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IEEFA.org

Australia's Offshore Industry: A Half-Century Snapshot

Analysis of the Government's Administrative Role, Key Players' Behaviour and the Looming Risks for the Sector

Executive Summary

On a global scale, Australia's identified offshore gas resources are about 3 times larger than its remaining onshore resources identified so far. Australia could produce conventional gas for the next 42 years, according to Geoscience Australia, based on 2019 production rate from its currently identified conventional gas fields. 93% of these identified conventional gas fields are located in offshore western Australia.

In reality however, gas reserves cannot be developed if we are to maintain a stable climate. The world has less than 3 decades to reach net zero emissions according to both the International Energy Agency's (IEA) flagship "Net-Zero by 2050" report which urges zero new spending on oil and gas projects globally, and the Intergovernmental Panel on Climate Change (IPCC) report which concludes global emissions must reduce by 45% by 2030 to avoid catastrophic climate collapse.

Australia took the crown from Qatar as the largest liquefied natural gas (LNG) exporter in the world in 2019, exporting 77.5 million tonnes with around 70% supplied by offshore gas.

The Federal government has actively backed the offshore oil and gas industry since the start of the LNG boom in late 2000s, with 13 exploration titles granted in 2019 alone - the highest number issued in the last decade. In the next 6 years, AUD5.1 billion will be spent by companies on offshore exploration activities in an area around 154,000km^2 wide, based on work-bid data submitted to the National Offshore Petroleum Titles Administrator (NOPTA).

The government has issued significantly more titles for exploration than production in recent years.

Oil and gas companies, on the other hand, have drilled twice as many production wells than exploration wells. These counterintuitive dynamics could be due to the fact that many companies prefer to focus on definite resources they have already explored rather than investment on risky exploration projects, despite government

encouragement. They are constrained by their balance sheets as they have written off billions of dollars over the last decade on gas assets.

The top 10 biggest companies that have the highest level of involvement in Australia's offshore sector are Australia's oil and gas icons Woodside, Santos and BHP along with the major multi-national incumbents ExxonMobil, Chevron, Shell and BP, followed by Japanese giants Mitsui, Mitsubishi and INPEX.

Of this, the top 4 operators are ExxonMobil, Woodside, Chevron and Santos. Together they operate 222 of the 373 existing offshore permits. While ExxonMobil and Woodside's focus is on the established side of the business, controlling 51% of the production and pipeline licences together, Chevron and Santos as younger offshore players have invested more in pre-production and exploration activities, acquiring 41% of all exploration permits and retention leases as operator partners.

AUD5.1 billion will be spent in the offshore exploration projects in the next 6 years.

Of AUD5.1 billion in Australia's offshore exploration expenditure to be spent in the next 6 years, Santos operates the most expensive projects collectively with AUD1.3 billion in expenditure. Chevron is next with AUD430 million, followed by Shell with AUD336 million. INPEX and BP complete the top-5 list, each being the operator of exploration projects costing more than AUD220 million.

Five Growing Risks in Australia's Offshore Sector

Despite the growing number of offshore exploration permits and development projects and their prospective expenditures, IEEFA has identified 5 major risks specifically confronting Australia's offshore sector.

1. **Australia's biggest LNG customer, Japan, is aiming to halve the LNG share in its electricity mix by 2030.**

   There has been a massive global energy policy shift, particularly from Japan as Australia's biggest LNG customer. Aiming for a near 50% reduction in LNG in its 2030 power generation mix, Japan will no longer be as LNG-thirsty as it used to be. This is a real threat for Australian LNG exports, especially considering the likely domino effect of Japan's ambitious policy on other southeast Asian nations like South Korea.

2. **Advanced satellite-based emission tracking systems have recently detected enormous methane leakages in remote offshore areas.**

   The emergence of advanced satellite-based emission tracking systems is providing data previously unknown or under reported, including the recent detection of enormous methane leakages in remote offshore areas. This

poses a serious threat to the social license of oil and gas companies and brings into question the validity of new industry terms such as 'carbon-neutral LNG'. It also increases the risk facing bankers and investors in financing such projects, particularly as more stringent carbon emission regulations become adopted globally.

3. **Financing offshore projects are riskier as companies have lost their ability to sell down interest with partners being unwilling to commit.**

   Another risk previously ignored is the changing profile of partners in joint ventures. Big oil and gas companies have lost their ability to sell down interest in billion-dollar projects due to partners being unwilling to commit. Large stakes in projects have made the cost of financing big projects higher. Financial institutions are more likely to consider higher interest rates for a project with one or two partners, compared to a project with several partners.

4. **Offshore well depths have been rapidly increasing, exponentially inflating the capex of projects.**

   Based on data from 700 offshore wells, IEEFA notes that the average total depth of wells has increased by around 600 meters (20%) during the LNG boom (2009-2019). According to the scientific research, deeper drilling leads to an exponential rise in costs, even with the deployment of advanced and more efficient drilling technologies.

5. **LNG contracts have become shorter and more flexible due to the uncertain future of the LNG market.**

   The current wave of country policy initiatives abandoning gas has led to customers migrating from rigid long-term (20-30 year) contracts to shorter ones (typically 10-15 years) with more flexible conditions including the ability to resell cargos in case of glut. As a result, there is now a lack of certainty that there will be enough demand for LNG cargos over the next 20-30 years, increasing investment risk and consequently the cost of financing.

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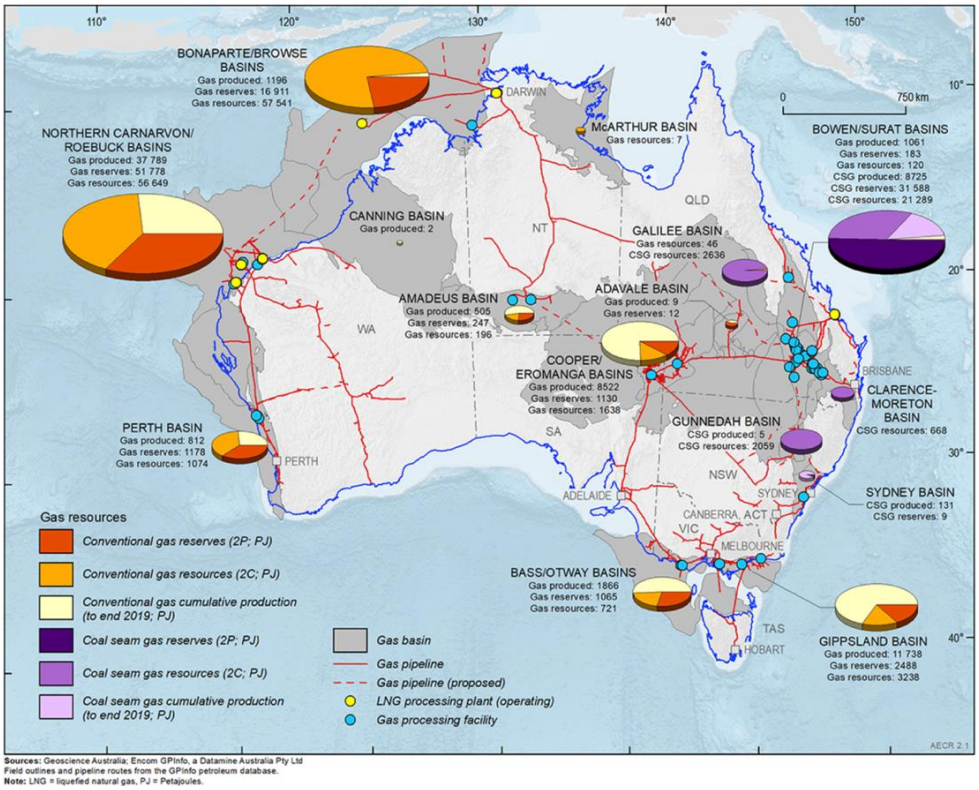
Australia's Offshore Resources

In 1965 an ExxonMobil/BHP Billiton joint venture drilled Australia's first offshore well and discovered the Barracouta gas field in Bass Strait.[1] It was the first step towards Australia's present day billion-dollar offshore oil and gas industry.

After the LNG boom in the late 2000's, although exploration and production of onshore coal seam gas (CSG) skyrocketed, offshore hydrocarbon deposits still outweighed onshore reserves by a considerable margin (Figure 1).

The remaining deposit discovered in the north Carnarvon Basin in the north-western shelf offshore western Australia is larger than the country's whole onshore proven oil and gas reserves, according to data published in 2019 by Geoscience Australia. Coupled with this, the nearly untouched Browse Basin north of Broome offshore West Australia demonstrates how massive Australia's offshore resources are.

Figure 1: Dispersion of Offshore/Onshore Australia's Hydrocarbon Resources



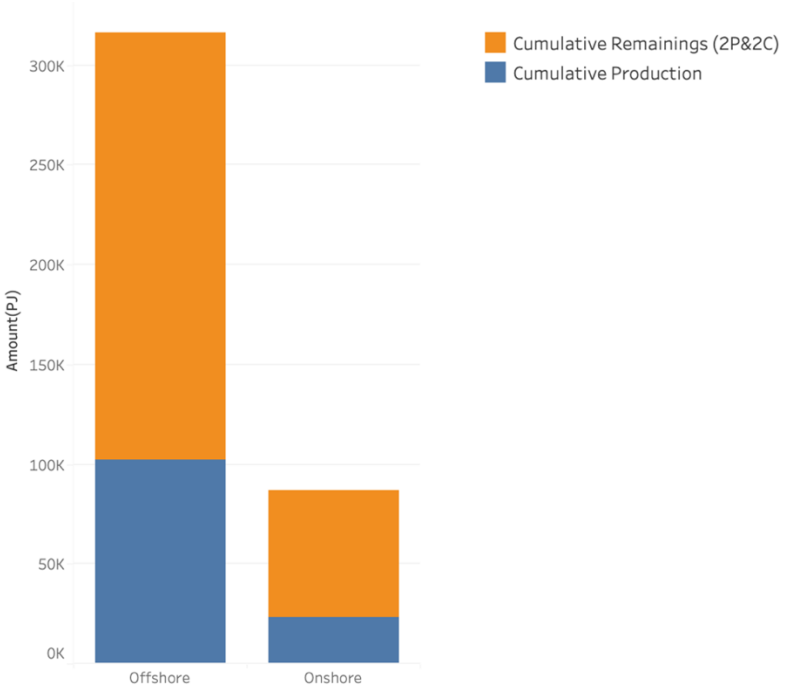
Source: Geoscience Australia.[2]

[1] ExxonMobil. Bass Strait. 12 May 2019.
[2] Geoscience Australia. Gas.

Oil and gas giants have been investing big in offshore projects, and numerous exploration and production (E&P) and development activities are on track to extract the massive oil, gas and condensates that lie beneath Australia's coastal and deep waters.

There are more than 200,000 petajoules (PJ) of unused offshore reserves in waters off Australia compared to the ~65,000PJ of identified onshore sources (Figure 2[3]).[4] Australia's yearly energy consumption in 2019 was just 6,196PJ[5], clarifying the magnitude of the remaining oil and gas in the country, especially offshore.

Figure 2: Australia's Offshore / Onshore Hydrocarbon Resources



Source: Geoscience Australia,[6] IEEFA calculation.

About 93% of identified conventional gas resources are located offshore along the North West Shelf of Australia, according to Geoscience Australia. Based on 2019 production rates of 4,641PJ (4.13Tcf), Australia's identified conventional gas resources would have a life of 42 years if all identified contingencies to development were mitigated.[7]

[3] This figure does not include coal resources and also undiscovered prospective resources (shale gas, tight gas, basin-centred gas, coal bed gas, and deep bed coal gas). The estimate of total potentially recoverable gas resources is much larger than proven resources.
[4] These are estimates and not exact numbers as some basins like Perth have both offshore and onshore resources.
[5] Department of Industry Science Energy and Resources. Energy consumption.
[6] Geoscience Australia. Gas.
[7] Geoscience Australia. Gas.

Putting aside CSG and probable new explorations, Australia would still have conventional gas to exploit more than a decade after the landmark climate milestone of 2050, set by the International Energy Agency (IEA) for countries to necessarily achieve net-zero.[8] The majority of this abundant fossil source is offshore.

Offshore vs. Onshore: Cost Structure, Time Horizon and Emissions Profile

The offshore oil and gas (O&G) sector differs from the onshore in several ways.

Onshore wells within a basin are often similar in terms of their design and cost profile, while each offshore project has completely distinct design specifications and cost profiles. Deepwater development typically takes the form of costly, high-risk, long-duration projects that are less susceptible to short-term oil price fluctuations. They have high capital cost and tend to produce almost regardless of the oil price. Conversely, onshore development is highly correlated to the oil price as the well life is short and the capital cost is relatively low.

In the onshore sector, drilling equipment and the cost of building infrastructure to access water, electricity and roads are the two most significant expenses incurred, while key distinct cost drivers for the offshore sector include drilling equipment and fleet, water depth, well depth, and distance from the shore.

Drilling in offshore development is a much larger share of total well costs than in onshore development, where tangible and intangible drilling costs typically represent only about 30% to 40% of total well costs.[9] That is because offshore wells are generally deeper than onshore wells which leads to longer periods of drilling, more complicated technical considerations, and higher uncertainty as the drillers go deeper into the seabed. These complexities lead to a more expensive, more complicated, and longer end-of-life decommissioning phase, as well as more expensive Plug and Abandonment (P&A) activities.

Drilling in offshore development has higher uncertainty than in onshore development.

"Trouble Costs" - unplanned and unscheduled costs arising during well operations - can also be different in nature and magnitude in offshore O&G projects. In offshore well drilling, some extreme weather conditions, fishing activities, hole stability, and lost circulation problems in the deep layers can increase the probability and magnitude of trouble costs.

[8] IEA. Net Zero by 2050. Revised version. July 2021.
[9] EIA. Trends in U.S. Oil and Natural Gas Upstream Costs. March 2016.

All of these complexities lead to the exponential relationship between the cost and depth of wells. As offshore wells are generally deeper, the rate of costs rising would be higher.[10] [11] [12] That explains why before drilling, O&G producers spend years and massive amounts of money conducting thorough seismological surveys to estimate the proven and probable reserves accessible for recovery.

On top of the emission-intensive value chain of O&G projects in general, there are specific environmental and emission concerns with offshore projects. These include, but are not limited to, potential oil spills and the impact on coastal areas, the production of thousands of gallons of waste drilling fluid which has toxic components, disturbances on marine life created by seismic surveys, and the threat of endangering bio-diversity.[13] The famous "Deep Water Horizon Oil Spill (BP)"[14] disaster in April 2010 in the gulf of Mexico and the more recent "Eye of Fire" (Pemex)[15] disaster in July 2021 show that the probability of environmental catastrophes is real in spite of technological advancements and stringent regulations.

As offshore wells are generally deeper, the rate of costs rising would be higher.

Tracking methane emissions from offshore oil and gas platforms by satellite has historically been challenging because of the absorption of sunlight by water, which skews observations. A new wave of emission tracing technologies specifically designed for offshore projects (including sealed and abandoned wells) will likely detect fugitive methane emissions from offshore fleets and wells more precisely.[16]

Considering the exclusive features of the offshore O&G sector along with the fact that Australia is a nation with massive offshore resources and a government that is not yet responsive enough to global pressure to cut emissions, looking at trends, players and market mechanisms in this sector may be insightful for investors and

[10] M. Enamul Hossain. Drilling Costs Estimation for Hydrocarbon Wells. De Gruyter. June 2015.
[11] Dalmo S. Amorim Jr., Otto Luiz Alcântara Santos and Ricardo Cabral de Azevedo. A statistical solution for cost estimation in oil well drilling. International Engineering Journal 72(4):675-683. October 2019.
[12] Gregory Robert Leamon. Petroleum well costs, School of Petroleum Engineering, The University of New South Wales. 2006.
[13] National Resources Defence Council. Protecting Our Ocean and Coastal Economics: Avoid Unnecessary Risks from Offshore Drilling. September 2009.
[14] United States Environmental Protection Agency. Deepwater Horizon – BP Gulf of Mexico Oil Spill.
[15] Reuters. 'Eye of fire' in Mexican waters snuffed out, says national oil company. 3 July 2021.
[16] Bloomberg Green. Shell, TotalEnergies Join Satellite Effort to Track Methane. 8 July 2021.

decision makers going forward.

History of Offshore Drilling in Australia[17]

The transition from onshore to offshore petroleum exploration had to be postponed until advancements in seismic and drilling technologies were made.

In 1959, Woodside (Lakes Entrance) Oil obtained Australia's first offshore exploration licence in the Gippsland Basin. Haematite Explorations undertook the first seismic study of the area in 1962-1963 using state-of-the-art methods to map Australia's initial offshore drilling potential. A joint venture between Esso and BHP drilled Australia's first offshore well in the Gippsland Basin in 1964.

In the late 1960s and late 1970s, the Esso BHP joint venture made successive oil and gas discoveries. In May 1971, the drilling ship Ocean Digger discovered the North Rankin field, followed by the Goodwyn field a few months later. Arco found gas in the Bonaparte Basin with their first offshore well. Due to some technological advancement at the time, Shell managed to drill the first well beyond the continental shelf in 256 meters of water in the Arafura Basin in 1971.

A series of deep-water wells were drilled in 1979 and 1980 by Esso, Woodside and Phillips in the Carnarvon and Browse basins. Large gas accumulations were encountered in Scarborough-1, North Scott Reef-1 and Gorgon. The remote location delayed development of these deep-water gas discoveries. Then in the 1980s, oil discoveries in the Barrow Sub-Basin revived interest.

Meanwhile, the Timor Sea had been receiving a lot of drilling attention. In 2003, Woodside drilled Gnarylknots-1 and -1A in the Great Australian Bight in 1,316 meters of water. The well was abandoned before reaching its objective. High mobilisation costs, high rig rates, weather delays and borehole problems contributed to the final cost of over AUD50 million. This was the most expensive exploration well drilled in Australia at that time.

The next wave of drilling started in the late 2000's, the beginning of the LNG boom in Australia. While Australia has been exporting LNG since the 1980s, the boom began in 2009 with Chevron's final investment decision in Gorgon, up until 2019 when Shell shipped out the first cargo from Prelude - the world's biggest floating LNG plant.

Chevron became the next big offshore driller after the LNG boom with the Gorgon plant on Western Australia's Barrow Island - the most expensive LNG project in history at $54 billion. Wheatstone, located in the Carnarvon basin, was Chevron's other big LNG project.

[17] Most of the information provided in this section is derived from the Doctoral Thesis written by Gregory Robert Leamon at the School of Petroleum Engineering, University of New South Wales. 2006.

INPEX was the next giant to drill in Australia. The Japanese company made the final investment decision in 2010 on the Ichthys LNG project, estimated to be the second most expensive LNG plant in Australia.[18]

All of these LNG plants required massive gas resources in order to operate at maximum capacity. To meet this need, the companies and their partners, as joint ventures, have been drilling in offshore basins, an activity undertaken since the beginning of the AUD200 billion LNG industry boom.

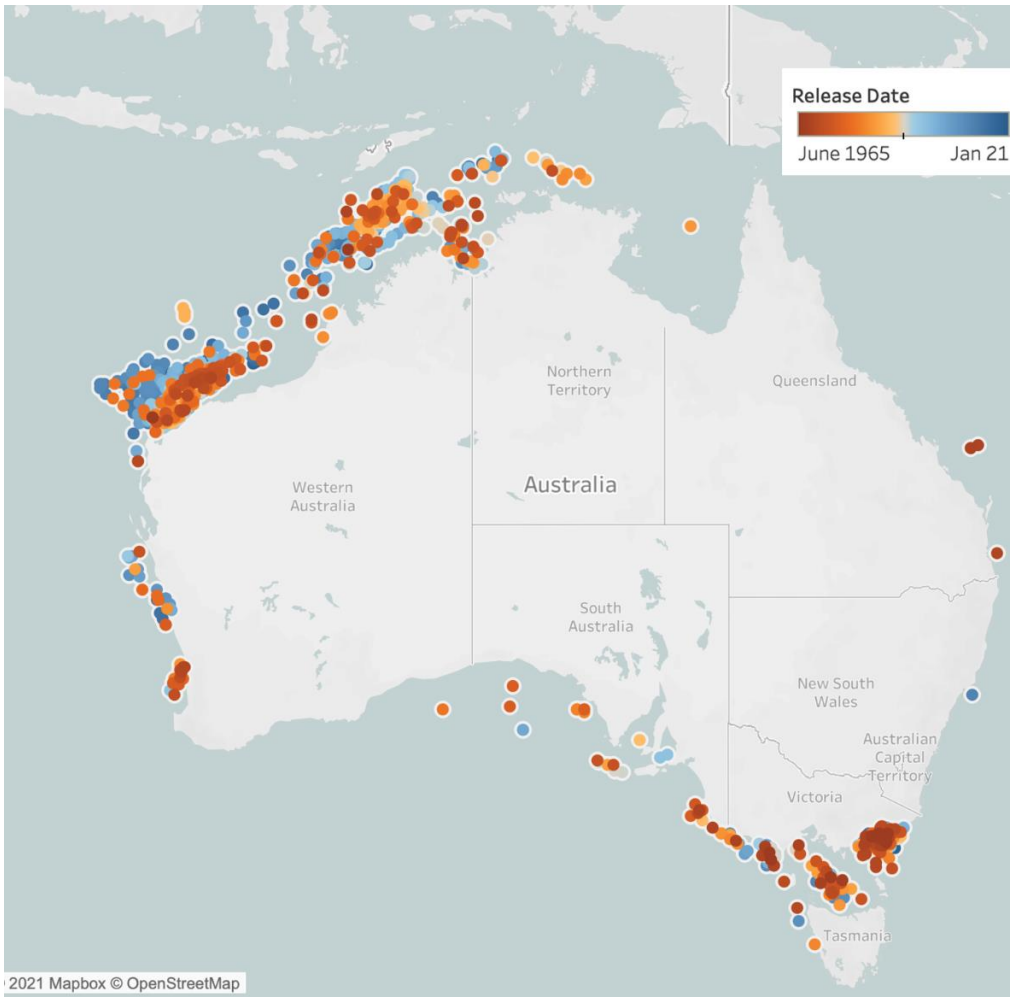
Ichthys LNG project is estimated to be the second most expensive LNG plant in Australia.

In Figure 3, the spatial historical trend of offshore well drilling in Australia (1965-2020) has been drawn by IEEFA based on data provided by National Offshore Petroleum Information Management System (NOPIMS). The colour spectrum shows the date of well drilling. The browner the colour, the older the date of drilling. On the other side, darker blues depict the most recent wells drilled in Commonwealth offshore waters.

As shown, Victorian shores were among the early targets for O&G exploration and production with about 1,000 wells drilled in the Gippsland Basin. Western Australia is the same age as Victoria in terms of drilling activity, however unlike Victoria whose main hydrocarbon resources are depleting, there has been more oil and gas discoveries in Western Australia in recent decades, with O&G companies very optimistic about the Northern Carnarvon and Browse Basin. More than 50% of the total wells drilled in Australia since 1965 are in these Western Australian basins. In fact, since 2000, 3 out of 4 wells have been drilled in Western Australia with 92% of the gas reserves feeding Australia's multi-billion dollar LNG sector located off the Western Australian coast in the Bonaparte, Browse, Carnarvon and Perth Basins.[19] There are few wells in offshore southern Australia and a recent new wave of well drilling in the Northern Territory/Western Australia's Bonaparte basin.

[18] Bloomberg. Australia's $200 Billion LNG Boom Waylaid by Covid and Cracks. 5 September 2020.
[19] Australian Government. Australian Trade Commission. Oil and Gas. March 2016.

Figure 3: Spatial-Historical Well Drilling in Australia (1965-2020)



Source: NOPIMS.[20]

Offshore Petroleum Titles Analysis

Offshore petroleum and carbon capture and storage (CCS) activities beyond designated state and territory coastal waters (three nautical miles) are governed by the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (OPGGSA) and associated regulations. The legislation provides for petroleum exploration and recovery and sets out a basic framework of the rights, duties, obligations, entitlements and responsibilities of governments and industry.

An offshore petroleum title grants the titleholder the right to explore, appraise or develop depending on the title type.

The government-led National Offshore Petroleum Titles Administrator (NOPTA)

[20] Australian Government. National Offshore Petroleum Information Management System.

established in January 2012 is responsible for the day-to-day administration of petroleum and greenhouse gas titles in Commonwealth waters in Australia. It was appointed under OPGGSA and is part of the Department of Industry, Science, Energy and Resources (DISER).

The four main types of titles: exploration permits, retention leases, production licences and pipeline licences comprise 97% of all titles. (Table 1) Exploration permits and retention leases (mostly issued in the appraisal phase) are indicators of the pre-commercial production phase of an O&G project, while production licences are issued for established and commercialized projects.

Table 1: Types of Offshore Petroleum Titles

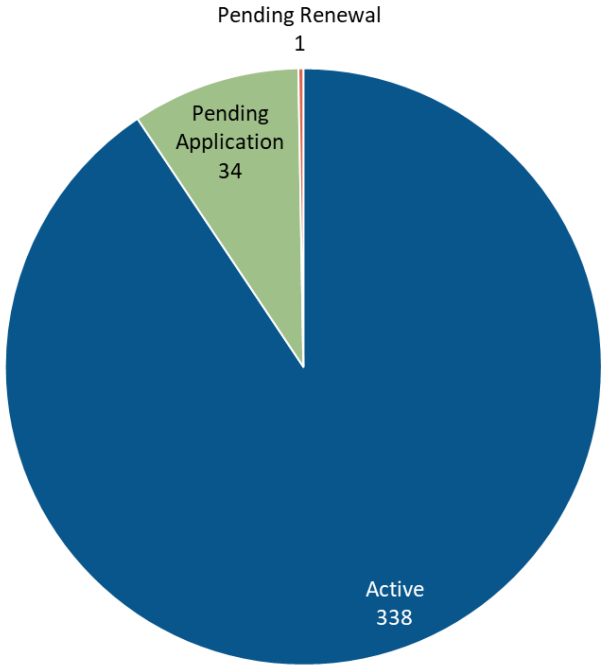
Action	Petroleum Titles
EXPLORE	Exploration Permit • Initial 6 year work program then relinquish 50% for each further 5 year term
DECLARE Required to progress to leases or licences	Petroleum Location (2 plus 2 years) (Declared Discovery) **Requires:** • Recovery of hydrocarbons • Understanding of pool extent (at P_{50})
APPRAISE	Retention Lease (5 years) • Field not currently commercial but likely to be within 15 years • Multiple renewals
OPERATE & DECOMMISSIONING	Production Licence (life of field) • Produce hydrocarbons • Production requires a Field Development Plan & rate of recovery

Source: NOPTA.[21]

Based on the dataset published by the National Electronic Approvals Tracking System (NEATS) in 2021, there are now 373 licences and permits across Commonwealth waters including 338 which are currently active, 34 pending application and 1 permit which is pending renewal (Figure 4).

[21] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA).

Figure 4: Offshore Petroleum Titles' Status



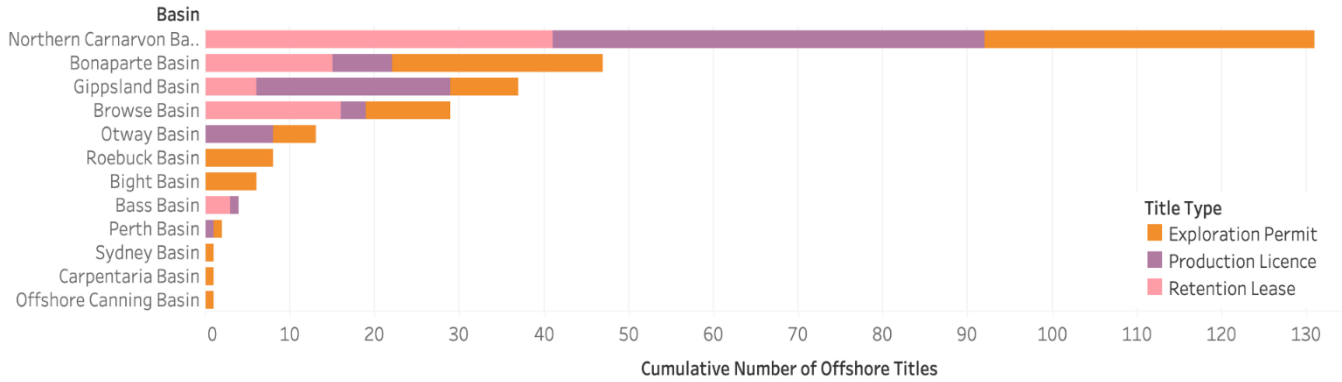
Source: NEATS.[22]

The busiest basin in terms of exploration and development O&G activities is the Northern Carnarvon Basin with more than 130 active licences. The next two are the Bonaparte and the Gippsland Basins.

Comparing the relative proportion of exploration permits/retention leases and production licences is informative in terms of the O&G business dynamics in each basin. For example, pre-production and established production have almost the same proportion in the Northern Carnarvon Basin which means that although this Basin is producing a lot of hydrocarbons, there are numerous exploration and appraisal activities running in parallel illustrating this basin still has plenty of unexplored resources under the seabed. Alternatively, Bonaparte, Browse and Roebuck are basins dominated by exploration permits and retention leases, highlighting they are newer basins under exploration. On the other side, the depleting Gippsland and Otway basins have much lower exploration activities compared to commercialised production.

[22] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA). National Electronic Approvals Tracking System (NEATS) reporting. 12 May 2021.

Figure 5: Offshore Petroleum Titles Across Basins

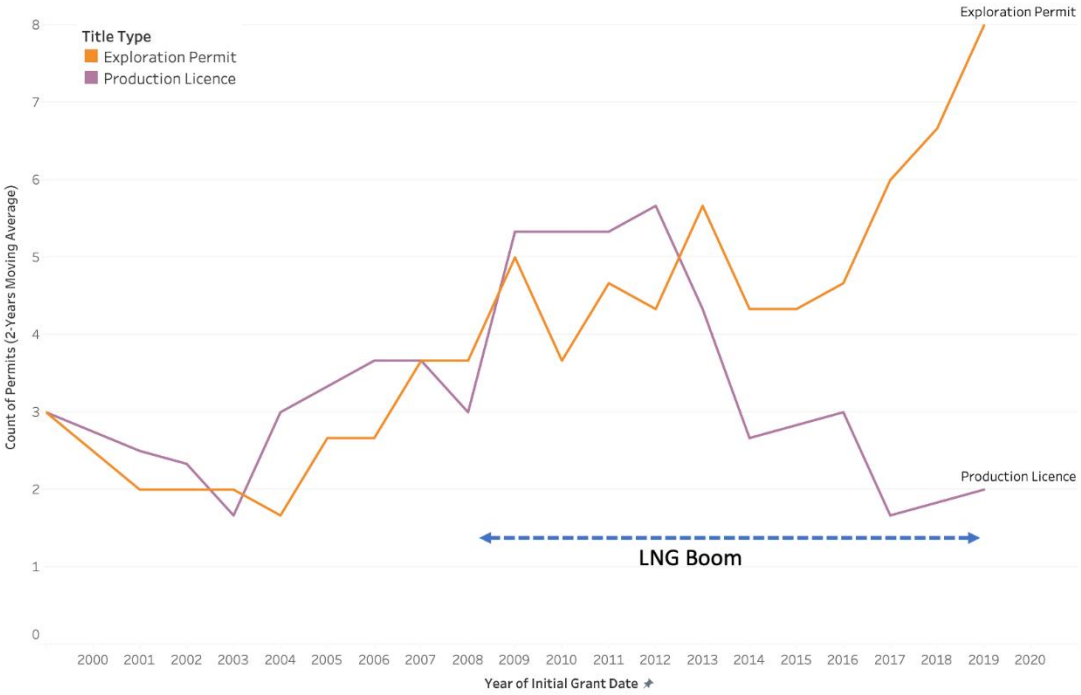


Source: NEATS,[23] *IEEFA analysis.*

Analysing data from 2000-2020 shows that NOPTA has been issuing many more exploration permits than production licences over the last decade. Figure 6 demonstrates the issuance rate for exploration permits has far outpaced the production licence issuance rate since 2011. Until 2011 both were increasing together, however after that, the production licence issuance rate dropped dramatically and the number of approved explorations permits jumped. The gap widened until 2020.[24]

[23] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA). National Electronic Approvals Tracking System (NEATS) reporting. 12 May 2021.
[24] For the title issuance trend (Figure 6), a 2-year moving average was employed to smooth the noisy data and aid in the illumination of the widening gap between exploration permits and production licences rather than close matching of data values.

Figure 6: Exploration Permits vs. Production Licences Issued in 21st Century



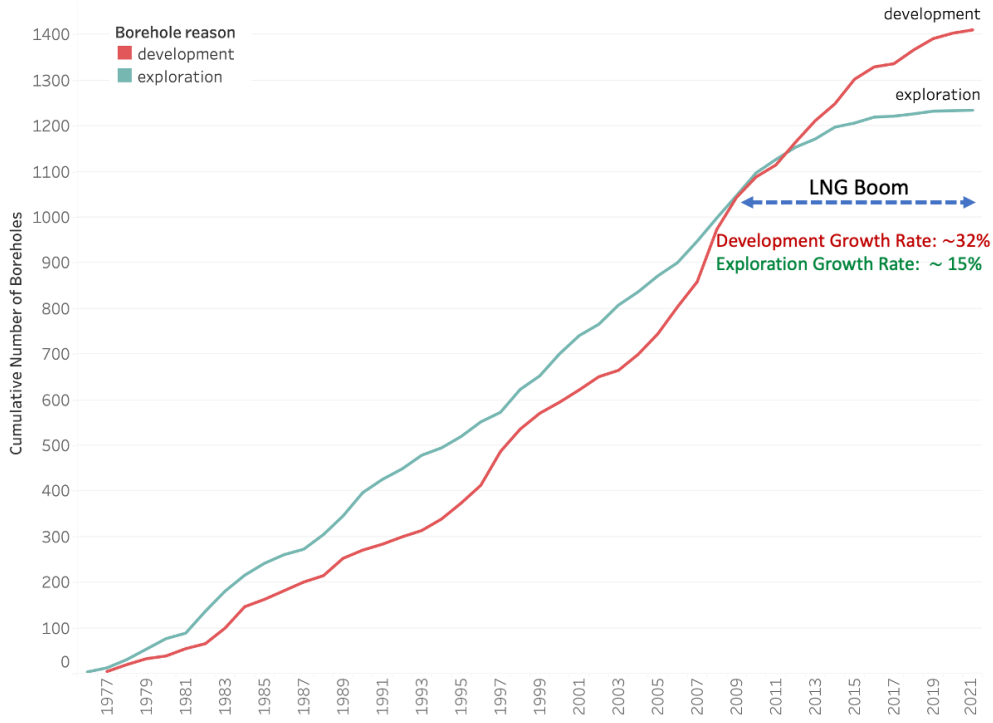
Source: NEATS,[25] IEEFA analysis.

This dramatic shift coincides with the LNG boom and confirms the government's tendency to pave the way for O&G producers to find backup gas fields for their gigantic LNG plants. The government may think the rise in exploration permits will lead to the next wave of O&G development, however, the global transition to low carbon economies makes large-scale development of these exploration permits unlikely to occur.

Another trend was explored by analysing the comprehensive offshore wells dataset administered by the National Offshore Petroleum Information Management System (NOPIMS). Figure 7 shows the cumulative trend of additional offshore wells drilled each year since 1975. Exploration wells and development (production) wells increased at the same pace until 2008, and with the beginning of the LNG boom, started to diverge with a higher increase in development (production) wells. Since 2009, development wells increased by 32% while the number of exploration wells grew by 15%, almost half of the development drilling' growth rate. This is the first time such a divergence can be seen in the history of offshore industry in Australia since 1970s.

[25] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA). National Electronic Approvals Tracking System (NEATS) reporting. 12 May 2021.

Figure 7: Exploration Wells vs. Development Wells - Drilling Trends (1975-2021)



Source: NOPIMS.[26]

In sum, since the beginning of the LNG boom, while more exploration titles were approved compared to production licences, the number of development wells drilled increased much faster than exploration wells. This could have some implications.

One could be the fact that exploration activities have become riskier (rising capital costs, higher risk of failure, social pressure for less new exploration) and companies are focussing on definite resources already explored for more gas and oil. This is especially the case for some LNG plants such as the North West Shelf plants Wheatstone and Gorgon where the companies had already explored massive gas fields before and at the time of the projects' commissioning.

In addition, some companies are constrained by their balance sheets as they have written off billions of dollars over the last decade or so and do not have money to bet on more exploration wells. The risk involved in new exploration is much higher than the cash generative expense on development wells.

Another explanation is that while the government has opened up huge exploration acreages to expand the industry, exploration wells will come online with a delay (due to prerequisite seismic surveys, renewing permits to the appraisal phases, and

[26] Australian Government. National Offshore Petroleum Information Management System.

market disruptions due to COVID-19). In this scenario the government would expect to see more development wells after about a decade than there were since the beginning of the LNG boom in 2009 (assuming exploration and appraisal phases take about 10 years on average to be completed). However, considering massive divestment from fossil assets has been initiated in recent years[27], it is unlikely to occur.

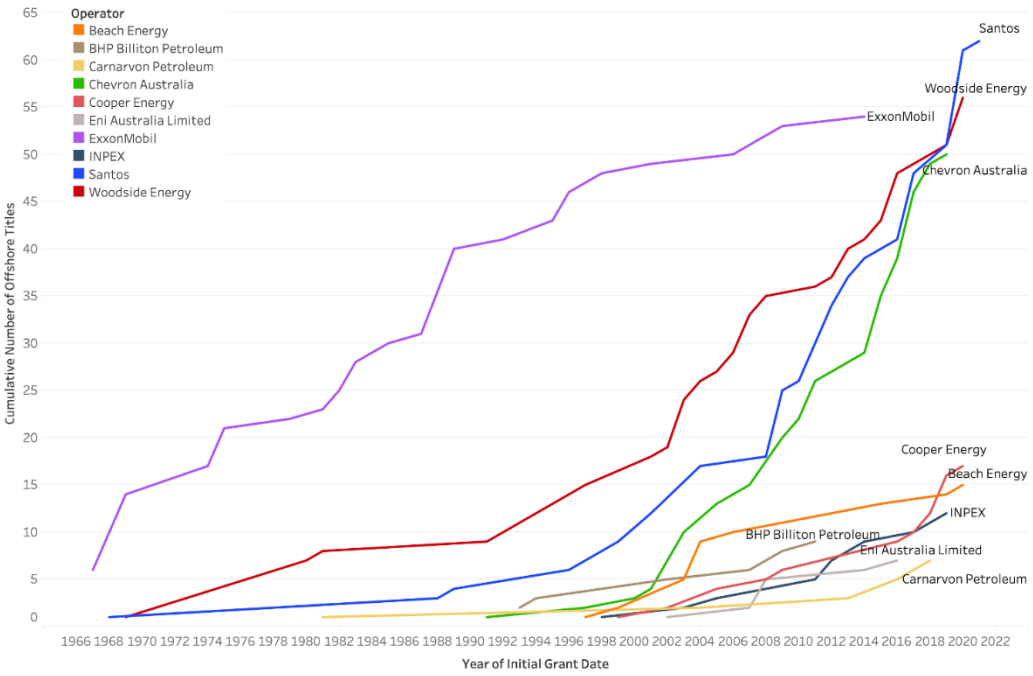
The Big 4 Operators and Some Emerging Companies

Operators are commonly the most important and dominant players of O&G oil joint ventures (JV) having the largest stake with the highest level of responsibility and liability.

Considering offshore active permits reflect the level of O&G-related activities of operators, time series data of the accumulated number of active permits since the beginning of the offshore exploration era, highlights the big players in this sector.

As demonstrated in Figure 8, Santos, Woodside Energy, ExxonMobil Australia and Chevron Australia are the Big 4 players with more than 50 active permits each as operator.

Figure 8: Top-10 Offshore Operators in Australia (1965-2020)



Source: NEATS,[28] IEEFA analysis.

[27] Institute for Energy Economics and Financial Analysis (IEEFA). Divestment from Fossil Fuels: The Financial Case. July 2018.
[28] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA). National Electronic Approvals Tracking System (NEATS) reporting. 12 May 2021.

From the very beginning of the offshore O&G era, ExxonMobil was on top by far. However, it was recently overtaken by the aggressive domestic giants Woodside and Santos. The ExxonMobil upward trend is stabilizing, as its main area of development and exploration - the Gippsland Basin located in Bass Strait - is being depleted.

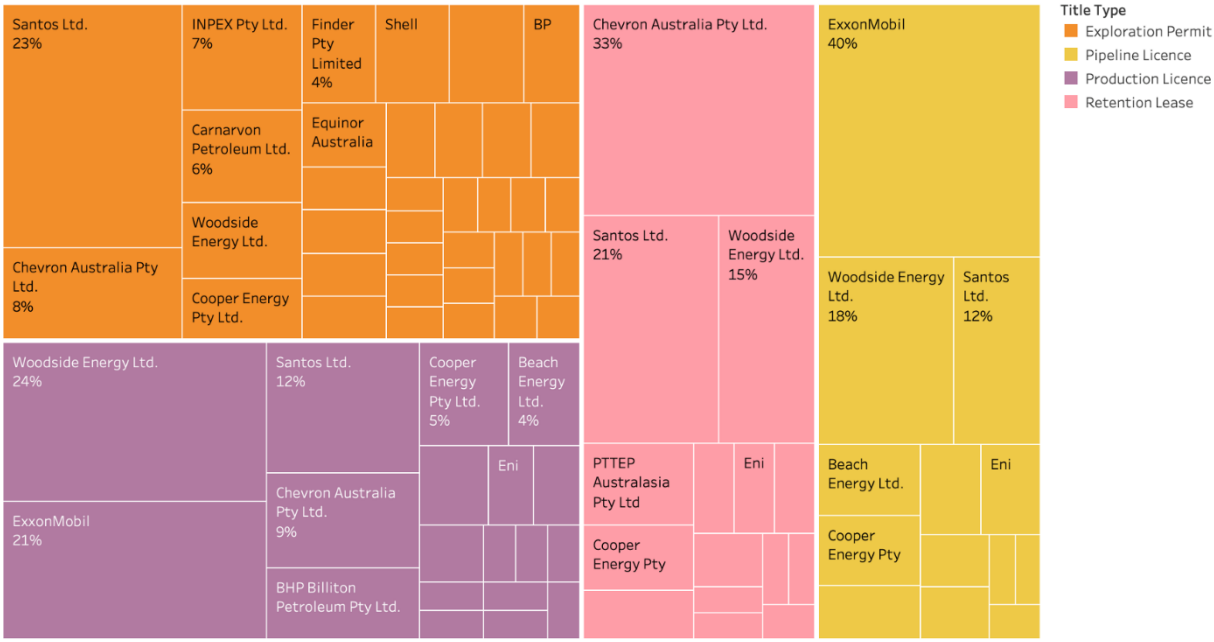
Woodside's exploration and production activity to support Northwest Shelf projects such as Scarborough has been increasing dramatically, though not as dramatic as Santos which is ranked first in terms of holding active petroleum titles (62 titles). Santos was more of an onshore driller historically. In recent years however it transformed itself into a large offshore operator with the acquisition of both the Dorado project (offshore West Australia) and ConocoPhillips' offshore assets in the Northern Territory. Both projects needed a lot of E&P drillings.

The fourth big operator is not as old as the other three in Australian waters. Chevron (Chevron Australia Pty Ltd) took off in the 21st century and surpassed some smaller Australian companies like Cooper Energy and Beach Energy in mid-2000, just a couple of years before the start of the LNG boom. In terms of growth rate in acquisition of offshore titles, Chevron is the fastest growing operator today.

Following the Big 4, other Australian companies include Beach Energy, BHP, Carnarvon Petroleum and Cooper Energy. Some multinational giants like INPEX and Eni are the other top-10 operators in offshore Australia.

Figure 9 demonstrates the share of operators in each of the major four types of offshore titles in Australia.

Figure 9: Companies with Lions' Share in 4 Types of Permits



Source: NEATS,[29] IEEFA analysis.

[29] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA). National Electronic Approvals Tracking System (NEATS) reporting. 12 May 2021.

The breakdown and determination of which big players hold the title types is insightful as there are dominant companies with the lion's share in each permit type. For instance, in exploration permits Santos is the biggest by far followed by Chevron and INPEX. In terms of production licences, Woodside and ExxonMobil take the lead. Also, ExxonMobil is the lead operator of pipelines holding 40% of all active pipeline licences across Australia followed by Woodside with 18%.

Chevron has the lion share of retention leases among all offshore operators. According to the NOPTA, a retention lease is awarded to a company when exploration results are not definite but are still promising (a field not currently commercial but likely to be within 15 years). From this, it could be inferred that Chevron aims to be the operator of huge amount of production and development projects in the next couple of years assuming a considerable proportion of its retention leases end up being commercial scale productions. Having said that, it is not a realistic aim considering the transformative world-wide departure from fossil fuelled-resources.

A dichotomy can be seen between two Australian giants, Santos and Woodside, and their approach as an operator in the offshore sector. While Santos is aggressively proceeding with pre-production activities (Acquiring exploration and appraisal) as a relatively younger offshore player, Woodside is depleting its already commercialized O&G resources.

While Santos is aggressively operating exploration and appraisal permits, Woodside has focused on depleting its already commercialized O&G resources with holding numerous production licences.

In a deal with ConocoPhillips in 2019, Santos acquired the Darwin LNG plant which sources its gas from the nearly depleted offshore Bayu-Undan field. It is now looking to replace this field with the carbon-intensive Barrosa gas project. Santos is also looking to develop its offshore West Australian field, Dorado. Both of these projects will need substantial exploration and development drilling.

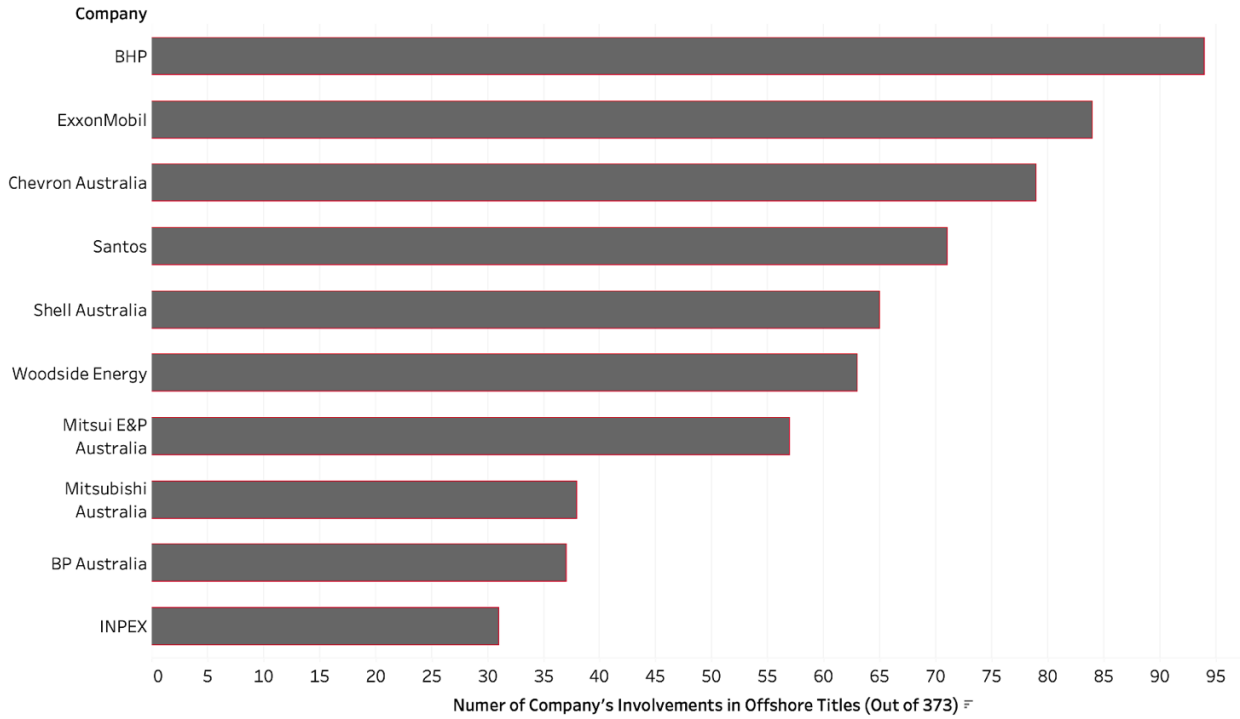
Woodside on the other hand, when facing a declining north-west shelf project turned to the Browse project to fill the gap. It has now abandoned Browse and is looking to develop the Scarborough field.

Also as illustrated in Figure 9, Chevron is the largest holder of retention leases as the projects could turn to production licences with commercialized production projects. Chevron's giant Wheatstone and Gorgon LNG plants with a total of 24.5 million tonnes per annum (MTPA) of capacity need a massive amount of gas.

The Most Involved Companies in the Offshore Sector

Figure 10 depicts the top-10 companies ranked by the number of titles that they have an interest in, either as an operator or non-operator partner.

Figure 10: Top-10 Companies Involved in Offshore Permits



Source: NEATS,[30] IEEFA analysis.

The total number of offshore titles is 373, administered by NOPTA. Apart from the direct share that companies may have in offshore ventures by being an operator or partner, some also have stakes in titles through their subsidiaries. That means their involvement in projects could be direct or indirect through their subsidiaries.

IEEFA has attempted to trace each title back to the parent company to provide a clearer picture of the role giant companies play in Australia's offshore sector. Three Australian industry leaders, BHP, Santos and Woodside are in the list along with multinational incumbents ExxonMobil, Chevron, Shell and BP. Three Japanese giants - Mitsui, Mitsubishi and INPEX - complete the top-10 list.

There could be a big shift in this ranking if BHP sells its oil and gas assets across Australia to Woodside.[31] In this case, Woodside would be top of the 'most-involved companies' list by a far margin.

[30] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA). National Electronic Approvals Tracking System (NEATS) reporting. 12 May 2021.
[31] Reuters. Australia's Woodside snares BHP oil, gas business in $28bln merger. 17 August 2021.

Although the exact percentage interest in each title has not been provided by NOPTA, assuming an equal weight for each involvement could be an approximate measure for calculating the share of each company in offshore sector projects in Australia. Operators like Chevron, Santos, Woodside and ExxonMobil have the lions share and non-operator partners like Mitsui and Mitsubishi have much smaller shares in projects which could approximately cancel each other out. Based on this rough approximation, IEEFA estimated that the top-10 companies depicted in Figure 10 could be considered as the owners of more than two-thirds of Australia's offshore projects.

Exploration Activity Until 2027 - Area and Cost Analysis

Area Under Exploration

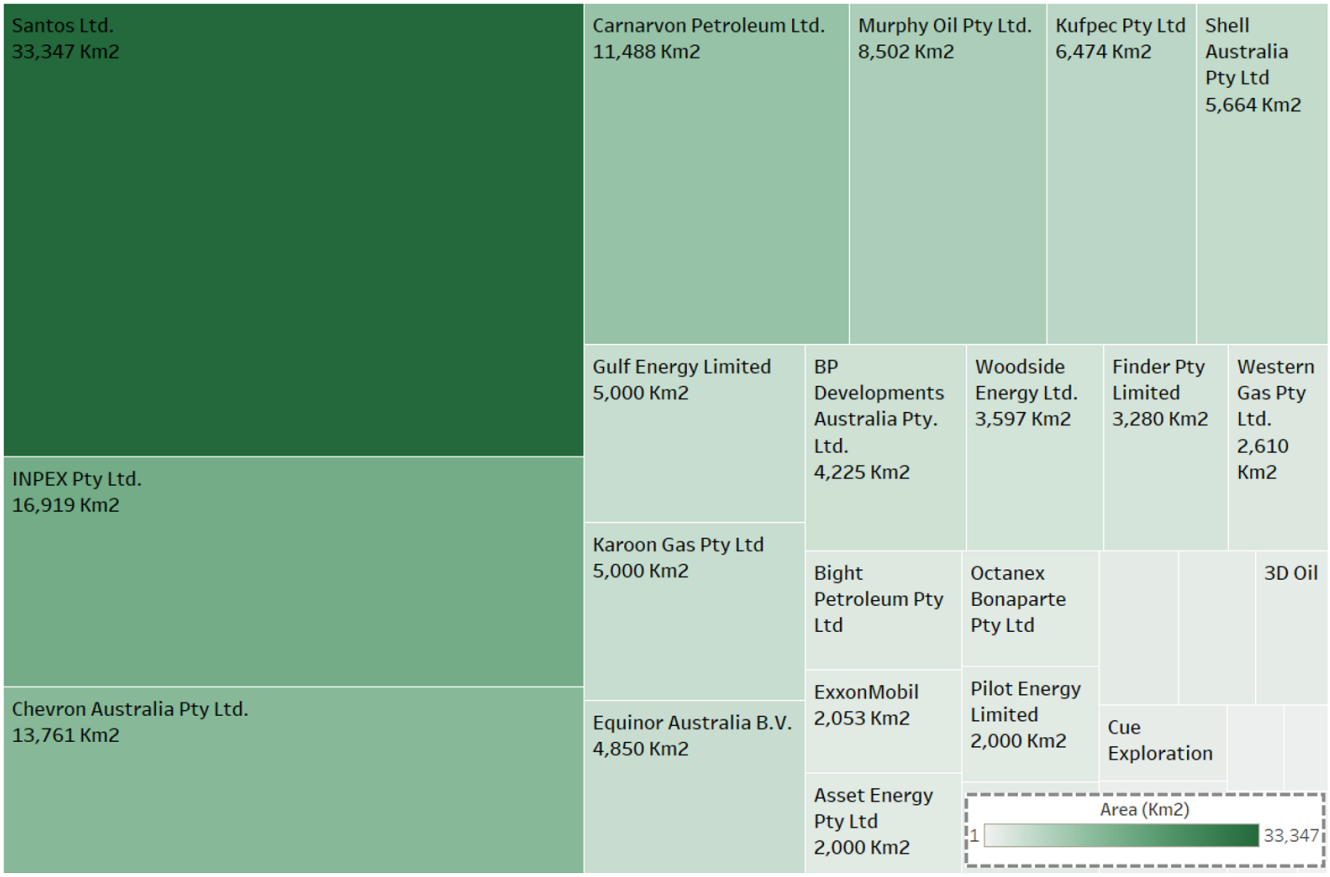
Based on National Electronic Approvals Tracking System's (NEATS) data[32] released on 12 May 2021, out of the 373 offshore permits, there are 101 active permits and 5 exploration permits pending in Commonwealth waters.

Exploration permits are granted on the basis of a work-bid.[33] This means that companies bid on the amount of exploration work they will undertake in an area should they be awarded a permit. An application requires the company to provide an indicative value of the cost and required area (in km^2) of each activity as the criteria of the scope of activities proposed. That means they provide the indicative cost incurred and the value of the area affected by every exploration activity. Each exploration permit has a 6-year life from the day it's awarded, and companies are obligated to submit a yearly breakdown of their activities and associated costs. The first 3 years are considered as primary activities and the second 3 years secondary activities.

Figure 11 shows the area that these companies would be operating in to explore oil and gas over the next 6 years. As mentioned, companies provide a breakdown of their activities and each activity needs a specific area. The maximum area needed for an activity in a specific permit has been considered as the geographical scope of the project that would be affected by the explorative activities.

[32] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA). National Electronic Approvals Tracking System (NEATS) reporting. 12 May 2021.
[33] Australian Government. Department of Industry, Science, Energy and Resources. Offshore Petroleum Exploration Guideline: Work-bid. In relation to the Offshore Petroleum and Greenhouse Gas Storage Act 2006. 1 July 2019.

Figure 11: Companies' Area of Exploration Activities



Source: NEATS,[34] IEEFA analysis.

The total area under direct exploration activities until year 2027 is 153,800 km^2 which is more than twice the size of Tasmania.[35] A breakdown of these exploration activities by operator companies reveals the operators who would operate on the largest area in Commonwealth waters. As depicted in Figure 11, Santos will use a much larger area (33,347 km^2) compared to other operators. The company's exploration activities in the next 6 years would cover an area greater than Belgium.

The first 4 operators in terms of the number of exploration permits depicted in Figure 9 (i.e.. Santos, INPEX, Chevron and Carnarvon Petroleum) are the same 4 operators with the largest area under exploration. They are followed by the American exploration company Murphy Oil and the Kuwait Foreign Petroleum Exploration Company.

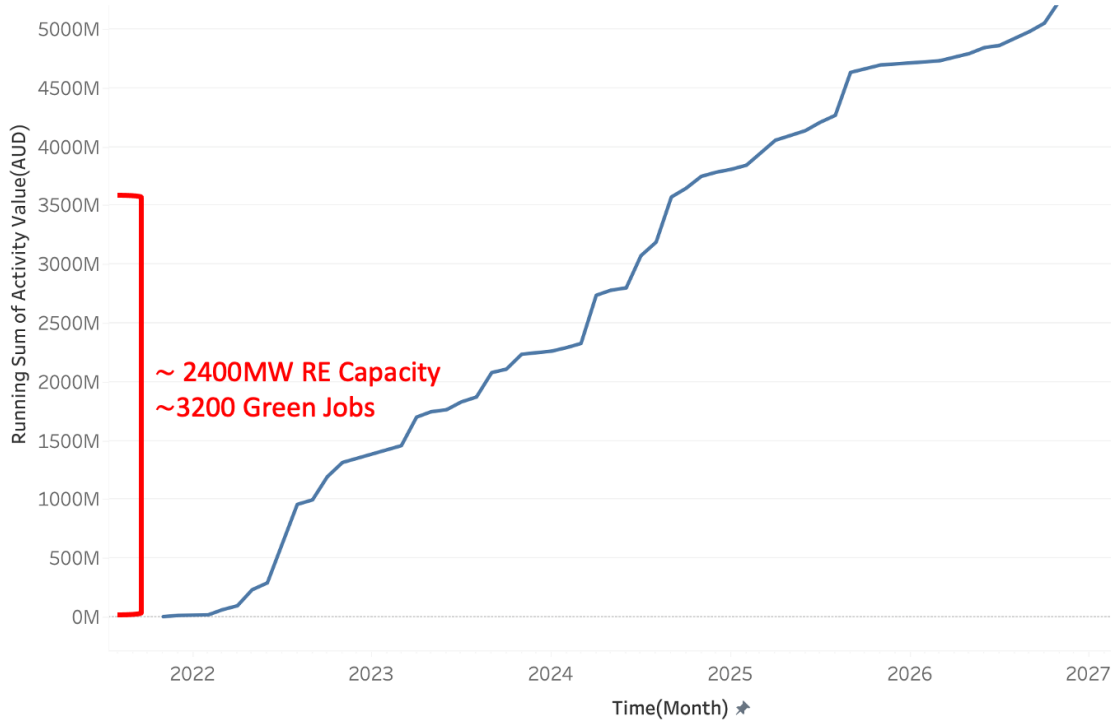
[34] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA). National Electronic Approvals Tracking System (NEATS) reporting. 12 May 2021.
[35] Assuming that there would be no new exploration permits to be awarded.

Exploration Cost

As mentioned, cost estimates have been provided by the companies themselves and so it would be the most accurate estimate of activities to be conducted during the exploration phase of O&G projects.

Figure 12 depicts that in the next six years, around AUD 5.1 billion will be spent on exploration activities alone in offshore Australia.[36] The graph has been drawn based on tentative plans and cost breakdowns provided in work-bids by operators.

Figure 12: Cumulative Offshore Exploration Expenditure Trend (2021-2027)



Source: NEATS,[37] IEEFA analysis.

Success rates of exploration projects depend on different factors, however typically it could be anywhere between 20% to 40%.[38] [39] It is also common for exploration projects to be discontinued.

The most recent discontinuation of an exploration permit occurred in the Bight Basin when Equinor decided to stop operations in exploration permits EPP39 and EPP40 with Jone Stangeland, Equinor's country manager for Australia stating: "The approval of the Stromlo-1 exploration well Environment Plan confirmed our ability

[36] Assuming that there would be no new exploration permits to be awarded in this interval.
[37] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA). National Electronic Approvals Tracking System (NEATS) reporting. 12 May 2021.
[38] Offshore-mag. Success rates rise for DHI-driven exploration drilling. 28 January 2020.
[39] Westwood Global Energy Group. The State of Exploration 2019. 7 May 2019.

to safely operate in the Bight. However, Equinor has decided to discontinue its plans to drill the Stromlo-1 exploration well, as the opportunity is not commercially competitive".[40]

For the Australian offshore sector, factoring in potential success rates means that roughly AUD3.5 billion will be simply wiped out in the next 6 years. This amount is equivalent to the current capital investment in around 2400MW of renewable energy projects under construction (or due to start construction soon) in Queensland, which as an aside are also creating 3200 direct jobs according to the Clean Energy Council.[41] That suggests that the money (or in some cases subsidies) being wiped out in the next couple of years on exploration in the offshore industry could instead be used to boost both several green jobs and a huge amount of renewable energy capacity for Australia.

Roughly AUD3.5 billion will be simply wiped out of Australia's offshore sector in the next 6 years.

In addition, it is common practice that of successful exploration projects, some will fail in the appraisal phase and only a few of them, after spending billions of dollars and overcoming protracted timelines of around 10-15 years, will pass commercial production hurdles. Even if they do, the possibility of mass production and prospects for sales is narrow over the next 10-15 years due to the transformational energy transition currently underway.

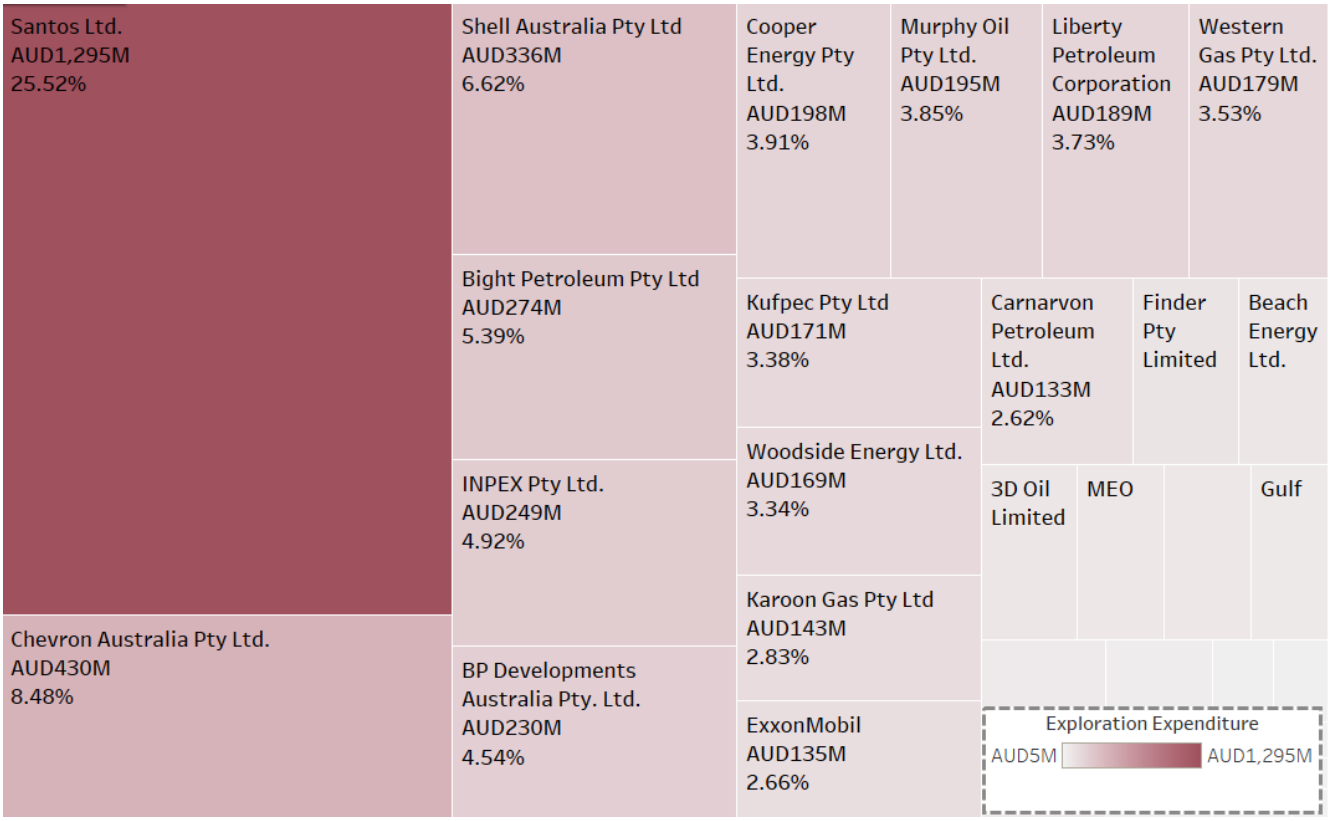
Santos' aggressive spending is evident when looking at the share of companies investing in offshore exploration (Figure 13). Santos is the operator of exploration projects worth AUD1.3 billion collectively; 25% of the total exploration expenditure to be spent until 2027. Although there are other partners in each permit, and while the operator would not be the only one spending this amount of money, operator is generally the dominant partner in joint ventures.

As expected, following Santos, Chevron is the second highest spending operator with AUD430 million worth exploration projects in total followed by Shell, Bight Petroleum and INPEX. While Bight Petroleum[42], Liberty Petroleum, Murphy Oil, and

[40] Equinor. Equinor to discontinue exploration drilling plan in the Great Australian Bight. Last modified, 26 February 2020.
[41] Clean Energy Council. Project Tracker. 27 July 2021.
[42] ABC. Bight Petroleum application to extend Great Australian Bight work rejected. 13 February 2021. The exploration permits EPP41 and EPP42 are still active in the NOPTA database. However, after Equinor's discontinuation of exploration activities in the Bight Basin last year, there is news that NOPTA has rejected Bight Petroleum's application to extend its exploration permits in this basin.

Western Gas are in the list of top-10 operators with largest exploration expenditure (Figure 13), they were not among the top-10 list in terms of the number of explorations permits held (Figure 9).

Figure 13: Companies' Indicative Cost of Exploration Activities



Source: NEATS,[43] IEEFA analysis.

Looming Risks Associated with Offshore O&G Projects

Based on the analysis provided, there are major risks that Australia's offshore industry may have to confront in the near future.

Growing LNG demand is no longer a given.

The first risk is the uncertain future of the LNG market. The LNG industry is the main booster of exploration and development O&G projects in Australia. However, growing LNG demand is no longer a given.

[43] Australian Government. National Offshore Petroleum Titles Administrator (NOPTA). National Electronic Approvals Tracking System (NEATS) reporting. 12 May 2021.

This year has seen a turning point in the climate change discourse, punctuated by U.S. leadership in the climate summit held in April[44], and the landmark IEA Net-Zero by 2050 report published in May[45] which urges nations to not to spend even a penny on new oil and gas projects to avoid the disastrous consequences of global warming beyond 1.5 degrees Celsius. The next flagship global summit is COP26 (United Nations Climate Change Conference) being held in November 2021. This will be another catalyst pushing countries around the world towards net-zero.

In the wake of this global will for accelerating the energy transition, many countries have already revised their goals and ambitions. For example, the U.S. has increased its target to reduce emissions from 26-28% to 50-52% by 2030. Japan has pledged to curb emissions from 26% to 46% by 2030. Canada, Brazil, South Korea and China have also increased their pledges in different ways.[46]

Countries' net-zero and decarbonisation pledges in the energy sector will hugely slash the demand for fossil fuels. Coal has been already smashed by the energy transition and is in terminal decline. Gas and LNG will be the next victim under the avalanche of batteries, renewable energy and energy efficiency programs.

Specifically affecting Australia's offshore industry, Japan's recent draft energy policy issued by the Ministry of Economy, Trade and Industry (METI) hits gas as hard as coal, with Japan determined to meet its new emission reduction targets. In the previous two decades, Japan has been viewed as a reliable source of LNG demand for Australia. If the draft of Japan's latest energy policy is enacted, Australia's secure LNG trade status with the world's third-largest economy may be jeopardised.

Japan aims to double its renewables' share in the electricity mix by 2030. This jump in renewable energy means LNG and coal will have to surrender market share, with coal dropping by 40% and LNG by around 50% in the power mix in less than 10 years.[47]

The Japanese energy plan poses a serious danger to Australia's offshore industry.

The Japanese energy plan poses a serious danger to Australia's offshore industry as the main supplier of the LNG sector. This will shake up the market, causing a domino effect on some countries like South Korea. There will be huge market volatilities and disruptions in the LNG sector. And consequently, the offshore

[44] U.S. Department *of* State. Leaders Summit on Climate.
[45] IEA. Net Zero by 2050. Revised version. July 2021.
[46] CNBC. Here's what countries pledged on climate change at Biden's global summit. Updated 22 April 2021.
[47] Bloomberg Green. Japan Seeks to Aggressively Cut Fossil Fuel, Lift Renewables. 21 July 2021.

industry as the backbone of LNG sector in Australia would be at major risk.

The offshore industry will also face greater social and financial pressure due to both emission tracking breakthroughs and a new branch of finance called spatial finance. Spatial finance integrates geospatial analysis into financial decision making, focusing on more accurate emission tracking, specifically in remote areas like offshore facilities.[48] Previously, satellite observations were skewed due to the absorption of sunlight by water. However, thanks to new state-of-the-art satellite-based initiatives such as GHGSAT[49] and Kayross[50], massive methane streams have been observed across the globe including leakages from offshore rigs and infrastructure as it is claimed that these initiatives are more accurate in tracing greenhouse gas emissions.

Although methane has a shorter life in the atmosphere compared to carbon dioxide, its' greenhouse effect is much more than CO_2. Following decades of research considering methane's climatic impact, the scientific community has learned that methane is worse for the climate than previously thought. Methane used to be seen as 25 times worse than CO_2 based on the Intergovernmental Panel on Climate Change (IPCC) fourth assessment report from 2007.[51] [52] However, the latest research by scientists from the UK's University of Reading and Norway's Center for International Climate and Environmental Research (CICERO)[53] shows the harmful climatic effect of methane is 99 times worse than CO_2 in a 20-year horizon.

Following decades of research considering methane's climatic impact, the scientific community has learned that methane is worse for the climate than previously thought.

Coupled with more stringent environmental laws, communities are increasingly suing rule-breaking companies (eg. Shell in the Netherlands[54]), and climate-friendly shareholders are realising they have the power to change the arrangement of the board of directors (eg. the ExxonMobil case in May 2021[55]).

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[48] Spatial Finance Initiative. Spatial Finance.
[49] GHGSAT.com
[50] KAYRROS.com
[51] Intergovernmental Panel on Climate Change (IPCC). Climate change 2007: Impacts, Adaptation and Vulnerability. 2007.
[52] Climate Council. Passing Gas: Why Renewables Are the Future. 2020.
[53] Etminan, M., Myhre, G., Highwood, E. J., & Shine, K. P. Radiative forcing of carbon dioxide, methane, and nitrous oxide: A significant revision of the methane radiative forcing. *Geophysical Research Letters*, *43*(24), 12-614. December 2016.
[54] The Guardian. The Guardian view on climate change lawsuits: Big Oil is in the dock. 29 May 2021.
[55] Anchorage Daily News. At least 2 ExxonMobil board members lose seats in shareholder fight over climate change. 27 May 2021.

Revealing the real magnitude of methane leakages is definitely a major risk for the offshore industry and will pull into question new gas industry terminology such as carbon-neutral LNG.[56] Both in terms of social licence, but also pending greenhouse gas emission taxes and levies, Australia's offshore industry is certainly at risk.

The other dynamics leading to a financial risk is the rising cost of offshore drilling. IEEFA found that on average, the depth of offshore wells in Australia has considerably increased over the last decade by around 20%. Based on data from 700 offshore wells, it has been calculated that the average total depth of wells has increased by around 600 meters during the LNG boom (2009-2019). There are numerous scientific works showing that well depth and the cost of drilling has an exponential relationship, and constitutes the largest proportion of an offshore project's capex.[57]

Looking back to Figure 3, the trend in well drillings towards deep offshore is obvious, especially in Western Australia. Oil and gas companies have been looking for more resources further from the shore in deep water. According to the Australian Trade and Investment Commission (Austrade) more than 80% of Australia's gas resources exist in deep, remote offshore areas.[58] As a result, companies will be incurring exponentially inflated drilling costs as they drill deeper.

Companies will be incurring exponentially inflated drilling costs as they drill deeper.

In addition, customers are transitioning from rigid long-term (20-30 year) contracts to shorter ones (usually 10 years) with more flexible conditions, including the opportunity to resell cargos in case of oversupply, as a result of the current wave of country policy actions abandoning gas. So, there is uncertainty about whether all LNG cargoes will find clients in the next 20-30 years, raising investment risk.

The other risk which has been ignored is the partners' profile in joint ventures which has changed in recent years. Big oil and gas companies have lost their ability to sell down interest in billion-dollar projects as partners are unwilling to commit. Large stakes in projects have made the cost of financing big projects higher. Financial institutions are more likely to consider higher interest rates for a project with one or two partners compared to a project with several partners. Woodside and its billion-dollar Scarborough project in the north-western shelf offshore Western Australia is an example of this phenomena.

[56] Boiling Cold. Ichthys flaring casts doubt on carbon-neutral LNG cargo. 22 July 2021.
[57] Dalmo S. Amorim Jr., Otto Luiz Alcântara Santos and Ricardo Cabral de Azevedo. A statistical solution for cost estimation in oil well drilling. International Engineering Journal 72(4):675-683. October 2019.
[58] Australian Government. Australian Trade Commission. Oil and Gas. March 2016.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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