Electrification of the oil and gas sector – does it have a global climate effect?

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Project description

Electrification of oil and gas installations reduces emissions from these. But to what extent such electrification yields global emission cuts is a subject of debate, given that the electricity is taken from a European market and the emissions are subject to the EU emission trading system (EU ETS). The purpose of this report is to strengthen knowledge about the relationships between physical changes and market effects with the aid of qualitative and quantitative analyses. These show that electrification cuts emissions in Norway and is crucial for reaching Norwegian climate goals. European emissions are reduced by almost as much because the increase in consumption is largely met by emission-free power generation. Emissions are cut even further in global terms because gas liquefaction is reduced and emissions in the liquefied natural gas (LNG) transport chain are higher than for pipeline gas. Furthermore, we find that many electrification projects are cost-effective at cutting emissions both in Norway and in the ETS sector. Should profitable electrification projects not be implemented, climate policy will become more expensive and its goals harder to reach.

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MAIN CONCLUSIONS

Electrification of Norwegian oil and gas installations reduces Norwegian, European and global greenhouse gas (GHG) emissions through its effects on the power, gas and emission-trading markets. The reduction in Norwegian national emissions equals that from offshore installations and their associated onshore facilities. It would be both harder and more expensive to reach Norway's climate goals without electrification. Such projects on Norwegian oil and gas installations and at land-based plants account for about 20 per cent of the emission reductions required to meet the country's climate goal for 2030. Compared with electrification projects in the land-based industry and transport sectors, many of those in the petroleum industry are efficient in terms of both power consumption (tonnes of CO_2/megawatt-hours) and abatement cost (NOK/tCO_2). The resultant increase in electricity demand is met mainly through new power station capacity in Europe which, given climate-policy parameters and goals, results in low or no emissions. CO_2 released from the Norwegian continental shelf (NCS) and its associated onshore facilities is subject to the EU emission trading system (EU ETS). The same applies to power generation. Overall, electrification projects reduce European emissions by increasing the surplus of ETS allowances and lowering their price. This increases the probability that allowances will be cancelled, and that the EU ETS cap will be further lowered. The most important global emission impact outside Europe results in Norwegian pipeline gas displacing gas with greater climate impacts along its value chain. Possible carbon leakage effects are small and positive in any case.

Electrification reduces global GHG emissions through lasting market changes

The emission impact of electrification depends on its long-term effects on the power and gas markets.

Electrification of NCS installations and their associated onshore facilities using power sourced from land reduces emissions in Norway. The alternative is to generate electricity using natural gas from the offshore installations themselves. In contrast, power generated in the Norwegian mainland is virtually emission-free. Increased operating regularity offshore has the potential to reduce emissions even further. Electrification also frees up additional gas for export to Europe.

The impact on total European and global emissions depends both on how higher Norwegian power consumption affects the European electricity market, of which Norway is an integrated part, and the way increased gas supplies to Europe influence the gas market. Account must also be taken of climate policy parameters, and particularly how the EU ETS is affected.

Electrification projects produce a lasting increase in power consumption, which the market will be aware of and adapt to in advance. Expectations of higher consumption boost price expectations and encourage investment in new power generation. The assumed emission intensity of long-term changes in generation is therefore central to any assessment of the impact on emissions from European electricity output.

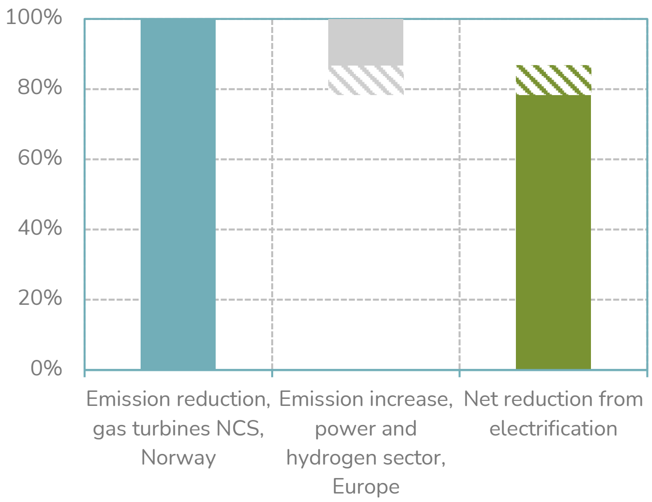
Both market and emission effects are influenced by the efficiency of energy consumption. Gas turbines on the NCS use energy less efficiently than when using the gas directly or in combined heat and power plants.

While the power market is European, the gas market is global. Increased supplies of Norwegian gas to Europe therefore also affect the global market. Most adjustments to changes in gas availability occur on the supply side, generally in the form of reduced European imports from other regions

European emission reductions are about 80 per cent of the cuts achieved in Norway

Simulations of several scenarios using our power-market model show that EU ETS emissions are cut by about 80 per cent of the reductions achieved on the NCS (see the figure). We have here also taken account of the impact on the hydrogen market, where blue and grey displace some green hydrogen. From 2030, increased power consumption will largely be covered by greater investment in renewable or low-emission electricity generation.

Modelled impact on EU ETS emissions owing to offshore electrification.[1]



Reduced prices for EU ETS allowances increase the probability of a more ambitious climate policy and further reductions to emissions from the EU ETS sector.

Lower emissions cut demand for EU ETS allowances. That tends to depress price expectations and allow for a larger surplus. With lower prices, some of the most expensive measures in the ETS can be shelved or postponed. In that event, emissions elsewhere in the system would rise.

But reduced prices create a presumption in favour of lowering the allowance cap. It will be cheaper to pursue ambitious climate policies, and thereby easier for the politicians to set even more ambitious goals. A lower allowance cap means reduced emissions.

Some of the allowances which are no longer used can also be saved, creating a larger surplus. Higher saving increases the likelihood that allowances will be drawn into the market stability reserve (MSR) or that fewer will be released from it, and the probability of permanent allowance cancellations. History shows that reductions to the EU ETS cap have been made with reference to both allowance price levels and the size of the current surplus.

In the gas market, exports from Norway primarily displace European LNG imports

Supply changes also affect both gas consumption and demand. Rystad Energy (2021) estimated that 90 per cent of the increase in Norwegian pipeline gas deliveries to Europe result in reduced LNG imports. The remaining 10 per cent goes to increase European gas consumption. As with the electricity market, changes in the supply chain have the biggest impact on emissions.

Norwegian pipeline gas deliveries to Europe displace pipeline gas or LNG from other sources with higher emissions in their production and transport chain. When pipeline gas replaces imported LNG, emissions related to regasification are reduced.

European gas consumption can rise in both ETS and non-ETS sectors, which are subject to different climate policies. Changes in gas usage for electricity generation, which is subject to the ETS, are captured by the modelling. The share of gas consumed in the non-ETS sector will displace a mix of other energy sources, ranging from oil to renewables, and the net impact on emissions is likely to be very limited. We

[1] The range of outcomes across the three modelled power-market scenarios with different assumptions is shown by shading.

therefore conclude that the effects on European emissions via the gas market are small.

Emissions outside Europe may be reduced via lower gas liquefaction, the leakage effects are small

To evaluate the impact on global emissions, we need to assess whether emissions outside Europe change as a result of "carbon leakage" or of other emissions impacts.

According to Rystad, 90 per cent of increased Norwegian exports to Europe displace LNG imports.

Lower LNG demand in Europe will tend to lower global gas prices, and in turn increase gas consumption and reduce supply. The emission impact of increased gas consumption globally depends on what this gas replaces. That could be anything from renewables/green hydrogen to coal-fired electricity or oil. The long-term outcome is likely to be a mix of these, and the total effect will be small.

Less gas liquefaction reduces global emissions compared with gas produced from Norway. Generally speaking, pipeline transport has lower emissions along the value chain, and studies show that Norwegian LNG emits less than supplies from other regions Equinor (2021) Rystad Energy (2021).

Carbon leakage usually describes the indirect adjustments made in the economy in response to higher European production costs as a result of climate policy in Europe. Increased European gas, power and allowance prices may prompt emission-intensive enterprises to move to countries and areas where climate policies are less rigorous. In this way, emission reductions in Europe may be to some extent or, in the worst case, more than offset by increased emissions elsewhere. Conversely, lower gas, power and carbon prices in Europe act to reduce carbon leakage and shift emissions more towards Europe.

In any event, analyses summarised by the European Commission (2020b) show that carbon leakage from the EU is small, both because measures exist to counteract it and because other regions and countries also apply GHG-reduction policies.

Implementing cost-effective measures is important for meeting European and global climate goals

Europe's goal is to decarbonise the EU ETS sector completely in the long term. This means that all relevant measures will have to be implemented sooner or later, with the ETS helping to ensure that the cheapest are made first. The important consideration here is that the market abatement cost curve is determined by the abatement cost of the measures over their economic lifetime, including the cost of postponing climate measures. It is much cheaper, for example, to electrify a field from the start rather than when gas turbines are already in place on the platform. At the same time, it is unlikely to be profitable to postpone a field's development because of uncertainty about the future trend of carbon prices.

According to the latest report from the UN Environmental Programme (Unep), current policies and commitments mean that the world is heading for a global temperature rise of 2.8°C in 2050. That is far above the goal set in the Paris agreement and the level considered to represent manageable global warming. Further emission cuts are thereby needed, and it is crucial that measures which are cost-effective on the basis of approved policies are implemented.

Offshore electrification is crucial for reaching Norway's climate goals

Under the Paris agreement, Norway has pledged to reduce its GHG emissions by 55 per cent in 2030 compared with 1990 emissions, which were 51.4 million tCO_2. In its Hurdal policy platform, the coalition government stated that the goal is for emission cuts to be achieved domestically. This means national emissions must be reduced from 49 million tCO_2 in 2021 to 23 million by 2030.

Electrification in all sectors, both directly and indirectly through the use of green hydrogen, can reduce emissions by 15-16 million tCO_2. Two-thirds of the identified measures required to reach the 2030 target call for electrification.

Electrification represents a cost-effective climate measure if its abatement cost is below the CO_2 cost

Electrification is a socioeconomically cost-effective climate measure if the net value of the reduced emissions exceeds its cost – in other words, the abatement cost. Expressed in NOK per tCO_2 saved, the latter is calculated by dividing the additional cost of electrification by the net emission reduction over the project's commercial lifespan. The additional cost is the difference in cost between a power-from-shore solution and alternative forms of energy supply – usually the use of gas turbines on the field. Costs for the power-from-shore solution also incorporate revenues from the gas which can now be sold in the market.

The abatement cost for offshore electrification varies from negative (in other words, it is cheaper than the non-electrification alternative regardless of the CO_2 cost) to above the 2030 level of Norway's CO_2 tax – which is set to reach NOK 2 000/tCO_2 in 2020 value.

Emissions reductions and CO_2 prices are higher when viewed from a Norwegian rather than European perspective

From a European perspective, the EU ETS allowance price is the relevant CO_2 cost when determining whether a measure is cost-effective. The relevant price in Norway is the sum of the allowance price and the CO_2 tax.

Emission reductions from Norwegian electrification projects are higher when the scope is restricted to Norway since any additional emissions from power generation occur outside the country. When Norway is set as the relevant scope, the abatement cost is lower and the calculation price higher. Some electrification projects will thereby be cost-effective measures for realising Norwegian climate goals but not be cost-effective when assessed within the EU ETS. These differences do not imply any difference in the underlying market effects.

Electrification projects on the NCS include those with very low abatement costs and relatively large emission cuts per MWh

Many offshore electrification projects have both low abatement costs and/or a high level of energy efficiency compared with measures in the land-based industry and transport sectors.

Looking at abatement costs and energy efficiency, no evidence exists that measures in one sector are generally more or less effective than those in others. Given current technologies and policies, a variety of electrification projects exist which are more or less profitable from an economic perspective and which use power more or less efficiently to reduce GHG emissions. Both abatement costs and energy efficiency vary between projects, and this variation is substantial in all sectors.

Reaching Norway's climate goals will be difficult without electrifying the oil and gas industry

Electrification projects in the petroleum industry account for almost 20 per cent of measures identified as necessary to reach the 2030 Norwegian emission target.

Emissions from Norway's oil and gas sector currently represent about 25 per cent of the national total. Power from shore to new fields and existing installations with long remaining production lives is needed to sustain offshore output while also meeting Norwegian climate goals for 2030 and 2050. A halt to sanctioned and planned electrification projects on the NCS would significantly reduce the likelihood of reaching these targets.

KonKraft (2022) has identified a potential emission reduction of three million tCO_2 up to 2030 from electrification projects sanctioned and matured for offshore installations and their associated onshore facilities in the petroleum sector. If more uncertain projects (amounting to

1.5 million tCO_2) are included, the total reductions would represent close to 20 per cent of the cuts required to reduce Norwegian emissions by 50-55 per cent in 2030. Since Norway is due to reach net zero emissions in 2050, it will be necessary to fully electrify oil and gas installations in combination with other climate measures while also offsetting residual amounts through mitigatory measures in the form of negative emissions.

If cost-effective electrification projects are not implemented, it will be harder and more expensive to reach the 2030 goals because other and costlier measures must be implemented instead. It will also be more expensive to meet the 2050 targets if cost-effective electrification of new fields is halted. The abatement cost of electrifying existing fields already equipped with gas turbines locally is generally much higher than for new fields.

1 BACKGROUND AND THE ISSUE

1.1 Background

Offshore Norge has asked THEMA Consulting Group, based on its knowledge and experience, to analyse how electrification of Norwegian oil and gas installations affects the power, gas and emission allowance (EU ETS) markets as well as GHG emissions nationally and globally.

This report helps to strengthen the knowledge base by describing the relationships between physical changes and market effects, supported by qualitative and quantitative analyses. The quantitative work describes the short- and long-term dynamics of the power, gas and EU ETS markets, and identifies uncertainties associated with the market effects. The quantitative analyses provide estimates of the global effects of electrification using model-based simulations with quantified and transparent assumptions and emission factors covering the past, present and future.

1.2 The issue

Assessing the electrification of offshore installations as a climate measure is complex because, in addition to changes in the physical flows of gas and electricity, mechanisms in the power, gas and ETS markets affect emission effects and the profitability of measures. Using analyses of the principles and quantities involved, this report assesses the overall emission effects of meeting energy requirements on NCS fields with power from shore rather than gas turbines on the installations.

The report will primarily address two overriding issues, and hereunder answer a number of subsidiary questions.

1) How does electrification affect GHG emissions nationally and globally?

- Does electrification of the NCS increase imports of coal-fired electricity, and does this also apply to alternative uses of power in Norway?
- What effect does electrification have on the power market when account is taken of investment in new renewable capacity?
- What significance does the removal of surplus allowances from the market have for the global effect?
- Does freed-up natural gas reduce the need for LNG imports? What is the climate footprint of pipeline gas compared with LNG from various suppliers?
- How would a halt to electrification affect the probability of meeting Norway's climate goals?

2) Is electrification a socioeconomically profitable climate measure?

- Does power from shore make sense in commercial and/or socioeconomic terms, given allowance prices and the CO_2 tax rate on the NCS?
- How important is electrification in all sectors for reaching global climate targets?
- How effective is electrification of the NCS compared with other abatement measures which require such action?

In addition, we discuss whether electrification of the NCS gives better overall energy utilisation, the significance of electrification as a climate measure in other sectors, and how important it is to reduce emissions in the value chain in order to meet requirements in the European market.

2 DESCRIPTION OF EMISSION EFFECTS

The analysis of emission effects assumes that electrification of an NCS installation increases power consumption in Norway and the supply of pipeline gas to Europe. We start by describing changes in the physical flows and then analyse market effects step by step in the short and long terms.

Since electrification projects are planned and long-running, the markets will also have time to adjust before they become operational. The immediate effect is therefore relevant as a starting point, *but the appropriate basis for considering emission effects is how the markets adapt to altered expectations about future power consumption and gas supplies.*

2.1 Long-term marginal effects: analysis of market changes

The starting point for the analysis is that we envisage a market position – in other words, market prices and investment plans – which reflects a specific expectation about future consumption, production, operating parameters, technology development and costs. A new offshore electrification project is then introduced, and the way the markets adapt to this change determines how the emissions alter. We explain the rationale for applying this method, based on long-term marginal effects, in more detail in chapter 3. In this context, "marginal" does not mean that that effect is small, but that we analyse the *changes* triggered.[2]

[2] When we say, for example, that LNG is the marginal supply in the gas market, we mean that a rise in gas consumption triggers an increase in gas liquefaction.

2.2 Impact on emission sources in the value chain

Offshore electrification affects emissions at several stages in the value chain Figure 1 presents a model for national and international gas, power and emission flows related to electrification of offshore installations, and shows which emission sources are affected in Norway and Europe. The figure covers the physical flows.

First, emissions from NCS installations are influenced by replacing electricity generation based on offshore gas turbines with power from shore.

The freed-up gas is exported from Norway via processing on land. Greater quantities being processed increase Norwegian emissions. We assume that the choice of energy supply does not affect actual gas output on the installations and that no export restrictions exist.

Following its delivery to Europe, the gas is used in various applications. The figure assumes that one-third goes to electricity generation, in line with today's breakdown of European gas consumption. The rest provides energy and heat for industry, buildings and households, and for heating purposes, and influences emissions in these sectors.

Power consumed by electrification can be provided by increased output in Norway and/or Europe (increased imports or reduced exports). That influences emissions from electricity generation, depending on the energy sources utilised.

Changes in energy and emission flows influence the markets. Increased gas deliveries from one source affect the market price and lead to adjustments in both supply and demand. When demand for electricity rises, prices for power are similarly affected and thereby its supply and demand. How much these aspects affect emissions in the various stages along the value chain depends on the dynamics of the gas, power and ETS markets in the short and long terms. The effects are described in more detail in sections 2.4-2.7.

Norwegian gas is exported primarily to Europe for use in power generation, households or industries, where it is utilised more efficiently than by generating electricity on offshore installations (Endrava, 2021). According to the Endrava report, the average efficiency of using gas for power and heat in Europe is 65-85 per cent. By comparison, it is about 35 per cent on the NCS. About a third of the gas delivered from Norway to continental Europe goes to heat and power stations. Even when emissions along the value chain are taken into account, Endrava estimates that GHG released per unit of power and heat generated from gas for consumption in Europe is substantially lower than on the NCS.

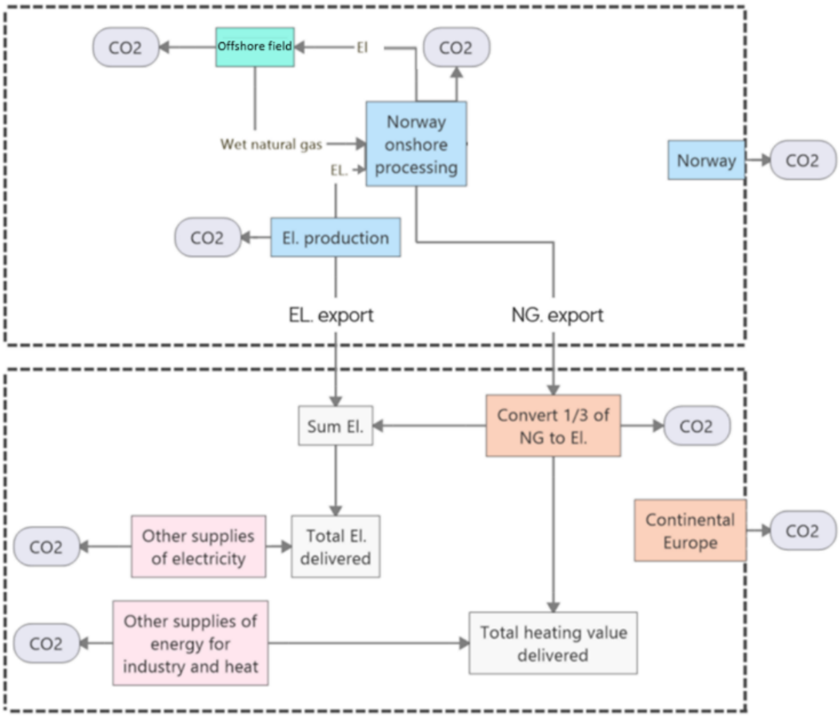
Apart from the influence on emissions in the value chain, an experience-based report from the Petroleum Safety Authority Norway (2018) indicates that some offshore installations with power from shore achieve very high operating regularity. This report also identifies reduced maintenance requirements related to energy provision as well as other health, safety and environmental (HSE) benefits, such as an improved physical working environment and a reduced threat of gas leaks and fires.

2.3 Climate-policy parameters

Climate policy influences how national and global GHG emissions are affected. Such policies have not been adopted once and for all, and the way emissions, technology and markets develop will be significant for policy formulation, market reactions and which measures are cost-effective.

Norwegian climate policy is guided by developments in and provisions of global and EU policies in this area. It sets the parameters for goal attainment and determines the value of emission cuts. That also applies to the value of reduced emissions on the NCS. In addition, climate policy influences renewable energy targets, which will contribute in the longer term to reducing emissions related to power generation and production of other energy carriers.

Figure 1: Gas, power and emissions flows related to electrified offshore installations



The following sections provide an overview of key climate-policy parameters internationally, in the EU and in Norway, and how they relate to each other. This description also forms the basis for formulating three scenarios which we believe cover the uncertainty range for the long-term climate-policy parameters, and for quantifying emission effects and the profitability of electrification in chapter 3.

Global climate policy

Parameters for global climate policy are set by the 1992 UN Framework Convention on Climate Change (UNFCCC), which has been ratified by 195 countries. The Paris agreement's goal is to limit the rise in the average global temperature to less than 2°C above pre-industrial times (about 1850).

This aim will be achieved by each country committing to its own nationally determined contribution (NDC). Signatories must report new and more ambitious emission targets every fifth year, with global climate policy thereby becoming more rigorous over time.

European climate policy

An EU target for reducing GHG emissions by 2030 was adopted in 2020. The emission reduction ambition in the European Green Deal has been upwardly adjusted from 40 to at least 55 per cent compared with the 1990 level. This green growth strategy establishes a roadmap for developing climate policy over coming years, and the European Commission presented its Fit for 55 package in the summer of 2021 to detail the Green Deal's parameters. This involves a number of revisions to EU regulations, including the renewable energy directive, the regulation on binding annual GHG emission reductions (non-ETS sector) and the EU ETS.

The last of these is the most far-reaching carbon-pricing mechanism and covers Iceland, Liechtenstein and Norway as well as the EU member states. It sets a cap for CO_2 emissions which corresponds to the EU's emission target for the ETS sectors – in other words, power generation, industry including petroleum, and civil aviation within the European Economic Area (EEA). It has been agreed to incorporate the maritime sector and waste incineration as well.

Until now, the ETS has covered about 45 per cent of the EU's GHG emissions. The Fit for 55 package proposes to raise the climate ambitions and make the ETS pricing mechanism more rigorous by incorporating more sectors, speeding up the pace of cancelling allowances on the market, and implementing a one-off reduction in allowances. The revision proposals are described in more detail in section 2.5.

Where non-ETS sectors such as transport, construction and agriculture are concerned, the EU member states have a common goal of reducing emissions by at least 30 per cent in 2030 compared with 2005. This target is in the process of being raised. A preliminary agreement has been reached by the Commission and the Council on a 40 per cent emission cut for 2030 (European Council, 2022). The common goal means that each member state reports how large an emission reduction it can achieve in the non-ETS sector, while taking account of the differing starting points of and resources for implementing cuts in the various countries. Each member state plus Norway and Iceland have submitted binding plans on how they will realise the necessary reductions by 2030.[3]

The Green Deal and Fit for 55 represent more rigorous European goals as well as far-reaching changes to policies and regulations for speeding up and ensuring sweeping decarbonisation of the European economy. In the wake of Russia's invasion of Ukraine in February 2022, the EU launched the REPowerEU package of measures aimed at reducing its dependence on Russian gas through a stronger commitment to renewables, enhanced energy efficiency and diversification of gas import sources. In this connection, the EU has also presented proposals to raise its ambitions for renewables and energy efficiency, which were already under revision. Current developments, with a further raising of ambitions, reflects the dynamic nature of climate and energy policy and put greater pressure on sectors to reduce their dependence on fossil fuels.

Norwegian Climate Policy

Norway collaborates closely with the EU on climate policy. When the Paris agreement was concluded, Norway pledged to reduce emissions by 40 per cent in 2030 compared with the 1990 level. That was in line with the EU target at the time. In February 2020, Norway's climate goal was raised to an emission reduction of at least 50 and preferably 55 per cent

[3] Policy measures applied in the non-ETS sectors have so far been determined by the member states. However, it has been decided to introduce a separate EU-wide allowance market for emissions from the use of fossil fuels in transport and construction from 2027.

by 2030 compared with the 1990 level.[4] This target is to be met in collaboration with the EU and Iceland. It was raised again to at least 55 per cent in connection with the UN climate summit in November 2022, still jointly with the EU and Iceland (Norwegian government, 2022). By contrast, the Norwegian government's Hurdal policy platform for 2021-2025 envisages that the whole 55 per cent emission reduction compared with 1990 will be reached nationally. Where petroleum is concerned, the Storting (parliament) set a sector-specific target of an absolute emission cut of 50 per cent in 2030 from the 2005 level in connection with its consideration of temporary changes to the tax regime for the industry.

About half of Norway's emissions fall within the EU ETS, and almost 85 per cent are covered by a climate tax, the ETS or both (Ministry of Finance, 2022). The Norwegian oil and gas industry are subject to both measures.

Where the non-ETS sector is concerned, Norway aims to cut emissions by 40 per cent from the 2005 level up to 2030. In its Granavolden policy platform, the previous centre-right coalition headed by Erna Solberg introduced a more rigorous emission-reduction ambition of 40-45 per cent. The EU has initiated a revision process for raising the target in the non-ETS sector, which will probably lead to the Norwegian goal also being increased (Norwegian Environment Agency, 2022b).

In its climate plan for 2021-30, the government describes how emissions in the non-ETS sector are to be reduced (Ministry of Climate and the Environment, 2020). One of key elements in this plan is an increase in the CO_2 tax to NOK 2 000 per tCO_2 in 2030. In addition to being covered by the EU ETS, CO_2 emissions from NCS installations are subject to a special Norwegian tax. Up to 2030, this is to be increased so that the overall CO_2 price for the petroleum sector – the sum of the ETS price and the special Norwegian tax – reaches NOK 2000 per tCO_2 in 2030.[5]

2.4 Effects via the power market

The Norwegian electricity market is closely integrated with the rest of the Nordic region and Europe, both through the other Nordic countries and via direct interconnector cables to Germany, the Netherlands and the UK. Price formation in these markets is based on a common algorithm which means that changes in one part of the market can influence all the others. Analysing the effect of offshore electrification on the power market solely in a national or, for that matter, a Nordic perspective is therefore meaningless.

We describe the market dynamics step-by-step below, starting with the immediate impact of electrifying installations on the power market, and then how the latter adapts over time.

The starting point is that price expectations in the market reflect the information available and expectations of future developments in demand and supply, costs and regulatory parameters. We analyse effects on the market and emissions of a new electrification project becoming known to the market. From that point, it takes a few years for investment to be made and power consumption to start. The project will then consume electricity for the expected production life of the field, which could extend over several decades.

[4] This is not a net goal – in other words, it does not take account of GHG emissions from land use, land use change and forestry (LULUCF).

[5] Measured in 2020 value in 2030.

Emission effects from electricity generation in Europe

The immediate impact on the power market is that it adjusts its expectations of future electricity demand to account for consumption from electrification of the installation. Expecting a rise in power demand initially leads to the presumption of higher electricity prices. Power demand from NCS installations is by and large stable per day and per year, as with an increased requirement from power-intensive industry, for example. The market impact is independent of whatever triggers the expectation of greater electricity use.

When higher power prices are anticipated, it becomes profitable to generate more electricity on land. Consumption will also probably respond, depending on its price sensitivity. The emission effects of increased power generation, and thereby the impact on net emissions (or the demand for EU ETS allowances) depends on which power stations increase their output.

Higher electricity demand can basically be met by expanding output from existing power stations and by installing new generating capacity. Norwegian electricity output does not rise in the short term, since it is determined by precipitation and for hydropower facilities and wind conditions for wind farms. Because electrification of NCS installations represents an *expected and lasting* change in power demand, it will influence long-term generating capacity. Investing in new capacity or expanding existing power stations becomes more profitable when electricity prices are expected to rise. It is therefore reasonable to assume that increased demand will generally be met with new generating capacity.

The reason we can expect new demand to help encourage investment in additional electricity output is that the power market is dynamic and competition-driven. Its players adapt continuously to alterations in market conditions. Changes in supply and demand influence both short-term price formation and long-term price expectations. Even small fluctuations in supply or demand affect the market.

If market demand changes abruptly and unexpectedly, the increased demand for electricity must be met by either utilising spare generating capacity or raising prices to curtail other demand. Typically, coal- and gas-fired power stations will have the spare capacity to increase output at short notice. If market players expect the higher demand and prices to persist, however, investment will eventually be made in new generating capacity and bring prices down.

Market players continuously analyse future demand for power. Both generators and consumers will base their investment decisions on developments in supply, demand and prices. Planned spending on electrification or the establishment of new industry, both sanctioned and anticipated, will be incorporated in such analyses. Realising electrification projects takes a long time, and they are known to the market in advance. Generating capacity will therefore be largely adjusted to developments in demand when the rise in consumption occurs.

Put briefly, it would be methodologically inconsistent to analyse the market effects of increased electricity demand without taking into account that the supply side also adjusts. That means it is the long-term effect on power generation, after allowing for the investment incentives, which is relevant for the impact of electrification on emissions. How much the generating capacity rises in Norway or in other countries depends on where investment in new capacity is most profitable in terms of price effects and cost considerations.

Given presumptions about climate policy, technological progress and fuel prices, gas-fired and/or renewable or low-carbon power generation represent in practice the only relevant investment options for new electricity capacity.[6]

[6] We assume that investing in new coal-fired power generation in Europe will be neither permitted nor profitable, and that developing new nuclear capacity is to a greater extent politically determined.

Capital spending on new generating capacity is driven partly by politics, through support schemes and climate-policy targets, and partly by the market. Where renewables investment is politically driven, we assume that the political goal is specified as a proportion of total consumption (like today's renewables goal in the EU). This means that politically determined investment in capacity is also influenced by consumption trends.

In other words, expectations of increased power consumption lead first and foremost to higher electricity output. The latter will be based on a mix of gas-fired and renewable capacity, with a steadily higher renewable proportion in the future because of ever more rigorous climate policies. Expanding coal-fired power capacity in Europe is not on the cards, even if electricity consumption rises. Emissions will therefore rise substantially less from power generation than they will decline on the NCS.

Part of the renewables capacity will also be utilised to produce hydrogen in the time to come. Higher electricity prices, particularly in low-price periods, will make green hydrogen more expensive.[7] Increased demand for power could thereby reduce green hydrogen output and increase production of the blue type – which will also yield higher emissions.[8] Power consumption by industry, households and transport may also be influenced by expectations of higher electricity prices, and be adjusted in a way which increases CO_2 emissions.

We quantify the emission effects in both power generation and hydrogen production in chapter 3.

2.5 Effects via the gas market

Electrification of an NCS installation increases the expected supply of pipeline gas to Europe. As with the power sector, higher gas availability will influence price expectations in the European market and thereby both consumption (rises) and supply from other sources (declines).

The relative distribution between consumption (substitution) and supply reductions depends on the elasticity of supply and demand – in other words, how expensive it is to adapt consumption and adjust supply. If the supply curve for gas is completely flat (perfectly elastic), the whole increase will be counterbalanced by reduced production from other sources.

Based on various reports which have analysed supply and demand curves for gas in Europe, Rystad Energy (2021) has estimated that delivering more Norwegian pipeline gas to Europe reduces European LNG imports by 90 per cent of the increase, while consumption rises by 10 per cent. This suggests that supplies from other sources are also most affected in the long term, and therefore have the greatest significance for the emission effect.

Emission effects from higher gas consumption in Europe

How higher gas consumption affects emissions depends on which alternative energy sources are displaced by the increased usage at the margin. Gas is primarily used in Europe for power generation, for producing heat or for direct use by

[7] Producing green hydrogen provides a way of storing surplus power output, particularly from wind and solar. The more hours with zero or very low prices, the more profitable green hydrogen production becomes. Increased demand could yield fewer low-price hours, and thereby make green hydrogen output less competitive than the blue variety. The impact on profitability depends on how the price structure is affected, and the effect could also be that green hydrogen becomes more profitable.

[8] Blue hydrogen is produced in combination with carbon capture and storage (CCS), but the latter does not eliminate all emissions.

industry and households.[9] While higher gas consumption viewed in isolation increases emissions, the net effect depends on what the alternative energy sources are.

The alternative to direct gas consumption will often be electrification. If increased supplies lead to more direct use of gas, it could yield a small reduction in electricity demand – but the emission effects will be small (see the section on effects in the power market). However, lower gas prices also create a presumption in favour of a reduced allowance price, and cuts in both gas and allowance prices reduce electricity charges. The net effect of electrification will thereby probably be small. As a result, the main effect is more likely to be that increased gas consumption displaces oil or other fossil energy sources and thereby reduces emissions.

Where gas supplies come from is assumed to have little influence on European emissions. However, some of the latter relate to regasification. Figures from Equinor (2021) show that this releases 0.9-0.12 grams of CO_2 equivalent (gCO_2e) per megajoule (MJ), which corresponds to 11-14 per cent of emissions in the production and transport chain. Greater supplies of pipeline gas replacing LNG would therefore reduce emissions in Europe.

The overall conclusion is that European emissions could rise somewhat because a larger supply of gas reduces prices and increases consumption. However, the latter is likely to rise by only 10 per cent of the increased delivery. A proportion of this increase will probably represent more direct use of gas in place of electricity (which increases emissions) or oil (which reduces emissions).

Effects of higher gas supplies outside Europe

Increased supplies of Norwegian gas will reduce EU imports from non-European countries. Relevant alternative sources are pipeline gas from Russia[10] and Algeria plus LNG – primarily from the USA and Middle East. According to Rystad's analysis, LNG is probably the marginal source of supply for gas to Europe in the short term.

LNG not imported to Europe will be utilised elsewhere around the world, where the emission effect will depend on whether the gas displaces renewable (or other emission-free) energy, coal or oil *in the long term*. We have not found analyses covering the long-term marginal effects of increased gas supplies globally, and the effects will also depend on which political scenario is assumed. The extremities are that the gas displaces burning coal, which gives a clear emission reduction, or renewable energy, which increases emissions outside Europe.

At the margin, larger gas supplies from the NCS create a presumption in favour of lower global gas prices and in turn some reduction in global gas supplies in the long term. We have no basis for assessing the size of this supply effect.

2.6 Effects via the EU ETS

When analysing the development of electricity and carbon prices, and changes to the power mix and emission consequences, the dynamics of the EU ETS must also be taken into account. This market regulates emissions from the installations it covers (power and heat generation and parts of industry).

[9] Natural gas is used in Europe by the power generation sector (32 per cent), industry (29 per cent), households (26 per cent), and other sectors – primarily private and public services (13 per cent) (Endrava, 2021).

[10] The way the world looks now, with Russia's invasion of Ukraine and gas conflict with the EU, it seems unlikely that Russian supplies will be an alternative to Norwegian supplies in the time to come.

The supply of allowances is determined by the number of these issued at EU level. Norway participates in the EU ETS on an equal footing with the EU member states. The main elements of this market include the following.

- Allowances issued are reduced annually in accordance with a linear reduction factor (LRF), starting from the average number issued per annum during the second trading period from 2008 to 2012.[11] The LRF has been upwardly adjusted a number of times, both temporarily and permanently.
- Allowances are auctioned off or awarded free of charge in line with more detailed rules. All can be traded in the market.
- Installations included in the ETS must ensure that they hold sufficient allowances every year to cover their emissions. Utilised allowances are cancelled.
- Unused allowances can be saved until later.
- If the total number of allowances in circulation (TNAC) exceeds 833 million, a proportion is transferred to the market stability reserve (MSR).[12] A rule has also been introduced that all surpluses between 833 million and a cap of 1 096 million must be transferred to the MSR. If the TNAC falls below 400 million allowances, 100 million are released to the market.
- If allowances in the MSR exceed the number auctioned the year before, the excess is permanently cancelled.

The system operates with different trading periods. It is now in period 4, running from 2021 to 2030. The usual practice is for parameters to be adjusted at the beginning of a new trading period, but several fairly large changes have also been made during them.

Allowance prices reflect the marginal abatement cost – in other words, the cost of the most expensive measure which must be implemented to ensure that emissions do not exceed the allowance cap. Since allowances can be saved, their price reflects the market's *long-term expectations* of the marginal abatement cost. These include the scope of offshore electrification.

Given the analysis above of effects in the power and gas markets, changes to expectations about the scope of electrifying installations on the NCS mean the market will anticipate a reduction in future demand for allowances. The allowance price will fall, with some marginal measures shelved or postponed.

If the allowance cap is fixed in both short and long terms, the freed-up allowances will be used to cover increased emissions elsewhere in the system. But the allowance cap is not given in the long term, and not all freed-up allowances will immediately be used elsewhere.

Two factors thereby create a presumption in favour of emissions nevertheless being reduced in the EU ETS sector.

- A lower emission price creates a presumption in favour of more allowances being saved because some of those freed up remain unused. Greater saving increases the TNAC and thereby the probability that more allowances will be permanently cancelled in accordance with the MSR regulations.

[11] This means that the number of allowances issued is reduced by the same amount as long as the LRF remains unchanged.

[12] In practice, correspondingly fewer allowances are issued the following year.

Relevant revisions to the EU ETS, 2022

Regulations governing the EU ETS are currently under revision. The Parliament and the Council reached a preliminary agreement in December 2022, but the final legal text including all the details is not yet available. The agreement implies the following.

The goal for ETS emission cuts for 2030 increases to 62 per cent compared with the 2005 level. That calls for an increase in the **LRF** to 4.3 per cent in 2024-2027, and 4.4 per cent in 2028-2030.

A **one-off cancellation** of 90 million allowances in 2024 and 27 million in 2026.

The **annual intake rate for allowances in the MSR** is maintained at 24 per cent of the surplus allowances.

The **threshold level** for the TNAC is lowered. If the number of allowances in the MSR is greater than 400 million, all excess allowances are permanently cancelled. The current thresholds are set at 833 and 1 096 million allowances. Earlier, the Parliament proposed reducing these to 700 and 921 million respectively and introducing dynamic thresholds which are automatically adjusted to the total number of allowances from 2025.

- Lower prices for and a larger surplus of allowances make it easier for politicians to lower the emission cap, typically by increasing the LRF. Reduced allowance prices signal that emission cuts in the ETS sector can be implemented at lower cost and less burden on the competitiveness of the European economy. The EU has increased the LRF in several stages.

In other words, the consequence could either be the same emissions in the short term but a reduced allowance price which yields a lower emission cap, or fewer emissions in the short term which increases the likelihood of permanent allowance cancellations and thereby lower emissions also in the longer term.

So far, all changes to the operating parameters both during and between trading periods have been made to tighten up the system. Allowances have been too plentiful, so a number of steps have been taken to lower the cap or to make the rules more rigorous through other measures. This could change after 2030. Earlier calculations show that, were the LRF to be increased to 4.2 per cent as proposed in 2020, the number of allowances would fall to zero by 2041. The Council and the Parliament agreed in December 2022 to a further tightening of the LRF (see text box).

Since it could be difficult to cut emissions that much without industry moving out of Europe, changes which increase the issuing of allowances are likely to be needed. The logic will nevertheless be the same, only with the sign reversed – the faster one manages to cut emissions, including from Norwegian oil and gas production, the less likely it is that the allowance cap will be breached in the second half of the 2030s.

If the EU ETS sectors are to decarbonise fully in the long term, all relevant measures must be implemented sooner or later. The ETS helps to ensure that the cheapest steps are taken first. An important consideration here is that the abatement-cost curve in the market is determined by the individual project's abatement cost over its commercial lifetime, including costs related to postponing a climate measure. It is much cheaper, for example, to electrify a field at the initial development stage than when it has already been equipped with gas turbines on the platform. At the same time, postponing a field development because of allowance-price trends is hardly likely to be profitable.

2.7 Effects via the non-ETS sector

Under the Paris agreement, the EU has an emission commitment for its whole economy – in other words, sectors both within and outside the ETS. Emission volumes from non-ETS installations and sectors are not directly regulated in the same way as in the ETS. However, the EU member states have a common goal of achieving emission reductions in the non-ETS sector as well, with a distribution of obligations between them. The member states have submitted binding plans for how they will achieve emission cuts in the non-ETS sector up to 2030.

Part of the rise in consumption driven by increased gas deliveries from Norway will probably occur in sectors outside the EU ETS. Again, the emission effect will depend on what this gas displaces. The most important consumer areas are probably the direct use of gas by businesses and households. Lower gas prices will make it cheaper to replace coal and oil where these are used, but that could be at the expense of electrification. We are not aware that more detailed analyses of this exist.

If fewer allowances are issued in the ETS sector, Europe could in principle increase emissions from the non-ETS sector. However, there is no reason to believe that either the total emission target or Europe's climate policy ambitions are set in stone – a view which is also supported by history.

Furthermore, climate goals are set not only for 2030 but also for 2050. The ultimate target is complete decarbonisation of the economy. Since this is demanding, the EU is likely to make some adjustment to the share of emission cuts borne by the ETS and non-ETS sectors. Big differences emerging in abatement costs may contribute to such a rebalancing, which could be accomplished both by tightening up the ETS so that more difficult and expensive cuts in the non-ETS sector can be avoided or by incorporating non-ETS emissions in the ETS. A lower allowance price could make both approaches easier, but could also mean some of the effect "leaks" to non-ETS sectors in that emissions there rise.

2.8 Carbon leakage

Changes to the allowance price influence the competitive relationship between the EU and the rest of the world. An increase may cause carbon leakage, which means that goods produced in Europe are outcompeted by non-European products. That takes the form of either production being moved out of Europe or consumption shifting towards imported commodities which have become relatively cheaper because control of GHG emissions in Europe becomes more rigorous. In the worst case, carbon leakage can lead to higher global emissions.

However, the EU has adopted a number of measures to counter carbon leakage. These are directed at industries which compete in the world market and are experiencing substantial cost increases under the EU ETS because they are emission- and/or energy-intensive. The support schemes deployed to combat carbon leakage are also under revision, including the introduction of a carbon border adjustment mechanism (CBAM). This means that, instead of subsidising European industry competing in the world market through carbon price compensation and the award of free allowances, the EU will add a carbon charge to imported goods based on their emission intensity.

In connection with introducing the CBAM, the Commission has conducted a metastudy covering analyses of carbon leakage (European Commission, 2020b). These studies find leakage effects for countries which have adopted climate policy instruments, where imports have risen by five per cent and the carbon intensity of imports by eight per cent. Where carbon leakage related to the EU ETS is concerned, great variations exist in the findings – depending in part on which methodology is used. While simulations show fairly substantial effects, empirical ex-post studies have found them to be small. Generally speaking, indirect effects through global energy markets are more important than direct impacts via global commodity markets.

Simulations also show that support schemes targeting carbon leakage can have a substantial effect. The more effective they are, the smaller the carbon-leakage effects – both positive and negative.

Small carbon leakage impacts indicate that the total global emission effects largely correspond to those in Europe. Other global effects emerge through impacts on the gas market.

3 ALTERNATIVE METHODS FOR QUANTIFYING EMISSION EFFECTS IN THE POWER MARKET

This chapter presents calculations of emission effects in the power market based on the methodology described in chapter 2 – in other words, based on long-term marginal changes. These calculations have been performed with the aid of our European power market model and for three climate-policy scenarios. We describe the scenarios and the model results in section 3.1.

We also summarise and comment briefly in section 3.2 on alternative methods and calculations presented in two other reports. Section 3.3 compares emission factors obtained by the different methods.

3.1 Long-term marginal emission factors

How electricity generation develops up to 2050 will depend on developments in the economy and the markets, energy- and climate-policy parameters, and technology. Although we assume that the EU's climate goals and commitments will be met in the long term (2050), it is uncertain what path this attainment will take. That is also significant for the emission effects and profitability of NCS electrification.

This means, too, that it will not be relevant to invest in new coal-fired generation without carbon capture and storage (CCS), and that spending on new generating capacity will involve a mix of renewable, nuclear and gas-fired power.[13] Towards 2050, investment may also be necessary in technologies which yield negative emissions (such as bioenergy with CCS – BECCS). The shares vary across the policy scenarios and over time.

More about the modelling

We have utilised the TheMA power market model to calculate changes in carbon emissions from increased electricity generation as a result of higher demand. When quantifying the long-term marginal emission intensity, it is irrelevant which consumption increases. The effect will be the same if the growth in power demand derives, for example, from new industry in the same price area.

As explained in chapter 2, we are seeking to quantify the marginal emission effects of an lasting rise in Norwegian demand for electricity. In practice, we do this by simulating how an increase in demand affects electricity generation in Europe when we allow the model to take into account that the development of consumption affects the profitability of investing in new generating capacity.

The model also includes a certain price sensitivity in industry consumption, while changes in the gas market are excluded. Representation of the EU ETS and allowance prices in the model captures abatement costs in industry and fuel switching for power generation in line with allowance availability.[14]

[13] The model permits investment in new gas-fired power without CCS before 2045 in certain countries. However, investing in gas-fired electricity will only be profitable in the turbulent transition scenario and then to a very limited extent.

[14] Allowance price trends are estimated in a separate simplified model based on long-term abatement-cost curves for ETS emissions. On that basis, we calculate emissions from the power and industry sectors. If the results are inconsistent with the allowance cap, we calibrate the price curve which is entered in the power market modelling.

Development of a future hydrogen sector will also be influenced by price alterations induced by lasting changes in demand for electricity. In TheMA, we model a future hydrogen market which responds to developments in power prices. The connection between the hydrogen and electricity sectors is revealed in the form of power utilised for electrolysis (power-to-gas) and hydrogen-fired electricity generation (gas-to-power).

Lower power-to-gas consumption means a reduced share of green hydrogen. We do not model the hydrogen market as such, but calculate emission effects on the basis that reduced output of green hydrogen will be replaced by grey or blue alternatives. Grey hydrogen is assumed to be phased out over time, with the share of blue (and green) types increasing correspondingly.[15]

Climate policy scenarios

Three scenarios describe the overall climate and energy policy framework relevant for the assumptions we apply when running the models. They are *base scenario, technotopia* and *turbulent transition*, and their underlying assumptions are outlined below. Europe reaches its long-term climate goals in all three, but the path taken to attainment differs. The scenarios are useful in illustrating the uncertainty range for the emission effects of increased power consumption in the long term.

[15] We have assumed that the share of blue hydrogen rises from zero per cent in 2030 to 100 per cent in 2045 and 2050. To calculate the emission effect, we use emission factors of 10.2 tCO_2 per tonne of H_2 for grey and 2.5 tCO_2/tH_2 for blue in line with the Hydrogen Council (2021).

Base scenario

In the reference scenario, the decarbonisation goal drives growth in renewable energy through both support schemes and market-driven investment. The various countries and markets in Europe become more integrated, in part through collaboration over joint offshore wind projects connected to an offshore grid. The CO_2 price rises as the cap in the EU ETS is lowered. Gas prices are expected to decline from today's heights to a stable lower level, where gas functions as a transitional technology in the energy transition. Power demand rises substantially through electrification of transport, industry and heating, as well as from new power-intensive industry. Hydrogen plays a crucial role in tomorrow's electricity system and represents a source of increased power demand and generation. By serving as an energy storage medium, it contributes to greater flexibility in the energy system. To meet the goal of net zero emissions, other decarbonisation technologies – such as BECCS – will also be needed in the longer term.

Technotopia

The scenario describes developments in the power market if the expansion of low-emission technology accelerates. The levelised cost of energy (LCoE) for renewables is reduced substantially faster than currently expected, and this progress results in more market-driven investment. Compared with the base scenario, using hydrogen in power-to-gas and gas-to-power becomes profitable earlier. The European CO_2 price will be lower than in the base scenario because new cost-effective solutions are developed for reducing industrial GHG emissions. Since low-emission energy technologies (renewable electricity generation, CCS and power-to-x) are globally available at low cost, oil and gas prices also fall compared with the base scenario.

Turbulent transition

This scenario describes circumstances where it proves harder to meet the EU's climate goals than first expected. The renewable energy target cannot be met because the build-out of these sources encounters substantial obstacles. Energy cooperation across national borders is less extensive, resulting in reduced capacity for electricity exchange between countries, and offshore wind power combined with an offshore grid (hybrid projects) is not established. Gas prices are higher than in the base scenario, since consumption is greater. No European hydrogen market is established, and this commodity thereby never attains the same role in the energy system which natural gas plays today. Decarbonisation of industry also turns out to be more expensive that expected. In the longer term, large negative emissions through direct capture from the air and CCS technologies will be needed to meet the climate goals. That leads to high CO_2 prices.

Calculated long-term emission factors

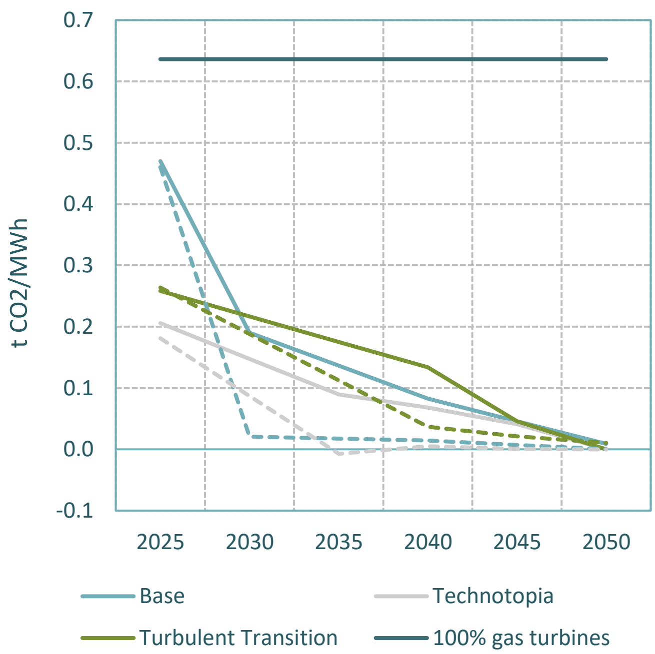
Figure 2 presents the long-term marginal emission factors assuming an lasting rise in demand in the electricity market alone (dotted lines) for the various scenarios and when account is also taken of emission effects in a future hydrogen market (solid lines).

Emissions increase in all cases from the power and hydrogen sector, and thereby demand for allowances. We assume that the lasting rise in demand begins in 2025 and is common knowledge in the market from 2022. That means the market in 2025 will not have had time to adapt fully by investing in renewable capacity. How much can be invested in various time perspectives has been entered as a restriction in the model. In the short term, increased *renewable generation* can only come from existing planned and sanctioned projects which enter the market. We will therefore experience greater utilisation of existing thermal power stations (coal, lignite and gas) in 2025, which means higher emission factors than in the long term.

Results vary between the scenarios. In turbulent transition, for example, the model may increase utilisation of existing biomass power stations in 2025 to meet increased consumption. That gives a lower emission factor than in the base scenario. After 2030, the marginal emission factor for the electricity and hydrogen system sinks to below 0.2 tCO_2/MWh in all scenarios and is (as presumed) virtually zero. Since the emission intensity of NCS gas turbines is constant over time, Figure 2 also illustrates how emission reductions are distributed over time.

Where industry and households are concerned, we assume an increasing proportion of flexible demand over time. But consumption alterations here are very small in relation to the changes for hydrogen. All the scenarios show a rise in thermal power generation in 2025. In the longer term, however, output increases in mixes of renewable technologies and reduced green hydrogen production which vary between the scenarios. Turbulent transition shows the biggest decline in production of green hydrogen, along with an increase in nuclear power (including new investment) and gas-fired electricity generation with and without CCS. That is because we anticipate bigger barriers to developing renewable power in this scenario.

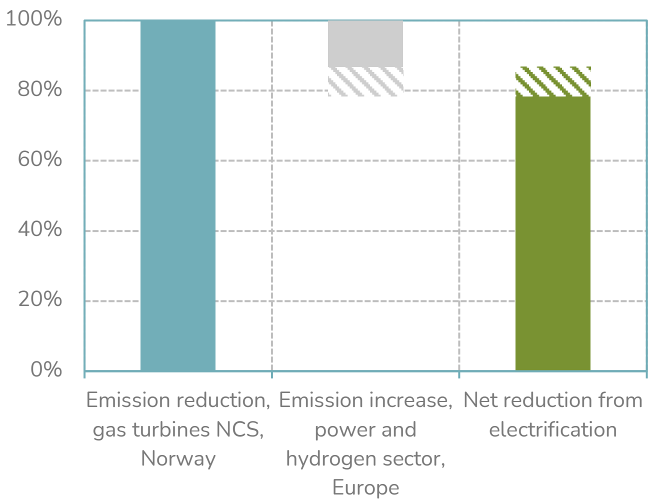
Figure 2: Marginal emission factors per MWh of consumption in the various scenarios.



With these emission factors, we can quantify the emission effect for a sample case involving an offshore field currently operated with gas turbines. Our calculation is based on an assumed power requirement of 100 MW, which can be met by either continued turbine operation or power from shore. We assume that the field operates around the clock from 2028 to 2050. The power requirement becomes known and a green light is given for the electrification project in 2022. In the non-electrification alternative, where the field is powered by gas turbines throughout its operating life, we assume an efficiency of 33 per cent (corresponding to the assumption also applied by the Pöyry report referenced in section 3.2).[16]

If the field is electrified, we assume a 10 per cent transmission loss in the cable from land. That is the same assumption we have made in earlier calculations of abatement costs. The power requirement is multiplied by the emission factors presented in Figure 2. With these stylised assumptions, aggregate CO_2 emissions over the field's commercial lifespan will be 12.8 million tonnes if power is supplied by local gas turbines.

Figure 3: Emission reductions for a field example.



In order to calculate the net effect of electrification in the EU ETS, aggregate emissions from European electricity generation and hydrogen production must be deducted from emission reductions on the field. The net reduction depends on the energy efficiency in the non-electrification alternative and the energy losses in the offshore-to-land connection. The aggregate emissions are 1.7 million tonnes in technotopia, 2.4 million tonnes in the base scenario and 2.8 million tonnes in turbulent transition. Figure 3 presents the emission effects, with the uncertainty range between the three scenarios shown by shading. The net emission reduction is largest in technotopia, where the electricity generating sector is decarbonised most rapidly, and smallest in turbulent transition.

The net reduction in the EU ETS sector varies from about 78 to 87 per cent of the local emission cut on the field, depending on the policy scenario.[17] The difference between the outcomes depends on the emission intensity of energy supply on the field, and of increased electricity generation and hydrogen production which varies across the policy scenarios. It nevertheless transpires that the uncertainty range for emission reductions from electrification does not vary substantially between the three scenarios. That is partly because all of them achieve net zero emissions in 2050, and the marginal emission intensity thereby becomes lower over time.

[16] Gas turbines on new fields and at onshore plants may be more efficient than those on existing offshore installations. This would reduce the net reduction somewhat.

[17] The power plant associated with Hammerfest LNG on Melkøya, for example, has an energy efficiency of 68 per cent and losses in the connection cable to the grid on land are estimated to be one per cent. The net savings from electrification in this case will be between 59 and 75 per cent of the emission reduction on Melkøya.

Emission intensities for fossil power generation

The long-term marginal emission intensities based on model calculations of the market changes are substantially lower than emission intensities for thermal power generation. Figure 4 presents how much net emissions would have been reduced if we assumed that the increase in consumption was fully met by different types of thermal power stations – gas-fired combined cycle facilities, gas turbines on land, and units fuelled by coal or lignite. Calculation of the emission intensity is based on the carbon content of the fuel (Norwegian Environment Agency, 2022c), (Umweltbundesamt, 2022) and the power station efficiencies presented in table 1.

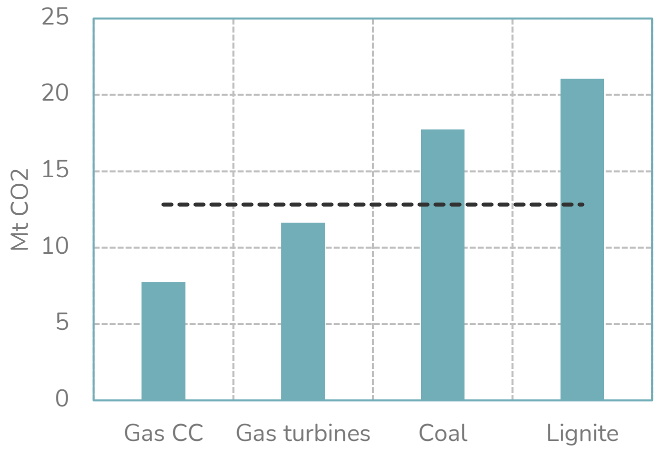
Table 1: Emission intensities for various fuels and power station types

Power station type	Emissions (tCO_2/ MWh fuel)	Efficiency	Emissions (tCO_2/ MWh power)
Gas-fired combined cycle	0.21	60%	0.35
Gas turbines	0.21	40%	0.53
Coal-fired	0.32	40%	0.80
Lignite-fired	0.38	40%	0.95

Figure 4 shows that electrification would also have had a positive emission effect if the electricity came from a modern gas-fired combined cycle power station on land. Correspondingly, onshore (open cycle) gas turbines have a somewhat higher efficiency (including transmission losses) than those offshore, while electricity generated from coal and lignite has higher emissions.

In other words, emission factors estimated on the basis of model calculations and long-term market effects yield much larger net emission cuts than supplies from a gas-fired combined cycle station, which corresponds to about 40 per cent of the local emission reduction on the field or from a coal/lignite-fired power station which would have increased emissions.

Figure 4: Emission effects from electrification for various thermal power stations



3.2 Emission factors based on the generation mix

The literature includes various reports and analyses of emission effects from electrifying offshore platforms. Their results depend on the assumptions made and the methodology used. As explained in chapter 2, our calculations of emission effects are based on a long-term marginal perspective where we take account of the market adapting to lasting and expected changes in demand. This perspective differs from the analyses in Torvanger and Ericson (2013), hereafter the Cicero report, and Lofsnæs and Torvanger (2014), hereafter the Pöyry report. The latter is a follow-up to the Cicero report, and a collaboration between Pöyry and Cicero.

The Cicero report

Prepared for the Norwegian Oil and Gas Association, the Cicero report studied emission effects in the electricity market based on averages. Emission effects in this market depend on where the electricity is assumed to come from – Norway, the Nordic region or Europe. That is because the power mix – in other words, the composition of electricity generation - varies between the different markets. Calculating emission effects is based on the actual and expected power mix in 2012 and 2030 respectively, while net emission effects are calculated by taking account of emissions related to the use of freed-up gas.

Where electricity generation is concerned, average emission factors are calculated from the CO_2 content in the Norwegian, Nordic and European power mixes. Total output is used as the basis for calculating average emissions per kWh. The CO_2 content per kWh depends primarily on the proportion of coal- and gas-fired electricity in the total generation mix. CO_2 emissions in the power sector will be lower in 2030 than in 2012 because more renewable energy is being developed over time. Furthermore, net emission effects depend on how the freed-up gas is utilised – in a gas-fired (thermal) power station or replacing electricity generated from a different type of facility.

The authors argue that the average method provides more accurate results than a marginal method based on the existing set of generating facilities. They do not discuss a marginal method based on how an increase in demand influences investment in new capacity.

Furthermore, they maintain that emission changes within the EU ETS will be counterbalanced by adjustments elsewhere in the system because the emission cap is a given.

The Pöyry report

Prepared for the Norwegian Union of Industry and Energy Workers (Industry Energy), the Pöyry report analyses how the emission effects of electrifying a specific field – Utsira – influence emissions in the power market. Its analysis utilises a market model and calculates emission effects on the basis of two different scenarios. The field is expected to be on stream from 2019 to 2050. We will look more closely here at the market scenarios – in other words, scenarios where electricity supply is sourced from the open market rather than dedicated power stations. Development is driven in the one scenario by subsidising renewable electricity generation, and in the other primarily by the allowance price.

The market scenarios assume that power generation in Norway will not increase because output from wind, hydro and small-scale sources is fixed and electrification of Utsira does not provide a basis for investment in new hydro or wind power (which the report maintains would be the case for demand growth in general). Electrification of Utsira would yield a small price increase, but this is not sufficient to trigger new investment in Norway. The rise in consumption would thereby be covered by reduced exports or increased imports.

Output must therefore expand in the European electricity system. Even in Europe, it does not appear that this leads to increased generating capacity. “Generation adjustments will primarily be based on fossil fuels, since renewable technologies are unable to adjust to higher demand.” Over time, replacement power will increasingly come from gas-fired power stations based on a short-term marginal approach.

As a starting point, the freed-up gas is assumed to be distributed across different sectors in the same way as in 2014. Furthermore, it is assumed that some of the freed-up gas replaces oil and thereby yields an emission reduction, while the remainder replaces other gas and accordingly has no net effect on emissions. In a worst case, the report shows that – if freed-up supplies lead to increased gas consumption in the non-ETS sector – emissions in Europe could rise by more than the reductions on the field. No account is taken of emission changes which are related to Norwegian pipeline gas displacing other gas supplies.

With reference to the Ministry of Petroleum and Energy (2011), it is assumed that emission reductions in Utsira will be counteracted by a corresponding rise in emissions from other installations covered by the EU ETS. However, the report adds that the emission cap will probably be lowered further after 2020 and that the level of political ambition will be influenced by a possible growth in surplus allowances. Possible consequences for cancelling allowances in the MSR are not assessed, although the decision to introduce this mechanism had been taken when the report was written.

Comparison of the methods

The approaches in the Cicero and Pöyry reports are based on the same principles. However, the latter uses a power-market model and two scenarios for electricity-market development in order to extrapolate trends in the power mix, rather that the case-based approach taken in the Cicero report.

The most important difference from our long-term marginal evaluation is that we take account of the market adapting to lasting changes and/or expectations of such alterations in demand. That applies to both power and gas markets, where demand and supply are likely to adjust continuously to new information. The EU ETS clearly has a different dynamic, since the supply of allowances is politically determined. However, regulation of the ETS is also likely to respond to market changes – including to investment, technology developments and demand. We believe this is also demonstrated by the history of the ETS. In any event, the introduction of an MSR, with a mechanism for permanent cancellation of unused allowances, means that the allowance cap is not fixed.

An electricity-market model is utilised in the Pöyry report to analyse the capacity mix in the market over the long term, and two scenarios are deployed to capture different development paths for the power markets, depending on climate policy. However, less emphasis appears to have been given to market-based investment than in our approach, where spending on wind and solar generating capacity over time is assumed to be market-based. The modelling is not used to assess how a rise in consumption would influence investment.

Both analyses discuss how the use of the freed-up gas influences emissions in Europe, including to what extent it displaces gas from other sources. The area covered by both analyses is Norway, the Nordic region and Europe. As far as we can see, carbon leakage and effects on global emissions are not discussed.

How have the basic assumptions changed ?

The assumptions forming the basis for the analyses affect their results. Expectations about future developments in the power market, the formulation of and level of ambition in climate policy, and the cost of various technologies have changed since 2013-14. A much stronger development of offshore wind is expected, and hydrogen will play a very important role in balancing a power system which will eventually be dominated by wind and solar power. Technology has advanced faster than expected, and climate policy in Europe has also become more rigorous (see chapter 2).

Assumptions about future climate policy developments

The reports were based on contemporary political parameters, with the ETS defined until 2020 and the EU's climate- and energy-policy ambitions enshrined in the 20-20-20 package. The latter set goals of a 20 per cent reduction in emissions, an enhancement in energy efficiency and an increase in the end-use of renewable energy in 2020 compared with 1990. With the exception of the energy-efficiency target, these ambitions were realised in 2020.

Looking towards 2030, the Pöyry report points to the climate goals set by the EU in 2014. These projected a reduction in GHG emissions of at least 40 per cent compared with 1990. Since then, the climate ambitions have been raised to an emission reduction of at least 55 per cent.

The EU's 2030 goals for the share of renewable energy and enhancing energy efficiency have also become more ambitious since the report was produced. It assumes at least 27 per cent renewable energy and improved energy efficiency in 2030 at the EU level. Negotiations were under way in the autumn of 2022 on new renewable energy and energy efficiency targets which involve a further raising of the ambitions from the 2019 Clean Energy package. The proposals under discussion on the share of new renewables will involve lifting the goal for 2030 from today's 32 per cent to at least 40 per cent. Where energy efficiency is concerned, the negotiations also involve increasing today's target from a reduction in end-use of 32.5 per cent to at least 36 per cent in 2030 compared with 1990.

The Pöyry report assumes that emissions in the non-ETS sectors will increase owing to a rise in gas consumption. Hence, the report does not take into account that emissions in these sectors are subject to climate policies in order to comply with the target of cutting overall EU emissions by 55 per cent in 2030.

Up to 2014, the target for the non-ETS sector involved a 10 per cent reduction in 2020 compared with 2005. This objective was then raised, and the current ambition implies a 30 per cent emission cut by 2030 compared with 2005 at the EU level, with national goals for each member state tailored to their abatement costs and ability to contribute. A revision process is under way on the goal for the non-ETS sector, with preliminary agreement to enhance it to a 40 per cent emission reduction in 2030.

In Norway, too, the climate-policy framework has changed, with an increase in national and petroleum-sector emission-reduction ambitions (see section 2.3). Where the CO_2 tax for the petroleum sector is concerned, the reports assume that the sum of this and the allowance price will remain at the same level as the CO_2 tax before the petroleum sector was incorporated in the EU ETS. This assumption is out-of-date, with the sum to be substantially increased and the tax set to be adjusted so that the combined tax and allowance price will be NOK 2 000/tCO_2 in 2020 value by 2030.

The short-term expectation for international climate policy proved accurate in so far as the key 20-20-20 climate- and energy-policy goals were realised apart from the energy efficiency target.

A more rigorous climate policy from 2020 towards 2050 which involves a virtually complete decarbonisation of the power system is assumed in the Pöyry report. The level of ambition in climate and energy policy for the period up to 2050 has been substantially raised since the two reports were written, which means that their medium-term expectations are out-of-date or do not reflect the details of medium-term developments.

Raising the climate targets and faster build-out of renewable energy help to increase the supply of low-emission electricity and thereby reduce the emission intensity of power supplies.

Costs for wind and solar power have been sharply reduced in recent years through technology advances and learning effects. This implies that it is now more reasonable to assume investment in renewable energy can be realised on the basis of market prices and be less directly induced politically through subsidy schemes.

Assumptions about EU ETS developments

The Cicero and Pöyry reports assume that the ETS continues virtually unchanged after 2020. When the Pöyry report was written, the EU had decided to introduce the MSR, and it notes that this in intended to contribute to a rise in the allowance price towards EUR 40-50 per tCO_2 in 2030. In its two scenarios, the carbon price in 2020 is EUR 25/tCO_2 or lower while the higher of the two puts it at EUR 50/tCO_2 by 2025. During the second half of 2020, the price began to rise considerably to a level which has largely lain around EUR 70-90 per tCO_2 in 2022. In the longer term, towards 2050, one scenario opens for an increase in the carbon price to EUR 120/tCO_2, which corresponds to the level in our long-term power price forecast.

Presuming that existing or similar policies will be extended does not necessarily take account of an expansion in the emissions covered by the ETS and a tightening of the pricing mechanism. The presumptions about the scope of and level of ambition for the system may therefore become outdated in the medium term. Nevertheless, the Pöyry report covers a broad uncertainty range for allowance price developments in its scenarios.

Assumptions about power market developments

Where Norwegian delivery capacity is concerned, the Pöyry report expects a tight power balance up to 2030 followed by growing electricity oversupply. In addition to some expansion in hydropower, new land-based wind-power capacity is expected. However, its scenarios assume modest development of solar and offshore wind power compared with our current expectations. The latter, in particular, has a substantial potential in the long term.

Both reports assume a stronger integration of the European electricity market. The assumptions in the Pöyry report include an increase in transmission capacity, with planned interconnectors from Norway to Germany and the UK – which are now in operation – and with even more links expected in the longer term. Greater integration between the Norwegian, Nordic and north European power systems by 2030 is also assumed in the Cicero report.

The Pöyry report's estimate for development of the power balance (probably for the EU) is lower than the actual and expected trend. It presumes growth in fossil-free electricity generation, but coal-fired power has been phased out more quickly than the two scenarios indicate. The probability that phasing-out coal generation will take rather longer has now increased as a result of reduced gas supplies from Russia.

In the scenario where capacity development is driven by the allowance price, nuclear energy increases its share much more than renewables on the grounds that it has lower costs. As mentioned above, the cost of renewable electricity has fallen and expectations for offshore wind have become more optimistic.

The share of CCS and negative emission technologies is also modest towards 2050 in both scenarios. A lot has happened both nationally and at the EU level which suggests that CCS could make an earlier entry. Nevertheless, great uncertainty continues to prevail here about future technology and market developments.

Analyses in the Cicero report cover a shorter timespan (up to 2030), and it chooses to ignore CCS since this is considered unlikely to be an important technology in the electricity system until then – an assumption which remains valid today. The report assumes a halving of CO_2 intensity in the EU electricity mix from 2012 to 2030 owing to the build-out of wind and solar power, but it is unclear which assumptions underlie this assessment.

Assumptions about gas market developments

The Pöyry report applies simplified assumptions about the gas market, including that fuel prices remain constant from 2015 to 2050, in order to isolate the effect of climate-policy measures on decarbonisation costs, and subsequently on generation and transmission capacity developments.

Furthermore, the breakdown of gas consumption between sectors in the EU is assumed to remain unchanged, with half the gas exported going to EU ETS sectors.

The gas market and expectations about the role of this commodity have changed since 2014 because climate policy has become more rigorous and renewable costs have fallen.

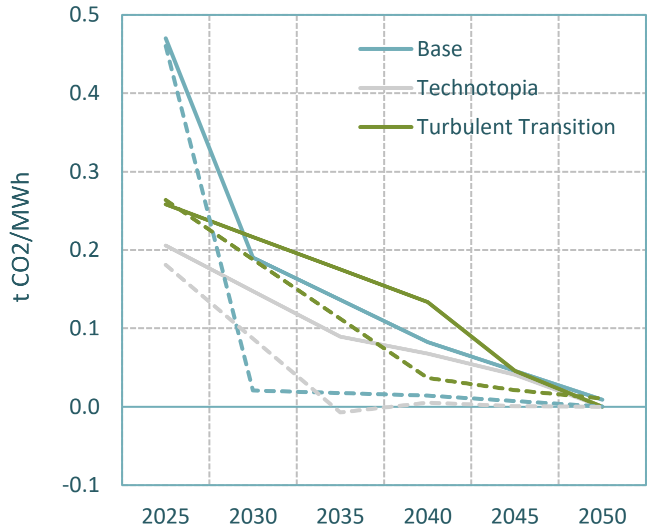
It is unlikely that the breakdown between different consumer sectors will remain unaltered up to 2050. This is likely to shift between consumption areas, depending on the availability and cost of decarbonisation options in the various sectors.

3.3 Emission effects quantified using different methods

Because the preconditions and expectations concerning future market conditions and policy parameters have changed since 2014, the calculated emission effects in the Cicero and Pöyry reports are not directly comparable with the estimates based on our updated scenarios. In order to compare how the various methods affect the calculated emission effects in the electricity market, we have applied the same methods as in the Pöyry report but based on the power-generation mix in our scenarios.

Figure 5 presents the emission factors for Europe as a whole based on the two methodologies. It compares these for power generation alone – in other words, excluding effects via the hydrogen market since this is not included in the methodology applied in the Pöyry report. Our marginal methodology is illustrated with a solid line, while the average approach taken by Pöyry is illustrated with dotted lines.

Figure 5: Marginal (solid) and average (dotted) emission factors



For 2025, our marginal methodology yields higher emission factors than the average approach. This is because generating capacity has not had time to adapt to increased consumption. (We have assumed that only three years pass from the market becoming aware of the relevant electrification project until it is in operation.) A large part of the short-term generation *increase* must therefore be covered from gas- and coal-fired power stations. The average methodology gives a smaller emission increase from electricity generation in this case, since the market generation mix includes a large proportion of emission-free output.

The market will have adapted to the consumption increase by 2030 in all the scenarios through investing in more renewable production. In the base and technotopia scenarios, the marginal emission intensity declines to almost zero. The average methodology provides higher emission intensities in this case because the system still includes a proportion of thermal/fossil generation.

In the long-term, the average emission intensity will become negative in all our scenarios, particularly in technotopia, because negative emissions will be needed to compensate for remaining amounts released in other sectors. In other words, net zero emissions are reached in 2050 through both “positive” emissions – in hard-to-abate industrial sectors, for example – and “negative” emissions deriving in part from the electricity sector.

Negative emissions can be achieved with various technologies, particularly using sustainable biomass in BECCS or utilising renewable energy to extract GHGs from the air – direct air CCS (DACCS). Opting for a marginal perspective to calculate the effects of electrification achieves higher emission factors than with the average method, since marginal demand will mean some marginal (positive) emissions to meet the extra power requirement.

The average methodology used in the Cicero and Pöyry reports is based on an average generation mix, and not on the way generation alters as a result of a lasting consumption change. That gives a less precise estimate for the emission effects in both short and long terms.

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4 PROFITABILITY OF ELECTRIFICATION

The climate-policy parameters are crucial determinants for both the commercial and the socioeconomic profitability of electrification.

Emissions from NCS installations are subject to the EU ETS and a special Norwegian tax. In other words, the overall CO_2 cost comprises the sum of the allowance price and the CO_2 tax. The latter is set so that the CO_2 cost does not exceed the general CO_2 tax level. In principle, the overall CO_2 cost reflects the marginal cost of implementing measures to reach Norway's national goal for emission cuts, while the European allowance price reflects the marginal cost of measures in the EU ETS.

The allowance price and CO_2 tax mean that the commercial and socioeconomic profitability of electrification from a Norwegian perspective largely coincide.

4.1 Recommended method for calculating abatement cost

The abatement cost is calculated for the lifetime of a project by dividing the present value of the cost difference between electrification and the non-electrification option (excluding the cost of buying allowances) with the discounted aggregated emission reduction.

This cost is expressed in NOK/tCO_2. That calculation method is recommended by the Norwegian Petroleum Directorate (NPD) and the Norwegian Water Resources and Energy Directorate (NVE), see, for example NPD (2020).

The abatement cost for an electrification project is calculated on the basis of the cost difference between electrification and local energy supply on the field from gas turbines (the non-electrification option). The most important elements in this calculation are:[18]

- investment costs (added cost of electrification)
- costs of buying power from shore.

To be able to compare projects with different cost and emission profiles, the abatement cost is calculated as the present value of the emission reductions over the lifetime of the measure.

Calculating present value uses a discounting factor which weighs future value against current value (Ministry of Finance, 2012).

4.1.1 Market value of freed-up gas

Investment costs are by far the largest component, and depend mainly on project-specific conditions, while energy prices vary across the scenarios. The significance of investment spending for the total cost is greater than its amount would suggest because power costs and the gas-market value are correlated and counteract each other – a high gas price increases the value of freed-up gas, which reduces the abatement cost if all other things are equal. At the same time, a high gas price means that the power cost in Norway rises, both directly though the interconnectors to continental Europe and indirectly because of the increase in the allowance price. More expensive power lifts the abatement cost.

[18] Electrification also cuts NO_x emissions from the NCS. A reduction in the NO_x tax is reflected in differences in Opex between the options.

Electricity purchases are an important element in the abatement cost. The value of Norwegian power output is influenced by coal and gas prices as well as the allowance price which power stations in Europe must pay. Developments in the European CO_2 price thereby represent an important driver for electricity prices in Norway and the abatement cost of electrification. In the long term, developments in the cost of renewable power will also affect electricity price levels, a result which also relates to climate policy.

4.2 Valuing emission cuts

If the abatement cost of electrification is lower than the CO_2 cost, the measure is cost-effective and socioeconomically profitable. Similarly, it is unprofitable where the abatement cost exceeds the CO_2 cost. Which CO_2 cost would be appropriate to apply depends on the climate-policy parameters. The price varies, for example, between ETS and non-ETS sectors as well as internally within them, for various reasons.

CO_2 costs for NCS emissions comprise the allowance price in the EU ETS and a special tax on emissions. Electrification is therefore commercially profitable if its additional cost is lower per tCO_2 than the sum of the allowance price and the CO_2 tax (calculated as the present value over the project's lifetime).

The allowance price reflects the marginal cost in the EU ETS, more specifically the present value of the abatement cost for the most expensive measure which the market expects will be necessary if total emissions are to remain below the emission cap over time. Similarly, the sum of the allowance price and the CO_2 tax can be regarded as the marginal cost of achieving *Norway's* climate goals. This means that, from a Norwegian perspective, electrification of NCS installations is socioeconomically profitable even if the abatement cost exceeds the allowance price.

As mentioned, the profitability of a measure depends on the value of emission cuts over the project's lifetime. The present value of the abatement cost and the emission cuts are therefore compared to determine whether the project is profitable. In other words, the trajectory of developments in the allowance price and the CO_2 tax, as well as for electricity and gas prices, must be assessed when calculating the socioeconomic profitability of an electrification project.

New rules from the Ministry of Finance for valuing Norwegian GHG emissions in socioeconomic analyses came into force on 1 January 2022. In accordance with these rules, the carbon price for emissions from petroleum and civil aviation must reflect the carbon pricing these sectors face – in other words, both ETS allowance prices and CO_2 taxes.

The guidelines by the Ministry of Finance (2021a) specify the rates to be applied in net present value calculations of public projects:

- general CO_2 tax: for the decade ahead, a price trend in line with the growth of the CO_2 tax up to 2030 should be used – in other words, a gradual stepping-up to NOK 2 000 per tonne (2020 value) by 2030
- emission allowance price: set in accordance with the expected development of this in the EU ETS
- long-term carbon prices (more than a decade ahead): estimate based on the global cost-effective carbon price necessary to meet the temperature target in the Paris agreement.

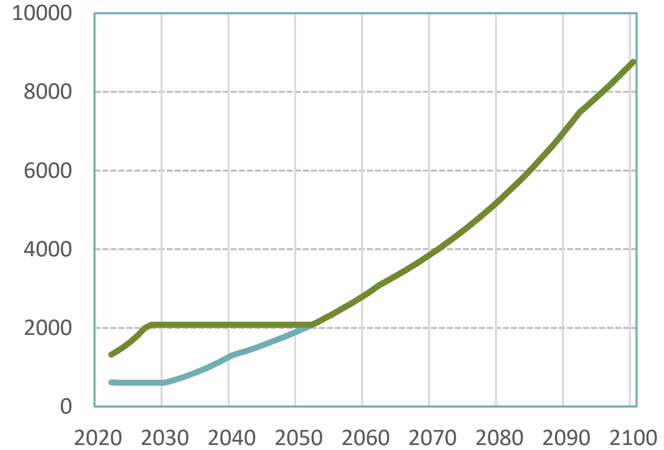
Petroleum and civil aviation are subject to both the EU ETS and the CO_2 tax. Where these sectors are concerned, the starting point is that the notified level for the sum of CO_2 tax and allowance price will not exceed NOK 2 000 (in 2020 value) up to 2030.

The finance ministry also comments that it would be reasonable to assume in the long term that all types of emissions move towards the same price consistent with the Paris agreement.

This means that the CO_2 cost for the petroleum sector remains unchanged in real terms until the long-term allowance price exceeds the Norwegian CO_2 cost. Emissions should thereafter be priced in accordance with the allowance price.

Rates applying for 2022 are presented in Figure 6. From 2028, the sum of the anticipated allowance price and CO_2 tax will reach NOK 2 000 or more. The allowance price is not expected to exceed NOK 2 000 until after 2050 (in 2022 value). In other words, the petroleum sector is expected to face a special tax in addition to the ETS allowance price throughout the period up to 2050. The principle for determining CO_2 costs is therefore fairly straightforward. But it is unclear, of course, whether the level will be adjusted in the future. Uncertainty also prevails about the movement of the allowance price. See the discussion of the dynamics of the EU ETS in section 2.6.

Figure 6: Development of the allowance price and the socioeconomic calculation price for CO_2 measures in the Norwegian petroleum sector, NOK/tCO_2 (2020 value)

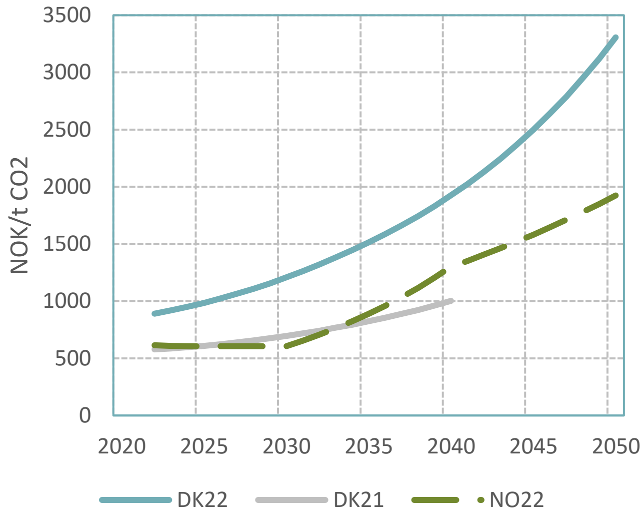


Source: Ministry of Finance (2021a)

The finance ministry's extrapolation of the allowance price reflects the prevailing expectation at any given time. With the stepping-up of the LRF currently under discussion – see the box in chapter 3 – the allowance price expectation will probably be raised in the next revision of the guidelines.

An extrapolation by the Danish Ministry of Finance for the allowance price curve from June 2022 shows a sharp increase in relation to the corresponding one from 2021 (Danish Energy Agency, 2022). Figure 7 presents both the Danish allowance price curves as well as that from the Norwegian ministry

Figure 7: Allowance price curves from the Danish (DK) and Norwegian (NO) finance ministries



Sources: Danish Energy Agency (2022) , *Ministry of Finance* (2021a).

4.3 Timing aspects

The present-value calculation method recommended by the NPD and the price curve proposed by the finance ministry mean that an electrification project may be profitable even with an abatement cost higher than the sum of today's allowance price and CO_2 tax.

Furthermore, it follows from the description above that the timing of such a project – in other words, when it is executed – affects its profitability. The allowance price is expected to rise over time, so that increasingly expensive measures must be implemented as the emission cap is lowered. It could therefore be profitable to postpone measures if the allowance price falls. Where electrification of new fields on the NCS is concerned, however, a postponement would involve higher abatement costs later. That is because a large part of the cost difference between power from shore and gas turbines offshore reflects the high cost of the space required for gas turbines on the field and the extensive conversion work needed to electrify later. At the same time, postponing production out of consideration for electrification would be very expensive – and therefore hardly likely.

This suggests that electrification when developing a new field also has an option value. If the project does not apply a power-from-shore solution from the start, the abatement cost of later retrofitting will be much higher.

The commercial lifetime is clearly crucial for the economics of a measure (Norwegian Environment Agency, 2022a). Profitability assessments will differ for a facility expected to be on stream in 2050 compared with one due to shut down during the coming decade. At the same time, experience suggests that many fields enjoy an extended commercial lifetime because more of their resources are matured or new discoveries are tied in.

4.4 Examples of abatement-cost calculations

4.4.1 Norwegian Environment Agency (2022)

The NEA's review of climate measures for petroleum, industry and energy supply provides an estimated socioeconomic abatement cost for offshore electrification projects of NOK 1 000-1 500 per tCO_2 (Norwegian Environment Agency, 2022a). Projects included in this calculation have a reduction potential of 600 000 tCO_2 on the NCS and will create an estimated power demand of one terawatt-hour (TWh) per year.

These projects are additional to those in the NEA's reference curve for climate measures expected to be implemented before 2030. Sanctioned and planned electrification projects included in this projection reduce emissions by about three million tonnes and require nine TWh of electricity. Several of them have an abatement cost below NOK 1 000-1 500 per tCO_2.

The variation in abatement costs between power-from-shore projects relates primarily to:

- field-specific investment costs depend on distance from land, proportion of direct-drive equipment involved and conversion requirements on the installation
- remaining commercial life, which determines the emission-reduction potential
- closeness to a wind farm which facilitates joint connection to shore with an offshore installation.
- distance to the connection point – where this is short, it permits an alternating current solution which reduces the need for heavy and space-intensive transformers.

The NEA also notes that future power and gas prices are uncertain, while they and allowance prices also influence each other. That makes it difficult to estimate future operating savings from the measures.

A substantial reduction potential related to power from shore is contained in the NEA's emission projection. However, it assumes that a further potential – in addition to the reference curve and the possible projects with an abatement potential of 600 000 t/CO_2e – could be triggered if adequate supplies of power from shore were available.

The NEA estimates that electrification measures in the petroleum sector (both offshore and on land) could increase electricity demand by up to 10 TWh/y. Energy-efficiency measures on the installations will reduce this demand.

4.4.2 Snorre expansion project (2017)

The Snorre expansion project (SEP) is intended to improve oil recovery (IOR) from this field, which lies in the Tampen area of the northern North Sea and has been on stream since 1992.

Under the non-electrification alternative, power will be supplied by the existing gas turbines on Snorre A and B and a steam turbine on the B platform. A separate feasibility study has been conducted with two options for supplying Snorre with power from shore (electrification), but both are considered to be clearly unprofitable in commercial and socioeconomic terms and are not recommended (Statoil, 2017).

Operator Statoil calculated the abatement cost for emission cuts on the NCS at NOK 1 360-1 411 per tCO_2. If emissions from electricity generation are accounted for on the basis of the European power mix (see section 3.3), the abatement costs are estimated to about NOK 3 00/tCO_2.

An appendix to the impact assessment also refers to abatement cost calculations made by THEMA (2017) using the long-term marginal methodology described in section 3.1. This analysis estimates the abatement costs for electrifying Snorre in relation to net emission cuts in the EU ETS at NOK 1 372-1 548 per tCO_2, depending on the climate-policy scenario and the electrification option.

We also carried out a sensitivity analysis, in line with recommendations from the Hagen commission (Ministry of Finance, 2012), using a substantially higher carbon price curve when calculating both the calculation price and the abatement cost. Carbon prices in that analysis reflected the average of a number of analyses of the *global carbon price* referenced by the Intergovernmental Panel on Climate Change (IPCC). Electricity purchase prices increase with this curve, and abatement costs thereby rise to NOK 1 703-1 776 per tCO_2.

By comparison, we calculated the present value of the emission cuts (calculation price) to be NOK 185-535 per tCO_2, based on analyses of future allowance prices in Europe and a possible global ETS scheme. In addition, an assessment was made of the socioeconomic benefit of electrifying Snorre if account is also taken of a continuation of the Norwegian special tax on offshore CO_2 emissions. The parameters which applied in 2017 meant that, as long as the allowance price was lower than NOK 490/tCO_2, the tax should be set at a level where the sum of allowance price and tax came to NOK 490/tCO_2.

The Hagen commission recommended that, where projects are particularly sensitive in the socioeconomic analysis to carbon-price expectations, a sensitivity analysis should be carried out where the calculation price reflects an effective two-degree trajectory for the whole duration of the project. This involves a substantially higher carbon price trajectory throughout the project's lifetime (based on the 2015 IPCC report). Carbon pricing (in 2016 kroner) rose then from NOK 490/tCO_2 in 2020 to NOK 1 450/tCO_2 in 2040. That gave a calculation price (present value) of NOK 871-891 per tCO_2.

4.4.3 NOA/Krafla power from shore (2021)

Aker BP and Equinor are pursuing a coordinated development of North of Alvheim (NOA), Fulla and Krafla on the NCS (Aker BP, 2021). The partners have a shared ambition of developing this area with a minimal carbon footprint, and a precondition is that the fields are provided with power from shore. Estimated at 40 MW in 2026, electricity consumption rises gradually to a maximum of 150 MW in 2029.

Calculations show that an electrification of NOA/Krafla with power from shore provides a total reduction of 9.2 million tCO_2 in *Norwegian emissions* over the commercial lifetime of the fields, compared with traditional power supply from gas turbines offshore. The socioeconomic profitability of electrification as a measure for cutting CO_2 emissions is the estimated value of the emission reduction less the cost of electrification – in other words, the abatement cost.

- The forecast CO_2 cost applied in the calculations is based on the prevailing CO_2 cost in Norway (allowance price plus tax) of around NOK 800/tCO_2, rising to about NOK 2 000/tCO_2 in 2030 and then increasing slightly up to 2050.
- The abatement cost for electrification of NOA/Krafla is calculated as the relationship between the discounted net costs (the additional cost of electrification) and the discounted emission reductions on the fields over the project's commercial life. Included in the cost saving from electrification are reduced operating and maintenance expenses (Opex) for energy supply on the platform, lower NO_x tax and the market value of the freed-up gas.

The alternative to electrifying NOA/Krafla with power from shore is assumed to be energy supply from gas turbines installed on a separate platform on NOA. Estimated investment costs are about NOK 17 billion. Other key assumptions in the present value calculation are:

- investment costs are incurred in 2024-26

- the field's commercial lifespan runs until 2050
- the NO_x price is set at NOK 23.2/kg in 2024-2050
- freed-up gas is valued at market price
- the value of power purchases is calculated on the basis of available electricity price forecasts
- the long-term EUR/NOK exchange rate is set at 10.

A discount rate of four per cent (the socioeconomic required return) is utilised in the calculations, as recommended by the NPD/NVE.

To sum up, electrifying NOA/Krafla with power from shore is found to be a socioeconomically profitable climate measure. In this case, it is considerably cheaper to supply the fields with power from shore rather than from gas turbines on NOA. As a result, the abatement cost of electrification is calculated at a negative NOK 1 175/tCO_2. This means that, if the project is developed without electrification, much more expensive emission cuts must be made in other areas of the EU ETS sector to meet the climate goals.

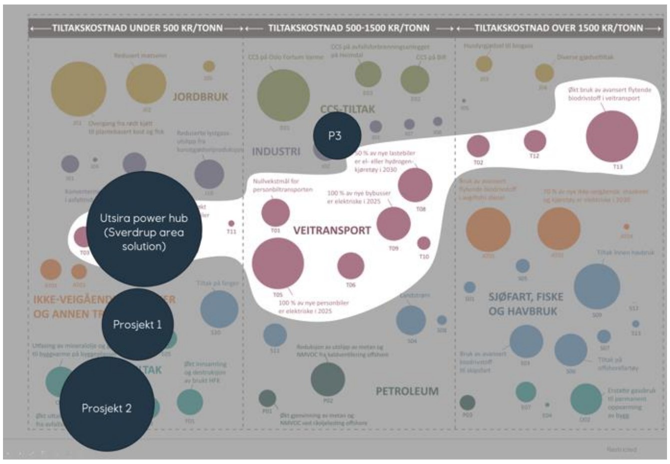
Calculations of net effects in the European electricity market are not included in Equinor's installation-licence application. But electrification is, in other words, profitable regardless because it does not represent an added cost in relation to the non-electrification option.

4.4.4 Four Equinor projects

We have also been given access to various calculations of socioeconomic abatement costs for specific electrification projects from Equinor. These data cover four different projects, and the calculations have been performed with the method used by the NEA (2020). Equinor applies a higher discount rate for its internal profitability calculations than the one used in socioeconomic calculations, and discounts emissions over the commercial lifetime of the fields.

Three of the four electrification projects have a socioeconomic abatement cost lower than NOK 500/tCO_2. The fourth project in Equinor's portfolio calls for more extensive modifications, and has higher abatement costs because of significantly higher Capex. Compared with measures in other sectors, projects on the NCS provide larger emission reductions – as illustrated by the size of the circles in Figure 8 .

Figure 8: Abatement costs for various measures in Norway and selected electrification projects from Equinor



Sources: NEA (2020) *and Equinor.*

4.5 Summary

Abatement costs for electrification offshore vary from project to project. They are lower, for example, for new field developments and for projects with a long commercial life.

An electrification project in Norway is commercially profitable if the abatement cost expressed in NOK/tCO_2 is lower than the sum of the allowance price and CO_2 tax, expressed in both cases as present values. This sum reflects the socioeconomic value of emission cuts in Norway, while the allowance price reflects the socioeconomic value of such reductions in the EU ETS sector.

Where abatement costs for projects exceed the allowance price but are below the Norwegian CO_2 cost, they are higher than for the marginal project in the rest of the EU ETS. Such schemes can in principle displace projects with lower abatement costs in Europe and pull towards a lower allowance price. This also means that Norway accepts a higher cost for reaching national climate goals than through purchasing ETS allowances.

Projects with abatement costs below the allowance price are profitable in both Norwegian and European perspectives and should be implemented in any event. They contribute to cost-effective emission cuts and lower overall costs for meeting climate-policy goals. That applies regardless of whether the measures are expected to contribute to overall emission reductions in the EU ETS sector. Failure to implement cost-effective measures mean that the allowance price rises because more expensive measures must be implemented elsewhere in the system. That makes it more difficult for the EU to implement an ambitious climate policy.

5 ELECTRIFYING THE NCS VERSUS OTHER ELECTRIFICATION MEASURES

A large part of the emission cuts required to reach Norway's climate goals call for electrification. If the country is to meet its targets for 2030, we have estimated in an analysis for Energy Norway (2022) that annual electricity demand must rise by up to 45 TWh/y in the transport, industry and petroleum sectors. That represents an increase of more than 30 per cent in total Norwegian electricity demand.

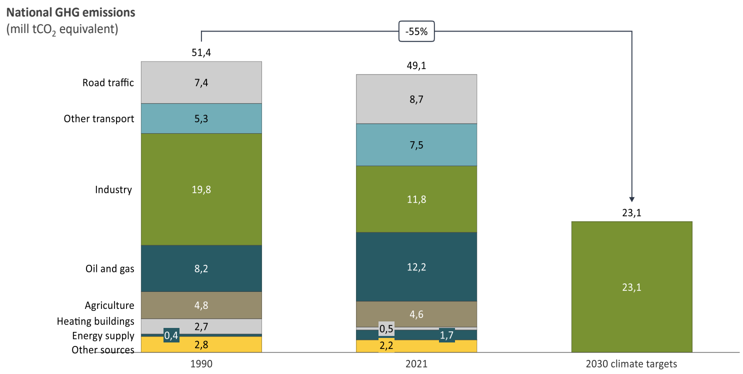
This chapter describes the relevant electrification projects in more detail. We estimate the size of the emission cuts per MWh attainable from different sectors and measures. Furthermore, we discuss estimates of abatement costs for electrification projects in the petroleum, industry and transport sectors.

5.1 Electrification as a climate measure in various sectors

Norway's climate commitment under the Paris agreement involves reducing its emissions in 2030 by at least 55 per cent compared with 1990. This goal is to be met in collaboration with the EU, and no indications are given in this connection of whether emission reductions are to be implemented nationally or via flexibility mechanisms in the form of allowance purchases, for example. However, the government's Hurdal platform proposes that the cuts take place in Norway.

If domestic emissions are to be reduced by 55 per cent compared with the 1990 level, they must be cut from 49 million tCO_2 in 2021 to 23 million by 2030. The land-based industry, petroleum and transport sectors currently account for 80 per cent of Norway's total GHG emissions. (see Figure 9)

Figure 9: National GHG emissions in 1990 and 2021 and the emission cuts needed to meet the 2030 target



Source: Statistics Norway (2022b).

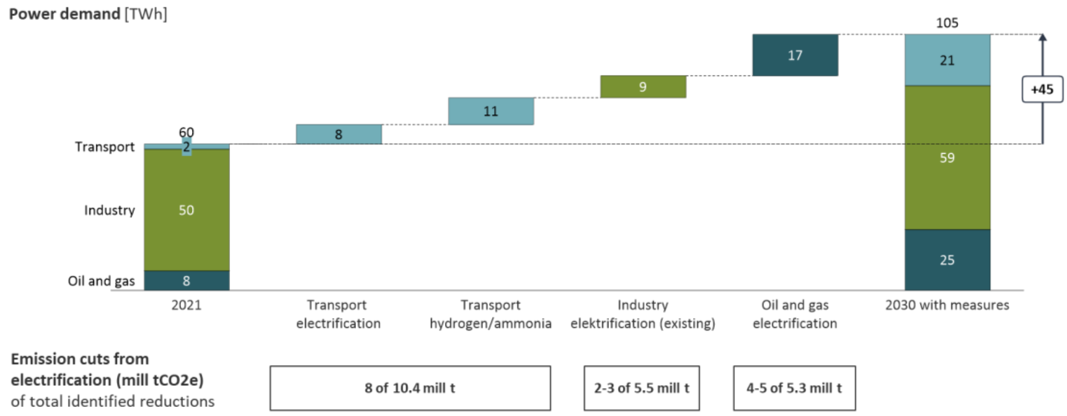
Several measures are relevant for reducing GHG emissions, including electrification, shifting to low-emission hydrogen products, enhancing energy efficiency, and CCS. Which of these are the most appropriate depends on such factors as technological maturity, costs, availability and complexity. However, it is clear that the 2030 climate goals require extensive electrification in all sectors.

We were commissioned by Energy Norway (2022) to make a more detailed evaluation of power requirements in the three sectors which account for the bulk of Norwegian GHG emissions if a national emission reduction of 50-55 per cent is to be achieved. The electrification potential is identified on the basis of projections and estimated potentials for further emission cuts in the national budget for 2022 and a number of sector reports.

According to the national budget estimates, a further 18 million tCO_2 must be eliminated to realise a national 55 per cent cut. Additional implementable measures are based on specific reports for the three sectors.[19] Identified measures include both planned and extremely uncertain projects. The overall potential is estimated at 24.4 million tCO_2, which corresponds to a 52 per cent reduction compared with the 1990 level.

This review shows that realising the proposed climate measures will yield a substantial growth in electricity consumption both for direct electrification and for hydrogen production. Up to 45 TWh/y is required for electrification as a climate measure in the three sectors, as presented in Figure 10. By comparison, total electricity consumption by these sectors in 2021 was 60 TWh.

Figure 10: Increased power demand from implementing selected electrification measures, including the emission reduction potential for the transport, industry and oil/gas sectors.



Excluded from the estimate are additional power requirements associated with new industry, such as battery factories and data centres. By comparison, the NEA (2022a) estimates an overall increase of 34 TWh/y in electricity demand for existing land-based industry, petroleum and transport. Zero's (2022) package of measures for reaching the climate goals in 2030, which includes the establishment of new green industry, involves an increased power requirement of 55 TWh/y.

The identified measures have an emission potential of 15-16 million tonnes of CO_2 (Figure 10). In other words, two-thirds of the emission-reduction potential for 2030 requires electrification – either directly or in the form of power for hydrogen production. Planned generation and possible energy-efficiency enhancements are far from sufficient to provide the electricity required to implement the emission reductions up to 2030 and the expected development of new green industry. Our power-price forecast assumes an output increase of 20 TWh/y, primarily from hydro, offshore wind and solar energy. The NVE (2021) estimates an increase of 8 TWh/y in electricity generation from 2021-30, while Statnett (2021) estimates a growth of 25 TWh/y in 2020-30. To meet the climate goals and develop new green industry, more additional generating capacity than currently planned for the next few years is likely to be needed. But it is also the case that Norway already has a power surplus of around 20 TWh in a year with normal precipitation as well as substantial opportunities for electricity imports.

One claim made in the discussion on electrifying offshore installations is that, if power is in short supply, using it for other emission-reduction measures will have a larger climate effect. It is therefore relevant to look in more detail at the size of reductions achieved per MWh from electrification in the different sectors, and at the estimated abatement costs of electrification projects in the petroleum industry compared with measures elsewhere. The next two sections assess these

[19] Reports assessed include Zero (2022), KonKraft (2022) and the Forum for Environmental Technology (2022).

aspects at the overall level for the petroleum, industry and transport sectors.

5.2 Emission cuts per MWh

To shed light on differences in abatement effects per MWh of electricity consumed, we have looked more closely at various electrification measures for petroleum, industry and transport. Within these sectors, however, the potential for emission reductions per MWh will vary substantially with the emission intensity of the energy carrier being replaced, the energy utilised in the process and the efficiency loss from using hydrogen. The electrolytic process for producing green hydrogen involves the conversion of renewable energy and yields an energy loss. Electrolysers typically have an efficiency of 60-70 per cent.

Petroleum

Where the oil and gas industry is concerned, the estimates are based on publically available data for electrification of installations at the Oseberg field centre, on Oseberg South and Njord, and at the onshore Hammerfest LNG plant. Partial electrification of Oseberg has already been sanctioned, with start-up planned for 2026, while Njord and Hammerfest LNG are mature but not sanctioned projects expected to come on line in 2025 and 2028 respectively.

According to Equinor's installation-licence application to the NVE in 2019, partial electrification of the Oseberg field centre and Oseberg South will create an average power requirement of 81 MW, including transmission losses (Equinor, 2019). With an annual operation time of 8 000 hours and an emission reduction potential on the field of 350 000 tCO_2 per year, the emission cut will be 0.54 tCO_2/MWh.

Njord is an offshore installation scheduled for electrification with Draugen. Its emission reduction potential is 150 000 tCO_2/y and, with a normal load of 30 MW and an estimated operation time of 8 000 hours, the emission effectiveness will be 0.63 tCO_2/MWh (OKEA, 2021)

Hammerfest LNG is a gas processing facility and one of Norway's biggest point emission sources, releasing 900 000-1 000 000 tCO_2 annually in recent years (Equinor, 2022). Its electrification will require a capacity increase of 340 MW at the grid connection and cut emissions by an estimated 840 000 tCO_2/y. That represents a reduction of 0.31 tCO_2/MWh.[20]

In addition, a selection of projects in the process of being realised by Equinor show a relatively high potential for emission reductions of 0.31-0.75 tCO_2/MWh. The estimates in the examples cited here thereby lie around 0.31-0.75 tCO_2/MWh.

Land-based industry

We have drawn on studies by the NVE (2020) and the NEA (2022a) to calculate estimates for electrification schemes and other measures for a couple of industrial facilities which are based on known or new technology and require appreciable quantities of power.

Replacing multifuel boilers with electric units at Borregaard's wood processing plant in Sarpsborg is expected to reduce emissions by eliminating the need to produce heat from waste incineration and bioenergy and the use of natural gas for peak load. Shifting to electric boilers is expected to reduce emissions by 100 000 tCO_2/y, and would increase power consumption by 0.25 TWh/y. That represents an abatement effect of 0.4 tCO_2/MWh.

The Norwegian Environment Agency (2022a) has also assessed an industry-wide measure for converting stationary combustion in industrial plants to electricity (typically by switching to electric boilers), and has identified an emission

[20] Assuming an annual operation time of 8 000 hours and one per cent transmission losses in the connection to the onshore power grid.

reduction potential of 325 000 tCO_2/y in 2030 with an associated power requirement of 1.43 TWh/y. That would give an average abatement effect of 0.23 tCO_2/MWh.

Yara in Porsgrunn wants to utilise electricity to produce green hydrogen for ammonia production, and thereby replace ethane as an input factor in producing hydrogen. This measure involves using technology which is not yet mature on an industrial scale, and the NEA currently expects stronger support schemes to be necessary for realising it by 2030. With an estimated emission reduction potential of 700 000 tCO_2/y and an electricity requirement of 3.9 TWh, the abatement effect would be 0.18 tCO_2/MWh. Converting power to green hydrogen involves an energy loss which has a negative impact when the emission effect is measured per unit of power.

These examples show an abatement efficiency of 0.2-0.4 tCO_2/MWh, which is relatively low compared with several of the cases from the oil and gas sector. However, we do not have sufficient information to assess how representative these examples are for the whole sector.

Transport

The transport sector is more diverse and covers requirements both on land and at sea, over varying distances and for different purposes – such as commercial operations and personal travel.

A current rail project involves electrifying the Trønder and Meråker line. Earlier studies by the Norwegian Railway Directorate (2014) have estimated an annual emission reduction potential of 12 300 tCO_2, while Tensio (2018) expected a power requirement of 45 GWh per year in 2018. Viewed overall, this project will have an abatement effect of 0.27 tCO_2/MWh.

Where public transport is concerned, Ruter expanded its electric bus fleet in Oslo and Viken county in the summer of 2019 to 115 vehicles. The emission reduction compared with continued operation of fossil-fuelled units was estimated at 5 500 tCO_2/y (Ruter, 2019). When the buses became operational, it was appropriate to compare the reduction with the power consumption for the whole electric bus fleet in 2020, which was 9 937 MWh across the area served by the company (Ruter, 2022). The abatement effect is then 0.55 tCO_2/MWh. Note that the number of electric buses was further increased to 156 during 2020, which means the abatement effect will increase since not all the electricity consumption is attributable to the 2019 expansion. Ruter did not operate electric buses in 2018 and before.

In the maritime segment, DNV in 2015 surveyed and calculated emission and power requirements for just over 50 car-ferry services in a report for Energy Norway (2015). Overall annual CO_2 emissions in conventional operation were estimated at 155 100 tonnes and annual power consumption with electrification at 238 GWh. That represents an abatement effect for the ferry fleet of 0.65 tCO_2/MWh.

Trøndelag county council also wants to replace its fossil-fuelled fast ferries which serve a number of places around the Trondheim Fjord. The annual emission reductions are estimated at 5 992 tCO_2, with electricity consumption expected to be 22.5 GWh/y. That represents an abatement effect of 0.27 tCO_2/MWh (Trøndelag county council, 2021).

The overall abatement effectiveness of the examples in the transport sector varies between 0.27 and 0.65 tCO_2/MWh.

5.3 Abatement costs – emission cuts per NOK

Abatement costs for electrification vary between and within the sectors in the same way as emission reductions per unit of power. They depend in part on the maturity of the various solutions and how demanding it would be to adapt existing solutions and value chains to new energy carriers. Socioeconomic abatement costs for electrification are discussed for each of the three sectors on the basis of the NEA studies for the EU ETS (Green Transition) and non-ETS (Climate Cure 2030) sectors (Norwegian Environment Agency, 2022a), (Norwegian Environment Agency, 2020) .

The methodology used in these reports has been criticised for failing to discount the emission reductions, as recommended by the NPD/NVE. That means the abatement cost estimates are lower than if the emissions were discounted. Furthermore, it is important to describe where the projects lie on the abatement-cost curve. Do the abatement-cost estimates in the reports cover all the climate measures necessary to reach the reduction goal of 55 per cent, for example, or are they only a selection of measures regarded as realistic up to 2030?

Petroleum

The NEA's green transition report (2022a) for the EU ETS sector identifies a socioeconomic abatement cost of NOK 1 000-1 500 per tCO_2 for power-from-shore projects on the NCS. This cost analysis is based on measures which are not included in the reference curve, and the latter already includes some electrification projects which power is still not allocated to or which are at an early development stage. The abatement cost in the NEA report is therefore higher than for many of the electrification projects currently being planned or assessed. Where several of the planned projects included in the NEA's reference curve are concerned, Equinor has estimated socioeconomic abatement costs of less than NOK 1 000 – and even below NOK 500 – per tCO_2. The Norwegian Petroleum Directorate (2020) calculated abatement costs of NOK 1 000-2 000 per tCO_2 for Hammerfest LNG, and below NOK 1 000/tCO_2 for electrification of the Oseberg field centre and Oseberg South. Unlike the NEA, the NPD discounts emission reductions but at a rate of five rather than four per cent.

Our calculations of abatement costs for offshore electrification projects, described in section 4.4, show a wide range of outcomes and even negative figures for new fields.

Electrification of the latter has substantially lower abatement costs because investment related to installing gas turbines offshore is avoided. Production shutdowns and the remaining production life of platforms are other factors influencing abatement costs for electrification of existing facilities.

Land-based industry

A socioeconomic abatement cost of NOK 0-1 000 per tCO_2 for direct electrification of land-based industry is stated by the NEA (2022a). Where indirect electrification with green hydrogen is concerned, the cost range is NOK 0-2 500 per tCO_2. In other words, the cost estimates are rather higher here – probably because this measure involves new process applications at a scale which is yet to be tested. To realise almost 80 per cent (6.1 million tCO_2 in 2030) of the identified emission reductions for existing industry in the NEA report (2022a), a strengthening of existing support measures and the implementation of new ones are both needed. This is because the barriers to implementing measures are too high, and because key policy parameters are not yet in place.

Furthermore, the NEA points to increased uncertainty regarding all abatement-cost estimates because energy and raw material prices have been affected by the pandemic and the war in Ukraine. In addition, a number of the measures require new technology to be utilised.

Transport

The NEA (2020) addresses climate measures and abatement costs for the non-ETS sector, and thereby covers transport. In Climate Cure 2030, electrification of various types of road transport – such as passenger cars, light vans and urban buses – by 2025 is assigned a socioeconomic abatement cost of NOK 500-1 500 per tCO_2, with passenger cars at the low end of the range (Norwegian Environment Agency, 2020). Similar abatement costs apply to a substantial proportion of new electric- or hydrogen-powered lorries and long-distance buses up to 2030. Were all new vans to be electric in 2030, the abatement cost is estimated at less than NOK 500 because maturation effects reduce investment costs.

Abatement costs are higher for various types of maritime transport. That applies to both electrification and hydrogen-based measures. Meeting the requirements for low-emission solutions related to reliability, low-emission energy infrastructure and range is more demanding for maritime transport. Climate Cure 2030 estimates a socioeconomic cost of more than NOK 1 500/tCO_2 for offshore support vessels with plug-in and hydrogen technology. The estimated level of abatement costs on ferries is similar for hydrogen and estimated at NOK 500/tCO_2 for plug-ins. That relatively low figure reflects the fact that electric ferries are available technology, and that many ferry routes are relatively short with fixed calling points, which makes it easier to establish associated charging infrastructure.

5.4 The role of electrification for achieving the climate goals

Electrification is a key measure and must be implemented in several sectors if the national climate goals are to be met. Our comparison of climate measures in section 5.1 shows that about two-thirds of the emission reductions needed to reach the 2030 target calls for direct electrification or for using power to produce hydrogen/ammonia.

Estimates for electricity requirements and emission reductions from the identified measures indicate variations between the share of emission cuts from electrification within the sectors, and that the cost ranges largely overlap.

How large a proportion of emissions in the various sectors which can be reduced through electrification also varies. The reduction potential from identified electrification measures in industry lies at about two-three million of today's emissions of nearly 12 million tCO_2, while the share in the petroleum sector is 30-40 per cent. Almost half the emissions in the transport sector can be eliminated through electrification measures up to 2030.

Many NCS electrification projects yield substantial emission reductions per MWh of electricity, and are socioeconomically cost-effective. Furthermore, large individual projects for electrifying land-based industry or petroleum facilities are generally pursued by a small number of players, while similar emission reductions in parts of the passenger transport segment call for coordination by and a commitment from several hundreds or thousands of decision-makers. Electrification of an individual field or a large land-based industry facility can yield emission reductions of several hundred thousand tonnes per year. By comparison, total GHG emissions in 2021 from pleasure boats or mopeds/motorbikes amounted to 277 000 and 144 000 tCO_2 respectively (Statistics Norway , 2022a).

Electrification of existing offshore installations and land-based industry gives absolute emission reductions measured against the 1990 reference year. That is not necessarily the case for much of the emissions from the transport segment, where electrification involves phasing in new low-emission vehicles or vessels over a lengthy period and where it might be uncertain how far these replace the amounts released by existing means of transport in the short term.

Emissions from the petroleum sector make such a substantial contribution to the national total (25 per cent in 2021) that power from shore for new fields and existing installations with a significant remaining production life will play a key role in maintaining oil and gas output while simultaneously meeting Norway's climate goals for 2030 and 2050.

Konkraft (2022) has identified an emission reduction potential up to 2030 of three million tCO_2 from sanctioned and mature electrification projects on NCS installations and at the land plants.[21] If more uncertain projects are included (1.5 million tCO_2), this amounts as mentioned above to almost 20 per cent of the cuts required to reach the 2030 goal of a 55 per cent reduction in emissions.

Given that the individual electrification measures yield such large emission reductions, and that the measures

[21] Includes the oil and gas processing plants at Kårstø, Kollsnes, Nyhamna, Melkøya and Sture.

implemented are (in some cases very) profitable, a halt to such projects offshore and at the land plants would significantly reduce the likelihood of reaching the national climate goals in 2030. Fulfilment would become more expensive, because cost-effective offshore electrification projects would have to be replaced by measures with a higher abatement cost. In addition, time is short if sufficient new measures are to be brought forward. According to the studies of the potential referenced in this chapter, measures are needed in all sectors if the national emission target for 2030 is to be reached.

Abatement costs vary greatly in all sectors. A cost-effective climate policy requires that measures which cut emissions at the lowest cost are implemented. That should also apply to measures in the petroleum industry. A number of the oil and gas facilities have an operating life up to 2050 or beyond. When the aim is to reach net zero emissions by 2050, it will be necessary to electrify petroleum production in combination with other climate measures and to handle residual emissions with mitigating measures in the form of negative emissions.

6 EMISSIONS IN THE NATURAL GAS VALUE CHAIN

Norwegian pipeline gas and LNG deliveries to Europe have a low climate footprint compared with gas supplies from other countries. Several factors contribute to low production, processing and transport emissions in the value chain, including electrification with renewable energy, a concentration on energy efficiency, and systems for monitoring and detecting leaks. Since the EU increasingly emphasise value-chain emissions where its products and energy collaboration are concerned, a low footprint for Norwegian gas will probably be an increasing competitive advantage in the time to come.

6.1 Climate footprint of pipeline gas and LNG

The climate footprint of pipeline gas and LNG deliveries to Europe from different countries of origin has been calculated by various players. Calculations of value-chain emissions by Equinor (2019), Rystad Energy (2021) and the North Sea Transition Authority (2020) are included in this review. Calculation methods differ somewhat between these reports, and their results are not directly comparable. Equinor, for example, employs a wider scope for calculating the climate footprint than Rystad.[22]

When assessing the carbon footprints of LNG and pipeline gas, all emissions in the value chain are taken into account – in other words, upstream (exploration, development and production), midstream (processing and transport) and downstream (transfer, storage and distribution). LNG deliveries have emissions upstream, related to liquefaction for transport, and downstream, related to possible regasification. Generally speaking, emissions depend on the properties of the gas source – whether it is produced from shale or together with oil, for example. The scope of methane leaks in the infrastructure, flaring practices and transport distance to the market also play a role. Generally speaking, emissions from pipeline gas deliveries to Europe are lower than for LNG.

Less substantial upstream emissions and shorter transport distances to the EU mean Norwegian pipeline gas has a lower emission intensity than either LNG or pipeline gas deliveries from other countries. Electrifying process plants and transport terminals in Norway also helps to keep emissions in the value chain down.

Equinor (2019) has assessed the CO_2 and methane released in the pipeline gas value chain, and shows that such deliveries from Norway to Germany have a total emission intensity of 2.8 gCO_2e/MJ. This breaks down into 1.5 gCO_2e/MJ upstream, 0.4 midstream and 0.9 downstream. By comparison, Equinor's value-chain emissions for pipeline deliveries to countries in central Europe are 3.5 gCO_2e/MJ. The difference largely reflects higher downstream emissions, at 1.9 gCO_2e/MJ.

Rystad Energy (2021) also finds that Norway has the lowest upstream and midstream CO_2 emissions of all gas delivered to Europe, at 1.1 gCO_2e/MJ. Pipeline gas from Algeria has almost three times the emission intensity, at 3.1 gCO_2e/MJ. Similarly, Russian pipeline gas deliveries have an emission intensity of 4.6 gCO_2e/MJ, largely because greater quantities are released in processing and transmission.

[22] Equinor includes upstream, midstream and downstream emissions as well as both CO_2 and methane releases in its calculations, while Rystad does not incorporate downstream or methane emissions.

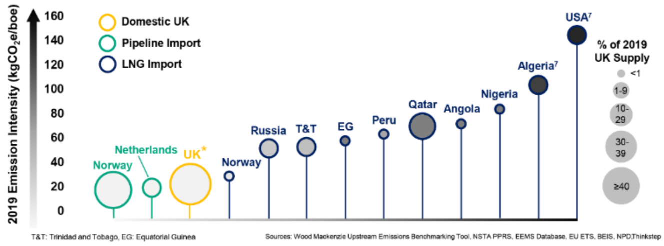
Emissions for LNG deliveries from various countries have also been assessed by Rystad Energy (2021). Where CO_2 emitted upstream and midstream is concerned,[23] LNG deliveries from Russia, Qatar and the USA emit 8.3, 9.6 and almost 10 gCO_2e/MJ respectively.

Liquefying natural gas for transport accounts for about 80 per cent of emissions for both Qatar and Russia, and roughly 50 per cent for US deliveries. Where American LNG is concerned, fracking adds additional flaring as well as large emissions in the value chain. This method releases twice as much CO_2 as Norwegian gas production. Furthermore, US natural gas must be pre-processed before liquefaction for quality reasons, a stage which represents 25 per cent of total value chain emissions for export to Europe.

Virtually all LNG from Norway is liquefied at Equinor's Hammerfest LNG plant on Melkøya. Emissions related to shipments from this facility to central Europe are slightly more than twice as large as from the company's pipeline-gas deliveries. However, the footprint is still small compared with other LNG deliveries to Europe, with emissions amounting to 8.3 gCO_2e/MJ for the whole value chain – upstream, midstream and downstream – including methane.

Other sources, such as a report from US consultancy Sphera, also conclude that LNG deliveries from the largest suppliers (the USA, Qatar, Algeria and Australia) have at least twice the lifecycle emission intensity as pipeline deliveries from Russia to their nearest landing points in south-eastern Europe, with regasification and freight again being the largest contributors to GHG emissions (Jurdik, 2020). And a comparison by the North Sea Transition Authority shows that the average emission intensity for LNG imports to the UK is at least three times as high as with pipeline gas deliveries from Norway. The emission intensity of the latter is also lower than for gas produced in the UK. See Figure 11

Figure 11: Emission intensity of British gas deliveries in 2019.



Source: North Sea Transition Authority (2020).

6.2 Increased EU attention to value-chain emissions

European consumers, companies and government authorities are increasingly demanding documentation of and taking decisions based on the environmental and climate footprint in a broader value-chain perspective. This means that they are looking not only at negative environmental and climate effects related to production of a commodity or a product in the EU, but also at impacts along the whole value chain.

This greater concentration on upstream emissions and environmental effects reflects in part that the EU imports raw materials and products on a large scale from other parts of the world, and that substantial emissions and environmental effects are or can be related to their extraction and production.

The increased attention also applies at the EU level, and is reflected in part by a growing inclusion of lifecycle considerations in classifying sustainability solutions such as those in the taxonomy. Deciding to introduce a CBAM on imported products sets a price on emissions which occur in the value chain outside the EU.

Where energy is concerned, upstream emissions are an important topic in the EU's green deal strategy. For natural gas deliveries, factors such as upstream flaring and methane

[23] Not including regasification.

leaks and upstream emissions are key factors in classifying low-emission gases.

The EU's 2020 methane strategy stresses the importance of cutting upstream emission global partners." (European Commission, 2020a). The Commission's proposal for a new methane regulation from 2021 initially called for steps to ensure better information on such emissions upstream, with the aim of encouraging reductions globally over time (European Commission, 2021b). In its impact assessment for the regulation, the Commission pointed out that data are lacking about the origin and scope of methane emissions outside the EU, particularly those related to the consumption of fossil fuels. It emphasised that, as one of the world's largest natural gas importers, more rigorous EU requirements for upstream emissions could lead to substantial global reductions (European Commission, 2021a).

Where blue hydrogen is concerned, lower emissions from the gas used in its production would be similarly advantageous. The EU's gas and hydrogen package identifies low-carbon hydrogen as an important technology for achieving scale quickly in the European hydrogen economy. The proposed definition for blue hydrogen is: "hydrogen the energy content of which is derived from non-renewable sources, which meets a greenhouse gas emission reduction threshold of 70%". The Commission intends to introduce a delegated act which will clarify the methodology for calculating the emission reductions achieved.

The European Parliament has proposed rather more specific requirements for what the Commission should include in this methodology, including lifecycle and methane emissions. It follows from this that low upstream emissions could be crucial for classifying "low-carbon hydrogen" and help to strengthen competitiveness with others wishing to export hydrogen to the EU.

Given the EU's work on securing an improved overview of, and helping in the longer term to cut, GHG emissions from gas production outside the union, producers who can deliver gas with low emissions are likely to strengthen their competitiveness in relation to suppliers with high upstream emissions.

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About THEMA

THEMA Consulting Group is a Norwegian consulting firm focused on Nordic and European energy issues, and specialising in market analysis, market design and business strategy.

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