Westwood Global Energy Group

What Seismic is Derisking High Impact Exploration?

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In collaboration with

Seisintel

Wildcat

Contents

Summary

336 high impact offshore exploration wells drilled over the five years from 2019 to 2023 have been analyzed against the Seisintel dataset of all seismic acquisition from 2014 to 2023. 79% (264) of these wells had some type of new seismic acquired over the well location between 2014 and the well spud. 61% (205) were covered by new 3D streamer seismic and only six were covered by new Ocean Bottom (OB) surveys, leaving 37% (125 wells) matured purely on legacy 3D acquired prior to 2014 and/or new 2D seismic data. Standard narrow azimuth 3D towed streamer survey remains the dominant seismic tool in high impact exploration.

Wells drilled in emerging and maturing plays, where commerciality is proven but running room remains, were the most likely to be covered by new 3D or OB seismic with 79% and 63% covered respectively. This compared to 54% for frontier wells, with their higher technical and commercial risks and 34% for mature play wells where extensive legacy coverage usually already exists.

There is no conclusive evidence that new seismic has positively impacted success rates. Although, technical success rates for high impact drilling are six points higher and commercial success rates were seven points higher for wells covered by new 3D or OB seismic, this is driven entirely by high success rates in the emerging plays of the Guyana-Suriname basin which have large coverage of new seismic. Outside this specific area, success rates were not found to be impacted by the acquisition of new seismic. The independence of success rates to new seismic data is likely due to improved seismic not necessarily decreasing the risk of exploration drilling, rather allowing prospects previously assessed as too risky to be de-risked.

A strong correlation was found between the time between completion of seismic acquisition and spud of the exploration well and the success rate. The technical success rate (TSR) drops from 66% for wells drilled within two years of seismic acquisition to 56% for three to five years to 26% for wells drilled 5-10yrs after new seismic. This trend suggests that prospects identified and matured soon after seismic acquisition are more likely to be successful.

Extended azimuth surveys (WAZ, MAZ and FAZ) were used almost exclusively to address imaging challenges in basins containing salt, but the results of high impact drilling based on these surveys does not show a significant increase in success rate over wells drilled on standard narrow azimuth surveys.

Ocean bottom (OB) data acquisition is an emerging technology in exploration that provides the ability to acquire very long offsets, large azimuthal coverage and high signal to noise ratio data, especially when combined with use of low or extended frequency sources. OB surveys allow for creation of improved velocity models which result in better imaging. Only six high impact exploration wells have been drilled based on new OB seismic data, and only one of those surveys was completed explicitly for exploration purposes showing that the use of this technology is still at a very early stage of development in support of exploration.

Seismic acquisition technology is undoubtedly improving but this study found no statistical evidence that acquiring new seismic improved success rates over using legacy pre-2014 seismic, frequently reprocessed, to mature high impact prospects in the 2019-2023 period. However, prospects drilled in the shortest time after seismic acquisition had the highest success rates. This suggests that the better prospects are easier to see, and better subsurface imaging alone is not the answer to improving exploration performance.

1. Introduction

High impact exploration uses seismic data of varying types and vintages to mature exploration prospects prior to investment decisions. This report combines the Wildcat dataset of offshore high impact (HI) exploration drilling from 2019 to 2023 with the Seisintel database of seismic acquisition activity which runs from 2014 to 2023.

The report looks at how seismic surveys of various types have been acquired to support HI exploration drilling and looks to answer the following questions:

- What type of seismic data is being acquired to generate HI exploration drilling prospects?
- Is there evidence that different seismic acquisition technologies influence geological and commercial success rates?
- What are the cycle times from seismic acquisition to drilling, do they impact success rates and are they different in different regions?
- How are different seismic technologies being applied in different geological settings?

From 2019 to 2023, 336 HI exploration wells were completed offshore globally. 121 were in shallow water and 215 in deep water (>500m). 50% of those wells were a technical success and 26% are considered commercial successes.

Of the 336 wells, a total of 264 (79%) had some seismic data acquired over the well location between 2014 and the spud date. 207 (61%) had new 3D towed streamer data acquired over the well location, 6 wells (2%) were within the full fold (node patch) area of an ocean bottom survey and 169 wells (50%) had 2D seismic acquired over the well location.

Seisintel services the global offshore energy industry with unique geospatial products derived from vessel Automatic Identification System (AIS) position tracking. Vessels tracked and analysed include 2D, 3D, 4D streamer vessels, Ocean Bottom Node and source vessels, multibeam and geotechnical and their support vessels. With a library of over 2500 recent multiclient and proprietary surveys in the database, Seisintel users can search, map and replay historical and live surveys from all regions of the globe. Seisintel provides a range of analysis, operational planning and review solutions through both web portal and GIS integrated solutions. For more information, visit www.seisintel.com. For this analysis, only 2D, 3D, 4D streamer and Ocean Bottom seismic surveys are considered.

This report is being published to both Westwood Wildcat and Seisintel subscribers.

The following acronyms are used throughout this report:

- 3D – Towed streamer seismic with multiple streamers covering an area
- 4D – A type of 3D towed streamer seismic used to monitor reservoirs through production by timestamped repeat surveys – initial survey is the baseline and future surveys are the
- OB – Any Ocean Bottom seismic where the receivers are located on the seabed in an array while source shots are made from a sea surface source vessel. Can use independent Nodes in an OBN survey or receivers on Cables laid on the seabed in an OBC survey
- WAZ, MAZ, FAZ – Wide, Multi & Full Azimuth 3D towed streamer acquisition geometries

- FWI – Full Waveform Inversion – a generalized seismic processing method utilizing reflected and refracted arrivals as well as shear and compressional seismic waves to improve imaging
- AIS – Automatic Identification System, tracks positions of marine traffic
- ASPAC – Asia Pacific region
- HI – High Impact – Exploration wells targeting a mid-case recoverable resource of >100mmboe, and all frontier play tests

2. High Impact Offshore Exploration 2019-2023

From 2019 to 2023, 336 HI offshore exploration wells were completed globally. Figure 1 shows the distribution and success rates of these wells by region.

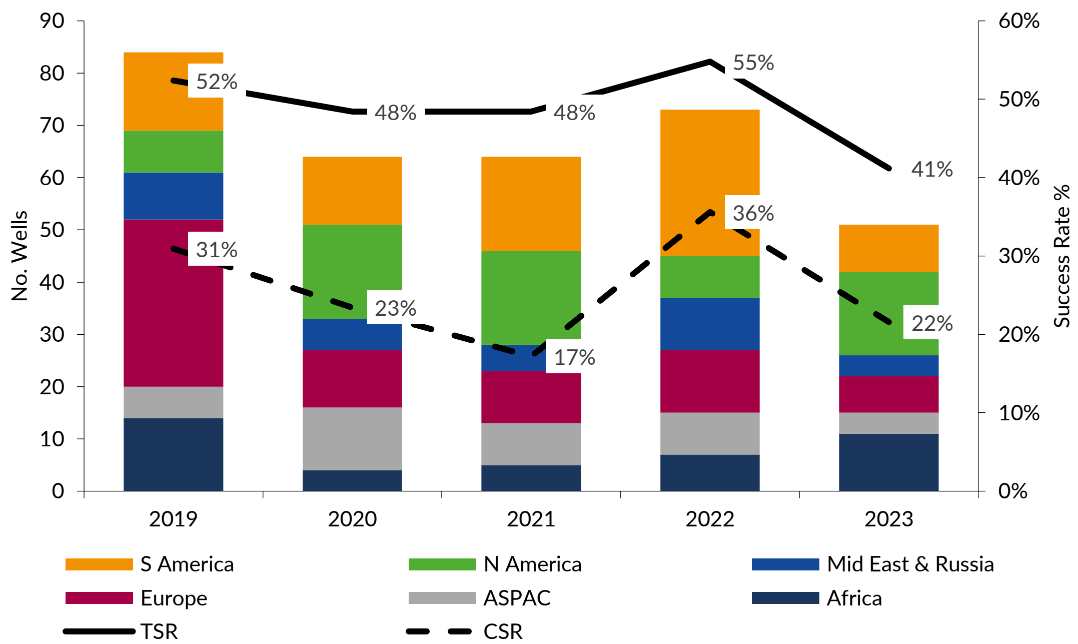

Figure 1: High Impact offshore exploration wells by region and by year along with Technical and Commercial Success rates for each year.

When considering the seismic data which has been used to mature prospects and support drilling decisions, the report considers only wells that sit within the full fold area of either a 3D towed streamer survey or the node patch of any ocean bottom survey. The analysis only considers seismic surveys which were completed prior to the spud date of the well. For 2D seismic, wells are considered covered if they are within the survey area and it should not be inferred that any of the 2D lines are necessarily directly over the well surface location.

Figure 2 shows the distribution of 2019-2023 HI offshore exploration wells coloured by the broad type of seismic data that has been acquired over the well location since 2014, the start of the Seisintel database. The seismic acquired over well locations prior to spud date is shown in Figure 3 and shows that 3D towed streamer data, including wide and multi azimuth configurations, remains the dominant data type used to characterize exploration prospects. 2D data, while still important for providing a regional view, is mainly used in conjunction with more detailed datasets and OB seismic data currently remains a novel technique in HI exploration.

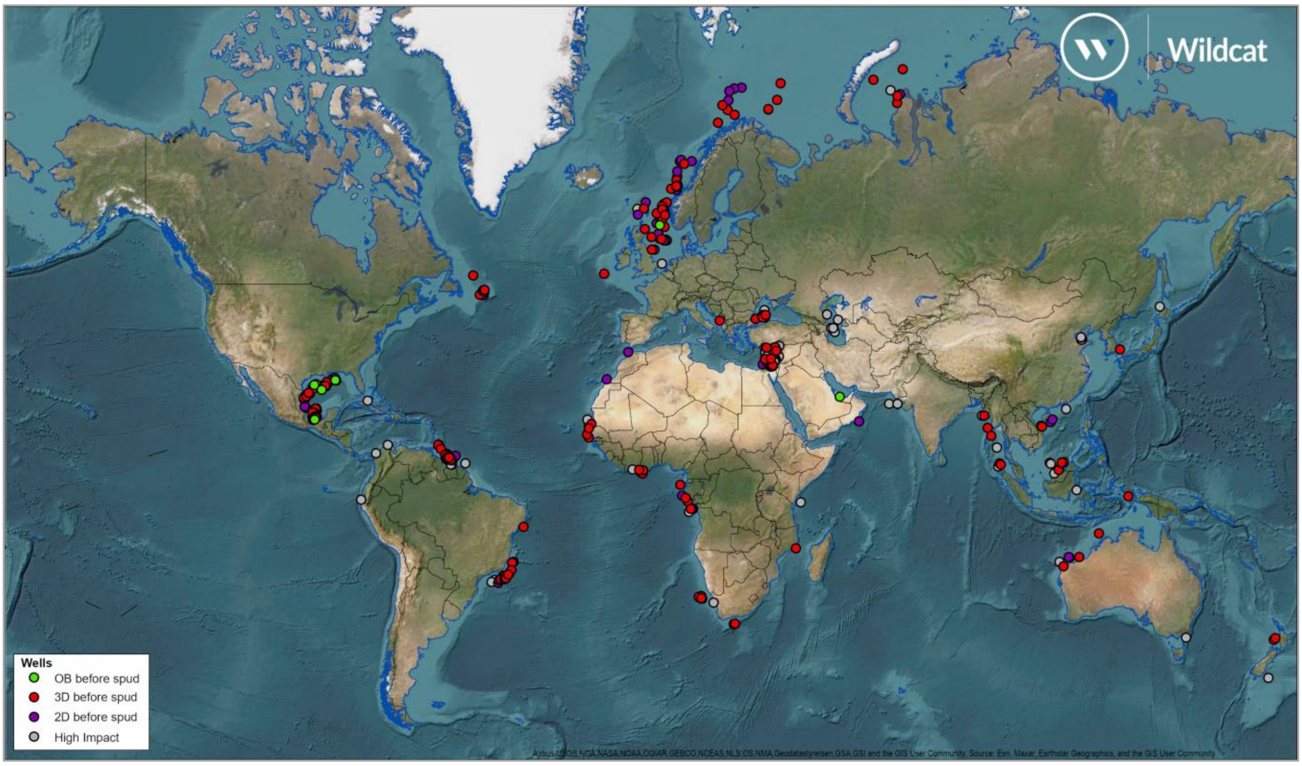

Figure 2: High Impact offshore exploration wells 2019 to 2023 (by completion date). Purple are wells only covered by new 2D, Red indicates wells covered by 3D, Green indicate wells covered by OB seismic and grey are wells not covered by any seismic since 2014. Only surveys completed prior to well spud are included.

High Impact offshore exploration wells – Total 336

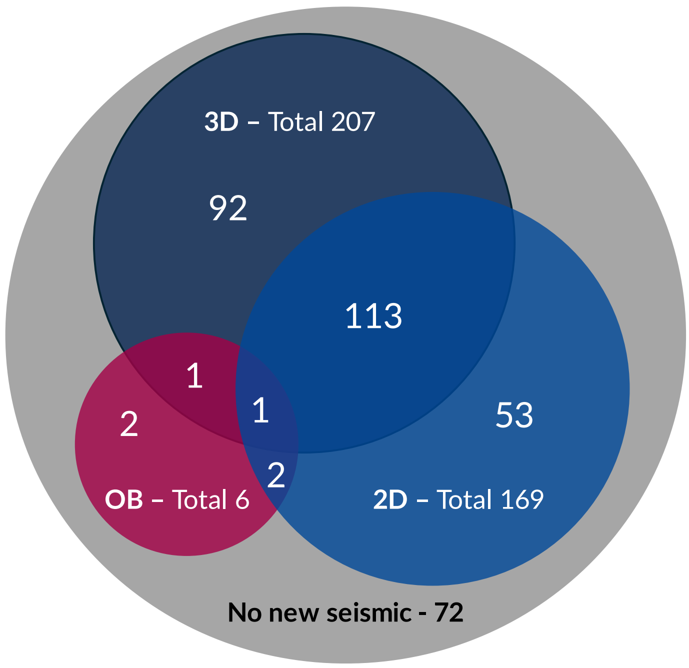

Figure 3: Venn diagram showing which high impact wells completed between 2019 and 2023 have been covered by what type of new seismic data prior to spud.

2.1 Which wells were covered by seismic acquired between 2014 to 2023?

Figure 4 shows the number of HI offshore exploration wells completed between 2019-2023 split by region. South America saw the most wells drilled, closely followed by Europe and North America. The chart also shows the percentage of those wells over which new seismic data was acquired 2014-2023, prior to spud.

The three regions with the most HI wells completed also had the highest proportion of HI wells covered by new seismic data.

Only 53% of the HI wells in Asia Pacific (ASPAC) and the Middle East & Russia had new seismic data available, suggesting that prospects in these regions were being matured and drilled on older vintage seismic data.

80% of the 41 HI wells completed in Africa had new seismic data available at well locations reflecting the higher levels of seismic investment in Africa during the period from 2014-2019 to exploration campaigns in the MSGBC and transform margin, for example.

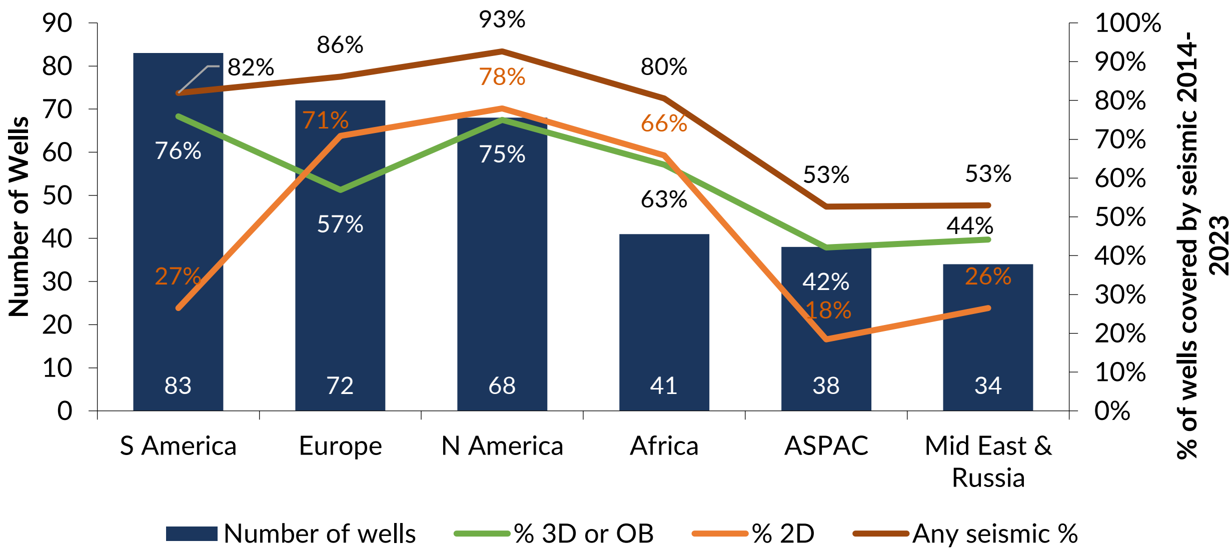

Figure 4: High Impact Offshore Exploration wells 2019-2023 by region, lines show % of those wells covered by new seismic data acquired 2014-2023. Note that some well locations are covered by both 2D and 3D data in the period.

Figure 5 shows the distribution of wells completed and the number of those wells covered by new seismic data by play maturity. Overall, emerging play wells are more covered by new seismic data than wells in frontier plays, where the investment case is yet to be proven and larger, simpler prospects are often drilled first and maturing and mature plays, where more well locations will be covered by legacy data.

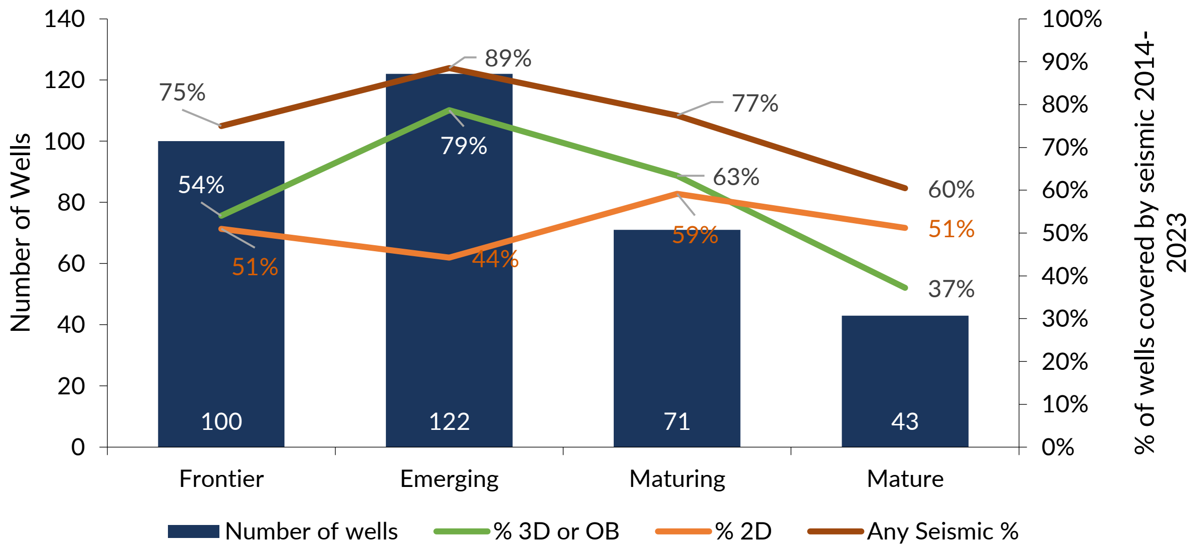

Figure 5: High Impact Offshore Exploration wells 2019-2023 by play maturity, lines show % of those wells covered by seismic data acquired 2014-2023 and prior to well spud.

When considering 2D seismic, the trend is less clear, reflecting that 2D seismic is less likely to be used in isolation to de-risk or mature an exploration target but it likely to be used more for regional geological understanding and lead generation. Consequently, there is little variation or discernable relationship between 2D acquisition and HI exploration drilling.

2.2 Does new seismic data improve success rates in high impact exploration drilling?

This section looks at the success rates of HI offshore exploration drilling compared to the seismic that was acquired over the eventual well locations. Beyond initial prospect identification, seismic data supports exploration decision making by improving prospect characterization and reducing uncertainty. This should, in theory, lead to lower risk/higher value prospects being drilled in preference to higher risk/lower value prospects and improved success rates.

Figure 6 shows the technical and commercial success rates for HI offshore exploration wells for various types of seismic data coverage.

Overall, the 336 HI exploration wells drilled had a 50% technical success rate (TSR) (167 successes) and a 26% commercial success rate (CSR) (89 commercial successes).

Prospects that were matured with newly acquired 3D or OB seismic data had a six point higher technical success rate (52% vs. 46%) and a seven point higher commercial success rate (29% vs. 22%) than those wells completed without new 3D or OB seismic or with 2D data only.

Table 1 shows the TSR and CSR rates for each play maturity split by the seismic that had been acquired over the well location. This shows that success rates in Frontier and Maturing plays are not impacted by the availability of new data and that success rates in Mature plays actually show lower success rates for wells with new 3D or OB data than for wells without new data.

36% (122) of the HI wells drilled in the period were in emerging plays, with 79% (96) of those wells covered by new 3D or OB seismic data. Table 1 shows that the highest TSR and CSR were recorded in emerging plays and that wells in emerging plays drilled with the benefit of new 3D or OB data show TSRs and CSRs 15 and 17pp higher than wells drilled without new seismic.

These figures would indicate that there is higher investment in seismic in emerging plays where existing data coverage is likely poor, and value is being unlocked as the basin follows the steep part of the creaming curve. The figures also show that the investment in further data has a significant positive impact on success rates in the emerging plays.

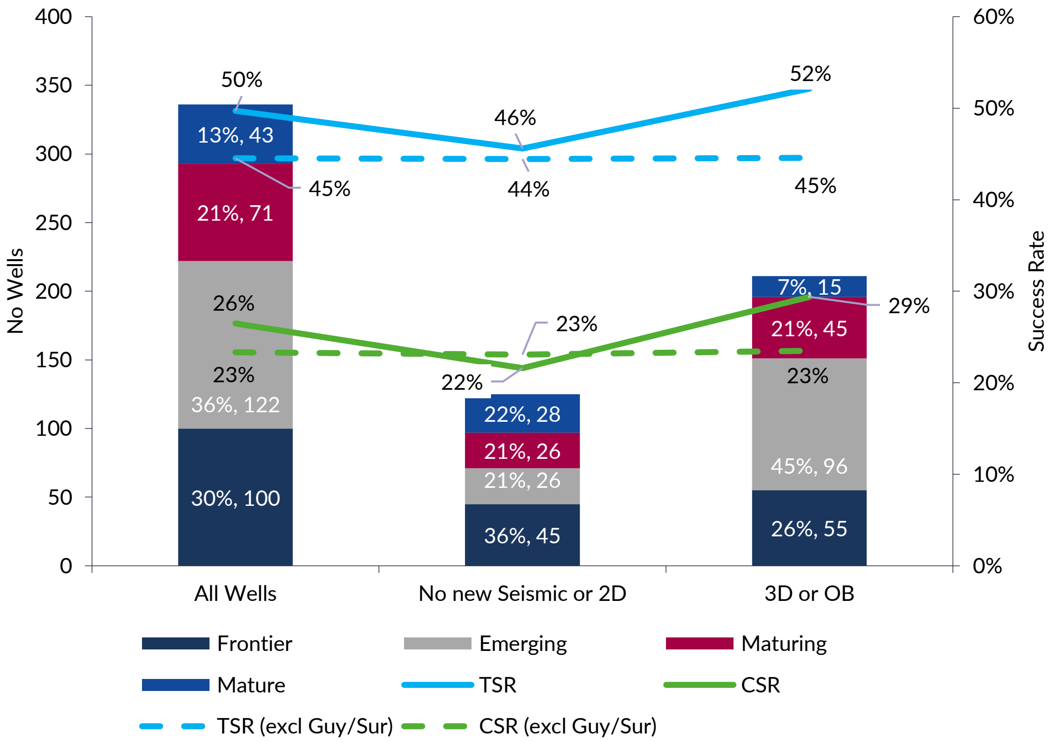

Figure 6: Wells drilled by play maturity and Technical (TSR) and Commercial (CSR) success rates for HI offshore exploration wells 2019-2023 where covered by new seismic data of different types. Labels show the percentage of wells in each play maturity drilled in each seismic coverage category.

	TSR %			CSR %		
Play Maturity	All Wells	No Seis or 2D	3D or OB	All Wells	No Seis or 2D	3D or OB
Frontier	31%	31%	31%	13%	13%	13%
Emerging	61%	50%	65%	40%	27%	44%
Emerging (ex. Guy/Sur)	51%	52%	50%	35%	33%	35%
Maturing	58%	58%	58%	25%	27%	24%
Mature	47%	54%	33%	21%	25%	13%

Table 1: Technical and Commercial success rates for wells by play maturity and seismic coverage for high impact offshore wells 2019-2023

However, further analysis of these data highlight that these success rate changes are exclusively driven by the success in the Guyana-Suriname basin. A total of 53 HI wells were drilled in this basin between 2019-2023, 47 of which were targeting emerging play objectives delivering a TSR of 79%

and a CSR of 49%, well above the global averages. 89% of those wells were covered by new 3D seismic. The dashed lines in Figure 6 show the TSR and CSR for HI wells drilled excluding those in the Guyana-Suriname basin and show that there is no improvement in success rates for wells with or without new 3D or OB coverage in this dataset. The additional line in Table 1 also shows the Emerging play statistics when the Guyana-Suriname basin is excluded.

The conclusion from this analysis is that while the acquisition of new seismic does have a positive impact on success rates globally, it is driven by successes in emerging plays which themselves are driven by specific high success rates and 3D coverage in the prolific Guyana-Suriname basin. While the Guyana-Suriname basin is a globally significant resource base, drilling trends in emerging basins will frequently be dominated by single ‘hot’ basins and in this case the high success rates are driven by the new seismic which has been acquired to exploit the play. There is no conclusive evidence that acquiring new 3D seismic systematically improves success rates in high impact wells.

3. Time between end of seismic acquisition and well spud

This section investigates the time taken between completion of seismic acquisition and the spudding of high impact exploration wells within the survey area and looks at the impact on exploration success rates. The most recent survey and the most advanced technology acquired over the well location is used. i.e. if a well location is covered by both 3D and OB seismic in the time period then the OB data used in the analysis. Figure 7 shows the time between completion of acquisition and the spudding of high impact exploration wells in the area of the survey.

When considering cycle times between acquisition and spud, clearly other above ground factors such as licence terms, permitting, well planning and rig availability also have an impact on the timing of drilling exploration wells. As such there is a large spread in many of the cycle time plots and what is considered here are general trends and averages over large sample sizes to draw conclusions.

The mean time between end seismic acquisition and well spud is 3.3yrs for those wells covered by new 3D towed streamer data and 2.6yrs for OB seismic. The shorter cycle times for prospects drilled from OB data likely reflects that OBN is a relatively new technology and surveys are being acquired to address specific known imaging issues on already identified prospects or enhance existing legacy 3D streamer data using technologies such as FWI to improve velocity models and imaging.

27 of the wells were spud within a year of completion of seismic acquisition, likely representing tight exploration licence timelines with existing well commitments made prior to seismic acquisition. Prospects drilled this rapidly were likely identified previously on legacy data with new data used to address specific risk elements and make final drill/drop decisions.

Wells only covered by new 2D seismic in the period have not been included as these data are unlikely to have been used to mature a prospect to drill status.

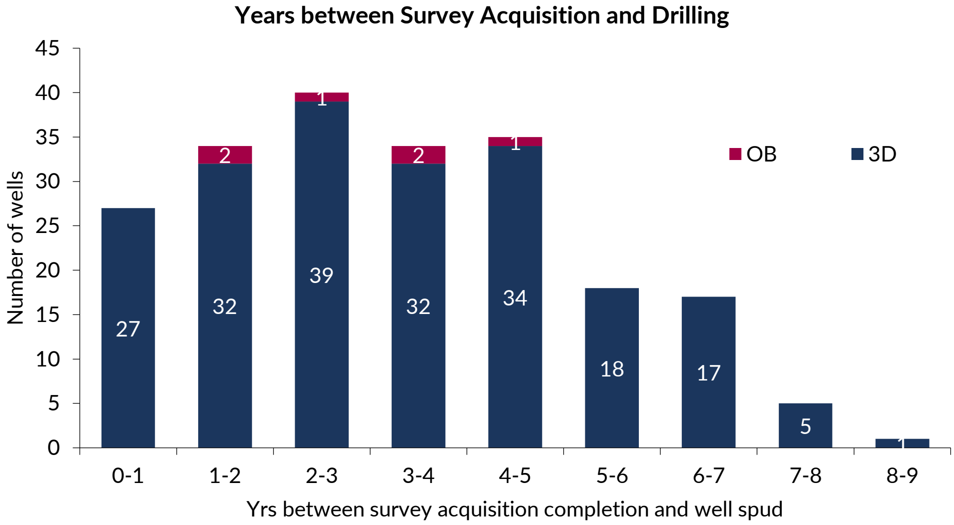

Figure 7: Time between completion of seismic acquisition and spud of high impact offshore exploration wells. For 3D & OB surveys only full fold areas are used to match surveys to wells and for OB surveys only the node patch areas are used. Surveys may be included several times if multiple wells are drilled in the survey area, wells may be included multiple times if more than one survey was acquired prior to spudding the well. Surveys acquired post drilling are excluded.

3.1 Cycle times for wells drilled on new 3D towed streamer data

3D towed streamer seismic data remains the main data type on which offshore high impact exploration prospects are matured to drill ready status and tested. 207 of the 336 wells drilled 2019-23 are within the full fold area of at least one new 3D towed streamer survey acquired since 2014. Of those 207, only 2 had additional OB surveys acquired over the well location prior to spud.

Figure 8 shows the results for high impact wells by time between survey acquisition and well spud and the TSR and CSR for those wells. For wells which resulted in a discovery (technical or commercial), the mean time from survey to spud was 2.8yrs whereas for dry holes the mean time was 3.9yrs.

The striking feature of this plot is the marked decrease in both TSR and CSR in wells drilled longer after acquisition of new seismic data, with no technical successes for wells spudded more than seven years after seismic data acquisition and no commercial successes after more than six years.

For wells drilled within two years of seismic being acquired, the TSR was 66% and the CSR 42% whereas for wells drilled more than five years from most recent seismic acquisition the TSR was 26% and the CSR 11%. This marked difference in success rates initially suggests that prospects characterized on new seismic data are more likely to be successful than those which take longer to mature.

Looking in further detail, Table 2 shows not only the wells covered by new 3D but also those wells matured from legacy seismic data, for these wells the exact time between acquisition and spud is not certain but it must be greater than 5yrs as the seismic dataset starts in 2014. This shows that wells drilled on legacy data also have a significantly lower TSR and CSR than those wells drilled in the first 5yrs from seismic acquisition. In short, this highlights that the best prospects are identified and matured rapidly and highlights the increased risks associated with HI drilling of prospects which are not immediately identified, de-risked and matured, or may be more subtle and harder to define.

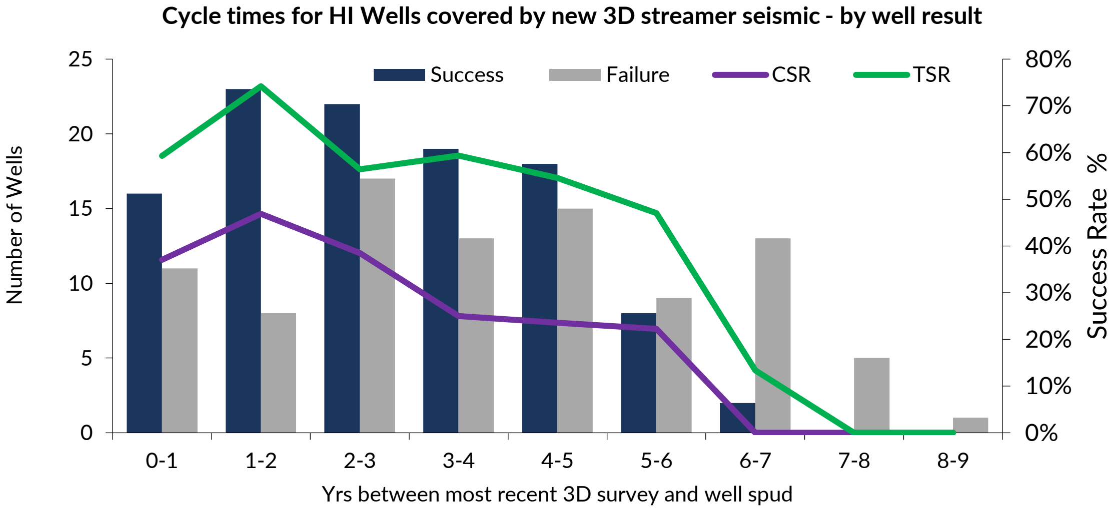

Figure 8: Time between survey completion and well spud for HI exploration wells covered by 3D towed streamer surveys, split by well result and also showing overall TSR and CSR for each year of cycle time.

	No. Wells	TSR%	CSR%
Wells drilled 0-2yrs from acquisition	59	66%	42%
Wells drilled 2-5yrs from acquisition	105	56%	30%
Wells drilled 5-10yrs from acquisition	38	26%	11%
Wells drilled on legacy data >5yrs before spud	125	46%	22%

Table 2: 2019-2023 Wells and success rates by time from seismic acquisition to well spud including wells matured on legacy data.

3.1.1 Cycle times by region

Figure 9 shows that whilst the average minimum time globally between marine seismic acquisition and well spud is 3.5years, North America has the longest average cycle time at 4.0yrs and South America (3.0yrs) and Mid East & Russia (2.4yrs) regions had the shortest average cycle times. A likely reason for this variation is the play maturity of the HI wells being drilled in those regions. In North America 43% of wells were testing Maturing and Mature plays where large volumes of legacy seismic are available whilst 83% of wells in South America and 100% of wells in Mid East & Russia were in Frontier and Emerging plays. Across Africa, Europe and ASPAC, 29% of the wells targeted maturing/mature plays.

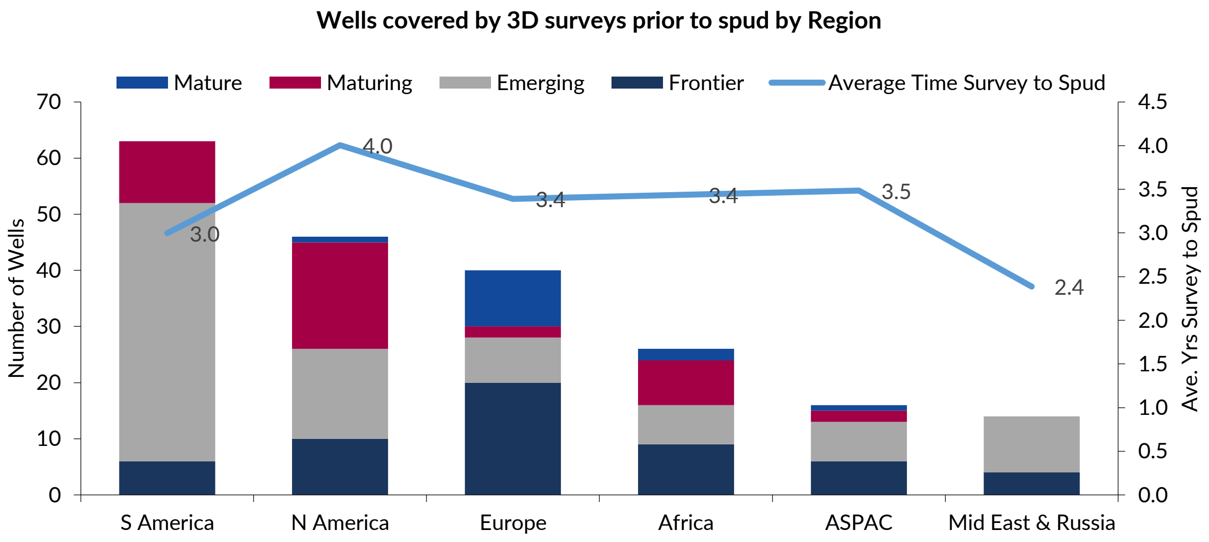

Figure 9: Average cycle times for HI wells drilled in different regions and play maturity.

Note that the analysis only considers the date of seismic acquisition, not processing or reprocessing. Recent advances in seismic imaging technology (e.g Full Wave Form Inversion, FWI) have improved the quality of some legacy datasets, extended their useful life, resulting in a longer time between the date of acquisition and well spud. In North America, 85% of those wells were drilled in the Gulf of Mexico basin with its complex salt related imaging challenges whereas in South America, only 21% of the wells were drilled in the salt basins of Brazil (Santos, Campos & Espirito Santos).

3.1.2 Cycle times by survey type

3D towed streamer surveys can use multiple acquisition technologies which may be modified according to the imaging challenges of the play. Here the surveys are split into three types:

- Standard, narrow azimuth 3D
- Wide, full and multi azimuth 3D
- 3D surveys that are part of a 4D baseline or repeat survey

Figure 10 shows the distribution of high impact wells drilled on different towed streamer survey types, the average times between survey completion and spud, and the success rates of the wells drilled on those data.

The 143 wells drilled based on new narrow azimuth 3D data took an average of 3.5yrs to spud from completion of the seismic survey and had a TSR of 50% and a CSR of 26%, identical to the success rates for all 336 HI offshore exploration wells in the period (See Figure 6).

The 40 wells drilled on wide, multi or full azimuth 3D data had the longest cycle times on average (3.9yrs) and the lowest success rates (TSR 45% and CSR 18%). 31 of these wells were drilled in salt basins where sub-salt imaging is challenging and where drilling is often also difficult, requiring longer planning times.

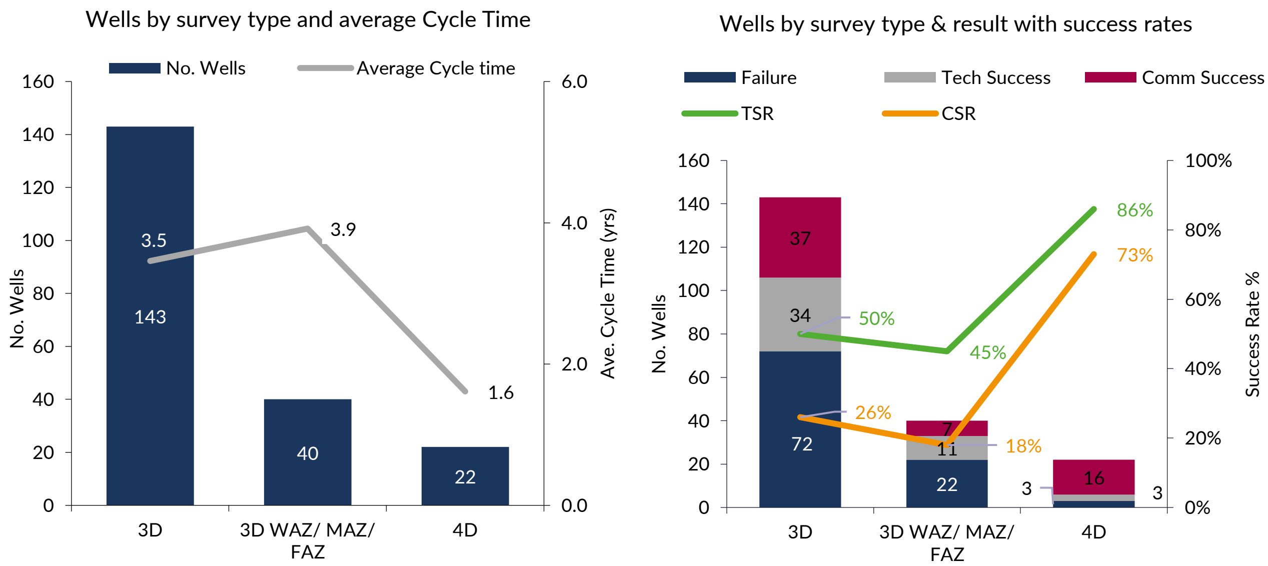

Figure 10: Cycle times and success rates by survey type

High impact exploration wells drilled on seismic data acquired for 4D reservoir monitoring purposes had the shortest average cycle time (1.6yrs) and the highest success rates (TSR 86% and CSR 73%). However, 19 of the 22 wells drilled on 4D were in the Suriname-Guyana basin where large 4D baseline surveys have been acquired while exploration has continued. The high success rates reflect the nature of the play rather than 4D data itself.

4. Geological Setting and Survey Type

The geological setting of the prospect being targeted by any exploration well defines the imaging challenges and forms an important input into the seismic survey design.

4.1 Wells defined by 3D towed streamer data

207 high impact offshore exploration wells were covered by 3D towed streamer seismic acquired since 2014 and prior to spud. Two of those wells were also covered by OB data and will be dealt with in the later section leaving a 205 well dataset to analyze. Of those, 155 of the prospects being tested have been categorised as being either “no salt”, “post salt”, or “pre/sub salt”.

Figure 11 left shows the number of wells in each setting and the type of seismic data used to mature the prospects prior to spud. Figure 11 right shows the TSR for wells drilled in each setting with different types of seismic data.

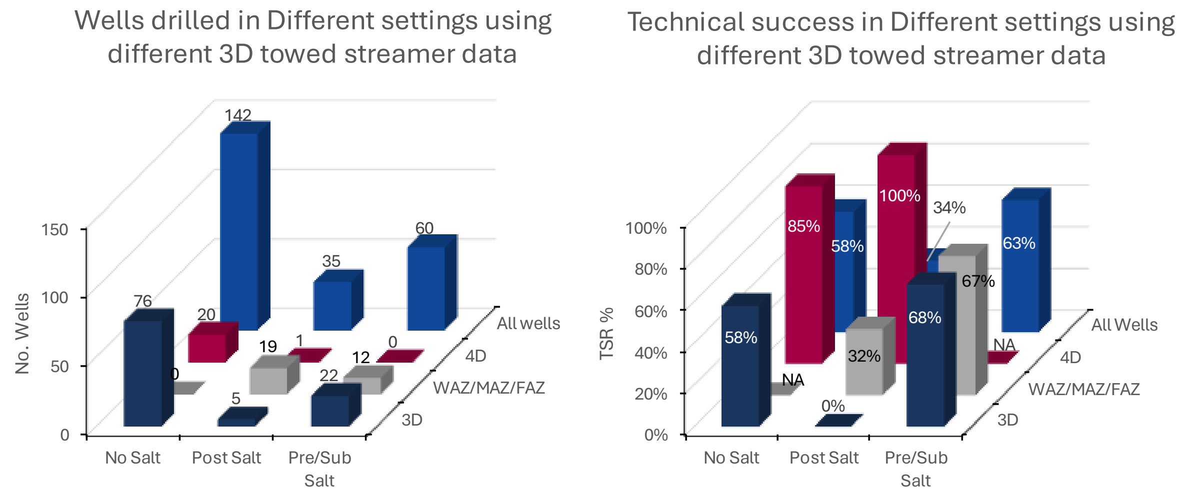

Figure 11: 3D column charts of number of wells drilled and TSR for well drilled in different geological settings in regards presence of salt and by the survey type of the most recent towed streamer survey acquired over the well location.

The first figure shows that 3D WAZ/MAZ/FAZ data is being used exclusively in salt basin settings where the increased azimuthal coverage provides improved imaging in and around salt structures and features. Wells drilled on 4D seismic as noted previously are dominated by activity in the prolific Suriname-Guyana basin and the high success rates reflect that.

Of wells drilled on normal narrow azimuth 3D data, 22 had pre or sub-salt targets and resulted in a TSR of 68%, similar to the TSR of 67% of pre/sub salt wells drilled on WAZ/MAZ/FAZ data. This suggests that the additional expense of MAZ/WAZ/FAZ acquisition may not have been justified by technical success at the drill bit. This may be contributing to the trend towards OB seismic data, both in dense node and sparse node configuration, to de-risk pre and sub-salt prospects.

Figure 12 shows the number of wells and TSR for wells drilled targeting different trap types and covered by different types of 3D towed streamer seismic. Of the 205 wells covered by new 3D towed streamer data, 180 have an identified trap type in the Wildcat database.

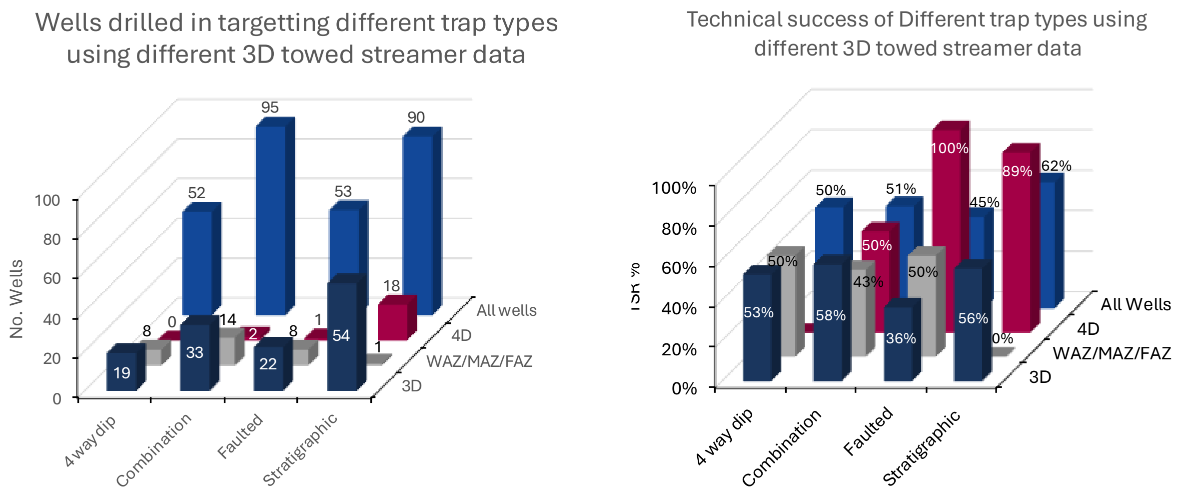

Figure 12: Charts of number of wells drilled and TSR for wells drilled targeting different trap types and by survey type of the most recent towed streamer survey acquired over the well location.

3D WAZ/MAZ/FAZ surveys have derisked mainly combination, 4-way dip and faulted traps highlighting their utilization in structurally complex areas; these surveys have been used to de-risked only a single stratigraphic trap target. The TSR for wells drilled on 3D WAZ/MAZ/FAZ surveys are slightly higher (50%) for faulted traps than the average for all wells (45%) but are lower or similar for 4 way and combination traps again showing that investment in these technologies has not materially increased success rates. 4D seismic surveys were used mainly to de-risk stratigraphic traps, and with a TSR of 89%, again this highlights the extensive continued exploration efforts and large 4D baseline surveys undertaken in the Suriname-Guyana basin and little can be concluded from these results.

4.2 Well locations covered by OB seismic data – exploration case histories

Ocean Bottom (OB) seismic is an emerging technology for exploration. Only 6 of the 336 high impact offshore exploration wells 2019-2023 were drilled following acquisition of new OB seismic data over the eventual well location. These are described in Table 3 with links to the Wildcat entry for each well and shown in Figure 13.

The relatively high cost of OB data, longer acquisition timelines and lead times has limited its use so far. Increasing market capacity and capability will in the future make OB seismic increasingly more relevant to exploration challenges.

The first two wells were both spud in September 2021, the Merckx well in Norway and the XF-002 well in the UAE, followed by two wells in 2022 and a further three in 2023.

To date only two successes have been confirmed in the six wells, at XF-002 and at Tiberius in the US GoM. Two other results at Polyphemus (US GoM) and Nanka (Mexican GoM) remain unknown.

Well	Country	Basin	Play	Water Depth (m)	Salt setting	Trap Type	Spud date	OB Completed	OB Type	Technical Result	Commercial
16/4-21 Merckx	Norway	CNS	Ty form - Paleocene	100	Post-Salt	Strat	Sept ‘21	Oct ‘19	OBN	Dry	No
Hoodoo-1	USA	GoM	Wilcox - Paleocene	941	Sub-Salt	Faulted 3 way	Oct ‘22	Mar ‘19	Sparce OBN	Dry	No
Polyphemus-1	USA	GoM	Norphlet U.Jurassic	2050	Undef	Faulted	May ‘23	May ‘20	OBN	Not Known	Not Known
Tiberius	USA	GoM	Wilcox - Paleocene	2239	Sub-Salt	4 way dip	Jul ‘23	Mar ‘20	OBN	Success – Oil	Yes
Nanka-1	Mexico	Campeche	Lower Miocene	34	Undef	Comb	Aug ‘22	Apr ‘18	OBC	Not Known	Not Known
XF-002	UAE	Rub al Khali	Jurassic & Permian	35	Post-Salt	4 way dip	Sept ‘21	Mar ‘20	OBN	Success - Gas	Yes

Table 3: High Impact exploration wells drilled following acquisition of OB seismic over the well location.

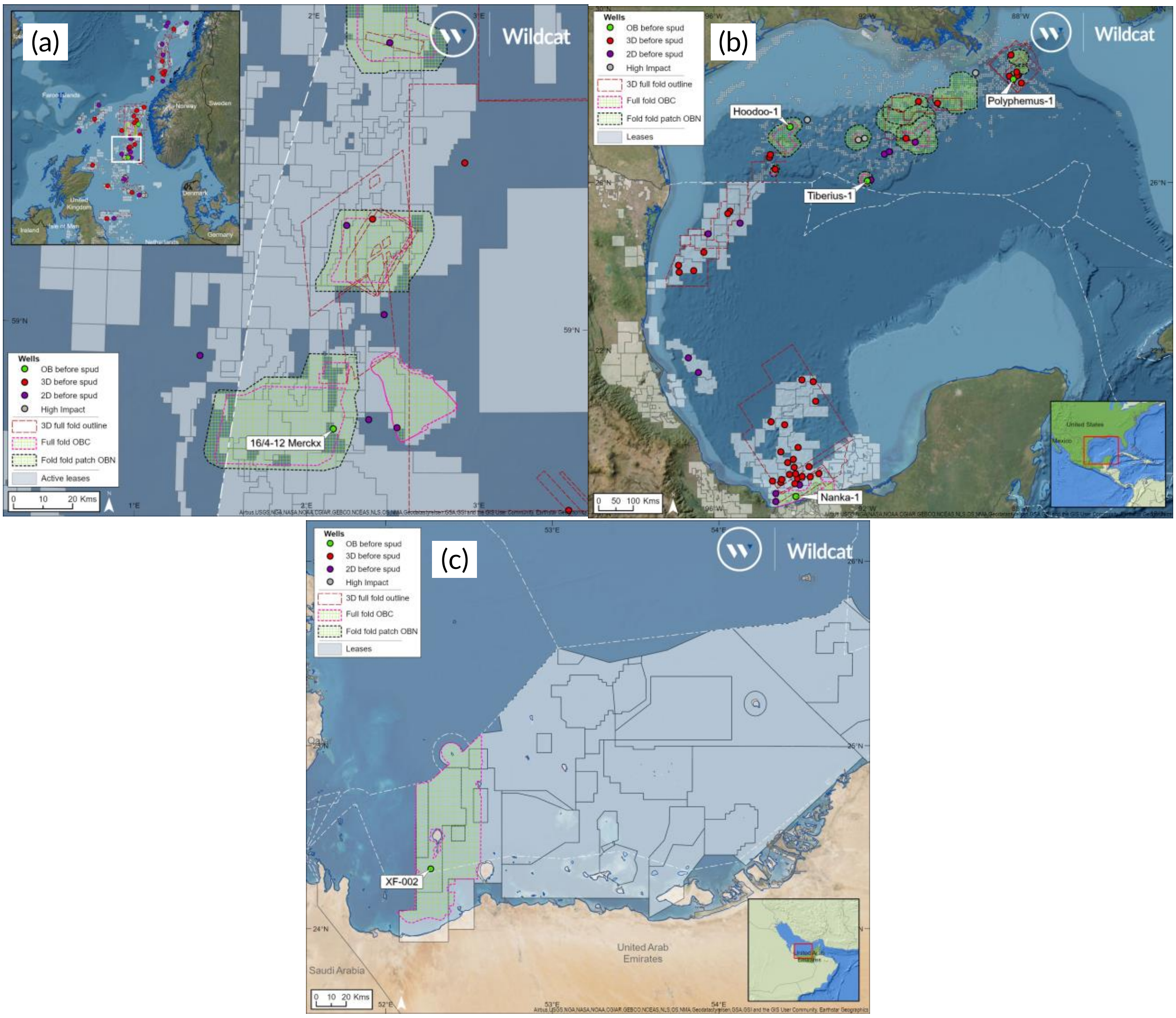

Figure 13: Maps showing well locations (green circles) of wells covered by new OB Seismic prior to spud. (a) Norwegian North Sea, (b) Gulf of Mexico, (c) Arabian Gulf. Only 3D & OB seismic covering high impact well locations are shown.

The 16/4-21 Merckx well in Norway was spud nearly 2 yrs after the completion of the >2,000km^2 multi-client Utsira dense node OBN survey which was a partnership between TGS and AGS. The well was drilled on the SW flank of the Utsira high, containing the giant Johan Sverdrup field. The Merckx well was <5km from the producing Solveig field and was considered an ILX target. The well targeted the Paleocene Ty Formation sands which pinch out onto the flank of the Utsira high with a secondary Permian Zechstein target. Good reservoirs were found but no hydrocarbons reported indicating potentially a charge failure. The well is classified as 'post salt' although the Zechstein evaporite unit is not mobile or deformed in this area. The dense node OBN multi-client survey offered very long offsets, high fold and full azimuth coverage in a prolific area with producing fields, undeveloped discoveries and many remaining exploration targets. The acquisition allowed for reflection FWI techniques to be used alongside tomography and improved AVO characteristics in the final data. Imaging challenges for the Paleocene play are that sand reservoirs in the area are known to have variable reservoir quality and there are shallow velocity anomalies related to injectites and quaternary channels (Jansen et al 2021).

In October 2022, the Hoodoo-1 well spud in the deepwater East Breaks area of the US GoM. The well was operated by Woodside who had acquired BHPs petroleum assets in June 2022. The sub-salt Paleocene Wilcox play in the Western GoM had been a focus for BHP. As part of BHPs maturation of the prospects in this area and as a result of the significant imaging challenges presented by the complex overburden and thick salt canopy, they identified that enhanced velocity model constraint could significantly improve seismic imaging in the complex sub-salt structural traps. In 2018 BHP decided to acquire the 'Western GoM' sparse node OBN survey focused entirely on velocity model constraint through Full Waveform Inversion which could be used to re-image existing WAZ towed streamer data. The Western GoM OB survey was acquired by Fairfield from Aug 2018 to Mar 2019 with a node spacing of 1 x 1km and a shot spacing of 200 x 400m. The node patch area was ~2,400km^2. The survey provides far offsets of over 40km (Lin et al 2021). Figure 14 shows before and after images of seismic from the survey.

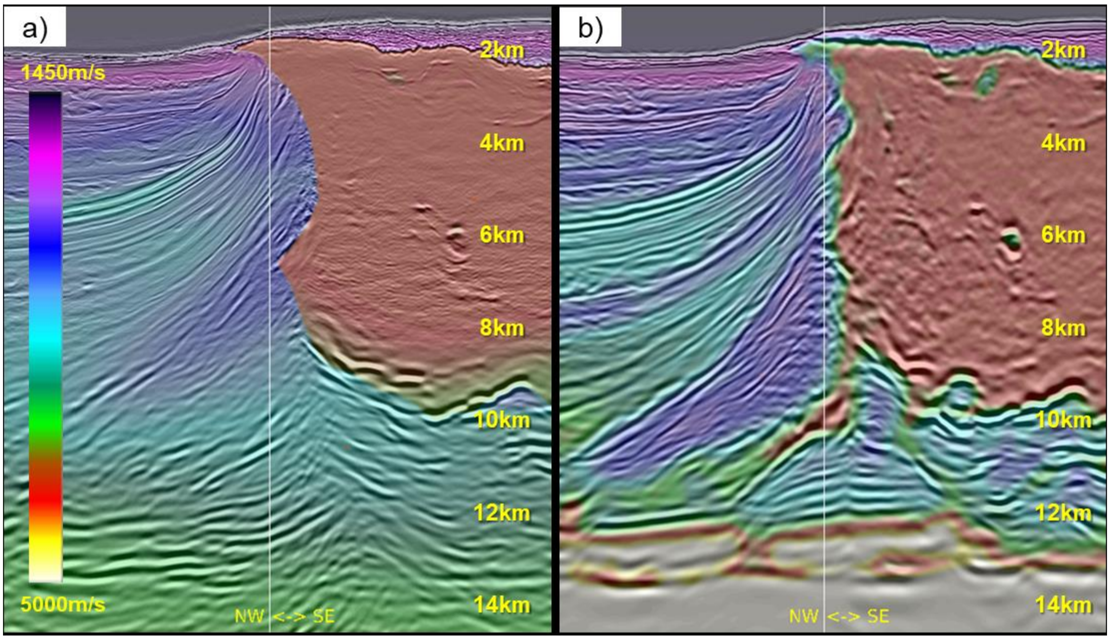

Figure 14: (a) Original WAZ velocity model and stack and (b) re-imaged WAZ data with velocity model from Sparse Node OBN survey (Lin et al 2021).

The Hoodoo-1 well did not encounter hydrocarbons and no details have been provided on why it failed. It is not possible to say whether the investment in OBN and reimaged seismic data worked, and whether the reservoir and trap were successfully characterized as charge failure could also have been the issue.

Chevron spud the Polyphemus-1 well in May 2023 in a faulted trap in the Jurassic Norphlet sandstones. The well was within the full fold (node patch) area of the 2020 Ballymore OBN survey shot as part of the appraisal program of the 2018 Ballymore oil discovery nearby. The dense node OBN survey was shot by Seabed Geosolutions and is 186km^2 full fold area and was acquired in 1,900-2,140m of water. Little is known about the critical risks of the Polyphemus prospect and the result is not reported, it is assumed to have been unsuccessful. It is likely the OBN survey was used to characterize the prospect prior to drilling.

The Tiberius-1 well spud in July 2023 in 2,239m of water in the Keathley Canyon area of the US GoM as a high impact ILX prospect 10km from the Lucius production facility. The well encountered 7m of net oil in Lower Paleocene Wilcox sandstones and is considered potentially commercial. The area has extensive and thick allochthonous salt canopy at Plio-Pleistocene levels creating imaging challenges. The well location is covered by the full fold node patch of the Hadrian-Lucius dense node OBN survey completed in March 2020 to support production and further exploration efforts in the area.

In the Mexican Campeche Salt basin, Pemex spud the Nanka-1 exploration well in August 2022 in the nearshore, shallow water part of the basin in the middle of the emerging Miocene play fairway and close to the Pemex Area 1 oil development in the same play with fields dominantly in faulted traps above/beside salt diapirs. The well targeted Lower Miocene turbidite sands at prognosed depth of ~6,000m though little is known about the trap geometry. Well results have not been released since the well completed in September 2023. The well location is within the 5,400km^2 shallow water Litoral de Tabasco ocean bottom cable (OBC) survey acquired by Western Geco, for Pemex from October 2016 to April 2018. The survey area contains producing fields, undeveloped discoveries and exploration prospects. The full fold, node patch of the survey covers areas from 5-140m of water depth and the full area would not have been possible to acquire with modern towed streamer 3D acquisition. It is uncertain whether the main driver for acquiring the OBC survey was coverage and the need to get into very shallow water areas or data quality in the notoriously difficult to image Campeche basin.

In the UAE, the XF-002 well was drilled by Eni in late 2021/early 2022. The well resulted in a commercial gas discovery in the shallow waters of Block 2 in Abu Dhabi. Gas was discovered in both Jurassic (Arab) and Permian (Khuff) carbonate reservoirs. While little is known regarding the trap and reservoir, the field is within the zone of mobile Hormuz salt with numerous discrete diarpiric salt structures nearby. Eni were awarded the acreage in 2019 following a license round the previous year. The ADNOC Offshore Phase I OBN survey, which covers the area, was acquired in 2019 and early 2020 by BGP. The survey area covers producing and discovered undeveloped fields and exploration opportunities and is part of a larger campaign to cover significant parts of offshore Abu Dhabi in new OBN data.

Of the six wells covered by OB surveys, only one of those surveys, the sparse node Western GoM survey over Hoodoo-1, was exclusively for exploration purposes. All the other surveys have had mixed purpose and have covered producing and/or discovered undeveloped fields. Also, only one of the surveys, the one over the Merckx well in Norway, was acquired on a multi-client basis highlighting that the value proposition of OB surveys in the exploration dominated multi-client market is still uncertain. While improvements in imaging from OB surveys can be shown, from both dense node or sparse node surveys, it is clear that the additional cost is still too high to be justified for exploration alone.

5. Discussion

The analysis above has demonstrated some intriguing relationships between seismic acquisition and exploration drilling results.

Wells drilled on new seismic have higher success rates than those drilled on legacy data. Or do they?

Globally TSR is 6pp higher and CSR 7pp higher for wells drilled on new seismic over legacy data. It is shown that this entire difference is driven by emerging play wells which have a 15pp higher TSR and 17pp higher CSR for wells with new seismic. Emerging play wells have high success rates and are found in areas attracting investment due to the perceived undiscovered value of the plays. These areas are also typically lacking in seismic data coverage and hence lots of new seismic is acquired in these areas. However, this argument is countered by the fact that when the Guyana-Suriname basin, which has mainly emerging play wells and has been highly successful, is removed from the figures then both TSR and CSR do not change where new seismic has been acquired. The Guyana-Suriname basin skews the global results as it is such a prolific play with almost blanket coverage of new seismic data. The independence of success rate to new seismic data is likely explained by considering that seismic is purely a tool that enables prospect characterization. Improved seismic imaging may enable characterization and de-risking of prospects which were previously deemed too risky. These prospects will be drilled once they are assessed to be value accretive, improved seismic will not necessarily decrease the risk of exploration drilling, rather allow prospects previously assessed as being too high risk to be derisked to a level that meets the investment criteria of the JV.

Time from Acquisition to Drilling – good prospects rise quickly to the top

Wells that spud within the first two years of completion of seismic acquisition had a TSR 40pp and CSR 31pp higher than those wells spud 5-10yrs after seismic. While these trends do not demonstrate causality, it is likely because the best prospects are more obvious and are identified more quickly. This supports the old exploration mantra ‘always drill your best prospects first’.

Where is the value in WAZ/MAZ surveys?

Towed streamer 3D surveys with increased azimuthal coverage have been used extensively in the salt basins around the world to provide enhanced wavefield coverage in and around complex, high velocity contrast salt bodies. In salt basins, over half of the HI wells drilled on towed streamer data used some form of MAZ or WAZ survey. However, the success rates of wells drilled on MAZ & WAZ data in salt basins are no higher than those wells drilled on narrow azimuth 3D data. This suggests that the improvement in image quality from MAZ & WAZ surveys has not improved prospect characterization and risk sufficiently to be justified. The decrease in deployment of WAZ and MAZ surveys likely demonstrates this.

The rise of OB seismic in exploration…. Or not

There has been much talk of the increasing use of OB surveys in exploration. The Westwood report on seismic in 2022-3 showed that OB seismic is growing overall and as an exploration tool with 27% of OB surveys in 2022-3 having at least a partial exploration purpose. However, this report shows that the OB acquisition has yet to be reflected in high impact drilling. Only 6 of the 336 high impact wells were drilled based on OB data and only one of the surveys, the sparse node Western GoM survey used to characterize the Hoodoo-1 prospect, was acquired explicitly for exploration purposes. The rest of the OB surveys which supported high impact wells were multi-purpose surveys also containing producing fields and/or discoveries under appraisal. It is likely true that the higher cost of OB seismic is yet to be borne exclusively by exploration spend within companies. Broader deployment of advanced imaging and velocity modelling tools such as FWI allow for a full exploitation of the data acquired by OB surveys and the remaining barriers for OB seismic to be widely utilized in exploration become time and cost. Exploration license terms frequently mean time is very short for the prospect identification and derisking. Also, exploration costs, of which seismic is a significant part, are spent entirely on an at-risk basis meaning exploration teams are extremely time and cost sensitive. As highlighted in the recent Andrew McBarnet article in Upstream[1], cost reduction is imperative to broader adoption of OB seismic in exploration.

What about reprocessing instead of acquiring new data?

Processing and imaging algorithms and methods have developed significantly over the last 10-15yrs. Tools such as de-ghosting and creation of broadband data imaging, advanced tomographic techniques and anisotropic velocity modelling, full waveform inversion are just some of the improvements which are now commonplace in the processing and imaging toolkit and are being used to unlock value held in older, legacy data as well as being applied to the newest acquisitions. The specific amount of reprocessed data which has been used in HI exploration in 2019-2023 cannot be seen in the datasets available to this study but the success rates from legacy data are similar to those from data acquired since 2014. This demonstrates that older legacy data is still proving valuable, reprocessed or not.

6. Conclusions

What type of seismic data is being acquired which leads to HI exploration drilling?

The vast majority of HI exploration wells in the 2019-2023 period were drilled on 3D towed streamer data. South and North America both had the highest percentage of wells drilled of post 2014 acquired data whereas ASPAC and Mid East & Russia regions had more reliance on older legacy seismic acquired prior to 2014. Only 6 exploration wells have been drilled on OB seismic data.

Is there evidence that different seismic acquisition technologies influence geological and commercial success rates?

Wells de-risked by post 2014 3D towed streamer data had higher technical (52%) and commercial (29%) success rates compared to those wells which relied on legacy data (46% TSR and 22% CSR). However, this is demonstrated to be driven entirely by emerging play tests in the Guyana Suriname basin. When excluded, wells drilled on post 2014 seismic have no greater success than those drilled on legacy data. Wells drilled on Wide and Multi Azimuth towed streamer surveys are almost exclusively in salt basins. However, the success rates of wells drilled on MAZ & WAZ data in salt basins are no higher than those wells drilled on narrow azimuth 3D data.

HI Exploration wells drilled based on 4D seismic surveys (either baseline or repeat surveys) had the highest success rates though this is likely due to proximity to producing fields and better understanding of the plays regionally rather than anything specific to do with the data.

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[1] *Ocean-bottom seismic champion says future still lies on the seafloor, https://www.upstreamonline.com/focus/ocean-bottom-seismic-champion-says-future-still-lies-on-the-seafloor/2-1-1623547*

What are the cycle times from seismic acquisition to drilling, do they impact success rates and are they different in different regions?

Average times between seismic acquisition and spud of HI exploration wells vary with technology, from 1.6 years for 4D, 2.6 years for OB, 3.5 years for 3D and 3.9 years for 3D MAZ/WAZ. The longer times for MAZ/WAZ surveys are likely due to their use in structurally complex salt basins which require extensive processing & imaging as well as interpretation prior to drilling.

Cycle times varied by region with South America and Mid East & Russia having the shortest average cycle times 3.0yrs and 2.4yrs respectively, whereas North America, had an average cycle time of 4.0yrs.

Wells spud within 2yrs of survey completion had a TSR of 68% while wells drilled based on seismic over 5yrs old had a TSR of 26% which seems to confirm that the best prospects tend to get drilled first and performance may not improve with time even as knowledge of the play improves.

Regions with the highest proportion of frontier and emerging play tests in their HI drilling, South America and Mid East & Russia, have the shortest average cycle times 3.0yrs and 2.4yrs, whereas the region with the lowest proportion of frontier & emerging play test, North America, has an average cycle time of 4.0yrs

How are different seismic technologies being applied in different geological settings?

OB seismic, has been exclusively used in salt basins so far where the imaging challenges justify the investment. WAZ & MAZ data is also exclusively used in salt basins but it does not provide an increased success rate over standard 3D. Standard narrow azimuth 3D remains the dominant seismic technology in HI exploration being used across salt and non-salt basins.

7. References

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