HELLENIC OPEN UNIVERSITY

Master in business Administration

Financial Viability of Medium-Scale RES Projects in Greece: A Strategic and Financial Analysis of Independent Power Producers

Liousas Dimitrios

Supervising Committee

Supervisor: Bekiaris Michalis

Co-Supervisor: Tsekrekos Andrianos

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Abstract

This dissertation examines the financial viability of medium-scale renewable energy projects developed by independent power producers in Greece. It investigates whether such projects can generate positive returns under current market conditions and how EU concessional financing through the Recovery and Resilience Facility affects their feasibility.

The study begins by tracing the evolution of the Greek regulatory framework from feed-in tariffs to competitive feed-in premium auctions to open market and identifies the structural barriers that small and medium-sized developers face relative to vertically integrated utilities. A risk assessment framework categorises regulatory, market, technical, and financial risks, with particular emphasis on curtailment and interest rate exposure following the post-2022 monetary tightening.

The financial analysis employs a discounted cash flow methodology applied to three representative projects: an 8.8 MW onshore wind farm, a 1 MW run-of-river hydropower plant, and a 5 MW solar photovoltaic installation paired with 20 MWh battery energy storage. The cost of equity is derived through the Capital Asset Pricing Model, with technology-specific risk captured via the Hamada equation for beta relevering. Two financing scenarios are compared: a blended structure incorporating Recovery and Resilience Facility concessional lending, producing a weighted average cost of capital of 4.84%, and a commercial-only counterfactual at 7.04%. Project viability is evaluated through net present value, internal rate of return, and debt service coverage ratio metrics.

Sensitivity analysis, including tornado analysis and curtailment threshold mapping, identifies the break-even points at which projects transition from viability to financial distress. The dissertation concludes that concessional public financing materially improves project feasibility and offers policy recommendations for auction design, blended finance deployment, and energy storage integration.

Keywords:

Renewable Energy Finance, Cost of Capital (WACC), Feed-in Premium Auctions, Recovery and Resilience Facility (RRF), Discounted Cash Flow Analysis, Project Finance

Περίληψη:

Η παρούσα διπλωματική εργασία εξετάζει τη χρηματοοικονομική βιωσιμότητα έργων ανανεώσιμων πηγών ενέργειας μεσαίας κλίμακας που αναπτύσσονται από ανεξάρτητους παραγωγούς ενέργειας στην Ελλάδα. Διερευνά κατά πόσο τέτοια έργα μπορούν να επιτύχουν θετικές αποδόσεις υπό τις τρέχουσες συνθήκες αγοράς και πώς η ευνοϊκή χρηματοδότηση της Ευρωπαϊκής Ένωσης μέσω του Ταμείου Ανάκαμψης και Ανθεκτικότητας επηρεάζει τη σκοπιμότητά τους.

Η μελέτη ξεκινά αποτυπώνοντας την εξέλιξη του ελληνικού ρυθμιστικού πλαισίου, από τις εγγυημένες τιμές αγοράς στις ανταγωνιστικές δημοπρασίες λειτουργικής ενίσχυσης, και εντοπίζει τα διαρθρωτικά εμπόδια που αντιμετωπίζουν οι μικρομεσαίοι παραγωγοί σε σύγκριση με τις καθετοποιημένες επιχειρήσεις του κλάδου της ενέργειας. Στη συνέχεια αναλύονται οι πιθανοί κίνδυνοι και ρίσκα και κατηγοριοποιούνται τους κινδύνους σε ρυθμιστικούς, αγοράς, τεχνικούς και χρηματοοικονομικούς με ιδιαίτερη έμφαση στην περικοπή παραγωγής και την έκθεση σε επιτοκιακό κίνδυνο μετά τη νομισματική σύσφιξη του 2022.

Η χρηματοοικονομική ανάλυση εφαρμόζει τη μεθοδολογία προεξοφλημένων ταμειακών ροών σε τρία ενδεικτικά έργα: ένα αιολικό πάρκο ισχύος 8,8 MW, ένα μικρό υδροηλεκτρικό έργο ισχύος 1 MW και ένα φωτοβολταϊκό πάρκο ισχύος 5 MW σε συνδυασμό με αποθήκευση ενέργειας 20 MWh. Το κόστος ιδίων κεφαλαίων υπολογίζεται μέσω της μεθόδου CAPM, με εκτίμηση εξειδικευμένου κίνδυνου μέσω της εξίσωσης Hamada. Συγκρίνονται δύο σενάρια χρηματοδότησης: μια μεικτή δομή με δάνεια του Ταμείου Ανάκαμψης και Ανθεκτικότητας, που παράγει μέσο σταθμισμένο κόστος κεφαλαίου 4,84%, και ένα συμβατικό σενάριο αποκλειστικά εμπορικής χρηματοδότησης στο 7,04%. Η βιωσιμότητα αξιολογείται μέσω καθαρής παρούσας αξίας, εσωτερικού βαθμού απόδοσης και δείκτη κάλυψης εξυπηρέτησης χρέους.

Μέσω της ανάλυσης ευαισθησίας, μέσω tornado analysis και αναγνώρισης των ορίων περικοπής, εντοπίζονται τα σημεία ισορροπίας στα οποία τα έργα μεταβαίνουν από βιώσιμα σε οικονομικά επισφαλή. Η εργασία καταλήγει ότι η ευνοϊκή χρηματοδότηση βελτιώνει ουσιαστικά τη σκοπιμότητα των έργων και διατυπώνει προτάσεις πολιτικής για τον σχεδιασμό δημοπρασιών, τη μεικτή χρηματοδότηση και την ενσωμάτωση αποθήκευσης ενέργειας σε έργα ΑΠΕ.

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List of Abbreviations

ADMIE: Independent Power Transmission Operator S.A.

BESS: Battery Energy Storage System

CAPM: Capital Asset Pricing Model

COD: Commercial Operation Date

CRE: Regulatory Authority for Energy

DSCR: Debt Service Coverage Ratio

ECB: European Central Bank

ELAPE: Special RES Account (Greece)

EPC: Engineering, Procurement, and Construction

ERP: Equity Risk Premium

EU: European Union

FiP: Feed-in Premium

FIT: Feed-in Tariff

FoSE: Aggregator of Balancing Responsible Parties

HHI: Herfindahl-Hirschman Index

HOU: Hellenic Open University

IPTO: Independent Power Transmission Operator

IPP: Independent Power Producer

IRR: Internal Rate of Return

LCOE: Levelized Cost of Energy

MBA: Master of Business Administration

NECP: National Energy and Climate Plan

NPV: Net Present Value

OPEX: Operational Expenditure

PPA: Power Purchase Agreement

PV: Photovoltaic

RAAEY: Single Registry of Renewable Energy Sources

RES: Renewable Energy Sources

RRF: Recovery and Resilience Facility

RTB: Ready-to-Build

WACC: Weighted Average Cost of Capital

Chapter 1: Introduction

1.1 Research Context and Problem Definition

The European Union's commitment to carbon neutrality by 2050 is driving unprecedented expansion in renewable energy investment across the continent. Greece's updated National Energy and Climate Plan says the country should achieve 72–80% renewable electricity by 2030, significantly higher than the current level. Technology costs have dropped substantially: the International Renewable Energy Agency reported that in 2024, onshore wind costs USD 0.033 per kilowatt-hour and solar costs USD 0.044 per kilowatt-hour, making these technologies economically competitive. However, medium-scale renewable projects in Greece still face considerable problems with financing access and costs.

The global financial situation adds significant complexity to project development. The European Central Bank tightened interest rates between 2022 and 2024, pushing the three-month Euribor from near zero to approximately 4%. This increase raised the cost of borrowing substantially for renewable energy projects dependent on debt financing. Geopolitical problems—particularly the Russia-Ukraine war—created supply chain disruptions that made turbines, solar panels, and transmission cables more expensive and harder to obtain. Greece occupies an intermediate risk position in Europe: Steffen's 2020 analysis shows the cost of capital for Greek renewable projects is substantially higher than comparable Northern European projects—Greek onshore wind WACC reached approximately 11.7% compared to around 3% in Germany, a gap of roughly 800–900 basis points.

Small and medium-sized independent power producers face structural barriers that large utilities do not encounter. These firms have limited capital reserves, weaker negotiating power with banks, and cannot use the internal hedging and cross-subsidization tools available to vertically integrated utilities with generation, distribution, and retail operations. The fundamental tension between ambitious national renewable energy targets and the structural difficulties facing smaller energy investors defines the core research problem.

After 2022, the geopolitical situation has important effects for Greek renewable energy. The Russia-Ukraine war showed that Europe relies heavily on Russian natural gas—prices went above

EUR 200/megawatt-hour in winter 2021-22. For Greece, which imports a lot of fossil fuels (coal, oil, natural gas), the conflict made it clear that renewable energy is important for security, not just for the environment. Greece wants energy independence—to not depend on unstable international markets. The International Energy Agency's 2023 report on Greece connects geopolitical security to faster renewable energy targets. At the same time, the European Central Bank's interest rate increases made borrowing much more expensive. The three-month Euribor was close to zero in early 2022 but reached 3.98% in October 2023 and stayed high through 2024. For a typical Greek renewable project with EUR 6.6 million debt at Euribor plus 150 basis points, interest costs went from about EUR 60,000 in 2021 to EUR 360,000 at the peak—a 600% increase in 24 months. This sudden financial shock changed the cash flows of projects that were developed or financed during this period. Projects approved with old assumptions no longer worked with new financing costs.

The Greek electricity market is changing toward competition, but the change is incomplete. The public utility (PPC) used to control everything—generation, transmission, and selling to customers. Markets opened to competitors, but big companies still have high market share. The grid operator (RAAEY) manages balancing, but data shows the old incumbent still has a lot of influence. HELLENiQ Energy (2025) documents that wholesale prices remain elevated at EUR 92–135/MWh despite high renewable penetration, as natural gas generators continue to set marginal prices, a pattern reinforced by limited interconnection capacity and strategic bidding behaviour by large incumbents — a structural feature of oligopolistic electricity markets that Hondroyiannis et al. (2023) associate, at the EU-wide level, with imperfect competition and oligopolistic pricing behaviour in national electricity generation. Makrygiorgou (2023) and Cetkovic (2016) show that the market rules, permit processes, and financing requirements advantage large integrated companies over small independent ones. So the Greek electricity market looks competitive but is really an oligopoly—a few big players still control it, and small companies face structural disadvantages.

1.2 Role and Significance of Non-Integrated IPPs

Small and medium-scale independent power producers generate electricity but do not sell directly to end-use customers. Instead, they sell to the wholesale electricity market, work through aggregation platforms, or negotiate long-term bilateral power purchase agreements with institutional buyers. These companies are important far beyond their direct economic contribution to the energy system. They distribute investment opportunities across a broader base of investors, support local economic development in rural areas, and provide competitive pressure on incumbent utilities that historically dominated electricity generation. The electricity market has become somewhat less concentrated over time since the introduction of competitive auctions, though large companies still retain significant market dominance.

However, small and medium-sized independent companies face substantial structural problems when competing against large integrated utilities. They carry more financial risk because they are smaller and less diversified (reflected in higher equity beta coefficients). They cannot employ the internal hedging strategies that large integrated companies use—larger firms can offset wholesale price volatility through their customer retail operations, offsetting losses in one segment with gains in another. Research by Kiefer et al. demonstrates that post-auction market structures still show elevated concentration, with the largest renewable energy firms capturing disproportionate shares of awarded capacity—a structural advantage that translates into better financing terms. Additionally, small independent companies exercise less political and regulatory influence over the policy changes and rule modifications that fundamentally affect project economics. This dissertation investigates the central question: can medium-scale independent power producers maintain financial viability and compete effectively in Greece's contemporary renewable energy market?

Small independent power producers have financing problems that come from several directions, as shown in research on renewable energy finance. Egli et al. (2023) show that small companies have higher risk because they are more concentrated. Simshauser (2020) shows that big integrated utilities save 13% in costs through internal hedging—when electricity prices go up, their customer sales lose money but their generation makes money, so the losses offset. Small companies do not have this. Angelopoulos et al. (2017) found that Greek wind projects cost about 12% to finance in 2016, much higher than Northern Europe at 6-7%. Ondraczek et al. (2015) showed across many countries that financing costs are the biggest factor in total cost of electricity, bigger even than technology differences. For small Greek independent companies, the total cost of capital is 10-12% versus 5-6% for big utilities. This 400-600 basis point difference means that when you calculate project value (NPV), small companies get 40-60% less value. So projects that would make money for big companies lose money for small ones. This is a market problem that needs government help to keep small companies competitive.

1.3 Research Aim, Objectives, and Key Research Questions

This dissertation systematically analyzes whether medium-scale independent power producers in Greece can achieve financial viability and generate positive returns from renewable energy projects under contemporary market and financial conditions. The analysis focuses on four distinct research questions that progressively build from feasibility assessment to strategic adaptation:

Question 1: Can a medium-scale renewable energy project in Greece generate positive net present value (financial viability) under current wholesale electricity prices and realistic, empirically-observed financing costs? This foundational question establishes whether the base case economic case exists without structural adaptations.

Question 2: How does curtailment risk—the mandatory reduction of electricity generation when grid operators must maintain system stability—affect the financial ability of independent power producers to service bank debt and satisfy lender debt service coverage ratio covenants? At what specific curtailment threshold does the project transition from financial viability to distress and default risk? This question translates operational grid constraints into quantified financial constraints.

Question 3: What is the quantitative magnitude of the macro-financial environment as a barrier to market entry for small and medium-sized enterprises in the Greek renewable energy sector? How much do elevated interest rates post-2022, equipment cost volatility, and geopolitical risk premiums increase the cost of capital relative to large integrated utilities? What is the financial cost of being small?

Question 4: What strategic adaptations—energy community structures, project portfolio aggregation, long-term power purchase agreements, recovery and resilience facility blended financing, and specialized market positioning—are necessary for small companies to achieve financial viability and survive in an increasingly oligopolistic market?

The analysis uses discounted cash flow modelling, as explained in Brealey et al. (2025), the standard corporate finance textbook. The method calculates free cash flows to equity, uses the capital asset pricing model for the cost of capital, and applies net present value to make decisions. Three projects represent the different technologies planned under Greece's National Energy and Climate Plan 2024. Wind projects—8.8 megawatt onshore installations—are the largest category, with 35-40% of planned capacity additions between 2025 and 2030. Solar installations are second-largest at 40-45%, modelled as a 5 megawatt solar installation plus 20 megawatt-hour battery storage. This combination is becoming common because batteries help manage when solar produces power. Small hydropower—a 1 megawatt run-of-river installation—represents a different type of project: it costs more per unit, depends on location, and has environmental challenges. But it has better reliability and higher capacity factors. Gomez-Restrepo et al. (2024) reviewed methods for evaluating renewable projects and found that net present value, internal rate of return, levelised cost, and payback period are the most used. By modeling three different technologies, the analysis shows the different risks and returns that Greek small independent companies face, rather than just one simple example.

These three technologies make sense because they represent Greece's renewable energy plan. Together they account for over 95% of the capacity additions planned through 2030 under Greece's National Energy and Climate Plan 2024. Wind and solar are mature technologies—costs are clear, historical data show how they perform, and competitive auctions establish prices. Small hydropower is different: it costs much more per megawatt (EUR 1,500-3,500/kW versus EUR 900-1,200 for solar), only works in certain locations, and has environmental licensing issues that wind and solar do not face, but it runs more consistently (20-95% capacity factor versus 32% for wind and 18-22% for solar). Solar with battery storage (5 megawatt plus 20 megawatt-hour) is a newer approach that helps match electricity production to when people need it. Liu (2023) studied wind costs; Klein (2022) covered small hydropower; the International Renewable Energy Agency (2024) provided solar costs; and Giannakopoulos (2025) studied battery costs. By choosing three different technologies, the dissertation tests whether the problems (financing and curtailment) affect all types of projects the same way, or if some projects face bigger problems than others.

1.4 Contribution and Relevance

This dissertation bridges and integrates multiple domains within the MBA curriculum, creating a comprehensive application of business school methodology to energy sector strategy. It applies corporate finance methodology from MBA51—specifically the discounted cash flow framework, weighted average cost of capital calculation, net present value decision criteria, and capital structure optimization. It incorporates industrial organization concepts from MBA50, particularly concentration measures (Lerner indices and Herfindahl-Hirschman indices) applied to analyze competitive dynamics in the Greek electricity sector. Strategic management principles from MBA61 inform the analysis of competitive positioning, strategic adaptation mechanisms, and firm capabilities. Quantitative methods from MBA60 underpin the deterministic sensitivity analysis, scenario construction, and risk assessment frameworks.

The work provides substantial practical value to three distinct constituencies. For investors and project developers, it provides a transparent, replicable financial modelling toolkit and decision framework applicable to renewable energy project evaluation in the specific Greek institutional and market context. For policymakers and government, it identifies specific market failures and provides evidence on where targeted policy interventions would deliver material impacts on project viability and deployment acceleration. For academic researchers and the broader knowledge base, it extends prior renewable energy financing research by explicitly integrating geopolitical macro risk, supply chain volatility, curtailment operational constraints, and country-specific regulatory risk into project-level financial models.

1.5 Dissertation Structure

Chapter 2 establishes the regulatory and market context for Greek renewable energy development. It traces the evolution from technology-specific feed-in tariffs through feed-in premium mechanisms to competitive auction systems. The chapter examines both European Union level regulatory frameworks and Greek national implementation mechanisms. It addresses the unique Greek institutional features including licensing procedures, grid connection requirements, and the distinctive letters of guarantee collateral requirements. The chapter also characterizes investor typologies, distinguishing medium-scale independent power producers from vertically integrated utilities.

Chapter 3 examines project financing mechanisms and financial evaluation methodologies. It explains the financing lifecycle from project development through construction to operational phases. It evaluates diverse funding sources including commercial bank debt, development finance institution support, and European Union recovery and resilience facility blended financing. The chapter establishes the analytical framework and key financial metrics: net present value, internal rate of return, weighted average cost of capital, levelized cost of electricity, and debt service coverage ratio covenants.

Chapter 4 explains the financial analysis method. It reviews principal investment evaluation methodologies: levelized cost of electricity, accounting rate of return, payback period, real options analysis, and discounted cash flow approaches. It justifies selection of the free cash flow to equity discounted cash flow framework and describes the financial model architecture in detail. It includes sensitivity analysis frameworks and scenario testing methodology. It acknowledges seven inherent limitations of the analysis and mitigation strategies.

Chapter 5 covers strategic and operational risks. Project-specific risks including resource variability and construction delays are distinguished from systemic risks including curtailment, electricity price volatility, and interest rate exposure. Curtailment risk and grid saturation constraints receive particular emphasis given their materiality in the Greek market context. Market concentration and competitive dynamics are analyzed using industrial organization frameworks.

Chapter 6 presents financial modelling results for three case studies. The 8.8 megawatt onshore wind farm, 1 megawatt run-of-river hydropower plant, and 5 megawatt solar photovoltaic installation with 20 megawatt-hour battery storage are modeled deterministically over 20-year operational horizons. Base-case financial results establish viability thresholds. Cross-case technology comparison identifies divergent risk profiles across renewable technology types.

Chapter 7 extends analysis through sensitivity and scenario testing. Single-variable tornado analysis ranks risk drivers by net present value impact magnitude. Multi-variable scenario analysis examines optimistic, pessimistic, and stress combinations. Curtailment threshold mapping identifies specific curtailment levels at which debt service coverage ratio covenants are breached. Macro-financial stress testing quantifies the cost-of-capital barrier.

Chapter 8 concludes with findings and recommendations. It provides direct answers to each of the four research questions grounded in analytical results. It presents evidence-based policy recommendations addressing identified market failures. It synthesizes practical implications for investors and developers. It discusses analytical limitations and directions for future research.

Chapter 2: Evolution of the Greek and EU Renewable Energy Market

2.1 Transition of Regulatory Frameworks (FITs to Market-Based Mechanisms)

2.1.1 Early EU Framework and Rise of FITs

Directive 2009/28/EC set the EU binding target for at least 20% renewable energy by 2020. Greece supported early renewable deployment through Law 3468/2006, which introduced technology-specific feed-in tariffs and long-term support contracts, later refined by subsequent laws. These guaranteed tariffs helped accelerate renewable investment, especially in photovoltaics, although they were later adjusted downward as costs and market conditions changed. Greece's renewable electricity capacity expanded rapidly in the late 2000s and early 2010s, rising from 753 MW of wind capacity alone at the end of 2006 to 2,148 MW of wind capacity by the end of 2015, while total renewable capacity reached several gigawatts by the mid-2010s, reflecting one of the faster renewable build-outs in the EU.

But costs grew too. The support prices were much higher than what coal and gas plants cost to operate. Greece's renewable subsidy account had big deficits. By 2013-2014, the cost was very visible and caused problems for government budgets. Both Greece and the EU wanted to change the system. The problem was clear: government wants renewable energy but cannot afford to pay for it.

2.1.2 Limitations of FITs and Fiscal Stress

High costs forced governments to rethink the system. The EU's rules changed in 2014 and now required competitive bidding for projects larger than 500 kilowatts. Greece had to move away from guaranteed prices to market competition. The old system had problems: people built expensive projects because prices were guaranteed, companies did not try to cut costs, and the market was not efficient. Greece reformed its renewable energy system between 2012 and 2016.

Greece's financial crisis between 2010 and 2015 forced the government to cut renewable energy support suddenly. Law 4254/2014 reduced the prices that existing solar projects received—a 30-40% cut that happened immediately, even for projects already producing electricity. This was unusual in Europe. No other country had done this. Angelopoulos et al. (2017) showed that this shock made investors afraid. Before 2014, investors trusted the government's contracts. After 2014, they assumed the government might change the rules again. Steffen (2020) found that Greek renewable projects faced substantially higher financing costs than Northern Europe—approximately 11.7% WACC for Greek onshore wind versus around 3.0% in Germany, a gap of roughly 870 basis points driven partly by this regulatory uncertainty. This one event from 2014 had long-lasting effects. It raised costs for all renewable projects through 2024 and probably longer. Investors lost money and also became worried about future rule changes.

2.1.3 Introduction of FiPs and Auctions in Greece

Law 4414/2016 replaced the fixed price system with a premium system. Under this system, renewable projects get the market price plus an extra amount (premium). They no longer get a guaranteed fixed price. Competitive auctions started in 2018. In the first auctions, wind prices were EUR 68-72/megawatt-hour. Later auctions had lower prices, and by 2022 prices had fallen to EUR 55-60/megawatt-hour. Prices went down because wind technology got cheaper and because more companies competed in the auctions. This change was good for efficiency but created problems for small independent companies competing against big utilities that can borrow cheaper.

The premium system works like this: auctions set a reference price. The premium is the difference between that reference price and the market price. If the market price is low, the premium is high. If the market price is high, the premium is low, zero or even negatice. Auctions in 2018–2020 had different prices for wind and solar. Lineiro (2023) found that auction design significantly affects project realisation rates and that technology-specific auctions allow each technology to reveal its true costs more effectively than mixed auctions. To participate in auctions, companies must pass several tests: they must bid in a sealed format, they must show they can repay debt (debt service coverage ratio of 1.20-1.30), and they must provide bank guarantees. Breitschopf (2022) found that one-sided sliding premiums can slightly reduce the weighted average cost of capital by lowering market-risk exposure, but this effect is not very robust and depends on the broader financial environment and policy design. Under one-sided sliding premiums, project revenues are partly protected from price drops, but developers still face market exposure compared with fully fixed-price schemes such as feed-in tariffs. As a result, this support design can still leave more revenue risk than a fixed-price system, especially for smaller or less experienced independent developers.

Greece ran auctions separately for each technology and region. Companies had to have already matured projects showing that they had money and environmental approval documents. Auctions were sealed bid (highest losing bid set the price) and winners had to prove they could repay debt. Dukan (2023) suggest that auction-based renewable support systems tend to reward firms with stronger balance sheets, lower financing costs, and greater ability to absorb market and interest-rate risk. In this context, large utilities and vertically integrated players are likely to be better positioned than small independent developers to win auctions and withstand tighter financing conditions. As a result, while auctions may improve allocative efficiency and reduce support payments, they can also create a competitive advantage for larger market participants, especially in higher-risk markets. This does not mean smaller developers cannot participate, but it does indicate that the auction structure may systematically advantage larger firms.

2.1.4 EU-Level Evolution: RED II and RED III

The EU set higher renewable energy targets over time. The second Renewable Energy Directive set 32% by 2030. The third one set 42.5%, with an aspirational goal of 45%. The war in Ukraine made the EU worry about energy security, so they accelerated permitting. Now the EU rules say wind and solar projects must get permits within two years. These EU rules set the framework that Greece must follow.

The third Renewable Energy Directive (EU 2023/2413, approved in December 2023) set binding targets of 42.5% renewable electricity by 2030, with a goal of 45%. It made targets legally binding on each EU country. For wind and solar in priority areas, the rule is maximum two-year permit approval. The REPowerEU plan from May 2022 expanded this to other areas too, except environmental protection areas. The reason was clear: Russia's invasion of Ukraine stopped gas supplies to Southern Europe (supplies fell to 20% of previous levels), so the EU needed renewable energy fast. But what happened in practice is different. EU rules say two years, but actual permits often take 3-4 years because of administrative problems and exemptions. This gap between rules and reality is especially bad in Greece and other countries on the edge of Europe where government agencies work slowly.

2.2 Licensing, Grid Access, and Operational Barriers

2.2.1 Greek Licensing Framework and Letters of Guarantee

Greece's regulatory framework for renewable energy project permitting remains relatively complex and capital-intensive compared to European standards. Developers must secure a sequence of approvals, including the Producer Certificate, environmental permitting, the Final Grid Connection Offer, and the final operation licence. Despite reforms under Law 4951/2022, which introduced digital processes and simplification measures, significant delays persist, with environmental permitting typically lasting 12-24 months on average.

Particularly burdensome is the system of bank guarantees required at early development stages. The Producer Certificate demands a guarantee of €35,000 per MW, while the application for the Final Grid Connection Offer under Law 4951/2022 (Article 6, paragraph 3) establishes a tiered structure as follows:

€42/kW for the first MW,

€21/kW for capacity from 1 to 10 MW,

€14/kW from 10 to 100 MW,

€7/kW beyond 100 MW.

For a typical 10 MW wind project, the connection guarantee is calculated as:

1 MW × €42/kW = €42,000,

9 MW × €21/kW = €189,000,

Total connection guarantee: €231,000.

Although the Producer Certificate guarantee (€350,000) is returned once a complete application for the Final Grid Connection Offer is submitted, there remains an overlap period during which both guarantees must be active simultaneously. This results in a peak upfront commitment of €581,000 before construction begins and prior to any revenue generation. Such levels of capital lock-up substantially raise entry barriers for small and medium-sized enterprises, increasing the cost of capital and limiting market competition in the RES sector. Moreover, Greek banks typically require debt service coverage ratios of 1.25-1.35 and equity contributions of 25-35%, further exacerbating financing pressures.

2.2.2 Grid Constraints and Curtailment

Greece's electricity transmission and distribution infrastructure lacks sufficient capacity to integrate the rapid expansion of renewable energy sources. Connection queues in congested areas, such as Thessaly and the Peloponnese, span 2-6 years. International comparisons show curtailment varies from 1–17% across different countries. For new projects entering the grid, actual curtailment is even higher than the average. Newbery (2025) shows this in detail.

Curtailment compensation is absent, leaving producers unremunerated for lost output and effectively subsidising grid constraints. On islands like Crete, rates exceed 15% during peaks. OECD (2023) analyses urge accelerated grid investments and permitting to unlock RES potential.

Grid connection has long procedures and high costs. ADMIE handles big transmission lines (150 kV and above, projects over 8 MW), and DEDDIE handles distribution (below 150 kV, projects up to 20 MW). Grid connection approvals are contingent upon a 36-month validity window, after which allocated capacity is forfeited if construction has not commenced. Despite a projected EUR 4.5 billion investment in infrastructure upgrades through 2033, the expansion of the network lags significantly behind project development, resulting in acute grid congestion. As noted by the OECD (2023), these systemic constraints in Greece suggest that without accelerated upgrades, curtailment will become a structural reality rather than a transient issue solvable by technology or investment alone.

2.2.3 EU-Wide Permitting Challenges

The permitting of wind and solar projects in the EU is subject to a two-year timeline, yet this deadline is frequently exceeded in practice. Permitting remains a significant constraint on renewable deployment, with processing times typically shorter and more predictable in northern Europe than in southern Member States such as Greece.

2.3 Investor Typologies: Medium-Scale IPPs vs. Vertically Integrated Utilities

2.3.1 Investor Groups in European RES

Different types of companies invest in renewable energy across Europe. Big utilities like EDF, RWE, and Iberdrola own generation, transmission, distribution, and customer sales. Independent developers build projects. Pension funds and infrastructure funds invest capital. Local utilities operate in their areas. Energy communities are new—groups of people pooling money to build renewable projects. Greece has the dominant utility PPC, many independent producers, and some energy communities starting.

2.3.2 Medium-Scale IPPs

Medium-scale independent power producers operate by developing, financing, building, and operating renewable projects in their regions. They sell electricity to the wholesale market, aggregators, or with long-term contracts. They face capital problems: they must spend money on development before they get any revenue. They do not have many projects to diversify with. Because they are small, they are riskier (higher equity beta). IRENA (2024) shows that development costs are 2-9% of the total project cost, and they must pay all of this with their own money before banks will lend to them.

In the Greek energy market, medium-scale Independent Power Producers (IPPs) operate under distinct structural and financial constraints that create significant barriers to entry and expansion. Typically managing portfolios of 0.5–50 MW across a limited geographical footprint of one to two regions, these developers face high asymmetric risk due to a lack of portfolio diversification. Unlike large-scale utilities, these entities are largely excluded from institutional debt markets, green bonds, and co-investment schemes during the pre-operational phase, forcing a reliance on personal equity or angel investors. With per-project development costs ranging from EUR 80,000 to EUR 250,000—representing 2–9% of total capital expenditure—and a prolonged construction timeline of 28–34 months following successful auction bids, these firms must endure nearly three years of capital accumulation without revenue. This lack of financial flexibility, coupled with the inability to spread risk across multiple projects, creates a "single-point-of-failure" scenario where the collapse of a single project can result in total insolvency.

The financing structure of independent power producers (IPPs) requires a detailed understanding of the capital waterfall and covenant mechanics. The standard model employs a special-purpose vehicle (SPV) to ring-fence project risk from the sponsor entity, enabling non-recourse or limited-recourse debt depending on lender appetite. Equity is typically contributed first by the sponsor, representing about 25–30% of the total project cost, followed by debt financing from banks or blended-finance instruments, which covers the remaining 70–75%. The operating cash flow hierarchy proceeds as follows: gross revenue, variable operating costs, fixed operating costs (including staffing, insurance, and maintenance reserves), debt service (principal and interest), debt service reserve (usually covering six months), and finally distributions to equity sponsors from residual cash. Mohamadi (2021) formalizes this cascade within project finance methodology, while Kashi et al. (2015) identify construction risk, resource variability, offtake uncertainty, and counterparty risk as the primary determinants of debt cost. The National Bank of Greece (2021) outlines its green energy financing framework, demonstrating a willingness among Greek banks to lend to wind and solar projects exceeding 5 MW, subject to strict covenants such as a minimum debt service coverage ratio (DSCR) of 1.20–1.30 (Dukan & Kitzing 2023), mandatory cash reserves, and leverage ratio limits. For smaller projects (1–5 MW), banks commonly require personal guarantees and cross-collateralisation against the sponsor's other assets, which in practice transforms the non-recourse structure into limited-recourse financing.

2.3.3 Vertically Integrated Utilities

Vertically integrated utilities operate across generation, transmission–distribution, and retail functions, creating internal hedging opportunities whereby wholesale price volatility affecting generation is partially offset by retail customer contracts. Simshauser's 2020 analysis of Australia's National Electricity Market shows that integrating an energy retailer with peaking gas turbine (OCGT) capacity yields around a 13% transaction-cost synergy (cost subadditivity) relative to non-integrated structures by internalising forward contracting and improving credit quality, rather than through pure technological cost savings. The paradox of the Greek electricity market, as highlighted in HELLENiQ Energy's 2025 analysis, similarly illustrates that wholesale electricity prices on the order of EUR 92–135 per megawatt-hour under high renewable penetration largely reflect gas-fired marginal pricing, limited interconnection capacity, and strategic bidding behaviour, rather than underlying physical scarcity. EU-wide empirical evidence from Hondroyiannis et al. (2023) confirms that high market concentration in electricity generation is associated with outcomes consistent with oligopolistic pricing, and that eliminating vertical integration between generation and supply companies is a precondition for competitive market outcomes.

2.3.4 Comparative Role in Auctions and PPAs

Del Río and Kiefer (2023) develop an analytical framework showing that renewable energy support policies, including auctions, contribute to market concentration in Spain's wind sector through consolidation effects and policy-induced barriers like higher entry costs for smaller firms. Kiefer and del Río (2023) find auctions reduce the number and diversity of project developers compared to administratively set feed-in tariffs/premiums, as large incumbents leverage financing access and development scale to secure higher award shares (e.g., CR5 often exceeding 80% in Spanish wind auctions). Del Río and Kiefer (2023) review academic literature on RES auctions, highlighting design elements like prequalification stringency and remuneration type as key influencers of outcomes such as effectiveness and actor participation, though without quantitative meta-analysis. While Dukan & Kitzing(2023) likely compares financing risks across support schemes, auctions without PPAs elevate WACC (potentially 5.8–7.2% vs. 4.1–4.5% under fixed FITs) due to revenue uncertainty, amplifying incumbents' advantages.

2.4 Current Market Status, Policy Targets, and Investment Trends

2.4.1 EU RES Targets

The European Union successfully met its 2020 renewable energy mandate, achieving a 22.1% (Eurostat) share of renewables in gross final energy consumption against a 20% target. Under the revised Renewable Energy Directive (RED III), the EU has established a binding 2030 target of 42.5%, with an aspirational goal of 45%. Meeting these objectives requires fundamental structural shifts in the electricity system, including managing the higher variability of weather-dependent generation, scaling flexibility through storage and demand response, and expanding cross-border interconnection capacity. The International Energy Agency and European Commission estimate that sustaining this trajectory will require annual investments in the range of EUR 250–350 billion.

2.4.2 Greece's NECP and RES Status

Greece's revised National Energy and Climate Plan establishes a renewable electricity target of 75.7% by 2030. Current status: renewable energy sources (RES) covered approximately 43% of the country's electricity generation in 2023. The installed capacity from renewable sources reached approximately 16 gigawatts by the beginning of the plan's reference period. Solar photovoltaic and onshore wind installations dominate the renewable portfolio. Meeting the 2030 target requires expanding installed RES capacity to 27.5 gigawatts (including hydro and offshore wind), necessitating total energy-related investments of approximately EUR 95.9 billion for the period 2025–2030, which implies an average annual mobilisation of roughly EUR 16 billion. This target-to-investment mapping illustrates the massive scale of capital mobilisation required for the green transition.

2.4.3 Investment Trends and Emerging Instruments

Corporate power purchase agreements (PPAs) serve as strategic mechanisms to accelerate the renewable energy transition by aligning corporate sustainability targets with stable financial frameworks. This aligns with the findings of Mohnot et al. (2025), whose scientometric analysis identifies regulatory certainty and supportive policy instruments—such as those found in the European Union's Green Deal—as fundamental drivers of investment dynamism and sector growth. At the regional level, Greece’s Law 4513/2018 provides an enabling legal framework for energy communities, while recovery funding and other public instruments can help lower financing barriers for renewable projects.

2.4.4 Policy Challenges

Persistent policy challenges constrain renewable energy deployment acceleration. Grid investment lags renewable capacity expansion. Curtailment compensation mechanisms remain incomplete. Permit reform advances remain fragmented. The International Energy Agency's 2023 Greece energy policy review recommends accelerated permitting timelines, grid investment acceleration, and institutional coordination enhancement as necessary preconditions for 2030 target achievement.

Chapter 3: Project Financing and Financial Evaluation

3.1 The Financing Lifecycle

3.1.1 Development Phase and Early-Stage Risk

Renewable energy project development follows a capital-intensive sequential process. Pre-development costs include meteorological or hydrological site surveys, legal and permitting fees, grid connection feasibility studies, and environmental assessments. Total pre-development expenditure ranges EUR 80,000–250,000. IRENA (2024) shows that development costs are 2-9% of the total project cost. Pre-development funding derives almost exclusively from equity capital. Commercial banks avoid lending against permits not yet awarded, reflecting the optionality value embedded in incomplete regulatory approvals. Kashi et al.'s (2015) analysis identifies construction risk, resource variability, and offtake uncertainty as primary drivers of cost of debt in renewable energy project finance.

Development stage activities consume 24–60 months or even more and require dedicated capital investment with substantial completion risk. Site identification and resource assessment requires 12–24 months of wind speed (anemometry) or water flow (hydrological survey) measurements. These measurements establish resource quality—critical determinant of project viability and lender debt service capacity assessment. Land negotiation and option agreements secure development rights from property owners, typically requiring annual payments EUR 2,000–10,000/megawatt throughout development phase and operational life. Initial environmental scoping identifies potential constraints (protected species habitat, water resource conflicts, cultural heritage sites) requiring formal environmental impact assessment. Corporate structure establishment (special-purpose vehicle formation, corporate governance documentation, regulatory registration) creates the legal vehicle through which project-level financing occurs. Each activity requires dedicated expenditure with no guarantee of project reaching commercial operation date. Industry experience suggests that only a fraction of projects commencing development ultimately reach commercial operation, reflecting regulatory rejection, permitting delays exceeding tolerance, and resource quality discoveries eliminating economic viability. The Eclareon (2020) RES-Simplify report for Greece documents that permitting timelines of 3–5 years and multi-agency coordination requirements create substantial attrition during the development phase. This selection process eliminates economically marginal projects but also requires larger sponsor equity reserves to absorb losses on failed development efforts.

3.1.2 Letters of Guarantee and Regulatory Collateral

The Greek regulatory framework for renewable energy remains capital-intensive and complex, characterized by a sequential permitting process and significant financial hurdles. While Law 4951/2022 aimed to streamline development through digitization, developers still face a multi-year approvals path—spanning Producer Certificates to final operation licenses—often stalled by environmental permitting timelines of 12–24 months. Central to these challenges is a tiered bank guarantee system that mandates substantial upfront liquidity, as mentioned on the 2.2.1 section of the thesis. For a 10 MW wind project, the cumulative burden of the Producer Certificate guarantee (€35,000/MW) and the Final Grid Connection Offer (ranging from €42/kW to €7/kW) creates a peak capital lock-up of €581,000. Because these guarantees often overlap before revenue is generated, they serve as a high entry barrier for smaller enterprises. When coupled with strict domestic lending criteria, including equity requirements of up to 35% and debt service coverage ratios of 1.25–1.35, the framework places significant financing pressure on independent power producers compared to broader European standards.

3.1.3 Construction Phase

During construction, risk transitions from regulatory to mostly execution risk. Primary hazards include contractor default, capital cost overruns, schedule delays, and technical failures. Post-2021 macro-financial turbulence created substantial capital expenditure volatility: turbine prices rose sharply amid supply constraints, photovoltaic module prices remained volatile, and steel and other construction-material costs stayed elevated. Engineering, procurement, and construction contracts with fixed-price provisions provide partial protection but shift cost-overrun risk and associated risk premiums to contractors. Feldman et al.'s 2020 research establishes construction risk as primary determinant of equity return variance for wind projects.

Construction risk management instruments redistribute completion and delay risk among project participants. In a fixed-price EPC contract, the turnkey contractor typically assumes responsibility for design completion, equipment procurement, site construction, and performance testing, thereby shifting a substantial share of cost-overrun and completion risk away from the project sponsor. Completion risk can be further supported by performance guarantee, which oblige the surety to step in, finance, or arrange completion if the contractor defaults, although the exact remedy depends on the bond wording and governing law. Construction all-risk (CAR) insurance covers physical loss or damage to the works during construction, while delay in start-up insurance protects the project owner against loss of expected revenue or soft costs when an insured physical loss delays commercial operation. For smaller independent power producers, however, the combined cost of EPC wrap, bonding, and broad construction insurance can be difficult to justify because premium structures and fixed placement costs do not scale linearly with project size, so smaller projects may face disproportionately high insurance loading. As a result, smaller sponsors may accept more residual construction risk through less rigid contracting structures, including open-book or cost-sharing arrangements, which leave equity more directly exposed to overruns and delay.

From 2021 to 2024, renewable energy markets navigated a period of intense capital expenditure (CAPEX) volatility as supply chain bottlenecks and inflationary commodity prices collided with rising global interest rates. In the wind sector, original equipment manufacturers (OEMs) such as Vestas and Siemens Gamesa shifted toward a "profits over volume" strategy to restore margins eroded by legacy fixed-price contracts and high input costs. This resulted in a stark pricing bifurcation: while turbine prices inside China plummeted to approximately USD 195/kW in 2024, prices in Western markets remained relatively stable at USD 998/kW. Simultaneously, utility-scale solar PV hardware costs continued their decade-long decline—with total installed costs (TIC) falling 11% year-on-year to USD 691/kW in 2024—yet global weighted average levelized costs of electricity (LCOE) remained flat or increased slightly due to macroeconomic headwinds. The elevated weighted average cost of capital (WACC), which reached 12% in certain high-risk regions, has emerged as a critical determinant of project viability, often neutralizing hardware cost reductions. For developers, these trends underscore the necessity of robust auction designs and procurement mechanisms that can protect project net present value (NPV) and debt service coverage ratios (DSCR) against margin compression in a high-interest-rate environment.

3.1.4 Operation Phase: Project Finance Structure

Upon completion, construction facilities transition to term loans with tenor of 6–15 years, matching support scheme contract duration or power purchase agreement term. Lender protections include: debt service coverage ratio covenants (minimum 1.20), debt service reserve accounts (typically 6 months), cash waterfall provisions controlling capital allocation, and step-in rights enabling lender assumption of operations upon covenant breach. Mohamadi's 2021 project finance framework documents non-recourse or limited-recourse structures as standard. Greek banks frequently employ blend of project finance with personal guarantees and cross-collateralisation for smaller independent power producers, reflecting residual credit risk concerns. Refinancing opportunities typically emerge after 3–5 years operational performance, enabling lower weighted average cost of capital reflecting reduced construction and performance risk.

3.2 Funding Sources

3.2.1 Commercial Bank Debt

Commercial bank debt has historically been the primary external funding source for utility-scale renewable energy projects in Greece, so movements in euro-area interest rates feed directly into project finance costs. The European Central Bank's tightening cycle between 2022 and 2024 moved the three-month Euribor from negative territory (around −0.5 %) to roughly 4 %, implying an increase of approximately 4.5 percentage points in the benchmark rate used for most construction and term loans. Greek banks add borrower- and project-specific margins above Euribor; Noothout et al. (2016), drawing on the DiaCore project's survey of European renewable-energy financing conditions, report a typical Greek renewable-project bank rate between 8.5 and 12.5%.

The cost of capital for Greek renewables reflects a structural financing disadvantage, not a temporary anomaly. Angelopoulos et al. (2017) combined a CAPM-based modelling framework with interviews of 43 Greek market participants and found that, for onshore wind projects in 2015–2016, the cost of debt generally fell in the 6–12 % range, the cost of equity in the 10–15 % range, and the resulting WACC between 7 % and 12 %, with similar or slightly higher values for large solar PV plants. They also document that, under post-crisis conditions, banks frequently reduced leverage from the stylised 70/30 debt–equity split to ratios such as 55/45 or 60/40, reflecting tighter credit-risk assessment and limited liquidity in the Greek banking system.

Steffen (2020), in a global meta-analysis of renewable-energy financing conditions covering 46 countries with harmonised, after-tax WACC estimates adjusted to a common interest-rate environment, confirms this pattern at the international level. German onshore-wind WACC values cluster around 3 %, whereas Greek estimates sit in the low-double-digit range 11.7%, implying a differential of roughly 8 percentage points between a core euro-area and a high-risk peripheral market. In practice, Greek renewable projects face both higher underlying benchmarks and significantly higher credit and country-risk premia, which commercial banks translate into higher all-in interest rates, shorter loan tenors, and lower maximum leverage than in Northern European markets. These conservative debt terms increase the levelised cost of electricity for Greek projects and constrain the amount of non-recourse debt they can support, making domestic banking conditions a critical determinant of which sponsors can bid competitively in Greek renewable-energy auctions.

3.2.2 RRF and Blended Structures

Steffen (2020), in a global meta-analysis of renewable-energy financing conditions covering 46 countries with harmonised, after-tax WACC estimates adjusted to a common interest-rate environment, confirms this pattern at the international level. German onshore-wind WACC values cluster around 3 %, whereas Greek estimates sit in the low-double-digit range (approximately 11–12 %), implying a differential of roughly 8 percentage points between a core euro-area and a high-risk peripheral market. In practice, Greek renewable projects face both higher underlying benchmarks and significantly higher credit and country-risk premia, which commercial banks translate into higher all-in interest rates, shorter loan tenors, and lower maximum leverage than in Northern European markets. These conservative debt terms increase the levelised cost of electricity for Greek projects and constrain the amount of non-recourse debt they can support, making domestic banking conditions a critical determinant of which sponsors can bid competitively in Greek renewable-energy auctions.

The financial model developed in Chapter 5 adopts a representative capital structure of 50 % RRF debt at 0.35 %, 20 % bank debt at 6.0 %, and 30 % sponsor equity. Table 3.1 below maps every key financial-model assumption to its primary data source, addressing the need for full transparency in the parameter selection process.

Parameter	Value	Source
A. Cost-of-Capital Parameters (CAPM / WACC)		
Risk-free rate (r_f)	3.98 %	Bank of Greece, 15-year government bond yield, April 2026
Unlevered beta (β_U)	0.58	Damodaran (2026), Green & Renewable Energy (Europe), average 2021–2026
Market risk premium (MRP)	5.24 %	Damodaran (2026), implied ERP for Europe plus risk-free rate
Corporate tax rate (T)	22 %	Law 4172/2013 (as amended 2021)
B. Capital Structure & Financing		
Equity share	30 %	Greece 2.0 RRF facility structure (minimum 20%)
RRF loan share	50 %	Greece 2.0 RRF facility (Ministry of Finance, 2022)
Commercial bank share	20 %	Residual after RRF and equity allocation
D/E ratio (market-value)	2.33	70 % total debt / 30 % equity → D/E = 2.33
RRF concessional rate	0.35 %	Greece 2.0 RRF facility (Ministry of Finance, 2022)
Commercial bank rate	6.0 %	Euribor ≈ 3 % + margin ≈ 3 % (assumption based on personal experience)
Debt tenor	15 years	Greek project-finance convention
DSCR covenant threshold	1.25×	Dukan and Kitzing (2023), European RES covenant range 1.20–1.30
C. Technology & CAPEX		
CAPEX — Onshore Wind (€/kW)	1,700	IRENA (2024), adjusted USD → EUR at 0.85
CAPEX — Small Hydro (€/kW)	1,870	IRENA (2024), SHP < 10 MW, adjusted at 0.85

CAPEX — Solar PV (€/kW)	600	IRENA (2024), adjusted at 0.85
CAPEX — BESS (€/kWh)	163.2	IRENA (2024), USD 192/kWh adjusted at 0.85
D. Capacity Factors & Revenue		
CF — Onshore Wind	30 %	IRENA (2024), Figure 2.12
CF — Small Hydro	40 %	IRENA (2024), range 35–55 %; Klein et al. (2022), Greek SHP 38–63 %
CF — Solar PV	17.1 %	IRENA (2024), Figure 3.1
FiP reference — Wind	57.66 €/MWh	RAAEY (2024), auction clearing prices 2022
FiP reference — Hydro	90.00 €/MWh	RAAEY (2024), run-of-river SHP reference price
Day-Ahead MCP 2025 – annual average (ENEX EL-DAM)	103.61 €/MWh	ENEX EL-DAM Market Watch Output PDFs, 365 trading days average
E. Tax & Depreciation		
Depreciation period	15 years	Law 4308/2014
Project operational life	20 years	Methodological assumption; aligned with FiP contract duration

Table 3. 1: Key Financial-Model Parameters and Data Sources

Under this structure, the blended pre-tax cost of debt combines the two debt tranches in proportion to their share of total financing:

$$r_D = \frac{w_{RRF} * r_{RRF} + w_{BANK} * r_{BANK}}{w_{RRF} + w_{BANK}} = 1.96\%$$

This blended rate of approximately 2 % compares favorably with the roughly 6 % all-in cost that would prevail if the entire 70 % debt tranche were financed through commercial bank loans alone. The after-tax WACC under the RRF-blended structure, derived fully in Section 4.4, is 4.84 %; the counterfactual WACC without RRF participation is 7.04 %, implying that the concessional facility compresses the cost of capital by approximately 220 basis points.

3.2.3 Equity Capital and Exit Options

Equity capital constitutes the risk-bearing layer of the capital structure. Large utilities access capital markets through rights issues and green-bond issuance, but small and medium-sized independent power producers typically rely on sponsor equity and co-investors including family offices, infrastructure funds, and specialised renewable-energy vehicles. The 20 % equity requirement under the Greece 2.0 blended-finance structure is in line with the 20–25 % equity share common in Northern European project finance (Angelopoulos et al., 2017), reflecting both Greek banking conservatism and the regulatory design of the RRF facility. Common exit strategies for IPP sponsors include ready-to-build (RTB) sales, where the project is transferred after auction award but before construction, and operational portfolio sales to infrastructure investors seeking stable, contracted cash flows.

3.3 Key Financial Indicators

3.3.1 NPV, WACC and Discount Rate Selection

The economic evaluation of renewable energy investments requires a valuation framework that incorporates both the timing of cash flows and the risk profile of the project. In project finance, this is typically achieved through discounted cash flow analysis, where expected future cash inflows and outflows are converted into present values using an appropriate discount rate. Because renewable energy projects are capital intensive and are normally financed through a mix of debt and equity, the discount rate used in valuation is not treated as an abstract parameter but as the project's cost of capital, commonly expressed as the weighted average cost of capital (WACC). In this context, the selection of the discount rate is particularly important because financing costs form a significant share of total project cost in renewable energy investments, especially for technologies such as solar PV and wind power. For that reason, the use of WACC in place of a generic discount factor r is considered appropriate for project-level financial appraisal, including net present value (NPV) analysis.

Net present value serves as a core indicator to assess the economic viability of an investment project, measuring the difference between the present value of expected future net cash flows and the initial investment cost. A positive NPV implies that the expected return of the project exceeds the discount rate applied, while a negative NPV suggests that the project does not generate sufficient value to compensate providers of capital at the required rate of return. The general NPV formula is expressed as:

$$\boldsymbol{NPV = -I + \sum_{t=1}^{T} \frac{FCF_t}{(1+r)^t}}$$

where *I* is the initial investment, *FCFt* represents the future net cash flow in period *t*, and *r* is the discount rate. In project finance applications, the discount rate *r* is typically substituted by the weighted average cost of capital because the latter reflects the combined required return of debt holders and equity investors financing the project. For renewable energy investments, NPV is particularly useful because these projects usually involve high upfront capital expenditures and relatively stable future operating cash flows over long project lives. Under such conditions, the present value of future revenues is highly sensitive to the discount rate assumed, meaning even small changes in WACC can significantly alter the estimated profitability of the project.

The discount rate acts as the mechanism to convert future project cash flows into present values. Steffen 2020 explicitly states that the cost of capital is equal to the discount rate used in investment appraisals, linking the valuation model directly to the financing structure of the investment rather than treating discounting as a purely mathematical exercise. Similarly, Mohamadi 2021 explains that present value calculations require a risk-adjusted interest rate that reflects both the time value of money and project risk. In renewable energy project finance, the discount rate must capture the actual financing terms faced by the project, including the cost of debt, the cost of equity, and the relative share of each source of capital in the overall capital structure.

The weighted average cost of capital represents the blended return required by all capital providers to finance a project. It is defined as the equity rate weighted by the equity share plus the debt rate weighted by the debt share. In its basic form, WACC can be written as:

$$\boldsymbol{WACC = \left(\frac{E}{D+E}\right)_{R_e} + \left(\frac{D}{D+E}\right)_{R_d}}$$

where *E* is the market value of equity, *D* is the market value of debt, *Re* is the cost of equity, and *Rd* is the cost of debt. It is important to distinguish between WACC, after-tax WACC, and pre-tax WACC, as after-tax WACC is often the preferred measure because debt financing usually benefits from the tax deductibility of interest payments. This distinction is vital in empirical studies of renewable energy because tax effects, leverage levels, and financing structures vary across countries, technologies, and years. Angelopoulos et al. utilize WACC as the central financial indicator in evaluating renewable energy investments in Greece, arguing that it efficiently captures the real cost of capital and serves as a practical benchmark in project profitability assessment.

The substitution of *r* by WACC in the NPV framework is justified by the nature of project-financed investments. Since renewable energy projects are normally funded through a capital structure that includes both debt and equity, the relevant discount rate must reflect the opportunity cost of all invested funds. WACC provides this aggregate measure, ensuring the valuation reflects the actual financing burden embedded in the project. Accordingly, the NPV equation in renewable energy project finance is formulated as:

$$\boldsymbol{NPV = -I + \sum_{t=1}^{T} \frac{FCF_t}{(1 + WACC)^t}}$$

This formulation is appropriate when the cash flows being discounted are project cash flows available to all capital providers. The use of WACC has major implications for renewable energy investment analysis, as differences in cost of capital across countries and technologies can materially affect estimated generation costs and investment decisions. For the Greek case, Angelopoulos et al. demonstrate that WACC is a practical indicator shaped by country risk, policy design, financing risk, and regulatory stability. Their analysis shows that the cost of capital for Greek renewable energy investments is heavily influenced by policy and market conditions, underlining that the discount rate in NPV analysis must reflect the actual financing environment of the project. Adopting WACC instead of a generic *r* strengthens methodological consistency and economic realism, aligning the valuation framework with the principles of project finance and the empirical literature on renewable energy investment appraisal.

3.3.2 IRR and Risk-Adjusted Return Requirements

The IRR is the value of *r* that makes NPV equal to 0. In project finance, an investment is acceptable when the project IRR exceeds the relevant hurdle rate or cost of capital, while equity investment is acceptable when equity IRR exceeds the required return on equity.

The required return on equity is commonly estimated using the Capital Asset Pricing Model (CAPM) as follows:

$$r_e = r_f + \beta * (MRP)$$

Where r_e is the cost of equity, r_f is the risk-free rate, β is the beta coefficient, and MRP is the market risk premium. Noothout et al. show that higher risk perceptions raise required returns and cost of capital, while de-risking measures reduce financing costs. Dukan and Kitzing (2023) similarly find that revenue stabilization and low-risk remuneration schemes reduce WACC and support payments, with debt de-risking being more effective than equity de-risking.

3.3.3 LCOE and Competitiveness

Levelized cost of energy (LCOE) represents the discounted cost of electricity over the project lifetime. A standard formulation is:

$$LCoE = \frac{CAPEX + \sum_{t=1}^{n} \frac{(OPEX)_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{AEP_t}{(1+r)^t}}$$

Where:

- CAPEX = initial capital expenditure
- OPEXt = operating expenses in year t
- AEPt = annual energy production in year t
- r = discount rate, usually the WACC of cost of capital
- n = project lifetime

IRENA explains that LCOE is highly sensitive to financing conditions because renewable projects are capital intensive and most of their costs are incurred upfront. IRENA reports global weighted-average 2024 LCOE values of USD 0.033/kWh for onshore wind, USD 0.044/kWh for solar PV and USD 0.057/kWh for hydropower, while also noting that regional values vary depending on capital costs, operating costs, capacity factors, and financing conditions. Competitiveness is therefore assessed by comparing LCOE with auction clearing prices or contracted tariff levels, since the margin between them indicates whether the project can remain financially viable.

3.3.4 DSCR and Payback

The debt service coverage ratio (DSCR) measures the ability of project cash flow to cover debt obligations. It is commonly defined as:

$$DSCR = \frac{EBITDA}{Debt\ Service}$$

Where:

- Earnings Before Interest, Taxes, Depreciation, and Amortization
- Debt Service is interest payment and principal repayment

In project-finance models, lenders use DSCR to size debt and to test whether the project can service its obligations under conservative production and revenue assumptions. Mohamadi notes that lenders often combine DSCR with debt sizing, loan tenor, and repayment sculpting, while Dukan and Kitzing (2023) show that DSCR requirements directly affect debt capacity and bid levels.

Payback period is the number of years required to recover the initial investment from project cash flows. In renewable project finance, payback is strongly influenced by the cost of capital, debt tenor, and support scheme design, so it should be presented as a model result rather than a universal market statistic unless you have a country-specific source.

3.4 Role of Aggregators (FoSE) and PPAs

In liberalised electricity markets, non-integrated Independent Power Producers (IPPs) must interact directly with volatile wholesale markets and complex market rules. Two institutional arrangements can partly compensate for the lack of vertical integration: (i) aggregators or intermediaries that take over market interface tasks for small and medium projects, and (ii) Power Purchase Agreements (PPAs), including corporate PPAs, that stabilise revenues and improve bankability. Both mechanisms are important because they provide external substitutes for functions that vertically integrated utilities perform in-house.

3.4.1 Aggregators

In electricity markets, forecasting, balancing, hedging and settlement are characterised by economies of scale and learning-by-doing, which makes them expensive for small IPPs to handle individually. As a result, specialised aggregators —termed FoSE (aggregator of balancing responsible parties) in Greece— emerge that pool many plants, internalise part of the balancing across their portfolio, and offer standardised services back to generators.

Simshauser's analysis of the Australian National Electricity Market (NEM) shows that separating generation and retail creates "non-trivial transaction costs", mainly in the form of hedging premia in forward markets. When peaking generation is integrated with a retail portfolio, total costs are about 13% lower than when the same combination is organised through market contracts, and the integrated firm can maintain investment-grade credit metrics. In practice, the retailer acts as an internal aggregator: it combines load and generation, optimises hedges and absorbs imbalance risk within the firm rather than via external contracts.

For non-integrated IPPs, external aggregators provide access to similar services. They can reduce the unit cost of forecasting and balancing by exploiting scale and by managing a diversified portfolio. However, buying these services on the market adds an extra fee that reflects the aggregator's own capital costs and risk. Thus, while aggregation lowers some operational and informational barriers, it does not fully remove the structural disadvantage that IPPs face compared with vertically integrated utilities, which can perform these functions internally without an additional margin to an intermediary.

3.4.2 Corporate PPAs

Long-term PPAs, especially corporate PPAs with creditworthy buyers, are a second key instrument for non-integrated IPPs. In project finance structures, future cash flows from the project are the main source of debt repayment, so lenders place great weight on revenue stability and downside protection. For merchant plants that rely mainly on spot prices and short-term forwards, cash flows are highly volatile and often insufficient to support non-recourse project finance, particularly for peaking capacity in energy-only markets

Simshauser's simulations for a merchant open-cycle gas turbine in the NEM indicate that a stand-alone project financed on a non-recourse basis and relying on spot and cap prices exhibits repeated breaches of its debt covenants and fails to maintain adequate debt service coverage ratios over the full market cycle. In contrast, when the same generation asset is held on the balance sheet of an energy retailer, the integrated firm can sustain materially stronger and more stable leverage positions because retail margins and generation profits are negatively correlated, smoothing cash flows and credit metrics. Mohamadi emphasizes the same point more generally: pure project finance is suitable for large, capital-intensive assets only when there is a predictable revenue stream, typically backed by long-term contracts such as PPAs or regulated tariffs.

Corporate PPAs partially replicate these advantages for IPPs. They provide a long-term price floor or fixed price, reduce exposure to wholesale price risk, and make it easier to reach acceptable debt service coverage ratios and tenors. Empirical work on European renewables shows that de-risking revenues through stable support schemes or contracts significantly reduces the weighted average cost of capital (WACC) and, therefore, required support levels. Dukan and Kitzing (2023) find that lowering debt risk (via more stable cash flows and better loan terms) is almost twice as effective in reducing support costs as lowering equity risk, underlining the central role of predictable debt servicing.

However, corporate PPAs are not a perfect substitute for vertical integration. First, they usually stabilise only a share of total output or a limited period, leaving residual merchant exposure that still has to be managed through costly hedging. Second, PPAs themselves involve negotiation, due diligence and ongoing monitoring costs that are proportionally higher for small projects. Third, outside the most creditworthy markets and off-takers, PPA prices must include a risk premium, which again reflects the absence of an internal retail portfolio that could absorb risk more efficiently.

3.4.3 Strategic Implications for Non-Integrated IPPs

Taken together, the evidence confirms that vertical integration remains a superior organisational form for managing market risks and financing large-scale generation in liberalised markets. Simshauser's results show that when peaking generation and retail are combined, the integrated entity avoids loss-making years that occur in the stand-alone cases, enjoys investment-grade credit metrics, and benefits from measurable economies of vertical integration over a long period. Transaction cost savings arise both from avoiding forward contract premia (especially for caps and peak swaps) and from lower financing costs due to stronger credit quality.

Aggregators and corporate PPAs allow non-integrated IPPs to access some of these benefits without owning a retail portfolio. Aggregators lower per-unit balancing and forecasting costs, while PPAs provide revenue stability that supports project finance and reduces WACC. Nonetheless, both solutions operate through markets and contracts, so their prices must cover their own transaction costs and risk premia. In other words, they narrow but do not close the gap between IPPs and vertically integrated utilities.

From the perspective of this thesis, the conclusion is that large, vertically integrated utilities retain a structural advantage over non-integrated IPPs in liberalised electricity markets. IPPs can make projects bankable through aggregators and PPAs, but only at the cost of paying additional margins to intermediaries and accepting residual merchant and policy risk that integrated firms can manage more cheaply inside the firm boundary.

Chapter 4: Methodology

The present chapter establishes the methodological foundation upon which the financial analysis in subsequent chapters rests. It proceeds in five stages: first, it positions the research within an appropriate design paradigm and justifies the epistemological choices made; second, it critically reviews the principal evaluation methods applied to renewable energy investments, identifying the strengths and limitations of each; third, it justifies the selection of a WACC-based discounted cash flow model using free cash flow to the firm as the primary valuation approach, and sets out the cost-of-capital framework in detail; fourth, it describes in precise terms how the financial model is constructed, parameterised, and subjected to scenario and sensitivity testing; and fifth, it acknowledges the limitations of the approach and the measures taken to mitigate them. Together, these sections provide an auditable account of the analytical choices made and the intellectual grounds on which they rest.

4.1 Research Design and Epistemological Positioning

This study uses a quantitative, deductive research design. It starts from well-known corporate finance theory—mainly the discounted cash flow framework in Brealey, Myers and Allen (2025) and the project finance principles in Mohamadi (2021). From this theory, it derives propositions and tests them using numerical input data. The goal is to produce numerical results for project performance that are clear, transparent, and repeatable. This makes a quantitative, model-based approach the most suitable choice.

This logic is different from inductive approaches that build theory from data patterns, and from interpretive approaches that focus on how actors think and behave. For project investment appraisal, a quantitative, deductive approach is the standard in both research and practice. Gomez-Restrepo, Gonzalez-Ruiz and Botero Botero (2024) review 268 studies on PV and storage investments and show that most of them use discounted cash flow models as their main tool.

The empirical strategy is a comparative case study of three typical project types in the Greek renewable energy market: a utility-scale onshore wind farm, a run-of-river small hydropower plant, and a solar PV plant with battery storage. The case study approach allows a detailed look at each project type and also a comparison between them. Each case is set up as a representative project. It uses parameters drawn from peer-reviewed studies and official sources rather than detailed data from one specific plant. This follows Steffen (2020), who uses representative project configurations to compare WACC across countries, and Feldman, Bolinger and Schwabe (2020), who benchmark financing terms for renewable plants in the United States. Using representative rather than confidential project data improves transparency and supports the recommendation by IRENA (2024) to use typical values in cross-country cost comparisons.

All data are secondary. They come from academic articles, international organisations, and Greek regulatory reports. Key sources are: IRENA (2024) for technology costs; RAAEY (2024) for Greek support schemes; Angelopoulos, Doukas and Psarras (2017) and Steffen (2020) for cost of capital in Greece; Feldman et al. (2020) for international project finance benchmarks; and Brealey et al. (2025) and Mohamadi (2021) for the core financial model structure. Where different sources give different numbers for the same input, the analysis uses either the most recent value or a central value (for example, the median), and records the full range in the sensitivity analysis in Chapter 6.

Having set out the research design, the next subsection reviews common financial evaluation methods and explains why the framework used here is chosen.

4.2 Review of Investment Evaluation Methods in Renewable Energy

The literature documents a wide range of financial evaluation methods applied to renewable energy investments. Five principal approaches have achieved significant adoption in academic and practitioner contexts: the Levelised Cost of Energy, the internal rate of return, the payback period, real options analysis, and discounted cash flow methods.

The Levelised Cost of Energy (LCOE) is the most widely cited benchmarking metric in energy policy and technology cost analysis. Defined as the constant real price per megawatt-hour at which the present value of lifetime revenues equals the present value of all costs, LCOE enables comparison across technologies with very different cost and output profiles. IRENA (2024), the IEA (2023), and Lazard's annual benchmarking reports employ this metric to document the global convergence of renewable technology costs over the past decade. Its limitation, however, is fundamental: LCOE assumes a uniform cost of capital across technologies, investor types, and jurisdictions. Egli, Steffen, and Schmidt (2020) expose the conceptual problem—applying a uniform discount rate to countries with vastly different risk profiles produces distorted LCOE rankings and misleading policy recommendations. The empirical magnitude of this distortion is documented by Egli et al. (2023), who reverse-engineer the cost of capital from 3,983 solar PV auction results across multiple markets and find that financing costs vary substantially across countries and investor types. A non-integrated independent power producer operating in a peripheral EU market faces a cost of capital that can be several percentage points above the uniform benchmark typically embedded in LCOE calculations. When the applicable cost of capital exceeds the assumed rate, LCOE understates the true cost of electricity generation for that investor. In this study, LCOE is therefore retained as a supplementary benchmarking tool, consistent with IRENA (2024), but is not used as the primary investment decision criterion.

The internal rate of return is the companion metric to NPV within the DCF framework, defined as the discount rate at which the net present value of a project's cash flow stream equals zero. In equity project finance, the relevant quantity is the equity IRR—the rate r* that satisfies:

$$\sum_{t=1}^{T} \frac{FCFE(t)}{(1+r^*)^t} = Equity\ Investment$$

The decision rule is straightforward: a project creates value for equity investors if and only if the equity IRR exceeds the cost of equity, r_e. The IRR metric is particularly useful in a comparative case study context because it is scale-invariant, enabling direct comparison of return profiles across project configurations of different sizes without requiring normalisation. Its well-known limitation—that it implicitly assumes interim cash flows are reinvested at the IRR itself rather than at the cost of equity—is acknowledged but is not material here, because the model cash flows are not subject to interim reinvestment: distributions follow a fixed debt-amortisation schedule. Gomez-Restrepo et al. (2024) confirm that IRR is reported in 87 percent of renewable energy investment studies surveyed, and its inclusion as a primary metric alongside NPV is standard practice in the literature this study builds upon, including Angelopoulos et al. (2017), Feldman et al. (2020), and Mohamadi (2021).

The payback period measures the time required for cumulative project cash flows—undiscounted or discounted—to recover the initial equity investment. Its appeal lies in its liquidity interpretation: a shorter payback implies faster capital recovery and lower exposure to long-term uncertainty. The discounted payback period, which applies the cost of equity to each year's cash flow before accumulating them, partially addresses the time-value limitation of its simple counterpart. Liu, Song, Li et al. (2023), in a comprehensive review of wind power life-cycle cost modelling, confirm that the payback period remains a standard supplementary metric in project finance, particularly for debt covenant design. This study calculates the discounted payback period as one of four reported performance indicators, consistent with this convention.

Real options analysis (ROA) extends the DCF framework by treating managerial flexibility — the option to delay, expand, contract, or abandon a project — as having quantifiable economic value. Developed from financial options pricing theory by Dixit and Pindyck (1994) and extended to energy investments by subsequent researchers, ROA is theoretically superior to static NPV for projects where material uncertainty creates valuable flexibility that managers can actively exploit. Relevant options in the renewable energy context include deferring construction pending grid-connection confirmation, scaling capacity following proven resource performance, or switching technology mid-development. Despite its theoretical appeal, three considerations led to its exclusion from the primary methodology of this study.

First, ROA requires stochastic modelling of the underlying risk drivers — typically electricity prices, capacity factors, or policy variables — and the results are highly sensitive to the volatility parameters used. As Delapedra-Silva et al. (2022) observe in their systematic review, calibrating these parameters demands either liquid traded options on the underlying asset or sufficiently long historical price series from which implied volatility can be extracted. Neither condition is met for Greek renewable energy projects: there is no organised options market for Greek wholesale electricity or Feed-in Premium contracts, the ENEX day-ahead market has operated for fewer than five years in its current form, and auction reference prices are administratively determined rather than market-discovered. Under these circumstances, any volatility estimate would rest on subjective assumptions rather than observable data, introducing a layer of model risk that could obscure rather than clarify the investment decision.

Second, the institutional design of the Greek FiP auction mechanism substantially limits the post-award flexibility that ROA is designed to value. Once a project secures an auction award, the developer faces binding deadlines for financial close, construction commencement, and commercial operation; failure to meet these milestones results in forfeiture of the awarded tariff and the associated bank guarantee. The option to defer is therefore effectively extinguished at the point of award, and the option to expand is constrained by the licensed capacity specified in the environmental and grid-connection permits. In practice, a Greek IPP that wins an auction at 57.66 €/MWh for 8.8 MW of wind capacity cannot meaningfully choose to "wait and see" — it must build or forfeit. This institutional rigidity reduces the value of the flexibility premium that ROA would estimate, making the incremental insight over a well-constructed sensitivity analysis marginal at best.

Third, the scope of this thesis is an applied financial-viability assessment for a practising MBA audience, not a methodological contribution to options pricing theory. The combination of DCF analysis with systematic sensitivity testing — including tornado analysis, break-even thresholds, and scenario variation across all key parameters — captures the range of plausible outcomes without requiring the additional assumptions that a real options model would introduce. This pragmatic approach aligns with the analytical tools available to the medium-scale IPPs that the thesis seeks to inform, for whom a transparent WACC-based DCF with clearly sourced parameters (Table 3.1) is both actionable and defensible.

Discounted cash flow (DCF) analysis is the foundational quantitative framework for investment appraisal in corporate and project finance, and the most directly applicable method for the valuation objectives of this study. In its project finance application, the DCF model projects all cash inflows and outflows over the asset's operational life, applies a risk-adjusted discount rate that reflects the opportunity cost of the capital committed, and derives the net present value (NPV) as the difference between the present value of cash flows and the initial investment. Two cash flow bases are used in practice: free cash flow to the firm (FCFF), which represents operating cash flow before financing charges and is discounted at the weighted average cost of capital (WACC), and free cash flow to equity (FCFE), which represents the residual cash flow after debt service and is discounted at the cost of equity. Brealey, Myers, and Allen (2025) establish the theoretical foundations of both approaches, while Mohamadi (2021) details their application in project finance. The principal outputs—NPV and IRR—are standard investment metrics in the renewable energy literature. A practical limitation of the DCF approach is its sensitivity to the assumed discount rate: because the NPV is highly convex with respect to the cost of capital for long-lived assets, small errors in WACC estimation produce large errors in estimated project value.

The comparative review establishes that DCF-based analysis, anchored in WACC and supported by multiple performance indicators, is the appropriate primary framework for this study. The following section sets out this framework in detail.

4.3 Justification for the Selected Valuation Framework

The preceding review establishes that discounted cash flow analysis, anchored in the weighted average cost of capital, as the appropriate primary framework for this study. This section sets out the specific reasons why a WACC-based DCF model reporting four performance indicators — project NPV, equity IRR, DSCR, and discounted payback period — is the most suitable choice for the research objectives, the Greek market context, and the comparative case study design.

The first justification is conceptual. A WACC-based DCF model operates at two complementary levels simultaneously: it assesses whether the project as a whole creates value relative to its total financing cost (project NPV at WACC), and it assesses whether equity investors earn a return that exceeds their required cost of equity (equity IRR on the post-debt-service cash flow stream). This dual perspective is essential for a study that must speak to both equity investors deciding whether to commit capital and debt providers deciding whether to lend. A model that discounts only at the cost of equity would obscure the enterprise-level value creation test; one that reports only a project NPV would leave the equity return unaddressed. Brealey, Myers and Allen (2025) formalise both perspectives within a unified framework, and Mohamadi (2021) demonstrates their joint application in renewable energy project finance settings.

The second justification concerns the role of IRR. The equity internal rate of return — the discount rate that sets the equity NPV to zero — is included as a primary metric alongside NPV because it is scale-invariant, making it the natural basis for comparing three project configurations of potentially different sizes without normalisation. The decision rule is direct: a project is financially viable for equity investors if and only if the equity IRR exceeds the cost of equity derived from CAPM. Noothout et al. (2016), in the European Commission DiaCore report, show that equity investors in European renewable projects assess viability against risk-adjusted hurdle rates, which supports using the equity IRR relative to the required cost of equity as a primary decision metric in this study.

The third justification is empirical and context-specific. WACC-based DCF analysis has been validated as the standard methodology for renewable energy project finance appraisal in the European and Greek context by several directly comparable studies. Steffen (2020) estimates WACC across 46 countries from project finance transaction data and uses DCF analysis to assess project viability — producing the benchmark cost-of-capital parameters adopted in this study. Angelopoulos et al. (2017), in the most directly comparable prior study of Greek wind investment, apply a risk-adjusted DCF model with CAPM-derived discount rates to assess project viability under different support schemes — an approach consistent with the framework adopted here and one that provides the WACC benchmarks against which the present parameterisation is validated. Feldman, Bolinger and Schwabe (2020), examining US renewable energy project finance, employ the same WACC/NPV/IRR structure and demonstrate its applicability to comparative case study designs. Gomez-Restrepo et al. (2024) document that NPV and IRR are among the most frequently applied traditional valuation methods in the renewable energy investment literature, supporting their selection as the primary indicators here.

The fourth justification concerns the inclusion of DSCR and discounted payback. A study of Greek IPP projects cannot limit itself to equity metrics: the project finance structure places lenders in a position of primary risk, and their covenant thresholds — particularly the minimum DSCR — are the binding constraints that determine whether a project can be financed at all. Dukan and Kitzing (2023) document DSCR requirements explicitly in European renewable energy project finance and confirm that 1.20 is the operative minimum threshold for onshore wind projects under a P-90 revenue scenario. The discounted payback period complements the equity IRR by providing a liquidity-based metric that lenders use to assess capital recovery within the loan tenor. Together, these four indicators — project NPV, equity IRR, minimum DSCR, and discounted payback —

ensure that the analysis addresses the full set of financial stakeholders in the project capital structure, consistent with the multi-metric approach recommended by De La Pedra (2022) and Liu et al. (2023).

The selection of this framework is therefore not a default but a deliberate methodological choice grounded in corporate finance theory, validated by the directly comparable European literature, and calibrated to the specific informational needs of the Greek IPP investment context. Section 4.4 now sets out in detail how the model is constructed and parameterised.

4.4 Financial Model Architecture

Each of the three representative project configurations is modelled using a five-module structure: revenue estimation, operating cost structure, capital structure and WACC parameterisation, free cash flow computation, and financial performance metrics. The model covers a 20-year operational period following a one-year construction phase, consistent with standard project finance conventions for renewable energy assets and the typical tenor of Greek Feed-in Premium (FiP) auction contracts. All monetary values are expressed in constant 2024 euros; no real escalation is assumed for revenues or costs over the project life, consistent with the fixed-price nature of FiP contracts and the real (inflation-adjusted) interpretation of the discount rate.

4.4.1 The Weighted Average Cost of Capital

The discount rate applied to FCFF is the after-tax weighted average cost of capital (WACC). Letting E denote the market value of equity, D the market value of debt, $V = D + E$ the total project value, r_E the cost of equity, r_D the pre-tax cost of debt, and T the corporate income tax rate, WACC is defined as:

$$WACC = \left(\frac{E}{V}\right) * r_e + \left(\frac{D}{V}\right) * r_d * (1 - T)$$

The term $r_d * (1 - T)$ reflects the tax deductibility of interest payments, which reduces the effective cost of debt finance and generates the debt tax shield. All weights are computed on a market-value basis, as prescribed by Brealey et al. (2025). The debt-to-equity ratio assumptions used in this study follow the benchmarks for Greek renewable energy project finance reported by Angelopoulos et al. (2017) and the European comparative parameters documented in Steffen (2020) and Feldman et al. (2020), ensuring that the leverage structure reflects realistic financing conditions rather than a theoretical optimum.

4.4.2 The Cost of Equity: CAPM

The cost of equity is estimated using the Capital Asset Pricing Model (CAPM). Letting r_f denote the risk-free rate, β the levered equity beta reflecting both business and financial risk, and MRP the equity market risk premium:

$$r_e = r_f + \beta * MRP$$

In the Greek context, the risk-free rate is proxied by the yield on the 15-year Greek government bond, similar duration with the debt tenor, consistent with the approach adopted by Angelopoulos et al. (2017), Steffen (2020), and IRENA (2024). This choice reflects the sovereign credit risk embedded in the Greek investment environment—a component that cannot be diversified away by any domestic energy investor and, crucially, cannot be mitigated by adjustments to the renewable energy support scheme.

The market risk premium (MRP) is calculated as the expected premium return on the market, as calculated by Damodaran's (2026) Green and Renewable Energy sector, plus the risk-free rate.

The equity beta reflects the systematic risk of renewable energy equity relative to the broader market. The Hamada (1972) equation adjusts the unlevered (asset) beta to reflect the additional financial risk created by leverage:

$$\beta_E = \beta_U * (1 + (1 - T) * \frac{D}{E})$$

where β_U is the unlevered beta, T is the corporate tax rate, and D/E is the market-value debt-to-equity ratio.

Applying the parameters used in this analysis: the unlevered beta of 0.58 is sourced from Damodaran's (2026) Green and Renewable Energy sector average for Europe over the period 2021–2026. The corporate tax rate is 22%, as specified by the Hellenic Republic Income Tax Code (Law 4172/2013, as amended). The target capital structure of 70% debt and 30% equity produces a D/E ratio of 2.333. Substituting these values:

$$\beta_E = 0.58 * \left(1 + (1 - 0.22) * \frac{70}{30}\right) = 1.6356$$

The relevered beta of 1.6356 is substantially higher than the unlevered asset beta, reflecting the amplification of systematic risk through financial leverage. This elevated beta is consistent with the capital structure of a project-financed renewable energy SPV, where 70% debt magnifies the volatility of equity returns relative to an all-equity firm.

The resulting cost of equity, derived through the CAPM as

$$r_e = 3.98 + 1.6356 * 5.24\% = 12.55\%$$

reflects both the underlying business risk of renewable energy generation and the financial risk arising from the chosen leverage ratio. If a more conservative 60/40 capital structure been adopted, the levered beta would fall to 1.18 and the cost of equity to 10.16%, illustrating the sensitivity of the CAPM output to capital structure assumptions.

4.4.3 The Cost of Debt

In Greek renewable energy project finance, commercial bank debt is priced as a floating benchmark rate plus a lender margin:

$$r_d = Euribor + Margin$$

Euribor serves as the floating benchmark that embeds the euro-area monetary policy rate, while the bank margin reflects lenders' assessments of country credit risk and project-specific risks such as construction complexity, limited-recourse structure, revenue concentration, and technology performance uncertainty. This "benchmark plus margin" structure is standard in European project finance, so the all-in cost of debt is driven both by movements in ECB policy rates (transmitted through Euribor) and by shifts in lender risk perception (captured in the margin). The ECB tightening cycle between 2022 and 2024 moved three-month Euribor from roughly −0.5% to close to 4%, implying an increase of about 4.5 percentage points in the floating leg relevant for Greek renewable-energy term loans.

Structured interviews with 43 Greek market participants reported by Angelopoulos et al. (2017) place the cost of debt for onshore wind projects in the range of 8.5–12.5% under post-crisis conditions, and indicate that banks often required leverage ratios of 55/45 or 60/40 instead of the textbook 70/30 structure. Cross-country evidence from Steffen (2020) shows Greek onshore wind and solar PV WACC in the low-teens (above 10%) versus about 3% for Germany, and identifies Greece among a group of EU member states with persistently elevated renewable-energy WACC. Against this backdrop, debt in the present model is represented as a 15-year amortising term loan with equal annual principal repayments, within the typical tenor and amortisation structures observed in European renewable-energy project finance.

4.4.4 Risk Decomposition and Cost-of-Capital Parameterisation

The risk environment for a Greek renewable energy project is decomposed into nine risk categories as identified by Angelopoulos et al. (2017) through structured expert interviews with Greek renewable-energy market participants: (i) country risk, encompassing macroeconomic instability and sovereign creditworthiness; (ii) social acceptance risk, including local opposition and permitting conflicts; (iii) administrative risk, relating to bureaucratic delays and regulatory complexity; (iv) financing risk, covering credit availability and project finance lending terms; (v) technical and management risk, including construction delays, equipment failure, and O&M performance uncertainty; (vi) grid access risk, arising from network congestion, connection delays, and curtailment exposure; (vii) policy design risk, associated with changes in support-scheme architecture; (viii) market design and regulatory risk, involving shifts in wholesale market rules and grid codes; and (ix) sudden policy change risk, representing discrete interventions that retroactively alter the investment environment. Country risk is treated as an irreducible baseline—captured through the 15-year Greek government bond yield—that cannot be mitigated by energy policy interventions. The expert-elicited WACC ranges from Angelopoulos et al. (2017) are used as plausibility bounds for the cost-of-capital assumptions adopted here and as reference points in the sensitivity analysis. The Greek corporate income tax rate of 22 percent is applied throughout, consistent with the prevailing legislation applicable to independent power producers.

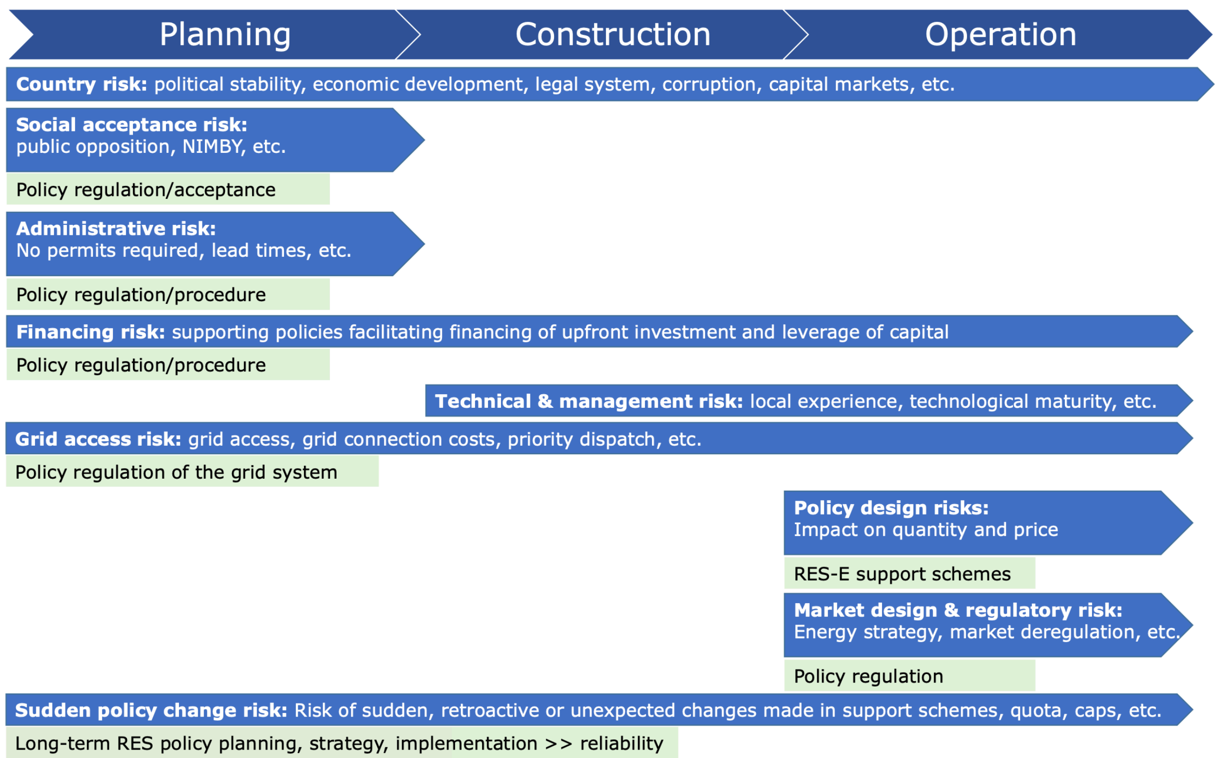

Figure 1: Risk Decomposition of RES projects, Noothout et al. (2016) Dia-Core project

4.4.5 Revenue Estimation

Annual revenue in operational year t is computed as:

$$Revenue_{(t)} = P_{auction} \times Capacity \times CF\ 8760 \times (1-c) \times (1-d)^t$$

Where:

$P_{auction}$ is the contracted FiP strike price in euros per megawatt-hour,

Capacity is the capacity of the plant usually in MW

CF is the long-run average capacity factor,

c is the annual curtailment rate applied uniformly across all hours for the purposes of this modelling exercise,

d is the annual output degradation rate,

t is the year of operation.

Capacity factors and cost benchmarks reflect site-specific resource quality drawn from published technology benchmarks, applied differently across the three configurations. For the onshore wind park, capacity factor, CAPEX, and OPEX parameters are drawn from IRENA (2024), which provides systematically assembled onshore wind cost and performance data across European and global markets for projects commissioned in 2023. For the run-of-river small hydropower plant, the capacity factor is primarily hydrology-driven rather than determined by turbine nameplate efficiency alone: it reflects the long-run average ratio of actual annual generation to nameplate capacity under mean stream-flow conditions, with performance and cost parameters drawn from Klein et al. (2022), whose systematic review harmonises small hydropower cost and performance results across multiple studies and countries, providing one of the most comprehensive published datasets and ranges for this technology class. Because the primary source of production variability for run-of-river assets is inter-annual hydrological fluctuation rather than equipment ageing, the degradation rate is set to zero in the base case for this configuration; hydrological variability is instead acknowledged as a distinct production risk and addressed in the sensitivity analysis. For the photovoltaic park with battery energy storage, PV capacity factor, CAPEX, and OPEX parameters are drawn from IRENA (2024), with an additional revenue premium to reflect arbitrage income from battery dispatch in the Greek day-ahead market and ancillary services, consistent with the price-spread evidence documented by Giannakopoulos (2025).

4.4.6 Operating Costs and Taxation

Operating expenditure (OPEX) covers annual maintenance, insurance, land lease, and management costs, expressed as a percentage of CAPEX per year and consistent with the cost ratios reported in IRENA (2024) for the relevant technology categories. Depreciation is calculated on a straight-line basis over 15 years, generating an annual tax shield against corporate income tax. The Greek corporate income tax rate of 22 percent is applied to taxable profit, defined as revenue less OPEX less interest expense less depreciation, consistent with the prevailing Greek tax legislation applicable to independent power producers.

4.4.7 Capital Structure and Debt Service

Capital expenditure encompasses all pre-operational costs, including equipment procurement, civil works, grid connection charges, and development fees, in a manner that is conceptually consistent with the total installed cost benchmarks reported in IRENA (2024) and the technology- and country-specific cost ranges published by RAAEY (2024). The capital structure follows leverage ratios typical of Greek renewable energy project finance, as documented by Angelopoulos et al. (2017) and benchmarked against European and NREL comparative parameters in Feldman et al. (2020). Debt is structured as a 15-year amortising term loan with equal annual principal repayments and declining interest on the reducing balance, at an all-in fixed rate calibrated to the prevailing Euribor level plus a bank margin at financial close. This structure is broadly consistent with the project finance conventions described in Mohamadi (2021) and with standard lending terms observed in recent Greek RES project financings.

4.4.8 Free Cash Flow Computation

Free cash flow to the firm in each operational year is computed from earnings before interest and taxes (EBIT(t) = Revenue(t) − OPEX(t) − Depreciation(t)) as follows:

$$\text{FCFF}(t) = \text{EBIT}(t) \times (1 - T) + \text{Depreciation}(t)$$

Since no capital expenditure is incurred during the operational phase and working capital requirements are assumed negligible for a single-asset project company, FCFF reduces to after-tax operating profit plus the depreciation add-back—that is, the cash flow available to all providers of capital before any financing costs are deducted. This formulation is consistent with the treatment of FCFF in Brealey et al. (2025) and Mohamadi (2021).

Free cash flow to equity is derived from FCFF by deducting after-tax interest expense and scheduled principal repayments:

FCFE(t) = FCFF(t) − r_D × D(t) × (1 − T) − Principal(t)

where D(t) is the outstanding debt balance at the beginning of year t and Principal(t) is the scheduled repayment in that year. The FCFE stream represents the cash remaining for equity holders after all senior claims have been satisfied; it is discounted at the cost of equity, rE, to compute the equity NPV and equity IRR.

4.4.9 Financial Performance Indicators

Four financial performance indicators are computed for each project configuration and each curtailment scenario. The project-level net present value discounts FCFF at WACC:

$$NPV_{project} = \sum_t \frac{FCFF_{(t)}}{(1 + WACC)^t} - Total\ Investment$$

$$NPV_{equity} = \sum_t \frac{FCFE_{(t)}}{(1 + r_E)^t} - Equity\ Investment$$

The equity internal rate of return (equity IRR) is the discount rate r* that sets NPV_{equity}= 0, providing a return measure directly comparable to the investor's required cost of equity.

The Debt Service Coverage Ratio in year t is:

$$DSCR_{(t)} = \frac{Revenue_{(t)} - OPEX_{(t)}}{r_D \times D_{(t)} + Principal_{(t)}}$$

The numerator is operating cash flow before tax and financing charges; the denominator is total debt service in year t. The minimum DSCR over the debt tenor is reported as the binding lender constraint. Based on the project finance lending conventions documented by Dukan and Kitzing (2023)—who identify a minimum DSCR of 1.20 at the P-90 generation scenario as the standard covenant threshold in European renewable energy project finance—a minimum DSCR of 1.25 is adopted here as the binding lender benchmark below which the debt structure is assessed as financially stressed. Finally, the discounted payback period identifies the first year in which cumulative discounted FCFE, accumulated from year zero, first turns positive—that is, the year in which the equity investor recovers the initial outlay on a time-value-adjusted basis.

4.4.10 Modelling Workflow

The analytical process follows a five-stage sequential workflow, illustrated in Figure 2.

Stage 1 ('Data inputs'): secondary data on CAPEX, OPEX, capacity factors, auction prices, support scheme parameters, and cost-of-capital components are assembled from IRENA (2024), RAAEY (2024), Angelopoulos et al. (2017), Steffen (2020), and Feldman et al. (2020).

Stage 2 ('Base-case cash flow model'): revenue, operating costs, tax, depreciation, and debt service are computed year-by-year across the 20-year project life, generating the FCFF and FCFE streams for each of the three configurations.

Stage 3 ('Discounting'): FCFF is discounted at WACC to produce the project NPV; FCFE is discounted at the cost of equity to produce the equity NPV and equity IRR.

Stage 4 ('Scenario and sensitivity analysis'): six curtailment scenarios (0 to 25 percent in five-percentage-point increments), a cost-of-capital counterfactual, and parametric sensitivity runs are applied to each configuration.

Stage 5 (‘Performance assessment’): the four financial indicators—project NPV, equity NPV/IRR, minimum DSCR, and discounted payback—are reported and compared across the three project configurations. This sequential workflow ensures full traceability from input assumptions to reported results, supporting the reproducibility criterion established in Section 4.1.

Figure 2: Modelling Workflow

4.5 Curtailment Scenario Modelling

Curtailment is modelled as a uniform proportional reduction in annual generation output, applied at six discrete levels: 0, 5, 10, 15, 20, and 25 percent of potential annual production. For each curtailment level, the financial model is recalculated in full, producing updated values for all four performance indicators. Two analytically significant thresholds are identified: the curtailment rate at which the equity NPV falls to zero (the equity break-even curtailment rate) and the rate at which the minimum DSCR falls below 1.25 (the debt covenant breach curtailment rate). The gap between these two thresholds defines a zone of financial distress in which lender covenants have been breached but some residual equity value may remain—a situation in which debt restructuring, cash sweep provisions, and lender step-in rights become operationally relevant. Identifying this zone for each technology configuration is one of the study's central analytical contributions.

The uniform curtailment assumption simplifies the temporal distribution of curtailment events. In practice, curtailment tends to occur disproportionately in hours of high system-level renewable output, which often coincide with the hours in which the curtailed technology would otherwise generate most. Newbery (2025) shows that marginal curtailment rates for incremental capacity additions can be around three times the average rate for wind and even higher for a mixed wind–solar portfolio, because additional capacity is curtailed first in the hours when it would otherwise produce most. The present study's use of uniform average curtailment rates therefore likely understates the revenue impact on marginal projects in high-curtailment settings: a real project may face curtailment concentrated in its highest-output hours, implying a proportionally larger revenue reduction than the uniform rate would suggest.

At the same time, the specific technologies examined in the case studies—onshore wind and a small run-of-river hydropower plant—are characterised by relatively smooth, weather- or inflow-driven production profiles without complex operational flexibility or bidding strategies. Given these characteristics, their long-run energy yield under a given annual curtailment rate can be approximated reasonably well by applying a proportional, randomly distributed curtailment factor to their simulated hourly generation, since the dominant driver of their economics is the overall reduction in delivered MWh rather than the precise hour-by-hour pattern of curtailment. By contrast, the PV–battery system is assumed to absorb surplus PV output during high-renewables hours and shift it to later periods, so it does not experience curtailment in the same way; its revenue impact is captured through the storage operation rather than an explicit curtailment factor.

4.6 Cross-Case Comparative Framework and Cost-of-Capital Counterfactual

The three project configurations are compared across all four financial performance indicators under each curtailment scenario. This cross-case structure reveals technology-specific patterns in base-case viability, resilience to curtailment stress, and sensitivity to financing conditions—patterns that would be obscured if each project were analyzed in isolation. Comparative sensitivity analysis across multiple project cases is highlighted in the renewable energy investment literature as a recommended approach for identifying robust drivers of project performance, and this study implements that approach through a tornado analysis that ranks input variables by their marginal effect on equity NPV for each technology configuration separately.

A cost-of-capital counterfactual is constructed by recalculating each project's NPV under a lower, best-practice WACC drawn from the lower bound of the cost-of-capital ranges documented by Steffen (2020) for comparable European renewable energy markets. By holding all project-level cash flows constant and varying only the discount rate, this counterfactual isolates the NPV impact of the financing cost differential faced by a Greek IPP relative to a lower-risk European market comparator, free from confounding variation in technology cost or resource quality. Cross-country analyses of renewable energy financing conditions use similar counterfactual WACC assumptions to quantify the effect of financing cost differences on project economics. The resulting NPV difference—the value forgone due to the Greek cost-of-capital premium—is expressed both in absolute monetary terms and as a percentage of total project investment, providing a metric directly comparable to cross-country financing-cost assessments in the existing literature.

The sensitivity analysis examines five key input variables for each project configuration: the auction price, the long-run capacity factor, total CAPEX, the WACC, and the curtailment rate. Each variable is varied independently across a range consistent with the bounds reported in the cited sources, rather than chosen arbitrarily, in line with recommended practice in techno-economic assessment of renewable projects. The resulting tornado charts present the ranked impact of each variable on equity NPV, providing actionable information for investors—who should prioritise hedging or contract design around the most impactful variables—and for policymakers, who should direct de-risking interventions towards the parameters with the greatest systemic influence on project economics and financing conditions.

4.7 Limitations of the Methodology

Five limitations of the methodology merit explicit acknowledgement. First, the deterministic modelling approach does not capture stochastic variation in input variables. Wind speeds, solar irradiance, and electricity prices all exhibit inter-annual variability that fixed capacity factor and price assumptions cannot represent. A Monte Carlo simulation would produce probability distributions of financial outcomes and thereby express the full range of project risk, but—as established in Section 4.2—the threshold-identification objectives of this study are adequately served by parametric sensitivity analysis without requiring full probabilistic treatment. Monte Carlo extension is recommended as the priority direction for future research.

Second, the study relies exclusively on secondary data. Actual project economics may deviate from published benchmark parameters due to site-specific conditions, privately negotiated contract terms, or temporal effects not captured in published averages. Access to primary data from operating Greek RES projects—including loan agreements, project financial models, and audited production records—would materially strengthen empirical validity, but such data are not publicly available and their collection was beyond the scope of this study.

Third, the uniform curtailment assumption abstracts from the temporal clustering of real curtailment events, as discussed in Section 4.5. The curtailment impact estimates presented in Chapter 6 should therefore be interpreted as lower bounds on actual project-level revenue loss under equivalent system-level curtailment conditions.

Fourth, the cost of capital is treated as static over the 20-year project life. In practice, project refinancing at lower rates becomes feasible once construction risk is resolved and an operational track record is established. Steffen (2020) documents a systematic compression in WACC between the construction and operational phases across multiple European markets, with post-construction refinancing typically reducing the cost of debt materially. The present study's static WACC therefore conservatively overstates the lifetime average cost of capital, which implies that the equity NPV results reported here may understate long-run equity returns to the extent that refinancing occurs.

Fifth, the single-country focus constrains the transferability of findings. A comparative analysis spanning Southern European markets—Greece, Spain, Italy, and Portugal—with similar renewable resource endowments but different regulatory regimes and banking traditions would illuminate whether the cost-of-capital premium and curtailment vulnerability documented here are country-specific phenomena or pan-Mediterranean structural features. Such comparative work is recommended as a priority for future research building on the methodology established here.

Chapter 5: Strategic and Market Risk Assessment

5.1 Distinguishing Project-Specific and Systemic Risks

Risks in renewable energy projects can be analytically separated into two broad categories: project-specific (idiosyncratic) risks and systemic (market-wide) risks. Project-specific risks include weather and resource variability (e.g. fluctuations in wind speeds, solar irradiance and hydrological patterns), construction-phase risks such as contractor default and cost overruns, project-level permitting delays linked to local administrative processes, technical equipment failures, and counterparty default on power purchase agreements. These risks are largely idiosyncratic to individual assets and can, in principle, be mitigated through insurance, contractual allocation (e.g. EPC guarantees, availability clauses) and careful project design. Systemic risks, by contrast, affect portfolios of renewable projects more broadly and cannot be diversified away at project level. They include grid curtailment risk (mandatory output reductions to maintain system stability and manage congestion), wholesale electricity price volatility driven by macroeconomic and market-design factors, interest rate risk transmitted through the cost of debt, supply-chain disruptions affecting equipment costs across many projects, and regulatory or policy risk, such as changes in support schemes, retroactive tariff adjustments or broader framework reforms.

In industrial organisation terms, market power is commonly measured by the Lerner index, defined as: $L = \frac{P-MC}{P}$, where P is price and MC marginal cost. A higher Lerner index or a higher Herfindahl-Hirschman Index (HHI) indicates a more concentrated market structure and greater ability of firms to sustain prices above marginal cost. While this framework is well established theoretically, empirical evidence on market-power abuse specifically in European renewable generation segments is still limited; thus, in the context of this thesis, the Lerner index and HHI are best interpreted as conceptual tools indicating potential for rent extraction rather than as directly measured indicators for the Greek RES sector.

Risk feeds directly into the cost of capital through explicit risk premia demanded by debt and equity providers. Noothout et al. (2016), in the context of the DiaCore project, develop a systematic framework that maps a set of renewable-energy-specific risk categories—such as country risk, policy design risk, administrative (permitting) risk, grid access risk, financing risk, and sudden policy change risk—onto the cost of equity, cost of debt and, ultimately, the weighted average cost of capital (WACC) for onshore wind projects across the EU-28. Their analysis shows that policy and regulatory risks, grid access uncertainty (including curtailment and connection delays), revenue volatility and construction risk are among the most important drivers of financing conditions, and that these risk factors vary substantially between Member States. DiaCore's WACC estimates indicate that Southern and Eastern European Member States, including Greece, face significantly higher WACC for onshore wind—up to around three times the level observed in low-risk benchmark countries such as Germany—primarily due to higher perceived country and policy-related risks and less favourable debt terms. Empirical studies on renewable cost of capital more broadly confirm this pattern, finding systematically higher financing costs in developing and higher-risk markets and substantial cross-country heterogeneity in WACC even within the OECD.

The Greek experience provides a concrete illustration of policy risk. The retroactive restructuring of support schemes for existing solar photovoltaic installations in the mid-2010s ("New Deal") undermined investors' expectations of regulatory stability and is widely interpreted in the literature as a salient policy-risk event. In line with the DiaCore results on the impact of retrospective changes in Spain, the Czech Republic and other markets, such interventions increase the perceived probability of adverse policy shocks and therefore raise the risk premia that investors require on subsequent projects, leading to higher WACC. The OECD Economic Survey of Greece (2023) likewise emphasises that Greece's sovereign risk profile and the need to achieve and sustain an investment-grade rating directly affect financing costs in the economy, including for the green transition, and that credible, stable policy frameworks are critical for lowering spreads and improving access to capital.

Beyond policy design and country risk, institutional and infrastructural constraints act as binding investment risks for renewables in Greece. The DiaCore analysis highlights that administrative risks (lengthy and complex permitting procedures) and grid-related risks (uncertain or delayed grid access, curtailment) are perceived as particularly severe in Southern European markets and directly translate into higher WACC. The OECD (2023) Economic Survey for Greece corroborates this picture, noting that limited electricity network capacity and complex spatial planning and permitting procedures are emerging as major constraints on scaling up renewable electricity generation, and that substantial investment in networks and improvements in administrative capacity will be required to unlock the planned expansion of wind and solar power.

The mechanisms through which project-level risk feeds into investment costs are not confined to Europe. Kashi (2015), analysing thermal IPP projects in developing countries, shows that in high-risk environments independent power producers systematically overstate the stated investment cost of power plants relative to benchmark turnkey prices, effectively embedding a risk premium as a mark-up on CAPEX. Econometric results in Kashi's study indicate that higher sovereign and political risk ratings are associated with significantly higher residual mark-ups over turnkey cost (on the order of 4–5 percentage points of turnkey cost per notch of risk), and that investors in riskier countries have an incentive to select less efficient but cheaper technologies, on which larger mark-ups can be charged. This behaviour increases the effective capital cost of generation and leads to long-term efficiency losses, as systems become locked into higher fuel consumption and higher lifecycle costs. Although Kashi's empirical focus is on conventional gas-fired IPPs in emerging markets, the underlying logic—risk premia being capitalised into project-level CAPEX and financing terms—parallels the way in which elevated risk in Southern and Eastern European RES markets manifests in higher WACC and higher levelised cost of electricity.

Taken together, these strands of evidence imply that risk is not merely a qualitative barrier but a quantitatively important determinant of financing conditions and, therefore, of the economics of renewable energy projects. Cross-country studies (DiaCore, Steffen; see above) show that policy design risk, administrative and grid-access risk, and broader country risk are closely linked to observed differences in WACC. Country-level policy assessments (OECD 2023) identify concrete institutional bottlenecks—such as permitting delays, spatial-planning complexities and network congestion—that underlie these risk categories in the Greek case. Micro-level analyses of IPP investment behaviour (Kashi 2015) demonstrate that, in high-risk environments, investors respond by embedding risk premia into capital costs and technology choices, raising system-level costs over the life of the assets. Consequently, targeted policy interventions that reduce specific risk categories—for example, transparent and credible curtailment-compensation regimes, streamlined and time-bound permitting procedures, regulatory stability commitments, and accelerated grid reinforcement—have a direct and measurable effect in lowering WACC and improving the bankability of renewable projects, particularly in higher-risk markets such as Greece and other Southern European Member States.

5.2 Impacts of Grid Saturation and Curtailment

Curtailment means the grid forces projects to stop producing electricity to keep the grid stable. Bird et al. (2014) show curtailment ranges from 1-17% across different countries. Newbery (2025) found that new projects entering the grid face curtailment rates typically 3 or more times higher than the system average, with some cases reaching substantially higher multiples depending on location and technology. Projects enter congested areas and face more curtailment than the average suggests.

Curtailment hurts projects more when their cost of capital is high. Hirth and Steckel (2016) show that levelized costs of capital-intensive renewables such as small hydropower rise steeply with the WACC, so that identical reductions in full-load hours (e.g. due to curtailment) erode project value more strongly at high discount rates than at low ones. Greece's system curtailment has been rising as installed renewable capacity outpaces grid upgrades, and islands like Crete experience even higher curtailment—over 15% in some periods.

Storage helps with curtailment. Giannakopoulos (2025) analyses battery profitability in the Greek electricity market and finds that batteries let projects shift production to different times, capturing additional revenue through peak-hour arbitrage and grid balancing services.

5.3 Competition and Market Concentration

Greece's electricity market is still concentrated—dominated by a few big companies. Makrygiorgou (2023) found that after the feed-in tariff system ended, the market is still concentrated even though auctions were supposed to help. HELLENiQ Energy (2025) found something strange: electricity prices are high (EUR 92-135 per megawatt-hour) even though lots of renewable energy is on the grid. This happens because natural gas plants set the system price—they run at low levels but set high prices. Also, there are not enough transmission lines to export power, and big generators bid strategically to keep prices high. At the EU level, Hondroyiannis et al. (2023), using panel data for 27 Member States, find that a 1% increase in the market share of the largest electricity production companies is associated with a 0.30% reduction in circular economy performance — empirical evidence that concentrated electricity market structures generate negative externalities beyond just consumer prices. Their conclusion that structural reform requires eliminating vertical integration between generation and supply and removing barriers to entry directly parallels the competitive disadvantage facing Greek medium-scale IPPs documented in this study.

Industrial organization theory explains oligopolies. A few firms compete on output. In Greek auctions, big utilities with cheaper borrowing can bid lower prices and push small independent companies out. Del Rio (2022) analyses post-auction concentration across European markets and finds that while competitive auctions improved market dynamics relative to feed-in tariff regimes, large incumbents still capture disproportionate auction volumes. Buschle et al. (2024) found that multi-technology auctions hurt smaller specialized companies.

5.4 Risk Mitigation Strategies for Non-Integrated IPPs

Small independent companies can compete if they use four strategies. First, lock in electricity prices. Use long-term contracts with fixed prices, long-term agreements with creditworthy companies, interest rate hedging, and insurance. Dukan's & Kitzing's (2023) comparative analysis shows that revenue certainty instruments substantially reduce the cost of capital for renewable projects.

Second, use good financing. Use EU recovery funding (cheaper loans), get co-financing from development banks, draw capital step-by-step, and refinance after the project is built. The National Bank of Greece and other studies show how to reduce risks this way.

Third, diversify. Build multiple projects in different locations with different technologies. Energy communities (Law 4513/2018) let small companies pool projects together. Partnering with institutional investors gets access to cheaper capital. Building projects in different places reduces curtailment risk.

Fourth, find a niche. Become expert in one technology (like small hydropower), develop projects and then sell them to others, be first with storage projects, or build institutional advantage. Cetkovic (2016) and Anatolitis (2025) show how these work. These strategies help small companies compete against big ones.

Chapter 6: Financial Modelling and Case Studies

This chapter presents the discounted cash flow models for three representative projects, establishing the financial baseline against which all subsequent risk analyses are anchored. The chapter develops three dimensions of analysis in sequence: first, the technical and financial assumptions underlying each project (sourced from market and academic data, regulatory benchmarks, and industry cost databases); second, the derivation of the weighted average cost of capital (WACC) using the capital asset pricing model; and third, the year-one cash flow projections and base-case investment performance metrics under zero-curtailment conditions. A cross-project comparison synthesizes the results and identifies the revenue-density threshold that separates financially viable from marginal projects.

6.1 Input Parameters and Capital Structure

All three project configurations employ an identical blended-financing structure established under the Greece 2.0 Recovery and Resilience Facility, comprising 30% equity capital, 50% RRF debt at 0.35% per annum, and 20% commercial bank debt at market rates (approximately 6.0% at the time of model construction – April 2026-). This capital structure, holding constant across all three technologies, isolates the effects of revenue generation and operational cash flows from the financing variables, enabling a pure technology-based comparison. The operational life is set to 20 years for all three projects, with debt repayment over 15 years and asset depreciation on a straight-line basis over the same period. The standard corporate tax rate of 22% applies uniformly.

Table 6.1: Project Input Parameters

Parameter	Project A – 8.8 MW Wind	Project B – 1 MW SHPP	Project C – 5 MW Solar+BESS
Technical			
Installed capacity	8,800 kW	1,000 kW	5,000 kW PV + 20,000 kWh BESS

Capacity factor	30%	40%	17.1%
Annual energy (base year)	23,126 MWh	3,504 MWh	7,490 MWh yr-1 (-0.5%/yr)
Revenue mechanism	FiP — EUR 57.66/MWh	FiP — EUR 90.00/MWh	MCP — EUR 103.61/MWh (2025 avg)
Annual base revenue (yr 1)	EUR 1,333.5k	EUR 315.4k	EUR 776.0k
Annual OPEX	EUR 228.8k (EUR 26/kW)	EUR 37.4k (2% of CAPEX)	EUR 29.7k (EUR 5.94/kW PV)
Capital structure (identical across all projects)			
Total CAPEX	EUR 14,960k (EUR 1,700/kW)	EUR 1,870k (EUR 1,870/kW)	EUR 6,264k (EUR 600/kW + EUR 163.2/kWh)
Equity — 30%	EUR 4,488k	EUR 561k	EUR 1,879k
RRF loan — 50% @ 0.35% p.a.	EUR 7,480k	EUR 935k	EUR 3,132k
Bank debt — 20% @ 6.0% p.a.	EUR 2,992k	EUR 374k	EUR 1,253k

Total debt — 70%	EUR 10,472k	EUR 1,309k	EUR 4,385k
Debt tenor / depreciation	15 yr annuity / 15 yr SL	15 yr annuity / 15 yr SL	15 yr annuity / 15 yr SL
Project operational life	20 years	20 years	20 years
Corporate tax rate	22%	22%	22%

Sources: RAAEY 2023 National Report (FiP prices); ENEX EL-DAM 2025 (MCP); IRENA 2024 (OPEX); Greece 2.0 NRRP (RRF). Solar degradation 0.5%/yr (Jordan & Kurtz, 2013).

6.2 Cost of Capital

Table 6.2 constructs the weighted average cost of capital using the capital asset pricing model framework standard in corporate finance. The calculation begins with the risk-free rate (Greek 15-year government bonds at 3.98% in April 2026), applies an unlevered equity beta of 0.58 from Damodaran's renewable energy sector dataset, adjusts for the project's leverage using the Hamada equation to arrive at a levered beta of 1.6356, and multiplies by the market risk premium (5.24%) to calculate the cost of equity at 12.55%. The blended cost of debt reflects the dual-tranche structure: the RRF loan at 0.35% and the bank facility at 6.0%, weighted by their proportions in the capital structure, yielding at 1.96%. The resulting baseline WACC of 4.84% reflects the RRF subsidy embedded in the financing structure. For sensitivity analysis, a counterfactual scenario replaces the concessional RRF tranche with commercial bank debt at 6.0%, raising the WACC to 7.04%—a 220-basis-point compression that proves critical to project viability for the wind project in particular. This counterfactual is developed in Section 7.3 as the cost-of-capital gap analysis.

Table 6.2: Cost of Capital Calculation

Parameter	Source	Value

Risk-free rate (RFR)	Greek 15Y government bond, April 2026	3.98%
Unlevered beta (Bu)	Damodaran 2026, Green and Renewable Energy sector	0.58
Capital structure	70% debt / 30% equity — D/E = 2.33	2.33x
Levered beta (Bl) — Hamada equation	Bl = 0.58 x (1 + 0.78 x 2.33)	1.6356
Market risk premium (MRP)	Damodaran 2026 (ERP + RFR)	5.24%
Cost of equity (re) — CAPM	3.98% + 1.6356 x 5.24%	12.55%
Blended cost of debt (rd)	(50/70 x 0.35%) + (20/70 x 6.0%)	1.96%
WACC — RRF baseline	0.30 x 12.55% + 0.70 x 1.96% x 0.78	4.84%
Counterfactual WACC (no RRF)	0.30 x 12.55% + 0.70 x 6.0% x 0.78	7.04%
DSCR lender covenant	Minimum requirement — project finance	1.25x

T = 22%. The RRF compresses WACC by 220 basis points relative to the bank-only counterfactual — a compression that determines project viability for wind (Section 7.3).

6.3 Project A: 8.8 MW Onshore Wind Farm

Tables 6.3.1 and 6.3.2 present the year-1 income statement and cash flow waterfall, followed by the base-case investment performance metrics. The central finding is the divergence between a positive project NPV (the asset creates value at WACC) and a negative equity NPV (equity IRR of 4.49% is below the cost of equity of 12.55%).

Table 6.3.1: Project A (Wind 8.8 MW) — Year-1 Income Statement and Cash Flow Waterfall

Item	EUR k
Income statement	
Annual energy output	23,126 MWh
Year-1 revenue	1,333.5
Annual OPEX	(228.8)
Year-1 EBITDA	1,104.7
Depreciation	(997.3)
Year-1 EBIT	107.3
Interest expense	(205.7)
Principal repayment	(607.1)
Total debt service	(812.8)
EBT = EBITDA + Depreciation + Interest Expense	(98k)

Tax on EBT (22%)	—
FCFF (year 1)	1,104.7
Debt service and free cash flow to equity (year 1)	
DSCR (EBITDA / total debt service)	1.359x
FCFE (year 1)	291.9

Table 6.3.2: Project A (Wind 8.8 MW) — Base-Case Investment Performance

Metric	Value
Project NPV (discounted at WACC 4.84%)	EUR +2,939.9k
Equity NPV (discounted at re 12.55%)	EUR −2,202.9k
Equity IRR	4.49%
Cost of equity (re) — CAPM benchmark	12.55%
IRR vs. re	− 8.06 pp (below hurdle rate)
Minimum DSCR (years 1–15)	1.359x (above 1.25x covenant)
Discounted payback period	>20 years

The low FiP reference price (EUR 57.66/MWh) produces a structural wedge between project viability and equity viability. At this price level, the project as a whole generates positive value — Project NPV stands at EUR 2.9 million — yet that value flows almost entirely to debt holders through the interest margin embedded in the RRF financing structure. Equity investors absorb the operational and market risks of renewable generation while receiving an IRR of 4.49%, an 8.06-

percentage-point shortfall against the CAPM-derived cost of equity (12.55%). The result is a negative equity NPV of EUR −2.2 million and a payback horizon that extends beyond the modelled 20-year project life — meaning equity capital is not recovered within the asset's operational lifespan under base-case assumptions.

What makes this outcome particularly constraining is that the gap is structurally fixed. Because the FiP price cannot be renegotiated once the auction is cleared, no feasible operational improvement — higher capacity factors, lower OPEX, faster construction — can close an 8-percentage-point return shortfall. The equity investor is locked into a return profile determined entirely by the auction clearing price and the cost of the RRF debt instalment. This limits rational equity participation to investors with below-market hurdle rates: patient institutional capital operating under government-mandated renewable allocation targets, or ESG-driven funds accepting below-CAPM returns as a portfolio-level constraint. Commercial equity investors applying standard capital allocation criteria have no financial basis for participation under the current price structure.

6.4 Project B: 1 MW Run-of-River Small Hydropower Plant

All financial metrics are positive and exceed lender requirements. Two factors drive this: the higher FiP price (EUR 90/MWh) and higher capacity factor (40% versus 30% for wind). Together they produce annual revenue equal to 16.9% of upfront costs—nearly double the ratio for the wind project.

Table 6.4.1: Project B (Hydro 1 MW) — Year-1 Income Statement and Cash Flow Waterfall

Item	EUR k
Income statement	
Annual energy output	3,504 MWh
Year-1 revenue	315.4
Annual OPEX	(37.4)

Year-1 EBITDA	278.0
Depreciation (D&A)	(124.7)
Year-1 EBIT	153.3
Interest expense	(25.7)
Principal repayment	(75.9)
Total debt service	(101.6)
EBT = EBITDA + Depreciation + Interest Expense	127.6
Tax on EBT (22%)	(28.1)
FCFF (year 1)	249.9
Debt service and free cash flow to equity (year 1)	
DSCR (EBITDA / total debt service)	2.736x
FCFE (year 1)	120.2

Table 6.4.2: Project B (Hydro 1 MW) — Base-Case Investment Performance

Metric	Value
Project NPV (discounted at WACC 4.84%)	EUR +1,754.8k
Equity NPV (discounted at re 12.55%)	EUR +305.4k

Equity IRR	20.71%
Cost of equity (re) — CAPM benchmark	12.55%
IRR vs. re	+8.16 pp (above hurdle rate)
Minimum DSCR (years 1–15)	2.736x (above 1.25x covenant)
Discounted payback period	8 years

All financial tests pass comfortably. The equity return (20.71%) is the strongest across the three projects. Investors put in EUR 561k and the project returns EUR 305.4k to them in net present value—a 54% return on the equity capital they invested.

6.5 Project C: 5 MW Solar PV + 20 MWh BESS

Tables 6.5.1 and 6.5.2 present the year-1 cash flow waterfall and base-case investment performance for Project C. Revenue declines gradually from year 1 due to 0.5%/yr PV output degradation; DSCR falls from 2.193x in year 1 to a minimum of 2.038x in year 15, remaining above the covenant throughout. No curtailment scenarios are modelled, as the BESS provides sufficient dispatch flexibility to avoid grid-constraint losses.

Table 6.5.1: Project C (Solar+BESS 5 MW + 20 MWh) — Year-1 Income Statement and Cash Flow Waterfall

Item	EUR k
Income statement	
Annual energy output (year 1)	7,490 MWh
Year-1 revenue	776.0

Annual OPEX	(29.7)
Year-1 EBITDA	746.3
Depreciation (D&A)	(417.6)
Year-1 EBIT	328.7
Interest expense	(86.1)
Principal repayment	(254.2)
Total debt service	(340.3)
EBT = EBITDA + Depreciation + Interest Expense	242.6
Tax on EBT (22%)	(53.4)
FCFF (year 1)	692.9
Debt service and free cash flow to equity (year 1)	
DSCR year 1 (EBITDA / total debt service)	2.193x
FCFE (year 1)	299.2

Table 6.5.2: Project C (Solar+BESS 5 MW + 20 MWh) — Base-Case Investment Performance

Metric	Value

Project NPV (discounted at WACC 4.84%)	EUR +3,761.1k
Equity NPV (discounted at re 12.55%)	EUR +185.8k
Equity IRR	14.12%
Cost of equity (re) — CAPM benchmark	12.55%
IRR vs. re	+1.57 pp (above hurdle rate)
DSCR year 1 / minimum DSCR (year 15)	2.193x / 2.038x (above 1.25x covenant)
Discounted payback period	15 years

Project C delivers the largest financial value (EUR 185.8k to equity, EUR 3,761.1k to the project) of the three options. Its main risk is price vulnerability: unlike wind and hydro with fixed-price contracts, this project sells power at market prices.

6.6 Cross-Project Comparison

Three findings stand out. First, revenue density—annual revenue divided by upfront investment—is the primary driver of both lender safety and equity returns. The hydro project's 16.9% ratio versus the wind project's 8.9% explains most of the difference in returns. Second, only Project A destroys equity value, and this holds true across all curtailment scenarios examined in Chapter 7. The wind auction price covers the blended cost of capital but fails to deliver the returns equity investors require. Third, Project C achieves the highest equity value despite full merchant price exposure because battery storage eliminates the curtailment risk and achieves higher price per kWh.

Table 6.6: Cross-Project Base-Case Summary

Metric	Project A — Wind	Project B — Hydro	Project C — Solar+BESS
Total CAPEX (EUR k)	14,960	1,870	6,264
Annual revenue / CAPEX (yr 1)	8.9%	16.9%	12.4%
Year-1 EBITDA (EUR k)	1,104.7	278.0	746.3
Year-1 DSCR	1.359x	2.736x	2.193x
Min DSCR (years 1-15)	1.359x	2.736x	2.038x
Project NPV (EUR k)	2,939.9	1,754.8	3,761.1
Equity NPV (EUR k)	−2,202.9	305.4	185.8
Equity IRR	4.49%	20.71%	14.12%
IRR vs. re (12.55%)	−8.06 pp	+13.69 pp	+5.10 pp
Discounted payback	>20 years	8 years	15 years

Project A equity metrics are below the cost of equity at every curtailment level, including the base case. Full curtailment analysis in Chapter 7.

Chapter 7: Risk Assessment and Sensitivity Analysis

This chapter operationalises the financial constraints identified in Chapter 6 through three analytical lenses. Section 7.1 quantifies production risk through curtailment sensitivity analysis, translating the grid constraints documented in Chapter 3 into debt covenant and equity return impacts. Section 7.2 sequences the critical financial thresholds—covenant breach and equity break-even—uncovering a technology-specific asymmetry with direct bankability implications. Section 7.3 isolates the macro-financial dimension through cost-of-capital sensitivity, quantifies the RRF subsidy's role in determining project viability, and closes with a tornado analysis that ranks the relative influence of all key input variables.

7.1 Curtailment Sensitivity Analysis — Projects A and B

Grid curtailment—mandatory output reduction when transmission operators must maintain network stability—is the primary operational constraint on solar, wind and run-of-river small hydro projects in Greece. As documented in Chapter 3, system-level wind curtailment ranges from 5% to 12% annually, with geographic clusters reaching 20–30% in specific hours. These reductions translate directly into revenue shortfalls and create financial stress that lenders must quantify when structuring project debt. Table 7.1 measures this impact across curtailment increments up to 48%.

Table 7.1: Curtailment Sensitivity — Project A (Wind) and Project B (Hydro)

Curtailment	Proj NPV (A) EUR k	Eq NPV (A) EUR k	DSCR (A)	Eq IRR (A)	Proj NPV (B) EUR k	Eq NPV (B) EUR k	DSCR (B)	Eq IRR (B)
0% — base case	2,939.9	−2,202.9	1.359	4.49%	1,754.8	305.4	2.736	20,71%
5%	2,152.0	−2,649.3	1.277	2.80%	1,599.4	241.7	2.581	19,05%

6.5% (covenant breach A)	1,911.4	−2,786.6	1.252	2.27%	—	—	—	—
10%	1,343.7	−3,111.1	1.195	0.97%	1,444.0	177.9	2.425	17,37%
15%	532.6	−3,574.7	1.113	-0.94%	1,288.6	114.2	2.270	15.67%
20%	−278.4	−4,038.3	1.031	-2.92%	1,133.2	50.4	2.115	13.94%
25%	−1,089.5	−4,501.9	0.949	-5.00%	977.8	−13.3	1.960	12.18%
23.95% (equity breach B)	—	—	—	—	1,010.4	~0	1.992	12.55%
48% (covenant breach B)	—	—	—	—	230.9	−352.9	1.246	2.12%

DSCR covenant threshold = 1.25x. 'b/e' = break-even. Dashes indicate the scenario falls outside the model's tested range or is not applicable.

The results reveal a sharp divergence between the two technologies. Project A (wind) breaches the lender covenant threshold (DSCR < 1.25x) at just 6.5% curtailment—well within the system-level curtailment range. Equity NPV remains negative at every tested scenario, including the zero-curtailment base case; no break-even threshold exists for wind equity. Project B (hydro) demonstrates materially greater resilience: DSCR stays above covenant floor through 48% curtailment, and equity NPV only turns negative above approximately 24% curtailment. Revenue density—annual revenue relative to invested capital—drives almost the entire divergence: hydro's ratio (16.9%) generates sufficient cash flow to absorb substantial output losses, while wind's lower ratio (8.9%) leaves no margin beyond mandatory debt service.

7.2 Critical Threshold Analysis: Covenant Breach and Equity Break-Even

Two thresholds are central to project finance risk. The first is the lender covenant breach point, at which DSCR falls below 1.25x and lenders may invoke acceleration clauses or covenant-lite remedies. The second is the equity economic break-even, at which equity NPV reaches zero and investors recover their principal without return above cost of capital. Standard project finance logic sequences these with covenant breach at lower curtailment and equity break-even at higher curtailment. Table 7.2 shows that this ordering holds for hydro but inverts critically for wind.

Table 7.2: Critical Threshold Comparison — Wind vs. Hydro

Threshold	Project A — Wind	Project B — Hydro
Lender covenant breach (DSCR < 1.25x)	6.5% curtailment (DSCR = 1.252x)	48% curtailment (DSCR = 1.246x)
Equity NPV break-even	Negative at 0% — does not recover	23.95% curtailment (Eq NPV ~0)
Equity IRR at break-even	4.49% at 0% — below re throughout	12.55% at 23.95% = re
Threshold sequencing	Lender breach at 6.5%; equity NPV negative at all curtailment levels	Equity exhaustion at 23.95% precedes lender breach at 48%
Gap between thresholds	N/A — no equity break-even for Wind	24.1 pp (equity exhausted before breach)

Policy implication	FiP insufficient for equity; RRF benefit captured by debt	High FiP and high CF create equity buffer exceeding lender needs

Project A has no equity break-even: equity NPV is negative at every curtailment level, including the zero-curtailment base case. The fixed FiP price (EUR 57.66/MWh) delivers an equity IRR of 4.49%—an 8.06-percentage-point shortfall against the CAPM-required 12.55%. Debt covenant breach occurs at 6.5% curtailment, while equity returns fall below the required threshold at every curtailment level, including the base case. No operational improvement can close this gap; the price is fixed by contract.

Project B inverts the sequence. Equity break-even occurs first, at 23.95% curtailment (Eq NPV ≈ 0, IRR ≈ re = 12.55%). Covenant breach follows much later, at 48% curtailment—a 24.1-percentage-point gap between the two thresholds. Hydro's higher revenue density generates enough cash to protect debt service fully, even as equity value is being gradually eroded by rising curtailment. Wind's lower revenue density cannot do both simultaneously.

7.3 Cost-of-Capital Gap Analysis and Tornado Sensitivity

Table 7.3 stress-tests project NPV across six WACC scenarios, ranging from a 3.0% sovereign-level rate to the 11.7% pre-RRF benchmark documented for Greek IPPs by Steffen (2020). The baseline (4.84%) reflects current RRF blended-finance conditions; the first counterfactual (7.04%) removes the RRF concessional tranche and replaces it with commercial bank debt at 6.0%, isolating the pure financing subsidy.

Table 7.3: Project NPV Sensitivity to WACC (EUR k)

WACC scenario	NPV A — Wind	NPV B — Hydro	NPV C — Solar	Context

3.0%	5.215	2.284	4.650	Sovereign / ESG fund
4.84% — RRF baseline (this study)	2.940	1.755	3.156	Model baseline
7.04% — no-RRF counterfactual	817	1.263	1.820	Bank-only financing
8.0%	51	1.086	1.352	Leveraged IPP market
11.7% — pre-RRF Greece	-2.242	558	-2	Steffen (2020) benchmark

The results reveal technology-specific sensitivity to capital costs. All three projects remain NPV-positive across the 3%–8% WACC band. Project A (wind) crosses zero-NPV just above 8% WACC—at 8.0%, project NPV is EUR 51k, effectively at the viability boundary—and falls to EUR −2,242k at the pre-RRF benchmark of 11.7%. Project C (solar with BESS) remains positive through approximately 11.7% WACC, where NPV reaches EUR −2k, making it the most capital-cost-resilient of the non-hydro technologies. Project B (hydro) stays positive beyond the entire tested range, with EUR 558k NPV even at 11.7% WACC, reflecting the revenue density advantage that insulates it from macro-financial stress. Above 8% WACC, Wind is no longer viable under current FiP pricing; above 11.7%, only Hydro retains positive project value.

The magnitude of the RRF subsidy is quantitatively explicit in the wind comparison: moving from the pre-RRF benchmark (11.7% WACC, EUR −2,242k project NPV) to the current RRF baseline (4.84% WACC, EUR 2,940k project NPV) produces a EUR 5.2-million swing in net present value. This is not a margin enhancement—it is the mechanism that moves Wind from value destruction to marginal viability. The 220-basis-point WACC compression delivered by the RRF concessional tranche accounts for the entire difference between a financeable and an unfinanceable wind project at current auction prices. This finding aligns with the cost-of-capital gap documented in Chapter 3, where small independent producers in Greece face a 400–600-basis-point disadvantage relative to integrated utilities. The RRF partially bridges this gap (220 basis points), leaving a residual of 180–380 basis points that cannot be closed without further policy intervention or structural market reform.

7.4 Strategic Implications

Wind prices need adjustment. To attract equity investors at standard cost-of-capital rates, the auction price must rise from EUR 57.66/MWh to EUR 80/MWh (35–40% higher). Until this happens, only investors willing to accept below-market returns will participate.

Location and storage matter. Wind projects in congested grid areas fail lender tests at only 6.5% curtailment. Adding battery storage should eliminate this risk entirely—as Project C demonstrates, batteries can be a cost-effective tool for reducing risk in wind projects located in congested areas.

After 2026, policy continuity is critical. The RRF loan is essential to wind viability. If it is removed without other support, new wind projects would be impossible to finance at current prices. The apparent wind viability today depends on a time-limited subsidy, not on the underlying economic strength of wind assets.

In summary: hydropower is economically viable across nearly all realistic scenarios. Solar with battery storage is safely viable under current policy. Onshore wind is the weak link—while projects can pass lender tests, they destroy equity value at every curtailment level. Fixing the wind financing problem is the sector's central policy challenge.

Chapter 8: Conclusions and Recommendations

8.1 Key Findings and Answers to Research Questions

The analysis set out to determine whether medium-scale independent power producers in Greece can achieve genuine financial viability under contemporary market and financing conditions. The answer is sharply technology-dependent, and in one case — onshore wind — structurally negative at current auction prices regardless of operational performance.

Research Question 1 asked whether a medium-scale Greek RES project can generate positive net present value under current wholesale prices and realistic financing costs. The short answer is conditional. Under the RRF-blended WACC of 4.84%, all three case studies produce positive project NPV: EUR 2,940k for the 8.8 MW wind farm, EUR 1,755k for the 1 MW run-of-river hydropower plant, and EUR 3,761k for the 5 MW solar PV installation with 20 MWh of battery storage. At the project level — measuring value accruing to all capital providers — the technology is economically worthwhile in every case. The critical distinction emerges at the equity level. Hydropower delivers an equity IRR of 20.71%, a premium of 8.16% above the CAPM-derived cost of equity of 12.55%, and recovers equity investment within eight years on a discounted basis. Solar with storage achieves an equity IRR of 14.12% — a narrower but positive margin of 1.57% above the hurdle rate, with a discounted payback of 15 years. Onshore wind, however, yields an equity IRR of only 4.49% — an 8.06% shortfall against the cost of equity — producing a negative equity NPV of EUR −2,203k even in the zero-curtailment base case. The FiP reference price of EUR 57.66/MWh is insufficient to compensate equity investors for the risks they bear: the project creates value, but that value flows entirely to debt providers embedded in the financing structure. Commercial equity participation in wind under current price conditions is therefore irrational from a standard capital-allocation standpoint.

Research Question 2 translated grid curtailment into quantified financial constraints. The divergence between wind and hydropower is striking. The wind project breaches the lender debt service coverage ratio covenant (DSCR < 1.25×) at just 6.5% curtailment — well inside the 5–12% system-level curtailment range documented for Greek onshore wind. Hydropower demonstrates a fundamentally different risk profile: DSCR remains above covenant threshold through 48% curtailment, and equity NPV does not turn negative until approximately 24% curtailment. This gap — of 24.1% between equity exhaustion and covenant breach — reflects the revenue density advantage: hydropower's annual revenue-to-CAPEX ratio of 16.9% generates a structural surplus sufficient to absorb large output reductions before impairing either equity or debt. Wind's ratio of 8.9% provides virtually no buffer beyond mandatory debt service. An additional structural finding is that the standard project finance threshold sequencing — covenant breach occurring before equity exhaustion — inverts critically for wind: equity is already impaired at zero curtailment, so no curtailment threshold triggers an equity break-even because one never exists.

Research Question 3 quantified the macro-financial cost of being a small independent producer in Greece. The RRF concessional tranche compresses WACC by 220 basis points relative to a commercial bank-only counterfactual (from 7.04% to 4.84%), generating a EUR 5.2 million swing in wind project NPV — the mechanism that moves wind from value destruction (EUR −2,242k at the pre-RRF benchmark WACC of 11.7% documented by Steffen, 2020) to marginal viability. Yet the RRF addresses only a portion of the structural disadvantage. As the cost-of-capital counterfactual analysis demonstrates, Greek medium-scale IPPs face a financing cost premium of 400–600 basis points relative to vertically integrated utilities operating under institutional balance-sheet terms. The RRF bridges approximately 220 basis points of this gap, leaving a residual of 180–380 basis points that cannot be closed without either further concessional financing or structural market reform. The financial cost of being small, measured as forgone equity NPV, exceeds EUR 5 million for a single wind project and can be described as "structural financing disadvantage" of non-integrated developers.

Research Question 4 identified the strategic adaptations through which viability is achievable. Three mechanisms stand out from the evidence. First, revenue certainty instruments — long-term PPAs with creditworthy offtakers and the fixed-price component embedded in FiP auction contracts — materially reduce WACC by narrowing lender risk perceptions of cash flow volatility. Second, battery energy storage is not just a revenue-boosting technology for projects in grid-congested areas, but can play a crucial role in the viability of these projects in cases of increased curtailments, Project C demonstrates that storage eliminates the curtailment channel through which wind projects fail lender tests at 6.5% curtailment. Third, portfolio aggregation through energy community structures or institutional co-investment allows smaller developers to access cheaper capital and distribute development costs across multiple assets, narrowing the systematic disadvantage that single-project SPVs face relative to large utilities. None of these adaptations is individually sufficient to close the full financing gap for wind under current FiP pricing; their value lies in combination, and in the interim period while structural reforms are implemented.

8.2 Policy Recommendations

The analytical evidence points to four targeted interventions with quantifiable impact on project viability.

The most urgent is a recalibration of the onshore wind FiP reference price. The current auction ceiling of EUR 57.66/MWh produces an equity IRR of 4.49% under optimal conditions — a return that no commercial equity investor with a standard CAPM-derived hurdle rate can rationally accept. A FiP reference price of approximately EUR 80/MWh would be required to generate an equity IRR approaching 12%, a 35–40% increase over the current ceiling. This is not a subsidy to inefficient technology: it is an acknowledgement that the cost of capital in the Greek market is structurally different from the Northern European benchmarks that likely informed the current price-setting. Del Río and Kiefer (2023) demonstrate that auction designs which ignore cost-of-capital heterogeneity across investor types systematically exclude smaller developers and concentrate market share among incumbents — precisely the dynamic this dissertation documents in the Greek case.

Second, the RRF concessional financing mechanism must be either extended beyond its current horizon or replaced with a permanent blended-finance instrument through the European Investment Bank, or a dedicated Greek green transition fund. The analysis makes clear that wind viability under current pricing is a function of the RRF, not of the underlying technology economics. Stopping the RRF without structural reform of either auction prices or the banking market leaves wind investment in Greece with no financeable path for commercial equity.

Third, compensation for curtailment is both necessary and economically justified. At present, Greece does not provide any payment for curtailed electricity generation, effectively transferring the impact of grid constraints entirely to project revenues. Introducing a compensation mechanism based on the avoided cost—defined as the marginal cost the system saves when a renewable unit is curtailed—would not remove curtailment but would reduce its financial impact on projects. The 6.5% covenant breach threshold documented for wind demonstrates that even modest system-average curtailment can push projects into covenant default territory; compensation would raise this threshold materially.

Fourth, the grid investment programme planned through 2033 should be front-loaded, with priority given to the high-curtailment congestion zones identified by DEDDIE and ADMIE. Accelerating grid expansion in these areas would structurally reduce curtailment exposure and benefit all projects, rather than relying on project-specific mitigation measures such as storage. At the same time, the development of storage projects—including pumped hydro storage and battery energy storage systems—should be expedited, as they can complement grid upgrades by improving system flexibility and absorbing excess generation.

8.3 Practical Implications for Investors and Developers

For investors conducting project-level due diligence, the revenue density metric — annual revenue relative to total invested capital — emerges as the single most informative early screening criterion. A revenue-to-CAPEX ratio below approximately 10–11% is incompatible with equity viability under Greek financing conditions, irrespective of DSCR performance. Wind projects at current auction prices sit at 8.9% and therefore fail this screen; developers should assess whether battery co-location, higher-yield sites, or a corporate PPA overlay can close the gap before proceeding to full financial modelling.

RRF eligibility should be confirmed before any project progresses beyond the feasibility stage. The 220-basis-point WACC compression delivered by the RRF tranche is not a marginal enhancement but the decisive variable in wind project viability; losing it — through timing misalignment, eligibility failure, or administrative delay — eliminates the financeable case.

Portfolio developers with multiple simultaneous projects should structure financing to ensure RRF availability for their highest-leverage, most curtailment-exposed assets first.

For developers considering technology selection, hydropower's superior curtailment resilience and revenue density make it the most robust choice where hydrological conditions permit. Small run-of-river plants are illiquid, location-constrained, and face longer environmental permitting timelines, but once financed they offer a 24-percentage-point buffer between equity exhaustion and covenant breach — a risk margin unavailable in any other technology class examined here. Solar with battery storage is the pragmatic second choice: commercially viable under current market prices, not exposed to curtailment in the same direct way as wind, and positioned to benefit from the peak-hour price arbitrage.

8.4 Limitations and Future Research

Five limitations of the methodology have direct implications for the generalisability of these findings. The deterministic modelling approach does not capture stochastic variation in wind speeds, hydrological inflows, or electricity prices. A Monte Carlo simulation framework, calibrated to the inter-annual variability distributions documented in Greek meteorological records, would produce probability distributions of NPV and IRR outcomes rather than point estimates, and would more precisely characterise the probability of covenant breach under realistic production uncertainty. This extension is recommended as the most direct methodological improvement for future work building on this framework.

The reliance on secondary data — IRENA benchmarks, published WACC estimates, and regulatory cost schedules — means that the case study results represent representative projects rather than specific operating assets. Access to primary financial data from Greek RES project companies — loan agreements, audited production records, and actual financing term sheets — would substantially strengthen empirical validity and enable direct calibration of the benchmark parameters used here.

The uniform curtailment assumption, as established in Chapter 4, likely understates the revenue impact on marginal projects. Since curtailment is concentrated during peak production hours, project-specific revenue losses often exceed system-average estimates. Therefore, the break-even thresholds in Chapter 7 should be viewed as upper bounds on resilience rather than precise empirical predictions.

The static WACC assumption conservatively overstates the lifetime cost of capital. Post-construction refinancing, documented by Steffen (2020) as a systematic feature of European renewable project finance, typically compresses the cost of debt once the construction risk premium is resolved. Incorporating dynamic refinancing into future models would improve the accuracy of lifetime equity return estimates, particularly for hydropower, where the long revenue runway provides multiple refinancing windows.

Finally, the single-country scope constrains transferability. A comparative analysis of IPP financing conditions across Southern European markets — Greece, Spain, Italy, and Portugal — would illuminate whether the cost-of-capital premium and curtailment vulnerability documented here are country-specific institutional failures or structural features of peripheral EU energy markets more broadly. Such comparative work would also enable direct testing of the policy recommendations offered here against the experience of markets that have implemented analogous reforms.

8.5 Concluding Remarks

The central tension this dissertation set out to investigate — between Greece's ambitious 75.7% renewable electricity target for 2030 and the structural financing disadvantages facing the medium-scale independent producers who must deliver much of the required capacity — is not resolvable through technology improvement or operational efficiency alone. The evidence is unambiguous on this point: at current auction prices, onshore wind destroys equity value in every scenario tested. The apparent viability of wind projects today is not a reflection of underlying technology competitiveness; it is an artefact of a time-limited public subsidy in the form of the RRF concessional tranche.

This conclusion should be read not as pessimism about the renewable energy transition but as a precise diagnosis of where the policy gap lies. Hydropower and solar with storage are genuinely economically viable under realistic Greek market conditions — not because they are inherently different technologies, but because their revenue density is sufficient to deliver equity returns above the cost of capital. Wind can achieve the same if auction prices are recalibrated to reflect the Greek cost of capital rather than Northern European benchmarks, and if curtailment compensation removes the arbitrary transfer of grid infrastructure cost onto project cash flows.

A market structure that requires emergency-era concessional finance to make standard renewable technology investments viable is not a stable foundation for a decade of sustained deployment. The EUR 95.9 billion investment required to meet Greece's 2030 NECP targets cannot be delivered on the balance sheet of the public sector alone; it requires commercial equity capital at scale. Attracting that capital demands a regulatory environment in which projects offering realistic risk-adjusted returns can be financed without access to instruments that will expire. The findings of this dissertation quantify precisely what closing that gap would cost — and what it would unlock.

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Appendix 1: Wind Project Cash Flows Tables

Curtailment = 0%																											
Line Item	**Unit**		**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6**	**Yr 7**	**Yr 8**	**Yr 9**	**Yr 10**	**Yr 11**	**Yr 12**	**Yr 13**	**Yr 14**	**Yr 15**	**Yr 16**	**Yr 17**	**Yr 18**	**Yr 19**	**Yr 20**	**Yr 21**	**Yr 22**	**Yr 23**	**Yr 24**	**Yr 25**
Annual Energy Output	MWh	0	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126	23.126
Revenue	€k	-	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k	1.333k
Operating Expenditure (OPEX)	€k	-	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)
EBITDA	€k		**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**
Depreciation (straight-line)	€k		(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		10.472k	9.865k	9.246k	8.615k	7.971k	7.315k	6.646k	5.963k	5.268k	4.558k	3.835k	3.098k	2.346k	1.579k	797k										
Principal Repayment	€k		(607k)	(619k)	(631k)	(644k)	(656k)	(669k)	(682k)	(696k)	(709k)	(723k)	(737k)	(752k)	(767k)	(782k)	(797k)										
Interest Expense pre-tax	€k		(206k)	(194k)	(182k)	(169k)	(157k)	(144k)	(131k)	(117k)	(103k)	(90k)	(75k)	(61k)	(46k)	(31k)	(16k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**(98k)**	**(86k)**	**(74k)**	**(62k)**	**(49k)**	**(36k)**	**(23k)**	**(10k)**	**4k**	**18k**	**32k**	**46k**	**61k**	**76k**	**92k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**
Tax on EBT	€k		-	-	-	-	-	-	-	-	-	-	-	-	(13k)	(17k)	(20k)	(243k)	(243k)	(243k)	(243k)	(243k)	(243k)	(243k)	(243k)	(243k)	(243k)
FCFF	€k	**(14.960k)**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.105k**	**1.091k**	**1.088k**	**1.084k**	**862k**	**862k**	**862k**	**862k**	**862k**	**862k**	**862k**	**862k**	**862k**	**862k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(4.488k)**	**292k**	**292k**	**292k**	**292k**	**292k**	**292k**	**292k**	**292k**	**292k**	**292k**	**292k**	**292k**	**265k**	**258k**	**252k**	**619k**	**619k**	**619k**	**619k**	**619k**	**619k**	**619k**	**619k**	**619k**	**619k**
DSCR (EBITDA / Debt Service)	x		1,36	1,36	1,36	1,36	1,36	1,36	1,36	1,36	1,36	1,36	1,36	1,36	1,36	1,36	1,36										
PV(FCFF) at WACC	€k		1.054k	1.005k	959k	914k	872k	832k	794k	757k	722k	689k	657k	627k	590k	561k	534k	405k	386k	368k	351k	335k	319k	305k	291k	277k	264k
PV(FCFE) at r_e	€k		259k	230k	205k	182k	162k	144k	128k	113k	101k	89k	79k	71k	57k	49k	43k	93k	83k	74k	65k	58k	52k	46k	41k	36k	32k
★ KPI SUMMARY			**Project NPV (€k)**		**Equity NPV (€k)**		**Equity IRR**		**Min DSCR (yrs 1-15)**		**Discounted Payback (yrs)**																
			2.940k		**(2.203k)**		**4,49%**		**1,36**		**>25 years**																

Curtailment = 5%																											
Line Item	**Unit**		**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6**	**Yr 7**	**Yr 8**	**Yr 9**	**Yr 10**	**Yr 11**	**Yr 12**	**Yr 13**	**Yr 14**	**Yr 15**	**Yr 16**	**Yr 17**	**Yr 18**	**Yr 19**	**Yr 20**	**Yr 21**	**Yr 22**	**Yr 23**	**Yr 24**	**Yr 25**
Annual Energy Output	MWh	0	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970	21.970
Revenue	€k	-	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k	1.267k
Operating Expenditure (OPEX)	€k	-	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)
EBITDA	€k		**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**
Depreciation (straight-line)	€k		(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		10.472k	9.865k	9.246k	8.615k	7.971k	7.315k	6.646k	5.963k	5.268k	4.558k	3.835k	3.098k	2.346k	1.579k	797k										
Principal Repayment	€k		(607k)	(619k)	(631k)	(644k)	(656k)	(669k)	(682k)	(696k)	(709k)	(723k)	(737k)	(752k)	(767k)	(782k)	(797k)										
Interest Expense pre-tax	€k		(206k)	(194k)	(182k)	(169k)	(157k)	(144k)	(131k)	(117k)	(103k)	(90k)	(75k)	(61k)	(46k)	(31k)	(16k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**(165k)**	**(153k)**	**(141k)**	**(129k)**	**(116k)**	**(103k)**	**(90k)**	**(76k)**	**(63k)**	**(49k)**	**(35k)**	**(20k)**	**(5k)**	**10k**	**25k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**
Tax on EBT	€k		-	-	-	-	-	-	-	-	-	-	-	-	-	-	(6k)	(228k)	(228k)	(228k)	(228k)	(228k)	(228k)	(228k)	(228k)	(228k)	(228k)
FCFF	€k	**(14.960k)**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.038k**	**1.032k**	**810k**	**810k**	**810k**	**810k**	**810k**	**810k**	**810k**	**810k**	**810k**	**810k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(4.488k)**	**225k**	**225k**	**225k**	**225k**	**225k**	**225k**	**225k**	**225k**	**225k**	**225k**	**225k**	**225k**	**225k**	**225k**	**214k**	**581k**	**581k**	**581k**	**581k**	**581k**	**581k**	**581k**	**581k**	**581k**	**581k**
DSCR (EBITDA / Debt Service)	x		1,28	1,28	1,28	1,28	1,28	1,28	1,28	1,28	1,28	1,28	1,28	1,28	1,28	1,28	1,28										
PV(FCFF) at WACC	€k		990k	944k	901k	859k	820k	782k	746k	711k	678k	647k	617k	589k	562k	536k	508k	380k	363k	346k	330k	315k	300k	286k	273k	261k	249k
PV(FCFE) at r_e	€k		200k	178k	158k	140k	125k	111k	98k	87k	78k	69k	61k	54k	48k	43k	36k	88k	78k	69k	61k	55k	49k	43k	38k	34k	30k
★ KPI SUMMARY			**Project NPV (€k)**		**Equity NPV (€k)**		**Equity IRR**		**Min DSCR (yrs 1-15)**		**Discounted Payback (yrs)**																
			2.152k		**(2.649k)**		**2,80%**		**1,28**		**>25 years**																

Curtailment = 10%																											
Line Item	**Unit**		**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6**	**Yr 7**	**Yr 8**	**Yr 9**	**Yr 10**	**Yr 11**	**Yr 12**	**Yr 13**	**Yr 14**	**Yr 15**	**Yr 16**	**Yr 17**	**Yr 18**	**Yr 19**	**Yr 20**	**Yr 21**	**Yr 22**	**Yr 23**	**Yr 24**	**Yr 25**
Annual Energy Output	MWh	0	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814	20.814
Revenue	€k	-	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k	1.200k
Operating Expenditure (OPEX)	€k	-	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)
EBITDA	€k		**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**
Depreciation (straight-line)	€k		(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		10.472k	9.865k	9.246k	8.615k	7.971k	7.315k	6.646k	5.963k	5.268k	4.558k	3.835k	3.098k	2.346k	1.579k	797k										
Principal Repayment	€k		(607k)	(619k)	(631k)	(644k)	(656k)	(669k)	(682k)	(696k)	(709k)	(723k)	(737k)	(752k)	(767k)	(782k)	(797k)										
Interest Expense pre-tax	€k		(206k)	(194k)	(182k)	(169k)	(157k)	(144k)	(131k)	(117k)	(103k)	(90k)	(75k)	(61k)	(46k)	(31k)	(16k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**(232k)**	**(220k)**	**(208k)**	**(195k)**	**(183k)**	**(170k)**	**(157k)**	**(143k)**	**(129k)**	**(116k)**	**(101k)**	**(87k)**	**(72k)**	**(57k)**	**(42k)**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**
Tax on EBT	€k		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(214k)	(214k)	(214k)	(214k)	(214k)	(214k)	(214k)	(214k)	(214k)	(214k)
FCFF	€k	**(14.960k)**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**971k**	**758k**	**758k**	**758k**	**758k**	**758k**	**758k**	**758k**	**758k**	**758k**	**758k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(4.488k)**	**159k**	**159k**	**159k**	**159k**	**159k**	**159k**	**159k**	**159k**	**159k**	**159k**	**159k**	**159k**	**159k**	**159k**	**159k**	**544k**	**544k**	**544k**	**544k**	**544k**	**544k**	**544k**	**544k**	**544k**	**544k**
DSCR (EBITDA / Debt Service)	x		1,20	1,20	1,20	1,20	1,20	1,20	1,20	1,20	1,20	1,20	1,20	1,20	1,20	1,20	1,20										
PV(FCFF) at WACC	€k		927k	884k	843k	804k	767k	732k	698k	666k	635k	606k	578k	551k	526k	501k	478k	356k	339k	324k	309k	295k	281k	268k	256k	244k	233k
PV(FCFE) at r_e	€k		141k	125k	111k	99k	88k	78k	69k	62k	55k	49k	43k	38k	34k	30k	27k	82k	73k	65k	58k	51k	45k	40k	36k	32k	28k
★ KPI SUMMARY			**Project NPV (€k)**		**Equity NPV (€k)**		**Equity IRR**		**Min DSCR (yrs 1-15)**		**Discounted Payback (yrs)**																
			1.344k		**(3.111k)**		**0,97%**		**1,20**		**>25 years**																

Curtailment = 15%																											
Line Item	**Unit**		**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6**	**Yr 7**	**Yr 8**	**Yr 9**	**Yr 10**	**Yr 11**	**Yr 12**	**Yr 13**	**Yr 14**	**Yr 15**	**Yr 16**	**Yr 17**	**Yr 18**	**Yr 19**	**Yr 20**	**Yr 21**	**Yr 22**	**Yr 23**	**Yr 24**	**Yr 25**
Annual Energy Output	MWh	0	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657	19.657
Revenue	€k	-	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k	1.133k
Operating Expenditure (OPEX)	€k	-	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)
EBITDA	€k		**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**
Depreciation (straight-line)	€k		(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		10.472k	9.865k	9.246k	8.615k	7.971k	7.315k	6.646k	5.963k	5.268k	4.558k	3.835k	3.098k	2.346k	1.579k	797k										
Principal Repayment	€k		(607k)	(619k)	(631k)	(644k)	(656k)	(669k)	(682k)	(696k)	(709k)	(723k)	(737k)	(752k)	(767k)	(782k)	(797k)										
Interest Expense pre-tax	€k		(206k)	(194k)	(182k)	(169k)	(157k)	(144k)	(131k)	(117k)	(103k)	(90k)	(75k)	(61k)	(46k)	(31k)	(16k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**(298k)**	**(286k)**	**(274k)**	**(262k)**	**(249k)**	**(236k)**	**(223k)**	**(210k)**	**(196k)**	**(182k)**	**(168k)**	**(154k)**	**(139k)**	**(124k)**	**(108k)**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**
Tax on EBT	€k		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(199k)	(199k)	(199k)	(199k)	(199k)	(199k)	(199k)	(199k)	(199k)	(199k)
FCFF	€k	**(14.960k)**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**905k**	**706k**	**706k**	**706k**	**706k**	**706k**	**706k**	**706k**	**706k**	**706k**	**706k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(4.488k)**	**92k**	**92k**	**92k**	**92k**	**92k**	**92k**	**92k**	**92k**	**92k**	**92k**	**92k**	**92k**	**92k**	**92k**	**92k**	**507k**	**507k**	**507k**	**507k**	**507k**	**507k**	**507k**	**507k**	**507k**	**507k**
DSCR (EBITDA / Debt Service)	x		1,11	1,11	1,11	1,11	1,11	1,11	1,11	1,11	1,11	1,11	1,11	1,11	1,11	1,11	1,11										
PV(FCFF) at WACC	€k		863k	823k	785k	749k	714k	681k	650k	620k	591k	564k	538k	513k	490k	467k	445k	331k	316k	301k	288k	274k	262k	250k	238k	227k	217k
PV(FCFE) at r_e	€k		82k	72k	64k	57k	51k	45k	40k	36k	32k	28k	25k	22k	20k	18k	16k	76k	68k	60k	54k	48k	42k	38k	33k	30k	26k
★ KPI SUMMARY			**Project NPV (€k)**		**Equity NPV (€k)**		**Equity IRR**		**Min DSCR (yrs 1-15)**		**Discounted Payback (yrs)**																
			533k		**(3.575k)**		**-0,94%**		**1,11**		**>25 years**																

Curtailment = 20%																											
Line Item	**Unit**		**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6**	**Yr 7**	**Yr 8**	**Yr 9**	**Yr 10**	**Yr 11**	**Yr 12**	**Yr 13**	**Yr 14**	**Yr 15**	**Yr 16**	**Yr 17**	**Yr 18**	**Yr 19**	**Yr 20**	**Yr 21**	**Yr 22**	**Yr 23**	**Yr 24**	**Yr 25**
Annual Energy Output	MWh	0	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501	18.501
Revenue	€k	-	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k	1.067k
Operating Expenditure (OPEX)	€k	-	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)
EBITDA	€k		**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**
Depreciation (straight-line)	€k		(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		10.472k	9.865k	9.246k	8.615k	7.971k	7.315k	6.646k	5.963k	5.268k	4.558k	3.835k	3.098k	2.346k	1.579k	797k										
Principal Repayment	€k		(607k)	(619k)	(631k)	(644k)	(656k)	(669k)	(682k)	(696k)	(709k)	(723k)	(737k)	(752k)	(767k)	(782k)	(797k)										
Interest Expense pre-tax	€k		(206k)	(194k)	(182k)	(169k)	(157k)	(144k)	(131k)	(117k)	(103k)	(90k)	(75k)	(61k)	(46k)	(31k)	(16k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**(365k)**	**(353k)**	**(341k)**	**(329k)**	**(316k)**	**(303k)**	**(290k)**	**(276k)**	**(263k)**	**(249k)**	**(235k)**	**(220k)**	**(205k)**	**(190k)**	**(175k)**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**
Tax on EBT	€k		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(184k)	(184k)	(184k)	(184k)	(184k)	(184k)	(184k)	(184k)	(184k)	(184k)
FCFF	€k	**(14.960k)**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**838k**	**654k**	**654k**	**654k**	**654k**	**654k**	**654k**	**654k**	**654k**	**654k**	**654k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(4.488k)**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**469k**	**469k**	**469k**	**469k**	**469k**	**469k**	**469k**	**469k**	**469k**	**469k**
DSCR (EBITDA / Debt Service)	x		1,03	1,03	1,03	1,03	1,03	1,03	1,03	1,03	1,03	1,03	1,03	1,03	1,03	1,03	1,03										
PV(FCFF) at WACC	€k		799k	762k	727k	694k	662k	631k	602k	574k	548k	522k	498k	475k	453k	433k	413k	307k	293k	279k	266k	254k	242k	231k	221k	210k	201k
PV(FCFE) at r_e	€k		22k	20k	18k	16k	14k	12k	11k	10k	9k	8k	7k	6k	5k	5k	4k	71k	63k	56k	50k	44k	39k	35k	31k	27k	24k
★ KPI SUMMARY			**Project NPV (€k)**		**Equity NPV (€k)**		**Equity IRR**		**Min DSCR (yrs 1-15)**		**Discounted Payback (yrs)**																
			(278k)		**(4.038k)**		**-2,92%**		**1,03**		**>25 years**																

Curtailment = 25%																											
Line Item	**Unit**		**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6**	**Yr 7**	**Yr 8**	**Yr 9**	**Yr 10**	**Yr 11**	**Yr 12**	**Yr 13**	**Yr 14**	**Yr 15**	**Yr 16**	**Yr 17**	**Yr 18**	**Yr 19**	**Yr 20**	**Yr 21**	**Yr 22**	**Yr 23**	**Yr 24**	**Yr 25**
Annual Energy Output	MWh	0	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345	17.345
Revenue	€k	-	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k	1.000k
Operating Expenditure (OPEX)	€k	-	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)
EBITDA	€k		**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**
Depreciation (straight-line)	€k		(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		10.472k	9.865k	9.246k	8.615k	7.971k	7.315k	6.646k	5.963k	5.268k	4.558k	3.835k	3.098k	2.346k	1.579k	797k										
Principal Repayment	€k		(607k)	(619k)	(631k)	(644k)	(656k)	(669k)	(682k)	(696k)	(709k)	(723k)	(737k)	(752k)	(767k)	(782k)	(797k)										
Interest Expense pre-tax	€k		(206k)	(194k)	(182k)	(169k)	(157k)	(144k)	(131k)	(117k)	(103k)	(90k)	(75k)	(61k)	(46k)	(31k)	(16k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**(432k)**	**(420k)**	**(408k)**	**(395k)**	**(383k)**	**(370k)**	**(357k)**	**(343k)**	**(330k)**	**(316k)**	**(301k)**	**(287k)**	**(272k)**	**(257k)**	**(242k)**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**
Tax on EBT	€k		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(170k)	(170k)	(170k)	(170k)	(170k)	(170k)	(170k)	(170k)	(170k)	(170k)
FCFF	€k	**(14.960k)**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**771k**	**602k**	**602k**	**602k**	**602k**	**602k**	**602k**	**602k**	**602k**	**602k**	**602k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(4.488k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**(42k)**	**432k**	**432k**	**432k**	**432k**	**432k**	**432k**	**432k**	**432k**	**432k**	**432k**
DSCR (EBITDA / Debt Service)	x		0,95	0,95	0,95	0,95	0,95	0,95	0,95	0,95	0,95	0,95	0,95	0,95	0,95	0,95	0,95										
PV(FCFF) at WACC	€k		736k	702k	669k	638k	609k	581k	554k	529k	504k	481k	459k	438k	417k	398k	380k	283k	269k	257k	245k	234k	223k	213k	203k	194k	185k
PV(FCFE) at r_e	€k		(37k)	(33k)	(29k)	(26k)	(23k)	(20k)	(18k)	(16k)	(14k)	(13k)	(11k)	(10k)	(9k)	(8k)	(7k)	65k	58k	51k	46k	41k	36k	32k	28k	25k	22k
★ KPI SUMMARY			**Project NPV (€k)**		**Equity NPV (€k)**		**Equity IRR**		**Min DSCR (yrs 1-15)**		**Discounted Payback (yrs)**																
			(1.089k)		**(4.502k)**		**-5,00%**		**0,95**		**>25 years**																

Curtailment = 6,5% = debt covenant breach curtailment rate																											
Line Item	**Unit**		**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6**	**Yr 7**	**Yr 8**	**Yr 9**	**Yr 10**	**Yr 11**	**Yr 12**	**Yr 13**	**Yr 14**	**Yr 15**	**Yr 16**	**Yr 17**	**Yr 18**	**Yr 19**	**Yr 20**	**Yr 21**	**Yr 22**	**Yr 23**	**Yr 24**	**Yr 25**
Annual Energy Output	MWh	0	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623	21.623
Revenue	€k	-	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k	1.247k
Operating Expenditure (OPEX)	€k	-	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)	(229k)
EBITDA	€k		**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**
Depreciation (straight-line)	€k		(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	(997k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		10.472k	9.865k	9.246k	8.615k	7.971k	7.315k	6.646k	5.963k	5.268k	4.558k	3.835k	3.098k	2.346k	1.579k	797k										
Principal Repayment	€k		(607k)	(619k)	(631k)	(644k)	(656k)	(669k)	(682k)	(696k)	(709k)	(723k)	(737k)	(752k)	(767k)	(782k)	(797k)										
Interest Expense pre-tax	€k		(206k)	(194k)	(182k)	(169k)	(157k)	(144k)	(131k)	(117k)	(103k)	(90k)	(75k)	(61k)	(46k)	(31k)	(16k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**(185k)**	**(173k)**	**(161k)**	**(149k)**	**(136k)**	**(123k)**	**(110k)**	**(96k)**	**(83k)**	**(69k)**	**(55k)**	**(40k)**	**(25k)**	**(10k)**	**5k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**
Tax on EBT	€k		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(224k)	(224k)	(224k)	(224k)	(224k)	(224k)	(224k)	(224k)	(224k)	(224k)
FCFF	€k	**(14.960k)**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**1.018k**	**794k**	**794k**	**794k**	**794k**	**794k**	**794k**	**794k**	**794k**	**794k**	**794k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(4.488k)**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**570k**	**570k**	**570k**	**570k**	**570k**	**570k**	**570k**	**570k**	**570k**	**570k**
DSCR (EBITDA / Debt Service)	x		1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25										
PV(FCFF) at WACC	€k		971k	926k	883k	843k	804k	767k	731k	698k	665k	635k	605k	577k	551k	525k	501k	373k	356k	339k	324k	309k	294k	281k	268k	256k	244k
PV(FCFE) at r_e	€k		182k	162k	144k	128k	114k	101k	90k	80k	71k	63k	56k	50k	44k	39k	35k	86k	76k	68k	60k	54k	48k	42k	38k	33k	30k
★ KPI SUMMARY			**Project NPV (€k)**		**Equity NPV (€k)**		**Equity IRR**		**Min DSCR (yrs 1-15)**		**Discounted Payback (yrs)**																
			1.911k		**(2.787k)**		**2,27%**		**1,25**		**>25 years**																

Appendix 2: Small Hydropower Project Cash Flows Tables

Curtailment = 0%

Line Item	Unit		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25
Annual Energy Output	MWh	0	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504	3.504
Revenue	€k	-	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k	315k
Operating Expenditure (OPEX)	€k	-	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)
EBITDA	€k		**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**
Depreciation (straight-line)	€k		(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		1.309k	1.233k	1.156k	1.077k	996k	914k	831k	745k	658k	570k	479k	387k	293k	197k	100k										
Principal Repayment	€k		(76k)	(77k)	(79k)	(80k)	(82k)	(84k)	(85k)	(87k)	(89k)	(90k)	(92k)	(94k)	(96k)	(98k)	(100k)										
Interest Expense pre-tax	€k		(26k)	(24k)	(23k)	(21k)	(20k)	(18k)	(16k)	(15k)	(13k)	(11k)	(9k)	(8k)	(6k)	(4k)	(2k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**127,6k**	**129k**	**131k**	**132k**	**134k**	**135k**	**137k**	**139k**	**140k**	**142k**	**144k**	**146k**	**148k**	**149k**	**151k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**	**278k**
Tax on EBT	€k		(28k)	(28k)	(29k)	(29k)	(29k)	(30k)	(30k)	(31k)	(31k)	(31k)	(32k)	(32k)	(32k)	(33k)	(33k)	(61k)	(61k)	(61k)	(61k)	(61k)	(61k)	(61k)	(61k)	(61k)	(61k)
FCFF	€k	**(1.870k)**	**250k**	**250k**	**249k**	**249k**	**249k**	**248k**	**248k**	**247k**	**247k**	**247k**	**246k**	**246k**	**246k**	**245k**	**245k**	**217k**	**217k**	**217k**	**217k**	**217k**	**217k**	**217k**	**217k**	**217k**	**217k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(561k)**	**120k**	**120k**	**119k**	**118k**	**118k**	**117k**	**116k**	**115k**	**115k**	**114k**	**113k**	**112k**	**111k**	**111k**	**110k**	**156k**	**156k**	**156k**	**156k**	**156k**	**156k**	**156k**	**156k**	**156k**	**156k**
DSCR (EBITDA / Debt Service)	x		2,74	2,74	2,74	2,74	2,74	2,74	2,74	2,74	2,74	2,74	2,74	2,74	2,74	2,74	2,74										
PV(FCFF) at WACC	€k		238k	227k	216k	206k	196k	187k	178k	170k	162k	154k	146k	139k	133k	126k	120k	102k	97k	93k	88k	84k	80k	77k	73k	70k	67k
PV(FCFE) at r_e	€k		107k	94k	83k	74k	65k	57k	51k	45k	40k	35k	31k	27k	24k	21k	19k	23k	21k	19k	16k	15k	13k	12k	10k	9k	8k
★ KPI SUMMARY			Project NPV (€k)		Equity NPV (€k)		Equity IRR		Min DSCR (yrs 1-15)		Discounted Payback (yrs)																
			1.755k		**305k**		**20,71%**		**2,74**		**8 years**																

Curtailment = 5%

Line Item	Unit		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25
Annual Energy Output	MWh	0	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329	3.329
Revenue	€k	-	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k	300k
Operating Expenditure (OPEX)	€k	-	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)
EBITDA	€k		**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**
Depreciation (straight-line)	€k		(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		1.309k	1.233k	1.156k	1.077k	996k	914k	831k	745k	658k	570k	479k	387k	293k	197k	100k										
Principal Repayment	€k		(76k)	(77k)	(79k)	(80k)	(82k)	(84k)	(85k)	(87k)	(89k)	(90k)	(92k)	(94k)	(96k)	(98k)	(100k)										
Interest Expense pre-tax	€k		(26k)	(24k)	(23k)	(21k)	(20k)	(18k)	(16k)	(15k)	(13k)	(11k)	(9k)	(8k)	(6k)	(4k)	(2k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**112k**	**113k**	**115k**	**116k**	**118k**	**120k**	**121k**	**123k**	**125k**	**126k**	**128k**	**130k**	**132k**	**134k**	**136k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**	**262k**
Tax on EBT	€k		(25k)	(25k)	(25k)	(26k)	(26k)	(26k)	(27k)	(27k)	(27k)	(28k)	(28k)	(29k)	(29k)	(29k)	(30k)	(58k)	(58k)	(58k)	(58k)	(58k)	(58k)	(58k)	(58k)	(58k)	(58k)
FCFF	€k	**(1.870k)**	**238k**	**237k**	**237k**	**237k**	**236k**	**236k**	**236k**	**235k**	**235k**	**234k**	**234k**	**234k**	**233k**	**233k**	**232k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**	**205k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(561k)**	**111k**	**111k**	**110k**	**109k**	**109k**	**108k**	**107k**	**107k**	**106k**	**105k**	**104k**	**103k**	**103k**	**102k**	**101k**	**147k**	**147k**	**147k**	**147k**	**147k**	**147k**	**147k**	**147k**	**147k**	**147k**
DSCR (EBITDA / Debt Service)	x		2,58	2,58	2,58	2,58	2,58	2,58	2,58	2,58	2,58	2,58	2,58	2,58	2,58	2,58	2,58										
PV(FCFF) at WACC	€k		227k	216k	206k	196k	187k	178k	169k	161k	153k	146k	139k	133k	126k	120k	114k	96k	92k	87k	83k	80k	76k	72k	69k	66k	63k
PV(FCFE) at r_e	€k		99k	87k	77k	68k	60k	53k	47k	41k	36k	32k	28k	25k	22k	19k	17k	22k	20k	17k	16k	14k	12k	11k	10k	9k	8k
★ KPI SUMMARY			Project NPV (€k)		Equity NPV (€k)		Equity IRR		Min DSCR (yrs 1-15)		Discounted Payback (yrs)																
			1.599k		**242k**		**19,05%**		**2,58**		**9 years**																

Curtailment = 10%

Line Item	Unit		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25
Annual Energy Output	MWh	0	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154	3.154
Revenue	€k	-	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k	284k
Operating Expenditure (OPEX)	€k	-	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)
EBITDA	€k		**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**
Depreciation (straight-line)	€k		(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		1.309k	1.233k	1.156k	1.077k	996k	914k	831k	745k	658k	570k	479k	387k	293k	197k	100k										
Principal Repayment	€k		(76k)	(77k)	(79k)	(80k)	(82k)	(84k)	(85k)	(87k)	(89k)	(90k)	(92k)	(94k)	(96k)	(98k)	(100k)										
Interest Expense pre-tax	€k		(26k)	(24k)	(23k)	(21k)	(20k)	(18k)	(16k)	(15k)	(13k)	(11k)	(9k)	(8k)	(6k)	(4k)	(2k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**96k**	**98k**	**99k**	**101k**	**102k**	**104k**	**105k**	**107k**	**109k**	**111k**	**112k**	**114k**	**116k**	**118k**	**120k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**	**246k**
Tax on EBT	€k		(21k)	(21k)	(22k)	(22k)	(22k)	(23k)	(23k)	(24k)	(24k)	(24k)	(25k)	(25k)	(26k)	(26k)	(26k)	(54k)	(54k)	(54k)	(54k)	(54k)	(54k)	(54k)	(54k)	(54k)	(54k)
FCFF	€k	**(1.870k)**	**225k**	**225k**	**225k**	**224k**	**224k**	**224k**	**223k**	**223k**	**222k**	**222k**	**222k**	**221k**	**221k**	**220k**	**220k**	**192k**	**192k**	**192k**	**192k**	**192k**	**192k**	**192k**	**192k**	**192k**	**192k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(561k)**	**103k**	**102k**	**101k**	**101k**	**100k**	**99k**	**98k**	**98k**	**97k**	**96k**	**95k**	**95k**	**94k**	**93k**	**92k**	**138k**	**138k**	**138k**	**138k**	**138k**	**138k**	**138k**	**138k**	**138k**	**138k**
DSCR (EBITDA / Debt Service)	x		2,43	2,43	2,43	2,43	2,43	2,43	2,43	2,43	2,43	2,43	2,43	2,43	2,43	2,43	2,43										
PV(FCFF) at WACC	€k		215k	205k	195k	186k	177k	168k	160k	153k	145k	138k	132k	126k	120k	114k	108k	90k	86k	82k	78k	75k	71k	68k	65k	62k	59k
PV(FCFE) at r_e	€k		91k	80k	71k	63k	55k	49k	43k	38k	33k	29k	26k	23k	20k	18k	16k	21k	18k	16k	15k	13k	12k	10k	9k	8k	7k

★ KPI SUMMARY	Project NPV (€k)	Equity NPV (€k)	Equity IRR	Min DSCR (yrs 1-15)	Discounted Payback (yrs)
	1.444k	**178k**	**17,37%**	**2,43**	**10 years**

Curtailment = 15%

Line Item	Unit		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25
Annual Energy Output	MWh	0	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978	2.978
Revenue	€k	-	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k	268k
Operating Expenditure (OPEX)	€k	-	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)
EBITDA	€k		**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**
Depreciation (straight-line)	€k		(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		1.309k	1.233k	1.156k	1.077k	996k	914k	831k	745k	658k	570k	479k	387k	293k	197k	100k										
Principal Repayment	€k		(76k)	(77k)	(79k)	(80k)	(82k)	(84k)	(85k)	(87k)	(89k)	(90k)	(92k)	(94k)	(96k)	(98k)	(100k)										
Interest Expense pre-tax	€k		(26k)	(24k)	(23k)	(21k)	(20k)	(18k)	(16k)	(15k)	(13k)	(11k)	(9k)	(8k)	(6k)	(4k)	(2k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**80k**	**82k**	**83k**	**85k**	**86k**	**88k**	**90k**	**91k**	**93k**	**95k**	**97k**	**98k**	**100k**	**102k**	**104k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**	**231k**
Tax on EBT	€k		(18k)	(18k)	(18k)	(19k)	(19k)	(19k)	(20k)	(20k)	(20k)	(21k)	(21k)	(22k)	(22k)	(22k)	(23k)	(51k)	(51k)	(51k)	(51k)	(51k)	(51k)	(51k)	(51k)	(51k)	(51k)
FCFF	€k	**(1.870k)**	**213k**	**213k**	**212k**	**212k**	**212k**	**211k**	**211k**	**211k**	**210k**	**210k**	**209k**	**209k**	**209k**	**208k**	**208k**	**180k**	**180k**	**180k**	**180k**	**180k**	**180k**	**180k**	**180k**	**180k**	**180k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(561k)**	**94k**	**93k**	**92k**	**92k**	**91k**	**90k**	**90k**	**89k**	**88k**	**87k**	**87k**	**86k**	**85k**	**84k**	**83k**	**129k**	**129k**	**129k**	**129k**	**129k**	**129k**	**129k**	**129k**	**129k**	**129k**
DSCR (EBITDA / Debt Service)	x		2,27	2,27	2,27	2,27	2,27	2,27	2,27	2,27	2,27	2,27	2,27	2,27	2,27	2,27	2,27										
PV(FCFF) at WACC	€k		203k	193k	184k	175k	167k	159k	152k	144k	137k	131k	125k	119k	113k	107k	102k	84k	81k	77k	73k	70k	67k	64k	61k	58k	55k
PV(FCFE) at r_e	€k		83k	73k	65k	57k	50k	44k	39k	35k	30k	27k	24k	21k	18k	16k	14k	19k	17k	15k	14k	12k	11k	10k	9k	8k	7k

★ KPI SUMMARY	Project NPV (€k)	Equity NPV (€k)	Equity IRR	Min DSCR (yrs 1-15)	Discounted Payback (yrs)
	1.289k	**114k**	**15,67%**	**2,27**	**13 years**

Curtailment = 20%

Line Item	Unit		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25
Annual Energy Output	MWh	0	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803	2.803
Revenue	€k	-	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k	252k
Operating Expenditure (OPEX)	€k	-	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)
EBITDA	€k		**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**
Depreciation (straight-line)	€k		(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		1.309k	1.233k	1.156k	1.077k	996k	914k	831k	745k	658k	570k	479k	387k	293k	197k	100k										
Principal Repayment	€k		(76k)	(77k)	(79k)	(80k)	(82k)	(84k)	(85k)	(87k)	(89k)	(90k)	(92k)	(94k)	(96k)	(98k)	(100k)										
Interest Expense pre-tax	€k		(26k)	(24k)	(23k)	(21k)	(20k)	(18k)	(16k)	(15k)	(13k)	(11k)	(9k)	(8k)	(6k)	(4k)	(2k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**65k**	**66k**	**68k**	**69k**	**71k**	**72k**	**74k**	**76k**	**77k**	**79k**	**81k**	**83k**	**84k**	**86k**	**88k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**	**215k**
Tax on EBT	€k		(14k)	(15k)	(15k)	(15k)	(16k)	(16k)	(16k)	(17k)	(17k)	(17k)	(18k)	(18k)	(19k)	(19k)	(19k)	(47k)	(47k)	(47k)	(47k)	(47k)	(47k)	(47k)	(47k)	(47k)	(47k)
FCFF	€k	**(1.870k)**	**201k**	**200k**	**200k**	**200k**	**199k**	**199k**	**199k**	**198k**	**198k**	**198k**	**197k**	**197k**	**196k**	**196k**	**195k**	**168k**	**168k**	**168k**	**168k**	**168k**	**168k**	**168k**	**168k**	**168k**	**168k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(561k)**	**85k**	**84k**	**84k**	**83k**	**82k**	**81k**	**81k**	**80k**	**79k**	**79k**	**78k**	**77k**	**76k**	**75k**	**74k**	**120k**	**120k**	**120k**	**120k**	**120k**	**120k**	**120k**	**120k**	**120k**	**120k**
DSCR (EBITDA / Debt Service)	x		2,12	2,12	2,12	2,12	2,12	2,12	2,12	2,12	2,12	2,12	2,12	2,12	2,12	2,12	2,12										
PV(FCFF) at WACC	€k		191k	182k	174k	165k	157k	150k	143k	136k	129k	123k	117k	112k	106k	101k	96k	79k	75k	72k	68k	65k	62k	59k	57k	54k	51k
PV(FCFE) at r_e	€k		75k	67k	59k	52k	46k	40k	35k	31k	27k	24k	21k	19k	16k	14k	13k	18k	16k	14k	13k	11k	10k	9k	8k	7k	6k

★ KPI SUMMARY	Project NPV (€k)	Equity NPV (€k)	Equity IRR	Min DSCR (yrs 1-15)	Discounted Payback (yrs)
	1.133k	**50k**	**13,94%**	**2,12**	**16 years**

Curtailment = 25%

Line Item	Unit		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25
Annual Energy Output	MWh	0	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628	2.628
Revenue	€k	-	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k	237k
Operating Expenditure (OPEX)	€k	-	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)
EBITDA	€k		**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**
Depreciation (straight-line)	€k		(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		1.309k	1.233k	1.156k	1.077k	996k	914k	831k	745k	658k	570k	479k	387k	293k	197k	100k										
Principal Repayment	€k		(76k)	(77k)	(79k)	(80k)	(82k)	(84k)	(85k)	(87k)	(89k)	(90k)	(92k)	(94k)	(96k)	(98k)	(100k)										
Interest Expense pre-tax	€k		(26k)	(24k)	(23k)	(21k)	(20k)	(18k)	(16k)	(15k)	(13k)	(11k)	(9k)	(8k)	(6k)	(4k)	(2k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**49k**	**50k**	**52k**	**53k**	**55k**	**56k**	**58k**	**60k**	**62k**	**63k**	**65k**	**67k**	**69k**	**71k**	**72k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**	**199k**
Tax on EBT	€k		(11k)	(11k)	(11k)	(12k)	(12k)	(12k)	(13k)	(13k)	(14k)	(14k)	(14k)	(15k)	(15k)	(16k)	(16k)	(44k)	(44k)	(44k)	(44k)	(44k)	(44k)	(44k)	(44k)	(44k)	(44k)
FCFF	€k	**(1.870k)**	**188k**	**188k**	**188k**	**187k**	**187k**	**187k**	**186k**	**186k**	**186k**	**185k**	**185k**	**184k**	**184k**	**184k**	**183k**	**155k**	**155k**	**155k**	**155k**	**155k**	**155k**	**155k**	**155k**	**155k**	**155k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(561k)**	**76k**	**75k**	**75k**	**74k**	**73k**	**73k**	**72k**	**71k**	**70k**	**70k**	**69k**	**68k**	**67k**	**66k**	**66k**	**112k**	**112k**	**112k**	**112k**	**112k**	**112k**	**112k**	**112k**	**112k**	**112k**
DSCR (EBITDA / Debt Service)	x		1,96	1,96	1,96	1,96	1,96	1,96	1,96	1,96	1,96	1,96	1,96	1,96	1,96	1,96	1,96										
PV(FCFF) at WACC	€k		180k	171k	163k	155k	148k	141k	134k	127k	121k	115k	110k	105k	100k	95k	90k	73k	70k	66k	63k	60k	58k	55k	52k	50k	48k
PV(FCFE) at r_e	€k		68k	60k	52k	46k	41k	36k	31k	28k	24k	21k	19k	16k	14k	13k	11k	17k	15k	13k	12k	10k	9k	8k	7k	7k	6k
★ KPI SUMMARY			Project NPV (€k)		Equity NPV (€k)		Equity IRR		Min DSCR (yrs 1-15)		Discounted Payback (yrs)																
			978k		**(13k)**		**12,18%**		**1,96**		**22 years**																

Curtailment = 23,95% = debt covenant breach curtailment rate

Line Item	Unit		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25
Annual Energy Output	MWh	0	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665	2.665
Revenue	€k	-	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k	240k
Operating Expenditure (OPEX)	€k	-	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)
EBITDA	€k		**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**
Depreciation (straight-line)	€k		(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		1.309k	1.233k	1.156k	1.077k	996k	914k	831k	745k	658k	570k	479k	387k	293k	197k	100k										
Principal Repayment	€k		(76k)	(77k)	(79k)	(80k)	(82k)	(84k)	(85k)	(87k)	(89k)	(90k)	(92k)	(94k)	(96k)	(98k)	(100k)										
Interest Expense pre-tax	€k		(26k)	(24k)	(23k)	(21k)	(20k)	(18k)	(16k)	(15k)	(13k)	(11k)	(9k)	(8k)	(6k)	(4k)	(2k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**52k**	**54k**	**55k**	**57k**	**58k**	**60k**	**61k**	**63k**	**65k**	**67k**	**68k**	**70k**	**72k**	**74k**	**76k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**	**202k**
Tax on EBT	€k		(11k)	(12k)	(12k)	(12k)	(13k)	(13k)	(14k)	(14k)	(14k)	(15k)	(15k)	(15k)	(16k)	(16k)	(17k)	(45k)	(45k)	(45k)	(45k)	(45k)	(45k)	(45k)	(45k)	(45k)	(45k)
FCFF	€k	**(1.870k)**	**191k**	**191k**	**190k**	**190k**	**190k**	**189k**	**189k**	**189k**	**188k**	**188k**	**187k**	**187k**	**187k**	**186k**	**186k**	**158k**	**158k**	**158k**	**158k**	**158k**	**158k**	**158k**	**158k**	**158k**	**158k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(561k)**	**78k**	**77k**	**77k**	**76k**	**75k**	**75k**	**74k**	**73k**	**72k**	**72k**	**71k**	**70k**	**69k**	**68k**	**67k**	**113k**	**113k**	**113k**	**113k**	**113k**	**113k**	**113k**	**113k**	**113k**	**113k**
DSCR (EBITDA / Debt Service)	x		1,99	1,99	1,99	1,99	1,99	1,99	1,99	1,99	1,99	1,99	1,99	1,99	1,99	1,99	1,99										
PV(FCFF) at WACC	€k		182k	173k	165k	157k	150k	143k	136k	129k	123k	117k	111k	106k	101k	96k	91k	74k	71k	67k	64k	61k	59k	56k	53k	51k	48k
PV(FCFE) at r_e	€k		69k	61k	54k	47k	42k	37k	32k	28k	25k	22k	19k	17k	15k	13k	11k	17k	15k	13k	12k	11k	9k	8k	7k	7k	6k
★ KPI SUMMARY			Project NPV (€k)		Equity NPV (€k)		Equity IRR		Min DSCR (yrs 1-15)		Discounted Payback (yrs)																
			1.010k		**0k**		**12,55%**		**1,99**		**>25 years**																

Curtailment = 48% = equity break-even curtailment rate

Line Item	Unit		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25
Annual Energy Output	MWh	0	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822	1.822
Revenue	€k	-	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k	164k
Operating Expenditure (OPEX)	€k	-	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)	(37k)
EBITDA	€k		**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**
Depreciation (straight-line)	€k		(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	(125k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	€k		1.309k	1.233k	1.156k	1.077k	996k	914k	831k	745k	658k	570k	479k	387k	293k	197k	100k										
Principal Repayment	€k		(76k)	(77k)	(79k)	(80k)	(82k)	(84k)	(85k)	(87k)	(89k)	(90k)	(92k)	(94k)	(96k)	(98k)	(100k)										
Interest Expense pre-tax	€k		(26k)	(24k)	(23k)	(21k)	(20k)	(18k)	(16k)	(15k)	(13k)	(11k)	(9k)	(8k)	(6k)	(4k)	(2k)										
EBT = EBITDA + Depreciation + Interest Expense	€k		**(24k)**	**(22k)**	**(21k)**	**(19k)**	**(18k)**	**(16k)**	**(14k)**	**(13k)**	**(11k)**	**(9k)**	**(7k)**	**(6k)**	**(4k)**	**(2k)**	**(0k)**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**
Tax on EBT	€k		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(28k)	(28k)	(28k)	(28k)	(28k)	(28k)	(28k)	(28k)	(28k)	(28k)
FCFF	€k	**(1.870k)**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**127k**	**99k**	**99k**	**99k**	**99k**	**99k**	**99k**	**99k**	**99k**	**99k**	**99k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(561k)**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**25k**	**71k**	**71k**	**71k**	**71k**	**71k**	**71k**	**71k**	**71k**	**71k**	**71k**
DSCR (EBITDA / Debt Service)	x		1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25										
PV(FCFF) at WACC	€k		121k	115k	110k	105k	100k	95k	91k	87k	83k	79k	75k	72k	68k	65k	62k	46k	44k	42k	40k	38k	37k	35k	33k	32k	30k
PV(FCFE) at r_e	€k		22k	20k	18k	16k	14k	12k	11k	10k	9k	8k	7k	6k	5k	5k	4k	11k	9k	8k	7k	7k	6k	5k	5k	4k	4k
★ KPI SUMMARY			Project NPV (€k)		Equity NPV (€k)		Equity IRR		Min DSCR (yrs 1-15)		Discounted Payback (yrs)																
			231k		**(353k)**		**2,12%**		**1,25**		**>25 years**																

Appendix 3: Solar +BESS Project Cash Flows Tables

Base Case (BESS – no curtailment)

Line Item	Unit		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12
Annual Energy Output	MWh	0	7.490	7.452	7.415	7.378	7.341	7.304	7.268	7.232	7.195	7.159	7.124	7.088
Revenue	€k	-	776k	772k	768k	764k	761k	757k	753k	749k	746k	742k	738k	734k
Operating Expenditure (OPEX)	€k	-	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)
EBITDA	€k		**746k**	**742k**	**739k**	**735k**	**731k**	**727k**	**723k**	**720k**	**716k**	**712k**	**708k**	**705k**
Depreciation (straight-line)	€k		(418k)	(418k)	(418k)	(418k)	(418k)	(418k)	(418k)	(418k)	(418k)	(418k)	(418k)	(418k)
Opening Debt Balance	€k		4.385k	4.131k	3.871k	3.607k	3.338k	3.063k	2.783k	2.497k	2.206k	1.909k	1.606k	1.297k
Principal Repayment	€k		(254k)	(259k)	(264k)	(269k)	(275k)	(280k)	(286k)	(291k)	(297k)	(303k)	(309k)	(315k)
Interest Expense pre-tax	€k		(86k)	(81k)	(76k)	(71k)	(66k)	(60k)	(55k)	(49k)	(43k)	(37k)	(32k)	(25k)
EBT = EBITDA + Depreciation + Interest Expense	€k		**243k**	**244k**	**245k**	**246k**	**248k**	**249k**	**251k**	**253k**	**255k**	**257k**	**259k**	**262k**
Tax on EBT	€k		(53k)	(54k)	(54k)	(54k)	(55k)	(55k)	(55k)	(56k)	(56k)	(57k)	(57k)	(58k)
FCFF	€k	**(6.264k)**	**693k**	**689k**	**685k**	**681k**	**676k**	**672k**	**668k**	**664k**	**660k**	**656k**	**651k**	**647k**
FCFE = FCFF + Interest(AT) + Principal + TAX	€k	**(1.879k)**	**299k**	**295k**	**290k**	**286k**	**282k**	**277k**	**273k**	**268k**	**263k**	**259k**	**254k**	**249k**
DSCR (EBITDA / Debt Service)	x		2,19	2,18	2,17	2,16	2,15	2,14	2,13	2,11	2,10	2,09	2,08	2,07
PV(FCFF) at WACC	€k		661k	627k	594k	563k	534k	506k	480k	455k	431k	409k	387k	367k
PV(FCFE) at r_e	€k		266k	233k	204k	178k	156k	136k	119k	104k	91k	79k	69k	60k

Line Item	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25
Annual Energy Output	7.053	7.017	6.982	6.947	6.913	6.878	6.844	6.809	6.775	6.741	6.708	6.674	6.641
Revenue	731k	727k	723k	720k	716k	713k	709k	706k	702k	698k	695k	692k	688k
Operating Expenditure (OPEX)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)	(30k)
EBITDA	**701k**	**697k**	**694k**	**690k**	**687k**	**683k**	**679k**	**676k**	**672k**	**669k**	**665k**	**662k**	**658k**
Depreciation (straight-line)	(418k)	(418k)	(418k)	-	-	-	-	-	-	-	-	-	-
Opening Debt Balance	982k	661k	334k										
Principal Repayment	(321k)	(327k)	(334k)										
Interest Expense pre-tax	(19k)	(13k)	(7k)										
EBT = EBITDA + Depreciation + Interest Expense	**264k**	**267k**	**270k**	**690k**	**687k**	**683k**	**679k**	**676k**	**672k**	**669k**	**665k**	**662k**	**658k**
Tax on EBT	(58k)	(59k)	(59k)	(152k)	(151k)	(150k)	(149k)	(149k)	(148k)	(147k)	(146k)	(146k)	(145k)
FCFF	**643k**	**639k**	**634k**	**538k**	**535k**	**533k**	**530k**	**527k**	**524k**	**522k**	**519k**	**516k**	**514k**
FCFE = FCFF + Interest(AT) + Principal + TAX	**244k**	**240k**	**235k**	**386k**	**384k**	**382k**	**380k**	**378k**	**376k**	**375k**	**373k**	**371k**	**369k**
DSCR (EBITDA / Debt Service)	2,06	2,05	2,04										
PV(FCFF) at WACC	348k	330k	312k	253k	240k	228k	216k	205k	194k	184k	175k	166k	158k
PV(FCFE) at r_e	53k	46k	40k	58k	52k	46k	40k	36k	31k	28k	25k	22k	19k

★ KPI SUMMARY	Project NPV (€k)	Equity NPV (€k)	Equity IRR	Min DSCR (yrs 1-15)	Discounted Payback (yrs)
	3.761k	**186k**	**14,12%**	**2,04**	**15 years**

Author's Statement:

I hereby declare that, in accordance with article 8 of Law 1599/1986 and article 2.4.6 par. 3 of Law 1256/1982, this thesis/dissertation is solely a product of personal work and does not infringe any intellectual property rights of third parties and is not the product of a partial or total plagiarism, and the sources used are strictly limited to the bibliographic references.