet. Due to the increased use of oil, the carbon emissions intensity factor for Crete is 0.69 t/MWh, which is 15% higher than the average national carbon intensity factor. Crete produces approximately 1.8-1.9 million carbon tones from electricity generation per year.

The average full production cost for Crete was approximately 180.7 €/MWh in 2016 (Hellenic Electricity Distribution Network Operator, 2016). The divergence between power generation costs in the NIIs and the interconnected system price (62.63 €/MWh) is remunerated through the ‘Public Service Obligation’ (PSO) policy (Hellenic Republic, 2014c). PSO sets a common electricity price for all the Greek electricity consumers pursuant to Laws 3426/2005 and 4001/2011 and is collected by the electricity suppliers through a levy on the electricity bills (Hellenic Republic, 2005, 2011; Regulatory Authority for Energy, 2014). PSO for Crete was configured to 403 Mil €, equivalent to 177.3 €/MWh according to the latest available data (Hellenic Republic, 2014b). Projections show that it could climb up to 600 Mil € for a slow growth scenario (equivalent to 272 €/MWh) and up to 1500 Mil € (equivalent to 370 €/MWh) assuming an aggressive demand and fuel price scenario by 2040 (Zafeiratou & Spataru, 2017). So far, this support scheme has limited the incentives for Crete to innovate in its own electricity system.

Directives 2010/75/EU and 2015/2193/EU have set environmental restrictions to the operation of combustion plants stations across Europe, to limit production of sulfur dioxides (SO₂), nitrogen oxides (NO_x) and dust. Small isolated systems, such as Crete are exempted from compliance with the emission limits as specified in Articles 30 and 31 of 2010/75/EU until the 31/12/2019. These two directives hamper power generation of oil-fired steam and gas turbines as 1,500 hours and 500 hours respectively from 2020 on an annual basis. From 2030 that number decreases to 500 hours horizontally (European Union, 2010, 2015). Taking into consideration that in general, electricity consumption in the small Mediterranean islands is higher compared to the inland consumption, with increasing growth trends (Beccali et al., 2017), such measures could result in demand and supply imbalances and power insufficiency. For internal combustion engines, technical operational constraints have not been specified yet, nevertheless similar restrictions are anticipated in due course.

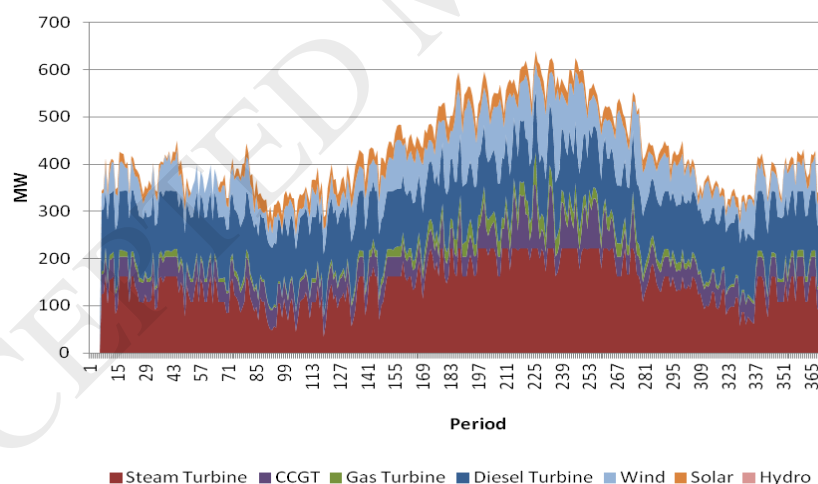


Figure 1. Average Hourly load profile of Crete per day in 2015 (Hellenic Electricity Distribution Network Operator, 2016)

Units	Fuel	Capacity (MW)	Retirement Year*	Technical Minima (MW)
<i>Linoperamata Power Station</i>				

* Retirement year will be prolonged in anticipation of the interconnection with the NGS or the introduction of NG (expected year 2020)

Steam Turbines - (Annual 2015 Gen.: 330 Gwh)				
Steam 1 [†]	HFO	6.25	2011	2
Steam 2 and 3	HFO	15	2017	8
Steam 4, 5 and 6	HFO	25	2021	18
Gas Turbines - (Annual 2015 Gen.: 47 Gwh)				
Gas 1 [‡] and 2	Diesel	16.25	2013	3
Gas 3	Diesel	43.37	2027	5
Gas 4	Diesel	14.72	2027	3
Gas 5	Diesel	28	2027	6
Diesel Engines - (Annual 2015 Gen.: 292 Gwh)				
Diesel (1-4)	HFO	12.28	2019	3
Chania Power Station				
Gas Turbines - (Annual 2015 Gen.: 46 Gwh)				
Gas 1	Diesel	16.2	2010	3
Gas 2	Diesel	24	2010	5
Gas 3	Diesel	30	2011	5
Gas 4 and 5	Diesel	59.4	2023	10
Gas 6	Diesel	28	2017	8
Combined Cycle Gas Turbines - (Annual 2015 Gen.: 419 Gwh)				
CCGT	Diesel	132.3	2030	35
Atherinolakos Power Station				
Diesel Engines - (Annual 2015 Gen.: 332 Gwh)				
Diesel 1 and 2	HFO	51.1	2034	25
Steam Turbines - (Annual 2015 Gen.: 578 Gwh)				
Steam 1 and 2	HFO	46.5	2047	20
Total Capacity	823.46 MW (including reserves)			

Table 1. Technical characteristics of thermal power plants (Hellenic Electricity Distribution Network Operator, 2017a)

2 ELECTRICITY SCENARIOS STUDIES FOR CRETE

Katsaprakakis & Christakis (2009) analysed the potential of wind and hydro pump systems for Crete. Results proved that RES penetration to medium and large sized systems could reach up to 90% of the annual demand with a resultant thermal electricity generation limitation. Anagnostopoulos and Papantonis (2012) examined the wind and hydro pump systems with storage proving that a 500 MW wind hydro power plant could offset a thermal power plant of 170 MW capacity. Karapidakis et al. (2014 ; 2011) compared two principal scenarios for Crete's system in 2020 using the energy system model LEAP. They propose a gradual (linear) increase of renewable energy up to 20% and a rapid increase with the support of hydro pump storage systems, showing increase of renewables and decrease of CO₂ emissions.

The spinning and non-spinning load reserves of an isolated power system with increased wind energy integration such as Crete has been examined by Ntomaris et al. (2014) who represented the day ahead through dispatch and reserve scheduling optimisation considering two scenarios: BAU and a High RES scenario. The results show reasonable reserve allocation for both autonomous scenarios. This has been achieved using a detailed stochastic unit formulation and a scenario reduction algorithm. The introduction of natural gas in the Electricity System of Crete has been analysed by Katsaprakakis et al.

[†] Cold reserve mode

[‡] Cold reserve mode

(2015) at an annual basis, through an inclusive techno-economic analysis which shows 36.6% reduction of power generation costs and 54% in carbon emissions reduction following the replacement of oil replacement with natural gas.

The interconnection plan of Crete with the National Grid System (NGS) was validated in 2014 with the inclusion of this project in the Ten Year Development Plan of the Transmission System Operator of Greece (Independent Power Transmission Operator, 2012). Papadopoulos et al. (2007) applied a probabilistic methodology to estimate energy production and the associated costs for autonomous versus interconnected operation for the Aegean Sea islands including Crete. Georgiou et al. (2016;2011) has addressed the techno-economic and environmental impact of the future interconnections of the islands, including Crete, with the NGS, at a national level, through a dynamic, long-term, mixed integer energy model. A generic Mid-term Energy Planning (MEP) problem has been incorporated with a unit commitment model to provide optimal solutions regarding the yearly energy balance and the viability of the interconnection of Crete's power system with the mainland by Koltzaklis et al. (2016). Loukarakis et al. (2011) explored different power system interconnection options using a Monte Carlo power flow method for Crete. Finally, Lignos and Tsikalakis (2015) have presented an alternative interconnection study between Thera and Crete islands evaluating future generation mix, power flows, losses and costs considering four different interconnection options. A summary of the studies dedicated on Crete's electricity system analysis is presented in Table 2.

<i>Author</i>	<i>Model/Methodology</i>	<i>Horizon</i>	<i>Resolution</i>
Katsaprakakis and Christakis (2009)	System Dimensioning Economic evaluation - Dynamic security assessment (DSA)	-	seconds (for DSA)
Anagnostopoulos and Papantonis (2012)	Computer algorithm for HPP operation	1 year	daily
Karapidakis et al. (2011; 2014)	LEAP	2009-2020	annual
Ntomaris et al. (2014)	Stochastic unit commitment	Day	hourly
Katsaprakakis et al. (2015)	Specialized software tool for techno-economic analysis	1 year	hourly
Papadopoulos et al. (2017)	Probabilistic methodology/Economic analysis	2010-2035	annual
Georgiou et al. (2011;2016)	Tailor made (MILP) energy model	2009-2020 2014-2024	annual
Koltzaklis et al. (2016)	Unit Commitment (MILP) model	Annual/Daily	hourly
Loukarakis et al. (2011)	Monte-Carlo probabilistic power flow method/Investment analysis	-	annual
Lignos and Tsikalakis (2015)	Unit Commitment model PowerWorld Simulator	1 year (2010)	annual/hourly

Table 2. Electricity Scenario Studies for Crete

This study builds from the existing work by developing a wide range of scenarios motivated by the requirement for costs reduction and innovation towards a more resilient low carbon energy system for Crete, under the holistic concept of the Energy Trilemma. This paper allows closer study of scenario analysis for Crete's autonomous electrical system, through a robust long-term simulation with PLEXOS Integrated Energy Model including capacity expansion planning and operation optimisation. The scenario analysis covers the prominent future supply options for the island: continuation of autonomous operation, introduction of natural gas and interconnectors implementation according to the final plan proposed by the Hellenic Independent Power Transmission Operator (IPTO). In parallel, renewable energy development, energy storage systems and abatement technologies will be examined; A high

spatio-temporal resolution analysis under the Energy Trilemma Index is applied aiming to fill the gap of a holistic techno-economic assessment for autonomous systems such as Crete.

3 SCENARIO DEVELOPMENT UNDER THE ENERGY TRILEMMA INDEX

The Energy Trilemma as specified by the World Energy Council (WEC) comprises three major elements: Environmental Sustainability, Energy Security and Energy Equity in terms of Affordability and Accessibility. Greece, ranked 29th out of 125 countries (World Energy Council, 2017a), has attempted to improve Environmental Sustainability over the last years, through the increase of renewable energy sources and concurrently energy consumption decrease. However, Energy Security and Equity mainly in terms of Affordability are still subject to improvement as illustrated in Figure 2. Crete records lower performance compared to the country level as it remains a non-interconnected island, with subsidized oil-fired capacity and limited RES integration as calculated by the WEC Pathway Calculator (World Energy Council, 2017b).

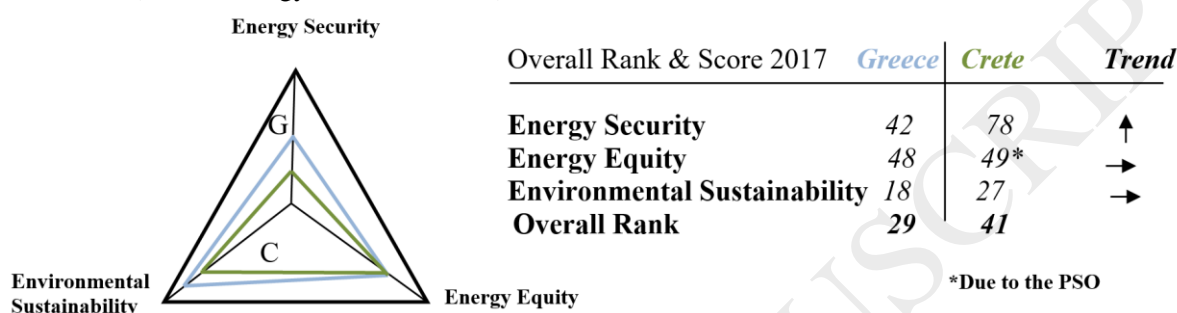


Figure 2. Trilemma index ranking and score for Greece and Crete⁵ (adapted from the World Energy Council, 2017a)

Under the Energy Trilemma prism at a regional basis, Crete will have to secure in the near future: compliance with the EU directives, smooth power supply, increase of RES as a further commitment to the 2020 and 2030 EU Climate and Energy Package and reduction of the high-power generation costs from oil-fired stations. In this study, we will consider only the Affordability, assuming Accessibility is achieved already in the power sector of Crete while exploring a number of future scenarios in order to assess the most viable solution, which meets the three major criteria of Energy Trilemma. The scenarios developed in the present study have been diversified in three major storylines: the Business As Usual (BAU) Scenarios, the Natural Gas (NG) Scenarios and the Interconnection (Int.) Scenarios (Figure 3).

BAU Storyline

- BAU Scenario 1: generation restrictions to the total power generation capacity (BAU 1)
- BAU Scenario 2: generation restrictions except for diesel engines (BAU 2)
- BAU Scenario 3: without generation restrictions (BAU 3)
- BAU Scenario 4: using abatement technologies and low sulfur HFO and diesel fuel (BAU 4)
- BAU Scenario 5: using abatement technologies and energy storage systems (BAU 5)

In the **BAU Storyline** the wind and solar capacity remain on the island mainly based on a repowering mechanism while new capacity is added under the limitation that it does not exceed the 30% of the previous year peak demand. Bioenergy from agricultural products and waste through biogas as well as hydro projects are developed in small-scale projects and at a limited level. The BAU scenarios are diversified among them based on the extent of the application of Directives 2010/75/EU and 2015/2193/EU. Energy storage systems with emphasis on hybrid wind-hydro systems and solar thermal plants have been also incorporated in one of the scenarios. Energy storage has a key role especially in isolated networks as it allows for higher RES integration and curtailments' elimination through peak shaving while transferring the power excess from periods of generation surplus to periods with higher demand levels (Krajacic et al., 2011).

NG Storyline

- Natural Gas introduction to the system (NG 6)
- Natural Gas introduction to the system and energy storage development (NG 7)

In the **NG Storyline**, despite the high initial capital costs for the LNG platform, gasification and transmission infrastructure with an estimated payback period of 3.5 years, the size of Crete's power system could allow the introduction of NG (Katsaprakakis et al., 2015). The gradual introduction of NG is considered as a viable and feasible scenario under prerequisites by the national gas authorities (Kardomateas, 2004). It is assumed to commence in 2020 as it is required a 3-year period for the implementation of this scenario. RES limitation of 30% applies also for the Natural Gas Scenarios without energy storage.

Interconnection Storyline

- Interconnection Scenario 8 with the NGS (Int. 8)
- Interconnection Scenario 9 with the NGS and introduction of Natural Gas (Int. 9)
- Interconnection Scenario 10 with the NGS and Energy Storage development (Int.10)

The **Interconnection Storyline** between Crete and the NGS demonstrates a plan for the direct support of the technical and economic inefficiencies experienced in autonomous systems which has already been agreed as a priority project for the further upgrade of the national grid network (Kabouris, 2016). The final proposal by the IPTO suggests the implementation of this project into two steps. The first step, completed by 2020, aims at reducing significantly local power generation and connects Crete (Chania area with Peloponnese) through AC 2*150 kV, 220 MVA cables, with a total length of approximately 120 km. The second step, estimated to be completed by 2024 (first cable immersion - 2022, second - 2024), proposes the interconnection of Linoperamata area with Attica (DC cables, 2*350 MW, ≈340km). The second interconnection will gradually alleviate the local thermal generation capacity and concurrently will allow for the export of the surplus of the RES generation installed on the island to the main consumption centres as depicted in Figure 4. The Interconnection Scenarios support the integration of more RES as the island's power network is enhanced through the interconnections with the mainland. In the context of an integrated European Electricity Market, with an interconnection target of 15% (European Commission, 2017b), similar infrastructure projects showcase across Europe e.g. the Sardinia and Malta interconnectors or the interconnection of the Balearic Islands.

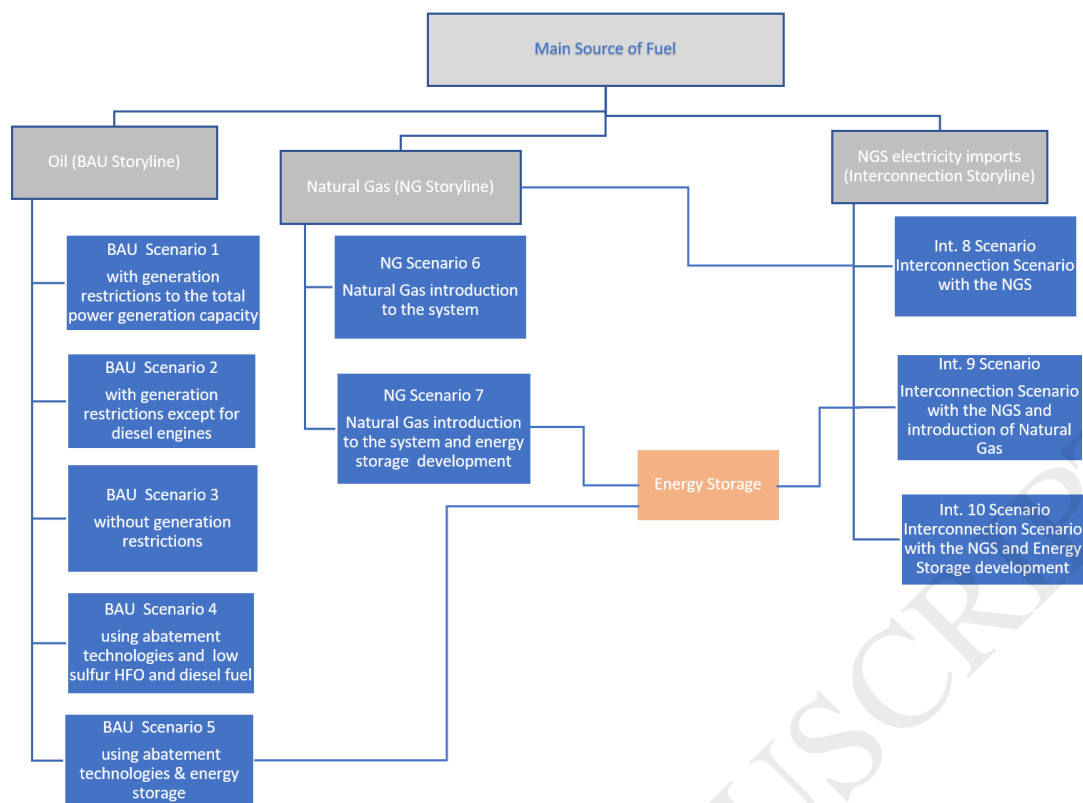


Figure 3 : Scenarios incorporated in the analysis

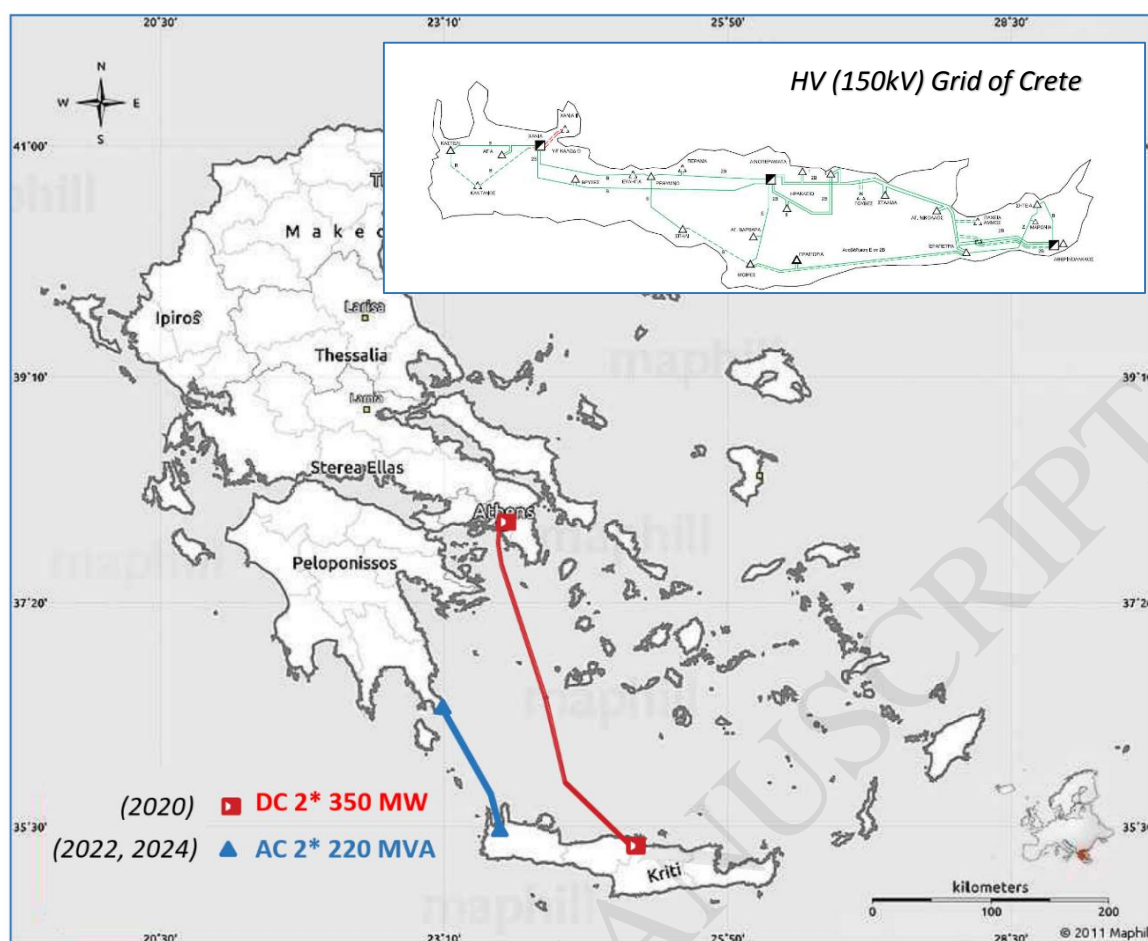


Figure 4. Interconnection plan of Crete with the NGS (adapted from: Kabouris, 2016)

4 METHODOLOGY

4.1 Modelling approach

PLEXOS Integrated Energy Model is a mixed-integer programming tool focused on simulating and optimizing electricity markets. The setup of PLEXOS is based on the objective function to minimize the total costs (generation, operation and maintenance, fixed, investment) subject to scenarios inputs and constraints (Equation 1). In the current work, this model is used for transmission and generation expansion optimisation as well as simulation and optimisation of the unit commitment and dispatch of power generation. PLEXOS covers the principal elements of the Energy Trilemma Index as beyond cost minimization it secures the balance of demand and supply, it simulates capacity reserves and assesses the environmental impact through GHG emissions outputs and employment of abatement tools.

The scope of the current analysis focuses on the long-term planning and attributed to that, the simulation process in PLEXOS has been performed in two phases: the Long Term (LT) Plan when new generation and transmission capacity is built and the Medium Term Schedule which optimises medium to long term decisions through a computationally competent approach. For the most part, this denotes handling hydro storage, fuel supply and emission constraints. The projection horizon considered in the model expands from 2020 to 2040 with a reference year of 2015. An hourly interval and annual simulation step have been considered through partial chronology within a monthly Load Duration Curve (LDC). In the Medium Term (MT) schedule a weekly step has been selected and a weekly LDC with fitted chronology, which allows a time decomposition in line with chronology. In the unit commitment function for improving the level of detail in the analysis, integer optimality has been selected.

For modelling simplifications, the island of Crete has been considered as a single transmission region with three nodes (interconnected with double 150 kV lines, 140MVA) splitting the island into three areas representing the thermal power stations areas and other distributed RES. The NGS is also represented as a region with five nodes, as an aggregation of the national administration division, representing the five major prefectures: Peloponnese, Central Greece, Western Greece, Thessaly and Northern Greece. The nodes have been simulated with a representation of the High Voltage (HV) transmission network of Greece (double lines of 150 kV - 280 MVA and 400 kV - 440 MVA). The other non-interconnected islands have not been included in the analysis.

Minimize:

$$\begin{aligned}
& \sum_{y,g} DF_y * (BC_g * GB_{g,y}) \\
& + \sum_y DF_y * FO\&M_{Cost} * Pmax_g * (Units_g \\
& + \sum_{i \leq y} GB_{Units_{g,i}}) \\
& + \sum_t DF_y * GL_{g,t} * (HR * Fuel\ Price + VO\&M) + \sum_t DF_{t \in y} * L_t \\
& * (VOLL * USE_t)
\end{aligned} \tag{1}$$

where:

g - generator; t -dispatch period, DF - Discount factor [$DF_y = 1/(1 + D)^y$ where D – Discount rate]; BC_g - Overnight build cost of generator g or transmission line; GB_g - Number of generating units build in year y for Generator g ; $FO\&M$ - Fixed operations and maintenance cost of generator g including also abatement costs; $Pmax$ - Maximum generating capacity of each unit of generator g ; $Units$ - Number of installed generating units of generator g ; $GB\ Units$ - Number of build generating units of generator g ; GL - Dispatch level of generating unit g in period t ; HR - Heat Rate; $VO\&M$ - Variable operations & maintenance costs including also reserves, emissions and abatement costs; $Emissions$ - Cost of emissions, L_t -Duration of dispatch period t ; $VOLL$ - Value of lost load (energy shortage price); USE - unserved energy

This equation is subject to a number of constraints:

$$Energy\ Balance: \sum_{(g)} GL_{(g,y)} + USE_t = Demand_t \forall_t \tag{2}$$

$$Feasible\ Energy\ Dispatch: GL_{(g,t)} \leq Pmax (Units_g + \sum_{i \leq y} GBUnits_{g,i}) \tag{3}$$

$$Feasible\ Builds: \sum_{i \leq y} GB_{gi} \leq MaxGB\ Units_{g,y} \tag{4}$$

Where: $MaxGB\ Units$ - Maximum number of units of generator g allowed to be built by the end of year y

A Declining Depreciation Balance Method has been applied to new builds and is related to the Tax Rate and the Inflation Rate to adapt the annuity calculations. Build costs of a generator, a transmission line or a storage system are annualized across their Economic Life and based on the weighted-average cost of capital for the project (WACC) applied in the year of build and every subsequent year as specified in Equation 2 for each Project (Generation/Transmission/Storage). The economic parameters used in the simulation analysis for the LT plan are summarized in Table 3.

$$Annuity_x = BuildCost_x * \frac{1 - \frac{TaxRate * DeclingDepreciationBalance_x}{WACC + InflationRate + DeclingDepreciationBalance_x}}{RealAnnuityFactor}$$

where:

$$RealAnnuityFactor = \frac{1 - (1+WACC)^{-EconomicLife}}{WACC} \quad (2)$$

$$DeclingDepreciationBalance_x = \frac{1}{EconomicLife_x} * DeclingDepreciationBalance_x \quad (4)$$

<i>Economic Indicator</i>	<i>Value</i>
<i>Tax Rate</i>	26%
<i>Inflation</i>	0.70%
<i>WACC (Generators)</i>	11%
<i>WACC (Transmission Lines)</i>	10%
<i>Discount Rate</i>	9%
<i>Economic Life (Generators)</i>	20 years
<i>Economic Life (Transmission Lines)</i>	35 years

Table 3. Economic indicators **

4.2 Modelling input data assumptions

4.2.1 Technical characteristics

Key techno-economic features attributed to each thermal generation turbine (existing and candidate) that was inserted in the model on a unit-by-unit level of detail are shown in Table 4. Intermittent renewable energy sources participate to the system at a no-fuel cost basis while they do not contribute as reserve capacity for the island and they do not provide spinning reserve.

Reserve capacities have been diversified in primary reserve provision including spinning and non-spinning reserve, secondary and tertiary reserve provision. To secure stability in the system the following thresholds have been inserted in the model: a minimum provision of 80 and 120 MW from 2020-2030 and 2030-2040 respectively reflecting approximately 10% of the local installed capacity in the two decades; a contingency generator reflecting the largest generator existing on the island for a given year and a regional load risk of 15%. In principal, all the steam generators contribute with a rate of 10%, 15% for gas and CCGT and 20% for diesel engines. In addition, relevant capacity that is retired is preserved as a cold reserve and could mainly contribute to the tertiary provision (60-100 MW). Also, hydropower stations have been modeled in a synchronous mode capable of providing spinning reserve for ancillary services. In the Interconnection Scenarios, the interconnection capacities are considered as further reserves while the N-1 criterion becomes the threshold in order to secure that local thermal capacity is equal to the maximum capacity of one of the cables interconnecting the island in addition to the reserves required for the demand that the interconnection cannot cover (mainly before 2024). Planned and forced outages have been included as inputs but handled implicitly by the LT Plan module (Hellenic Electricity Distribution Network Operator, 2017b)

All the scenarios illustrated in Figure 5, follow the same growth rates for electricity demand and planning peak load as specified by the Regulatory Authority for Energy, the Public Power Corporation and the IPTO in the common report published for the interconnection of Crete island (Regulatory Authority for Energy, Public Power Corporation, & Independent Power Transmission Operator, 2011).

** Assumptions based on the following sources: Hellenic Republic, 2013; Trading Economics, 2018 Authority, 2015; WACC Expert, 2018

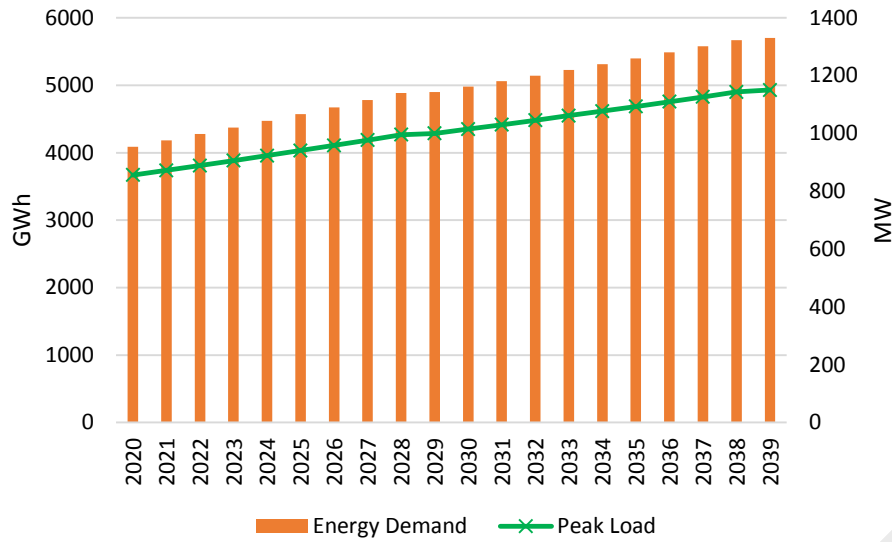


Figure 5: Demand and Peak Load Development through the projection horizon (2020-2040)

Generator Type	Tech Life	VO&M	FO&M	Reserves VO&M	Heat Rate*	Min up time (warm)	Min down time (warm)	Max Ramp Rate	Build Cost
	(years)	(€/MWh)	(€/kW/year)	(€/MW)	(GJ/MWh)	(hour)	(hour)	(MW/min)	(€/KW)
Oil Turbines									
Steam	30	1.3	60	2	11-15	4.5	4	0.2-0.3	1,200
Gas	20	2	27.5	0.8	11-20	0.3	0.15	10	550
Diesel	25	2.5	45	2.5	9-10	0.1-0.2	0.1	12	900
CCGT	25	1.8	37	1.8	9	1.8	1.2	5	750
NG Internal Combustion Engine									
Diesel	25	3	29	1.8	7.8	0.1	0.05	12	1,525
CCGT	30	2.5	30	2.5	7.2	1	0.5	6.6	730

Table 4: Techno-economic features of thermal capacity on Crete ^{††}

4.2.2 Renewable energy

Renewable energy resources are split into the existing projects and new projects including wind, photovoltaics (PVs), bioenergy, solar thermal and hydro pump-wind hybrid technology. Under a high spatio-temporal resolution analysis, data of the existing and future projects (on a unit-by unit level) have derived from the database provided by the Regulatory Authority for Energy (2017) excluding projects applications in natural protected sites (Spiropoulou, Karamanis, & Kehayias, 2014). Wind onshore energy projects in Crete present considerable investment interest due to high wind speed levels ranging between 7-14 m/s (Regulatory Authority for Energy, 2016). With solar irradiation levels exceeding 1,900 kW/m², one of the highest in Europe (Huld, Müller, & Gambardella, 2012) and lower intermittency than wind, solar energy could also replace significant thermal capacity, especially when combined with energy storage systems. For solar thermal, the direct irradiance at normal incidence (DNI) synchronised with the solar irradiation rating for PV was incorporated as natural inflow in the storage model (Solar Irradiation Data, 2016).

^{††} (Hellenic Electricity Distribution Network Operator, 2017a), (Hatziaegyriou, Karapidakis, Stavrakakis, Dimopoulos, & Kalaitzakis, 2001; National Renewable Energy Laboratory, 2012; U.S. Energy Information Administration, 2016a; Wartzila, 2016)

In terms of hydro, the island presents an interesting geomorphology that could facilitate a number of medium-scale hydro plants. Bionenergy has also limited potential, either in the form of biogas or through agricultural byproducts as raw-source materials. Existing projects have been assumed to continue their operation following the expiration of their lifetime (25 years) through a repowering mechanism, for those projects, a limited cost has been assumed as presented in Table 5. In the autonomous scenarios, the integration of new intermittent renewable energy sources is limited as aforementioned, unless energy storage systems such as solar thermal power plants or hydro-pump wind projects are deployed. The electricity price for RES is derived from the past and the existing legislation framework, which specify Feed in Tariff or Feed in Premium support mechanisms for RES.

<i>Fuels</i>	<i>Price</i> (€/KWh)	<i>Build Cost</i> (€/KW)
Solar (existing projects)	0.3	800
Solar (candidate projects)	0.09	1150
Solar Thermal (with storage)	0.278	4800
Wind (existing projects)	0.095	875
Wind (candidate projects)	0.080	1250
Hydro pump	0.100	2300
Hybrid (wind and hydro)	0.137	3350
Bioenergy (waste)	0.225	
Bioenergy (agricultural byproduct)	0.184	2500
Bionergy (biogas)	0.129	

Table 5. Fuel prices and cost of renewable energy sources^{**}

4.2.3 Fossil fuels and emissions

The existing fossil fuel mix on the island includes HFO and diesel fuels. Reference price for HFO has been configured at 5.64 €/GJ, for diesel fuel at 10.9 €/GJ and for NG at 10.65 €/GJ (European Commission, 2016b; U.S. Energy Information Administration, 2016b). Projection scenarios for oil and natural gas (

Figure 6) follow the New Policies (NP) Scenario of the World Energy Outlook by IEA, as a moderate estimation for gradual increase in oil prices through the years (IEA: Directorate of Global Energy Economics, 2015). The relevant taxes have been considered at a national basis 0.4 €/GJ for HFO and 9.7 €/GJ for diesel (Hellenic Republic, 2010). For NG used for electricity production, no tax has been imposed. In NG prices the liquefaction and shipping costs have been estimated at 2.84 €/GJ and 1.89 €/GJ (Jefferies LCC, 2013). The Emissions Trading System (ETS) mechanism places additional costs to conventional power generation with 2015 carbon costs circa 6 €/tn (Hellenic Republic, 2014a). Projections derive from the Reference Scenario of the European Commission (European Commission, 2016a) as, placing emphasis on a rapid grow of ETS as a key decarbonisation measure. Emissions production per fuel has been configured as indicated in Table 6.

^{**} (Hellenic Republic, 2014a, 2016; International Renewable Energy Agency, 2013; Papaefthimiou, 2012; REN21, 2016)

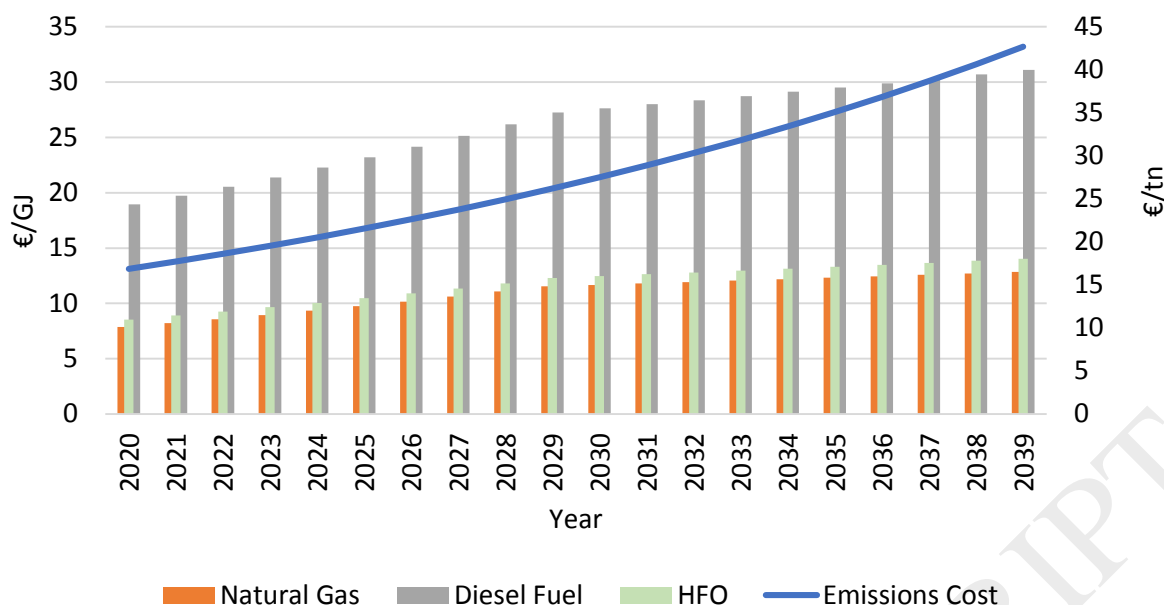


Figure 6: Natural Gas, Diesel, HFO and Emissions Costs Projections (2020-2040)

The investment costs for new infrastructure related to NG includes the construction of LNG storage tanks, a gasification station, the gas transmission and a distribution pipeline. The total estimated costs for gas infrastructure on Crete according to the literature review are estimated to 850 Mil € (D. Katsaprakakis et al., 2015), (A. Katsaprakakis, Moniakis, Pasadakis, & Skias, 2010). The total estimated cost for the Interconnection of Crete with the NGS based on the updated budget is configured at 164 Mil € for the AC 220 MVA Cable and 365 Mil € for the DC 350 MW cable including the required equipment such as substations, converters, inverters etc (Kabouris, 2016).

<i>Emission</i>	<i>HFO (kg/GJ)</i>	<i>Diesel (kg/GJ)</i>	<i>NG (kg/GJ)</i>
CO ₂	77.4	74.1	50.23
NO _x	0.063	0.058	0.003
SO ₂	0.045	0.04	8.59*10 ⁻⁵

Table 6. Emissions production per fuel^{§§}

4.2.4 Abatement technologies

PLEXOS addresses the environmental indicator while capturing and controlling emissions as an exogenous input. Emissions' control can be diversified through a range of options such as emissions' constraints, costs, shadow prices, abatement tools and generation constraints.

As an alternative scenario for the continuation of the operation of the existing oil-fired thermal power plants, a range of refurbishment scenarios has been proposed with the installation of abatement tools mainly to capture and remove NO_x emissions during combustion. SO₂ emissions will be alleviated with the use of ultra-low sulfur fuels. Abatement tools are usually cost intensive solutions with different techno-economic characteristics per technology and emission type. Table 7 indicates suitable abatement tools for electricity generator turbines and their associated costs.

^{§§} (National Renewable Energy Laboratory, 2012), (IPCC, 2014), (U.S. Environmental Protection Agency, 2016)

<i>Turbine Type</i>	<i>Abatement Tool (Technology)</i>	<i>Efficiency (%)</i>	<i>Abatement Cost (€/kg)</i>	<i>VO&M Charge (€/MWh)</i>	<i>FO&M Charge (€/KW)</i>	<i>Capital Cost (€/kW)</i>
Steam	Low NO _x Burners and Flue Gas Recirculation	66	2.67	0.2	6.38	71.8
Gas	Selective Catalytic Reduction and Water Injection	90	4.24	0.4	0.35	32.3
Diesel	Selective Catalytic Reduction	80	4.69	0.4	0.49	28.9

Table 7. Characteristics of abatement tools (U.S. Environmental Protection Agency, 1999)

4.2.5 The National Grid System

The installed capacity of the National Grid System has been considered as specified in Table 8 for the five aforementioned nodes. The demand load profile followed the EU Reference projections, with a reference value of 51,355 GWh for 2015 and a peak load of 9.19 GW (European Commission, 2016a; Hellenic Electricity Market Operator, 2015). The wholesale system generation costs, equal to 57.5 €/MWh for 2015, have been considered uniform for the mainland and the projections aligned with the Greek Electricity Market Operator (Hellenic Electricity Market Operator, 2015). The demand growth rates for the NGS are aligned with the EU Reference Scenario for Greece (European Commission, 2016a).

<i>Power Generator Type</i>	<i>Installed Capacity (GW)</i>
Lignite fired	4.45
Natural Gas fired	5.17
Wind	1.85
Solar	2.44
Biomass	0.05
Large Hydro	3.17
CHP	0.1
Total	18.17

Table 8. Installed capacities in the NGS (Hellenic Electricity Market Operator, 2015)

5 RESULTS

5.1 Energy security

5.1.1 Generation mix and installed capacity

The BAU Scenarios outputs show continuation of the historical trends. BAU 1 (Figure 7) presents an infeasible scenario where supply cannot meet demand by reason of thermal generation restrictions, leading to 4,100 GWh of un-served power in 2040. At an hourly level, un-served energy follows the demand pattern with an average rate of un-served energy divided by the total load equal to 42.7% for 2025 which is intensified to 74.8% in 2040. Generation capacities remain approximately stable following 2020 as a result of the firm generation limitations applied. BAU 2 (Figure 8) assumes no restrictions imposed to the diesel engine fleet, and no further policies. The model leads to an over-capacity of diesel engines (mainly following 2025) which will substitute the rest of the thermal units. However, the island still faces frequent power disruptions from 2028 and onwards leading up to 400 GWh of un-served energy by 2040 at an hourly average rate of 3.5%. BAU 3 (Figure 9), assuming a derogation of Crete from the imposed directives, shows that the predominant generator remains the

diesel engine attributed to the comparatively higher efficiency. Scenarios BAU 4 and 5 (Figures 10 and 11) assume that the existing power stations are refurbished with abatement tools. Furthermore, BAU 5 increases energy storage capacity on the island mainly through hybrid and solar thermal projects. The installed capacity in these two cases follows similar trends since the power generation restrictions have been mostly overridden. Both scenarios, built mainly steam and CCGT units as they embed lower abatement costs. In BAU 5, considerably higher rates of RES are observed (47% compared to 28% in BAU 4 by 2040). Wind curtailments are reduced from 9 GWh in Scenario 3, to 2.7 GWh by 2040.

NG 6 Scenario (Figure 12) shows that gradually the use of oil is eliminated and replaced by new or upgraded CCGT turbines running on natural gas. NG 6 leads to relatively small share of RES in the system equal to 18% in 2040. In contrast, NG 7 (Figure 13) which incorporates energy storage systems development presents higher penetration of RES by 2040 accounting for the 37% of the total generation mix. The RES mix includes mainly wind, hydro and solar, while bioenergy preserves low levels. NG 7 Scenario presents a capacity decline between 2026 and 2027 mainly as an outcome of the retirement of the old fleet of gas turbines on that year. Wind curtailments in Scenarios NG 6 and 7 are reduced by 4.2 GWh and 1.8 GWh respectively by 2040.

The Interconnection Scenarios show that electricity imports become the predominant fuel, while wind shedding is abolished. In Int. 8 (Figure 14), following the cables' submergence there is no requirement for new local thermal stations. Local capacity remains on the island, at the same point between 2020 and 2029 as an offset between the retired steam and gas turbines and the build of new RES. Following 2030, the RES development pace increases and by 2040, RES participate by 65% in the electricity mix, imports by 30% while diesel and CCGT units cover only the demand within the peak hours (5%). Int. 9 (Figure 15) incorporates interconnection and concurrently energy storage showing that by 2040 electricity imports from the mainland account only for the 18% of the total annual demand. In Int. 10 (Figure 16), NG use is limited to oil replacement accounting only for the 5.5% in the electricity share, which shows that NG infrastructure is underutilized. On the other hand, it presents increased imports levels (52% in 2040) as they stand for the least-cost available option. In addition, Int. 10 projects low levels of local thermal capacity while RES is also relatively constrained by natural gas.

The exchange profiles among the years show that for 2020 as anticipated, imports match the load demand trend with higher import levels during the summer and lower during the winter months. By 2030, RES intermittency is reflected in the interchanges, showing overall a smoother annual profile, however with instantaneous random picks of increased import demand. Also, due to higher wind production between October and November, the modeling outputs show periodically exports. By 2040, Int. 8 and Int. 9 manage to increase renewables exports during the winter months. Nonetheless, in Int. 10 due to lower introduction of RES, exports are significantly reduced.

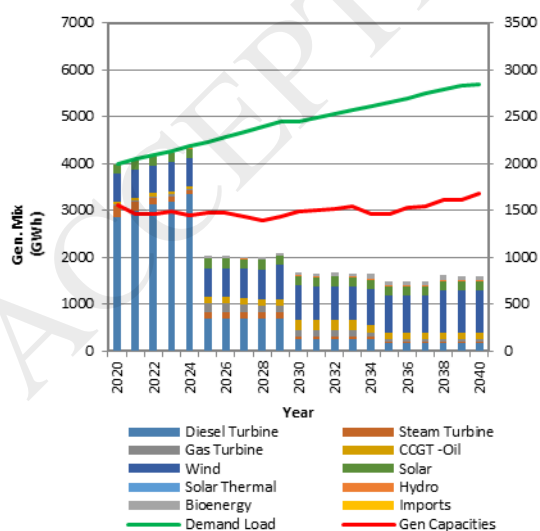


Figure 7. Generation mix for BAU 1

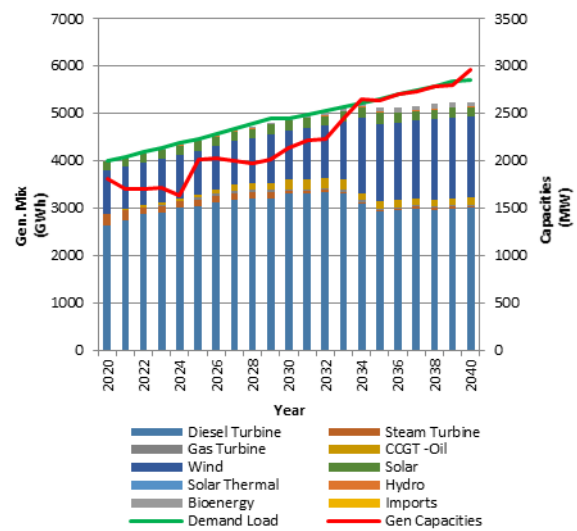


Figure 8. Generation mix for BAU 2

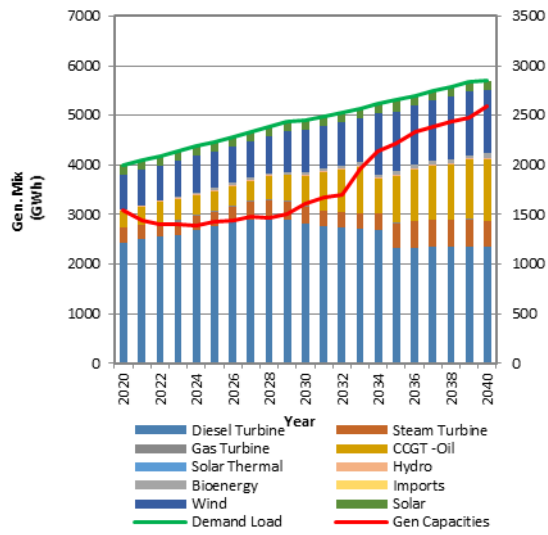


Figure 9. Generation mix for BAU 3

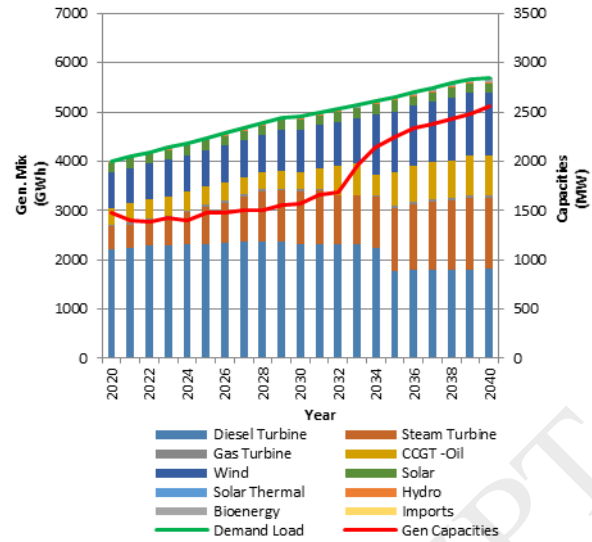


Figure 10. Generation mix for BAU 4

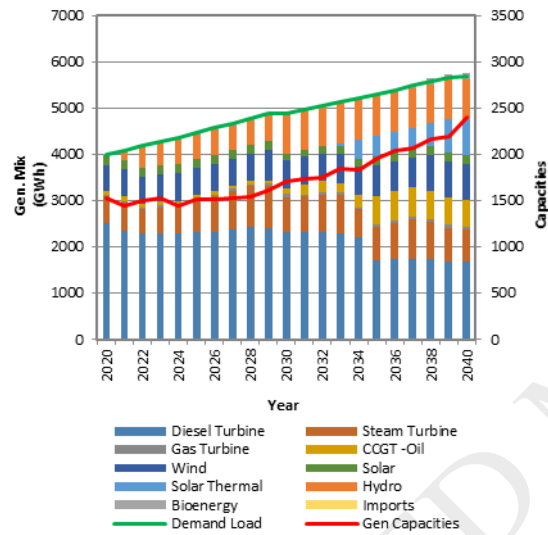


Figure 11. Generation mix for BAU 5

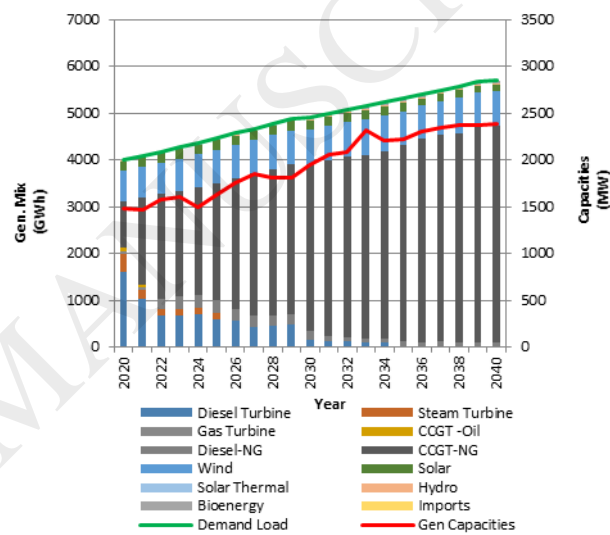


Figure 12. Generation mix for NG 6

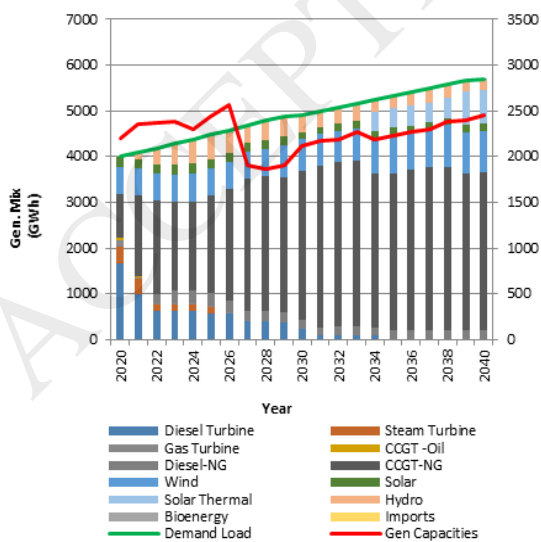


Figure 13. Generation mix for NG 7

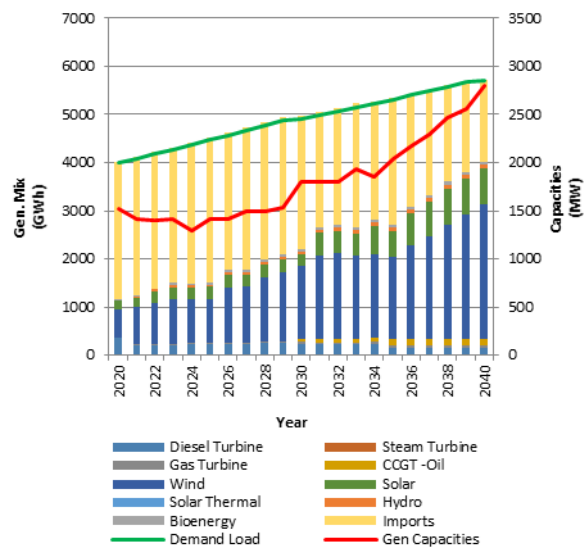


Figure 14. Generation mix for Int. 8

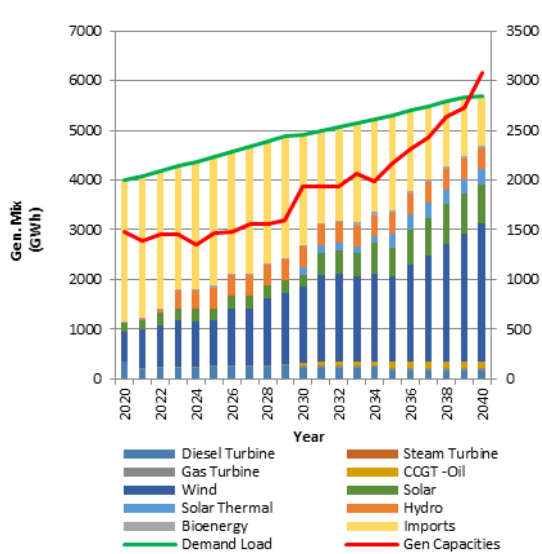


Figure 15. Generation mix for Int. 9

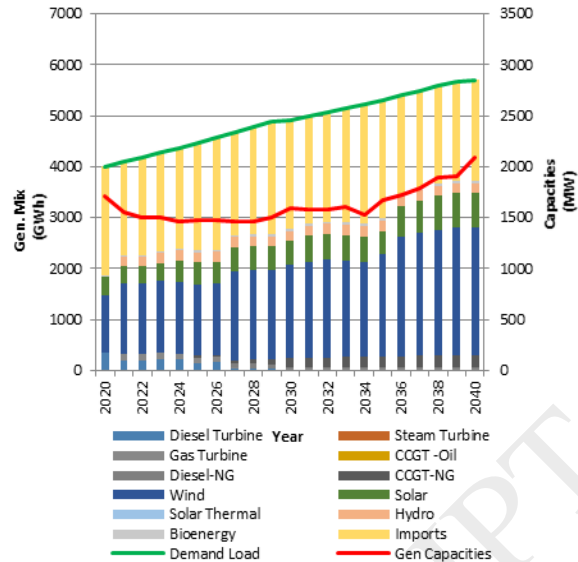


Figure 16. Generation mix for Int. 10

5.1.2 Reserve capacities

Reserve Capacities have been represented through the Capacity Reserve Margin (CRM) indicator as illustrated in Figure 17. The CRM has been indicated as a fraction of the fixed operating capacity located on the island, including also turbines preserved in cold reserve mode, to contribute in the tertiary reserve requirement, minus the annual peak demand load divided by the peak demand (North American Electric Reliability Corporation (NERC), 2016). This indicator contributes to the long term capacity expansion planning and provides a benchmark for long-term reliability assessment. All scenarios meet the requirement of Installed Capacity > Peak Demand while they allow for an additional margin of 15-40% except BAU 1. BAU 1 shows limited installed capacity as an outcome of the rigid generation restrictions which lead to incapability meeting the criterion by 2040. NG 7 presents over-capacity in 2030 mainly due to new RES and NG capacity built though it reverts by 2040, when the old oil-fired fleet has been retired. In the Interconnection Scenarios, the N-1 criterion replaces the generator contingencies. By 2040, CRM is reduced as the local thermal generation is retired and the new capacity added is limited to renewable energy sources in addition to the required local thermal reserves.

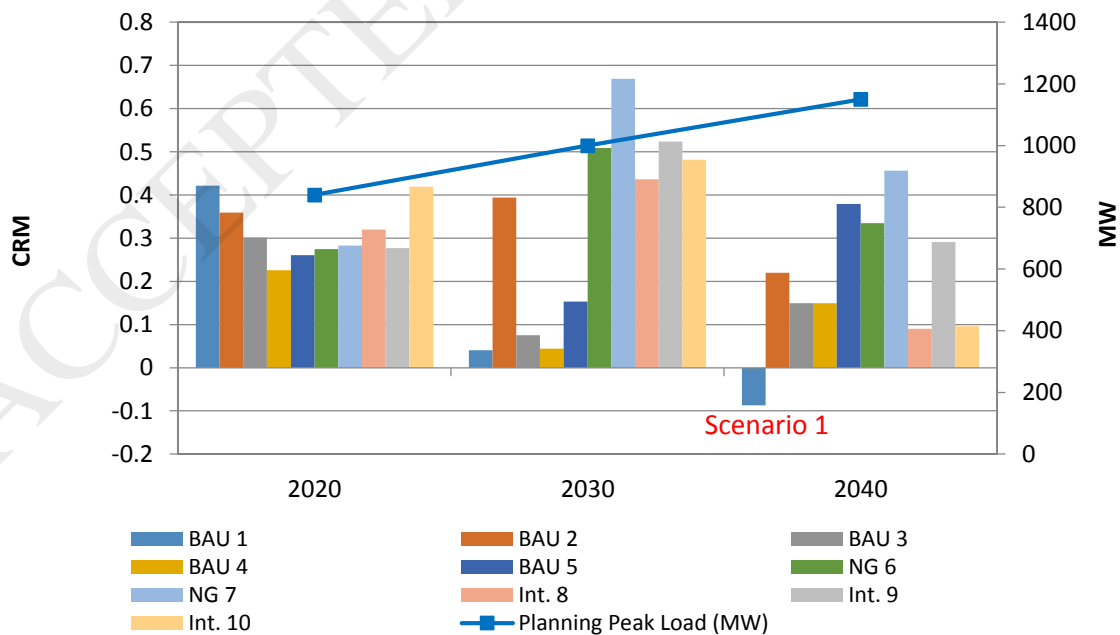


Figure 17. Capacity reserves margin for 2020, 2030 and 2040 for the power system of Crete

5.2 Energy affordability

5.2.1 Electricity generation costs

Electricity costs in the region of Crete are represented by the average generation costs of the conventional generators as specified from the dispatch merit order as well as renewable energy generation costs returned in a fixed €/MWh value. Generation costs in BAU Scenarios follow increase trends as an outcome of the increasing oil prices. Scenario BAU 1 has not been depicted in Figure 18 as constantly fails to meet demand following the milestone year 2025. It presents power generation costs which reach 3 k€/MWh equal to the VOLL as derived by the IPTO (Kabouris, 2016). Similarly, BAU 2 results into frequent power cuts, configuring an average electricity cost of 1.98 k€/MWh following 2028. Scenarios BAU 3 and 4 follow similar trends, although BAU 4 presents slightly reduced costs due to the increased operation of steam turbines, which incur lower costs. BAU 5 reduces to some extent costs (255.78 €/MWh) as by 2040, 45% of the electricity generated is received from RES.

Natural Gas scenarios: NG 6, 7 manage to bring considerable reduction in generation costs, down to 147.41 €/MWh for NG 6 and 133.17 €/MWh for NG 7. In Scenarios Int. 8-10, the price which serves the load is configured at a national level with decreased costs as low-cost units such as lignite and large hydropower stations contribute to the electricity generation mix. The Interconnection Scenarios produce results which experience small fluctuations from 2020 to 2040, ranging between 68 €/MWh and 59.5 €/MWh. Particularly, Int. 9 presents the highest decrease in electricity generation costs equal to 79% compared to BAU 3, and 63% compared to 2015.

5.2.2 Total costs

The total costs in the current scenario analysis, depicted in Figure 19, include operation and maintenance costs, abatement, investment costs reflected in annuities, and power generation costs. Scenario BAU 1 records the lowest total costs (11.2 Bil €) since it is imposed in generation constraints impacting also new builds, however without including the VOLL. BAU 2 on the other hand, records the highest increase pace, resulting in the highest total costs (26 Bil €) as the system builds new diesel capacity to replace the rest thermal capacity. Scenario BAU 3 retains the same pace with Scenarios BAU 4 and 5 which led to increased total system costs (25.7 and 25.2 Bil € respectively) due to the abatement technology incorporated as well as the increased storage capacity assumed by BaU 5.

Scenarios NG 6 and 7 results match through the projection horizon while proving that the NG Scenario could demonstrate as a viable solution for Crete. They manage to reduce the total costs by 25.2% compared to BAU 3 and reach 17.2 Bil € during the considered 20 year period. Int. 8 and 9 attain to decrease the total expenditures by 45% in year 2040, while the total costs for the 20-year projection horizon are reduced by 53.8% and 52.3% respectively, compared to BAU 3. Int. 10 is notionally the cost optimal case (9.8 Mil € total costs, 57.5% reduction). However, the cost reduction originates mainly from the relatively lower RES capacity built locally and the increased electricity imports, which demonstrate as the most in-expensive power supply option.

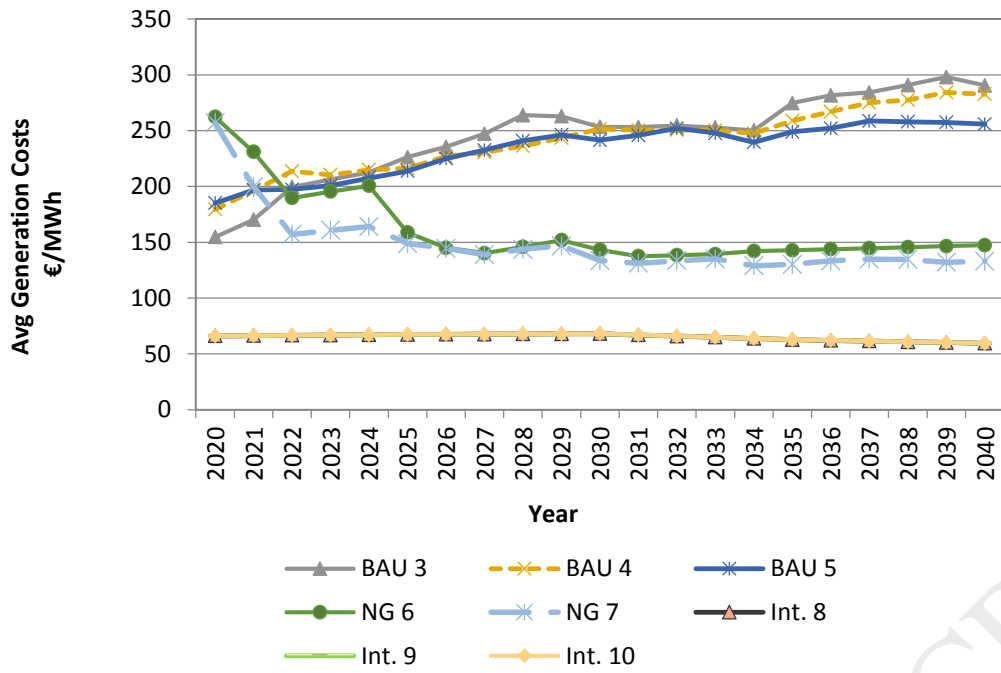


Figure 18. Electricity generation costs for the power system of Crete

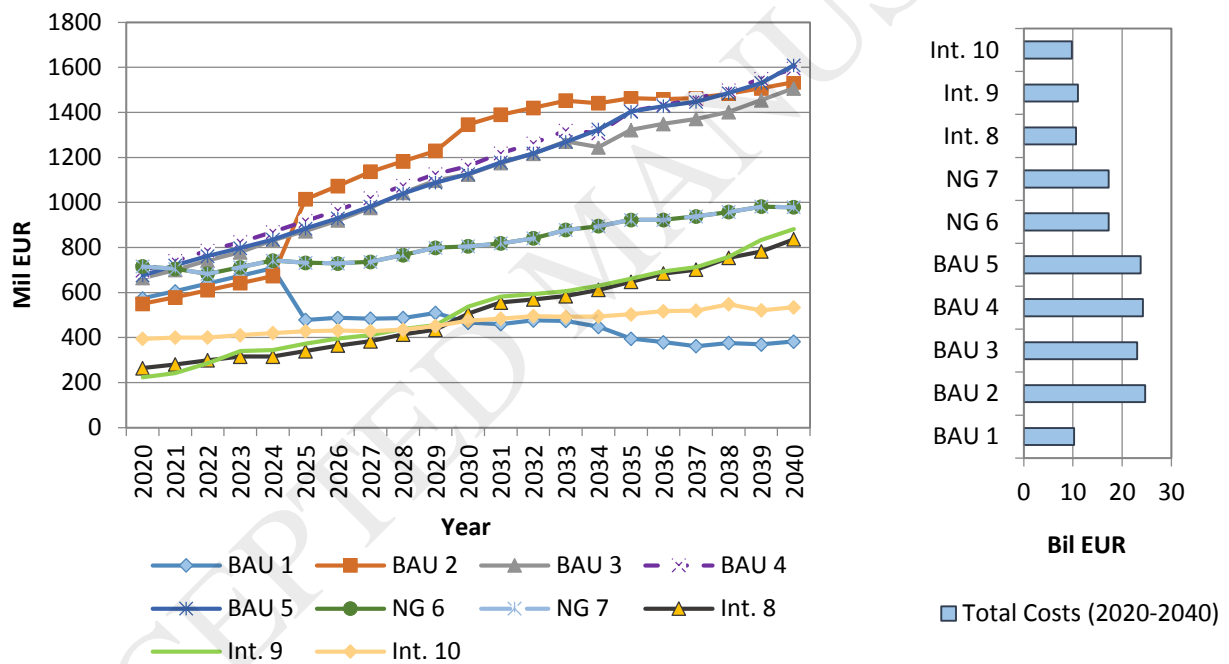


Figure 19. Total costs for the power system of Crete

5.3 Environmental sustainability

The EU policies for environmental sustainability in the form of GHG emissions reduction has been considered as a modelling constraint reflected in the maximum generation per year: 1,500 hours and 500 hours for steam and gas turbines respectively from 2020 and 500 hours for both generator types from 2030, as indicated in 2010/75/EU and 2015/2193/EU. For diesel engines, we considered a value of 1,000 hours from 2030, the same for non-spinning reserve capacities, however applied from 2020.

In the BAU Scenarios, which accomplish to balance supply and demand (BAU 3-5) the continuation of emissions increase in parallel with demand growth is evident (Figure 20). In BAU 1, as generation is significantly lower to the demand, a steep reduction is recorded. BAU 2 also results in relatively lower production of emissions due to power generation inefficiencies and the exclusive use of diesel engines. BAU 5 although it supports RES capacity development does not manage to reduce emissions levels by 2040.

Scenarios NG 7 and Int. 8 achieve significant reduction, 24% by 2040 compared to 2015 levels. NG 7 proposes a combination of NG and RES, while Int. 8 replaces local generation with imports from the mainland assuming considerably lower carbon intensity. Finally, Int. 9 succeeds the highest limitation dependence on fuel imports in 2040 while it eliminates local thermal generation, resulting in 44.8% decrease in 2040 compared to 2015 and by 68.6% compared to BAU 3. Scenario Int. 10 restricts the development of further RES following the interconnection, due to the introduction of new NG capacity and preserves approximately the same emissions levels between 2020 and 2040.

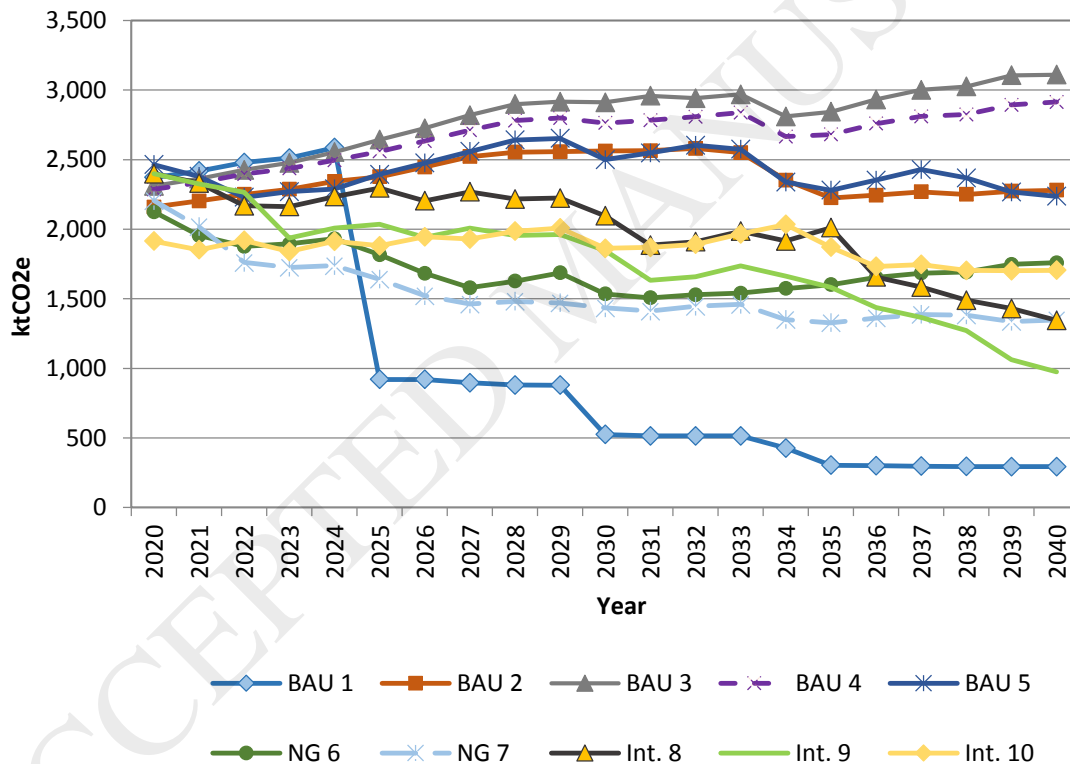


Figure 20. GHG emissions from the power system of Crete

5.4 Scenarios Performance in line with the Energy Trilemma Index

A summary of the scenarios performance in practice is shown in Figure 21 below, illustrating the range of trade-offs, as calculated with the use of the pathway calculator (World Energy Council, 2017b). While taking into consideration the smooth supply of the system, and the reduction of emissions and costs, the results showed that Scenario NG 7 offers many advantages if the energy isolation is to be continued. However, the optimum scenarios meeting the three Energy Trilemma criteria are Interconnection

Scenarios (Int. 8, Int. 9). Particularly, Int. 9 which proposes increase of energy storage and as a result increase of renewables, presents the highest decrease in electricity prices equal to 79% (EUR/MWh) compared to BAU 3, and 63% compared to 2015 prices while the total costs reduction reaches 52.3%. GHG emissions are reduced by 68.6% compared to BAU 3 and 44.8% compared to 2015 values. BAU Scenarios 1-3 do not meet any of the criteria, while Scenarios BAU 4 and BAU 5 fail also to present a more sustainable and economically feasible status. At last, Scenarios NG 6 and Int. 10 do not achieve significant decrease on GHG emissions as they limit the development of further renewable energy projects.

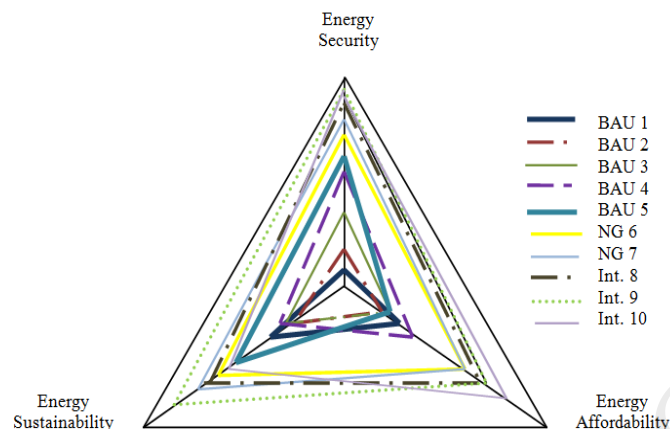


Figure 21. Scenario assessment under the Energy Trilemma Index

6 CONCLUSIONS

The Greek islands phase a number of practical challenges related to energy supply due to their geographical isolation. This paper examines the required transition that the Crete island must undergo following the power generation restrictions, as imposed by the Directives 2010/75/EU and 2015/2193/EU. In order to identify the optimum future plan for Crete, different technologies and assumptions have been considered that could bundle energy and power generation capacity on the island. The primary objective was to perform a systematic long-term scenario analysis based on the Energy Trilemma principles, which could be also replicated to other isolated electrical systems. In contrast with the existing literature, this study aimed to cover and amalgamate a wide range of electricity supply options for the island of Crete including energy storage, new infrastructure and abatement tools.

A high-resolution spatio-temporal methodology was performed including thermal, wind, hydro, solar thermal and bioenergy capacity at a unit level and solar photovoltaics aggregated at a node level. PLEXOS integrated energy model allowed for capturing the required temporal resolution with a long-term projection horizon and an hourly interval while using a weekly load duration curve. The results showed that the approved, best performing scenarios incorporating improvement in decarbonisation and costs reduction while addressing effectively Security, Sustainability and Affordability of the Electricity Sector are Scenarios: NG 7 (NG and Energy Storage), Int. 8 (Interconnection). The optimum Scenario balancing the three indicators while tacking energy isolation in the optimum way is Int. 9 (Interconnection + Energy Storage).

Future work based on this analysis, suggests further study of Crete's electrical system and of the proposed interconnection options, while increasing the temporal granularity of the horizon at full resolution without employing the LDC simplification such as the LDC. Further analysis on higher renewable penetration, energy storage and transport electrification is considered exceptionally interesting for the island of Crete and similar isolated energy systems.

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