Wood Mackenzie
A Verisk Business

Newfoundland & Labrador

Competitiveness in Oil & Gas Investment

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2. Definitions

1. **ATCF**: After-Tax Cash Flow – refers to the cash flow of a project available to the equity owners. This is the remaining cash flow after paying all forms of government sharing / take.
2. **bnboe**: Billion barrels of oil equivalent
3. **Capex**: Capital Expenditure
4. **COP21**: The 21st Conference of the Parties meeting that took place in Paris in 2015, also referred to as the '2015 Paris Climate Conference'
5. **Deepwater**: Projects in water depths greater than 400m
6. **EPIC**: Engineering, Procurement, Installation and Commissioning
7. **GORR**: Generic Oil Royalty Regime – Regime in NL, effective from November 1, 2017.
8. **Government Share**: The amount of cash that goes to the government from all forms, including royalties, production taxes, income taxes, leases, fees, profit splits, etc. Formula: PSCF minus ATCF.
9. **GS%**: Government Share % - refers to the proportional share of PSCF that Government Share consumes. Formula: Government Share / PSCF.
10. **ICSID**: International Centre for Settlement of Investment Disputes – ICSID, one of the five organisations of the World Bank group, is the world's leading institution devoted to international investment dispute settlement. ICSID provides for settlement of disputes by conciliation, arbitration or fact-finding1 .
11. **IOC**: International Oil Company
12. **MCFS**: Multi-Client Fiscal Study – Study of global fiscal regimes published by Wood Mackenzie in November of 2016.
13. **mmboe**: Million barrels of oil equivalent,
14. **NL**: Canada (Newfoundland & Labrador)
15. **NOC**: National Oil Company
16. **NS**: Canada (Nova Scotia)
17. **Opex**: Operating Expenditure
18. **Peer Group / Peers**: Australia, Brazil, Canada (Newfoundland & Labrador), Canada (Nova Scotia), Ireland, Mexico, Norway, United Kingdom, United States (Gulf of Mexico – Deepwater)
19. **PSCF**: Pre-Share Cash Flow – refers to the cash flow of a project that is available to all interest holders (governmental and private). Formula: Gross Revenues minus Gross Capex minus Gross Opex
20. **Shallow water**: projects in water depths between 0m and 400m
21. **SURF**: Subsea Umbilicals, Risers and Flowlines
22. **US GoM DW**: United States (Gulf of Mexico – Deepwater)
23. **UK**: United Kingdom
24. **YTF**: Yet-To-Find – refers to resources that are expected to be found given new exploration wells drilled in the future

[1] https://icsid.worldbank.org/en/Pages/about/default.aspx

3. Executive Summary

This report is a jurisdictional review by Wood Mackenzie, to assess the international competitiveness of the Newfoundland and Labrador (NL) offshore oil and gas sector against a selected number of competing jurisdictions in attracting investment in oil and gas exploration and development.

The primary objectives of the study are to provide:

- An overview of the key factors impacting offshore exploration and development decisions;
- Analysis of Newfoundland and Labrador's (NL) competitiveness on key factors relative to other jurisdictions;
- Expert opinion on Newfoundland and Labrador's competitive position;
- Identification of competitiveness issues facing other jurisdictions; and,
- Identification of potential areas for future consideration that may enhance the competitiveness of the Newfoundland and Labrador's offshore oil and gas sector.

The key factors are covered as follows:

- Geological prospectivity & data availability;
- Geopolitical and above ground risk considerations;
- Cost and operating environment;
- Fiscal regime;
- Regulatory structure; and
- Breakeven price.

A summary of the study findings for each of these factors is provided below.

Peer Group

To allow us to determine how NL compares, we developed a peer group of offshore and deepwater jurisdictions. This peer group is selected as being the most comparable jurisdictions with which to compare NL in terms of the type of development that is being targeted. Certain jurisdictions are geographically close, some are still in the early stages of development, whilst others, such as Norway and the UK are later in their life, but provide a view of the current position of these countries. In practice, oil and gas companies will look to invest in a range of different opportunities: offshore and onshore, oil and gas and conventional and unconventional and therefore NL competes for investment with this broad set of opportunities.

List of Peer Group Jurisdictions

- Australia,
- Brazil,
- Ireland,
- Mexico,
- Norway,
- Nova Scotia,
- United Kingdom, and
- US (Gulf of Mexico)

Geological Prospectivity & Data Availability

For many of the jurisdictions analysed, prospectivity remains one of the challenge areas. NL compares favourably in terms of Yet to Find (YTF) pool size distribution (the distribution of future discoveries into categories depending on expected size). The other assessment areas, including overall yet to find volumes and plays per basin scores mid to low marks. Much of the analysis is predicated on historical trends and may not reflect the recent commitments made by oil and gas companies, largely as a result of the investments made by the Province in new data.

When ranked by scale of pool sizes NL ranks in the top three due to two potential large pools within the Flemish Pass sub basin. Recent substantial discoveries in the Flemish Pass have de-risked the area and demonstrated the potential for sizeable discoveries. It should be noted that the Flemish Pass represents only 3% of Newfoundland and Labrador's offshore area.

NL's prospectivity index, a weighted view of various backward looking prospectivity indicators, is akin to that of Australia and the UK, placing the Province 6th out of the 10 in the Peer Group. One of the areas where NL performs low on the prospectivity index is the comparatively low discovered volumes in the past ten years. For example, NL's discovered 670 mmboe compares to the corresponding figure for the UK of 2.8 bnboe, albeit the average discovery size, over this time period, has been larger with 112 mmboe vs 24 mmboe, respectively.

The overall volume expectation of YTF and average number of plays per basin is low in NL. Other jurisdictions that rank poorly against YTF volumes are Australia, Ireland, the UK and Nova Scotia. On plays per basin, Brazil, Ireland, and Norway rank poorly, which shows the danger of using this factor in isolation given the industry leading YTF volumes in Brazil. Looking forward, NL has identified several new sedimentary basins and recent seismic acquisition and analysis has identified 650 leads and prospects which speaks to the potential for new discoveries.

With regard to data availability and confidentiality periods the majority of jurisdictions are aligned. The notable exceptions are Australia which comes out on top due to its slightly more favourable access to data, and the US GoM which is at the opposite end of the spectrum because there is no formal mechanism for the state to provide information and confidentiality periods are lengthy.

While NL offers geologically attractive acreage, as evidenced by recent discoveries in the Flemish Pass and significant potential identified in other basins, it needs to compete with other jurisdictions such as Brazil, Mexico, the US GoM, and Norway. In Brazil, investors can expect the world's largest and most productive deepwater reservoirs where the average discovery size is 1 billion barrels (Santos Basin). Large discovery sizes make the Gulf of Mexico similarly attractive, although a number of technical challenges including extreme depths, high pressures, and variable reservoir quality make exploring and developing costly. Of the top regions, Norway's Southeast Barents Sea is most comparable to NL. Its harsh Arctic environment would require high-specification facilities as well as ice management systems. Although, it should be noted that NL has had successful production since 1997 and the industry has successfully met obstacles that the operating environment has presented. The de-risked Flemish Pass might not be able to compete against Brazil's presalt but as seen, the other top regions have their own challenges.

The approach that NL has taken is to ensure that companies have as full an understanding of the subsurface potential of the region as possible, through sponsored geological studies released in conjunction with licence rounds, which has added to the understanding of the region. Continuing geological success will improve the perception of geological prospectivity. High work commitments of $2.6 billion in recent Calls for Bids in the Flemish Pass and West Orphan Basin will ensure continued exploration activity in the Province.

Geopolitical and Above Ground Risk Considerations

On geopolitical factors related to access (Ease of entry, Contract sanctity, State presence, Regulation, Corruption and Geopolitics) NL ranks favourably against the competing jurisdictions. The only area where it does not score a zero (the most attractive score) is state presence and this relates to the equity participation of Nalcor Energy (Nalcor) in certain projects. At the same time, the effect on overall returns of Nalcor's presence is much less than the effect of National Oil Company involvement in many other jurisdictions.

East Coast Canada also ranks well on above ground development risk although there are concerns around a number of factors that make up the overall score such as natural hazards (an assessment of where operations can be vulnerable to mudslides, heavy ocean currents, icebergs, freezing conditions and other natural phenomena). This has implications for:

- costs;
- the physical environment, although environmental considerations in other jurisdictions can be equally as challenging;
- supply chain, related to NL's geographic location;
- the relatively low level of oil and gas activity; and
- local content which is not mandatory, but highly encouraged and actively negotiated.

On this last point, NL needs to ensure that any local content provisions do not reduce the overall attractiveness and competitiveness of the jurisdiction vis-à-vis competing areas.

Out of the three geopolitical metrics, which are Access, Development and Commercialisation, NL struggles most on the commercialisation aspect compared to the peer jurisdictions. This is attributed to the lack of gas infrastructure and currency risk.

For gas resources, NL's current use of natural gas for enhanced oil recovery, distance to market and lack of pipeline infrastructure impedes its ability to commercialise its discovered gas resources. Future opportunities for development will be dependent on markets, resource availability and project costs.

There are no infrastructure difficulties related to oil reserves and resources in NL, as oil production is transported by shuttle tanker to market or to the Whiffen Head transshipment terminal.

Of the competing jurisdictions, Mexico and Brazil score poorly on infrastructure. In Mexico pipeline infrastructure exists but lacks in coverage, particularly with regards to gas, and the mechanism for access is not clear. Pipelines in Brazil are NOC owned and third-party access needs to be commercially negotiated which can be a problem due to lack of competition. Stringent environmental approval provisions can also delay project development. Norway is on the other side of the spectrum as it has an extensive and established infrastructure with sufficient capacity. Norway also has legislation in place which provides a framework for negotiating third party access. Given the emerging nature of oil and gas activities, Ireland scores the poorest on infrastructure and other commercialisation factors.

With respect to currency risk, the Canadian dollar remains exposed to fluctuations on account of the performance of the oil and gas sector. Canada's currency risk ranks alongside that of Mexico. The weakness of the Canadian dollar has, however, mitigated to some extent the fall of the oil price in Canadian dollar terms.

Cost and Operating Environment

Although it is challenging to assess the competitiveness of the cost environment in NL with other jurisdictions, based on expected costs for deepwater development using a standard modelling approach (see Exhibit C), NL ranks amongst the highest cost areas. The high costs in a challenging offshore environment are compounded by the long duration of EPIC activities.

Development capital and opex for deepwater projects are estimated to be almost US$14/boe higher than the average for deepwater projects in the peer jurisdictions. Drilling is the highest cost area followed by the cost of production facilities. The harsher environment of cold weather and ice complicates development. However, another factor is the "frontier" nature of activity in NL. There are projects in the area, but they are relatively few. The primary components of developments are similar to those in other regions. But the harsher environment increases the costs, pushing up total EPIC costs in NL.

One of the contributing factors to the costs in NL has been the rig intake process, which means only a small number of drill rigs meet the criteria for operating in its waters. This has meant that operators in NL have had a smaller pool of the global rig fleet to draw from, contributing to higher costs.

Fiscal Regime

While NL scores relatively highly for fiscal attractiveness, it ranks lower for fiscal stability and in a similar position to Australia, Brazil (PSC), Ireland, Norway, and Nova Scotia.

The relatively high ranking for NL for fiscal attractiveness is driven mainly by the Government Take %, which achieves a high ranking along with the UK, Ireland and NS. The Province is not the top ranked of the Peer Group for fiscal attractiveness mainly because it has an average score on the front-end loading measure. This measure gives higher scores to regimes that have a low level of upfront payments to the government.

The mid ranking for fiscal stability is mostly due to the changes in fiscal terms from project-to-project, hence the imperative to keep a stable and appropriate fiscal regime. The current terms compare favourably on their progressivity, at least in undiscounted terms, alongside other jurisdictions such as the UK, Ireland, Nova Scotia and Norway.

When combining the fiscal attractiveness and fiscal stability scores to give an overall fiscal ranking, the Province ranks fourth out of the nine jurisdictions, behind only the UK, Ireland and Nova Scotia.

Breakeven Price

Whilst NL has less onerous fiscal terms, the comparatively high capital and operating costs in the deepwater, using a standard modelling approach (see Exhibit C), mean that Mexico is the only country that shows breakeven prices higher than in NL.

Regulatory

For the upstream regulatory scoring, NL and Nova Scotia can be considered comparable, apart from the frequency of licensing rounds, which are more sporadic in Nova Scotia.

Overall, NL's regulatory metrics compare favourably with those of the Peer Group. Development permitting, R&D and local content are the areas where there could be improvement. NL's approach to exploration licensing and permitting is in contrast to a number of the other jurisdictions that have challenges in this area, although in recent years the role of the Canadian Environmental Assessment Agency in exploration drilling permitting has raised concerns about unnecessary delays in the system.

Development permitting in NL scores less attractively than it could, due to the number of potential steps and consultations required in order to have a development plan approved. This includes the benefit plan which typically has to provide secondary benefits to the jurisdiction's economy. This is by no means unique and similar challenges present themselves in numerous jurisdictions. In some areas such as Brazil this has been detrimental to industry's development as regulatory agencies have slowed the pace of activities which has been exacerbated by onerous local content stipulations.

Local content requirements vary within the Peer Group and can be divided into three tiers. The most development inhibiting requirements can be found in Brazil. This was recognised as an issue and recently addressed with, for example, new rules that cut local content for offshore exploration by half to 18%. Ranking highest in this category are the US GoM, the UK, Australia, Ireland and Mexico. In particular, Mexico has learned from Brazil by not setting high requirements and staying as flexible as possible. NL sits in the middle tier alongside Nova Scotia and Norway. Norway has no local content requirements but ensures that local content is considered via state-owned Petoro's involvement in opportunities.

Brazil also ranks poorly for requiring research and development (R&D) investment, where an additional royalty payment, albeit tax deductible, of between 0.5% and 1% is required. In NL, benefits plans often provide details of expenditures for research and development to be carried out in the Province and for education and training to be provided in the Province. The same situation exists in Nova Scotia although research & development and education & training within Period 1 of the Exploration licence are biddable items. In NL, the provisions are governed by the Canada-Newfoundland and Labrador Atlantic Accord Implementation Act, section 45(3)(c) stating "expenditures shall be made for research and development to be carried out in the Province and for education and training to be provided in the Province".

Comparison of Key Factors

The matrix below shows where NL and peer jurisdictions have challenges against key factors analysed

Figure 1 – Challenges against key factors analysed

		Australia	Brazil	Ireland	Mexico	Norway	UK	US GoM	Nova Scotia	Newfoundland & Labrador
Geological Prospectivity	Prospectivity index	●		●			●		●	●
	YTF volumes	●		●	●	●	●	●	●	●
	YTF pool size distribution	●		●		●	●	●	●	
	Plays per basin	●	●	●	●	●	●		●	●
	Data availability		●	●	●	●	●	●	●	●
	Confidentiality period for data		●		●	●	●	●	●	●
Geopolitical	Access	●	●	●	●					
	Development	●	●	●	●	●				
	Commercialisation		●	●	●					●
Cost and operating environment			●	N/A	●		●	●	N/A	●
Fiscal regime	Fiscal stability	●	●	●		●	●	●	●	●
	Fiscal attractiveness		●		●	●		●		
Regulatory	Licensing Frequency		●	●	●				●	
	Licensing Transparency		●		●			●		
	Exploration Permitting	●	●		●					
	Development Permitting	●		●	●		●		●	●
	R&D		●	●					●	●
	Local content		●			●			●	●

The main purpose of this report is to identify where NL and other jurisdictions have challenges against the key factors analysed. But it is worthwhile to provide some balance and recognise the multiple areas where NL is attractive. These attractive areas include:

- The indicative YTF pool sizes that are expected are skewed to the larger end of the field sizes considered which will enhance the potential for future commercial developments;
- The view of the industry as indicated by the recent Cdn $2.6 billion of exploration work commitments, despite low oil price environment;
- The process to access acreage is clear and understood by the industry;
- There is minimal labour activism in the Province and a willing and available workforce;
- A track record of bringing on major oil projects;
- An attractive fiscal system which achieves the highest ranking for attractive Government Take % for contractors; and
- The frequency and transparency with which acreage is offered to the industry.

4. Geological Prospectivity & Data Availability

The East Coast of Canada ranks amongst the most important frontier exploration basins globally. Since the development of Newfoundland and Labrador's ("NL") Hibernia field, which commenced production in 1997 and Nova Scotia's ("NS") Cohasset/Panuke field, which commenced production in 1993, operators have successfully commercialised the region's resources. Offshore drilling began in NL waters in the 1960s. The first commercial discovery, the Hibernia field, was made in 1979.

The main basins offshore NL are the Flemish Pass, Jeanne d'Arc Basin and Orphan Basin, which are all part of the wider Grand Banks basin. The Jeanne d'Arc Basin is home to all of NL's large oil fields discovered to date, including Hibernia, Hibernia South, Terra Nova, Hebron/Ben Nevis, White Rose, and the White Rose Satellite fields. To date, no discoveries made in the Flemish Pass or Orphan Basin have been developed. The nature of the basins' evolution is similar to that of the Jeanne d'Arc Basin, indicating future exploration discovery potential. By itself, offshore NL is an attractive area in which to invest in terms of geology: firstly, there are undrilled structures in proven areas which are proximal to major markets; the crude is sweet and of high quality with good production rates and recovery factors. A drawback of the region is the harsh environment, making development a challenge.

In order to compare and rank the geological prospectivity of NL with its Peers, we use four categories: (1) prospectivity index, (2) Yet-To-Find ("YTF") volumes, (3) YTF pool size distribution, and (4) average number of plays per basin per jurisdiction. These four factors are then collated into an overall relative ranking.

Brazil outperforms in all four categories and hence tops the Peer Group with respect to "Geological Prospectivity". The middle tier includes Norway, Mexico, and the US GoM DW. The lowest tier includes Australia, NL, the UK, NS and Ireland.

4.1 Prospectivity Index

The prospectivity index has been created as part of Wood Mackenzie's Fiscal Multi Client Study and is made up of six historical metrics:

- total volumes discovered (a discovery refers to a discrete accumulation of hydrocarbons found as a result of exploration drilling. All volumes referred to are expected 2P resources that could ultimately be recovered);
- percentage that oil makes up of discovered volumes;
- the average discovery size;
- percentage of reserves discovered in the last 10 years; and
- exploration well success rate.

The rating is from 1 (lowest prospectivity) to 5 (highest prospectivity). The table below lists how each metrics is calculated. For example a jurisdiction with total volumes discovered of more than 20 bnboe will get a five in this category. Each metric is then weighted to arrive at the overall prospectivity index.

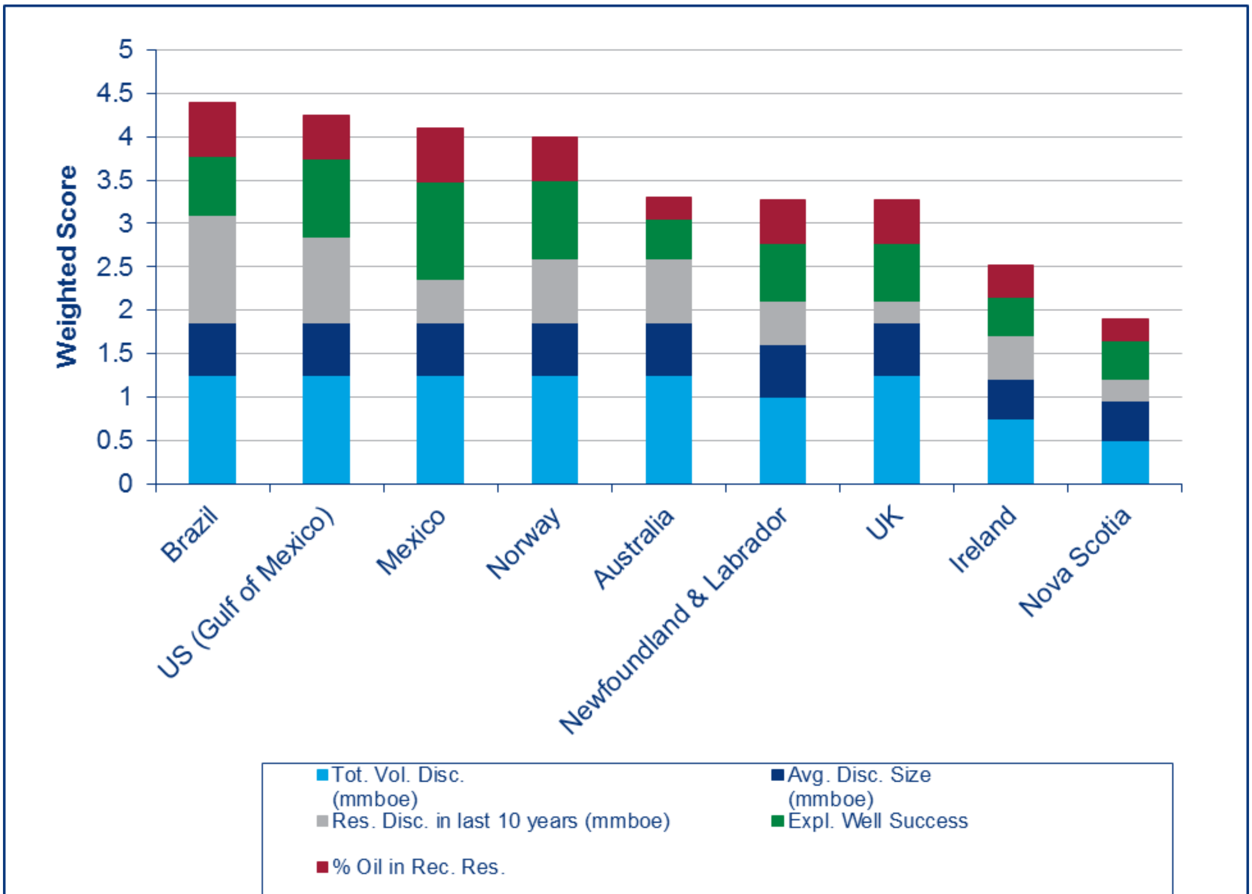
Table 1 – Prospectivity index metric calculation

Rating	Total Volumes Discovered (mmboe)	% Discovered Volumes = Oil	Average Discovery Size (mmboe)	% Reserves Discovered in last 10 years	Exploration Well Success Rate
5	>20,000	>75%	>200	>50%	>50%
4	5,000-20,000	50-75%	50-200	25-50%	30-50%
3	1,000-5,000	25-50%	20-50	10-25%	20-30%
2	100-1,000	5-25%	5-20	5-10%	10-20%
1	<100	<5%	<5	<5%	<10%
Weighting	**25%**	**12.5%**	**15%**	**25%**	**22.5%**

It is recognised that this approach does not take into account information around the number and size of prospects in upcoming areas as mapped from subsurface data, petroleum system evidence, etc. As a result, new areas that have large prospects which could have significant potential but have not yet been drilled will tend to score poorly.

NL scores 3.3 on the prospectivity index. Only NS and Ireland have lower rankings, while the UK reaches the same score. Brazil's top spot isn't surprising. In terms of oil, the world's largest and most productive deepwater reservoirs are in the carbonate pre-salt plays of Brazil. Discovery sizes here are also large. In the Santos Basin, they have typically ranged from a couple of hundred million bbls of oil to over 8 billion barrels, and the average size is more than 1 billion barrels. Even compared to the US GoM and Mexico, the Santos basin looks impressive. The large Perdido Foldbelt discoveries, in the GoM, are less than 300 mmbbls each. Yet the most sought-after blocks in Mexico's Round Two deepwater licence round are those in the Salinas Sureste and Sabinas Rio Grande basins, both in the Perdido area. This highlights the fact that prospective blocks are able to attract significant interest from investors.

Figure 2 – Prospectivity Index (5=most attractive)



Source: Wood Mackenzie

With the exception of Ireland (37 mmboe) and NS (61 mmboe), NL trails the rest of the group in volumes discovered last ten years with only 670 mmboe. All other peers boast additions of between 2.8 bnboe (UK) and 36.2 bnboe (Brazil) over the last 10 years. However as the resources discovered in the last ten years in the Prospectivity Index is as a proportion of overall volumes discovered NL is not unduly penalised on this metric. NL's reserves largely consist of volumes related to three fields: Bay du Nord, Harpoon, and Mizzen North (Wood Mackenzie estimates 300mmboe at Bay du Nord, 130mmboe at Mizzen North, 100mmboe at Harpoon and the remainder of the 670mmboe discovered in the last ten years in Baccalieu, Bay de Verde and Ballicatters). The largest field, Bay du Nord, was discovered by Statoil and Husky Energy in 2013.

Discovering and adding resources requires drilling activity. In this measure, NL only recorded 55 spudded E&A wells in the last 10 years, compared to the top six peers (Australia, Brazil, US GoM, the UK, Norway and Mexico) who drilled between 123 and 976 offshore E&A wells over the same time period.

Figure 3 – Exploration investment and expected YTF to 2035

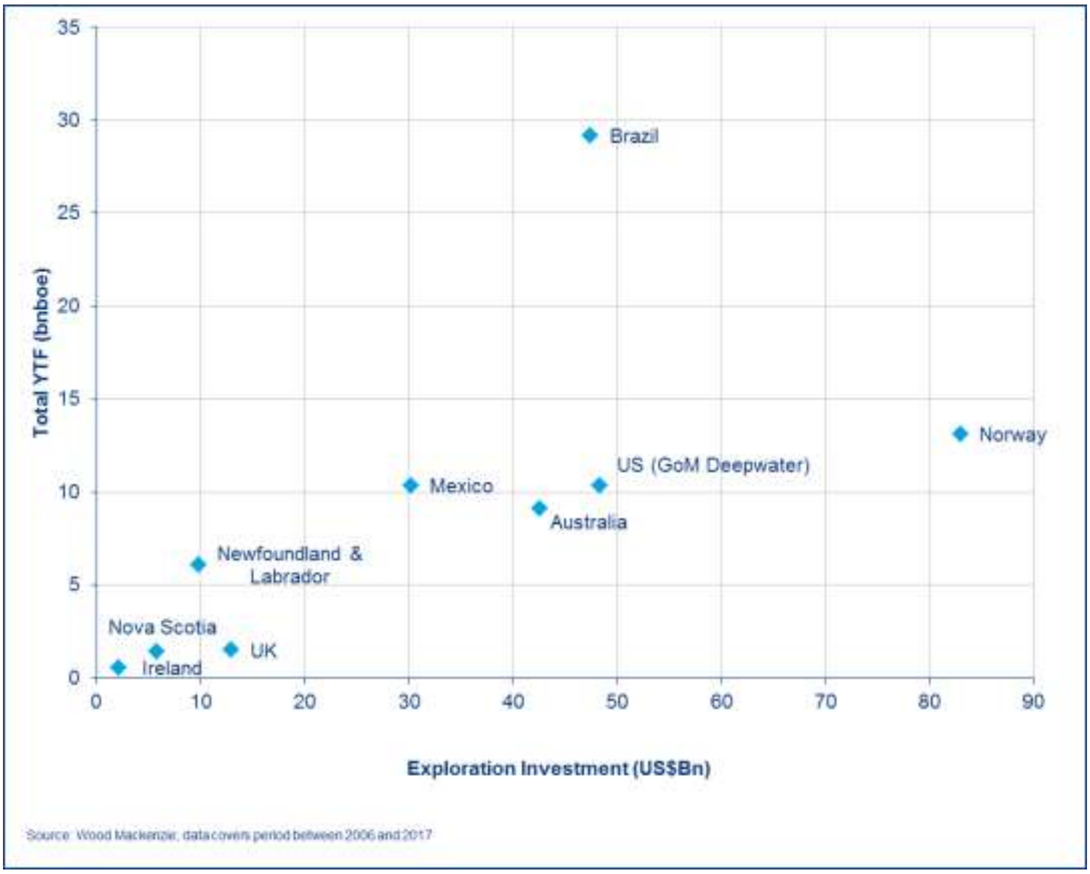
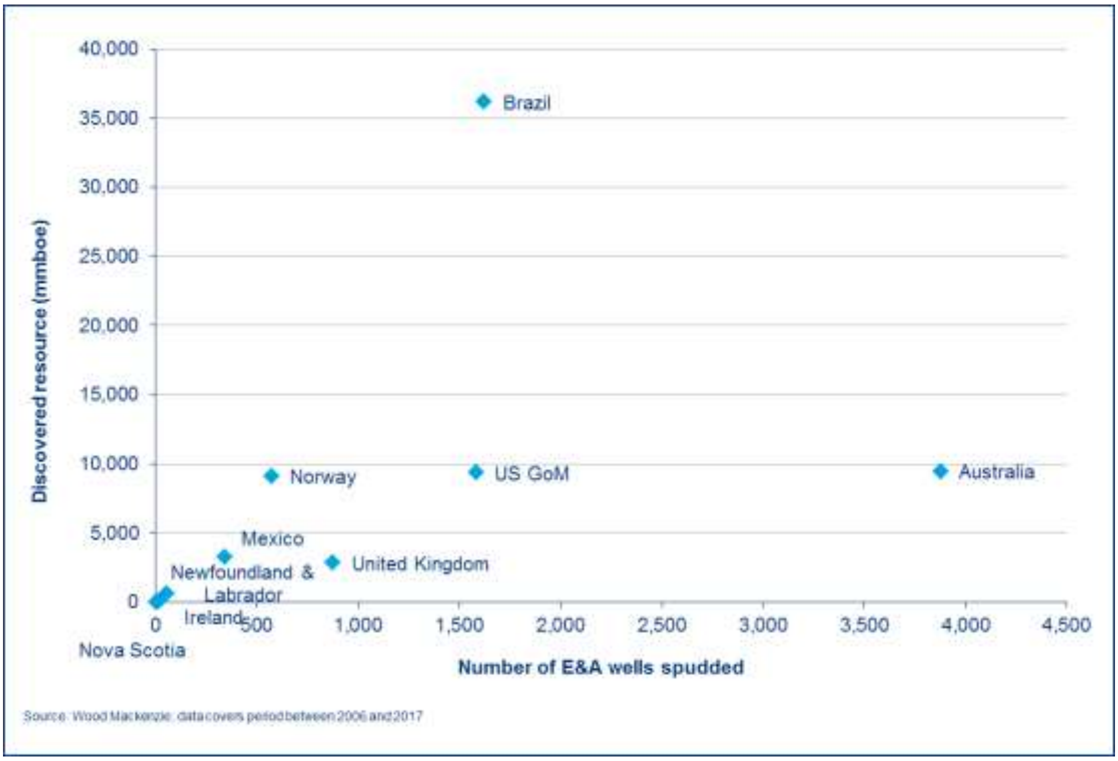


Figure 4 – E&A wells drilled vs discovered resource to date



4.2 YTF Volumes

YTF volumes are calculated using Wood Mackenzie's standard methodology. This methodology uses a projected creaming curve to derive our assumption of yet-to-find potential in each play. The curve is generated using best fit of a hyperbolic trend to historical data on cumulative reserves by cumulative exploration wells. The curve's trajectory is also an assumption of reserves that will be discovered per exploration well. The overall play yet-to-find assumption is constrained by our forecast of exploration well numbers to 2035. In NL the basins that have been included in our assessment are Jeanne d Arc, Flemish Pass and Orphan.

It is recognised that this methodology assumes the past is a good indicator of the future. This creates a challenge in NL where different play trends and areas are expected to be explored in the future. The methodology is not a substitute for a geologically constrained resource assessment.

In terms of YTF, the picture looks slightly more positive for NL. With about 6 bnboe of YTF, NL is ahead of the UK, NS, and Ireland. The top peers in this category again are Brazil, Norway, Mexico, US GoM and Australia. There are roughly two groups within the distribution. In Australia, Norway, and the UK, the YTF sizes are relatively evenly split across its basins. Within the remaining jurisdictions, the expected discoveries fall within just one or two basins: For example, 75% of Brazil's YTF is in the Santos pre-salt, similarly 75% of NS's YTF is in the Scotian Shelf DW. In the basins assessed by Wood Mackenzie in NL, the YTF is mostly concentrated (90%) in the Flemish Pass and Orphan sub basin, with the remaining located in the Jeanne d'Arc basin.

Figure 5 – YTF to 2035 split by expected hydrocarbon phase of discoveries

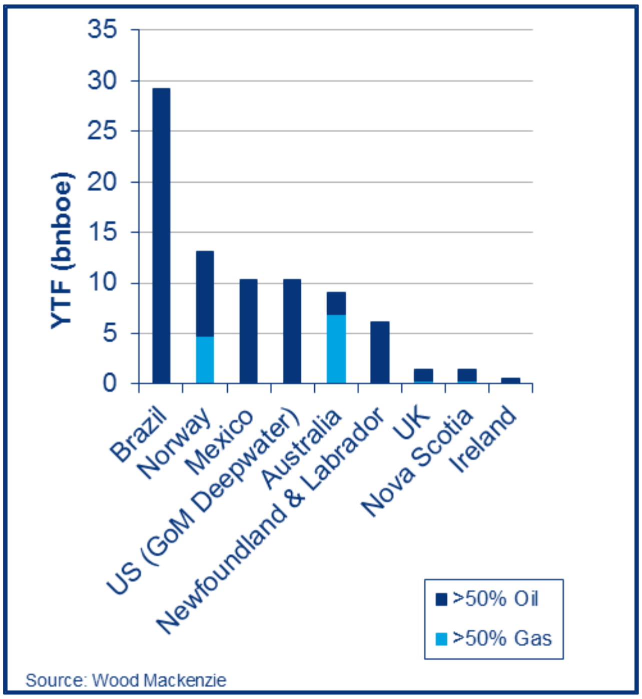
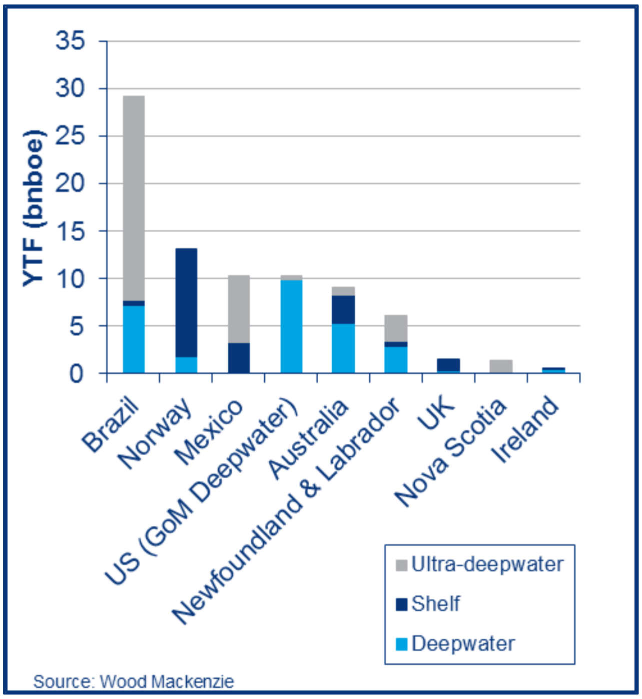


Figure 6 – YTF to 2035 split by water depth



4.3 YTF Pool Size Distribution

We look at the expected pool size distribution in each jurisdiction's key play to determine what operators might expect. A key play is defined by having the largest YTF volume in each region. A pool is classified as a potential discovery ranging from very small (up to 50 mmboe), to very large (greater than 800 mmboe) and expected to be found by activity prior to 2035.

Expected pool sizes

Pool size	Volume (mmbbl)
Very small	50
Small	100
Medium	200
Large	400
Very Large	800

Brazil

Brazil's Early Cretaceous pre-salt play in the Santos Basin is the only play that potentially contains very large pools. It has several giants that have confirmed this play to be the world's largest new oil play of recent years. Once the magnitude of the volumes in the pre-salt play became apparent, those areas were classified of strategic importance to the country, and acreage was withdrawn from licensing to IOCs. Since then, almost the entire basin has been deemed to be of strategic importance, and the government has introduced a new contracting system for the pre-salt area. New awards are made under a Production Sharing Contract (PSC) regime.

Newfoundland and Labrador

When ranked by scale of pool sizes NL finds itself in the top three due to two potential large pools within the Flemish Pass sub basin. This is based on a statistical estimate and should not be confused with a more rigorous approach that could be applied using subsurface data. Recent substantial discoveries in the Flemish Pass have de-risked the area and demonstrated the potential for sizeable discoveries. Our estimate of yet-to-find reserves is substantial at 1.8 bnboe, despite the relatively small aerial extent of the sub-basin. Note that while it looks like Brazil and NL have the same number of large pools, the chart depicts pools in relative terms. Brazil's key play in the Santos basin contains potentially eight large pools.

Norway

The majority of the yet-to-find potential in Norway is in the Paleozoic-Mesozoic Shelf Oil play (West Barents sea) where several large oil discoveries have been made in recent years. The West Barents Sea environment remains however relatively under-explored with complex geology. It requires that most discoveries be developed via subsea installations or in some cases with FPSOs. The regional market for subsea equipment and services remains extremely tight, making subsea developments a costly and lengthy proposition.

Mexico

In Mexico the Paleogene DW play is located in the Sabinas – Rio Grande basin which encompasses the Perdido Foldbelt discoveries. The potential for giant DW prospects exists not only in the immediate vicinity of these discoveries, but also in the subsalt belt and further afield. However the lack of infrastructure will be a challenge. The Shell-operated Perdido Hub lies close by over the US maritime border.

US Deepwater GoM

The Paleogene DW play also extends into the US GoM side. The play offers the potential for giant oil discoveries but carries huge technical risks. The technical challenges include extreme burial depths, high pressures, high temperatures and variable reservoir quality, which make it expensive to both explore and develop. Widespread salt makes imaging of prospects very difficult, although increasing wide-azimuth seismic coverage and advances in seismic processing are aiding explorers.

Australia

In Australia the vast majority of exploration drilling has been in the Mesozoic Northwest Shelf play, and this is where most discoveries have been made. However, over the last 10 years explorers have moved into the deepwater sector of the basin, resulting in large gas/condensate discoveries. The basin already supplies two LNG facilities, with a further two under construction.

Nova Scotia

While the Scotian Shelf in NS offers potentially large volumes, value creation will be challenging due to high costs. The existing gas pipeline system that serves Shelf gas fields does not currently extend into the deepwater, and there are no oil export lines. Small amounts of Nova Scotia offshore oil production have previously been exported via shuttle tanker, and this is the export solution used for oil fields further north off NL.

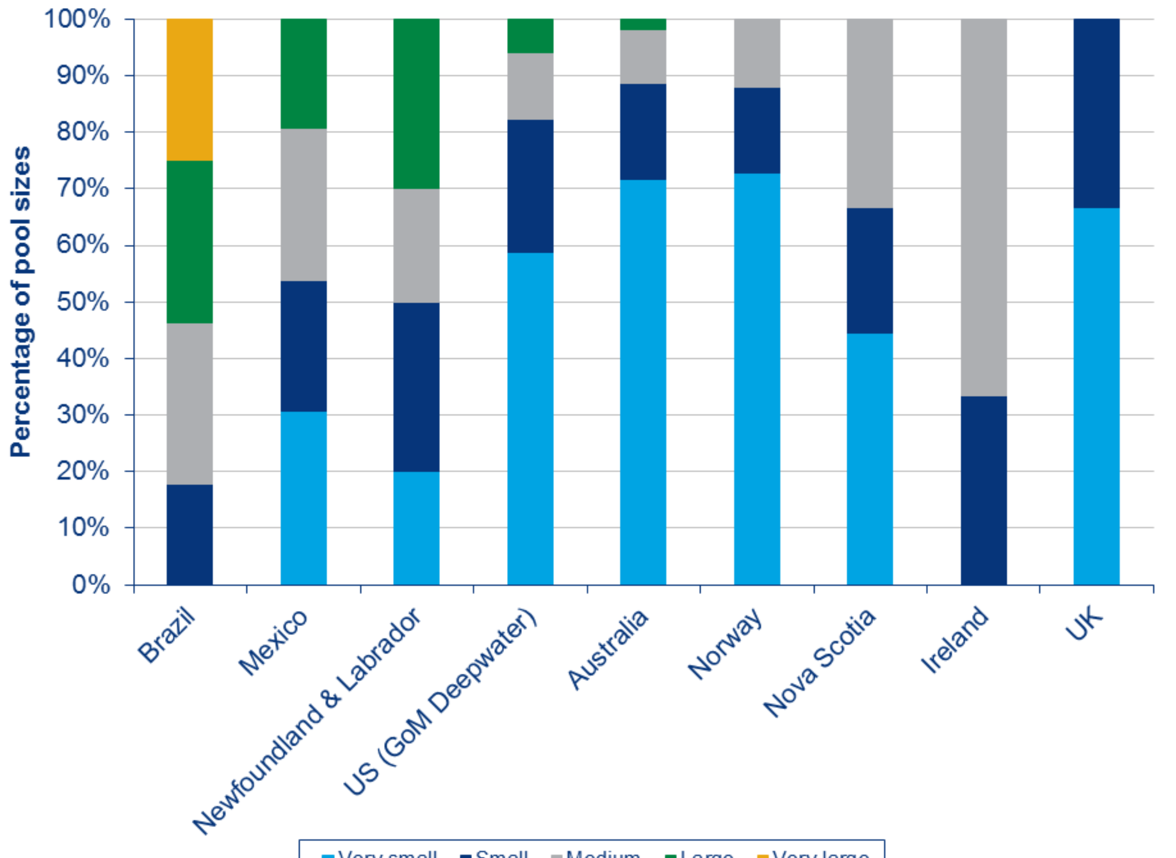
Ireland

In Ireland the key play is the Cretaceous – Tertiary DW extending underneath the Porcupine basin. While significant resource potential is thought to exist in the deeper waters to the south of the basin, the play needs to be de-risked through successful exploration. No commercial discoveries have yet been made in the basin and there is currently no infrastructure. It is anticipated large discoveries will need to be developed first via FPSO solutions in order to establish an export route to market. Future, smaller, discoveries could be developed as subsea tiebacks.

United Kingdom

The key play identified in the UK is the Mesozoic HP/HT extending underneath the Central Graben basin. It remains of interest to explorers following two large discoveries (Jasmine and Culzean) over the last decade. Our outlook assumes companies will continue to target HP/HT prospects in this emerging play as this is where the material volumes exist. Higher costs, technical challenges and marginal development value have delayed the development of a number of legacy discoveries, but future discoveries will benefit from fiscal incentives targeting HP/HT fields. The basin is well served by existing infrastructure. The main infrastructure in the Central Graben, CATS, has spare capacity available for new discoveries.

Figure 7 – Distribution of expected pool sizes for the key exploration play in each jurisdiction



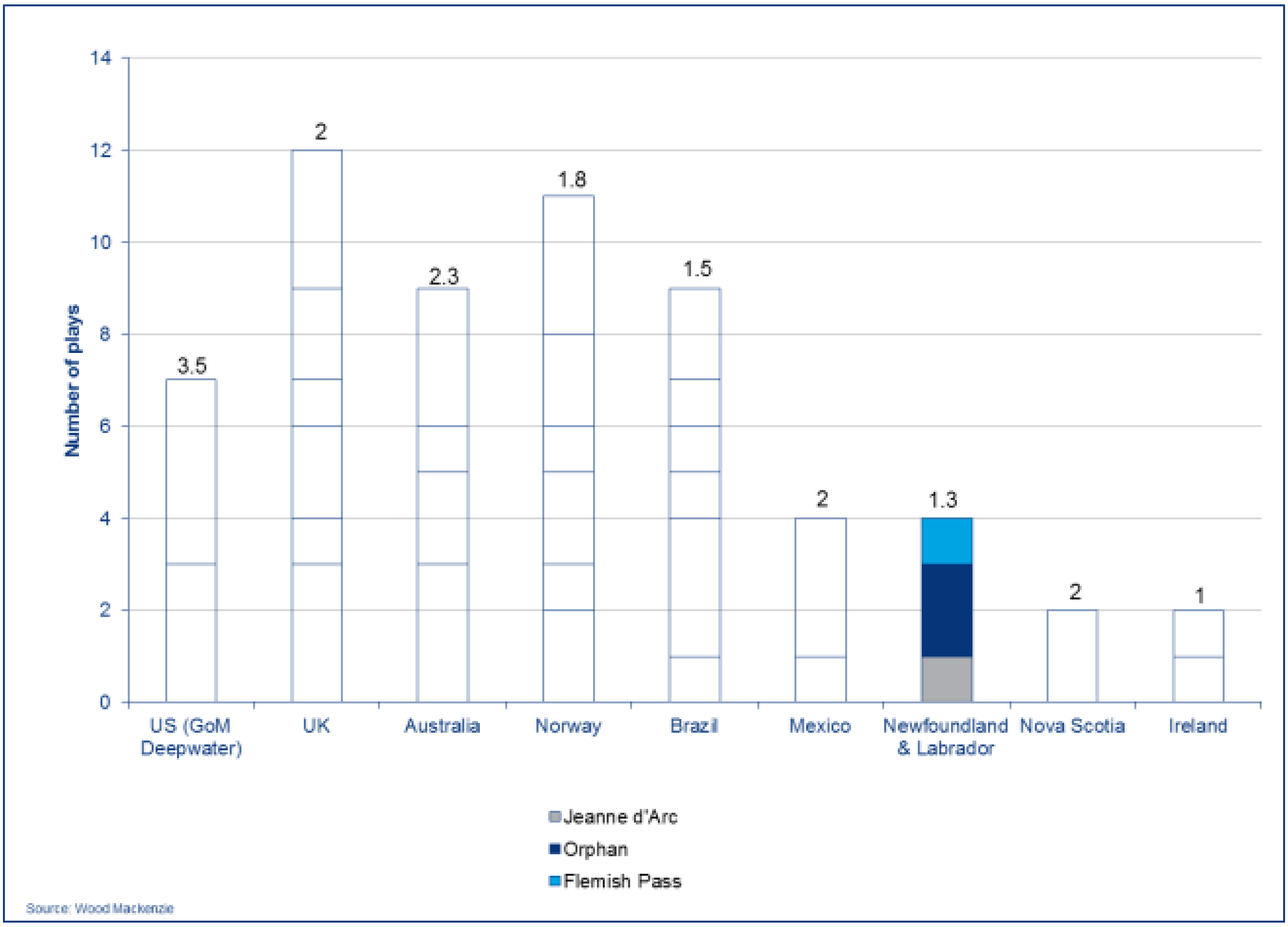
Source: Wood Mackenzie

4.4 Plays Per Basin

Companies prefer basins with multiple plays to increase the probability of making a discovery. For the analysis we break down each peer country by basin and show the number of key plays per basin. The US GoM for example is split into two basins: East Gulf Coast and West Gulf Coast, which is shown as two stacked bars in the below chart. Within the East Gulf Coast there are three plays Mid-late Miocene, Subsalt Miocene and Jurassic, while the West Gulf Coast has four plays Paleogene, Subsalt Miocene, Ultradeep Subsalt Mio-Pliocene, and Plio-Pleistocene. Since it is the only region in our Peer Group with a four play basin, it is ranked first. The number on the chart refers to the average number of key plays per basin.

The UK has the highest number of plays, 12 spread across six basins, while Nova Scotia and Ireland are at the bottom, with two plays each. NL has four plays, which are distributed across three basins. On an average basis, the US GoM region leads the group with 3.5 plays per basin. NL with an average 1.3 plays per basin is at the lower end of the ranking with only Ireland having a lower average of 1. The situation in NL is expected to change over the coming years as new plays and basins are explored on the back of recent licensing successes.

Figure 8 – Number of plays in the key exploration basins in each jurisdiction with average number of plays highlighted



Note – The number above each column refers to the average number of key plays per basin in each jurisdiction

4.5 Data Availability

To support exploration activity governments provide geological as well as drilling data to operators. All peers except the US GoM, in our group do this via a dedicated authority. In the US, the government purchases seismic or other geoscience data just like any other operator and release information according to data confidentiality provisions.

The dedicated bodies provide data in two ways:

1) via government funded studies (e.g. the UK's Oil and Gas Authority); and
2) release of data provided by operators once confidentially periods have expired.

Most jurisdictions offer transparent online platforms providing details of high level exploration activities, including wells drilled, seismic studies undertaken etc. Accessing seismic and well data is provided either via outright purchase or membership which is usually fee based. For bidders data is often made available during licensing rounds in exchange for application fees.

The majority of jurisdictions have similar data availability in terms of confidentiality. The notable exception is the US GoM where the government purchases data just like any other operator. The objectives of the various agencies whether they are national, regulatory or even for profit, are similar, namely:

- to increase knowledge of the sedimentary basins to encourage exploration; and
- to provide central online databases.

Geoscience Australia offers the National Offshore Petroleum Information Management System (NOPIMS), an online system for offshore data. Brazil's Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (ANP) created the Exploration and Production Database. Norway's NPD has Diskos, a national data repository and the OGA in the UK initiated Open Data, an online platform available to anyone.

In NL, there are various ways in which information can be accessed by the industry. These include Canada-Newfoundland & Labrador Offshore Petroleum Board (C-NLOPB) Information Resource Centre that contains technical information dating back to 1964 and NESS (Nalcor Exploration Strategy System) that provides key information about the Province's basins including weather patterns, historical well data and discoveries and well and rock evaluations. The resources mentioned here can be accessed by anyone for a small fee, to cover labour and reproduction charges, as is the case with the Information Resource Centre or for free in the case of NESS.

In NL, surveys and studies to provide new geoscience data are carried out by Nalcor. Nalcor's current studies are:

- A satellite seep survey in partnership with Airbus Defence and Space;
- 2D and 3D studies with partner TGS and Petroleum Geo-Services (PGS); and
- A surficial geochemistry project with partners MG3 and AGI.

Details of all surveys and how to access them are provided on NESS.

Ireland

Similar to the situation in NL, the Irish government undertook a 2D seismic survey in conjunction with Eni in 2014/2015 prior to its most recent licence round. The shoot covered 16,000 km^2 of the Atlantic margin and was offered as part of the 2015 licensing round in exchange for a small fee. The offer went down well with interested operators and was highlighted as one of the reasons the round was such a success.

United Kingdom

The UK government funded seismic programme during the 29th round in 2015/2016 was seen positively with the data downloaded more than 3,000 times. A combined 40,000 km^2 data package was made available to download for free to all bidders. However, appetite was low in the 29th round compared to previous rounds which is not surprising given the volatile oil price in 2016 and the frontier nature of the round.

Australia

In Australia Geoscience Australia, the government agency responsible for its natural resources has responded to feedback from operators. While most offshore data is managed by the NOPIMS, exploration data is also spread across the many federal states. The Resource Data Initiative attempts to reconcile this issue by creating a one stop shop, similar to Norway's Diskos or the UK OGA's Open Data repositories.

Table 2 – Comparison of Data Sources and Availability

Country	Provider	Product coverage / access	Confidentiality period for data
Australia	Geoscience Australia (public sector organisation)	National Offshore Petroleum Information Management System (NOPIMS) as an online data discovery and delivery system for all Australian offshore petroleum wells and seismic surveys acquired in Commonwealth waters	2-3 years for seismic, 1-2 for well data
Brazil	National Agency of Petroleum, Natural Gas and Biofuels (ANP) – regulatory agency	ANP´s Exploration and Production Database (BDEP). Membership as well as one-off purchase.	5-10 years for seismic data and 2 years for well data
Ireland	IHS	Exploration Database (IPAS) provides information on petroleum E&P activity in Ireland and available technical (wells, seismic, gravity & magnetic) data. Released data can be purchased via IHS.	<=5 years
Mexico	The National Hydrocarbons Information Center (CNIH) – government agency	In each bidding process, a package of information related to the bidding areas is made available to the interested companies.	12 years
Norway	Norwegian Petroleum Directorate (NPD) – government agency	Diskos accessed by membership. Data covers wells, seismic and production	10 years if market available, 5 or 2 years if not market available
NL	Nalcor Energy – provincial energy corporation	Through proprietary database: Nalcor Exploration Strategy System (NESS)	2 years for well data, 5 – 10 years for geophysical surveys
NS	C-NSOPB runs a digital Data Management Centre	Data Management Centre is accessible by registration	2 years for well data, 5 – 10 years for geophysical surveys
UK	Oil and Gas Authority – limited company working with government	OGA's Open Data is freely available to everyone to use and republish as they wish under the terms and conditions set out in the Open Government licence	3 years
US GoM	Bureau of Ocean Energy Management	Since the US government purchases the seismic surveys from specialised service companies as private operators do, geophysical data is not released for very long periods via BOEM	25 years

5. Geopolitical and Above Ground Risk Considerations

Wood Mackenzie's affiliate, Verisk Maplecroft, generates indices that provide qualitative and quantitative information on business risks in different countries. For the above ground and geopolitical risk analysis, the countries are scored based on multiple upstream risk factors depending on their political and economic situation.

The risk factors are divided in three risk stages that represent the steps that a company goes through while attempting to establish business in the country. The risk stages and their associated risk factors that we analysed for this engagement are as follows:

1. Access: Ease of entry
    a. Contract sanctity
    b. State presence
    c. Regulation
    d. Corruption
    e. Geopolitics
2. Development
    a. Labour activism
    b. Natural hazards
    c. Civil unrest
    d. Security
    e. Environment
    f. Supply chain
    g. Local content
3. Commercialisation
    a. Infrastructure
    b. Pricing
    c. Currency risk

The score of each risk factor varies from 0 to 1 with 0 being the most beneficial (i.e. lowest risk) from a company perspective and 1 to be the least (i.e. highest risk).

5.1 Above Ground Risk Factors for East Coast Canada ("ECC")

5.1.1 Access

- The political and economical conditions in the Canadian provinces of Nova Scotia ("NS") and Newfoundland & Labrador ("NL") render the market easily accessible for upstream operations.
    - ECC's offshore resources are not contested by any third-party, which makes the region deemed of negligible geopolitical risk;
    - Bidding rounds are timely and consistent;
    - Licensing regulations are transparent;
    - All contract terms are clear and agreed on at the time of approval; and
    - The tendering and bidding process for contracts is subject to strict anti-corruption legislation, at both the provincial and federal levels, which sharply reduces the scope for illicit practice.
- The only limiting factor when accessing the region is state equity participation through Nalcor, NL's provincial energy company, although its effect on project economics is much less than in many other jurisdictions with National Oil Companies.
    - Based on NL's energy policy, Nalcor can acquire up to a 10% equity interest in new developments;
    - Upon acquisition, Nalcor is required to pay its prorata share of the historical costs associated with licenses and exploration and its prorata share of development costs; and

  - In supporting industry knowledge, Nalcor has created a program to evaluate the resource potential of blocks on offer in annual bid rounds. The assessments include 2D and 3D seismic data, seabed coring geochemistry, metocean studies and historical drilling performance reviews. The substantial upfront data gives bidders more confidence and also shortens the time between licencing and drilling.

5.1.2 Development

The development stage is where companies encounter most of the ECC risks:

- Oil and gas operations are exposed to freezing weather conditions and other adverse conditions. While these have yet to significantly inhibit operations, difficult conditions have periodically impeded production, although this is a relatively rare occurrence. The jurisdiction has been producing since 1997 and the impact of these issues has become minimal.
- Environmental groups are active in Canada and routinely lobby federal and provincial governments over issues related to the environment in the extractives sectors.
  - Reputational risks are a persistent concern in the sector as local, regional and national environmental civil society actors are highly motivated with respect to hydrocarbon development and its impact on the surrounding environment.
  - There is a strong dependence on the oil and gas industry in provincial economies such as NL, where the majority of citizens support its development. As such, the federal government is motivated to strike a balance between environmental responsibility and the development of the energy industry.
  - Following COP21, the federal government announced that it will implement a nation-wide carbon tax if provinces do not introduce their own systems. The target of the policy is to meet or exceed the national target of reducing greenhouse gas emissions of 30% below 2005 levels by 2030. All jurisdictions are required to have a carbon pricing system in place by 2018. If jurisdictions fail to implement a system, then the Federal Government will introduce an explicit price-based carbon pricing system. Provinces are given one of two options for their carbon pricing system:
    - For jurisdictions with an explicit price based system, the carbon price should start at a minimum of $10 per tonne in 2018 and rise by $10 per year to $50 per tonne in 2022
    - Provinces with a cap and trade system need a 2030 emissions reduction target equal to or greater that Canada's 30% reduction and declining annual caps to at least 2022 that at a minimum correspond to the projected emissions reductions resulting from the carbon price that year in a price based system
    - More details can be found at https://www.canada.ca/en/environment-climate-change/news/2016/10/canadian-approach-pricing-carbon-pollution.html
  - Article 82 of the United Nations Convention on the Law of the Sea (UNCLOS) may apply to certain projects offshore NL. Under this article, the host government is liable to pay to the United Nations an additional royalty on production where there is exploitation of resources more than 200 nautical miles from the baselines from which the breadth of the territorial sea is measured. Its application however will not be limited to NL and other jurisdictions such as Norway have already started to consider its implications.
  - Canada also approved a number of energy infrastructure projects subject to a number of conditions to ensure environmental protection.
  - Ottawa and provincial leaders will remain particularly sensitive to environmental activism in the sector.
  - The Canadian Environmental Assessment Agency role in exploration drilling has raised concerns from the industry about unnecessary delays in permitting.
  - The Frontier and Offshore Regulatory Renewal Initiative (FORRI) is a partnership of federal and provincial government departments designed to modernize and amalgamate existing regulations in a number of areas (Drilling and Production Regulations, Geophysical Operations Regulations, Certificate of Fitness Regulations, Operations Regulations, Installation Regulations) into one single Framework Regulation.
- A well developed supply chain does currently exist in the region.
  - Given the high unemployment rates and the slow pace of offshore development, services and labour is ample.
  - Two major construction sites located on NL's coast, the Bull Arm construction site and the Marystown shipyard, are capable of completing a wide variety of construction, fabrication and engineering work for offshore developments.
  - However if large-scale activity returns to the region, and multiple projects are developed at one time, the risk for supply chain bottlenecks could increase.
- Local content is an ongoing issue in NL and although not mandatory, it is highly encouraged.
  - In NL, along with regulator required benefit plans, benefits agreements are also negotiated for all offshore petroleum projects to provide the Province with employment and expenditure commitments and industrial benefits.

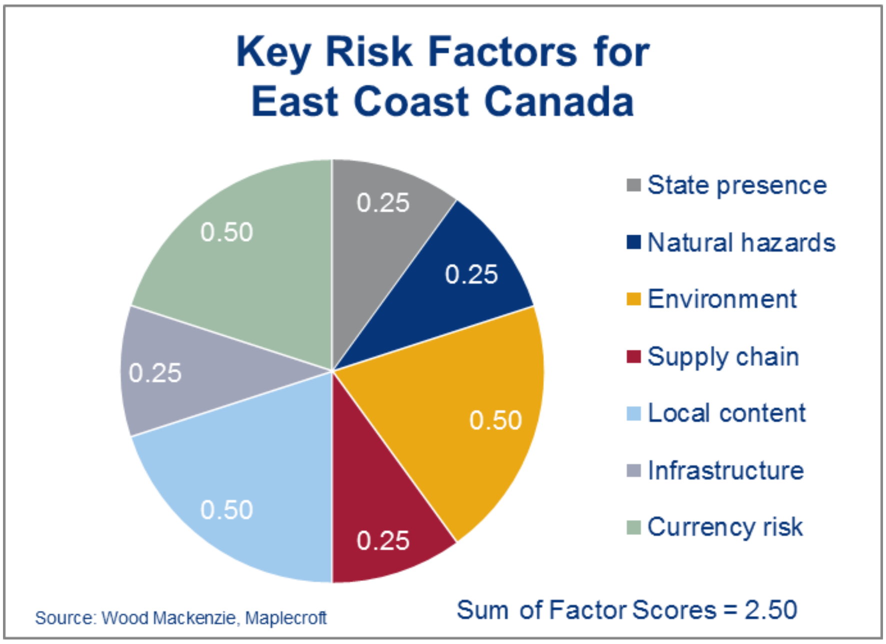
  - The most recent offshore development, Hebron was officially sanctioned in 2012 and came online in late 2017. The government of NL and Hebron project partners (operated by ExxonMobil) signed a Memorandum of Understanding that included provincial benefits. The MoU required the project to ensure first consideration for services, employment, construction and manufacturing provided within the Province.
  - During the construction of Hebron, a dispute did arise where a key equipment module was constructed in South Korea rather than in NL at the Bull Arm site. ExxonMobil paid the government Cdn$150 million to settle the dispute.
  - To maximise employment opportunities in Newfoundland and Labrador and Nova Scotia, historically, these types of arrangements have been made between companies and the provincial governments. The expectation would be for these agreements to continue as other developments are proposed.
  - Details of Benefits Agreements are made public and can be reviewed on the Newfoundland and Labrador Department of Natural Resources website.
- Labour activism threatening operational disruptions in the oil and gas sector in NS and NL is rare.
  - The majority of NL's population is resource development friendly.
  - Risk of security or civil unrest disrupting oil and gas operations in ECC's offshore operations is negligible.

5.1.3 Commercialisation

Commercialisation risks in ECC are linked to the infrastructure and the currency risk.

- Despite the considerable amount of gas resource, offshore NL does not export gas.
  - There is no pipeline infrastructure currently in place, and given the over supplied North American market, there is no major incentive for operators to commercialise gas resources.
  - Nova Scotia produces only gas
    - Gas is transported from offshore developments to the Goldboro gas plant onshore Nova Scotia.
    - From Goldboro, the gas can be moved onto the Maritimes and Northeast Pipeline.
    - The pipelines feed markets in the Canadian Maritime provinces as well as the US Northeast (Maine, New Hampshire and Massachusetts).
    - The Goldboro facility also feeds into the Point Tupper NGL Plant.
    - Both offshore gas projects in Nova Scotia (Sable Island and Deep Panuke) are expected to cease production in 2019, which will leave ample pipeline and processing capacity for any new developments.
    - A five mmtpa LNG facility has also been proposed at Goldboro, Nova Scotia. Given the soon to be decommissioned projects and a lack of any exploration success, Wood Mackenzie views this project as unlikely to move forward.
- Oil production is transported by shuttle tanker to market or to the Whiffen Head transshipment terminal, which has over three million barrels of storage capacity, with room for expansions. This means that there are no infrastructure difficulties related to the export of oil reserves and resources in NL.
- NL also has an oil refinery with a capacity of 130,000 b/d and a seven million barrel storage facility.
- With respect to currency risk, the Canadian dollar remains exposed to fluctuations on account of the performance of the oil and gas sector.
  - Historically, there has been a relatively strong correlation between the price of oil and the Canadian dollar-US dollar exchange rate. When crude oil prices rise, the Canadian dollar appreciates against the US dollar, as oil prices are traded in US dollars. The opposite dynamic occurs when crude prices decline.
  - Monetary policy and economic growth divergence between Canada and the US is also a major arbiter of the Canadian dollar's performance.
  - It is important to note that a number of the other jurisdictions analysed also have currency risks.

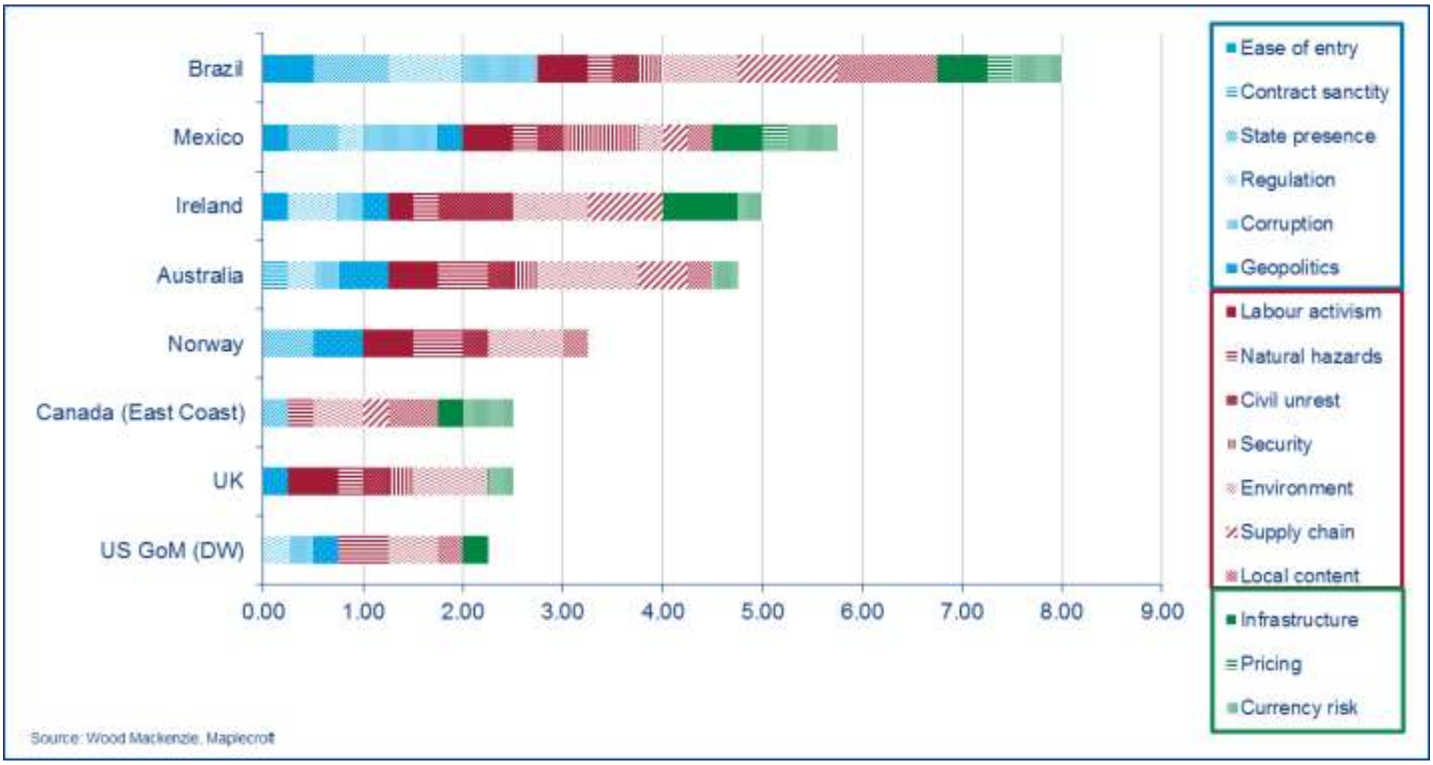
Figure 9 – Key risk factors for East Coast Canada - 0 to 1 with 0 being the most beneficial (i.e. lowest risk)



5.2 Above Ground Risk Factor Comparison and Ranking

Relative to the rest of the Peer Group, ECC shows one of the lowest geopolitical and above ground risk profiles, only slightly higher than US GoM DW (because of currency risk and risks and local content).

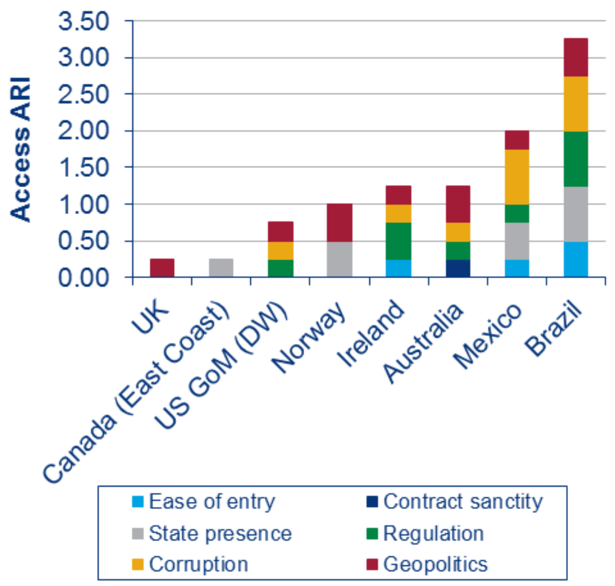
Figure 10 – Above ground risk factors by country - 0 to 1 with 0 being the most beneficial (i.e. lowest risk)



5.2.1 Access

The top three countries in which Access is considered an issue are Brazil, Mexico and Australia. Corruption and state presence are particularly problematic in Brazil and Mexico, while in Australia domestic political considerations are heightened.

Figure 11 – Access – Above ground index - 0 to 1 with 0 being the most beneficial (i.e. lowest risk)



Source: Wood Mackenzie, Maplecroft

Corruption

Brazil

Brazil's corruption scandal (Lava Jato) in Petrobras has become one of the defining issues of President Dilma Rousseff's second term, paralysing politics, the oil sector, and the economy. Petrobras directors admitted deliberately overpaying on contracts with various companies for drilling rigs, refineries and exploration vessels. Contractors were given excessively lucrative terms if they agreed to channel a share of 1% to 5% of every deal into secret slush funds. 23 Petrobras contractors were blacklisted from public tenders in November 2014, slowing oil sector activity.

However the various allegations of graft that have entwined the Brazilian NOC and the executive have spared the government's regulatory agencies thus far. The ANP and Instituto Brasileiro do Meio Ambiente e dos Recursos Naturais Renováveis (IBAMA) are unbiased and technocratic and the ANP's bidding rounds have long been heralded as a model of transparency and fairness.

Mexico

While not as headline grabbing as Lavo Jato, Mexico is dealing with similar corruption issues. The upstream sector has seen a high-profile case emerging in 2014 involving Oceanografia, a Mexican oil service provider and Pemex, the NOC. Pemex Exploration & Production has faced corruption accusations in the past. Between 2006 and 2010 there were 153 cases of fraud detected in the business unit. Common instances of corruption allegedly includes inflating contracts, trading contracts for favours, and awarding contracts without a formal tender to insiders.

Australia

Australia compares favourably against Brazil and Mexico, however deals with its own problems. The oil and gas sector is caught up in a public debate over foreign corporate donations to political parties. In February 2017, Chevron was accused of trying to buy political influence through donations just prior to a government review of offshore drilling in the environmentally sensitive area of the Great Australian Bight. Energy companies should anticipate greater public and political scrutiny over the financial transactions, as well as ties with state and federal government.

State presence

Besides corruption, state presence is a major Access issue. In particular the NOCs may cause problems. They are tasked with securing domestic energy supply which often shapes available upstream opportunities for private and foreign entrants.

Newfoundland and Labrador

In NL, the Province's equity participation is through Nalcor. Based on current energy policy, Nalcor's role is to obtain up to a 10 per cent equity position in all future oil and gas projects requiring a Development Plan approval, where it fits with strategic long-term objectives. Nalcor pays its proportionate share of the historical exploration and predevelopment costs incurred by the license co-venturers as well contribute its share of subsequent development and operations costs. Nalcor's role does not cause the problems that have been witnessed occurring in other jurisdictions with NOC's. Nalcor's goal of maximizing the benefits of the Province's petroleum reserves also means that it has been active in promoting the region and attracting new investment.

Brazil

Again, Brazil ranks high in terms of state presence. Petrobras' de-facto dominance impacts every aspect of the industry, especially in areas such as supply chain and infrastructure. State presence was increased with the 2010 pre-salt legislation: Petrobras must have a minimum 30% stake (and operatorship) while the newly created government entity PPSA (Pré-Sal Petróleo SA) holds overall control of the resource. Pre-salt operations are administered by an operating committee, with PPSA designating half of the members, including the chairman who has right of veto and tie-breaking power. The Libra project is the first test of this new arrangement and it remains to be seen how well the relationship between Petrobras and PPSA will function. With Petrobras overburdened and engulfed in a corruption scandal, there is a possibility that the rule mandating Petrobras' operatorship law in the unlicensed pre-salt could be reconsidered.

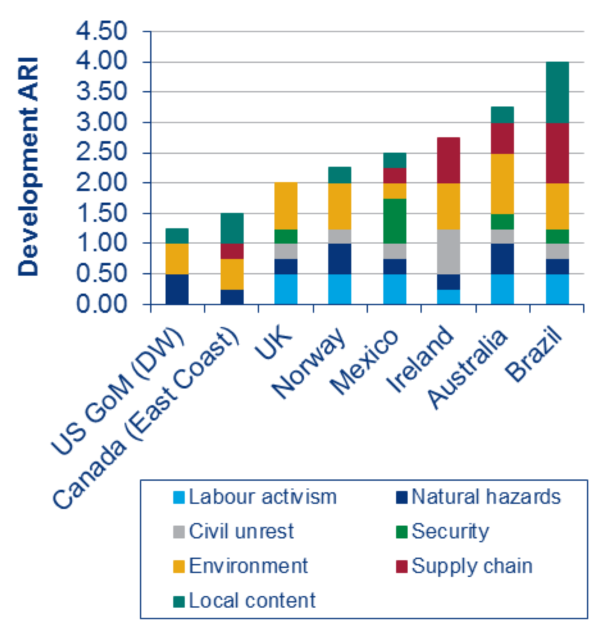
Mexico

In Mexico the liberalisation of the upstream segment by the 2013 Energy Reform introduced competition and reduced Pemex's influence. In August 2014, during "Round Zero" Pemex was granted 83% of the country's 2P reserves, but only 21% of prospective resources. Pemex will clearly remain a prominent actor in production in its shallow water acreage in the Bay of Campeche. In special instances the state can take a stake in projects. In the event of major discoveries deemed to be of national interest, Pemex, or other productive state enterprises, may be required to take a 30% stake in contracts. Similarly the law states that Pemex can take 20% in trans-boundary fields. In projects where opportunities to acquire new technologies are present, the government can also take a 30% stake through Pemex or via a financial vehicle. Amid the weak oil price environment, Pemex cut spending and investments to shore up its weak financial state after the NOC posted a net loss of about US$29 billion in 2015. In the aftermath of the cuts (worth US$5.5bn for 2016), the new CEO, José Antonio González Anaya, was quoted saying that Pemex will look for alliances to develop its deepwater assets. The first opportunity will be the Trion deepwater field to be offered in parallel to the deepwater phase of Round One. Pemex will have a 45% stake in the JV and will need to receive a US$209 million carry as reimbursement for its E&A expenditures in Trion. The bidding variable will be additional royalty. The maximum royalty will be capped, a first for a Mexican licensing round.

5.2.2 Development

The ECC has the second lowest development risks, only behind the US GoM. Most of the risk relates to the adverse environmental conditions and the ensuing stricter policies. The highest development risks appear in Brazil and Australia where the majority of risk emanates from local content (see Regulatory section for details), supply chain and environment. Labour activism is another key issue in Australia and Brazil, although it rarely results in extensive strike action. Ongoing concerns with working conditions and wages of industry workers mean that labour tensions are unlikely to subside in the coming years. The natural hazard risk is considerable for deepwater E&P in both Brazil's and Australia's remote offshore areas, while in both countries the environmental impact of offshore oil and gas is subject to heavy public scrutiny and strict regulations that can significantly increase operational costs and lead to project delays. Supply chain has been stretched by the sheer volume of activity and the lack of skilled labour relative to needs in Brazil and Australia resulting in an additional development bottlenecks. Brazil has the additional major impediment of local content with stipulated minimum percentages, while in Australia, although it is encouraged that projects prefer local workforce and services, there is nothing codified in terms of local content.

Figure 12 – Development – Above ground index - 0 to 1 with 0 being the most beneficial (i.e. lowest risk)



Source: Wood Mackenzie, Maplecroft

Environment

Environment is by far the greatest of all development risks in all jurisdictions with a total score of 5.25 – labour activism, natural hazards, and supply chain share second place with a score of 2.75 each. Stricter regulations in environmentally sensitive areas can as described earlier lead to project delays, increased operating costs, and in some cases may even lead to barring of all drilling activity.

Newfoundland and Labrador

In NL, where the majority of citizens support the development of the oil and gas industry, federal and provincial governments are motivated to strike a balance between environmental responsibility and the development of the energy industry. Currently there is a debate around the Canadian Environmental Assessment Agency 2012 legislation and the impact that this has on oil and gas activity.

In recent years the CEAA2012 process has been cited numerous times for the delays that it has caused with regards to offshore development. Within this process, which is currently being reviewed, the approvals for exploration programmes rest with the Canadian Environmental Assessment Agency rather than with C-NLOPB which was previously the case.

With the exception of exploration permitting, the C-NLOPB has the responsibility to ensure that offshore oil and gas industrial activities proceed in an environmentally acceptable manner. The C-NLOPB will review proposals for all physical activities offshore from seismic surveys to production projects to identify their potential effects upon the natural environment.

Australia

In Australia the environmental impact of offshore oil and gas is subject to heavy public scrutiny while strict regulations can significantly increase operational costs on environmentally sensitive areas. The Gorgon LNG operation (Barrow Island) is classified as an A class reserve and Chevron is subject to highly restrictive requirements in regard to construction (permitted to use approximately 1% of land) and strict quarantine procedures for equipment, which has driven up operational costs. Gorgon is likely to act as a litmus test for other offshore developments in environmentally sensitive areas. A success so far, but any accident or evidence of severe ecological impact would have severe consequences for Chevron's reputation and narrow prospects for similar ventures in the Great Australian Bight.

The Bight presents significant potential but holds ecological importance. NOPSEMA requires operators to provide exceptional environmental cases for exploration permits, effectively barring drilling in Stromlo-1 and Whinham-1. The complexity of the regulatory environment fed into BP's decision to drop E&P plans in December 2016. Chevron plans to go ahead, but will face intensive scrutiny, especially over its oil spill modelling.

The federal government is urging states to relax bans on the development of onshore unconventional resources, such as CGS and fracking, to meet energy demand. This policy will likely increase calls for the development of offshore resources, even in environmentally sensitive areas. Public resistance is nonetheless likely to slow the relaxation of environmental regulation, and progress will be dictated much more at the state level than from the federal government.

Brazil

The main challenge for upstream operators in Brazil stems from strict environmental regulations and excessive bureaucracy that often lead to severe project delays. One example is the difficulty Petrobras had in obtaining permits to build subsea gas pipelines from its Santos Basin discoveries to shore – the focus of disputes being the landfall sites. Better cooperation between IBAMA and the ANP is improving the situation.

The oil spills at Chevron's deepwater Frade field in 2011/12 also serve as a warning to the potential legal risks that IOCs could be exposed to in the event of a pollution incident. Operators were unnerved by the poor handling of the affair by Brazilian authorities, and the attempt to make punitive charges against the various parties. The surprise re-opening of the case, after an apparent solution, reinforces the uncertainty confronted by operators. Most recently, public environmental consciousness increased after a tailings dam at an iron ore mine released more than 60 million tonnes of toxic mud that buried towns and killed at least 19 people. It has been called Brazil's worst environmental disaster by authorities, who seek US$5 billion in compensation from the mine's owners, BHP Billiton and Vale.

Norway

Norway has experienced a continuous decline in oil output over the past ten years. To maintain and further increase current production levels, the country will need to develop so-far untapped deposits. Consequently, Norway's rich biodiversity, protected ecosystems and diverse species are increasingly competing with commercial interests, thrown into sharp relief by the current debate on exploration in Lofoten, Vesterålen and Senja as well as the Barents Sea – areas recognised internationally for their biodiversity and pristine environment. Strong environmental regulation and effective institutional support helps foreign investors minimise the risk of violating environmental regulation and incurring associated legal and reputational damage. The permitting and impact assessment regime in Norway is burdensome as it increases the time and cost of compliance. Scrutiny from the public and environmental NGOs poses the greatest legal and reputational risk to operators and buyers further along the supply chain.

Supply chain

Brazil

In Brazil, supply chain bottlenecks are a major problem, especially in the booming deepwater sector, where project delays are the norm. The situation has worsened due to fallout of the Lava Jato corruption investigation. Service companies were complicit in billions of dollars in inflated contracts and 23 companies have been blacklisted from public tenders as the investigation continues. As a result, several of the country's largest construction and service companies have declared bankruptcy, aggravating the strain on the supply chain. A significant slowdown in Petrobras' activity has resulted in many contractors' orders evaporating overnight, theoretically alleviating the backlog, but the volatility brought about by the corruption probe has also left the supply chain in a state of near paralysis.

Even before the corruption was revealed, several factors had choked the upstream supply chain. Firstly, Brazil's oil services segment most recently suffered from a tight market, with high demand for goods and services. Secondly, strict local content requirements exacerbated the situation. A third factor is the fact that Brazil's service sector has been geared towards Petrobras.

For IOCs, accessing the local supply chain is difficult as service providers usually prefer the long-term contracts that the state company has historically offered, despite the fact that the NOC has driven down prices and can be slow to pay bills. The government has recognised the gravity of the current situation and taken initial steps to improve local conditions. In January 2016 the government launched the Pedefor programme, which is tasked with improving the oil and gas supply chain.

A particular bottleneck is the lack of capacity in Brazil's ship yards. Amongst other work, Petrobras awarded tenders for 12 FPSOs units (Floating Production, Storage and Offloading) to local firms, but they are struggling to deliver and overseas yards are being used once again. Well equipment is also in short supply, such as flowlines and wellheads. There are also long lead times on subsea equipment, even when using international suppliers. Lastly, Brazil's booming oil industry is also handicapped by the insufficient supply of skilled workers.

Mexico

Mexico has a robust oilfield services sector, with both international oil service companies and a burgeoning domestic services sector. Pemex's historical monopoly of the oil and gas industry forced the NOC to lean on the oil services segment as it was not permitted to partner with foreign companies. In response to the recent oil market downturn, Pemex began to defer payments to suppliers and ultimately racked up just over US$8 billion in debts by end-2015. Many of the suppliers closed until March 2016 when Pemex secured credit lines (via a treasury bailout) to begin paying back the 1,300 small and medium companies that account for over 90% of suppliers.

While oil service providers in Latin America have tended to focus on less technical or secondary needs (e.g., transport), a number of the larger Mexican oil service companies have taken a longer term view and have engaged in more technically challenging projects. As Pemex's portfolio has shifted from conventional development of the shallow water Cantarell to the complex reservoirs of Chicontepec and deepwater exploration, Mexican service providers have attempted to follow suit. For example, to boost its technical expertise, Mexico's Grupo Diavaz, parent company of D&S Petroleum, formed a consortium with China's Sinopec. Others, such as Grupo R, offer semi-submersibles and other high-end services.

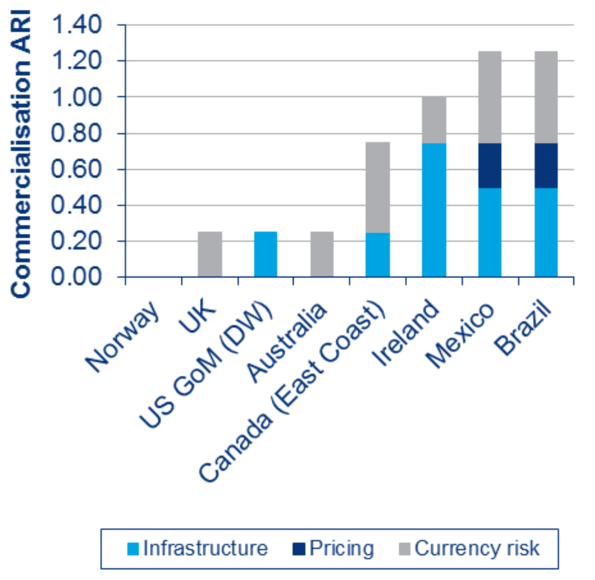
As Mexico liberalises its upstream sector, some Mexican service companies may also consider transitioning to operatorship. With regards to logistics, the ports of Altamira and Tampico are those closest to the Perdido Foldbelt, while Tuxpan, Veracruz and Coatzacoalcos are strategically located to meet the needs of companies operating off the coast of Veracruz de Ignacio de la Llave. Dos Bocas and Isla del Carmen in Campeche serve the southern parts of the Gulf of Mexico. Separately, contracting adequately trained personnel may prove to be a major constraint as E&P activities ramp up but an anticipated wave of Pemex retirees may help mitigate the gap.

Australia

Australia's supply chain has been stretched by the sheer volume of activity in the LNG space that has occurred over the last few years. While delays to Gorgon and Ichthys may not be fully explained by the tight market it has had a heavy impact. The heat has come off the market over the last couple of years and will continue to do so.

5.2.3 Commercialisation

Figure 13 – Commercialisation – Above ground index - 0 to 1 with 0 being the most beneficial (i.e. lowest risk)



Source: Wood Mackenzie, Maplecroft

Infrastructure limitations and currency fluctuations affect Canada, Brazil and Mexico alike, but the two Latin American countries have additional pricing issues. Mexico is moving towards liberalisation of prices, but the government still manipulates the net prices for oil and gas. In Brazil, gas prices onshore, although deregulated during the 2000s, continue to be controlled by Petrobras due to the NOC's infrastructure dominance. Norway presents the most beneficial environment in terms of commercialisation with an extensive, established infrastructure network that has sufficient capacity, market-led prices for both oil and gas and a free exchange rate policy with no currency controls. Since currency and infrastructure represent the greatest threats we will look into these in more detail in the following.

Infrastructure

In NL, although there are infrastructure challenges that have hindered gas developments, no such challenges exist for oil focused projects which have well established tanker shipment procedures and onshore facilities. All oil production is transported by shuttle tanker to market or to the Whiffen Head transshipment terminal, which has over three million barrels of storage capacity, with room for expansions.

As yet there is no gas pipeline infrastructure currently in place, and given the over supplied North American market, there is no major incentive for operators to commercialise gas development. Various projects have been suggested over the years, particularly in relation to the stranded gas opportunities off the Labrador coast, but for the reasons mentioned above it is likely to be a number of years before these can be commercially developed if at all.

Mexico

The Mexican government is aware of the limitations of the current infrastructure due to age and insufficient coverage, particularly with regard to gas. Midstream bottlenecks for crude are expected to persist across the forecast period in the newly licenced areas. The oil pipeline network comprises three main spurs located in the southeast, central and northeast portion of the country. The northeast pipeline connects the Cadereyta refinery at Monterrey to crude fields to its south. The second network crosses the central region providing the Salamanca and Tula refineries crude oil from the Tampico-Misantla and Veracruz basins. The third pipeline is in the south of the country, carrying crude oil from the onshore south region fields and the offshore Bay of Campeche fields. The crude is supplied to the Minatitlán refinery and the adjacent port of Coatzacoalcos on the Gulf Coast. There is another pipeline south of Minatitlán that connects to the refinery and export port at Salina Cruz on the Pacific Coast. Gas pipeline bottlenecks, conversely, may be reduced due to the construction of new infrastructure and also due to associated gas being re-injected. Considerable investment is necessary to expand the gas network and connect the southwest portion of the country to the main grid. Seven new major gas pipelines are under construction or projected over the next three years. There is a push to increase the gas supply to Mexico from the US as gas-fired generation increases. SENER (the Energy Ministry) predicts that gas imports should reach 3.8 bcf per day by 2018.

Brazil

Petrobras controls most of the existing oil and gas infrastructure, be it offshore platforms, onshore production units, pipelines, processing plants or refineries. Third-party access to pipelines is enshrined in law but tariffs must be negotiated on a commercial basis and the lack of competition can be a problem. This is less of an issue offshore, where most IOC oil production is tanker-loaded and exported. Gas flaring is not allowed so, if all gas cannot be utilised in-field, it must be piped ashore – relying again on Petrobras infrastructure, where bottlenecks can occur. A stringent environmental approval process has slowed pipeline construction.

For example, the gas pipeline to Río de Janeiro state, planned for the pre-salt cluster of fields in the Santos Basin, has been severely delayed. This could impact Santos Basin developments, where pre-salt associated gas production is expected to grow throughout the forecast period. Similarly, the Campos Basin's south-eastern fields will require an additional pipeline to be built for the associated gas production. Most of the country's onshore gas processing infrastructure was designed for Petrobras' own needs, leaving little spare capacity for other actors. Given Petrobras' financial constraints, private companies would need to invest heavily in their own facilities to process any gas. Another infrastructure issue facing Petrobras is its poor safety record on its ageing – but still vital – Campos Basin infrastructure. Maintenance is underway to better protect personnel and avoid production outages.

Currency

Brazil

There are no limits on profit repatriation, but currency fluctuations are an issue. In 2015, the Brazilian Real witnessed a particularly volatile year. The currency depreciated 48%, from BRL2.66 per dollar in January 2015 to BRL3.96 per dollar in December, as confidence fell due to a domestic recession, slumping commodity prices, and the normalisation of interest rates in the US. The currency's volatility should continue, albeit not to the same levels as 2015. Though the weaker real is beneficial for investors, its volatile nature can complicate planning. The depreciation of the real has also been accompanied by inflationary pressure. The major negative impact of a weakened real is on Petrobras, which sees a rise in the value of its foreign debt and, before the 2014 drop in oil prices, faced paying a higher cost for importing oil products. Brazil' s poor economic growth outlook, the persistence of high inflation and the future rate hikes in the US will weigh on the Brazilian real, with further depreciation likely in the next few years.

Mexico

After its 1994 economic crisis, Mexico made two substantial macroeconomic changes - it switched to a freely floating currency and introduced independent monetary policy managed by the Mexican Central Bank. These two changes allow the Mexican peso to adjust better to any external monetary shock. Recently, like most emerging-market currencies, the peso was affected by the latest wave of global volatility, causing it to depreciate by 16% in 2015. Following the rate increases in the US, Mexico's Central Bank has responded by increasing rates to prevent any capital outflows.

The Central Bank had maintained daily dollar auctions to prevent major swings in the exchange rate, but ended them as of February 2016 to preserve foreign currency reserves. In 2016 the currency has remained volatile. Between January and 1 September 2016, the peso depreciated by nearly 12% on an absolute basis, although it did witness volatility with two separate peaks below 19 pesos per dollar. A weaker exchange rate could deliver some growth via stronger exports and deeper remittance flows in order to help offset weakening pressures by the US Federal Reserve's tapering. Central Bank Governor, Agustin Carstens, has signalled that Mexican interest rates can be raised following the Fed's next hike in order to keep the peso from depreciating. Mexico also has a low inflation rate and has accumulated a historic amount of foreign currency reserves that it can utilise to hedge against any international currency risk. On a related note, profit repatriation and currency convertibility are non-issues in Mexico.

Newfoundland and Labrador

In NL the currency risk is associated with the Canadian dollar which remains exposed to fluctuations on account of the performance of the oil and gas sector. Canada's currency risk ranks alongside that of Mexico. The weakness of the Canadian dollar has however mitigated to some extent the fall of the oil price in Canadian dollar terms.

6. Cost and Operating Environment

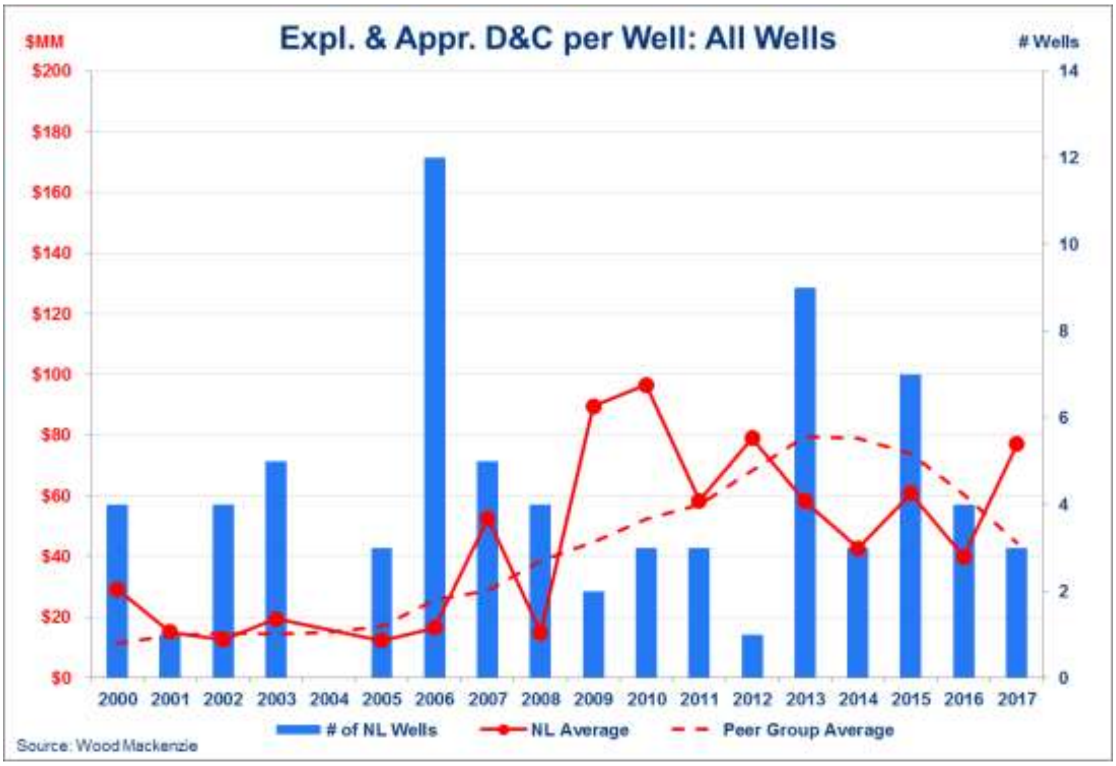
6.1 Exploration & Appraisal Capital

With respect to Exploration & Appraisal ("E&A") Drilling and Completion ("D&C") capital, as illustrated in the following charts, average E&A costs per well in NL has historically been slightly higher per well than for the average well in the Peer Group. Back in 2007 and 2010, two ultra-deepwater wells were drilled in the Orphan basin at costs of around $200mm. Another ultra-deepwater well in Orphan was drilled in 2013 for around $150mm. Unfortunately, none of these wells resulted in a commercial discovery. After these attempts, there was very little activity in the ultra-deepwater, and average well costs dropped considerably. Therefore, due to the ultra-deepwater attempts, the wells in the mid-2000s were considerably higher than the Peer Group. Once activity moved to shallower water, the average wells costs dropped to less than the average of the Peer Group. Since 2013 the majority of E&A activity has been targeting opportunities in the Flemish Pass basin, a return to deepwater activity that has seen average well costs increase.

With respect to the rest of the Peer Group, drilling costs for E&A wells have been trending down since the drop in oil prices in 2014. This phenomenon is less evident in NL. Until this year, prices had remained fairly constant but still below average. Most recently, there were three wells drilled in 2017 that averaged over $77mm per well. Two were exploration wells that averaged around $72mm, and one was an appraisal well for the White Rose project that was approximately $88mm.

One of the contributing factors to the well costs in NL has been the rig intake process which means only a small number of drill rigs meet the criteria for operating in its waters. This has meant that NL operators have had a smaller pool of the global rig fleet to draw from which contributes to higher costs.

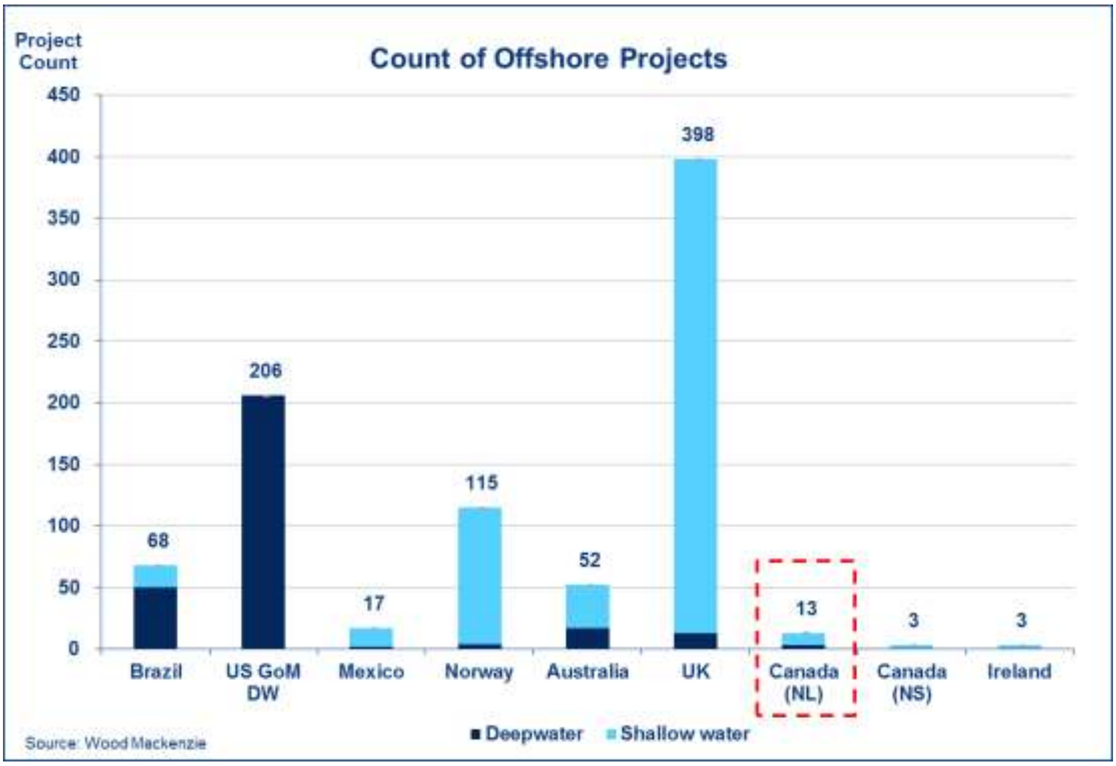
Figure 14 – Comparison of Newfoundland and Labrador average well cost with Peer Group



6.2 Development & Operational Costs

To understand how costs for full field developments compare across the Peer Group jurisdictions, we analysed the costs of 875 projects starting up or expected to start up post 1990. The distribution of projects was as follows (details of Wood Mackenzie's cost categories have been provided in Exhibit C, including the methodology applied good technical fields such as Bay du Nord, Harpoon and Mizzen North):

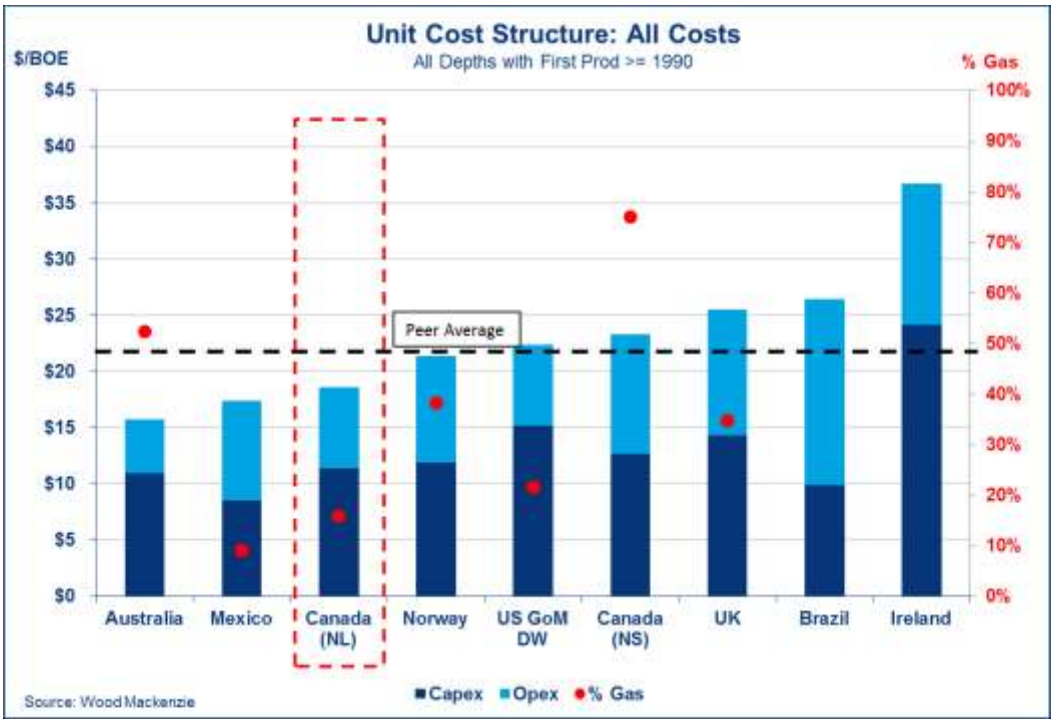
Figure 15 – Count of offshore projects for cost analysis



Shallow water projects are fields/discoveries in water depths up to 400m, deepwater projects are fields/discoveries in water depths greater than 400m. In Newfoundland and Labrador the shallow water projects are Hebron/Ben Nevis, Hibernia, Hibernia South (AA Blocks), Hibernia South Extension, Kings Cove, Mara, Terra Nova, West Bonne Bay, White Rose and White Rose Satellites. Deepwater projects consist of Bay du Nord, Harpoon and Mizzen North.

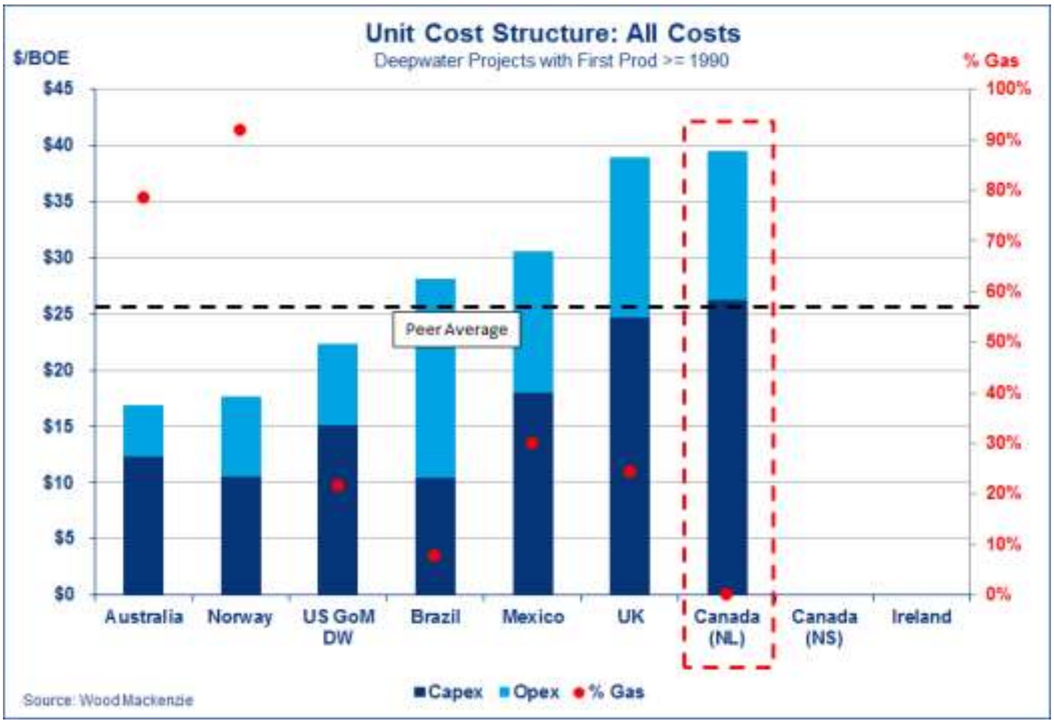
When considering all offshore projects, those in NL compare favourably relative to the rest of the Peer Group. As indicated below, the overall average is approximately $18.6/boe for NL versus $22.3/boe for the entire group. If the Hibernia project from 1990 is removed, the average for NL increases to almost $24/boe, higher than Norway, US GoM DW and Nova Scotia.

Figure 16 – Comparison of Newfoundland and Labrador costs with peer jurisdictions



Given that 10 of the 13 projects in NL that we analysed are in the shallow water, and most of the more recent activity has been in the deepwater, one must also understand the differential of moving to deeper waters. The following chart highlights that development capital and opex for deepwater projects for offshore NL are estimated to be almost $14/boe higher than the average for the Peer Group's deepwater projects. In should be noted however that the costs have a high degree of uncertainty and have been generated using a standard modelling approach (see Exhibit C).

Figure 17 – Comparison of Newfoundland and Labrador costs with peer jurisdictions



Wood Mackenzie estimates for the three deepwater projects in NL that contribute to this average as follows:

- Bay du Nord – Expected start-up 2022, CAPEX (2018, real terms) US$24/boe (46% drilling, 32% production facilities and 23% subsea installations), OPEX (real terms) US$15/boe

- Harpoon– Expected start-up 2025, CAPEX (2018, real terms) US$30/boe (36% drilling, 46% production facilities and 18% subsea installations), OPEX (real terms) US$12/boe
- Mizzen North– Expected start-up 2028, CAPEX (2018, real terms) US$29/boe (46% drilling, 41% subsea installations, 9% production facilities and 4% pipeline), OPEX (real terms) US$9/boe

Each of these fields is currently classed as a technical discovery and there is a high degree of uncertainty around their underlying costs and development solutions but these indicative costs have been calculated using Wood Mackenzie's technical modelling approach (see Exhibit C).

This approach calculates indicative values based on an analogue approach. The key driver of value is the potential development solution chosen, and the reserves believed to be potentially recoverable. Using these, our model interpolates between sets of model asset production profiles for liquids and gas streams, and capital investment profiles, for that specific development solution type at different reserves levels.

Capital costs are based on the two key inputs of development solution and reserves, and a number of other controls around water and reservoir depths, well costs and recoveries, distance to any infrastructure likely to be used, and local cost environments. Operating costs are based on assumed costs for the development solution indicated, adjusted for local costs and the inclusion of any tariffs likely to be paid, if appropriate.

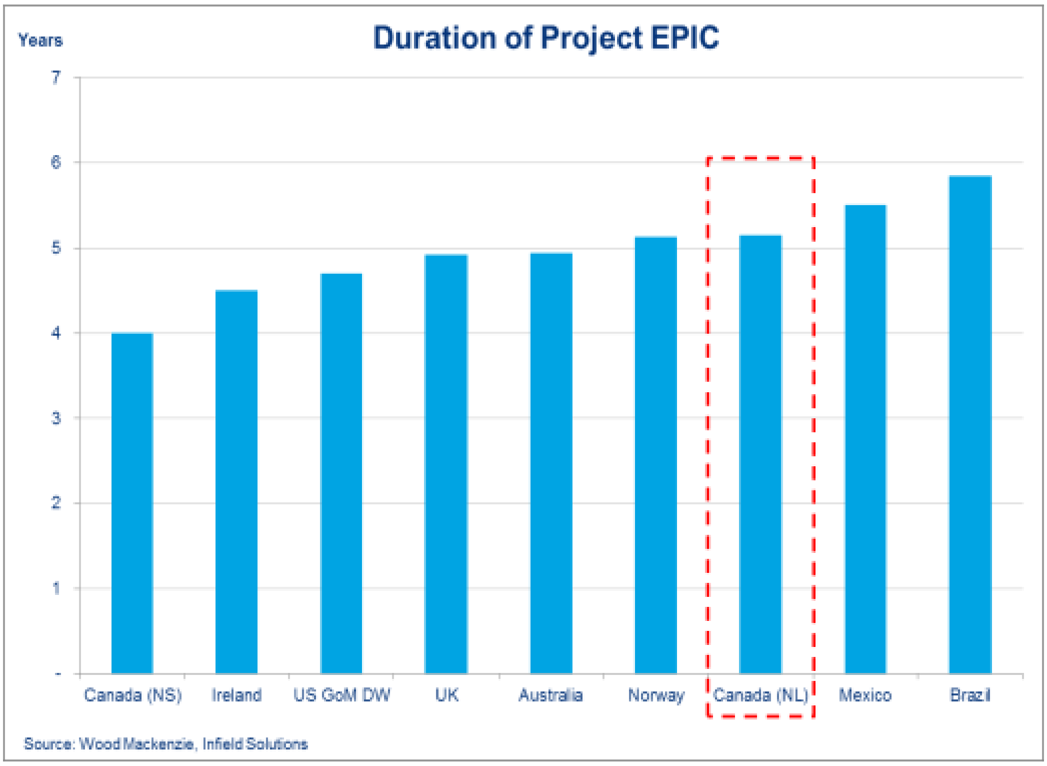
6.3 Supply Chain

To understand the challenges around exploring and developing in NL relative to other jurisdictions in the Peer Group, one must also consider the relative makeup of the primary components of the developments. For this analysis, we used research and data from Wood Mackenzie's tracking of the breakdown of project costs and insight from Infield Solutions ("Infield"), an affiliate company that focuses on the global markets for oil and gas infrastructure. Infield tracks hundreds of projects around the world and their component contracts. This information on the facilities side is one of the fundamental portions of the cost of development.

Infield breaks up the data from their research into various categorizations of Engineering, Procurement, Installation, and Construction ("EPIC") and each category has an associated estimate for timing. By analysing this data, one can understand how long facility construction is likely to take.

One measure for understanding relative costs is the time it takes to construct the facilities. The longer crews and equipment are mobilized, the more facilities cost. Using the data from Infield, we looked at the time from the first activity to the last for each component of each category of EPIC. The following chart illustrates the overall average duration of construction time in each country.

Figure 18 – Comparison of Newfoundland and Labrador average EPIC duration with peer jurisdictions

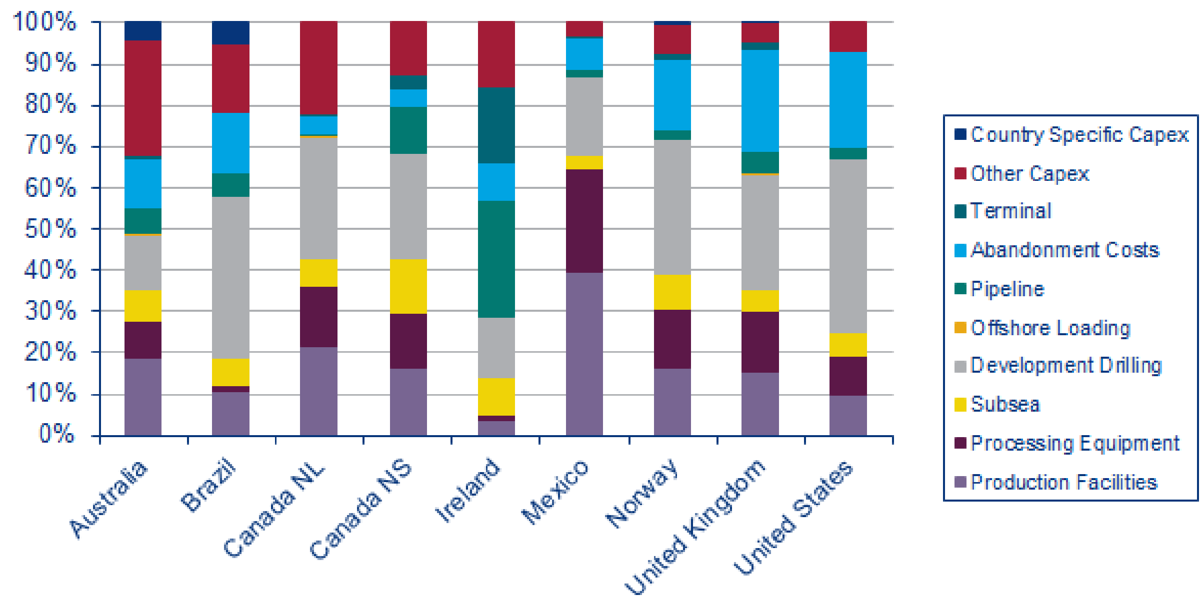


With the exception of Mexico and Brazil, the time to develop a project in NL is longer than in the rest of the Peer Group. The obvious harsher environment of cold weather and ice certainly means developments are more technically complex. In NL the bulk of construction occurs at sites onshore or in international yards with facilities typically floated offshore for installation, commissioning and hook-up.

Using the breakdown of capital costs tracked on a project by project basis in Wood Mackenzie's Global Economic Model (GEM) we are able to compare the relative proportion of spend in different areas across the jurisdictions analysed. Whilst there are some factors that are intrinsic to each location, such as water depths, sea conditions, reservoir depth etc., there are some conclusions that can be drawn from the comparison.

- With the exception of Mexico, NL has the highest proportion of spend on production facilities. This is expected given the unique nature of each development, as opposed to areas where more "commoditised" solutions can be employed, and the specifications necessary for developments in a harsh operating environment;
- Given the nature of developments in NL it has amongst the lowest proportion of subsea expenditure as a proportion of overall spend;
- The proportion of drilling capex for NL is similar to Norway which has the most analogous operating environment and rig requirements, but is lower than in some other areas such as Brazil; and
- A relatively large proportion of spend is captured as Other Capex in NL. Looking at the two fields with the largest expenditure in this area, Hebron/Ben Nevis and Hibernia this capex typically relates to sustaining capex for maintenance and turnaround activities.

Figure 19 – Breakdown of CAPEX spend areas for onstream or under development projects (water depths less than 500m)



Source: Wood Mackenzie

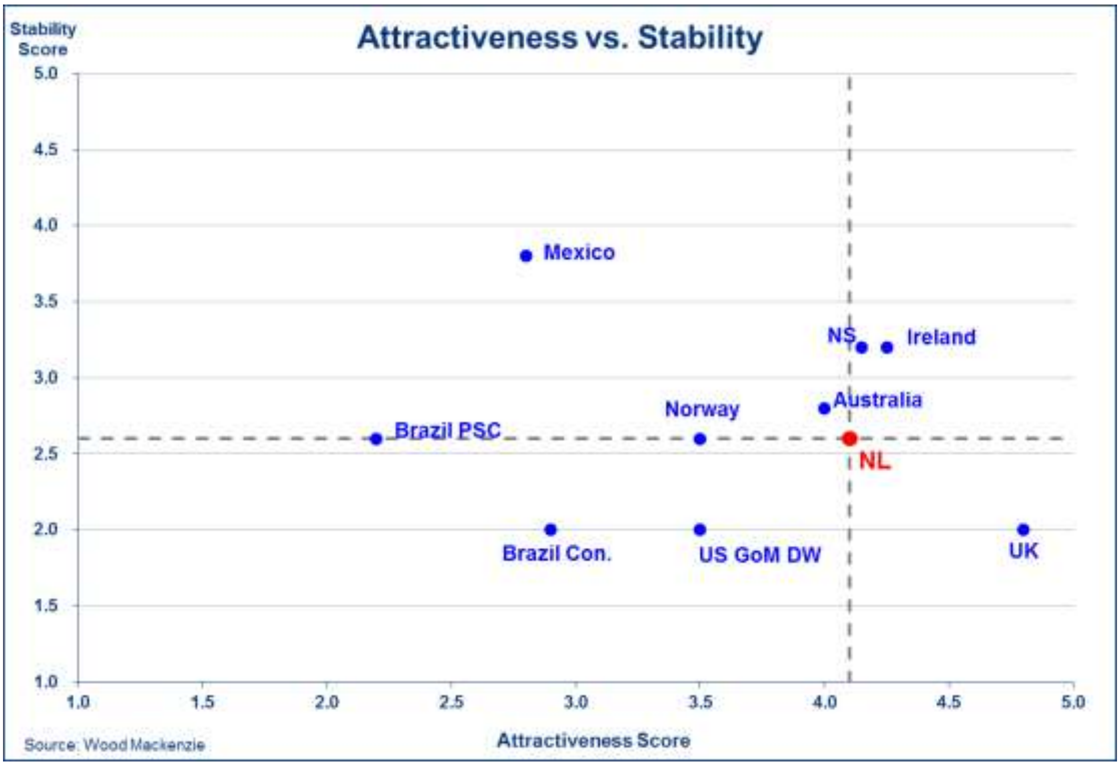
7. Fiscal regime

Just over one year ago, Wood Mackenzie completed a comprehensive Multi-Client Fiscal Study ("MCFS") of fiscal regime comparisons, "A Balancing Act: Global Fiscal Terms and Benchmarking". The purpose of the MCFS was to analyse and rank the most important hydrocarbon-producing regimes in the world with respect to the parameters that most affect oil and gas-related Foreign Direct Investment ("FDI") flowing into a country. The MCFS divided the drivers into two broad categories of (1) fiscal and (2) non-fiscal.

The fiscal drivers were defined by parameters that impact (1) fiscal stability and (2) fiscal attractiveness. The two groups of fiscal factors illustrate the relative perspective that a rational investor would likely take if comparing each regime using common development profiles and unbiased data. In other words, "all else being equal," (same costs, same production, same risk profile, etc.) a given regime's structure can be isolated and characterized as more or less stable/attractive than another regime. The broad categories each reflect a weighted summation of several sub-categories that provide granularity into the regimes' relative positioning.

For this analysis, the MCFS analysed the current terms for each Peer, including the Generic Oil Royalty Regime ("GORR") in NL. The final comparison of these regimes is as follows:

Figure 20 – Fiscal attractiveness vs fiscal stability (5 is the most attractive/stable)

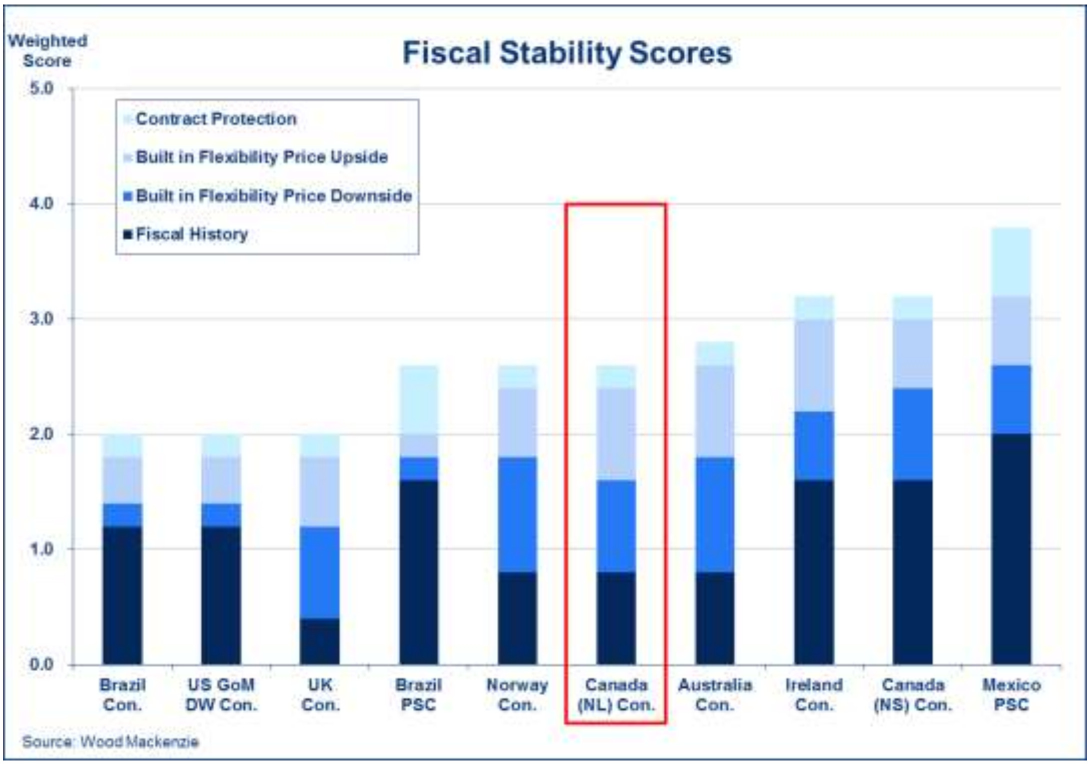


As illustrated in the above chart, NL compares favourably with respect to attractiveness if all other considerations are held constant. Only three of the Peer Group regimes are more attractive to investors. However, NL is scored lower with respect to stability because of its concession structure and the number of changes that have been implemented over the last several years.

7.1 Fiscal Stability

Factor	Description	Weighting
Fiscal History	Measures the number of fiscal "events" that have historically been implemented. The more events that have been implemented, the less stable the system.	40%
Price Flexibility	Measures the relative movement in the government's percentage share ("GS%") in the pre-share cash flow ("PSCF"). Whether prices move up or down, the more movement / volatility there is in the GS%, the less stable the industry perceives the system to be.	40%
Contractual Protection	Scores the systems based on the level of stability that is offered from contracts. Concessions score the lowest, whilst jurisdictions with PSC regimes that are members of ICSID score highest.	20%

Figure 21 – Breakdown of fiscal stability score (5 is the most stable)



As illustrated in the above chart, NL ranks in the middle of the Peer Group. Relative to most of the other regimes, NL is challenged mostly by the changes in fiscal terms that have occurred in the past. However, the regime shows a relatively strong performance with respect to how GS% moves as prices change. The middle two blue sections of the bar are noticeably larger than those of many of the other regimes. This part of the scoring system ranks alongside fiscal changes with respect to relative importance from a scoring perspective.

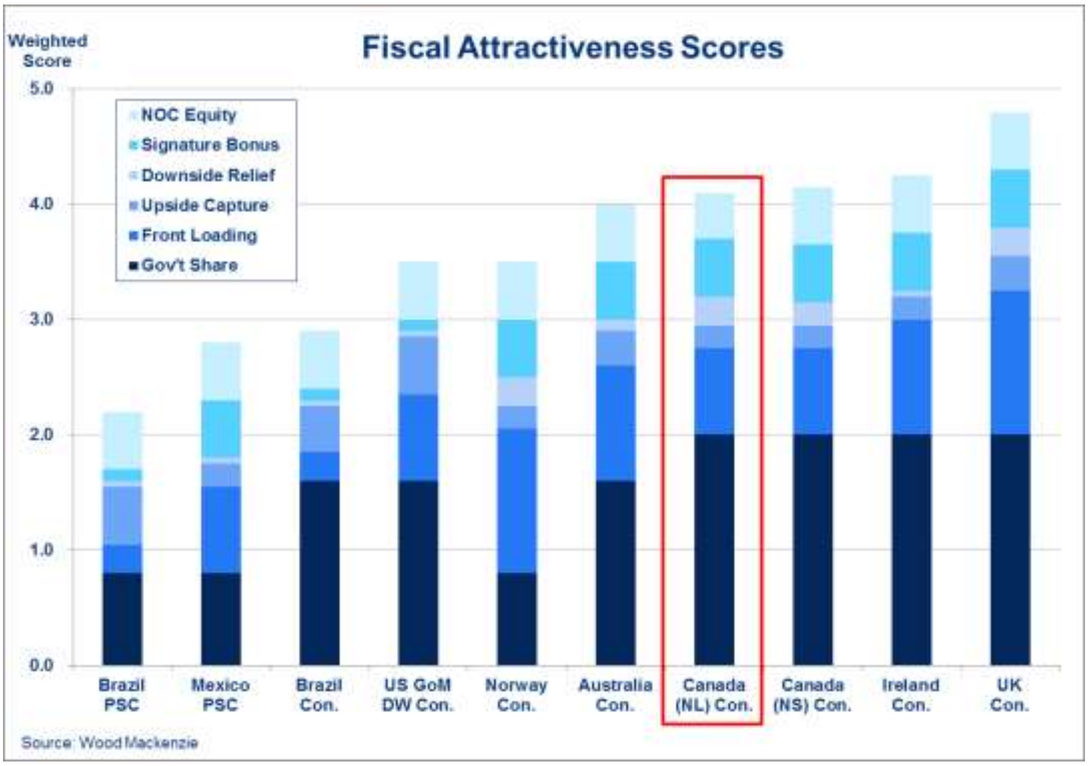
If the system flexes and adjusts so that the relative proportion of government sharing increases as profitability increases,(and decreases as profitability decreases) industry views the regime as being more stable. Specifically the system should not require to be changed by the government to capture more as prices and/or profitability increases, since such adjustments are already built in to the fiscal terms. A failure of the regime to adjust in this way is likely to mean that the government may need to adjust the regimes in the future, making it less stable.

NL shows a reasonably consistent GS% when prices move. The R-Factor structure for the royalty in offshore NL means that the royalty as a percentage of revenue will adjust as prices move. Once costs are recovered, and the maximum R-Factor tier is reached, this flexibility is less evident since the GS% approaches a maximum rate. However, by contrast, regimes such as the concessions in Brazil and US have material fixed royalty rates that do not adjust when prices move. This rigidity reflects a "regressive" system and although it can be attractive in terms of companies capturing upside, it does mean that the system is potentially unstable. Additionally, when prices drop, there is generally no "downside relief", for such regimes meaning the relative amount of GS% increases.

7.2 Fiscal Attractiveness

Factor	Description	Weighting
Government Share (GS%)	Measures the overall level of the governments' percentage share in the PSCF. The lower the GS%, the more attractive the system.	40%
Front-Loading Index	Measures the degree to which government sharing occurs early in a project's life	25%
State Equity	Measures the amount of required state equity and level of cost carry	10%
Signature Bonus	Scores the regimes based on the amount of bonus required to be paid at licensing	10%
Downside Relief	Measures the degree to which the GS% changes when prices decrease. Clearly, the system is perceived to be more attractive the more the GS% decreases, regardless of the direction of the price movement. Thus, if GS% decreases, the more attractive the system appears.	10%
Upside Capture	Measures the degree to which the GS% changes when prices increase.	5%

Figure 22 – Breakdown of fiscal attractiveness score (5 is the most attractive)



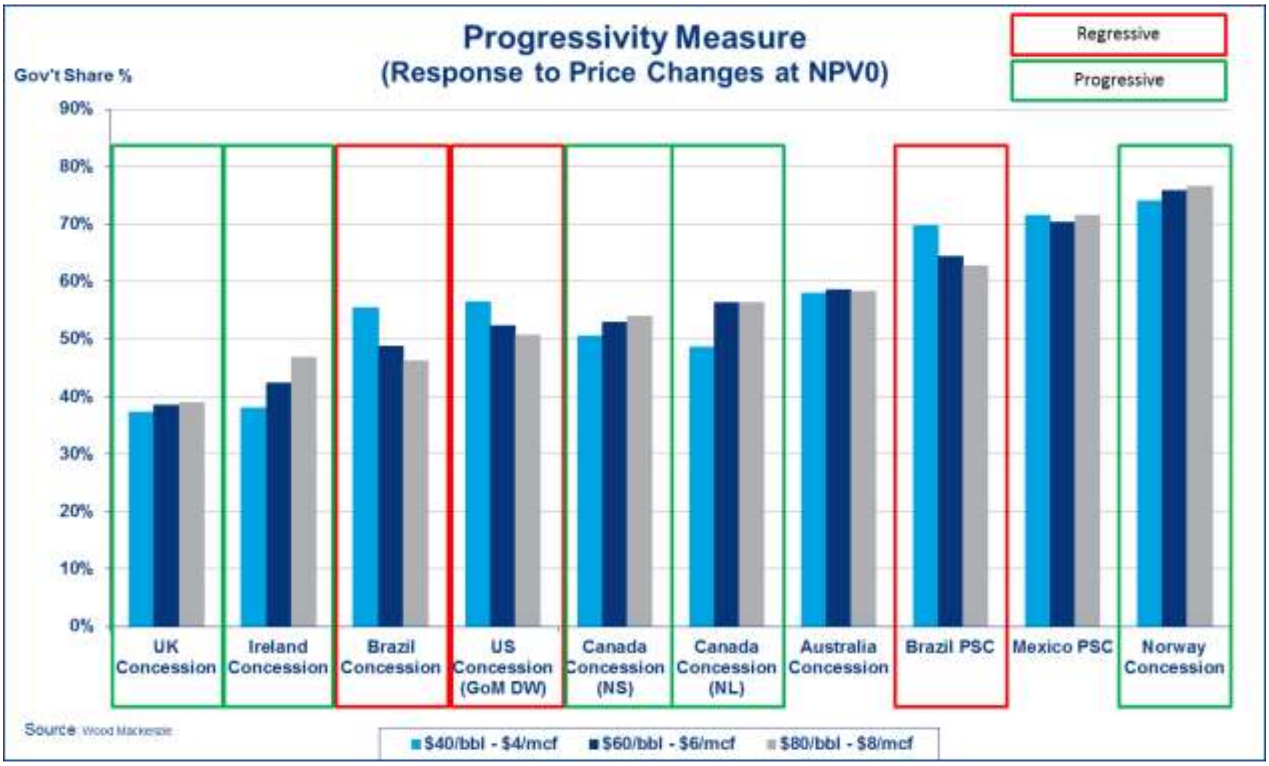
As the name suggests, "attractiveness" measures how investors perceive the system relative to competing regimes. Understanding the country's system from this vantage point provides another perspective on a country's position when competing for investment dollars. All else being equal, a regime will be considered more attractive if it allows the investor to retain relatively more economic rent than a similar project in another country.

The two categories that weigh the heaviest in the Attractiveness measure are GS% and frontend loading. All else being equal, NL has an expected GS% of around 50% for deepwater oil projects when prices are assumed to be $60 per barrel . The Government Share comprises royalty and Federal and Provincial corporate income tax (CIT). The GS% is a measure of how much of the pre-share profits (revenues less costs) flows to the Federal and Provincial Governments in the form of royalties and taxes. In addition a portion of the post share revenues will flow to Nalcor through their equity holding.

The rate for the shelf is slightly higher at 56%, but overall, NL is considered to be relatively less onerous than other regimes and ranks in the top position within the study under the GS% measure. Only two regimes outside of Canada, Ireland and UK, also receive the top score. The other key category, frontend loading, indicates the degree to which a fiscal structure pushes much of the financial obligations due to the government toward the front of the lifecycle of a given project. In this respect, NL's score is neither particularly good nor bad. There are some systems, such as Norway, that are considerably more backend loaded, with effectively all of the payments being a function of profit. For this Norway receives a high score. On the other end of the spectrum, regimes with fixed royalties and indirect taxes on capital, like in Brazil, score very low on the frontend loading scale and force the projects to pay the government very early in a given lifecycle.

Although it represents a comparatively smaller weighting in the scale, in addition to impacting stability, the degree to which the GS% moves with prices also impacts perceived attractiveness. Fixed royalty systems are typically symmetrical in their responses to price movements. There is usually a high degree of upside capture (ranking high on the scale), but the downside relief is very low (ranking low on the scale). The US and Brazil show this specific relationship. Both systems reflect good upside capture scores, but they also have the lowest downside relief scores. NL scores very similar to Norway in these categories. The opportunity for capturing upside is relatively low since the governments participate in all incremental profits, and it does so at a fairly constant rate. However, because the system is heavily influenced by profits, the governments also collect proportionally less as profits decline. Therefore, the downside relief offered is fairly high. Compared to the Peer Group, downside relief is a positive feature of the NL GORR, in terms of fiscal attractiveness.

Figure 23 – Progressivity of standard terms in each jurisdiction NPV0/undiscounted



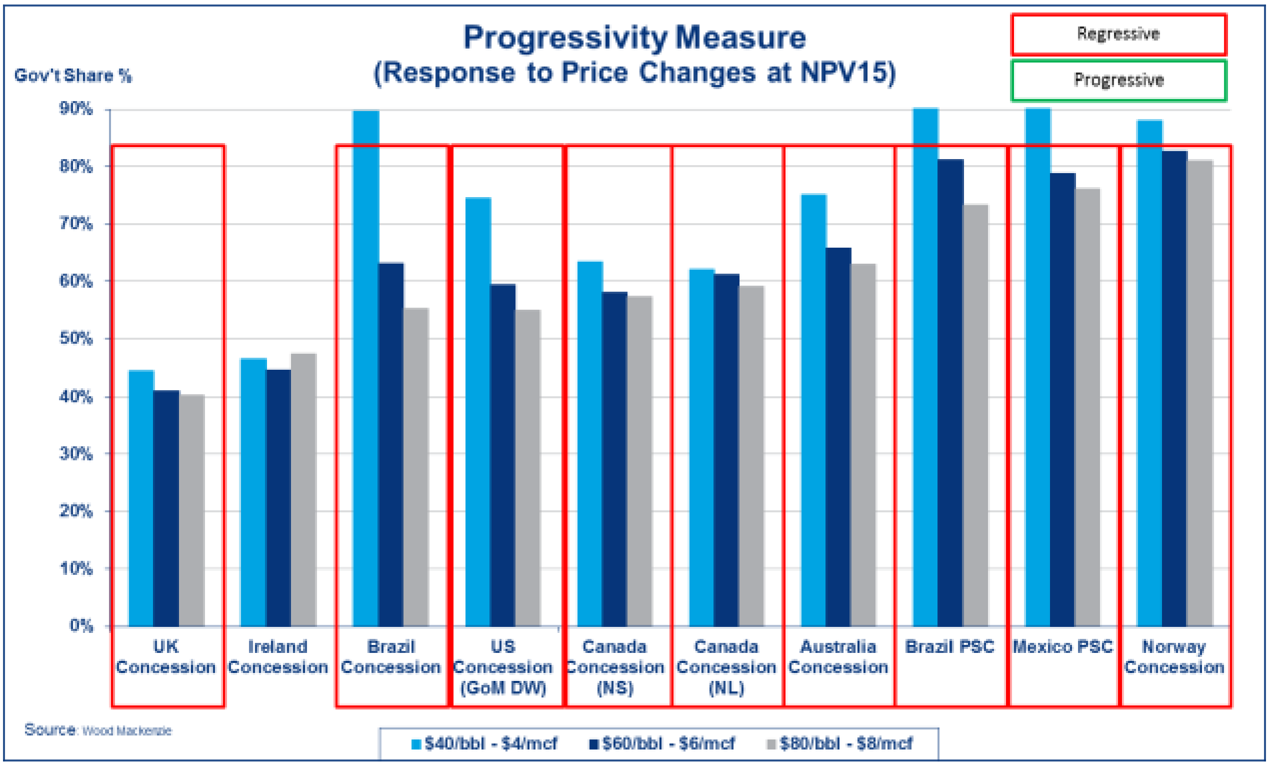
As illustrated in the above chart, the Brazilian and US systems are both regressive with changes in prices. A similar effect is noted when costs are adjusted. As the amount of PSCF increases (whether from increases in price or decreases in costs), the GS% decreases. While this relationship might seem attractive to investors, one must keep in mind that they are also very rigid. Therefore, as margins decline, the burden demanded by the government stays fixed as a percentage of revenue, and therefore the proportion of the net economic rent that the government receives increases. This relationship is illustrated above by the steep changes in GS% when moving from a low margin environment to a high margin environment or vice versa.

In progressive structures, such as in Norway and UK, as margins increase, the government keeps a consistent portion of the incremental economic rent. However, after reaching a certain level, the rate of increase drops substantially. Furthermore, if profits are low, the share that the government demands also drops to partially offset the lower realized margins. This relationship is also driven by the R-Factor system in NL.

The GS% metric is often quoted in undiscounted terms, but investors participate with an understanding of the present value of expected results. When one includes the impact of discounting on the calculations, systems typically become less progressive / more regressive as PSCF changes. As illustrated below, applying a 15% discount rate to the ratios shows that the present value of the GS% will either exacerbate the degree of regressivity or can reverse the characterization of a progressive system to one that is regressive. Government payments within systems that are backend loaded become relatively less impactful when viewed in present value terms. Thus, the GS% drops. By comparison, regimes that are heavily frontend loaded, like Brazil, will show a considerably higher degree of both GS% and regressivity.

The following chart highlights that in present value terms, almost all regimes in the Peer Group exhibit some degree of regressivity. Only Ireland stays relatively flat across all price cases.

Figure 24 – Progressivity of standard terms in each jurisdiction NPV15



The following chart shows the ranking of the fiscal terms across the Peer Group.

The key elements within those rankings are summarised below:

- Fiscal stability

  Mexico's relatively new PSC lands in the top spot, and the relatively inflexible concession in Brazil shows up as least stable. In contrast, NL benefits from its flexibility, but multiple historical changes and no contractual protection mean its stability score sits towards the middle of the Peer Group.

- Progressivity

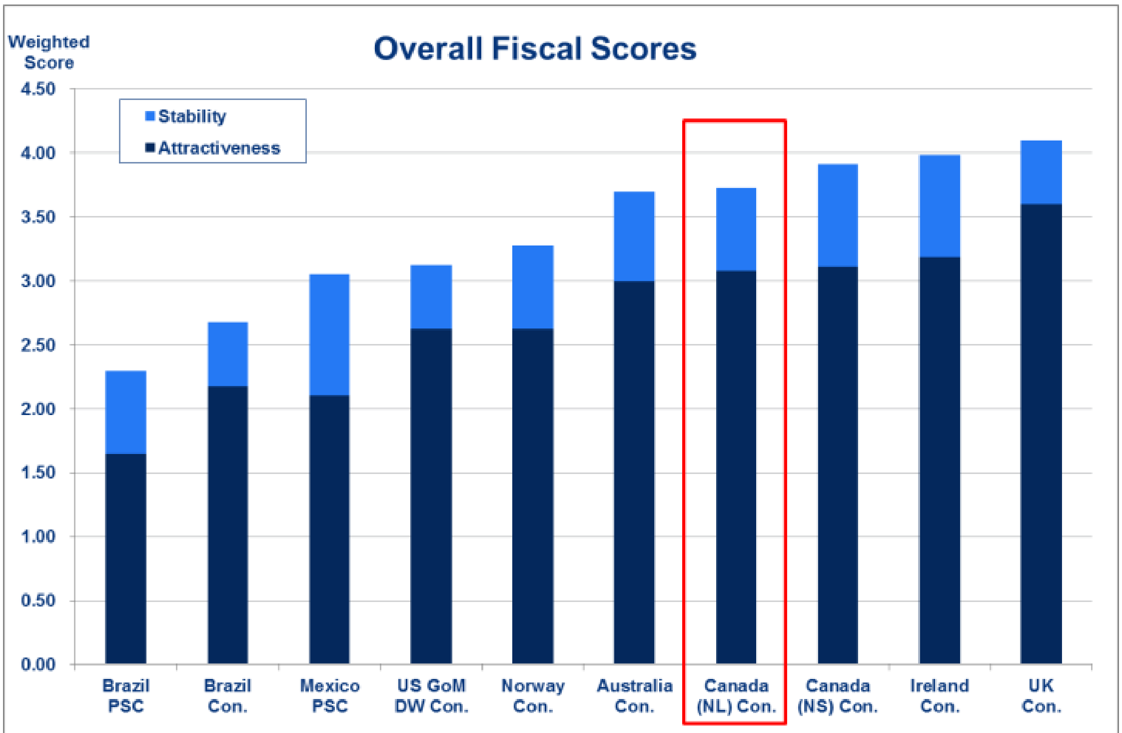
  This is very sensitive to the discount rates used. On an undiscounted basis, half of the regimes including NL show progressivity. On a discounted basis however all of the regimes show at least some element of regressivity. On both bases NL ranks better than average.

- Fiscal attractiveness

  NL is ranked towards the top of the group. A low GS% and effective downside relief are only offset by slightly more frontend loading and limited upside capture. However, the weighting of the scores means NL still shows up as relatively strong in this category.

  If a weighting is applied to each of the major categories, a final overall assessment is made. In the MCFS, the relative weighting is 75% for attractiveness and 25% for stability. Using this weighting, NL compares well against the Peer Group regimes.

Figure 25 – Overall ranking of weighted fiscal attractiveness and stability scores



Source: Wood Mackenzie

7.3 Exploration Incentives

Oil and gas regimes commonly include elements to incentivise activity that may otherwise not be economically viable. Such incentives can apply to development activity and exploration activity. In this section we look to see what exploration incentives are provided by the peer group countries to encourage investment in exploration.

Australia

Exploration costs are treated differently for Petroleum Resource Rent Tax (PRRT). Where deductions exceed revenues in any year, the excess is carried forward so it can be deducted in the following years. Losses are carried forward at a threshold rate, set at the Commonwealth long-term bond rate (LTBR), plus 5% for development costs and plus 15% for exploration costs. Exploration and development expenditure incurred more than five years prior to the award of the area's first production licence is compounded at the GDP factor (the GDP factor rate is based on the annual change to the GDP implicit price deflator index as first published by the Australian Bureau of Statistics - https://www.ato.gov.au/Rates/PRRT-augmentation-and-GDP-factor-rates/), rather than threshold rates.

For Federal Income Tax exploration costs are written off immediately when incurred, whilst development costs are written off over set time periods.

Brazil

There are no specific exploration incentives. Costs from outside the licence area (ring fence) cannot be offset against the special participation profits of the field, however, dry hole costs and seismic costs from within the original exploration licence can be offset.

Ireland

No specific exploration incentives.

Mexico

Under the Shallow Water PSC terms applying under the first shallow water licensing round a 25% uplift on exploratory costs was introduced for the purposes of cost recovery. . Additionally, these costs are allowed a 300% uplift for calculating the IRR used to control the IRR-based government profit share. .Such uplift only applies to costs that were included in the original work commitment. Such incentives have however, not been made available in subsequent rounds.

Exploration costs can be depreciated immediately for corporate income tax, compared to most development costs that are written off over four years on a straight line basis.

Newfoundland and Labrador

No specific exploration incentives, although exploration costs are written off immediately for corporate income tax purposes. Historical expenses, including exploration costs, that are certified by the government as pre-development under the royalty regulations are deductible within the royalty terms.

Norway

In Norway a relatively unique approach is applied to incentivising investment. Prior to 2005, companies without production income had to capitalise exploration costs until the company gained production. A radical change to the treatment of exploration costs was introduced in 2004 under which the Government decided to place companies that were not paying tax in the same position as those companies that paid tax. It did so by paying such non-tax paying companies an amount equivalent to the tax relief that such companies would have received for their exploration expenditure had they been in a tax paying position. Therefore the cost of exploration for tax payers and non-tax payers is made the same.

IN addition exploration costs are written off immediately against tax, unlike development costs that are written off on a straight line basis over six years.

Nova Scotia

No specific exploration incentives, although exploration costs are written off immediately for corporate income tax purposes. Historical expenses, including exploration costs, that are certified by the government as pre-development under the royalty regulations are deductible within the royalty terms.

United Kingdom

There are no specific exploration incentives in the United Kingdom. Certain reliefs are available to allow an uplift of costs by 62.5% but this covers both exploration and development costs.

United States (Deepwater Gulf of Mexico)

No specific exploration incentives are granted, although all unsuccessful drilling costs are generally expensed as incurred. This differs from the treatment of drilling and completion costs for successful wells. Tangible drilling and completion costs are considered to be well equipment costs and are depreciated over seven years using the modified accelerated cost recovery system (MACRS). Intangible drilling and completion costs (IDCs) are either (i) expensed (100%) as incurred (for independent producers), or (ii) split 70% expensed and 30% capitalised (for integrated producers).

Conclusions

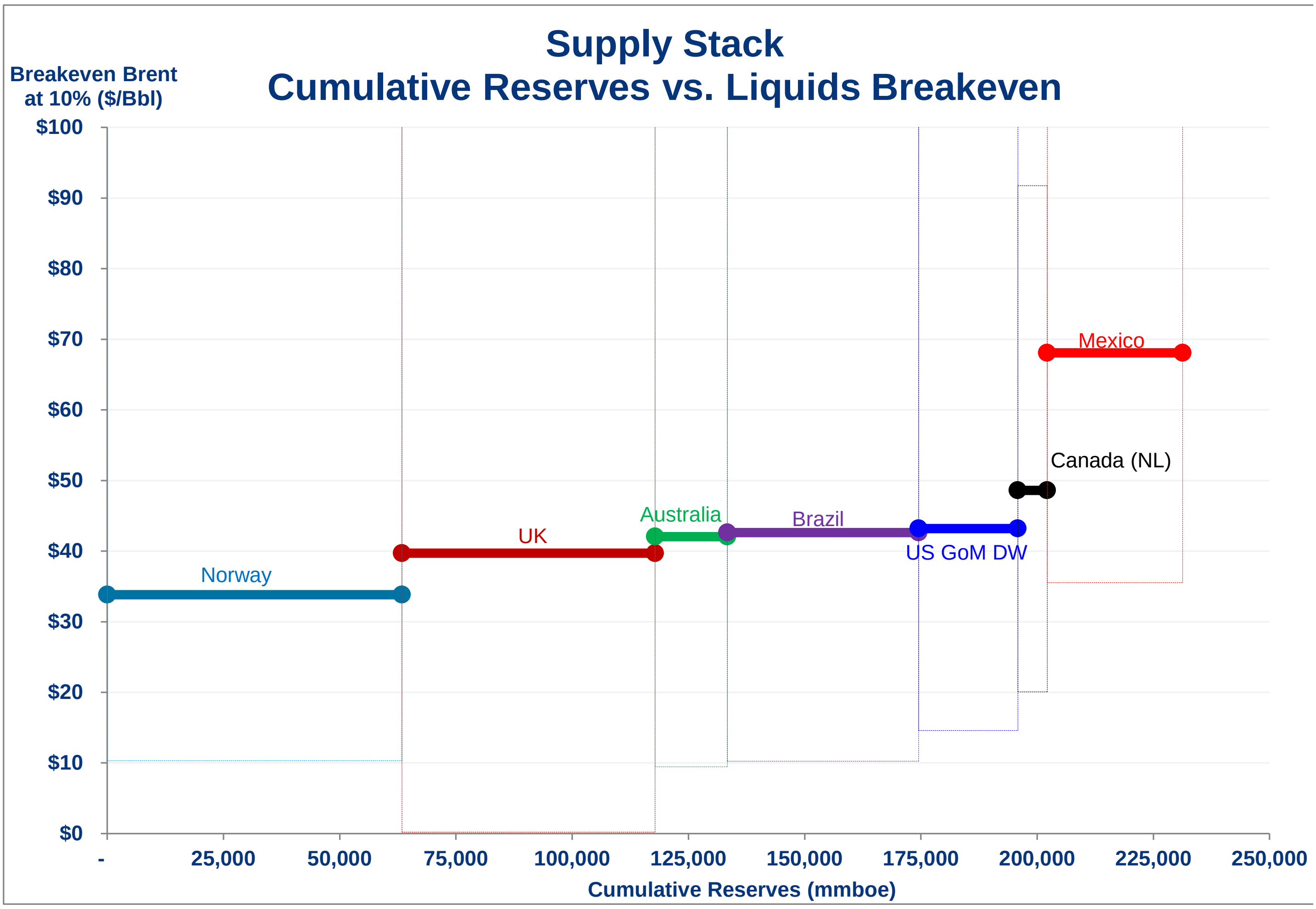
In summary, specific exploration incentives, that is incentives applying to all exploration costs and not to development costs, currently apply only in Australia. Mexico did grant exploration incentives in a prior licensing round and Norway gives support to a specific set of companies. More broadly many regimes allow exploration costs to be written off immediately, whilst development costs are usually depreciated over a number of years.

8. Breakeven price

One of the most popular measures of economic viability includes the price of oil that must be maintained in real terms for a prospective investor to achieve a minimum acceptable level of return, or breakeven price. Although the breakeven price is not the only economic factor that is analysed, it does allow for an initial overview of the relative price required within each regime. Analysing the price needed provides an all-in view on the underlying cost structure and the fiscal systems. A given country might have a very low cost environment that could support the government's argument to increase the government take. Conversely, in an effort to compete, another country, might attempt to mitigate the negative effects of a very costly area by minimizing the government take.

The breakeven price is an effective measure for capturing all the facets of developing a project. The following chart represents around 1,000 projects across the Peer Group that are either onstream, under development, will probably be developed or are 'good technicals', i.e. fields that could be economic under our current cost and price projections, but significant uncertainty remains over the nature and timing of their development (details of Wood Mackenzie's cost categories are provided in Exhibit C). The x-axis shows the sum of the reserves for each jurisdiction, and the y-axis shows the weighted average breakeven price of those reserves.

Figure 26 – Average breakeven by jurisdiction



The above graph illustrates the competitiveness of a country with respect to the economic viability of projects. Whilst NL has less onerous fiscal terms, the high capital and operating costs in the deepwater, as estimated by Wood Mackenzie, where much of industry's interest has been, mean that its projects sit behind those of most of the Peer Group. Mexico is the only country that shows breakeven prices higher than in NL.

9. Regulatory structure

The regulatory structure in NL has been compared with the peer jurisdictions across a number of assessment areas as follows:

- Licensing Frequency;
- Licensing Transparency;
- Exploration Permitting;
- Development Permitting;
- R&D; and
- Local Content.

Wherever possible this comparison has been carried out using quantitative information, but due to the variety of regulatory approaches that are taken, a qualitative assessment has been used in a number of instances. This qualitative assessment has been undertaken from the viewpoint of an IOC investing in each of the jurisdictions and the burden or uncertainty that any regulations or approaches place upon it in growing a position.

9.1 Gaining Access

9.1.1 Summary of Exploration Licence Types

Jurisdiction	Exploration Licence Length (Years)	Type	Notes on Exploration Contract Terms
Australia	6 – 11	Concession	Exploration permits are initially granted for six years, with the option of five-year renewal periods after that.
Brazil	8	Mixed	A typical exploration period for a contract is eight years, divided into three phases of generally three, three, and two years.
Ireland	3 – 16	Concession	There are four types of exploration licence with varying levels of terms: Standard Exploration Licence, Deepwater Exploration Licence, Frontier Exploration Licence and Reserved Area Licence
Mexico	4 – 10	Mixed	Initial exploration periods are for four years with two optional extensions of three years each. At the first extension 50% of the area must be relinquished
Norway	2 – 8	Concession	Biennial rounds for frontier acreage, annual for mature areas, bids assessed on technical, financial capability, existing interest, contribution to economy
Newfoundland & Labrador	6 – 9	Concession	The term is extended to 9 years if a well is drilled in the first 6 years of the licence term
Nova Scotia	5 – 9	Concession	Exploration Licences have a term of up to 9 years - the term is extended to 9 years if a well is drilled in the first 5 years of the licence term
UK	6 - 9	Concession	Varying levels of exploration terms depending on nature of acreage (frontier, harsh, etc.). Depends on nature of licensing round. Largely mature province but term incentives for challenging areas.
US GoM	5 – 10	Concession	Signature bonus bidding by pre-qualified candidates. Terms defined by water depth, between 5 and 10 years, extensions possible

9.1.2 Licensing Process

Australia

In Australia there have been two methods by which permits are awarded: a work programme bidding system and a cash bidding system.

The application for a permit under the work programme bidding system must be accompanied by details of the minimum amount of work (drilling, seismic, etc.), with estimated expenditure that the applicant is prepared to commit during each year of the permit term. This work must be completed to avoid the cancellation of the permit. This work programme competes against those submitted by other applicants. The application must also include the technical qualifications of the applicant, together with details of the technical advice and financial resources available to it.

Rescheduling of the annual work and expenditure commitments may be allowed only with the prior approval of the relevant authority. Satisfactory evidence that arrangements have been made to fulfil the requirement may be required if the work programme is to be delayed.

All data, including special studies, cores etc., are submitted to the relevant State Department. The basic information from these reports is released to the public when a licence or part of a licence is relinquished, surrendered or cancelled.

A cash bidding system was introduced in 1985. Unlike the work programme method, no commitments were necessary, with the exploration permit simply being awarded to the highest cash bidder. Cash bidding was reintroduced in 2013, however very few licences have been offered under this system and there have been no awards.

Highly transparent system with annual licence rounds.

Brazil

Bidding processes are completely transparent, with all bids opened in public and subsequently published on the ANP website.

Bids traditionally have the following elements, although recent pre-salt PSC rounds deviate from this norm:

- Formula for conversion of signature bonus, work commitments (seismic and drilling) and local content into a combined value
- The initial phase generally requires seismic, followed by drilling in phases two and three. Commitments are backed up by minimum expenditure guarantees.

Bidding criteria are transparent but the frequency of rounds tends to be adhoc rather than structured. Recent rights awarded to Petrobras in pre-salt PSC areas mean there is uncertainty on the process by which consortia are formed

Ireland

New licensing terms covering the award of exploration and production licences were brought into effect in 1992. In combination with an overhaul of the country's petroleum taxation system, in which royalties and production levies were abolished, the new licensing terms were introduced to encourage companies to commit to exploration licences and the drilling of wells by providing considerable tax benefits.

Although Ireland maintains an 'open door' approach to licensing, the 1992 reforms also introduced structured licence rounds. Companies are asked to nominate blocks of interest to be included within the round prior to the actual licensing of the acreage. Companies applying for licences must include statements concerning their policies on the safety, health and welfare of their workforce and on the environment.

The timing of the licence rounds has become much more structured in order to generate momentum for continued exploration of Ireland's frontier acreage. As a company progresses with its work commitments for one licensing round, a second area will be opened, freeing up new acreage and allowing the expansion of a company's portfolio in a structured progression.

In response to concerns over declining exploration activity, significant changes were made in 2003 to the terms of the Licence Option for exploration in the Celtic Sea. In a similar fashion to the Promote Licensing Round in the UK, the Department of Communications, Marine and Natural Resources approved more competitive terms that shortened the initial exploration licence and reduced rental fees. The objectives were to rejuvenate exploration in the Celtic Sea by making the Irish offshore sector more accessible to small and independent companies.

In August 2007, the Minister for Communications, Energy and Natural Resources announced new terms for offshore licences, in response to calls for the Government to ensure a greater return for the State from its natural resource. The new terms, which included both fiscal and non-fiscal changes, are applicable to all licences awarded after 1 January 2007. The main change was the introduction of a profit resource tax, in addition to corporation tax, that would increase the State's income in relation to a development's profitability. As well as fiscal changes, non-fiscal changes were introduced, including a reduction in the overall length of certain licences, increased licensing fees and a reduction in confidentiality periods for data. The fiscal changes were ratified in the Irish Finance Bill 2008.

These terms were superseded in 2014 with all licenses first awarded from 18 June 2014 containing the new Petroleum Production Tax (PPT) terms. The new Petroleum Production Tax is calculated by an R factor ratio based on the cumulative gross revenue less PPT paid relative to the cumulative field costs for each taxable period.

Award is decided by regulator based on:

- the work programme proposed by the applicant;
- the technical competence and offshore experience of the applicant;
- the financial resources available to the applicant;
- the applicant’s policy to health, safety and the environment; and

- where relevant, previous performance by the applicant under any authorisations to which the applicant has been a party

Transparent bidding process with an open-door policy and semi-regular official rounds.

Mexico – offshore

Until recently Mexico was essentially closed to IOCs. However in December 2013, Mexico approved a constitutional reform to revamp Mexico's energy sector. It opened the door for IOCs to participate in the upstream sector through service contracts, profit and production sharing contracts and licenses. Licenses work very similar to concessions. Licenses do not award mineral rights per Mexico's constitution, but they do allow companies to book reserves. Secondary legislation was subsequently passed to codify the reforms enabled by the constitutional change. The legislation was passed in August 2013.

The next step in the reform process was Round Zero in which Pemex chose which assets to keep and which to relinquish. Pemex could retain assets that were in production or that it had the capacity to develop. In terms of exploration acreage, Pemex needed to have drilled exploration wells or have done subsurface studies in those areas.

In November 2014, the Mexican government announced the launch of its inaugural licensing round. The round was launched in staggered phases.

1. Shallow-water exploration blocks.
2. Shallow-water discovered resource opportunities.
3. Onshore conventional fields.
4. Deepwater exploration blocks.

All opportunities awarded in Round One were offered through competitive licensing rounds, although transparency of the process was an issue, rectified in round two.

In July 2016, the Mexican government launched Round Two. The government has announced four phases and may announce more.

1. Shallow-water exploration and discovered resource opportunities. This phase concluded on 21 June 2017.
2. Onshore licensing of gas-prone acreage. This phase concluded on 14 July 2017.
3. Onshore exploration and discovered resources opportunities. This phase closed on 14 July 2017.
4. Deepwater. This phase will close in 2018.

In addition, in July 2015, the government published its 2015-2019 licensing plan. There are three rounds planned in addition to Round One. The government is planning to offer more than 750 opportunities covering 227,000 square kilometres in these three rounds. These opportunities will include deepwater exploration blocks, mature fields, and unconventional resources. The government will update the plan annually and will seek feedback from industry to offer the most attractive opportunities.

There is a regular licensing process established in Mexico but there have been delays, particularly in earlier rounds, and a lack of clarity around bid and selection criteria which Mexico continues to evolve with the aim of creating a fully transparent system.

Norway

In Norway licenses are offered to the industry in regular structured rounds. There are two types of licence round, the frontier round which is held every two years and the annual Awards in Predefined Areas (APA).

The first licensing round was undertaken in 1965, and the most recent round, the 23rd round was awarded in May 2016. This included blocks in the recently-demarcated area near the Russian border.

As part of the licence process, companies are first invited to nominate acreage to the Ministry, which then decides which areas to include in the round after a public consultation process. The area is then offered up for applications which can be made either by individual companies or by groups. The option to submit a group application has now become a standard feature of the licensing process since it was first introduced for the 2000 licensing round. The area is strategically offered by the Ministry to ensure that there are core areas of exploration and development. Following applications for licences, the Ministry of Petroleum and Energy in co-operation with the Norwegian Petroleum Directorate (NPD) formulate the awards.

Initial license periods are typically between two and four years, with full licence periods between four and eight years. The companies submit work commitments as part of the bidding process. These usually involve initial geological and seismic studies followed by the option for drilling in the second phase. Firm wells in the first phase are less common in frontier rounds. However, for the 23rd licensing round, the seismic studies had been conducted before the round and so five firm wells were committed in the first phase.

In 1999, an additional system of licensing was introduced by the Norwegian authorities, known as Awards in Predefined Areas (APA). Through this system, open acreage in the mature parts of the shelf is made available on an annual basis. A number of changes were made to the terms of the licences under the APA system, including a shortening of the licence periods, greatly reduced mandatory work commitments and the introduction of a formal timeline of key milestones that have to be reached for retention of the acreage. The aim is to reduce the level of fallow acreage and maximise the use of existing infrastructure, whilst facilitating access to acreage for new and smaller companies.

Licence periods are usually three to six years and agreed work commitments have to be reached to retain the acreage. This generally require seismic assessments during the first one to three years, followed by a drilling programme. At the end of the exploration phase, a decision must be made to proceed to develop any discoveries or relinquish the acreage. The licence can be relinquished at any stage if it is thought a commercial discovery is unlikely.

The award of licences is based on:

- the company's/companies' technical expertise;
- understanding of geology;
- financial strength; and
- experience (from the Norwegian shelf or other locations, other activities, etc.)

Very well understood and transparent process.

Nova Scotia

Prior to 2007, the Canada-Nova Scotia Offshore Petroleum Board (C-NSOPB) relied fully on industry to nominate parcels during a call for nominations. These could be submitted at any time but the C-NSOPB established a semi-annual cycle with a June and December call for bids.

During 2007, the C-NSOPB adopted a new strategic direction, with new flexible terms and conditions introduced for exploration licences. These include a lower minimum work expenditure bid, a delay in the payment of the work deposit, and a 150 per cent credit on allowable expenditures incurred during the first three years of a licence. In addition, the C-NSOPB has actively opted to pursue calls for bids, rather than rely on industry nominations. The exploration licences have an initial term of five years, which may be extended to nine years by drilling.

In Nova Scotia bids are assessed on highest Work Expenditure Bid determined by:

- the amount of money proposed to be spent on exploration of the respective parcel;
- research & development and education & training within Period 1 of the Exploration licence

The licensing process is transparent although the frequency of calls for bids is only semi regular.

United Kingdom

There were five types of available offshore licence awarded in the UK, until the 29th Round in 2016. Following the introduction of the Innovate Licence, all new offshore licences awarded by the OGA will be under this designation. However, the OGA and operators can tailor the flexible innovate licence to match the previous licence terms, if so desired. The currently contracted licences will remain until expiry.

The regulations contained within the Petroleum (Production) Act and the Continental Shelf Act govern how applications for licences must be made and by whom. For regulatory purposes, the UKCS is divided into quadrants of 1° longitude by 1° latitude. Each quadrant is numbered and contains 30 blocks, each with an area of 250 square kilometres. Divisions of blocks into part-blocks occur when the block is partially relinquished, which occurs when areas are particularly sought after or heavily licensed.

Licence holders are required to pay an application fee in addition to a licence fee, which is calculated for each square kilometre included in the licence area, for the initial term, and then subsequent payment for each year in the further term. As part of the 20th UK Offshore Licensing Round announced in January 2002, it was stated that Joint Operating Agreements would no longer be approved if they included pre-emption provisions, except in special circumstances. The rental fees were significantly reduced in the 29th Round.

In the UK there are regular rounds and out of round applications. Awards are made based on work commitments and companies must have the necessary financial and technical capability.

USA - Gulf of Mexico – deepwater

Licence, or lease, allocation in the Gulf of Mexico has generally been conducted on an annual or biannual basis under a cash bonus bidding system. The first federal awards, relating to Outer Continental Shelf (OCS) acreage, were made in 1954, deepwater activity did not commence until the mid-1970s

The administration of offshore leasing was divided among the coastal states, and two federal agencies until 1982, when the Department of the Interior established the Minerals Management Service (predecessor agency to the Bureau of Ocean Energy

Management, or BOEM) to manage the leasing of and receive revenues from OCS acreage. MMS conducted its first area-wide lease sale in May 1983 (Lease Sale 72).

Prior to 1983, the average number of leases awarded was around 375 per annum. Leasing activity increased greatly in 1983, with the introduction of the MMS's new leasing system. The subsequent slump in 1986 corresponds with a global drop in oil price at that time, although near-normal levels were established soon after. The other significant reduction in lease award activity occurred in the early 1990s, when industry interest in the region dwindled.

In 1983, a new system of block selection and allocation was introduced, whereby the Outer Continental Shelf was divided into the Alaska, Atlantic, Gulf of Mexico, and Pacific regions. Each region sub-divided into a number of 'planning areas.' GoM consists of the Eastern, Central, and Western Gulf of Mexico planning areas and 70 'protraction areas'. Each protraction area is then divided into hundreds of nine square mile (5,760 acres or 23.3 square kilometres) 'blocks' or 'tracts'

In general, Central and Western Gulf of Mexico lease sales are conducted on an annual basis. Eastern sales are less frequent, due to opposition by the state of Florida to oil and gas activities within 100 miles (161 kilometres) of its coast. The majority of proven reserves and existing infrastructure is located in the Central Gulf planning region, hence Central lease sales commonly generate a higher level of industry interest and subsequently higher revenues than Western Gulf sales.

Starting in August 2017, the Central, Eastern and Western planning area lease sales were held jointly.

Exploration and development rights are granted to authorised oil and gas companies through the allocation of specific 'leases', generally on the basis of one lease per block (or tract). Leases are allocated, usually, on a cash-bid basis (with no obligatory work commitments) via regular auctions, or 'Lease Sales'.

The vetting procedure is conducted by BOEM in two phases. Phase 1 is generally completed approximately two weeks after the lease sale date. Leases that are not awarded under Phase 1 are referred to Phase 2. Phase 2 can take up to three months, depending upon the number of high bids and the quantity of referred bids. BOEM is required to announce its final decisions on the selection of leaseholders within 90 days of the auction date. Due to the high numbers of bids at some recent sales, MMS/BOEM has sometimes taken longer than three months.

The frequency and blocks available under each lease sale are well understood, but there have been instances where the transparency of the allocation process has been called into question, particularly around minimum bid amounts and where there have been delays.

Newfoundland and Labrador

All activity in the NL offshore area requires authorisation by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB). NL has a land management cycle that companies must go through to submit bids and satisfy the criteria for award. Calls for bids on packages are submitted between March and November and a call for nominations occurs between October and December. Successful bids are awarded based on exploration spend on the respective parcel during the first five years of the licence. If the bid is successful then an exploration licence will be awarded for up to nine years. A well must be drilled in the first six years in order for the licence to qualify for the extension into the final three years or alternatively an annual drilling deposit of Cdn$5 million must be paid.

In 2013, the C-NLOPB implemented changes to the land tenure system to allow for increased call for bid timeframes in more frontier areas. As part of this, the Province has been divided into eight regions and right issuance cycles will be four, two and one years of length depending on the level of seismic and drilling information. These regions are Labrador North, Labrador South, North Eastern Newfoundland, Western Newfoundland and Labrador, Southern Newfoundland, South Eastern Newfoundland, Eastern Newfoundland and Jeanne d'Arc. Nominations can now be made for an area of interest, which at a later date will be followed with a call for parcels. Other changes included increasing Period 1 from five to six years for a well to be drilled, crediting allowable expenditures that are incurred after the call for nominations and before licence issue, and increasing the minimum bid to Cdn$10 million. No call for bids will close prior to 120 days after the completion of a strategic environmental assessment (SEA).

The sole criterion that the C-NLOPB will apply in assessing bids is the work expenditure bid (expressed in terms of the amount of money the bidder commits to spend on exploration within the first period of the exploration licence term (6 years)). A plan for future licence rounds is published five years in advance to ensure maximum transparency and to allow companies time to evaluate areas.

The process in NL is an open and transparent and frequency of rounds well understood.

9.2 Permitting Process

Comparing the permitting process across different jurisdictions can be a challenge given the unique nature of activities and developments in the oil and gas business and the pace with which different companies look to advance opportunities in accordance with their overall strategies and capital requirements.

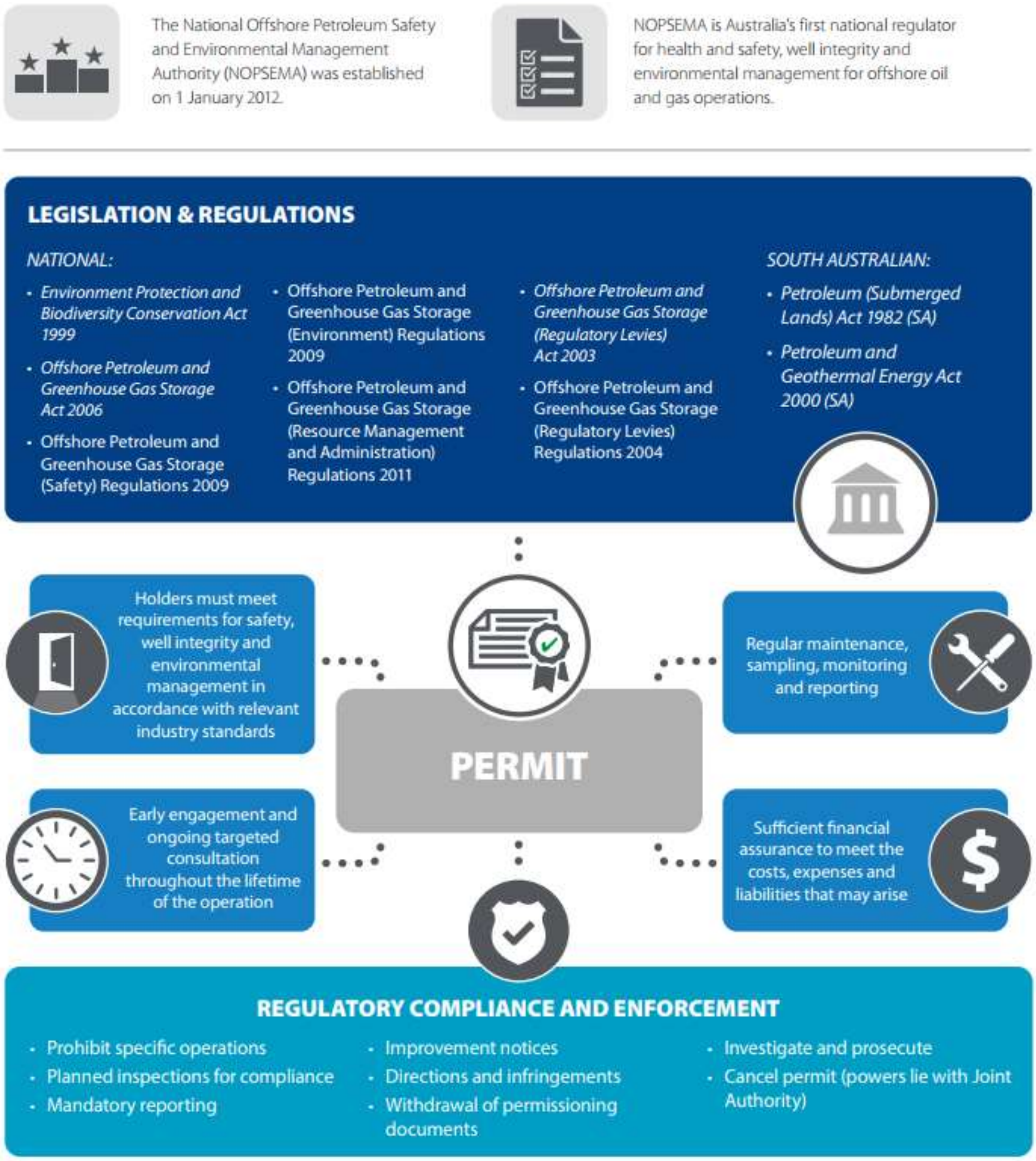
In order to determine how NL compares to other jurisdictions an assessment has been carried out to compare the different steps and approval bodies involved in the permitting for exploration activities and appraisal and development activities.

9.2.1 Exploration Permitting

Australia

In Australia there are a number of regulatory bodies involved in permitting, as shown in the diagram below.

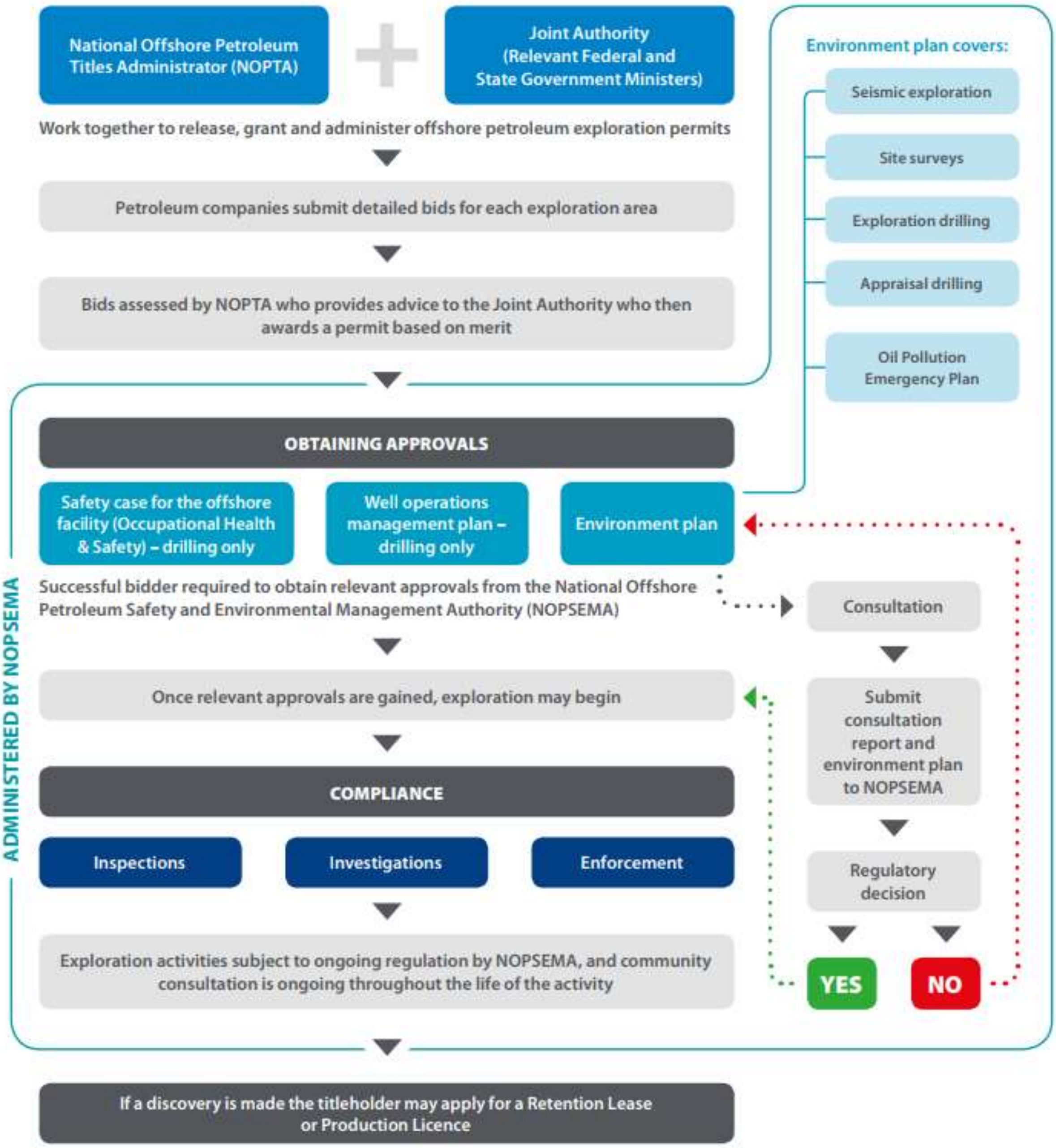
Figure 27 – Australian exploration permitting process



Source: The facts about offshore oil and gas exploration in South Australia, Government of South Australia

For exploration activities under the Offshore Petroleum and Greenhouse Gas Storage Act 2006, and associated regulations, approval will only be granted once the Commonwealth regulator, NOPSEMA, is satisfied that all impacts and risks to the environment are acceptable and will be reduced to as low as reasonably practicable. The authorities themselves declare that no offshore petroleum activity is allowed without stringent assessment. The approval process for offshore exploration is provided below. The most stringent element of the permitting process is around environmental approvals and in recent years this has delayed a number of high profile exploration campaigns from proceeding.

Figure 28 – Australian exploration approvals process



Source: The facts about offshore oil and gas exploration in South Australia, Government of South Australia

Overall the exploration permitting process can be onerous in Australia particularly where there are environment concerns.

Brazil

In Brazil the ANP (Agência Nacional do Petróleo) is Brazil's hydrocarbons resource manager and safety regulator for the industry. It has grown rapidly as part of Brazil's liberalization of the hydrocarbons sector. Over the course of its 19 years in existence, the ANP has drawn upon other countries' regulations and best practices, for example:

- Offshore operational safety regulations (ANP Resolution 43/2007) are based on a comprehensive study of regulations adopted in countries such as Australia, Canada, UK and the United States; and
- The ANP's database of seismic and well data, BDEP, is modelled on the Norwegian Petroleum Directorate database.

Regulation is performance-based for offshore safety while maintaining minimum requirements in areas such as mechanical integrity, contract selection, internal audits, etc. The ANP acts as a central clearing house, but relevant agencies support the regulatory requirements. For example, in terms of HSE requirements, the Maritime Authority and the Labour Ministry provide the subject matter expertise and ANP will not move without approval from each agency.

Both exploration and development plans are scrutinised on:

- Adherence to specific environmental and safety rules and standards; and
- Compliance with norms, technical and scientific procedures (including production rationalisation and control of reserves depletion). Deviations must be explained and justified. It is non-negotiable on environmental and HSE. Checklists provided by ANP ensure clarity and compliance by operators.

ANP acts independently despite being a government entity; funding is primarily through signature bonus payments and rental fees

Environmental regulator IBAMA is responsible for approving offshore environmental plans and sanctioning wells, but fragmented state environmental institutes regulate onshore assets. Delays in environmental permitting are a major operator concern in Brazil today, but the situation is improving

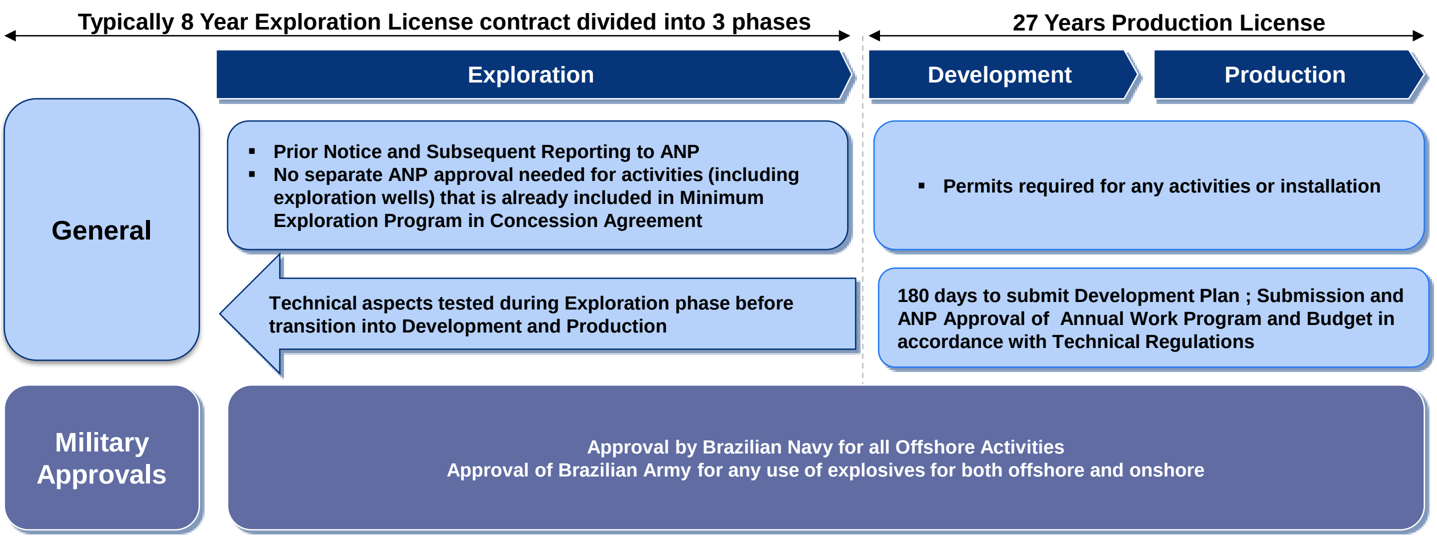
It takes IBAMA roughly 6 months to approve an exploration plan, but much effort goes into preparation, usually 1 year in advance of drilling. IBAMA may require the operator to meet with communities and get feedback on the plan before it is submitted. Once the plan is approved, each well must be a approved individually, which IBAMA can delay until just days before spud.

Civil servants are particularly conservative because they can come under legal pressure in the event of environmental damage, public prosecutors have pursued IBAMA employees in the past.

Issues related to oil and the environment are politically sensitive, so in presidential transitions, bureaucracy can grind to a halt.

A schematic of the approvals process in Brazil is provided below:

Figure 29 – Schematic of the Brazilian approvals process



The permits required for activity are relatively straightforward but in practice delays can significantly inhibit activity.

Permit requirements, all E&P activity

Exploration		Development		Production
Seismic Activity	Drilling and well operating consent	FDP	EPIC	Operational scrutiny and additional PDOs
Operational Permit (LO) requiring Environmental Study (EA)	Prior Permit for Drilling (LPer) requiring Environmental Control Report (RCA)	Prior Permit for Production test for Resource Evaluation (LPpro) requiring Environ. Feasibility Assessment	Installation Permit (LI) requiring Environ. Impact Study (EIA/RIMA) or Environ. Assessment Rpt (RAA)	Production and Operation Permit (LO) requiring Assessment of projects for minimizing environmental impacts

The permitting process in Brazil is akin to the process in Australia. The challenge is not the work programme or budget but is related to the necessary environment approvals from IBAMA which have been slow in recent years. The situation should be better in PSC (pre-salt) areas due to the intervention and role of Pré-Sal Petróleo S.A. (PPSA).

Ireland

In Ireland there are four main pieces of legislation which are currently relevant to petroleum industry operators. These are:

- Ambassador/Marathon Taxation Agreement 1960
- Licensing Terms for Offshore Oil and Gas Exploration and Development 1992
- Changes to the terms of the Licence Option 2003
- Licensing Terms for Offshore Oil and Gas Exploration and Development 2007

In order to explore the Irish offshore, or onshore, companies need to be issued an authorisation to do so by the Minister. For a standard exploration licence during the first phase of a Licence the licensee shall undertake, in respect of the area covered by the Licence, an exploration programme which shall be agreed with the Minister before the issue of the Licence. That work programme shall include the drilling of an exploration well. At least three months before the end of the first phase of a licence, a work programme for the second phase shall be proposed by the licensee for the approval of the Minister.

It shall be the responsibility of the authorisation holder to propose the details of work programmes which shall in all cases be submitted for the approval of the Minister prior to the commencement of such programmes. In granting approval the Minister may attach conditions including conditions relating to the nature, depth and location of wells.

Mexico – offshore

There are a number of key regulatory bodies in Mexico as follows:

CNH - National Hydrocarbons Commission responsible for promotion and execution of exploration and extraction agreements with private parties. Approves work programmes and plans, arbitrators for dispute resolution

SENER - Ministry of Energy determines the type of contract for each Call during the Bid Rounds, gives social impact authorisation, authorisation for import or export, permits for oil refining and natural gas processing activities

SHCP - Tax Administration with financial oversight of oil and gas permitting, not always aligned with other administrative functions as evidenced by lack of clarity around early rounds

CRE - Energy Regulatory Commission provides regulatory permits for export, tariffing, LNG plant permitting, marketing of oil, gas, petrochemical or petroliferous product (including those of PEMEX). Implements after advice from COFECE (Federal Economic Competition Commission) provisions in the case of actions that do not promote the efficient development of competitive markets. Arbitrators for dispute resolution.

ASEA - National Agency for Industrial Safety and Environmental Protection for the Hydrocarbons Sector regulates and supervises environmental protection and health and safety

The permitting requirements are governed by CNH's Guidelines for the approval of exploratory & production plans and Guidelines for Drilling Wells for Exploration and Production of Hydrocarbons. The Guidelines regulate well permitting, design, construction, integrity, maintenance, and abandonment standards and requirements for all oil, gas, and injection wells in Mexico, whether on-shore or off-shore, conventional or non-conventional. They regulate best oil field practices and standards for various activities; provide for inspection, audit, and enforcement; and, include provisions on operator and non-operator liability.

Given the opening of Mexico there is a lack of clarity around the rules and regulations for many activities common elsewhere.

Norway

The Ministry of Petroleum and Energy (MPE) is responsible for all aspects relating to petroleum and energy.

There are four departments in the MPE which are responsible for:

- E&P and market - covers issues relating to development, operation and transport for oil fields and marketing of oil and NGL;
- Petroleum - covers environmental issues, the petroleum supplies industries, the management of the relationship between the government and the states shareholding in Statoil, the State's Direct Financial Interest (SDFI) and Petoro AS. The department also supports in the preparation of government policies and legal issues;
- Energy and water resource department - Administration of land based energy generation, water courses and energy consumption; and
- Budgets and accounting - all administrative functions.

The Norwegian Petroleum Directorate (NPD) also reports to the Ministry of Petroleum and Energy. The NPD has four functions:

- The NPD is an adviser to the MPE;.
- The NPD has a national responsibility for data from the Norwegian continental shelf;.

- The NPD emphasises long-term solutions, upside opportunities, economies of scale and joint operations, as well as ensuring that time-critical resources are not lost; and
- In cooperation with other authorities, the NPD is to ensure comprehensive follow-up of the petroleum activities.

The NPD sets frameworks, stipulates regulations and makes decisions in areas where it has been delegated authority. Is responsible for conducting metering audits and collecting fees from the petroleum industry and the mapping of resources and petroleum data administration for the development aid programme "Oil for Development".

An exploration licence authorises geological, petrophysical, geophysical, geochemical and geotechnical activities. Shallow drilling may be carried out to a depth stipulated by the Norwegian Petroleum Directorate.

The Norwegian Petroleum Directorate may limit the individual exploration licence to apply to particular types of exploration. The Norwegian Petroleum Directorate may make it a condition for an exploration licence that information shall be given about sale or exchange of exploration results, and may stipulate conditions for the implementation of the exploration activities.

The licensee shall no later than five weeks prior to the commencement of activities according to an exploration licence, submit the following information to the Norwegian Petroleum Directorate, the Directorate of Fisheries and the Ministry of Defence:

- time, duration and accurate information about the area of the exploration activities, stating position lines;
- exploration methods to be used;
- what vessel is to be used; and
- the form in which the results of the exploration will be available.

In new areas for petroleum activities there are specific impact assessments required to include the following:

- A description of the area(s) planned to be opened for petroleum activities;
- A description of the relationship to national plans relevant for the area to be opened for petroleum activities, and of relevant environmental goals/standards laid down through national guidelines, national environmental goals, white papers and how these are reflected in the impact assessment;
- A description of assumed impacts on employment and commercial activities, as well as expected economic and social effects of the petroleum activities;
- A description of important environmental issues and natural resources, including an overview of the mapping that has been carried out;
- A description pursuant to the above of the possible transboundary effects of the opening;
- A description of the impact of opening the area for petroleum activities in relation to, i.e.: living conditions for animals and plants, the sea bed, water, air, climate, landscape, emergency preparedness and risk, and the joint impact of these;
- A short summary of the data and methods used to describe the impacts, and any professional and technical problems in relation to the collection and use of the data and methods;
- An assessment of the need for, and any proposals in relation to further investigation before the execution of the opening;
- An assessment of the need for, and any proposals in relation to investigations and measures to monitor and show the actual impacts of the opening and the potential measures to reduce and compensate any adverse effects of importance;
- A description of measures available to prevent or compensate for any possible damage and disadvantage.

This assessment must be submitted to the Storting.

Overall the process is well understood and there have been few instances of delays.

Nova Scotia

Petroleum exploration and production activities offshore Nova Scotia are regulated by the Canada Nova Scotia Offshore Petroleum Resources Accord Implementation Act of 1988. This Act resulted in a joint collaboration between the Government of Canada and the Government of Nova Scotia. Between them they formed a petroleum agency called the Canada-Nova Scotia Offshore Petroleum Board (C-NSOPB). The C-NSOPB is responsible for ensuring that all activities associated with offshore exploration and production are carried out in a regulated and safe manner, which will also benefit the Province. In addition, the C-NSOPB has the power to issue exploration and production licences.

All operators must receive authorisation from the C-NSOPB prior to conducting any petroleum-related activity in the offshore Nova Scotia area including seismic surveys, drilling, development and production activities. The C-NSOPB also has a strong environmental protection plan and the assessment starts at the call for bids stage when potential bidders must submit an environmental impact study.

An operator must make application to the C-NSOPB for authorization on one of the following activities:

- Certificate of Fitness Form;
- Declaration of Operator;
- Diving Program Authorization;

- Geophysical Work Authorization Application;
- Geotechnical/Geological/Engineering/Environmental Program Authorization;
- Operating Licence;
- Operations Authorization - Drilling Application;
- Operations Authorization - Install/Remove Application;
- Operations Authorization - Production Application;
- Well Approval: Approval to Alter the Condition of a Well;
- Well Approval: Approval to Drill a Well Application; and
- Well Termination Record.

Focusing on the drilling application companies must provide information on:

- a description of the scope of the proposed activities;
- an execution plan and schedule for undertaking those activities;
- a safety plan that meets specified requirements;
- an environmental protection plan that meets specified requirements;
- information on any proposed flaring or venting of gas, including the rationale and the estimated rate, quantity and period of the flaring or venting;
- information on any proposed burning of oil, including the rationale and the estimated quantity of oil proposed to be burned;
- in the case of a drilling installation, a description of the drilling and well control equipment;
- in the case of a production installation, a description of the processing facilities and control system;
- in the case of a production project, a field data acquisition program that allows sufficient pool pressure measurements, fluid samples, cased hole logs and formation flow tests for a comprehensive assessment of the performance of development wells, pool depletion schemes and the field;
- contingency plans, including emergency response procedures, to mitigate the effects of any reasonably foreseeable event that might compromise safety or environmental protection, which shall
  - provide for coordination measures with any relevant municipal, provincial, territorial or federal emergency response plan, and
  - in an area where oil is reasonably expected to be encountered, identify the scope and frequency of the field practice exercise of oil spill countermeasures; and
- a description of the decommissioning and abandonment of the site, including methods for restoration of the site after its abandonment.

The process in Nova Scotia is clear and transparent and approvals required in line with common industry practice.

United Kingdom

Applications for exploration permitting are regulated by the OGA and Department for Business, Energy & Industrial Strategy. Prior to any activity the key requirement is that the operator has passed the requirements for exploration operators:

- Capability to plan, supervise, manage and undertake the proposed exploration operations including interfaces with contractors
- Arrangements for pollution liability;
- Details of the management of environmental responsibilities (including the company's environmental policy and environmental management system);
- Details of past record of compliance with environmental legislation; and
- Insurance coverage.

Prior to any activity an application for consent to drill exploration, appraisal, and development wells must be made. This application must be submitted not less than 21 calendar days prior to expected start of operations. The following information must be provided:

- Basic well data should be supplied;
- Prospect summary sheet;
- One sheet should be submitted for each major reservoir target. The scale of the map should be shown, and the direction of North indicated if not the usual top of the form. At least two reference Latitudes and two reference Longitudes should be annotated;
- Seismic depth map and representative seismic section A depth map should be provided at an appropriate scale (1:10,000, 1:25,000 or 1:50,000) on top of or near to the prospective horizon(s), with the surface and planned bottom hole locations indicated, where applicable. One or two representative seismic sections, preferably through the well location, would be helpful;
- Synopsis briefly describing the geological rationale and objectives of drilling the well;
- Sampling/coring/logging and testing programme;
- An indication of the mud type and proposed weight of mud for each casing interval; and
- Details of proposed well testing operations. If no testing is planned, give reasons.

Overall the regulations are straight forward and alongside the operator pre-qualification give the assurance necessary to the OGA.

USA - Gulf of Mexico – deepwater

The key federal regulatory bodies responsible for petroleum exploration and production are the Bureau of Safety and Environmental Enforcement (BSEE), Bureau of Ocean Energy Management (BOEM), and the Office of Natural Resource Revenue (ONRR). The agencies were formerly in one organization, called the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE), which used to be the Minerals Management Service (MMS). The agencies are a division of the US Department of the Interior (DOI).

Other agencies having jurisdiction over hydrocarbon exploration, development, and production operations on the OCS include: the Environmental Protection Agency (EPA), the Department of Transportation (DOT), the Department of Homeland Security (DHS), the United States Coast Guard (USCG), the US Army Corps of Engineers (COE), and the Federal Energy Regulatory Commission (FERC).

Various key administrative procedures dictate the activities of the lessee, once a lease has been issued. Submissions must be made to BOEM regarding all aspects of industry activity including exploration, development, production and abandonment.

An Exploration Plan (EP) and its supporting information must be submitted for approval to BOEM and BSEE before an operator may begin exploratory drilling on a lease. The EP describes all exploration activities planned by the operator for a specific lease(s), the timing of these activities, information concerning drilling vessels, the location of each well, and other relevant information.

A 'revised plan' is a revision to an approved EP that proposes changes such as surface location, type of drilling unit, or location of the onshore support base. A 'supplemental plan' constitutes a revision to an approved EP that proposes additional activity that requires a permit. An 'amended plan' is any revision to an EP pending approval. Each of these types of plans need contain only information related to or affected by the proposed revision.

Drilling requires a Application for Permit to Drill (APD). Prior to conducting drilling operations, the operator is required to submit and obtain approval for an Application for Permit to Drill (APD) for each well. The APD is filed by the lessee/operator along with, or following submission of the EP or Development Operations Coordination Document (DOCD) and supporting information.

The APD requires detailed information about the drilling programme for evaluation with respect to operational safety and pollution-prevention measures. Approval of an APD requires a BSEE-approved EP or DOCD, and receipt or presumption of Coastal Zone Management (CZM) consistency concurrence. The approved APD constitutes the drilling permit.

Any activity that deviates from the APD plans must be submitted for approval in the Application for Permit to Modify (APM). These activities include recompletion, repair, and abandonment. The results of the modified activity must be submitted as well.

A Well Activity Report is required to be submitted weekly to BSEE during drilling operations, no later than seven days after the end of the reported week. The reports include detailed well information including logs, surveys, and core samples.

A Rig Movement Notification Report must be submitted within 24 hours of a rig arriving or departing a wellsite. Qualifying facilities include drilling rigs, workover rigs, and coiled tubing and snubbing units.

An End of Operations Report must be submitted to the BSEE District Office within 30 days of the initial abandonment or initial completion or recompletion of a well, detailing copies of logs, cores, and DST/well test results.

An operator must submit a Well Test Notification to BSEE if it wishes to test the well in order to qualify it as capable of producing in paying quantities.

An Application for Determination of Well Producibility must be submitted for the determination of a well's capability to produce, to place a lease on minimum royalty, and to obtain a Suspension of Production (SOP).

Overall requirements are considered reasonable and easy to navigate in the US Gulf of Mexico.

Newfoundland and Labrador

The C-NLOPB manages the petroleum resources in the NL Offshore Area on behalf of the Government of Canada and the Government of Newfoundland and Labrador. The C-NLOPB's responsibilities include:

- granting and administering offshore areas interests ("land sales");
- authorizing seismic and drilling programs;
- declaring significant and commercial discoveries.

Before carrying out any work or activity respecting petroleum operations in the NL Offshore Area, an Operator must obtain both an Operating Licence and an Authorization as specified by sections 137 and 138 of the Atlantic Accord Act. A centralized regulatory coordination function has been established within the C-NLOPB to ensure a consistent and timely review of applications for authorizations and approvals.

In order to obtain an authorization, the Operator must ensure that the statutory and regulatory requirements pertaining to the work or activity are satisfied. These matters pertain to:

- Safety
- Environment
- Resource Management
- Exploration
- Legal and Land
- Industrial Benefits

Exploration activities and other activities that do not involve development activities can be carried out without a Development Plan Approval.

The three types of authorizations administered by the C-NLOPB include:

- Operations Authorization - An Operations Authorization (OA) may include a drilling program, a production project, well operations, or all three activities.
- Geophysical Program Authorization - Operators applying to undertake a seismic program, a wellsite seabed survey, vertical seismic profiling, an electromagnetic program, or any other type of geological or geophysical program, (including a program that does not involve any fieldwork), a geotechnical program or an environmental program, may obtain a Geophysical Program Authorization (GPA) by submitting an application to the C-NLOPB.
- Diving Program Authorization - A Diving Program Authorization (DVPA) may be obtained by submitting a Diving Program Authorization form to the C-NLOPB. The application should be made six months in advance of the anticipated commencement date of the program.

The Exploration Permitting process in NL is clearly spelled out and transparent.

9.2.2 Development Permitting

Australia

After making a discovery, the permit holder must declare a 'location' by identifying which graticular block or blocks constitute the discovery. The permit holder then has two years, with an option to apply for a further two to four years, to consider whether to apply for a production licence or a retention lease, depending on the commerciality of the discovery. During this period the permit holder may apply to alter the size of the location, or indeed to have it revoked completely if the discovery is thought to be ultimately non-commercial.

If the permit holder makes a non-commercial discovery that has a reasonable chance of becoming commercially viable in the next fifteen years, a retention lease may be applied for. A retention lease has a five year duration and may be extended for further five year term. It may require a work programme that would lead towards improving the commercial viability of the reserves. At each renewal, the permit holder must demonstrate the likelihood of the discovery becoming commercial within the following fifteen years.

Once the commerciality of a discovery has been established, the licence holder must submit a formal application for a production licence to the relevant Authority prior to development commencing. The application is vetted by the appropriate State or Federal Authorities and a production licence is only issued once all technical and environmental conditions have been met. Following amendments to the Petroleum (Submerged Lands) Act 1967 in July 1998, new production licences and third term renewals are now awarded for a term which expires five years after the cessation of production.

Brazil

Acreage surrounding any potentially commercial discoveries can be retained so long as the, operator agrees an Evaluation Plan with the ANP. The maximum allowable time for agreeing the Evaluation Plan is 180 days after the expiry of the exploration licence. Under the current system all discoveries have to be reported to the ANP immediately, regardless of commerciality.

If commerciality is declared, the ANP will then grant the standard 27-year development licence for the field, becoming effective on the date that the Evaluation Period expired. The operator then has 180 days to submit a Development Plan, which must be approved by the ANP within 60 days. A Development Area is defined and acreage outside of this area must be relinquished. There may be multiple Development Areas within a single Concession Contract area. An extension to the 27-year development licence may be requested in advance of the expiry of the contract.

In Brazil, the ANP will grant extensions if there are issues beyond operators control that have delayed projects, such as the when the environmental regulator takes longer than usual to extend a license. To date, there have been no instances where a contractor is forced to stop producing when a license expires. However, it is important to note that Petrobras is a participant in most of the fields in Brazil.

Ireland

When a discovery has been declared commercial, a company can apply to convert an Exploration Licence to a Petroleum Lease, which allows for production to take place. The PL will cover the area of the discovery rather than a specified block, and its duration will cover the life of the field. The application cost for a PL is €9,122 and there is an annual fee of €2,643 per square kilometre until first production. From first production an annual fee of €4,133 per square kilometre is payable.

If it is thought that a discovery may be commercial, and the government agrees, a Lease Undertaking can be issued under which the government undertakes to grant a Petroleum Lease in the future. The Petroleum Lease will be awarded under the standard terms. The application cost for a Lease Undertaking for one year is €3,040. There is an initial annual fee payable of €1,216 per square kilometre, and this fee increases by €152 per square kilometre in each subsequent year. The Leaseholder must also hold a Petroleum Prospecting Licence, which effectively governs any work carried out as part of the Lease Undertaking. A Petroleum Prospecting License typically covers a three year period.

In the case of a gas discovery the applicant may either choose a date for the Petroleum Lease to become effective that is up to eight years from the date of notification, or is six years or less from the date of expiry of the Exploration Licence. For an oil discovery the applicant may choose a date which is up to five years from the date of notification, or a date of three years or less from the date of expiry of the Exploration Licence. Petroleum Leases have a 21-year duration and are awarded under special terms which include a drilling commitment. There is no specific work commitment for a Lease Undertaking other than the establishment of the commerciality of the discovery.

The Corrib development is one example of potential delays due to technical and licensing issues in Ireland. However, the government was active in the negotiations and was willing to work with the contractors to work out a solution. The Corrib development was originally expected to come onstream in 2003, but the project has been beset by a number of delays related to planning approvals for the Bellanaboy gas processing terminal and the route of the onshore pipeline. The offshore pipeline was installed in the summer of 2009 and the installation of subsea infrastructure which began in 2008. The decision on planning permission for the re-routed pipeline was deferred in late 2009 pending revision of the pipeline route from landfall at Glengad to the terminal at Bellanaboy via a tunnel under Sruwaddacon Bay. The field partners submitted the revised route proposal in June 2010. Following a series of public consultations in late 2010, strategic infrastructure approval was granted by An Board Pleanála (ABP) in January 2011.

Mexico – offshore

Given the early stage of the opening of the Mexican sector it is currently unclear the process that will apply to development approvals.

Norway

To achieve commerciality and development approval three regulatory stages are required for the field and infrastructure developments:

- submission of a proposal for an environmental impact assessment to be carried out;
- conducting an environmental impact assessment; and
- submission of a PDO.

When a commercial discovery has been adequately appraised and the environmental impact assessment favourably concluded, the operator will submit a PDO to the Ministry so that the field can be developed. Depending on the scale of the project both the Ministry and Storting (parliament) need to approve the plans before the development may proceed.

Norway's government has shown to have a pragmatic approach in handling potential issues with regards to development and licensing. One example is the Ekofisk development which was discovered in the 1970s and was the first development on the Norwegian Continental Shelf. Production did not start until 1999 due to concerns over the safety of operations due to subsidence.

In addition, the installation of the concrete wall around the Ekofisk Tank was considered to have compounded problems by impeding air circulation around the processing and compression facilities. Furthermore, the authorities were concerned over possible disruptions to gas sale contracts. In 1992, the Norwegian Petroleum Directorate (NPD) served an injunction on the Phillips Group, demanding a long term solution to the subsidence problem. In late 1993, Phillips submitted a PDO offering two redevelopment scenarios. The first included a complete redevelopment of the field outside of the subsidence bowl, whereas the alternative was moving processing facilities from the Tank and upgrading other existing facilities to meet safety requirements.

To incentivise the development of the project, the Norwegian government extended the duration of the contract to 2028 and exemption for royalties on oil and wet gas production were granted once the 2/4-J processing and transportation platform was brought onstream. In return, the Norwegian government acquired a 5% direct financial interest in the development and funded its share of redevelopment costs.

Nova Scotia

In Nova Scotia for a development to proceed a development plan must be submitted, except with the consent of both the federal and provincial Ministers of Natural Resources, to the C-NSOPB to authorize any work or activity in relation to developing a pool or field. The Development Plan must be set out in two parts a description of the general approach of developing the pool or field and all technical or other information and proposals, as may be prescribed, necessary for a comprehensive review and evaluation of the proposed Development.

The general approach must include:

- the scope, purpose, location, timing, and nature of the proposed Development;
- the production rate, evaluations of the pool or field, estimated amounts of petroleum proposed to be recovered, reserves, recovery methods, production monitoring procedures, costs and environmental factors in connection with the proposed Development; and
- the production system and any alternative production systems that could be used for the Development of the pool or field.

The approval of Part I of the Plan is a "fundamental decision", meaning that notice of the decision must be given to the federal and provincial Ministers of Natural Resources. The decision cannot be implemented for 30 days after notice has been given to the ministers, unless both ministers approve it before that time. In addition, either the federal or the provincial minister may suspend implementation of the decision for up to 60 days after receipt of the notice.

Before the C-NSOPB may approve any Development Plan or authorize any work or activity, a Canada-Nova Scotia Benefits Plan must be approved by the C-NSOPB, unless the C-NSOPB waives that requirement.

Under the Accord Act and regulations the C-NSOPB has a requirement to satisfy itself that activities associated with the Development Project can be conducted in an environmentally safe manner prior to authorizing those activities. The C-NSOPB accomplishes this by, among other things, undertaking an environmental assessment of the Project. The Canadian Environmental Assessment Act also requires an environmental assessment to be undertaken by responsible authorities for projects identified in the Canadian Environmental Assessment Act or its regulations. The Applicant seeking approval of a Development Plan shall prepare an Environmental Impact Statement outline based on the requirements of these guidelines with input from the public.

Where the C-NSOPB is of the opinion that it is in the public interest to do so it may conduct a public review in relation to the exercise of any of its powers as per the Guidelines On Plans And Authorizations Required For Development Projects 5 08/16/95.

If a public review is conducted, the C-NSOPB will require the applicant to prepare a summary of its application and the various plans and statements to be considered, for wide distribution to the public.

The Development Plan will not grant the applicant authority to undertake any work in the offshore area. Prior to work being undertaken, job-specific authorizations are required from the C-NSOPB.

United Kingdom

Authorisation is required from the OGA to install facilities or produce hydrocarbons. When considering whether to authorise a proposed field development, the OGA will take into account whether the proposed project supports the MER UK strategy and wider government policy objectives.

The process aims to review aspects of the field development plan that relate to the OGA’s principal objective to maximise the economic recovery of UK offshore oil and gas, and to identify those aspects on which the views of the OGA and licensees may diverge.

The outcome will be a Field Development Plan (FDP) document that provides a summary description of the actual development, the principles and objectives that will govern its management, and how those objectives will be achieved.

The OGA considers the economics of field and incremental developments as part of the assessment of field development programmes. Environmental Impact Assessments will be required for most new offshore oil and gas developments. The environmental aspects of offshore oil and gas activity are the responsibility of Department for Business, Energy and Industrial Strategy (BEIS, formerly DECC). An Environmental Statement (ES) describing the environmental impact assessment needs to be submitted to BEIS as part of the project authorisation process.

All environmental statements are subject to a period of consultation during which time any person or body with an interest in the proposed development may make their views known to the Secretary of State. The Environmental Impact Assessment process generally proceeds in parallel with the preparation of the FDP. Licensees should bear in mind that the consideration of an environmental statement generally takes several months and can take significantly longer than this if substantial representations are made by any of the consultees or members of the public, or if insufficient information is presented within the environmental statement.

Safety is the responsibility Offshore Safety Directive Regulator (OSDR), a separate government body to the OGA.

Design Notifications (or Relocation Notifications where applicable) may be required under the Offshore Safety Directive.

The development will be authorised (i.e. the necessary consent/approval granted pursuant to the applicable model clauses and/or EIA regulations) once the OGA is satisfied of the following:

- The FDP meets the OGA's MER UK policy objectives
- The Environmental Impact Assessment process has been completed successfully
- A proposed Field Determination has been issued
- Where appropriate, a Unitisation and Unit Operating Agreement has been put in place
- Each licensee has approved funding sufficient for their share of the development costs
- The OGA has approved a Field Operator for the development
- BEIS Offshore Decommissioning Unit are satisfied that appropriate decommissioning security arrangements are in place

The operator needs to submit a formal application for the necessary consents via the oil and gas portal.

USA - Gulf of Mexico – deepwater

A development and production plan and supporting documentation must be submitted for approval to BSEE before an operator may begin development or production activities. A Development Operations Coordination Document (DOCD) is considered a development and production plan for the purpose of any references in any law, regulation, lease provision, agreement, or other document referring to the preparation or submission of a plan.

The plan describes a schedule of development activities, platforms, or other facilities including environmental monitoring features and other relevant information. Supporting documentation may include environmental information, archaeological reports, biological reports, or other environmental data determined necessary.

After receiving a DOCD, BOEM prepares either a Categorical Exclusion Review (CER), an Environmental Assessment (EA), and/or an Environmental Impact Statement (EIS). As part of the review process, the DOCD and supporting environmental information, as required, are sent to the affected state(s) having an approved CZM plan for consistency certification review and determination. On the basis of the findings of the CER, EA, or EIS, and the plan completeness review, the plan is either approved or disapproved, or a modification of the plan is requested. After plan approval, the operator submits for approval specific applications to BOEM, such as those for pipelines and platforms, to conduct activities described in the plan.

Effective as of 19 August 1996, a Deepwater Operations Plan (DWOP) must be approved by BSEE prior to the commencement of a deepwater development or utilisation of subsea production technology. In this context, BOEM defines deepwater as in water depths over 1,000 feet, or 305 metres.

The DWOP is required to demonstrate that a field is being developed in an acceptable manner and to enable BSEE to review deepwater development activities from a total system prospective, emphasising the operational safety, environmental protection, and conservation of natural resources. The submittal, which is required in addition to other mandatory submittals, is in three parts - Conceptual, Preliminary, and Final - with different timeframes for submission and approval.

A Worst Case Discharge Scenario must be included with any EP, DOCD, and Oil Spill Response Plan submitted to BSEE. The WCD requires operators outline blowout scenarios that include: estimated flow rate, total volume, maximum spill duration, rig availability, bridge-over potential, relief well drill time, analogue well analysis, and blowout prevention and response measures, among other specifications.

A report of operations for each lease or unit agreement must be made for each calendar month, beginning with the month in which drilling operations commenced, and must be filed on or before the fifteenth day of the second month following the period being reported. The report must be submitted each month until all wells on a lease are permanently plugged and abandoned.

The BSEE must be notified orally the day on which a well is placed on production and in writing within five days. The operator must also indicate whether or not the production is the first production from the lease.

All flaring and venting of oil and gas wells must be reported to and approved by BSEE, except for small volumes or short-term flaring or venting. Gas-well gas must not be flared beyond that required to eliminate a temporary emergency.

Newfoundland and Labrador

According to the Offshore Petroleum Drilling and Production NL Regulations, 2009 the following is required prior to any activities:

- a description of the scope of the proposed activities;
- an execution plan and schedule for undertaking those activities;
- a safety plan;
- an environmental protection plan;
- information on any proposed flaring or venting of gas, including the rationale and the estimated rate, quantity and period of the flaring or venting;

- information on any proposed burning of oil, including the rationale and the estimated quantity of oil proposed to be burned;
- in the case of a drilling installation, a description of the drilling and well control equipment;
- in the case of a production installation, a description of the processing facilities and control system;
- in the case of a production project, a field data acquisition program that allows sufficient pool pressure measurements, fluid samples, cased hole logs and formation flow tests for a comprehensive assessment of the performance of development wells, pool depletion schemes and the field;
- contingency plans, including emergency response procedures, to mitigate the effects of any reasonably foreseeable event that might compromise safety or environmental protection, which shall
    - provide for coordination measures with any relevant municipal, provincial, territorial or federal emergency response plan, and
    - in an area where oil is reasonably expected to be encountered, identify the scope and frequency of the field practice exercise of oil spill countermeasures; and
- a description of the decommissioning and abandonment of the site, including methods for restoration of the site after its abandonment.

In addition to the above a benefits plan, as highlighted elsewhere in this document, must be included.

Where an Operator seeks an authorization to carry out work or activity relating to developing a pool or field, a Development Plan must first be approved, unless consent to issue the authorization is otherwise granted by both the provincial and federal governments.

Approvals are required for the following activities:

- Development Plan Approval
- Approval of a Canada-Newfoundland and Labrador Benefits Plan
- Approval of Flow System and Flow Calculation and Allocation Procedures
- Approval to Commingle Production
- Approval to Drill a Well
- Approval to Alter the Condition of a Well
- Approval of a Formation Flow Testing Program

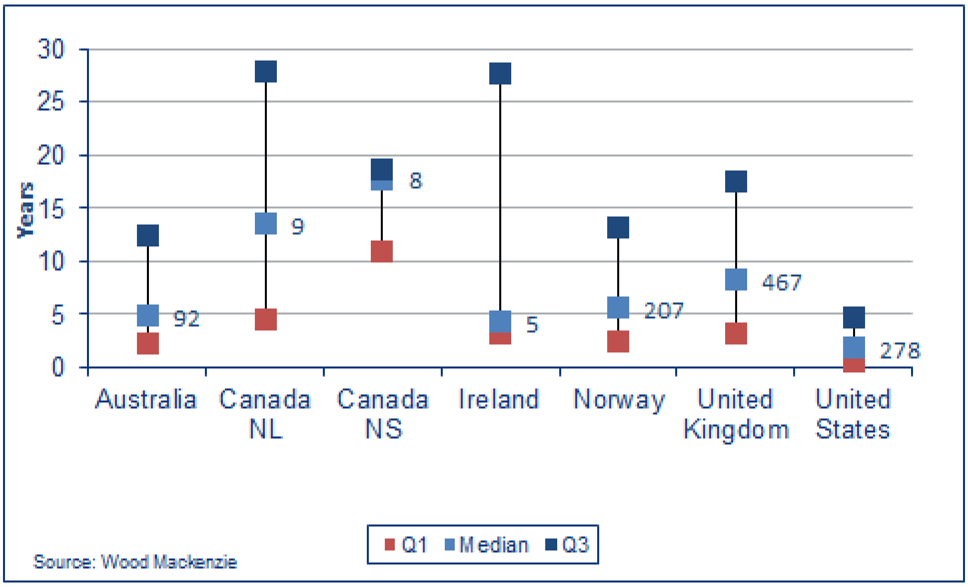
9.3 Project Timelines

Due to project and company specific circumstances and the impact that they have on the approval process it is challenging to analyse the typical approval timeline in each jurisdiction. What can be analysed is the average time it has taken, for currently onstream fields, between discovery and development consent and development consent to production start-up where this information is available. This analysis has been provide in the charts below comparing NL to the other jurisdictions. To ensure that outliers do not overly impact the results the interquartile range and median have been presented.

Field discovery to development consent

NL and Nova Scotia have the longest lead-times between discovery and development consent of all the jurisdictions analysed. The median time between discovery and development consent in NL is 13.5 years. This can be partially explained by the infrequency of developments compared to other jurisdictions and the remote operating environment but may also be symptomatic of more protracted processes for approval, both within oil and gas companies and the jurisdiction.

Figure 30 – Discovery to development consent lead-times for all offshore onstream or under development projects (the figures next to the median value refer to number of projects)



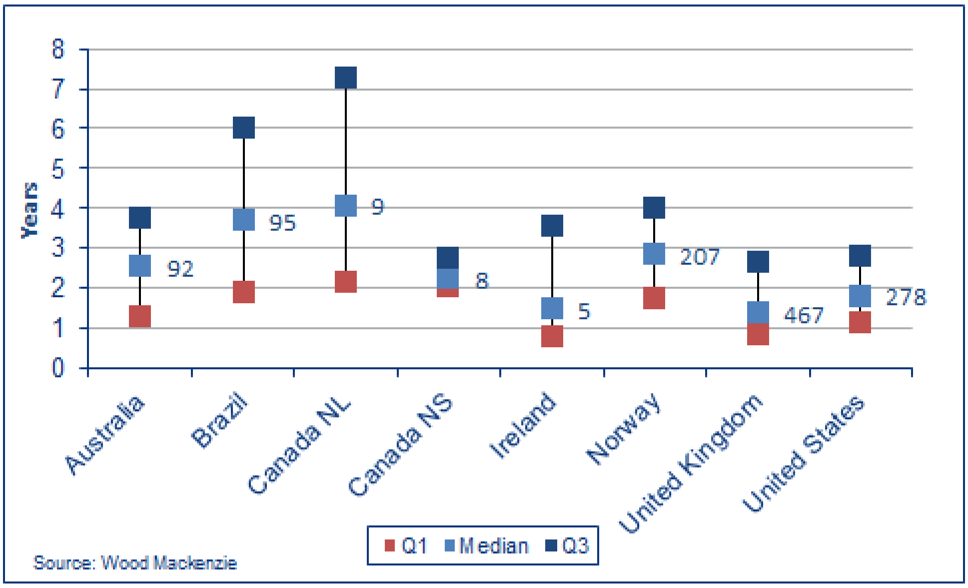
Note – Brazil and Mexico have been removed due to a lack of consistent information

The US GoM deepwater has the shortest median time between discovery and development sanction, 1.9 years, followed by Ireland, Australia and Norway with medians that ranges from 4.3 to 5.6 years.

Development consent to production start-up

Similar to the discovery to development consent lead-times, NL has the longest development consent to production start-up lead-time of all the jurisdictions analysed. The median time between development consent and production start up in NL is 4.1 years. Once again this can be partially explained by the infrequency of developments compared to other jurisdictions and the remote operating environment.

Figure 31 – Development consent to production start-up lead-times for all offshore onstream or under development projects (the figures next to the median value refer to number of projects)



Note –Mexico has been removed due to a lack of consistent information

The UK and Ireland have the shortest median time between development sanction and production start up of 1.4 years and 1.5 years respectively. However Ireland also has one of the longest lead-time projects, Corrib, which had a lead-time of 14 years.

Both of these lead-times have the potential to impact the economics and therefore competitiveness of projects in NL.

9.4 Development Restrictions

9.4.1 Local Content Requirements

Local content requirements in the oil and gas industry have been used to ensure that secondary benefits from oil and gas extraction remain in country. But, whilst local content is an essential part of a vibrant in country oil and gas industry, overly onerous requirements can inhibit development. This has been the case in Brazil in recent years where the local content requirements have impeded investment e.g. Round 13 in 2015 where the government's resistance to reduce high local content requirements resulted in a low number of bids. Although there has been some relaxation of these local requirements in Brazil in recent years the previous guidance was a minimum level of 37% for the exploration phase, rising to 55% for the development phase for modules with first oil prior to 2021. Minimum levels increase to 59% from 2022. In 2017 the requirements have been reduced by around two thirds and simplified so for example now only 25% of well construction must be with local suppliers

Mexico learned from Brazil in not setting high requirements and tried to remain as flexible as possible. In the most recent round, Round Two, the local content requirement was set at 5%.

In Norway there are no local content requirements but a high degree of stipulations on developments and the state stake option through Petoro ensures that local content is considered. The government stake through Petoro, all non-operated, ensures that the state maximises economic recovery, looks after the state's interest, provides local content and lobbies for local content. In addition companies must have an in-country office with a minimum number of qualified staff in order to be qualified as a non-operator or operator on the Norway continental shelf.

Section 10-2 of the Norwegian Petroleum Act stipulates the requirement that companies must establish an organisation in Norway and that this organisation must possess competence in the fields of resource management and health, safety and environment (HSE). The personnel in Norway must possess technical competence in the following disciplines geology, geophysics, reservoir technology, production technology and other relevant technology. The distribution of expertise among the various technical disciplines will depend on the phases of the licence(s). Experience to date shows that players that have established themselves on the Norwegian shelf have built up an organisation consisting of at least 8-9 persons with technical and HSE expertise, in order to safeguard their obligations as a licensee in Norway.

In Nova Scotia the Department of Energy helps to promote local involvement in the industry. As stated in the Accord Acts an Operator must have an approved Canada-Nova Scotia Benefits Plan prior to the authorization of any work or activity or the approval of any development plan. This entails a commitment to providing opportunities for residents of Canada, and particularly Nova Scotia, to participate in the work or activity for which the Benefits Plan has been submitted. The main requirements of the Benefits Plan are as follows:

- Full and fair opportunity for manufacturers, consultants, contractors and service companies in Nova Scotia, and other parts of Canada, to participate on a competitive basis in the supply of goods and services used in any proposed work or activity referred to in the Benefits Plan;
- The establishment of an office in the Province where appropriate levels of decision-making are to take place;
- Residents of the Province are given first consideration for training and employment in the work or activity for which the Benefits Plan is being submitted;
- The development and implementation of an education & training and research & development expenditure program in the Province related to petroleum resource activities in the offshore area;
- First consideration is given to services provided from within the Province, and to goods manufactured in the Province, where those services/goods are competitive in terms of fair market price, quality and delivery; and
- It may require that any Canada-Nova Scotia benefits plan include provisions to ensure that disadvantaged individuals or groups have access to training and employment opportunities and to enable such individuals or groups or corporations owned or cooperatives operated by them to participate in the supply of goods and services used in any proposed work or activity referred to in the benefits plan.

A number of the jurisdictions considered have no specific local content requirements but actively encourage companies to use or consider local companies whenever possible. This is the situation in:

- Australia where during development there is an expectation to use local content when applicable, accompanied by small tax breaks. Until 1988, the Foreign Investment Review Board could demand that development projects have at least 50% Australian equity. At the start of 1988, this requirement was dropped and oil and gas developments may now proceed in Australia with 100% foreign equity; and
- Ireland, United Kingdom and US Gulf of Mexico which have no local content requirements;

In NL, whilst the overall goals of local content requirements are shared between policy makers and operators, industry players have raised concerns related to the need for the NL supply and service community to work to be competitive internationally. The provision is the same as the benefits plan in Nova Scotia, namely:

Under the "Canada-Newfoundland and Labrador benefits plan" companies must state a plan for the employment of Canadians and, in particular, members of the labour force of the Province and provide for manufacturers, consultants, contractors and service companies in the Province and other parts of Canada with a fair opportunity to participate on a competitive basis in the supply of goods and services used in a proposed work or activity referred to in the benefits plan.

To ensure that all local contents considerations are taken into account a Canada-Newfoundland and Labrador benefits plan shall be submitted to and approved by the C-NLOPB, unless the C-NLOPB directs that it is not necessary to comply with that requirement.

This benefits plan shall contain provisions intended to ensure that:

- before carrying out any work or activity in the offshore area, the corporation or other body submitting the plan shall establish in the Province an office where appropriate levels of decision-making are to take place;
- consistent with the Canadian Charter of Rights and Freedoms, individuals resident in the Province shall be given 1st consideration for training and employment in the work program for which the plan was submitted and a collective agreement entered into by the corporation or other body submitting the plan and an organization of employees respecting terms and conditions of employment in the offshore area shall contain provisions consistent with this paragraph;
- expenditures shall be made for research and development to be carried out in the Province and for education and training to be provided in the Province; and
- 1st consideration shall be given to services provided from within the Province and to goods manufactured in the Province, where those services and goods are competitive in terms of fair market price, quality and delivery.

In addition the C-NLOPB may require that a Canada-Newfoundland and Labrador benefits plan includes provisions to ensure that disadvantaged individuals or groups have access to training and employment opportunities and to enable those individuals or groups or corporations owned or cooperatives operated by them to participate in the supply of goods and services used in a proposed work or activity referred to in the benefits plan.

In reviewing a Canada-Newfoundland and Labrador benefits plan, the C-NLOPB shall consult with both ministers on the extent to which the plan meets the requirements.

In addition to the benefits plan there are negotiated benefits agreements which are industrial benefits agreements between the Government of NL and the operator. The C-NLOPB has no statutory duty with respect to such agreements either in terms of negotiating, monitoring, or enforcing such agreements. However, these agreements typically include clauses specifying that such agreements will be provided to the C-NLOPB for monitoring and oversight. In cases where the C-NLOPB agrees to provide monitoring and oversight duties, the C-NLOPB’s role would be to monitor benefits agreement reports from proponents on a regular basis, and to identify areas of non-conformance. The C-NLOPB would then notify the Government of NL of such non-conformances, which is then responsible for resolving the matter in accordance with the provisions of the agreement.

For the Hebron project, the benefits agreement included the following:

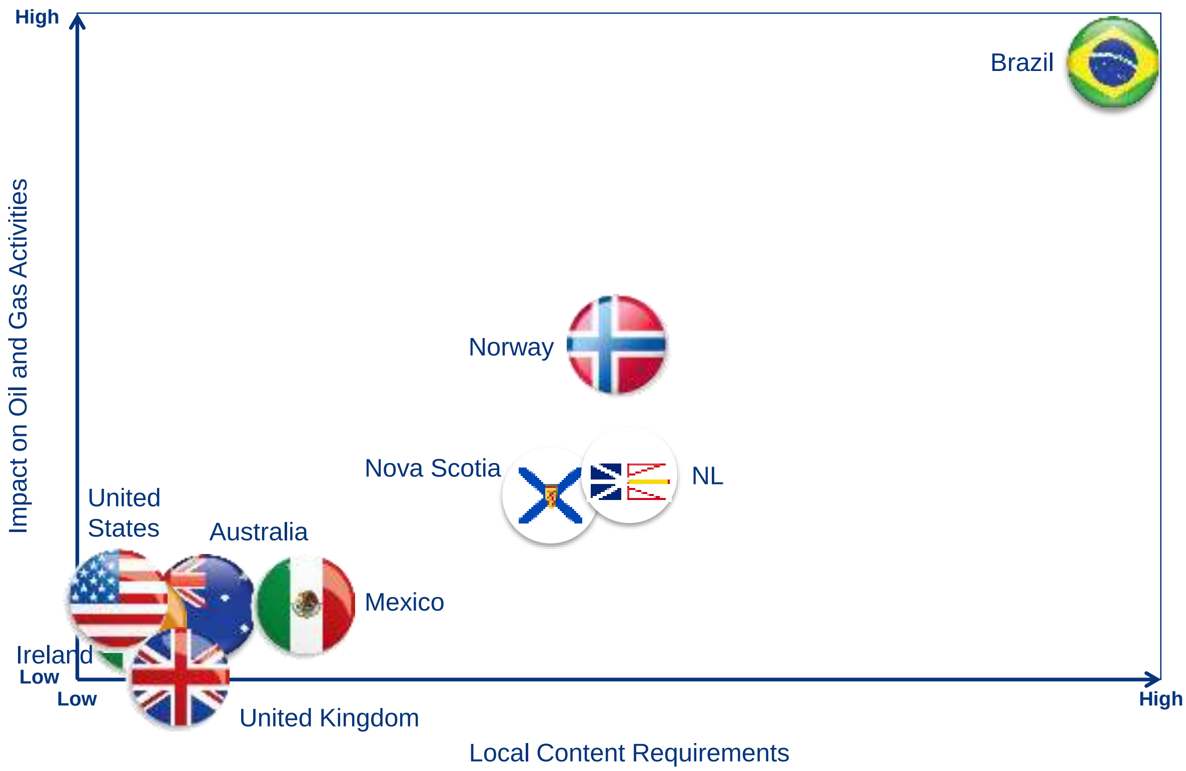
- Agreed elements to be fabricated and constructed in the Province;
- At least 50,000 person hours of GBS FEED-phase engineering will be done in NL;
- Engineering / technical or other professional positions will be made available to residents of the Province to work in contractors’ offices outside the Province for any FEED done outside of the Province.
- Provision of a travel fund of $1 million, to begin during the pre-sanction FEED phase, for travel of NL contractors/suppliers to visit engineering offices for work done outside the Province;
- Detailed engineering for GBS (including GBS mechanical outfitting) and topsides components to be constructed in the Province will be done in the Province;
- At minimum, there will be 1.2 million person hours of detailed engineering in the Province;
- Late FEED will be transitioned to the Province for all components to be fabricated in the Province;
- Engineering / technical or other professional positions will be made available to residents of the Province to work in contractors’ offices outside the Province for any detailed engineering undertaken outside the Province;
- Project management office will be opened in the Province;
- At minimum, there will be one million person hours of project team activities prior to first production performed in the Province;
- First consideration to Newfoundlanders and Labradorians when staffing this office;
- The operator and the main engineering, procurement and construction contractors will have a contracts and procurement office in the Province which will co-ordinate and manage procurement and contracting activities;
- Proponents will conduct early supplier development workshops for the local service and supply community so contractors can prepare for bidding and establish joint ventures, and promote and encourage technology transfer opportunities;
- Request for Proposal (RFP) and bid packages will require bidders to use standards that meet the requirements of Canadian authorities;

- A commitment of $120 million for research and development over the life of the project provided such commitment meets the C-NLOPB's requirements;
- Includes commitment of $1 million pre-sanction to College of North Atlantic and Memorial University to enhance skills training; and
- The operator commits to:
  - Full access to employment opportunities;
  - Implementation of proactive programs and processes to create inclusive work environment and corporate culture;
  - Promotion of accountability and responsibility for diversity;
  - A comprehensive Gender Equality and Diversity Program; and
    - Women's employment plan and business access strategy in which the operator will establish quantifiable objectives and goals for the employment of women throughout the project.
    - Diversity plan that addresses training and recruitment of disadvantaged groups.
  - Implementation, monitoring and reporting for these commitments to C-NLOPB, with emphasis on continuous improvement.

As can be seen in the above benefits agreements have been both non-prescriptive and prescriptive, i.e. best endeavours vs firm commitments to carry out work within Newfoundland and Labrador.

The following diagram summarises the extent of local content requirements in each of the jurisdictions and an indication of its impact on oil and gas activity.

Figure 32 – Impact of local content on oil and gas activities



9.4.2 Research & Development Requirements

Typically regulations or requirements related to research and development (R&D) are contained as specific clauses within fiscal terms.

Australia and Mexico

In Australia there is no specific R&D requirement but companies are eligible for tax incentive for R&D investment for eligible companies. A similar system has been suggested in Mexico.

Brazil

In Brazil companies are obliged to invest 0.5% to 1% of gross revenues from each tax ring-fence in petroleum-related research and development work once production becomes high enough to be liable for special participation tax (SPT) payments. The research and development tax is deductible (expensed) for SPT purposes. It is also deductible against CIT in that it can be included within general company costs.

Ireland

In Ireland the holders of Frontier Exploration Licences shall pay annual contributions to petroleum research programmes as directed by the Minister to support the funding of research and applied research projects that have the aim of developing knowledge of the Irish offshore with a view to assisting in promoting exploration and development activity. These contributions shall include both an annual contribution per licence and a single annual contribution per company.

Norway

In Norway there are no specific R&D requirements but The Ministry of Petroleum and Energy encourages research, development and demonstration via research programmes where both companies and research institutions may seek funding for specific projects. The authorities encourage research and technology development primarily through legislation or other forms of regulation and through direct allocations to the Research Council of Norway from the Ministry of Petroleum and Energy. Most of these allocations go to the PETROMAKS 2 and DEMO2000 research programmes and to research centres in Stavanger, Tromsø and other locations.

Nova Scotia

In Nova Scotia research & development and education & training within Period 1 of the Exploration licence are biddable items. Any benefits plan that must be submitted for developments must include implementation of an education & training and research & development expenditure program in the Province related to petroleum resource activities in the offshore area.

Newfoundland and Labrador

In NL there are R&D obligations to ensure that expenditures shall be made for research and development to be carried out in the Province and for education and training to be provided in the Province. These provisions are governed by the Canada-Newfoundland and Labrador Atlantic Accord Implementation Act, section 45(3)(c) stating "*expenditures shall be made for research and development to be carried out in the Province and for education and training to be provided in the Province*"

The level of R&D expenditure by operators is expected to be consistent with the norms for such expenditures by the upstream petroleum industry in Canada.

R&D expenditures in the development phase of projects tend to focus primarily on education & training activities, whereas it is expected that in the production phase there will tend to be more focus on research & development activities. In the exploration phase R&D expenditures up to a maximum of 5 percent of the expenditure bid will be allowed. In the development and production phase allowable expenditures are based on a formula based on industry practice in Canada. A benchmark is used based on industry practice in Canada, using the most recent five-year data for R&D spend as a percentage of revenues as reported by Statistics Canada.

The formulae for calculating R&D spend on a project are as follows:

- Total Development and Production Phase R&D

  Total Development and Production Phase R&D = Benchmark (5 year spend) x (Total Oil Recoverable x Long term oil price)

- Development Phase R&D

  Development Phase R&D expenditure = 0.5% x total project capital cost

- Production Phase R&D

  Production Phase R&D expenditure = Total R&D requirement less Development Phase R&D expenditure

  The R&D spend in each period in the Production Phase will be in proportion to the production in that period.

Any R&D must be reasonable and consistent with that contemplated by the legislation and the C-NLOPB will consider expenditure proposed by an operator as appropriate, on a case-by-case basis.

United Kingdom and USA

Countries with no specific R&D requirement include the UK and the US.

10. Comparison of key factors and recommendations

Based on the key factors identified previously, this section will compare and discuss NL's current situation with its peer jurisdiction. Broadly NL's performance can be split into two groups:

1) A competitive positioning matrix showing where NL and peer jurisdictions have challenges against key factors analysed; and
2) A competitive positioning matrix showing where NL and peer jurisdictions are attractive against key factors analysed.

Figure 33 – Competitive positioning matrix showing where Newfoundland and Labrador and peer jurisdictions have challenges against key factors analysed

		Australia	Brazil	Ireland	Mexico	Norway	UK	US GoM	Nova Scotia	Newfoundland & Labrador
Geological Prospectivity	Prospectivity index	●		●			●		●	●
	YTF volumes	●		●	●	●	●	●	●	●
	YTF pool size distribution	●		●		●	●	●	●	
	Plays per basin	●	●	●	●	●	●		●	●
	Data availability		●	●	●	●	●	●	●	●
	Confidentiality period for data		●		●	●	●	●	●	●
Geopolitical	Access	●	●	●	●					
	Development	●	●	●	●	●				
	Commercialisation		●	●	●					●
Cost and operating environment			●	N/A	●		●	●	N/A	●
Fiscal regime	Fiscal stability	●	●	●		●	●	●	●	●
	Fiscal attractiveness		●		●	●		●		
Regulatory	Licensing Frequency		●	●	●				●	
	Licensing Transparency		●		●			●		
	Exploration Permitting	●	●		●					
	Development Permitting	●		●	●		●		●	●
	R&D		●	●					●	●
	Local content		●			●			●	●

Note –Cost environment assessed by comparing the costs of deepwater developments (onstream, under development, probable developments or "good technicals") post 1990

10.1 Key challenge areas for Newfoundland and Labrador

Based on the above matrix, the key challenge areas for NL are as follows:

- Prospectivity Index - Prospectivity remains one of the challenge areas for NL, although this is also the case in a number of the jurisdictions analysed. In terms of prospectivity, the only metric where NL compares favourably is YTF pool size distribution, with the other assessment areas scoring mid to low marks;
- YTF Volumes and Plays per Basin - The overall volume expectation of YTF and average number of plays per basin is low in NL. Other jurisdictions that rank poorly against YTF volumes are Australia, Ireland, the UK and Nova Scotia. On plays per basin Brazil, Ireland, and Norway rank poorly, which shows the danger of using this factor in isolation given the industry leading YTF volumes in Brazil;
- Data Availability and Confidentiality Period for Data - With regard to data availability and confidentiality periods the majority of jurisdictions are aligned. The notable exceptions are Australia which comes out on top due to its slightly more favourable access to data, and the US GoM which is at the opposite end of the spectrum where there is no formal mechanism for the state to provide information and confidentiality periods are lengthy;
- Commercialisation - For gas resources, NL's current use of natural gas for enhanced oil recovery, distance to market and lack of pipeline infrastructure impedes its ability to commercialise its discovered gas resources. Future opportunities for development will be dependent on markets, resource availability and project costs;
- Cost and Operating Environment - based on expected costs for deepwater development NL ranks amongst the highest cost areas. The high costs in a challenging environment for oil and gas activities are compounded by the long duration of

EPIC activities and lead-times from discovery to development consent and development consent to production start-up. Estimated development capital and opex for deepwater projects are estimated to be almost US$14/boe higher than the average for deepwater projects in the peer jurisdictions;

- Fiscal Stability - fiscal stability ranks lower than fiscal attractiveness and in a similar position to Australia, Brazil (PSC), Ireland, Norway, and Nova Scotia;
- Development Permitting - Development permitting in NL scores less attractively than it could due to the number of potential steps and consultations required in order to have a development plan approved, including the benefit plan which typically has to provide secondary benefits to the jurisdictions economy;
- R&D – Levels of R&D spend are consistent with the norms for such expenditures by the upstream petroleum industry in Canada and while there maybe other jurisdictions with lower commitments no changes are recommended in this area; and

Local Content - In NL, whilst the overall goals of local content requirements are shared between policy makers and operators, industry players have raised concerns related to the need for the NL supply and service community to work to be competitive internationally.

Figure 34 – Competitive positioning matrix showing where Newfoundland and Labrador and peer jurisdictions are attractive against key factors analysed

		Australia	Brazil	Ireland	Mexico	Norway	UK	US GoM	Nova Scotia	Newfoundland & Labrador
Geological Prospectivity	Prospectivity index		●		●	●		●		
	YTF volumes		●							
	YTF pool size distribution		●		●					●
	Plays per basin							●		
	Data availability	●								
	Confidentiality period for data	●		●						
Geopolitical	Access					●	●	●	●	●
	Development						●	●	●	●
	Commercialisation	●				●	●	●		
Cost and operating environment		●		N/A		●			N/A	
Fiscal regime	Fiscal stability				●					
	Fiscal attractiveness	●		●			●		●	●
Regulatory	Licensing Frequency	●				●	●	●		●
	Licensing Transparency	●	● *	●		●	●	●	●	●
	Exploration Permitting			●		●	●		●	●
	Development Permitting		●			●		●		
	R&D	●			●	●	●	●		
	Local content	●		●	●		●	●		

** Brazil Concession*

Although the main purpose of this report was to identify where NL and other jurisdictions have challenges against the key factors analysed, there are multiple areas where NL is attractive. Based on the above matrix ,and from discussions during the compilation of this report, the attractive areas include:

- The indicative YTF pool sizes that are expected are skewed to the larger end of the field sizes considered which will enhance the potential for future commercial developments;
- The view of the industry as indicated by the recent Cdn $2.6 billion of exploration work commitments, despite low oil price environment;
- The process to access acreage is clear and understood by the industry;
- There is minimal labour activism in the Province and a willing and available workforce;
- A track record of bringing on major oil projects;
- An attractive fiscal system which achieves the highest ranking for attractive Government Take % for contractors; and
- The frequency and transparency with which acreage is offered to the industry.

10.2 Recommendations

Geological Prospectivity

While by itself NL can offer geologically attractive acreage, in particular via the Flemish Pass, it needs to compete with the likes of Brazil, Mexico, the US GoM, and Norway. In Brazil, investors can expect the world's largest and most productive deepwater reservoirs where the average discovery size is 1 billion barrels.

Overall the approach that NL has taken to ensure that companies have as full an understanding of the subsurface potential of the region as possible through sponsored geological studies released in conjuncture with licence rounds has added to the understanding of the region. It is likely that only continued geological success can improve the perception of geological prospectivity. To achieve this NL must ensure that there are:

- no unnecessary barriers to companies carrying out exploration campaigns;
- continued sharing of rig schedules and plans amongst companies given the specification requirements in NL;
- continued support writing off exploration costs for corporate tax purposes; and
- adequate promotion of the jurisdiction and the advances that have been made in the understanding of its sub-surface.

Geopolitical and above ground risk considerations

We would have no specific recommendations around the role of Nalcor. Whilst we recognise some of the challenges that companies commonly raise around state companies regarding back-in rights, we also recognise the work that Nalcor has done to promote the region and ensure a clear and transparent licensing process support by geoscience studies.

NL needs to ensure that any local content provisions do not reduce the overall attractiveness and competitiveness of the jurisdiction vis-à-vis competing areas, in terms of both delays to projects due to time to negotiate provisions or unduly burdening projects with costs when company capital budgets remain strained and project breakevens are studied more conscientiously than may have previously been the case.

Cost and Operating Environment

Given its location and the challenging nature of developments it is likely that NL will remain a relatively high cost area. However there are steps that NL can take to ensure that everything possible is done to enhance project costs and therefore economics:

- As mentioned above, ensure local content provisions are not overly onerous;
- Look to reduce project lead-times, modify an approach such as "Drilling the Limit" previously developed by Shell (http://www.ogj.com/articles/print/volume-105/issue-39/drilling-production/shell-revitalizes-lsquodrilling-the-limitrsquo-program.html) and apply to developments in the jurisdiction. The goal for future project should be to reduce median lead-times as follows:
  - Reduce median discovery to development consent lead-times from 13.5 years to around 5 years, the average of the median times for Australia, Ireland and Norway;
- Reduce median development consent to production start-up lead-times from 4.1 years to around 2.3 years, the average of the median times for the other jurisdictions, although given the technically complex and standalone nature of the developments in NL this may be too ambitious. Ensure regulatory requirements/changes such as CEAA2012 do not add additional delays.

One of the contributing factors to the costs in NL has been the rig intake process which means only a small number of drill rigs meet the criteria for operating in its waters. This has meant that NL operators have had a smaller pool of the global rig fleet to draw from which contributes to higher costs. The high costs associated with procuring a rig have eased in recent years with the drop in rig rates that has followed the fall in oil prices since 2014. As an example Suncor signed a 15-month rig contract with Transocean in October 2016 for a day rate of Cdn$260,000. In October 2014 the rig, the Transocean Barents, had been utilised with a day rate of US$591,000 (CDN$750,000 at current exchange rates). Whilst the market has contributed to a saving in this area the appropriateness of the rig intake process could be analysed to ensure that NL does not overly burden the industry with unnecessarily high costs.

Fiscal regime

It is imperative to keep a stable and appropriate fiscal regime. The current terms compare favourably on their progressivity, at least at NPV0 or on an undiscounted basis, alongside other jurisdictions such as the UK, Ireland, Nova Scotia and Norway and NL should continue to ensure that its fiscal regime works for all developments and project by project negotiations are kept to a minimum.

Regulatory

Development permitting in NL scores less attractively than it could due to the number of potential steps and consultations required in order to have a development plan approved, including the benefit plan which typically has to provide secondary benefits to the jurisdictions economy. NL should look to provide a clear timetable and process to be agreed with the industry on development permitting that is in line with the necessary time for the consultation required.

Local content requirements have been negotiated on a project by project basis to date in NL. Whilst this has meant a flexible approach has been adopted there are calls from the industry for more clarity on the overarching strategy in relation to local content to ensure that the local supply community can remain competitive in a global context. The recommendation would be to identify the areas that are likely to be most applicable to local content and where local suppliers can be competitive vs global options and ensure that there is a concerted plan in place that must be referenced and supported in future development plans.

Exhibit A – Fiscal terms

The following is a summary of the fiscal systems for each country in the Peer Group:

Australia

Government Equity Participation

None

Bonuses, Rentals & Fees

For areas under Federal jurisdiction annual rental charges are payable relating to:

1. Exploration acreage - 10,000 A$ per title;
2. Production licenses - 20,000 A$ per block;
3. Infrastructure and pipelines - 100 A$ per km.

Indirect Taxes

1. VAT: 10% Goods and Services Tax (GST) is paid on expenditures. The amount of GST could be reclaimed through input tax credits. Export is exempt, however input tax credits still apply.
2. Import Duties: Levied at the rate of either 0% or 5% (for certain types of goods).

Royalty

Does not apply to offshore fields taxed under the PRRT system. Royalty still applies for onshore fields.

Corporate Income Tax

Federal Income Tax (FIT) is levied at 30% of gross income less allowable deductions, including exploration costs, depreciation of development costs and operating costs, abandonment costs, royalty, PRRT and Excise duty payments.

Contractors can normally choose between a straight line depreciation or a double declining balance method based on 'useful life of asset'. We assumes double declining balance over 15 years for tangible onshore investments, and 20 years for offshore investments. Exploration costs and operation costs are expensed in the year they occurred.

Tax losses, apart from those arising from exploration expenditure, can be carried forward indefinitely (without uplift).

Additional Profits Tax (PRRT)

Petroleum Resource Rent Tax (PRRT) is a tax on petroleum production. PRRT rate is 40%. PRRT is levied on 'profit', which is defined as gross revenues of hydrocarbons at market price minus various deductions. These deductions are exploration costs, development and operating costs, abandonment costs (deductible in full in year incurred). Certain expenditures, such as interests payments on borrowings, are non-deductible.

Where deductions exceed revenues in any year, the excess is carried forward so it can be deducted in the following years. Losses are carried forward at a rate known as the threshold rate, set at the Commonwealth long-term bond rate plus 5 or 15%, for development and exploration costs, respectively.

Brazil PSC

Government Equity Participation

There is no automatic state participation in concessions. State oil company Petrobras is a dominating player in the E&P sector, and frequently takes part in licensing rounds. In the PSC pre-salt developments, Petrobras is a minimum 30% equity partner, though the NOC is not carried.

Bonuses, Rentals & Fees

1. Signature bonus - Biddable signature bonuses are payable.;
2. Area Rentals - Annual rental fees are payable annually for each licence. They vary by basin and maturity of each area. Typical acreage rental rates are as follows:
    a. Exploration period: R$10 to 500/km²/year.
    b. Extension of exploration licences: R$20 to 1,000/km²/year.
    c. Development period: R$20 to 1,000/km²/year.
    d. Production period: R$100 to 5,000/km²/year.;
3. Environmental Fee - In Rio de Janeiro state, a R$2.71/bbl environmental charge is payable.

Indirect Taxes

Name	Abbreviation	Detail
Imposto sobre a Importação	I.I	An import tax on foreign physical goods. Rates vary by product type. A 10% rate is used in the model.
Imposto sobre Produtos Industrializados	IPI	A federal tax on tangible industrial products placed into service. Rates vary greatly by product. A 10% rate is assumed in the model. Tax basis for this levy includes I.I
Imposto sobre a Circulação de Mercadorias e de Serviços	ICMS	A recoverable, state level value-added tax applied to all expenditures. Tax basis for this levy includes I.I and IPI. The rates used vary by state as well as product type. While 19% is assumed in the model, it is also assumed that the charge is immediately recovered.
Contribuição para os Programas de Integração Social e de Formulação do Patrimônio do Servidor Público	PIS	A value-added tax applied to all expenditures at a 7.6% rate
Contribuição Social para o Financiamento da Seguridade Social	COFINS	A value-added tax applied to all expenditures at a 1.65% rate
Imposto de Renda Retido na Fonte (Withholding Tax)	IRRF (WHT)	Instead of the service provider paying income tax, purchasers of the services must withhold and pay the income tax themselves. This applies to intangibles and the majority of leased equipment. Levied at 15%.
Municipal Service Tax	ISS	Levied at the municipal level, this tax applies to intangible services. The rate is 5%.
Contribuição e Intervenção no Domínio Econômico	CIDE	CIDE is a 10% tax on imported services. This tax is not included in the model.
Tax on Financial Operations	IOF	A levy applying to imported financial services such as credit, fx, insurance, and securities transactions. It has a 0.38% rate. This tax is not included in our models.

The REPETRO programme allows IOCs to import tangible, non-permanent equipment into Brazil without paying the federal I.I and IPI taxes. The ICMS charges on non-permanent, tangible imports during the exploration and development are reduced or eliminated as well. The REPETRO programme is currently allowed to continue through 2020. Assumptions in the model concerning the percentage of expenditures that are tangible and imported are in the summary of modelled terms.

Royalty

Under PSC terms, the total rate is 16%. The Landowner Override does not apply and the R&D assessment is payable regardless of the lack of SPT charges.

Cost Recovery

Cost recovery is capped at 50% of gross revenue in the first two years of production, dropping to 30% in subsequent years. If the costs are not recovered within two years, the PPSA may increase the ceiling up to 50% for subsequent years to guarantee timely cost recovery.

Profit Share

PSC profit oil is a biddable item. The bid is targeted at a profit share presuming an expected price/bbl and an expected per-well production level, and place in terms of the governments share. In the model, these are set at the Libra base values of $100-120/bbl and 10,000 to 12,000 b/d. Variance from these levels will change the effective profit share by predetermined differentials. The differentials used in the model are those for the Libra development, as shown below. The base bid used in the model is a government share of 41.65%.

Corporate Income Tax

CIT is levied at 34%, comprised of a basic 15% income tax, a 10% surtax and a 9% social contribution on net profit tax. Bonuses, depreciation, expensed costs, royalty and SPT paid are deductible. Most tangible investments are depreciated straight line over 10 years, floating vessels over 20, and intangibles generally over no more than 10 years.

Losses carry forward indefinitely, but are limited in their application to future gains. A maximum amount of 30% of taxable income can be offset by carried losses in any single accounting period.

Additional Profits Tax

Special Participation Tax is not applicable under the PSC

Canada (Newfoundland & Labrador)

Government Equity Participation

Since 2007 the Government of NL has the right to negotiate the acquisition of up to 10% equity in all projects via Nalcor Energy. Nalcor can take its equity at the development plan approval stage and negotiates payment of its share of exploration and appraisal costs already incurred. After that, Nalcor contributes as a conventional equity partner in future appraisal and development costs. Through Nalcor the Province has an equity stake of varying levels in three offshore projects - the White Rose Satellites (5%), Hebron (4.9%) and Hibernia South (10%).

Bonuses, Rentals & Fees

1. Work deposit - Work deposit equal to 25% of the work expenditure bid (work expenditure bid of at least C$10 million is required);
2. Area rentals - The annual rental fee ranges from C$2.50 to C$15 per hectare, depending on the area and year of the licence.

Indirect Taxes

The Harmonized Sales Tax (HST) is a value added tax that combines the provincial sales tax with the federal Goods and Services Tax (GST), to create a single, federally administered HST. In NL. The current HST rate is 15% which comprises 5% Federal Goods and Services Tax (GST) combined with a 10% provincial portion. It applies on all supplies made in Canada and certain imports.

HST is generally payable by companies but can be subsequently recovered in the case the goods or services are used in commercial activities (with the intention of passing the burden to the consumer). Oil and gas businesses are typically considered engaged in commercial activities.

Royalty

Royalty is levied on a two tier system including a basic and a net royalty.

1. basic royalty is levied on wellhead revenue (gross revenue net of transportation costs) and is payable once the project starts producing the hydrocarbon.
2. net royalty is levied on net revenue (gross revenue + incidental revenue -transportation costs - project capital & operating costs) and is payable once the project has recovered its costs.

For offshore oil projects, both basic and net royalty rates are derived from a single R factor calculation based on project lifetime return.

Oil

1. The basic royalty rate is defined by the R factor and increases from 1% to 7.5% as the project recovers its cost. The R factor is calculated as: (cumulative gross sales revenue + incidental revenue - cumulative transportation costs - cumulative basic and net royalty paid to prior month) / (cumulative pre-development costs, capital and operating costs).
2. The net royalty rate is 0% until the R factor is 1. For R factors between 1 and 3, the royalty rate escalates on a sliding scale from 10% to 50%.

Basic royalty is a credit for net royalty, so only the highest amount of either basic or net royalty is payable in any period.

Gas

1. The basic royalty rate depends on the realised gas price. The rate is 2% when the netback price (price net of transportation costs) is less than 4C$/mcf and 10% when the netback price is more than 8C$/mcf. For gas prices between C$4 and C$8, the gas royalty rate is pro-rated.
2. The net royalty rate is based on the R Factor which is the ratio (cumulative revenue less cumulative transportation costs less cumulative royalty) / (cumulative costs). The rate ranges from 0% when R<1 to 50% when R>4. For R factor 1 to 4, the gas royalty rate is pro-rated. Basic gas royalty is a deduction in calculating net revenue for net gas royalty.

Total gas royalty payable is basic royalty plus net royalty.

Natural gas royalty is currently a framework regime and no specific regulations have been developed to date.

Federal Corporate Income Tax

The basic federal corporate income tax (FIT) rate is 38%. There is a 10% provincial abatement that brings the federal tax rate down to 28%, which compensates for provincial and territorial income taxes. A general tax reduction of 13% is applied to corporate income which qualifies, effectively bringing the federal tax rate down to its current level of 15%. In the model the effective 15% federal tax rate is used. Federal Income Tax is levied on gross revenue less operating costs, royalty, freehold mineral taxes and capex depreciation. Provincial tax payments are not deductible for the calculation of FIT. Capital losses can be carried back three years and forward for up to twenty years.

Tangible development costs are depreciated at 25% per annum on a declining balance basis. These expenditures become available for depreciation when the asset is capable of generating products or revenue, or two years after the expenditure occurs if that is sooner. Currently exploration costs are treated as Canadian Exploration Expenses (CEE) and these can be immediately expensed. Intangible development drilling and completion expenditures are depreciated at 30% per annum on a declining balance basis from the year in which they are incurred. The 2017 Federal Budget introduced proposals to removal successful wells from being eligible for CEE with relief instead being granted at 30% on a declining balance basis. Pipeline capex is depreciated at a 4% per annum on a straight-line basis.

Provincial Corporate Income Tax

Provincial corporate income tax (PIT) is charged at the rate of 15% on the same taxable base as used for FIT . FIT payments are not deductible for the calculation of provincial tax. Capital losses can be carried back three years and forward for up to twenty years.

Scientific Research and Experimental Development (SR & ED)

Tax credits are available for qualifying expenditure on SR&ED expenditure. A Canadian-controlled private corporation (CCPC) can earn a refundable ITC at the enhanced rate of 35% on qualified SR&ED expenditures, up to a maximum threshold of $3 million. This 35% ITC is 100% refundable on qualified SR&ED expenditures and 40% refundable on qualified SR&ED capital expenditures incurred before 2014.

A CCPC can also earn a non-refundable ITC at the basic rate of 15% on an amount over the $3 million threshold. Other corporations can earn a non-refundable ITC at the basic rate of 15% on qualified SR&ED expenditures. The ITC can be applied to reduce tax payable.

Carbon Taxes

In October 2016 it was announced that the federal government would set a national "floor price" on carbon that must be charged by all provinces on emissions. The announcement stated that pricing should commence in 2018 at a minimum price of $10 per tonne of carbon dioxide emissions with this amount rising by $10 each year to $50 per tonne by 2022.

To date, the Government of NL has not announced details of how it will implement such a system, but in October 2017 Premier Ball said that an announcement is expected in Spring 2018.

Canada (Nova Scotia)

Government Equity Participation

None

Bonuses, Rentals & Fees

1. Work deposit - Work deposit equal to 25% of the work expenditure bid;
2. Area rentals - The annual rental fee is C$2.50 for the 9 year term of the license.

Indirect Taxes

The federal Goods and Services Tax (GST) is a federal value-added tax (VAT) that applies on a every supply made in Canada and certain imports into Canada. GST is applied at a 5% rate on the purchase of most goods and services. GST is generally payable by companies but can be subsequently recovered in the case the goods or services are used in commercial activities (with the intention of passing the burden to the consumer). Oil and gas businesses are typically considered engaged in commercial activities.

Royalty

The Generic Royalty Regime is levied on a two tier system comprising a gross revenue royalty and a net revenue royalty.

1. Gross revenue royalty is levied on wellhead revenues at 2% until simple payout using a Return Allowance based on a 5% plus the Canadian Long Term Bond Rate. Thereafter a 5% gross revenue royalty is charged until simple payout is achieved based on a Return Allowance using 20% plus the Long Term Bond Rate. Simple payout is calculated on the basis of cumulative wellhead revenues less cumulative gross and net royalty, capital and operating costs, uplift and a return allowance. There is uplift on costs at a rate 1% for development capital costs and 10% for operating costs.

Net revenue royalty is levied on net revenues at 20% until a simple payout return allowance is reached based on the long term bond rate plus 45%. There after the net revenue royalty rate is 35%. Net revenues are calculated as wellhead revenues less capital costs, operating costs and uplift on costs (uplift rates are the same as for gross revenue royalty

Total royalty payable is the greater of gross royalty and net royalty.

Federal Corporate Income Tax

The basic federal corporate income tax (FIT) rate is 38%. There is a 10% provincial abatement that brings the federal tax rate down to 28%, which compensates for provincial and territorial income taxes. A general tax reduction of 13% is applied to corporate income which qualifies, effectively bringing the federal tax rate down to its current level of 15%. In the model the effective 15% federal tax rate is used. Federal Income Tax is levied on gross revenue less operating costs, royalty, freehold mineral taxes and capex depreciation. Provincial tax payments are not deductible for the calculation of FIT. Capital losses can be carried back three years and forward for up to twenty years.

Tangible development costs are depreciated at 25% per annum on a declining balance basis. These expenditures become available for depreciation when the asset is capable of generating products or revenue, or two years after the expenditure occurs if that is sooner. Currently exploration costs are treated as Canadian Exploration Expenses (CEE) and these can be immediately expensed. Intangible development drilling and completion expenditures are depreciated at 30% per annum on a declining balance basis from the year in which they are incurred. The 2017 Federal Budget introduced proposals to removal successful wells from being eligible for CEE with relief instead being granted at 30% on a declining balance basis. Pipeline capex is depreciated at a 4% per annum on a straight-line basis.

Provincial Corporate Income Tax

Provincial corporate income tax (PIT) is charged at the rate of 16% on the same taxable base as used for FIT . FIT payments are not deductible for the calculation of provincial tax. Capital losses can be carried back three years and forward for up to twenty years.

Scientific Research and Experimental Development (SR & ED)

Tax credits are available for qualifying expenditure on SR&ED expenditure. A CCPC can earn a refundable ITC at the enhanced rate of 35% on qualified SR&ED expenditures, up to a maximum threshold of $3 million. This 35% ITC is 100% refundable on qualified SR&ED expenditures and 40% refundable on qualified SR&ED capital expenditures incurred before 2014.

A CCPC can also earn a non-refundable ITC at the basic rate of 15% on an amount over the $3 million threshold. Other corporations can earn a non-refundable ITC at the basic rate of 15% on qualified SR&ED expenditures. The ITC can be applied to reduce tax payable.

Carbon Taxes

In October 2016 it was announced that the federal government would set a national "floor price" on carbon that must be charged by all provinces on emissions. The announcement stated that pricing should commence in 2018 at a minimum price of $10 per tonne of carbon dioxide emissions with this amount rising by $10 each year to $50 per tonne by 2022.

Ireland

Government Equity Participation

None

Bonuses, Rentals & Fees

1. Social Development Fee - Contribution to Research Funds, both annual and single contributions: Irish Shelf Petroleum Study Group (ISPSG) €87,361 per licence per annum.
2. Area Rentals - Between €29 / km^2 and €7,600 / km^2 depending on license type.

Indirect Taxes

1. VAT - 13.5% VAT is levied on the supply of natural gas.
2. Import Duties - Goods imported from countries outside the European Union are liable to customs duty at the appropriate rates specified in the EU's Combined Nomenclature (CN) Tariff.
3. CO2 - EU Emissions Trading Scheme (ETS) applies
4. Withholding tax on sub-contractors - Relevant Contracts Tax (RCT) applies, related to Construction work. RCT rates are 20%, 35% - dependant upon tax and location status. 0% rates can also apply to some sub-contractors.

Royalty

None

Corporate Income Tax

Corporation Tax of 25% applies to the offshore industry.

Corporate income tax is levied on gross revenue less operating costs, depreciated capital costs, Petroleum Production Tax (PPT), interest costs (unless the loans were for exploration expenditure) and abandonment costs.

Free depreciation on both development and exploration capital expenditure i.e. 100% of expenditure to be written off against Corporation Tax in first year of production. The terms also allow expenditure not written off in the in the first year to be carried forward indefinitely against subsequent years. Past exploration costs can be claimed as an allowance on first production.

Abandonment relief: 100% allowance for costs incurred on abandonment is available with loss carry back over 3 prior years. Corporation tax losses and any abandonment costs not fully written off can be carried forward indefinitely.

Payment dates: Smaller companies with a tax liability of less than €200,000 in their previous accounting period: 90% of the corporation tax payable for the financial year must be paid one month before the end of the accounting period. For companies with a tax liability of more than €200,000 in their previous accounting period, the payment of preliminary tax is made in two instalments. The first being payable in the sixth month of the accounting period, and the second in the eleventh month. The tax return must be filed nine months after the end of the accounting period, at which time the 10% balance of tax due must be paid.

Petroleum Production Tax

The Petroleum Production Tax (PPT) is calculated on a field's net income at a rate that is determined by an R factor ratio of the cumulative gross revenue less PPT paid relative to cumulative field costs, calculated for each taxable period.

The legislation provides that:

- PPT will be payable in addition to corporate income tax.
- PPT payments are deductible for the purposes of calculating the amount of corporate income tax due.
- The maximum marginal tax take on a producing field (combining the corporation income tax and petroleum production tax) is 55%.
- Once a field starts producing oil or gas, a minimum PPT payment of 5% will be payable in each year of production on the gross revenue (net of transportation costs) of a field.

R Factor	Petroleum Production Tax (PPT) Rate
<1.5	0%
1.5	10%
$1.5 < R < 4.5$	pro-rata
$>=4.5$	40%

Mexico PSC

Government Equity Participation

Partnerships with Pemex have not been required on exploration acreage, though discovered fields have required a participation.

Bonuses, Rentals & Fees

1. Signature bonus - In the majority of rounds, no signature bonus has been payable. In the most recent rounds, caps were placed on biddable fiscal elements and any bids tied at the maximum amount were to include a biddable signature bonus.
2. Area Rentals - Area rental payments are due during the exploration period only. During the first 5 years of this period, the annual rate is 14,570 pesos per square km. (~810 US$). In subsequent months, the annual rate is 34,842 pesos per square km. (~1,936 US$).

Indirect Taxes

1. VAT - Titled IVA, VAT is set at 16% and is recoverable.
2. Import Duties - Import duties apply at variable rates, depending on the type of goods. Machinery and equipment are generally taxed at rates ranging from 3-23%. (Under NAFTA and the European Free Trade Agreement, preferential rates of 0-8% for the same goods apply.)
3. Withholding tax on sub-contractors - A 25% withholding charge is levied on any payment made for technical services. International treaties may reduce this rate.

Royalty

Several royalties may be due on production in Mexico, depending on the field's water depth. The applicable royalties for each depth are:

Water Depth	Shelf (PSC)	Deepwater (License)
Price based Royalty	Yes	Yes
Production-based Royalty		
R-Factor Royalty		Yes
Royalty Bid		Yes

Each of these rates are levied on gross revenues less transportation and storage (well-head value). The royalties are additive, summing to an overall rate for each period.

Price-based

A price-based royalty is levied on all hydrocarbons in Mexico. This royalty is payable at increasing percentages depending on well-head price. The calculation of these royalties is adjusted by PPI with the figures shown below in 2015 terms.

Hydrocarbon type	Price (P)	Royalty (%)
Oil	P < $48/bbl	7.50%
Oil	P ≥ $48/bbl	(0.125 * P + 1.5)/100
Condensate	P < $60/bbl	5%
Condensate	P ≥ $60/bbl	(0.125 * P - 2.5)/100
Associated gas	No price threshold	(P / 100)
Non-associated gas	P ≤ $5.00/mcf	0%
Non-associated gas	$5.00/mcf < P ≤ $5.50/mcf	[(P - 5) x 60.5] / (P * 100)
Non-associated gas	P ≥ US$5.50/mcf	(P / 100)

R-Factor based

For deepwater fields, an additional royalty may be due, depending on project profitability. The additional royalty is based upon two elements, an R-Factor and a Coefficient of Operating Results (CRO).

- R-Factor (All figures are cumulative from the start of the license) = (revenues - royalties and rentals) / costs

- CRO (All figures are non-cumulative, quarterly values) = (revenues - royalties, rentals, and costs) / revenues

R-Factor	R-Factor Royalties
Less than 2	0.0%
2 to 4	(R-Factor - 2) / 2 x 33% x CRO
Greater than 4	33% x CRO

Additional Biddable

In deepwater and onshore rounds, one of the prime biddable elements is an additional flat royalty percentage. In the onshore round, highly competitive bidding caused many of these bids to become so high as to make the fields sub-economic. For this analysis, we have assumed bids of 50% for onshore oil, 25% for onshore gas, and 10% for deepwater.

Cost Oil

Maximum recoverable cost oil is set to 60% of gross revenues in any given month. All allowable costs are immediately available for cost recovery. Unrecovered costs are carried forward without accruing interest.

Cost oil is limited in the amount payable over the budgeted amount. No cost category (as grouped within the original PSC) can be claimed for amounts greater than 10% over its original budget. Total recoverable costs cannot exceed 5% over the original budget.

Profit Oil

Profit Oil after Royalty and Cost Oil is distributed between the government and the contractor using a sliding scale based on an initial bid and the project's internal rate of return before income tax in the previous month.

Initial contractor profit share is set to the accepted bid percentage. This amount will begin to decline at 25% IRR, linearly scaling to a minimum of 25% of the initial bid amount at 40% IRR.

The chart below shows declining profit share as IRR increases for various initial bid levels. IRR for each month is calculated as Cost Oil + Profit Oil - Costs

In the model, a 50% initial bid is assumed, based on results from Rounds 2.1.

Corporate Income Tax

Contractors are liable to pay corporate income tax (CIT). E&A costs, non-capitalizable expenses, and maintenance capex can be expensed immediately. Development and production costs are depreciated along a four-year straight-line schedule. Pipeline, storage, and other transportation capital is depreciated on a ten-year straight-line schedule.

CIT is levied at a flat 30%.

Decommissioning Treatment

An escrow account is required to be prepare for eventual decommissioning expenses. Each production period, the current account balance is subtracted from the projected abandonment expense and the unfunded amount is to be deposited on a units of production basis.

The deposits to this account are not recoverable for cost oil purposes or deductible for income tax purposes. Additionally, no carry-back provisions are allowed, though decommissioning costs may be recovered from other wells in a PSC and deducted from company-level income.

Norway

Government Equity Participation

The State reserves the right to take direct participation, through state entity Petoro, which manages the State's Direct Financial Interest (SDFI). In recent licence awards, the state participation has typically been between 20-30%, but can be as low as zero. Petroro pays its share of costs from day one. We have assumed 20% state equity in our model.

The State also has a major, indirect participation through its majority ownership of Statoil. Statoil has no mandatory right to participate in licences, so only Petoro's interest has been included as State equity.

Bonuses, Rentals & Fees

Area Rentals	Rate, per annum
Application Fee (one off fee)	123,000 NKr
Area Rentals: Production phase, Year 1	34,000 NKr per km²
Area Rentals: Production phase, Year 2	68,000 NKr per km²
Area Rentals: Production phase, Year 3 onwards	137,000 NKr per km²
Seismic Survey Fee (payable for each seismic survey)	33,000 NKr

Indirect Taxes

1. CO2 - levies are payable on gas flared, gas or oil/condensate used for power generation: Continental Shelf: natural gas is taxed at 7.16 NKr/Sm3 whilst petroleum is taxed at 1.04 NKr/Sm3 (from 2017).
2. NOx - Nitrous oxide emissions @ NKr 11.00/kg. The current rate will remain until 2017 from where it will increase to NOK 17.01/kg

Royalty

None

Corporate Income Tax

Corporate Income Tax (CIT) is levied at 24% of revenue less operating costs and depreciation.

Offshore production assets are depreciated straight line over 6 years, measured from date of purchase. Leased assets may be capitalised and depreciated according to a deemed purchase price. Exploration costs can either be expensed or capitalised without uplift.

Companies that are not in a tax paying position may claim an annual cash refund from the state of 78% of the exploration costs, limited to the tax value of such losses.

Losses are carried forward indefinitely with interest at after-tax risk free rate.

Abandonment costs are tax deductible. Companies that end up in a loss position when they exit their Norwegian operations are given a cash refund of the tax value of that loss, (i.e. 78% of their losses, based on 24% CIT and 54% Special tax), which can be no more than the tax they have paid to date.

Additional Petroleum Tax

Special Tax is levied at 54% of taxable income for CIT purposes, with an additional 21.6% uplift on capital expenditure over 4 years (i.e. 5.4% per annum commencing upon investment year).

Corporate Income Tax is not deductible for the Special Tax calculation and vice versa.

United Kingdom

Government Equity Participation

None

Bonuses, Rentals & Fees

1. Oil and Gas Authority (OGA) funding levy.
2. Area Rentals - Between £150 / km^2 and £7,500 / km^2 depending on license type.

Indirect Taxes

1. VAT - Payable at 20.0% on most goods and services. VAT on exports is zero rated.
2. CO2 - EU ETS scheme applies

Royalty

None

Corporate Income Tax

Corporate Income Tax is levied at 30%. An additional Supplementary Charge (SCT) is levied from a similar tax base.

Corporate Income Tax is levied on gross revenue less operating costs and depreciation. The majority of capital costs can be depreciated 100% year incurred and losses can be carried forward indefinitely and may be carried back for three years - relief for decommissioning costs can be carried back to April 2002.

Supplementary Charge (SCT)

The Supplementary Charge is levied at a rate of 10%; levied on similar tax base as Corporate Income Tax with the exception of an investment allowance equal to 62.5% of the capital expenditures.

United States Gulf of Mexico

Government Equity Participation

None

Bonuses, Rentals & Fees

1. Signature bonus - Signature bonuses are bidding factors. Average winning bids close to US$100 million with minimum bids US$25/acre for shallow water and US$100/acre for deepwater.
2. Area Rentals - Surface rental fees depend on water depth and escalate over the life of the field. Lower rates are at US$7/acre and higher rates reach US$44/acre.

Indirect Taxes

None

Royalty

Royalty is levied on "wellhead value" at a fixed rate of 18.75% (since the 2008 licensing rounds). Wellhead value is defined as the sales value of production net of certain 'off-lease' costs incurred in processing (for gas) and transporting (for oil and gas) the petroleum from the lease area to the point of sale.

Federal Income Tax

Federal Income Tax (FIT) is levied at 35% on gross revenue less operating costs, royalty, and depreciation.

Tangible development costs are depreciated using the 7 year MACRS method, with half year conversion. (MARCS is comprised by double declining balance method, switching to straight line as soon as that allowance is greater.) Intangible development drilling and E&A costs are directly expensed. In the model, it is assumed that 80% of the development drilling costs are intangible.

Exhibit B – UNCLOS payment

UNCLOS Article 82 Payment

Article 82 of the United Nations Convention on the Law of the Sea (UNCLOS) may apply to certain projects offshore NL. Under this article each country as a signatory to UNCLOS is liable to make an additional payment on production to the United Nations where there is exploitation of resources more than 200 nautical miles from the baselines from which the breadth of the territorial sea is measured.

The payment will be made annually with respect to all production at a site with the payment commencing after five years of production at that site. For the sixth year, the rate of payment or contribution is set at one per cent of the value or volume of production at the site. The rate increases by one per cent for each subsequent year until the twelfth year and remains at seven per cent thereafter.

No final decision has been made in Canada on who will pay and if the companies are to pay, then what relief would be available against existing levels of government share. The Norwegian Ministry of Oil and Gas suggested it would make the UNCLOS royalty paid by companies deductible from the tax base when it offered Barents acreage in 2016.

Its application however will not be limited to NL and other jurisdictions such as Norway have already started to consider its implications, The recent Korpfjell gas discovery in Norway is outside of the 200 nautical mile limit.

Exhibit C – Wood Mackenzie field modelling methodology

Wood Mackenzie's underlying field by field cost dataset used in its fiscal modelling software (Global Economic Model or GEM) is built up through conversations with operators, non-operators, regulatory bodies etc. An individually constructed GEM file accompanies each onstream, under development or probable development. Fields that could be economic under our current cost and price projections, but where significant uncertainty remains over the nature and timing of their development are referred to as good technicals. For these fields, a more automated approach is used to modelling, that takes account of the expected recoverable reserves, cost environment and likely development solution.

Details are provided below of the cost categories and their constituent parts for each onstream, under development or probable development and the technical modelling assumptions applied to the deepwater opportunities in NL. Note: Wood Mackenzie produces development cash flows rather than full-life (unless otherwise stated), therefore all E+A/pre-FID capex is treated as sunk, although their fiscal impact is captured in regimes where this is necessary.

Onstream, under development or probable development cost categories

Upstream Capex	
Production Facilities	Platforms, TLPs & FPSOs: e.g. jacket, piles, substructure, topside structure, including accommodation facility, drilling facilities
Processing Equipment	Any facilities related to topside production systems: e.g. compressors, pumps, separators, dehydrators, processing modules, chemical systems
Subsea	Templates, manifolds, subsea xmas trees, subsea processing units, control units (electrics / valves), subsea umbilicals, flowlines, risers (SURF)
Development drilling	Site preparation, rig costs, personnel, materials, completions, fraccing
Pipeline	Survey, pipeline construction, pipeline coating, pipeline laying, including pipelines/flowlines from satellites to host platform and export pipelines
Offshore Loading	Offshore loading systems e.g. floating buoys
Terminal	Any onshore systems related directly to producing fields
Other Capex	Anything not directly covered by the above categories, plus unallocated sustaining capex
Country Specific	Costs that have their own individual depreciation schedule
Abandonment Costs	Any costs related to well plugging, facility removal, disposal, site restoration
Capital Receipts	Money received from selling (in whole or in part) fixed assets such as land, buildings, facilities

	and equipment.
Upstream Opex	
Field Fixed/Variable	All costs related to manpower, logistics (transport of personnel and materials), maintenance, consumables (fuel, chemicals), licence fees, well workovers associated with existing reservoir zones
Non-tariff transport	Costs of running and maintaining transport facilities (pipelines or tankers/trucks) that are owned by asset partners
Tariff payments (oil, gas)	Usually costs that are production-linked and paid on a unit cost basis, paid to owners of transport or processing infrastructure and tanker owners
Tariff receipts	Tariff receipts paid to the asset owner, for use of its processing or transportation facilities.
Other Costs	Cost for leased FPSOs, production facilities and other plant and equipment
Insurance	Cost of insuring the asset against loss or damage
G&A	General & Administration: Any onshore-based costs associated with the asset, i.e. G&G work, office and supporting staff, administration, legal, finance, etc
Other Opex	Any other costs that cannot be capitalised, that are not part of any of the above categories
Country Specific 2	Country or regime specific operating costs or taxes *e.g. EUETS Costs - modelled in Norway at present*
Country Specific 3	Country or regime specific operating costs or taxes *e.g. CO2 and NOx tax - specific to Norway only*
Upstream Other	
Oil Capex	Where applicable, pre-set percentage of capex to be allocated to cost oil recovery. Remainder allocated to cost gas (Combined total = 100%).
Oil Opex	Where applicable, pre-set percentage of opex to be allocated to cost oil recovery. Remainder allocated to cost gas (Combined total = 100%).
Sunk Costs Oil/Gas	Pre-FID costs that should be included in tax calculations. The cost is not included in the cash flow or output metrics but the cash flows, NPVs and IRR will be affected by effect that these sunk costs have on different levels of Government Share.
Bonuses	Non production-related bonuses, such as signature bonus

Technical modelling assumptions applied to the deepwater opportunities in NL

The following outlines the assumptions used in the creation of the technical models for the three deepwater fields modelled in NL:

Bay du Nord

Development solution – FPSO

Cost Environment – 200% of standard (very high)

Technical Recoverable Oil – 300mmbbls

Reservoir Depth – 3km (medium)

Oil Recovery Per Well – 10mmbbls (medium)

Start-up Year – 2025

Oil Tariff – US$2/bbl

Harpoon

Development solution – FPSO

Cost Environment – 200% of standard (very high)

Technical Recoverable Oil – 100mmbbls

Reservoir Depth – 3km (medium)

Oil Recovery Per Well – 10mmbbls (medium)

Start-up Year – 2028

Oil Tariff – US$2/bbl

Mizzen North

Development solution – subsea

Cost Environment – 200% of standard (very high)

Technical Recoverable Oil – 130mmbbls

Reservoir Depth – 4km (deep, x1.25multiplier on standard well cost)

Oil Recovery Per Well – 10mmbbls (medium)

Start-up Year – 2030

Distance to Infrastructure – 40km

Oil Tariff – US$2/bbl

These assumptions are used to create field costs related to analogues based on project scale and development type.

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