FDE

Carbon-Negative & Profitable Multi-Energy Producer

Initiating Coverage on FDE: High Return, Energy Transition Exposure

FDE (FP:FDE) is a French-listed (Euronext Paris) multi-energy company focused on low carbon solutions supplying natural gas, electricity, heat, hydrogen and CO_2; achieving premium energy pricing and high returns. It is the only French energy producer with a negative carbon footprint. FDE is involved in several high return and high growth energy sector verticals giving it exposure to structurally higher European gas and power prices. The key area of focus is Abandoned Mine Methane (AMM) where it has a strong track record of value creation, with significant further growth potential from Liquefied Biogas (LBG) and Bio-CO_2 markets, Coal Bed Methane (CBM), hydrogen pyrolysis, carbon capture and storage (CCS) in coal seams and natural hydrogen production.

Core business: high cashflow and returns from AMM with strong further growth

FDE's core AMM business captures and utilises methane escaping from abandoned coal mines in France and Belgium for power generation, reducing emissions of a potent greenhouse gas (>80x warming effect versus CO_2 over 20 years), delivering a negative CO_2 equivalent footprint as well as generating strong returns from the sale of electricity and heat produced from the gas, without the need for subsidies. It is a proven, profitable business model, which is modular and repeatable with a long-term, stable cashflow stream. FDE owns exclusive rights until 2042 that will be automatically renewed by the French State if the resources still exist. As a result, FDE can secure cheap financing, helped by AMM's green credentials. There is a large amount of growth potential within its existing French assets, where it has exclusive rights plus the ability to leverage its experience by expanding into new markets. We forecast €45mm in EBITDA for FY'24 and expect FDE to increase its installed capacity by 160% between FY'23 and FY'26.

Cryo Pur: strong growth potential based on proven patented technology

Following the acquisition Cryo Pur, FDE now has integrated purification and liquefaction of all types of gas (biogas, landfill gas, flare gas, rare gases, etc.). The integration of Cryo Pur therefore allows FDE to strengthen its position in the strategic and high growth LBG and CO_2 markets. It plans to build 8 more plants (to a total of 10)[1] by FY'26, the larger of which can generate up to €10mm of EBITDA each with >€50mm NPV8 on our estimates.

Catalysts: New AMM projects, CBM approvals and Natural Hydrogen tests

The major external driver of the profitability and value of FDE's business is European gas pricing. FDE has been awaiting authorisation to access many more AMM wells, which is expected to happen by YE'23. We expect strong growth in new AMM power plants being commissioned, each adding >€8mm in NPV [2]. FDE is awaiting the decree to grant it the de-risked Bleue Lorraine concession where it can target a very large CBM resource base, which can also unlock activities further downstream in hydrogen and carbon capture. FDE is planning to undertake a study on three wells for natural (geological) hydrogen in eastern Lorraine. Cryo Pur is actively working on the implementation of six new LBG and Bio-CO_2 production sites in Norway some of which construction will begin in 2024.

Valuation: 220% upside to our risked NAV of €129/sh

We see the current share price discounting only the value of the current production from the AMM business; therefore, the strong growth from the AMM business, potential of Cryo Pur and CBM are all sources of upside yet to be fully recognised by the market, in our view. We estimate that FDE has access to 90TWh of energy production through its various businesses worth on average €12/MWh, implying €1.1bn of unrisked value. For 2024, we estimate that FDE is trading on ~6x EBITDA and ~8x P/E multiple and the potential will generate a 29% return on equity or 22% return on capital.

[1] Changed from "It plans to build 10 plants by FY'26"; [2] Changed from ">€8mm in EBITDA".

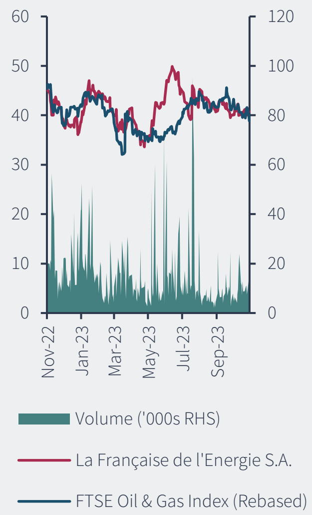
GICS Sector	Energy
Ticker	FP:FDE
Market cap 13-Nov-23 (€mm)	215
Share price 13-Nov-23 (€)	40.25

+220%

Upside from current share price to our €129/sh risked NPV

90TWh

Potential unrisked energy production from its various businesses



The cost of producing this material has been covered by FDE as part of a contractual engagement with H&P Advisory Ltd.

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Investment Case

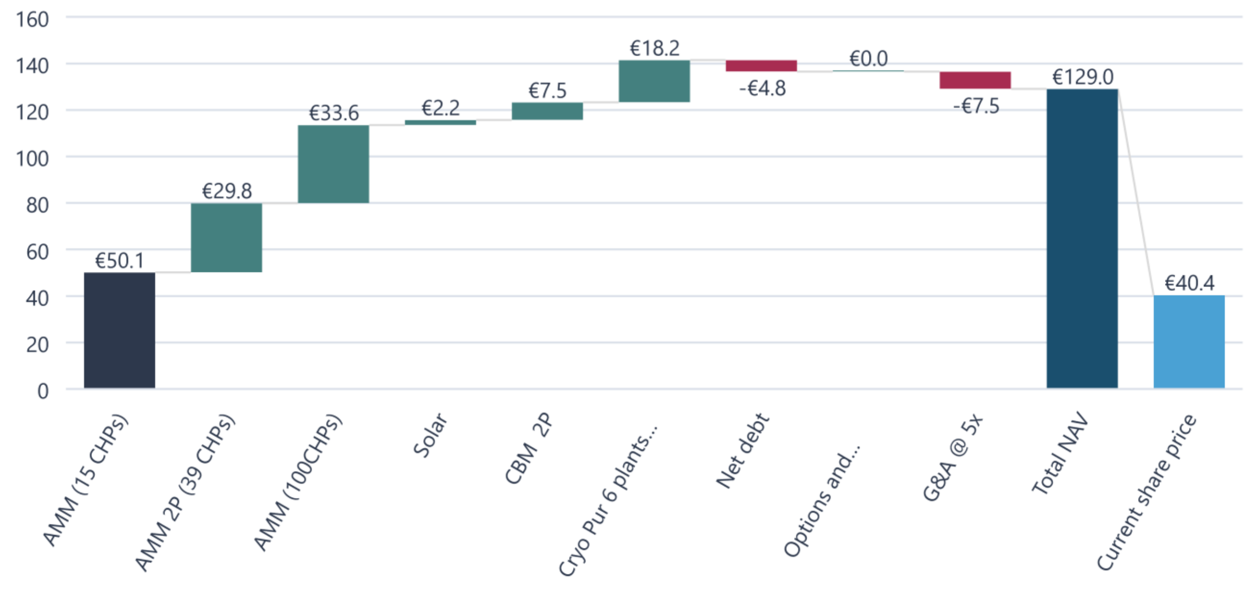
FDE is a multi-energy company focused on low carbon solutions supplying natural gas, electricity, heat, hydrogen and CO_2. It is involved in the production primarily of various forms of methane, which we see as a core competency.

FDE is involved in several energy verticals, including European gas, European electricity pricing, Abandoned Mine Methane (AMM), Coal Bed Methane (CBM), Biomethane and the related LBG and Bio-CO_2 markets, hydrogen pyrolysis, carbon capture and storage (CCS) in coal seams and natural hydrogen production. We look at each of these markets and the macro trends driving them.

The business was built on finding a profitable solution to capture fugitive methane emissions (>80x warming effect versus CO_2 over 20 years) from abandoned coal mines in France. It does so without the need for subsidies and with a long-term stable cashflow stream that allows for significant green debt financing. It is now a proven, profitable business model, which is modular and repeatable with a long-term stable cashflow stream given wells produce for many years with very shallow decline. We estimate ~45% IRR per new ~€1.75mm plant based on an electricity price of €125/MWh (L.T. futures pricing) and an NPV8 of >€8mm. We estimate FDE's AMM projects would still generate a positive NPV8 at electricity prices as low as €50/MWh; this compares to FDE's average PPA price signed for FY'24 of ~€260/MWh.

There is a large amount of growth potential within FDE's existing French AMM assets, where it has the exclusive rights, with the potential to grow from 15 CHPs currently (€27mm[3] of EBITDA in FY'23) to 66 CHPs by 2026 supported by a ~60-year reserve life plus the ability to leverage its experience by expanding into new markets. Capacity growth of 27% to 19 units is planned for FY'24. The projects allow for very high debt financing of 90% given the floor on the revenues and low cost (1.5-2% margin) given the green credentials. Our risked valuation of the assets of €606mm implies a 12x multiple based FY'24 EBITDA or 10x on FY'26.

Risked NAV build up (€/sh)



Source: H&Pe

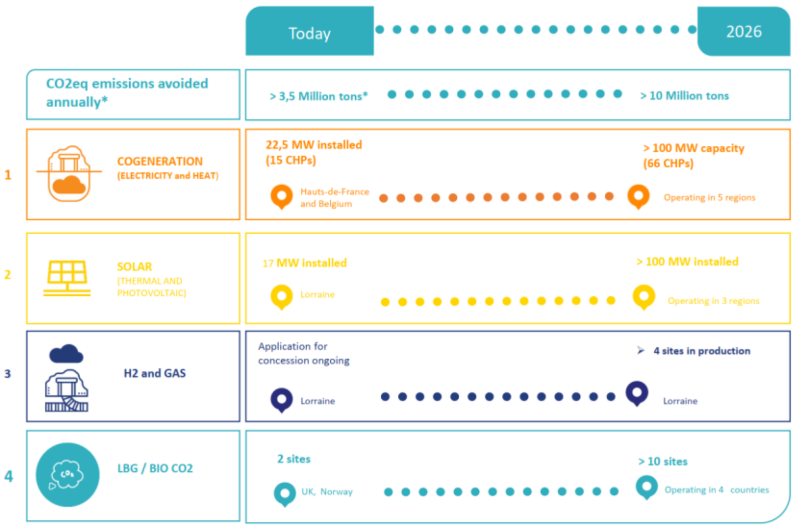
[3] Changed from "~€30mm".

Valuation – We see the current share price discounting only the value of the current production from the AMM business with further upside from growth in the AMM reserve base plus short-term high optionality from the growth of the Cryo Pur business, longer-term from the development of the CBM assets and expanding down the value chain into hydrogen and CCS. The current business is high return (16% ROE in FY'23 for FDE) and cash generative (8.5% maintenance FCF yield).

Agile Innovation in Energy – FDE has showed itself nimble and reactive to capitalise on the emerging new energy trends by leveraging off its existing asset base and the knowledge base within its team. For example, its coal seam gas assets, whilst having strong potential to produce high value gas into a structurally short market also provide multiple avenues to market these gas resources as low carbon hydrogen production, the possibility of directly producing "natural hydrogen", carbon capture and storage and also utilising the land for solar power generation.

Profitable and high return company – FDE reported FY'23 fiscal year EBITDA grew ~70% y/y to €27mm (68% margin) putting it firmly on track to meet (and in our view exceed) its FY'26 target of €100mm of revenue and €50mm in EBITDA, without the need for any further equity funding. Its revenues have grown at a compounded annual rate of almost 50% to FY'23 since IPO. FY'23 return on average equity was >15%.

FDE's 2026 Growth Plan



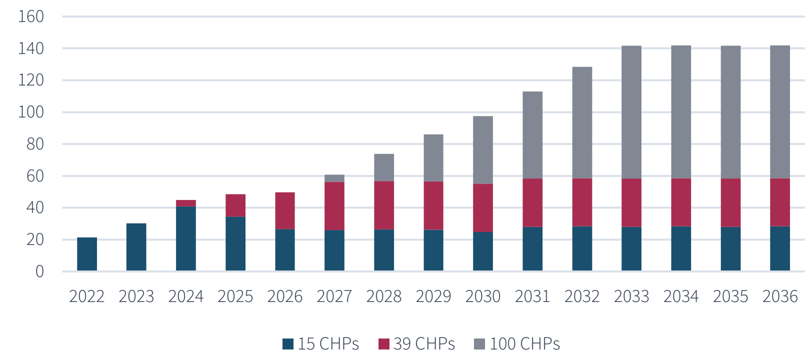
Source: FDE

Exposure to many profitable energy transition growth areas – Building on the company and management team's experience in energy, FDE is exposed to exciting macro growth areas of methane emission management, bio-methane, carbon storage, solar, hydrogen pyrolysis and natural hydrogen. Its core European market is likely to have structurally higher gas and electricity prices than in the past given the indigenous declines in supply as well as the war in Ukraine cutting supplies.

Negative carbon footprint – FDE's current 22.5MW of CHP capacity is avoiding 3.5mmtpa (million tonnes per annum) of CO_2 equivalent emissions of which 1.4mmtpa has been certified since 2019. It has been the leading European SME in the energy sector since 2016 according to the Gaia Rating. Based on its FY'26 target it should reach >10mmtpa of avoided emissions.

Low financing costs and ample liquidity – FDE has a much lower cost of capital compared to other European energy companies. This is because it has been able to raise debt with low coupons (e.g., Green Bonds) and it can heavily debt finance its projects[4]. This has meant minimal equity is required, leading to above average returns on equity.

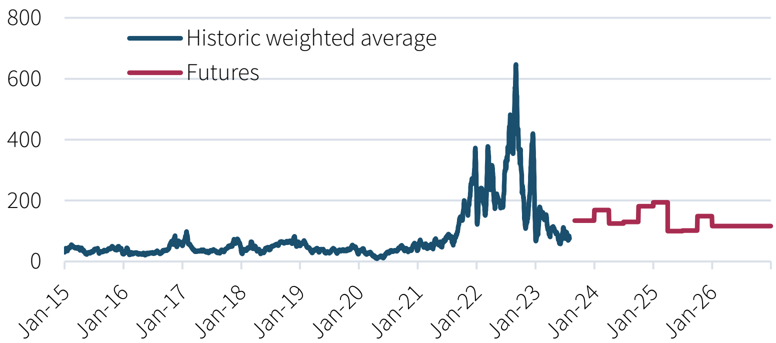
AMM business forecast EBITDA (€mm) by fiscal year under different scenarios for number of CHPs installed



Source: H&Pe

AMM – This is a green business that cuts GHG emissions and generates strong returns. It can benefit from an electricity feed in tariff that provides a stable revenue stream with strong upside potential from higher power prices. FDE has the exclusive rights for this in France. It is now a proven, profitable business model, which is modular and repeatable. As a result, FDE can secure cheap financing also helped by the green credentials and excellent track-record since production started 6 years ago.

French electricity price, 10 day M.A. (€/MWh)



Source: EEX, Endex, H&Pe

Exposure into structurally higher gas and electricity pricing in Europe – The war in Ukraine, and resulting disruption of gas from Russia into Europe, have led to structurally higher gas and electricity prices in Europe. Furthermore, the perception of gas has changed with the EU viewing it as a solution to the energy transition and energy security becoming a much more important part of the conversation. As a result, there is an added value for domestic European gas, as the continent becomes increasingly reliant on LNG and pipeline imports. European (ex-Norway) domestic gas production has fallen 30% over the last five years and the situation will be further exacerbated this year with the closure of the Groningen field, Europe's largest onshore gas field.

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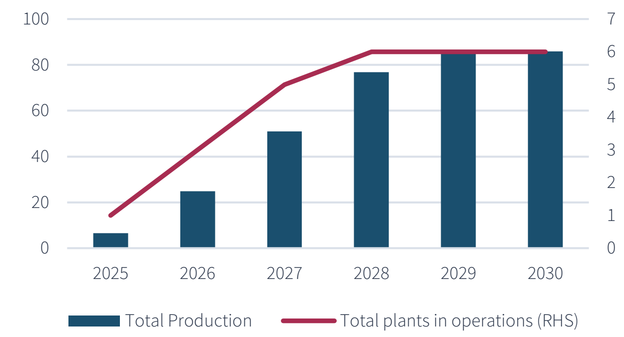
[4] Changed from "it has been able to heavily debt finance its projects".

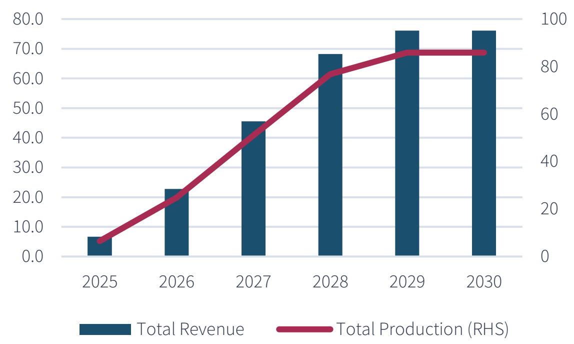
Ability to leverage the EU green incentives – FDE has also been successful in building a business that takes advantage of the incentives and subsidies in place for reducing emissions. The EU in general and France are difficult places to operate as an energy company with a myriad of legislations that need to be complied with and hoops to jump through. FDE has had years of experience navigating and understanding the processes to deliver projects, giving it a significant competitive advantage versus its peers. It has spotted opportunities such as abandoned mine methane leaks and has been able to navigate the difficult legislation, permitting and regulations to be able to execute on the strategy.

Cryo Pur: Six plant scenario by fiscal year:

LBG and liquid CO_2 production (kt/y) vs total plants in operation



Total revenue (€mm) vs total production (kt/y)



Source: H&Pe

Cryo Pur: strong growth potential based on proven patented technology – Following the acquisition Cryo Pur, FDE now has integrated purification and liquefaction of all types of gas (biogas, landfill gas, flare gas, rare gases, etc.). The integration of Cryo Pur will therefore allow FDE to strengthen its position in the strategic and high growth LBG and CO_2 markets. It plans to build 10 plants by FY'26, the larger of which could generate up to €10mm of EBITDA each with >€50mm NPV8 on our estimates.

Natural hydrogen: a potential game-changer – We believe FDE is the only European listed company with exposure to natural hydrogen, which we think could transform the hydrogen sector if it is able to be commercialised with the expectation that cost of production could fall to <$2/kg. FDE has had some initial promising results with a well containing close to 20% hydrogen.

High quality share register for a small cap stock - The shareholder make-up is important for a small cap stock, which can influence the trading of the stock (availability of liquidity), the valuation and the ability to raise capital. FDE benefits from having some of the largest long only funds as significant shareholders, which is rare for small cap energy companies in Europe. Shareholders include Arbevel, Allianz, Amiral, Amundi, HSBC.

Management team with a proven track record – The management team has both strong global energy sector expertise as well as significant financial markets experience. There is a mix of scientific, financial and technical background with project management and capital markets expertise. They have created a profitable growth business and spotted emerging trends as well as capitalising on acquisition opportunities. Management is also highly aligned with other shareholders: it has recently significantly increased its stake in the Company with over €13mm worth of shares bought in May and July 2023 by the Executive Chairman and the CEO of the Group.

Catalysts

There are various catalysts that we see potentially impacting the equity story over the coming year.

New CHPs for Abandoned Mine Methane – FDE has been awaiting authorisation to secure access to many more AMM wells, which is currently expected to happen in November 2023. We expect strong growth in new CHPs being commissioned over the next couple of years. We see the potential for at least a further 27 units in a first phase, each generating ~€1.5mm in EBITDA (at €125/MWh power price) for capex of ~€1.75mm. It can do this without new equity issuance given the high debt capacity of the assets. There is also the potential for FDE to obtain more projects in other countries in Europe.

European gas and electricity pricing – The major external driver of the profitability and value of FDE's business is European gas pricing. Electricity pricing is clearly a key driver but it is intrinsically linked to European gas prices. Its core AMM business' revenues are directly linked to both gas and electricity prices. The business is built to work at electricity prices ~€75/MWh in France (and worked at lower prices during Covid in Belgium) but futures pricing for the next couple of years is currently around 50% above this. It will generate an additional 12% in EBITDA for every €10/MWh increase in the electricity price above €125/MWh in our base case long-term. 73% of the portfolio is under PPAs with 52% fixed at €260/MWh for FY'24.

Shareholder returns – FDE bought back shares in 2023 as it believed the market was not recognising the value of the assets. We see the potential for further share buybacks and think that this is a more likely way to return capital to shareholders than dividends.

CBM development approval – FDE is awaiting the decree to obtain the Bleue Lorraine concession. If the concession is granted, FDE has the ability to target a very large CBM resource base producing lower emission gas than existing French LNG imports, which can also unlock activities further downstream in hydrogen and carbon capture. FDE is a leading member of the French Research programme to store carbon in coal seams.

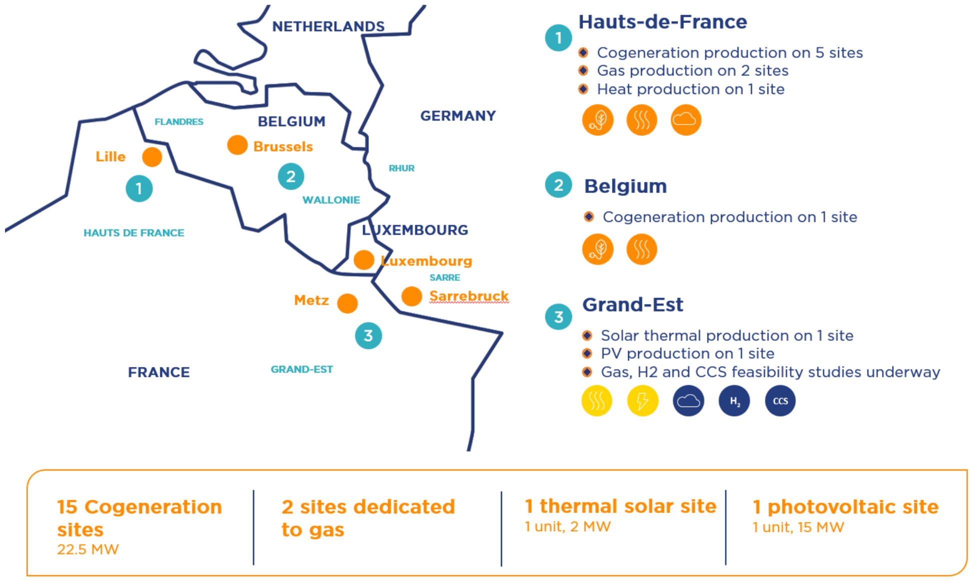
Natural hydrogen test results – FDE is planning to undertake a study on three wells after applying to explore for natural/white hydrogen in eastern Lorraine. There is the potential to produce low-cost hydrogen with no associated carbon emissions.

Hydrogen pyrolysis progression – FDE is involved in two novel technologies that convert natural gas to hydrogen through pyrolysis, avoiding CO_2 emissions through the production of solid carbon instead. The results of this could drive a move towards commerciality.

New larger scale Cryo Pur plants – Cryo Pur, is actively working on the implementation of 6 new LBG and Bio-CO_2 production sites in Norway on some of which construction will begin in 2024 with land acquisition, sourcing of feedstock and engineering of facilities already underway. We see each large site potentially generating €10mm in EBITDA with an NPV8 of €54mm.

Company Overview

FDE's current asset base



Source: FDE

FDE (formerly Française De l'Énergie) is a dynamic, carbon-negative, multi-energy producer, providing eco-friendly solutions. Its portfolio includes natural gas, electricity, and heat derived from local resources and solar energy. It is the only French energy producer with a negative carbon footprint. There are three key business areas with synergies and spin-off potential off for all of them: AMM, Cryo Pur and CBM.

FDE's current core business is Abandoned Mine Methane (AMM) in Northern France (Hauts-de-France) and Belgium (Wallonia). It has 15 CHPs (10 in France and 5 in Belgium) with a combined 22.5MW of power generation capacity with a plan to reach >100MW by FY'26. Once online each 1.5MW CHP should generate ~€1.5mm of EBITDA based on a realised electricity price of €125/MWh and an additional 8% in EBITDA for every €10/MWh increase in the electricity price. Currently AMM accounts for >95% of the revenue stream of FDE and is the bulk of 2026 revenue guidance. It also has 17MW of installed solar capacity with plans to grow to 100MW by 2026.

Following the acquisition Cryo Pur, FDE now has integrated purification and liquefaction of all types of gas (biogas, landfill gas, flare gas, rare gases, etc.). The integration of Cryo Pur will therefore allow FDE to maximise the value of its large gas reserves but also to strengthen its position in the strategic green gas and CO2 markets. It plans to build 10 plants by FY'26 operating in four countries; each large plant will generate ~€10mm of EBITDA on our base case assumptions.

FDE is the owner of the largest onshore gas resources in continental Europe in Lorraine (137bcf of 2P reserves with 1.1tcf of contingent resource), independently valued at €318mm on a 3P basis. It derisked the CBM acreage with prior drilling and has been waiting years for permits to develop the gas. The carbon footprint of the gas will be 10x lower than France's LNG imports that it could displace. FDE is looking to further reduce the GHG footprint by utilising the gas to produce low-carbon hydrogen either through pyrolysis (with a solid carbon waste product) or producing hydrogen through SMR and using the coal seams to sequester the produced CO_2.

Valuation and NAV

Given the different business lines and the strong growth potential in them, we believe that a sum of the parts valuation is most appropriate, utilising a net asset value (NAV) or DCF of the various businesses and risking them appropriately. We also look at how FDE trades on various multiples short-term and further out with our projected growth expectations. Our base case discount rate is 8% which is significantly lower than that used for oil and gas companies, given the lower risk profile of FDE's businesses and the high level of borrowing possible, at low cost given green financing.

Our risked NAV is €129/sh, which implies ~220% upside from the current share price. We see the current share price discounting only the value of the current production from the AMM business; therefore the growth from the AMM business, potential of Cryo Pur and CBM are all sources of upside not yet reflected in FDE's market cap, in our view. On an unrisked basis we see around 5x upside from the current share price. For 2024, we estimate that FDE is trading on ~6x EBITDA and ~8x P/E multiple and with the potential to generate a 29% return on equity or 22% return on capital. It has a net debt/EBITDA ratio of <1x. Using only maintenance capex, we estimate it could generate close to a 15% FCF yield.

There are several commodity price assumptions that drive our valuation the key ones being European gas prices (TTF) and electricity prices long term.

Key commodity price forecasts

TTF to 'Jun '24	per MWh	€50
TTF to 'Jun '25	per MWh	€50
TTF post 'Jun '25	per MWh	€35
Electricity to 'Jun '24	per MWh	€150
Electricity to 'Jun '25	per MWh	€150
Electricity post 'Jun '25	per MWh	€125
Wallonia Green Certificate	per cert	€0
Solar price	per MWh	€70
Liquid CO_2 price	per ton	€175
Bio-LNG price	per ton	€2,325

Source: H&Pe

Build-up of risked NAV

Asset	Net TWh	NPV €/MWh	Unrisked €mm	Unrisked €/sh	Risking CoS	Risked €mm	Risked €/sh
Net debt			-€25	-€4.8	100%	-€25	-€4.8
Options and warrants			€0	€0.0	100%	€0	€0.0
G&A @ 5x			-€39	-€7.5	100%	-€39	-€7.5
AMM (15 CHPs)	12	€21	€260	€50.1	100%	€260	€50.1
AMM 2P (39 CHPs)	7	€28	€206	€39.7	75%	€154	€29.8
AMM (100CHPs)	17	€21	€348	€67.2	50%	€174	€33.6
Solar	3	€4.5	€13	€2.4	90%	€11	€2.2
CBM 2P	43	€2.7	€118	€22.8	33%	€39	€7.5
Cryo Pur 6 plants @ 80%	8	€23	€189	€36.4	50%	€94	€18.2
Total	**90**	**€12**	**€1,069**	**€206**		**€669**	**€129**

Source: H&Pe

For the AMM business we look at three different scenarios. The first one assumes no further growth from the current number of CHP's installed and hence we use 100% chance of success, delivering €50/sh of value. The second assumes the base case of growth to 39 CHPs which is what the 2P reserves are based on, and we risk this at a 75% chance of success to factor in some development risk and delays. This gives an incremental €40/sh of value. In the upside case we see FDE reaching 100 CHPs and we risk this at 50% to factor in some resource risk as well as development risk, which adds a risked value of €34/sh. We see the AMM business is worth €157/sh unrisked or €113/sh risked.

For Cryo Pur we only include the six plants that are currently planned in Norway in which we assume that FDE will have an 80% stake. We assume four large and two small plants are developed which have a total NPV8 of €189mm on an unrisked basis. Given the early stage in the development process, we risk this heavily at a 50% chance of commercialisation to give a risked value of €94mm or €18/sh. We do not currently include any upside for the plans to get to 10 plants.

For FDE's CBM reserves our base case valuation uses the 2P reserves of 139bcf or 43TWh, which we model out to derive an unrisked valuation of €118mm or €2.7/MWh on an NPV10 basis. We use a higher 10% discount rate for this given that this is an upstream project. We risk the project heavily with a 33% chance of commercialisation to factor in the permitting risk and the development risk and end up with €7.5/sh of risked value.

The solar business has an unrisked value of €13mm on an NPV8 basis, which we put a high chance of commercialisation on of 90% given there is little risk involved giving €2/sh of value on a risked basis.

Risked NAV sensitivities

		Long-term power (€/MWh)				
		€75	€100	€125	€150	€175
Long-term TTF (€/MWh)	€15	€63	€87	€111	€134	€158
	€25	€73	€96	€120	€143	€167
	€35	€82	€105	€129	€153	€176
	€45	€91	€115	€138	€162	€186
	€55	€100	€124	€148	€171	€195

		Long-term power (€/MWh)				
		€75	€100	€125	€150	€175
Discount rate	4%	€142	€180	€218	€256	€294
	6%	€107	€137	€167	€196	€226
	8%	€82	€105	€129	€153	€176
	10%	€63	€82	€101	€120	€140
	12%	€48	€64	€80	€96	€112

		Long-term TTF (€/MWh)				
		€15	€25	€35	€45	€55
Discount rate	4%	€192	€205	€218	€231	€245
	6%	€145	€156	€167	€178	€189
	8%	€111	€120	€129	€138	€148
	10%	€85	€93	€101	€109	€117
	12%	€66	€73	€80	€87	€94

Source: H&Pe

Financial ratios and peer comparison

Financial ratios and multiples	2023E	2024E	2025E	2026E	2027E
Market cap (€mm)	210	207	207	207	207
Net debt (€mm)	23	32	105	139	120
Current EV (€mm)	**234**	**234**	**234**	**234**	**234**
Equity (€mm)	74	100	128	163	211
Capital employed (€ mm)	98	132	233	302	331
EBITDA margin	68%	75%	71%	72%	72%
Net debt/EBITDA	0.9x	0.8x	2.2x	1.6x	1.0x
Net debt/CFFO	0.9x	1.0x	2.8x	1.9x	1.1x
P/E	20.3x	8.1x	7.3x	6.0x	4.3x
EV/EBITDA	9.3x	5.9x	5.0x	2.8x	1.9x
EV/CFFO	9.4x	7.4x	6.2x	3.2x	2.2x
ROAE	15.1%	29.3%	24.8%	23.6%	25.9%
ROACE	10.8%	22.3%	15.5%	12.8%	15.3%
FCF yield	5.1%	-2.8%	-33.6%	-15.4%	10.6%

Source: H&Pe

On our estimates, FDE is trading on an EV/EBITDA multiple of 6x in FY'24 dropping to just 2.9x in FY'26. Using our base case risked NAV of ~€650mm, it would trade on an EV/EBITDA multiple of 17x in FY'24 dropping to 8.2x in FY'26. Given the growth potential, we see this as reasonable. Many companies in the energy transition sector with much more risky growth profiles trade on higher multiples than FDE.

There are no listed companies in FDE's core business - the AMM sector - so it is difficult to find direct comparables. The closest comparables are green power producers. The integrated green power producers such as Enel and Iberdrola trade on average on a ~8.5x next twelve-month consensus EBITDA multiple but EBITDA margins are ~20% versus ~70% for FDE; they also have a high leverage ratio of ~4x net debt to LTM EBITDA. The leading French independent producer of renewable energy is Neoen, which trades on 11x FY'24 consensus EBITDA.

In the biofuel sector there are again no direct comparables. Neste, as the leading independent biofuel producer trades on 8x FY'24 consensus EBITDA; Verbio a waste-to-energy provider, trades on 9x and French listed Waga (biomethane producer) is generating negative EBITDA but has an EV of €440mm. In the US there are a few listed renewable natural gas players OPAL fuels trades on 12x EBITDA, Aemetis on 11x EBITDA, Clean Energy Fuels on 9x EBITDA and Montauk Renewables on 18x EBITDA.

There have been several high profile acquisitions in the biogas sector with the most notable, in our view, being Shell's purchase of Nature Energy and Chevron's US$2.75bn purchase of Renewable Energy Group. Shell spent $2bn on Nature Energy for 17mmcf/d or 3kboe/d of production, which implies $666k per boe/d falling to $450k per boe/d based on 2030E production of 4.5kboe/d. Natural gas acquisition multiples for producers have been around $25-50k per boe/d. This implies Shell is paying 10-15x what it would pay for conventional production. In its annual report, Nature Energy expected profit of <US$5mm in 2022. We see this as encouraging for the future value potential from Cryo Pur.

Balance Sheet and Funding

At the last reporting date, 30th June 2023, FDE had gross financial debt of €68mm and cash of €43mm (>20% of its market cap), which resulted in net debt of €25mm. The net debt to equity ratio was 34% and net debt to EBITDA of 0.9x. As well as FDE's positive cash flow from operations, cash on hand was bolstered, by additional financings, including the issuance of a second green bond for €20mm, with €15mm of undrawn debt still available to fund growth. The company ended the year (FY Jun'23) with total assets worth €163mm (+11% y/y).

FDE's capital raises

Date	Amount (€mm)	Type	Main Investor(s)	Coupon	Maturity
10-Jun-16	37.5	IPO			
16-Jan-18	3.0	Convertible Debt	CAP 3RI	3%	
09-May-18	6.4	Debt	Bpifrance Financement and SaarLB	2.39%	6 years
24-Oct-19	1.3	Debt	Bpifrance Financement	1.50%	6 years
04-Nov-19	2.8	Grant	EFRD - European Social Fund		n/a
19-Dec-19	4.2	Debt	Triodos Bank	1.65%	
01-Jun-20	1.6	Debt	LCL and Société Générale	0.25%	5 years
15-Dec-20	1.3	Debt	Caisse d'Epargne	Livret A + 1%	20 years
03-Jan-21	2.4	Crowdfunding	Lendosphere	4.75%	4 years
17-Feb-21	3.1	Crowdfunding	Lendosphere	4.75%	4 years
25-Aug-21	2.5	Crowdfunding	Lendosphere	4.75%	2 years
27-Sep-21	40.0	Debt	Edmond de Rothschild	6%	7 years
03-Oct-22	20.0	Debt	Edmond de Rothschild	6%	7 years

Source: H&Pe, Company data

FDE has been successful in raising non-dilutive funds through a combination of grants for low carbon projects, crowd-funding at the project level and issuance of green bonds. FDE is generating substantial cash flow from operations with minimal maintenance capex. Therefore, the debt is being used to fund growth in the business. Having substantial available liquidity from the green bonds means that these can act as initial project financing (that would normally be equity or higher cost debt); once onstream this can be replaced by lower cost project-level debt.

In our view, FDE has a much lower cost of capital compared to other similar sized European energy companies. This is as a result of the lower risk nature of its core AMM business (meaning the ability to use more debt) and the green credentials of the business lowering the cost of debt. It has been able to raise debt with low coupons (e.g. Green Bonds) and it is able to heavily debt finance its projects. This has meant minimal equity is required and boosts the return on equity. It is helped by the strong regional banking relationships (Edmond de Rothschild, BPI, Société Générale, ING, Crédit Agricole group, Caisse d'Epargne).

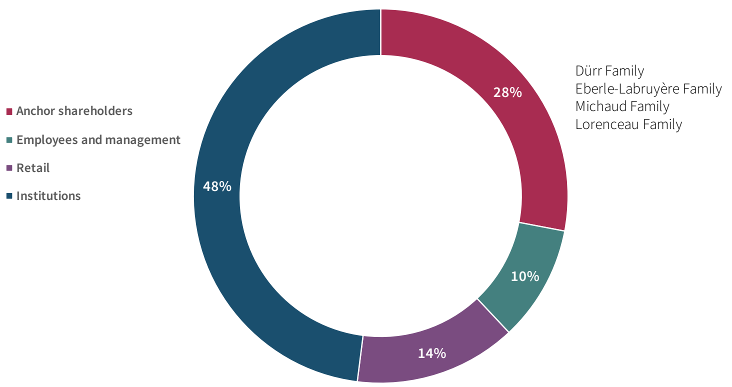
Notably in the face of rising interest rates, in September 2022 FDE issued a new 7-year term, €20mm Green Bond with an interest rate of just 6%, dropping to 5.5% after it achieved €27mm in EBITDA in FY'23[5]. The proceeds of this bond will enable FDE to finance its planned growth in AMM, solar and Cryo Pur. €5mm had been drawn down at 31st December 2022. In September 2021, FDE issued its first green bond consisting of a first tranche of €25mm and an optional second tranche of €15mm (yet to be drawn) with a 7-year term and 6% initial interest rate that has now reduced to 5.5%. The main covenants on the bonds are debt service ratio of >1.05, net debt/EBITDA <4.9x until end 2025, interest coverage ratio >2.8x and net debt/capital employed <55%.

FDE has been successful in raising a substantial amount of debt through crowdfunding loans in total €11.3mm over three loans all at 4.75% p.a. interest rates. A large portion of the funds has come from the local areas where the money is being invested. For example, €5.5mm was raised in <2 months – a record time – for the Gazonor Béthune project at an interest rate of 4.75%. La Nef, an ethical banking cooperative that offers credit solutions oriented exclusively towards projects with social, ecological and/or cultural utility also invested. We expect that FDE could look to tap this market in the future. Furthermore, €4.9mm of grants have been allocated for low carbon projects.

In January 2023, FDE opportunistically launched a share buyback of up to €50mm as it believed that the market capitalisation was considerably below the value of its portfolio of profitable, low-carbon energy solutions. The current balance sheet structure and ongoing cash generation are more than sufficient to achieve the projected development plan for the financial year 2026 and FDE will ensure that any share buybacks do not reduce the consolidated cash and cash equivalents position below €15mm. The amount of buy back will therefore vary depending on available cash levels, the attractiveness of new investments and other business opportunities beyond those announced in the 2026 plan, and the degree of discount to management's estimate of intrinsic value. Since 1st of January 2023, 84 000 shares have been acquired by FDE at an average price of € 37.5 per share.

Shareholders

FDE's shareholder base (as of 30 June 2022)



Source: Company data

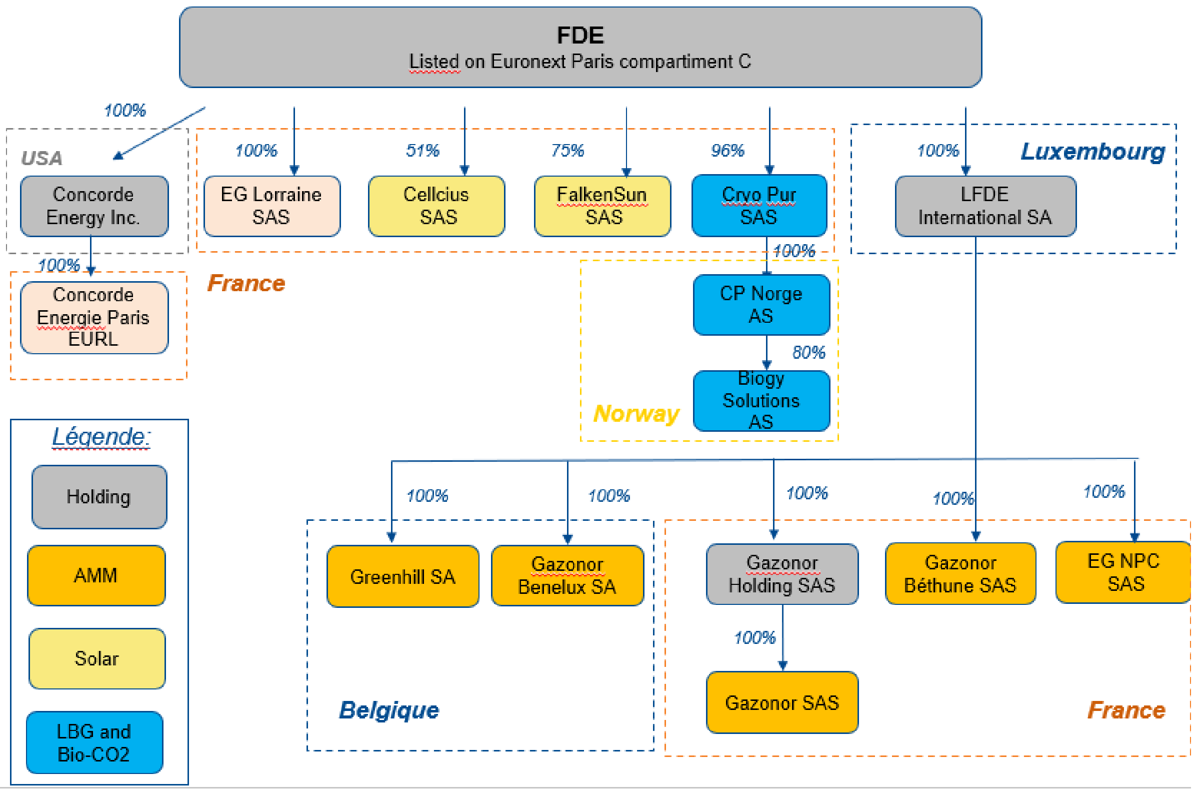
[5] Changed from "it achieves €25mm in EBITDA (which it is on track to do in FY'24)".

FDE has several prominent shareholders including:

- Michaud family: former board member and anchor shareholder of Maurel & Prom (exited in 2012)
- Lorenceau family: Co-founder of Addax Petroleum (sold in 2009 to Sinopec for > $7bn)
- Labruyère family: Board member and shareholder of Addax Petroleum and Plastic Omnium
- Tier 1 asset management groups, ESG funds and small cap funds: FO, Arbevel, Allianz, Amiral, Amundi, HSBC

It is worth noting that the Management Team has recently significantly increased its stake in the Company with over €13mm worth of shares bought in May and July 2023 by the Executive Chairman and the CEO of the Group.

Organisation chart



Source: Company data

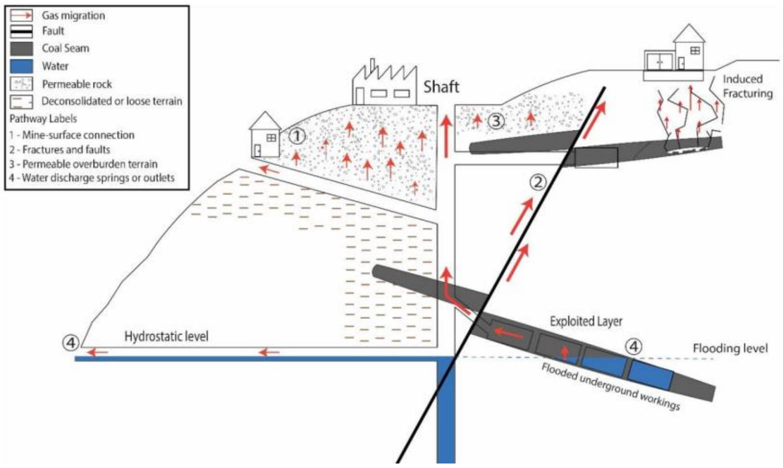
Abandoned Mine Methane

FDE's core AMM business captures and utilises methane escaping from abandoned coal mines in France and Belgium for power generation, reducing emissions of a potent greenhouse gas (>80x warming effect versus CO_2 over 20 years), delivering a negative CO_2 equivalent footprint as well as generating strong returns from the sale of electricity and heat produced from the gas without the need for subsidies.

Fixed floor electricity feed in tariff prices (~€75/MWh) provide a stable revenue stream with significant upside from higher power prices (~€260/MWh PPA price for calendar 2024). We estimate €45mm in EBITDA from AMM in FY'24. It has proven to be a profitable business model, which is modular and repeatable, that can provide long-term, stable cashflows. FDE owns exclusive rights (until 2042) that are automatically renewed by the French State if the resources still exist. As a result, FDE can secure cheap financing, also helped by AMM's green credentials. There is a large amount of growth potential within its existing French assets, where it has exclusive rights plus the ability to leverage its experience by expanding into new markets. It aims to more than quadruple production by FY'26.

Background

Potential pathways for methane migration develop after mining has ceased



Source: INERIS, 2019. Post-Mining Hazard Evaluation and Mapping in France

Coal mines are the fourth largest source of anthropogenic methane emissions globally, behind livestock, oil and gas, and landfill sites. Cessation of coal mining due to exhaustion of commercial reserves does not halt gas emission. Methane naturally desorbs from coal seams and collects in mine galleries. As more coal mines globally close, there is a potential increase in abandoned mine methane emissions.

In France and Belgium there are many abandoned coal mines, a legacy of the now shuttered industry. However, these mines continue to release methane; upon closure, decompression wells were drilled to prevent the pressure building up in the old mine workings, which would then vent the methane into the atmosphere. At the time these vents were put in place they were not seen as an environmental issue.

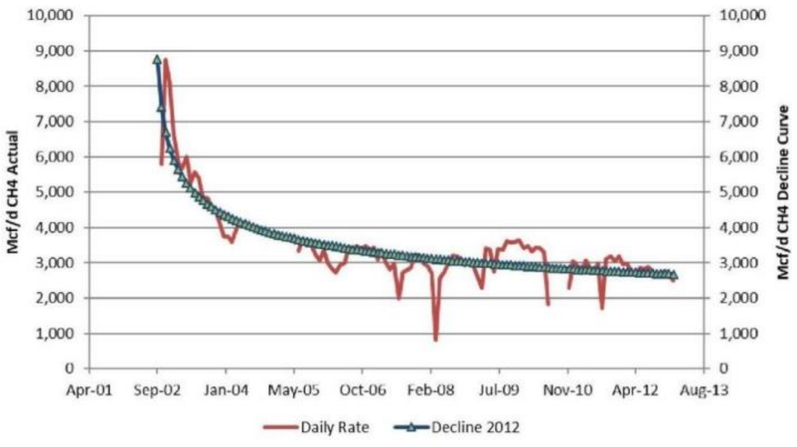
The methane FDE produces is associated with abandoned coal mines known as Abandoned Mine Methane (AMM) or Coal Mine Methane (CMM), which would otherwise naturally leak to the atmosphere over time, contributing to climate change. It is difficult to seal old mines as the gas can escape through fractures and faults, even if the shafts and access portals are covered. AMM capture and use offers many benefits, such as improved safety, air quality and health, energy supply and environmental performance. The gas is mainly composed of methane, a greenhouse gas (GHG) with a warming effect 82.5x that of CO_2 over 20 years. Methane escaping also poses safety risks due to its flammability.

A very efficient way to reduce the GHG impact of the abandoned mines is to capture and produce the methane and use it for power, generating CO_2, lowering the carbon equivalent emissions by >95%. Using this methane locally, also reduces the carbon footprint of transportation of gas (e.g. substituting LNG imports in France and Belgium). Repurposing mine lands after closure can be beneficial for environmental and economic sustainability. The recognition of the environmental benefits of capturing and utilising mine methane by the UN underscores the importance of addressing methane emissions from various sources, including coal mines, to mitigate climate change and promote sustainable development.

The collective emissions from both closed and closing mines could be substantial and of growing importance. Global projections suggest that AMM, which comprised 17% of total mine methane emissions in 2010, could potentially rise to 24% by 2050 with the acceleration of mine closure in certain parts of the world.

Not all abandoned mines are suitable for AMM projects. Favourable mining and geological conditions must exist, but the most critical condition is a suitable end user to generate demand for the gas or derived power. Without a market for AMM-based energy, it is unlikely that there will be a viable and sustainable project. However, destruction of the gas by flaring may be feasible in some countries as a carbon offset project. FDE could also leverage its Cryo Pur business in the area to produce AMM LNG that can then be transported to demand centres.

Project actual production and matched decline curve



Source: Coté, M., 2018c.

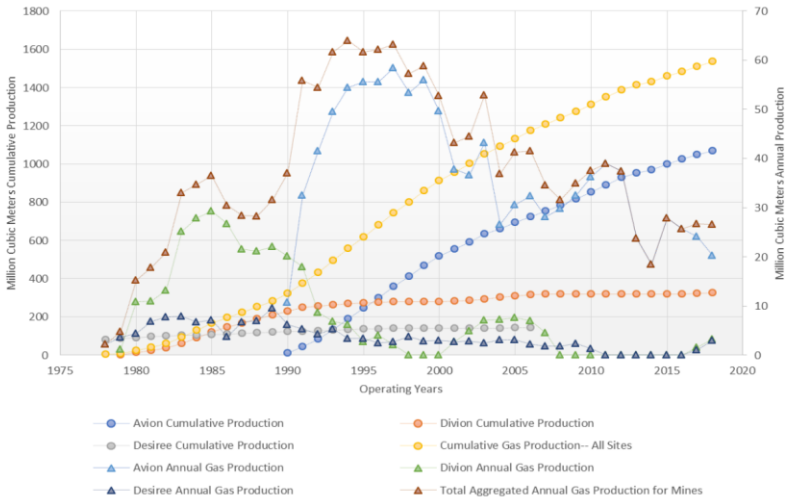
Extrapolated hyperbolic decline curves, based on measured data, are frequently used to estimate AMM emissions from abandoned mines. The wells tend to produce over a long-period of time with very shallow declines as the methane continues to escape from the coal seams. Therefore, unlike conventional production there is no need to continuously drill new wells to replace the decline.

EU methane strategy

Coal related methane emissions account for approximately 5% of EU anthropogenic methane emissions. Improving measurement and reporting of methane emissions is a priority to reduce uncertainties and better inform policies. The EU plans to support effective closure, sealing, and methane capture from abandoned coal mines, including training, funding, and capturing methane for local use.

France

Annual / cumulative gas production from Avion, Divion, and Desiree Mines



Source: FDE

The last coal mine in France, La Houve, closed in 2004 but the capture and use of AMM began in 1978 in response to the Middle East Oil Crisis which began in 1973 and caused elevated oil prices to persist for several years. Since that time, several gassy abandoned coal mines in the Lorraine region of northern France have produced gas, which is injected into gas pipelines and used for electricity generation. For many years, these activities were carried out by Gazonor, a former subsidiary of the national coal company of France, which was disbanded in 2008. Three coal mining sites are the principal sources of gas production: Avion, Divion, and Desiree. FDE has the exclusive rights to produce AMM from these concessions.

Germany

Germany has deployed more than 35 AMM projects all involving electricity generation or combined heat and power (CHP) production. In 2015, there were 94 AMM-fired CHP units (one project usually involves several CHP units) with a combined installed generating capacity of 120 MWe. These AMM projects generate >500 GWh of electricity and 75 GWh of heat annually, avoiding 2.3mmt of CO_2e emissions. Most projects commenced in the early 2000s when a special feed-in tariff for AMM-fired power generation was created. Annual reported GHG emissions from abandoned mines dropped from 5,000 kt CO_2e in 2000 to just 18 kt CO_2e in 2015. Active AMM projects utilised an estimated 99% of total methane emissions from abandoned mines in Germany in 2015. Iqony GmbH ("Igony") is the market leader in power generation from mine gas with more than 100 plants in the Saar and Ruhr areas and has been acquired recently by Asterion Industrial Partners on a €2.6bn valuation.

FDE's business

FDE's AMM acreage position in France and Belgium

Source: Company data

FDE has the rights to develop methane gas associated with coal fields in northern France (Hauts-de-France) and southern Belgium (Wallonia), a large gas resource for which there are multiple commercialisation options. FDE's AMM licences cover a large area, roughly 180km east to west and around 20km north to south. Within this acreage lies over 100,000km of mine galleries and more than 100 wellbores. In France, FDE benefits from having exclusive access to the concessions to 2042 and therefore it is the only company that can exploit these resources.

Although the Group has an operating monopoly on its concessions in France and in Belgium, the Group's competitors would be, among others, Infinis in the United Kingdom (another company that has built up a substantial AMM business in the UK), Iqony and RWE in Germany for AMM, and other French producers of renewable or recovery energy (RRE) such as Akuo, Albioma, and Innovent.

FDE purchased Gazonor in July 2016 for €20mm, which had two production licences and two exclusive exploration permits with 225bcf of 2P reserves and 1.9tcf of 2C contingent resources. Gazonor was created in 1991 to manage and operate the evacuation of coal gas upon abandonment of mines and was previously owned by the French state-owned coal monopoly, Charbonnages de France.

In Belgium, there is a mix with some concessions having gone back to the state and some are private. To obtain the licences there is a tender at the European level and FDE has never had any competition. The licences FDE currently holds are valid until 2038. FDE bought 100% of Greenhill in February 2021 for a net price of €95k, which held multiple concessions covering 74km^2, with large volumes of gas in old mining galleries. FDE's initial plans were to install six cogeneration plants (9MW combined).

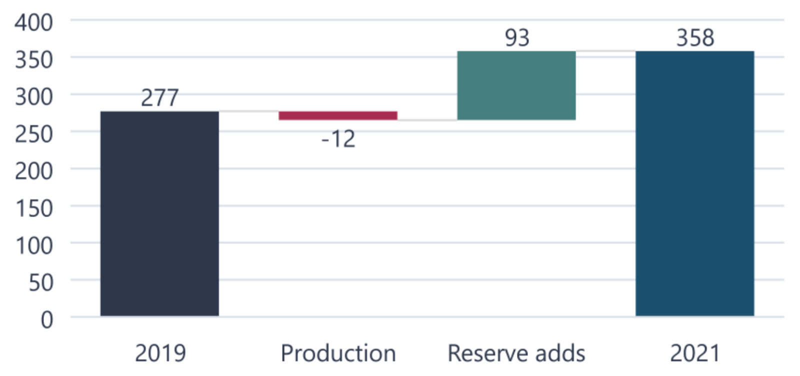
Béthune case study

In early 2017, the city of Béthune with a population of 26,000 sought a clean energy supplier for their district heating network through a bidding process. Key requirements were a long-term commitment of at least 18 years, local energy production within a 50km radius and cost-effectiveness. After winning the energy supply contract in May, FDE used two wellbores within 20km of Béthune connected to an unused gas pipeline. Using a mobile test unit, they verified the gas potential, pressure and quality, leading to the decision to refurbish the pipeline. The project was completed in 42 months, supplying energy to Béthune from January 2021, with a negative carbon footprint for 30 to 50 years, reducing local pollution and energy bills, and contributing to the region's sustainable development. The heat is sold under a 20-year contract to Dalkia, a subsidiary of EDF. The success showcases the potential for similar projects across Europe, contingent upon favourable regulations and political support. FDE is looking to replicate the Béthune model in other cities with district heating systems.

Production and reserves

Based on the end 2021 reserves report, FDE had 3,552mmcm (125 bcf or 21.6TWh) of 2P reserves. 0.36mmcm of gas had already been produced by FDE since the purchase of Gazonor up to that report. In France, the reserves had increased by 1% since the last report in 2017 despite the production over the period, therefore there was >100% reserves replacement.

FDE AMM reserves replacement in Belgium (mmcm)



Source: FDE, H&Pe

In Belgium, in September 2021, FDE reported a 29% increase in 2P reserves at its Anderlues concession since April 2019 to 358mmcm (13bcf or 2.2TWh), implying an organic addition of 33% when factoring in the production to date.

In the financial year to end-June 2023, we estimate that FDE extracted 63 mmcm (2.2 bcf) of methane from its mines of which it sold 25 mmcm (0.9 bcf or 224GWh) as gas and 38 mmcm (1.3 bcf) was used to generate 158 GWh of power. Based on the reserves report in the 2P scenario FDE should be able to extract 3,800 mmcm (136 bcf) of gas.

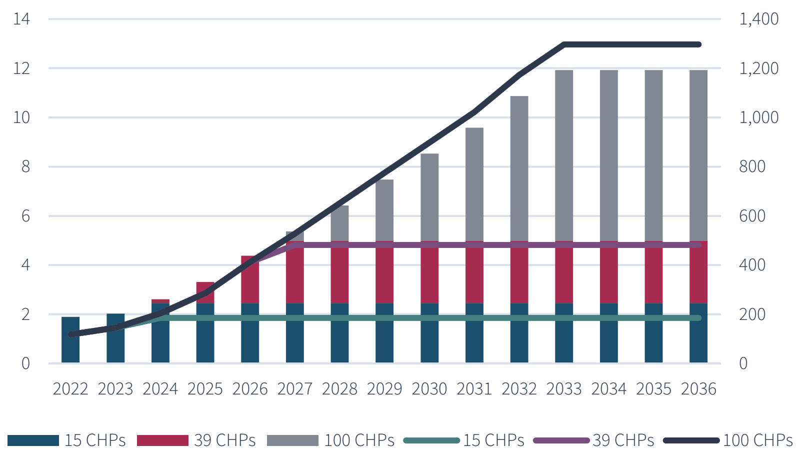
Based on the CPR, there is the potential for 150MW from the current acreage position, with a more conservative target of 100MW by 2026, which also includes growth into new areas. FDE has seen its reserves grow over time despite producing from the reservoirs as with the change in atmospheric pressure in the mines, more gas has been coming out, allowing more reserves to be booked.

The limiting factor on growth is the permitting as FDE currently has all the concessions, the technical capability, framework agreement for the CHPs and access to the financing. FDE has asked for access to an additional seven out of the 150 existing decompression wells but the process has taken almost two years. However, a decision is expected later this year. In some areas there is the potential to target pockets of gas that are not linked to the decommissioning wells but again the permitting has been taking a long time. It has continued to make progress on the operational and financial aspects and optimisation of sales contracts in the meantime.

What delayed this authorisation was a legal framework which suggested that anyone involved in mining activities would take responsibility for the mine. This meant that FDE would potentially be taking on the prior environmental liabilities for the mines. In November 2022, the law was clarified such that FDE will not be taking on any liability but it will take responsibility for monitoring and surveillance work that it agreed to share with the state.

As well as organic growth in its core markets of France and Belgium (with several further concessions to target) there are opportunities to expand internationally with Poland and Czechia as logical options. Germany (which already has larger AMM developments) and Poland are the largest producers of coal in Europe, followed by the Czechia.

Gas and electricity production under different scenarios by fiscal year – LHS bars: Total production (bcf/y); RHS line: Total electricity produced (GWh/y)



Source: H&Pe

Hannam&Partners

Pricing

In France there is a floor price that FDE receives for its electricity through a Feed-in-Tariff (FiT) whilst in Belgium there is no floor price

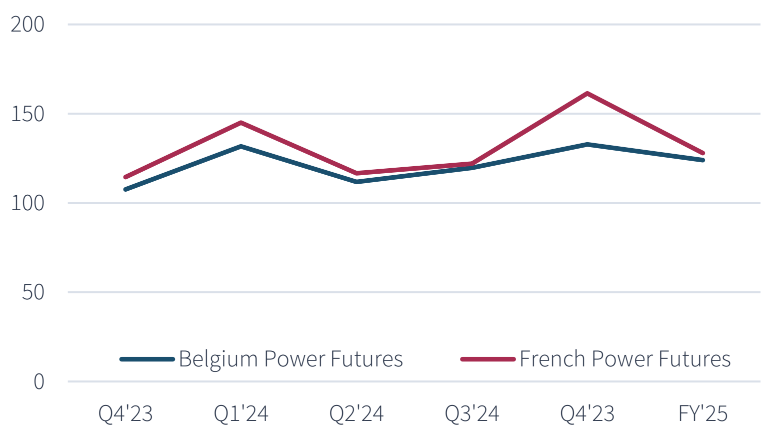
A November 2016 decree put in place a 15-year FiT in France under a purchase obligation (i.e. this is the guaranteed price available to FDE, but it does not stop it from exiting that mechanism and selling at a higher price). The FiTs are inflation linked with the current tariff at an average of €74-81/MWh (FY'23). The FY'23 realised electricity price was €176/MWh.

27% of the CHP volumes are fixed for 10 years at €74/MWh. Of the remaining 73% so far:

- 52% is fixed at €260/MWh for FY'24
- 9% of FY'25 at €273/MWh and 6% of FY'26 at €122/MWh.

Electricity from the two new 1.5 MW cogeneration units installed at the Avion site in 2022 is sold under a three-year PPA contract, with selling prices for 2022 and 2023 that are considerably higher than the existing feed-in tariff. The vast majority of FDE's power generation portfolio is expected, by the end of the financial year 2023 to be under PPAs with creditworthy partners. We assume pricing around in line with futures pricing for electricity that is currently not locked in to a fixed price. For FY'24 we assume a blended realised electricity price of ~€180/MWh and for FY'25 a price of ~€150/MWh with a long-term price of ~€120/MWh.

French and Belgian Electricity Futures pricing €/MWh



Source: EEX, Endex, H&Pe

Gas sales

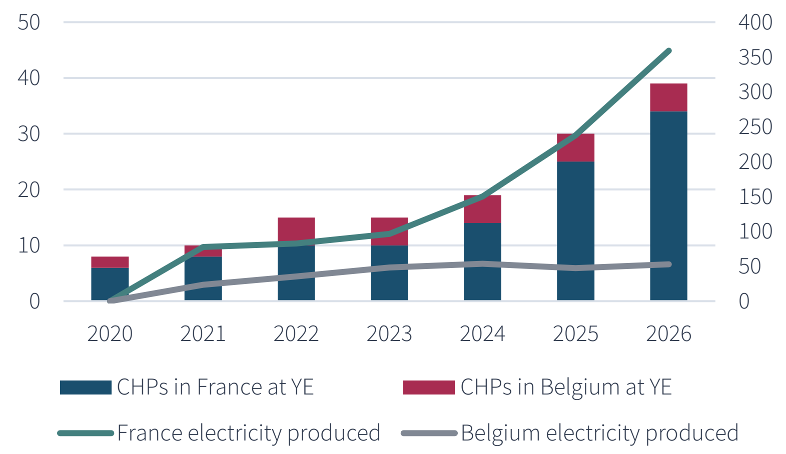
Some of the AMM gas is sold as methane rather than as power. The gas sold directly is from the Avion site with minimal processing and injected directly into the grid. In fiscal year 2022, we estimate 0.9bcf or 253GWh of gas sales, which generated €11.8mm of revenue at a gas price of €47/MWh or €13.7/MMBtu. FDE has the capacity to reach 300GWh of gas sales as the future growth is expected to come largely from power through CHPs. With TTF futures gas pricing averaging >€50/MWh over the coming years, this implies >€15mm in revenue per annum. 3% of gas revenues are fixed for over 15 years at >€25/MWh with the remaining exposed to the forward curve.

CHPs

FDE is primarily focused on burning the AMM to produce and sell electricity, rather than direct gas sales. FDE uses modular 1.5MW combined heat and power (CHP) plants, which it sources from German company 2G under a framework agreement, providing it a rapid, dedicated production line. This means that its time to market is fast, with the ability to install and commission within 12 months. The CHPs have an electrical efficiency of ~42% at full load. The skid-mounted, modular nature and repeatability mean that this is in essence "plug and play" with no new engineering required for further facilities. Also, the number of CHPs can be scaled up between one and five per site depending on the size of the resource and the proximity to the tie-in point on the electrical grid. For example, two were initially deployed to the site in Belgium and then another three added after positive reservoir performance established that five was the optimal number.

The decompression wells either flow naturally or require some form of compression to produce the methane. The CHP burns the methane to produce electricity that is fed into the grid and where there is a market, the heat produced through the process can also be monetised. The wells tend to access a large network of "galleries" and so are generally expected to produce for around 10 years. The nature of the CHPs means that if an area is depleted, they can be picked up and moved to the next site.

Base case CHPs (LHS) and electricity production (GWh/y) by fiscal year



Source: Company data, H&Pe

There are 15 CHPs currently installed with a capacity of 22.5MW. The plan is to add four new CHPs by the end of 2023, a further, 11 CHPs by FY'25, and we expect FDE to reach at least 39 CHPs by FY'26. The plan is to reach >100MW (66 CHPs) by FY'26; however, we are more conservative and assume that production stays flat at this level from FY'27 onwards in our base case.

Over 150 MW additional capacity could be installed out of 2P reserves outside of Lorraine. In Hauts-de-France there are 3,552mcm (125mmcf) of 2P reserves versus 51mcm (1.8mmcf) of annual production (70 year reserve life) and in Belgium 358mcm (12.6mmcf) versus 12mcm (0.4mmcf) of production (30 year reserve life).

Economics of AMM

The economics of the CHPs are relatively straightforward and repeatable. The key drivers are the capex and the electricity price. The capex will vary between €1.5-2mm per site with the variance down to the civil works and tie-in costs given the framework agreement on the CHPs. Operating costs (maintenance and electricity) are ~€250k per annum with likely €50k of G&A that can be attributable per plant plus a €250k major overhaul required every 7-8 years. The maintenance is outsourced to the equipment provider 2G and alongside this FDE is guaranteed 94% uptime.

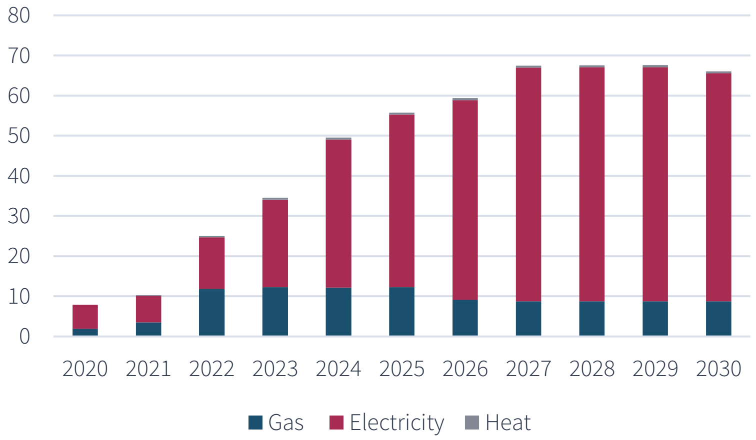
The revenues per plant have a floor level around €1mm/year, based on an electricity price of €75/MWh, which is the current Feed-in-Tariff (FiT) provided to incentivise these projects in France. Based on more recent electricity pricing and longer-term contracts known as power purchase agreements (PPAs) that are available, there is potential for revenues of ~€2mm/year per plant. Currently FDE is not obtaining carbon credits from the CO_2 emissions avoided in the process - this is a time-consuming process but could be one that provides a lucrative revenue stream on top and is not currently factored into the economics.

As a result of these investments, FDE is avoiding the emission of 3.5mmtpa of CO_2 equivalent - in France and Belgium. In the current EU Emissions Trading Scheme (EU ETS) market, this level of emission credits cost a company ~€315mm at a carbon price of €90/t (around the average in 2023 to date).

The projects allow for very high debt financing of 90% given the floor on the revenues, the guarantees offered on the uptime and the green nature of the project meaning that there is plenty of ESG-linked funding available. The margin on the debt is between 1.5-2%: costs have clearly been going up but in our opinion are still easily manageable, especially given electricity prices are well above the floor levels.

We estimate each CHP has an NPV8 of ~€8mm for an investment of €1.75mm and will generate €1.25mm in EBITDA at a €125/MWh electricity price. This is equivalent to an NPV8 of US$3.1/mcf of gas based on 2P reserves.

Forecast AMM segment revenue (€mm) by fiscal year



Source: Company data, H&Pe

The table below shows the NPV sensitivity (based on FDE getting to 39 installed units) to long-term power prices and the discount rate.

NPV (€mm) of the AMM business (39 CHPs) at various power prices and discount rates

		Long-term power price				
		€75	€100	€125	€150	€175
Discount rate	4%	431	561	692	823	953
	6%	353	457	561	666	770
	8%	296	381	465	550	635
	10%	253	323	393	464	534
	12%	219	279	338	397	457

Source: H&Pe

We see AMM as a high value business given its strong existing profitability (€27mm of EBITDA in FY'23E), the high growth potential (more than doubling capacity by 2026 and further EBITDA growth potential of 10% p.a. beyond this), long reserve life (~60 years at current production) with further resource potential beyond this and the ability to raise low cost debt against the asset (we use an 8% discount rate). Our valuation of the assets of €465mm implies a 10x multiple based FY'24 EBITDA or 9x on FY'26.

Economics under different scenarios

We look at the AMM business under three different scenarios based on plants built – 15 CHPs, 39 CHPs and 100 CHPs with the other assumptions remaining the same.

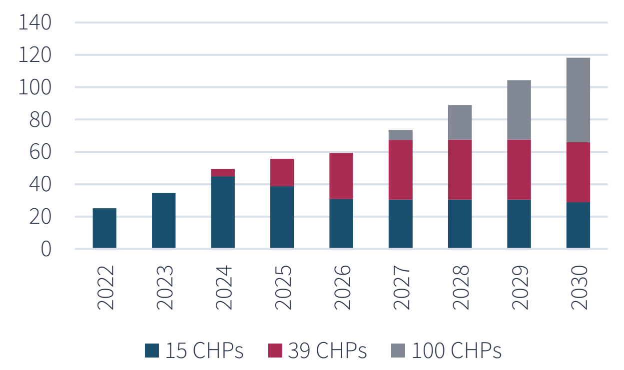
In the conservative scenario of no growth from 15 CHPs (current number of plants FDE has in operation), we estimate annual gas production usage of 2.5 bcf, of which 1.6bcf is used by CHPs to generate 185GWh of power with the rest sold as gas. At long-term €125/MWh, EBITDA will be ~€27mm and would lead to a NPV8 of €260mm (above the current EV and implies ~9.6x EBITDA).

If we take our base case scenario of 39 CHPs by 2026, we expect annual gas production to reach 5 bcf by FY'27 with 4.1bcf generating ~0.5TWh of power and the rest sold as gas. At long-term €125/MWh, EBITDA will be ~€56mm and would lead to a NPV8 of €465mm (implies ~8.3x FY'27 EBITDA).

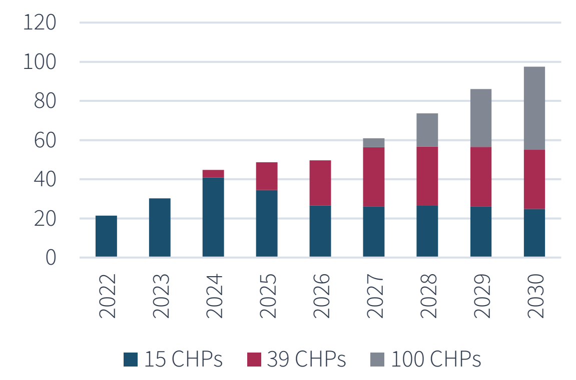
In the high case of 100 CHPs, we assume that all plants would be operational by 2032 with an annual gas production of ~12 bcf and electricity production of 1.2 TWh/y. In the high case, the NPV8 will be €814mm and would be generating €142mm of EBITDA at peak.

The charts below show the key profitability measures for the three different scenarios on a fiscal year basis.

Revenues (€mm)

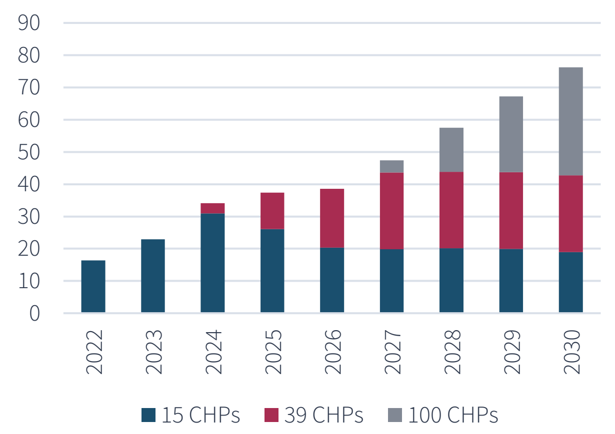


EBITDA (€mm)

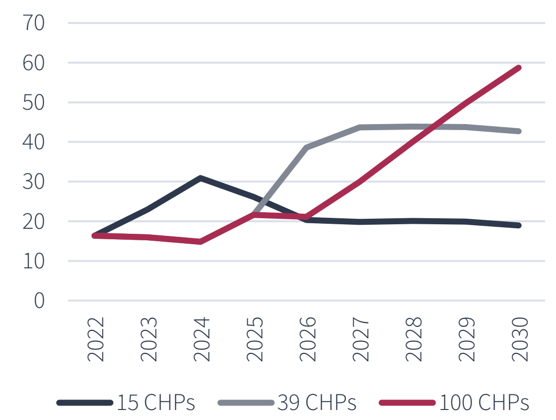


Source: H&Pe

Cashflow from operations (€mm)



Free cashflow (€mm)



Source: H&Pe

Cryo Pur

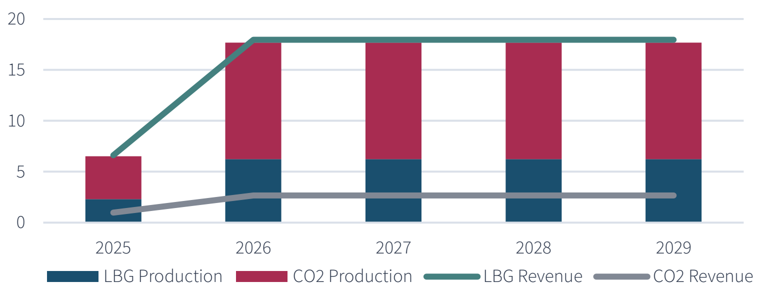
FDE has bought into a highly innovative cryogenic technology business that has strong synergies with its existing business and is exposed to a huge addressable market of dealing with stranded natural gas and CO_2. The bio-methane space has seen considerable growth and interest from major energy companies (e.g. Shell's purchase of Nature Energy for US$2bn) as it is a key component of Europe's decarbonisation strategy. In particular , Liquified Biogas (LBG) has potential for strong growth in the "hard to abate" transportation sectors of trucking and shipping. The production of liquid CO_2 is also a valuable commodity given the shortages in Europe.

FDE was able to acquire a 96% stake in Cryo Pur for just €2.5mm purchasing it out of bankruptcy, which gave FDE a sizeable discount to the ~€30mm that had been invested to date. The core competency is the ability to deal with impure methane with other gases and produce LBG and high-quality liquid CO_2. The company has proven patented technology with a key ability to process the gas without compression. There are two existing sites in operation and a strong growth pipeline of opportunities, with plans to reach 10 sites by 2026. Cryo Pur is adopting a standardised approach for large deployment with pre-assembled and shipped units with an expectation of 10 months to build and commission a new site.

Cryo Pur's contribution over the first half-year stood at €562K, mostly representing the final revenues associated with the sale of the first LBG and Bio-CO_2 production from its facility in Norway. FDE recently created a new subsidiary call Biogy Solutions in which it has an 80% equity stake partnered with Norwegian entrepreneur Jan Kåre Pedersen with 20%, who was a customer of Cryo Pur for its existing plant in Norway. Biogy has six projects underway in Norway with a target of 500-800GWh of energy production. Land acquisition, pre planning, and engineering are already underway, with its first project set to be announced shortly.

A standardised large plant produces ~100GWh per annum, generating ~€15mm in revenue and ~€10mm in EBITDA. LBG is expected to be sold at ~€155/MWh with the feedstock cost ~€35/MWh plus additional revenue from CO_2 sales. Estimated capex is around €25mm, of which a considerable amount may be covered by subsidies (which we do not currently factor into our economics) and is expected to be 80% debt financed. Therefore, at an 8% discount rate we estimate an NPV of €54mm per large plant. We currently forecast four large and two small plants are built giving a total NPV of €236mm gross or €189mm net to FDE's 80% stake. At full capacity the projects should generate 462GWh/y (4mmcf/d) of LBG generating ~€50mm of EBITDA.

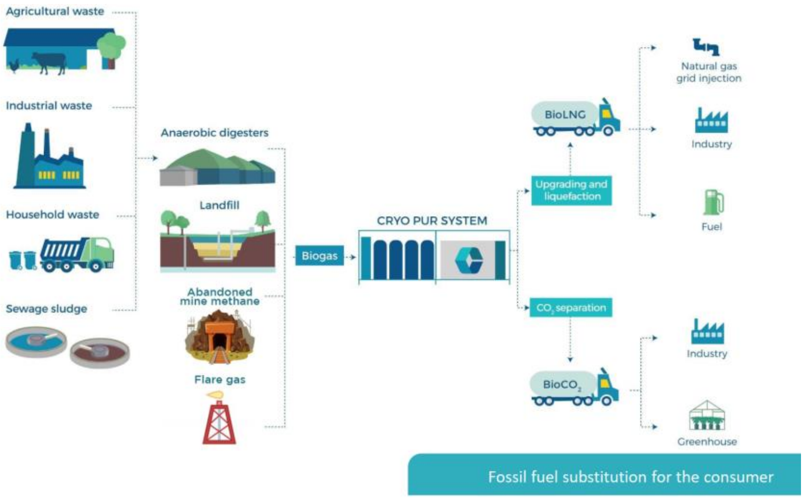
LBG and liquid CO_2 production (kt/y) vs revenue (€ mm) by fiscal year



Source: H&Pe

Overview

Methane emission mitigation for farmers, cooperatives, waste managers, industrials and oil producers

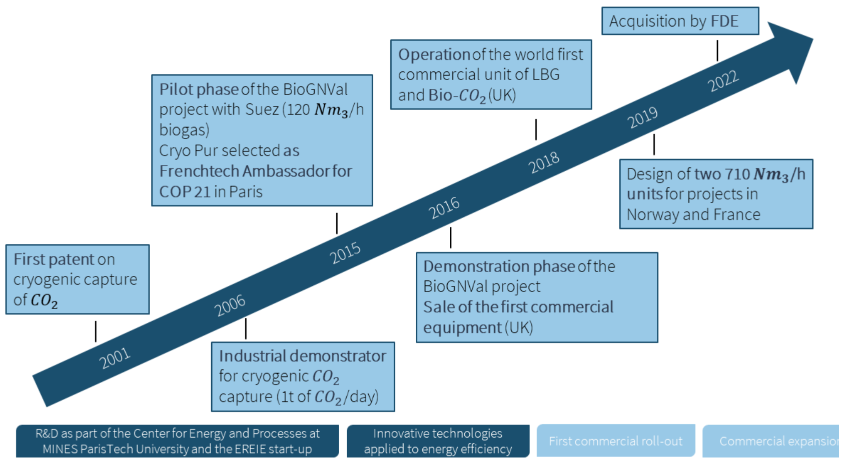


Source: Company data

Cryo Pur is a technology leader dedicated to upgrading and liquefying gases It has harnessed its expertise over 15 years of development, safeguarded by seven international patents with more to be filed. This innovation empowers Cryo Pur to provide a comprehensive suite of turnkey solutions where methane and CO_2 are converted into fuel and industrial feedstock, considerably curbing emissions. There are three distinct markets the technology can be applied to: biogas, flare gases, and synthetic gases, underscoring its multidimensional expertise. Its advanced technology employs cryogenic methods to produce LBG and bio-CO_2.

Guided by a team of 11 experts, including the leadership of a Nobel Prize laureate renowned for his contributions to the IPCC, it was also French Tech Ambassador during COP21. The €30mm invested to date has advanced the real-world applicability of the Cryo Pur process. In our view, its technology provides a major edge over the competition.

Corporate history



Source: Company data

Market opportunity

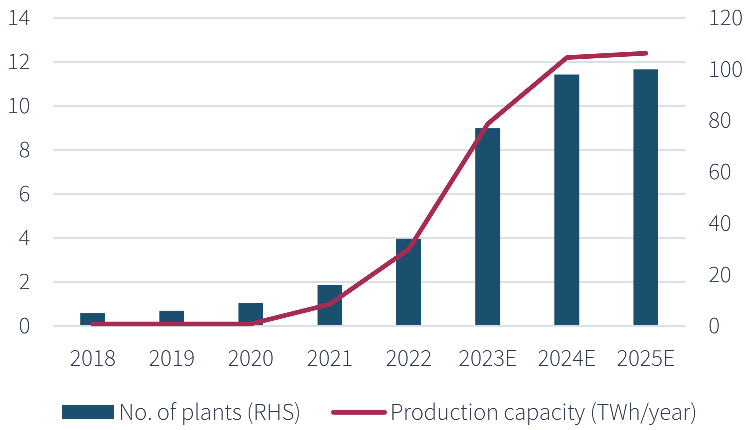
Cryo Pur's vision of the future of the biogas industry

Source: Company data

By 2040, global biogas potential could reach a formidable 8,500 TWh, constituting a quarter of current natural gas consumption according to the IEA. Meanwhile, in Europe, Engie anticipates a remarkable 1,700 TWh by 2050, including an impressive 600 TWh from pyrogasification of wood waste. This signals a compelling leap towards renewable energy sources and underscores the evolving energy landscape.

In many countries, the task of linking small-scale methane production facilities to an expansive natural gas grid network presents a formidable challenge. Even in Europe, boasting a more closely intertwined grid, a quarter of potential biomethane projects face impediments stemming from grid restrictions, encompassing issues of distance and capacity. Globally, the landscape is more complex, with around two-thirds of the remote small-scale upstream flaring locations positioned at considerable distances from both gas and electricity networks.

Current and future development of the number of LBG plants and production capacity in Europe by fiscal year



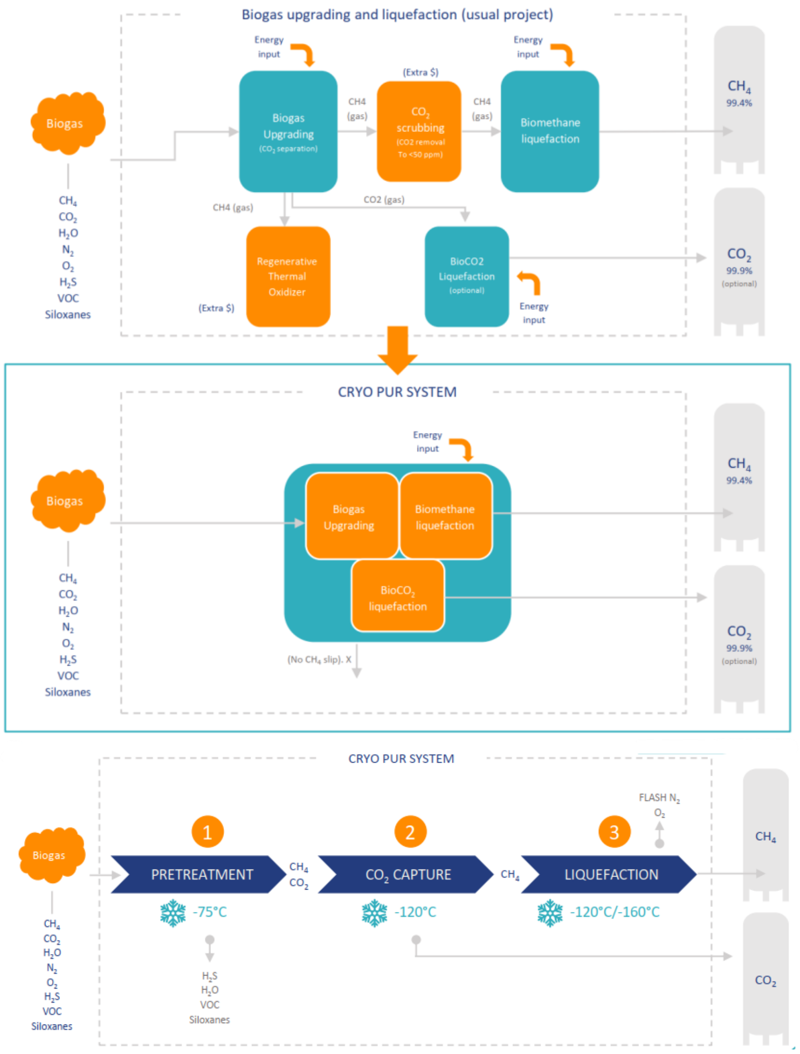
Source: EBA

The biomethane business has been growing in Europe. The first wave involved the biogas being burnt for co-generation. The second wave saw incentives being put in place leading to >1,000 biomethane units coming into operation by the end of 2021 with >90% of this production being injected into the gas networks. The current third wave is seeing the promotion of liquid biogas (LBG) by operators and regulators given the technological progress and renewed focus on CO_2 emissions. Scandinavia is leading the effort with voluntary regulatory policies to push LBG as key solution to accelerate fuel decarbonisation by 2030.

Key opportunities to use LBG are in shipping and European road fuel market. The European shipping industry is joining the EU ETS mechanism in 2023, accelerating its migration towards cleaner fuel with the expectation that LBG takes a significant share of the market. In the European truck market, a switch from diesel to LNG will help cut emissions, but we believe the real game-changer would be utilising more LBG. Hydrogen is another alternative to decarbonise the trucking fleet, however LBG is much easier and less costly to transport than liquid hydrogen, so will have an advantage where the hydrogen refuelling infrastructure is not built out.

Unique technology

Cryo Pur's unique integrated approach versus a conventional project



Source: Company data

Cryo Pur uses controlled cooling for the valorisation of molecules of interest which are CH_4; CO_2, CO, H_2 and Rare gases. Cryogenics makes it possible to produce Bio LNG at 50 ppm of residual CO_2. Cryo Pur's technology involves separating the feedstock in a three-step pre-treatment process

1. Chill the biogas to 2°C.
2. Further cool it to -40°C to frost off most of the water vapour.
3. Perform additional cooling in water vapour extraction, reaching temperatures down to -75 °C.

It then utilises specific Cryo Pur technology to lower the CO_2 temperature to between -90°C and -120°C. This unique process extracts liquid carbon dioxide at a purity of 99.95%, stored for producing dry ice on site. The pure liquid CO_2 can be sold to various industries for different applications. The biomethane is compressed to a pressure of 14 bars and transferred under this pressure to the container filling station. Containers are filled and switched automatically. The LNG is shipped to location for use as cogeneration fuel for motors, producing clean electricity.

The key patents that Cryo Pur has are:

- WO 2015 / 173491 "Method and device for liquefying methane": This patent claims to achieve optimal pressure from the point of view of minimising energy consumption and is directly used in Cryo Pur equipment.

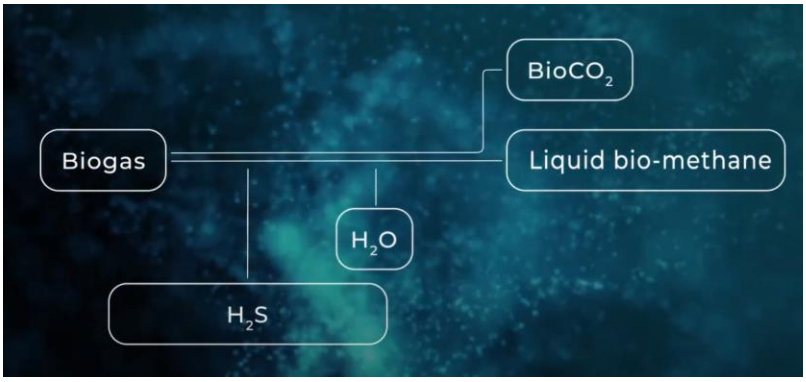
- WO 2016/162643 "Method for recovering energy from dry ice at infra-atmospheric pressure". This patent claims to recover the coldness of solid CO_2 by sublimation at an optimal infra-atmospheric pressure, with an energy gain of more than 15% compared to the current method.

- EP 20158502.3 "Method and device for subcooling refrigerants". This is a generic patent for all refrigeration systems, to avoid a loss of energy efficiency. This device and regulation will be implemented on the new Cryo Pur systems.

- FR 21101231 "Extraction of carbon dioxide". This patent relates to the process of extracting carbon dioxide (CO_2) from liquid methane at a pressure greater than 6 bar.

Biogas

Biogas processing

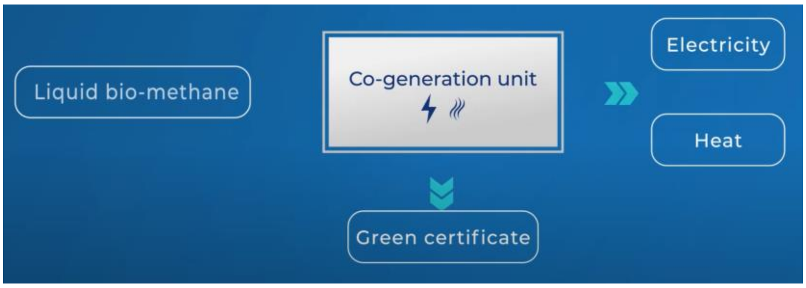


Source: Company data

Cryo Pur's technology can be used to liquefy CH_4 and CO_2 from renewable sources and transform them into fuel for transport and raw materials for industry. In comparison to diesel, it can provide a 90% reduction in GHG emissions while providing enough energy to travel 1,700km without a refill. Producing biomethane from biogas consists of eliminating sulphur (H_2S) and water, recovering bio-carbon dioxide (bio-CO_2) and liquefied bio-methane (LBG).

Cryo Pur has built a solid reputation in the field following two successful projects in Europe, especially the Greenville Energy site in Northern Ireland. This LBG production site is the first of its kind in the world, built on a farm transforming organic waste biogas into LBG. The installation has been running continuously for three years, producing 3t/d of LBG and 5t/d of liquid CO_2, which are then sold to local industries and for electricity and heat production. Every month, it produces an average of 500MWh, generating an annual revenue of €1.2mm. Over past year, Greenville Energy has also been selling liquid phase-extracted CO_2 to the food and beverage industry.

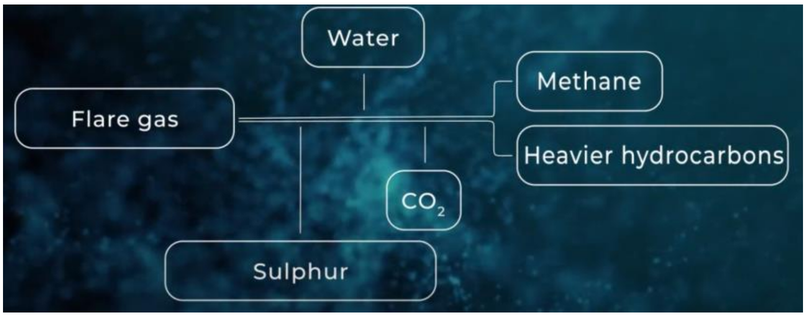
Co-generation unit



Source: Company data

Flare gas

Flare gas processing

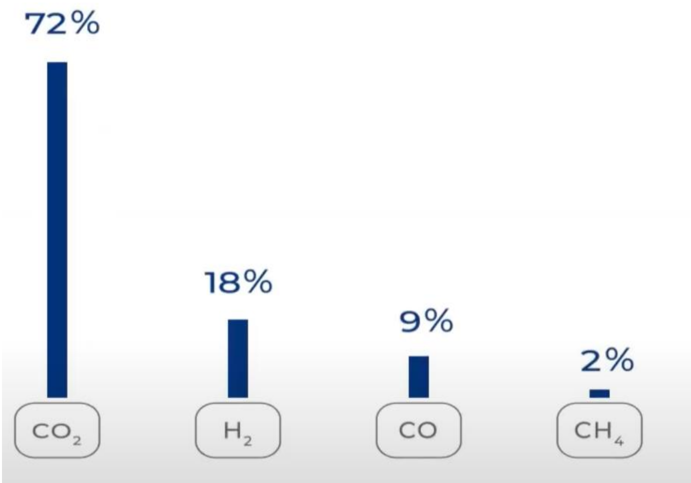


Source: Company data

The second market is flare gas: Cryo Pur's technology can also be used in the oil and gas industry where its excellent economic and environmental performance can be put to good use. Reprocessing flare gas consists of eliminating sulphur (H_2S), water and CO_2 and liquefying methane (CH_4) and other heavier hydrocarbons to produce LNG. If there is enough propane and butane in the mix, the unit can also produce LPG fuel. Around the world, more than 1,500 small-scale flares could potentially benefit from its technology. These installations are currently unable to use their gas on site. Cryo Pur could liquefy their flare gas and transport it, allowing it to be used elsewhere or injected into the system. Cryo Pur is currently working on an installation to produce 11t/d of LNG and 7.5t/d of LPG.

Synthetic gas

Synthetic gas composition



Source: Company data

The third market is synthetic gas. Cryo Pur's technology can play a crucial role in the purification of green hydrogen released from biomass gasification. Synthetic gas from the gasification process contains more than 70% CO_2 by mass. If this can be extracted and resold, it could be highly attractive in economic terms. The process is similar; the CO_2 is extracted by frosting and defrosting before the methane and CO_2 are liquefied to obtain hydrogen of the desired purity. Several projects are currently being negotiated with varying objectives for the purification process.

Proven technology

Cryo Pur started its first demonstration plant in October 2015 at a waste water plant in France using sewage sludge as a feedstock at a rate of 120 m_3/h of raw biogas.

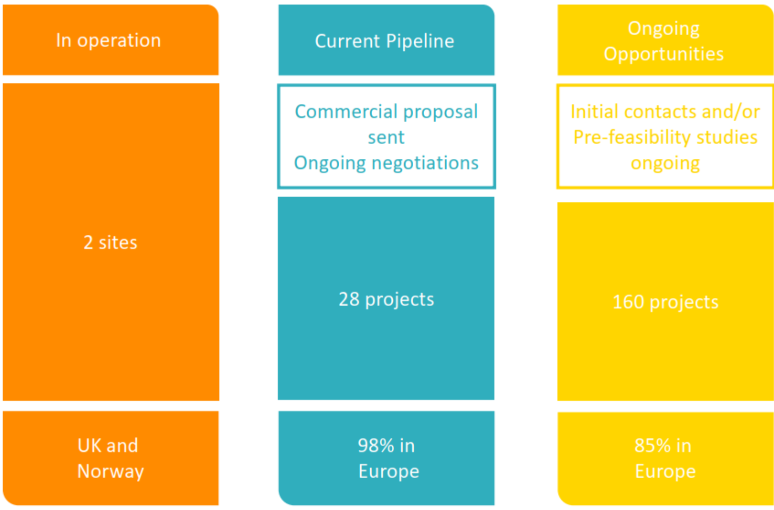
It launched the world's first farm-scale LBG plant in Northern Ireland for Greenville Energy in January 2018. The feedstock was agricultural waste, with a raw biogas flow rate of 300 m^3/h with the production of 3t/d of LNG and 5t/d of CO_2.

Its first industrial scale plant was launched in April 2022 in Norway for Renevo, a local operator, utilising salmon farming waste, with a raw biogas flow rate of 600 m^3/h with the production of 8t/d of LNG and 10t/d of CO_2.

The existing revenues of the Cryo Pur business are coming from the operations and maintenance services being provided to these two commercial plants, which is expected to be ~€1mm per annum.

Growth potential

Pipeline



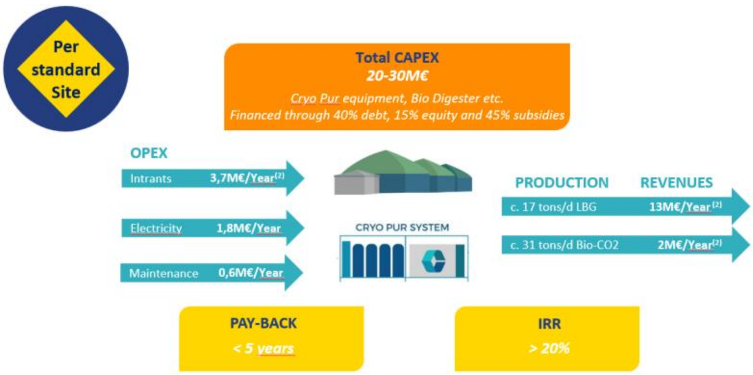
Source: Company data

Previously Cryo Pur has been the provider of the plants (and doing the operation and maintenance) but has not owned the plants or owned the offtake. The business model for the future is for FDE to build, finance and maintain the plants, whilst securing both feedstock and offtake. This is similar to its business model for the AMM business.

Cryo Pur has the capacity to start up and finance project companies using banks or infrastructure funds, paving the way for assets to be created over the 10 years that these project companies will be active. It is currently in the final stages of several different negotiations and recently announced a pipeline of 6 projects in Norway.

FDE is looking to build sites at a standardised size of 700 m^3/h and 1,750 m^3/h of biogas feedstock containing 60% CH_4. The larger size would produce 17t/d of LBG and 31 t/d of bio-CO_2.

Economics



Source: Company data

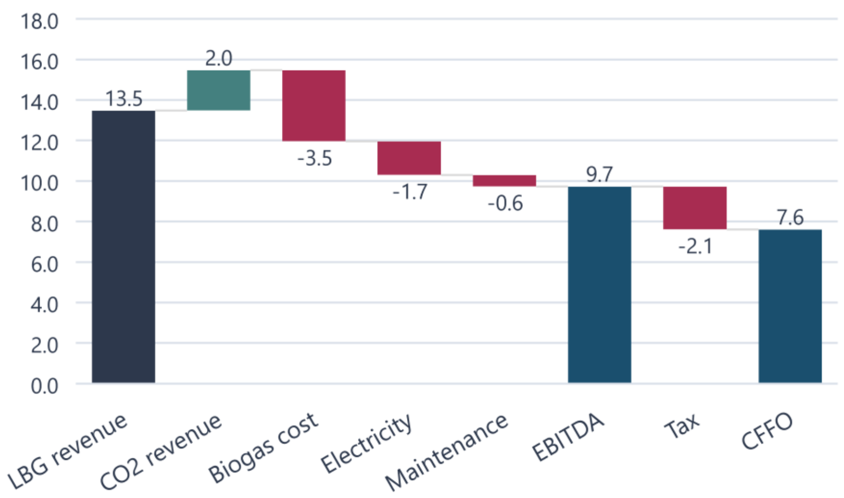
A standard Cryo Pur plant is expected to have an inlet capacity of 1,750m3/hr (1.1mmcf/d) of biogas. Each plant is expected to cost €20-30mm with FDE expecting to be able to finance 80% of this with debt, 15% through grants and subsidies, leaving just 5% required to be equity financed (€1.1mm). Each plant is expected to produce 6.2kt (300mmcf or 93GWh) per annum of LBG and 11.4 kt per annum of CO_2.

In FDE's base case it uses an LBG price of €2,150/t, equivalent to €155/MWh or €45/mcf. This is around triple the current price for gas in Europe but the higher cost is justifiable based on the premium that buyers are willing to pay to use low carbon fuels. This means that a standard plant should generate €13.5mm in revenue from LBG per annum. In Germany, the market price for LBG is ~€200/MWh so we see the potential for even higher pricing than what we assume. This has been demonstrated for many years in the biodiesel market in Europe with biodiesel pricing trading around double fossil diesel pricing: Neste for example has ~US$100/bbl sales margin on biofuels but its crude oil refining margin is closer to ~US$10/bbl.

The CO_2 price achieved is assumed to be €140/t by FDE but we see upside to this given the tightness in the CO_2 market in Europe. We estimate that European CO_2 import pricing has averaged €225/t over the year to June '23. Therefore, we use a higher CO_2 realisation of €175/t. This would generate €2mm in revenue per annum.

In terms of costs, the largest cost is for the biogas input to the plant which FDE expects to be able to purchase at the equivalent of €35/MWh. The total costs per site are expected to be €3.5mm per annum plus the cost of electricity at €1.7mm (at €120/MWh) plus €400k of maintenance. Total operating costs are expected to be €5.7mm per annum.

Breakdown of cashflow from a single plant (€ mm)



Source: H&Pe

This would result in EBITDA of €9.7mm per plant. Assuming ~€1mm p.a. in debt service and €2mm in tax would leave around €6.5mm in post-tax cash flow. This gives a base case NPV8 valuation of €54mm per plant or around a 5.5x EBITDA valuation. If we assume that Cryo Pur is able to have at least 6 plants (four large and two small) fully commissioned by June 2028, we see a total NPV of ~€235mm. One key benefit is the cheap financing of the projects.

Single plant scenario:

EBITDA (FY'2026) sensitivity to LBG price and CO_2 price (€mm)

		Liquid CO_2 price (€/t)				
		125	150	175	200	225
LBG price (€/MWh)	1850	4.4	4.6	4.9	5.2	5.5
	2000	6.5	6.8	7.1	7.4	7.7
	2159	9.2	9.4	9.7	10.0	10.3
	2300	10.8	11.1	11.4	11.7	12.0
	2450	13.0	13.3	13.6	13.9	14.2

EBITDA (FY'2026) sensitivity to LBG price and biogas input price (€mm)

		Biogas input price (€/MWh)				
		25	30	35	40	45
LBG price (€/MWh)	1850	5.9	5.4	4.9	4.4	3.9
	2000	8.1	7.6	7.1	6.6	6.1
	2159	10.7	10.2	9.7	9.2	8.7
	2300	12.4	11.9	11.4	10.9	10.4
	2450	14.6	14.1	13.6	13.1	12.6

NPV8 sensitivity to LBG price and CO_2 price (€mm)

		Liquid CO_2 price (€/t)				
		125	150	175	200	225
LBG price (€/MWh)	1850	13	15	17	19	21
	2000	29	31	34	36	38
	2159	50	52	54	56	58
	2300	63	65	67	69	71
	2450	79	81	83	86	88

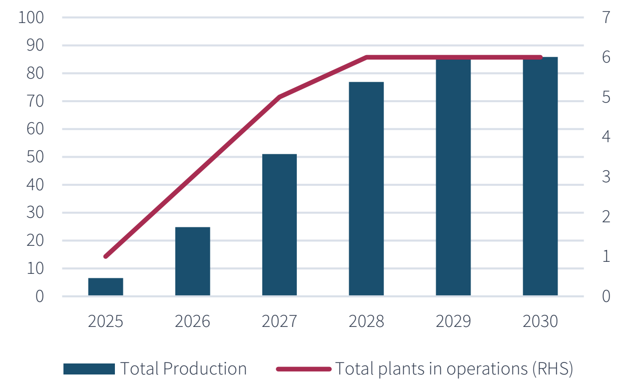
NPV8 sensitivity to LBG price and biogas input price (€mm)

		Biogas input price (€/MWh)				
		25	30	35	40	45
LBG price (€/MWh)	1850	25	21	17	13	9
	2000	41	38	34	30	26
	2159	62	58	54	50	46
	2300	75	71	67	63	59
	2450	91	87	83	80	76

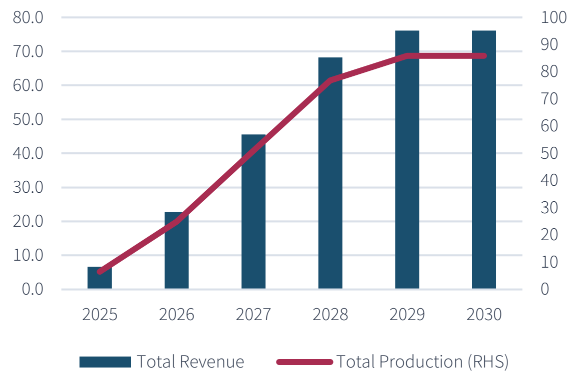
Source: H&Pe

Six plant scenario by fiscal year:

LBG and Liquid CO_2 (kt/y) vs total plants in operation

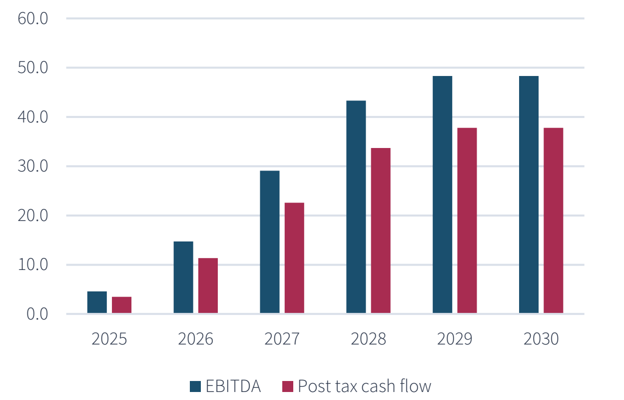


Total revenue (€mm) vs total production (kt/y)

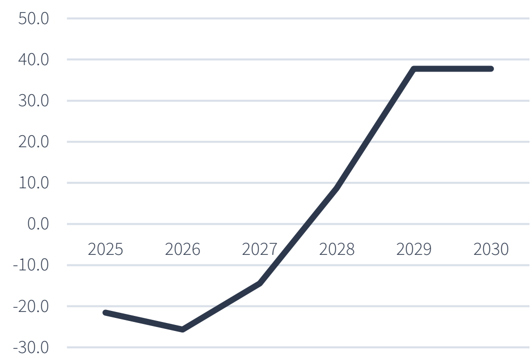


Source: H&Pe

EBITDA vs cashflow from operations (€mm)



Free cashflow (€mm)



Source: H&Pe

CBM: Lorraine Gas

FDE holds rights to develop CBM resources in France: CBM has been extensively developed in the US and Australia but has not been commercialised in France. Producing CBM is viewed as a pragmatic solution in the Energy Transition. FDE has derisked the assets but has been unable to progress development due to permitting delays, which are expected to be resolved in the coming months. The plan was to develop two sites with 300GWh/y in 2024 and 1,042GWh/y (9mmcf/d) by 2026.

According to the 2018 reserves report by MHA Petroleum, Lorraine contains 3.9bcm or 137bcf of 2P recoverable gas or 6.7bcm on a 3P basis. However, there is a further huge contingent resource of 31.9bcm equivalent to >1.1tcf of gas or ~200mmboe of oil equivalent.

According to the independent reserve report, the net asset value of Lorraine's gas has been estimated at €318mm, based on a gas price of only 28€/MWh, up sharply from the last certification carried out by MHA (Sproule Group) in 2018 (€162mm on a 3P basis). This value of the Lorraine project was estimated in January 2022 based on price curves which have since improved further.

At the end-June 2022, €46mm of exploration expenses had been capitalised as intangible assets to reflect the costs of the drilling campaigns conducted on the Bleue Lorraine permits to date. This demonstrates the significant investment that has been poured in so far to gather valuable data to move towards development.

Licensing

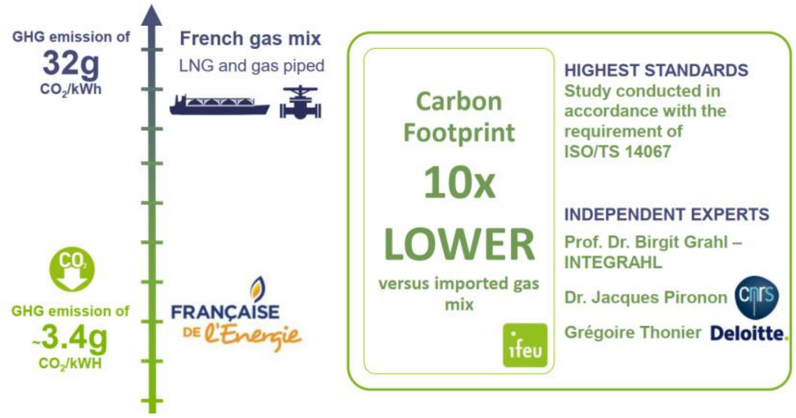
The third period of the Bleue Lorraine exclusive exploration permit expired on 30 November 2018, the date prior to which an application for a concession had to be made or it would no longer be deemed admissible. In this context, on 28 November 2018, La Française de l'Energie filed an application for a Bleue Lorraine concession with the Ministry of Ecological Transition and Solidarity. This concession covers an area of 191 km^2, including the wells of Lachambre, Folschviller and Tritteling, which demonstrated FDE's ability to continuously produce gas from coal seams.

An implicit decision to reject the application for the Bleue Lorraine concession was issued on 11 June 2022 due to failure by the French administration to finalise the processing of the application. A petition challenging the implicit rejection of the Bleue Lorraine concession application was filed on 12 July 2022 with the Administrative Court of Strasbourg with a request for a penalty payment from the State.

That permit is under implied refusal with an ongoing administrative appeal. In a letter dated 4 October 2022, FDE applied for formal notice to be served on the Minister responsible for mines to provide his observations as soon as possible. In late July 2023, the court annulled the order of 26th April 2023 rejecting the concession request and ordered the State to grant FDE the Bleue Lorraine concession within three months, subject to a penalty of €500 per day of delay.

Emission comparison to imported French gas

CBM has 10x lower emissions than French gas mix



Source: Company data

A February 2016 study by IFEU (Institut für Energie- und Umweltforschung), the German reference institute in exploration dedicated to energy, environment and ecology, based in Heidelberg, with the support of CNRS and Bio-Deloitte, highlighted the very low carbon footprint of the Lorraine coal-gas project. The results reveal that this high-quality, 100% French energy would emit on average ten times less CO_2 than natural gas imported and consumed in France (mainly from Norway, Russia, the Netherlands, Algeria and Qatar).

The study found that the overall carbon footprint of the gas to be produced by the Group is about 3.4 g CO_2/kWh, an environmental footprint ten times lower on average than that of imported gas, which is about 32 g CO_2/kWh. The CBM gas is of very high quality and has high calorific value. It is also intended to be produced and consumed locally, which further reduces its environmental footprint and contributes to the energy transition currently underway in France and Europe.

Historic activity

During the fiscal year ended 30 June 2017, the Company completed the successful drilling of the Lachambre well in the Lorraine region, where seven layers of coal with vertical thicknesses ranging from 1.8 to 10.8 metres, and average gas levels greater than 10 m^3/tonne, were identified between 950 and 1,200 metres on the stratigraphic portion of the well located in Lachambre. The number of coal layers and the overall thickness of the coal part correspond to the predictions made on the Petrel 3D model developed by the Company.

During the year ended 30 June 2018, the Group continued the production test of the CBR-1 well at the Lachambre site in Lorraine. Continuous surface gas production has been established and the quality of the gas produced has been confirmed over these periods to more than 95% methane with very little impurities. In accordance with its plan, but with a few months' delay in its schedule, the Group continues its production testing phase in order to dehydrate the coal seam and determine the well's maximum production level.

During the year ended 30 June 2019, the Group continued the production test of the CBR-1 well at the Lachambre site in Lorraine, to refine its reservoir model, furthering the project's development plan. Continuous surface-gas production has been established, and the quality of the gas produced has been confirmed over these periods at more than 95% methane, with very few impurities.

Valuation and assumptions

We have modelled out the development of the 2P reserves at Lorraine to provisionally assess what a development could look like, however the estimates are subject to change as there is not a firm development plan or timetable as yet. We assume that the total capex over the life of the project to develop 139bcf is ~€300mm or €1.6/mcf (€10/boe). We estimate that production could start in FY'26 at ~10mmcf/d and ramping up to >30mmcf/d at peak at the end of the decade. Based on a long-term gas price of €10.3/mcf, this would generate initial revenues post royalties at 30% of €30mm and peak revenues of €85mm. We estimate opex of ~€10/boe or €1.5/mcf, which leads to EBITDA of ~€35/boe, which is ~€70mm at peak at the end of the decade.

Overall, this gives an NPV10 of €118mm or €0.85/mcf or €5/boe. Given the regulatory and development risks, we use a conservative 33% chance of commercialisation resulting in a risked value of €39mm or €7.5/sh. There is further value creation upside by using the gas to produce hydrogen, which we have not factored into our economics.

NPV10 sensitivity to gas price (€mm)

		TTF gas price (€/mcf)				
		6	8	10	12	14
Discount rate	6%	23	106	201	273	357
	8%	3	74	154	216	288
	10%	-13	49	118	172	233
	12%	-24	30	90	137	190
	14%	-32	15	68	109	156

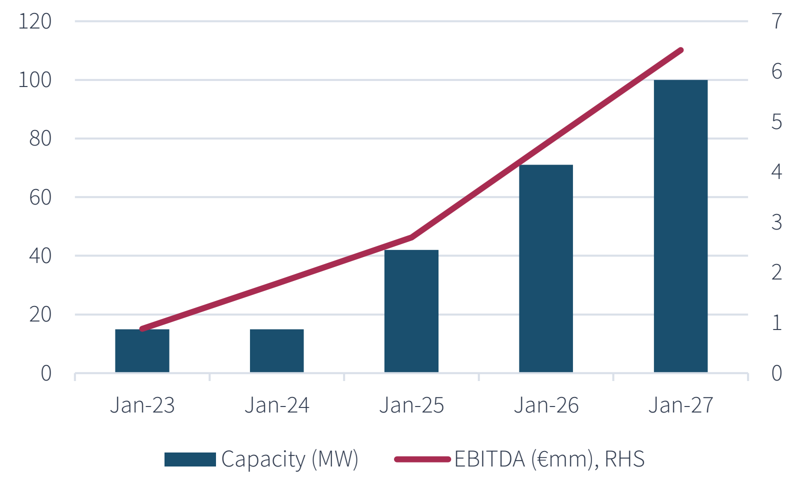
Source: H&Pe

Solar

Overall, we see the solar business as profitable and stable but the least material in the context of FDE's wider business and growth. We see the photovoltaic (PV) business having an NPV7 of €13mm based on growth to 100MW by FY'27, using a long-term PPA price of €80/MWh. We expect the current PV business to generate €1.6mm in EBITDA in FY'24 at a €130/MWh power price.

Photovoltaic

FDE planned solar capacity growth and estimated EBITDA



Source: Company data, H&Pe

In October 2020, FDE was awarded a 15MW ground-based photovoltaic power plant project in the call for solar tenders issued by the French Energy Regulatory Commission (CRE). The plant started full production in January 2023.

This plant is located in the Grand Est region in Lorraine, on the site of a former landfill in Tritteling-Redlach. It is located over 24 hectares, cost €10mm to construct and is expected to produce 16.5GWh/y, which implies a capacity factor of 12.5%. The project was funded through an SPV and required no significant equity investment from FDE with 90% debt financing. Operating costs excluding associated G&A are around €21/MWh or ~€350k/annum.

NPV of the Solar PV business at various power prices and discount rates

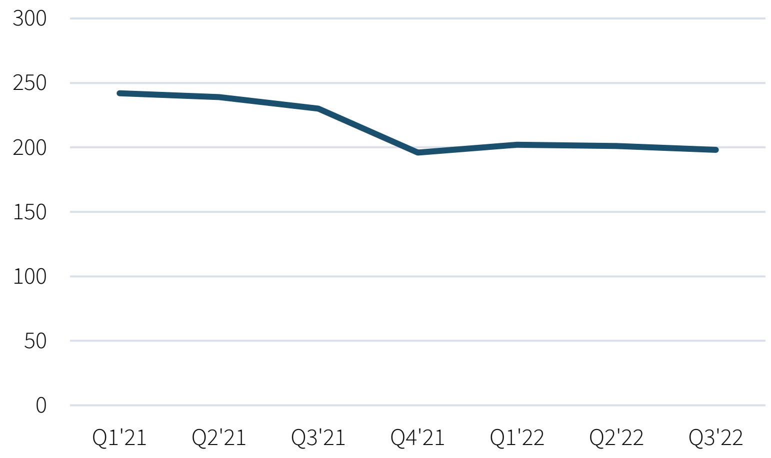
		Long-term power price				
		€60	€70	€80	€100	€125
Discount rate	5%	3	14	25	47	74
	6%	-1	9	18	38	62
	7%	-5	4	13	30	52
	8%	-8	0	8	23	43
	9%	-11	-4	3	18	36

Source: H&Pe

Capacity auctions can determine power prices from solar PV projects in France, which are fixed (with an inflator) for 20 years. There is a minimum price for 20 years of €56/MWh, sold into the local distribution network, which would generate ~€0.9mm in revenue per annum. However, the project will be selling at market price for 18 months until early 2024, which we assume is ~€130/MWh on average and we assume that from FY'25 onwards FDE signs PPAs for its current and future facilities at €80/MWh.

TotalEnergies previously released data on its solar PPA pricing in Europe which was >US$200/MWh for the majority of 2021 and 2022.

TotalEnergies reported European solar PPA pricing ($/MWh)



Source: TotalEnergies, H&Pe

FDE plans to reach >100MW of installed capacity by 2026, which we estimate would entail a further gross investment of >€50mm. This could come either through projects owned outright by FDE, or in partnership with Total Quadran. FDE will be carried through the up-front costs on any projects pursued under the partnership. FDE has already secured lands in the Grand Est region and in the Hauts-de-France to reach 100MW by the end of FY2026.

Thermal

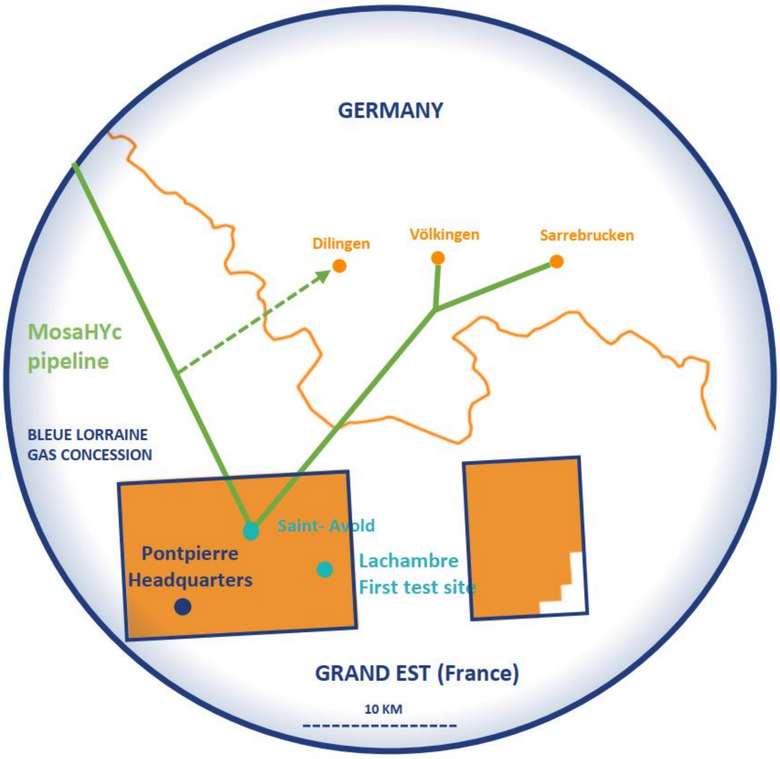
In Lorraine, FDE has pioneered the construction of France's largest thermal solar plant in Creutzwald at a cost of €2.4mm (of which >50% was covered by subsidies). This cutting-edge facility injects energy into a public district heating network under an 18-year Power Purchase Agreement (PPA) at a price of €52/MWh, rising with inflation. Additionally, FDE is revitalising industrial and mining areas by developing multiple solar projects, including the rehabilitation of a pithead.

Hydrogen

FDE has several opportunities to participate in the hydrogen market. Demand for hydrogen is predicted to grow rapidly as a carbon substitute in the drive to net-zero emissions. FDE is currently exploring a range of strategic pathways for hydrogen production, capitalising on both its existing gas production capabilities and the discovery of natural hydrogen reservoirs within its acreage. Among the viable approaches, a notable solution involves the implementation of methane pyrolysis sourced from FDE's coal bed methane or abandoned mine methane facilities. We see a lot of promise in FDE's various hydrogen ventures; however, for now we do not include any value in our NAV but see very large optionality.

In addition to its current usage in fertilisers and petrochemicals, hydrogen has gained prominence as an "energy vector" in decarbonisation efforts, as well as a carbon substitute in "hard-to-abate" sectors such as steel. However, current production methods face multiple challenges. The most widely used process, SMR, emits high levels of CO_2, requiring carbon-capture and storage to cut emissions. FDE has the potential to produce methane from its CBM acreage and use the same acreage to sequester the CO_2. Methane pyrolysis is an alternative low-emission process, applying heat in the absence of oxygen to split natural gas into hydrogen and carbon, creating a fraction of the CO_2 of SMR.

FDE assets and hydrogen infrastructure



Source: Company data

FDE's acreage is strategically located very close to a planned major hydrogen infrastructure network in France and Germany. FDE is <5km away from MosaHYc (Mosel Saar HYdrogen Conversion), which will focus on the conversion of two existing pipelines into a 70-km pure hydrogen infrastructure, connecting Völklingen (Germany), Carling (France), Bouzonville (France) and Perl (Germany), capable to transport up to 20,000 m^3/h (60 MW) of pure hydrogen.

Hannam&Partners

Methane pyrolysis (turquoise hydrogen)

The conversion of methane through pyrolysis into hydrogen represents a cutting-edge concept that, while not yet fully matured on an industrial scale, holds considerable promise. This process is particularly appealing due to its potential to yield hydrogen without CO_2 emissions, thus significantly reducing its carbon footprint. FDE is actively positioning itself to seize this opportunity and is actively engaged in two global consortiums (HyMEPP and the HECO2-PLASMALYSE HYBRIDE) dedicated to advancing this technology.

HyMEPP

Plenesys has developed a proprietary methane pyrolysis technology, called HyPlasma, to produce hydrogen and solid carbon. HyMEPP is a consortium formed between FDE and Plenesys (Plasma Energy Systems) to validate the technology on an existing FDE site. HyPlasma® is an AC plasma methane pyrolysis process. It is a containerised solution designed to be decentralised and scalable, allowing the units to be installed near the end user and adapted to the production needs.

HECO2 Plasmalyse Hybrid

FDE has been chosen by the Walloon government, Belgium, to lead the HECO2-PLASMALYSE HYBRIDE consortium. The consortium's primary objective is developing a pilot plant to use its patented Hybrid Plasmalysis technology for methane pyrolysis. The goal is to establish a facility capable of producing 15 kt of hydrogen and 45 kt of carbon materials while making big strides in CO_2 reduction.

H2 through steam reforming including CO_2 storage

In relation to the storage of CO_2, after six years of work in partnership with the University of Lorraine and the CNRS, combined with support from the Region and the State, and investments of roughly €5mm, the large CO_2 storage capacity of the coal reservoirs in Lorraine has been demonstrated in the laboratory for the coal reservoirs in Lorraine. The water contained in the natural fractures of the rock has a basic pH that is highly favourable to the storage of important quantities of CO_2 in mineral form. Once dissolved, the CO_2 cannot migrate outside the coal seams, thus creating a particularly interesting opportunity for CO_2 storage, hence contributing to achieving carbon neutrality in this region, which has historically seen significant emissions.

Natural hydrogen

FDE submitted an application for a 2,254 sq km permit in the eastern Lorraine region to explore for natural (or white) hydrogen (H_2) after well analysis revealed a high content of H_2 in a carboniferous aquifer. The application is known as Trois-Evéchés and lies close to the Bleue Lorraine area, for which the company filed a production licence in November 2018.

As part of a research project conducted in collaboration with the University of Lorraine and the National Centre for Scientific Research (CNRS), measurements on the Folschviller well have indicated significant levels of dissolved hydrogen, with fluids reaching 15% concentration at 1,093 m depth and 98% at 3,000 m.

A similar study is now planned to be undertaken on three other wells to better understand the commercial potential of the find ahead of the drilling of a deep well (3,000m depth) around Q4 2024.

FDE’s Environmental Credentials

In recent years, the global market has exhibited a more pragmatic approach towards carbon emissions, marked by increased scrutiny of claims made by companies. This shift in perspective is driven by a dual focus on the economic implications of reducing carbon emissions and the need to balance these efforts with energy security considerations. In this evolving landscape, FDE emerges as a company that offers, in our view, a pragmatic and investor-friendly approach to addressing the energy transition.

FDE's core mission revolves around two key principles: reducing carbon emissions and providing cost-effective energy solutions to consumers. At first glance, the process of extracting natural gas from coal seams may appear to contribute to carbon emissions through gas combustion. However, a closer look reveals a more nuanced reality. FDE's operations involve capturing methane that would otherwise seep into the atmosphere over time from coal seams. Methane, a potent greenhouse gas, carries a global warming potential (GWP) significantly higher than carbon dioxide (CO_2) over shorter timeframes.

Over a 20-year period, methane's GWP is estimated to be approximately 84 to 87 times that of CO_2. By preventing methane emissions and converting them into CO_2 through combustion, FDE effectively reduces the global warming potential of these emissions by ~97%. This demonstrates FDE's commitment to mitigating the impact of methane, even if it results in CO_2 emissions.

FDE's contributions to reducing carbon emissions extend beyond methane capture. The company is actively exploring low-carbon hydrogen production through pyrolysis, a process with lower emissions compared to conventional steam methane reforming. Moreover, FDE's approach emphasises localised energy production and consumption, significantly reducing carbon footprints in the regions it serves. This "close-to-home" strategy empowers regions to make substantial reductions in energy-related emissions.

The global push to minimise methane emissions from natural gas-related activities and certify gas as "responsibly sourced" is gaining momentum. FDE plays a pivotal role in this effort, particularly in Hauts-de-France and Wallonia, where abandoned mine methane is harnessed to prevent emissions while providing environmentally and economically sustainable energy to households through combined heat and power units.

FDE's unique position in the energy landscape is underscored by its status as the sole French energy producer with a negative carbon footprint. Based on the latest IPCC assessment report (AR6), the company's abandoned mine methane capture and existing production activities alone prevent more than 3.5mmt of CO_2 equivalent emissions annually in France and Belgium. If a company had to go into the EU market and purchase this level of emission credits it would cost them €315mm at the current carbon price of €90/t (around the average in 2023 to date). This significant reduction in carbon emissions aligns with the broader goal of energy independence.

In Lorraine, where FDE plans to capture coal bed methane without hydraulic fracturing or equivalent techniques, the use of this local resource could reduce the carbon footprint by a factor of 10 compared to gas imports from other regions. This initiative not only contributes to emission reduction but also bolsters national energy security.

FDE's commitment to transparency and environmental responsibility has earned recognition in the form of the Greenfin France green finance label in the circular economy category. This prestigious label, focused on energy and ecological transition, highlights FDE's role in driving positive environmental change. It serves as a guarantee to investors regarding the environmental integrity of funds associated with FDE and their contribution to the broader goals of energy transition and climate change mitigation.

Furthermore, FDE's consistent leadership among energy sector SMEs is reflected in its Gaïa Research rating. Over the past six years, the company has improved its rating, demonstrating its dedication to environmental, social, and governance (ESG) principles. Notably, FDE stands out as the only energy producer with a negative carbon footprint in both France and Belgium, thanks to its proactive approach in capturing fugitive methane emissions.

Looking ahead, FDE's abandoned mine methane capture and recovery activities are projected to prevent over 10mmt of CO_2 equivalent avoided annually by 2026. This ambitious goal underscores FDE's unwavering commitment to mitigating climate change while simultaneously providing cost-effective energy solutions.

FDE's fulfilment of UN Sustainable Development Goals

Source: FDE

There are a wide variety of GHG programs that include CMM projects as emission reductions and thus provide some guidance on CMM GHG accounting. For instance:

- United Nations Framework Convention on Climate Change (UNFCCC)
- Guidelines for National GHG Inventories by the Intergovernmental Panel on Climate Change (IPCC)
- Clean Development Mechanism (CDM) projects
- Chicago Climate Exchange (CCX)
- Greenhouse Gas Services (GHGS)
- The Voluntary Carbon Standard (VCS)
- California Climate Action Registry (CCAR)

FDE's Targeted Markets

FDE is involved in several energy verticals. We look at these markets and the macro trends. The areas of focus are European gas, European electricity pricing, Abandoned Mine Methane, Coal Bed Methane, Biomethane and the related LBG and Bio-CO_2 markets, hydrogen pyrolysis, carbon capture and storage in coal seams and natural hydrogen production.

European gas and electricity markets

The major external driver of the profitability and value of FDE's business is European gas pricing. Electricity pricing is clearly a key driver, but it is intrinsically linked to European gas prices. Its core AMM business' revenues are directly linked to both gas and electricity prices. Although it benefits from a FiT or floor pricing, electricity prices are currently significantly above this meaning that market prices in essence drive the value. Its Cryo Pur business is also geared into gas pricing as the price of LBG will be somewhat linked to gas prices. Furthermore, the future profitability of the CBM assets will be linked to the gas price.

European Gas

European TTF gas price (€/MWh)

Source: EEX, Endex, H&Pe

European gas prices have seen significant volatility over the past 5 years. During COVID, prices reached extremely low levels; conversely last year following the war in Ukraine hit unprecedented record high levels. Overall, we expect European gas prices to remain structurally higher than they were in the past driven by trends on the supply side. European gas demand has taken a large hit from the impact of higher prices, however we would expect that to recover as prices have fallen, although remaining above historic levels. However, more importantly Europe has lost a large amount of domestic production over the last few years and suffered from the almost complete loss of Russian gas.

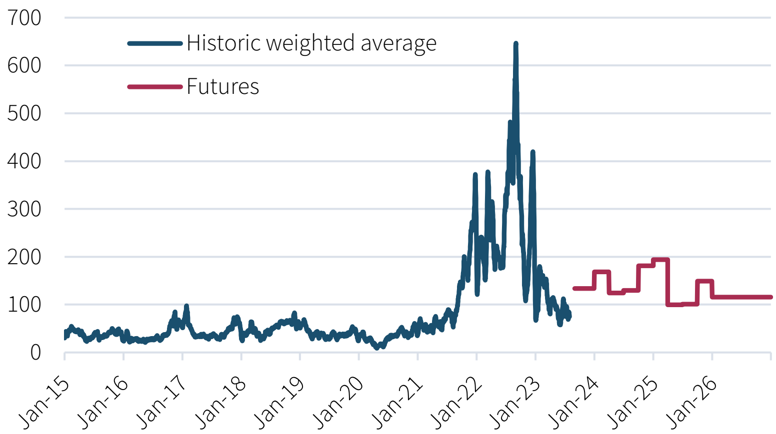
Over the winter of 2022/23, Europe was able to cope with the loss of Russian gas supply as it had built up large gas inventories (at a huge cost) and was helped by milder than expected weather. The lost Russian gas was replaced by high-cost LNG. Also, it is worth noting that the LNG has a much higher carbon footprint given the energy required to chill the gas, the distance travelled, energy used for transportation, and the methane losses from the whole value chain. Another major supply issue has been the reduction in supply and eventual closure of Europe's largest onshore gas field, Groningen.

In general, European gas supply has been declining due to mature fields, difficulties obtaining permitting and a lack of investment. Futures pricing at >€50/MWh (US$16/MMBtu) over the next couple of years remains high relative to pre-COVID levels (e.g. €15/MWh in 2019). In June 20, FDE's breakeven price was only €5/MWh.

Despite the medium to long-term ambitions to phase out fossil fuels, natural gas is likely to remain a key part of the energy mix given the need for base-load power. The EU has agreed to classify gas as a sustainable investment considered as a "transitional" technology. TotalEnergies, for instance, notes that gas will remain steady at 40% of total sales in 2050, but within that, new forms of green gas – hydrogen, biomethane, synthetic gas – will occupy a significant chunk. We see this trend as positive for FDE's current and future business growth.

European electricity

French electricity price, 10 day M.A. (€/MWh)



Source: EEX, Endex, H&Pe

The French electricity market has suffered from nuclear outages over the past couple of years, which further exacerbated the loss of Russian gas. France is the EU's largest producer of zero emissions power (412 TWh in 2022) and is significantly ahead of other EU countries in decarbonising electricity, having one of the lowest shares of fossil fuels in the electricity mix (12% in 2022). Most of French electricity production is already from zero emission sources (88%), primarily nuclear power (63% share in 2022). Wind and solar reached 12% of French electricity in 2022, up from 5% in 2015.

However, this growth has been primarily at the expense of nuclear power rather than fossil fuels, which have maintained a low share. In 2022, French nuclear power suffered a further fall with large-scale maintenance and safety outages, leading to a 22% shortfall in output compared to the previous year. French nuclear availability dropped to its lowest level in 34 years in 2022 after stress corrosion problems were discovered.

In 2015 to 2019 French wholesale day-ahead electricity prices averaged €42/MWh, however in 2022 they surged to average €275/MWh. For Cal-24 French Futures prices for baseload are €150/MWh and €135/MWh in 2025. To put this in context, FDE's Feed-in Tariff (FiT) is ~€75/MWh. The price for its solar power is €56/MWh.

European Coal Bed Methane

Coal bed methane (CBM) is a type of “unconventional” natural gas that is found in coal deposits, trapped within the pores of coal seams. As coal forms over millions of years, organic material is compressed and heated, and this process generates methane gas.

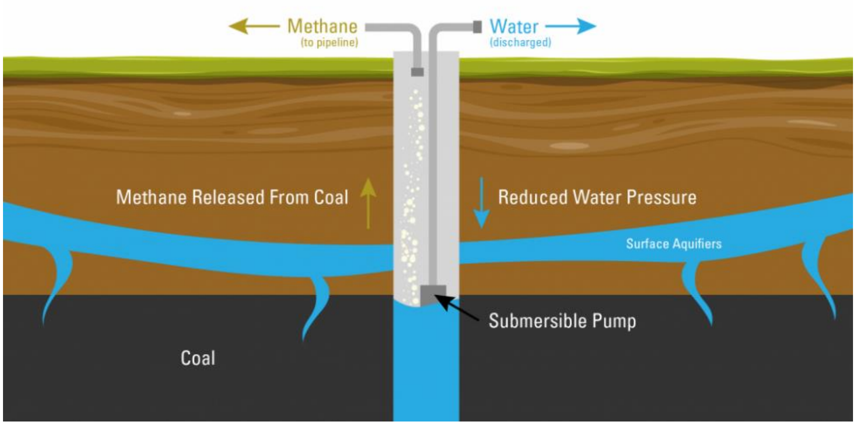
Methane from mines can be subdivided into three types: coal mine methane (CMM), abandoned mine methane (AMM) and coal bed methane (CBM). CMM is generated during active coal mining operations, while AMM is released from abandoned coal mines. CBM, on the other hand, is trapped within coal seams and can be extracted through specialised drilling techniques that focus solely on recovering methane from coal deposits, without the extraction of coal itself.

Coal has a complex and porous structure, providing a large surface area for gas molecules like methane to interact with and be held on it surface. Furthermore, when the methane is trapped with the coal under high pressure, the gas molecules are pushed into the porous spaces of the coal, leading to adsorption into the coal seams (a process where a solid holds liquid or gas molecules on its surface). Methane stays trapped within the coal matrix, as well as in fractures and pores within the coal seams.

Extraction of coal bed methane

CBM is considered unconventional because it requires specific extraction techniques different from those used for conventional natural gas.

Coal bed methane extraction process



Source: Kimray Inc

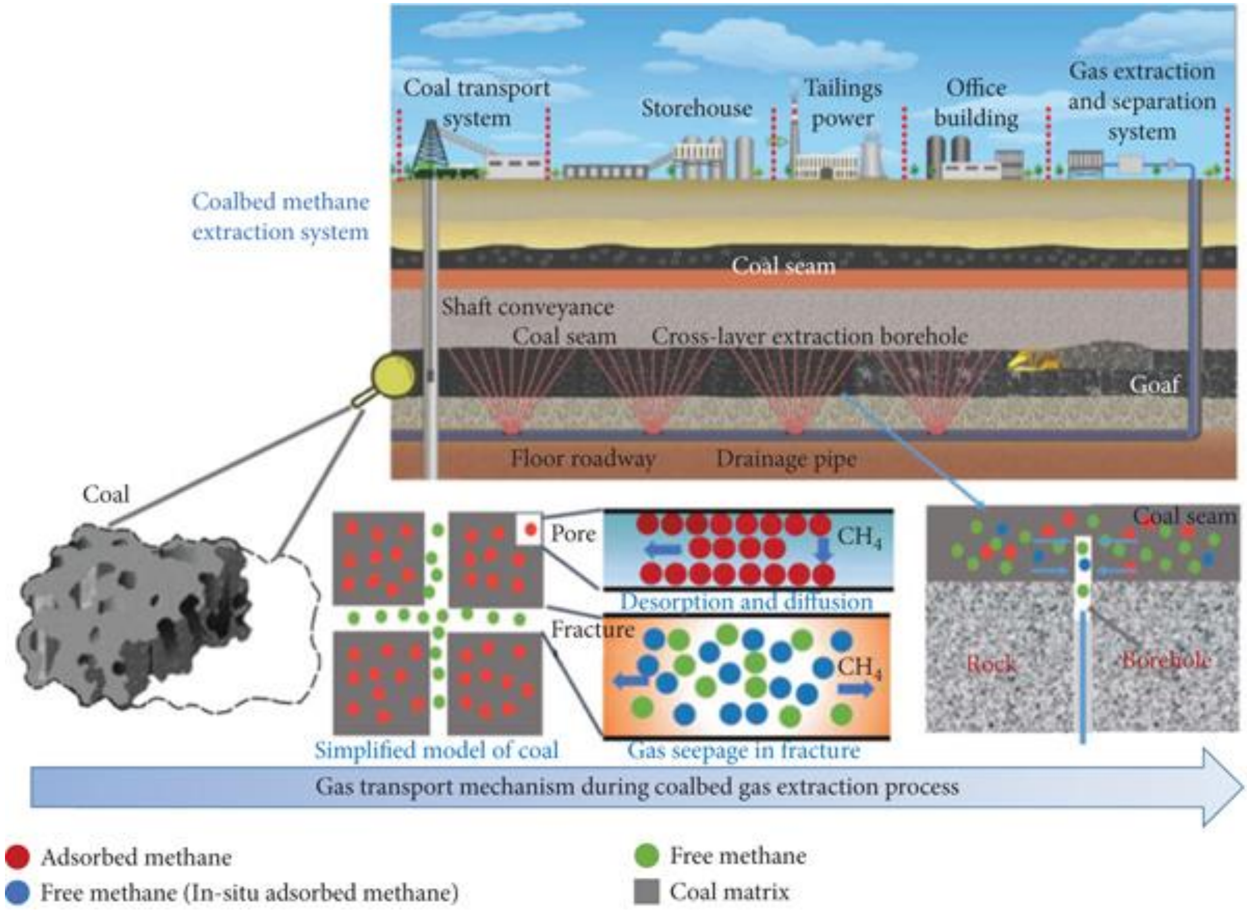
Within coal beds, methane is contained in solution on clean surfaces and is held in place by hydraulic pressure. To extract the methane, first the pressure needs to be reduced to allow the methane to desorb. For this, coal bed methane projects involve the dewatering of coal beds which considerably reduces the pressure in the coal seams. Effective water management is a critical aspect of CBM extraction, as the pumped water — also referred to as “produced water”— often carries minerals salts, and occasionally hydrocarbons. Proper handling and disposal of produced water are essential to prevent environmental contamination.

As the pumping process lowers the water levels within the coal seams, the pressure within the coal diminishes. This reduction in pressure allows the methane to disengage or desorb from the surfaces of the coal. With pressure decreasing, methane starts to flow through the fractures and pores present in the coal.

In CBM production, a well is drilled into the coal seam and water is pumped out to lower the pressure in the seam. This allows methane to desorb from the internal surfaces of the coal and diffuse into the cleat, where it is able to flow, either as free gas or dissolved in water, towards the production well. Permeability (imparted mainly by the cleat) is necessary to achieve CBM production. The natural permeability of coal seams can be low, so some CBM wells are stimulated (hydrofractured) to improve connectivity between the borehole and the cleat system. Wells may have many subsurface horizontal or multilateral sidetracks drilled from one surface location to penetrate more coal.

The liberated methane, along with associated water and other gases, ascends to the surface via the wellbore. Upon reaching the surface, the gas is collected and directed through a separator. This separation step effectively segregates water and impurities from the methane. The water typically undergoes treatment and proper management, while the methane recovered from coal beds can be used as a source of energy, either for electricity generation, heating, or as a feedstock for industrial processes.

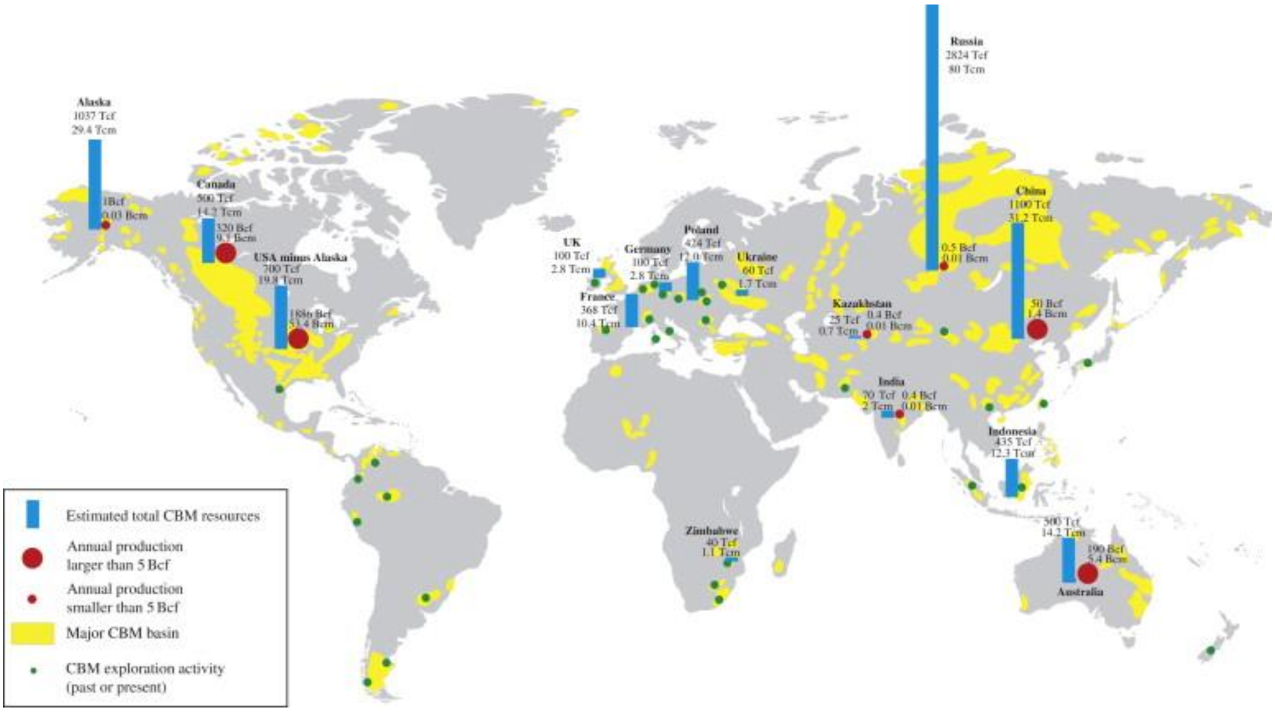
Methane adsorption and surface migration



Source: Stimulation Techniques of Coalbed Methane Reservoirs - Geofluids, vol. 2020

Leading geographies for CBM

Global CBM potential



Source: Maria Mastalerz, in Future Energy (Second Edition)

CBM extraction has gained attention in several regions around the world where extensive coal deposits exist.

The United States has been a pioneer in coalbed methane extraction. CBM production is particularly significant in states with abundant coal resources such as Wyoming, Colorado, Montana, and New Mexico. The Powder River Basin in Wyoming, for instance, is one of the largest CBM-producing regions in the world.

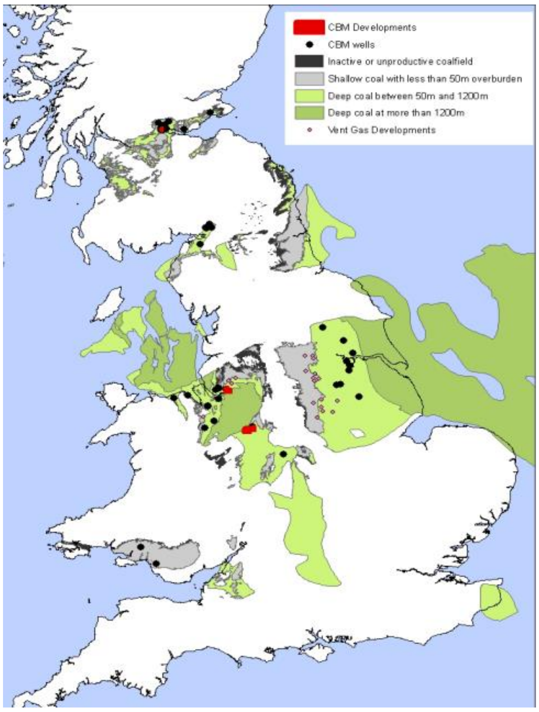
Australia possesses vast coal reserves, and CBM extraction has become a notable industry in the country. The Surat Basin and Bowen Basin in Queensland are key areas. China is another major player due to its substantial coal resources: Shanxi and Inner Mongolia are among the regions where projects are underway.

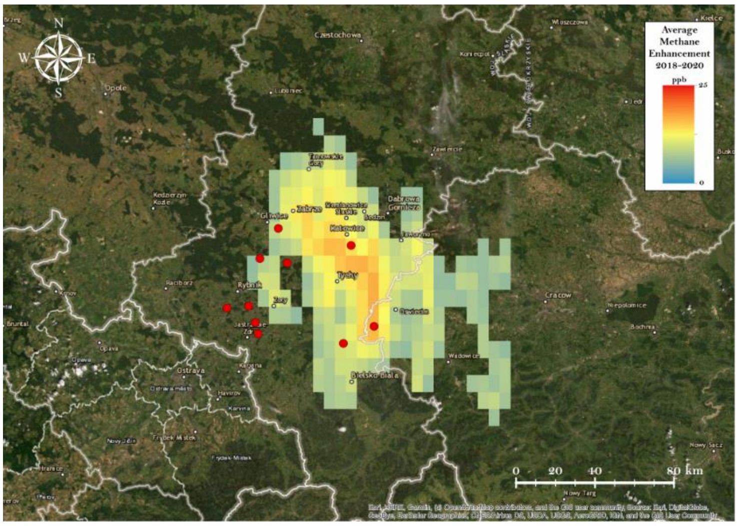
There have been efforts taken to develop CBM in Europe, but the scale is much smaller than that of the US or Australia. CBM in Europe has faced a lot of regulatory challenges, however, some countries and companies are progressing with the development of CBM with FDE in France as a notable example given the extensive legacy coal industry.

In the past, some coal mines in northern and eastern France did produce methane as a by-product of coal mining operations. In 1991 DuPont Conoco Hydrocarbures (now ConocoPhillips) began CBM exploration. CBM production in France was concentrated in the Lorraine Basin in the northeast of the country. Production began in the early 1990s and peaked in 2008 at around 65 mmcm/y. However, production has declined since then due to several factors, including the depletion of reserves and rising costs. The largest CBM resource rests in Lorraine, where FDE operates.

In the UK, there is CBM potential in Wales and Scotland, but companies are facing pushback from the communities living in the area due to environmental concerns. Poland has significant coal resources and CBM potential, especially in the Upper Silesian Coal Basin. However, progress has been slow due to technical challenges and uncertainties about economic viability. Lastly, Spain also holds CBM potential, but commercial production has not been widely realised.

CBM developments in the UK (LHS) and methane detected above coal mines in Poland (RHS)

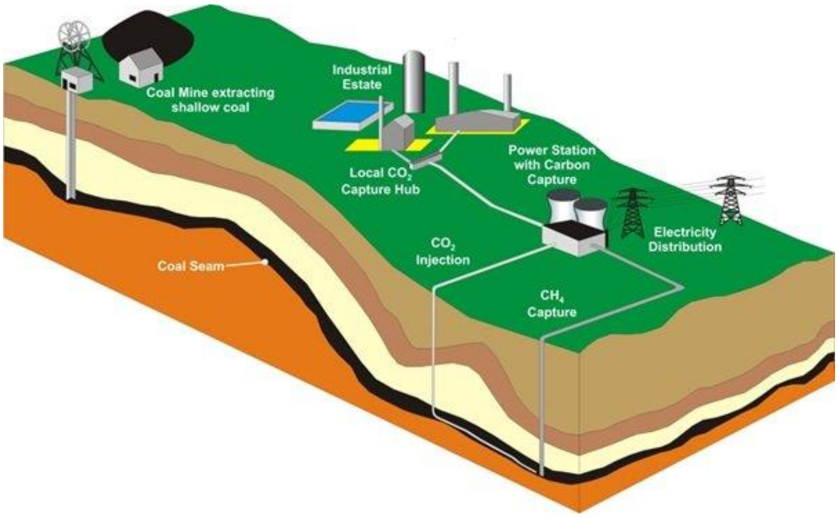




Source: UK Department of Energy and Climate Change, 2012; National Centre for Earth Observation

Coal seam carbon capture and storage (CCS)

Carbon Sequestration in Coal



Source: Flexis

FDE sees a huge potential opportunity to use its licences for carbon capture and storage. This could be used for third party storage of CO_2 or for the CO_2 associated with the production of its gas: e.g. CO_2 emissions from combustion for power generation or from the production of hydrogen via SMR of methane. Leading service company Schlumberger has performed 3D modelling and FDE is looking at an injection pilot project.

CO_2 storage in deep unminable coal seams, also known as coal seam CCS, is a technique that involves injecting CO_2 into coal seams that are too deep or unminable for coal extraction. This process serves to mitigate greenhouse gas emissions by securely storing CO_2 in geological formations, while also potentially enhancing methane recovery from the coal seams.

It is important to select the optimal coal seam, which possesses the geological characteristics to allow proper sorption (adsorbed and absorbed) of the CO_2. Once the right coal seam is selected, the captured CO_2 is compressed into a dense, fluid-like state (supercritical CO_2) and injected into the selected coal seams. The high pressure and density of the supercritical CO_2 enable it to fill the pore spaces within the coal matrix.

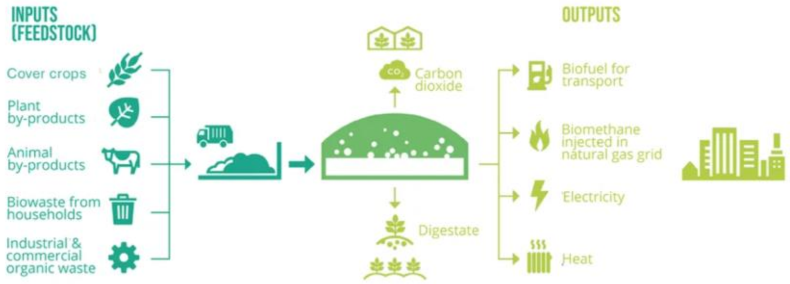
Coal seam CCS has the additional benefit of enhanced methane recovery where the injection of CO_2 into coal seams can lead to the displacement of methane that was originally adsorbed within the coal. This displaced methane can be collected and utilised, thus contributing to energy production. The gas by-product can offset the capital and operating expenditure of carbon capture and sequestration. Carbon dioxide has a higher absorption to coal than methane. Therefore, methane can also be harvested and used to provide energy, with the resulting carbon dioxide re-absorbed into the coal bed.

Over time, geochemical reactions can occur between the injected CO_2, the coal, and the surrounding rock formations. These reactions can result in mineralisation of the CO_2, converting it into stable carbonate minerals, such as calcite. This also helps prevent any risk of leakage of the CO_2.

The largest CO_2-ECBM field test was performed by Burlington Resources (now ConocoPhillips) at the Allison unit in the San Juan Basin from 1995 to 2001. In this pilot test, approximately 336,000 t of CO_2 was injected into four wells completed in the Fruitland coal. Improvement in ECBM recovery was predicted, and the ability of the coal to adsorb and retain CO_2 was demonstrated. Smaller two-well and single-well tests have also been performed in Poland, Japan, Canada, and China.

Biogas

Schematic overview of inputs and outputs of the biogas and biomethane production process



Source: EBA Statistical Report 2021

Biogas is produced from the decomposition of organic materials, such as capturing gases from landfill. These residues are placed in a biogas digester in the absence of oxygen. With the help of a range of bacteria, organic matter breaks down, releasing a blend of gases: 45 – 85 vol% methane (CH4) and 25 – 50 vol% carbon dioxide (CO_2). The output is a renewable gas which can be used for multiple applications.

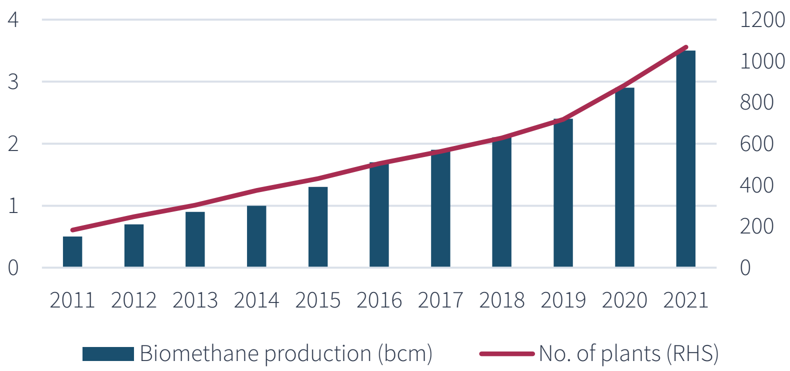
Biogas upgrading into biomethane provides a means of mitigating the harmful effects of climate change as biomethane can be both a non-fossil based renewable energy source and a biofuel, helping to decarbonise the energy and transport industry. The reduction of GHG emissions, such as the recovery of biogenic CO_2 during the production process, is a key value driver.

Large integrated oil company interest

There have been several high-profile acquisitions in the biogas sector with the most notable in our view Shell's purchase of Nature Energy and Chevron's purchase of Renewable Energy Group. Shell spent $2bn on Nature Energy for 17mmcf/d or 3kboe/d of production, which implies $666 per boe/d falling to $450k per boe/d based on 2030E production of 4.5kboe/d. Natural gas acquisition multiples or producers trade on around $25-50k per boe/d. This implies Shell paid 10-15x what it would pay for conventional production. Nature Energy in its annual report expected profit of <US$5mm in 2022.

Biomethane

Biomethane capacity (bcm) and number of plants by fiscal year



Source: H&Pe, EBA

When carbon dioxide and trace gases in biogas are removed, a methane-rich renewable natural gas substitute is left in the form of biomethane. Biomethane can be injected into the gas grid, used as a vehicle fuel or used for combined heat and electricity generation. This is also known as renewable natural gas (RNG).

Biomethane is the cheapest and most scalable form of renewable gas available today. It can directly substitute natural gas and is flexible as it can be readily stored and deployed across the whole energy system, using existing gas infrastructure and end-use technologies. Moreover, biomethane is a dispatchable energy carrier and as such can be deployed to balance intermittent renewable energy generation. It is well placed to deliver meaningful, long-term economy-wide benefits beyond renewable energy provision, thereby supporting the European Green Deal and the transition to a more sustainable and circular economy. Europe reached a total of 1,322 biomethane-producing facilities by April 2023.

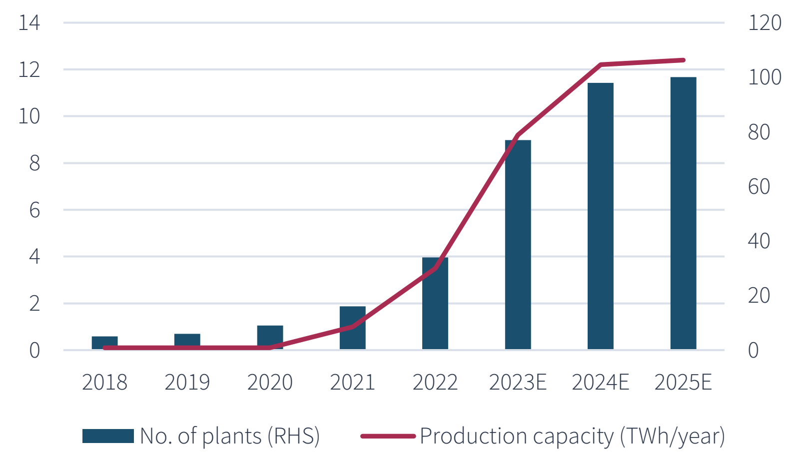
Part of Europe's plan to replace Russian gas is to use more biomethane. Today the EU produces 3.5bcm of biomethane. €18bn has already been earmarked for investment in biomethane production, helping to deliver Europe's energy security and climate mitigation ambitions. In 2022, the REPowerEU target of 35bcm of sustainable biomethane production by 2030 was announced; the investment needed to reach this target is €83bn, depending on the size and location of plants built or expanded, and the types of sustainable feedstock used. €4.1bn will be invested in the coming two years. France set a target of injecting 10% of biomethane into the country's gas network by 2030.

According to the IEA, biomethane becomes competitive with fossil based natural gas in gas turbines and combined-cycle power plants as a flexible generation option at a CO_2 price of ~$100/t in regions with cheap biomethane and high natural gas prices.

Snam said that it could possibly develop a biomethane chain for transport, following the approval of a new legislation by the EU to allow €4.7bn of incentives to the sector. To date, Snam has already received about 500 requests from potential biomethane producers to connect their upcoming biomethane production sites to the existing gas grid.

LBG

LBG capacity (bcm) and number of plants by fiscal year



Source: H&Pe, EBA

To make LBG, the methane is separated from the carbon dioxide and other critical components, and then liquefied. Liquefaction increases the energy density 600 times and makes the biofuel economically viable for long-haul road and maritime transport. As the chemical composition is the same, LBG can be blended at any ratio with fossil LNG. Therefore, LBG production is a critical component of the European biogas sector. It plays a key role in providing sustainable and renewable energy for the transport sector, contributing to reducing greenhouse gas emissions and promoting environmental sustainability.

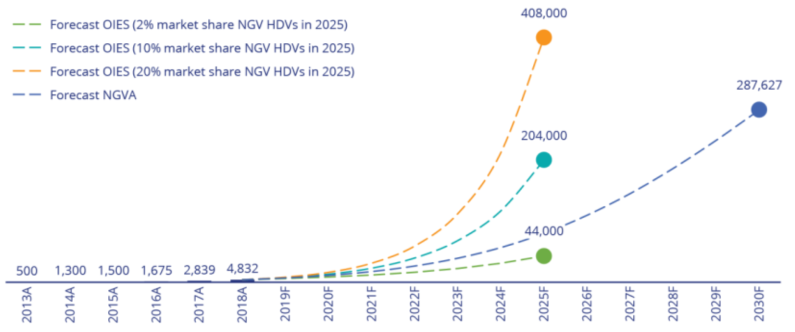
In FDE's base case it uses an LBG price of €2,150/t or €155/MWh or €45/mcf. This is around triple the current price for gas in Europe but the higher cost is justifiable based on the premium that buyers are willing to pay to use low carbon fuels.

The number of LBG projects is rapidly increasing. There are already 100 confirmed LBG projects in Europe, with this number projected to grow further. This growth is a positive indicator of the sector's development and its potential impact on the European energy landscape. The projected production capacity of LBG is expected to reach 12.4 terawatt hours by 2025. This significant production capacity demonstrates the sector's potential to contribute meaningfully to Europe's renewable energy goals and decarbonisation efforts.

LBG is particularly relevant for the transport sector. The renewable nature of LBG makes it an attractive alternative to traditional fossil fuels in the transportation industry. LBG projects are not limited to specific countries. New countries are joining the trend and implementing LBG projects with 10 countries active in LBG production.

The transport sector offers attractive prices for LBG. This is a result of an urgent need for this sector to become more sustainable, with LBG being one of the best options to do so. LBG pricing is also largely determined by carbon intensity, which creates a strong value to the business case. By contrast, business cases for biomethane grid injection and CHP are often based on rigid incentive programs, which do not account for dynamics in feedstock and energy pricing.

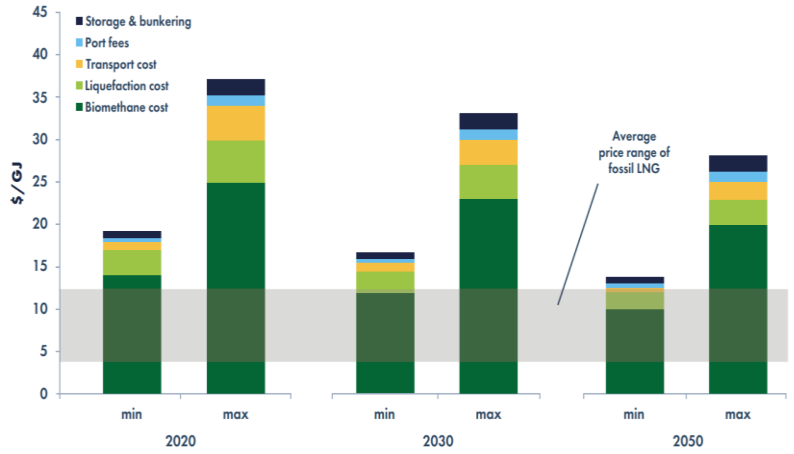
Number of LNG trucks in Europe



Source: Nordsol

Several studies forecast steep growth of the number of LNG trucks in Europe. For example, the Natural & bio Gas Vehicle Association (NGVA) Europe estimates that the amount of LNG trucks in Europe will grow from 12,000 in 2020 to 280,000 trucks in 2030. These vehicles will use approximately 100 TWh of fuel. At least 40% of that amount is expected to be LBG. That is 2.8 Mton LBG.

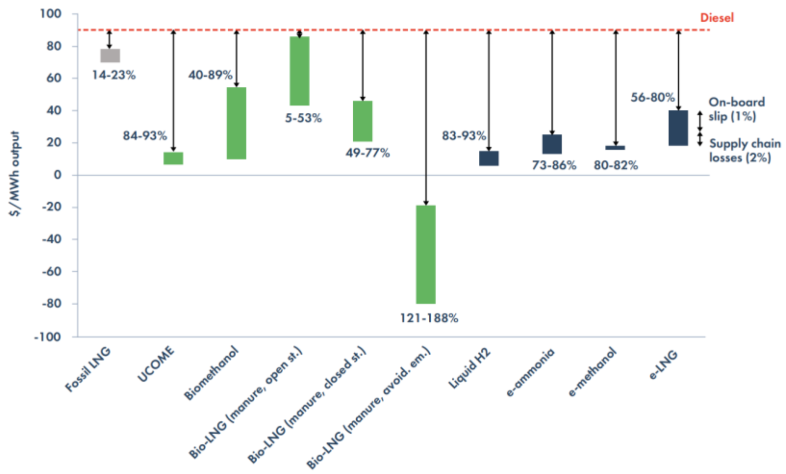
LBG from anaerobic digestion total cost range in 2020, 2030 and 2050, compared with fossil LNG bunker price (range)



Source: SEA-LNG

LBG could play a major role in the decarbonisation of shipping. LNG as a fuel is dominating the orderbook of larger ships and according to Clarkson Research - orders for LNG dual-fuel vessels total 298 or 38% of all tonnage ordered (year to date when surveyed in 2022). LBG has the potential to meet up to 3% of the total energy demand for shipping fuels in 2030 and up to 13% in 2050. LBG is among the cheapest sustainable alternative marine fuels by 2050. In general, LBG can reduce GHG emissions by up to 80% compared to marine diesel if methane leakage in the production process and on-board methane slip are minimised.

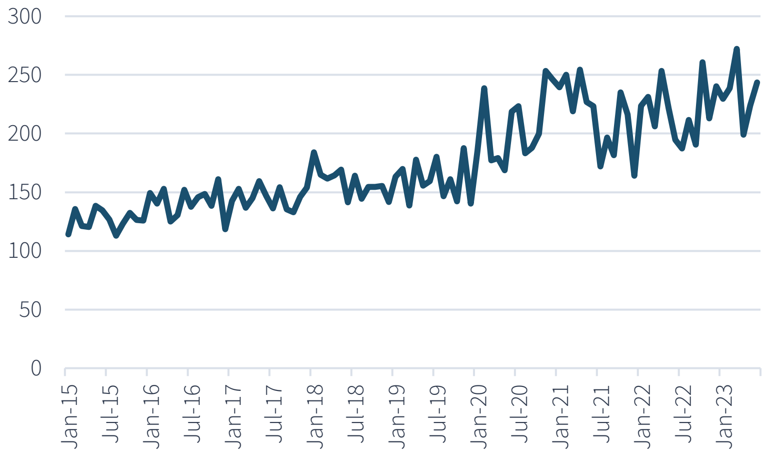
Well-to-wake GHG emissions of alternative fuels compared to diesel. Includes emissions during fuel production and onboard emissions.



Source: SEA-LNG Note: Electrofuels are produced with wind energy and their cost range is estimated for 2050.

Bio-CO_2

European CO_2 import pricing (€/t)



Source: H&Pe, Eurostat

Biogas typically consists of 60% biomethane which is used as a renewable fuel, while the remaining 40% is a natural residual product in the form of CO_2. Instead of releasing this residual CO_2 into the atmosphere, certain biogas facilities are equipped with specially designed units to recover and recycle CO_2. After being captured, CO_2 undergoes a complex purification procedure that brings the gas up to the quality level required to be food-grade.

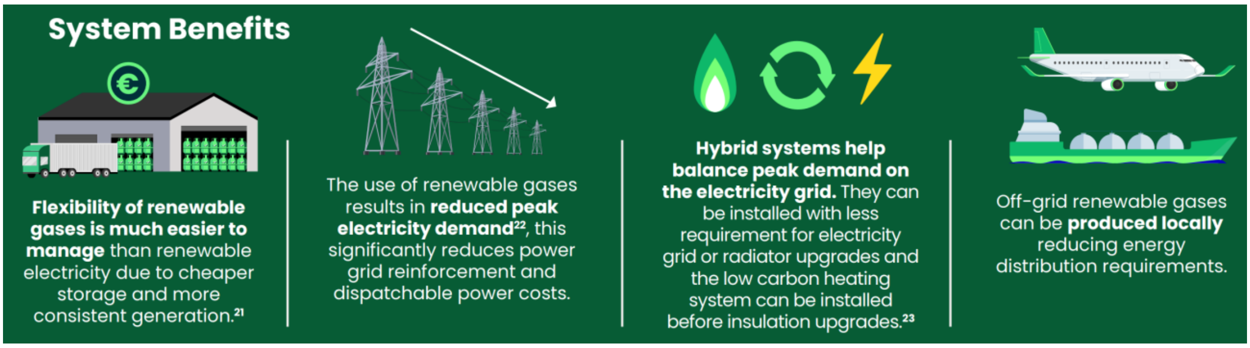
Liquid carbon dioxide is a colourless liquid produced by the cooling and compressing of gaseous carbon dioxide. It is further used to manufacture dry ice, which serves as a refrigerant or preservative for various industrial purposes. It finds primary applications in preserving food and beverages, acting as an anti-flammable liquid in fire extinguishers, and supporting industrial processes.

In 2022, the British government warned its food producers to prepare for an astounding 400% rise in carbon dioxide (CO_2) prices after extending emergency state support to avoid a poultry and meat shortage caused by ever-increasing costs of wholesale natural gas. The industry saw bought-in CO_2 prices shoot up from £300 per tonne to (in some cases) £3,000 per tonne. In mid-2022 the price of liquid CO_2 was reported at $390/t in Europe.

According to the European Biogas Association, the use of biogenic CO_2 to replace products based on CO_2 of fossil origin is included in the majority of business plans analysed. The importance of biogenic CO_2 in offsetting CO_2 of fossil origin is often underestimated, however. One of the highlighted uses of biogenic CO_2 is the production of green synthetic methane (using green hydrogen), which could add significant volumes of sustainable green gas into the energy system.

Off-Grid Renewable Gases

System benefits



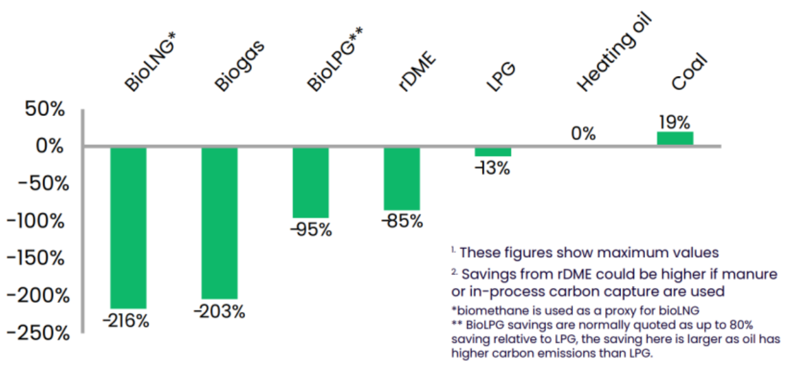
Source: EBA

One of the major advantages of using Cryo Pur's technology is the ability to produce gas that can be used in an off-grid location given that it is transportable in the form of LBG. BioLPG, Biogas, BioLNG and rDME are all examples of off-grid renewable gases that can be used in a wide range of sectors including domestic, agriculture and industry. They can be produced in a range of processes such as bio-refining, power to gas, anaerobic digestion, gasification and pyrolysis.

These gases require either no or small modifications to existing infrastructure such as boilers, CHP or engines. Keeping existing heating systems makes it convenient for consumers to opt for solutions that are increasingly renewable and lower carbon. Gas boilers which can run on renewable liquid gases are roughly a quarter of the investment cost of heat pumps and even cheaper compared to biomass boilers, making them more affordable for households and business with low levels of disposable income.

There are 49.2 million rural households in the EU and most of them are not connected to a gas grid. These buildings primarily use fossil fuels for heating, these are generally higher carbon fossil fuels.

Greenhouse Gas Emission Saving Relative to Oil



Source: EBA

Hydrogen market

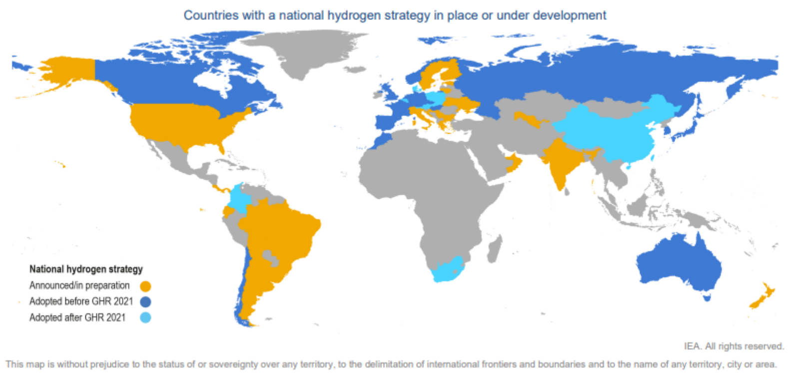
In the current landscape of energy transition, the distance to go in decarbonisation is often overwhelming, and suggests bridging this gap will take commitment across industries and countries, requiring a lot of technological advancement. Electric vehicles and wind turbines are certainly not the only answer. One of the main impacts of this transition is that the demand for certain key commodities will increase substantially, which includes hydrogen.

Low-carbon emission hydrogen is expected to see an increase in demand for two reasons. First, existing hydrogen production for use in industrial processes, such as fertiliser production, is very carbon intensive, using ~850Mtpa of CO_2 annually. The demand for hydrogen in this sector is not expected to fall; however, from a net zero standpoint, the hydrogen that goes into these processes will need to be carbon neutral, or as close to it as possible. Second, demand for hydrogen as a clean energy source in other industries, replacing high-emission energy sources such as LNG, natural gas or coal, is expected to increase substantially. Again, it would be preferable that the hydrogen used is carbon neutral – or at the very least considerably less CO_2-intensive than simply burning the fossil fuels it is replacing - as we move towards net zero emissions.

The growth of national hydrogen strategies

The drive for hydrogen to play an increasingly important role in the transition to a cleaner energy future is exemplified by the growth in national hydrogen strategies. As of YE22, 25 countries, together with the European Commission, have formulated and published national hydrogen strategies, detailing the role of hydrogen in reaching decarbonization targets, while also providing nations with greater energy security. The International Energy Agency ("IEA") has stated that an additional 20+ governments are working on their own national hydrogen strategies, setting out their visions as to how the hydrogen economy is set to develop and how they will lead progress in the sector.

Nine countries have adopted national hydrogen strategies since September 2021



Source: IEA

Hydrogen Production

There are five main ways to produce hydrogen: steam methane reforming or SMR (~75% of current production), coal gasification (~20% of production), electrolysis of water, methane pyrolysis and drilling for natural hydrogen. GHG emissions from hydrogen production are currently ~850Mtpa of CO_2 and there is a push to both lower emissions from existing production and bring on new production with low to no emissions, such as methane pyrolysis.

The physical properties of hydrogen

Property	Hydrogen	Comparison
Density (gaseous)	0.089 kg/meter^3 (0°C, 1 bar)	1/10 of natural gas
Density (liquid)	70.79 kg/meter^3 (-253°C, 1 bar)	1/6 of natural gas
Boiling point	-252.76°C (1 bar)	90°C below LNG
Energy per unit of mass (LHV)	120.1 MJ/kg	3x that of gasoline
Energy density (ambient cond., LHV)	0.01 MJ/liter	1/3 of natural gas
Specific energy (liquefied, LHV)	8.5 MJ/liter	1/3 of LNG
Flame velocity	346 centimeter/s	8x methane
Ignition range	4–77% in air by volume	6x wider than methane
Autoignition temperature	585°C	220°C for gasoline
Ignition energy	0.02 MJ	1/10 of methane

Source: IEA, Notes: LHV = lower heating value, MJ = megajoule

The key advantage of hydrogen as an energy source is that when it is used it emits no carbon dioxide. Hydrogen has the highest energy content of any common fuel by weight, but the lowest by volume. When hydrogen (H) reacts with oxygen (O), there are only two products: lots of energy and water (H_2O). This combination of high energy and zero emissions opens the door to decarbonising energy-intensive industries that are hard and/or expensive to electrify ("hard-to-abate").

Hydrogen's energy per unit of mass is 3x that of gasoline. However, due to its low density, its energy density is only 1/3 that of natural gas or LNG. As such, a larger volume is required to store an equivalent energy capacity of hydrogen. In order to reduce this volume, hydrogen can be stored as a liquid. However, this requires cooling to -253°C (90°C below that of LNG) requiring more energy. As a result, any hydrogen production technologies that can reduce the need for transport or storage are advantageous.

The major goal for future hydrogen production is to reduce the CO_2 intensity of production in a cost competitive way, as currently using fossil fuels to generate hydrogen is significantly cheaper than the greener alternatives. The hope is that new technologies will bring down the costs of low-carbon hydrogen production by lowering the cost of renewable energy, increasing the efficiency of the processes and reducing the construction and operating costs associated with newer technologies such as electrolysis or methane pyrolysis.

Government policy and support may be a positive driver of the economics, either through direct subsidies for low-carbon hydrogen production or through carbon credits/taxes. A carbon tax would increase the price of hydrogen produced from SMR or gasification, while quotas of hydrogen from renewable sources could also be introduced. A push-back on carbon capture is that it is not 100% effective, and the gas sector leaks greenhouse gas-intensive methane into the atmosphere. Other technologies, however, such as methane pyrolysis, produce a solid carbon by-product, meaning the carbon is 100% locked down and will not form CO_2.

Also, key is the reduction in the cost and method of transportation of hydrogen. Similar to the oil and gas industry, the areas with the lowest cost of production may be very different to the main areas of hydrogen demand. Hydrogen can be converted to derivatives such as ammonia, which has a higher energy density per volume than liquid hydrogen and can be stored and transported as a liquid at low pressures or in cryogenic tanks at around -33°C at 1 bar. The caveat is that the ammonia synthesis, and its subsequent dehydrogenation to release hydrogen, requires a lot of energy.

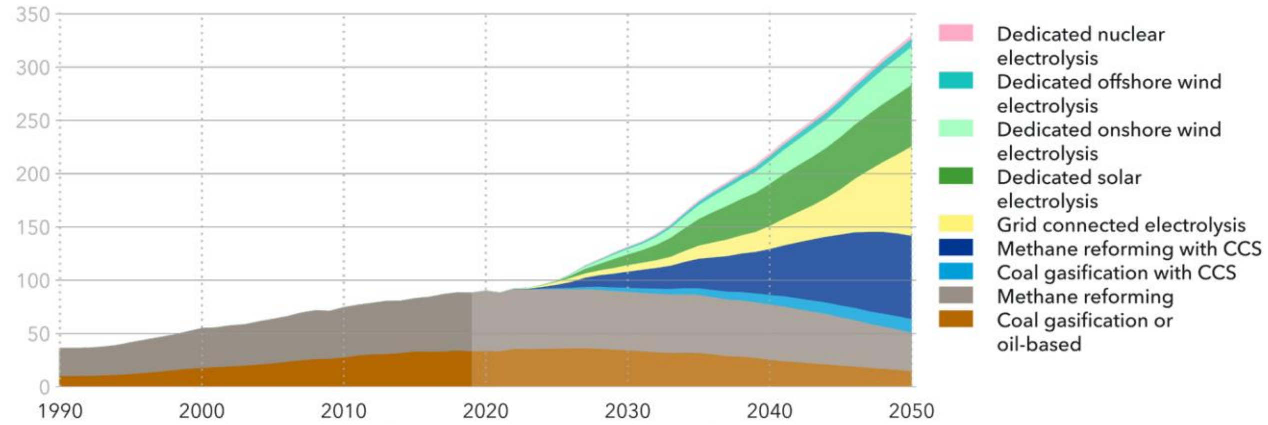
The Hydrogen Rainbow

Colour	Technology	Energy Source	GHG emissions
Black	Gasification	Black coal	High
Brown	Gasification	Brown coal	High
Grey	SMR	Natural Gas	Medium
Yellow	Electrolysis	Grid/Solar	Varies
Blue	SMR + CCS	Natural Gas	Low
Turquoise	Pyrolysis	Natural Gas	Low
Purple/pink	Electrolysis	Nuclear	Minimal
Gold/White	Drilling	None	Minimal
Green	Electrolysis	Renewable	Minimal

Source: H&Pe

The widely adopted convention for the provenance of hydrogen is the use of colours, which refer to the process of producing the hydrogen and the energy source used to produce it. The main reason for the classification is to establish the potential GHG emissions associated with the production of hydrogen. There is some debate about the nomenclature: for example, in some literature yellow hydrogen is said to be grid powered and in others said to be sourced from solar.

Global hydrogen production by production route (Mt H_2/yr)



Source: DNV

The chart above shows one forecast for the growth in hydrogen production by type. It shows strong growth in methane reforming with CCS. However, given the nascent nature of the industry and the strides being made in technological improvements, we expect the reality to be very different to what is shown in the projections. For example, methane pyrolysis is not included in the projections above, whereas we see a lot of technical and economic potential for this technology.

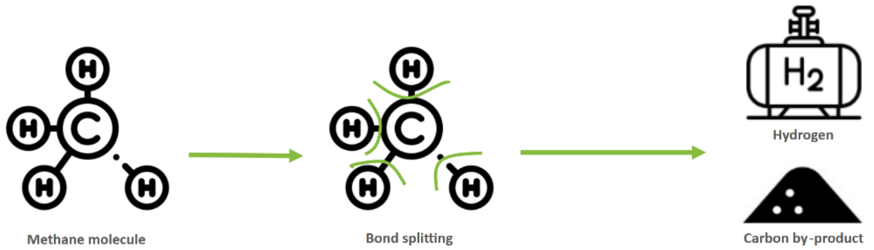
Hydrogen Production: Methane Pyrolysis

In addition to its current usage in fertilisers and petrochemicals, hydrogen has gained prominence as an "energy vector" in decarbonisation efforts, as well as a carbon substitute in "hard-to-abate" sectors such as steel. However, current production methods face multiple challenges. The most widely used process, SMR, emits high levels of CO_2, requiring carbon-capture and storage to cut emissions. Electrolysis, by contrast, is 7x more energy intensive than SMR, needing cheap renewable power to compete and be truly considered "green". Methane pyrolysis is an alternative low-emission process, applying heat in the absence of oxygen to split natural gas into hydrogen and carbon, creating a fraction of the CO_2 of SMR. It also has a logistical advantage in that the process can be co-located with the end user. This allows hydrogen molecules to be transported using existing natural gas infrastructure, whereas moving H2 over longer distances from SMR or electrolysis plants is likely to require investment in new pipelines and liquefaction facilities.

Methane Pyrolysis

Methane (CH_4) is the main constituent of natural gas and holds a large amount of energy which can be released through burning in oxygen. This produces heat, but also large amounts of carbon dioxide, which is contributing to climate warming and thus the need for an energy transition. However, when methane is heated to extreme temperatures (usually around 900°C) in the absence of oxygen (the process known as pyrolysis), it can be broken down into its constituent parts: $CH_4 \rightarrow C + 2H_2$. The lack of oxygen in the process means that the carbon does not form CO_2 and the hydrogen does not form H_2O giving out only solid carbon and two molecules of hydrogen.

Methane pyrolysis process



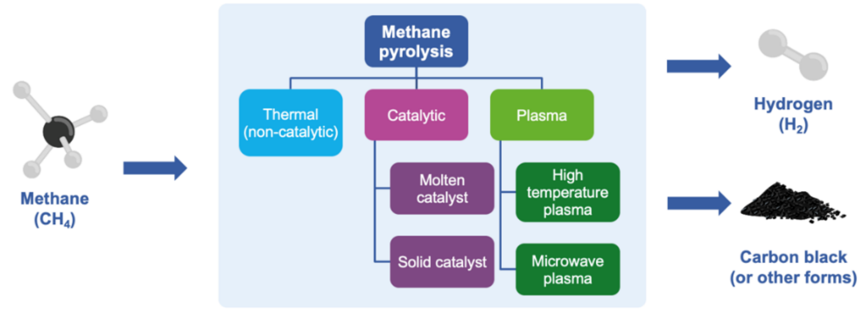
Source: Gas Pathways

Unlike other methods of hydrogen production with methane as an input, such as Steam Methane Reforming ("SMR"), the carbon produced is a solid carbon product which does not require CO_2 sequestration. This means the processing facility does not need to be built where the geology is suitable for CO_2 sequestration and can be built adjacent to the hydrogen demand. This either saves on the expensive cost of transporting the hydrogen or on the cost of converting the hydrogen to ammonia (as a way of transporting the "energy storage" more easily and at a lower cost) before converting it back to hydrogen when required.

Pyrolysis requires very high temperatures and on a pure heating basis, such as Monolith's plasma methane pyrolysis, temperatures of 2,000°C are needed, which uses a lot of energy. However, a catalyst can be used to reduce the energy required for the decomposition of the methane.

There are three ways to achieve methane pyrolysis – Catalytic, Thermal, and Plasma methane pyrolysis.

Types of methane pyrolysis



Source: Offshore Energy

Catalytic methane pyrolysis involves heating methane gas in the presence of a catalyst, like iron ore or manganese chloride. In an oxygen-free fluidised bed reactor operating at 900°C, the gas is pushed through a distributor plate, suspending fluidised iron ore catalyst. Methane molecules interact with the catalyst's surface, breaking down into nanofragments known as "dusting." Graphite accumulates on the catalyst's surface, rendering it less dense and preventing it from sinking. When using manganese chloride, the catalyst is molten through salt heating. Methane gas is bubbled through the molten column, converting it into carbon and hydrogen. Hydrogen gas is collected, and solid carbon rises with the bubbles to form a carbon layer. Notably, this process minimises catalyst coking, reducing the need for catalyst replacement.

Thermal methane pyrolysis utilises renewable electricity for heating. When gaseous LNG is used, gas flows into a vertical reactor, where carbon granules move downward at ~1,000°C. Hydrogen and unreacted gas exit from the top, while solid carbon is discharged from the bottom. An alternate method is to use renewable electricity to generate microwave energy, breaking methane into solid carbon and hydrogen. Hydrogen can be collected, and solid carbon either sequestered or utilised. This technique claims an 80% reduction in electricity consumption compared to electrolysis. Lastly, a method called pulsed methane pyrolysis can be applied where the reactor uses the principles of pulse-combustion and high-speed gas dynamics to dissociate the methane molecule, giving out hydrogen gas and solid carbon.

Plasma methane pyrolysis involves extremely high temperatures. Methane along with a process gas (which helps heat the natural gas) into a plasma reactor, heats up to ~2,000°C, breaking the bonds between the hydrogen and carbon in the methane molecules. The hydrogen and carbon are extracted out of the bottom of the vertical reactor and the carbon is further processed into carbon black.

By employing these diverse methods of methane pyrolysis, researchers and industries aim to harness the energy potential of methane while mitigating environmental impacts.

Technology comparison

Technology	Company	Input	Process	Current Scale	Future Scale
Catalytic	Hazer	Gaseous LNG or biogas	Within the oxygen free fluidised bed reactor at 900°C, the gas is forced through a distributor plate, the force of which suspends the Iron Ore catalyst which is fluidised. The methane molecules interact with the catalyst's surface and are broken down. The catalyst is broken down into nanofragments known as "dusting". Graphite accumulates on the surface of the catalyst making it less dense and free from the catalyst bed.	The CDP is under construction with first production scheduled for H2'23. Capacity will be 100tpa hydrogen and ~380tpa graphite.	FID for the Burrard project due by year end - 2,500tpa hydrogen and 9,000tpa graphitic carbon.
	C-Zero	Gaseous LNG or biogas	The catalyst, mainly manganese chloride, is salt heated until molten. The methane gas is then bubbled through the column which converts it to carbon and hydrogen. The hydrogen gas is then collected, and the solid carbon produced is carried to the top by the bubbles where it forms a layer of solid carbon. Here the carbon is not coking the catalyst, meaning less catalyst replacement is needed.	A pilot plant was expected to be online in Q1'23 producing 146tpa.	After commissioning the pilot plant, the plan is to produce a 2,190tpa commercial unit.
Thermal	BASF	Gaseous LNG or biogas	External electrical heating, ideally of a renewable source, heats the vertical reactor to 1,000 degrees Celsius. The methane flows through the bottom and carbon granules move downwards against the flow. The hydrogen and unreacted gas rise out of the top of the reactor whilst the solid carbon leaves the column from the bottom.	A pilot plant for methane pyrolysis is being built, but they are also working on the electrolyser route.	
	Aurora Hydrogen	Thermal Microwav -e	Renewable electricity is used to generate microwave energy which breaks the methane into solid carbon and hydrogen. The hydrogen can then be collected and the solid carbon either easily sequestered or used. This process claims to use 80% less electricity than electrolysis.	Plans for a 73tpa pilot plant this year.	
	Ekona Power	Pulsed Methane pyrolysis	The pulsed methane pyrolysis (PMP) reactor uses the principles of pulse-combustion and high-speed gas dynamics to dissociate feedstock methane. No carbon fouling but a solid carbon by-product for simple disposal/use.	N/A	
Plasma	HiiROC	Methane, Flare Gas, bio-methane or natural gas	Thermal Plasma Electrolysis ("TPE", technically not methane pyrolysis). Electrical fields in the plasma torches split hydrocarbons apart rather than heat them up, at a very high pressure. The carbon solid collected is carbon black used in tyres, rubbers, plastics, inks, and toners.	The prototype unit will be able to process 100m^3/hour of waste gas (flue/flash gas), which will produce more than 400kg/day of emission-free hydrogen.	

Technology	Company	Input	Process	Current Scale	Future Scale
	Monolith	Traditional or renewable natural gas or renewable biogas feedstock	Natural gas and a process gas (which helps heat the natural gas) are added to the reactor where super heating to 2,000°C breaks the bonds between the hydrogen and carbon in the methane molecules. The hydrogen and carbon are extracted out of the bottom of the vertical reactor and the carbon is further processed into carbon black.	The Olive Creek I facility produces 4ktpa of hydrogen and 13ktpa of carbon black.	The Olive Creek II facility which will produce hydrogen, ammonia, and carbon black.

Source: H&P

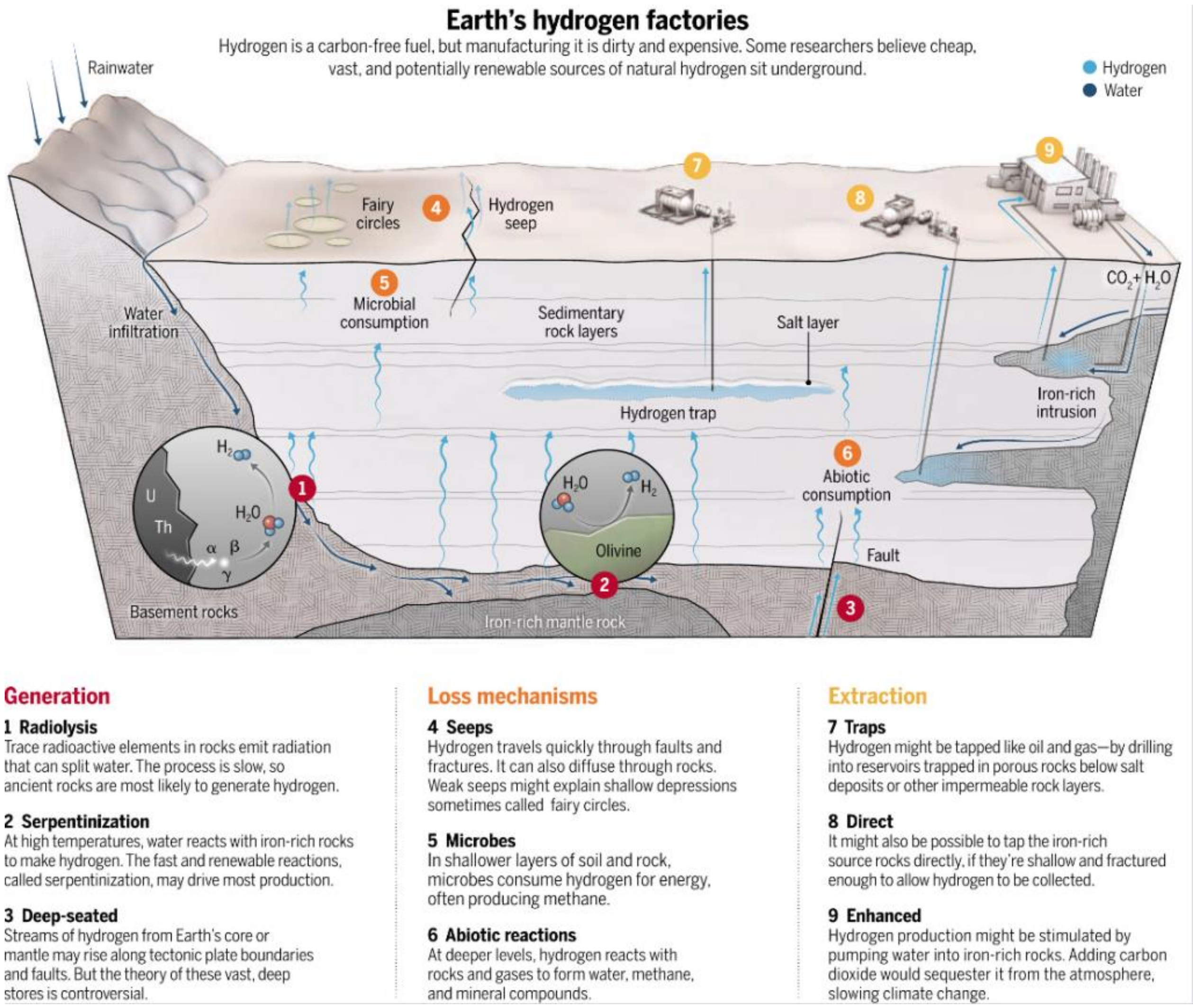
Natural Hydrogen

Hydrogen has long been viewed as a key element in the future of the energy industry and is expected to play a crucial role in the global energy transition but its scarcity in the Earth's atmosphere and its perceived lack of existence in its crust have hindered the pursuit of this clean fuel. Recently, however, exciting discoveries have shed light on the potential of natural hydrogen to disrupt the energy industry and revolutionise the way we produce and consume energy. They have shown that natural hydrogen can exist in much larger quantities in the Earth's mantle than previously thought. This form of natural hydrogen is categorised as "gold" or "white".

The geological exploration for hydrogen follows the same approach as for the hydrocarbons with the identification of the source rock, then the migration pathways, and finally of the reservoirs and traps. Since hydrogen is a very reactive molecule, it can be consumed by many oxidants, and therefore, destroyed during its migration. Bacterial growth can also be promoted by natural hydrogen, which acts as an energy provider for the microbes. Therefore, a temperature above 120°C can preserve hydrogen by eliminating microbial activity, while increasing kinetics of reactions.

Natural Hydrogen Generation

Geology and extraction of natural hydrogen



Source: Advanced Science News

Serpentinisation

One of the methods by which hydrogen is formed is through a process called "serpentinisation", which is when water reacts with iron-rich mantle rocks containing minerals like olivine and orthopyroxene to form hydrogen gas and serpentine. The reaction responsible for hydrogen production can be simplified by the reaction equation:

$2(Fe_2{+}O) + H_2O \longrightarrow (Fe_3{+})2O_3 + H_2$

In essence, the lower oxidation state of iron in the minerals olivine and orthopyroxene serves as a reducing agent that converts water to hydrogen. In the process, the iron is oxidised and turns into the mineral serpentine.

Radiolysis

Another process that forms natural hydrogen under the Earth's surface is through "radiolysis" of water, which involves splitting the water molecule with the radioactive radiation emitted by the decay of radioactive uranium (238U, 235U), thorium (232Th) or potassium (40K).

This is called an ionisation process because radiation knocks off electrons from the water molecules creating ions (an atom with an unequal number of protons and electrons). This also leads to the formation of a free radical (an atom that contains one or more unpaired electrons in its outermost orbit and is not part of a stable atom). The presence of the free radical makes the atom extremely reactive. These free radicals can include hydroxyl radicals (OH•) and hydrogen radicals (H•), among others which react with other water molecules to form molecular hydrogen (H_2) and hydroxyl radicals (OH•):

$H\bullet + H_2O \longrightarrow H_2 + OH\bullet$

This is the natural hydrogen that is generated through the radiolysis of water. The hydrogen (in gaseous form) then rises to the surface and escapes to the atmosphere unless it gets trapped, creating a reservoir.

Deep-seated hydrogen

There are other sources such as deep-seated hydrogen stored below the Earth's mantle which rises slowly in the form of hydrides that could gradually decompose and support continuous hydrogen outgassing over geologic time. Another source is through the over-maturation of organic matter which generates hydrogen. However, serpentinisation and radiolysis are the two main processes that are being researched with respect to natural hydrogen generation.

Extraction

Hydrocarbons such as oil tend to float up from the deeper rocks where they are produced until trapped in porous rocks called reservoirs. But hydrogen, on the other hand, moves upwards wherever possible and it is so mobile that it can easily slip through many rocks and escape to the atmosphere. It may only be worth recovering if there are big enough reservoirs where it has accumulated under, say, an impermeable rock layer like shale or salt.

The hydrogen can then be extracted by drilling into reservoirs formed by porous rocks below impermeable salt or rock layers. If the rocks are sufficiently thin and fractured, it may be feasible to tap them directly for the gas trapped within.

Benefits of Natural Hydrogen

Natural hydrogen presents several distinct advantages as an energy resource. It stands out for its environmental cleanliness, devoid of carbon components, and requiring no anthropogenic electricity or water input. Notably, it exists as a standalone resource, eliminating the need to trade off one energy source for another, without any dependence on external energy or specialised raw materials.

Recent research spanning global regions has identified multiple feasible opportunities for cost-effective harnessing of this resource. Furthermore, the European continent's diverse range of production sites, including France, Spain, Italy, Poland, and Romania, ensures flexibility and complements other low-carbon hydrogen production methods, enhancing energy security and averting supply fluctuations.

Unlike alternative hydrogen production methods, natural hydrogen's distinctiveness lies in its independence from purified water (green hydrogen), CO_2 storage (blue hydrogen), or waste disposal. A standout feature is its steady and uninterrupted production profile, while its cost-effectiveness, projected to outperform other production avenues, holds promise for unlocking the hydrogen economy.

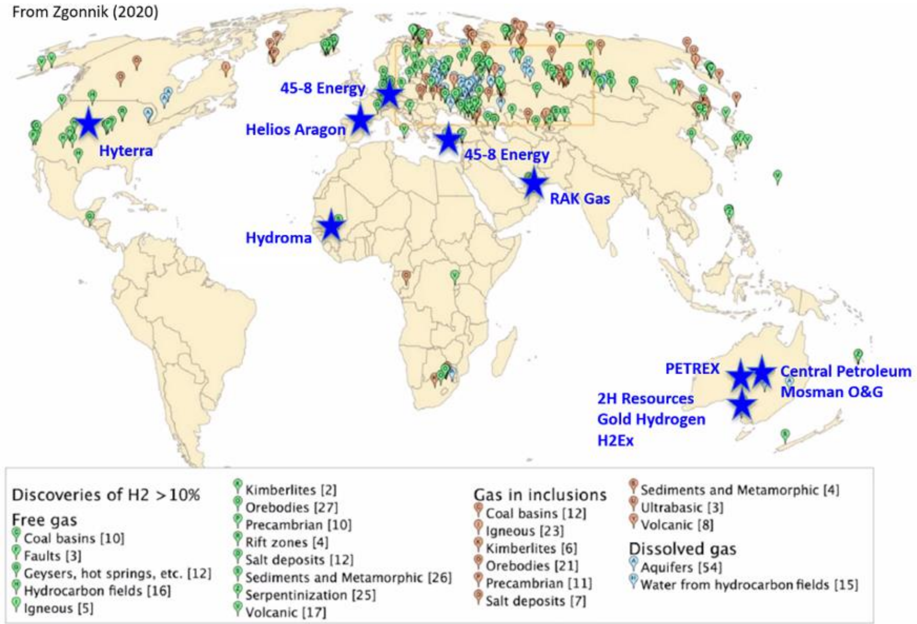
Pricing and Economics

The potential of natural hydrogen is already becoming clear. It is predicted that the selling price of natural hydrogen could be as low as US$0.5/kg, far below the cost of producing hydrogen from either fossil feedstocks or renewables which ranges between US$3/kg – US$8/kg. Hydrogen from fossil fuels is still produced at a cheaper rate than from renewables due to the lower processing costs and nascent technologies relating to hydrogen from renewables. This propels natural hydrogen to the limelight as it can be produced at a significantly cheaper level.

Furthermore, Earth creates natural hydrogen at a much faster rate than it produces hydrocarbon fuels. Based on the resource structure, it is also possible that hydrogen could be continuously produced through serpentinisation. If there is a constant stream of basement water that flows over olivine, the resource size would remain constant (or even grow).

Market Players

Global natural hydrogen exploration activities



Source: RISC Advisory

Natural hydrogen is an emerging play so only a handful of companies have engaged the opportunity. However, natural hydrogen can be traced back to 1987 when a failed water drilling attempt accidently discovered hydrogen in the village of Bourakébougou in western Mali. The well was quickly plugged and forgotten. But almost 20 years later, drillers on the hunt for fossil fuels confirmed the accidental discovery: hundreds of feet below the arid earth of west Africa lies an abundance of naturally occurring hydrogen. Today, it is used to generate green electricity for Bourakébougou by Hydroma.

But geologists believe that untapped reservoirs of white hydrogen in the US, Australia and parts of Europe have the potential to provide the world with clean energy on a far greater scale.

There are a few notable efforts being made into natural hydrogen production. FDE has discovered significant concentrations of natural hydrogen in one of the wells previously drilled in Eastern France. The next measurement campaigns planned by FDE will make it possible to assess more precisely the potential for exploiting this strategic resource and the company is currently evaluating the feasibility of production.

Natural hydrogen could be developed together with geothermal power plants which would enhance their value chains as well by co-producing natural H_2 and mineral substances like lithium, with thermal energy. Coupling hydrogen production with the storage of CO_2 in ultrabasic rocks will also add additional benefits to natural hydrogen production.

Natural hydrogen may play a major role in the future of the energy industry. Its potential to reduce costs, emissions, and energy intensity could make it a game changer for the energy sector, in our view.

Financial Summary (EUR)

Operational data	2023E	2024E	2025E	2026E	2027E	2028E
Price Assumptions						
TTF (€/MWh)	50	50	50	35	35	35
Electricity (€/MWh)	150	150	150	125	125	125
Wallonia Green Certificate (€/certificate)	0	0	0	0	0	0
Solar (€/MWh)	70	70	70	70	70	70
Liquid CO_2 (€/t)	175	175	175	175	175	175
LBG (€/t)	2159	2159	2159	2159	2159	2159
Biogas input (€/MWh)	35	35	35	35	35	35
Natural H2 (€/t)	2.3	2.3	2.3	2.3	2.3	2.3
CryoPur						
Total LBG production (kt/y)	0	0	2	9	18	27
Total LBG production (mmcf/y)	0	0	109	416	852	1,284
Total liquid CO_2 production (kt/y)	0	0	4	16	33	50
Total Production (kt/y)	0	0	7	25	51	77
AMM						
Total number of CHPs in operations	15	19	30	39	39	39
Installed capacity (MW)	23	28.5	45	58.5	58.5	58.5
Total electricity produced (GWh/y)	145	204	285	412	482	482
Total gas production (bcf)	2	2.6	3.3	4.4	5.0	5.0
Lorraine CBM						
Gas production (mmcf/y)	0	0	0	4,070	6,894	9,165
Gas production (TWh/y)	0	0	0	1.2	2.0	2.6
Solar						
Cumulative capacity installed (MW)	15	15	42	71	100	100
Energy produced for the year (GWh/y)	8	16	46	78	110	110

Income statement (€ mm)	2023E	2024E	2025E	2026E	2027E	2028E
Lorraine CBM	0	0	0	29	49	66
Cryo Pur	1	1	7	23	46	68
AMM	35	50	56	59	67	68
Solar	1	2	4	6	9	9
Revenue	**37**	**53**	**66**	**118**	**171**	**210**
Other income	1	0	0	0	0	0
Total revenue	**38**	**53**	**66**	**118**	**171**	**210**
Lorraine CBM	0	0	-1	-6	-10	-13
Cryo Pur	0	-1	-2	-8	-17	-25
AMM	-4	-5	-7	-10	-11	-11
Solar	0	0	-1	-2	-2	-2
Opex	**-5**	**-6**	**-11**	**-25**	**-40**	**-51**
Other costs	-8	-8	-8	-8	-8	-8
Lorraine CBM	0	0	-1	23	40	53
Cryo Pur	1	1	5	15	29	43
AMM	30	45	49	50	56	57
Solar	1	2	3	5	6	6
EBITDA	**25**	**39**	**47**	**84**	**124**	**152**
Depreciation	-9	-3	-7	-35	-55	-32
EBIT	**16**	**36**	**40**	**50**	**69**	**120**
Net financial costs	-2	-2	-3	-4	-4	-4
Profit Before Tax	**14**	**34**	**38**	**46**	**64**	**116**
Tax	-4	-9	-9	-11	-16	-29
Net profit	**10**	**26**	**28**	**34**	**48**	**87**

Earnings per share	2023E	2024E	2025E	2026E	2027E	2028E
Shares outstanding	5,182,604	5,182,604	5,182,604	5,182,604	5,182,604	5,182,604
Earnings per share	2.00	4.94	5.46	6.62	9.33	16.79
Growth	*44%*	*146%*	*10%*	*21%*	*41%*	*80%*

Cashflow (€ mm)	2023E	2024E	2025E	2026E	2027E	2028E
Net Income	**10**	**26**	**28**	**34**	**48**	**87**
Income tax expense	4	9	9	11	16	29
Income tax paid	-2	-9	-9	-11	-16	-29
Depreciation	9	3	7	35	55	32
Non-cash adjustments	3	3	3	3	3	3
Cash Flow (pre-working capital)	**25**	**31**	**38**	**72**	**106**	**122**
Changes in Working Capital	-6	0	0	0	0	0
Cash Flow from Operations	**19**	**31**	**38**	**72**	**106**	**122**
Capex	-7	-37	-108	-104	-84	-72
Other investing activities	-1	0	0	0	0	0
Free Cash Flow	**11**	**-6**	**-70**	**-32**	**22**	**49**
Debt and other financing payments	-1	-3	-3	-3	-3	-3
Increase in cash	**9**	**-9**	**-73**	**-35**	**19**	**46**

Balance Sheet (€ mm)	2023E	2024E	2025E	2026E	2027E	2028E
Exploration assets	39	39	39	39	39	39
Intangible assets	30	30	30	30	30	30
Tangible assets	34	68	169	238	267	308
Non-current financial assets	2	2	2	2	2	2
Deferred tax assets	2	2	2	2	2	2
Total non-current assets	**106**	**141**	**242**	**311**	**340**	**381**
Stocks	0	0	0	0	0	0
Trade receivables and related accounts	11	11	11	11	11	11
Other current assets	4	4	4	4	4	4
Prepaid and deferred expenses	0	0	0	0	0	0
Cash and cash equivalents	34	26	-47	-82	-63	-16
Total current assets	**50**	**41**	**-31**	**-66**	**-47**	**-1**
Total assets	**157**	**182**	**210**	**245**	**293**	**380**
Capital and reserves	31	31	31	31	31	31
Premium	44	70	98	132	181	268
Non-controlling interests	-0	-0	-0	-0	-0	-0
Equity capital of the consolidated group	**74**	**100**	**128**	**163**	**211**	**298**
Non-current financial debt	44	44	44	44	44	44
Non-current provisions	3	3	3	3	3	3
Deferred tax liabilities	7	7	7	7	7	7
Other non-current liabilities	1	1	1	1	1	1
Total non-current liabilities	**55**	**55**	**55**	**55**	**55**	**55**
Current financial debt	13	13	13	13	13	13
Current provisions	0	0	0	0	0	0
Trade payables and related accounts	4	4	4	4	4	4
Fixed assets suppliers	3	3	3	3	3	3
Other current liabilities	7	7	7	7	7	7
Current liabilities	**27**	**27**	**27**	**27**	**27**	**27**
Total equity capital and liabilities	**157**	**182**	**210**	**245**	**293**	**380**

Source: H&Pe

Management Overview

FDE's management team has both strong global energy sector expertise as well as significant financial markets experience. There is a mix of scientific, financial and technical background with project management and capital markets expertise. The CEO and CFO have both worked within energy companies and the CFO and Chairman both worked in the financial sector. We see this as important both to be able to run the company with deep technical expertise, whilst having the financial acumen and market understanding to pursue the right commercial options. The three senior members of the team have worked internationally, are all French-English citizens and French Canadian, helping to navigate the complex politics and regulations in their core market but also helping to deal with the global complexities that shape energy markets. The non-executive directors provide further support from the banking sector as well as Government experience. A climate related performance criteria has been added to the group incentive plan.

Board of Directors & Key Management

Name	Profile
Julien Moulin Executive Chairman	• Mr. Julien Moulin is Executive Chairman of FDE and former CEO at FDE until 2022 • In May 2002 to September 2003, Mr. Julien Moulin served as an Investment Analyst at UBS Global Asset Management. • From September 2003 to June 2004, he held the position of Investment Manager at SKI Capital. • In 2005, Mr. Moulin co-founded Maoming Investment Manager Ltd. and has been its Managing Partner till 2016. • From 2007 ill 2012, he was Vice-Chairman of the Board of Envision Energy, a leading wind farm manufacturer in China • Mr. Moulin holds a BA in Economics and Business Sciences from Sorbonne University and a Master's Degree in Asset Management and Financial Markets from the University of Paris-Dauphine.
Antoine Forcinal CEO and Executive Director	• Mr. Antoine Forcinal is Chief Executive Officer of FDE since 2022. He was Deputy CEO until 2022 and served as COO since joining the Company November 2015. He is also Executive Director of FDE. • Prior to FDE, Mr. Forcinal has worked as an Engineer and Technical Manager for several firms. He has been a Petroleum Engineer with Perenco UK, Reservoir Engineer and Manager with Foxtrot International, and a Technical Manager with Investcan Energy and Quebenergie. • Mr. Forcinal received a Master's Degree in Petroleum Engineering from Imperial College London in 2006.
Aurelie Tan Chief Financial Officer	• Aurelie Tan is the Chief Financial Officer of FDE and previously was its Director of Administrator & Finance since June 2020[6] until 2022. • Ms. Tan possesses diverse expertise in banking within the energy industry. Prior to FDE, she was the Executive Director at Natixis as an Energy Industry banker in Paris. • She has also held senior positions at Seplat Energy as the Head of Corporate Finance and Director at the Standard Bank Group in the Energy Finance and Debt Advisory team. • Ms. Tan holds a Master's in Banking and Finance from the Université Paris Dauphine.

[6] Changed from "October 2020".

Name	Profile
Christophe Charlier Independent Director	• Mr. Christophe François Charlier serves as an Independent Director at FDE. • From 1998 to 2002, Mr. Charlier served as Vice President at LV Finance. During this time, he worked in the Investment Banking Group of Renaissance Capital and in the mergers and acquisitions Group of JP Morgan. • Following his tenure at LV Finance, Mr. Charlier served as Director of Strategic Development and Mergers and Acquisitions at MMC Norilsk Nickel from 2002 to 2004. • Starting in September 2008, Mr. Charlier took on the role of Deputy Chief Executive Officer at The ONEXIM Group. • From November 2012 to June 2014, he held the position of Non-Executive Director at United Company RUSAL PLC. • Mr. Charlier then moved on to become Deputy General Director of Quadra - Power Generation. • In 2010, he served as a Director at RBC. • From April 2017 until 2020, Mr. Charlier held the positions of Chairman and Director at Renaissance Capital Limited. • In September 2021, he became a Director at Tingo, Inc., and later took on the role of Co-Chairman, which he held until April 2023. • Mr. Charlier holds a B.S.E. with a major in Finance, cum laude from the Wharton School of Business of the University of Pennsylvania and a B.A. in International Relations from the College of Arts & Sciences of the University of Pennsylvania in 1994.
Alain Ligier Independent Director	• Mr. Alain Ligier serves as an Independent Director of FDE. • Mr. Ligier served as the Regional Director and Representative of the Ministry of Industry in Alsace and the Ministry of Environment in Lorraine from 2002 to 2013. • He held senior operational, managerial and advisory positions in the international mining industry, such as BHP Billiton for 4 years and the state-owned French mining group BRGM for 17 years. • He has a high-level of experience regarding the development of mineral resources. • From 2013 to 2016, he was a Key Member of the Mining Commission for the Ministries of economic and finance. • He graduated from the Mines ParisTech.

Source: Capital IQ and LinkedIn

Company History

2006

- FDE began its exploration activities in Lorraine to capture and produce coal gas /drilling of the Diebling and Folschviller wells.

2013

- Drilling of Tritteling well (Lorraine).

2015

- First certification of the group's gas reserves by Beicip Franlab (IFP Energies Nouvelles).

2016

- FDE's initial public offering.
- Acquisition of Gazonor, specialised in capturing and producing AMM in Hauts-de-France.
- Drilling of Lachambre well.

2017

- January: FDE achieved first drilling goal - CBR-1 well, Moselle, confirmed its first target located at a depth of 1,080 meters.
- February: FDE achieved second drilling goal - CBR-1 well, confirmed its target located at a depth of 1,178 meters and constituting a 7m coal seam.
- May: FDE subsidiary, Gazonor, installed four plants each to produce 1.5 MW of power.
- June: First production of green electricity in Hauts-de-France.

2018

- January: FDE secures €3mm financing from CAP 3RI for Gazonor.
- May: FDE obtains further financing of €6.4mm from Bpifrance Financement and SaarLB to support the production of green electricity.
- May: FDE obtains government approval for exploration on the Anderlues site (coal mining gallery) in Belgium.
- October: FDE renewed its gas supply from Total Gas & Power and installed its first plant on its Avion site.
- October: Gazonor begins production tests at the Anderlues site in Belgium after mobilising a test station.
- November: FDE files a concession request for exclusive gas production rights from the Lorraine basin until 2040.
- December: FDE reports significant increase in gas reserves in Moselle with 1P reserves at 1.78 bcm (62.9 bcf) which is 122% higher than 2016 estimates.
- December: Startup of the Siemens plant with a 60% higher production capacity than the previously used motors at the Avion site.

2019

- March: FDE installs first cogeneration engine on the Anderlues site to produce green electricity from gas captured at Wallonia mines.
- April: FDE confirms 2P gas reserves of 277 mmcm (9.8 bcf) in Belgium and inaugurates the Anderlues site.
- July: FDE launches second test campaign in the Valenciennes area, made up of 6 tests and enabling FDE to develop more green electricity production sites.
- October: FDE receives new financing of €1.34mm from Bpifrance Financement.
- November: €2.8mm subsidy granted to Gazonor for its “Zéro Emission Gazonor 2022” plan.
- November: FDE partners with Total Quadran to jointly develop green electricity production based on solar energy in the Hauts -de-France and the Great East.
- December: Gazonor receives €4.2mm loan from Triodos bank for refinancing its green electricity production facilities in Anderlues in Belgium.

2020

- January: FDE entered a contract with Lendosphere to set initial crowdfunding target of €2.25mm for Phase 1 of the Gazonor Béthune project.
- February: FDE launches the largest thermal solar power plant in France in the Creutzwald region.
- August: FDE signs 3-year framework agreement with 2G Energietechnik for cogeneration units in France and Belgium.
- November: FDE wins 15 MW solar project in France's latest tender.
- December: FDE achieves €1.5mm committed capital in its crowdfunding campaign with Lendosphere, which has a target of €2.25mm.

2021

- January: FDE exceeds fundraising target for Gazonor Béthune project; launches second crowdfunding phase.
- January: FDE secures extension of Désirée Concession in Hauts de France mining basin.
- February: FDE Raises €5.5mm in record time through its crowdfunding campaign. The financing was raised by Gazonor to support the Gazonor Béthune project.
- February: FDE acquires Greenhill SA, a subsidiary of the Brederode SA, holder of the Monceau-Fontaine, Marcinelle and North Charleroi Concession, for €95k to expand its presence in the Walloon mining basin.
- March: FDE successfully delivers heat to Béthune site from mine gas, powering urban heating network.

- **June**: FDE and Lendosphere close €3.3mm crowdfunding campaign for cogeneration units construction.
- **August**: FDE completes €2.5mm crowdfunding for the pre-construction of a photovoltaic plant in Tritteling-Redlach, in Moselle.
- **September**: FDE announced 29% increase in 2P gas reserves in Anderlues Concession to 358 mmcm (12.6 bcf).
- **September**: FDE raises €40mm its first green bond issue. The bond has a committed first tranche of €25mm and an optional second tranche of €15mm.

2022

- **January**: FDE attained new 2P abandoned mine gas reserve certification of 3.6 bcf held in the Hauts-de-France's region. FDE also commissioned 3 additional cogeneration units at its Anderlues site, in Wallonia.
- **February**: FDE's abandoned mine methane activity enters the Greenfin France green finance label.
- **March**: FDE's abandoned mine gas recovery achieves GHG emissions reduction of 808 kt of CO_2 eq/y.
- **April**: FDE acquires Cryo Pur, a leading player in the production of liquefied biogas (LBG) and bio-CO_2.
- **October:** FDE secures a new €20mm green bond for the development of its low carbon energy solutions in Europe.

2023

- **April**: FDE buys back 0.1% of its share issued (51,282) via its buy-back programme.
- **May**: FDE buys back further 0.63% of its share issued (32,718) via its buy-back programme.
- **May**: FDE discovers natural hydrogen in the Lorraine mining basin.
- **July**: FDE and HECO_2 consortium dedicated to clean hydrogen production by Plasmalyse technology, selected by the government of Wallonia.
- **July**: Record FY 2023 revenues reaching €39.2 million (+50% yoy), FY 2026 objectives confirmed; progress on additional growth opportunities.
- **September**: FDE plans to further its biogas and bio-CO_2 business in the Scandinavian region through its Norwegian subsidiary, Biogy Solutions AS.

Investment Risks

Other than the usual risks facing energy companies (e.g. COVID-19, security, geopolitical, geological, ESG, cybersecurity and health & safety risks), the main specific risks that we see facing FDE and how they are mitigated are described below:

Non-compliance – FDE operates its industrial facilities under strict environmental regulations, adhering to French laws derived from European directives. Regulatory oversight is provided by Prefects and the Directorates of Environment, Development, and Housing (DEAL), who inspect the installations. Non-compliance could result in administrative penalties or even the suspension or closure of operations by the Prefects, with potential involvement of the Council of State.

Price – In general, lower gas and electricity prices have a negative effect on the FDE's results due to the decline in revenue generated by production. In addition to the negative effect on the Group's revenue, margins and profitability, an extended period with low natural-gas prices may lead it to review its development plans, make downward adjustments to its reserves. The Company has market price sales contracts for most of its electricity, gas and heat production and has introduced gas and electricity price hedges for part of its production which is subject to market prices.

Reserves – Numerous uncertainties exist in estimating quantities of gas reserves and resources as well as net cash flows of the Group's proved reserves. The estimates set forth herein are based on various assumptions, which may ultimately prove to be inaccurate. The determination of such data is a subjective process of estimating underground accumulations of gas that cannot be measured in an exact manner. The history of reserve certifications demonstrates the conservative nature of the reserve volumes certified by FDE, since each new certification has indicated an increase in gas reserves, despite the volumes produced.

Competition - The Group operates in a demanding international business environment where there is competition among Recovered and Renewable Energy producers. The Group is a young company engaged in energy production and may be exposed to strong competition from larger, well-established energy companies. The Group's entire activity is protected by exclusive long-term permits or licences which have already been subjected to competitive bidding.

Acquisition integration – The integration of a strategically important asset or company into the Group might not yield the anticipated results. FDE has undertaken and might need to undertake acquisition operations across different energy sectors and with companies of diverse scales in Europe. In 2021, it acquired Greenhill SA, which possesses assets in Belgium. The challenges associated with acquisitions are multifaceted (including synergies, governance, operational approach, key personnel, availability of FDE teams, etc.) and necessitate tailored adjustments for each specific case.

Counterparty– Given the strength of its clients in France and Belgium, FDE has little exposure to counterparty risk regarding its client accounts. As part of the mine-gas business in France, the Group sells the electricity it produces under long-term contracts concluded with EDF OA in France under a purchase obligation. For the rest of its business, the Group has concluded contracts for the sale of its electricity, gas and heat with major commercial companies and leading local authorities. Each partner's performance is assessed annually using a multi-criteria framework. Partners considered crucial undergo the execution of specialised action plans, aimed at preventing any deviation from the Group's performance benchmarks.

Human Resource – FDE's success relies heavily on its experienced management team and senior managers in the energy sector, who have established and developed its activities. The departure of key employees could adversely affect the Group, as their expertise is crucial for daily operations. The Group's ability to retain and replace these individuals quickly is pivotal to avoid major disruptions. Additionally, attracting and retaining qualified staff is essential for technical and engineering services, such as in coal-bed methane development. Challenges in retaining specialized personnel could lead to higher costs and hinder development progress. The implementation of a profit-sharing plan for all Group employees contributes to the stability of qualified staff. Management also dedicates a significant part of its time to looking for talent and to the individual development of each employee, to support the Group's growth sustainably.

Industrial and environmental-damage - The operation of energy production plants, especially combustion plants, carries the risk of industrial accidents, potentially leading to production interruptions or even complete installation destruction. The Group faces fire and explosion hazards at its installations. While insurance coverage may apply to damages within the program's scope, incidents could also result in harm to individuals, property, or the environment, leading to compensation claims or legal actions against the Group. The Group has set up procedures to minimize the risk of such incidents occurring and to reduce their potential impacts on people, property and the environment.

Climate – Given the nature of some of its activities, the Group is exposed to risks related to climatic conditions. The Group's solar business is particularly vulnerable to the risk of a prolonged decrease in sunshine, which could affect its results. This uncertainty is considered starting at the preliminary design studies. In-depth impact studies are conducted within operational authorisation applications to anticipate and address these risks. Concerning climate change, the Group's strategy aims to decrease the carbon footprint of energy consumption in the regions where FDE operates. It's noteworthy that FDE currently stands among the rare energy producers in Europe with a negative carbon footprint.

Changing regulatory and public-policy environment – FDE's operations are subject to strict regulations encompassing environmental, social, and fiscal aspects. Changes in the regulatory environment could lead to substantial investments for compliance, potentially affecting profitability. Negative alterations in regulations for tariffs in electricity sales from abandoned mine methane or photovoltaics, or tax changes, might impact current and upcoming activities. Unfavourable shifts in public policies, particularly those related to climate change, could also hinder the Group's strategic execution. Despite this, the Group's primary low-carbon activity aligns with carbon-footprint reduction objectives, and favourable electricity price trends in France and Belgium indicate growing competitiveness of low-carbon energy assets without heavy reliance on regulatory mechanisms.

Litigation – There is the potential for legal disputes, including administrative, tax, judicial, or arbitral proceedings. Such cases might arise from contractual breaches, failure to adhere to laws or regulations, third-party appeals against permits, or incidents causing injury or property damage. FDE manages this risk by adhering to ISO 9001 standards, strict compliance policies, continuous monitoring of legal changes, and securing contractual documents. If necessary, provisions related to ongoing litigation are recognized, reflecting the potential adverse financial impact.

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