Integrating Geothermal and Bioenergy with Wind and Solar for Island Decarbonization: The Green Transition of Lesvos (Greece)

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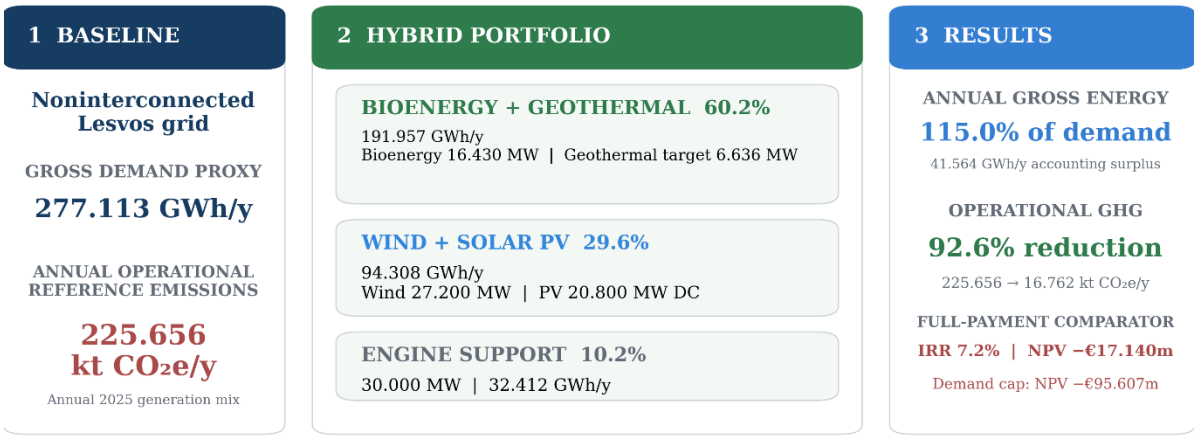
Graphical Abstract



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Abstract

Non-interconnected islands require portfolios combining variable renewables with controllable low carbon generation. This study develops a Lesvos screening framework integrating bioenergy, a conditional geothermal target, wind, photovoltaics and limited dual fuel engine backup. RETScreen Expert and an Excel balance were applied to reconstructed 2025 electricity demand of 277.113 GWh. The 101.066 MW configuration produces 318.677 GWh annually. Renewables provide 286.265 GWh, or 89.8 percent. Bioenergy and geothermal generation contribute 191.957 GWh, equal to 60.2 percent, demonstrating the role assigned to dispatchable renewables. The seasonal screening allocation produces a 41.564 GWh annual accounting margin, but adverse and low-renewable peak tests identify supply deficits. With a EUR 77.372 million public contribution and full remuneration at EUR 0.16 per kWh, the project gives a 7.2 percent pretax internal rate of return, a 14.0 year simple payback and a negative EUR 17.140 million net present value at 9 percent. At an equal annual gross reference quantity, operational reference emissions decrease from 225.656 to 16.762 kt CO_2e, a 92.6 percent reduction. The demand-capped payment gives NPV of EUR -95.607 million. The study provides a transparent island transition portfolio while identifying resource, dispatch, surplus, financial and emissions assumptions requiring validation before investment.

Keywords: hybrid renewable energy system, geothermal energy, bioenergy, RETScreen, syngas, gasification, technoeconomic assessment

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1. Introduction

Noninterconnected islands are highly exposed to costs of imported fuel, seasonal demand peaks, limited reserve margins, and the technical constraints of relatively small power systems. At the same time, many islands possess abundant renewable resources and can serve as demonstrators of accelerated energy transition. Studies of Greek and European islands show that renewable deployment can reduce fuel dependence, improve local energy security, and support development at community scale, but the transition requires portfolios that address both energy adequacy and power system flexibility (Katsaprakakis et al., 2022b; Groppi et al., 2021; Blechinger et al., 2016; Gioutsos et al., 2018). International perspectives also relate renewable deployment to emissions and economic development (Devianto et al., 2025) and to changing European energy-consumption patterns (Jenei et al., 2025). Hybrid renewable energy systems (HRES) combine technologies with complementary production profiles. Most island studies emphasize wind and photovoltaic (PV) generation coupled with batteries, pumped storage, demand side management, or thermal backup (Villena-Ruiz et al., 2023; Leon Gomez et al., 2023; Hassan et al., 2023; Khan et al., 2025; Groppi et al., 2021; Ma et al., 2014; Maizi et al., 2018; Mason et al., 2013). These architectures can achieve high renewable penetration, yet their performance is sensitive to weather variability, storage sizing, curtailment, and reserve requirements. A complementary strategy is to combine variable renewable energy with dispatchable renewable resources. Geothermal power and bioenergy can provide controllable or nearly continuous generation, potentially reducing reliance on fossil backup and moderating storage requirements (Mendrinos et al., 2010; Andritsos et al., 2011; Kavadias et al., 2019; Olabi et al., 2020; Lund and Toth, 2021; Perea-Moreno et al., 2019; Lee et al., 2019; Wang and Wu, 2023; Hackstein and Madlener, 2021; Nilsson et al., 2017). The Greek islands provide several relevant precedents. Integrated transition pathways have been examined for Crete, while geothermal and solar configurations have been assessed for Nisyros (Katsaprakakis et al., 2022a; Kavadias et al., 2019). Earlier work on Lesvos investigated multiobjective energy planning and mapped the island's wind

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resource (Koroneos et al., 2004; Palaiologou et al., 2011). Nevertheless, an assessment specific to the island that explicitly combines geothermal energy and locally derived bioenergy as modeled dispatchable renewable supply with wind and PV generation remains limited. This combination is particularly relevant to Lesvos because the island has extensive olive cultivation and associated residues, documented geothermal manifestations, and exploitable wind and solar resources (Palaiologou et al., 2011; Mendrinos et al., 2010; Andritsos et al., 2011; HEDNO, 2024; ELSTAT, 2023; Kourou, 2020; Clean Energy for EU Islands, 2026; Vogiatzis et al., 2004; Fytikas et al., 1989; Bencini et al., 2004; Konstantinidis et al., 2026). Lesvos is included in the European Union initiative for 30 renewable islands by 2030, creating a policy context for accelerated decarbonization (European Commission, 2026; European Commission, 2023; Clean Energy for EU Islands, 2026). Its electricity system remains noninterconnected and is still dominated by thermal generation, although wind and PV are already present. This setting creates a practical need for a transition portfolio that is sufficiently low carbon but also capable of meeting demand throughout the year. The objective of this study is to evaluate a predefined hybrid electricity portfolio at screening level for Lesvos using RETScreen Expert and Excel. The proposed configuration combines bioenergy, a conditional geothermal power target, wind energy, solar PV, and limited reciprocating engine backup. The study quantifies: (i) annual and seasonal screening energy balances, (ii) the contribution of dispatchable and variable renewables, (iii) capital and operating requirements, (iv) financial performance under the public capital contribution and full output remuneration assumptions selected by the authors, and (v) operational GHG emissions relative to a HEDNO baseline. The contribution lies in the Lesvos portfolio and in the transparent identification of assumptions governing the screening result.

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2. Materials and Methods

2.1. Energy metrics on Lesvos

Lesvos is a noninterconnected island in the North Aegean. The existing installed portfolio reported for the study period comprised 102.6 MW of conventional generation, 13.95 MW of wind power, 8.84 MW of independent producer PV, and 1.15 MW of self producer PV, for a total installed capacity of 126.54 MW (HEDNO, 2026; HEDNO, 2024). The autonomous thermal station therefore remained the dominant source of dependable generation. Monthly 2025 generation bulletins published by the Hellenic Electricity Distribution Network Operator (HEDNO) were used to reconstruct electricity demand (HEDNO, 2026). Local electricity generation was used as a gross screening proxy for demand; delivered consumption and distribution losses were not separately resolved. The retained screening reference is 277.113 GWh/y; its reconciliation with the supplied provisional settlement data is reported in Appendix A4. The highest monthly demand occurred in July (31.811 GWh), followed by August (29.988 GWh), while the minimum occurred in October (18.040 GWh). This reconstruction is suitable for a screening energy balance, although it does not reproduce hourly load shape, losses, or operational reserve requirements. Figure 1 retains the 2024 historical generation comparison, separately from the 2025 screening demand series, and shows a thermal majority in every month. In the plotted series, fossil fuels account for between 72.3% and 83.9% of monthly production. Wind ranges from 9.8% to 18.9% and PV from 2.8% to 9.4%. On an annual basis, the plotted shares are 80.2%, 13.8%, and 6.0%, respectively. The persistence of a thermal majority even in months with stronger renewable output illustrates the structural fuel dependence typical of small noninterconnected systems and supports the need for a diversified portfolio that combines variable and dispatchable renewable sources (Blechinger et al., 2016; Gioutsos et al., 2018; Katsaprakakis et al., 2022b). The seasonal variation of wind and PV also shows why annual renewable totals alone cannot establish adequacy or quantify the need for reserves, flexibility, or storage (Groppi et al., 2021; Gandhi et al., 2020; Kumar et al., 2020).

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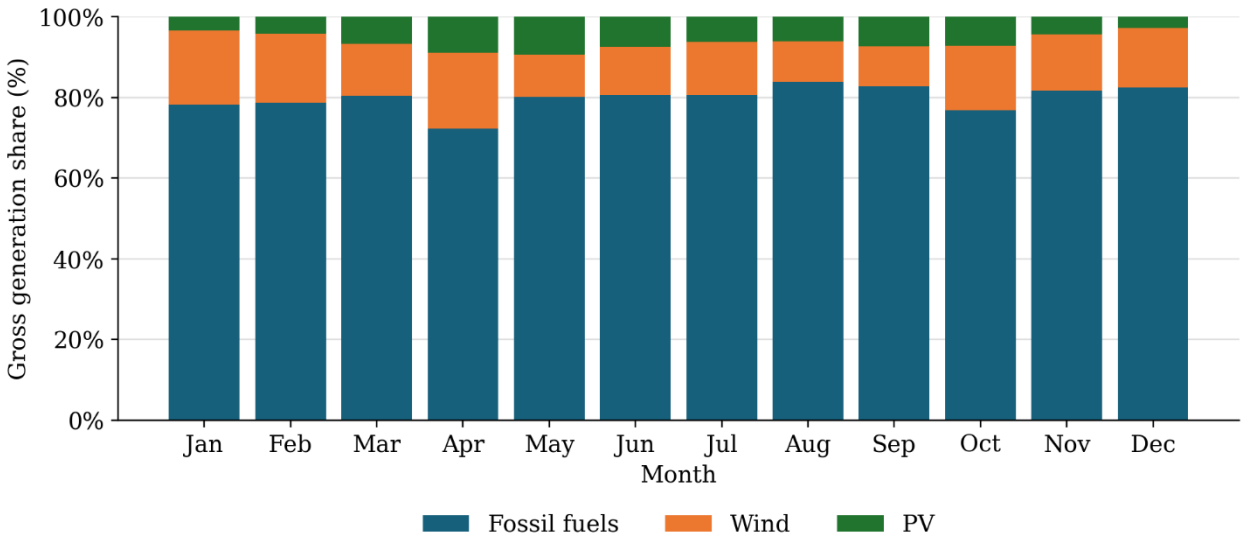

Figure 1. Historical 2024 monthly gross electricity **generation mix for Lesvos. Each column sums to 100%; the original thermal, wind and PV series are retained.**

The resource assessment combined public data, literature values, and RETScreen climate inputs. The model used a mean wind speed of 5 m/s at 10 m height and selected an ENERCON E-48 turbine, consistent with prior analyses of the North Aegean and Lesvos wind resource (Palaiologou et al., 2011; Vogiatzis et al., 2004). For PV, the RETScreen climate data indicated annual average horizontal solar irradiation of approximately 4.63 kWh/ (m^2 * day). A fixed tilt of 40 degrees increased modeled irradiation on the collector plane to approximately 5.00 kWh/ (m^2 * day). Bifacial monocrystalline modules were selected to represent a high efficiency commercial configuration (Gu et al., 2020). Geothermal manifestations on Lesvos generally indicate low to medium enthalpy resources, with reported fluid temperatures from approximately 40 to 90 °C depending on location (Mendrinos et al., 2010; Andritsos et al., 2011; Clean Energy for EU Islands, 2026; Fytikas et al., 1989; Bencini et al., 2004; Konstantinidis et al., 2026). The revised RETScreen case therefore defines a separate deep resource target rather than attributing the modeled output to the documented shallow manifestations. The target assumes 100,000 kg/h of steam at 120 °C and 70 kPa absolute, 10 kPa absolute back pressure, 80% steam turbine efficiency, and 95% availability. For the biomass component, olive

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pruning residues, olive kernels, other crop residues, and animal wastes were considered. The source assessment estimated 151.75 GWh/y of potentially usable electricity from plant biomass and 33.40 GWh/ y from animal biomass, for a combined technical estimate of 185.15 GWh/y (HEDNO, 2024; ELSTAT, 2023; Kourou, 2020).

2.2. RETSCREEN model and hybrid energy system design

RETScreen Expert, developed by Natural Resources Canada, was used for energy, cost, financial, and GHG screening (Natural Resources Canada, 2026). Mytilene, a city on Lesvos, was selected as the geographic reference for the RETScreen model. The portfolio concerns the island electricity system; this reference does not specify final sites for all units. Figure 2 summarizes the functional architecture. Bioenergy and geothermal generation were assigned the role of modeled dispatchable renewable supply. Wind and PV provided variable renewable generation. Two reciprocating engine groups were assigned support energy in the screening schedule. Dedicated electricity storage was not included in the final configuration.

The bioenergy unit was represented by five Vericor ASE 40 gas turbines with an aggregate capacity of 16.43 MW and 95% availability. The fuel mix was specified as 35% biogas and 65% synthesis gas equivalent derived from biomass. Because RETScreen did not offer a direct syngas option in the selected module, the latter was entered using the software's sewage gas proxy (Nilsson et al., 2017; Gomez-Barea et al., 2005; Narvaez et al., 1996; Vera et al., 2014; Aguado et al., 2025). These are fuel-energy shares. The resulting modeled annual generation is 136.730 GWh. A Lesvos inventory supplied by the authors reports gross resource quantities of 30,279 t/y of olive pruning within 37,450 t/ y of agricultural waste, 18,901 m^3/ y of olive pomace, 9,000 t/ y of municipal green cut, and 26,387 m^3/y of dairy whey. These are as-received solid quantities and reported liquid or semisolid volumes, not verified recoverable dry-fuel quantities. Olive pruning is included within the agricultural-waste total. The geothermal unit was modeled at 6.636 MW and 95% availability, corresponding to 8,322 operating hours and 55.227 GWh/ y at a RETScreen actual steam rate of 15.1 kg/ kWh. These values are conditional on the deep resource steam target described above.

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For gasification only, a gross electricity yield of 1 kWh per kg of as-received biomass was assumed, before plant auxiliary consumption. The coefficient is benchmarked against 0.93 kg/kWh reported for wood chips below 10% moisture (Vakalis et al., 2014); it is not a validated yield for untreated local wet residues. The 65% gasification contribution corresponds to 88.875 GWh/y and requires approximately 88,875 t/y at this assumed yield. The listed agricultural residues and green cut total 46,450 t/y, while pomace remains reported as 18,901 m³/y without a density. The available local inventory therefore does not establish the required recoverable fuel supply. The biogas route is accounted for separately (Appendix A1).

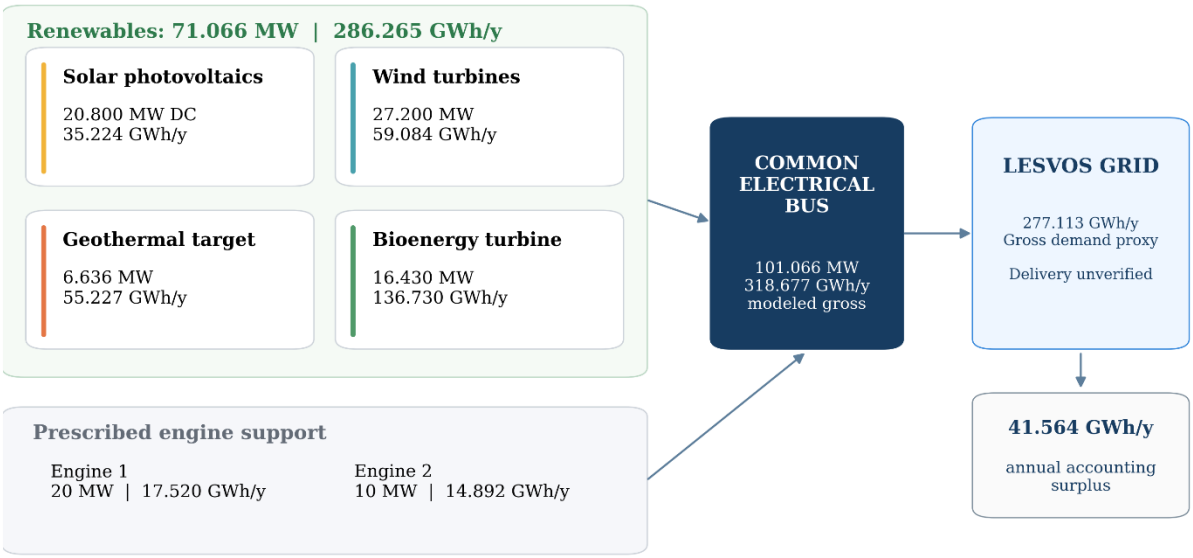

Figure 2. Functional architecture **of the predefined portfolio. Wind and PV complement modeled bioenergy, a conditional geothermal target and prescribed engine support. Capacities and gross annual outputs are distinguished from reconstructed demand and the accounting surplus; accepted delivery, storage and export are not demonstrated.**

The wind plant consisted of 34 ENERCON E-48 turbines rated at 0.8 MW each (27.20 MW total), with 97% availability and a modeled capacity factor of 24.8%. The PV plant comprised 40,000 bifacial monocrystalline modules rated at 520 W, for 20.80 MW DC. Module efficiency was 20.25%, inverter efficiency was 97%, and the modeled PV capacity factor was 19.3%. Two MAN L32/40 reciprocating engine groups were included. Engine 1 had 20 MW installed capacity and 10% annual

capacity factor. Engine 2 had 10 MW installed capacity and 17% annual capacity factor and was assigned generation only in February, July, and August. This assignment was imposed for monthly screening rather than derived from chronological unit commitment. Both engines used an assumed fuel mix of 80% diesel and 20% bio-oil. Table 1 summarizes the installed capacities entered in RETScreen, modeled annual electricity outputs and assigned operational roles. Capacity factors equal annual output divided by installed capacity and 8,760 h/y. Installed capacity and energy contribution are not proportional: wind has the largest installed capacity (27.200 MW), whereas the bioenergy block has the largest modeled output (136.730 GWh/y) because of its assumed 95% availability. Bioenergy and the conditional geothermal target together supply 191.957 GWh/y, or 60.2% of total generation. Wind and PV supply 94.308 GWh/y (29.6%), and the two reciprocating engine groups supply 32.412 GWh/y (10.2%). The distinctive feature of the configuration is therefore that dispatchable renewables, rather than fossil backup, form the majority energy backbone. This complements the wind, PV, and storage architectures commonly examined for island systems (Blechinger et al., 2016; Gioutsos et al., 2018; Groppi et al., 2021; Villena-Ruiz et al., 2023).

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Table 1. Technical **inputs, capacity factors** and modeled annual **gross** electricity **generation for the RETScreen screening configuration. PV capacity is DC module nameplate; the total is a portfolio accounting sum.**

Technology	Capacity (MW)	Capacity factor (%)	Generation (GWh/y)	Operational role
Bioenergy gas turbine	16.430	95.0	136.730	Dispatchable renewable base load
Geothermal power	6.636	95.0	55.227	Conditional deep resource target
Wind farm	27.200	24.8	59.084	Variable renewable generation
Solar PV	20.800	19.3	35.224	Variable renewable generation
Reciprocating engine 1	20.000	10.0	17.520	Peak and reserve support
Reciprocating engine 2	10.000	17.0	14.892	Imposed seasonal peak support
Total	**101.066**		**318.677**	**Hybrid island supply portfolio**

Annual energy coverage compares modeled gross generation with the retained gross demand proxy. The 95% bioenergy and geothermal inputs assume full-load operation whenever available; they are

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196 operating targets rather than measured availability. For the seasonal check, annual wind output was
197 distributed using normalized monthly wind generation from the supplied 2024 hourly series, and PV
198 output using the supplied normalized Mytilene solar profile. These historical/profile shapes are
199 proxies, not measured 2025 production forecasts. Bioenergy, geothermal and Engine 1 were allocated
200 by month length, and the original Engine 2 allocation was retained. A high-demand/low-variable-
201 output test applies +10% demand and -20% wind/PV output; a reduced-availability test uses 85% for
202 bioenergy and geothermal. Half-output and no-geothermal cases and an instantaneous low-renewable
203 peak test are also included (Appendix A2). These deterministic checks do not simulate chronological
204 dispatch or reliability. Auxiliary electricity has not been quantified, so gross generation is not
205 established net delivery. Renewable and dispatchable-renewable shares retain the original
206 technology-group definitions.

207 **2.3. Economic assessment**

208 The assumed electricity remuneration was EUR 0.16/ kWh. The project evaluation period was 25
209 years, with 2% annual inflation, a 9% discount rate, and 2% annual fuel cost escalation. The revised
210 finance case assumed no debt and retained the fixed public capital contribution of EUR 77.372 million
211 entered by the authors. This equals 41.2% of the revised gross investment, rather than 40.0%.
212 Financial indicators included NPV, pretax IRR, MIRR, simple payback, equity payback, benefit to
213 cost ratio, annual life cycle savings, and energy production cost. The original RETScreen case credits
214 all modeled electricity as grid sales (Case A). Case B caps payment at the gross demand reference
215 and retains all generation and costs; it is a conservative payment bound. Case C reduces annual
216 bioenergy output by the accounting surplus and reduces its fuel budget proportionally, retaining
217 installed capacity, fixed operating costs and public support. These are annual screening cases, not
218 chronological curtailment simulations (Appendix A3). Table 2 shows that the EUR 187.719 million
219 gross investment is concentrated in the wind farm (EUR 62.560 million, equivalent to 33.3% of the
220 total), followed by the two engine groups together (EUR 42.000 million, equivalent to 22.4%), the
221 bioenergy block (EUR 29.574 million), PV (EUR 27.040 million), and geothermal power (EUR

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26.545 million). At the assumed EUR 0.16/ kWh remuneration, base-price annual gross revenue is EUR 50.988 million, while fuel and operating costs amount to EUR 36.529 million and EUR 6.560 million, respectively. Their difference is approximately EUR 7.900 million, before capital recovery and the discounted project evaluation. These values should be read as RETScreen screening outputs, not as vendor quotations or a bankable cost estimate (Natural Resources Canada, 2026).

The pattern by technology explains the weak discounted financial result. Using the rounded table values, geothermal, wind, and PV generate positive operating margins before capital recovery of approximately EUR 8.006 million, EUR 7.387 million, and 5.324 mil EUR/y, respectively, while the bioenergy block contributes only about 2.025 mil EUR/y after its fuel and operating costs. In contrast, the two engine groups have a combined negative operating margin of approximately 14.842 mil EUR/y because their modeled fuel and operating costs greatly exceed their electricity revenue. The engines provide peak support energy in the imposed schedule, but their fuel burden materially reduces project economics, illustrating the importance of fuel price, dispatch frequency, tariff design, and capital support in hybrid system screening (Hackstein and Madlener, 2021; Vera et al., 2014; Aguado et al., 2025).

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Table 2. Capital, operating, and fuel costs and modeled gross electricity revenue by technology.

Technology	Initial cost (mil. EUR)	Operating costs (mil. EUR/ y)	Fuel (mil. EUR/ y)	Gross revenue (mil. EUR/ y)
Bioenergy gas turbine	29.574	1.282	18.57	21.877
Geothermal power	26.545	0.83	0	8.836
Wind farm	62.560	2.067	0	9.454
Solar PV	27.040	0.312	0	5.636
Reciprocating engine 1	28.000	1.38	9.707	2.803
Reciprocating engine 2	14.000	0.69	8.251	2.383
Total	**187.719**	**6.56**	**36.529**	**50.988**

2.4. Assessment of GHG emissions

The operational reference factor was recalculated from the supplied HEDNO provisional January–December 2025 settlement data for Lesvos (HEDNO, 2026). Renewable and thermal generation sum to 49.077 and 227.242 GWh, respectively, giving an energy-weighted annual renewable share of 17.761%. Thermal production retains the original diesel proxy, its RETScreen emission factors and 25.275% efficiency; zero direct emissions are assigned to wind/PV. The resulting annual reference factor is 0.814310 t CO_2e/MWh. Reference emissions are calculated at the same retained annual gross demand proxy of 277.113 GWh. The complete proposed-case emissions of 16.762 kt CO_2e/y are

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retained, including emissions associated with any unused generation, and no credit is assigned to the annual surplus. Both sides are compared at the gross generation boundary; no additional 7% distribution-loss uplift is applied. This is an annual operational accounting bound, not verified delivery or a life-cycle result. Alternative baseline mixes and the settlement-total reference are reported in Appendix A4.

3. Results

Under the specified model assumptions, the hybrid configuration has 101.066 MW of installed capacity and produces 318.677 GWh/y. This exceeds reconstructed 2025 demand by 41.564 GWh, corresponding to an annual coverage ratio of 115.0%. Renewable technologies supply 286.265 GWh/y, or 89.8% of total modeled generation. Bioenergy and geothermal power together contribute 191.957 GWh/y, equivalent to 60.2% of annual generation. Figure 3 emphasizes the proposed generation distribution rather than installed capacity. Bioenergy is the largest contributor at 136.730 GWh (42.9%), followed by wind at 59.084 GWh (18.5%), geothermal power at 55.227 GWh (17.3%), and PV at 35.224 GWh (11.1%). The two backup engines generate 32.412 GWh in total (10.2%). Consequently, 89.8% of modeled generation is renewable and 60.2% is assigned to dispatchable bioenergy and geothermal sources, whereas variable wind and PV contribute 29.6%. This composition is the central novelty of the case: dispatchable renewable sources are modeled as the portfolio anchor rather than as minor supplements to a wind and PV system. Such complementarity may reduce exposure to extended periods of low wind or solar generation, but its adequacy benefit cannot be quantified without chronological dispatch and reserve modeling (Ma et al., 2014; Maizi et al., 2018; Mason et al., 2013; Groppi et al., 2021).

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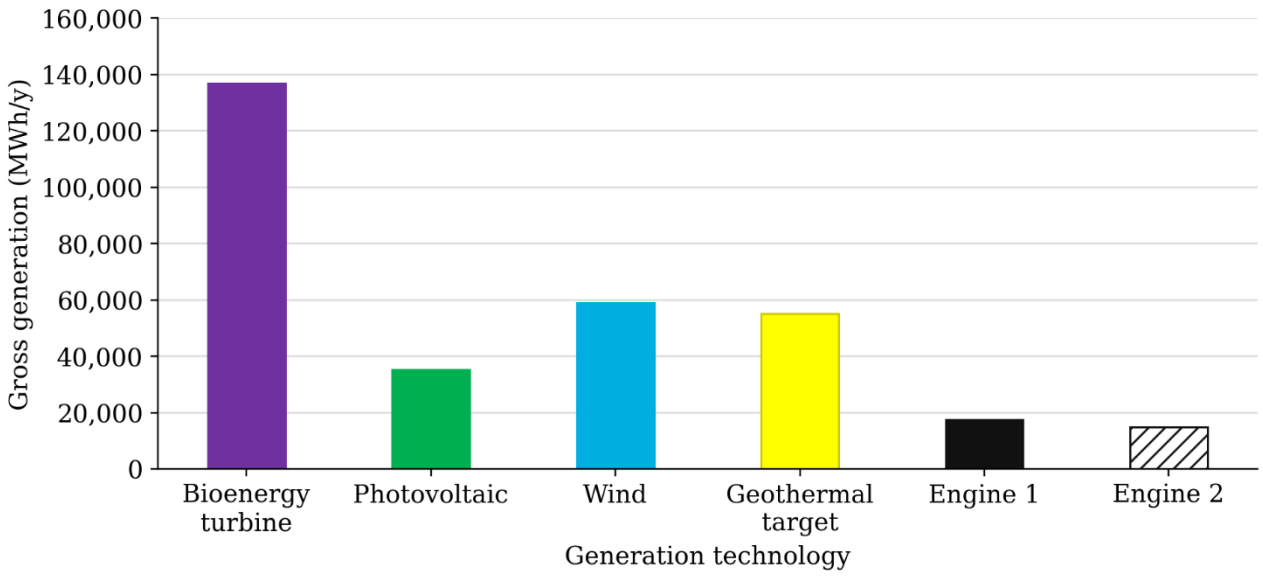

Figure 3. Modeled annual gross electricity **generation by technology in the predefined Lesvos portfolio (MWh/y).**

Figure 4 presents the proposed case as represented in the RETScreen emissions module. The displayed accounting mix comprises 39.4% syngas, 21.2% biogas, 10.5% wind, 10.2% diesel, 9.8% geothermal, 6.3% solar, and 2.6% bio-oil. These percentages are the software's proposed case emissions accounting mix. They are not the technology generation shares shown in Figure 3 and should not be interpreted as a second annual electricity balance (Natural Resources Canada, 2026). Modeled proposed case operational emissions total 16.762 kt CO_2e/y. Diesel is the dominant source at 14.421 kt CO_2e/ y, or approximately 86.0% of the proposed case total, while syngas, biogas, and bio-oil contribute 1.460, 0.786, and 0.095 kt CO_2e/ y, respectively. Geothermal, wind, and PV are assigned as zero direct operational emissions. RETScreen's treatment of the bioenergy carriers reflects the selected operational accounting convention, including zero biogenic CO_2 and nonzero CH_4 and N_2O factors. It does not establish life cycle carbon neutrality. Feedstock collection and processing, transport, plant construction, geothermal drilling, equipment manufacture, and end of life stages remain outside this figure and require a separate life cycle assessment (Turconi et al., 2013).

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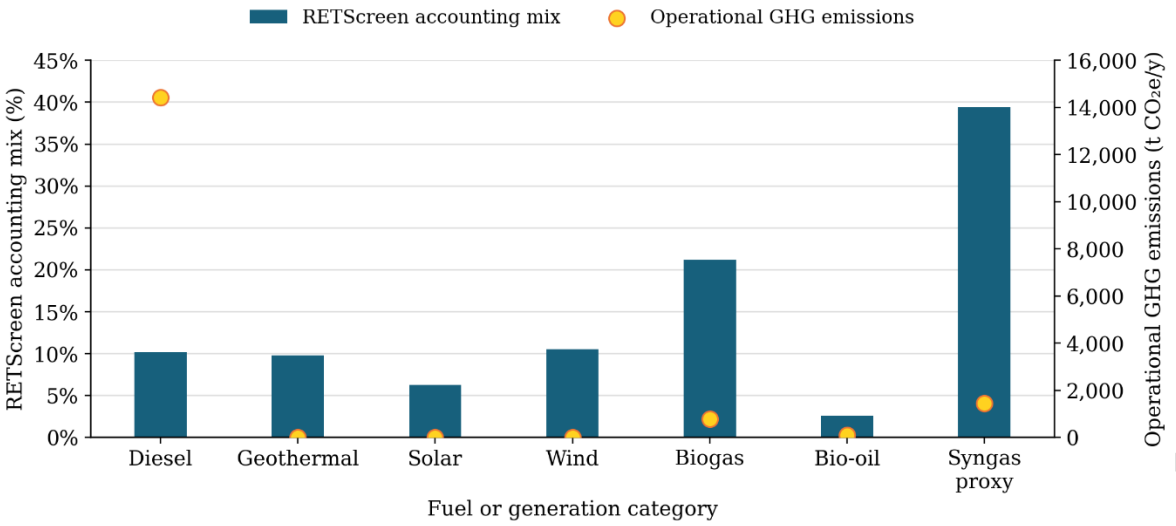

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287 **Figure 4. RETScreen proposed-case accounting** mix **(left axis)** and **annual operational** GHG
288 emissions **(right axis) by fuel or generation category. The mix percentages are not the** technology
289 **generation shares in Figure 3.**

290

291 Figure 5 compares the retained 2025 screening demand series with seasonal gross generation using
292 the proxy shapes described in Section 2.2. The base balance is positive in every month; the smallest
293 margin is 0.801 GWh in Aug, and the largest is 7.193 GWh in Oct. The high-demand/low-wind-and-
294 PV case has a 5.009 GWh annual deficit and eight deficit months. With bioenergy and geothermal
295 operating factors reduced to 85%, the annual balance remains positive by 21.358 GWh, but August
296 and December have deficits. Half geothermal output gives a positive annual margin but four deficit
297 months; no geothermal output gives a 13.662 GWh annual deficit (Appendix A2). These results
298 demonstrate dependence on resource and operating assumptions, not chronological reliability. In a
299 separate instantaneous stress test, the recorded 2024 maximum grid load of 59.73 MW is combined
300 with zero wind/PV. Even with all modeled dispatchable units at nameplate, their 53.066 MW leaves
301 a 6.664 MW shortfall before auxiliaries and reserves. This is an imposed stress condition, not an
302 assertion that those events were observed together. Ramping, minimum generation, operating
303 reserves, network constraints and stability remain outside the assessment (Blechinger et al., 2016;
304 Gioutsos et al., 2018; Groppi et al., 2021).

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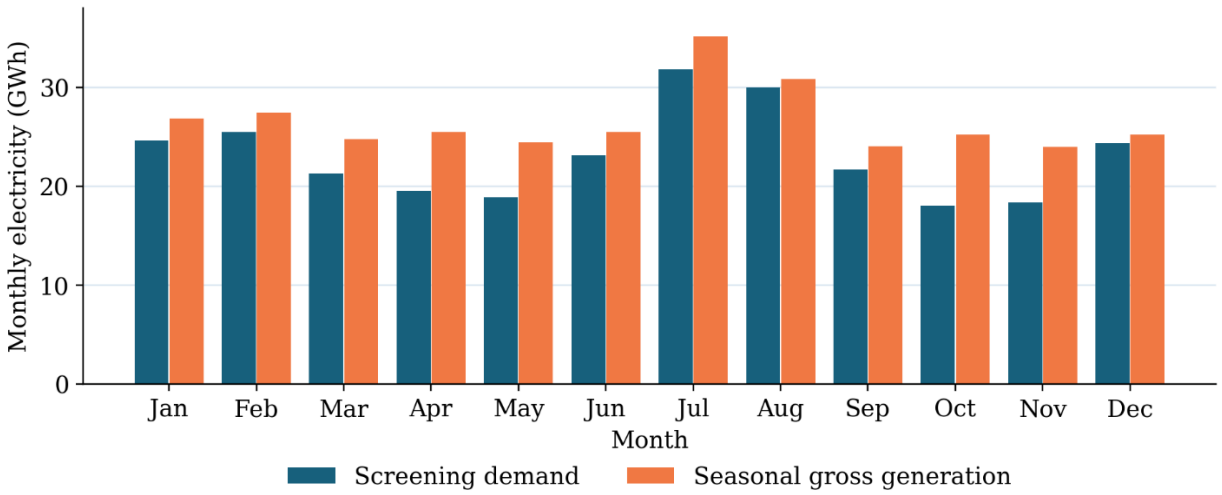

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306 **Figure 5. Retained** 2025 monthly **screening** demand and **seasonal allocation of modeled gross**
307 **generation. Wind and PV use normalized historical/profile weights; Engine 2 retains its**
308 **prescribed February, July and August schedule. Stress results are reported in Appendix A2.**

309

310 Figure 6 shows positive annual pretax cash flows throughout the operating period and a cumulative
311 undiscounted balance that changes from EUR -2.279 million at the end of year 12 to EUR 7.940
312 million at the end of year 13. This crossing is consistent with the reported equity payback of 12.2
313 years, while the separate simple payback indicator is 14.0 years. The cumulative undiscounted
314 balance reaches EUR 147.737 million by year 25, but this does not imply a positive discounted return.
315 At the selected 9% discount rate, NPV remains EUR -17.140 million, IRR is 7.2%, and the benefit to
316 cost ratio is 0.84. The figure therefore illustrates the difference between recovering nominal invested
317 equity and meeting the required discounted return. Its trajectory is also conditional on the fixed capital
318 contribution, 2% escalation assumptions, the EUR 0.16/ kWh tariff, and remuneration of all modeled
319 output (Natural Resources Canada, 2026; Beckers and McCabe, 2019; Hackstein and Madlener,
320 2021).

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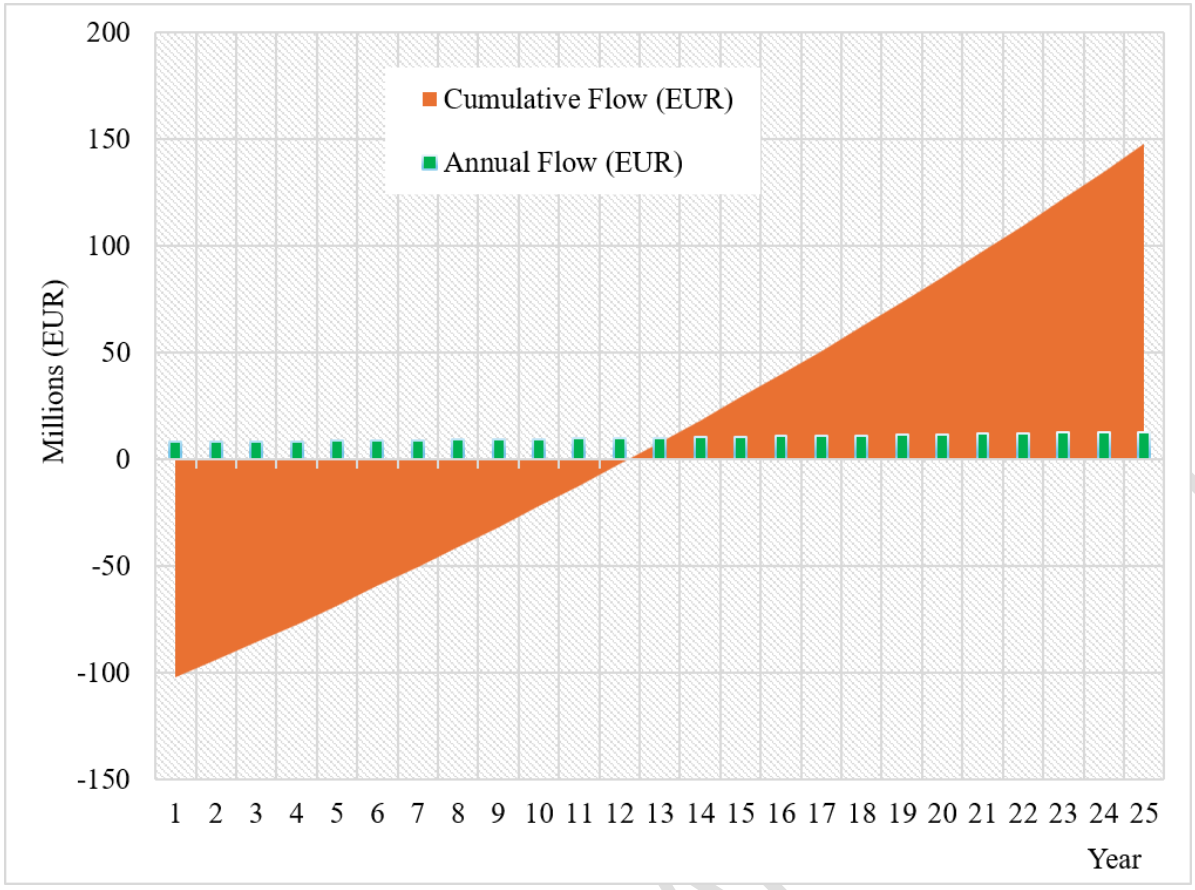

Figure 6. Undiscounted annual and cumulative pretax cash flows **for the original full-output-payment comparator (Case A).**

4. Discussion

The central modeled result is the high contribution of dispatchable renewable generation. Bioenergy and the conditional geothermal target provide 60.2% of annual output, while wind and PV add 29.6%. This differs from conventional wind, PV, and storage formulations in which most energy is dependent on weather (Villena-Ruiz et al., 2023; Leon Gomez et al., 2023; Hassan et al., 2023; Khan et al., 2025; Groppi et al., 2021; Ma et al., 2014; Blechinger et al., 2016; Gioutsos et al., 2018; Maizi et al., 2018; Mason et al., 2013). The portfolio structure may reduce exposure to prolonged periods of low wind or solar generation, but chronological operation is not demonstrated by the present monthly accounting.

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The modeled bioenergy output of 136.730 GWh/y is approximately 74% of the sum of the reported plant and animal biomass electricity-potential estimates (185.15 GWh/y). This comparison of aggregate estimates is not a validation of recoverable fuel supply. The inventory supplied by the authors confirms that several residue streams exist on Lesvos, especially olive pruning, but gross annual quantities do not establish a bankable fuel supply. The retained RETScreen proxy does not resolve dry recoverable tonnes, moisture and LHV, competing uses, collection and transport, storage losses, gas cleaning requirements, cold gas efficiency, or parasitic loads. The requirement-side gasification balance in Appendix A1 identifies the unresolved mass conversion for pomace and the lack of a recoverable-supply balance. The modeled output and EUR 18.570 million annual fuel cost remain conditional screening inputs pending a supply-chain audit (Perea-Moreno et al., 2019; Lee et al., 2019; Wang and Wu, 2023; Spinelli and Picchi, 2010; Nilsson et al., 2017; Gomez-Barea et al., 2005; Vera et al., 2014; Aguado et al., 2025).

The revised geothermal block remains conditional. The RETScreen run assumes 120 °C steam at 100,000 kg/ h and produces 6.636 MW, whereas published evidence for Lesvos primarily documents surface manifestations and shallow wells at lower temperatures (Fytikas et al., 1989; Bencini et al., 2004; Mendrinos et al., 2010; Andritsos et al., 2011; Konstantinidis et al., 2026). The model therefore represents a deep resource target, not a confirmed well. Exploration drilling, pressure and sustainable flow tests, enthalpy and noncondensable gas measurements, reinjection design, scaling and corrosion assessment, and permitting are required before the 55.227 GWh/y contribution can be treated as available. If only the documented lower temperature liquid resource is confirmed, a binary ORC or direct use pathway would require a separate calculation (Franco and Villani, 2009; Quoilin et al., 2013; Astolfi et al., 2014a, 2014b; Beckers and McCabe, 2019). The reduced and no-geothermal cases in Appendix A2 quantify this dependence while retaining the other installed technologies. Site-specific shallow-ground thermal measurements, such as those reported by Irshidat et al. (2025), inform shallow heat-exchange applications and do not confirm the deep steam target.

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The annual accounting balance is positive: gross generation exceeds annual demand by 41.564 GWh. Renewable generation alone (286.265 GWh) exceeds reconstructed demand by 9.152 GWh, yet the imposed schedule retains 32.412 GWh from reciprocating engines. The 32.412 GWh engine allocation was prescribed rather than calculated from hourly residual demand; it is not a demonstrated minimum backup requirement. In the absence of export, storage or flexible demand, production that cannot be absorbed must be reduced or curtailed. The annual surplus alone does not quantify that chronological curtailment. Storage, demand response, sector coupling, flexible renewable dispatch, or future interconnection could alter both backup use and the disposition of excess production (Groppi et al., 2021; Gandhi et al., 2020; Kumar et al., 2020; Blechinger et al., 2016; Gioutsos et al., 2018; Maizi et al., 2018; Mason et al., 2013). None of these alternatives was optimized in the present screening run.

The positive monthly margins do not demonstrate hourly reliability. The seasonal energy check uses historical/profile shapes, Engine 2 remains prescribed, and the 2025 demand series has no intraday shape. The separate 2024 peak stress identifies a capacity shortfall under its stated zero-wind/PV assumption. Consequently, the analysis cannot quantify loss of load probability, operating reserve, ramp rates, minimum stable generation, frequency response, network congestion, or real time grid acceptance. A subsequent study should use measured hourly or subhourly load and meteorological series with explicit dispatch rules, followed by power flow and dynamic stability checks.

The revised financial result is unfavorable at the selected 9% discount rate even after the fixed EUR 77.372 million public contribution: NPV is EUR -17.140 million, IRR is 7.2%, and the benefit to cost ratio is 0.84. The same input is equivalent to 41.2% of revised gross investment, so describing it as a 40% grant would be inaccurate unless the model is rerun. The result reflects high capital requirements and continuing bioenergy and engine fuel costs. It also confirms that tariff, support design, capital cost, and fuel cost are defining parameters of the screening business case (Beckers and McCabe, 2019; Hackstein and Madlener, 2021; Vera et al., 2014; Aguado et al., 2025).

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Electricity acceptance materially changes the financial result. Full remuneration of all 318.677 GWh at EUR 0.16/kWh remains an optimistic comparator, with no demonstrated entitlement to payment for unused electricity. Capping payment at 277.113 GWh reduces base-price annual gross revenue from EUR 50.988 to EUR 44.338 million. With costs retained (Case B), NPV is EUR -95.607 million and IRR is -6.18%. Reducing annual bioenergy production by 41.564 GWh and its fuel budget proportionally (Case C) improves NPV to EUR -28.999 million and IRR to 5.85%, still below the selected return criterion. Case C is an annual generation-reduction scenario; it does not establish the timing or technical feasibility of dispatch reductions. All three cases remain optimistic regarding unquantified auxiliary consumption and depend on the unverified resource targets (Appendix A3).

The reported production cost of EUR 0.198/kWh exceeds the assumed EUR 0.16/kWh remuneration. One-way sensitivity tests now examine tariff, capital cost, bioenergy fuel cost, discount rate, support, operating factors, gasification yield/quantity and wind/PV output, together with a combined adverse case (Appendix A3). Break-even tariffs from the same 25-year cash-flow model are EUR 0.1646/kWh for full-output payment, EUR 0.1892/kWh for the payment-only demand cap, and EUR 0.1689/kWh for annual bioenergy reduction. These thresholds are conditional calculations and are distinct from the reported production-cost indicator. They do not establish investment feasibility under chronological operation or uncertain local fuel supply.

The corrected annual operational comparison gives reference emissions of 225.656 kt CO_2e/y and proposed emissions of 16.762 kt CO_2e/y, avoiding 208.893 kt CO_2e/y or 92.6%. It uses an annual generation-weighted baseline and credits only the retained demand-level reference quantity, while retaining all proposed-case emissions. At the same reference quantity, the December renewable-share proxy gives 93.2%, and the plotted historical 2024 mix gives 92.4%. Using the 2025 settlement total of 276.319 GWh instead of 277.113 GWh gives 92.55%; the difference between the two data series is not interpreted as measured losses. The comparison retains the diesel proxy for aggregate thermal production and excludes upstream biomass supply, geothermal drilling, construction, equipment manufacture and end-of-life stages (Appendix A4; Turconi et al., 2013).

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The environmental case would be strengthened by a consequential or attributional life cycle assessment that includes biomass counterfactuals, land and ecosystem effects, air pollutants, water use, geothermal reinjection, equipment manufacture, and end of life management. Local air quality benefits from reducing heavy fuel oil and diesel operation may be important but were not quantified.

The next phase should integrate measured hourly demand and weather data, explicit dispatch rules, reserve constraints, local network studies, and feasible surplus management or interconnection arrangements. Parallel work should include geothermal exploration and well testing, a geographic biomass collection assessment, measured feedstock moisture, LHV and conversion performance, gas cleaning and parasitic load design, environmental and social assessment, and probabilistic technoeconomic analysis. These steps would convert the screening concept into an assessment suitable for implementation.

5. Conclusions

This study developed a transition portfolio at screening level for Lesvos in which bioenergy and a conditional deep geothermal target serve as dispatchable renewable anchors, complemented by wind, PV, and limited reciprocating engine generation. The principal contribution is therefore not a claim of optimized or fully renewable operation, but a quantified configuration specific to the island that tests how modeled dispatchable renewable supply can change the composition of a system otherwise dominated by variable renewables and imported fuels. Under the RETScreen assumptions selected by the authors, the 101.066 MW portfolio generates 318.677 GWh/y against reconstructed 2025 demand of 277.113 GWh. Renewable technologies provide 286.265 GWh (89.8%), while bioenergy and geothermal power provide 191.957 GWh (60.2% of total generation). The 41.564 GWh annual accounting margin and positive seasonal base balances show gross energy sufficiency under the stated inputs; adverse cases produce deficits, and the low-renewable peak stress leaves a 6.664 MW capacity shortfall. They do not establish hourly adequacy, reserves, stability, or grid acceptance. Indeed, renewable generation alone exceeds annual demand by 9.152 GWh while the schedule still assigns 32.412 GWh to the engines, reflecting the prescribed engine allocation rather than a quantified

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minimum backup requirement. The environmental outcome is substantial within the selected operational boundary: reference emissions decline from 225.656 to 16.762 kt CO_2e/y, corresponding to 208.893 kt CO_2e/y or 92.6% avoided at the retained annual gross reference quantity. The configuration does not meet the selected 9% return criterion. Even with the fixed EUR 77.372 million public contribution (41.2% of gross investment) and full remuneration of modeled output, NPV is EUR -17.140 million at 9%, IRR is 7.2%, the benefit to cost ratio is 0.84, and the energy production cost of EUR 0.198/ kWh exceeds the EUR 0.16/ kWh tariff. The demand-capped payment case gives NPV of EUR -95.607 million, while annual bioenergy reduction with fuel savings gives EUR -28.999 million. The simple payback of 14.0 years is therefore an undiscounted result and should not be interpreted as proof of financial viability. The configuration should consequently be considered a transparent basis for subsequent engineering, not a final investment design. Before implementation, the 120 °C and 100,000 kg/ h geothermal steam target must be confirmed with well and reinjection data. The chain from feedstock to syngas must be validated on a recoverable dry basis. Chronological dispatch, reserve, and network stability studies must be performed. The treatment of the annual accounting margin must be agreed. The included deterministic sensitivities quantify dependence on selected inputs; further chronological and life-cycle assessments should determine whether the proposed dispatchable renewable concept can be implemented as modeled or should be adapted through binary geothermal use, storage, flexible loads, or future interconnection.

Author contributions

Conceptualization: R.G. and S.V. Methodology: R.G. and S.V. Software and formal analysis: R.G. Data curation and visualization: R.G. Supervision: S.V. Original draft: R.G. Review and editing: R.G. and S.V. Both authors have read and approved the manuscript.

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Data availability

The public electricity-system and resource sources are identified in the reference list. The retained inputs, additional annual and seasonal calculations, financial assumptions and emissions boundaries are reported in Appendix A. The RETScreen project, source workbooks and feedstock inventory are available from the corresponding author; the volumetric pomace entry has no verified mass conversion.

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Appendix A Additional screening checks

The checks retain the original installed portfolio and gross annual model outputs. They assess energy accounting and financial/emissions assumptions; they do not establish operational dispatch, verified resource availability or net delivered electricity. Calculations use unrounded model values. Displayed cells may therefore differ slightly from sums of rounded entries.

A1 Fuel and geothermal calculations

The bioenergy turbine heat rate is 9,000 kJ/kWh, equivalent to 40% electrical conversion of its modeled fuel-energy input. The confirmed input fractions are 35% biogas and 65% syngas proxy on a fuel-energy basis. Of 136.730 GWh/y gross electricity, 47.856 GWh/y is allocated to biogas and 88.875 GWh/y to gasification. Corresponding modeled fuel-energy requirements are 119.639 and 222.187 GWh/y, respectively. At the assumed gross gasification yield of 1 kWh/kg as received, the latter requires 88,875 t/y of biomass. This is a requirement-side energy balance, not a measured gasification or gas-cleaning balance.

Agricultural residues total 37,450 t/y, including 30,279 t/y of olive pruning; municipal green cut adds 9,000 t/y. The 18,901 m^3/y pomace and 26,387 m^3/y whey entries retain their reported units. No density, solids content or recoverable-fraction conversion is imposed on those volumes. Moisture, collection efficiency, competing uses, transport/storage losses, conditioning and auxiliaries are not sufficiently specified to validate the local supply requirement. The 1 kWh/kg coefficient is a gross screening assumption supported only in order of magnitude by the low-moisture wood-chip benchmark of Vakalis et al. (2014). It does not verify its applicability to wet local residues or provide net export.

The gasification proxy also does not establish actual syngas composition, heating value, gas-cleaning requirements or turbine compatibility. The modeled annual fuel budget is EUR 18.570 million: approximately EUR 18.561 million for biogas and EUR 0.009 million for the syngas proxy. These are software cost inputs, not an audited biomass procurement cost. Kourou (2020) reports 33.40

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GWh/y animal-biomass electricity potential; this alone is below the 47.856 GWh/y biogas allocation, and substrate-specific contributions from other wet streams have not been established. The aggregate literature potential cannot substitute for a recoverable local supply balance.

For geothermal reproduction, inlet and outlet pressures are treated as absolute. The retained target is 120 °C, 70 kPa and 100,000 kg/h (27.7778 kg/s), expanding to 10 kPa with 80% turbine efficiency. The RETScreen steam-property calculation gives an isentropic enthalpy drop of approximately 298.631 kJ/kg. Multiplying flow, enthalpy drop and efficiency reproduces 6.636237 MW. At 8,322 h/y this gives 55.226767 GWh/y; the corresponding actual steam rate is 15.069 kg/kWh, rounded to 15.1. This reproduces the model arithmetic and thermodynamic target, not a confirmed well or sustainable resource.

The 95% annual operating target allows 438 unavailable hours but has no separate measured maintenance, forced-outage or feedstock-interruption model. Reduced operating factors and geothermal output cases below therefore test, rather than validate, this assumption.

A2 Seasonal and peak tests

Wind weights are each month's share of the supplied 2024 wind series (39.705 GWh/y before normalization). PV weights are the supplied normalized Mytilene monthly profile; only its shape is used. Both are scaled to the original annual RETScreen wind/PV outputs. The base annual totals are preserved. Engine 2 retains 3.500, 7.048 and 4.344 GWh in February, July and August; other dispatchable outputs follow month length in the 365-day screening year. Rounded monthly demand entries sum to 277.114 GWh, so their weights are normalized to the retained 277.113 GWh reference. The stress factors are illustrative deterministic inputs, not probability statements or observations of coincident weather.

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699 Table A1. Seasonal weights and monthly gross energy balances. Quantities are GWh; weights are
700 percentages.

Month	Wind weight	PV weight	Demand	Base generation	Base balance	High-demand / low-output balance	85% operating balance
Jan	12.14 %	5.40%	24.615	26.864	2.249	-2.027	0.533
Feb	9.81%	5.79%	25.465	27.405	1.940	-2.174	0.390
Mar	7.00%	8.02%	21.310	24.751	3.441	-0.082	1.725
Apr	8.61%	9.04%	19.513	25.489	5.976	2.371	4.316
May	5.25%	9.99%	18.870	24.410	5.540	2.329	3.824
Jun	7.89%	10.13 %	23.111	25.448	2.337	-1.620	0.676
Jul	10.73 %	11.18 %	31.811	35.115	3.304	-1.932	1.588
Aug	8.07%	11.04 %	29.988	30.789	0.801	-3.928	-0.915
Sep	5.67%	9.77%	21.705	24.010	2.306	-1.224	0.645
Oct	7.66%	8.27%	18.040	25.233	7.193	3.901	5.477
Nov	7.69%	6.25%	18.357	23.961	5.604	2.420	3.944
Dec	9.49%	5.12%	24.329	25.200	0.872	-3.043	-0.845

701

702 The high-demand/low-output case increases each monthly demand by 10% and reduces wind/PV
703 output by 20%, retaining the prescribed dispatchable generation. The 85% case scales bioenergy and

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geothermal annual outputs by 85/95 with the seasonal wind/PV profiles retained. The 50% and 0% geothermal cases leave all other technology outputs fixed. These energy cases do not include a dispatch response.

Table A2. Annual and minimum monthly balances for the additional energy cases (GWh).

Case	**Gross generation**	**Annual balance**	**Minimum month**	**Deficit months**
Seasonal shape	318.677	41.564	0.801	None
High demand / low wind and PV	299.816	-5.009	-3.928	Jan, Feb, Mar, Jun, Jul, Aug, Sep, Dec
Bioenergy and geothermal 85%	298.471	21.358	-0.915	Aug, Dec
Geothermal 50%	291.064	13.951	-1.544	Jan, Feb, Aug, Dec
Geothermal 0%	263.451	-13.662	-3.889	Jan, Feb, Mar, Jun, Jul, Aug, Sep, Dec

The supplied 2024 hourly grid-load series records 59.73 MW on 23 July, in the row labelled hour 15; that row is not an interpolated entry. An imposed stress combines this maximum with zero wind/PV output. With all bioenergy, geothermal and engine capacity available, gross dispatchable capacity is 16.430 + 6.636237 + 20 + 10 = 53.066237 MW, giving a 6.664 MW shortfall. Loss of the 20 MW engine group increases the shortfall to 26.664 MW. These are capacity screens, not an assertion of historical coincidence or a quantified loss-of-load probability. Auxiliary consumption, reserves and network constraints would require further provision.

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A3 Financial cases and sensitivities

The original no-debt, pretax cash-flow model is reproduced with EUR 187.718950 million capital cost, EUR 77.372 million initial support and EUR 110.346950 million initial equity. The period is 25 years, nominal discount rate 9%, and revenue, fuel and operating costs escalate by 2% annually. For each operating year t, cash flow is the base-price annual revenue minus fuel and fixed operating costs, multiplied by 1.02 to the power t. Initial investment occurs at year 0. This convention reproduces NPV of EUR -17.139884 million and IRR of 7.19095%. Revenue values in Table A3 are at the stated base price; first-year operating values include the 2% escalation.

Case A remunerates all gross output. Case B caps paid electricity at the smaller of gross output and the 277.113 GWh reference while retaining all original production and costs; it is a payment bound, not physical curtailment. Case C reduces bioenergy generation by 41.564369 GWh to 95.166091 GWh/y and scales its fuel budget proportionally to the reduction in full-load operation. Other generation, installed capacity, fixed operating costs, support and escalation remain fixed. Paid output is then 277.113 GWh. A real dispatch model would also need acceptance timing, minimum loads, start-up costs and auxiliary consumption.

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731 Table A3. Annual payment and generation-reduction cases. Monetary values are million EUR; annual
732 electricity is GWh.

Case	Gross output	Paid output	Base-price revenue	Base-price fuel	NPV at 9%	IRR
A Full-output payment	318.677	318.677	50.988	36.529	-17.140	7.19%
B Demand-capped payment	318.677	277.113	44.338	36.529	-95.607	-6.18%
C Annual bioenergy reduction	277.113	277.113	44.338	30.883	-28.999	5.85%

733

734 Fixed annual operating costs at base prices are EUR 6.560270 million in all three cases. All generation
735 and payment bounds are optimistic regarding unquantified plant auxiliaries. No contractual payment
736 for the surplus, export route, storage benefit or avoided fuel from battery operation is assumed.

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737 Table A4. One-way financial sensitivities about Case A. The original case has NPV of EUR -17.140
738 million. NPV columns are million EUR.

Parameter	**Input 1**	**Input 2**	**NPV 1**	**NPV 2**
Electricity tariff	0.128 EUR/kWh	0.192 EUR/kWh	-137.463	103.184
Gross capital cost	-20%	+20%	20.404	-54.684
Bioenergy fuel budget	-20%	+20%	26.683	-60.963
Discount rate	7%	11%	2.090	-31.631
Public contribution	-20%	+20%	-32.614	-1.665
Bioenergy operating capacity factor	85%	90%	-21.246	-19.193
Geothermal operating capacity factor	85%	90%	-28.115	-22.627
Gasification gross yield at fixed fuel input	0.8 kWh/kg	1.2 kWh/kg	-50.696	16.417
Available gasification feedstock	80% of requirement	100% of requirement	-50.675	-17.140
Wind and PV annual generation	-20%	+20%	-52.748	18.468

739

740 Capital-cost sensitivity retains the absolute public contribution. Bioenergy operating-factor changes
741 scale bioenergy generation and its fuel budget together, with fixed operating costs retained.
742 Geothermal and wind/PV output tests retain installed costs. The gross gasification-yield test changes
743 gasification electricity at fixed input mass and fuel budget; it represents uncertainty in the aggregate
744 feedstock/conversion yield. The available-quantity test uses 80% or 100% of the case's required

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gasification feedstock and proportionally scales only the software syngas fuel-cost entry. These are analytical parameter tests, not separate measured plant performances; they do not establish independent values for moisture, LHV, cold-gas efficiency, procurement prices or collection losses.

A combined adverse test uses +20% capital cost, +20% fuel costs, 11% discounting, 85% bioenergy/geothermal operating factors, -20% wind/PV output, demand-capped payment and the same absolute support. Gross output is 279.610 GWh and NPV is EUR -184.867 million. The resulting operating cash flow is negative, so an investment IRR is not defined for that cash-flow sign pattern. These chosen ranges are deterministic stress assumptions, not probabilistic confidence limits.

Solving the same cash-flow model for NPV = 0 gives base-price tariffs of EUR 0.1646/kWh (A), EUR 0.1892/kWh (B), and EUR 0.1689/kWh (C), with all other case inputs fixed. Alternatively, additional upfront support of EUR 17.140 million closes the Case A NPV gap; a 7.82% reduction in its bioenergy fuel budget has the same effect at the selected discount rate. These are conditional break-even calculations, not recommendations or established tariff entitlements.

A4 Operational emissions accounting

The 2025 provisional settlement workbook reports 49,077.276 MWh renewable and 227,242.015 MWh thermal electricity for Lesvos, totaling 276,319.291 MWh. Annual renewable share is calculated from summed energy, not the arithmetic mean of monthly percentages. The original 277,113 MWh screening demand reference is retained for fixed-case comparability; the 793.709 MWh (0.29%) discrepancy between the source series is exposed and tested below, not assigned to a measured loss category. Figure 1 is a separate historical 2024 illustration and is not used as the 2025 baseline.

The diesel proxy retains CO_2, CH_4 and N_2O fuel factors of 69.3123061013, 0.002016546 and 0.0005687694 kg/GJ, 25.275327% electrical efficiency, and GWP factors of 28 for CH_4 and 265 for N_2O. This gives 0.990176 t CO_2e/MWh of thermal electricity. Multiplying by the 2025 thermal share (82.238925%) gives 0.814310 t CO_2e/MWh of gross reference electricity. Both sides use a gross

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generation boundary; the earlier textual 7% loss uplift is not added to either. Reference emissions equal this factor times the selected service-level gross reference quantity. All 16,762.377 t CO_2e/y of proposed emissions are retained, including emissions from potentially unused output; the accounting surplus receives no avoided-emissions credit.

Table A5. Operational reference-boundary and baseline-mix checks. Emissions are kt CO_2e/y; all proposed-case values retain full modeled emissions.

Reference assumption	**Baseline**	**Proposed**	**Avoided**	**Reduction**
2025 annual mix / retained demand	225.656	16.762	208.893	92.57%
December proxy / same demand	246.046	16.762	229.284	93.19%
2024 plotted mix / same demand	220.145	16.762	203.382	92.39%
2025 annual mix / settlement total	225.010	16.762	208.247	92.55%

The operational convention excludes biogenic CO_2 but retains the selected CH_4 and N_2O factors for the bioenergy carriers. Geothermal, wind and PV retain zero direct operational factors. The result remains conditional on resource targets, fuel properties, proxy emission factors and unquantified auxiliary consumption. It is not a life-cycle assessment or proof that all annual reference demand can be served chronologically.

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