Phasing out coal and phasing in renewables – good or bad news for arctic gas producers?

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Abstract:
This paper examines to what extent downscaling of global coal based electricity generation encourages gas demand and affects regional activity in gas production, with emphasis on the arctic regions. In our reference scenario up to 2050 we take into consideration that renewables is set to increase its contribution to global electricity production over time, while coal will contribute less. We find that a policy scenario with further phasing out of coal and phasing in of renewables in line with the 2 degrees scenario for the power sector up to 2050, will lead to reduced arctic gas production compared to the reference scenario, although total worldwide electricity production doubles over the same period. However, even in a situation with less resources and higher costs in the Arctic, future investments in new reserves in the region are still profitable in our policy scenario, as total arctic gas production then is only marginally lower in 2050 than today.

Keywords: Arctic, coal market, gas market, electricity market, equilibrium model

JEL classification: Q31, Q41, Q58.

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Abstract in Norwegian:

CREE - Working Paper 03/2017

Utfasing av kull og innfasing av fornybar energi - gode eller dårlige nyheter for gassprodusenter i Arktis?

Lars Lindholt and Solveig Glomsrød

Vi undersøker i hvilken grad en nedbygging av den globale kullbaserte kraftproduksjonen vil stimulere etterspørselen etter naturgass fram til 2050, og dermed også gassproduksjonen i arktiske områder. Arktis er fremfor alt rik på naturgass da denne utgjør om lag 70 prosent av de uoppdagede petroleumsressursene i regionen.

Vi bruker en rekursiv, dynamisk partiell likevektsmodell for de globale energimarkedene. Vårt referansescenario tar utgangspunkt i New Policy Scenario i IEA's World Energy Outlook fra 2015. I dette scenariet vil fornybar energi øke sitt bidrag til global elektrisitetsforsyning, mens kull sin andel vil avta. Vår politikkanalyse ser på en videre utfasing av kull og en videre innfasing av fornybar energi i tråd med 2 graders målet for den globale kraftsektoren slik World Energy Outlook skisserer. Vi analyserer så konsekvensene for den framtidige gassproduksjonen i fem arktiske regioner: Alaska, arktisk Canada, Grønland, arktisk Russland og arktisk Norge.

Den sterke trenden mot ikke-fossil kraftproduksjon i politikkscenariet for 2-gradersmålet, fremfor alt etter 2030, fører til en lavere markedsandel for naturgass i den globale kraftforsyningen fram mot 2050, selv om den totale elektrisitetsproduksjonen dobles over hele perioden. Men selv om det blir mindre behov for gass, så er det først og fremst kull som blir rammet.

Dette innebærer også redusert arktisk gassproduksjon i forhold til referansebanen. For Arktis som helhet er nedgangen i samlet produksjon fram til 2050 på rundt 9 prosent, mens Grønland og Alaska opplever en sterk nedgang på hhv. 69 og 31 prosent, Årsaken er at størstedelen av deres framtidige gassproduksjon kommer etter 2030, og det er først og fremst i denne perioden at fornybar energi begynner å fortrenge gass (og kull). Reduksjonen i samlet produksjon i arktisk Russland av å fase ut kull og fase inn fornybar energi er så lav som 6 prosent, mens reduksjonen for arktisk Norge er på 13 prosent. Årsaken er at arktisk Russland og til dels arktisk Norge har en relativ større andel av sin produksjon i årene før 2030 enn de andre regionene, altså før fornybar energi begynner å fortrenge gass i kraftsektoren i særlig stor grad.

Resultatene viser at selv i en situasjon med mindre ressurser og høyere kostnader for gass i arktiske områder, er produksjonen i 2050 ikke mye lavere enn i dag i vårt politikkscenario. Dette viser at på tross av dårligere utsikter for regionen i scenariet med utfasing av kull og innfasing av fornybar energi, vil det fortsatt være lønnsomt med investeringer i og utbygging av gassfelt, gitt våre forutsetninger.

1. Introduction

Coal has been running the wheels and warming the homes for centuries. Unfortunately it has also warmed the globe and changed its climate (IPCC, 2013). When mitigating climate change, coal stands out as a major target due to its high emissions of CO_2 per unit thermal energy. Coal also generates high emissions of health damaging air pollution and causes tragic mine and traffic accidents (Sovacool, 2008).

Coal and gas are close substitutes in power generation, hence, the future role of gas is closely linked to the future role of coal. Both fuels are subject to climate policy, but gas has the advantage of being less GHG emission intensive and less of a burden on local air pollution and health. In a green transition gas is regarded as a low carbon alternative. This study investigates how a low carbon policy will affect the gas market and in particular the supply from arctic regions, where the cost of extraction is relatively high for many fields compared to more temperate regions.

Coal covers almost 30 per cent of global primary energy demand and plays a particularly important role in electricity production. In 2012 coal generated 41 per cent of global electricity, however, its share is falling. Gas is the only fossil feedstock that is on the rise (IEA, 2014a).

In 2012 coal use was the source of 44 per cent of global CO_2 emissions (IEA, 2014a). According to the Global Carbon Budget (2016) the world must limit accumulated future emissions to 860 $GtCO_2$ to ensure, with 66 per cent probability, that the global mean temperature increase stays within 2 degrees Celsius. If the 2013 emission level of CO_2 from energy use persists, the carbon budget will be consumed within 24 years. With a 1.5 degrees ambition there is hardly room for future use of fossil energy (Oil Change International, 2016). Hence, some argue that also gas resources have to be left in the ground and that it is least costly to leave high cost resources unused (McGlade and Etkins, 2015 and Oil Change International, 2016).

A decade of new climate research culminating in the IPCC 5th assessment report has changed the sense of urgency and lifted the issue of climate mitigation to a higher political level, as demonstrated at the COP21 meeting in Paris where a new climate agreement was made based on pledges from 196 nations in December 2015. It adds to the urgency that carbon capture and storage (CCS) has turned out less promising for the next decades than earlier expected. IEA (2014a) expects CCS to start being deployed from around 2020, but only 3 per cent of coal fired power plants are expected to be equipped with

CCS by 2040. Coal with CCS will raise the cost of electricity by 40-75 per cent (IEA, 2014a). However, emissions reductions become more feasible as the costs of solar and wind power have been falling rapidly over the last few years (IEA, 2016). The coal future seems bleak considering that coal power is also facing strict and costly regulation of air pollutants in major coal burning countries.

USA and China are the two largest economies and the two largest coal users in the world. Well in advance of the Paris meeting both countries had explicit policies in place to reduce both CO_2 emissions and local air pollution. At a summit meeting in 2014 President Barack Obama and President Xi Jinping gave statements pledging to reduce CO_2 emissions substantially towards 2030. Obama pledged a 26-28 per cent reduction from the 2005 emission level, whereas Xi promised to cap CO_2 emissions by 2030 at the latest. Behind these pledges lie ambitious domestic plans for emission reductions from coal based electricity.

In August 2015 the Obama administration implemented the Clean Power Plan, estimated to reduce CO_2 emissions to 32 per cent below 2005 level by 2030 (EPA, 2015a). The plan introduces a cap on CO_2 emission intensity in power production at state level. The electricity consumption in USA is expected to grow marginally with only 0.1 per cent per year on average towards 2040 (IEA, 2015). During 2016 the gas share of power production is expected for the first time to surpass the share of coal power (EIA, 2016). The move towards low carbon energy is further supported by the Mercury and Air Toxics Standards (EPA, 2015b), which particularly increase the costs of coal based electricity. Switching from coal to gas power is convenient as it creates a market for domestic shale gas and has substantial advantages regarding health damage.

Total benefits of the Clean Power Plan are estimated to be in the range of USD 55 billion to USD 93 billion per year in 2030 (EPA, 2016), far above the costs. Health benefits through reductions in particle emissions and other local pollutants are estimated to yield 60 per cent of the plan's gross benefits (Fowlie et al., 2014). President Donald Trump signals a supporting attitude to the coal industry. However, even if the Clean Power Plan and the Mercury and Toxic Standards were removed under Trump, the risks of facing future returns of high cost regulations after his presidency might discourage investments in new capacity.

In China there is a strong political pressure on the government to improve local air quality. To control the smog problem, the State Council required the emissions from all coal-fired power plants to comply with emissions standards for gas turbines by 2020 (State Council, 2015), with hastened deadlines for existing plants in the Eastern region by 2017 and the Central region by 2018. Already in January 2015 the government announced a cap on investments in new coal-fired power plants in the Eastern provinces (National Energy Bureau, 2015) and a five year moratorium on new coal-fired plants in the coal rich province of Shanxi (Shanxi Provincial Government, 2015). The logical consequence of these regulations would be a phase out of coal for power production and a switch to gas powered and renewable energy sources. Details on implementation will be decided on in the further elaboration of the 13th Four Year Plan 2016-2020.

Hence, the two largest coal users and emitters of CO_2 have both clean air and low carbon policies in the pipeline and the Paris agreement left a clear message that most other countries will make efforts to reduce emissions, not least the EU pledging to reduce CO_2 emissions by 40 per cent by 2030.

These events make prospects of stranded assets in coal mining and coal fired power production emerge as a real risk to private and public investors (Carbon Tracker Initiative, 2014). A Citigroup analysis warns that the 2 degree target might involve stranded assets of USD 100 trillion by 2050 (Citigroup, 2015). The risk of stranded assets has also started to worry central banks. In 2015 the Bank of England Governor Mark Carney warned investors that "the vast majority of reserves are unburnable" if the 2 degrees target shall be reached (The Guardian, 2015a). Hence, for climate reasons we might face a situation similar to a sharp decline in reserves. The significance of reserves in company value was illustrated for oil when Shell restated its reserves in 2004. The 20 per cent reduction of oil reserves led to a 10 per cent reduction in the share price and a £3 billion in company value over night (Carbon Tracker Initiative, 2011).

Further, there is a trend towards low or no carbon finance among large private investors. There is a fast growing interest in Green Bonds, issued with a label to finance sustainable investments, largely in renewable energy, environmental friendly infrastructure and energy efficiency (Climate Bonds Initiative, 2016). A trend among investors to divest in coal and keep coal out of their future portfolios has also taken off during the last few years. In the wake of the UN Climate Summit in New York 2014 the Rockefeller Brothers Fund pledged to keep coal and tar sand out of their endowments. Further breakthrough occurred when the Norwegian Parliament decided to divest the Norwegian Government Pension Fund Global with USD 900bn in coal by 2020 at the latest (The Guardian, 2015b) and the French global insurance company AXA with assets of € 1200bn pledged to divest in coal (Bloomberg, 2015). Bank of America Merrill Lynch was the first large bank to divest in coal in early 2015, followed by Citigroup's pledge to stop coal mining in general in addition to their earlier decision to quit lending to mountain top removal mining (Financial Times, 2015).

As demonstrated already by the swift transition from coal to gas in US after the phase in of shale gas, transitions can be rapid and change the energy pattern of regions substantially when alternatives are available. These shifts in energy patterns might also have marked regional implications, and one of these is the potential impacts on the role of the Arctic in global gas supply.

This study looks at how a greener power market might affect the future gas market, with focus on the arctic supply. The Arctic is above all rich on natural gas as 70 per cent of undiscovered petroleum resources in the region are gas. With around one fourth of global undiscovered gas resources, the Arctic has attracted attention as a last large frontier of gas outside the Middle East and North African regions (MENA). However, gas production in some arctic regions is facing harsh weather conditions, high costs and long lead times, at least when production moves to more remote offshore areas. Further, there will be continued competition with US lower 48 and other regional production as shale gas is increasing, in addition to huge conventional gas reserves in the Middle East coming on stream, above all in Iran and Qatar.

For the present study we first develop an updated reference scenario based on the New Policy Scenario (NPS) of IEA (2014a) and identify the path of future arctic gas supply to 2050. Second, we assess the effects of gradually phasing out coal and phasing in renewables for electricity production in broad outline with the 2 degree scenario for the power sector of IEA (2014a). However, in our policy scenario coal is not totally phased out prior to 2050, while renewables are on the rise.

In an earlier study of arctic petroleum extraction towards 2050 (Lindholt and Glomsrød, 2012), the future coal scenarios were largely based on expectations in the late 2000s, as e.g. IEA (2008). Total coal demand already in 2020 is now expected to be around 20 per cent lower than was predicted in the latter publication.

This paper analyzes the competition between coal, renewables and natural gas for electricity production under a more stringent policy towards coal. The particular strength of our approach is that supply of natural gas is modeled with plausible costs and reserves estimates, enabling an assessment of the economic potential for gas supply from the Arctic. Gas and coal represent David versus Goliat among the fossil fuels in a transition to low-carbon electricity. Given the long term perspective underlying investments in petroleum, the study provides useful insights into the economic potential of the two in light of climate policy.

Various studies have looked at consequences of various climate policies on the mix in energy demand at a regional scale. E.g. von Hirschlausen (2017) applies various models to analyze effects on natural gas production in Europe and its neighboring regions of the development to a lower-carbon Europe. To the best of our knowledge, we are the first to analyze how the competition between gas, coal and renewables in the power sector on a global scale can affect the regional gas production in the Arctic.

This paper is organized in the following way: In Section 2 we describe the FRISBEE model of the global energy markets. Section 3 describes the scenarios, while Section 4 concludes.

2. The global energy model FRISBEE

FRISBEE is a recursive, dynamic partial equilibrium model for the global energy markets, previously used for studies of arctic petroleum production (Lindholt and Glomsrød, 2012), emission from shipping and petroleum activities in the Arctic (Peters et al., 2011), impacts of petroleum industry restructuring (Aune et al., 2010) and globalization of natural gas markets and trade (Aune et al., 2009).

The start-year is 2012 and the recursive model is solved sequentially year by year. The model covers coal, oil and gas, and further, electricity generation based on either of the fossil fuels and non-fossil feedstock, assisted by a transformation sector. For each energy good demand equals supply, with manufacturing and households/services combined as two final end-users. The end-user prices are the sum of producer price, transport, distribution and marketing costs, VAT and a carbon tax, and are mainly taken from IEA (2012a), IEA (2012b) and GIZ (2013). Demand from the final end-users is log-linear functions of prices, population, GDP per capita and autonomous energy efficiency improvements (AEEI). The per capita income elasticities vary a lot, from negative elasticities for coal in Western Europe to somewhat below one for natural gas in several other regions. The long-run direct price elasticity varies between -0.1 and -0.6 with a weighted average of -0.30 for households and -0.21 for industries for all energy goods. The cross-price elasticities are low, however, substitution possibilities are markedly higher in the power sector than in manufacturing and households/services. The elasticities are mainly taken from Liu (2004), IEA (2007), Tsirimokos (2011) and Burke and Yang (2016).

FRISBEE has an elaborate modelling of (oil and) the regional gas markets, while the worldwide markets for coal, electricity and renewables are modelled with less detail. In FRISBEE fossil fuels are traded between regions, whereas electricity is only traded *within* each region. Coal (and oil) trade takes place via a common pool, whereas gas trade takes place bilaterally between 16 regions due to larger transport costs. The gas and coal markets are assumed to be competitive. FRISBEE depicts the gas market both as global and integrated, as liberalization is taking place both in OECD and non-OECD regions, gradually reducing the gas market power of large, downstream companies. North America and the UK have liberalized their markets and trends towards liberalization also characterize other OECD countries (such as countries in the EU and Japan) and some non-OECD countries also (Aune et al., 2009).

The extent of spot trade is growing fast, and gas price indexation is partially replacing the oil price link in long-term contracts. A major factor behind this development is the decline in costs of transportation of LNG (Barnes and Bosworth, 2015). Thus, within the gas markets we have perfect competition both upstream and downstream, and the gas price is determined endogenously in regional markets.

The potential for arbitrage from price differences between two regions is never larger than the transportation cost. LNG and pipeline costs are from IEA (2009) and Songburst (2014), and unit costs are assumed to be constant in this analysis. Both capital and operating costs are included in the cost figures, except for pipeline capacities before 2022 (where only operating costs matter). Total transportation costs are linear functions of the distance between two regions. There is no restriction on investments in transport capacity between regions as long as it is profitable. New transport infrastructure can be both LNG and pipeline. Each year the cheapest transport technology between pair of regions is chosen for given capacity investments. Thus, a region may import both via LNG and pipeline transport, but not from the same region. However, changes in transport costs over time might imply changing transportation methods.

FRISBEE provides elaborate modelling of investments and production[1], accounting explicitly for discoveries, reserves, field development and production of gas. Gas production generally takes place in 16 regions and 4 field categories depending on location onshore/offshore, depth of offshore fields and size of resources (see Appendix A). We focus on six arctic regions: Alaska, Arctic Canada, Arctic

[1] For this modelling work we have benefited from access to the comprehensive IHS Energy field database, see www.ihs.com.

Norway, Greenland, East Arctic Russia and West Arctic Russia. The East Arctic Russian region covers the petroleum provinces from the Sakha region and eastwards, i.e. from the Laptev Sea to the Russian part of the Chukchi Sea. We do not distinguish between single fields within the field categories.

We assume perfect competition and endogenous prices in the 16 regional gas markets. For gas FRISBEE distinguishes between three field stages within each field category, i.e. fields in production, undeveloped fields and undiscovered fields. Supply from developed fields in the model is determined so that marginal operating costs equal producer prices net of gross taxes. Operating costs are increasing functions of production, but are generally low unless production is close to the fields' production capacity; then they increase rapidly. The cost functions are calibrated based on data on production costs in different locations.

Gas companies may invest in new fields and in reserve extensions of developed fields. Investments decisions are driven by expected net present values (NPV), which are calculated for each field category in each region. Expected NPV depends on expected price (the average over last six years), a pre-specified required rate of return (10 per cent in real terms), unit operating and capital costs, and net and gross tax rates. Unit capital costs are convex in the short term, and increase when the pool of undeveloped reserves available for new fields declines and when the recovery rate rises in the case of reserve extension. Investments first target the most profitable areas and gradually shift to more remote and costly areas, leading to a geographically spread of the global gas production.

New gas discoveries are modelled in a simpler way than investments in already discovered fields. The amount of discoveries generally depends on expected prices and the amount of undiscovered resources in each region. It is based on data from USGS (2000), with a partly update in USGS (2012). The undiscovered gas resources for the arctic provinces are from the special regional study reported in USGS (2008). The expected unconventional shale gas resources are updated with data from EIA (2013).

For arctic regions the time lag from investment decision to maximum plateau production is generally 50-100 per cent longer than in comparable fields within the non-arctic regions of the corresponding arctic state (Lindholt and Glomsrød, 2012). The operational and capital costs are based on the IHS database.[2] Investment costs in arctic and non-arctic regions are assumed to increase over time as the reserves are depleted. However, additional discoveries and technological progress reduce the cost of developing new fields. In addition, costs will increase as arctic production moves from onshore to offshore areas, which also often contain smaller fields (USGS, 2008).

The global gas industry allocates up to 50 per cent of the annual cash flow to field investments. The cash flow constraint is generally not binding in our scenarios, i.e. the gas companies invest in all projects that give at least the required rate of return of 10 per cent.[3]

We also assume perfect competition and endogenous prices in the 16 regional coal markets. Regional coal prices are world coal market price plus region specific transportation costs. For coal we apply more simple cost functions than for gas as we do not distinguish between the investment and the production phase. Costs are increasing in accumulated supply, while technological progress leads to lower cost. Regional supply is determined so that marginal operating costs equal producer prices (production capacities are not explicitly modelled). The cost functions are calibrated based on data on production costs in different locations. Costs are based on information based on IEA (2014a) and IEA (2015).

Regional electricity production is a function of the electricity price, prices of energy inputs, carbon taxes, fuel efficiency (conversion rates) and generation costs. The regional volume of supply of renewables and nuclear is exogenous. We emphasize, as explained above, that the endogenous variables in our model are the regional supply, demand and prices of gas, coal and electricity.

3. Scenarios

This section compares a policy scenario reflecting phase out of coal and phase in of renewables for power production with a reference scenario. Further, we develop various sensitivity scenarios to check the robustness of our results.

[2] The initial regional costs from IHS have been updated with data on break-even prices from Rystad Energy, see http://www.rystadenergy.com/.

[3] For a more extensive presentation of the FRISBEE model, see Aune et al. (2005). Aune et al. focus on the oil market, but natural gas supply is modelled quite similarly as oil supply, so most of the model description carries over.

3.1. Reference scenario

Our reference scenario follows the IEA (2014a) New Policy Scenario (NPS) taking into account energy and climate oriented policy measures as determined by mid-2014. In addition, two major policy proposals were included in NPS although specific measures to implement them were not yet in place at that time. One is the US EPA Clean Power Plan (CPP, 2015) expected to reduce CO_2 emissions by 30 per cent in 2030 compared with the level in 2005 (18 per cent reduction from the level in 2016). The other is the EU climate and energy policy framework with a 40 per cent reduction in CO_2 emissions compared with 1990 level by 2030 as a step to reduce emissions by 80 per cent or more by 2050. On the other hand, China´s 13th Five Year Plan target of capping energy use by 2020 and a reduction in CO_2 intensity by 18 per cent were not included. For Japan, the NPS assumes that the majority of the nuclear reactors will be restarted.

GDP and population are exogenous in the model. Population growth rate is based on United Nations (2015), while the annual GDP growth rates per capita in real terms are based on IMF (2012) until 2017 and the World Bank (2012) from 2018 until 2030. After 2030 we assume unchanged GDP per capita growth rate in the US (0.6 per cent p.a.), and that other countries gradually approach the US GDP per capita level by 2100. The AEEI-indices for energy intensity are calibrated so that demand for electricity and other energy goods in the two end-user sectors in the various regions in 2040 are broadly in line with the projections in NPS. We impose carbon taxes in the power sector such that regional electricity production in 2040 by source aligns with the NPS.[4] We let the yearly average linear growth in electricity demand in each region in the period 2015-2040 continue the subsequent decade.

The regional volume of supply of renewables and nuclear into the power sector is exogenous, based on the pathways of the NPS. Table 1 shows that currently oil contributes only 4 per cent to electricity production globally and is gradually phased out as an energy source for power production. The exogenous share of renewable and nuclear electricity in total supply increases from 35 per cent in 2015, to 42 per cent in 2040[5] and further to 45 per cent in 2050. Hence, as much as 55 per cent of global electricity is still based on coal and gas towards the end of our projection period in the reference scenario.

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[4] The regional CO_2-prices vary from 20 USD to 50 USD per ton in 2040 and 2050 (2012-prices).

[5] The share of nuclear power of total electricity supply is 12 per cent in 2040 in NPS.

Electricity supply almost doubles over the period,[6] while the use of non-fossil feedstock in the power sector increases by as much as 240 per cent. Coal-based supply of power increases towards 2030, when demand levels off. However, coal still has a share in electricity production of 28 per cent in 2050. The level of gas demand from the global power sector more than doubles and reaches a share of 26 per cent in 2050.[7]

Table 1. World electricity production by source. Reference Scenario

	2015	2015	2040	2040	2050	2050
	Mtoe	Share in per cent	Mtoe	Share in per cent	Mtoe	Share in per cent
Total electricity production	2 092	100	3 471	100	3 891	100
Natural gas	490	23	944	27	1 030	26
Coal	795	38	1 059	30	1 055	28
Oil	92	4	28	1	25	1
Renewables and nuclear	715	35	1 440	42	1 781	45

We assume a natural gas resource situation in the Arctic as depicted by USGS (2008) and that the gas companies have full access to all reserves. Total gas resources consist of proven reserves (developed and undeveloped) defined as fully identified and economically viable reserves, whereas undiscovered resources are identified through geological surveys. Undiscovered resources are found and may be developed if they are profitable.

Figure 1 shows the distribution of total undiscovered gas resources among arctic regions. Arctic Russia dominates with about 70 per cent of total arctic undiscovered gas resources, whereas Alaska is second with 14 per cent, almost as much natural gas as in Greenland, Northern Canada and Northern Norway together. Greenland has larger gas resources than Arctic Canada and Arctic Norway combined. For the Arctic as a whole, about 80 per cent of the undiscovered gas resources are found in offshore areas, however, Arctic Russia stands out with almost as much as 90 per cent offshore.

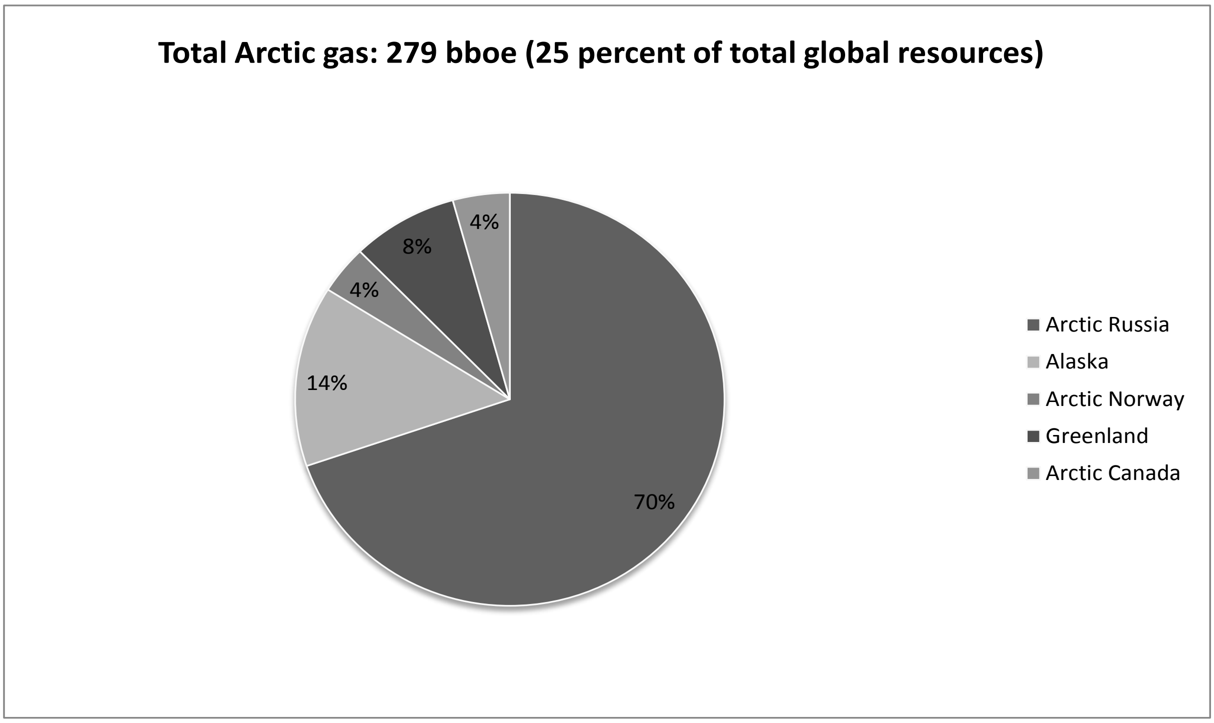
[6] India and China experience the highest growth in electricity production over the projection period, with 340 per cent and 225 per cent, respectively. The lowest growth is found for Western Europe and the US, with around 120 per cent and 130 per cent, respectively. Still, Western Europe and the US combined have a share of 22 per cent of the global power supply in 2050, while India and China taken together has 35 per cent.

[7] The share of gas in electricity supply in 2050 in the US and Western Europe is 34 per cent and 24 per cent, respectively. The share in India is 12 per cent, while China has the lowest share of 7 per cent. This means that the volume of gas as an input to the power sector is twice as high in the US and Western Europe taken together compared to India and China combined.

The global average gas price in our reference scenario increases by around 35 per cent from 2012 to 2040 and a further 10 per cent to 2050, when it reaches almost 520 MUSD/Mtoe (2012-prices). The future prices still differ somewhat across regions, albeit less than today.

Figure 2 shows arctic gas production in the reference scenario. Arctic supply of gas will slightly decline from 500 Mtoe in 2012 to about 450 Mtoe by the early 2020s, when the supply starts to increase.[8] The increase in total arctic gas production is primarily due to higher Russian volumes, but also partly a result of increases in gas supply from the other arctic regions, although from generally low levels. The development in supply in the reference scenario from the West Arctic regions is shown in more detail in Figure 3.

Figure 1. Regional distribution of arctic undiscovered gas resources



Source: USGS (2008) and EIA (2013).

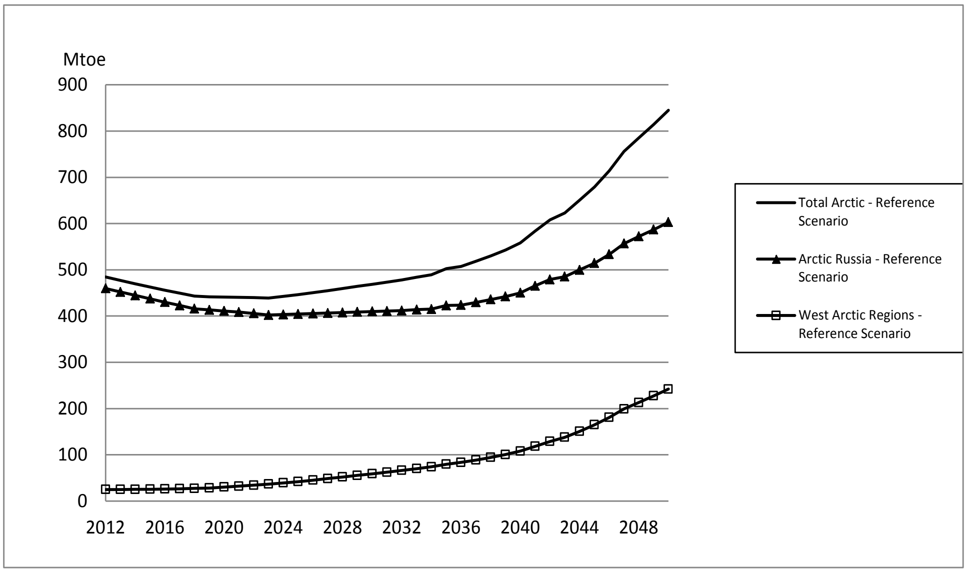
In the reference scenario the global share of coal for electricity production is reduced from 38 to 28 per cent by 2050 (see Table 1). Global electricity production is driving a marked increase in arctic gas supply from around 2030, even though the exogenous share of non-fossil feedstock is increasing from

[8] The gas volume in 2050 is almost 50 per cent higher than in Lindholt and Glomsrød (2012), which based their future coal scenarios on expectations in the late 2000s, as e.g. IEA (2008). Since then there has been a change in expectations towards less coal and more gas fired power plants (in the NPS).

35 per cent in 2015 to 45 per cent in 2050. In the reference scenario the amount of arctic gas supply increases by around 70 per cent during the period 2030-2050.

Arctic Russia is a giant gas producer in arctic and global context, with 95 per cent of total Arctic production today and almost 90 per cent of total Russian supply. Arctic Russian production increases by 33 per cent towards 2050 and the lion's share of this increase beyond 2030 has to come from resources that are not yet discovered and to a large extent in offshore areas. One might question if this is realistic as so far there is no gas production in Russian Arctic waters. Currently the only offshore gas production is taking place in more temperate regions near the island of Sakhalin. Russian engineers are world leaders in inland arctic pipeline technology as demonstrated in the Yamal Peninsula (Stern, 2009), where almost all Arctic Russian production takes place. The supergiant Bovanenko onshore gas field began production in 2012. Bovanenko is even larger than the huge offshore Stockman gas field, which is put on hold, and total supply from Bovanenko is expected to be almost 20 per cent of total Russian gas supply as from 2020 (Gazprom, 2016). However, for Russian arctic gas production to move offshore, the industry might need technological transfers from more experienced foreign partners, e.g. in deep sea operations.

Figure 2. Arctic gas production. Reference Scenario. Mtoe



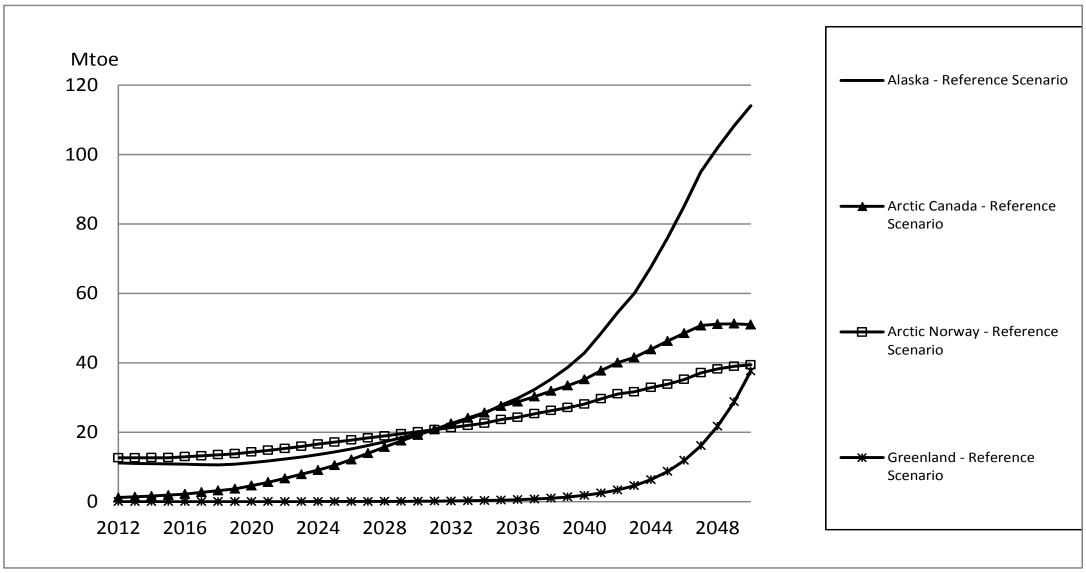
Although there will be a relatively constant future demand for Russian gas in Europe, there will be a substantial increase in Asian demand both through pipelines and LNG shipping. A new pipeline - Power of Siberia - is being built, mainly with the purpose of transporting gas from the fields of

Chayanovskoye and Kovyktinskoye in the Republic of Sakha to Vladivostok with further access to China and East-Asia. Power of Siberia is expected to transport gas soon after 2019 (IEA, 2014b).

There are plans for connecting this pipeline to the rest of the Russian pipeline system, so that eventually gas from Yamal in Western Siberia can be transported to the Asian markets. In addition, the Yamal LNG plant, which is under construction, will start production in 2017 for export to Asia along the Northern Sea Route and to Europe (Total, 2016). Hence, although there will be a relatively constant future demand for Russian gas in Europe, the model predicts an increase in Asian demand, leading to increased Russian output of gas after 2025.

Although Alaska has 14 per cent of the undiscovered gas in the Arctic, resources will only gradually be developed the first years and only really take off from around 2035. Such an increase is probably conditioned by an 800 miles gas pipeline from Prudhoe Bay to the southern parts of Alaska, similar to the existing North Slope oil pipeline. There are plans of other pipelines and LNG factories, e.g. a new LNG plant in southern Alaska besides that the plant at Cook Inlet might come on stream (EIA, 2017). Shell and Statoil withdrew from exploratory drilling in the Chukchi Sea in 2015 for commercial reasons, and this raised the question if the Alaskan increase in gas supply is realistic. However, almost as much as 90 per cent of the Alaskan undiscovered gas could be found onshore on the North Slope or offshore in adjacent areas closer to land than more remote fields far out in the Chukchi Sea. Hence, Alaska might harvest considerable amounts of gas without having to battle offshore in a harsh environment.

Figure 3. Regional distribution of West Arctic gas production. Reference Scenario. Mtoe



Canada starts out with a rapid growth from low levels in the reference scenario, matching the production level of Alaska around 2030, when Canadian production enters a path of somewhat slower growth reaching a plateau of 50 Mtoe in 2050. A rapid initial development of Canada's gas reserves is likely to depend on the development of LNG plants and/or the much talked about (and delayed) Mackenzie pipeline supposed to transport gas from the North West Territories and south to Alberta and further. According to Transcanada (2017) natural gas market conditions do not signal a commercially viable opportunity for this pipeline today, but project activities may be restarted at some future date. In addition, indigenous rights have postponed the project several times. Further, Canada's indigenous stopped seismic surveys in Baffin Bay near Greenland as they had not been consulted on the issue, and thus not complied with their legal rights.

Today Norway is producing gas in the Barents Sea (the Snøhvit field) and the Norwegian Sea. Polarled, a new pipeline was opened in 2016, crossing the Arctic Circle and transporting gas from e.g. the Aasta Hansteen field to Nyhamna/Molde on the west coast of southern Norway. The reference scenario lifts the supply path of Arctic Norway somewhat from the mid-2020s. Total supply increases almost fourfold over the whole 2012-2050 period.

In Greenland gas resources have been detected by seismic surveys, but no findings have proven viable so far. Several petroleum companies have stopped their exploration activities the last couple of years. With relatively high costs and long lead time Greenland is unable to start production before the end of the 2030s, but from then on it will gradually produce from present undiscovered fields and output rises to 38 Mtoe and reaches almost 5 per cent of arctic supply in 2050.

3.2 Phasing out coal and phasing in renewables scenario

For our phase out of coal scenario we align the pathways of fossil versus non-fossil based electricity with the 2 degree scenario of IEA (2014a). Our approach is as follows: The share of non-fossil feedstock (renewables and nuclear combined) for power production is set exogenously and equal to their joint share of 69 per cent as in the 2 degree scenario towards 2040 (IEA, 2014a) as shown in Table 2. This share, which is 51 per cent renewables and 18 per cent nuclear, is kept constant towards 2050 as global power production continues to increase. The remaining share of electricity supply is a mix of coal and natural gas (with a tiny share of oil). A CO_2-tax is imposed on fossil feedstocks and due to differing carbon content this constrains the coal use to the advantage of the use of natural gas as this is the least carbon intensive fossil fuel. The CO_2 tax level is chosen so that the development of the shares of gas and coal in regional electricity generation follows relatively closely to the 2 degree scenario, reaching a global share of 17 and 14 per cent for gas and coal, respectively, at the end of the projection period.[9] Both coal and gas lose much of their growth momentum in power generation around 2030, when renewables really start to manifest themselves. In this way we mimic the relative strength between gas, coal and non-fossil power in the 2 degree scenario, however, when adapting this in the FRISBEE model of the petroleum market we end up with a somewhat higher total consumption of electricity worldwide.[10]

Table 2. Volume of world electricity production by source. Reference Scenario and Phasing Out Coal Scenario. Per cent

	2015	2050	
		Reference	Phasing Out Coal
Natural gas (per cent of total)	23	26	17
Coal (per cent of total)	38	28	14
Oil (per cent of total)	4	1	1
Renewables/nuclear (per cent of total)	35	45	69

In 2050 coal has its share reduced from 28 per cent in the reference scenario to 14 per cent in phasing out coal scenario. The strong trend towards non-fossil electricity generation, above all after 2030, also reduces the market share of natural gas substantially from 26 to 17 per cent. Hence, if a CO_2 tax is used to regulate the mix of coal and gas, natural gas is less constrained than coal, but still hurt by the policy.

Figures 4, 5a and 5b show that the market shares of arctic gas will be reduced. Around 2030 the supply is departing from the reference path – still increasing but at a markedly lower rate. By 2050 total supply is 600 Mtoe compared with almost 850 Mtoe in the reference scenario. However, the Arctic will still deliver an increasing volume of gas as feedstock for electricity production as deliveries increase 36 per cent or 160 Mtoe from the 2020s towards 2050.

Russia reduces supply in 2050 by the largest amounts (ca. 130 Mtoe), but Greenland and Alaska loose the most in relative terms, both seeing a boom in production foregone (Figure 5a and 5b). The Alaskan gas production in 2040 is around 29 Mtoe, close to the projected reference level in EIA (2016). Our increase in gas production in Alaska beyond 2040 goes along with a further increase in US gas prices.

[9] As the share of renewables is exogenous it is possible to reach the goals for both coal and gas with one policy instrument, the CO_2-tax. The regional CO_2-prices vary from 105 USD to 125 USD per ton in 2035 and between 145 USD and 165 USD in 2050 (2012-prices).

[10] In IEA (2014a) electricity production is 13 per cent lower in the 2 degrees scenario than what follows from NPS in 2040. However, IEA include various policy measures beyond carbon pricing.

Figure 4. Arctic gas production. Reference and Phasing Out Coal Scenario. Mtoe

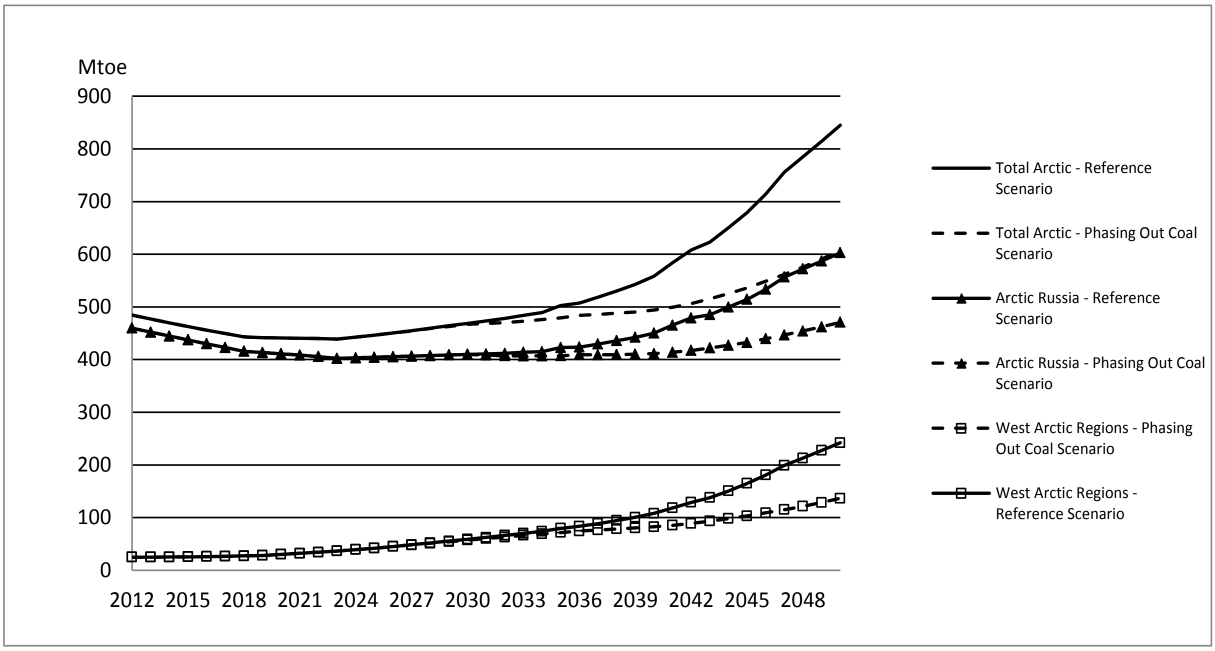


Figure 5a. Alaskan gas production. Reference and Phasing Out Coal Scenario. Mtoe

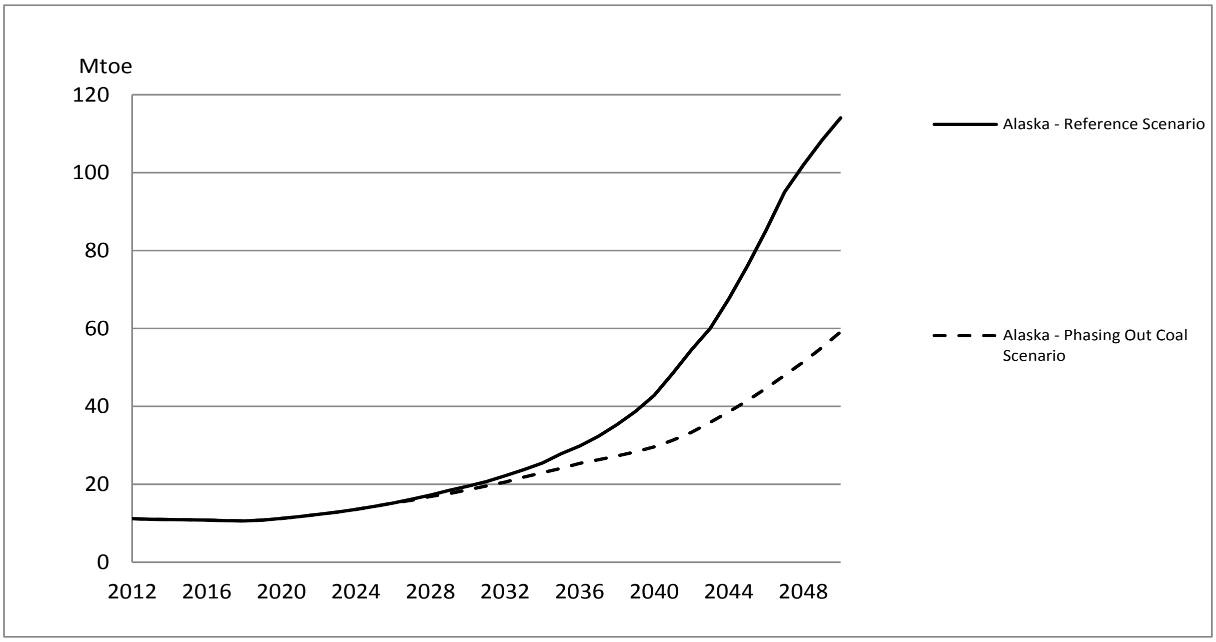


Figure 5b. Other West Arctic gas production. Reference and Phasing Out Coal Scenario. Mtoe

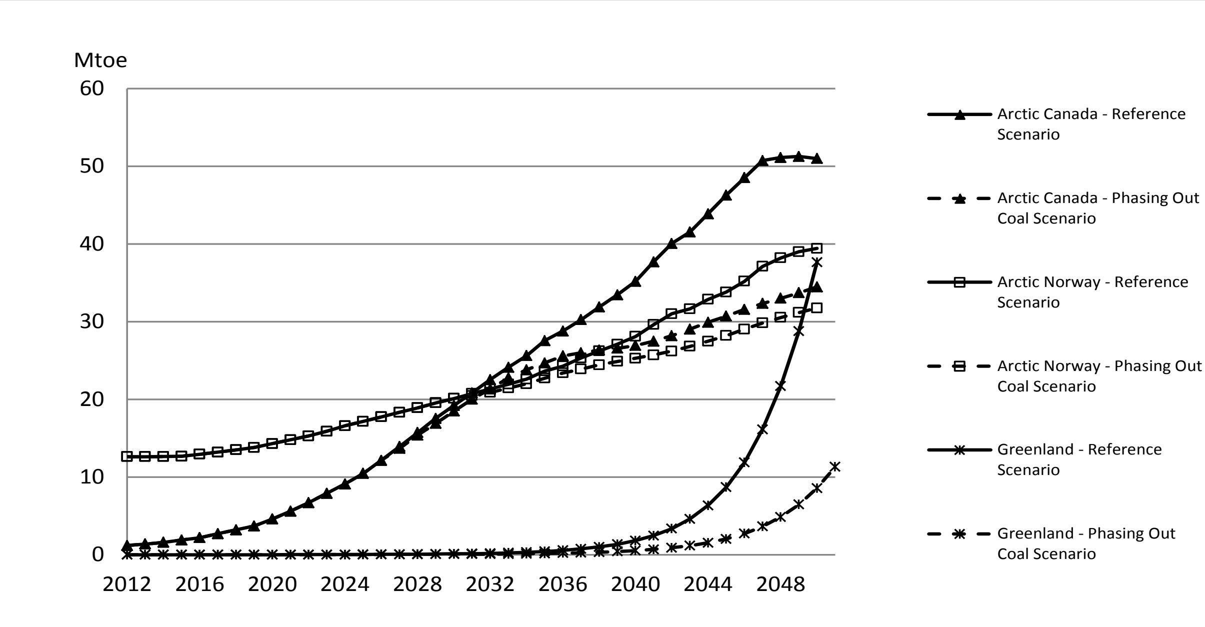


Table 3 shows the results in terms of the decline in accumulated natural gas production over the period 2015-2050. For the Arctic as a whole the decline is 9 per cent, for Greenland and Alaska as much as 69 and 31 per cent, respectively. Their golden age was supposed to be after 2030 in the reference case, however, this vision is under pressure in our policy scenario, as renewables really start to crowd out gas (and coal) after 2030. The reason for the large decline in supply from Greenland is also due to its relatively high capital and operational costs compared to what is the case in the other arctic regions. Although Russia no longer sees as rapid growth from around 2035 as in the reference scenario, the effect on accumulated production in Arctic Russia of phasing out coal is as low as 6 per cent. After Arctic Russia, Norway has the second lowest effect by a reduction of 13 per cent. The reason is that Arctic Russia and to some extent Arctic Norway have a relatively smaller share of their accumulated production after 2030 in the reference scenario compared to the other regions. The reason for the small decline in output from Arctic Russia is also due to its relatively low costs.

Table 3. Accumulated gas production 2015-2050. Phasing Out Coal Scenario. Deviation from Reference Scenario. Per cent

Total Arctic	Greenland	Arctic Russia	Arctic Canada	Alaska	Arctic Norway
-9	-69	-6	-21	-31	-13

We see from Figure 6 that the Middle Eastern/North-African (MENA) region achieves a market share of around 50 per cent towards 2050. There are abundant and cheap gas resources in the MENA region, above all in Iran and Qatar. Table 4 shows the arctic share of total gas production outside the MENA region as well as the arctic share of global supply.[11] In the reference scenario the share of the Arctic in world supply of gas is reduced from 17 per cent in 2015 to 14 per cent by 2050, while it declines to 12 per cent in the policy scenario.[12] In the reference scenario the Arctic increases its share in production outside MENA from 27 per cent in 2015 to 35 per cent in 2050. The share in 2050 turns out somewhat lower at 33 per cent in the policy scenario, still above today's share. The reason is that arctic production is on an increasing trend towards the end of the production period, while in Non-MENA production levels off because costs increase as their reserves are being depleted.

Figure 6 Arctic gas production in relation to MENA and global gas supply. Reference Scenario and Phasing Out Coal Scenario. Mtoe

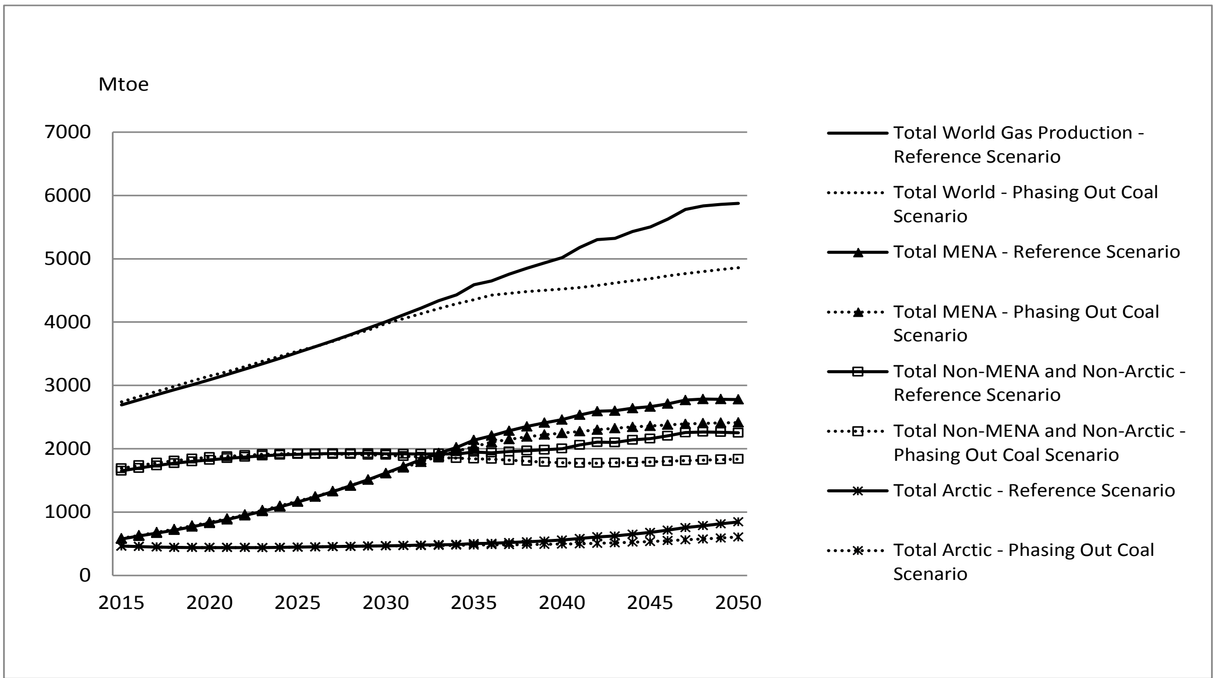


Table 4. Arctic gas in relation to MENA and global production. Reference Scenario and Phasing Out Coal Scenario. Per cent

	2015	2050	
		Reference	Phasing Out Coal
Arctic share of total production outside Middle East/North-Africa	27	35	33
Arctic share of world gas production	17	14	12

[11] Global gas production in 2040 is almost 4 per cent higher than the NPS in IEA (2014a).

[12] The reason that the reduction in global gas production is over the double of the reduction in gas fired power supply is efficiency of generation. Less than 50 per cent of the energy ends up as electricity on the other end of the generator. In addition, there is some substitution from gas to electricity in the household and industry sectors.

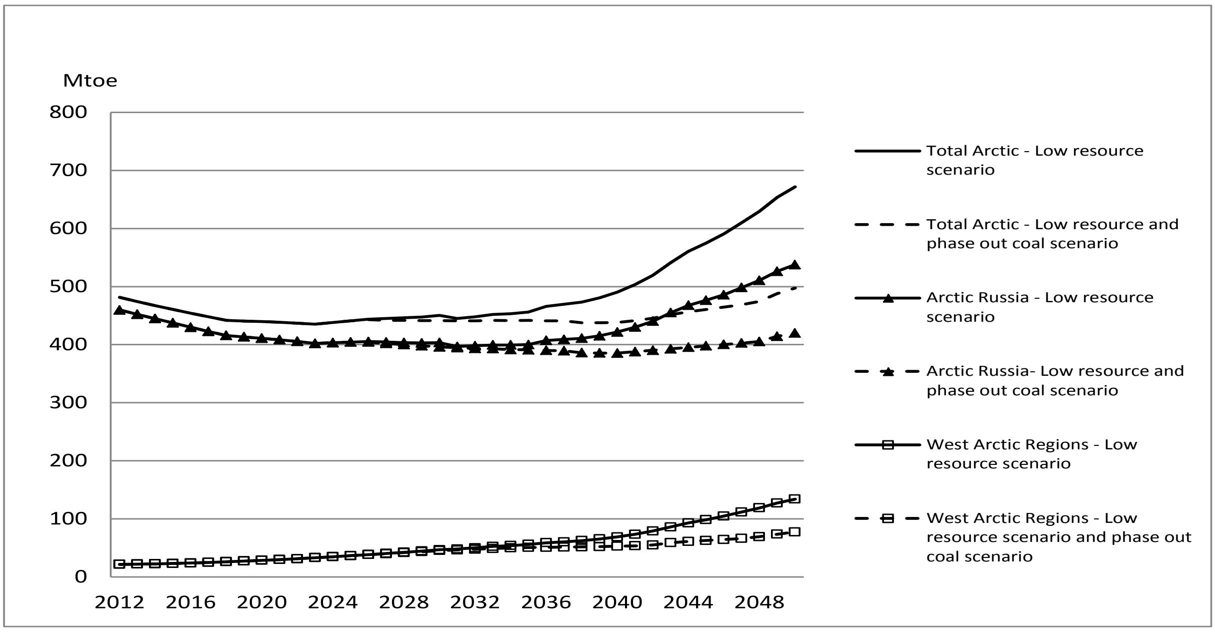
3.3. Sensitivity Analysis

In a situation with increased power supply compared to the level we so far have assumed, demand for natural gas from the Arctic and other regions will increase if we do not impose any further restrictions. To simulate such a situation we let global demand for power increase by 10 per cent above the reference scenario level in 2050, which is comparable to the level in the Current Policy Scenario of IEA (2014a) in 2040, the scenario with the highest level of power demand. This simulation shows that phasing out coal and phasing in renewables now will lead to a somewhat smaller reduction in total arctic gas production compared to the original global power demand, that is a reduction of 227 Mtoe instead of 250 Mtoe in 2050. However, to prevent the level of arctic gas production from declining in 2050 from the reference scenario, global power demand has to be 50 per cent higher at the end of our projection period, which does not seem very plausible.

Another issue involving uncertainty is to what extent all of the gas resources will be accessible, with production only limited from a commercial point of view. In our scenarios so far it is assumed that the gas companies have full access to resources with no environmental or other political barriers. Access to all resources and the subsequent increase in extraction in e.g. Alaska and Canada might meet constraints in the building of new gas pipelines or LNG plants, which have been postponed several times. In Alaska a large share of land is federal, of which large areas already are national parks and precious wilderness. In Canada indigenous peoples' rights have a strong position and use of these rights have postponed or blocked infrastructure projects required for petroleum extraction. In Norway production from resources in Lofoten, Vesterålen and Senja are subject to strong political opposition as the area is the core spawning ground of the valuable North Atlantic cod stock, with fish farming along the coast and with natural landscapes experiencing increased interest as a target for tourism. Environmental concerns may play a larger role in the future, preventing access to all gas resources. Further, some resources are hard to get at, like in Greenland where gas has been detected by seismic surveys, but, several petroleum companies have stopped their exploration activities the last couple of years, because no findings have proven viable so far. Further, without technological transfers from more experienced foreign partners, e.g. in deep sea operations, Russian gas industry might be prevented from getting access to all offshore resources. To sum up, we run a scenario to illustrate limited access to resources looking at a situation where the arctic gas companies only have access to 50 per cent of the undiscovered gas resources and trace the effects of phasing out coal in that benchmark case.

Figure 7, 8a and 8b show the effects of 50 per cent lower arctic undiscovered gas resources on future supply. Whereas arctic gas supply embarked upon a marked upwards trend by 2025 in the original reference scenario, the case with less available resources delays the upwards trend with another decade. We see that gas production in Arctic Russia in the resource adjusted reference scenario is hit less towards the end of the projection period compared with the other regions as the vast majority of gas production in Russia before 2050 is from proven and already discovered reserves.

Figure 7. Arctic gas production. Low Resource Scenario and Phase out coal Scenario. Mtoe



We also see that gas production of above all Alaska and Greenland is hit relatively more with less access to undiscovered resources in the new baseline case, because the bulk of their production increase after 2035 stems from resources that are still undiscovered today. Figure 7, Figure 8a and Figure 8b also show that phasing out coal and phasing in renewables in this low resource scenario will lead to somewhat lower relative reduction in gas deliveries in the various regions, as the baseline supply now is below the original reference scenario. Again, Arctic Russia and, hence, total Arctic supply is affected to a relatively limited extent in the policy scenario. Once more, those regions with increased volumes after 2030 end up with the highest relative losses and total arctic gas production turns out only marginally higher in 2050 than in 2012. The 9 per cent lower gas production in Arctic Russia in 2050 compared to 2012 is compensated by increased production from all other arctic regions.

Figure 8a. Alaskan gas production. Low resource Scenario and Phase out coal Scenario. Mtoe

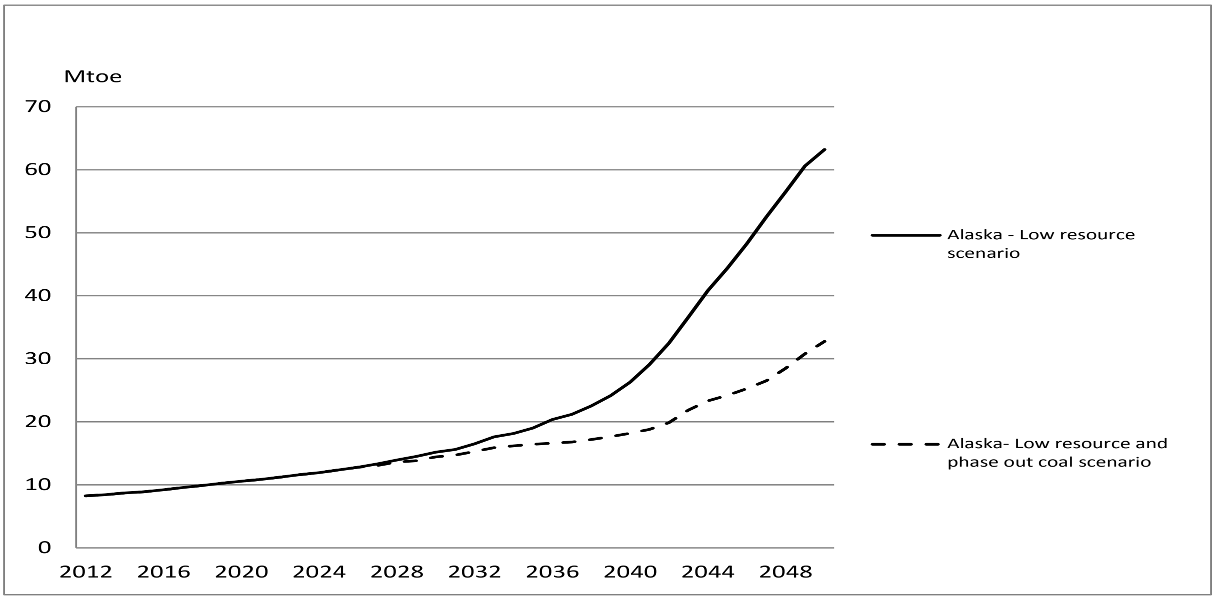
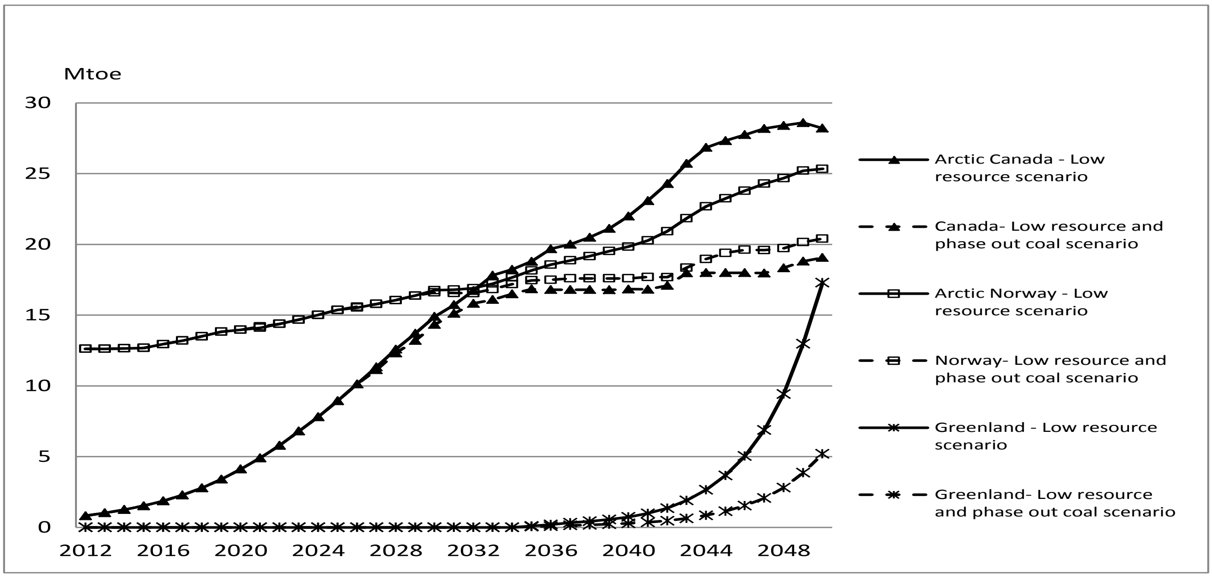


Figure 8b. Other West Arctic gas production. Low resource Scenario and Phase out coal Scenario. Mtoe



To further check the robustness of our results, we run a scenario with 25 per cent higher operational and capital costs in addition to less access to resources. If we phase out coal and phase in renewables to comply with the 2 degree scenario in the power sector in this situation, we get further reductions in gas supply in all arctic regions. Total Russian supply is around 15 per cent lower towards the end of the projection period than today, while the other arctic regions again experience increases in supply over the period, albeit to a lesser extent than in the scenario with only less access to reserves. This means that total arctic gas production is not much lower in 2050 than in 2012, even when we phase out coal in this bleaker situation for gas producers with higher costs and less resources. In this context we emphasize that behind all scenarios many fields are emptied and new ones are discovered and developed. Hence, even if phasing out coal leads to lower arctic supply, it will still be profitable to develop many new arctic gas fields, even with less promising prospects for arctic activity. Further, we will point out that *without* arctic gas deliveries prices of electricity and non-fossil feedstock could experience a large increase. However, to study how the supply of renewables/nuclear reacts to changes in demand has to be a part of a future study, where we have endogenized the quantities and prices of the non-fossil feedstock.

4. Conclusion

This paper examines to what extent downscaling of global coal based electricity generation encourages gas demand and affects regional activity in gas production, with emphasis on the arctic regions. The Arctic is above all rich on natural gas as 70 per cent of undiscovered petroleum resources in the region are gas.

We apply a recursive, dynamic partial equilibrium model for the global energy markets, which is solved sequentially year by year. Our reference scenario is aligned with the New Policy Scenario in IEA's World Energy Outlook, accounting for that renewables is set to increase its contribution to global electricity production over time, while coal will contribute less. Our policy scenario reflects further phase out of coal and phase in of renewables in line with the 2 degrees scenario for the power sector.

The strong trend towards non-fossil electricity generation in our policy scenario, above all after 2030, reduces the market share of natural gas. Natural gas is less constrained than coal, but still hurt by the policy. This also entails reduced arctic gas production compared to the reference scenario. For the Arctic as a whole the decline in accumulated production is 9 per cent, while for Greenland and Alaska it is as much as 69 and 31 per cent, respectively. The reason is that the bulk of their production increase in the reference scenario comes after 2030, when renewables really start to crowd out gas (and coal). The effect on accumulated production in Arctic Russia of phasing out coal and phasing in renewables is as low as 6 per cent. The reason is that Arctic Russia has a relatively larger part of its production prior to 2030, when production is not so much crowded out by increased renewables in the global power sector.

However, Arctic still increases its share in production outside Middle Eastern/North-African (MENA) region from 2015 to 2050 in our policy scenario. The reason is that arctic production is on an increasing trend towards the end of the production period, while in Non-MENA production levels off because costs increase as their reserves are being depleted.

Even in a situation with less resources and higher costs for arctic gas, production in the Arctic is not much lower in 2050 than today in the phasing out of coal and phasing in of renewables scenario. Hence, even in this bleaker situation for arctic gas producers, it is still profitable to invest in and develop new gas reserves.

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Appendix A

Table A1. List of gas regions and field categories in the FRISBEE model

	Gas[13] field category			
	1	**2**	**3**	**4**
Africa	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore shallow	Offshore deep
Canada	Arctic	Non-Arctic Onshore	Non-Arctic Offshore shallow	Non-Arctic Offshore deep
Caspian region	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore shallow	Offshore deep
China	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore shallow	Offshore deep
Eastern Europe	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore shallow	Offshore deep
Greenland	All			
Latin America	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore shallow	Offshore deep
Norway	Arctic	Non-Arctic Onshore	Non-Arctic Offshore shallow	Non-Arctic Offshore deep
OECD Pacific	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore shallow	Offshore deep
OPEC Core	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore	Venezuela
Rest of Asia	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore shallow	Offshore deep
OPEC Rest	Nigeria	Onshore	Offshore	Angola
Russia/Ukraine/ Belarus	Non-Arctic Onshore	Non-Arctic Offshore	East Arctic Russia	West Arctic Russia
USA	Non-Arctic Onshore	Alaska	Non-Arctic Offshore shallow	Non-Arctic Offshore deep
Western Europe	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore shallow	Offshore deep
United Kingdom	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore shallow	Offshore deep

[13] Conventional and unconventional.