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Evaluation and update of Norwegian and Danish oil production forecasts and implications for Swedish oil import

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Abstract
This paper presents an updated historic oil production analysis as well as an updated future oil production forecast for Norway and Denmark. Previous forecasts conducted by academic and official agencies using a variety of methodologies are contrasted and their accuracy examined. The bottom-up field-by-field methodology is found to be precise in the short-term, as it deviates by less than 1% from actual production.

The impact of declining oil production in the North Sea on Sweden is explored as a case study. The historic and future trends regarding Swedish oil imports are presented and their vulnerability assessed using the Herfindahl–Hirschman index.

Key words
Decline curve analysis, field-by-field analysis, oil security, energy security, Herfindahl-Hirschman index

1. Introduction

Oil is an essential resource in the modern economy. Reliable forecasts and accurate predictions of how future oil production is expected to develop are vital for planning and strategic decisions at all levels of a globalised economy. Reliable oil forecasts are important for the planning of state budgets and revenues in oil producing countries, oil companies' profit estimates and also for numerous countries that are dependent on oil imports. Import possibilities and patterns may experience significant changes in the future due to decreases or increases in production from various exporting countries, which could in turn affect the energy security of importing countries.

One of those importing countries lacking any significant domestic oil resources is Sweden, and consequently, Sweden is dependent on oil imports. At the moment, Swedish oil imports originate from a few actors, the majority originating from the North Sea [1]. North Sea oil has already reached its peak, with production in continuous decline. This incessant depletion will force Sweden to either decrease its dependence on oil or look for other suppliers in a global market witnessing increasing oil demand. This development is likely to affect Swedish energy security. The importance of proficient forecasts, especially forecasts of production from the North Sea, is crucial in appreciating the security of Swedish oil imports.

Projections of how the future may develop in the selected survey area can be driven by a number of goals. *Predictive methods* aim to find the most likely future outcome, *normative projections* (e.g. backcasting) aim to find a path to a desired future, while *explorative methods* (e.g. scenario building) attempt to illuminate possible future outcomes. This study focuses on the predictive methods. Three main approaches for oil production predictions can be distinguished; *top-down*, *bottom-up*, and *economic* methodologies [2].

The first influential top-down oil production model was developed by Hubbert [3] and since then many variations of his approach have been developed. Individual fields are not examined, as an aggregation into a larger collective (i.e. regional, national or global focus) is assumed to diminish the importance of single units, highlighting prevailing general patterns. Hubbert originally made a forecast of production by using a bell-shaped curve reflecting discovery trends [4]. Some authors use curves and models based on good empirical agreement with historic data [5] [6]. Others rely on more theoretical arguments to explain the observed collective behaviour [7]. When discussing peak oil, it is usually top-down models that are the focus.

The bottom-up approach investigates smaller units - typically single fields - and forms a framework for relating the properties of individual fields to the observed properties of aggregated regions in reality. Bottom-up methods may rely solely on physical/empirical factors such as decline curve analysis [8] [9], but can also integrate economic factors [10]. Consequently, bottom-up analysis requires a more detailed and comprehensive data set that may be difficult to obtain due to the lack of transparency in oil producing countries and companies.

Finally, economic methods deviate from the two previous methods by chiefly relying on qualitative mechanisms rooted in market behaviour and economic theory, where geological constraints are regarded as irrelevant [11]. Technological innovations, investments and future demand are assumed to be key determinants for future production trajectories. To construct a formal economic model is complex as it usually depends on many variables [12].

Oil forecasts may also be divided into different time horizons. In this paper, we define them as follows: short-term 1-5 years, mid-term 6-15 years and long-term > 15 years. Sometimes, the forecasting methodology is most useful within a certain time frame. For example, long-term projections aimed at depicting general trends should not be used as a substitute for meticulous economic studies to forecast perturbations in production over a few months or years [6].

1.1 Aim of study

It is important to evaluate previous forecasts as it provides feedback for both forecast makers and analysts as well as for policy makers and decision takers acting on these forecasts. The unavoidable fact of reality is that forecasts only can be verified in hindsight, but looking at track records of previous forecasts can provide useful information for methodological development and determine whether the selected methodology was appropriate or not.

This paper evaluates forecasts conducted for Norwegian and Danish oil production performed by Höök and Aleklett in 2008 [13] and Höök et al. in 2009 [14]. The passing of time only allows for a short-term accuracy evaluation using the last 5 years actual production data. These studies will also be compared with the equivalent predictions made by Norwegian and Danish petroleum authorities.

The difficulties of bottom-up forecasting and its uncertainty regarding short- mid- and long-term forecasts will be address by illuminating the factors that influence oil production and uncertainties in the forecast models. This involves factors such as data availability, decline rates, ultimate recoverable resources (URR), new field developments, start up time and new discoveries.

Finally, this paper examines and quantitatively assesses the historical trend of Swedish oil imports, and, combined with the updated mid- and long-term forecast for Danish and Norwegian oil production, a future scenario is created for Swedish oil imports. The import assessments use an index to quantify the oil supply's volume share and origin.

1.2 Data sources

The data sources for crude oil production were obtained from the Norwegian Petroleum Directorate (NPD) [15] and the Danish Energy Agency (DEA) [16] public databases. The partition of conventional oil is consistent with the respective countries data. The forecast data for Denmark were obtained from Danish Energy Agency reports *Oil and Gas Production in Denmark 2007* and *Denmark's Oil and Gas production 2008 and subsoil use* [17] [18]. The forecast data for Norwegian oil production were obtain from NPD reports *The Petroleum resources of the Norwegian Continental shelf 2008* and *2009* [19] [20]. Historic import data for Sweden was obtained from the Swedish Petroleum and Biofuel Institute (SPBI) [1]. Swedish crude oil import and petroleum product export data were obtained from the oil company Preem [21]. This is to be seen as indicative of how the Swedish export flows of petroleum products look geographically, since Preem refine over 80% of Swedish oil imports [22].

2. Methodological background

This study uses a bottom-up methodology based on field-by-field decline curve analysis consistent with previous studies by Höök and Aleklett [13] and Höök et al. [14]. The bottom-up method is well suited to Norwegian and Danish oil production as each country has transparent, publically available, data. The bottom-up method assigns an individual decline rate for each field that is then used for future production extrapolation. The results of each field are then aggregated to provide the national outlook.

Crude oil production models for Denmark and Norway are divided into two classes; giant and dwarf fields. Oil fields with an URR of 0.5 billion barrels (Gb) or higher are classified as giants, while oil fields with less URR are considered to be dwarfs [13]. Detailed data supplied by the NPD allows for two additional subclasses; natural gas liquids (NGL) and condensate. This is consistent with previous articles on Norway's and Denmark's oil production [13] [14]. This partitioning will provide a more accurate result regarding the decline rate due to the different behaviour and properties of the different oil classes and field sizes. The field-size distributions are also highlighted as it plays a vital role, when the giant fields tend to be discovered at an early stage and consequently exploited first.

This method is based on empirically observed behaviour determined by physical factors. Economic factors are not explicitly included. Calculations were facilitated by using statics; reserve values referred to as URR. The URR figure corresponds to the amount of oil recovered from an area in the past plus all future production. However, URR can vary due to changes in the petroleum recovery strategy, operator decisions and geological conditions.

2.1 Decline curve analysis and earlier work

The historic production data for each field is used to calculate characteristic properties of each field, such as decline rate or depletion level. Production is projected into the future using decline curve analysis, as originally developed by Arps [8]. A more comprehensive presentation of the framework can be found in Höök et al. [23].

The notation of the model is as follows; t_0 is the time production starts to decline, r_0 the initial production rate and Q_0 the cumulative production, q(t) is the production rate at time $t > t_0$ and Q(t) is the corresponding cumulative production at the same time, λ is the decline rate parameter, β is the shape parameter and URR is the ultimate recoverable resource, t_{cut} indicates when production is not economically viable to exploit, V_{rec} stands for what is technically possible to extract [14]. Decline curves can use different numerical adjustment methods to find the best curve fit. These methods include exponential, harmonic or hyperbolic functions (see Table 1). The exponential method may underestimate production towards the end of the curve as production typically flattens out. To obtain a more accurate result in this phase either harmonic or hyperbolic method can be applied due to their mathematical properties [14]. Figure 1 and 2 depict this method and also highlights the difference between exponential and hyperbolic curve fit.

Table 1. *Key properties of Arps exponential and hyperbolic decline curves*

	Exponential	**Hyperbolic**
β	$\beta = 0$	$\beta \epsilon [0,1]$
q(t)	$r_0\exp(-\lambda(t-t_0))$	$r_0[1+\lambda\beta\,(t-t_0)]^{-1/\beta}$
Q(t)	$Q_0+\frac{r_0}{\lambda}\,(1-\exp(-\lambda(t-t_0)))$	$Q_0+\frac{r_0}{\lambda(1-\beta)}\,[\,1-(1+\lambda\beta(t-t_0))^{1-(1/\beta)}\,]$
URR	$Q_0+\frac{r_0}{\lambda}$	$Q_0+\frac{r_0}{\lambda(1-\beta)}$
t_{cut}	$t_0+\frac{1}{\lambda}\ln\left(\frac{r_0}{r_c}\right)$	$t_0+\frac{1}{\lambda\beta}\left[\left(\frac{r_0}{r_c}\right)^{\beta}-1\right]$
V_{rec}	$Q_0+\frac{r_0-r_c}{\lambda}$	$Q_0+\frac{r_0}{\lambda(\beta-1)}\left[\left(\frac{r_0}{r_c}\right)^{\beta-1}-1\right]$

An advantage of decline curve analysis is that it is not dependent on field size, form, or reservoir drive-mechanism [24]. This makes the method applicable as long as production data is available. For more accurate methods additional data is required, which may be challenging to obtain. It is important to examine the production data in order to find possible production interruptions, as this may give a misleading decline rates.

Figures 1 and 2 illustrate the characteristic behaviour of oil fields when no major disruptions have occurred in these fields. Siri is classified as a dwarf field, with typical behaviour containing a shorter peak plateau production compared to the giant field Statfjord that has a longer peak plateau production [25].

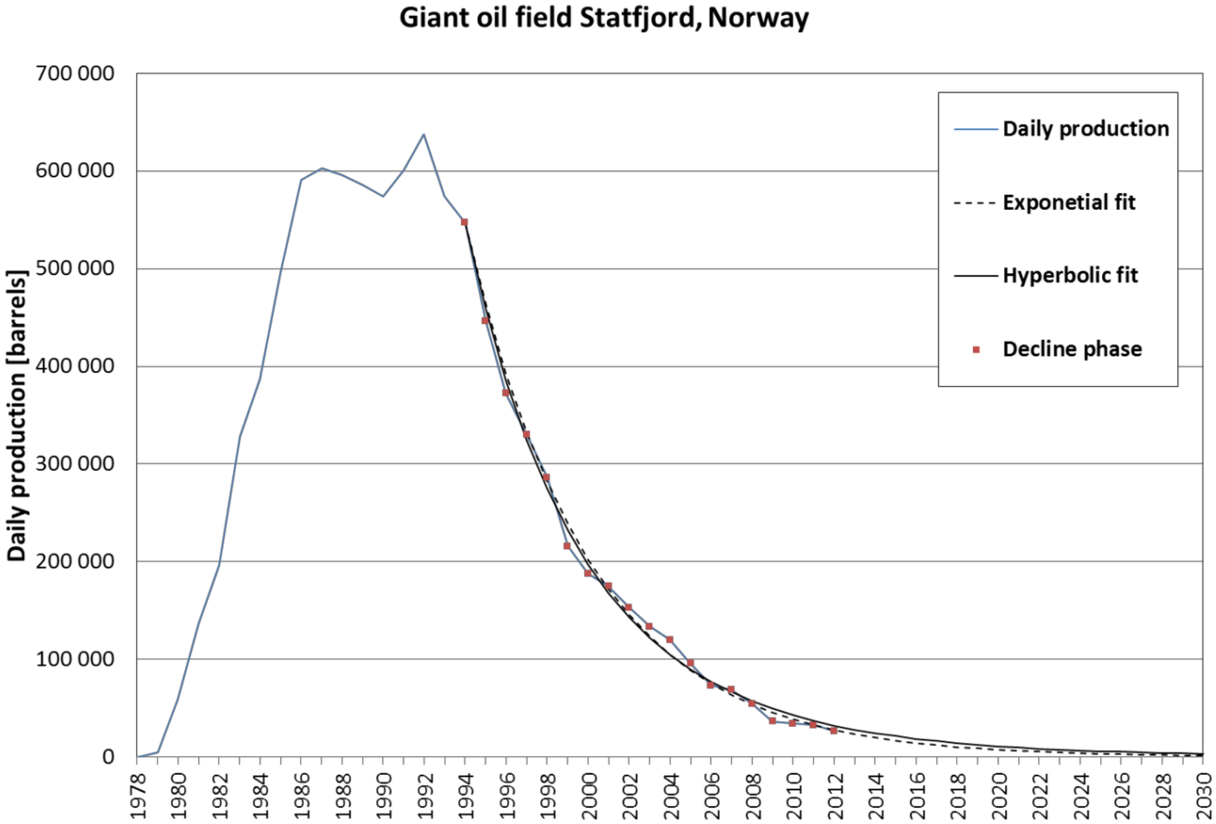

Figure 1. *Exponential and hyperbolic curve fit for the Norwegian giant oil field Statfjord.*

The accuracy of the curve fit obviously varies as some fields are below the exponential fit. In the Siri case, the actual production is in the divergence between exponential and hyperbolic curves.

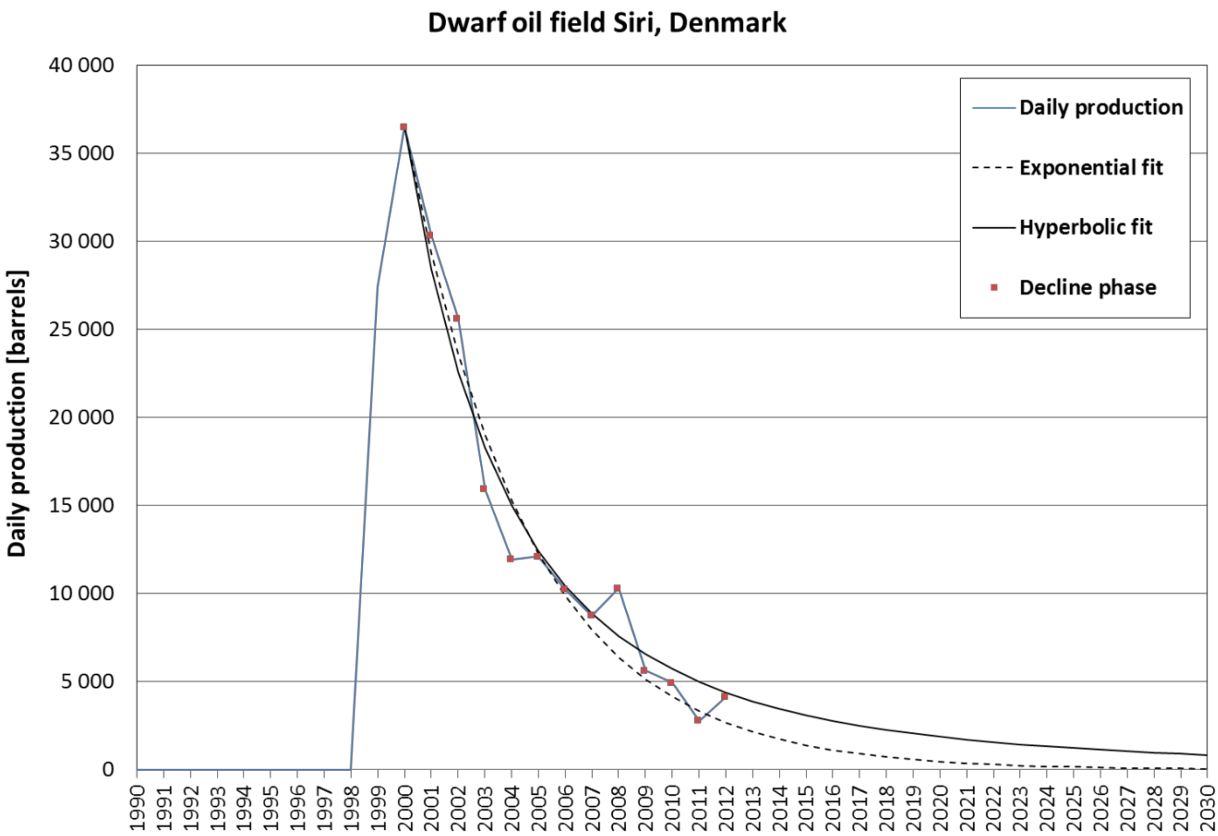

Figure 2. *Exponential and hyperbolic curve fit for the Danish dwarf oil field Siri.*

2.2 Forecasting models used by NPD and DEA

The DEA and NPD publish both short and long term forecasts in their annual reports on Danish and Norwegian oil and gas production.

The DEA forecast is based on an expected production profile of assessed resources, combined with a risk assessment regarding the contingent resources. Regarding long-term forecasts, technical and prospective resources are added. DEA also clarifies that their forecasts are uncertain [18].

The NPD forecast is based on assessments of production data provided by the operators. The NPD points out that the forecast is uncertain. Uncertainty in the short term forecast is mainly linked to the production volume. Other uncertainties include new fields' start-up year and expected production volumes. The uncertainties in long term forecasts are connected to undiscovered oil resources and new development areas geological condition and resources. To handle these uncertainties NPD is applying an 80 % confidence interval, which means that there is a probability of 10% that production will be lower than the low estimates and the reverse probability of 10 % that the production will be higher than the high estimates [26].

2.3 A quantitative indicator for import vulnerability analysis

The Herfindal-Hirschman index (HH-index) is a well-known tool for assessments of commodities, for example the U.S. Federal Trade Commission applies this method to analyse different markets [27]. HH-index handles both the number of actors and their share of the selected commodity thus reflecting the dependence on individual suppliers and the diversity of the market (Equation 1). In this paper the HH-index is used to assess the Swedish oil import vulnerability. The actors consist of countries, as their governments usually have the last word regarding the extraction of commodities.

$$\boldsymbol{D} = \sum_{\boldsymbol{i}=\boldsymbol{1}}^{\boldsymbol{N}} \boldsymbol{S}_{\boldsymbol{i}}^{\boldsymbol{2}} \qquad (\boldsymbol{1})$$

S_i in Equation 1 represents the market share of supplier *i.* A HH-index of 0.01 indicates a highly competitive index and an index value of 1 reflect a monopoly situation. A more detailed description is shown in Table 2.

Table 2. *The definitions of HH-index.*

HH-Index	**Market characteristics**
<0,01	Highly competitive
<0,15	High diversity
0,15 to 0,25	Moderate concentration
>0,25	Low diversity
1	Monopoly

The HH-index can be further improved by introducing an additional parameter that describes the country's stability and thus has an increased weighting for the supply security of the commodity [27]. As this paper also addresses future scenarios, making it difficult to predict a country's future stability, this parameter will not be included. This paper assesses the resource oil, which is geographically restricted to certain regions, resulting in only a few countries being actors in this market. Disruptions in the form of accidents or political events such as the Iranian revolution, the Gulf crisis etc. will thus have large impact on the market. Oil import vulnerability may therefore increase when there is a low diversity among import sources. The more diversified the oil market is, the better a country’s ability to cope with unforeseen events. The development of this index over time gives a clear picture of import diversification and changes in vulnerability [28].

3. Updated Norwegian and Danish oil production

Oil production in the North Sea region began in the early 1970s and is now considered to be a mature region. The majority of North Sea oil consists of valuable light oil and the seabed consists mainly of sandstone and limestone. Sandstone is mainly located in the north while the limestone is located in the south [29].

3.1 Historic oil production of Norway

The updated historic oil production of Norway is depicted in Figure 3. Norway had its peak production in 2001 and its decline phase is now well underway. New fields' start-up year were consistent with previous studies [13], however, one can distinguish a faster development trend from discovery to production on new fields. In the 1990s the average time from discovery to production was 13 years, by the 2000s this had fallen to only 4 years. New fields consist mainly of satellite fields located in regions with existing infrastructure accounting for a faster start-up rate.

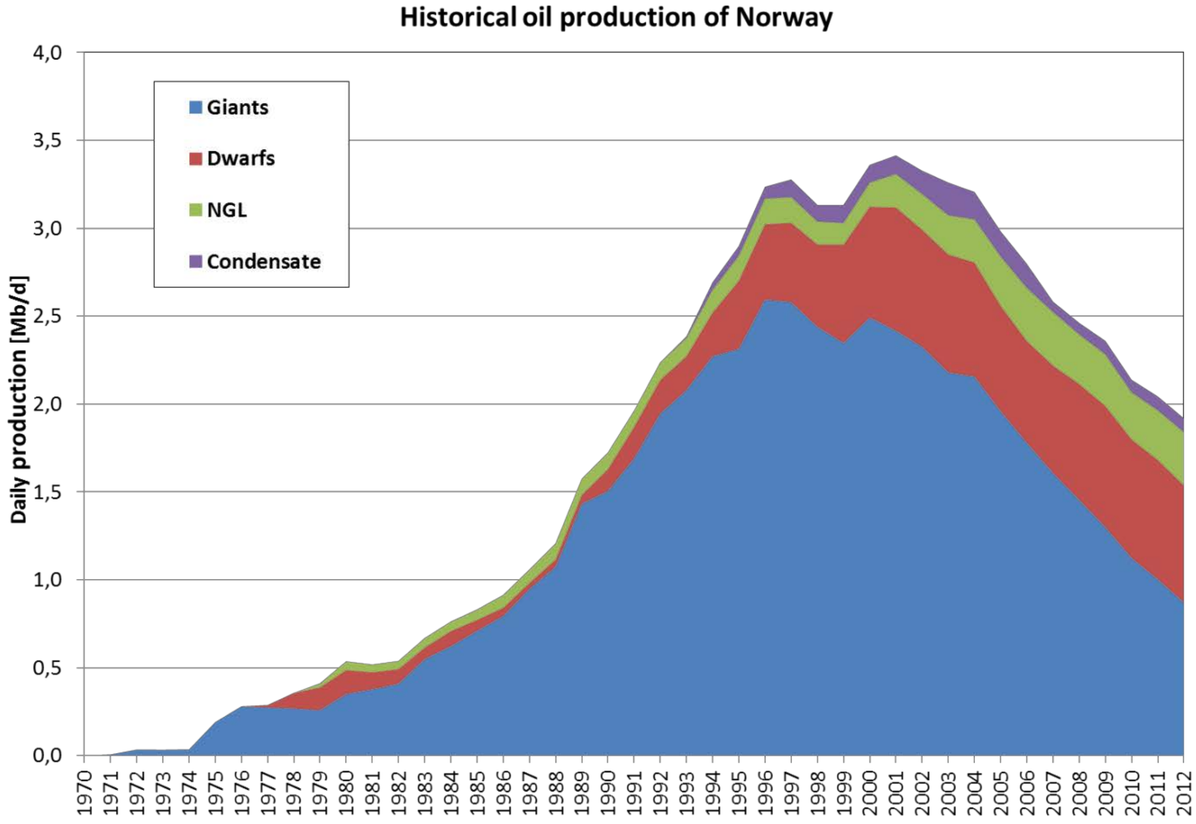

Figure 3. *Updated Norwegian historical oil production divided into subclasses.*

Figure 3 illustrates the significance of the giant fields for total oil production. These giants, producing the majority of the oil, have experienced a substantial decline in production in recent years. One can see a clear correlation between the decline of giant production and the decline of overall Norwegian production. Production dropped by 1.5 Mb/d from 2001 to 2012 of which the giants constituted the majority (1.45 Mb/d). During the same period the production share of the giants has reduced from 71 % to 45%, as depicted in Figure 4. Thus, the importance of the giant oilfields for Norwegian oil production is underlined.

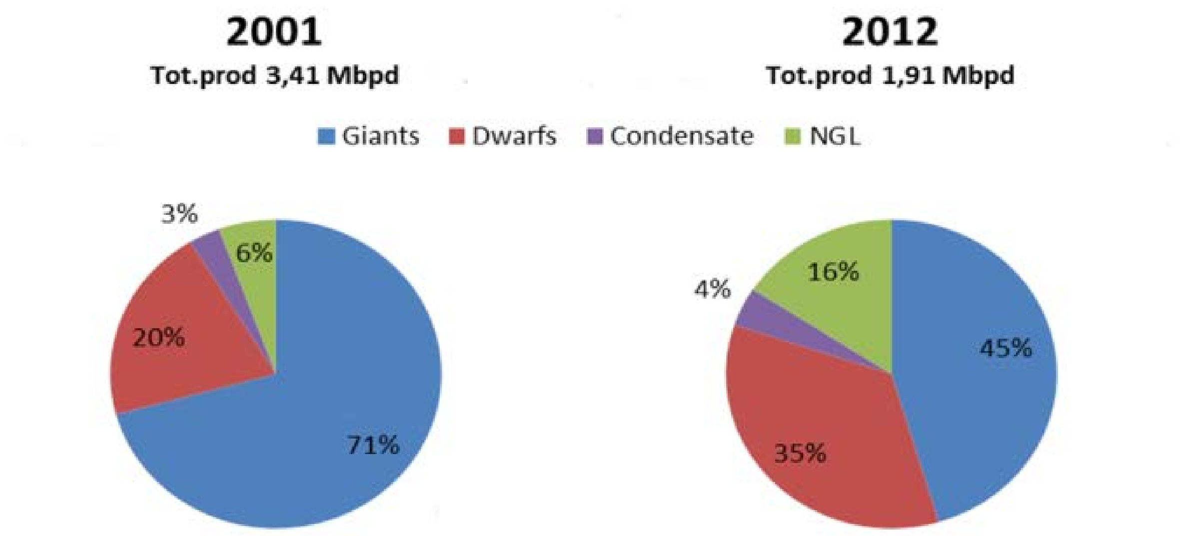

Figure 4. *Norwegian oil production divided into subclasses, 2001 and 2012.*

The calculated production weighted decline rate of the Norwegian giants (see Table 3) corresponds to 12.5%, while the dwarfs production weighted decline rate was 16%. Dwarf fields generally tend to be exploited more quickly to maximize the net present value [10]. The net present value indicates the cost that a producer would be willing to pay to extract oil from the ground. Condensate has a high decline rate due to a more intensive extracting process, as condensate has a high viscosity and is therefore easily recovered.

Table 3. *The Norwegian mean, production weighted and median decline rate of respective subclasses. Values from the previous 2008 studies are presented in parenthesis.*

	Giant [%]	Dwarf [%]	Condensate [%]	NGL [%]
Mean	-12,6 (-13,2)	-18,0 (-21,3)	-36,7 (-35,2)	-15,1 (-19,5)
Prod.Weight	-12,5 (-13,6)	-16,0 (-18,1)	-31,3 (-32,6)	-11,4 (-15,6)
Median	-11,2 (-13,9)	-16,3 (-15,9)	-25,9 (-30,0)	-14,3 (-13,3)

Compared to previous studies one can discern that the decline rates of both giants and dwarf fields have slightly decreased. This can be explained by the fact that an increasing number of fields are further out in the tail region of the decline phase and start to diverge from exponential decline and head towards hyperbolic trajectories. Aggregating all Norwegian fields fade any disturbances in one single oil field, which therefore does not have any significant impact on decline rates.

3.1.1 Evaluation of earlier projections

The forecast for Norwegian oil production from 2007 by Höök et al. [13] can now be compared with actual production data up till 2012 to evaluate the accuracy of the prediction. Figure 5 shows the 2007 forecast together with two official NPD forecasts of 2007 and 2008 as well as actual production.

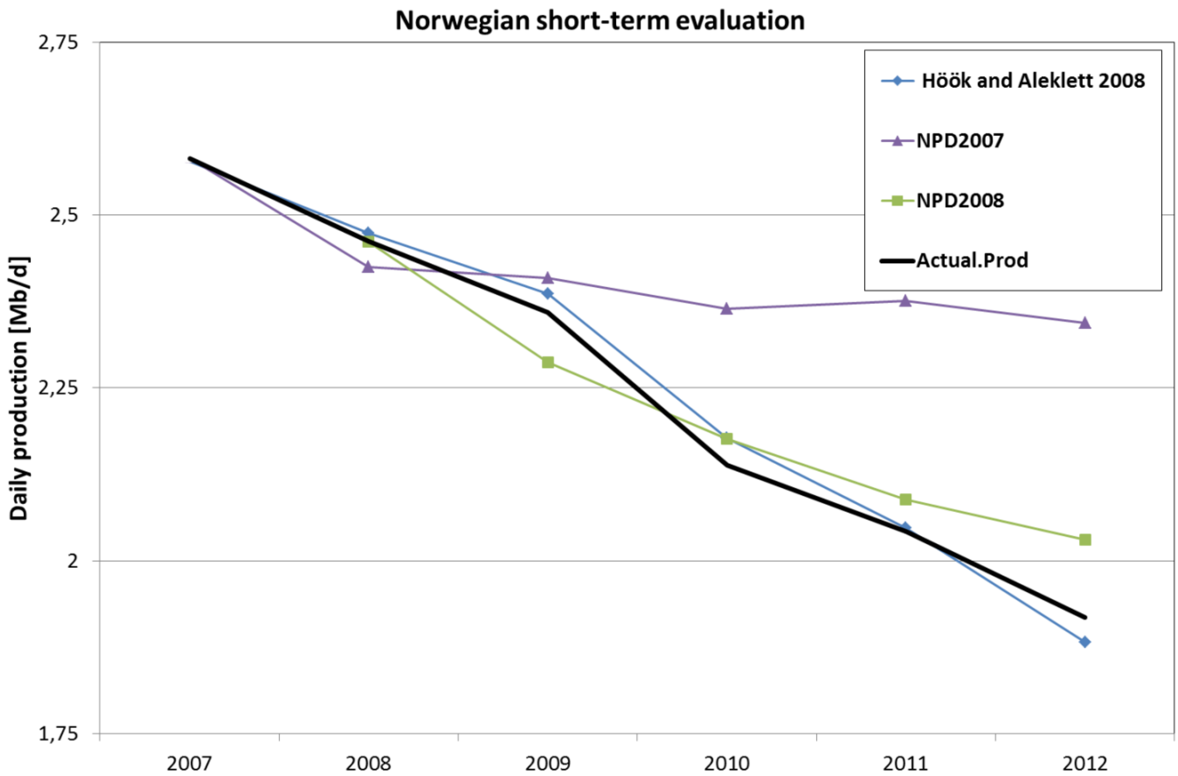

Figure 5. *Evaluation of Höök and Aleklett 2008 forecast combined with NPD forecasts from 2007 and 2008.*

The average yearly deviation from actual production was 0.4% for the forecast by Höök. The NPD predictions from 2007 and 2008 had a deviation of 8% and 1% respectively. The large difference in the two NPD forecasts is explained by the postponement of new projects and lower expectations on the amount of new production wells being drilled [26].

3.2 Historic oil production of Denmark

The updated historic Danish oil production is depicted in Figure 6. The production peaked in 2004 and has been in decline ever since. The importance of giant oil fields for Danish oil production is evident. Denmark has a relatively limited number of fields that consequentially makes it more complicated to perform qualitative analysis and draw viable conclusions, as a new field, or a single disruption in oil production, may have a major impact factor for Danish total oil production.

Production from the three giant fields is of great significance for Denmark, since they account for over 64% of the country's total oil production. The share has increased since 2004, indicating that Danish oil production is increasingly dependent on these three giant fields. The total Danish oil production has dropped by 0.18 Mb/d from 2004 to 2012. The three giants were responsible for more than half of this decrease.

Updated decline rates for Danish fields are presented in Table 4. For giants the production weighted decline rate was 7.8%, which is significantly lower compared to Norwegian giants. This can be explained by the fact that a majority of the Danish oil is located in limestone, making it more difficult to extract due to geological conditions [14]. For dwarfs the production weighted decline rate was 12.4%.

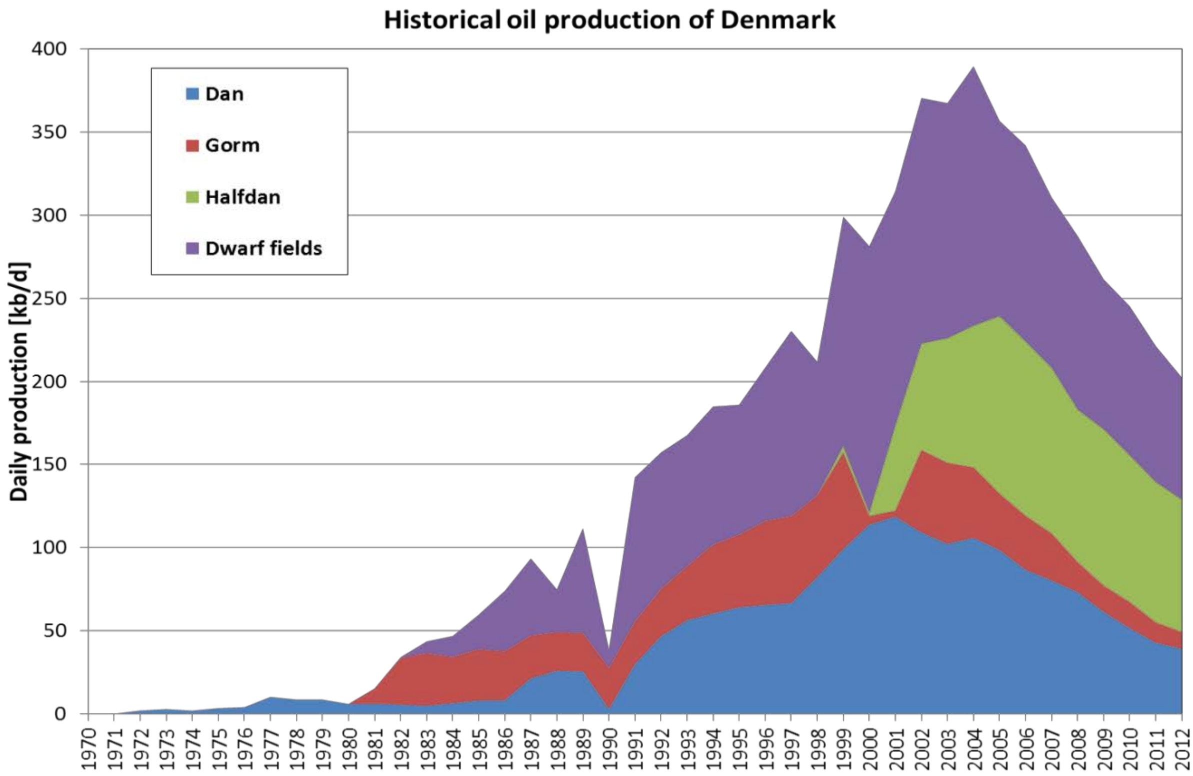

Figure 6. *Updated Danish historical oil production divided into giants and dwarfs*

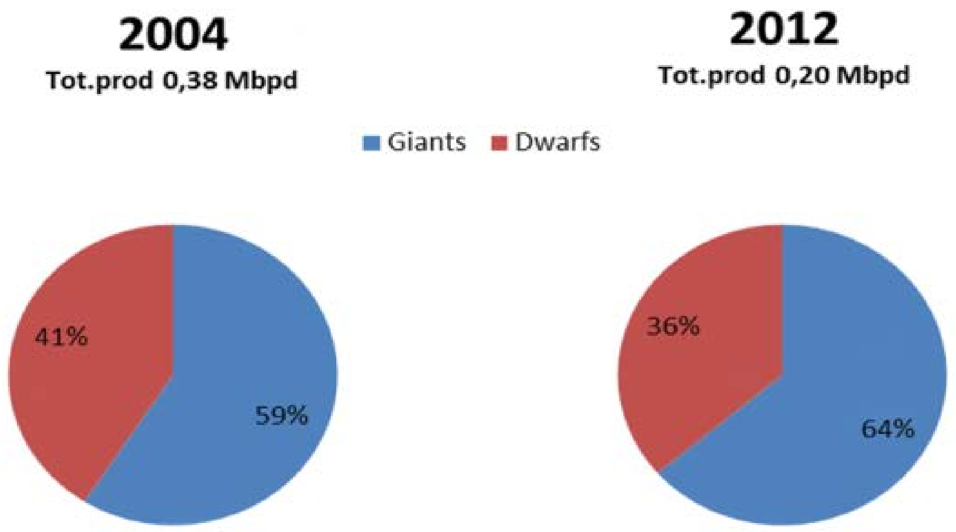

Figure 7. *Danish oil production divided into subclasses, 2004 and 2012.*

Table 4. *The Danish mean, production weighted and median decline rate of respective subclasses. Values from the previous 2009 studies are presented in parenthesis.*

	Giant [%]	**Dwarf [%]**
Mean	-8,2 (-6,7)	-13,4 (-16,2)
Prod.Weight	-7,8 (-6,4)	-12,4 (-16,9)
Median	-9,4 (-6,1)	-13,4 (-14,7)

Previous studies of decline rates are depicted within the parenthesis (see Table 4). We can discern that the decline rates for the giants have increased whereas the decline rates for the dwarfs have decreased. The increasing decline rates of giant fields can be explained by the production pattern of the Halfdan field. The previous study was conducted near the production peak of Halfdan, which was in the early stages of decline. This illustrates the problem associated with aggregating a small number of fields, as a single field can have a significant impact. The decrease in decline rates for the dwarf fields indicates that most Danish dwarf fields are mature with production volumes flattening out.

3.2.1 Evaluation of earlier projections

The forecast for Danish oil production from 2008 can now be compared with actual production data during 2009 - 2012 to evaluate the accuracy of the prediction [14]. Figure 8 shows the 2008 forecast together with two official NPD forecasts of 2007 and 2008 as well as actual production. The average deviation of the Danish production forecast compared with actual production data was 0.5%.

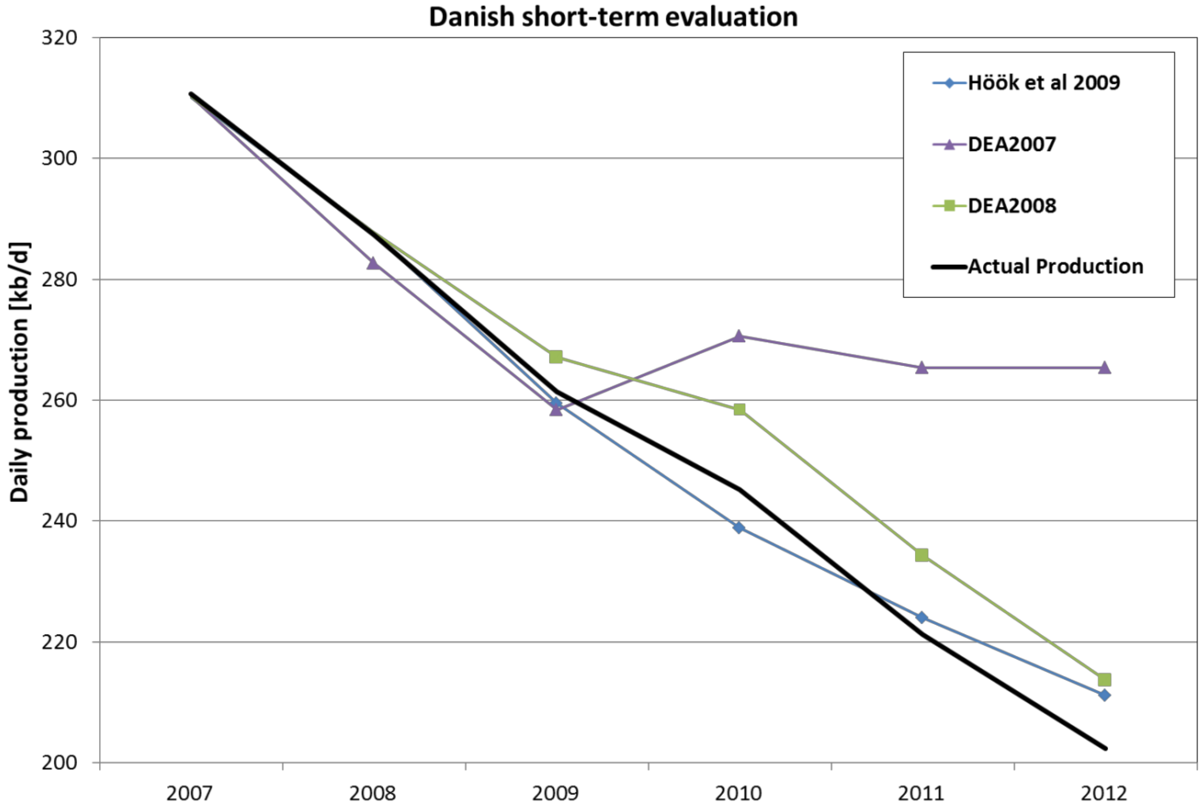

Figure 8. *Evaluation of Höök et al forecast combined with DEA forecasts of 2007 and 2008.*

The predictions conducted by the DEA in 2007 and 2008 had an average deviation of 9% and 3% respectively. The DEA prediction of 2007 is levelling off from 2009 and onwards, leading to a deviation of 24% compared with actual production data in 2012. In the DEA prediction of 2008 the production forecast was written down primarily due to reduced production expectations from the Dan and Halfdan fields as well as to a postponement of production commencement at the Hejre field [18]. An examination of production data and decline rate presented in this paper indicates that both Dan (peak year 2001) and Halfdan (peak year 2006) had an anticipated decline of -9.4% and -4.4% with no severe production deviations from expected behaviour.

The Danish oil production only had one notable disturbance as the Rolf field was shut down due to pipeline leakage, thereby affecting total output. However, The Rolf field did not have a significant impact as it was in decline and produced about 1000 b/d in 2010, which is less than 1% of the total Danish production.

4. Updated future projections

Future projection of oil production in the North Sea differs between Denmark and Norway because of some specific differences. Denmark has a more limited geographic exploration area compared to Norway, which reduces the possibility of new discoveries. As the North Sea is a mature region most of the potential structures have already been identified. Some uncharted regions remain though, particularly in Norway, which has an active exploration program. Interesting areas include the Barents Sea and the area around Jan Mayen. The region around Lofoten is also of interest, if the Norwegian government opens it for oil exploration [30].

4.1 Norwegian new field development and discovery trends

The number of fields and new projects that became operational during the update period 2008-2012 for each class were as follows; a total of 17 giant fields were updated and no new giant fields were added, a total of 61 dwarfs, of which 19 new fields were added and also updated, a total of 20 Condensate fields, of which 5 new were added and updated, a total of 58 NGL classes of which 11 new were added and updated. Corresponding figures from the previous study of new developments where: 11 new dwarf fields, 6 new condensate fields and 12 new NGL. The NPD divides the various new oilfield developments into different classes. The classes included in this study are; *approved for production and operation* (PDO), *planning phase* and *development likely but not clarified*. The total number of fields in this category is 52.

Almost all PDO fields have a defined start-up year. For fields in the categories "*planning phase*" and "*development likely but not clarified*" estimates are carried out regarding the fields start-up year. These approximations are based on the year of discovery as well as the expected time needed for the appraisal phase. Usually it takes 5-10 years from field discovery to first oil production [13]. The specified URR for new field developments are compared with similar URRs of existing fields, and in this way we derive the expected behaviour of yearly production and decline rate for new field developments.

The discovery peak for giant oil fields was in the early 1980s. "Johan Svedrup" was the latest giant field to be discovered in 2010. The URR for this field is currently estimated to be 1.89 Gb but this figure could, due to new drilling results, be adjusted in the future [15].

By extrapolating future discoveries a more realistic forecast for Norwegian future oil production can be determined (Figure 9). The use of a logarithmic extrapolation of the historic discovery trends for both the URR and number of fields allows us to estimate future discoveries for each subclass [13]. To obtain the most realistic extrapolation possible, adjustments were performed on some of the data points where the data were deviant. The total extrapolated discovery URR corresponded to 3.04 Gb. To obtain a reliable estimation of the production profile for the fields yet to be discovered, the extrapolated URR is divided so that it corresponds to already existing producing fields. Future discoveries of giant oil fields URR accounted for 1.5 Gb, which were divided into two giant fields in the forecast.

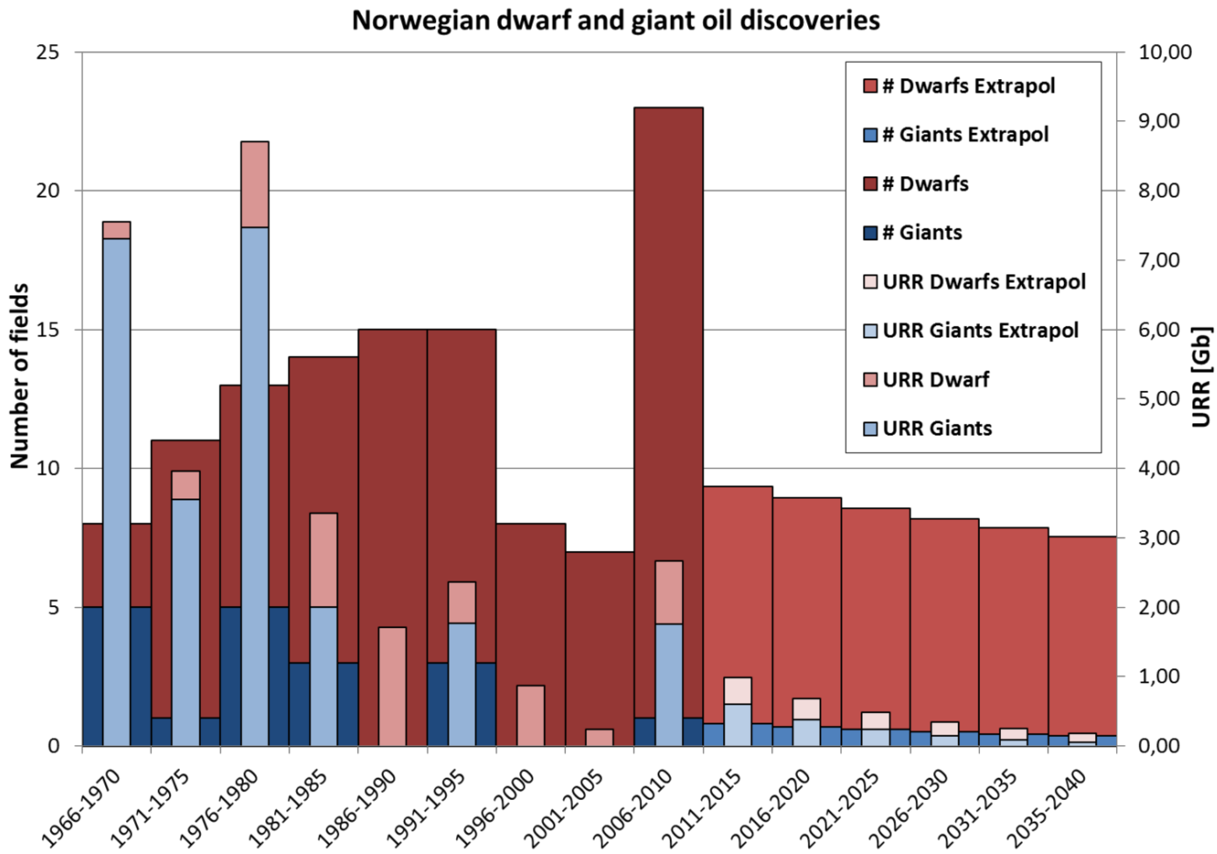

Figure 9. *Extrapolation of the undiscovered amounts of giant and dwarf oil fields in Norway with respect to both URR and number of fields. Thin bars refer to URR, thick bars to the number of fields.*

The dwarf fields had an active discovery period between 2006 and 2010, when a total of 22 new fields were discovered. However the estimated URR was in the same range as the URR of the 12 dwarfs found between 1996 and 2000. The extrapolation of dwarf fields was adjusted due to the abnormal discoveries between 2006 and 2010. The future discoveries of dwarf fields URR accounted for 1.4 Gb. One can clearly see how the number of dwarf oil fields has held up whereas the amount of oil per field decreases. With regard of the extrapolation for NGL and condensate no adjustments were performed. URR for NGL were 0.07 Gb and for condensate 0.03 Gb.

4.1.1 Norwegian production forecast

The updated forecast of total Norwegian oil production is presented in Figure 10. The forecast is based on the results from the decline curve analysis of producing fields combined with new field developments and the extrapolation of new discoveries. The "Johan Svedrup" giant oil field is highlighted in the prediction. Due to its large size production commencement will significantly affect the forecast. The Johan Svedrup field was an expected discovery; a previous study [13] had predicted that two giants would be found before 2030. In this forecast the "*Johan Svedrup*" field is assumed to start its production in 2017. Comparing the new results with the previous study [13], we can see the addition of the new dwarf field discoveries resulted in an increased future oil production. This does nevertheless change the overall picture, where the majority of Norway's oil fields are in a steady decline.

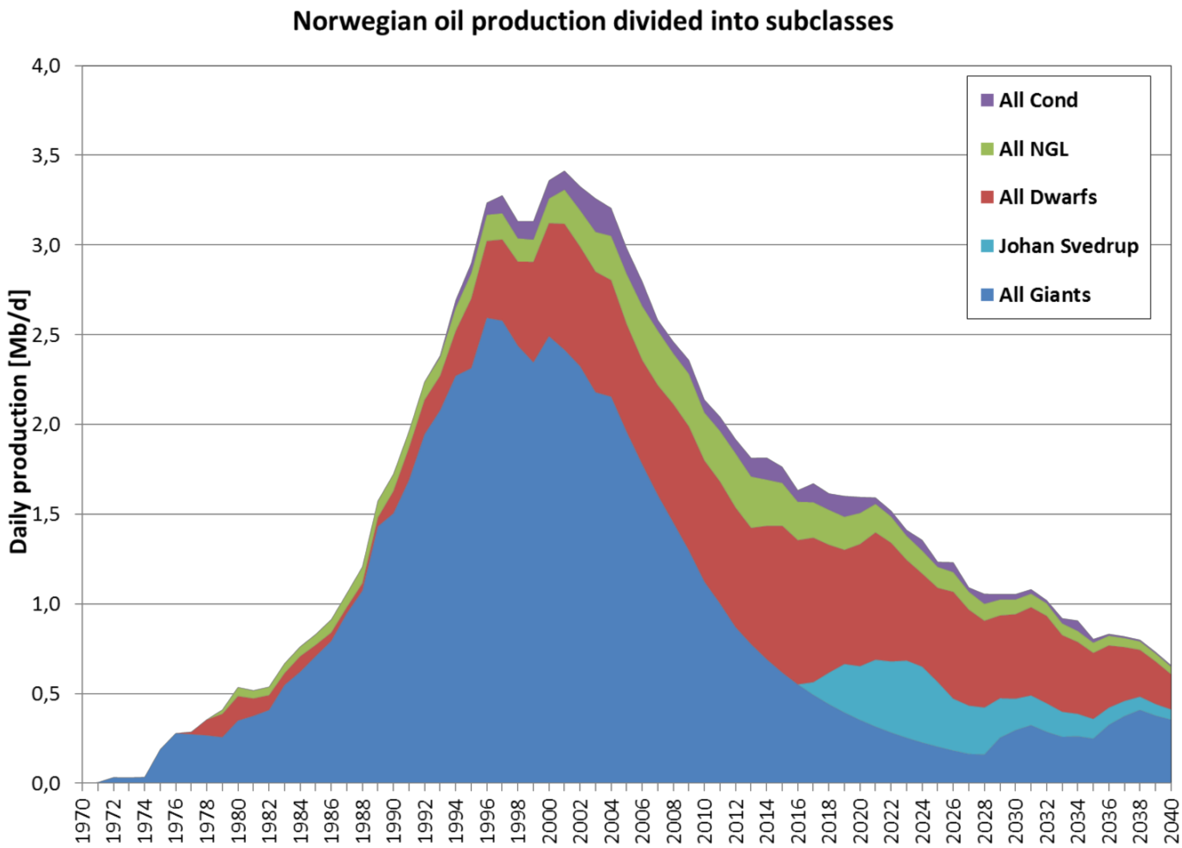

Figure 10. *Updated forecast of Norwegian oil production divided into subclasses.*

Norway's domestic oil consumption is currently 247 000 b/d [31] and Norway will therefore be self-sufficient in oil well into the future. However, their ability to export will be severely reduced in the coming decades. This study projects that oil production will be reduced by almost one half by 2030 compared to the 2012 production volumes. The trajectory resembles the current NPDs forecast for Norway's future production [31].

4.2 New fields development and discovery trends in Denmark

No new field came into production during the period 2009-2012 despite previous studies by DEAs where Adda and Boje Area fields were expected to start production in 2010 and 2011 [14]. Both Adda and Boje Area field would however not have a big impact on Danish oil production due to their insignificant size. The total number of fields that were updated during the period 2009-2012 consisted of 3 giants and 16 dwarf fields. These fields form the basis for the data model to obtain the updated historic oil production for Denmark.

A new discovery is the Hejre oil field where hydrocarbons found at 5 km depth, a depth that is significantly greater than the 1.5 to 3.5 km depth for other Danish deposits. The greater depth leads to difficult geological conditions, requiring equipment that can handle high pressures and temperatures. Due to the small numbers of Danish oil fields, a separate extrapolation of future oil field discoveries was not created. Instead an estimate was performed for Danish future oil discoveries.

4.2.1 Danish production forecast

The prediction for Danish oil production is depicted in figure 11. Estimates of the undiscovered oil are equivalent to 0.41 Gb.

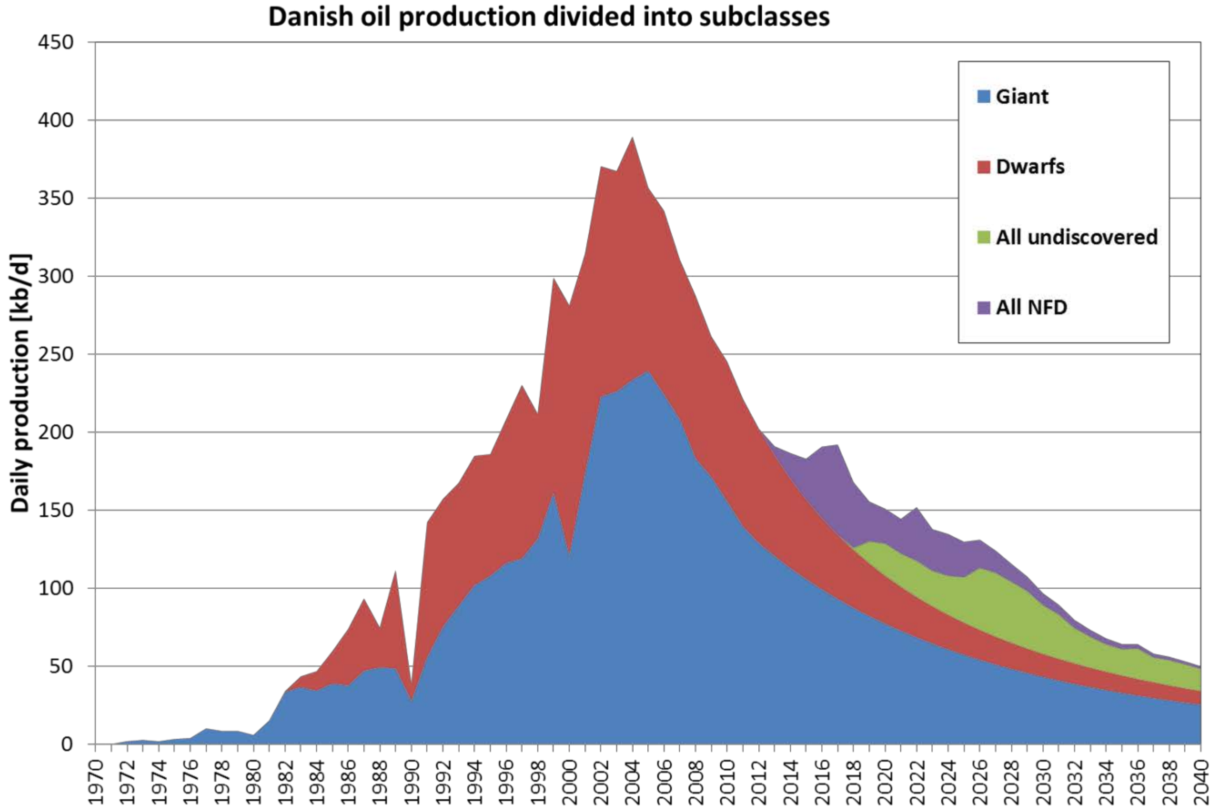

Figure 11. *Updated forecast of Danish oil production divided into subclasses.*

Hejre field with an estimated URR of 0.1 Gb is expected to be operational in 2015. It will affect oil production since Denmark has few oil fields. This field's production is expected to begin around 2016 (Figure 11). Danish domestic oil consumption has steadily decreased since 2007 and is currently 160 000 b/d [32]. Enhanced oil recovery (EOR) is a measure which is likely to increase production allowing Denmark to cover its domestic needs until 2018 or just beyond. EOR is an expensive technique and requires large investments, and thus only maintaining profitability if oil prices remain high [14, 23]. The EOR method will not be taken into account in the model due to uncertainty regarding the number of fields that will implement this method and its potential production increase.

5. Re-evaluated implications for Swedish oil imports

Sweden has no significant domestic production of oil, and thus depends entirely on oil imports. In the 1970s, Sweden was among the most oil intensive countries in the world, but this was drastically reduced in the 1980s in the wake of the oil crises [1]. Furthermore, Sweden has a large refinery capacity and consequently more oil is imported than consumed domestically. The Swedish domestic market consumed 295 000 barrels/day in 2012 which shows a decrease of 4.8 % compared to 2011. The Swedish installed refinery capacity increased from 422 000 to 434 000 barrels/day during 2011 [32].

The oil market is a complex market with different market types such as spot, over the counter and future markets [33]. It is primarily dominated by spot trading, unlike the coal market were most trade is conducted through bilateral agreements between countries and companies. However, some bilateral agreements exist for oil, but only to a small extent.

Oil quality also differs. For example, Brent Blend is a light and sweet crude oil with API gravity of approximately 38 and sulphur content around 0.4%, while the Russian Export Blend is a medium, sour crude oil with an API gravity of approximately 32 and sulphur content around 1.2% [34]. Quality is an important factor for refiners. Light oil with low sulphur is more expensive than heavier and sourer crude oil because it requires less processing and produces a slate of products with a greater share of value-added products, such as gasoline, diesel, and aviation fuel. Consequently, heavy oils with high sulphur typically sell at a discount. This is exploited by Swedish refiners, as they are capable of processing heavy and sour oils such as Russian oils.

Historically, the North Sea has been an important supplier of oil to the Swedish market with nearly all imports taken from this region after the 1980s [35]. The peaking of Norwegian and Danish oil production in early 2000s has changed the picture and Russia has begun to emerge as an increasingly important supplier.

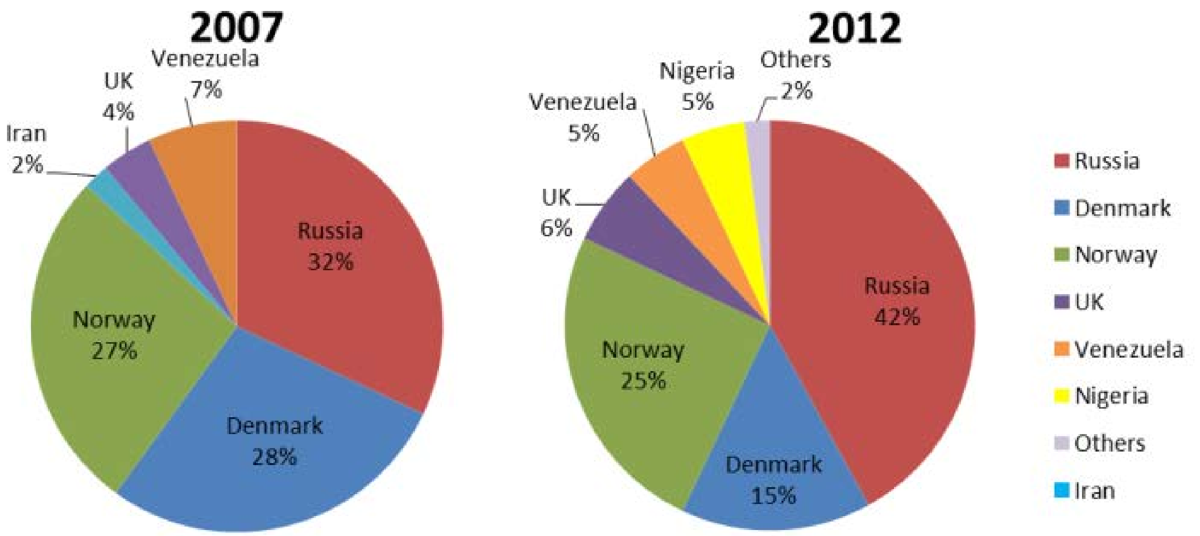

Figure 12. *Swedish oil import shares of 2007 and 2012, divided into countries [1].*

When the production declines in the North Sea, this could affect the distribution shares of importing countries. In 2007, when the previous study was conducted [14], Russia, Norway and Denmark accounted for about 30% each of the Swedish oil imports, depicted in Figure 12. The HH-index for the 2007 oil import distribution resulted in 0.26 which is just over a reasonable amount of diversity. In 2012, the shares had changed and Russia emerged as Sweden's main supplier of oil by as much as 42%, while Norway and Denmark's share dropped to 25% and 15% respectively. The HH-index of 2012 corresponds to 0.27 which indicates a trend towards a low diversity of the import market shares. The diversity in 2011 was lower compare to 2012 due to reduced import volumes arriving from Norway and, primarily, oil imports from Nigeria that did not materialize. Historically oil imports from Nigeria have varied widely and had a low consistency. The loss of oil imports from both Norway and Nigeria resulted in Russia filling the gap and thus accounting for 50% of Swedish oil imports. This resulted in a HH-index of 0.33 in 2011.

There is also a fine substructure in the import/export interactions for Sweden and Denmark. Analysis of Preem export data shows that imported oil volumes from Denmark and the refined petroleum products that Sweden exports to Denmark have a correlation coefficient of 0.83, suggesting a strong trade correlation (Figure 13). This indicates that Danish oil only has a minor importance to Sweden's domestic energy consumption and that Sweden chiefly act as an outsourced refinery for Denmark. Similar trade correlation also exists between the United Kingdom and Swedish refineries.

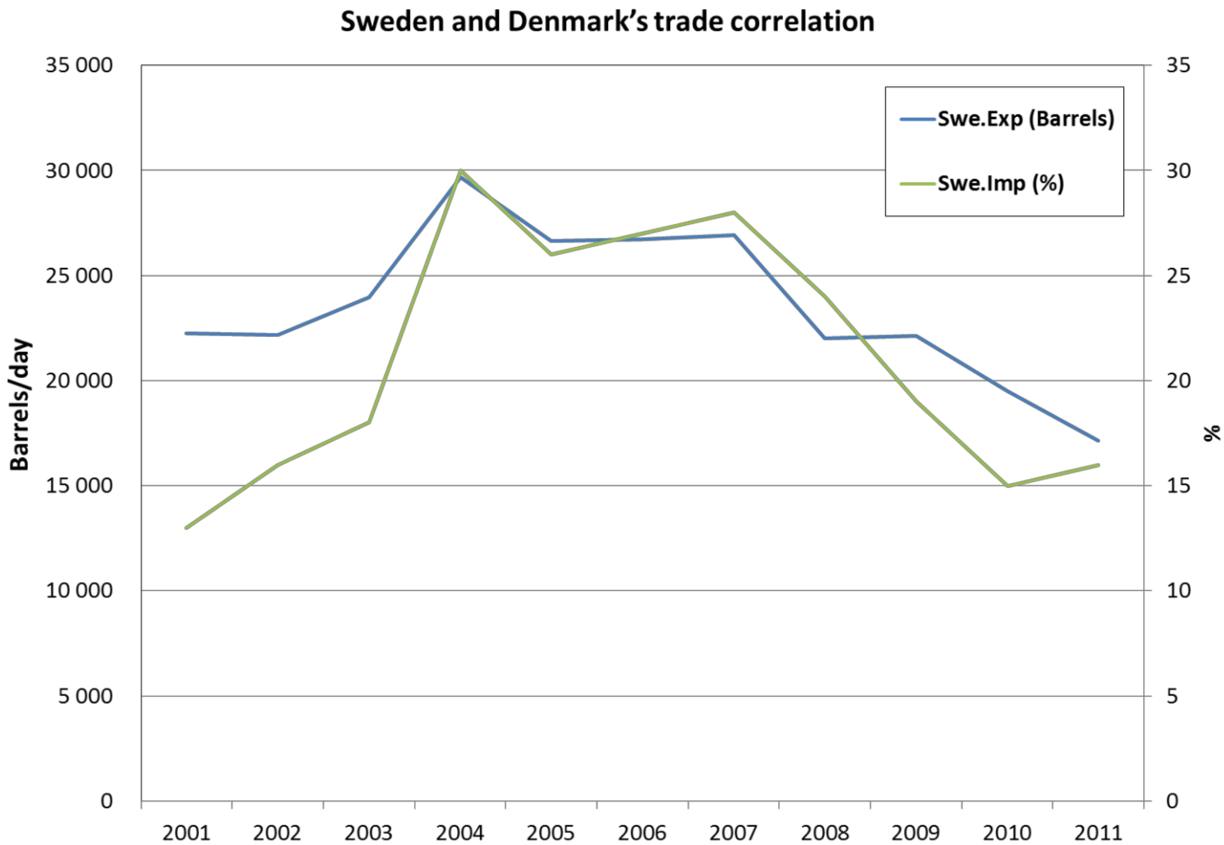

Figure 13. *The correlation between Swedish import of crude oil from Denmark and the Swedish export of refined petroleum products to Denmark.*

Continuing decline in North Sea output will continue to affect Swedish imports of oil from Norway and Denmark. Meanwhile, continued and increased reliance on Russian oil appears likely due to geographical proximity. This will be explored in some future scenario outlooks.

5.2 Swedish oil imports scenario for 2020 and 2030

When examining the proportion of the Norwegian and Danish oil production that were exported to Sweden, an outlook of how Norwegian and Danish oil import shares are decreasing can be estimated. Two scenarios for import shares in 2020 (mid-term) and 2030 (long-term) were created, combined with the historic imports depicted in Figure 14.

Future Danish and Norwegian oil production is expected to decline as modelled in section 4. The share of Norway's total oil production over a 9 year average value that is exported to Sweden corresponds to about 4%, in Denmark's case the average share value corresponds to 29% of the total oil production. For illustrative purpose these values are assumed to be constant for both future scenarios.

Sweden's import demand is assumed to remain stable at 395 000 b/d in both 2020 and 2030, not because Sweden's domestic consumption will remain at these levels but due to the Swedish refinery production capacity. Imported oil flow from Nigeria is largely irregular, and to reflect a more general historic import flow the Nigerian imports are assumed to be covered by Russia.

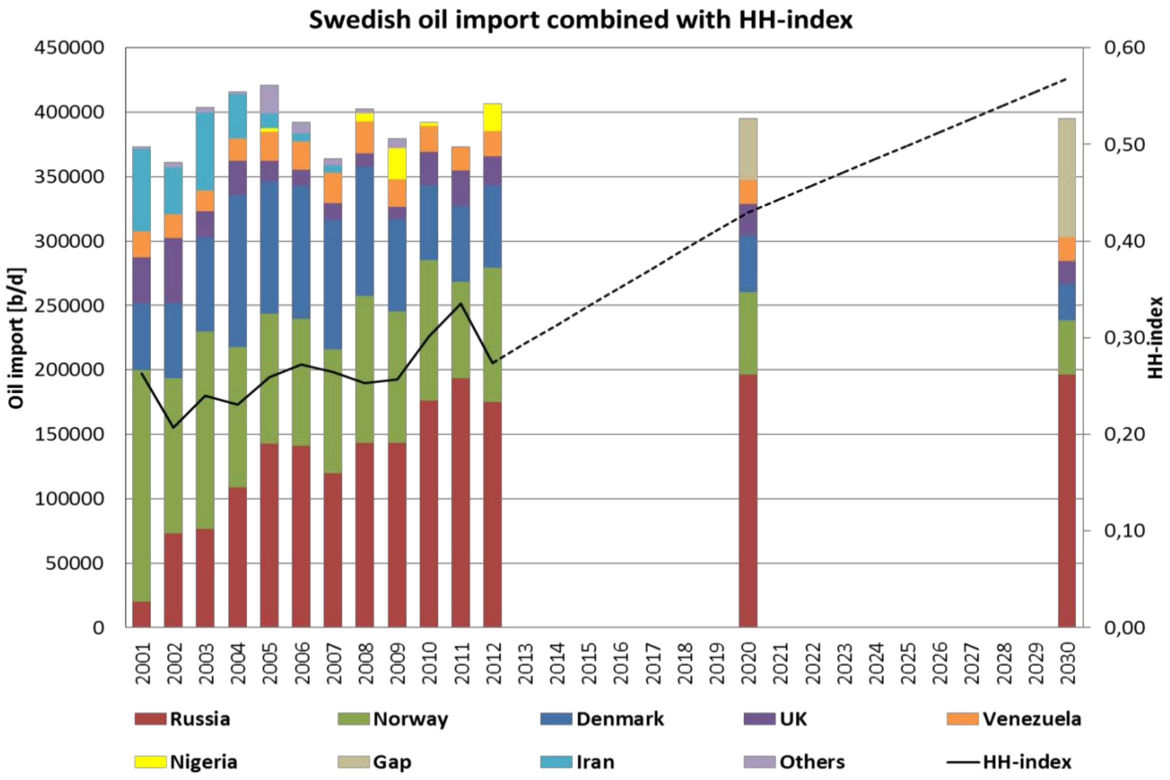

Figure 14. *Swedish historical development of oil import shares by country and in combined with the Herfindahl-Hirschman index.*

The future import gap emerging by 2020 would be in the region of 12% (Figure 15). If Russian oil were to cover this future gap in imports, it would generate an HH-index of 0.43 which indicates a very low diversity. For 2030 the future gap has increased to 24% (Figure 15). If Russian oil would cover this gap then it would generate an HH-index of 0.57 indicating an extremely low diversity. In this scenario, Venezuela has the same import volumes as per 2012, obviously a rough estimate. The United Kingdom's oil production is in decline, but the oil recovered has a high sulphur content suited to Swedish refineries. The volume of oil imported to Sweden from the United Kingdom under current conditions is returned to the United Kingdom. This collaboration is assumed to proceed, however with a diminishing share due to production decline. Venezuelan oil production is unlikely to decline, given they have the second highest proven oil reserves in the world. Focus is on the influence of Norwegian and Danish production declines, leaving a future gap in supply that must be covered by other countries, or must be simply transformed into a shortfall if new suppliers are not found.

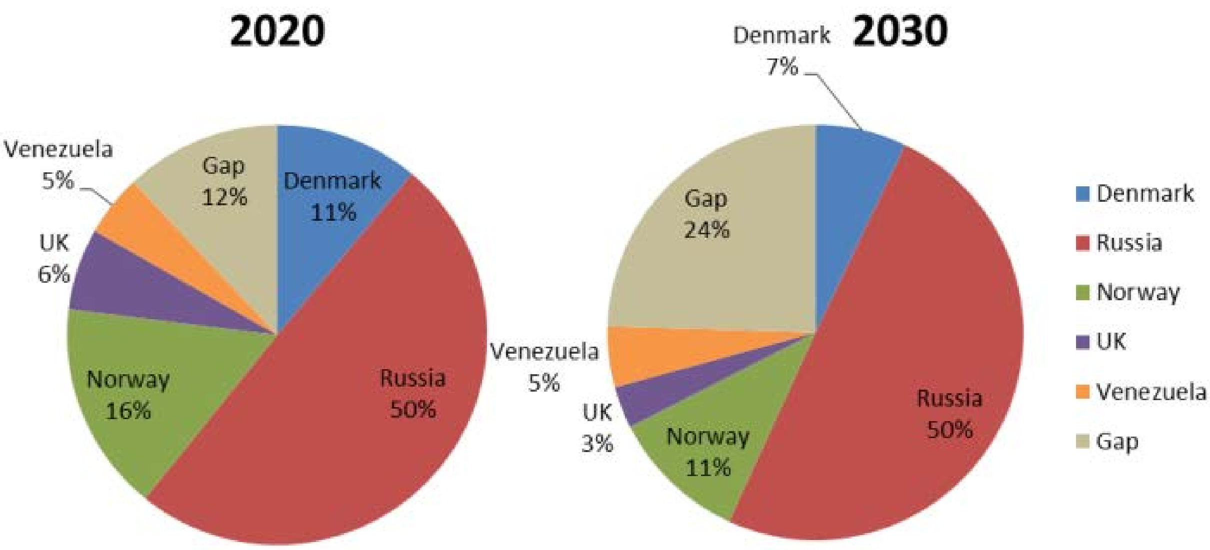

Figure 15. *Swedish oil import shares scenario for 2020 and 2030, divided into countries. The future gap also include the category "others".*

6. Concluding remarks

The difficulties in the creation of oil forecasts vary, as future oil production can be affected by numerous factors. There may be significant disruptions in production due to maintenance or accidents. Reduced economic growth is also a factor contributing to reduced oil consumption. The time range for new oil field exploration can be shifted forward or have a faster production start-up depending on geological conditions as well as other complications. The URR estimates are more accurate once the fields have been test drilled more extensively.

The conclusions based on the historic forecasts for Danish and Norwegian oil production is that both countries have passed their peak production rate and decline is well under way. The giants influence on oil production is well illustrated, where the giants of both countries are responsible for a substantial share of production. The significance for oil production is consistent with the rest of the world where a small number of giant fields dominate global oil production [25].

The calculated production weighted decline rates are higher for offshore fields when compared to on-shore production. This is explained by the need for a more rapid return on investments for offshore projects due to higher costs. Consequently offshore fields have a higher decline rate and depletion at peak due to a higher rate of extraction. As a result the average life time for an offshore field is shorter when compared to an onshore field [25].

6.1 Evaluation of short term outlooks

The evaluation of the bottom-up method indicates that the bottom-up decline curve method is reliable for short-term projections (5 years), as the deviation between the old historic production data compared with updated production data for both Norway and Denmark were relatively small. Both NPD and DEA forecasts showed larger deviations. Due to the lack of information on the exact workings of these models, an illuminating explanation for this is hard to derive. One possible reason for the NPDs forecasting deviations may be misleading data and information about future events provided by the operators.

One important factor is the number of fields. Norway has a large number of oil fields, which is advantageous, since the uncertainty in the mean decline rate is reduced. In the case of Denmark were the number of oil fields is smaller, disruptions in production or a new oil discovery will have a much greater impact on the forecast due to smaller field population size.

The impact of the financial crisis on the Norwegian and Danish oil production in 2008-2009 cannot be clearly distinguished in the production data. However, it may have led to reduced capital investments for new developments that will become increasingly apparent in longer time frames. It is concluded that the short-term forecasts performed using bottom-up decline curve methods are reliable when the physical and geological properties are the main limiting factors for production.

Finally when looking ahead, it is noteworthy that the short-term predictions for Norwegian oil production the next five years from NPD compared to the bottom-up approach deviate yet again. Only time will tell if this may be another overestimation by the NPD.

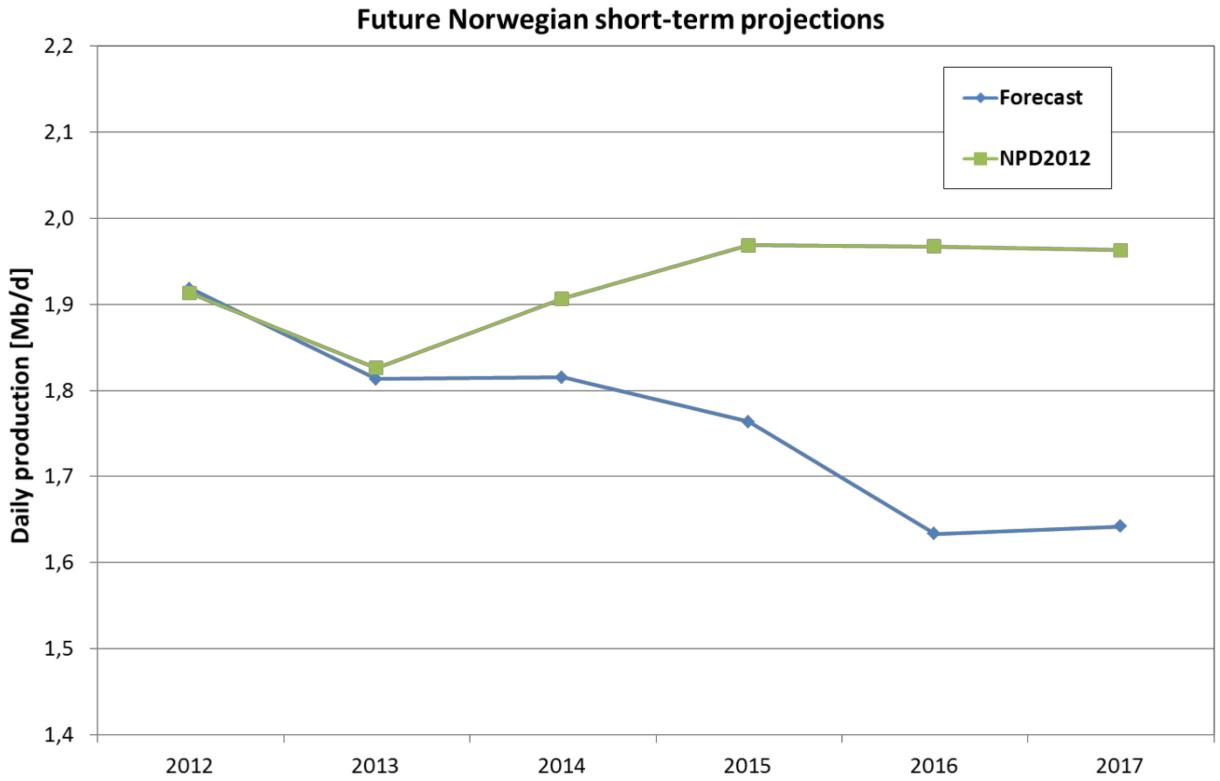

Figure 16. *The study's updated forecast compared with NPD short term forecast of 2012 regarding Norwegian oil production.*

6.2 Medium and long-term discussions

Regarding mid- and long term projections, the decline curve method might not be as reliable due to expected deviation from an exponential decline further out in the tail of production for individual fields. This is true in particular for long-term projections, as the use of bottom-up modelling leads to unavoidable deviations as new fields and the exact shape of the decline curve becomes important over longer time frames.

Intrinsic uncertainties for forecasting future oil production are caused by the large number of new fields to be introduced, uncertainties in the expected ultimate recovery of the fields and the year of production commencement. Simultaneously the backbone of production, i.e. the giant fields, shows decreases in production and significance over time.

This causes, to some extent, oil field regeneration, impairing the reliability of the bottom-up method since it is a more optimal mature region with most fields already in production.

If more sophisticated production techniques are to be applied by the operators to new fields, the future production outlook could change. This concerns those new fields that are not yet in operation in particular, as such fields are projected to exhibit similar behaviour as existing old fields in the current model. It is debatable to what extent production would increase significantly, although it could change production patterns.

6.3 Updated future outlooks

The updated Norwegian future outlook differs somewhat from the previous forecast performed in 2008 (Figure 16). This is partly caused by new discoveries during 2006-2010 which were more numerous than expected. The Danish outlook was consistent with the previous forecast. Anticipating future new discoveries is challenging, especially in the case of Norway where unexploited areas still exist (such as the Barents Sea and Lofoten). The Arctic is also a region that might potentially contribute to Norwegian and Danish future oil production. To some extent the Arctic is included in the expected future discoveries, however technical and environmental constraints cause further uncertainties.

An important factor regarding the realization of new discoveries are the price of oil; the higher the price is, the more profitable it will be to increase the discovery rate, and extract small deposits. However, projecting future oil price is difficult since it also requires a complex interconnectivity of market reactions, like diminishing demand through a shift to new energy sources.

Based on our analysis the following conclusions can be made: Denmark will have difficulties in covering their domestic oil consumption by as early as 2018. An important factor that may significantly affect future production volumes of Norwegian oil production is the field John Svedrup. Its size has a substantial effect on Norwegian oil production, although one should keep in mind that the URR has yet to be accurately determined. Norway will be able to cover their domestic consumption beyond 2040. However, Norway’s export volumes will be significantly reduced. Long-term forecasts are always accompanied with many uncertainties.

6.4 Swedish oil vulnerability

The decline in North Sea oil production will influence Swedish oil import patterns. A trend can be seen towards a lower diversity among import countries. Therefore, Swedish energy security could be affected in different ways depending on what countries will fill the import gap. If imports remain stable at around 395,000 b/d, the future import gap is estimated to be around 24% by 2030.

Russia is the most likely actor to fill that gap, partly because of its geographical proximity but also the suitability of Russian oil for Swedish refineries. If Russia, which already accounts for 42% of the Swedish oil imports, covers this gap, Russian influence would increase as Sweden becomes heavily dependent on a single supplier. This can have severe consequences for Sweden’s energy security depending upon future Russian export policies. Other players that could cover this gap are mainly countries with a turbulent history and are geographically distant. Examples of such countries are Venezuela, Saudi Arabia, Iran and Iraq. As North Sea oil production continues to decline, global competition for oil resources increases significantly.

Neighbouring countries that produce oil such as Denmark and the United Kingdom are in steady decline and will eventually need to increase their imports to meet domestic demand. The United Kingdom is already a net importer of oil. This means that it is difficult to predict whether Sweden can maintain an import average of 4% of Norway's total production. Since future oil import distributions are inherently difficult to predict, this study consequently highlights the predicament of an increased vulnerability in oil importing countries such as Sweden.

7. Acknowledgments

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