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Has the North Sea entered a late-life crisis?

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Virendra Chauhan, Oil Analyst, Energy Aspects,
Maarten van Mourik, Consultant
& Amrita Sen, Chief Oil Analyst, Energy Aspects

Introduction

The latest oil price downturn has once again brought the already challenged outlook for the North Sea oil industry into focus, something which has been predicted many times during its 50 year history.[1] Each oil price crash has brought with it talks of decommissioning, and of bringing down the curtain on North Sea production once and for all.

Despite this grim outlook, caution must be taken not to tarnish the whole region with a single brush. The outlooks for the UK and for Norway differ quite substantially. The latter has benefited from the discovery of the Johan Sverdrup field in 2010; this ranks amongst one of the largest oil discoveries ever made on the Norwegian Continental Shelf (NCS) and is expected to prolong the life of the Norwegian oil industry for several decades. Even during the current downturn, Statoil has invested $5.1 billion (2015 terms) on contracts to develop the field, which is expected to produce 0.55–0.65 mb/d at peak capacity (40 per cent of NCS output).[2]

The UK Continental Shelf (UKCS), on the other hand, is suffering from several factors, which range from being one of the most mature basins in the world, to falling activity in a neglected province. For example, a report published by the Oil and Gas Authority (OGA) – a new independent regulator set up since the acceleration of the oil price fall in Q4 14 – showed that exploration and appraisal activity fell to an all-time low in 2014.[3] Only 32 wells (14 exploration and 18 appraisal wells) were drilled in 2014, whilst the trend appears to have worsened in 2015 with as few as eight exploration wells planned. Production has been on a clear downward trend for the best part of a decade. The situation has not been helped by haphazard policy, likely a result of the fact that there have been 14 different energy ministers in 17 years. A complex tax regime has done little to encourage investment in an ever-dwindling reserve base. While production has stabilized over the last few years and should register modest growth in 2016 as an era of $100 oil bears fruit, the medium–long term outlook for the UKCS is fairly dire.

In this comment, we consider the current state of, and outlook for, UK and Norwegian oil by taking a deep dive into historical and future development of these basins at the field level. We analyse costs and structures of the two basins as well as declines – which have become synonymous with the North Sea. These factors have assumed more importance in the current low price environment.

2. UK – wagging a long tail

UK production has been in steep decline since its peak in 1999 (see Figure 1). Only after record investment between 2010 and 2013 did the pace of decline slow, when declines eased from a peak of 16.3 per cent in 2011 to 8.3 per cent in 2013. 2014 output was lower year-on-year (y/y) by just 3 per cent at 0.78 mb/d, while H1 15 has seen y/y growth return for the first time in seven years, a remarkable achievement for a mature basin such as the UKCS.

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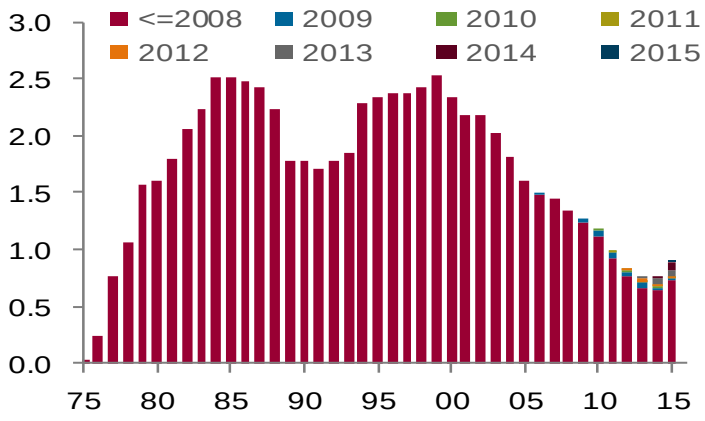
[1] Since peaking in 2003, UK and Norwegian production has been in decline while costs have accelerated. Several studies have been conducted into how to meet the increasing challenges of operating in the North Sea and oil majors have slowly reduced investments over the past few years: 'UK North Sea Oil Production Decline', Euan Mearns, *Energy Matters*, 8 October 2013, http://euanmearns.com/uk-north-sea-oil-production-decline/; 'North Sea Faces Record Decline, Bad News For BP (NYSE:BP)?',Jason Stutman, Energy and Capital, 23 August 2013, www.energyandcapital.com/articles/north-sea-faces-record-decline-nyse-bp-statoil-sto-tsla-nasdaq/3772.

[2] 'Statoil is awarding the contract for integrated drilling services', www.statoil.com/en/NewsAndMedia/News/2015/Pages/06Jul_JSdrilling.aspx.

[3] 'Call to Action: The Oil and Gas Commission 2015', Dr Andy Samuel, Chief Executive Oil and Gas Authority, 26 February 2015, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/421367/Call_to_action_OGA_Commission_2015.pdf.

Figure 1: UK crude production by vintage, mb/d (1975–2015



Source: DECC

However, looking beyond the project start-ups from the high oil price era, the outlook looks bleak. The risks facing the UKCS were apparent when Energy Secretary Edward Davey made a request for a study on mitigating the risks facing the oil industry, as the decline in crude prices accelerated late last year.[4] Indeed, the urgent need for industry action was made a year before, in a report commissioned by the government which highlighted the need for industry, government, and regulators to create a more simple and competitive operating environment for producers to extract hydrocarbons.[5] But the warning signs were in place many years earlier and were most apparent during the four-year period between 2010 and 2013 when prices were close to $100 per barrel. During this period, UK production declined by 0.6 mb/d, or at a rate of 11.5 per cent per annum.

Concern about the future of the UKCS is not unwarranted. The UK Department of Energy & Climate Change (DECC) estimates that of the recoverable reserves of 32.5 billion barrels, 27 billion barrels, or 83 per cent, have been produced.[6] Production peaked in 1999 at close to 2.6 mb/d, but it languishes today in a range of 0.8–1 mb/d – some 65 per cent below the peak achieved 15 years before. Since 2008, the number of exploration and appraisal wells has fallen from above 100 to less than 20 in 2015, whilst the number of plugged and abandoned wells has risen from 10 in 2011 to above 75.[7] In fact, rather than production, the future looks bright for the UK's oil and gas decommissioning sector, with decommissioning expenditure on UKCS expected to reach £16 billion over the next decade.[8]

2.1 IOCs moving out of the basin

With a maximum 5.5 billion barrels of remaining reserves, the UKCS is undoubtedly in the 'development of a mature basin' phase,[9] a fact that is accepted both by producers and the government. Even before

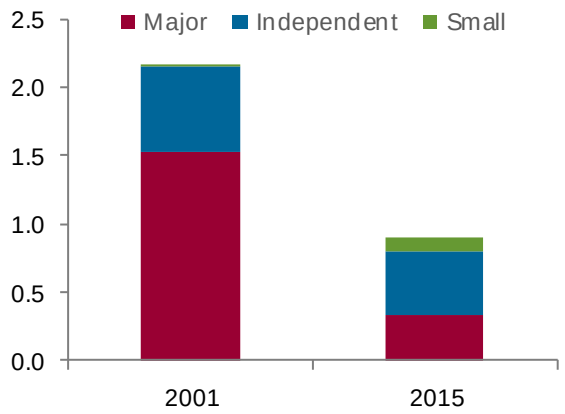
[4] 'Edward Davey asks new Oil and Gas Authority CEO to lead urgent commission into North Sea industry', Department of Energy & Climate Change and The Rt Hon Edward Davey, 15 January 2015, https://www.gov.uk/government/news/edward-davey-asks-new-oil-and-gas-authority-ceo-to-lead-urgent-commission-into-north-sea-industry.
[5] 'Sir Ian Wood calls for new offshore oil and gas regulator', BBC News, 11 November 2013, www.bbc.co.uk/news/uk-scotland-24898532.
[6] 'UK Oil and Gas Reserves and Resources', GOV.UK, https://www.gov.uk/guidance/oil-and-gas-uk-field-data#uk-oil-and-gas-reserves-and-resources.
[7] DECC; Oil & Gas UK, Annual Activity Surveys and Decommissioning Insights.
[8] *Decommissioning Insight 2015*, Oil and Gas UK, 2015, http://oilandgasuk.co.uk/decommissioninginsight.cfm.
[9] 'Making the most of the UKCS, the Oil and Gas fiscal framework: is it fit for purpose?', Deloitte, http://www2.deloitte.com/content/dam/Deloitte/uk/Documents/energy-resources/making-the-most-of-the-ukcs.pdf.

oil prices halved, the North Sea was falling out of favour with IOCs. For example, Royal Dutch Shell CEO, Ben van Beurden stated recently:

> Like any other province that gets mature, and certainly one where we have high cost structures and still a very high tax regime, we will have to look at how to restructure this.[10]

There has been speculation that some IOCs would even consider retaining decommissioning liabilities in order to push through a disposal.[11] Merger and acquisition activity in the region has remained muted despite the sharply lower oil price environment. The behaviour of IOCs towards a prospective oil province remains a key barometer for the outlook of that basin. For the last few years, IOCs have been looking to exit the North Sea. For example, in 2001, around 70 per cent of output was operated by IOCs – equivalent to 1.5 mb/d from a total production pot of 2.2 mb/d (see Figure 2). Fast forward 15 years and that percentage figure has fallen to 37 per cent, or 0.33 mb/d of the 0.9 mb/d total production pot (year-to-May statistics). Almost the entire decline between 2001 and 2015 is accounted for by IOCs whilst independent operators (who produced 0.63 mb/d in 2001 or 29 per cent of production) now produce 52 per cent, with small companies accounting for the remaining 11 per cent (see Figure 2).

Figure 2: UK output by operator type, mb/d



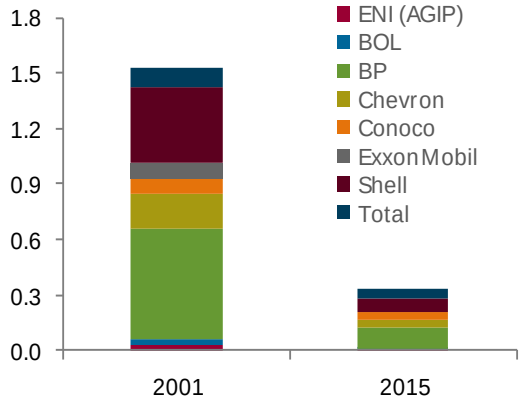
Source: Company reports

Shell has gone from operating at over 0.4 mb/d in 2001, to 75 thousand b/d in 2015, and the 2015 figure is distorted by Shell's 2002 acquisition of Enterprise (see Figure 3). Back in 2001, 20 per cent of UK output came from Shell. Today it sits at 8 per cent. A similar trend applies to BP, where output has fallen from 0.6 mb/d in 2001 to 0.11 mb/d in 2015. Total saw its production fall from 0.11 mb/d to 50 thousand b/d. Conoco output fell by less by 30 thousand b/d over the time period.

[10] 'Shell to "take a good look" at North Sea after BG deal', Reuters, 30 July 2015, http://uk.reuters.com/article/2015/07/30/uk-shell-bg-group-northsea-idUKKCN0Q41J520150730.

[11] Indeed, in 2003 BP sold the Thistle field to DNO (now operated by EnQuest) by retaining decommissioning liabilities. 'Oil firms may retain clear-up costs for hard-to-sell N. Sea assets', 21 July 2015, Reuters, http://uk.reuters.com/article/2015/07/21/oil-northsea-ma-idUKL5N1002UC20150721.

Figure 3: IOCs UK production, mb/d

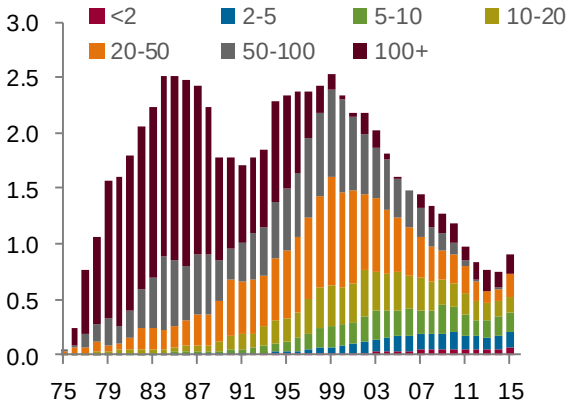


Source: Company reports

2.2 Offshore UK Production Profile

As of May 2015, 170 fields were producing liquids in offshore UK with combined output pegged at 1 mb/d, recovering slightly from 2014 as per data from DECC.[12] The number of fields in a 'producing' phase will fluctuate over time, not only because some fields will cease production or new fields start up, but also because major modifications can halt production for an extended period of time. Of the 170 fields in production, 70–75 fields produce less than 2 thousand b/d each and another 40 fields produce around 0.15 mb/d in total with flow rates between 2 and 5 thousand b/d (see Figure 4). These numbers have not experienced a material change since 2010 and, when seen together, the number of fields producing less than 5 thousand b/d has been remarkably stable since 2006. The distribution of field sizes in the UK would suggest that the likelihood of an imminent and material impact on UK production from the closure of several smaller fields is rather limited.

Figure 4: UKCS production by size class, mb/d (1975–2015)



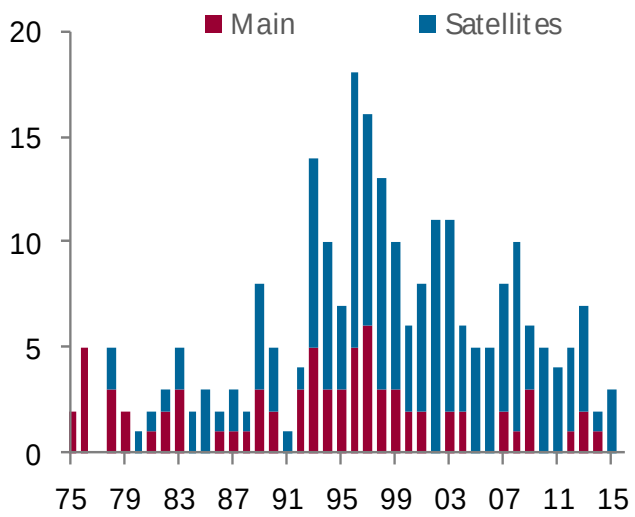
Note: Numbers in the key are thousand b/d, Source: DECC

[12] 'Energy Trends section 3: oil and oil products', National Statistics, GOV.UK, https://www.gov.uk/government/statistics/oil-and-oil-products-section-3-energy-trends.

Still, the main problem for the UKCS is that around two fifths (0.37 mb/d) of UK production is produced from 77 fields which have been depleted by more than 90 per cent. Of the 0.37 mb/d (from total output of 0.9 mb/d), more than 0.2 mb/d is produced from 15 fields, many of which have seen considerable redevelopment. And for several of these fields, many have already produced more than the originally reported recoverable reserves. Looked at differently, since 2005 five to six fields have added 0.1 mb/d of peak capacity. And yet production has fallen from 1.6 mb/d in 2005 to 0.84 mb/d in 2012, and it appears to have stabilized around those levels since.

For fields that were producing before 2009, output halved between 2008 and 2014, from 1.3 mb/d to 0.63 mb/d, which represents an annual average production decline of 12 per cent. The increase in decline rates has come as a result of several satellites being brought on stream – these are typically produced and depleted more quickly than main fields. Since 2000, an average five satellite fields have been brought online annually (see Figure 5). During the period of high oil prices, the incentive was to install larger systems to which satellites could later be tied back. Indeed, depletion rates for new fields have risen to well over 30 per cent. Whilst this trend is not as extreme as that seen for the development of tight oil in the USA, it is one of the factors that make producing from the North Sea a costly process.

Figure 5: UK Continental Shelf new fields by system types, number (1975–2015)



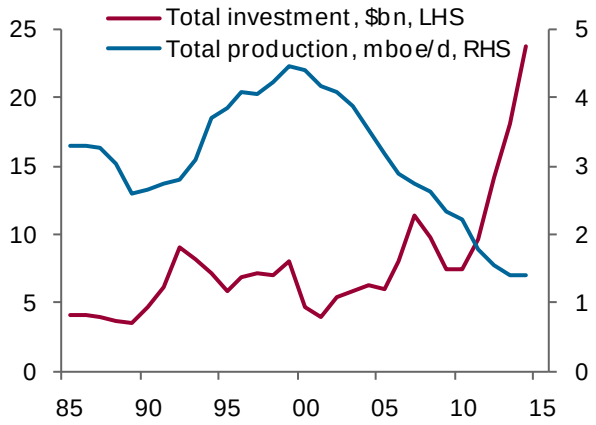
Source: DECC

2.3 Soaring costs underpin the challenging outlook

After hovering in a range of $5–10 billion for a 15 year period between 1990 and 2005, development spending in the UK's E&P sector accelerated sharply (with the exception of 2009 during the global financial crisis), before increasing towards $25 billion in 2014 (see Figure 6). Over the past five years investment has increased at a CAGR of 35 per cent. The results of this high investment are only just evident – where a combination of field start-ups and lower maintenance has supported output. Looked at on a per barrel basis, however, the decline in production over the same time period has resulted in UK costs rising at a steeper pace of 50 per cent CAGR. This is why companies have expressed concerns about further investments in the sector. Indeed, even at $100 oil the industry was challenged, as costs had blown out of control and the profitability of oil majors had fallen substantially. There were calls for the industry to take a different approach and to stop over-engineering, taking a more 'fit-for-

purpose' development plan to reduce costs.[13] If the billions that have been invested over the past five years do not achieve more than managing declines, then focus on cost control will be re-enforced.

Figure 6: Development spending in the UKCS (1985–2015)



Source: Oil Gas UK, Company Reports

2.4 Looking Ahead – the tail wags for a bit longer

Still, 2015 has seen oil production growth. Of the top 20 producing fields in H1 15, five fields have started or ramped up this year (see Table 1). In addition to new field start-ups, the largest field (the 0.2 mb/d Buzzard field) has had considerably less maintenance across 2014 and 2015, which has boosted production.

[13] Total, a key producer in the North Sea, mentioned this [to stop over-engineering to reset the cost base] at its recent strategy presentation. Proserv's CEO echoed these sentiments: 'Proserv's CEO: We must stop over-engineering if we want to cut costs', Offshore Energy Today.com, www.offshoreenergytoday.com/proservs-ceo-we-must-stop-over-engineering-if-we-want-to-cut-costs/.

Table 1: H1 15 top 20 producing fields in the UK, thousand b/d

	Jun '15	YoY Ch.	May '15	YoY Ch.	Apr '15	YoY Ch.	2015 to Jun	YoY Ch.
Buzzard	168	*(1)*	179	*(11)*	167	*(7)*	170	*(12)*
Golden Eagle	47	*47*	44	*44*	36	*36*	37	*37*
Forties	40	*(2)*	41	*0*	43	*4*	43	*4*
Kinnoull	38	*38*	38	*38*	33	*33*	27	*27*
Foinaven	35	*16*	38	*28*	33	*30*	30	*17*
Franklin	32	*14*	36	*20*	34	*17*	33	*17*
Balloch	28	*17*	22	*10*	18	*10*	18	*8*
Captain	28	*8*	31	*11*	22	*(5)*	25	*1*
Alba	19	*2*	17	*2*	16	*(1)*	17	*0*
Wytch Farm	15	*(2)*	15	*(3)*	17	*(1)*	17	*(1)*
Huntington	15	*(4)*	18	*6*	20	*11*	13	*(3)*
Gannet F	12	*12*	7	*7*	8	*8*	8	*8*
Harding	12	*1*	8	*(3)*	11	*(0)*	11	*(0)*
Gryphon	11	*(1)*	10	*2*	11	*(2)*	10	*(1)*
Gannet A	11	*11*	9	*9*	10	*10*	7	*7*
Beryl	10	*(3)*	9	*(3)*	8	*(5)*	9	*(3)*
Machar	10	*(1)*	9	*(1)*	10	*(4)*	9	*(3)*
Peregrine	10	*10*	10	*10*	11	*11*	7	*7*
Shearwater	10	*10*	12	*12*	12	*12*	8	*8*
Scott	10	*1*	8	*(3)*	9	*7*	10	*1*

Note: Highlighted are new field start-ups

Source: DECC, Energy Aspects estimates

The fruits of $100 oil will continue to provide some more short-term respite for UK production, as a slew of projects are brought to the market. Additions in 2016 total 0.17 mb/d, which will help offset an underlying decline pegged at 12 per cent. In 2017, the backlog of projects due to come is even larger, pegged at 0.22 mb/d (see Table 2). The Capex for these projects has been largely sunk, and the economics for some of these projects are receiving a temporary boost from fiscal manoeuvres – which have been implemented to encourage investment.[14] Once the benefits of lower/no taxes are removed, the challenges that face the UKCS will re-assert themselves once again. This will become apparent post 2017, where the project backlog is extremely thin, with no new projects scheduled for start in 2018 and only small ones in 2019 and 2020. Therefore, with underlying annual declines likely to accelerate above current levels of 0.1 mb/d as infill drilling activity has stalled, the risk of a return to double digit declines in total UK output are non-trivial.[15]

[14] In his latest budget, the UK Chancellor announced new measures worth £1.5 billion: effective tax rates on production from older oil and gas fields will be reduced from 80% to 75% immediately, and backdated to January, while on newer fields it will be cut from 60% to 50%; further tax cuts which come into effect next year will reduce the overall tax rate on older fields to 67.5%; There were also 'simple and generous' tax allowances to encourage investment, following a patchwork series of tax allowances for specific kinds of fields and developments in recent years ('Budget 2015: tax breaks for North Sea oil industry', 18 March 2015, *The Telegraph*, www.telegraph.co.uk/finance/budget/11480374/Budget-2015-tax-breaks-for-North-Sea-oil-industry.html).

[15] For instance, the Bentley field (45 thousand b/d) is a heavy oil field which was originally scheduled to come on by mid-2018. However, the field development plan has been placed on hold as project economics became compromised during the current oil price downturn. A similar fate impacted Antrim Resources Fyne field which has resulted in the abandonment of some wells and stalling of future development.

UK production is therefore expected to decline over the medium term owing to:

(i) front-end loaded capacity additions, where more than 80 per cent of capacity additions are expected to come on over the next 24 months and

(ii) investment from IOCs drying up, where data suggest that the number of plugged and abandoned wells has been outpacing the number of exploration and appraisal wells.

Indeed, the same bearish outlook is reflected in DECC forecasts,[16] which indicate that output will decline from 0.85 mb/d in 2015 to 0.6 mb/d by 2020, after which a gentler decline to 0.4 mb/d by 2030 ensues.

Table 2: UKCS peak capacity additions – 2015–20, thousand b/d

Field name	Operator	Start Year	Size
Laggan-Tomore	Total	2015	19
Solan	Premier	2015	20
Alma/Galia	EnQuest	2015	20
Montrose Area Redevelopment	Talisman	2016	26
Orlando	Iona	2016	14
Quad 204 (Schiehallion expansion)	BP	2016	50
Greater Stella Area	Ithaca Energy	2016	30
Western Isles (Harris and Barra fields)	Dana Petroleum	2016	35
Alder	Chevron	2016	14
Mariner	Statoil	2017	55
Kraken	EnQuest	2017	50
Clair Ridge expansion	BP	2017	60
Catcher Area (Catcher, Varadero & Burgman)	Premier	2017	50
Fyne	Antrim	2019	25
Cheviot (formerly Emerald)	Alpha Petroleum	2020	30
Total			**498**

Source: Company reports, Energy Aspects estimates

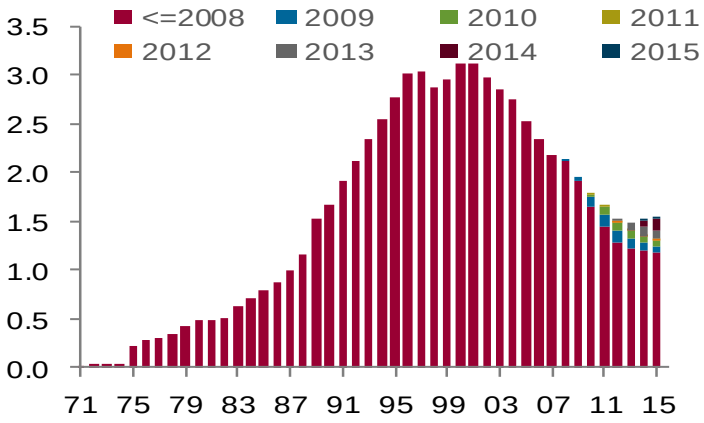
3. Norway – all eggs in one basket

Whilst the UK's remaining reserve base hovers around 3–5 billion barrels, Norway's reserve base is much larger, at 18–28 billion according to the Norwegian Petroleum Directorate.[17] But, even though Norway is more promising from a reserve perspective, the challenges from a production standpoint are analogous to those of the UK. Output declined every year between 2001 and 2013, from 3.12 mb/d to 1.48 mb/d, at a CAGR of 6 per cent per annum. Record investment undertaken during a four-year period of $100 oil saw development Capex rise.[18] Investment in producing fields reached $14.3 billion in 2014,

[16] 'UKCS Oil and Gas Production Projections', GOV.UK, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/414172/Production_prjections.pdf.
[17] Factpages, Norwegian Petroleum Directorate, http://factpages.npd.no/factpages/Default.aspx?culture=en&nav1=field&nav2=TableView%7cProduction%7cTotalNcsYear. Calculation of the data performed by Energy Aspects.
[18] 'Investments set to flatten out in 2016', Oil and gas activities, investments, Q2 2015, Statistics Norway, 12 June 2015, https://www.ssb.no/en/energi-og-industri/statistikker/oljeinv/kvartal/2015-06-12.

pushing Norwegian output higher y/y for the first time in 12 years, a trend likely to be replicated in 2015 as production in the year-to-September is higher y/y by 58 thousand b/d, at 1.92 mb/d.

Figure 7: Norway crude production by vintage, mb/d (1971–2015)



Source: NPD

3.1 NCS development has come through satellites as well

Output from main fields, defined here as fields with independent processing facilities, accounted for around 90 per cent of total production between 1970 and 2000, but has dropped to 70 per cent today. There are 31 main fields and 45 satellites currently in production. Of the 31 main fields, three fields produce less than 2 thousand b/d, and at the opposite end of the spectrum, Troll (0.12 mb/d), Ekofisk, and Snorre (0.11 mb/d each) produce 0.34 mb/d, according to NPD data.[19]

In 2000, Troll, Ekofisk, and Statfjord, the three largest fields at the time, produced 0.8 mb/d, with main fields accounting for 90 per cent of Norwegian output, at 3.1 mb/d. Today these three fields produce 0.26 mb/d from a total output of 1.1 mb/d from main fields. Interestingly, most of the decline is observed from fields where drilling activity is high. Relatively few wells have been drilled in the remainder of the fields and yet production has remained relatively resilient, highlighting good productivity. However, for the older fields, increased drilling activity is struggling to stem the pace of decline.

The number of development wells (including injection and producer wells) has mirrored the production trend in Norway. In 2010, activity hit its low point, with 75 wells drilled (targeting oil or condensate or combined oil/gas); this figure has since rebounded to an average of 90 during 2011–14, leading to production stabilizing over the past 18–24 months.[20] Most of the wells drilled came from a select few fields. For instance, the Troll field accounts for 20–25 per cent of all wells drilled, followed by Statfjord and Ekofisk. These three fields alone account for half the wells drilled on main systems and they produce 0.26 mb/d, or 15 per cent of total NCS oil output.

As these fields declined, 42 satellite fields were developed, which have been brought into production between 2000 and 2015 at a rate of around 2–3 fields per year. These fields had a combined output of 0.33–0.4 mb/d until 2013, but have increased to 0.48 mb/d on average this year, following record investment between 2012 and 2014. Over the 2000–14 period, 40 satellites were installed with a

[19] Factpages, Norwegian Petroleum Directorate, http://factpages.npd.no/factpages/Default.aspx?culture=en&nav1=field&nav2=TableView%7cProduction%7cTotalNcsYear. Calculation of the data performed by Energy Aspects.

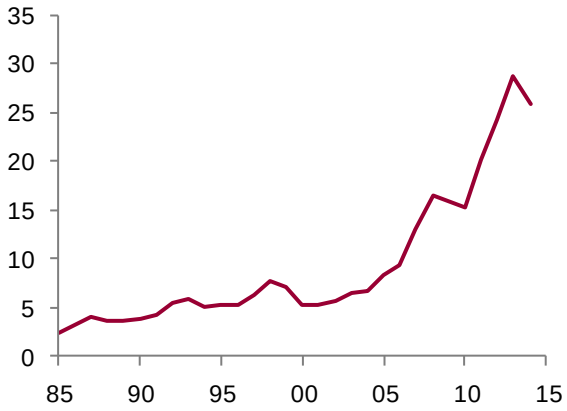
[20] Factpages, Norwegian Petroleum Directorate, development wells, calculation of the data performed by Energy Aspects: http://factpages.npd.no/factpages/ (section: Wellbore, subsection: Statistics).

production capacity of 0.82 mb/d, implying a decline rate of 14 per cent per annum among these satellite projects. A decline at this rate suggests that at least 60 thousand b/d of output from satellite fields needs to be replaced with new developments. And given that a satellite development delivers around 20 thousand b/d on average, three satellites need to be added to stand still. Among the satellite fields, 13 produce less than 2 thousand b/d and another 12 produce between 2 and 5 thousand b/d. In a high oil price environment, adding infrastructure to satellite developments (which have been the main source of production growth over the past few years) can be justified, but it is less so in the current oil price environment.

3.2 Costs have accelerated since 2000

In the 1985–2000 period, E&P spending increased from $2.3 billion to $7.6 billion, underpinning a four-fold increase in liquids production, and a doubling of gas production (see Figure 8). After peaking in 1998 at $7.6 billion, field development spending was cut substantially to $5.2 billion in 1999 and it failed to recover back to those levels until 2005. After this period, however, development spending rose steadily to $28.6 billion in 2013. Whilst development spending ebbed and flowed, the real increase in spending was seen in producing fields, where spending started in earnest in the 90s, and only experienced a momentary pause in 1998. By 2000, spending on existing fields equalled spending on new developments, rising almost four-fold to $8 billion by 2008 and pausing only briefly with the oil price crash. By 2013, an additional $10 billion had been added to the annual outlays, hitting a total of $18 billion.

Figure 8: Development spending in the NCS, $bn (1985–2015)



Source: Statistics Norway, Energy Aspects

In 2014 this changed as spending was cut, a trend which has continued in 2015. Data from Statistics Norway indicate spending in 2015 is lower y/y by 18 per cent (NOK terms) at NOK 190.1 billion. Within this, investment in exploration activity is estimated at NOK 27.2 billion, 24 per cent below 2014, whilst field development costs were pegged at NOK 138.7 billion, 22 per cent below 2014.[21] Early indications suggest total investment in 2016 is likely to be flat on 2015 levels, at NOK 184.9 billion. Investment in field development is pegged at NOK 128.7 billion, whilst exploration investment is expected to increase to NOK 36.9 billion, higher in comparison with 2015.

The fall in investment that has taken place suggests that once projects for which capital is already sunk are brought on, there is likely to be a gap due to lower activity come late 2016 and 2017. This underpins

[21] 'Investments set to flatten out in 2016', Oil and gas activities, investments, Q2 2015, Statistics Norway, 12 June 2015, https://www.ssb.no/en/energi-og-industri/statistikker/oljeinv/kvartal/2015-06-12.

the forecast of falling output in the medium term. Norway differs from the UK in recognizing that exploration efforts need to be sustained; this is highlighted by the increase in exploration investment next year.

3.3 Looking Ahead: A smaller tail than the UK

Total capacity additions between 2015 and 2020 equate to 0.82 mb/d, although omitting the giant Johan Sverdrup field (which is a story for the next decade) leaves additions at 0.51 mb/d and front-end loaded (see Table 3). Lundin Petroleum discovered the Johan Sverdrup field in 2010 and it ranks amongst the largest oil finds in the NCS. According to operator Statoil, the field has expected resources of 1.7–3 billion barrels. This comes after many years of minor discoveries, whose development occurred only through tying back to existing fields, being profitable as a result of high oil prices. Even during the price downturn, Statoil remains committed to pressing ahead with the development of the Johan Sverdrup field, a commitment reflected by its decision to award an engineering, procurement, and construction contract to develop, amongst other things, subsea systems. Production at Johan Sverdrup is likely to commence at the back end of this decade, or in early 2020.

2015 is set to benefit from a number of field start-ups, for which capacity totals almost 0.3 mb/d.[22] In contrast to previous years, many of the fields are main systems as opposed to satellites, which will boost volumes significantly.[23] However, by H2 16, it is likely that Norwegian production will stagnate or even start declining. This is particularly the case as offshore production is expected to be impacted by reducing amounts of infill drilling as IOCs look to reduce Capex. Whilst the market often pays attention to the impact of Capex cuts on future project capacity and delays to projects, the impact of lower spending on existing production is less well documented. Infill drilling is used to stem the pace of declines from mature fields, and a pullback will see acceleration in decline rates, which are close to double-digit territory for mature basins such as the North Sea. There are also a number of smaller satellites affiliated to the large fields that will start up in the coming years. But satellite fields lose 50–60 thousand b/d annually and so at least 0.2 mb/d is expected to be lost over the next four years. This will only be partially offset by the aforementioned new developments.

[22] January saw the 60 thousand b/d of the Eldfisk extension project start-up, which was followed shortly with BG's 63 thousand boe/d Knarr field (currently producing around 20 thousand b/d of oil).

[23] The largest project to start this year is Lundin's 90 thousand b/d Edvard Greig project. The latest investor presentation by Lundin suggests the field will come on before year-end, ramping up to 35 thousand b/d, and the benefit will be felt across H1 16.

Table 3: NCS peak capacity additions: 2015–20, thousand b/d

Field name	Operator	Start Year	Size
Eldfisk extension	Conoco	2015	60
Edvard Grieg (formerly Luno)	Lundin	2015	90
Goliat	Eni	2015	70
Knarr (formerly Jordbaer)	BG	2015	63
Ivar Aasen (formerly Draupne)	Det Norske	2016	16
Froy redevelopment	Det Norske	2016	35
Gina Krog (Dagny)	Statoil	2017	60
Aasta Hansteen (Luva)	Statoil	2017	20
Njord future	Statoil	2018	50
Martin Linge (formerly Hild)	Total	2018	45
Johan Sverdrup	Statoil	2020	315
Total			**824**

Source: Company reports, Energy Aspects estimates

The Norwegian Petroleum Directorate forecasts liquids production to remain fairly static through 2019, according to its latest assessment published in July.[24] Combined condensate and NGLs output are expected to stay constant at 0.38 mb/d, whilst crude oil is expected to stay at 1.5 mb/d until 2017, before declining to 1.4 mb/d by 2019. However, this projection was made prior to the latest delays on fields under development, and so the decline is likely to come earlier in the cycle. Indeed, the capacity additions suggest that production will grow again in 2015 following a rise in 2014. Back-end loaded capacity additions will mean that H1 16 will see the effects of the ramp up in fields. But after that, the backlog thins materially, which will weigh on production for the following few years, until the next chapter of NCS starts in 2020 as the Johan Sverdrup fields come online.

4. Conclusions: Is The North Sea – heading South?

The UK and Norway face different prospects regarding their diminishing resource base. At present, both countries are benefiting from the fruits of several years of high and stable prices, which filled producers with a false sense of confidence, allowing them to chase projects at seemingly any cost. However, one year of low oil prices has transformed the outlook. The UK will benefit in the next two years from new project start-ups and from producers shifting capital to maximize short-term output to manage the downturn. However, beyond the next two years, the outlook looks challenged. Oil and Gas UK have already estimated that the industry has been behind on areas such as maintaining critical equipment and infrastructure over the past four to five years, and the problem has started to accelerate now.[25] The UK has also seen some 5500 jobs cuts since late 2014 and exploration activity has fallen sharply. Beyond the short-term respite, UK production is likely to fall as decline rates accelerate, and as the investment, along with the expertise, of IOCs exits the basin.

For Norway, the reserve base is much higher so the challenges are different. There has not been a mass exodus of major players from the basin, although managing high declines and rising costs remains

[24] 'Historical and expected production of oil, gas, NGL and condensate in Norway 1971–2019', Norwegian Petroleum Directorate (Oljedirektoratet), 16 April 2015, www.npd.no/Tema/Ressursregnskap-og-analyser/Temaartikler/Norsk-sokkel-i-tall-kart-og-figurer/Historisk-og-forventet-produksjon-av-olje-gass-NGL-og-kondensat-i-Norge/.

[25] 'North Sea oil producers face a perfect storm', Kiran Stacey, Oil & Gas, *Financial Times*, 18 October 2015, www.ft.com/cms/s/0/37da458c-5b7f-11e5-a28b-50226830d644.html?siteedition=uk#axzz3qRXKquBU.

a tall obstacle to overcome. Total capacity additions between 2015 and 2020 equate to 0.82 mb/d, although without the giant Johan Sverdrup field (which is a story for the next decade as it is only due to come on stream in late 2019) additions are only 0.51 mb/d, and very front-end loaded. Therefore, by H2 16, it is likely that Norwegian production will stagnate or even start to decline. This is particularly true as offshore production is expected to be impacted by reduced amounts of infill drilling, as IOCs look to reduce Capex.

Whilst new areas – such as tight oil – have a lot of scope for efficiency, mature basins will struggle to achieve similar efficiency gains and to push service costs down. High costs, declining reserves, growing decommissioning activity in the UKCS, and plummeting tax revenues for governments[26] are forcing through some very difficult decisions, which arguably should have been made many years ago. It may be a case of too little too late for the North Sea.

[26] 'North Sea tax revenues plummet to negative for the first time in sector's history', Severin Carrell, *The Guardian*, 21 October 2015, www.theguardian.com/business/2015/oct/21/north-sea-tax-revenues-plummet-negative-first-time-history.