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The Impact of Large-Scale Wind Energy Development on Islands' Interconnection to the Mainland System

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***Abstract*—**Greek islands' interconnection (IC) with larger power systems, such as the mainland grid, is a crucial issue that has attracted a lot of interest; however, the recent economic recession that the country undergoes together with the highly capital intensive nature of this kind of projects have stalled or sifted the development of many of those on a more long-term basis. On the other hand, most of Greek islands are still heavily dependent on the lengthy and costly supply chain of oil imports whilst the majority of them exhibit excellent potential for wind energy (WE) applications. In this respect, the main purpose of the present work is to investigate −through a parametric study which varies both in wind farm (WF) and submarine IC capacities− the impact of large-scale WE development on the IC of the third in size island of Greece (Lesbos) with the mainland system. The energy and economic performance of the system is simulated over a 25-year evaluation period assuming two possible scenarios, i.e. S(a): without the contribution of the local Thermal Power Plant (TPP) and S(b): the TPP is maintained to ensure electrification of the island. The economic feasibility of the two options is investigated in terms of determining their Levelized Cost of Energy (LCOE) including also a sensitivity analysis on the worst/reference/best Cases. According to the results, Lesbos island IC presents considerable economic interest for covering part of island's future electrification needs with WE having a vital role in this challenging venture.

***Keywords*—**Electricity generation cost, levelized cost of energy, mainland grid, wind energy rejection.

I. Introduction

THE Aegean Sea boasts about 100 inhabited islands, with most of them not being connected to the mainland grid and relying on polluting oil-fired generation to fulfil electricity demand requirements. Particularly, electricity generation in the islands is mostly based on gas turbines, internal combustion engines, steam turbines and combined cycle units which consume significant amounts of foreign diesel, light and heavy oil products at high electricity generation cost which may exceed 200€/MWh. As a result, islands contribute a notable share of the country's total CO_2 emissions, despite the fact that their population is comparatively small in the national system, while at the same time, mainland consumers bear the high costs of electricity generation in the islands through a national equable pricing system. On the other hand, the contribution of Renewable Energy Sources (RES) to islands' energy supply is still very limited due to local grids' technical limitations [1], [2] even though the remarkable wind (8-10 m/s wind speed at hub height) and solar (1800-2000 kWh/m^2 solar radiation for optimally inclined south oriented modules) resources that most of these regions possess. As a matter of fact, in order to avoid severe renewable energy curtailments, installation of new RES-based projects is discouraged after exceeding a certain capacity limit in case that a remote island grid has already reached its "saturation" point [3].

Under this framework and in accordance to the energy and climate change commitments undertaken by the country related to the environmental protection, the main focus of many studies [4], [5] in the last few years is paid on possible IC of Aegean Sea islands with the mainland grid (Fig. 1). In fact, islands' submarine IC with the mainland system is a crucial issue that has attracted a lot of interest [6], [7] for enhancing security of supply into these isolated regions and reducing the expensive and polluting oil-fired power generation [8]. As a result, some projects like the IC of some major Cycladic islands with Attica region (Fig. 1), have already entered a more mature phase, while some others, such as the IC of Crete [9] or other Aegean Sea islands [4], [10] with the mainland system, have been blocked or planned on a more long-term basis as the budget required for such projects is considered quite challenging under the current economic conditions of the country. In this context, the present study evaluates −from the energy-economic point of view− the IC of the third in size island of Greece (i.e. Lesbos) (Fig. 1) with the mainland grid of the country, as a possible alternative to its current autonomous operation, while the dominant and essential role of large-scale WE development towards that direction is determined as well. More precisely, the investigated solution involves the IC of the island with the mainland grid for satisfying part of electricity demand by establishing two alternative scenarios, i.e. S(a): without the contribution of local thermal generators and S(b): local thermal generators are kept in cold reserve to ensure electrification of the island, while remarkable WE penetration is also achieved. Subsequently, the economic feasibility of the two scenarios is investigated by determining their LCOE for the time-period 2020-2045. Furthermore, a sensitivity analysis is undertaken with respect to possible deviations in the values of the most uncertain variables, in order to identify the worst (pessimistic-Pe), reference/baseline (most likely-Ba) and best (optimistic-Op) output results.

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Fig. 1 A map of Greece and Lesbos island

II. Case Study Presentation

The island used as a study case is Lesbos. It is located in the North-Eastern part of the Aegean Sea (Fig. 1) and it has an area of 1,630 km^2. The island faces significant electricity generation problems related to several black-outs especially during summer months where the demand is increased due to tourism. The system is primarily supplied by an Autonomous Power Station (APS), comprising several oil-fired generators, which consume on annual basis significant oil-fuel quantities (approx. 60,000 t per year). The maximum available power of the power station is currently almost 80MW. The total electricity generation cost in the island (taking into account the contribution of local RES applications) currently approaches 170€/MWh.

The WE potential of the island is quite significant, with the annual mean wind speed being approx. 8 m/s (at 10 m height) (Fig. 2). Three major WFs of total rated power 13.7 MW contribute to the electrification of the island, covering 15% of the annual demand (see also Fig. 3). One the other hand, if one considers a possible increase in WE applications (e.g. up to approx. 68MW), WE contribution to the island's annual load demand would still be limited (<25%) indicating that there is an upper limit for economically viable new WF investments, as is the case of the majority of remote islands around the world. In this respect, a curve is plotted (Fig. 4) depicting the expected annual WE absorption from the local grid (y-axis of the figure) along with its contribution to the annual load demand (x-axis of the figure) for several indicative installed WF capacities and for three selected wind power upper participation limits "λ" to the instantaneous load demand. The estimations have been based on previous work of the authors [11]-[13] concerning the calculation of the maximum WE penetration ability combined with more recent data about the load demand profile of the island, the Thermal Power Plant (TPP), etc.

As far as solar power is concerned, with an average annual radiation per square meter being between 1,700 and 1,800 kWh/m^2 the total installed photovoltaic (PV) capacity has reached 8.8MW. PVs annual energy production is about 1,550 MWh$_e$ per installed MW on an inclined plane (30^o).

Currently, the annual energy consumption of the island is about 300GWh$_e$, while the peak load demand is approx. 70MW. The hourly load demand time-series which is taken into account in the simulations in the present study is adjusted every year considering a realistic annual growth rate of the order of 1.5% up to 2020 while for the rest 25-year period until 2045 the respective growth rate is considered equal to 2.5% (Fig. 5). Thus, according to the "baseline Case" (or reference Case), the estimated annual energy consumption at the end of the project's lifetime (2045) is found equal to ~648GWh$_e$ and the peak load demand equal to ~146MW. It is noted that further information on the three investigated Cases (i.e. optimistic, baseline, pessimistic) is given in Section VI.

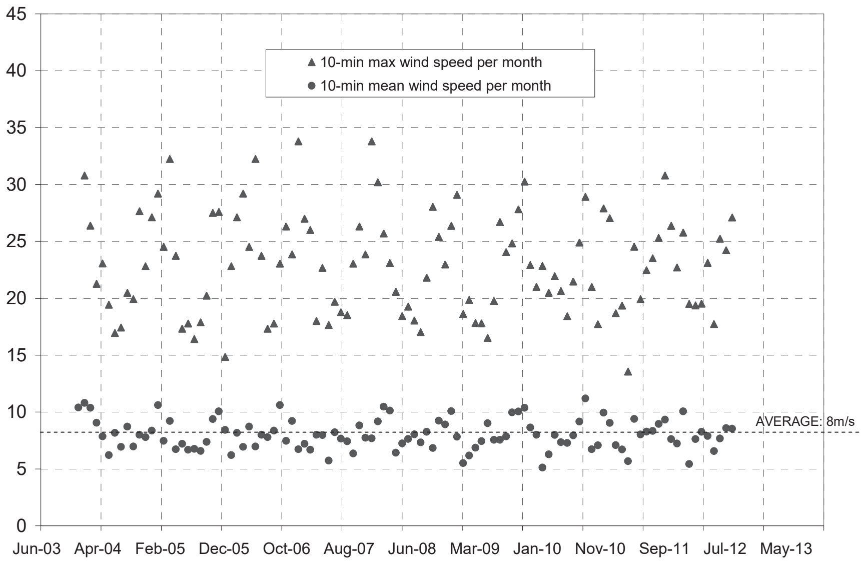

Fig. 2 Mean and maximum ten-minute wind speed per month (10m height) measured at a site located at the west part of the island where local WFs exist

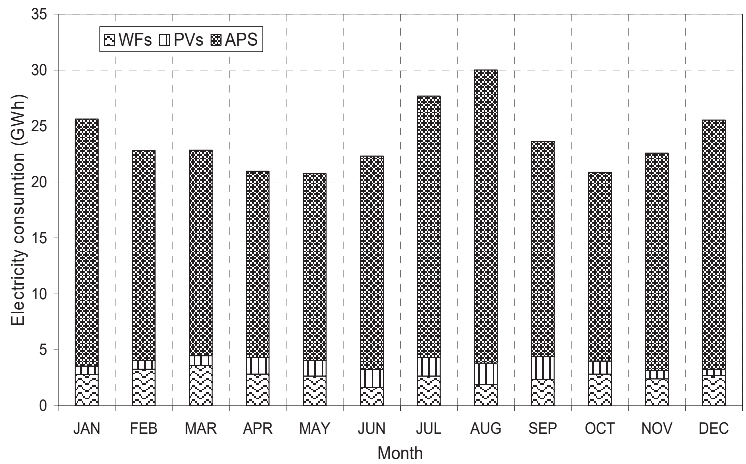

Fig. 3 Island's electricity generation mix per month

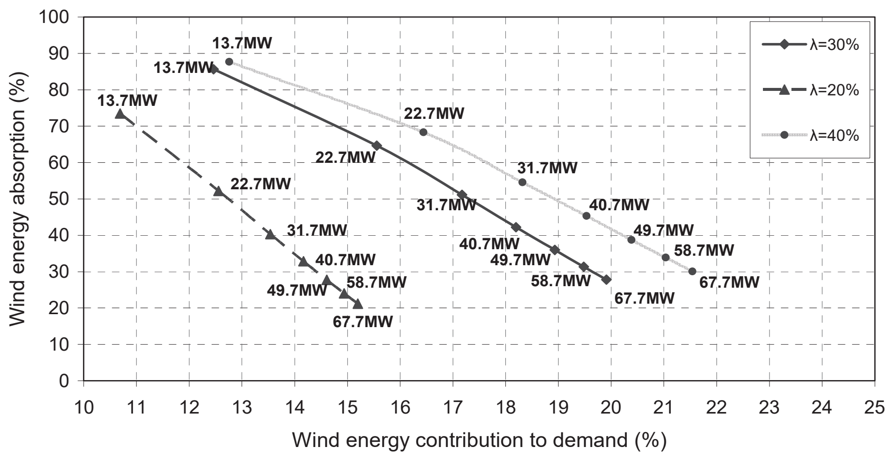

Fig. 4 Annual absorption percentage of WE production from the existing and new WFs along with the corresponding WE contribution to the demand for three wind power upper participation limits "λ"

III. The Interconnection Scheme

Public Power Corporation (PPC) began to study and implement submarine ICs of the islands with the mainland system of the country from the 60s, using at first cables 1 5kV and 66 kV (Corfu island), and then cables 150 kV (e.g. IC between the rest Ionian islands and the mainland in the 70s). Thereafter, the issue of submarine IC of the island of Crete (i.e. the biggest of Greek islands) with the mainland grid (see also Fig. 1) emerged but quickly left the spotlight mainly due to the capital intensive nature of the project as well as the limited capabilities of submarine technology at that time in terms of length and laying depth. Thus, the IC of Crete and other islands has not been implemented up to date due to technical and economic reasons. However, the continued maturation of new technologies, especially the DC transmission systems [10] but also the increasing relevant activity that took place in more recent years on a global scale with the design and construction of several ICs between countries (such as Norway with the Netherlands, Estonia with Finland etc.) or islands with mainland systems, brought back to the fore the issue of remote islands' IC with mainland systems and created the conditions for successful implementation of similar projects in Greece [6]. Thus, during the last decade plethora of studies have already implemented or are currently under development concerning Aegean Sea islands IC with the mainland grid, e.g. [4], [5], [9], [14], with the project of IC of some major Cycladic islands (Fig. 1) with Attica region (the completion of the project is expected before 2020) to be considered as a precursor for all other major ICs in the region of the Aegean Sea [8].

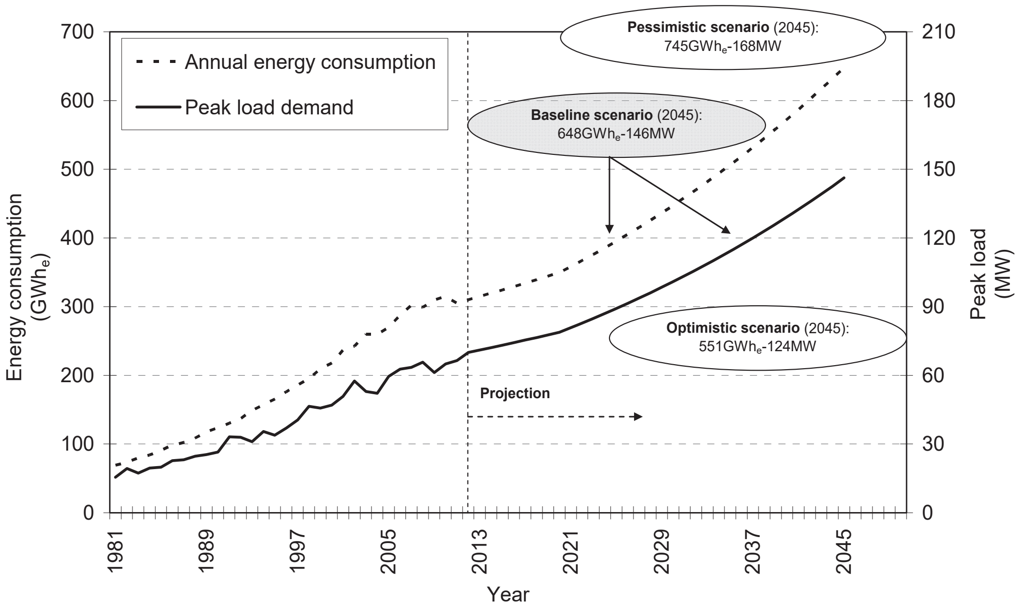

Fig. 5 Evolution in energy consumption and peak load demand of Lesbos island

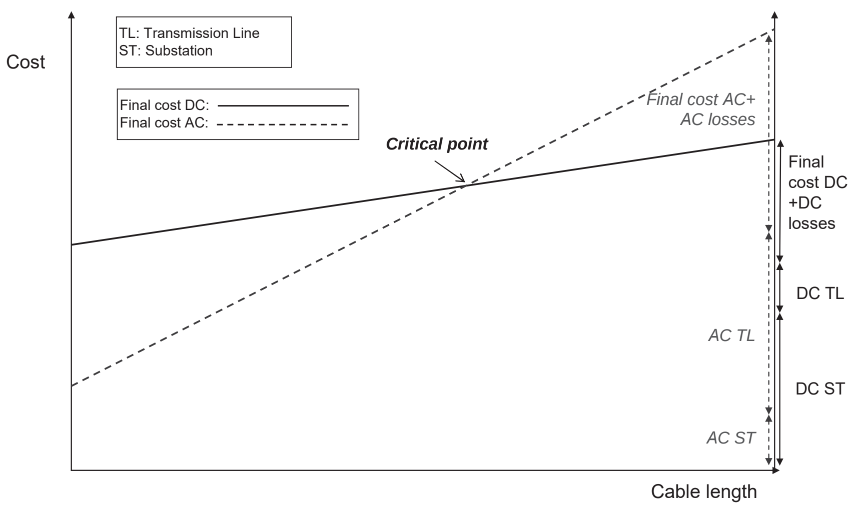

Fig. 6 Qualitative comparison between the final costs of HVDC and HVAC systems

One of the main purposes of the present study is the investigation of the investment cost of the supposed IC scheme between Lesbos island and the mainland system based on economic criteria and technical conditions of the already existing design [4], [5] as regards the determination of IC points, the route and the length of the new electrical network (underwater, underground and overground) [14], and the technical characteristics of the technologies involved (e.g. number/positions of substations, type of submarine cables, etc.). Thus, at this stage relevant official information regarding these characteristics is considered as a given fact while on the other hand the suitable capacity of the submarine cable(s) serves as a parameter for investigation. In this context, the total length of the IC is estimated equal to 288km, connecting at first Lesbos island with Euboea (213km) and then Euboea with Larymna (75 km) which belongs to the mainland part of the country (Fig. 1). The total length of the submarine, underground and overhead line(s) is considered 233km, 50.4 km and 4.6 km, respectively. Furthermore, it is assumed that the IC incorporates underwater HVDC cable technology which is considered the most appropriate method of transporting large quantities of energy over long distances. In this framework, several studies have shown that there is a critical point (break-even point) of between 50 and 60km wherein HVDC technology becomes a better economic option in comparison to the HVAC technology [15], [16]. More precisely, HVDC cable technology:

- Requires fewer cables (2 cables, +DC and –DC, instead of three cables per phase which are required in HVAC),
- Requires a smaller cross sectional area of cables for transferring the same amount of energy compared to HVAC. Moreover, the skin effect is absent in DC technology which otherwise would limit the load capacity and hence the amount of energy transmission,
- Has the advantage of not requiring capacitive charging current at steady state. In contrast, in the AC long-distance submarine technology, much of the current flowing through the cables is used to charge their capacitance; a situation which limits the permissible length of the AC cable. Thus, the preferred option in cases of undersea long-distance power transmission is the use of HVDC systems,
- Has fewer power losses because there is no need to charge and discharge the capacitance of the cables and due to the fact that fewer cables are used to transfer the same amount of power compared to HVAC technology. However, it should be noted that the comparison of the total losses between the two systems takes also into account the losses in the substations which are greater in the case of HVDC systems due to the converters' operation and the harmonics which are produced,
- Has a higher construction cost of converter substations compared to HVAC. However, this high cost may be offset by the lower final cost (capital cost + losses) of the long-distance DC transmission lines. Fig. 6 presents a qualitative comparison between the final costs in case of DC and AC systems, depending on the length of the transmission line. One can see the critical point where the costs of both systems are equal, and beyond that, the cost of an HVDC system is lower than that of the HVAC system.

IV. Energy Model

In the context of the present study, it is assumed that a large part of the island's energy needs will be covered by RES (mainly wind), while the rest will be covered mainly by electricity imports from the mainland. It should be mentioned that; high penetration of RES is mainly associated with energy production primarily from WFs (parametric study of installed capacity with a specific constant calculation step). Nevertheless, the benefits of dispersed PV energy production close to consumers are also considered by taking into account specific PV power output, especially during midday hours, which is absorbed in preference to WFs. It should be noted that given the technical characteristics of PV systems and their great dispersion all over the island, their operation is difficult to control, so it is assumed that there is no limitation in PV power absorbed by the local grid.

As far as the development of new WFs is concerned, it is common belief that the island presents high WE potential which can supply much of its electricity needs as well as that there is already great interest from private investors concerning new installations of the order of 300 MW (see for example the privately-owned project called "Aegean Link" which aims to install 306 MW of wind power at the western part of the island [14]). However, since the investigation of spatial peculiarities for installing new WE projects is out of the scope of the present study, wind power installed capacity is parametrically investigated starting from the existing 13.7 MW (~14 MW) and ending to 310.7 MW (~311 MW), bearing in mind as an order of magnitude the existing applications for new projects in the island. The expected WE production is calculated with the use of specific wind turbine power curves and analytical real wind speed measurements referred to the hub height of the turbines and being representative for the average wind conditions met in the area of interest. On the other hand, as for PV installations it is considered they will achieve their upper limit capacity during 2020-2029, which has been set equal to 28.5% [17], [18] of the estimated mean load demand by 2020, corresponding to 11MW (applications for new installations already exceed these limits). For the years 2030-2045 installed PV capacity is taken equal to 26MW, considering a relatively conservative growth of the permitted upper limit (from 28.5 to 35%) as a continuation of the first amendment made by RAE increasing the specific limit of the Decisions 85/2007 and 96/2007 with the relevant Decisions 702/2008 and 703/2008. In order to calculate PVs energy production, time-series solar radiation data on a horizontal plane representative for the island conditions are used along with a typical PV collector power curve [19].

Two sub-scenarios are investigated, i.e.:

S(a) IC of the island with the mainland takes place with the objective of complete removal (either directly or after a certain trial operation period of the project) of the TPP and the parallel exploitation of the high local WE potential which otherwise would not be possible due to the well-known technical limitations.

S(b) IC of the island with the mainland takes place with the objective of exploitation of the high local WE potential, while at the same time the operation of the TPP is ceased. However, specific thermal generation is kept in cold reserve to ensure the electrification of the island in case of a possible failure of the IC.

As far as Scenario a (S(a)) is concerned, if the energy produced by local RES applications is insufficient to fulfil the entire electrical needs, the rest of the demand is assumed to be covered by energy imports from the mainland. More specifically,

$$N_L(t) \le N_{RES}(t) \rightarrow N_R(t) = 0 \tag{1}$$

$$\begin{gathered} N_L(t) > N_{RES}(t) \rightarrow \\ N_R(t) = N_L(t) - N_{RES}(t) = \frac{N_{tr(m\rightarrow i)}(t)}{1+\delta \mathrm{N}_{\mathrm{tr}}} \end{gathered} \tag{2}$$

where N_L is the hourly electricity demand of the island (forecasted load), $N_{tr(m\rightarrow i)}$ is the power which is imported through the submarine cable(s) from the mainland grid to the island and N_{RES} is the power output of local RES applications. Furthermore, δN_{tr} represents the percentage of power transmission losses (4%) through the submarine cable(s) and N_R is the rest of load demand which cannot be covered by local RES production.

In case that the power output of local RES applications N_{RES} is higher than the island's load demand, the power surplus $N_{eRES(i\rightarrow m)}$ (primarily wind power as respective PV curtailments are neglected) is forwarded through the submarine cable(s) from the island to the mainland. Thus,

$$N_{RES}(t) \le N_L(t) \rightarrow N_{eRES(i\rightarrow m)}(t) = N_{tr(i\rightarrow m)}(t) = 0 \tag{3}$$

$$\begin{gathered} N_{RES}(t) > N_L(t) \rightarrow \\ N_{eRES(i\rightarrow m)}(t) = N_{RES}(t) - N_L(t) = N_{tr(i\rightarrow m)}(t) \cdot (1+\delta \mathrm{N}_{tr}) \end{gathered} \tag{4}$$

where $N_{tr(i\rightarrow m)}$ represents the amount of wind power surplus that reaches the mainland taking into account the power losses of the IC.

Accordingly, as for Scenario b (S(b)), if the energy produced by local RES applications is insufficient to fulfil the entire electrical needs, the rest of the demand is covered by energy imports from mainland while at the same time it is assumed (as an extreme −most expensive− case scenario) that specific thermal power capacity (i.e. at least 100% of the annual forecasted peak load demand during the time horizon of the investment) is maintained in cold reserve to ensure power supply of the island in all cases of potential damage (partial or total), including the loss of the submarine connector. However, the power balances in case of zero contribution of the local thermal power units (absence of failures) are given again by (1)-(4).

For each sub-scenario the technical features of the corresponding IC are determined on a case-by-case basis (e.g. total power capacity of the cables N_{tr}^{rated}, power of the inverters, etc.) according to the maximum -resulted from the simulations- supplied energy from the island to the mainland grid and vice versa, provided that the forecasted peak load demand $N_L^{\max}$ is always satisfied over the entire lifetime of the investment even in case of zero power output of local RES applications ($N_{RES}(t) = 0$).

More specifically, in S(a) it is assumed that the system operator (project owner) bears the cost to install two pairs of unipolar cables (4 unipolar cables) so as to ensure −as an extreme case− power transmission from the mainland to the island equal to 100% of the required capacity in case of failure of the one connector. Thus, the determination of total power capacity of the IC in this case is bounded by the following two conditions:

$$2N_L^{\max} \cdot (1+\delta \mathrm{N}_{tr}) \ge N_{e_w(i\rightarrow m)}^{\max} \rightarrow N_{tr}^{rated} = 2N_L^{\max} \cdot (1+\delta \mathrm{N}_{tr}) \tag{5}$$

$$2N_L^{\max} \cdot (1+\delta \mathrm{N}_{tr}) < N_{e_w(i\rightarrow m)}^{\max} \rightarrow N_{tr}^{rated} = N_{e_w(i\rightarrow m)}^{\max} \tag{6}$$

where $N_{e_w(i\rightarrow m)}^{\max}$ is the maximum resulted amount of wind power surplus which is forwarded to the mainland grid.

Accordingly, in S(b) it is assumed that the system operator bears the cost to install one pair of unipolar cables (2 unipolar cables). Thus, the power capacity of the IC in this case is determined as:

$$N_L^{\max} \cdot (1+\delta \mathrm{N}_{tr}) \ge N_{e_w(i\rightarrow m)}^{\max} \rightarrow N_{tr}^{rated} = N_L^{\max} \cdot (1+\delta \mathrm{N}_{tr}) \tag{7}$$

$$N_L^{\max} \cdot (1+\delta \mathrm{N}_{tr}) < N_{e_w(i\rightarrow m)}^{\max} \rightarrow N_{tr}^{rated} = N_{e_w(i\rightarrow m)}^{\max} \tag{8}$$

V. ECONOMIC MODEL

The time horizon of the financial analysis in both scenarios is considered 25 years, from 2020 to 2045 (j=5 to j=30). All the estimated cash flows are discounted to the year 2015 (j=0). It is assumed that the installation of the project (WFs and IC) in any case will have been completed in 2020 and it will start to operate on 1/1/2021. Moreover, it is considered that the project owner of the new WFs (S(a) and S(b)), the IC (S(a) and S(b)) and the new thermal power units (only S(b)) is the same. Table I provides in detail all the planning procedures for the required installations of all kind of projects in both scenarios, during the time horizon of the analysis. Note that Op, Ba and Pe represent the respective Optimistic, Baseline and Pessimistic Cases, which are determined based on criteria which are described in Section VI.

In the present study, LCOE is selected as the objective function that should be determined in order to realize the economic effectiveness of each investigated scenario. In order to estimate the LCOE numerous technical and economic parameters are used based on empirical data most of them deriving from recent bibliography and various technical reports. It is noted that in both examined scenarios (S(a) and S(b)) the same data and assumptions are used where possible in order to secure comparability of results.

TABLE I
PLANNING PROCEDURES OF THE REQUIRED INSTALLATIONS

		2020	2025	2030	2035	2040
S(a)-Op	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+ (2.2)		+ (15)		
	IC with mainland	+				
S(a)-Ba	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+ (2.2)		+ (15)		
	IC with mainland	+				
S(a)-Pe	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+ (2.2)		+ (15)		
	IC with mainland	+				
S(b)-Op	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+ (2.2)		+ (15)		
	IC with mainland	+				
	Installation of new thermal power units (155MW)	+ (45)	+ (10)	+ (60)	+ (15)	+ (25)
	Disposal of old thermal power units (86MW)	+ (38.5)		+ (47.5)		
S(b)-Ba	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+ (2.2)		+ (15)		
	IC with mainland	+				
	Installation of new thermal power units (170MW)	+ (55)	+ (15)	+ (60)	+ (15)	+ (25)
	Disposal of old thermal power units (86MW)	+ (38.5)		+ (47.5)		
S(b)-Pe	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+ (2.2)		+ (15)		
	IC with mainland	+				
	Installation of new thermal power units (200MW)	+ (75)	+ (15)	+ (60)	+ (25)	+ (25)
	Disposal of old thermal power units (86MW)	+ (38.5)		+ (47.5)		

A. Scenario (a)

In general, the LCOE includes all lifecycle costs over the considered economic lifetime of a project "n", i.e. capital costs, ongoing system-related costs -along with the total electricity produced- and converts them into a common metric, e.g. €/kWh. Note that in the present study, for simplicity reasons, the residual value at the end of the investment's lifetime is assumed to be zero. Thus, the LCOE may be defined as:

$$LCOE = \frac{\sum_j^n [\widetilde{IC}^{\text{inter}}_{o(j)} + \widetilde{IC}^{w}_{o(j)} + \widetilde{C}^{w}_{(j)} + \widetilde{C}^{FIT,i}_{RES(j)} + EP\widetilde{C}_{m(j)}]}{\sum_j^n [E_{tr(m\rightarrow i)(j)} + E_{w(j)} + E^{w}_{e(i\rightarrow m)} + E_{PV(j)}] \cdot f_i} \tag{9}$$

where symbol "~" represents costs expressed in terms of present values using a specific discount rate "i" (8%). f_i is the escalation factor which is introduced in order to appraise the time value of money. Thus,

$$f_i = \left(\frac{1}{1+i}\right)^j \tag{10}$$

In (9), $\widetilde{IC}^{w}_{o(j)}$ expresses the initial cost (in present values) for new WE applications (state subsidization or other incentives are not taken into account) which is assumed equal to 1,100€/kW by 2020 [20].

Following, $\widetilde{C}^{w}_{(j)}$ (or $\widetilde{C}^{O\&M}_{w(j)}$) denotes the annual maintenance and operation cost of the new WE projects (other costs, such as taxes etc., are not taken into account), namely,

$$\widetilde{C}^{O\&M}_{w(j)} = m^{O\&M}_{w} \cdot IC^{w}_{o(j)} \cdot f_i \tag{11}$$

where $m^{O\&M}_{w}$ represents a specific percentage (e.g. 3%) of the initial cost of the investment ($IC^{w}_{o(j)} = P_{r_w} \cdot N^{rated}_{w}$).

In the present analysis the LCOE is also formed by the annual renewable energy payments $\widetilde{C}^{FIT,i}_{RES(j)}$ to renewable energy producers (mainly for existing applications) depending on the technology and the corresponding compensation mechanism (feed-in-tariff) for the non-interconnected islands, i.e.:

$$\begin{aligned}\widetilde{C}^{FIT,i}_{RES(j)} &= \widetilde{C}^{FIT,i}_{w(j)} + \widetilde{C}^{FIT,i}_{PV(j)} = \\ &= p^{FIT,i}_{w} \cdot E_{w(j)} \cdot f_i + p^{FIT,i}_{PV} \cdot E_{PV(j)} \cdot f_i\end{aligned} \tag{12}$$

with $\widetilde{C}^{FIT,i}_{w(j)}$ and $\widetilde{C}^{FIT,i}_{PV(j)}$ expressing the annual payments to investors of existing WE installations (13.7MW) and PV projects (11-26MW), respectively. $E_{w(j)}$ and $E_{PV(j)}$ represent the annual wind and PV energy production which is absorbed by the local grid. $p^{FIT,i}_{w}$ and $p^{FIT,i}_{PV}$ (in €/kWh or €/MWh) are the corresponding selling prices to the grid which are assumed to remain stable in the coming years. Thus, selected feed-in-tariff (as for non-interconnected Greek islands) for WE projects is taken equal to 99.45 €/MWh while for PVs is considered equal to 95 €/MWh [21].

In (9), $EP\widetilde{C}_{m(j)}$ is the Energy Production Cost (EPC) in the mainland (depending on the power source) and $E_{tr(m\rightarrow i)(j)}$ is the annual energy imported from the mainland's grid to the island. $E^{w}_{e(i\rightarrow m)(j)}$ is the WE surplus that is delivered to the mainland's grid the year j. $\widetilde{IC}^{\text{inter}}_{o(j)}$ is the investment cost for the IC in present values. It is noted that (9) does not include -for simplicity reasons- other costs, such as the annual cost for maintenance of the IC. Furthermore, it does not include any capital expenditures for new power units in the mainland for covering the expected energy demand of the island as it is assumed that the demand will be covered by existing and planned power units. Note that at present, installed firm power capacity in the mainland is already approximately 13 GW (10 GW thermal and 3 GW hydroelectric power). On the other hand, in the extreme Cases (optimistic and pessimistic Cases, see also Fig. 5) examined up to 2045, the peak load demand of the island is estimated between 124 and 168 MW (±15% variation of the estimated values in the baseline Case), i.e. about 1% of the already installed power capacity in the mainland.

The average EPC in the mainland, for the present study, is assumed equal to the average production cost of a Natural Gas (NG)-fired combined cycle power plant (or unit). According to estimations found in technical reports [4], [8], [9], the EPC of a NG-fired power plant (neglecting the contribution of the initial cost) is about 67 €/MWh, of which 63 €/MWh comprise the fuel cost and 4 €/MWh the operation and maintenance cost. Taking also into account the environmental impact of CO_2 emissions (~10 €/t CO_2) the present production cost of the NG-fired power plant (or unit) is finally estimated equal to 71 €/MWh. It is noted that according to the UNO's Intergovernmental Panel on Climate Change (IPCC), NG releases 56.1t CO^2/TJ. Considering the efficiency performance of the station equal to 45%, it is estimated that NG emits about 0.4t CO_2 per produced MWh [8]. As for the calculation of the total EPC in the mainland for the period 2020-2045 the following assumptions are made:

- The average price for CO_2 allowances for the period 2020-2045 is taken by considering in 2020 a price equal to 20 €/t. Subsequently, it is assumed that the development of average prices will follow the estimated trend in the baseline scenario (i.e. 20 €/t) of the European roadmap for reducing greenhouse gas emissions by 2050, where it is considered that current trends and policies will continue to be valid [22].
- The long-term evolution in total EPC and more specifically, the evolution in NG-fuel cost is directly connected to global oil prices fluctuations [22], [23], following an average annual increase rate of the order of about 1% (Fig. 7).

For the economic evaluation of the IC several cost parameters should be assessed which depend on the selected technical characteristics of the project. So, a rough estimate in this preliminary stage may include the required electric equipment cost (e.g. substations, AC/DC or/and DC/AC converters, etc.) as well as the cost of the IC cables (submarine, underground and overhead line(s)). However, an accurate assessment of the capital cost of the IC −in a preliminary stage− is quite difficult as all associated expenses strongly depend on market conditions as well as on certain project peculiarities that may emerge in a later, more mature stage of the study. Thus, for safety reasons, although specific costs derive from bibliography [5], [8], it is chosen −on the basis of investigating the worst/reference/best Cases− a variation of the estimated capital cost at a relatively wide range of the order of ±20%. In this context, selected submarine IC costs along with the cost of substation (with AC/DC or/and DC/AC converters) for the baseline Case (or reference Case) are presented in Fig. 8. Other costs such as the cost of underground (150kV-HVDC) and overhead line(s) are taken equal to 0.50 m€/km and 0.20 m€/km, respectively [5].

Finally, as already mentioned, in Scenario (a) it is assumed that the project owner bears the cost to install two pairs of unipolar cables. Furthermore, it is assumed that this scenario also includes the installation of two pairs of substations with two converters AC/DC or DC/AC, the one pair to the island and the other to the mainland.

B.Scenario (b)

In this scenario the LCOE (in €/kWh or €/MWh) expressed in present values is determined as:

$$LCOE = \frac{\sum_j^n [I\widetilde{C}_{o(j)}^{inter} + I\widetilde{C}_{o(j)}^{w} + \widetilde{C}_{(j)}^{w} + \widetilde{C}_{RES(j)}^{FIT,i} + EP\widetilde{C}_{m(j)} + \widetilde{C}_{(j)}^{th}]}{\sum_j^n [E_{tr(m\to i)(j)} + E_{w(j)} + E_{e(i\to m)}^{w} + E_{PV(j)} + E_{th(j)}]\cdot f_i} \tag{13}$$

It is noted that in (13), the capital cost of the IC includes the cost of installing one pair of unipolar cables and two substations with converters, one to the island and the other to the mainland. The new variable in the estimation of LCOE (see (13)) is the cost of thermal power generation $\widetilde{C}_{(j)}^{th}$ which is kept in cold reserve to ensure the electrification of the island. Particularly, $\widetilde{C}_{(j)}^{th}$ includes the investment cost $I\widetilde{C}_{o(j)}^{th}$ for new thermal power capacity (see (14)) and the fixed annual costs (~10 €/kW) of the TPP (e.g. maintenance of thermal engines, salaries, etc.) in case of no contribution (e.g. absence of damages in submarine IC) to the electrification of the island ($E_{th(j)} = 0$). Investment cost per thermal power unit at the year j may be defined as:

$$I\widetilde{C}_{o(j)}^{th} = P_{r_{dv}} \cdot N_{dv} \cdot f_i \tag{14}$$

where "$P_{r_{dv}}$" is the price of the investment cost (in €/kW) per thermal power unit (or plant) and "N_{dv}" its nominal power (in kW). Investment cost per kW for oil-fired plants during the whole period of 2020-2045 is taken equal to 1,100€ as it is considered a mature technology possessing many years a large share in the electricity sector and it is not expected to change in the future [20].

In order to estimate any potential future modifications/ reinforcements of the TPP, the existing thermal power characteristics are considered. The main purpose is to identify any future requirements in new installed (thermal) capacity in order to safely cover the island's electricity demand during the time period under investigation in the extreme case of a possible failure of the submarine connector. For instance, as for the year 2020 and the baseline Case, it is assumed that the TPP will comprise 9 thermal power units (4 existing: 47.5MW and 5 new: 55MW) of total rated power 102.5MW whilst every five years' thermal capacity is properly modified (Table I) in order to meet the forecasted load (Fig. 5).

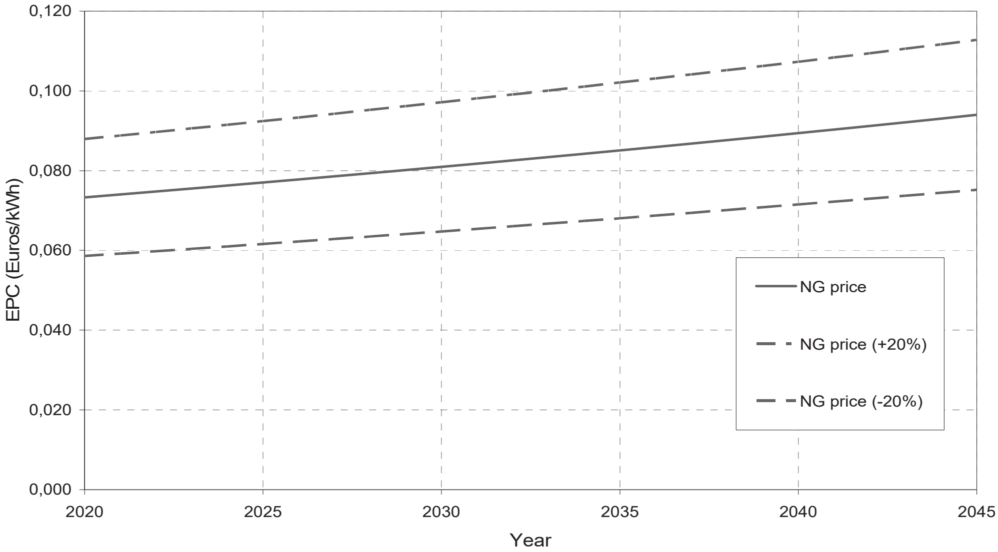

Fig. 7 Projected evolution in EPC for NG (without the environmental impact)

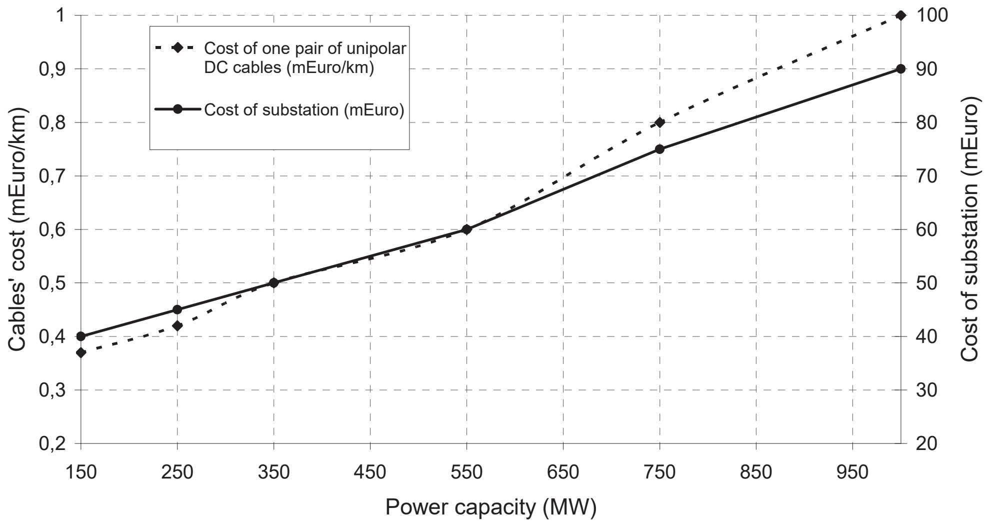

Fig. 8 Costs of IC equipment. Based on data from [5], [8]

VI. Sensitivity Analysis

The analysis of the techno-economic behavior of the two scenarios currently investigated is based on a substantial number of variables and assumptions. In this context, an extensive sensitivity analysis is performed with respect to possible deviations in the values of the most uncertain variables in order to identify the worst (pessimistic-Pe), reference/baseline (most likely-Ba) and best (optimistic-Op) output results. Note that the selected value of variables used in the baseline Case corresponds to those data found in bibliography and in technical reports. More specifically, the main input variables in the sensitivity analysis along with the respective variation in reference values are:

- *Baseline Case* (or reference Case): mainland's EPC→ 0% variation in reference value [4], [8], [9] (Fig. 7), capital cost of IC→ 0% variation in reference value [5], [8] load demand→ 0% variation in reference value (Fig. 5)
- *Optimistic Case*: mainland's EPC→ -20% variation in reference value, capital cost of IC→ -20% variation in reference value, load demand→ -15% variation in reference value
- *Pessimistic Case*: mainland's EPC→ +20% variation in reference value, capital cost of IC→ +20% variation in reference value, load demand→ +15% variation in reference value

VII. Energy Model Results

This section summarizes the main findings after the application of the analysis presented in Section IV during the years 2020-2045 for the two investigated scenarios, i.e. S(a) and S(b).

Fig. 9 presents the overall electricity mix for both scenarios from the beginning of the project until the end of its life in relation to WF installed capacity for each investigated Case. Also from the same figure one may obtain the average (annual) share of WE penetration to the electricity consumption of the island which ranges between 8 and 70%. These high percentages indicate that island's IC along with the absence of technical constrains in WE absorption may result to remarkable WF contribution increase into the island's energy balance.

As far as the overall contribution of NG (energy from mainland) in total electricity generation is concerned (Fig. 9), its share ranges between 24% (2,473 GWh) and 86% (12,122 GWh), depending on the WF capacity and the investigated Case. It is worth mentioning that the Capacity Factor (i.e. the ratio of the annual WE which is absorbed by the (local and mainland) grid, to WFs potential output if it were possible to operate at full nameplate capacity continuously over the same time period) equals to almost 37% (corresponding to the wind speed time-series data used in the simulations) in all examined Cases.

Finally, Fig. 10 presents the power capacity of the IC for each examined Case on the basis of (5)-(8). As can be seen, in S(a) the total IC capacity is determined only by the forecasted maximum load demand on the basis of (5) as, according to simulation results, in all examined Cases, $2N_L^{\max}\cdot(1+\delta N_{tr})$ has been found greater than $N^{\max}_{e_w(i\to m)}$. On the other hand, in S(b) the total power of the IC cable is determined on the basis of both (7) and (8), depending on the installed WF capacity and on the examined Case (Ba, Op, Pe).

VIII. Economic Model Results

LCOE for both scenarios is presented in Figs. 11 and 12. As already mentioned, the pessimistic and optimistic Cases represent the maximum (worst) and minimum (best) cost-related solutions, respectively.

Common base for the three examined Cases (Op, Ba, Pe) in S(a) is that the increase in WF capacity leads to remarkable decrease in LCOE which ranges from 190€/MWh (S(a)-Pe) to almost 80€/MWh (S(a)-Op) (Fig. 11). The degree of reduction in LCOE in the beginning is more drastic, while with further increase in WFs capacity the cost seems to stabilize between 80 and 100€/MWh. In the baseline Case the cost ranges from about 90 to 170€/MWh, depending on wind capacity.

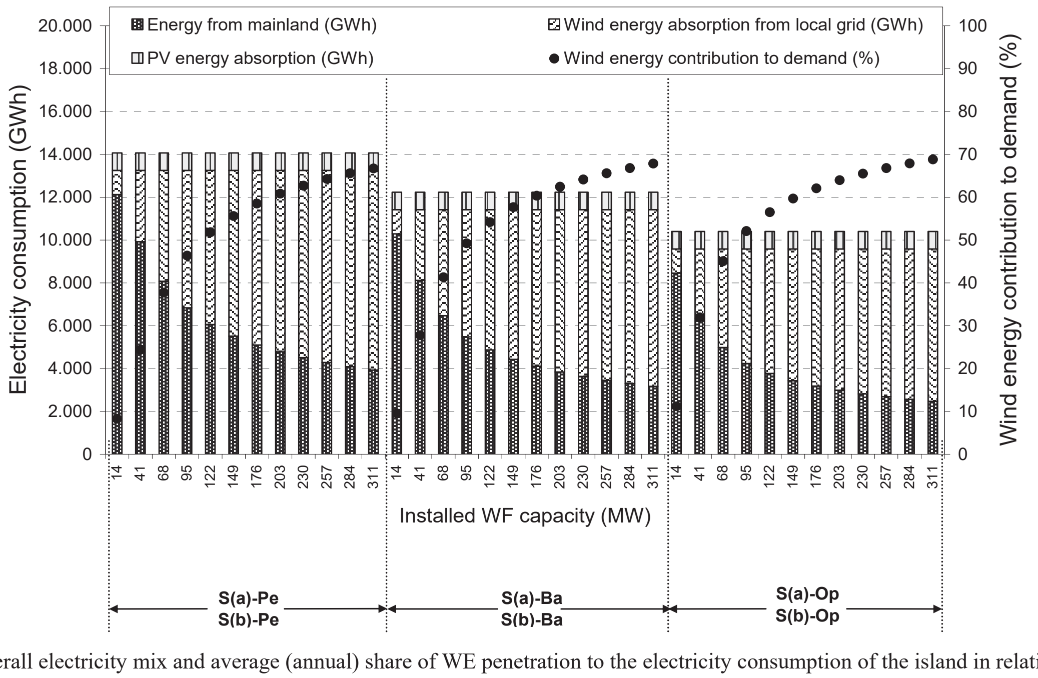

Fig. 9 Overall electricity mix and average (annual) share of WE penetration to the electricity consumption of the island in relation to WF installed capacity for the three examined cases

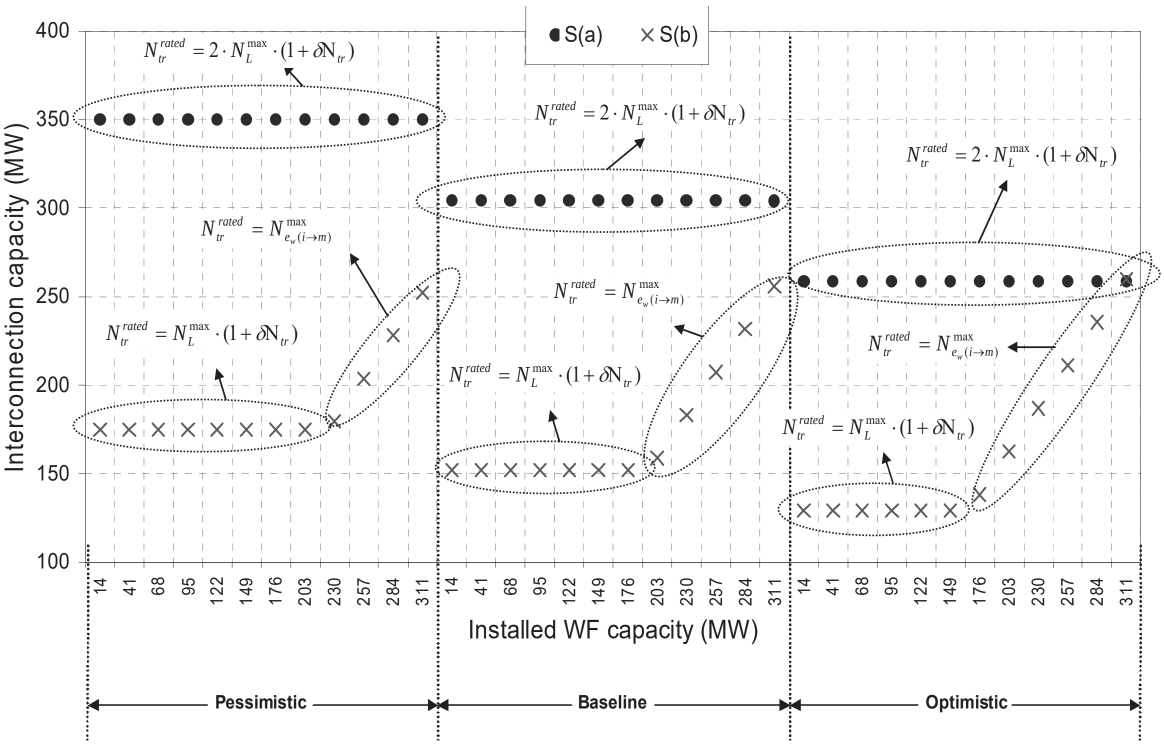

Fig. 10 IC power capacity in relation to WF installed capacity for the three examined Cases (Scenarios (a) and (b)

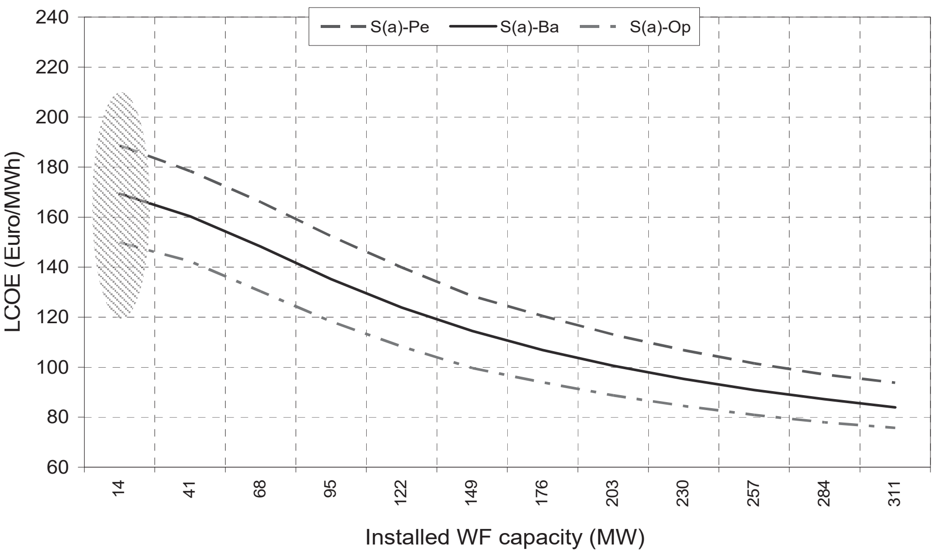

Fig. 11 LCOE during the lifetime of the investment in relation to WF installed capacity for the three examined Cases (S(a))

Fig. 12 presents the respective results concerning Scenario (b). Similar to S(a), the increase in WF capacity results in considerable decrease of the LCOE which ranges from 175€/MWh (S(b)-Pe) to almost 75€/MWh (S(b)-Op). In the baseline Case the cost is found between 80 and 155€/MWh. It is noted that the variations in LCOE between the two scenarios (S(a), S(b)) are minor, with S(b) displaying marginally better results. In any case however, IC allows significant cost savings to occur by taking the full advantage of both the clean electricity generated by local WFs, as well as the stable and less costly (compared to oil-fired generation) electricity generated in mainland. The resulting economic benefits from large-scale WE contribution may also be obtained if one considers a scenario of "IC only" (shaded areas in Figs. 11 and 12) where it may be assumed that wind power installations are limited at their current level (i.e. ~14MW) and only IC with the mainland takes place. In this situation, as can be seen from both graphs, the LCOE would remain quite high, varying from 150 to 190€/MWh in S(a) and from 140 to 175€/MWh in S(b). On the contrary, as WE applications increase (>14MW), the arising economic benefits may be impressive and the LCOE may fall well below 100€/MWh while substantial independence of the island from conventional fossil fuels is also achieved.

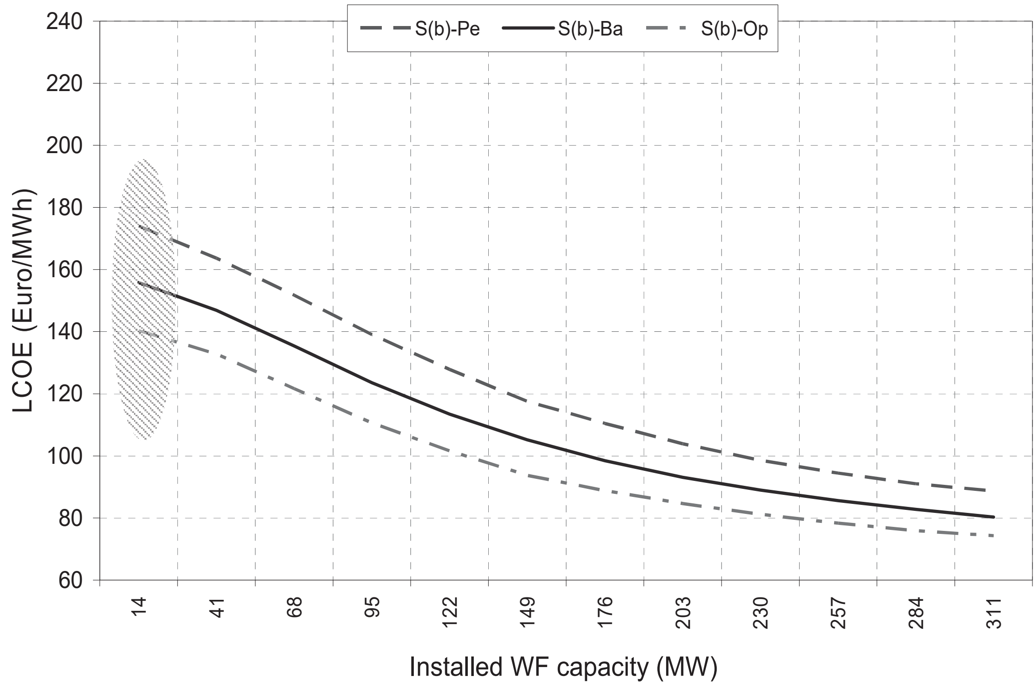

Fig. 12 LCOE during the lifetime of the investment in relation to WF installed capacity for the three examined Cases (S(b))

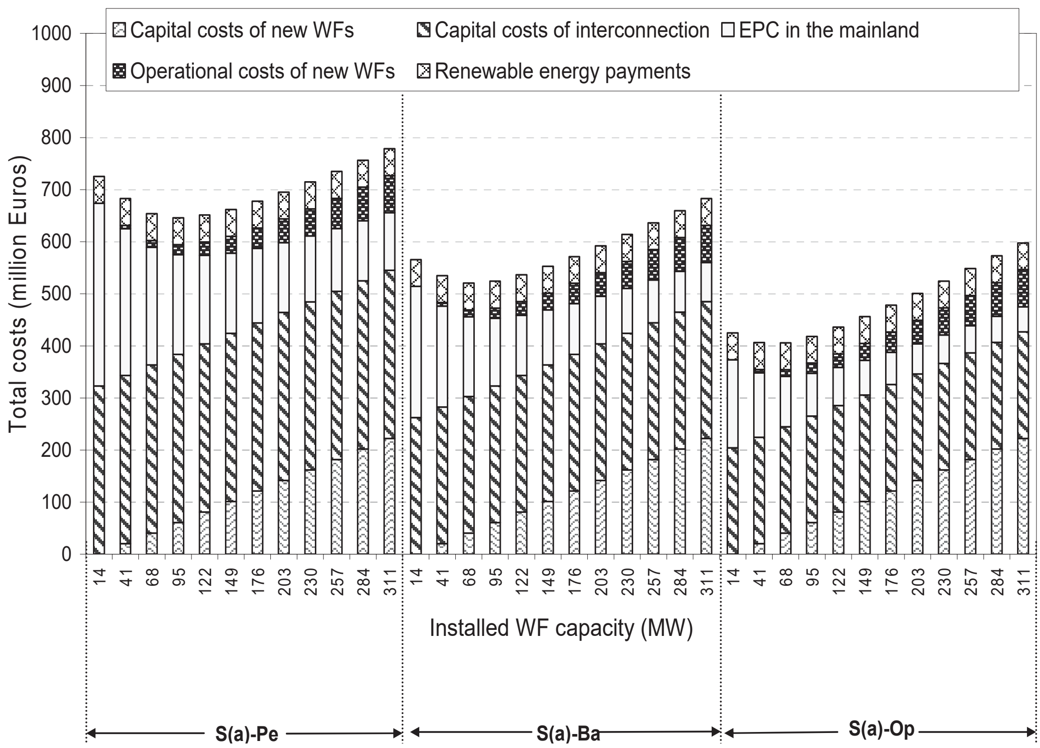

Fig. 13 Total costs breakdown in relation to WF installed capacity for the three examined Cases (S(a)) (in present values)

Figs. 13 and 14 depict the breakdown of total costs (in present values) from the beginning of the project until the end of its life cycle for the two scenarios.

In S(a) (Fig. 13) total cost is formed by the investment and operating costs of new wind power systems, the capital cost of IC, the cost of energy supply from the mainland grid and the cost of purchasing energy from (existing or new) RES-based plants. The arising differences among the examined Cases (Op, Ba, Pe) seem to be significant. The pessimistic Case (S(a)-Pe) comprises the most expensive solution as the demand is considered by 15% higher than S(a)-Ba, a condition which increases the energy requirements from the mainland grid and the power capacity of the IC. Moreover, in the pessimistic Case, an increase of 20% compared to S(a)-Ba is also taken into account for the total EPC in the mainland as well as for the IC investment cost. The remaining costs (capital and operational costs for new WFs, renewable energy payments) that form total lifetime expenses are the same in all three Cases (baseline, optimistic, pessimistic).

Accordingly, total costs breakdown (in present values) for S(b) (Fig. 14) includes −in addition to the already mentioned expenses for S(a)− the capital cost of new thermal power generators, as well as the fixed operating cost of the local APS, which anyway should be paid by the plant operator irrespectively of the amount of electricity production. Nevertheless, total lifetime cost in S(b) is lower compared to S(a) due to the significant reduction in IC capital cost (use of one pair of unipolar cables) in the former case.

Recapitulating the results concerning the two investigated scenarios, it becomes clear that if the "costly" project of Lesbos island IC with the mainland part of the country is combined with large-scale WE integration, it may be considered as an economically attractive solution succeeding in significant reduction in the LCOE. Furthermore, apart from cost savings from the investor's (system operator) perspective, the WE amounts which cannot be absorbed in the island and are considered to be "pumped" to the mainland through the submarine cable(s) will contribute to the sustainable development of the whole Greek power sector concerning environmental objectives and international commitments. To this end, Fig. 15 presents the total environmental benefits −in terms of CO_2 emission savings− and avoidable EPC (in present values) over the considered lifetime of the project from the excess WE, which will cover part of mainland's energy needs. Note that the depicted WE surplus that reaches the mainland grid has been estimated by taking into account the power transmission losses through the submarine cable(s). For the purposes of the present study, the avoidable EPC is thought to result from the reduction in the NG-fired plant according to the baseline cost which is presented in Fig. 7. Similarly, the environmental benefit is assumed to result from the reduction in CO_2 emissions due to the reduced operation of the NG-fired power station.

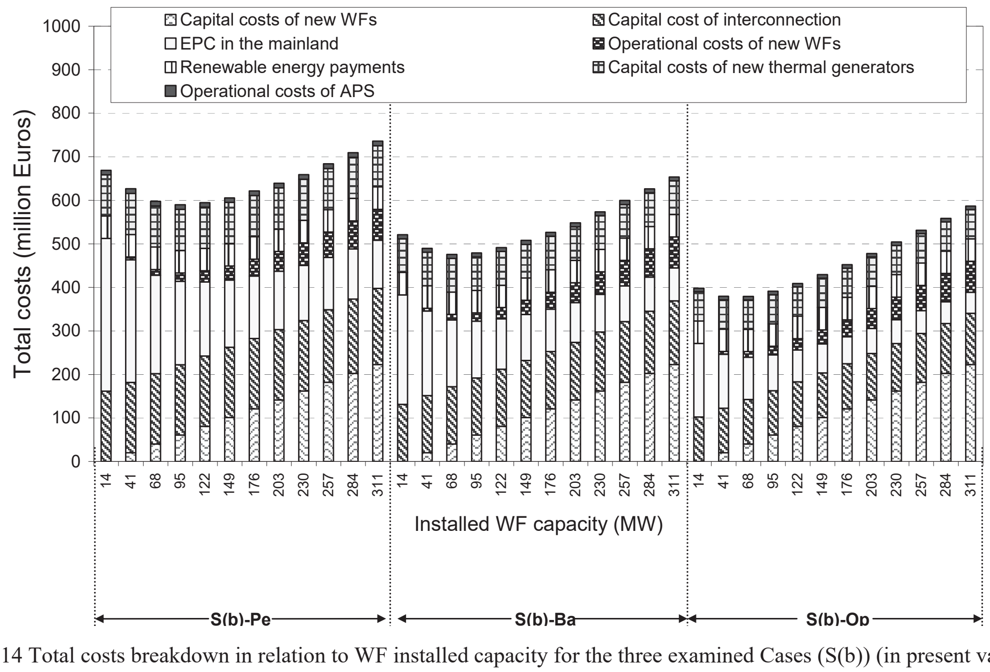

Fig. 14 Total costs breakdown in relation to WF installed capacity for the three examined Cases (S(b)) (in present values)

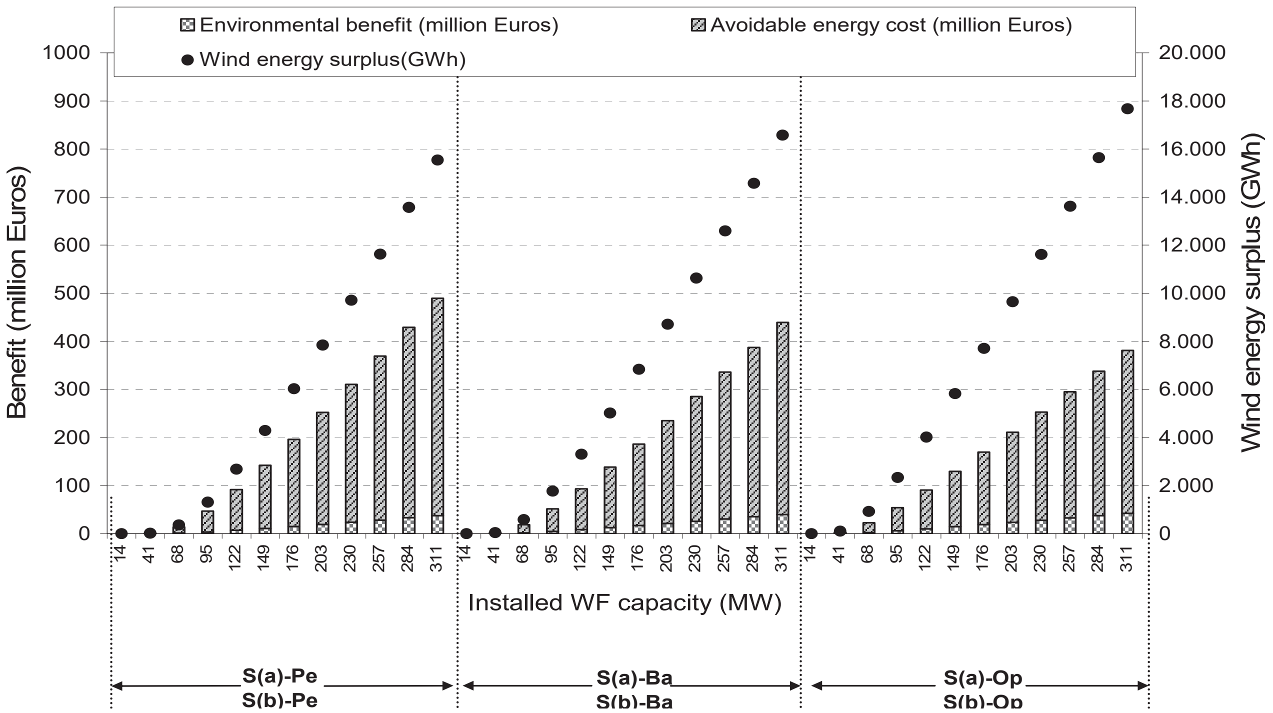

Fig. 15 Total environmental and economic benefit in mainland from the contribution of the WE surplus in relation to WF installed capacity for the three examined Cases in S(a) and S(b)

IX. Conclusions

The results of a preliminary feasibility analysis which examines two indicative IC solutions between the island of Lesbos and the mainland grid of the country were presented in the present study. The hourly energy performance of the system was simulated over a 25-year evaluation period and the LCOE of each solution was estimated, identifying also the worst (pessimistic), most likely (baseline) and best (optimistic) output results.

According to the results, island's IC is worthy of further investigation as it presents considerable economic interest and may be seen as a great challenge for covering part of island's future electrification needs. IC may take place either with local conventional generation being entirely removed or with keeping specific thermal power capacity in parallel to the IC. The variations noted in the economic results between the two options were minor.

An IC project alone may be considered quite capital intensive and its investment cost represents a major obstacle in its realization, however, when combined with large-scale WE development, remarkable cost savings may be achieved. More precisely, according to the results and the baseline Case, an IC project alone would have a LCOE approx. 160-170€/MWh, whilst, if it is combined with large-scale WE development, LCOE could fall well below 100€/MWh. IC, not only provides the island with cheaper electricity from the mainland (compared to oil-fired generation), but also increases security of energy supply and may be used to back-up and enhance the role of WE into the island's energy balance. Furthermore, one should not disregard that apart from cost savings from investor's (system operator) perspective, the WE amounts which cannot be absorbed in the island (during low demand periods) and are considered to be "pumped" to the mainland through the submarine cables can contribute to the sustainable development of the whole Greek power sector.

Finally, it should be mentioned that future research on island's IC should include a dynamic stability analysis of the power system especially when studying high wind power penetration levels in order to ensure reliability of the system and enable a cost effective integration of the whole project. Also, future research should weigh the resulting economic benefits of high WE use against issues such as social acceptance or other environmental and spatial planning concerns for new WFs installation.

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