



In this issue

Editor's introduction	2
IFRS 16: The impact of the new lease accounting standard on the drilling industry	3
US: Tax update	8
UK: Autumn budget 2017—upstream oil and gas taxation changes	13
Mozambique: Amendments to income tax rules for upstream oil and gas projects	16
Kazakhstan: Long-awaited fiscal reform	17
Norway: Petroleum tax refund regimes under scrutiny by ESA	20

Global oil & gas tax newsletter

Views from around the world

April 2018

Editor's introduction

Bill Page, Deloitte UK



Welcome to the first edition of the Global oil & gas tax newsletter for 2018.

In this edition, there is less emphasis on base erosion and profit shifting (BEPS), but we have included a short update on the draft toolkit on offshore indirect transfers of assets that was analyzed in our last edition, as this is a key issue for the industry and forms part of the overall BEPS agenda. The Platform for Collaboration on Tax, which issued the draft, initially intended to issue the final version by the end of 2017. This has not happened at the time of writing (March 2018), which may be due to the complexities of the issues raised in the comments on the toolkit (including those prepared by Deloitte in the UK). The comments have been published on the Organization for Economic Co-operation and Development's (OECD's) website and are worth reading to appreciate the range and strength of opinion the issue has generated. We will continue to monitor the situation and prepare an article once the toolkit has been finalized.

Our content for this issue varies as we consider the lease accounting changes under the international financial reporting standard (IFRS) 16, and how they could have significant tax and financial reporting implications for businesses with expensive plant and machinery items held under operating leases, such as drill ships, production platforms, pipelines, etc. Other articles overview recent tax law changes in both Mozambique and Kazakhstan that aim to encourage investment. This edition also includes fascinating insight into the Norwegian upstream tax regime and the question of whether certain elements may be deemed unlawful state aid. It is worth noting that a state aid determination could result in significant cash costs for upstream companies operating in Norway if past reliefs are to be clawed back following an adverse determination. Finally, we consider the potential impact on the industry of the major package of US tax reforms that became law at the end of 2017, although I expect this is another issue we will return to in future editions given the extensive nature of the reforms.

As always, I welcome comments and suggestions from readers and may be contacted by email at bpage@deloitte.co.uk.

Bill Page,
Editor

IFRS 16: The impact of the new lease accounting standard on the drilling industry

Ailish McNamara, Peter Westaway and Simon Cooper,
Deloitte UK

IFRS 16 (the Standard) is the proposed new lease accounting standard for accounting periods beginning on or after 1 January 2019.¹

Although this article focuses on the drilling sector, the implications of IFRS 16 may apply to any lessor or lessee of assets within the scope of the standard, assuming they report under IFRS.

IFRS 16 could have a significant impact on how lease arrangements are accounted for, in particular for lessees that currently use assets under operating leases. For lessees, the concept of operating leases and finance leases will no longer apply. Instead, there will be a single lessee model (with limited exceptions) yielding a right of use asset on the balance sheet that is depreciated, a lease liability on the balance sheet, and interest expense. This new approach may affect key financial metrics and ratios including debt equity ratios and earnings before interest, tax, depreciation, and amortization (EBITDA). Lessors will continue to apply finance lease and operating lease concepts.

The IFRS 16 definition of a lease, whilst similar to its predecessor, also may change the population of arrangements within the scope of lease accounting.

If IFRS accounts are prepared by a taxpayer, any resulting accounting changes could affect the amount of corporate income tax payable in any one period and/or the tax position reported in the financial statements.

Relevance to drilling contractors

Multinational drilling groups typically separate the ownership and operation of drilling units between group entities. In the discussion that follows, it is assumed that the owner of a drilling rig provides the asset to the drilling contractor or operator on a bareboat charter (BBC)

basis, and the operator time charters the drilling unit with crew to a customer (an exploration and production company).

Many drilling contractors prepare their consolidated accounts under US generally accepted accounting principles (GAAP) or other local GAAP, but group entities may be required to prepare standalone accounts under IFRS (currently, or in the future).

Effect of IFRS 16 on a rig operator entering into a BBC with a rig owner

Depending on the commercial terms of the contract and whether it meets the definition of a lease, the rig operator may have to record a liability on its balance sheet (for the BBC payments) with a right of use asset that is depreciated and an interest expense. If the customer contract includes a lease component, this would be accounted for differently to the service element.



1. Early adoption is allowed.

If the operator is acting as a lessor to the customer, the operator would need to classify this as a finance or an operating lease. If the conclusion is a finance lease, this would mean removing the right of use asset recognized under the lease with the rig owner and replacing it with a receivable for future lease payments due from the customer, which would accrue interest income.

If the nature and timing of accounting expenses (or income) changes on a period-by-period basis, this could affect current tax and/or deferred tax amounts.

IFRS 16 includes many areas where accounting judgments will be needed. Depending on the commercial terms of the contracts it is possible that, in relatively limited circumstances, lessees would not need to recognize right of use assets and the current accounting treatment may not change (see below).

Entities reporting under IFRS should act now to understand how IFRS 16 may affect the accounting and tax treatment of leases and perhaps the accounting treatment to be applied by their customers.

Current lease accounting and tax

Under international accounting standard (IAS) 17, the current international leasing standard, leases are classified as finance or operating leases. If the lease transfers all of the risks and rewards of ownership to the lessee, it will be classified as a finance lease; otherwise, the lease will be an operating lease.

For the lessee:

- Finance lease obligations are recognized on the balance sheet as liabilities at the present value of the minimum lease payments, typically with property, plant and equipment fixed assets that are depreciated and interest expensed.

- Operating leases are “off balance sheet” with rental expense accounted for in the income statement.

For the lessor:

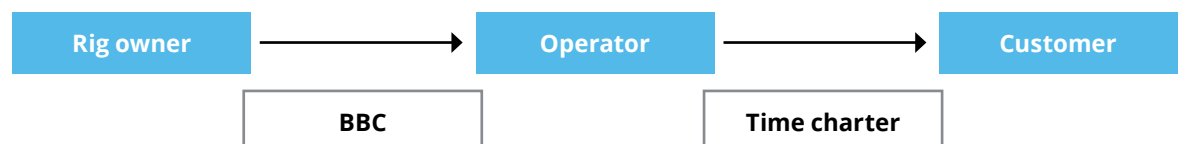
- Finance lease lessors recognize a finance lease receivable in the balance sheet with interest income.
- Operating lessors have the underlying asset on their balance sheet that is depreciated, with gross lease rental in the income statement.

Practical implications

Assume the fact pattern referred to above with a BBC to the operator and a time charter to the customer. For organizational, legal or other commercial reasons, there may be other group companies in the transaction chain between the rig owner and operator, but this is not discussed in the interests of simplicity.

For the rig operator:

- The BBC from the rig owner typically may be accounted for as an operating lease under IAS 17 with lease rentals payable expensed to the income statement. For purposes of this article, we assume the time charter does not include a lease component (this would need to be determined based on the contract terms).
- Depending on the relevant tax jurisdiction, IFRS accounts may form the starting point for calculating taxable profits or losses. In some jurisdictions, the taxable profits or losses follow the accounting treatment; in other jurisdictions, there are separate tax rules that modify or replace the accounting treatment. Cash tax and/or deferred tax implications may arise if IFRS accounts are used to calculate taxable results and if IFRS 16 changes the accounting treatment.



For the rig operator:

- The BBC from the rig owner typically may be accounted for as an operating lease under IAS 17 with lease rentals payable expensed to the income statement. For purposes of this article, we assume the time charter does not include a lease component (this would need to be determined based on the contract terms).
- Depending on the relevant tax jurisdiction, IFRS accounts may form the starting point for calculating taxable profits or losses. In some jurisdictions, the taxable profits or losses follow the accounting treatment; in other jurisdictions, there are separate tax rules that modify or replace the accounting treatment. Cash tax and/or deferred tax implications may arise if IFRS accounts are used to calculate taxable results and if IFRS 16 changes the accounting treatment.

Changes to lease accounting—IFRS 16

Identification of the lease

A lease is defined in IFRS 16 as a contract that “conveys the right to control the use of an identified asset for a period of time in exchange for consideration.”

It is an explicit requirement of IFRS 16 that where a contract is, or contains, a lease, the lease component should be accounted for separately from any non-lease component and the consideration under the contract allocated between the lease and non-lease elements. As a practical expedient, the lessee, but not the lessor, may instead choose to treat the entire contract as a lease for accounting purposes.

Accounting changes for lessors

Lessors will continue to apply finance and operating lease concepts (see below for specific comments for a head-lessee or sub-lessor in a chain of leases).

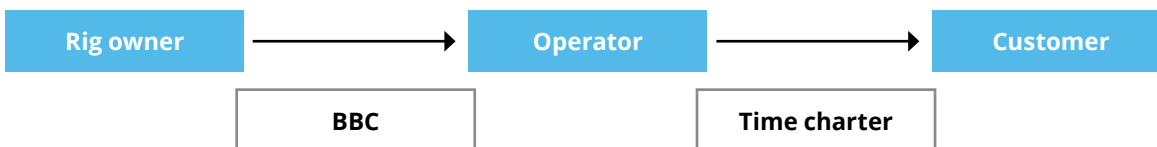
Accounting changes for lessees

The distinction between finance and operating leases under IAS 17 will no longer apply to lessees. IFRS 16 has a single lessee model:

- Liabilities related to leases that previously were off balance sheet will be brought onto the balance sheet; the lessee will record a liability for relevant payments measured at present value, discounted at the interest rate implicit in the lease (or, if that is not readily determinable, at the entity’s incremental borrowing rate), with an interest expense.
- The lessee also will have a right of use asset that is depreciated.

For the operator (assuming the time charter does not include a lease component):

- Where the new lease accounting applies to the BBC, the operating lease rental expense will be replaced with depreciation of the right of use asset and an interest charge. The overall expense to the income statement over the term of the lease should not change, but there will be a change to the timing and nature of expenses.
- Interest costs will be higher in the early stages of a contract so there is a front-loading of total lessee expenses.
- EBITDA will increase as an operating expense is replaced by interest and depreciation.



Headlease/sublease arrangements

Under IFRS 16, unlike IAS 17, an intermediary lessor (headlessee/sublessor) determines whether the sublease is a finance or operating lease by reference to the right of use asset (the headlease) rather than the physical asset that is the subject of the lease. This may mean that if an intermediary has a headlease and sublease on mirror terms, the intermediary may have a lease liability on its balance sheet (for the headlease obligations), but instead of a right of use asset on its balance sheet there may be a finance lease receivable in respect of the sublease. In the above example, there is no intermediary because it assumes the time charter does not include a lease component and there is only a single BBC to the operator rather than a chain of back-to-back BBC arrangements into the operator.

There may be no change to the current accounting treatment

As mentioned above, depending on the specific commercial terms in a contract, it is possible that the new single lessee model bringing right of use assets on balance sheet does not have to be applied. Some of the areas that will affect the accounting outcome in this way can include:

- **Lease definition is not met**—A contract may not convey the right to control the use of an identified asset and hence the accounting is not governed by IFRS 16.
- **Short-term leases**—A lessee may elect, by class of underlying asset, for IFRS 16's recognition provisions not to apply for leases with a "term" of no more than one year, in which case lease payments can be spread over the lease term on a straight-line or other systematic basis, similar to historical operating lease accounting. Extension options or early termination options will need to be reviewed in determining the lease term.
- **Type of lease payment**—Only certain types of payment are included in the calculation of the lessee's lease liability. Variable lease payments (except for those that depend on an index or rate for instance payments linked to a benchmark interest rate) are not included, so that variable lease payments that are linked to the future performance and/or use of an asset may be excluded from the lessee's balance sheet liability.

- **Low value assets**—A lessee may elect, on a lease-by-lease basis, for IFRS 16 not to apply to a lease of "low value" assets. An indicative threshold of USD 5,000 is included in the IAS board's Basis for Conclusions paper.

Tax consequences of IFRS 16—Lessee

Multinational drilling groups may have rigs that are leased across a number of different jurisdictions. The potential tax consequences of IFRS 16 will depend on the tax rules that apply to the relevant taxpayers.

Possible income tax outcomes if there is a change of accounting

If IFRS 16 accounts are the starting point for calculating taxable profits and if the accounting treatment of a contract changes, this will have cash tax and/or deferred tax implications.

Assume IFRS 16 applies because a contract is, or includes a lease, there are payments that are included in the balance sheet liability and no exemptions apply. The total lessee expenses are front-loaded because there is a higher allocation of interest expense in the early periods.

- If the taxpayer follows the accounting results in computing taxable results, this may result in higher deductions at the start of the contract and lower deductions towards the end.
- If the local tax treatment is to start with accounts prepared under IFRS and then apply tax rules to modify the accounting treatment to calculate taxable results, the change to IFRS 16 may not affect the current tax expense, but there will be deferred tax implications.

Change in nature of expenditure

If operating expenses are replaced by depreciation and interest expense, there may be local tax rules that may need to be revisited to determine the amount of deductible expenses for tax purposes. For example, any local interest deductibility rules may need to be revisited in light of the new IFRS 16 category of lessee interest expense.

Other tax rules that target particular types of deductions may need to be reviewed if there is a change to accounting treatment (e.g. transfer pricing). Any tax rulings that rely on accounting treatment also may need to be reviewed.

Response of tax authorities to IFRS 16

It is our understanding that not many tax authorities in oil and gas producing countries have made detailed announcements on how they will respond to the introduction of IFRS 16. In the UK, HM Revenue and Customs (HMRC) has announced that it intends to retain existing tax legislation and make necessary changes to the legislation to enable this to continue to apply as intended (see below).

Country case study: UK

In the UK, accounts prepared under IFRS (or UK GAAP) is the starting point for calculating profits chargeable to corporation tax. Tax rules then may apply to adjust the amount of taxable profits. For plant or machinery (P&M) lease arrangements in particular, the tax treatment depends on whether the taxpayer applies finance lease or operating lease accounting. References to finance leases and operating leases appear elsewhere in UK legislation—for example, in the controlled foreign company rules—and certain anti-avoidance rules apply where there is finance lease liability or loan accounting. HMRC recognized that with the introduction of IFRS 16, changes may be required to UK legislation, and issued a discussion document in August 2016 setting out various options in relation to P&M leasing.

On 1 December 2017, HMRC produced two consultation documents to begin a formal public consultation process.

The first document, Leasing: Tax response to accounting changes, follows on from the 2016 discussion document but is not limited to P&M leases. In this document, HMRC has started to set out its views on the tax legislation that will need to change

in response to IFRS 16 to enable the legislation to continue to work as intended. For an operating lease that is of the type where currently the profit and loss (P&L) rental expense is followed for tax purposes, HMRC propose that the lessee may follow the new accounting (depreciation and interest) expense deductions as a method of achieving a spread of the lessee's rentals (similar to the Statement of Practice 3/91 currently for finance lessees). Furthermore, any accounting adjustments on transition to IFRS 16 should be brought into account in the first period of the new basis.

The second document addresses the UK's corporate interest restriction (CIR) rules (BEPS Action 4) that currently apply to finance lease interest income and expense. The document sets out three possible options to determine what is "interest" for the purposes of the CIR rules, following the introduction of IFRS 16. The proposals range from "follow the accounting classification" of interest (which would bring IFRS 16 lessee interest within the CIR rules) to "apply detailed tax tests" to determine whether or not a lease includes "interest" amounts. HMRC has invited suggestions for any other options.

In addition to leasing specific tax rules, the UK has various tax rules that target the deductibility of expenses, including anti-hybrid and other mismatches rules (BEPS Action 2), a BBC hire cap and a diverted profits tax regime that taxpayers may need to revisit following the introduction of IFRS 16.

Next steps for international drilling contractors

Drilling contractors may take a structured approach to understand how the new Standard may affect their business and to manage the implications.

- **Assess and prepare** for the various impacts of IFRS 16 on existing and future contracts.
- **Implement** the required changes.
- **Manage** the impact which may include renewed focus on future leasing strategies.

US: Tax update

Jeffery Wright, Deloitte US

The US tax cut bill from 2017 officially known as an Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018 ("2017 Tax Act" (Act)^{*}) signed into law by President Trump on 22 December 2017 is a massive package of changes to the US tax code that lowers tax rates on corporations, pass-through entities, and individuals. It is advertised as moving the United States toward a participation exemption-style system for taxing foreign-source income of domestic multinational corporations, and some of the cost of that tax relief is offset by provisions that scale back many longstanding deductions, credits and incentives for businesses and individuals. The estimated net cost of the tax changes is roughly USD \$1.46 trillion for the 10-year budget window covering 2018–2027, according to a revenue estimate from the Joint Committee on Taxation (JCT) staff and will be added to the deficit.

While it is always precarious to generalize because each company's tax situation is different, the provisions in the new law generally do not specifically target the oil and gas industry in a negative manner. As with companies across all industries, there are provisions of broad applicability that are both beneficial and detrimental to industry participants based on their individual business profile. From an industry perspective, however, most existing tax provisions specific to oil and gas taxation remain unchanged by the proposed legislation. As many legislative proposals in recent years have targeted some of these oil and gas-specific provisions for removal, this generally is viewed as a welcome outcome by many in the industry.

Overview

The 2017 Tax Act is an amalgam of two competing tax reform measures—one approved in the House on 16 November 2017, and the other approved in the Senate

on 2 December 2017—although in some significant ways it tracks more closely with the Senate bill.

That outcome is a likely nod to several factors, most notably, the fact that the legislation moved through Congress under budget reconciliation protections that allow certain legislation to clear the Senate with a simple majority vote rather than the three-fifths supermajority required to overcome procedural hurdles that normally arise in that chamber. Those protections come with a price, however, including strict budgetary and procedural rules—the Byrd Rules—that, among other things, prohibit reconciliation legislation from increasing the federal budget deficit outside the 10-year budget window and make it more difficult for lawmakers to include provisions that have no impact or only an incidental impact on the federal budget.

Another significant factor in play was the Republican party's (GOP) narrow margin of control in that chamber, a mere four seats in 2017, which left Senate Republican leaders with little margin for error in securing final passage.

Here are a few highlights of the new law:

- **Corporations:** The 2017 Tax Act replaces the prior law graduated corporate rate structure with a flat 21 percent rate, effective in 2018 and fully repeals the corporate alternative minimum tax (AMT) (for corporations, but not for individuals). It also permits most capital purchases that were amortized under prior law to be fully expensed in the year placed in service through 2022, with a phase-out of that benefit thereafter. On the offset side, it imposes new limits on the deduction for net business interest, repeals the section 199 manufacturing deduction² and the deduction for state and local lobbying expenses, and disallows like-kind exchanges other than for real property.



^{*}An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018.

² This historical provision basically provides an incremental tax "deduction" of up to nine percent for income attributable to certain domestic production activities.



- **Pass-throughs:** The Act allows a deduction of up to 20 percent of certain pass-through income, although the deduction is available only for owners of specified service businesses with income under USD 157,500 (twice that for married filing jointly) and the definition of specified service no longer includes architecture or engineering but does include areas such as law, medicine, and accounting. property. The deduction is available to electing small business trusts (ESBTs), as well as individuals, and owners are allowed to calculate their maximum deduction based on either 50 percent of their share of W-2 wages paid or a combination of 25 percent of their share of W-2 wages paid plus 2.5 percent of the unadjusted basis of all qualified property. While mechanically complex, the intention is basically to provide individuals with a reduced tax rate on certain income earned through pass-through entities (e.g. partnerships and subchapter corporations) that do not pay federal income tax at the entity level. Carried interest income

retains its treatment as a capital gain, although it will be subject to a longer holding period (three years as opposed to one year in prior law) to qualify for lower long-term capital gains rates.

- **International:** The Act moves the US from a worldwide tax system to a what has been described as a participation exemption system under which corporations are given a 100 percent dividends-received deduction for dividends distributed by a controlled foreign corporation (CFC). To transition to that new system, the Act imposes a one-time deemed repatriation tax, payable over eight years, on unremitted earnings and profits at a rate of 8 percent for illiquid assets and 15.5 percent for cash and cash equivalents. The Act generally follows the Senate-passed structure in establishing new base erosion prevention provisions, with modifications. These are complex and potentially significant to affected companies.



- **Individuals:** The Act generally follows the structure of the Senate-approved tax reform bill and 2017 law, by maintaining seven individual income tax brackets. The top individual income tax rate is 37 percent (lower than in either the House or Senate bills or prior law's 39.6 percent) but includes a significant marriage penalty. It also nearly doubles the standard deduction, repeals the current "Pease limitation" on itemized deductions (applicable to higher income taxpayers), and expands the refundability of the child tax credit. It retains the deduction for unreimbursed medical expenses (and even offers a boost for 2017 and 2018) and leaves intact the capital gains exclusion on the sale of a primary residence in effect prior to its enactment. On the revenue side, the measure repeals personal exemptions, retains the individual AMT (albeit with higher exemption amounts), pares back the deduction for home mortgage interest (with existing mortgages grandfathered), and places substantial new limits on the ability of taxpayers to deduct state and local taxes. As in the Senate-passed bill, almost all of the Act's individual tax changes (including all of those just mentioned and the pass-through deduction described above) expire after 2025.
- **Estates:** The Act generally follows the Senate-passed bill by retaining the estate tax (which applies to the value of property owned on death) at its current rate but doubling the exemption amounts. As in the Senate bill, the expanded estate tax exemption amounts sunset after 2025.

Oil and gas considerations

The Act's provisions of broad applicability noted above will be important to many oil and gas companies just as they are across other industries. While important, most are not expected to uniquely affect the oil and gas industry as compared to the broader business community. For example, the general business provisions impacting interest deductibility, full expensing, treatment of net operating losses, and changes to the international tax system are significant. For many of the oil and gas companies with multinational operations (whether inbound or outbound), the provisions modifying the existing treatment of cross-border transactions may be the most significant considerations.

The following summarizes some of the key oil and gas-related considerations in connection with the Act.

- **Historically targeted industry:** Specific provisions unchanged. Some of the key unchanged items include:
 - The deduction for intangible drilling costs (IDCs);
 - Percentage depletion cost recovery rules;
 - Recovery timing of geological and geophysical costs;
 - Designation of certain natural resource-related activities as generating qualifying income under the publicly traded partnership (PTP) rules, which allows these entities to operate as pass-through entities for tax purposes and avoid entity level taxation; and
 - Exception to passive loss treatment for certain working interests, which impacts the ability of certain investors to deduct losses attributable to oil and gas investments.³
- **Oil and gas production credits:** Although initially targeted for repeal, the Act retains the current law's marginal well and enhanced oil recovery credits, which provide tax credits for certain properties during periods of low commodity prices.
- **Like-kind exchanges:** Many oil and gas companies routinely use like-kind exchanges in connection with acquisition and disposition transactions. The Act now limits the non-recognition of gains for like-kind exchanges to real property that is not held for sale and this change applies to exchanges completed after 31 December 2017. However, an exception is provided for any exchange if either the property being exchanged or the property received is exchanged or received on or before 31 December 2017. Operating and non-operating interests in oil and gas reserves generally have qualified as real property under these rules, so these transactions should largely remain unscathed by the narrowing of this provision.

Any personal property included in the exchange, such as plant and equipment, however, would not qualify, potentially leading to taxable gains. As it is common for a transaction to include a mixture of real and personal property, the value of like-kind exchange planning on prospective transactions will obviously be impacted by the amount of personal property included in a transaction involving both property types.

3. More details of these reliefs can be found in Deloitte's US oil and gas taxation guide:

<https://www2.deloitte.com/global/en/pages/energy-and-resources/articles/international-oil-gas-tax-guides.html>

- **Alternative minimum tax:** As noted above, the Act repeals the corporate AMT for years beginning after 31 December 2017. It will continue to allow the prior year AMT credit to offset the taxpayer's regular tax liability for any tax year. Given the capital-intensive nature of drilling programs and development projects in the upstream sector, many such companies historically have been AMT taxpayers. The AMT for individuals is retained (with some modifications).
- **Section 59(e):** The statutory language modifying the AMT rules did not remove current law section 59(e), a provision that allows annual flexibility in determining the amount of IDCs that an E&P company capitalizes or deducts.
- **Research credits:** The existing research and development (R&D) credit, which provides an incremental tax credit for certain R&D activities, is retained. With the repeal of corporate AMT, this credit could become more relevant for companies that could not historically benefit from the credit due to their AMT profile. With the continued proliferation of technology innovation in the industry, the retention of this credit is important as many of these activities potentially qualify for the credit. However, to help offset the cost of the bill and keep it under the \$1.5 trillion ten-year score allowed in reconciliation, R&E expenses will have to be capitalized over five years after 2021 (fifteen if the research is done outside the US).
- **Section 199 repealed:** This provision (see explanation above) historically was used by oil and gas companies across all subsectors.
- **Full expensing:** The Act initially allows full expensing for property placed in service after 27 September 2017, reducing the percentage immediately deductible each year after. Also, the Act allows "used" property to qualify. This could impact the structure and pricing of M&A transactions and increase the desire of buyers to structure an acquisition as an asset purchase in order to potentially deduct a significant portion of the purchase price immediately.

The Act also repeals the ability to claim a refund of prior year minimum tax credit carryovers, in lieu of claiming bonus depreciation. Moreover, property used in certain trades or businesses does not qualify for full

expensing, including certain businesses transporting gas by pipeline if their rates are subject to certain regulatory oversight (generally referred to as the "regulated utility" exception).

- **Interest disallowance:** In summary, the Act limits the deduction for net interest expenses incurred by a business to the sum of business interest income and 30% of the business's taxable income (adjusted in accordance with specific and complex rules). Any disallowed interest can be carried forward indefinitely.
- **PTPs:** The Act does not change or otherwise limit the qualifying income exception in section 7704 that allows certain oil and gas PTPs to be classified as partnerships for US federal income tax purposes. The Act protects this rate differential between corporations and pass-through entities, which some suggest is an important consideration impacting a decision to operate as a PTP. The Act also retains a key exclusion for PTPs from the Form W-2 wage limitation in the new pass-through rules, which is key to achieving this result.
- **Specific international provisions affecting oil and gas:** As with multinational companies across industries, some of the potentially most impactful areas of the Act are those that affect multinational corporations with cross-border operations or ownership. These provisions are complex and interrelated, which makes planning exercises complex. Although not specific to the oil and gas industry, because of the importance of these rules to MNCs, a few additional comments on some of the key international provisions in the Act are warranted.

As noted above, the US is essentially moving from a system whereby foreign earnings were generally taxed upon receipt of a dividend (termed "deferral") to a system whereby, for most US multinationals, a significant portion of (though not all) foreign earnings will be exempt from US tax. A transition tax is introduced to transition to the new system.

A new concept introduced in the Act are the special rules around global intangible low-taxed income (GILTI). GILTI is a new category of income which will have the effect of ending deferral of taxation on a significant portion of foreign earnings.

Another new provision in the Act relates to foreign-derived intangible income (FDII). FDII is a new type of income category for US corporations. Many new terms of art have been created for the calculation of FDII, and the calculation itself is complicated. FDII is income earned directly by US corporations for which a deduction is allowed. From 2018 through 2025, the deduction is 37.5 percent; and starting in 2026, it is 21.875 percent. When combined with the 21 percent corporate income tax rate, the effective US tax rate on FDII is 13.125 percent for 2018 through 2025 and 16.4 percent starting in 2026. The deduction also is potentially available for US corporations owned by non-US multinationals.

Another new concept introduced by the Act is the base erosion anti-abuse tax (BEAT). This provision applies to both US-parented and non-US-parented MNCs. BEAT is an alternative tax computation. US companies are required to pay the greater of their regular tax liability or BEAT tax liability. There are a number of special rules and other complicated defined terms applicable in determining the base erosion percentage, which are beyond the scope of this summary.

In addition to the foregoing, some other key items of importance to international oil and gas companies include:

- Repeal of treatment of foreign base company oil related income as subpart F income.⁴
- An exclusion is provided under the GILTI provisions for foreign oil and gas extraction income, which is key for maintaining deferral.

Navigate the complexity with confidence

The Act increases both the complexity and potential opportunity in tax planning. Now more than ever, oil and gas companies need to undertake proactive tax planning. It is important for groups to understand their starting

positions, analyze options, plan and execute next steps, and monitor future tax law and regulatory changes. Some of the key action items to consider include:

1. Understand the starting position
 - Understand data, systems, and process needs and evaluate:
 - Tax accounting methods
 - Multinational tax planning
 - Global employment programs
 - Potential impacts on financial reporting
2. Analyze and model options:
 - Model options
 - Drill down, compare, and analyze alternatives
 - Review financial reporting impacts
3. Plan and take action:
 - Identify opportunities with significant impact
 - Align international and domestic planning
 - Implement necessary enterprise resource planning and other system changes
4. Monitor and address changes:
 - Potential technical corrections
 - State legislative changes
 - SEC/FASB financial reporting guidance

Conclusion

As the above discussion illustrates, the Act will have an impact on almost every taxpayer and increases both the complexity and potential opportunity in tax planning. For a more detailed summary and discussion of the Act, readers are encouraged to refer to Deloitte's publication, [Reshaping the code: Understanding the new tax reform law](#).

4. Subpart F income is excluded from deferral. Subpart F generally targets passive income and income that is split off from the activities that produced the value in the goods or services generating the income.

UK: Autumn budget 2017—upstream oil and gas taxation changes

Roman Webber and Simon Lee, Deloitte UK

Following a relatively quiet 2017 spring budget for companies with UK North Sea oil and gas operations, the 2017 autumn budget contained a number of significant announcements across a range of issues. A unifying theme is that each of the key policy changes should facilitate transactions across the sector, allowing assets to pass into the hands of those best placed to operate them.

The industry should take comfort from the continuing commitment to the UK government's 2014 fiscal policy paper "Driving Investment," which set out a framework to support the maximization of economic recovery within the UK Continental Shelf (UKCS).

This article summarizes the key details of the tax measures announced.

Transferable tax history (TTH)

As the UKCS enters its next phase of life, it is crucial that the companies that are best placed to operate assets in the most efficient way possible are given the opportunity to acquire them.

In recent years, companies have been reluctant to buy mature oil and gas assets where there has been uncertainty as to whether they will be able to access tax relief on their full decommissioning spend. Such tax relief would have been available to the incumbent if the asset remained in their hands by way of carryback of such costs against their tax payment history, but current law does not enable a purchaser to access repayments in this way. This has created a valuation gap between buyers and sellers. Consequently, new entrants or mature asset specialists with the potential to innovate alternative approaches have not been able to acquire appropriate assets.

After extended consultation and the establishment of an industry-wide expert panel in the summer of 2017, the UK government published a paper on the proposed mechanism, which will enable oil and gas companies to transfer tax histories, breaking new ground for the UK tax system. Where this mechanism applies, the buyer would be able to utilize tax losses arising during their period of ownership (e.g. because of unforeseen performance issues or decommissioning expenditure) against tax payments made by the seller(s) during the period of ownership, generating tax repayments that would arise to the buyer. Draft legislation is expected in late spring 2018 for technical consultation, with final legislation to be included in Finance Bill 2018–2019. At the date of this publication, no introduction date had been set, although the implementation of recent oil and gas tax measures suggests that this would, at earliest, be the date of the 2018 autumn budget.

Key design elements

The government paper contains useful guidance on a number of the key overarching principles that will govern the implementation of the measure, including the following:

- The transfer of tax history is expected to be optional (so that the measure does not interfere with transactions that would be carried out under existing tax legislation).
- There will be safeguards to ensure that the amount of tax history transferred is not grossly disproportionate to the tax that would have been paid on the profits of the transferred interest by the seller. This will include a cap at the level of the buyer's estimated share of the decommissioning cost of the asset purchased per the asset's decommissioning security agreement (DSA). Companies will be required to have this number verified by an independent third



party. Details regarding the nature of this verification will be established through the period of technical consultation, but it is expected that assurance will need to be obtained from independent parties in the industry and will not be provided by either HM Revenue and Customs (HMRC) or the UK Oil and Gas Authority (OGA).

- The TTH will become available only to companies when it is activated. This activation will require the buyer to track the profits and losses generated by that asset post purchase, in a shadow calculation, which will be included in the buyer's tax return. The TTH will become activated once that asset has permanently ceased production and become loss-making in the hands of the buyer on a cumulative basis (taking account of decommissioning costs incurred).
- Activated TTH will be treated as part of the buyer's tax history and will be available for use against any decommissioning loss within that company (regardless of whether that decommissioning loss is as a result of expenditure incurred decommissioning the transferred asset or any other field).
- If the field is transferred again, TTH may pass to the new purchasing entity. The shadow calculation passes with the TTH and both the new transferee and the original transferee's tracked history must be worked through before TTH can be activated.

Our view

This welcomed change should facilitate transactions where access of the perceived value of decommissioning tax relief has been an obstacle, and encourage new entrants and the development of alternative business models for mid- and late-life assets.

Although, at first sight the delayed introduction of the measure (November 2018 at soonest) may be disappointing, the complexity and innovative nature of these changes will require careful legislative drafting with robust safeguards to protect all stakeholders. It is important that the government takes the time necessary to ensure that the implementing legislation is fit for purpose and provides sufficient clarity to those contemplating deals across the UKCS; this is particularly important at a time when much of the legislative agenda will be taken up by Brexit.

Treatment of tariff income

Tariff income from a UK oil and gas perspective includes that derived from providing other companies access to, and use of, oil and gas infrastructure, including transport through pipelines and processing through other facilities. Further to correspondence with the industry in 2017, the government clarified that any tariff income earned by license holders for use of infrastructure is subject to the UK ring fence corporation tax (RFCT) regime for oil and gas. Revised legislation confirming this treatment has been included in Finance Bill 2017–2018.

This clarification is reassuring for companies that have treated income from, and expenditure on, key infrastructure as falling within the RFCT regime. This has removed the uncertainty regarding the historical treatment of those costs and the losses or tax relief to which they may have given rise. However, the clarification could cause concern to those that have taken a different interpretation of the original legislation, paying tax on certain tariff income under the non-RFCT regime, as these profits will be subject to the higher rate of taxation going forward.

One additional concern is that the legislation could be read in a manner that broadens the existing coverage of the UK oil and gas tax regime, bringing the profits of companies deriving income from tariff-charging assets that have group companies with UK upstream operations within the RFCT regime. The industry is discussing this with the authorities to allay any concerns, as this outcome was not understood to have been an objective of the tax authorities.

Major change in the nature or conduct of trade

In the autumn budget, the government committed to providing additional guidance on the application of the "major change in the nature and conduct of a trade" (MCINOCOT) rules for the oil and gas sector. MCINOCOT rules operate to prevent companies accessing historical tax losses where that company has changed ownership with the primary intention to access losses rather than for the purchaser to acquire a genuine viable trade. These rules have become increasingly important to the sector given the abundance of losses in certain companies following the precipitous decline in oil prices in 2014 and 2015.

This new legislation was released at the end of 2017 and built on existing examples that Deloitte previously discussed with HMRC on which agreed principles were established.

HMRC provided examples where they would not seek to enforce the rules (including situations where a company's method or route of exporting hydrocarbons changed and where the mix of hydrocarbons produced evolved) and where they would be highly unlikely to enforce the rules (including situations where decommissioning activity increased or where the identity of particular customers changed). Finally, they outlined a number of more specific examples reflecting potential commercial scenarios or previous transactions, and explaining whether HMRC would consider whether or not there could be a MCINOCOT based on the facts at hand and application of legislation.

Given the depressed oil and gas prices in recent years, companies have built up substantial commercial and tax losses, so in the context of the recent upturn in merger and acquisition (M&A) activity, the additional guidance is considered helpful.

Petroleum revenue tax (PRT) treatment of retained decommissioning liabilities

PRT was abolished for new fields in 1993, but despite this, continues to apply to older fields, some of which

have paid significant amounts of tax over the course of their operations. Many of these fields are getting closer to decommissioning. The government has confirmed that it will launch a technical consultation in spring 2018 on allowing a PRT deduction for decommissioning costs incurred by a previous license holder. The consultation will inform new legislation to be introduced in Finance Bill 2018–2019 that will support transfer of assets subject to PRT where the seller retains the decommissioning liability. Similar to the TTH legislation, no effective date has been announced for these changes but we would expect them to apply from late 2018.

The announcement followed a similar measure in the 2016 spring budget, which clarified that companies would be able to obtain corporation tax relief on expenditure in respect of decommissioning liabilities that are retained after the asset is sold. Whilst the 2016 clarification was well received, it did not fully alleviate the issue for fields subject to PRT. The selling company still was required to retain an interest in the field to be eligible for PRT relief on retained decommissioning liabilities. The 2017 announcement should remedy this, and will be welcomed by industry as a further step towards encouraging transfers of mature assets to facilitate the government's aim of maximizing economic recovery from the North Sea.



Mozambique: Amendments to income tax rules for upstream oil and gas projects

Eugenia Santos and Dercio Da Barca, Deloitte Mozambique

The specific taxation and tax benefits regime for petroleum operations, approved by Mozambique's Law No. 27/2014 of 23 September 2014, was amended by Law No. 14/2017 of 28 December 2017, which became effective on 1 January 2018. Law No. 14/2017 includes the following key changes:

- The 50 percent reduction in tax on petroleum production (analogous to a royalty and normally charged at 10 percent for crude oil and six percent for gas) that previously applied when production was sold for domestic industrial use is eliminated.
- Any taxes arising from the transfer (for consideration or free-charge) of shares or participating interests in the petroleum sector are considered nondeductible for purposes of computing corporate income tax.
- Taxable gains realized by nonresidents on the sale of shares in entities holding oil rights or other immovable property no longer are subject to a 50 percent reduction. In addition, such gains are subject to separate taxation for both residents and nonresidents. For resident taxpayers, this means they can no longer include such gains in the annual tax return and consequently, cannot offset tax losses to reduce the taxable amount.
- As a result, capital gains resulting from direct or indirect transfers of oil rights located in the Mozambican territory (for consideration or free-charge) always will be taxed in full. The normal corporate income tax rate of 32 percent will apply to the difference between the realization value and the acquisition value of the shares, movable or immovable property, regardless of whether the transferor is a resident. It should be noted that the realization value will be market value in the case of non-arm's length transactions.
- With respect to the fiscal stability which is granted for a 10-year period to the holders of oil rights, the following rules apply in the case of contracts signed on or after 1 January 2018:
 - The beginning of the 10-year period is the commencement of commercial production (instead of the date of approval of the development plan).

- The minimum required investment must be equivalent to USD 100 million for fiscal stability to be available.

- Subject to an authorization from the Ministry of Economy and Finance, it will be possible to submit statutory accounts in US dollars, provided an investment of at least USD 500 million has been made and more than 90 percent of the transactions undertaken are in US dollars. It is not clear whether this will be available for projects that are projected to cost more than the threshold amount in the period before the investment reaches that amount of expenditure. Current projects are not affected by this change.

VAT changes

Decree No. 77/2017 of 28 December 2017 approved the regulation on value added tax (VAT) refunds, revoking a decree dating back to 1998 (Decree No. 77/98 of 29 December 1998), which approved the previous regulations dealing with VAT refunds.

Decree No. 77/2017 introduces a new regime for companies in the mining and petroleum sectors that are operating in the production phase. Large projects in these industries, which predominantly make zero-rated export sales, previously accounted for about 80 percent of the overall volume of VAT refund applications. The new mechanism aims to eliminate the necessity for companies to pay and reclaim input VAT if they meet the relevant requirements. To qualify, at least 75 percent of the sales of a company must have been exports in the preceding year. Where companies qualify, they may apply to the tax authorities for approval of an alternative method of VAT accounting, which would require them to issue a tax regularization note (using an authorized format) in satisfaction of VAT charged on an invoice issued to the company by a supplier. This will avoid the requirement for VAT to be paid by the supplier to the tax authorities on issuance of the invoice, paid by the company to the supplier on settlement of the invoice and then reclaimed from the tax authorities by the company.

Kazakhstan: Long-awaited fiscal reform

Anthony Mahon and Maken Iskakova, Deloitte Kazakhstan

Following the introduction of Kazakhstan's previous tax code (which set out the current unstable taxation regime⁵) in 2009, oil prices increased from around USD 60 to their 2014 peak of more than USD 100 per barrel. During this period of rising prices, upstream companies in Kazakhstan were faced with continuous pressure as the authorities sought to augment tax revenues using a fiscal regime designed for an environment of lower oil prices. The cumulative effect was that by 2014, the level of government take for oil and gas projects in Kazakhstan was seen to be increasingly uncompetitive.

Even before the slump in global oil prices, the outcome of this re-balancing of economic interests in favor of the state was a reduction in new investments in projects in Kazakhstan's oil and gas sector. With the exception of the recently launched "Future Growth Project" at the supergiant Tengiz field, there has been a near total absence of significant new investment into the sector in Kazakhstan over the last five years.

Whilst there has been continued interest in potential oil and gas projects in Kazakhstan over this period, the overwhelming sentiment from investors has been that fresh investment would not flow under the existing fiscal terms. As oil prices bottomed out at the end of 2015, a degree of emergency relief was handed to a market in distress with the rates of export customs duty (applicable to exports of crude oil) reduced to mitigate the tax burden on producers as prices remained depressed. Throughout the last couple of years, however, representation from the extractive industries (both hard minerals and oil and gas) led to a breakthrough in dialogue between the state

authorities and the extractive industry in relation to taxation regimes (in addition to general tax reform). These discussions led to the new Kazakh tax code that generally applies as from 1 January 2018, but certain provisions are to be phased in during the period 2018 to 2020. This new code has been greeted with cautious but widespread approval from the industry and observers. Whilst there are clear areas where there is scope for continued improvement (most notably, the absence of incentives for producers to make investments into brownfield acreage and/or employ more sophisticated enhanced recovery technologies and processes), there is clear potential for this newly issued legislation to be a trigger for new investment to flow into this sector in Kazakhstan.

New concepts applicable to all taxpayers

The new law is intended to provide more clarity on the taxation of companies in the extractive industries (normally referred to as subsoil users in the relevant legislation) and related tax administration, with the objective of fostering a more attractive investment climate. Amongst the conceptual changes introduced is the principle of taxpayer good faith, which shifts the burden of proof regarding taxpayer fault to the tax authorities.

Along with the tax code, a new concept of "horizontal monitoring" is introduced, which is based on information exchange between the state tax authorities and the taxpayer, and relies on the principles of trust and transparency, giving the tax authorities enhanced access to taxpayers' records and information. The horizontal

5. This applies to all upstream projects with the exception of nine grandfathered contracts that are stabilized.

monitoring rules will take effect from 2019 and allow taxpayers that meet certain criteria (as yet to be specified by the state authorities) to sign an agreement for the exchange of information with the state tax authorities, which also will grant access to taxpayers' business and tax accounting systems. Taxpayers opting into this monitoring regime will secure certain advantages that include: (1) an automatic VAT refund (without a tax audit); (2) an exemption from tax audits; and (3) an exemption from administrative fines if the tax authorities discover a tax violation in the course of horizontal monitoring.

Oil and gas-related changes

The following are the most significant reforms to the bases and mechanisms of taxation for the oil and gas industry. This will affect current and future projects apart from those that are stabilized.⁶

Discovery bonus

As from 1 January 2019, the obligation to pay commercial discovery bonuses will be abolished for all subsoil users in Kazakhstan. This reform has long been called for by the industry. The existing commercial discovery bonus regime has been contentious as payment is due, often significantly in advance of a subsoil user actually being certain that such a discovery would be commercially exploited. Consequently, the amount of bonuses payable to the state budget could lead to significant adverse impacts upon project returns, especially if the level of bonus due was substantial. The abolition of this regime is considered a positive step for the industry.

Alternative tax

A new and elective tax regime has been introduced starting from 1 January 2018 as an alternative to subsoil user taxes for entities that have concluded mineral extraction contracts for exploration and production from deep (4,500 meters and lower) and continental shelf deposits. If a taxpayer elects to apply the alternative tax, this charge will be due in place of the

taxpayer's obligations in respect of mineral extraction tax, historical cost payments⁷, rental tax on export and excess profits tax.

In general, a taxpayer may opt to apply the alternative tax on a voluntary basis, but once this method is chosen, it cannot be reversed until the expiration of the relevant contract.

Tax rates range from zero percent to 30 percent, depending on the world market price of crude oil⁸, increasing by six percent for each USD 10 step change in oil prices. For example, the tax rate is zero percent when the global price of oil is below USD 50 per barrel, six percent, when the price is between USD 50 and USD 60, etc. See the following table for further detail:

World market price	Percentage rate
Below USD 50 per barrel	0%
Below USD 60 per barrel	6%
Below USD 70 per barrel	12%
Below USD 80 per barrel	18%
Below USD 90 per barrel	24%
Above USD 90 per barrel	30%

Early depreciation of exploration expenses

Subsoil users are entitled to deduct tax depreciation in respect of exploration expenses incurred from 1 January 2018 under a subsoil use contract where production has not commenced against taxable income arising under another contract where production has started. However, these expenditures will not be available for tax offset if the costs relate to abortive exploration.

Prior to this change, there was a requirement to maintain ring-fenced accounting of income and expenditures for each subsoil use contract. Failure to comply with this requirements was considered to violate tax legislation and constitute a breach of the subsoil user's contract obligations, which, in principle, could lead to the contract being forfeited.

6. See footnote 2.

7. Meaning reimbursement of costs incurred by state entities/agencies in relation to the contract area.

8. Defined as the average value of daily price quotations of each separate standard grade of crude oil "Urals Mediterranean" (Urals Med) or "Dated Brent" (Brent Dtd) in the tax period on the basis of information published in Platts Crude Oil Marketwire.

VAT control account

A new VAT control account (regionally known as the Azerbaijani method of VAT accounting) has been introduced to optimize the VAT refund process and reduce fraudulent VAT schemes. A VAT control account should be opened by an eligible taxpayer in a Kazakh commercial bank. This is effectively an escrow account into which a purchaser of taxable goods and services will transfer VAT charged to it, instead of paying the amount to the supplier. Only taxpayers using the e-invoicing system may elect to use VAT control accounts. Once VAT liabilities are settled, all amounts remaining in the VAT control account will be subject to a refund within 15 business days.

Other changes

The new tax code adds software technical maintenance, software updates and internet resource access to the list of services whose place of sale is determined by the buyer's place of registration for VAT purposes. Thus, when Kazakhstani taxpayers procure such services from a nonresident, Kazakhstan will be recognized as the place of supply and charges will be subject to the reverse charge VAT in Kazakhstan.

In addition, the categories of nonresidents' Kazakh source income subject to withholding tax has been expanded to include:

- Income from the provision of engineering and marketing services outside Kazakhstan to a Kazakhstan-based customer; and
- Income of a tax haven-registered nonresident entity in the form of an advance payment for goods or services not provided within a two-year period from the date the advance payment was made.

It is worth noting another fundamental change in the tax legislation. The new tax code states that any ambiguities and gaps not covered by the tax law should be interpreted in favor of the taxpayer. Whilst there is uncertainty as to how this will work in practice, it is an important milestone in Kazakh tax legislation, and one that could potentially go a long way towards protecting the interests of taxpayers acting in good faith.

Conclusion

It is still too early to assess the impact of the government's attempt to tailor the new tax legislation to create a more adaptable investor-oriented environment. However, both the new code itself and (most importantly) the fact that industry consultation was one of the primary factors driving its development could be viewed with real optimism regarding the positive impact this may have upon the oil and gas industry in Kazakhstan.



Norway: Petroleum tax refund regimes under scrutiny by ESA

Per Christian Ask, Deloitte Norway

Recently, there has been significant attention in the Norwegian press about the tax regime for exploration costs. On 21 August 2017, the Bellona Foundation (Bellona)⁹ submitted a complaint to the European Free Trade Association (EFTA)¹⁰ Surveillance Authority (ESA)¹¹ regarding the exploration refund regime, claiming that the regime constitutes unlawful state aid. State aid may be defined as, "any advantage granted by public authorities through state resources on a selective basis to any organizations that could potentially distort competition and trade."¹²

ESA has requested information about various aspects of the Norwegian petroleum tax regime. The Ministry of Finance has taken the position that no state aid is granted in connection with the petroleum tax regime in Norway.

Academics in Norway have suggested that there is a risk that the exploration refund regime could be considered state aid, which then would be regarded as unlawful because of the lack of notification.

The case has created some concern among upstream companies and investors with interests in the Norwegian Continental Shelf (NCS). Unfortunately, it is difficult to predict the outcome of the case or when it will be resolved.

This article presents a summary analysis of the case, along with more detailed explanations of certain aspects of the technical background.

Introduction to Norwegian petroleum tax policy

The oil and gas sector is Norway's largest economic sector measured in terms of value added, government revenues, investments and export value. This sector, therefore, plays a vital role in the Norwegian economy and the financing of the Norwegian welfare system.

The overall objective of Norway's petroleum policy has always been to provide a framework for the profitable production of oil and gas over the long term. Another priority has been to ensure a considerable share of the value created accrues to the state, to the benefit of the citizens of Norway. According to the Norwegian Public Administration, this is partly obtained via the tax system.

In 2017, Norway's estimated tax revenues from petroleum activities (see figure 1) were about NOK 72 billion (approximately USD 9.28 billion), while the total estimated net cash flow from the petroleum industry in 2017 was NOK 180 billion (approximately USD 23.21 billion).

9. The Bellona Foundation is an independent, non-profit organization based in Oslo that focuses on environmental issues, particularly climate change.

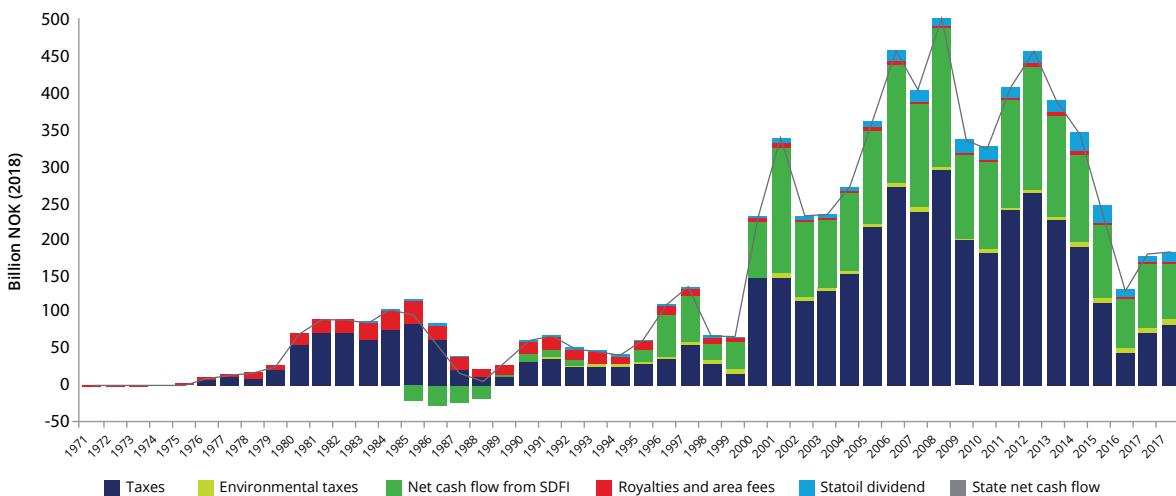
10. EFTA is the European Free Trade Association, consisting of Iceland, Liechtenstein, Norway and Switzerland. Together with the EU states, the members of EFTA participate in European Economic Area (EEA) and are subject to certain EU rules.

11. ESA monitors compliance with EEA rules in Iceland, Liechtenstein and Norway, enabling them to participate in the European internal market.

12. Source: www.gov.uk.

Figure 1: The net government cash flow from petroleum activities—1971–2018

(Updated: 12 October 2017)
 2017 and 2018 are preliminary numbers from the 2018 National Budget. Paid taxes are adjusted for repayments and numbers are inflated using the Norwegian Consumer Price Index (CPI).



Source: Ministry of Finance, Statistics Norway

The petroleum tax regime is based on standard company taxation rules and is set out in the Petroleum Taxation Act of 13 June 1975 No. 35 (PTA). The base for petroleum tax (see figure 2) is the company’s overall net income from petroleum activities on the NCS (i.e., the system allows consolidation of income and costs between different fields and licenses).

Upstream companies are subject to an additional special tax due to the excess returns potentially arising on the production of petroleum resources. In 2017, the ordinary corporate income tax (CIT) rate was 24 percent, and the special tax rate was 54 percent, giving rise to a marginal tax rate of 78 percent, which is unchanged since 1992.

The petroleum taxation regime is intended to be neutral (i.e., an investment project that is profitable for an investor before tax also should be profitable after tax). This is intended to ensure substantial revenues for Norwegian society and, at the same time, encourage companies to carry out profitable projects.

Figure 2: Petroleum tax base

Sales income

- Operating costs
- Capital depreciation
- Financial costs
- (Deficits from previous years)

= Ordinary tax base - liable to 24 percent tax

- Uplift (extra depreciation, 5.34 percent per annum for four years)
- (Excess uplift from previous years)

= Special tax base - liable to 54 percent tax

Tax refund regimes

The Norwegian petroleum tax regime has some features that are not common in other jurisdictions and that are not present in the general CIT system in Norway.

To attract new upstream companies to the NCS at the beginning of the twenty-first century, Norway introduced a scheme where losses could be carried forward indefinitely and subject to an interest supplement to reflect the time value of money (“interest supplement regime”). The intention of the interest supplement is to compensate companies not in a taxpaying position for the disadvantage of having to delay the deduction of the losses.

The interest rate should reflect a risk-free return (0.7 percent for income year 2017) and is much lower than the rates of return generally used by upstream companies. Therefore, the present discounted value of any tax losses carried forward for most companies will be lower than the nominal value (even after including the interest supplement). The interest supplement is available only for upstream companies.

The introduction of the interest supplement regime had moderate success in terms of promoting new investment and attracted only a few new companies. Thus, in 2005 Norway introduced a refund scheme for the tax value of the exploration costs (exploration refund regime), which was intended to reduce the entry barriers for new players and encourage economically viable exploration activity. This was seen as potentially beneficial as it usually takes a long time for an offshore discovery to be developed and put into production (10–15 years is not uncommon). Carrying forward losses for extended periods is financially challenging, and the exploration refund regime is intended to mitigate this challenge.

Under the exploration refund regime, companies that are making a loss may choose between requesting an immediate refund of the tax value of exploration costs or carrying forward the resulting losses to a later year when the company becomes taxable. If a company opts to claim a refund, the exploration costs cannot be deducted in a later year. The intention of this regime is that the value of the tax deduction is the same, regardless of whether a company is liable to pay tax, and that all companies are treated equally.

ESA monitors compliance with the Agreement on the European Economic Area (EEA Agreement) in Iceland, Liechtenstein and Norway, enabling those states to participate in the Internal Market of the European Union.

ESA is independent of the states and safeguards the rights of individuals and undertakings under the EEA Agreement, ensuring free movement, fair competition and control of state aid.

The exploration refund regime is considered a successful measure since a number of new companies entered the NCS after 2005. The number of exploration wells has increased significantly since 2006 and has led to a number of discoveries, including the Johan Sverdrup field (currently estimated to hold two to three billion barrels).

The exploration refund regime is important for upstream companies operating in the NCS that are not yet liable to pay tax. The claim for a refund may be pledged and used as security for external financing, which reduces the requirement for equity financing for exploration activities. Therefore, the case has created some uncertainty for lenders (i.e. banks) providing exploration financing facilities.

Also, a new refund regime was introduced in 2005 for losses to carry forward, comprising costs not covered by the exploration refund regime (e.g., depreciation of investments and other operating losses). Under this regime (the cessation refund regime), an upstream company may claim a refund of the tax value of the loss carried forward, including the interest compensation mentioned above, when the activity liable to special tax ceases. The tax value is the loss carried forward multiplied by the tax rate (i.e., currently 78 percent). The “cessation refund regime” again reduces the risk of participants in the Norwegian petroleum sector, by ensuring that the state ultimately will carry 78 percent (provided the tax rates are upheld) of any losses resulting from the investments and operations in the NCS.

Both the exploration refund regime and the interest supplement regime now are under investigation by ESA as possible unlawful state aid.

Status of the case

In the appeal to ESA, Bellona claimed that the exploration refund regime is unlawful state aid in breach of Article 61 of the EEA Agreement.

The claim was supported by the argument that the tax refund available to upstream companies engaged in exploration activities is discriminatory compared to the tax rules applicable to companies engaging in the production of renewable energy.

The Ministry responded to the appeal from Bellona in a letter to ESA on 22 September 2017. Not surprisingly, the Ministry stated that it was of the opinion that the refund regime for exploration costs does not constitute state aid and is in compliance with the EEA Agreement.

After receiving the response from the Ministry, ESA requested further clarifications from the Norwegian government. In a letter dated 7 December 2017 to the Ministry, ESA stated that two separate measures might entail unlawful state aid:

1. The loss carryforward system with the interest supplement; and
2. The introduction in 2005 of the tax rules allowing reimbursement for exploration costs.

The complaint from Bellona did not include the interest supplement regime, but it appears from ESA's letter that it also is looking at this regime.

ESA pointed out that the measures had not been notified and to the extent these measures were state aid, ESA would treat the measures as "unlawful aid." The letter from ESA is a formal request for information and not a final decision. In their response of 9 February 2018, the Ministry maintains that the exploration refund regime and the loss carried forward with interest do not constitute state aid.

It also should be noted that ESA in its letter requested more information but did not explicitly identify the cessation refund regime as a measure that might entail unlawful state aid. Whether this is because it is still early in the process remains to be seen.

Next steps

It is now up to ESA to decide the next steps and three options are available:

- Continue the correspondence with the Ministry and ask for further information and/or clarifications.
- Decide to take no further action and close the case.
- Issue a letter of formal notice because of the possible unlawful state aid.

Should ESA decide to issue a letter of formal notice, ESA's view on the matter will be presented with supporting arguments and the Ministry will have the opportunity to respond. If ESA maintains its position, it will deliver a reasoned opinion on the issue. The Ministry then will have to choose whether the reasoned opinion should be accepted.

Based on the present communication from the Ministry, it is not likely that it will accept that the petroleum tax regime includes any unlawful state aid. A decision from the EFTA court likely will be required to resolve this case. Upstream companies that have an interest in the case, because they have received exploration refunds, may participate in the hearings.

The EFTA court

The EFTA court has jurisdiction with regard to the EFTA states that are parties to the EEA Agreement (currently Iceland, Liechtenstein and Norway). The court is competent to deal with infringement actions brought by ESA against an EFTA state with regard to the implementation, application or interpretation of EEA law; providing advisory opinions to courts in the EFTA states on the interpretation of EEA rules and appeals to ESA decisions. Thus, the jurisdiction of the EFTA court largely corresponds to the jurisdiction of the Court of Justice of the European Union (CJEU) over EU member states.

Technical background

1. Summary of the legal framework concerning state aid

The European Commission must ensure that companies operating within the EU do not gain an unfair advantage over competitors as a result of government support.

Article 61 of the EEA Agreement corresponds to Article 107 of the Treaty on the Functioning of the European Union (TFEU). When applying the EEA Agreement, the EFTA court and ESA will follow the relevant decisions of the CJEU and decisions by the European Commission to maintain consistent application of the state aid rules throughout the EEA. Accordingly, decisions of the CJEU on TFEU Article 107 and decisions by the European Commission are relevant when assessing the scope of Article 61 of the EEA Agreement.

Article 61(1) of the EEA Agreement stipulates the criteria that must be met for a measure to be considered unlawful state aid. The regulation applies to “undertakings,” which the CJEU and the EFTA court have consistently defined as entities engaged in an economic activity, regardless of their legal status and the way in which they are financed.

To qualify as state aid, a measure typically must have four features:

1. Be an “intervention by the State or through State resources”;
2. Give the “recipient an advantage on a selective basis,”
3. Distort competition; and
4. Be capable of affecting trade between member states.

Even if the aid fulfills the four conditions, there are exemptions that may be invoked as long as they meet the policy objectives of the EU/EEA.

Whether a measure confers an advantage on the recipient is one of the most important conditions in determining whether state aid is present. Without the presence of a real advantage compared to other

taxpayers, the tax benefit (i.e. relief of tax burden) will not be considered substantial enough to affect intra-community trade and distort competition.

2. Selectivity test and reference system

To fall within the scope of Article 61(1) of the EEA Agreement, a state measure must favor, “certain undertakings or the production of certain goods.” Hence, not all measures that favor economic operators fall within the definition of aid, but only those that grant an advantage in a selective way to certain undertakings or categories of undertakings or to certain economic sectors.

Over the years, the CJEU and EFTA court have developed a special selectivity test for measures that mitigate the normal tax charges on undertakings, typically advantages granted within the scope of national tax provisions. One question arising in this case is whether this special selectivity test will be applied.

Subsidy or tax advantage

Bellona’s main argument is that the exploration refund regime is a subsidy and not a tax advantage to be evaluated under the special selectivity test developed for tax advantages.

If the exploration refund regime is a mere subsidy, this should be assessed according to the material selectivity test. According to that test, measures granted only to undertakings in a specific sector of the economy may be considered selective. The exploration refund regime is a measure available for the upstream sector only and may favor this sector of the economy. As the oil and gas sector competes with other energy sectors, Bellona’s view is that there is a material selective measure, in breach of Article 61 of the EEA agreement.

As to why the exploration refund regime is in its form and content a subsidy, Bellona’s main arguments are:

- The exploration refund regime is a part of the PTA, but the mere fact that the regulations are located in this Act does not imply that they should be assessed under the three-step analysis applied in cases related to tax

measures (see below). That test should be applied only to real tax advantages (i.e., provisions that regulate the tax burden of taxable persons).

- The system has the expressed objective of increasing a specific economic activity in Norway—namely, exploration for new oil and gas resources—in particular for small companies with limited capital. The refund regime partly relieves the undertakings of the normal inherent economic risk connected to exploration activities, namely, that the activity may not result in a commercial discovery of hydrocarbons. This is a known and familiar risk in a number of activities linked to the exploitation of natural resources.
- There is an inherent lack of symmetry or tax logic in the system with no correlation between the grants to the individual companies and their future taxable income.

The Ministry disagrees with Bellona and submits that the exploration refund regime should be assessed under the three-step analysis as a genuine element of the tax system and not a subsidy.

In the letter of 7 December 2017, ESA states with respect to identification of the reference system:

1. On the assumption that the PTA (i.e., the 54 percent tax rate) would be the correct reference system, as you argue in your comments, for the reimbursement rules for exploration costs: why do you consider the reimbursement rules non-selective, given that these rules also include the part that would arguably be subject to a separate CIT reference system (i.e., the 24 percent tax rate), which applies to companies in all economic sectors?
2. Following the above question, if the measure would be found to be prima facie selective, how do you justify the inclusion of the 24 percent tax rate in the reimbursement rules, by the nature and logic of the petroleum tax system?

There is no indication in the letter that ESA agrees with Bellona that the exploration refund regime should be considered a subsidy and not a tax advantage. Thus,

at this stage of the case it seems that ESA will consider these elements as tax advantages under the guidelines on state aid.

Applying the selectivity test and defining the reference system for tax advantages

In cases related to tax advantages, the selectivity of the measures normally should be assessed by means of a three-step analysis based on Article 128 in the guidelines on state aid:

- What is the commonly applicable tax reference system (i.e., the general tax rules against which the specific tax mechanism should be compared)?
- Does the measure constitute an exception to the reference system?
- Is this deviation justified by the nature/general scheme of the reference system?

The two measures that ESA is examining are not available for undertakings other than upstream companies with activities on the NCS. On the other hand, the upstream companies' marginal tax rate is 78 percent. Thus, the identification of the reference system is essential and may be decisive for the final outcome.

When designing the petroleum tax regime for upstream companies operating on the NCS, neutrality has been a main objective for the Norwegian government. It may be argued that upstream companies subject to a tax rate of 78 percent are not beneficiaries of state aid. Based on the correspondence in the case, it seems the essential question is whether the petroleum tax regime will be the relevant reference system or whether some of the features are selective because they are not available for companies subject only to CIT.

As described above, there are two separate taxes for upstream companies under the PTA: one for special tax at 54 percent and one for the ordinary CIT at 24 percent. The ordinary tax rate is equal to the income tax rates for most other industries. The two questions raised in the

letter of 7 December 2017 may indicate that ESA wants to separate the base for CIT from the base for special tax in their evaluation.

The Norwegian Ministry's view is that the reference system is the overall tax regime applicable for upstream companies. The Ministry states that since its introduction in 1975, the petroleum tax system has consisted of two interlinked elements (CIT and special tax), and these two elements in combination constitute the petroleum tax system. The overall tax system also is relevant when evaluating the petroleum tax regime's effect on investment decisions.

In the complaint, Bellona accepts that there is probably a basis for considering the petroleum tax regime in entirety as a separate reference system, rather than looking at CIT and special tax separately.

Three-step analysis: Bellona's view

From Bellona's perspective, the question is whether a derogation exists within the petroleum tax regime. Bellona's focus with respect to the three-step analysis is that the exploration refund regime means that many participants for years have benefitted from direct payments from the Norwegian state, without ever becoming taxable in Norway.

- Bellona refers to the fact that of the 74 companies listed as upstream companies with the Norwegian tax authorities in 2015, only 20 companies were in a tax-paying position. The remaining companies received payments of a total of NOK 13 billion (approximately USD 1.68 billion) from the Norwegian state for 2015 alone, and since the refund regime's introduction in 2005 up to 2015, the Norwegian state has paid a total of NOK 91.3 billion (approximately USD 11.78 billion) to upstream companies as exploration refunds.
- Bellona also states that the refund for companies that are not in a tax-paying position in Norway is limited to specific exploration activities, and other companies that perform different activities on the NCS (e.g., drilling) are not granted similar advantages. Therefore, the exploration refund regime also appears selective under the three-step analysis.

- Bellona states that the refund of the tax value of exploration costs, applicable to nontaxable persons is unusual in any tax system. This regime seeks to provide special incentives for specific economic activities consisting of exploration for oil and gas in Norway, and this cannot be justified by the nature or the general scheme of the reference system.
- In Bellona's view, the desire for such an increase in economic activity (and hopefully higher total tax revenues) should be considered as an external policy objective that may not be relied on to defend the measure. If such objectives could be relied on, any aid scheme to increase economic activities on national soil would be justifiable because the aid ultimately could lead to a total increase in the state's tax revenue.

Three-step analysis: Ministry's view

The Ministry holds that the correct reference system is the petroleum tax system, with a total tax rate of 78 percent, and not merely the special tax.

- The Ministry emphasizes that the petroleum resources are owned by the state and the petroleum tax regime was introduced to capture a large share of the extraordinary return from the extraction of these resources without distorting investment incentives. The fact that the petroleum tax system consists of two tax elements, rather than one, does not have any material effect on the substantive parts of the petroleum tax system.
- The two tax elements in combination have constituted the petroleum tax system since the petroleum tax system was introduced in 1975 (i.e., the special net income tax system designed to collect the resource rent deriving from the extraction of petroleum and pipeline transportation on the NCS).
 - In the general 1992 tax reform in Norway, the ordinary CIT base was broadened and the rate was reduced from 50.7 percent to 28 percent. At the same time, the special tax rate for petroleum activities was increased from 30 percent to 50 percent. The Norwegian government then stated that the general broadening of the tax base liable to CIT did not have material effect for petroleum companies

due to the special rules of the petroleum tax system. To maintain the total tax revenues from petroleum activity, the special tax rate was increased.

- Similarly, in the latest tax reform in Norway, the ordinary corporate tax rate was reduced from 28 percent in 2013 to 23 percent in 2018. During the same period, the special tax rate was increased from 50 percent to 55 percent. The marginal tax rate for petroleum activity has remained unchanged at 78 percent. The objective has been to maintain the total government take from the petroleum sector.
- This demonstrates that the PTA constitutes a distinctive and indivisible system in which the relevant point of reference is the total tax rate of 78 percent, regardless of the rates applicable at different times under the ordinary corporate tax system.
- There are several special rules that apply to all the income relevant for the 78 percent tax rate, which also underscores the fact that it is the total tax rate of 78 percent that is the relevant point of reference within the petroleum tax system.

The Ministry also has stated that a neutral resource rent tax requires that all relevant costs can be deducted at the same tax rate to which the income is subject (i.e., symmetrical treatment of costs and income). To achieve this objective, the Ministry argues that the exploration refund regime does not imply an advantage because:

- A neutral resource rent tax requires that all relevant costs can be deducted at the same tax rate as the income is subject to (i.e., symmetrical treatment of costs and income).
- The introduction of the exploration refund regime in 2005 should further equalize tax treatment in line with a neutral petroleum tax. For companies with taxable income, exploration costs are deducted immediately and reduce the taxable surplus in the income year.

- Carrying losses forward for years potentially could give companies a liquidity disadvantage. The exploration refund regime thus secures full tax benefit for exploration costs with the same value and at the same time for all upstream companies.
- Companies without taxable income can receive an annual tax refund of exploration costs, instead of carrying the exploration costs forward with interest. Consequently, the introduction of the exploration refund regime did not affect the value of the tax deduction or the state's risk in exploration activities.
- The present value of the tax revenues from the petroleum sector was not affected and the exploration refund regime does not imply any advantage.

With respect to the interest supplement regime, the Ministry states that this regime is not selective because the rules equalize the tax treatment for petroleum companies that were in a different factual and legal situation before the rules were introduced, consistent with the nature and logic of the petroleum tax system. Further, the Ministry states that applying CIT as the reference system would imply that one element of the petroleum tax regime (tax treatment of companies with tax losses) is compared to the corresponding tax treatment for companies' subject only to CIT, without taking into account the other elements of the petroleum tax regime.

3. Recovery of state aid

In cases where an EFTA state does not notify ESA of its plans to grant aid prior to implementation of a scheme, the aid is unlawful under EEA law from the time it was granted. If the state aid is unlawful, ESA can order the relevant state to request repayment of aid from the beneficiaries. This must be done within six months of the entry into force of ESA's decision.

4. What should be recovered?

Exploration refund regime

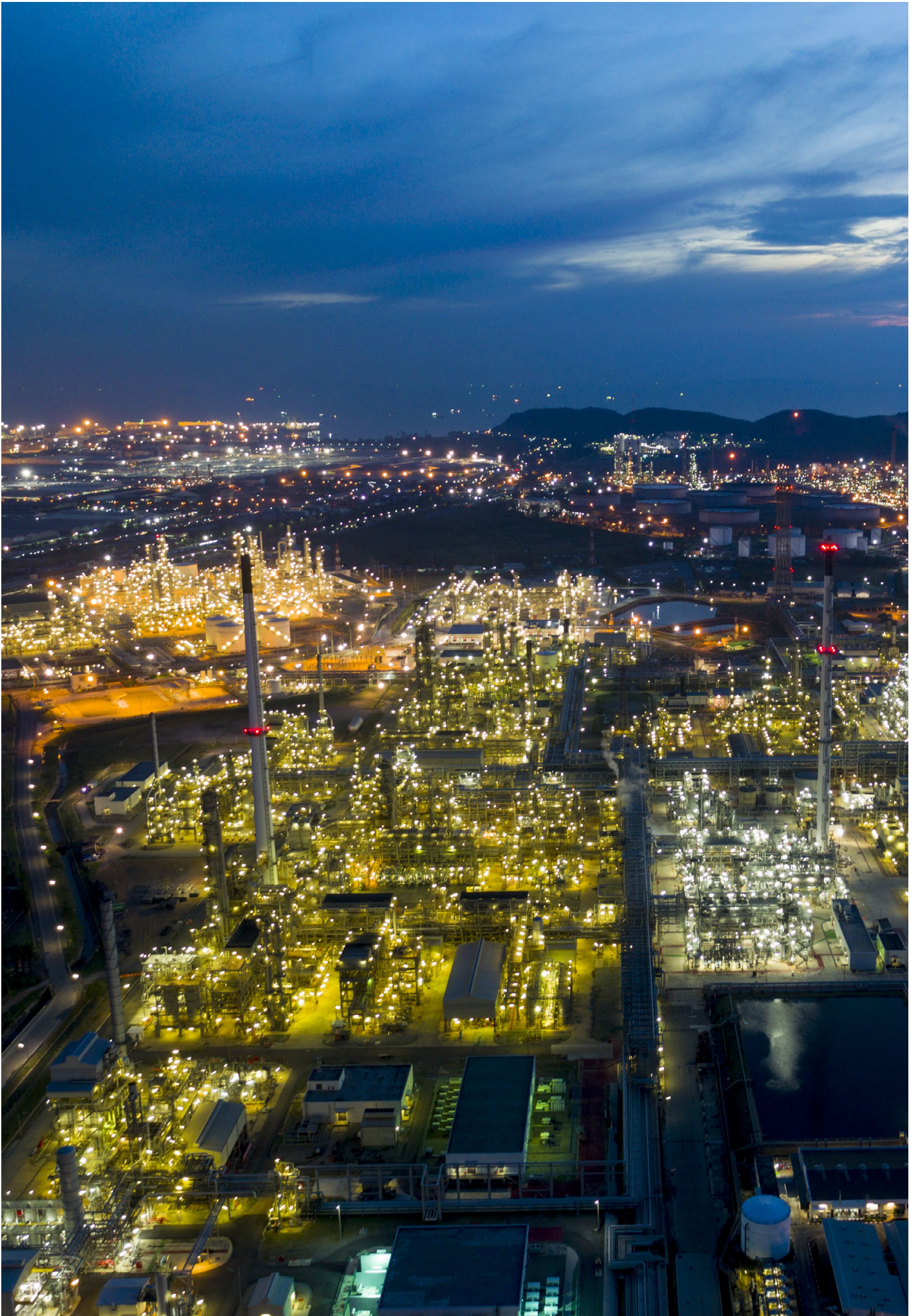
All exploration costs on the NCS are tax deductible. As there is no ring fencing between licenses, the exploration refund is an instrument to ensure the same value and timing of tax deductions for exploration costs for all upstream companies.

Consequently, for companies that have received an exploration refund, but later have more taxable net profits exceeding the previous exploration costs, the refund is a timing (and cash flow) issue only. It is unclear how the amount to be recovered should be decided in such a case.

The possible consequences are probably more important if the upstream company is still not in a tax-paying position or if the historical basis for an exploration refund is higher than the taxable profits in subsequent years. A possible consequence may be that the amount on which the exploration refund was based is converted to a tax loss to carry forward, and the exploration refund should be repaid to the state. In such a case, the deduction is a timing issue and the exploration costs would still be deductible against future taxable profits from production (if any).

Interest supplement regime

Losses may be carried forward indefinitely under Norway's general CIT regime. As stated above, the interest supplement on losses to carry forward for upstream companies is not available for other industries. Thus, in this respect, the difference between upstream and other sectors is the interest compensation. On this basis, the benefit is easy to identify and it seems likely that the interest supplement embedded in the loss carryforward is the amount that may be required to be recovered.



Article contributors

Deloitte has tax professionals who specialize in oil and gas-related matters across our global member network. For further information relating to any of the areas covered in this edition of the newsletter, please contact any of the practitioners listed below.

Chris Roberge

Global Oil & Gas Leader—Tax | Deloitte China

Tel: +852 2852 5627

Email: chrisroberge@deloitte.com

Bill Page (Editor)

Senior Advisor African Projects | Deloitte UK

Tel: +44 20 7007 6937

Email: bpage@deloitte.co.uk

Ailish McNamara

Director | Deloitte UK

Tel: +44 20 7007 5329

Email: amcnamara@deloitte.co.uk

Peter Westaway

Director | Deloitte UK

Tel: +44 20 7007 9024

Email: pwestaway@deloitte.co.uk

Simon Cooper

Director | Deloitte UK

Tel: +44 20 7007 0982

Email: sjcooper@deloitte.co.uk

Roman Webber

Partner | Deloitte UK

Tel: +44 20 7007 1806

Email: rwebber@deloitte.co.uk

Simon Lee

Associate Director | Deloitte UK

Tel: +44 20 7007 4904

Email: simolee@deloitte.co.uk

Dercio Da Barca

Associate Director | Deloitte Mozambique

Tel: +25 820 600 131

Email: dbarca@deloitte.co.mz

Eugenia Santos

Manager | Deloitte Mozambique

Tel: +25 820 600 132

Email: eusantos@deloitte.co.mz

Anthony Mahon

Partner | Deloitte Kazakhstan

Tel: +77 272 581 340

Email: anmahon@deloitte.kz

Maken Iskakova

Senior Manager | Deloitte Kazakhstan

Tel: +77 272 581 340

Email: miskakova@deloitte.kz

Per Christian Ask

Partner | Deloitte Norway

Tel: +47 51 815 748

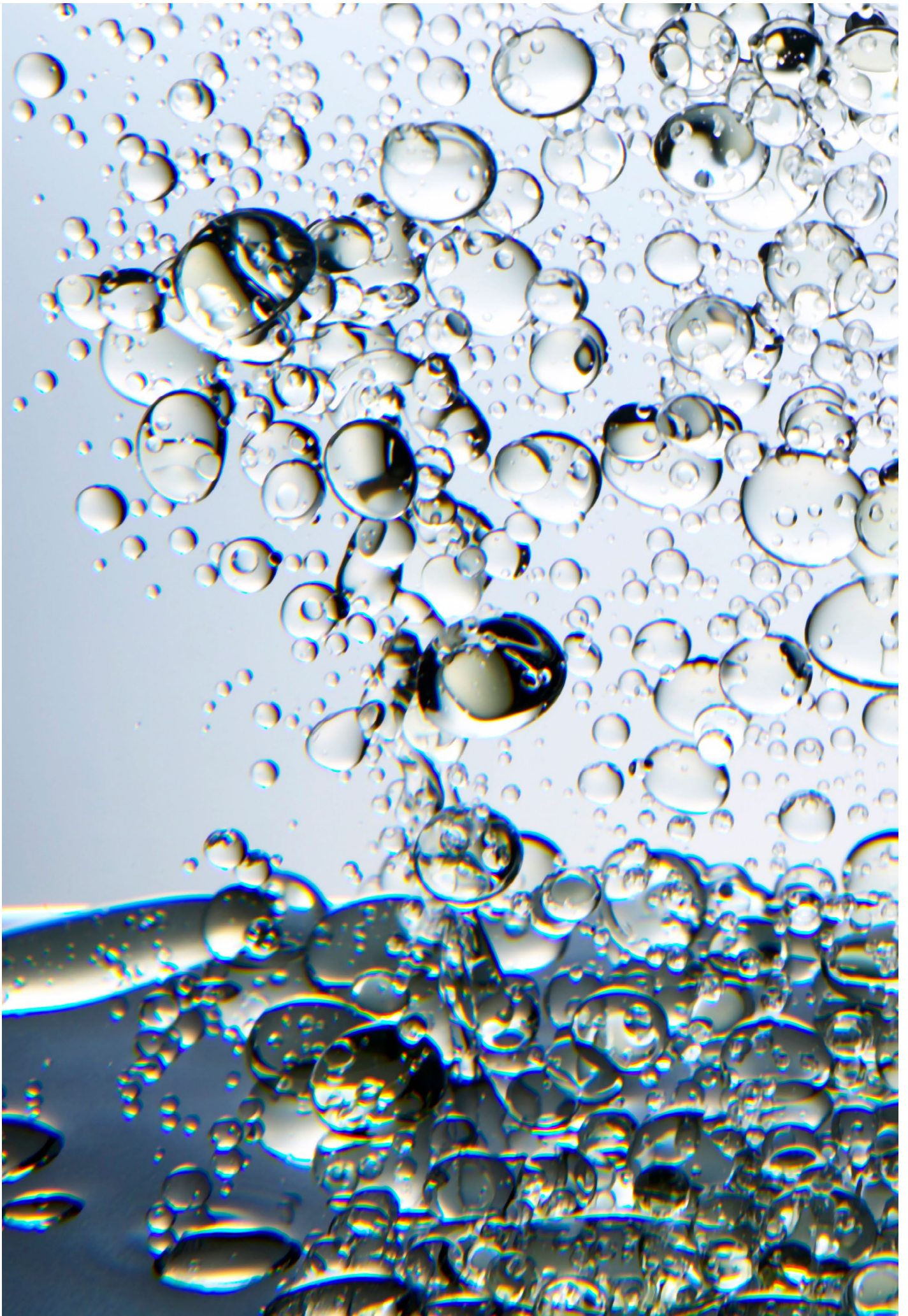
Email: pcask@deloitte.no

Jeffery Wright

Principal | Deloitte US

Tel: +1 713 982 4940

Email: jeffwright@deloitte.com





Deloitte refers to one or more of Deloitte Touche Tohmatsu Limited (“DTTL”), its global network of member firms, and their related entities. DTTL (also referred to as “Deloitte Global”) and each of its member firms are legally separate and independent entities. DTTL does not provide services to clients. Please see www.deloitte.com/about to learn more.

Deloitte is a leading global provider of audit and assurance, consulting, financial advisory, risk advisory, tax and related services. Our network of member firms in more than 150 countries and territories serves four out of five Fortune Global 500® companies. Learn how Deloitte’s approximately 264,000 people make an impact that matters at www.deloitte.com.

This communication contains general information only, and none of Deloitte Touche Tohmatsu Limited, its member firms or their related entities (collectively, the “Deloitte network”) is, by means of this communication, rendering professional advice or services. Before making any decision or taking any action that may affect your finances or your business, you should consult a qualified professional adviser. No entity in the Deloitte network shall be responsible for any loss whatsoever sustained by any person who relies on this communication.