ARCTIC GAS:
TOO LITTLE, TOO LATE

How fossil fuel reliance weakens Europe's energy security, and why Arctic gas is not the solution.

WWF-US / Elisabeth Kruger

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How fossil fuel reliance weakens Europe's energy security, and why Arctic gas is not the solution.

Against the backdrop of another fossil fuel crisis, 2026 has shown that future energy security will depend on domestic, homegrown and renewable energy production. Limiting emissions is no longer a hindrance to energy security, it is the way towards it. To make this fossil fuel crisis the last one, the EU must plan and carry out both short and long-term measures to build robust and resilient energy systems. The strategic decisions made in the upcoming revision of the Arctic Policy is important for exactly that.

The EU faces pressure to soften its stance on oil and gas extracted in the Arctic. Doing so would risk endangering vulnerable Arctic ecosystems and creating a new geopolitical vulnerability, including greater dependence on expensive and exposed infrastructure in a high-risk area, while only receiving small amounts of gas in return. This report explores how Arctic gas will be too little, too late. To bolster energy security, the EU must instead reaffirm its commitment to reduce emissions by 90% by 2040 and strengthen its stance against new Arctic oil and gas.

Key findings:

- The potential for more Arctic gas is extremely limited towards 2050, due to long lead times, lack of infrastructure, and small amounts of resources.
- Only 1.4% of the EU's gas imports currently comes from the Norwegian Arctic, and that is unlikely to change.
- Continued fossil fuel reliance means being at risk of new energy shocks, as well as pushing exploration and development of fossil fuels into vulnerable and risk-filled areas and locking in CO_2 emissions way beyond 2050.
- The 2026 fossil fuel crisis has as of September cost EU countries €90 bn in additional fossil fuel import costs.
- €16 bn has been spent on alleviating high energy prices as of June, of which only €1-2.5 bn has been spent towards energy measures such as electrification, efficiency, and more renewable energy.
- Electrification and more renewable energy have made 2026 less expensive than 2022, but the EU is still structurally dependent on fossil fuel imports, and thus still vulnerable.

EXECUTIVE SUMMARY

The story of energy markets in the 2020s is a story of shocks and disruptions. The last decade's fossil fuel chaos has shed a light on a new side to the necessity of an acceleration to a renewable energy system, namely energy security and independence.

As the EU is stalling on decreasing fossil fuel imports, supplier countries are aggressively pushing for expansion into more vulnerable, remote, costly and unsafe areas, such as the Arctic, while price volatility remains unavoidable regardless of supplier reliability.

In the lead up to the revision of the EU Arctic Policy, intense efforts have been made by industry, interest groups and governments from fossil fuel producer countries to frame Arctic oil and gas as a quick and safe source of energy. This could not be further from the truth.

The challenges from lack of infrastructure, volumes of available resources, as well as high north security concerns are too serious to aid Europe in any capacity before 2040, the same time as when the EU have committed to reduce emissions by 90%.

Barring exceptional exploration outcomes, as timelines, Arctic gas cannot help alleviate European demand. To do that, huge infrastructure investment would be required, large resources would need to be discovered, and fields would have to be built in record times. There is nothing in current exploration plans or trends that indicate this is a probable future.

The only gas export solution from the Barents Sea is operating at capacity until the mid-2040s. As of the publication of this report, current discovered resources are not sufficient to merit a pipeline to increase exports.

Even with further discoveries and accelerated infrastructure development, our analysis shows that Arctic gas remains too little, too late.

Therefore, the EU should honour its commitment to work towards a multilateral legal obligation not to allow any further hydrocarbon reserve development in the Arctic or contiguous regions, and commit to not purchase such hydrocarbons if they were to be produced.

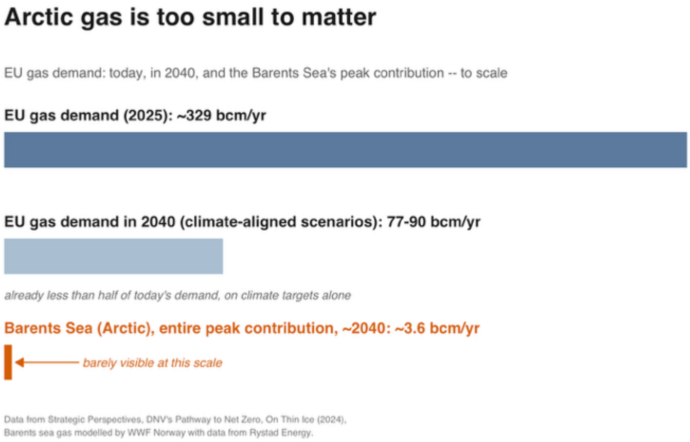

Figure 1.1

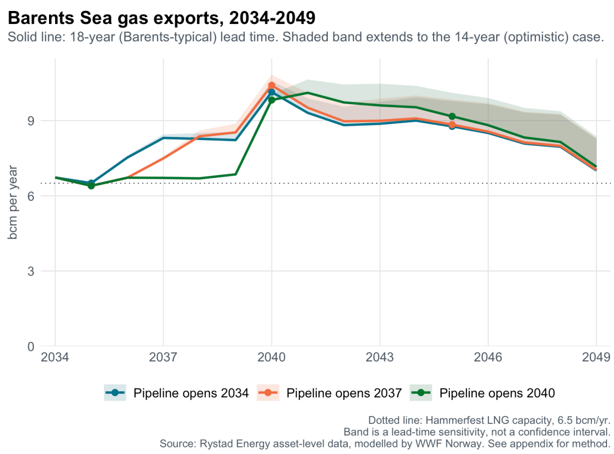

Figure 1.2

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THE COST OF THE EU'S FOSSIL FUEL RELIANCE

Cost of the 2026 Hormuz closure

In 2023 oil and fossil gas accounted for about 37.4% and 19.7% of the EU's final energy use[1]. The crises of 2022 and 2026 have shown that there still is a long way to go to make the energy systems more robust and resilient and reduce emissions in line with the European Commission's targets and the temperature caps agreed on in the Paris Agreement.

This chapter will look at the cost of the 2026 and 2022 crises, both in terms of the premium paid for energy, the cost of the fiscal response to alleviate high prices, and the broader macroeconomic effects, as well as considering the cost and consequences of extreme heat and weather events in the same time span.

The two crises compared

	2022 - Russian gas crisis	2026 - Hormuz closure
Trigger	Russian supply cuts from autumn 2021; invasion of Ukraine, February 2022	Closure of the Strait of Hormuz, 28 February 2026
Peak gas price (TTF)	~EUR 350/MWh	EUR 60/MWh in March; EUR 82/MWh in September
Average gas price	EUR 121/MWh (2022)	EUR 47.7/MWh (2026, projected)
Peak oil price (Brent)	~USD 128/bbl	USD 126/bbl
Fossil fuel import premium	EUR 930bn (2021-24)	EUR 90bn to September, from EUR 46bn in June
Fiscal response	3.2% of EU GDP per year (2022-23)	EUR 16bn to June, around 0.1% of GDP
Of which poorly targeted	~75% untargeted or price-distorting	86% increases fossil consumption incentives
Of which electrification	-	EUR 1-2.5bn, under 5% of the total bill
Household impact	8.5% consumption loss	~EUR 375 per household
Macroeconomic effect	Cumulative -2.4pp of GDP over five quarters	2026 growth revised down 0.3pp to 0.9%; inflation up 0.7pp to 2.6%

Ember; Bruegel; Jacques Delors Institute; CREA; ECB; Intereconomics; European Commission, State of the Union, 16 September 2026.

Table 2.1

The International Energy Agency (IEA) deemed the current closure of the Strait of Hormuz as the largest supply disruption in history[2]. Although EU countries source comparatively small amounts of oil and LNG from inside the strait, 6.2% and 8.7% respectively, the impact on prices are felt across Europe.

Brent, the benchmark oil price most relevant to the EU, spiked to a high of $126/bbl[3] against a pre-conflict level of around $70. In the summer months, Brent has been sitting at $80-$100.

Gas prices surged, with the Dutch TTF, Europe's main wholesale gas price benchmark, reaching €60/MWh shortly after the outbreak of the conflict, double the pre-conflict price. Towards the summer, prices calmed before increasing towards record levels again, with September prices climbing over €82/MWh and still rising[4].

[1] Eurostat, Energy statistics – an overview, Statistics Explained, May 2025.
[2] IEA - Key facts on the Strait of Hormuz, oil and gas markets, and the IEA's response, 2026
[3] IEA - Oil Market Report, April 2026
[4] Trading Economics, EU Natural gas (sourced sept. 2026)

It is not just crude and natural gas volumes that is flowing through the strait, but also a sizeable portion of refined products. While some amounts of crude have been able to use other transportation routes, Middle Eastern refineries are not capable of doing the same. Since the disruption, diesel, gasoil and jet fuel have seen price increases upwards of 170% at the April peak[5]. In September, European Diesel cracks climbed over $100 for the first time[6].

As of June, the fossil fuel surcharge, which is the premium paid on oil, gas and its derivatives compared to pre-conflict levels, is estimated at €46 billion, per Jacques Delors Institute[7]. A more recent number from the Centre for Research on Energy and Clean Air (CREA) puts the gross extra costs for fossil fuels at €67 bn excluding pipeline gas[8], meaning the actual costs are substantially higher. Considering the strait is yet to see a long-lasting opening, with rising prices after the summer, the cost is only expected to increase. In her State of the Union address on September 16th, Ursula von der Leyen stated that the fossil fuel premium sits at €90 bn.

2026 costs and fiscal response

For 2026, EU GDP growth is expected to decrease by between 0.3 and 0.7 percentage points (pp), compared to the forecast from autumn 2025, with a larger interval of 0.1 to 0.8pp for 2027. Inflation is expected to increase by 1.0 to 1.2pp for 2026, and 0.2 to 1.3pp for 2027. In a more dramatic scenario, inflation could spike by over 6.3 percentage points through 2028, according to the ECB[9].

Bruegel estimates that a year of a €60/MWh gas price would amount to an extra €100bn a year spent, almost doubling the total EU gas expenses of 2025, which sat at about €117bn[10].

While it is impossible to restructure the EUs energy systems to handle fossil shocks after they have occurred, the time required to proactively build energy resilience, while also lowering emissions, is well within reach

According to the IMF, energy efficiency efforts and a shift to renewables in the last five years have reduced the shock on households by an estimated 12%[11]. A good example of this is Spain, who has reduced the share of hours where gas power effectively sets the electricity price from 75% in 2019 to just 19% in 2025[12].

Since the outbreak of the conflict in Iran, more than 210 measures have been implemented in EU members states to alleviate high energy prices, as per Jacques Delors Institute. Governments have allocated €16 bn in increased public spending, with only €1-2.5 bn going to electrification. Most of the spending is directed to general measures, not decreasing exposure to future shocks, and increasing fossil consumption incentives, such as cuts to VAT for fuel. According to Bruegel, those measures account for about 86% of the extraordinary spending[13].

Only four years after the last fossil crisis, the data from 2022-23 provide a stark illustration of the economic consequences fossil fuel shocks can have on the EU.

Starting in the fall of 2021, Russia reduced gas supplies to Europe as part of a broader

[5] Intereconomics, Energy Security and Green Transformation Under Geopolitical Shock, 2026
[6] FT – «Diesel premium in Europe jumps to record high», Sept 2026
[7] Institut Jacques Delors, War in Iran: a hundred days in, sixty billion out, June 2026
[8] CREA (Centre for Research on Energy and Clean Air), What the Hormuz crisis has cost fossil fuel importers — March to August 2026, 26 August 2026
[9] ECB (Piero Cipollone), The new energy shock: economic scenarios and policy implications, speech, 6 May 2026
[10] Bruegel, How Europe should respond to the Iran gas shock – and how it shouldn't, 1 April 2026
[11] IMF, cited in ECB (Piero Cipollone), The new energy shock: economic scenarios and policy implications, speech, 6 May 2026
[12] Ember, Decoupled: how Spain cut the link between gas and power prices using renewables, 2025
[13] Bruegel, 2026 European energy crisis fiscal response tracker

strategy that culminated in its full-scale invasion of Ukraine in February of 2022. Russia being the EUs largest supplier of natural gas, prices surged, with a peak of €350MWh. The EU implemented measures to rapidly decrease dependence on Russian gas, while also decreasing gas demand all together. However, energy systems do not change overnight, and the economic consequences were substantial.

The energy price shock cost the euro area a cumulative 2.4 percentage points of GDP over five quarters, the largest such loss since the launch of the euro[14]. Governments absorbed much of the rest: EU member states committed the equivalent of 3.2% of EU GDP annually over 2022–23 to shielding consumers, around three-quarters of it through untargeted or price-distorting measures[15]. Households still bore a recorded consumption loss of 8.5%[16]. From 2021 throughout 2024, EU countries paid a premium of €930 bn[17].

The other invoice – the heat summer of 2026

Summer 2026 at a glance

Figures to early September and still developing. The climate bill and the energy bill arrived in the same year.

Excess deaths	~35,000 across Europe; ~25,000 in France, Germany and Spain alone
Economic damage	~€180bn, around 1% of EU GDP — erasing the growth forecast for the year
Summer crop yields	14% below the five-year average
Area burned	650,458 hectares in 1,940 fires to 6 September
For comparison	999,145 hectares and 2,006 fires at the same point in 2025
Heatwaves	Five, the first in May and the fifth lingering into late August

The Guardian; Triodos Bank; JRC MARS Bulletin, August 2026; EFFIS; NASA.

Table 2.2

By August 21st, NASA described the summer of 2026 as consisting of five heatwaves, the first one arriving in May, and the fifth lingering in late August[18]. In the first week of September, Europe continues to see high temperatures. Heat waves are getting more frequent, longer and stronger, with one ending just before the next one starts. While 2026 is far from the first year with warm summers, this year has seen records break and then break again across different waves within the same summer. Experts are clear that these temperatures cannot be delinked from man-made climate change, the largest source of which continues to be the burning of fossil fuels.

Record high temperatures are not cheap, and EU countries bear the cost in several dimensions. As this report is being finalized in September of 2026, figures are preliminary, uncertain and incomplete. Nevertheless, reports of lost economic growth, yields and lives must be taken seriously as they are developing.

[14] ECB, Who foots the bill? The uneven impact of the recent energy price shock, ECB Economic Bulletin, Issue 2/2023
[15] Bruegel, The fiscal side of Europe's energy crisis: the facts, problems and prospects, march 2023
[16] Intereconomics, Europe's second energy shock: avoiding the mistakes of 2022, Vol. 61, No. 3, 2026
[17] Ember, Shockproof: how electrification can strengthen EU energy security, October 2025
[18] NASA Earth Science, Europe's Scorching Summer, 2026

The August edition of the JRC MARS bulletin, the European Commission's agriculture monitoring programme, predicts a sharp decline in the yield for summer crops, falling 14% below the five-year average[19]. temperatures is the driving force behind the low yield for summer crops.

An analysis by Triodos Bank in early August forecasted that the impact on the EU's GDP in 2026 from extreme heat would be on average –1%, or about €180 bn, erasing the growth forecasted this year[20].

By late August, heatwaves have resulted in at least 35 000 excess deaths across Europe[21,] of which about 25 000 excess deaths are in France, Germany and Spain alone.

As of September 6th, wildfires have burnt 650 458 hectares in the EU, with 1940 fires, since the start of the year[22]. This is severe and significant, but still below the worst year on record, which was last year, with 999 145 hectares burnt and 2006 fires at the same time.

This is the other invoice of the EU's fossil fuel use. Although the transition to renewable energy is underway, these costs, which are fiscal, physical, geographical and human, show that speeding up the transition is vital to the EU's energy security, as well as to the physical security and food security of its citizens.

[19] Joint Research Centre (European Commission), Exceptionally dry and hot weather threatens summer crops, 24 August 2026
[20] Triodos Investment Management, Extreme heat could wipe out EU economic growth in 2026, 12 August 2026
[21] The Guardian, At least 35,000 excess deaths recorded in Europe's back-to-back heatwaves, August 2026
[22] Joint Research Centre / EFFIS, Current wildfire situation in Europe, retrieved September 6th.

UNCERTAIN, UNSTABLE AND UNSAFE: HOW THE ARCTIC CANNOT HELP

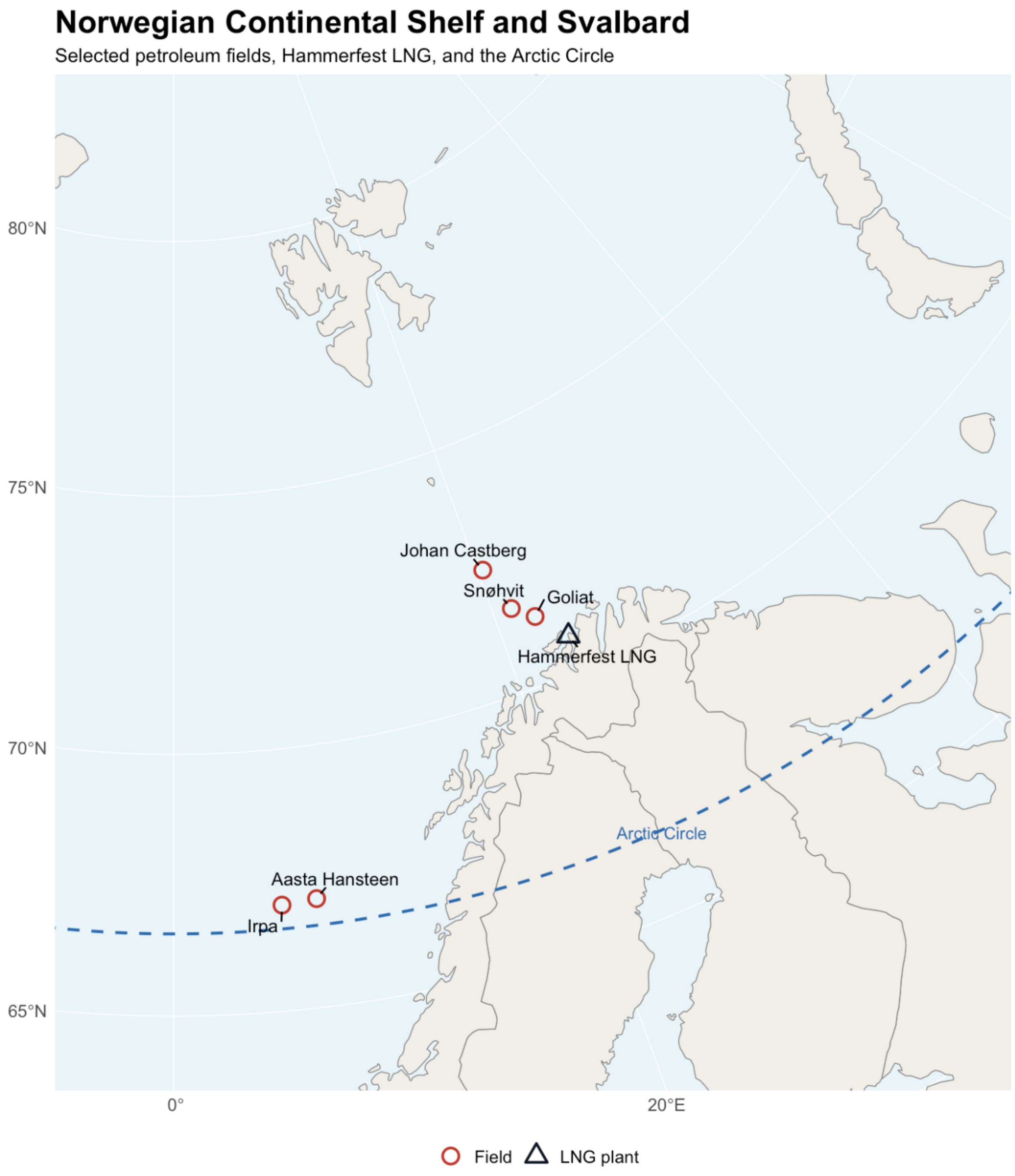


Figure 3.1

As of 2026, about 1.4% of the EU's total gas imports stems from the Norwegian part of the Arctic[23] [24]. Long lead times, harsh conditions, and disappointing exploration activity have left gas production from the Arctic stationary since the development of the Snøhvit-field, almost 20 years ago. Currently, there are no undeveloped standalone gas projects in the Arctic under consideration.

As the situation stands, the Hammerfest LNG plant is at capacity until the mid-2040s[25]. This

[23] Snøhvit is the only gas field in the Arctic exporting to the EU, supplying 4.1bcm of EU imports of 288.7, i.e. 1.4%. Data from Bruegel and Norwegian Offshore Directorate

[24] By "the Arctic" we mean north of the Polar Circle, which is also the definition that the EU uses

[25] Norwegian Offshore Directorate (Sodir), Gassbanken i Barentshavet, 2023

effectively means that if any new gas discoveries were to be developed before then, new infrastructure would be required to export this. The Norwegian pipeline operator Gassco has considered a new pipeline to the Barents Sea but have shelved these plans[26], as the companies in the area consider the current gas resources to be insufficient. The Norwegian Offshore Directorate have described the situation as there not being enough resources for more infrastructure, and not enough infrastructure to justify more exploration.

If new gas resources are discovered in the Barents Sea tomorrow, a pipeline would take around 7 years from an investment decision to becoming operational, according to Gassco[27]. But the lead times, meaning time from discovery to production, pose a bigger challenge for increasing gas production. The Barents Sea has structurally longer lead times than the rest of the continental shelf, with a mean lead time of 18.7 years.

This might be due to a high threshold and costs to economically justify development in this area, as well as infrastructure constraints for gas. No field in the Barents Sea has seen a shorter lead time than 14 years.

Arctic developments take longer

Years from discovery to first production.

Area	Fields	Median lead (yrs)	Mean lead (yrs)	Middle half (yrs)	Full range (yrs)	Median size (mill boe)
Barents Sea	3	**16,0**	18,7	15-21	14-26	600
Norwegian Sea	25	**10,0**	12,1	8-16	2-33	113
North Sea	99	**12,0**	15,4	7-20	0-51	122
All fields	127	**11,0**	14,8	7-19	0-51	122

Source: Norwegian Offshore Directorate.

Table 3.1

As of this report, only three standalone fields have been developed in the Norwegian part of the Barents Sea. The smallest of those three, Goliat at about 202 million boe, is still larger than 61% of onstream fields anywhere on the Norwegian continental shelf. This reflects that smaller developments are not feasible in the same way as the North Sea or Norwegian Sea, where tie-back density allows for development of modest discoveries. Compared to the other parts of the continental shelf, discoveries in the Barents Sea are required to be substantially larger to justify development. The Wisting oil field is an example of this, still sitting unsanctioned even at almost 500 million boe. To expand production in the Barents Sea, discoveries need to be of a magnitude which is becoming increasingly rare.

[26] E24, Aasland om Barents-gassrør: – Ikke bestått markedstesten, 10 February 2026

[27] Gassco Pipeline report 2023, «Vurdering av gasstransportalternativer fra Barentshavet sør»

It is not expected that any new gas resources from the Arctic could help the EU's gas imports before the mid-2040s, in a time where the EU's own climate targets will decrease gas demand substantially.

Assuming a discovery in early 2027, the average Barents lead time would indicate production start in 2045. Even shorter lead times comparable to the other parts of the continental shelf would not yield more gas before 2041.

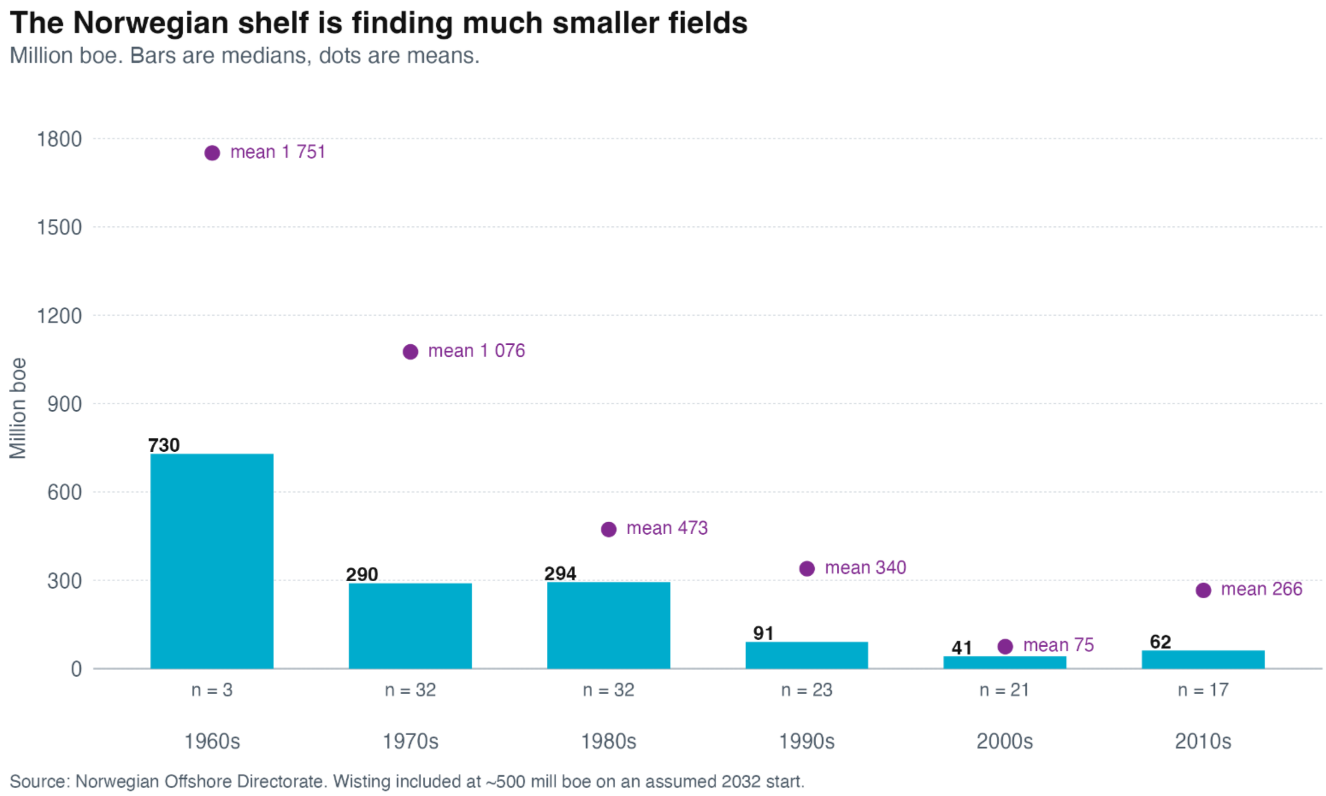


Figure 3.2

As this data only includes fields that have started production, the numbers and sizes of fields discovered in the 2010s and then developed are naturally lower than in previous decades. Nevertheless, there are no undeveloped discoveries that indicate that this number is set to change dramatically.

The distribution of fields by lead times, as seen in table 3.2, show very few fields have lead times shorter than five years. While the share increases to 39% when increasing to 10 years, the median size remains quite low. It is in the 10-15 years bucket that size becomes substantial, but as seen in figure 3.2, larger fields have become few and far between in the last decades.

Resources and discovery frequency by lead time
Norwegian fields, grouped by years from discovery to first production.

Bucket	Fields	Median size (mill boe)	Share of volume	Frequency
0-2 yrs	2	**4**	0%	1 / 30,0 yrs
2-5 yrs	9	**28**	7%	1 / 6,4 yrs
5-10 yrs	39	**93**	32%	1 / 1,4 yrs
10-15 yrs	30	**374**	23%	1 / 1,7 yrs
15-20 yrs	17	**157**	25%	1 / 2,6 yrs
20-25 yrs	11	**87**	5%	1 / 3,6 yrs
25+ yrs	20	**174**	8%	1 / 1,8 yrs

Source: Norwegian Offshore Directorate. Wisting included at ~500 mill boe on an assumed 2032 start.

Table 3.2

This data is selected on fields which have been or is expected to be developed. Fewer fields have been built in the Barents Sea, both because fewer attractive discoveries have been made, but also because of long distances, harsh conditions, extreme weather and a lack of infrastructure, making this area more costly.

An increase in resources produced in the Arctic would require discoveries which are economically viable, and robust to different emission scenarios, as well as cost overruns.

Figure 3.3 shows how Arctic projects without exceptions experience significant overruns. Aasta Hansteen and its satellite field Irpa are both in the northern part of the Norwegian Sea, while the four other projects are in the Barents Sea. They are all north of the Arctic Circle, but as seen in figure 3.3, projects in the Barents Sea exceed their budgets by substantially larger margins than the Arctic fields in the Norwegian Sea.

The difference reflects significantly different weather conditions and maturity of the continental shelf. Whereas Aasta Hansteen and Irpa are closer to existing infrastructure in the Norwegian Sea, which is then again closely connected to the North Sea, there is a substantial disconnect between them and the Barents Sea.

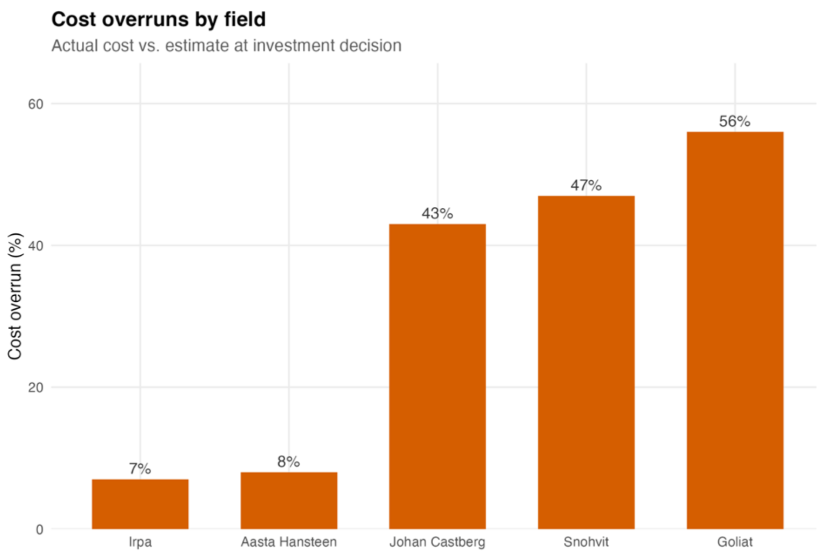


Figure 3.3

New gas infrastructure

The Norwegian gas operator Gassco was tasked with investigating the prospects for a new 800-kilometre pipeline, extending from the Aasta Hansteen gas field in the northern Norwegian Sea, towards today's LNG plant in Hammerfest. The minister of energy stated in February 2026 that there are not enough discovered resources for the companies to justify investing in a pipeline[28]. The Norwegian Offshore Directorate's latest resource report[29] points to a self-reinforcing cycle in which limited resource discoveries constrain infrastructure development, while inadequate infrastructure reduces incentives for further exploration.

In 2023, Gassco estimated a seven-year timeline from planning to a finalized pipeline, with a NOK53 bn price tag, or about €5 bn (2023 prices)[30]. Hypothetically, if sufficient discoveries are made in the exploration campaign in the spring of 2027 to warrant a pipeline investment, 2034 would be the earliest a pipeline could be operational.

For seven years, lack of infrastructure is the practical hindrance to any more gas exports from the Barents Sea to Europe. The pipeline is the *strict* obstacle, but long lead times in the Barents Sea is the most significant factor in why any new gas production cannot reach Europe in time to be of any help.

No business case for Barents gas

To illustrate this, we have modelled gas production in the Barents Sea from 2027 to 2049. Using asset-level data from Rystad Energy, our scenarios show that a large barrier is the resource potential itself, in addition to long lead times and lack of infrastructure. There is simply no business case to justify large investments in the Arctic.

We looked at both obstacles to unlocking more Barents gas: the timing of a new pipeline, and shorter lead times. The production profiles are surprisingly similar. A fully operational pipeline in 2034, compared to 2040, only changes the production in 2040 by 0.3 to 0.5 bcm. The difference between a 14-year and 18-year lead time is similar, less than 0.5 bcm in 2040.

The total of six scenarios model gas exports from the Barents Sea with a fully operational 5,4bcm/year pipeline from 2034, 2037 and 2040, in addition to the 6,5 bcm/year LNG plant today. The lead times are distributed around median lead times of 14 and 18 years, which is the mean of the non-Arctic and Arctic fields respectively. A more in-depth explanation of the methodology can be found in the appendix.

[28] Written Parliamentary question from Lars Haltbrekken to Terje Aasland, minister of energy, February 2026

[29] Norwegian Offshore Directorate (Sodir), Resource Report 2026, "Exploration" section, 2026

[30] Gassco Pipeline report 2023, «Vurdering av gasstransportalternativer fra Barentshavet sør»

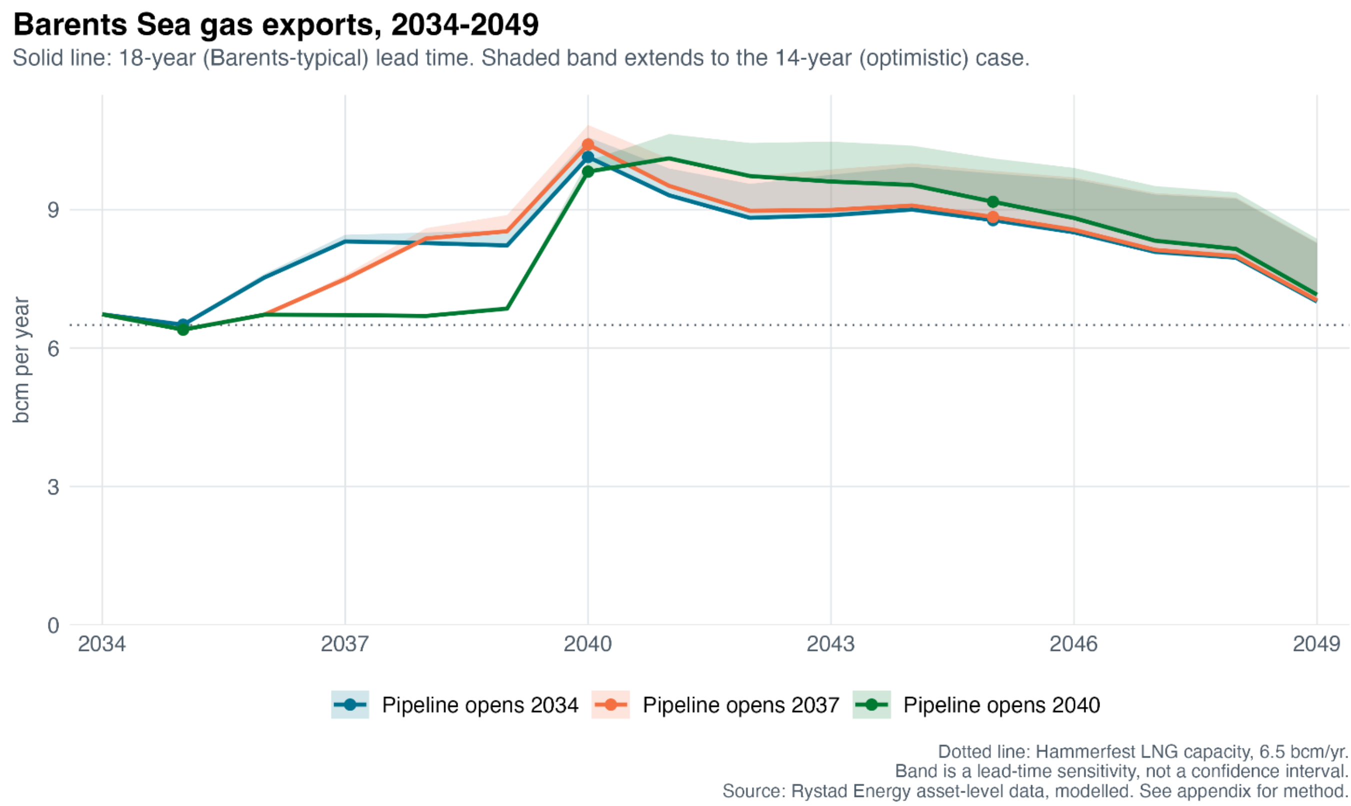


Figure 3.4

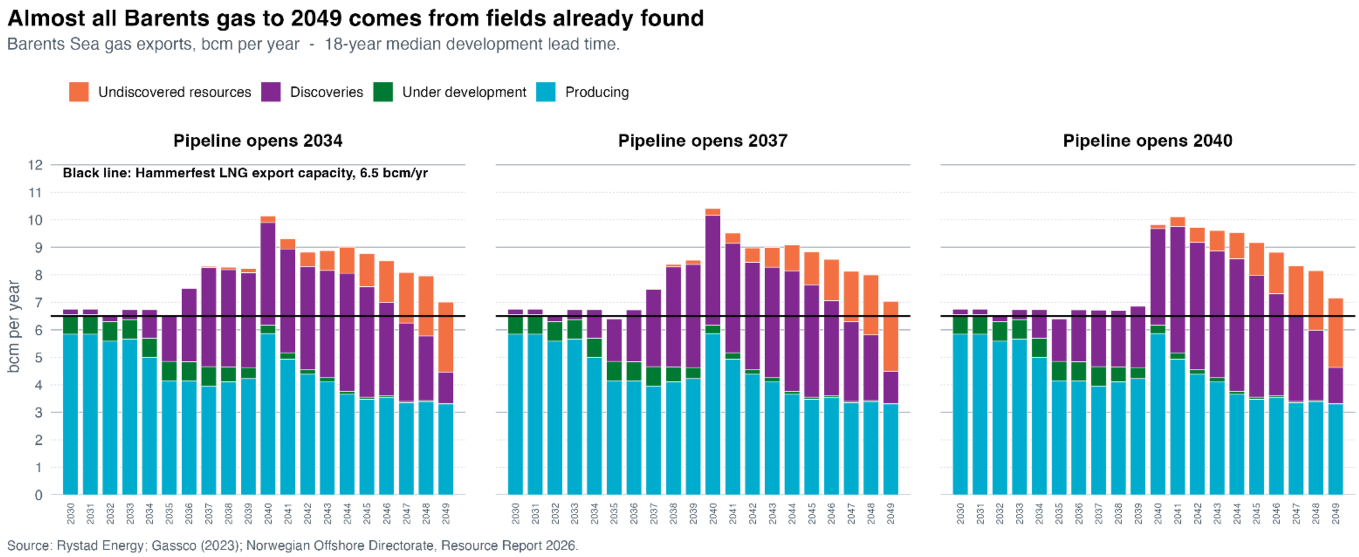


Figure 3.5

The three scenarios above use a median lead time from discovery to production of 18 years, which is akin to historic lead times in the Barents Sea. The results are clear; while a lack of infrastructure is a limiting factor towards 2049, lead times are a bigger constraint. In all scenarios, the impact of new infrastructure on supply only becomes more pronounced from 2040. The similar export profiles of the 2034 and 2037 pipeline years showcase that the lead times is the larger issue.

But even with a shorter lead time of 14 years, closer to the non-Arctic parts of the Norwegian continental shelf, the picture does not change dramatically.

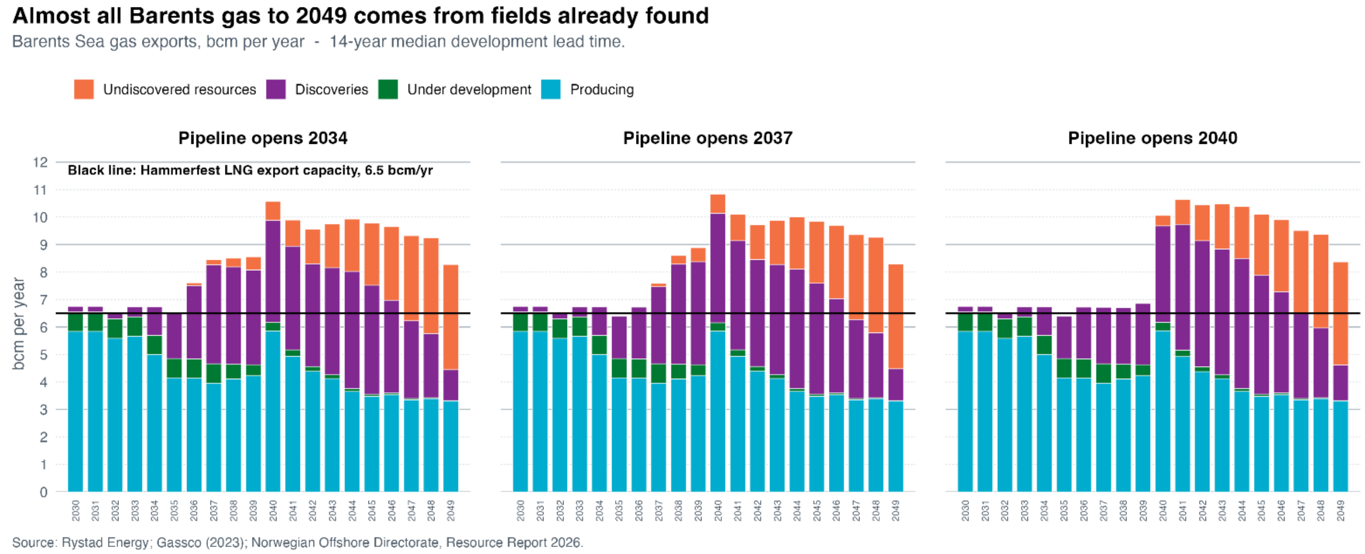


Figure 3.6

Barents Sea gas exports by scenario

bcm per year. Pipeline year is the year a new 5,4 bcm/yr export route opens.

		14-year lead time			18-year lead time		
Pipeline year	**Year**	**Producing & in devt.**	**Discoveries & undisc.**	**Total**	**Producing & in devt.**	**Discoveries & undisc.**	**Total**
2034	2034	5,69	1,05	**6,74**	5,69	1,04	**6,73**
	2037	4,66	3,79	**8,45**	4,66	3,65	**8,31**
	2040	6,16	4,41	**10,57**	6,17	3,97	**10,14**
2037	2034	5,69	1,04	**6,73**	5,69	1,04	**6,73**
	2037	4,66	2,92	**7,58**	4,66	2,84	**7,50**
	2040	6,15	4,68	**10,83**	6,17	4,24	**10,41**
2040	2034	5,69	1,04	**6,73**	5,69	1,04	**6,73**
	2037	4,66	2,06	**6,72**	4,66	2,06	**6,72**
	2040	6,17	3,89	**10,06**	6,17	3,65	**9,82**

Totals above 6,5 bcm/yr need export capacity that does not currently exist.
Source: Rystad Energy; Gassco (2023); Norwegian Offshore Directorate, Resource Report 2026.

Table 3.3

With these findings, it is easy to see why a pipeline has not been warranted an investment decision yet.

In both lead time scenarios, even with a pipeline functional from 2034, it seems projected to operate well below capacity.

A new pipeline would carry little, and less over time

Barents Sea gas exports, bcm per year. 18-year median development lead time, new export route opening 2034.

Year	Total exports	Above 6,50 bcm	Implied pipeline use
2035	6,51	0,01	~ 0%
2040	10,13	3,63	~ 67%
2045	8,76	2,26	~ 42%
2049	7,04	0,54	~ 10%

Data from Rystad Energy, modeled by WWF Norway

Table 3.4

These production profiles do not consider other price scenarios than the Rystad base case, which is not aligned with any of the EU's emission targets. If the EU were to continue their commitment to a 90% reduction of emissions in 2040, it is safe to infer that several of the assets assumed to produce in these scenarios would become less economically attractive, and production would be at a lower level. We therefor consider these scenarios to be conservative.

In the months leading towards the revision of the EUs Arctic Policy, the oil and gas industry has overplayed the potential and downplayed the costs, lead times and difficult conditions for gas production in the Arctic.

While some have suggested the possibility of shorter lead times, existing data does not support significantly shorter developments.

The data on Barents Sea oil and gas development is limited, which complicates possible analyses. Nevertheless, the combination of lack of infrastructure, coupled with the decreasing number of large discoveries made, makes it more likely that future Barents production will be lower than these scenarios imply, rather than higher.

While industry actors have communicated positively about the prospects in the Arctic, others have expressed doubts about the outlook for higher gas production in the area. The scenarios presented in this report echoes those concerns. Long lead times and lack of infrastructure are serious challenges to any increase in Barents Sea gas production, but the main barrier is the lack of gas resources in the area itself. The prospect of the Arctic contributing meaningfully to the EUs energy security is rapidly fading.

This analysis shows that the case for Arctic gas seems weaker than ever. This is in stark contrast to what one would believe following news concerning oil and gas in Norway in recent months and years. Statements and efforts from industry groups, alongside continued engagement from Norwegian government officials, suggests that the region remains of strategic interest. At the same time, a growing disconnect is emerging between claims about the Arctic's importance as a future oil and gas province and its actual prospects for production.

Potential explanations can be found in the government's optimism in the potential from undiscovered resources, especially in areas not yet opened for oil and gas activity. Another reason could be that the industry is betting on high levels of demand long past 2050, effectively hoping for electrification efforts and emissions reductions in the EU to fall short. Given the high cost of a new pipeline, the limited export volumes expected before 2050 would not justify such an investment. To be commercially viable, substantial gas volumes would need to be produced and exported to the EU well into the 2060s and 2070s. Any EU support for this infrastructure could therefore lock in fossil fuel dependence beyond its climate objectives, while exposing the Arctic to increased warming and the risks associated with new petroleum development.

The only areas which could hold a certain resource potential would be the areas outside Lofoten, Vesterålen and Senja, as well as the northern parts of the Barents Sea, up towards and north of Svalbard. These areas are considered very ecologically vulnerable, vital for fisheries, and to have extreme conditions. For these reasons these areas are and have been politically closed for exploration by the current and all former Norwegian governments. Around Svalbard, sea ice is a serious challenge. Even looking beyond the high risks of opening for oil and gas activities, these areas are considerably less mature and have no current infrastructure, meaning timelines for production would be vastly longer than the already long lead times currently seen in the opened parts of the Arctic.

Connecting to the EU gas demand towards 2040

The production scenarios above show that the EU's fossil fuel dependency cannot hope to receive any alleviation by opening for new Arctic oil and gas for a long while. At the same time, the amount of fossil fuels in the energy mix is expected to decrease substantially.

In 2024, WWF, along with Zero Carbon Analytics, Transport & Environment, as well as Oil Change International and Greenpeace, published the report *On Thin Ice, Norway's fossil ambitions and the EU's green energy future*[31], which analyses how the EU's gas demand is set to decrease towards 2050. Across the IEA's Stated Policies (STEPS) and Announced Pledges (APS) scenarios, as well as DNV's Pathway to Net Zero, EU gas demand is projected to decline by 56%, 93% and 97%, respectively. A key finding is that, if the EU remains on track to meet its long-term climate objectives, gas supply from currently producing fields in the EU, Norway, and Algeria, together with existing contractual commitments, would be sufficient to meet demand. By around 2035, supply would begin to exceed demand, and by 2040 it could be roughly twice the level required in a net-zero-aligned scenario. The report therefore concludes that new gas fields are not needed to meet Europe's future gas demand and would instead create additional surplus supply.

In 2025, Menon Economics used the European Commission's own PRIMES model for the 2040 target[32]. Under a 90% reduction in emissions, EU fossil gas demand falls to about 85 bcm.

Strategic Perspectives have, in their Gas Insight tool[33], analysed future supply and demand scenarios. They compare the APS and STEPS scenarios from the IEA and the European Commission based on REpowerEU and 2040 targets, as well as their own Visionary scenario. The Gas Insight shows several paths to serious reductions in gas consumption.

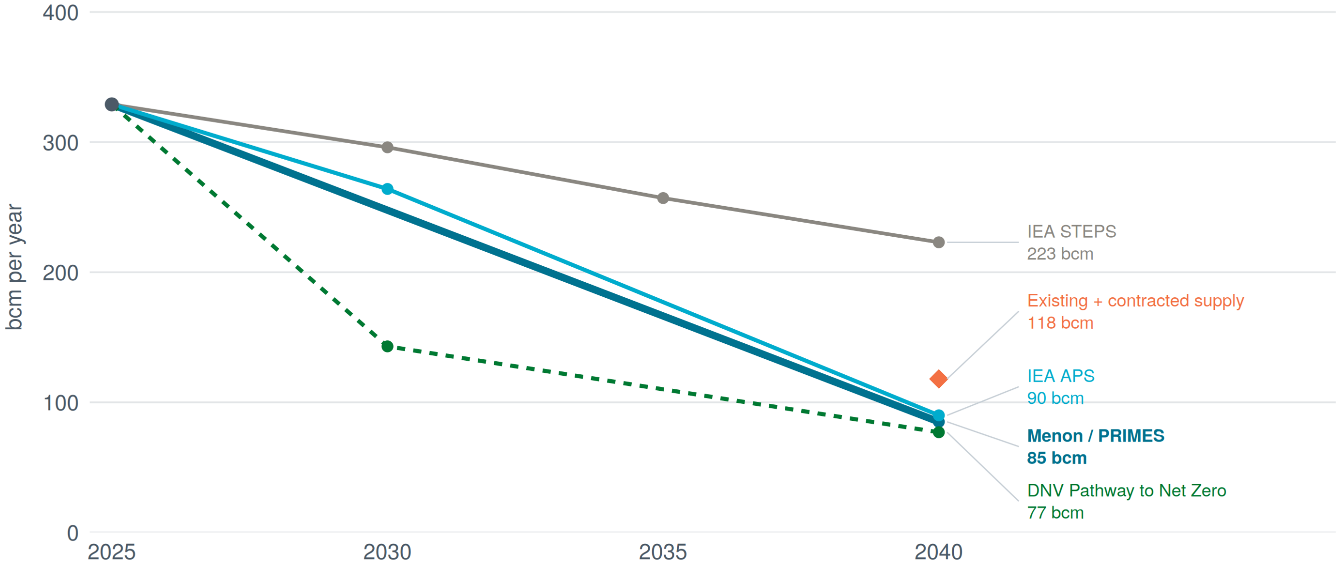
[31] WWF Norway, Zero Carbon Analytics, Transport & Environment and Oil Change International, On Thin Ice: Norway's fossil ambitions and the EU's green energy future, 2024

[32] Menon Economics, EU Demand for Norwegian Natural Gas in 2040, August 2025

[33] Strategic Perspectives, EU Gas Insight

The EU's own target implies gas demand of 85 bcm in 2040

EU gas demand, bcm per year. Menon / PRIMES is the European Commission's own model under its 90% reduction target.



Menon / PRIMES and the supply figure are 2040 endpoints, not modelled trajectories.
Source: Strategic Perspectives, EU Gas Insight (IEA STEPS, IEA APS); Menon Economics (2025), using the European Commission's PRIMES model; DNV Pathway to Net Zero via On Thin Ice (2024); Zero Carbon Analytics (2026).

Figure 3.7

While there is a significant gap between the scenarios, the direction is clear, and the message strong. The demand scenarios show that there is a clear path for the EU to dramatically decrease gas demand. Even with a more pessimistic outlook, the amounts of gas available from the Barents Sea are negligible compared to what electrification efforts, energy efficiency and a steadier transition to renewable energy can contribute to the EU's energy systems. By the time Arctic gas could realistically reach European markets, the EU's demand for it is expected to have largely disappeared.

Security risks – Svalbard and the border with Russia

Arctic oil and gas is not insulated from geopolitical and security risks, rather the contrary. Today, production activity is concentrated in the southwestern parts of the Barents Sea, but any expansion in exploration, field development, or supporting infrastructure would push operations into more contested and challenging areas, as described in the most recent resource report by the Norwegian Offshore Directorate[34],. This includes waters near Svalbard, where the legal framework governing petroleum activities remain unresolved, as well as areas close to Norway's maritime border with Russia. Both of these areas carry significant legal, geopolitical, and operational challenges.

While Norway holds that the Svalbard archipelago, its territorial waters, and the surrounding continental shelf is as Norwegian as the other parts of Norwegian oceans, the EU and other treaty parties dispute this. As international treaties go, settling a legal framework for oil and gas extraction in the far-northern Arctic would not be simple and quick process.

The physical conditions around Svalbard do not help fasten or ease such a process. Sea ice would be a significant issue for large parts of the year, of which there is no existing technology to clean oil spills if an accident occurs. In addition to darkness and extreme temperatures, marine mammals and polar bears make the area severely vulnerable.

The eastern part of the Norwegian Barents Sea runs toward the Kola Peninsula. In its 2026 threat assessment[35], the Norwegian Intelligence Service stated that Russia "*continues to develop military capability to strike Western critical infrastructure at great ocean depths*", and that the specialised submarines representing that capability are based only on Kola. The Norwegian Climate Foundation's February 2026 analysis of security-political risk in the Barents Sea[36] reaches the same conclusion from the civilian side: hybrid operations against offshore infrastructure are close to cost-free and hard to attribute, and Melkøya, Johan Castberg and any future pipeline are the assets most exposed.

The vulnerability is not hypothetical, and it does not require military action. Hammerfest LNG on Melkøya is the only export route for Snøhvit gas and the only exit point for any Norwegian Barents Sea production. When it caught fire in 2020, the plant was out for 21 months and repairs cost NOK 14 billion[37]. A single accident removed an entire production basin from the European market for nearly two years. Any new export infrastructure would concentrate risk in the same way, on a longer route.

Response capacity is the third problem. The 2026 Nordic energy security review contrasts the Arctic with the Baltic directly: north of the Arctic Circle, response times run to days rather than hours, search and rescue coverage is thin, and repair vessels capable of working in ice are scarce. Baltic cable repairs already take between two and five months. Svalbard itself depends on two submarine cables to the mainland; when one was severed in January 2022, the second carried the full load with no margin to spare.

This is not to argue that Norway is an unreliable partner for the EU. Nevertheless, the specific assets Europe would be asked to depend on are harder to protect, slower to

[34] Norwegian Offshore Directorate (Sodir), Resource Report 2026
[35] Norwegian Intelligence Service, Fokus 2026, 23 January 2026
[36] Norsk klimastiftelse (Norwegian Climate Foundation), Barentshavet i spill (Aage Borchgrevink), 23 February 2026
[37] Nordic Energy Research, Energy Security in the Nordics, Section 4, 2026

repair and closer to a hostile navy than anything in the existing supply chain. The Climate Foundation concludes that Barents expansion would require Norway to obtain a credible European security guarantee alongside binding long-term gas purchase agreements, and that heightened activity demands extra security spending from both companies and the state.

Conclusion

Fossil fuel reliance in the EU threatens economic stability and energy security, while increasing the human cost of climate change.

The EU economy is robust but is being tested by the second fossil fuel crisis of the decade. The crisis of 2022 resulted in years of higher inflation and lower growth. The current crisis has yet to see as serious consequences but also remains uncertain. Predicting the outcome and time of final opening of the strait is virtually impossible. This means that the scope of the economic fallout is as futile to anticipate.

While the EU can rely on other sources of fossil fuels than those that pass through the Strait of Hormuz, the price will still be set internationally. The EU cannot allow its consumers to be exposed to the high prices of the next fossil fuel crisis, or the next one after that.

What is certain is that European-produced renewable energy cannot get stuck in a Strait or blocked by a pipeline breakdown. Electrification, energy efficiency, and renewable energy sources cannot react in real time to a crisis, but by accelerating the development, they can anticipate one.

What is currently lacking is the leadership and clear path towards the energy secure and renewable future Europe needs. For industry, consumers and investors to trust this process, the EU cannot stray from this path.

Softening its stance on Arctic oil and gas is a way to deviate from the path towards real energy security. The signal sent would be that decarbonization efforts are not prioritized, and that fossil fuel producers are able to sway the EU away from its commitment to renewable and secure energy, remaining exposed to volatile prices and fossil fuel shocks from other parts of the world.

The signal would also be that the EU would sacrifice credibility and commitment to its climate targets for uncertain promises of small amounts of gas that would take decades to arrive, be expensive to develop, in an ecologically vulnerable area with significant security risks.

In its revised Arctic Policy, the EU should therefore keep its commitment to work towards a multilateral legal obligation not to allow any further hydrocarbon reserve development in the Arctic or contiguous regions, and commit to not purchase such hydrocarbons if they were to be produced.

APPENDIX

Methodology for Barents Export Scenario

The scenarios are built on Rystad Energy asset-level data for the Barents Sea, using Rystad's production parameter rather than its resource estimates. The model does not ask how much gas exists in the Barents Sea, but how much of it Rystad expects to be produced, and when. Assets Rystad does not expect to produce are excluded entirely. The dataset covers 112 assets.

Each asset is assigned to one of four life-cycle classes: producing, under development, discoveries, and undiscovered resources. Annual production profiles run from 2026 to 2049. The model itself runs past 2049, so that volume which cannot be exported in the year it is produced has somewhere to go; the figures report 2030 to 2049.

What the model changes, and what it leaves alone

For producing assets and assets under development, the model uses Rystad's production profiles unchanged. These are fields whose development timing is already determined, so there is nothing to simulate.

Six assets feed Hammerfest LNG and are already connected to an export route. They are modelled as Rystad has them, without a lead time and without any dependence on new infrastructure.

For existing discoveries, the model keeps Rystad's own first-gas year. It does not simulate a lead time for them, because Rystad's assumptions for discovered assets are already conservative: the six discoveries not connected to Hammerfest carry implied lead times of between 19 and 56 years. Four of the six are slower than the 95th percentile of the distribution used elsewhere in this model. A discovery is delayed only if the export route it depends on opens later than Rystad's own first-gas year.

For undiscovered resources, the model retains Rystad's assumed discovery year and Rystad's production profile but replaces Rystad's assumption about how quickly a discovery reaches production. The profile is shifted in time by the simulated lead time; its shape and total recoverable volume are unchanged. This is where the model departs from Rystad, and it is the only place it does.

Why the undrilled prospects need a different lead time

Across the 99 undrilled prospects, Rystad's own numbers imply a median lead time of six years from discovery to first gas, and a production-weighted average of under three years. That is far shorter than anything observed in the Barents Sea. As set out in Figure 3.1, the realised average time from discovery to production is 18.7 years for fields in the Barent Sea and 14.8 years for the entirety of the Norwegian continental shelf. It is also far shorter than Rystad's own assumptions for the assets it has already found, set out above.

The model therefore uses central lead times of 18 years and 14 years (a deliberately optimistic case, applying non-Arctic performance to Arctic assets).

The distribution

Applying a single fixed value to every prospect would misrepresent the real spread: some developments are quick, some take decades. Lead times are drawn from a lognormal distribution, which is right-skewed and bounded below at zero, matching the observed pattern in which delays are open-ended, but acceleration is not.

The dispersion parameter is $\sigma = 0.35$, with the central value entered as the distribution's median. Draws below six years are then raised to six, on the grounds that no Arctic development has been completed faster, so while the distribution itself is bounded at zero, no lead time in the simulation is shorter than six years. The share of draws affected is given in the last column below.

Prospect lead times are not drawn independently of one another. Half the variance is common to every prospect in each iteration and half is specific to the prospect ($\sigma_{common} = \sigma_{idio} = 0.25$). The shared component represents the cost, regulatory and market conditions that move all Barents developments together; the prospect-specific component represents reservoir, weather and project-level variation. Treating the draws as fully independent would let the average across ninety-nine prospects converge on the median and would understate the chance that Arctic development is slow across the board.

The resulting distributions are:

Simulated development lead times

Years from discovery to first gas. Lognormal, sigma = 0,35, floored at 6 years.

Central lead time	5th pct	25th pct	Median	75th pct	95th pct	Share hitting the 6-year floor
14 years	7,9	11,1	14,0	17,7	24,9	0,8%
18 years	10,1	14,2	18,0	22,8	32,0	0,1%

Distribution as specified in the model; percentiles are analytic and agree with 297,000 simulated draws to the precision shown.

Export routes

Barents Sea gas can only reach market through export infrastructure. The model represents two routes:

- Hammerfest LNG, capacity 6.5 bcm/year, the only route in operation today.
- A new export pipeline, capacity 5.4 bcm/year, modelled as fully operational from 2034, 2037 or 2040.

The 2034 pipeline date reflects the earliest plausible completion: Gassco's 2023 estimate of a seven-year timeline from decision to commissioning, assuming sufficient discoveries in the 2027 exploration campaign.

Where available volume exceeds the capacity of the new route in a given year, capacity is allocated pro rata across the four life-cycle classes, and the excess is deferred to a later year rather than lost. One consequence is worth stating plainly: because the backlog is finite, a route that opens in 2034 has already shipped some of the volume a route opening in 2040 is still holding. A later opening date can therefore show marginally higher flows in individual years around 2040 while delivering less in total across the period. The effect is under one bcm a year against annual totals of eight to eleven.

How the simulation is run

Crossing the three pipeline dates with the two lead-time cases gives six scenarios, each run 3000 times. A single iteration assigns every undrilled prospect its own lead time, shifts that prospect's production profile forward accordingly, aggregates volumes across all four life-cycle classes, and applies the export capacity available in each year, yielding one complete annual export profile. The 3000 profiles are then summarised year by year, and the values reported in Figures 3.4–3.7 are the means across iterations. Means are used rather than medians so that the four life-cycle segments add exactly to the annual total.

All six scenarios are evaluated on the same set of random draws. A prospect's development lead time has nothing to do with when a pipeline opens, so there is no reason for the scenarios to differ in their draws, and holding them fixed means any difference between scenarios reflects the mechanism being tested rather than sampling noise.

Drawing lead times prospect by prospect, rather than applying one value to all of them, matters for the shape of the result as well as its level: because assets come onstream at different times, aggregate exports rise and fall gradually instead of stepping up as a block, and the peak is correspondingly lower and broader than a fixed-lead-time model would produce. At 3000 iterations the Monte Carlo standard error on each annual mean is approximately 1.8% of the cross-iteration standard deviation.

Limitations

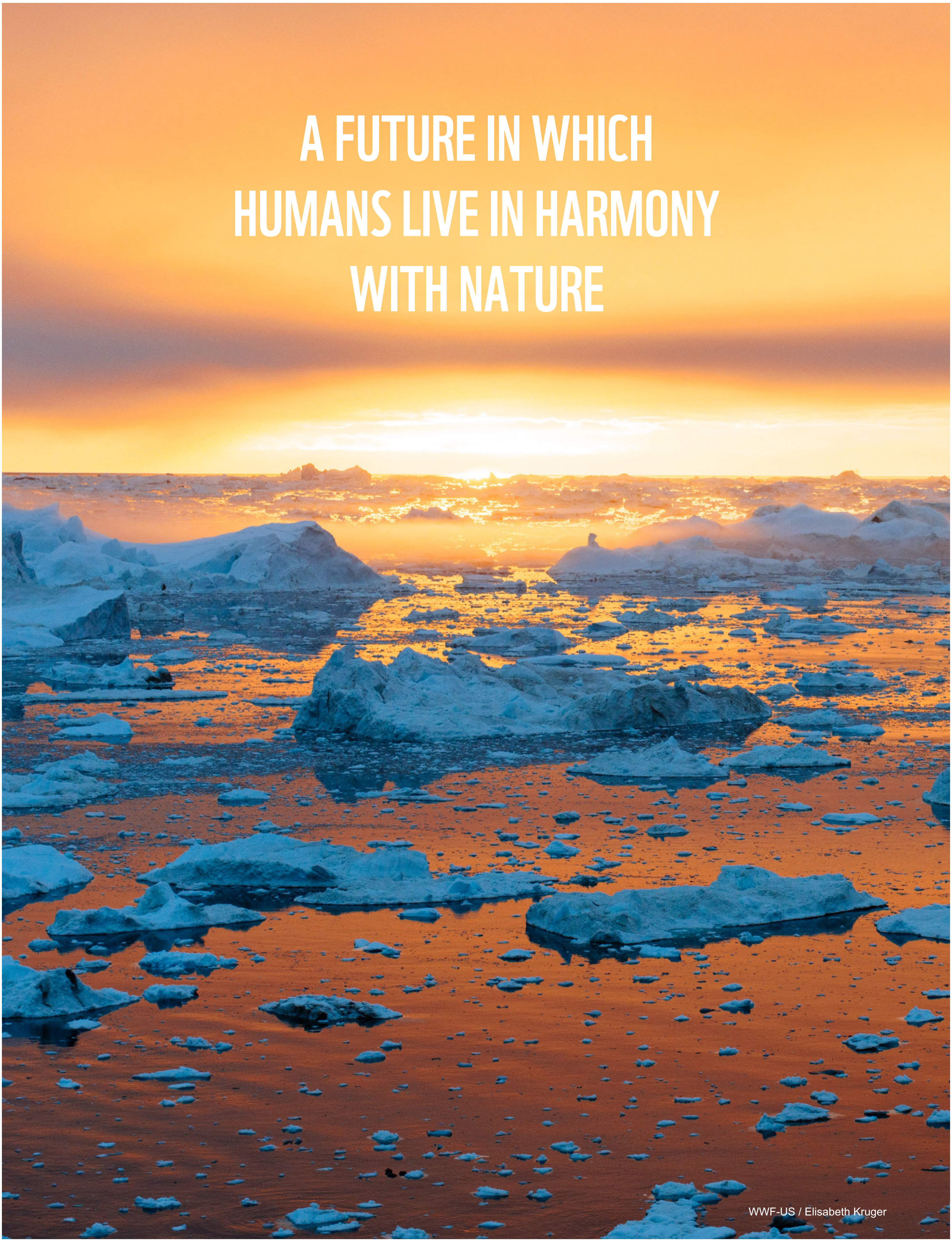
- **Economic viability is not modelled.** The scenarios include every asset Rystad expects to produce, without testing whether those assets remain commercially attractive under lower gas prices, a tighter EU demand outlook, or the cost overruns documented in Figure 3.3. Barents developments have overrun by an average of 40%. Volumes here should therefore be read as an upper bound.

- **Exploration success is taken as given.** Undiscovered volumes enter on Rystad's assumed discovery schedule. The model tests what happens if those discoveries occur as expected; it does not test the probability that they do. Recent Barents campaigns have underperformed, which is the stated reason Gassco shelved the pipeline in 2025.

- **Infrastructure cost is not modelled**, and the pipeline is assumed available on its scenario date irrespective of whether the volumes would justify the investment.

- **Existing discoveries keep Rystad's timing.** Applying the simulated distribution to them as well would delay first gas by a volume-weighted average of 0.05 years in the 14-year case and 0.21 years in the 18-year case — immaterial, and in the direction of later gas rather than earlier.

Each of these assumptions is generous to Arctic gas. The central finding, that neither earlier infrastructure nor faster development materially changes Barents export volumes before 2040, therefore holds.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