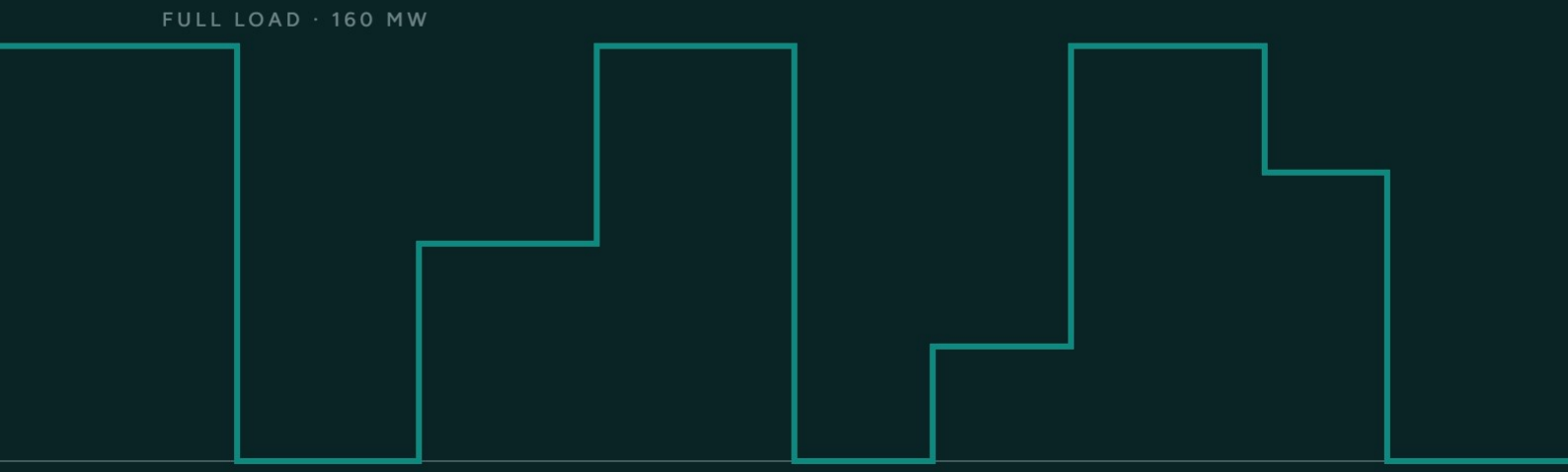
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WHITEPAPER

Flexible e-methane production in Finland

An hourly dispatch model of a plant built on 160 MW of electrolysis in the Finnish day-ahead market

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Table of Contents

Executive summary 3

Introduction 4

Regulatory drivers of demand 4

The flexibility lever 6

Goal 6

Our approach 6

Plant and system concept 6

Method 7

How the results should be read 8

Results and discussion 8

The minimum-load constraint 9

Sensitivity to PPA size 10

Procurement without a PPA 10

The RFNBO grid-price ceiling 11

Wider implications 11

Project financing 11

Regulatory calibration 12

Conclusion 13

Sources 14

Appendix 15

Executive summary

32%	16%	73%	6%
LCOM cut by full flexibility	Further cut with no PPA	Lower average power price without a PPA	Further cut with a higher ceiling

Of the factors examined in this study, operational flexibility has the largest effect on the levelized cost of RFNBO-certified e-methane. The study uses an hourly dispatch model of a plant based on 160 MW of water electrolysis, trading in the Finnish day-ahead market. At constant load with a 320 MW wind PPA, the levelized cost of methane is 3.74 EUR per kg. With fully flexible operation, no PPA and electricity purchased only in compliant grid hours, it is 2.14 EUR per kg. This is a reduction of 43 percent, with capital cost, efficiency and feedstock assumptions held constant.

The 43 percent reduction comes from lower electricity cost and is realised in two steps. Electrolysis uses 97 percent of plant electricity, and electricity accounts for most of the variable cost. A plant held at constant load under a wind PPA must buy at the day-ahead market price whenever PPA generation falls below its demand, and low-wind hours are often high-price hours. A fully flexible plant under the same PPA can shut down in those hours. It can also sell PPA electricity on the day-ahead market when that is more profitable than producing methane, and the sales revenue is credited against the cost of production. Without a PPA, the plant buys electricity only in low-price hours, which lowers the average electricity cost further. Under the RFNBO criteria, grid electricity counts as fully renewable when the day-ahead price is below a defined ceiling, so these low-price hours are also hours in which the output qualifies for certification.

The first step, full flexibility under the 320 MW wind PPA, reduces the levelized cost by 32 percent to 2.54 EUR per kg. The average price paid per MWh consumed falls from 53 to 33 EUR per MWh. The capacity factor falls from 1.00 to 0.73, which increases the capital cost component by 0.36 EUR per kg and reduces the electricity cost component by 1.01 EUR per kg. The second step, removing the PPA, accounts for a further 16 percent, at an average electricity price of 9 EUR per MWh. Beyond these two steps, raising the RFNBO price ceiling from 0.36 to 0.8 times the EU ETS allowance price, equivalent to 36 and 80 EUR per MWh at 100 EUR per tonne of CO2, reduces the levelized cost by a further 6 percent to 2.02 EUR per kg. Figure 2 shows the three steps in sequence.

At constant load, the project does not reach a positive internal rate of return (IRR). In the fully flexible case without a PPA, the IRR is 8.25 percent, rising to 9.84 percent at the higher price ceiling. These absolute values depend directly on the assumed certificate and gas prices, so the relative change between scenarios is what this paper aims to report. Purchasing electricity without a PPA also makes production volume variable. With debt service fixed, this variability is borne by equity and is likely to be reflected in a lower offtake price. The increase in IRR from flexible operation must therefore exceed the associated increase in the equity hurdle rate.

Headline results

1. Relaxing the minimum-load constraint from 100 percent to fully flexible operation lowers the levelized cost of methane by 32 percent, from 3.74 to 2.54 EUR per kg, under an identical 320 MW wind PPA.
2. For a fully flexible plant the cost-optimal procurement strategy is to hold no PPA at all, which lowers the levelized cost by a further 16 percent to 2.14 EUR per kg and lifts the internal rate of return from 4.98 to 8.25 percent.
3. The average price paid per MWh consumed falls by 73 percent, from 33 to 9 EUR per MWh, when the PPA is dropped.
4. Raising the RFNBO grid-price ceiling from 0.36 to 0.8 times the ETS allowance price lowers the levelized cost by a further 6 percent to 2.02 EUR per kg and raises the internal rate of return to 9.84 percent.

Introduction

Natural gas supplies a large share of heat and industrial energy in Europe, and the gas grid is likely to remain in use over the period covered by current climate targets. E-methane is produced by combining renewable hydrogen with biogenic CO2 in a methanation reactor. It is chemically identical to natural gas and can be injected into the existing gas grid. Its value above the commodity gas price depends mainly on certification. Under the recast Renewable Energy Directive [1], e-methane made from compliant renewable electricity qualifies as a Renewable Fuel of Non-Biological Origin (RFNBO). For e-methane, RFNBO status is the only route to counting toward the binding targets in RED III [2], and therefore the only source of a price premium backed by regulation. Any premium for uncertified low-carbon methane depends on voluntary willingness to pay.

This paper examines how far the cost of e-methane can be reduced through flexible production and through changes to the EU RFNBO criteria. Production cost is one of the main factors in how widely e-methane can be adopted, and therefore in whether it can contribute at the scale required by EU emission reduction targets.

Regulatory drivers of demand

The RFNBO credit takes its value from legally mandated demand, and that demand is conditional on full compliance. A batch qualifies only if every criterion is satisfied at once, including hourly temporal correlation and the life-cycle greenhouse-gas threshold, so compliance is all or nothing rather than a matter of degree. A batch that meets only some of the criteria cannot be counted toward the mandate. Where its carbon intensity is nonetheless low it can be sold as low-carbon methane, for which demand rests on voluntary willingness to pay rather than on any legal obligation. Where the carbon intensity is high the batch is effectively grey and earns no more than the commodity price. The three price tiers in Table 1 follow from this cascade.

RED III sets quotas requiring that 42 percent of the hydrogen used in industry be RFNBO by 2030, rising to 60 percent by 2035, alongside a combined target for advanced biofuels and RFNBOs in transport [2]. The quota is expressed on hydrogen rather than on the finished fuel, and e-methane qualifies through the renewable hydrogen it consumes. These targets are binding on member states. They create an obligation for individual companies, the obligated parties, only once a member state transposes them into national law. In many

member states transposition is still incomplete, and until it is, the demand on which the RFNBO premium depends remains uncertain. Where the targets have been transposed, obligated parties must procure RFNBO-certified fuel to meet their quota, which creates a structural willingness to pay. The penalty for non-compliance set in national law broadly determines its upper limit.

Commission Delegated Regulations (EU) 2023/1184 and 2023/1185 define what counts as an RFNBO [3][4]. Between them they cover renewable power sourcing, additionality, temporal and geographical correlation, and a life-cycle greenhouse-gas reduction above 70 percent against the 94 gCO2e per MJ fossil comparator. In parallel the EU Emissions Trading System penalises fossil methane [5], and national quota and blending schemes add demand at member-state level.

Together these instruments convert RFNBO status into a monetizable credit. This study uses a certified green methane price of 190 EUR per MWh as a worked example, of which 140 EUR per MWh reflects the certificate value and 50 EUR per MWh the underlying gas. That is equivalent to 2.64 EUR per kg, against a grey methane commodity value of 0.69 EUR per kg. These levels are illustrative assumptions rather than market quotations. Nearly three quarters of project revenue therefore depends on maintaining compliance under hourly matching. For methane the certification carries a dual requirement. The hydrogen input must satisfy the renewable-electricity rules, and the carbon input must come from biogenic or otherwise eligible captured CO2.

Table 1: RFNBO certification requirements and the price tier each one unlocks.

Requirement	RFNBO e-methane	Low-carbon methane	Grey methane
Life-cycle greenhouse-gas reduction above 70% against the 94 gCO2e per MJ comparator	✓	✓	×
Hydrogen produced from renewable electricity	✓	×	×
Grid power only where the zone exceeds 90% renewable share or the price sits below the ceiling	✓	×	×
Hourly temporal correlation with the renewable generation	✓	×	×
Same bidding zone as the renewable asset, plus additionality	✓	×	×
Biogenic or otherwise eligible captured CO2 feedstock	✓	×	×
Counts toward the RED III mandate	✓	×	×
Price tier assumed in this study, EUR per kg	2.64	above 0.69	0.69

Price tiers reflect the assumptions of this study. The RFNBO tier includes the certificate value of 140 EUR per MWh. The low-carbon tier rests on voluntary willingness to pay and has no floor in regulation. Sources [2], [3], [4].

The flexibility lever

Electricity accounts for most of the variable cost of e-methane production. In the plant studied here, electrolysis uses 97 percent of total plant electricity. A pay-as-produced wind PPA delivers electricity on the wind generation profile, so an electrolyser constrained to a high minimum load must buy the shortfall at the day-ahead market price whenever PPA generation falls below its demand. Hours of low wind output are often hours of high market prices. A fully flexible electrolyser can shut down in these hours and concentrate production in periods of PPA generation or low market prices.

The RFNBO criteria are set out in Commission Delegated Regulation (EU) 2023/1184. They are meant to ensure that hydrogen production draws on additional renewable generation and does not divert existing renewable supply from other consumers. A producer using grid electricity must hold a PPA with a new, unsubsidised renewable installation in the same bidding zone. These two conditions are called additionality and geographical correlation. Production must also match the installation's output in time, which is called temporal correlation. The matching is monthly until the end of 2029 and hourly from 1 January 2030. This paper applies the hourly rule throughout, since a new project would be financed into that regime. Temporal correlation is also deemed met in any hour when the day-ahead price is at or below 20 EUR per MWh, or below 0.36 times the EU ETS allowance price. At an allowance price of 100 EUR per tonne of CO2, this ceiling is 36 EUR per MWh. Low prices are taken as a sign of renewable surplus. This paper extends that treatment to plants without a PPA and counts grid electricity bought in these hours as fully renewable. Under this assumption, a fully flexible plant can remain compliant on grid power alone. This raises the question of whether a PPA still adds value for such a plant.

Goal

The overall aim of this paper is to quantify how electrolyser flexibility and electricity procurement strategy jointly shape the levelized cost and profitability of RFNBO-certified e-methane. Three questions follow.

1. What effect does the minimum-load constraint have on the levelized cost of methane (LCOM) and on the internal rate of return (IRR) under a fixed procurement strategy.
2. How sensitive are those results to the size of the wind power purchase agreement, including the limiting case of holding no PPA at all.
3. How does the regulatory grid-price ceiling that defines compliant hours affect the viability of PPA-free operation.

Our approach

Plant and system concept

The plant modelled here combines 160 MW of water electrolysis with a methanation reactor and an intake of biogenic CO2. Electrolyser and reactor are coupled one to one, so hydrogen is consumed by methanation as it is produced, with no intermediate hydrogen storage to decouple the two units. The plant is connected to the Finnish high-voltage grid and trades in the Finnish bidding zone. The zone is chosen for the market conditions it represents rather than for any site.

Water electrolysis produces 3,019 kg of hydrogen per hour at a specific consumption of 53 kWh per kg. Methanation combines that hydrogen with 18,054 kg per hour of biogenic CO2 to deliver approximately 6,008 kg of pipeline-quality methane per hour, at 83 percent efficiency on a lower-heating-value basis. That is 3.01 kg of CO2 per kg of methane, and a plant-level specific consumption of 27.5 kWh per kg of methane. The product is injected into the existing gas grid.

The defining design choice is the electrolyser's operating envelope. A conventional system constrained to a 20 to 100 percent load range must buy from the spot market whenever the contracted wind is not generating. Holding a PPA does not remove price exposure, because a pay-as-produced contract delivers energy on the wind profile. Hours of low wind still have to be covered from the spot market, and those are the hours in which low renewable output sets a high marginal price. A fully flexible electrolyser can shut down entirely and restart when contracted wind returns or when prices fall. Conventional electrolysers cannot follow frequent shutting down and restarting, because the cycling causes irreversible degradation.

Every kilogram produced in a compliant hour earns the gas price plus the RFNBO certificate. Methane produced in a non-compliant hour cannot be sold as an RFNBO. Depending on its carbon intensity, it is sold either as low-carbon methane, at a premium set by voluntary demand, or at the grey commodity price. The analysis values it at the grey price. For a fully flexible plant this choice has little effect. At the grey price of 0.69 EUR per kg, methane covers the cost of its CO2 and electricity inputs only when the electricity price is below about 11 EUR per MWh. This is well below the price ceiling of 36 EUR per MWh, so any hour cheap enough for uncertified production to be profitable is already a compliant hour. Certified methane at 2.64 EUR per kg covers the same inputs up to about 82 EUR per MWh. Figure 1 sets these thresholds side by side. A flexible plant therefore has no reason to produce uncertified methane, and uses its flexibility to capture more compliant hours. A plant held at a high minimum load does produce in non-compliant hours, so its results are more sensitive to this valuation.

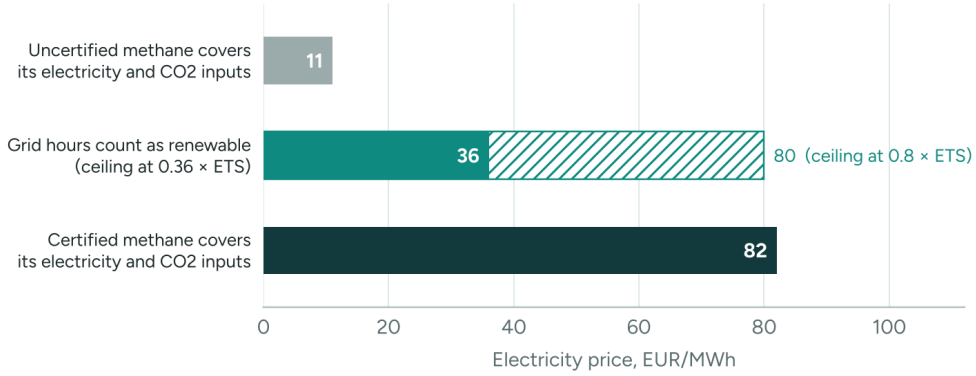


Figure 1: Electricity price below which each activity covers its electricity and CO2 inputs, against the compliance ceiling, in EUR per MWh. Every hour in which uncertified methane covers its inputs already falls inside the 36 EUR per MWh ceiling, and the 80 EUR per MWh option sits just below the break-even of certified production.

Method

The analysis rests on an in-house Python techno-economic model that simulates hydrogen and derivative projects at hourly resolution. An earlier version of the model has been

externally reviewed, and a full exposition of the modelling approach, its inputs, objective function and constraints is given in Połchłopek, de Haas and Massabié [6].

LCOM is the ratio of discounted lifetime costs to discounted lifetime methane output over a 25-year horizon, at a weighted average cost of capital of 7.7 percent. Lifetime costs comprise capital expenditure, fixed and variable operation and maintenance, electricity and CO2 feedstock, net of secondary revenues from power trading, excess energy sales and non-credited gas sales. The IRR is computed on projected cash flows including RFNBO certificate revenue.

Dispatch is determined by a mixed-integer quadratic programming optimiser, following the framework for flexible electrolyser dispatch described in the same source [6]. For every hour of the year the model decides whether to buy or sell electricity, produce hydrogen, or shut down, maximising gross margin subject to the minimum-load level, ramping behaviour, the one-to-one coupling of electrolysis and methanation, and market prices. The model supports day-ahead, intraday and imbalance markets. Trading in this study is restricted to the day-ahead market.

Each operating hour is tested against the delegated-act criteria. Hours covered by the wind PPA are compliant through temporal correlation with the contracted asset, and grid hours are compliant when the day-ahead price falls below the applicable ceiling. Only compliant production earns the certificate. The most recent full year of Finnish day-ahead prices and wind generation profiles is taken as representative of the whole project horizon. Grid carbon intensity is assumed to average 230 kg CO2e per MWh.

The scenario matrix combines four minimum-load levels, namely 100 percent, 40 percent, 20 percent and fully flexible operation, with wind PPA sizes swept from 0 to 480 MW. For the no-PPA configuration the price ceiling is varied between 36 and 100 EUR per MWh, with 80 EUR per MWh examined as a focal case because it approximates the break-even electricity price of certified production. Unless stated otherwise, results are reported for a 320 MW PPA, with prices on a lower-heating-value basis and excluding grid fees. Table A1 in the appendix lists the technical and economic assumptions.

How the results should be read

The average electricity price reported for each scenario is the volume-weighted average paid across the PPA and spot volumes consumed. It is not an average of market prices. For any flexible configuration it will sit well below the market average by construction, because the flexible plant declines to buy in expensive hours.

The absolute IRR values depend on the certificate and gas prices assumed in Table A1, and they change if those assumptions change. The differences in IRR between configurations are more informative, since every configuration uses the same assumptions. The results should therefore be read for the change in IRR from one option to another.

Results and discussion

Figure 2 traces the levelized cost from the constant-load plant with a 320 MW PPA to the fully flexible plant without a PPA at the higher ceiling. Full flexibility delivers the largest single reduction, and each later step adds a smaller one. The subsections below take the steps in turn.

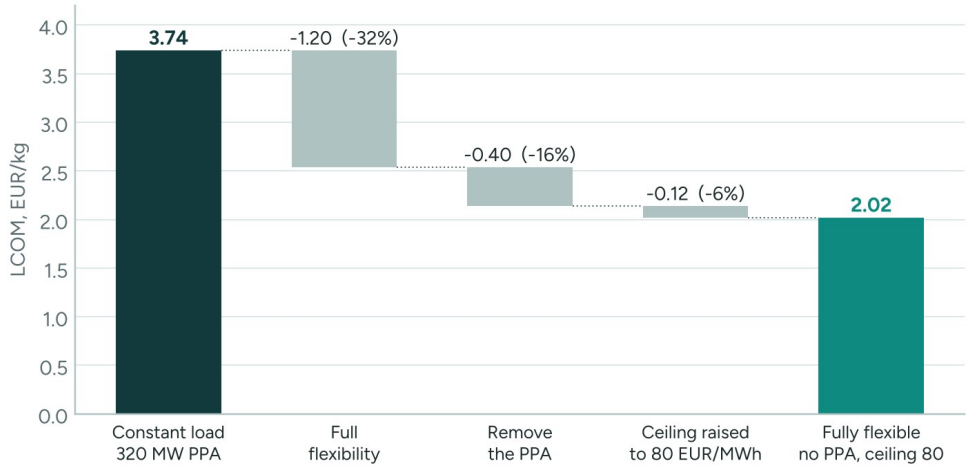


Figure 2: LCOM in EUR per kg from the constant-load case to the fully flexible plant without a PPA, with the ceiling raised to 80 EUR per MWh. Full flexibility removes 1.20 EUR per kg, dropping the PPA a further 0.40 and the higher ceiling a further 0.12.

The minimum-load constraint

Relaxing the minimum-load constraint reduces LCOM and raises IRR monotonically. Under an identical 320 MW wind PPA the non-flexible plant produces at 3.74 EUR per kg without a positive return. At 40 percent minimum load LCOM falls to 2.85 EUR per kg with an IRR of 1.53 percent. At 20 percent it falls to 2.65 EUR per kg and 3.77 percent, and fully flexible operation reaches 2.54 EUR per kg and 4.98 percent. Table 2 reports the full comparison, including the no-PPA cases discussed below.

Table 2: Scenario results for a 320 MW PPA unless noted, day-ahead market only.

Scenario	Capacity factor	Electricity price, EUR per MWh	LCOM, EUR per kg	IRR
Non-flexible, 100% minimum load	1.00	53	3.74	n/a
40% minimum load	0.82	42	2.85	1.53%
20% minimum load	0.77	38	2.65	3.77%
Fully flexible	0.73	33	2.54	4.98%
Fully flexible, no PPA	0.64	9	2.14	8.25%
Fully flexible, no PPA, ceiling 80	0.80	19	2.02	9.84%

The electricity price is the volume-weighted average paid per MWh consumed, across PPA and spot volumes. A value of n/a means no positive IRR. The two no-PPA rows assume RFNBO grid-price ceilings of 36 and 80 EUR per MWh respectively.

The mechanism is visible in the electricity term of the cost decomposition, shown in Figure 3. The average price paid per MWh consumed falls from 53 to 33 EUR per MWh as the plant sheds its most expensive operating hours, which cuts the electricity component of LCOM from 2.01 to 1.00 EUR per kg. The capital component rises from 0.97 to 1.33 EUR per kg as the capacity factor falls from 1.00 to 0.73. That increase of 0.36 EUR per kg is well short of the 1.01 EUR per kg saved on electricity. The remaining 0.55 EUR per kg of the reduction

sits in the other cost lines, which are reported net of secondary revenues, including the resale of PPA electricity the flexible plant chooses not to consume.

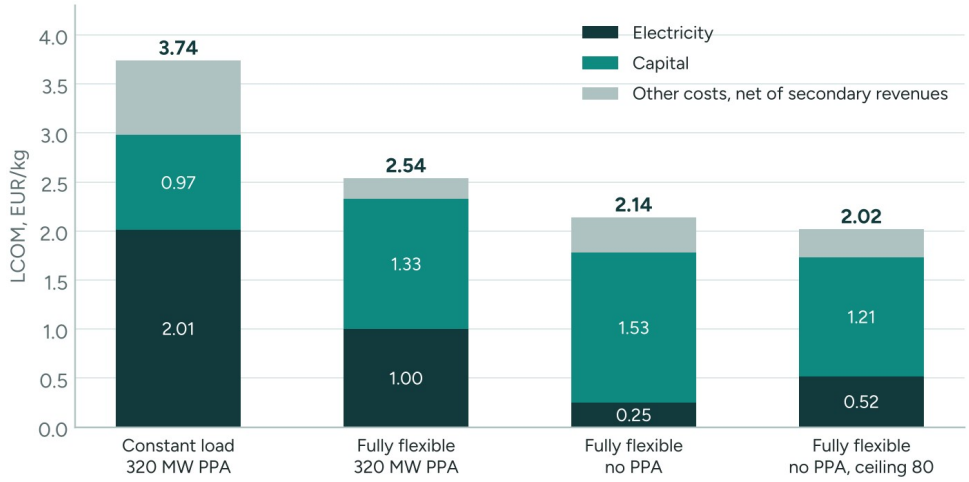


Figure 3: LCOM in EUR per kg split into electricity, capital and other costs net of secondary revenues, for the four scenarios with a reported cost decomposition. The other component is the remainder after electricity and capital. Flexibility trades a smaller rise in capital cost for a larger fall in electricity cost.

Sensitivity to PPA size

For every flexible configuration, LCOM increases and IRR decreases as the wind PPA grows from 0 to 480 MW. A larger PPA locks the plant into a fixed-price power stream that is on average more expensive than the compliant spot hours a flexible plant could otherwise select. The fully flexible plant is cheapest at every PPA size, and its advantage widens as the PPA shrinks. At 480 MW the gap between fully flexible operation and the 40 percent minimum-load case is roughly 0.2 EUR per kg. At zero PPA it exceeds 0.5 EUR per kg.

Procurement without a PPA

The central finding is that the best procurement strategy for a fully flexible plant is to hold no PPA at all. Dropping the 320 MW PPA reduces LCOM from 2.54 to 2.14 EUR per kg, a reduction of 16 percent, and lifts IRR from 4.98 to 8.25 percent. That is a gain of 3.3 percentage points, or two thirds in relative terms.

The trade-off decomposes cleanly. On the cost side the no-PPA plant sacrifices capacity factor, from 0.73 to 0.64, which inflates the capital component from 1.33 to 1.53 EUR per kg. Against that, it pays only ultra-low compliant spot prices, at an average of 9 EUR per MWh instead of 33 EUR per MWh, which collapses the electricity component from 1.00 to 0.25 EUR per kg. It also avoids the PPA premium and the need to oversize contracted wind to roughly twice plant capacity. The energy term wins. The 0.75 EUR per kg electricity saving dwarfs the 0.20 EUR per kg capital penalty.

Figure 4 places all six configurations on the same two axes. Each step towards flexibility under the PPA lowers both the capacity factor and the average price paid. Dropping the PPA gives up a further 0.09 of capacity factor but cuts the average price by 24 EUR per MWh, a larger move in price than any change in minimum load achieves.

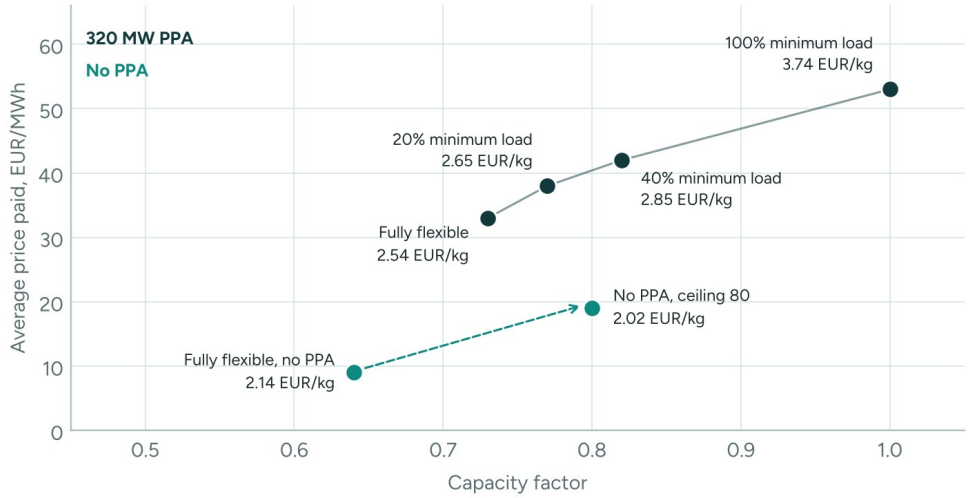


Figure 4: Capacity factor against the volume-weighted average price paid per MWh, with the resulting LCOM, for all six configurations. Flexibility gives up running hours in exchange for cheaper ones, and the no-PPA plant sits furthest down the price axis.

The RFNBO grid-price ceiling

The no-PPA strategy depends on how many grid hours qualify as compliant, which the regulator controls by setting the maximum qualifying price. Raising the ceiling admits more hours, and on average more expensive ones. Raising the multiplier in the ceiling formula from 0.36 to 0.8 times the ETS allowance price, that is from 36 to 80 EUR per MWh at an assumed ETS price of 100 EUR per tonne of CO2, raises the fully flexible plant's capacity factor from 0.64 to 0.80 and the average price it pays from 9 to 19 EUR per MWh. The dashed arrow in Figure 4 shows this move.

The higher capacity factor lowers capital amortisation faster than the energy cost rises. The capital component falls from 1.53 to 1.21 EUR per kg while the electricity component rises from 0.25 to 0.52 EUR per kg, as the last two bars of Figure 3 show, so LCOM falls from 2.14 to 2.02 EUR per kg and IRR improves from 8.25 to 9.84 percent, a gain of 1.6 percentage points.

The 80 EUR per MWh case is of particular interest because it lies just below the break-even electricity price of certified production, approximately 82 EUR per MWh (Figure 1). A ceiling at that level admits essentially every hour in which certified production is marginally profitable, so little further gain is available from raising it. Load-constrained plants benefit more in relative terms, and full flexibility remains the cheapest configuration at every ceiling level.

Wider implications

Project financing

Project financing requires, from the bank's perspective, that the project's cash flows are sufficiently robust to repay the debt, including interest (debt service coverage ratio). The target is normally to maximise the amount of debt in the project to increase the return on equity. This holds true when all the elements driving free cash flow (FCF) to equity are fixed.

Running the plant flexibly based on power input, without a PPA, introduces volatility into the cash flow. To secure the cash flow, lenders would require offtake contracts for the product matching the tenor of the debt. Since the volume produced by the plant is not fixed, these offtake contracts also need to be structured with some degree of flexibility. This would normally have a negative effect on the offtake price, as the customer takes on more risk regarding the volume received.

Since debt payments are fixed, the cash flow volatility is borne entirely by the equity owners. For equity owners to consider it a good investment, their return must meet or exceed their hurdle rate, which is based on their risk-adjusted return requirements.

As a result, in our scenarios, the increase in IRR from a "no flex, with PPA" case to a "full flex, no PPA" case must be greater than the corresponding increase in investors' IRR hurdle rate driven by the higher cash flow volatility stemming from PPA price, production volume, and offtake price. Figure 5 shows the size of that increase across the configurations studied. From this perspective, it could also be beneficial for the equity IRR to reduce the debt level, as debt increases cash flow risk to equity and could limit other project elements such as offtake strategy.

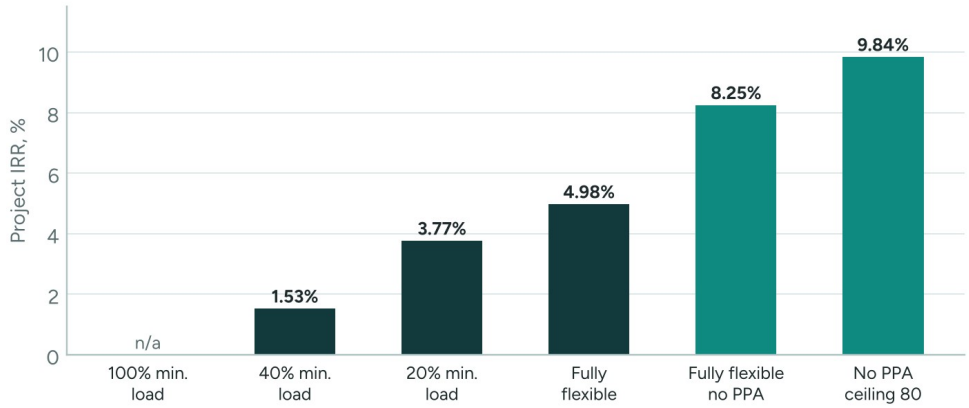


Figure 5: Project IRR by configuration. The constant-load plant reaches no positive return. Absolute values follow from the assumed certificate and gas prices, so the steps between bars are the relevant reading.

Regulatory calibration

The ceiling result matters to regulators as much as to developers. The multiplier in the ceiling formula moves LCOM by roughly 6 percent and IRR by 1.6 percentage points on its own, so the RFNBO grid-electricity criteria, rather than technology cost alone, can determine whether grid-connected e-fuel production is viable. Setting the multiplier near the break-even electricity price of certified production admits the hours in which production is profitable and few beyond them, which captures most of the available benefit without extending compliance to hours that carry no renewable surplus. The reasoning also limits how much a higher ceiling can be worth. A ceiling set well above that break-even admits hours in which certified production loses money, and a plant optimising its own dispatch declines to run in them, so the additional compliance headroom changes nothing.

Conclusion

The overall aim of this paper was to quantify how electrolyser flexibility and electricity procurement strategy jointly shape the levelized cost and profitability of RFNBO-certified e-methane. Three insights follow from the hourly dispatch analysis of a plant built on 160 MW of electrolysis capacity.

On the effect of the minimum-load constraint:

Flexibility pays for itself several times over. Moving from a plant held at 100 percent minimum load to a fully flexible one lowers LCOM by 32 percent under an identical 320 MW PPA, from 3.74 to 2.54 EUR per kg, and takes IRR from no positive return to 4.98 percent. The electricity saving of 1.01 EUR per kg outweighs the 0.36 EUR per kg capital penalty that comes from running fewer hours.

On the sensitivity to PPA size:

For a fully flexible plant in a low-price, high-renewables bidding zone, the cost-optimal strategy is to forgo the PPA entirely. That cuts LCOM by a further 16 percent to 2.14 EUR per kg and lifts IRR by 3.3 percentage points to 8.25 percent, because an average purchase price of 9 EUR per MWh outweighs the fall in capacity factor from 0.73 to 0.64. LCOM rises and IRR falls at every PPA size above zero, so the result is not a corner case of the sweep.

On the regulatory grid-price ceiling:

The ceiling is a decisive lever. At 80 EUR per MWh, approximately the break-even electricity price of certified production, the no-PPA case strengthens to 2.02 EUR per kg and 9.84 percent. A corollary of the break-even analysis is that only compliant production is worth running. Above roughly 11 EUR per MWh, and so well below the 36 EUR per MWh ceiling, uncertified methane fails to cover even its electricity and CO2 inputs. Uncertified output can still be delivered as low-carbon methane, competing with biomethane, but not at a price that would support the investment.

Two consequences follow for practice. Plant design should prioritise true shutdown and restart capability rather than a wide turndown range, and grid connections should be sought in bidding zones with frequent sub-ceiling pricing, such as the Nordic and Iberian markets. The conventional assumption that power-to-gas requires a PPA deserves re-examination. Further work should test the robustness of the no-PPA optimum across multiple price years and bidding zones, make the effect of electrolyser fleets on price formation endogenous, incorporate multi-market trading, and examine the financing structures that debt providers will accept for merchant-sourced, certificate-backed power-to-gas projects.

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Appendix

Calculation parameters

Every scenario shares the same capital cost, efficiency, feedstock and price assumptions. Only the minimum-load constraint, the PPA size and the RFNBO grid-price ceiling change between scenarios, so the differences reported in Table 2 are not driven by differences in cost inputs.

Table A1: Key technical and economic assumptions.

Parameter	Value	Parameter	Value
Electrolyser capacity	160 MW	Green methane price	190 EUR per MWh
Electrolysis efficiency	53 kWh per kg H2	Green methane price per kg	2.64 EUR per kg
Plant-level efficiency, LHV	27.5 kWh per kg CH4	Grey methane price	0.69 EUR per kg
Methanation efficiency, LHV	83.0%	CO2 feedstock cost	0.39 EUR per kg CH4
Methane output per kg H2	1.99 kg	ETS price	100 EUR per tonne CO2
Grid carbon intensity	230 kg CO2e per MWh	Total capital expenditure	535 MEUR
Project horizon	25 years	Weighted average cost of capital	7.7%

LHV means lower heating value. The green methane price comprises 140 EUR per MWh of certificate value and 50 EUR per MWh of gas value. All prices exclude grid fees and tariffs.

Method notes

- Efficiencies and gas prices are reported on a lower-heating-value basis, chosen to match the basis on which the gas sales contracts are set. An electrolysis efficiency stated on a higher-heating-value basis would change the reported figures, and the two conventions should not be mixed when comparing these results with other studies.
- Trading is restricted to the day-ahead market. Intraday and balancing revenues would favour flexible plants further, so the flexibility results are conservative in this respect.
- Hourly temporal correlation is applied throughout, matching the regime in force from 1 January 2030 rather than the transitional monthly rule.
- Compliance is tested hour by hour. PPA hours qualify through temporal correlation with the contracted wind asset, and grid hours qualify when the day-ahead price sits below the ceiling.
- The break-even prices in Figure 1 divide the methane price net of CO2 feedstock cost by the plant-level consumption of 27.5 kWh per kg. They exclude operation and maintenance and capital cost.

- The other cost component in Figure 3 is calculated as LCOM minus the reported electricity and capital components. It covers CO2 feedstock and operation and maintenance, net of secondary revenues.

Limitations

- A single reference year of Finnish day-ahead prices and wind profiles is assumed representative of a 25-year horizon. That abstracts from structural price developments and from the feedback of large-scale electrolyser deployment on the price distribution itself.
- Certificate and gas prices are held constant across the project life. Nearly three quarters of revenue depends on the certificate, so the IRR results are more sensitive to this assumption than to any technical parameter.
- None of the configurations reported here reaches an IRR that would clear a typical equity hurdle rate. The claim made in this paper concerns the size of the improvement flexibility delivers, and not the bankability of the modelled project as it stands.

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Alquion builds fully flexible industrial electrolysers that shut down cleanly to zero output, so e-fuel projects can run on qualifying renewable electricity alone.

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