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Economic analysis of an electricity and desalinated water cogeneration plant in Cyprus

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ABSTRACT

This paper builds on and extends the R&D work on the techno-economic analysis of the cogeneration of desalinated water and electricity by the Cyprus Institute (2012) (Solar Thermal Cogeneration of Electricity and Water: Research and Development study for a Concentrated Solar Power—Desalinization of Sea Water (CSP–DSW) C.N. Papanicolas & G. Tzamtzis editors. The Cyprus Institute, Nicosia, Cyprus, 2012. ISBN: 978-9963-2858-0-8). Three different Concentrated Solar Power (CSP) plant configuration options for operating in Cyprus are examined in this paper: an electricity-only, electricity with Reverse Osmosis desalination and electricity with Multi Effect-distillation desalination. All plants' rated output is 4 MWe, and desalination capacity is 5,035 m^3/d. A discounted cash flow model was developed and used, designed to represent the financial performance of the CSP–DSW concept. The expected financial costs for equipment, operation and maintenance and replacements were estimated. The expected performance in terms of annual electricity and water yields are considered for calculating financial revenues. In addition, to model uncertainty in the inputs, a Monte Carlo algorithm was used. The results show that the CSP–DSW concept is financially feasible for all systems even though the electricity-only plant performs best. If, however, the production of water from renewable sources is supported by policy schemes similarly to electricity production, the projects would perform similarly.

Keywords: Solar energy; CSP; Desalination; Renewable energy sources; Monte Carlo risk analysis

1. Introduction

Cyprus has experienced a number of important events in the last decades that have brought issues of renewable energy, electricity generation and water scarcity at the forefront of public and official discussions. Of these, two in particular stand out: the 2008 drought that depleted the available fresh water reserves of the island (resulting in the need to import water in ships from neighbouring countries) and the 2011 explosion near the village of Mari that all but wiped out the main electricity generating plant of the country at the site of Vasilikos. The

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water drought brought to surface a long-standing issue with water collection and the sensitivity of the local water system to periods of low rainfall, combined with an ever-increasing demand for fresh water supply. The Mari explosion demonstrated the perils of centralised electricity generation and total reliance on fuel imports, but also the fragility of an isolated electric system shown by shortage of electric power, frequent power cuts and instability experienced for some time after the explosion.

On the other hand, Cyprus is endowed with ample amounts solar irradiation, and is a prime candidate for the development of solar-based renewable energy technologies. Solar Photovoltaics (PV), while progressively getting more competitive, are intermittent sources and at high penetration percentages add to the instability of the grid (see e.g. [1,2]). Sustained winds for power generation are sparse in Cyprus (as demonstrated by the operation of the existing wind farms thus far). It is therefore worthy to investigate Concentrated Solar Power (CSP) as a solution for both power generation and desalinated water (DSW) in a combined CSP–DSW system. Essential to the design and to addressing the aforementioned considerations is the fact that the systems examined here are combined with energy storage that allows for full 24-h operation.

This paper assesses the economic performance of such a system by investigating three different systems: the first, Case (A), is an electricity-only plant; the second, case (B) uses, additionally, a Reverse Osmosis (RO) system for desalination; and Case (C) is an advanced Multi Effect-distillation (MED) unit with eight effects, also used for desalination.

2. Methodology

2.1. The discounted cash flow model

The CSP–DSW plant considered here would generate revenue by selling electricity and DSW. Annual cash flow streams were estimated and prepared in order to be able to conduct a financial efficiency analysis, based on the Discounted Cash Flow (DCF) technique for the proposed CSP–DSW project. The analysis was performed using Microsoft Excel as the software tool. The analysis compares estimated direct financial costs with estimated direct financial revenues. All future cash flows are estimated and discounted to give their Present Values the sum of all future cash flows, both incoming and outgoing, is the Net Present Value (NPV), which is taken as the value or price of the cash flows in question. As customary in such analyses, if the value arrived at through DCF analysis is higher than the current cost of the investment, the opportunity may be deemed to be a feasible one.

Once all the project costs, revenues and benefits are defined, this model calculates a variety of financial measures, including:

- NPV
- Internal Rate of Return (IRR)
- Benefit cost ratio (also known as profitability index)
- Levelised Cost of Energy (LCOE)
- Payback time
- Minimum Debt Service Coverage Ratio (DSCR) in case project financing is included

3. Assumptions and considerations

3.1. Overall financial environment

Assumptions on the financial environment in which the plant will operate (Cyprus) are presented in this section. The investment environment for Cyprus has altered dramatically due to the financial crisis experienced since 2008, but intensely so after 2013 that experienced a partial bank collapse. The Republic of Cyprus is using some reference values in its guidelines for Renewable Energy Systems (RES) investments under the NER300[1] funding scheme [3] and they are used here unchanged. Namely, the cost and revenue values were used with an annual discount rate of 7% (which includes a 1% risk premium) and inflation rate of 1.8% that extends over 20-year project horizon. The debt interest rate was set to be 6% and assumed to cover 50% of the investment, maturing after 10 years. The prevailing Feed-in Tariff (FiT) system for concentrating solar power plants in Cyprus is valid for 20 years. A 12.5% income tax was considered on the gross profit as per prevailing Cypriot financial system. The equipment depreciation rate is set at a linear rate of 10% as mandated by Cyprus legislation. In the analysis, an amount equivalent to 0.5% of initial capital requirement was allocated for insurance. The construction time (gestation period) was assumed to be two years, the financing of which follows the same debt assumptions as above.

[1]NER300 is a financing instrument managed jointly by the European Commission, European Investment Bank and Member States of the EU that aims to promote environmentally safe carbon capture and storage and innovative renewable energy (RES) technologies on a commercial scale.

3.2. Design options and revenue streams

The nominal specification of the power block of the system is 4 MWe. However, depending on three different design cases, different amounts of electricity generation and desalination options were considered for this financial analysis. The estimated design values of daily electricity and water production are given in Table 1.

Case (A) is an electricity-only CSP plant. Case (B) is a RO system with advanced water production capacity of 5,035 m^3/d. Case (C) is an advanced MED unit with eight effects, also able to produce 5,035 m^3/d.

3.3. Revenues

Financial revenues are estimates of revenues that are expected to occur as a result of the project. This was assumed to consist of money from selling electricity, selling the DSW and from selling Greenhouse Gas (GHG) emission permits.

3.3.1. Electricity

The selling price of the electricity is set at 0.26 €/kWh of energy sold to the grid as per the most recent FiT regulations for CSP in Cyprus that assigned a tariff for CSP plants (October 2013). In the analysis, it is assumed that the electricity generation will have an availability factor of 85% over the project lifetime of 20 years. In addition, the plant will be able to generate only 50, 60 and 70% of the designed capacity during the first three years of operation. The CSP–DSW plant for case (A) was designed to deliver 30,309,600 kWh of electricity per year [4]. Therefore, from the fourth year till the 20th year, the annual electricity production will be 25,763,160 kWh (due to the 85% factor), which corresponds to a revenue of €6,698,422 per annum. Subsequently, case (B) will generate €5,670,427 p/a and case (C) €5,620,092 after year 4.

3.3.2. Water

Similarly, for the DSW sales, it was assumed that the price would be €0.90/m^3 of desalinated sea water. This is based on a number of published water costs from desalination plants in Cyprus in the last 15 years. The first unit to come online was in 1997 in Dhekelia with an agreement to sell water at €0.92/m^3 for a number of years; this contract was revised in 2005 when the government bought the plant and the subsequent agreement with an external operator set the price at €0.64/m^3 [5]. Several other plants have come online ever since, more frequently after the 2008 drought. Indicatively, mobile desalination units were contracted to sell at around the 1.3 €/m^3 range, whereas the newly completed unit close to Limassol signed a contract to sell water to the local board for €0.872/m^3 [5].

The output load factor of the plant was again assumed to be 85% as was with the generation of electricity. Case (A) is an electricity-only plant and does not generate water revenue. Cases (B) and (C) generate identical DSW volumes at 5,035 m^3/d, which corresponds to 1,837,775 m^3 per annum from fourth year onwards, or €1,653,997 of revenue p/a.

3.3.3. Benefit from participation in the EU ETS

Cyprus entered the 3rd phase of the EU Emissions Trading Scheme (EU ETS) in 2013 as a full member eligible for trade of carbon allowances. The GHG emission factor for the baseline emissions from the Cypriot conventional electricity network was assumed to be 0.673 tonnes/MWh of electricity production [6]. The monetary benefit from participating in the EU ETS mechanism was assumed to be €4.50 per tonne of CO_2. This has been a very volatile market, and this value is a mere reflection of recent prices. For case (A), the annual GHG emission reduction is about 17,345 tonnes from the fourth year, which becomes 14,683 tonnes for case (B) and 14,552 tonnes for case (C). This translates to €78,050, €66,072 and €65,486 for cases (A)–(C) after year 4 respectively. A summary of the annual revenue composition for all cases is shown in Fig. 1 and Table 2.

3.4. Estimation of project costs

Initial capital costs, operation and maintenance (O&M) costs including salary of the personnel, and equipment replacement costs are some of the main

Table 1
Design options

	Case (A)	Case (B)	Case (C)
Net electricity to grid (kWh/d)	83,040	70,296	69,672
Net water to sell (m^3/d)	0	5,035	5,035

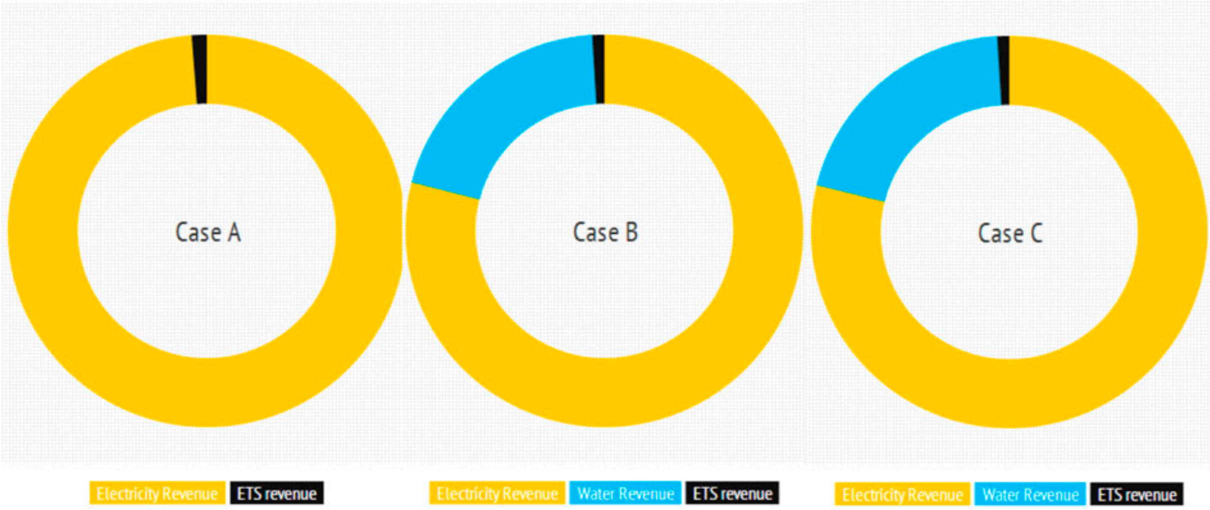

Fig. 1. Revenue stream for all cases, year 4.

Table 2
Revenue stream for year 4, all three cases

Annual revenue stream	Case (A)	Case (B)	Case (C)
Electricity sales (€/yr)	€6,698,422	€5,670,427	€5,620,092
Desalinated water sales (€/yr)	€0	€1,405,898	€1,405,898
GHG emissions sales (€/yr)	€78,050	€66,072	€65,486

cost elements of the project. The capital (construction) cost data presented are derived from a literature review, vendor quotations, experience and personal cost data files. The operating costs are derived, in part, from a literature review and actual CSP, RO and MED plants in service, supplemented by performance estimates. The data used serve to compare alternative schemes at a planning level, or for similar purposes. The implied level of accuracy of the data presented in this section is approximately ±10%.

The major cost elements and their cost data are listed in the following sections:

3.4.1. Heliostats (solar field)

The capital cost for the solar energy collection area is determined by a multitude of factors. The most important is the thermal energy harvested (a function of the size of the solar collection area) compared to the rated power of the power block. This ratio is called the solar multiple. If the power that the solar array delivers at reference radiation conditions is equal to the rated power of the power block, then this ratio equals 1. These conditions are however rarely met; it is therefore common to design CSP plants that have a solar multiple greater than one, usually in the region of 1.2–1.5. Adding thermal storage allows the plant to operate beyond the times with adequate irradiation, even continuously. In those cases, the solar multiple is in the region of 1.5–4 to provide enough energy to the system for prolonged—or even continuous operation. Performing calculations in the Solar Advisory Model (SAM) [7] for a system rated at 4MWe and operating continuously using a solar multiple of 3.5 resulted in a total reflective area of 78,395 m^2.

There are a number of reported costs for CSP heliostats, and no case is identical to the other. Kolb et al. [8] cite various upfront costs,[2] ranging from €106 to €184/m^2. Turchi and Heath [9] use the same source, but settle at a cost around €145/m^2. For this study, a baseline cost of €150/m^2 will be used. The same study points to an annual O&M of 0.3% of the solar fields cost p/a; for this study, 0.5% will be used. In addition to O&M, replacement or major overhauling of mirrors is required, taking place after 10 years at 10% of the heliostats' initial value.

[2]Conversions between USD and EUR were performed in May 2013 using a conversion rate of 1USD = 0.77464 EUR.

3.4.2. Solar tower and receiver

The costs associated with a typical molten salt receiver are dominated by the receiver and by the solar tower. IRENA [10] calculates that the cost of the receiver—tower subsystem constitutes on average 16% of the total cost of a CSP plant. Kolb et al. [8] assign a base value of €150/kW$_t$, whereas an independent study by WorleyParsons [11] commissioned by NREL points to a cost of €103/kW$_t$. Another recent study for the Australian market indicates a cost around €74/m^2 [12]. The System Advisor Model [7] uses a rather more complex formula for calculating costs of tower and receiver, based on the system size and design considerations. For this study's needs and assuming a solar multiple of 3.5 (as seen earlier), the tower-receiver subsystem is assumed to cost €1,550,000 or €110.7/kW$_t$. The annual O&M costs are relatively low according to Turchi and Heath [9], around 0.3% of the initial capital costs for a reference plant—0.5% will be used here, as before due to the smaller size of the plant in question. The lifetime of the receiver before requiring a major overhaul is set at 15 years after completion of works. This overhaul cost is set at 35% of the subsystem initial capital.

3.4.3. Power block including steam generator

The Power block, steam generator and balance of plant costs are easier to calculate as the technology has reached high levels of maturity. Still, the salt water heat exchangers dominate the cost composition [8], whereas IRENA [10] also notes the cost of connection to the electricity grid. SAM [7] indicates a cost of €875/kWe for the power block and €255/kWe for the steam generator, whereas Kolb et al. [8] points towards a lower cost of €727/kWe for the power block and the same for the steam generator. WorleyParsons Group [11] indicates €727/kWe for the power block and, slightly higher, €265/kWe for the steam generator. This study uses an overall cost for this subsystem of €995/kWe, which works out at €3,980,000. The O&M for the power block is set at 2.5% of its cost (mainly due to technology maturity), whereas there are no provisions for a replacement, as the equipment is projected to last beyond the 20-year analysis period presented here.

3.4.4. Storage

The storage cost depends on the technology employed and the number of hours the plant is required to operate without the assistance of solar input. This in turn dictates the solar multiple (see Section 3.4.1), as there should be enough solar energy stored in the storage medium to fuel full operation for a complete 24-h cycle. In order to achieve this, SAM calculates that around 233 MWht will be required for the size and solar multiple of this plant. Most studies cite a linear relationship between thermal energy stored and cost, e.g. Hinkley et al. [12] indicate €17/kWh$_t$ for a plant in Australia for three hours of autonomy, but also €65/kWh$_t$ for six hours of storage in South Africa. SAM [7] defaults on €20/kW$_t$, similarly to Kolb et al. [8], that indicates €22/kW$_t$. A value of €21/kW$_t$ will be used here. Hence, the cost of the storage system equals €4,893,000. The annual O&M is set at 0.5% for the TES system and 0.2 for the storage medium, as indicated by Turchi and Heath [9], and there are no replacement costs provisioned.

It should be noted here that using a desalination plant in parallel effectively adds seasonal storage to the system, because water that is directed to the water boards for consumption is water not displaced in water dams and reservoirs. This is especially true during the summer months when water demand is high and availability is low. Added to that is the generation of DSW without the need of drawing electricity from the grid, which is needed the most in the summer period to serve the cooling demand of buildings.

3.4.5. Desalination unit

While data on the cost of DSW is more readily available, costs of plants are scarce. Data used here were used in the CSP–DSW book by the Cyprus Institute [4], ch. 12. The desalination units examined—cases (B) and (C)—produce the same volume of DSW per year, but using a different technology. Case (B) uses a RO process, whereas case (C) uses MED. Case (B) is slightly more efficient (see Table 1), which results in higher electricity yields, but it has larger O&M costs, as seen in the following table:

3.4.6. Other capital costs

The costs for other auxiliary costs are summarised in the table below:

Specifically, for land, a heliostat reflective area was calculated to be 78,395 m^2 (see Section 3.4.1), which corresponds roughly to a field area of 234,719 m^2, assuming a solar land field area multiplier of 1.2. Allowing for 32,374 m^2 for the power and the desalination plants, and extra space for future capacity expansion, the total land area required is calculated at 267,093 m^2. Assuming land price to be 10 €/m^2, the total cost for land is €2.67 m (Tables 3 and 4).

3.4.7. Personnel costs

Personnel costs are given in Table 5 for all three cases.

In the analysis, an annual salary increase of 1% in addition to the annual inflation rate was considered.

3.4.8. Total costs

The total initial capital cost needed for case (A) is about €27.1 m or €28 m including financing costs for the construction phase, whereas the annual O&M cost (including salaries) is estimated to be about €750 k p/a. Fig. 2 clearly shows that the heliostats constitute the largest percentage of the capital investment, followed by the storage component, as the system is designed to operate on a 24-h basis. Similarly, for cases (B) and (C), the heliostats are again dominating the upfront costs, but they are higher due to the inclusion of the desalination unit, where the total now is €31 m.

It should be mentioned here that the CSP–DSW concept is unique with respect to solar energy harvesting and steam generation methods. However, it is not tested in a real life situation as yet. Therefore, a conservative approach was taken for the financial analysis in terms of higher O&M cost allocations. A separate provision for contingency fund was not considered in the analysis.

4. Financial analysis results

A financial analysis is a comparison of those costs and benefits that can be quantified in terms of actual money spent or received within the project at one point in time. The results are described in detail for case (C), while the key results of all other cases are summarised in parallel.

4.1. Financial analysis results

The first results from the financial analysis show the initial costs (negative value) in the cash flow graph of Fig. 3 for case (C). This is followed by a series of positive cash flows up to year 20. The ramping up of revenues in year 4 is due the gradual introduction of the system's full capacity (as described in Section 3.3.1). The production of electricity and water remain constant from the fourth till the 20th year and the selling tariffs are also fixed over the project life, whereas the operation and maintenance costs are subject to inflation and annual salary hike. The low value in year 10 is due to debt repayments (the loan was assumed at 50% equity for 10 years) and due to the fact that there is a one-off payment for the replacement of the heliostat mirrors. Taxation is also minimal in the first 10 years due to the dampening of the taxable profit brought by the depreciation of equipment —total taxes paid in the first 10 years are €1.7 m, and €6.9 m thereafter.

Several metrics can be used to assess the project's profitability. The most common used in project financial appraisal is the NPV, which examines costs (outflows) and revenues (inflows) of a project, all converted to present value using an appropriate discount rate [13]. Another common metric used is the IRR, which is the rate that sets the NPV of a series of future cash flows to zero. The non-discounted payback duration is also a well-understood metric, which can be seen in Fig. 4.

Whereas the above figures include the effect of using the ETS, the volatility of the market merits a simple sensitivity analysis of those streams being "on" or "off". Table 6 shows the several metrics and the effect of the inclusion of using the carbon market on all cases examined using the price mentioned in Section 3.3.3, where results naturally improve:

Similar analyses were conducted for the rest three types of design options. The key financial performance results of all of the cases are summarised in the table above.

At first, it seems that the electricity-only option (case A) is the most lucrative solution, and is better than the desalination options in every metric. This is mainly due to the increased electricity production that attracts a relatively high FiT, the lower upfront cost and the slightly lower O&M costs. The tariff system

Table 3
Capital and O&M requirements for the desalination module

Desalination costs	Case (B)	Case (C)
Initial capital	€3,900,000	€3,900,000
Annual O&M	€215,000	€138,000

Note: No replacements costs are included in the calculations.

Table 4
Other costs

Balance of plant	€700,000
Site improvements	€700,000
Piping	€700,000
Storage medium (salt)	€460,000
Land	€2,670,000

Table 5
Annual personnel costs

Annual revenue stream	Nr. of people	Yearly cost (per head)	Total cost (per head)
Administration	5	€26,400	€132,000
Operations	4	€24,000	€96,000
Power block/TES maintenance	8	€24,000	€192,000
Solar field	5	€24,000	€120,000
Desalination	3	€24,000	€72,000
Total	22 (25)		€540,000 (€612,000)

Note: Numbers in parentheses denote changes for case (A).

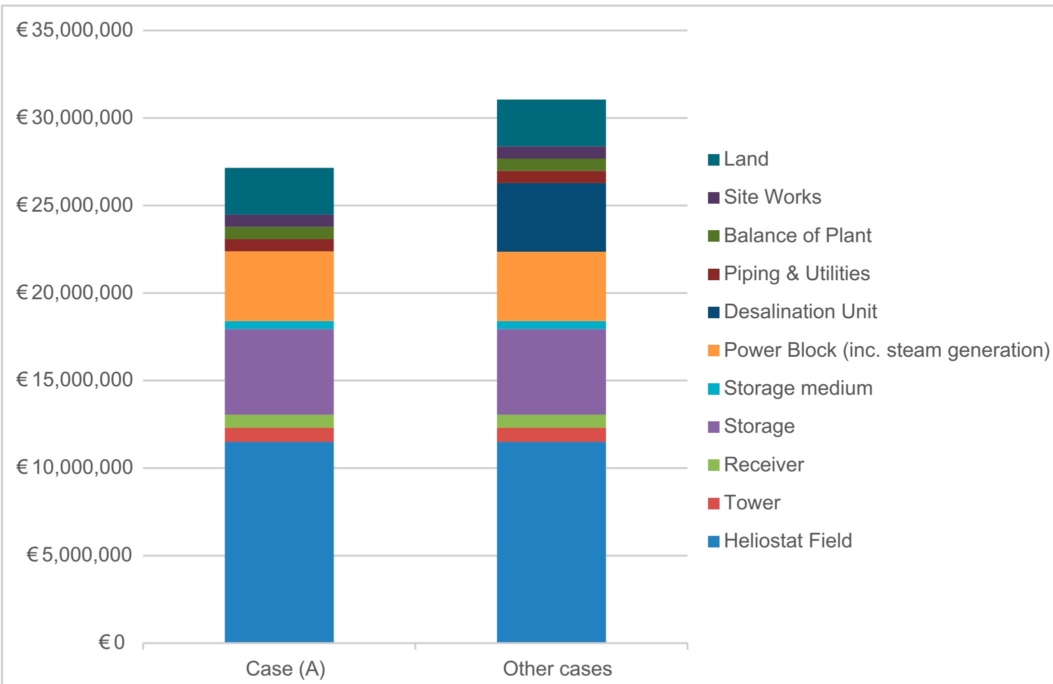

Fig. 2. Initial capital cost breakdown for all cases.

for RES in Cyprus (and in Europe by extension) seems to place its importance on electricity tariffs, and ignoring cogeneration systems. The reasons for central and northern European countries are mainly connected to the fact that there is no need for DSW, but the climatic characteristics of a country like Cyprus are unique for Europe, being mostly similar to countries of the MENA region. Case (C) appears to be better than case (B), even though the upfront cost is the same and the electricity produced is slightly lower. The reason is the difference in O&M costs, where an RO plant requires more capital annually to operate, as seen in Section 3.4.5.

In terms of absolute assessment of the metric values, all three cases satisfy the general rule of finance that appropriately risked projects with a positive NPV that can be accepted, even though case (A) is the best performer. Subsequently, as an investment, if there is a choice among many mutually exclusive alternatives, the one yielding the highest NPV should be the most attractive option. The IRR value does not have a predefined “cut-off” point as what is favourable and what is not depends on market conditions. As a minimum, the IRR value should be more that the discount rate used for the calculation of NPV, which in this case is 6%. Projects of this nature usually require an IRR of 10% or more, which is satisfied in all cases. The minimum DSCR shows the ability of the investment to generate enough revenues to cover its debt payments in any given year. This has to be above 1 at all times

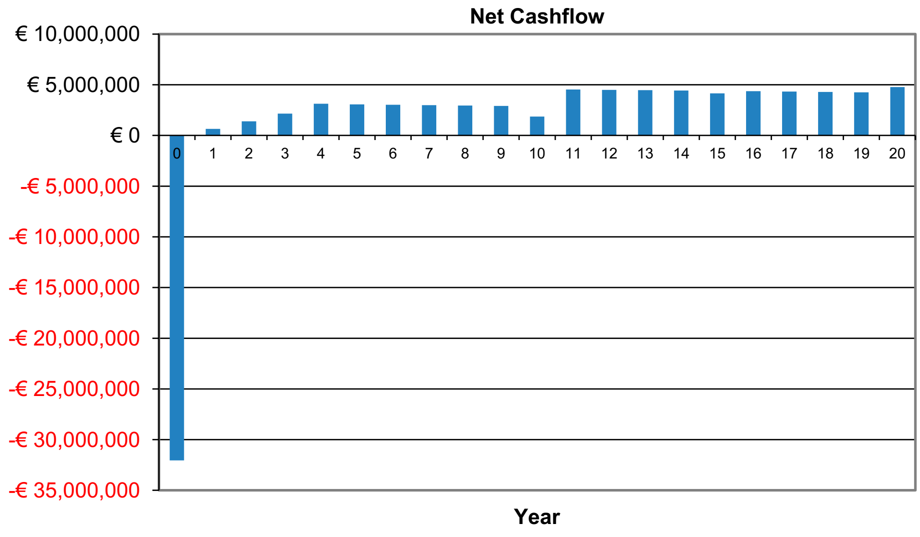

Fig. 3. Net cash flow for case (C)—cogeneration using MED.

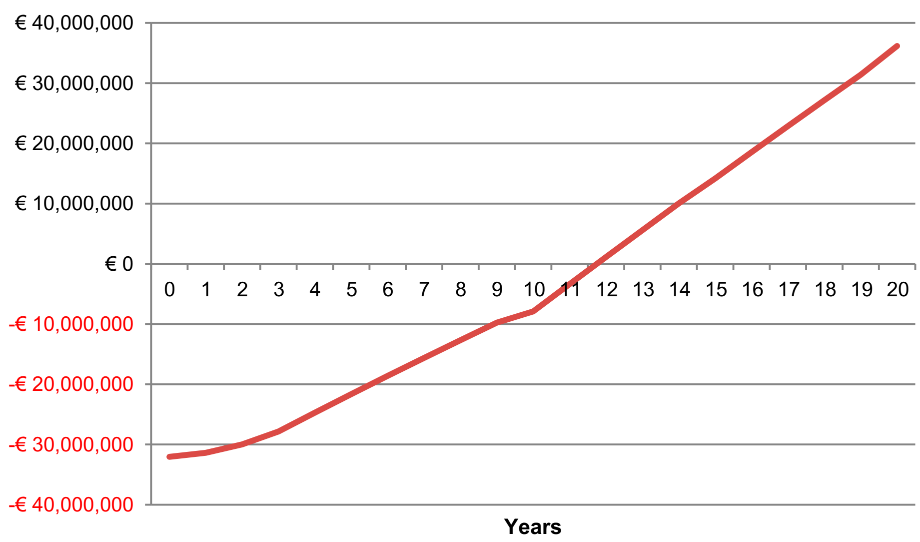

Fig. 4. Cumulative non-discounted payback cash flow for case (C)—cogeneration using MED.

Table 6
Financial metrics for all cases, with and without using carbon markets

	Case (A)—elec. only		Case (B)—desal. RO		Case (C)—desal. MED	
	No ETS	ETS	No ETS	ETS	No ETS	ETS
NPV	€8.9 m	€9.6 m	€3.16 m	€3.75 m	€3.63 m	€4.20 m
IRR	13.77%	14.00%	11.63%	11.82%	11.78%	11.96%
Payback (non-disc.)	8.63	8.49	10.07	9.93	9.96	9.83
Minimum DSCR	1.65	1.67	1.40	1.42	1.42	1.44

(to avoid years with a negative cash flow), and should be greater than 1.2 to ease project financing. As noted in Section 3.1, the debt ratio is set at 50%.

It is interesting to test these results in the absence of a FiT. The price at which the Electricity Authority of Cyprus (EAC) buys electricity from renewable energy sources varies to reflect global fuel prices and domestic market conditions. Current selling prices (Feb 2014) are €0.1121/kWh for connecting to the Medium Voltage (MV) network.[3] Substituting this to the financial model results in all NPV indices to be deeply in negative ground (around -€30 m). The following table shows the price needed to have NPV set to zero for all cases:

It is quite evident that none of the study systems can be financially viable without a support scheme—a FiT in this case. The above table also shows that the FiT should be at levels close to the ones offered at the moment to provide adequate incentive to prospective investors.

4.2. The importance of the water selling rate

The discussion so far has highlighted the fact that case (A) is the most financially attractive option on all metrics tested. These results are based on the assumptions made in Section 3. The cases where cogeneration of electricity and water takes place suffer from the increased upfront costs, lower efficiency for the electricity part and slightly increased O&M expenses. All these would have to be compensated by selling water to local water boards at a rate that would improve the financial performance of CSP–DSW systems considerably. Currently, however, there are no policy mechanisms in Cyprus that offer support for water produced from renewable sources in the same manner as there are for electricity. This is a distortion of the spirit of support schemes for commodities produced by renewable energy. An interesting exercise would be to see at what price of selling water the project would break even (i.e. have an NPV = 0), if the FiT for electricity was abolished. Fixing the price of selling electricity to the non-FiT supported value (€0.1121/kWh) and solving for the water selling rate reveals that this rate would have to be quite higher than the initial value of 0.90 €/m^3 (Table 7).

4.3. Levelised cost of production for all cases

While the net cash flow and financial performance of the entire cogeneration plant are relatively simple to estimate, determination of the cost of electricity and water separately from a cogeneration plant is a less straightforward process. There are several methods which have been attempted but no universally agreed final method exists. Research papers by El-Nashar [14], Saeed [15] and Hamed et al. [16] have shown that cost allocation between power and water for a cogeneration plant of simultaneous production of water and electricity is not a settled issue. Consequently, a number of methods have been recommended for cost analysis. Some are based on rigorous accounting procedures in which the cost of each involved energy/exergy streams is determined, while others are based on direct cost accounting, which allocates all cost components between water and electricity according to certain rules of thumb such as exergy pro-rating, power loss due to extraction of steam to the desalination unit or cost allocation based on functional considerations.

4.3.1. Using the kWh-eq

Generally, the LCOE is defined as the sum of expenditures in a project's lifetime in present value, divided by the revenues of this project, again converted to present value (e.g. see [17]). Here the LCOE for the whole plant is used by converting the revenues from water and from selling GHG allowances into equivalent electricity production units (kWh), essentially treating the whole plant as an electricity-only system. This way, all production can be added and used in the LCOE calculation.

Table 8 shows the LCOE of all cases (using ETS or not) in nominal values that incorporate inflation in recurring and O&M costs; real values do not. In this case, we use a nominal (current) discount rate of 7% and an inflation rate of 1.8%, which translates to a real discount rate of 5.11%. Extensive discussion of this concept can be found in Short et al. [13].

Here again the costs for case (A) are lower, but also crucially case (C) is cheaper than case (B) as mentioned in the previous section.

The above results essentially depend on the assumption that the ratio between the water and electricity rates remains constant, to provide a fixed conversion coefficient. Using the rates proposed in Section 3.3, this conversion becomes:

$$\frac{R_w}{R_e} = \frac{0.9\,€/\mathrm{m}^3}{0.26\,€/\mathrm{kWh}} \approx 3.46\,\mathrm{kWh/m}^3 \tag{1}$$

This can be used for conversions of water production to kWh. Similarly, the income from using the ETS

[3]URL: http://goo.gl/8W3eqy.

Table 7
Financial performance for NPV = 0

	Case (A)—elec. only		Case (B)—desal. RO		Case (C)—desal. MED	
	No ETS	ETS	No ETS	ETS	No ETS	ETS
Threshold electricity tariff for breaking even (€/kWh)	€0.2202	€0.2171	€0.2434	€0.2404	€0.2408	€0.2378

Table 8
Total LCOE production for all cases

	Case (A)—elec. only		Case (B)—desal. RO		Case (C)—desal. MED	
	No ETS	ETS	No ETS	ETS	No ETS	ETS
LCOE (nominal)	€0.1886	€0.1868	€0.2091	€0.2074	€0.2069	€0.2053

market can be converted to kWh (by the assumptions found in Section 3.3) using the same methodology, in which case

$$\frac{R_c}{R_e} = \frac{4.5\,€/\mathrm{tCO_2}}{0.26\,€/\mathrm{kWh}} \approx 17.31\,\mathrm{kWh/tCO_2} \tag{2}$$

where R_w = water selling rate; R_e = electricity selling rate (FiT); R_c = carbon selling rate.

In cases where the Monte Carlo (MC) algorithm is used, these ratios are constantly changing with every sample, and therefore calculating the LCOE this way leads to inconsistent results. It is therefore assumed that the ratios remain constant as seen is Eqs. (1) and (2).

4.3.2. Using the "substitution" principle

According to Short et al. [13], the LCOE value is that cost which if assigned to every unit of energy produced by the system over the analysis period, will equal the Total Life-Cycle Cost (TLCC) when discounted back to the base year. The TLCC is defined as

$$\mathrm{TLCC} = \sum_{n=0}^{N} \frac{C_n}{(1+d)^n} \tag{3}$$

where TLCC = present value of the TLCC; C_n = cost in period n; N = analysis period; d = annual discount rate.

The TLCC value is different across the three cases, as the upfront costs and variations in maintenance produce different outcomes. A way to calculate a separate Levelised Cost for Water is to assume that the difference of possible revenue streams between an electricity-only plant and the cogeneration plant has occurred because of introducing the desalination facility into the electricity-only system (Case A), according to the following:

$$\mathrm{LCOW} = (\mathrm{TLCC_e} - \mathrm{TLCC_{cg}}) / \sum_{n=1}^{N} [Q_n/(1+d)^n] \tag{4}$$

where LCOW = Levelised Cost of Water; $\mathrm{TLCC_e}$ = Total Life-Cycle Cost of Electricity-only plant (Case A); $\mathrm{TLCC_{cg}}$ = Total Life-Cycle Cost of cogenerating plant (Cases B & C); Q_n = water output in year n; d = annual discount rate; N = analysis period

This way, there can be an LCOE for the electricity part only, and an LCOW for water.

5. Uncertainty analysis

An accepted method of assessing the uncertainty of an input variable of the financial model is to allow them to vary according to a predefined input sample distribution. This can lead to a more accurate assessment of the potential financial performance of the investment instead of relying on static values that are prone to change, and is performed by using a Monte Carlo analysis of uncertainties (see e.g. [18]). The choice of the variables and their assigned distributions is important in the final outcome of the uncertainty analysis; it is also important to monitor certain metrics as outcome that are deemed important. The effect of the isolated or simultaneous change in those inputs is recorded chiefly on an output variable, the NPV of project, as well as the project's IRR, the payback time and the LCOE.

5.1. Assignment of uncertainty distributions to select input variables

The assignment of input probability distributions does not produce an exact prediction of the value, but their use allows forecasting of uncertainty margins of an appropriately chosen range [19]. Probability distributions are hence assigned to the input variables presented in the following sections.

5.1.1. Inflation rate

The inflation rate influences the future payments of the plant, which includes both O&M costs and personnel expenses. The rate is allowed to fluctuate using a normal distribution with the mean μ at 1.8% and the standard deviation at $\sigma = 0.017$. These assumptions result in an input distribution that has the shape shown in Fig. 5.

The downward slope shown in Fig. 6 is mostly a function of the financial crisis in Cyprus and Europe. This trend may reverse in the future, but there are no grounds to consider that the above input distribution will not represent reality.

5.1.2. Electricity feed-in tariff

The electricity FiT is the main support mechanism used in the Republic of Cyprus for renewable energy projects. These, and similar mechanisms are set up to motivate investors to support renewable energy projects that would otherwise have to compete with the more established traditional generation. As technology matures and the market penetration increases, these mechanisms tend to subside in value, as per e.g. the spread of PV in Germany or Spain despite the continuously lower tariffs. The choice of distribution here reflects this trend—an equal probability is given to the FiT being between 0.22 €/kWh and 0.26 €/kWh, but it can also go down to 0.15 €/kWh, with a small chance of it increasing to 0.27 €/kWh.

5.1.3. Water selling rate

The water selling price is determined by the water boards in the various administrative divisions of the RoC. Projections for the trend of water prices are though difficult to make as Cyprus has a history of drought, shortages and a heavy reliance on DSW. This uncertainty dictates the use of a flat input distribution that incorporates most of the probable cost of water in the near future. The range is set between 0.85 and 1.6 €/m^3.

5.1.4. ETS carbon selling price

The inclusion of the CSP plant in the EU ETS (Emissions Trading Scheme) will also bring additional benefits. The trading price for a ton of carbon, however, has been varying wildly in the last few years, with issues of excess supply of allowances pushing

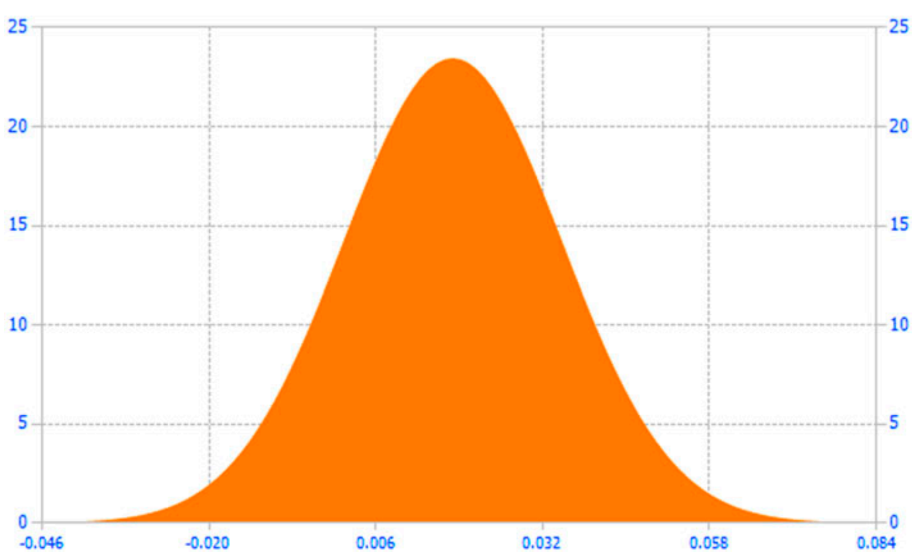

Fig. 5. Inflation input distribution.

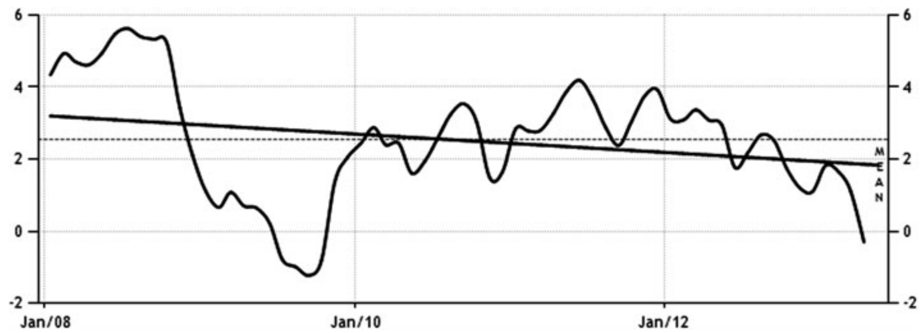

Fig. 6. Historical inflation data for Cyprus, 2008–2013.
Source: Cyprus Statistical Service.

the price downwards. At the current price point, however, the scheme is not very effective; hence, the price is most probably going to increase after successful policy interventions. The distribution in Fig. 7 shows this. It is a Pert distribution with a minimum value of 2.5, a mode of 4.5 and a max of 15.

5.1.5. CAPEX

The uncertainty in the capital expenditures reflects the accepted trend that technology maturity and market penetration drive prices down. The landed cost of heliostats is also a function of the order size, the type of mount and the tracking device and the mirror area per tracker [20]. As with nearly all renewable energy technologies, the cost of the equipment gradually declines through technological advances, economies of scale, EPC familiarisation, parts standardisation and supporting policies. Fig. 8 shows that the distribution used is a pert distribution (minimum value of 8.2 m, mode 11.36 m and a max of 12.2 m).

5.1.6. Project O&M

The project O&M changes are reflected by applying a normal probability distribution to the O&M expenses for the heliostat field. The central value is kept as described in Section 3.4.1, while the standard deviation is set at $\sigma = 15{,}000$. This creates the curve seen in Fig. 9.

5.2. Monte Carlo simulation results

In order to monitor the effects of the changing input variables, three basic metrics of the system's

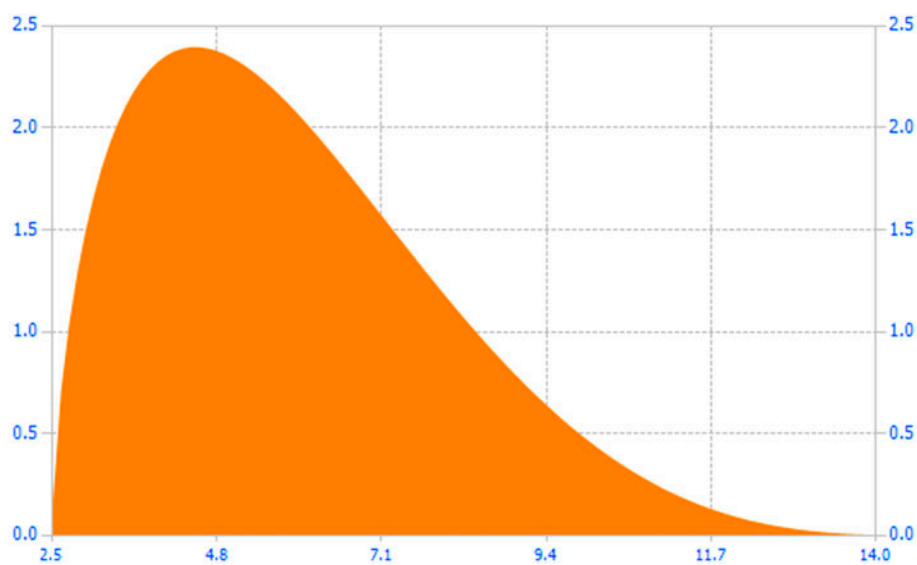

Fig. 7. GHG emissions credits selling input distribution.

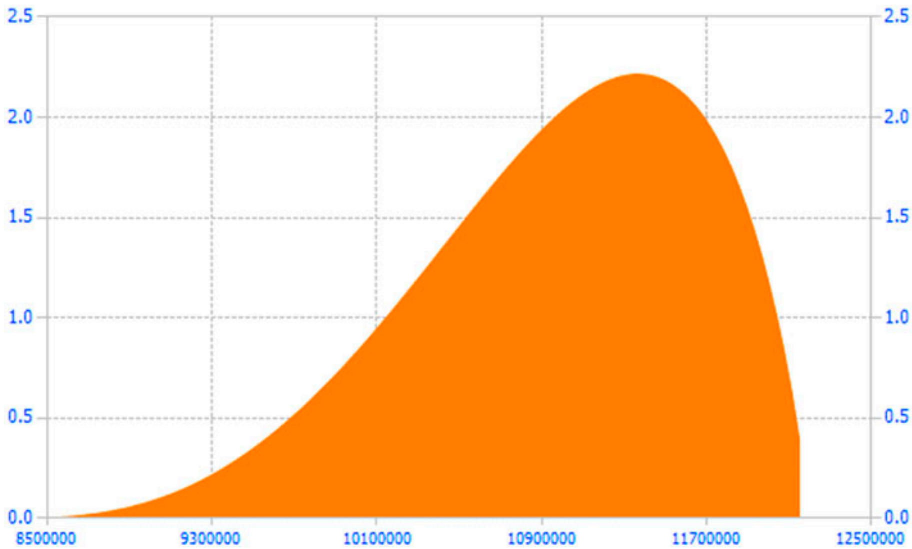

Fig. 8. Heliostat CAPEX input distribution.

financial performance were chosen: the project's NPV, the MIRR on the total investment and the LCOE of the whole plant, as calculated using the method in Section 4.3.1. The choice of MIRR instead of the more usual IRR is due to two reasons: first, it is a more realistic representation of the project's financial performance because it does not imply that the positive cash flows are reinvested at the same rate as that of the project that generated them (as is the case of IRR), but at a different user-defined rate [21]. This would usually be the Weighted Average Cost of Capital (WACC). Secondly, it treats alternating negative and positive cash flows clearly producing only one result, whereas IRR can lead to ambiguity and difficulty using, and MC sampling algorithm as it leads to errors in calculations.

For the purposes of the analysis, all three cases were assigned with a sample size of $n = 1$ m random samples drawn from the input distributions described above. Fig. 10 shows the output distribution for Case (C), where the line that corresponds to the NPV threshold of €0 is marked in red. This analysis shows that there is 42% chance of the NPV of the project being negative, and 58% being

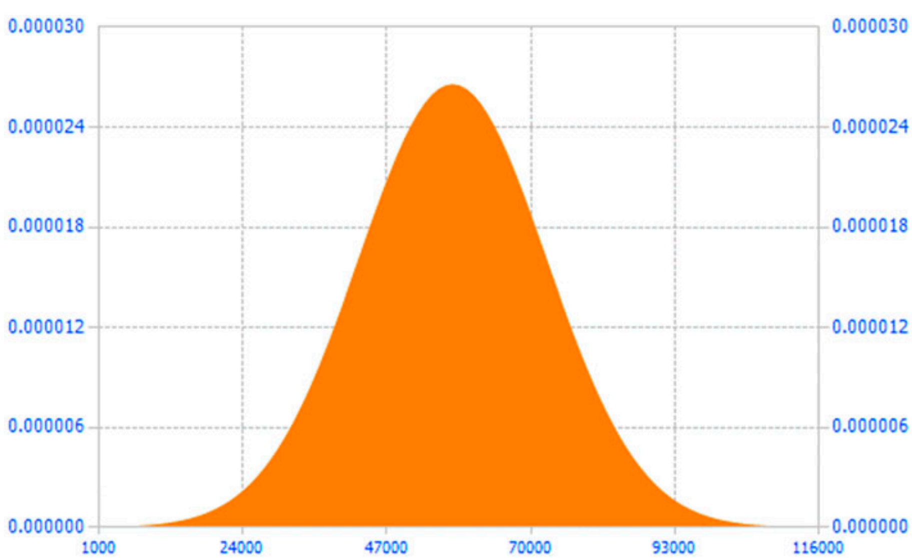

Fig. 9. Heliostat O&M input distribution.

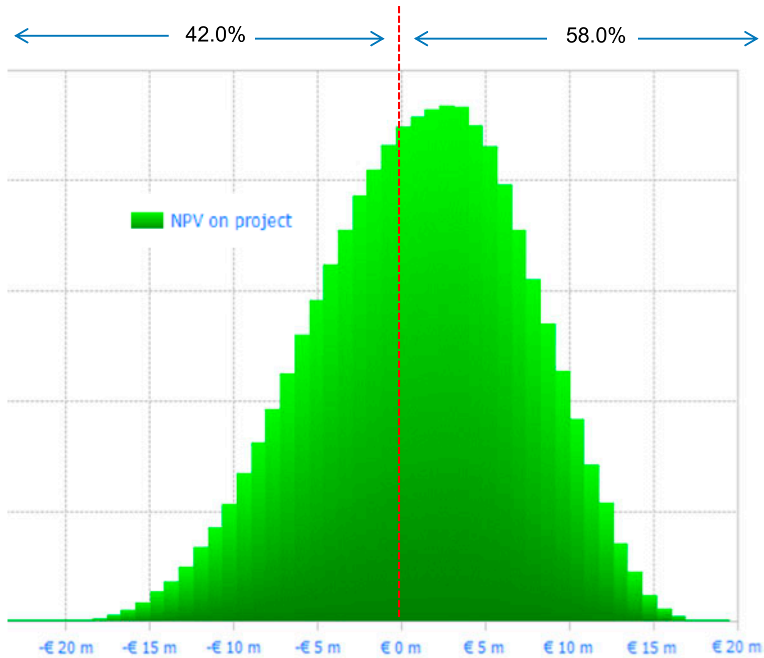

Fig. 10. NPV on project output distribution case (C)—desalination using MED.

Table 9
Water selling rates (€/m^3) for cogenerating cases

	Case (B)—desal. RO		Case (C)—desal. MED	
	No ETS	ETS	No ETS	ETS
NPV = 0	2.73	2.69	2.68	2.64

positive. The average NPV value however is lower for Case (A), as is the probability of negative NPV value (36%). This is to be expected because, as seen, the capital and O&M costs are higher for a system configuration that produces water and the revenues (even projected ones) cannot compensate. The NPV for case (B) is lower than all cases at 45.1% probability of negative NPV. This has to be attributed, again, to the higher O&M costs of the desalination solution of this case and the input distribution chosen for water that used an outlook of increased returns for every m^3 sold in the future, but not enough to warrant a better performance than the electricity-only system (see also Table 9). This highlights the fact that a cogenerating system could perform better than an electricity-only in an environment of increased DSW revenues.

The LCOE and MIRR results also seem to corroborate this finding. LCOE progressively falls and MIRR increases going from the electricity-only case (A) to case (C). The output distributions also show a smaller degree of data dispersion Table 10.

Compared to the results obtained in Section 4, the financial metrics show a less certain picture towards a positive investment decision. This is attributed to the input distribution for the electricity rates, as the performance of each system is heavily reliant on the price of each kWh produced. Whereas in the static analysis, the FiT was set at 0.26 €/kWh; here, it is allowed to

Table 10
LCOE and LCOW values for all cases

	Case (A)—elec. only		Case (B)—desal. RO		Case (C)—desal. MED	
	No ETS	ETS	No ETS	ETS	No ETS	ETS
LCOE (€/kWh, nominal)	€0.1886	€0.1868	€0.2609	€0.2547	€0.2587	€0.2499
LCOW (€/m^3, nominal)	–	–	€0.5261	€5,168	€0.4634	€0.4569

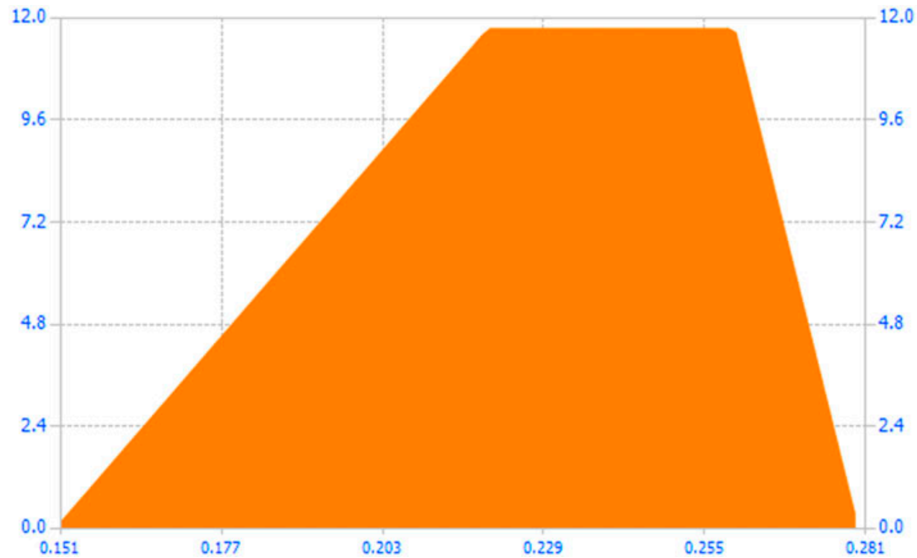

Fig. 11. Electricity rate (FiT) input distribution.

Table 11
Distribution metrics for all output variables

	Case (A)—elec. only		Case (B)—desal. RO		Case (C)—desal. MED	
	Mean	σ	Mean	σ	Mean	σ
NPV (€)	€2,147,099	6,281,003	€540,008	6,232,858	€1,060,847	6,156,702
LCOE (€/kWh)	€17.94	0.69	€18.59	1.36	€18.38	1.34
MIRR (project)	8.78%	0.93%	8.55%	0.83%	8.62%	0.81%
IRR (project)	11.35%	2.36%	10.75%	2.06%	10.92%	1.95%

vary from a much lower position of 0.15 €/kWh to 0.27 €/kWh (see Fig. 11), that negatively impacts the results. The relative importance of the electricity FiT will be explored in the next section.

The presentation of results in Table 11 using parameters of a normal distribution is illustrative of the distribution of the output variables, even though they do not always conform to the strict rules of normality. The MIRR output for example has a skewness coefficient of −0.864, indicating a clustering of the data to the right (see Fig. 12), but does not invalidate the results.

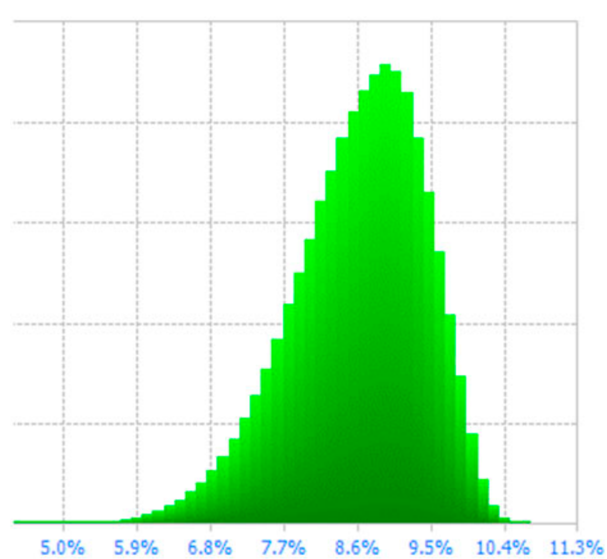

Fig. 12. MIRR output distribution, Case (C)—desalination using MED.

5.3. Sensitivity analysis results

All assumptions used in undertaking DCF analysis should be supported by reasoned judgment, particularly where factors are difficult to predict and estimate. It is of interest to see which random model inputs or intermediate results have the strongest impact on model outputs, so it is useful to perform a

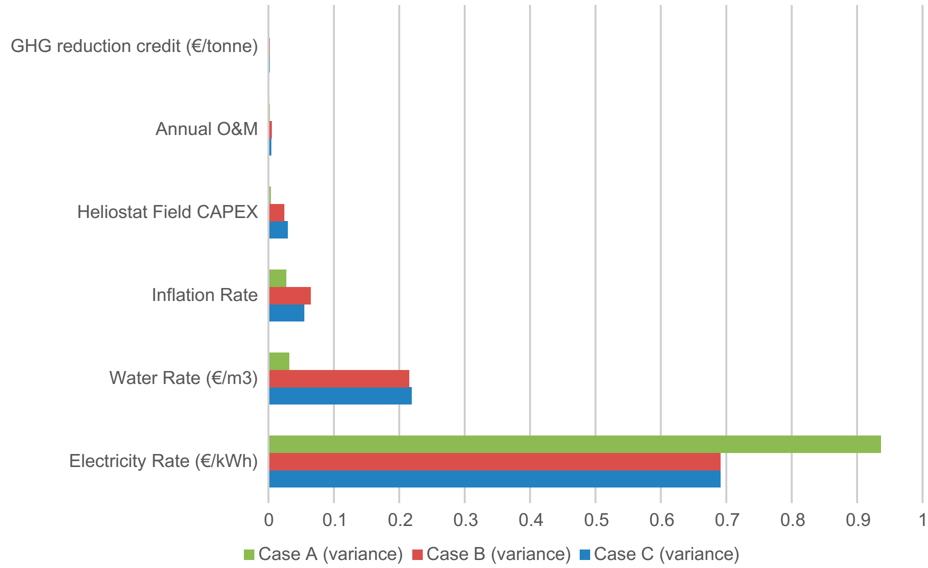

Fig. 13. NPV sensitivity on project by contribution to variance.

sensitivity analysis. All assumptions for the sensitivity analysis are identical to what is described in Section 3, with the exception of the use of MIRR instead of the more traditional IRR, as explained in Section 5.2. The following picture articulates the relative magnitude that each of the input variables for all cases using the contribution to variance method. This way, the sensitivities are defined as squared rank correlations that are standardised to sum to 100%. In the figure above, this means that 93.6% of the variance on Case A is caused by changes in the electricity rate, with the other factors accounting for the rest (Fig. 13).

The coefficients in Table 12 show the relative importance of each of the input variables on the MIRR and NPV of the project. Case (A) is an electricity-only plant and naturally the water rate has a very small effect on both the output metrics. The electricity rate on the other hand has a huge impact on the outputs, and is the single most important determinant of the financial metrics. In other words, the financial viability and performance of such a plant is heavily dependent on the electricity selling rate, and much less on other income streams, as the selling GHG emissions permits. Cases (B) and (C) introduce the desalination plant, and water selling rates is now important, ranking behind the electricity selling rate. As expected, a positive ranking correlation is observed with income streams, and a negative with determinants of increased costs. It is interesting to note the effect of the inflation rate on all cases, which is larger than the other input variables examined. This is due to the effect it has on how O&M costs are calculated, and shows the sensitivity of the project's success to the investment environment.

Table 12
Spearman's ρ rank correlation coefficients for all cases

	Case (A)—elec. only		Case (B)—desal. RO		Case (C)—desal. MED	
	MIRR	NPV	MIRR	NPV	MIRR	NPV
Electricity rate	0.961	0.964	0.815	0.816	0.818	0.819
Water rate	−0.177	−0.178	0.461	0.462	0.466	0.467
Inflation rate	−0.169	−0.157	−0.240	−0.241	−0.231	−0.231
Heliostat CAPEX	−0.064	−0.062	−0.172	−0.168	−0.177	−0.171
Annual O&M	0.039	0.039	−0.058	−0.057	−0.066	−0.065
GHG reduction	−0.004	−0.004	0.045	0.045	0.035	0.035

6. Conclusions

The financial performance of a 4-MW CSP–DSW plant has been examined in this paper, which uses three distinct income streams for the analysis: selling electrical energy to the grid, selling DSW to the government and selling emissions allowances for avoiding CO_2 emissions on a trading platform such as the EU ETS. It was found that when testing an electricity-only system, the project is financially attractive according to a set of assumptions employed. This performance, however, deteriorates with the introduction of the desalination sub-system, and the NPVs of the systems using DSW are lower, indicating a less attractive investment.

It is argued that the water selling price is not given the same treatment as electricity from systems that use renewable energy as their source even though for Cyprus, DSW carries significant importance. Had there been support for water (in the form of a FiT, as the case for electricity), the DSW systems would perform much better (see Table 9). In fact, there is scope to further look into the economics of cogeneration systems in place of pure desalination units in the context of an isolated power grid, as is the case of Cyprus. However, there is no distinct way in the literature yet for calculating the cost of production for such plants, and two different approaches are used here.

Given the uncertainties that surround the calculation of costs for cogenerating plans, a method of analysing the uncertainty of these inputs was also examined. Some of the most important determinants of upfront and operating costs were allowed to vary using random samples drawn from pre-determined input distributions that attempt to forecast the most likely scenarios of shifts in value in the future. Using a Monte Carlo simulation, the output distribution of important financial metrics was also captured. The results of this and a complementary sensitivity analysis show that the financial performance is largely dependent on the tariff for electricity, even for the cogenerating cases. It is therefore important to emphasise the fact that the policy environment is crucial in the success of such endeavours.

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