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Asia Pacific Unconventionals: Where to Next?

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Introduction

In recent years, considerable capital has been expended to quantify and unlock the shale and tight gas and oil potential of the Asia Pacific region. This has been spurred by the stunning success of horizontal drilling and fracture stimulation across wide ranging regions and a variety of plays in the United States. Although North American tight gas plays extend back many decades, the success of the Barnett Shale gas play in the 1990s proved commercial production from source rock shales. This success was followed by exponential production growth and rapid innovation driven by independent operators. By the mid to late 2000s the world's energy market was transformed. During the price collapse of the last two years, the US industry has nimbly responded and aggressively driven down break even prices in the core of the best plays. New geological plays and refined drilling and fracture stimulation techniques continue to deliver results barely imagined only a few years ago.

In the Asia Pacific region, despite generally significantly higher gas prices than in North American markets, the highly touted EIA numbers for unconventional resource potential have yet to be realized. Exceptions include the coal bed methane projects in Australia and China and tight gas production in China. The reasons for this slower pace of development are numerous and inter-related. Geologic complexity, poor access to subsurface data, rugged and/or difficult to access terrain, water resources issues, limited infrastructure networks, high operational costs, less flexible fiscal regimes and highly regulated gas markets have stifled unconventional growth. Given regional market demands and declining production, we believe the significant and real potential of this region will ultimately drive an Asia Pacific unconventional revolution. Companies that take a systematic, focused approach, prudently adapting lessons from North America will be rewarded for their persistence.

It should be noted that in this discussion, "unconventionals" typically refers to oil and gas production from both shale and tight reservoirs, extracted using fracture stimulation and/or horizontal drilling techniques. We also refer to some statistics for coal-bed methane (CBM) projects, which falls under a broader unconventional definition.

Current situation and lessons from the US

In reviewing US data, it is clear that the major unconventional plays (shale and tight reservoirs) are all in basins that have significant conventional reserves and production. The map below (Fig. 1) compares USGS estimates for produced hydrocarbons with estimates for the unconventional potential across the key US basins. The numbers show the major unconventional plays are all in existing prolific conventional basins and, in our opinion, this correlation is an important initial ranking criteria for a new region such as South East Asia.

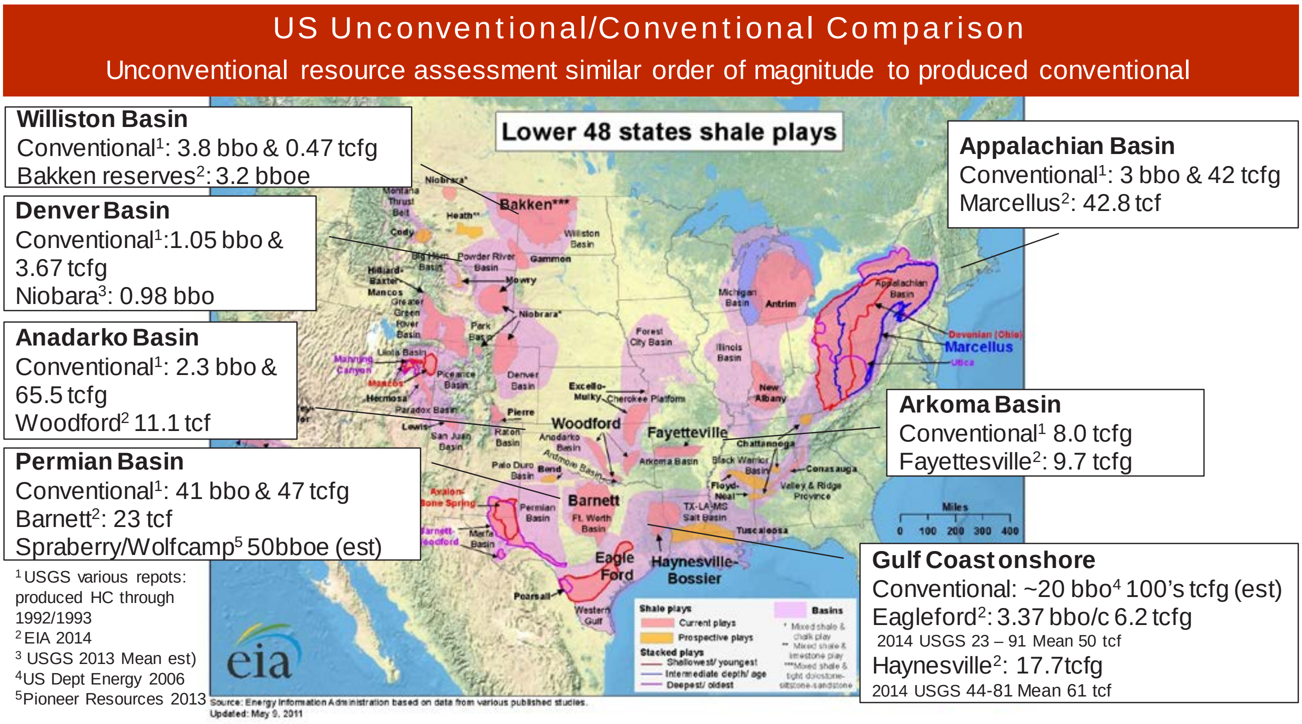

Figure 1: Source: Energy Information Administration (EIA).

2016 EIA estimates have US Lower 48 tight oil production at 1.67 billion barrels for the year (4.6 mmbopd); tight gas at 4.67 tcf (12.8 bcfgd); shale gas and gas from tight oil plays at 14.08 tcf (38.6 bcfgd); and CBM at 1.14 tcf (3.1 bcfgd). Given these impressive figures, it is worth listing some of the key observations and lessons from the unconventional industry in the US:

- A century of E&P activity in North American basins provided a rich subsurface dataset in all of the major unconventional plays prior to their "discovery." Nearly all of these plays produced vertically in at least a few wells.
- After initial proof of production, operators rapidly focused on innovation and optimization to improve returns. The mind set was on maximizing EUR, not strictly volume, and, accelerating production especially in the price downturn.
- The competitive nature of leasing land and in certain areas the need to drill in order to maintain rights helps force activity and maintain momentum.
- Market driven gas pricing exists in the US with the customer being the ultimate beneficiary.
- Almost regardless of pricing the core of the best plays will compete for global capital. Simply put "GREAT rock trumps good rock, all the time." As such it is imperative to define core early in the exploration process, integrating; geology and production data to optimise completions and reservoir management.
- The entirety of some petroleum systems are being developed: e.g. the greater Mississippian-STACK play in the Anadarko basin, Oklahoma, extends over 300km down dip to up dip from the dry gas window to high water cut transition zones.
- In the Permian Basin (Wolfcamp) there is increasing recognition of not only storage in thin carbonates but also their role in enhancing brittleness.
- Driving down cost and drilling efficiency in development- pad drilling, pre-drill multiple surface locations with smaller rig. Continuous operations with the same crews results in greater efficiency and shorter drill to completion times.

- High sand volume fracks (2500lbs/ft) with closely spaced stages are now the norm. More completion jobs are customized for the well bore rather than mass produced. Thus steering and data acquisition in the horizontal are important even in pad drilled wells.
- Supply chain critical especially access to large volumes of consistently high quality sand. The demand for finer mesh sand in the newer completions is particularly acute and may be a bottleneck in the ramp-up of production.
- In transition zone plays, long-term high volumes of water (~ 1.8 mmbw/well per year) must be disposed. A hydrologic-seismicity risk assessment in development plans must include identification of suitable aquifer above basement for water disposal.
- Some recent highlights of improvements in efficiency and production include:
  - STACK- Meramec benches[3] in the Oklahoma Anadarko Basin: the Angus Trust well had an initial production of 2,088 bopd and 15.3 mmcfgd. Down-spacing tests (7) with >6 months production indicate 6 to 10 well per section in development.
  - PERMIAN- 2nd Wolfcamp bench: rates of 3,000 boepd not uncommon with some operators pushing 4,000 boepd. Driven by both better completions and resolution of land issues to permit extended reach laterals.
  - UTICA SHALE (Appalachian Basin): IPs > 70 mmcfgd and some operators drilling 15,000ft lateral section in 16 days. Midstream bottlenecks a being solved with new takeaway capacity.
  - HAYNESVILLE SHALE: super fracks (5,000 lbs/ft) of extended reach laterals are delivering 40,000 mmcfgd. Operators are eying US LNG export market.

[4]Bench (noun): a single flow unit of stimulated rock volume in horizontal well. Because of the limits on vertical fracture height and proppant emplacement, thicker reservoirs have more benches.

Where to focus in the Asia Pacific region

With the correlation we see in the US between existing conventional production and unconventional potential, we have listed the conventional onshore reserves for the top 15 major onshore basins in the region, sorted by discovered hydrocarbons (Figure 2). The graph shows 6 of the top 15 basin are in China (Bohai Gulf (1), Songliao (2), Tarim (4) Ordos (5), Sichuan (6)) followed by Indonesia with 5 basins in the top 15 (Central Sumatra (3), South Sumatra (7) North Sumatra (9) Kutei Basin (12) East Java Basin (15)). The PNG fold belt comes in at number 10 followed by the Cambay Basin of India and in Australia its Cooper-Eromanga Basin ranks at number 13 with the Bowen Surat at number 14.

The graph also plots hydrocarbon density in terms of discovered reserves per square kilometre, with Central and North Sumatra Basins having the highest density, which may be significant in terms of their unconventional potential.

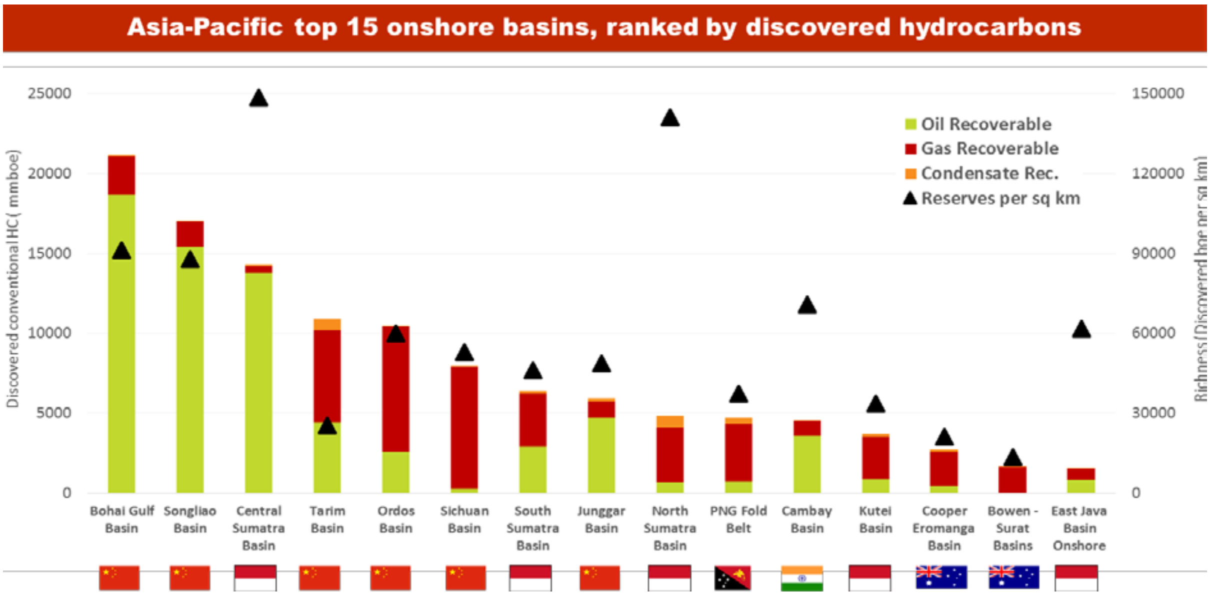

Figure 2: (Source IHSE, various)

Current status of unconventional hydrocarbons in the region

China (Conventional onshore discovered resource estimate Oil/cond: 48 bbo, Gas: 170 tcf)

China is already a major tight gas producer with 2013 annual production of approximately 1.47 tcf (~4 bcfgd) (Dai JX et al, 2015). A huge effort since the late-2000s on developing its shale gas potential has seen China's 2015 shale gas output reach approx. 158 bcf (430 mmcfgd) (Ministry of Land and Resources (MLR) 2016) which represents growth of approx. 260% over 2014. Shale gas production has now just overtaken CBM production which was approx. 156 bcf (~430 mmcfgd) in 2015 (MLR, 2016).

These relatively modest results in China shale gas, by US standards, have been hard won with billions of dollars invested and an impressive research effort across companies, government departments and universities. The main success to date is from the Sichuan Basin targeting marine Silurian shales. Sinopec Fuling and CNPC's Weiyuan-Changning project which contribute the bulk of the production. Participation of international majors has had mixed results, with ConocoPhillips and Shell not continuing their investment citing operational challenges, geology and drilling results. However, against this trend of majors exiting, in 2016 BP announced it had entered into an agreement with CNPC to develop the Neijiang-Dazu block in the Sichuan Basin.

Despite many challenges, shale gas and tight oil production will continue to grow in China to meet its demand and policies of replacing coal with gas. Certainly given the prolific nature of many of the onshore basin (Fig. 2) this growth will include new plays and prospective regions.

Australia (Conventional onshore discovered resource est. Oil/cond: 1.1 bbo, Gas: 20 tcf)

In the broader unconventional space, coal bed methane (or coal seam gas) has experienced major growth in Australia. In 2015 CBM production was 0.596 tcf (APPEA 2016) from around 4,400 producing wells, with reserves in Queensland estimated to be 40 3 tcf. Three Queensland based LNG projects are now producing:

- Queensland Curtis LNG, (Shell/BG/CNOOC/Tokyo Gas) the world's first dedicated coal seam gas to liquefied natural gas project, loaded its first cargo for export in late 2014
- Gladstone LNG (Santos/Petronas/Total/KOGAS) exported the first cargo of LNG in October 2015

- Asia Pacific LNG (Origin/ConocoPhillps/Sinopec) shipped first cargo in in early-2016

In terms of shale and tight hydrocarbons, there has been considerable activity since 2010, helped by the EIA in 2013 highlighting Australia to have 430 tcf tight gas and 15 billion bbls tight oil (unproven technically recoverable). Many hundreds of millions of dollars have been spent and 100's wells drilled in focus areas including: South Australia's Cooper Basin, Western Australia's Perth and Canning basins and North Territory's Amadeus, Beetaloo, McArthur and Georgina basins. Initial work involved fracture stimulating vertical wells with Australia's first horizontal shale gas well drilled by Santos in the Cooper Basin in 2013.

Key local players have been Beach/Drillsearch, AWE, Buru Energy, Senex, Strike Energy, Origin and Santos. Significant international companies have had forays into the industry with transaction commitment of up to A$1.6 billion (RFC Ambrian, 2013). These companies include: BG, Chevron, ConocoPhillips, Total, Hunter-Magnum, Hess, Mitsubishi, PetroChina, Statoil, Sasol and American Energy Partners. Success has been elusive and many of these players have since withdrawn. As an example, Chevron spent US$190 million in the Nappamerri Trough venture with Beach prior to the decision to withdraw in 2015.

In recent news, Origin's announced a discovery with the Amungee NW-1H well in the Beetaloo Basin in late-2016. The well drilled a 600m horizontal section and fracture stimulated the Pre-Cambrian Middle Velkerri "B" Member shale, recording a modest flow of 0.8-1.2 mmscf/d of dry gas (Composition: 95% C1, C2+ 1-3%, CO2 2-4%). In February 2017, Origin released estimates of Original Gas in Place of 61 tcf and Gross Contingent Resources of 6.6 tcf over an area of 1,968 km^2 in their held acreage.

With current fracture stimulation bans or moratoriums in North Territory, NSW (certain areas), Tasmania and Victoria and considerable community opposition in other states, there are significant "licence to operate" issues for unconventional focussed companies in Australia. Combined with the overall limited success to date, geological issues such as lack of overpressure and unfavourable stress regimes, high operating costs, infrastructure and service sector capability limitations there are many challenges. However, the east coast gas shortage presents an increasingly attractive pricing environment and Federal and State Governments are under pressure to increase gas exploration and it may well be a time for a renewed exploration and appraisal phase building on lessons learned.

Indonesia (Conventional onshore discovered resource est. Oi/cond: 22.5 bbo, Gas: 90 tcf)
Since mid-2008 there have been 54 CBM Production Sharing Contracts (PSC's) awarded in Indonesia concentrated in Kalimantan and South Sumatra. To date around 160 wells have been drilled and pilot well testing conducted in just 11 of the 54 blocks. However, despite this activity there are no proven commercial projects as yet with issues related to: fit-for-purpose services e.g. drilling rigs; permeability; drilling costs and infrastructure logistics. New potentially more favourable fiscal terms and operating rules were announced in January 2017 and this, combined with work on reducing costs, may help turnaround the industry.

In early 2012, reacting to the shale and tight gas and oil success in the US, the government introduced new unconventional licences with regulation defined unconventional as rocks requiring fracture stimulation. Companies including Lion Energy Ltd, moved quickly with unconventional joint study applications over most of the productive onshore basins. With the industry downturn in 2014 progress has been slow and to date only total approximately six of these joint studies have progressed to being awarded unconventional production sharing contracts. Resource potential in these six blocks alone is estimated at over 4 billion barrels and 90 tcf (SKK Migas).

Of considerable interest PERTAMINA is currently drilling the countries first dedicated shale gas well, Melucut-1 in the Sumbagut PSC in the North Sumatra basin. This is a vertical well to ~3600m with coring planned of Miocene age tight-sandstone targets and also key marine source rocks intervals. Fracture stimulation and testing of key unconventional zones is also anticipated to be conducted.

In light of the subdued industry appetite for new exploration acreage, the Government is actively considering ways to promote unconventional exploration activity. In addition to the above mentioned new regulations for unconventional PSC's, this may include improved data access and government funding of early stage exploration activity.

With a range of prolific non-marine to marine basins with world class source rocks; a strong local gas market; and existing underutilised infrastructure due to declining conventional production; we see significant potential in the country. Early focus will likely be on the tight sandstone and carbonate plays which have been under-evaluated in the past.

India (Conventional onshore discovered resource est. Oil/cond: 5.5 bbo, Gas: 20 tcf)
The Director General of Hydrocarbons (DGH). has been taking a lead role in fostering the development of unconventional resources in India. With the fifth largest proven coal reserves in the world it holds significant CBM potential estimated at 92 tcf (DGH website). The Gondwana sediments of eastern India host the bulk of India's coal reserves. In March 2015 CBM production was approximately 27 mmscfgd from CBM blocks in West Bengal and this is forecast to grow significantly with new projects coming on-line.

Various bodies (i.e. EIA, ONGC, USGS and Schlumberger) have estimated huge potential shale gas and shale oil resources for India with the main focus basins being the Cambay, Gondwana Basin, KG Basin, Cauvery Basin, Indo-Gangetic Basin and Assam-Arakan Basins. Most of the work to date has been by the national oil company, ONGC, who hold up to 50 shale licences. Although limited results are available, in 2016 ONGC reported they were planning on drilling up to 17 dedicated shale wells. Australian company, Oilex Ltd, has attempted to fracture stimulate horizontal wells to test tight gas potential in the Cambay Basin with modest results to date. Certainly there will be continued growth in activity, especially if foreign participation is encouraged.

Thailand (Conventional onshore discovered resource est. Oil/cond: 0.4 bbo, Gas: 3 tcf)
Unconventional potential may exist in rich lacustrine source rocks and interbedded sandstone within depocentres of Thailand's onshore Tertiary rift basins. However sweet-spot areas are small and many may not be sufficiently thermally mature to be viable unconventional plays. In 2014 the USGS released a report of the unconventional oil and gas resources on the Phitsanulok Basin, the largest of the onshore rifts, with estimated mean oil potential of 53 mmbbl and mean gas of 320 bcf.

Tight gas and shale gas potential may also exist in Permian and Triassic sediment of the Khorat Plateau area. With declining Thai oil and gas reserves and increasing dependence on imports the Government will certainly be encouraging any unconventional exploration activities.
PNG (Conventional onshore discovered resource est. Oil/cond: 1.3 bbo, Gas: 30 tcf)
In mid-2016 Australian company South Pacific Resources Limited (SPR) was awarded rights to newly gazetted unconventional blocks in the PNG fold belt and foreland area. Recently it announced commercial and technical alliance with Malaysian company Tamarind Management Sdn Bhd. Clearly there are major challenges with cost of operations for any unconventional project in PNG.

Vietnam (Conventional onshore discovered resource est. Minor gas only)
In the Hanoi Trough (NW Vietnam) efforts by Dart Energy (formerly Arrow Energy) and others drilling a number of CBM wells in 2008-2011 period indicated the potential was not sufficiently attractive to warrant continuing the effort. There may still be some tight-gas potential in the area although CO_2 and operational issues may present significant challenges.

Other areas
Unconventional potential also exists in the following areas although as with countries above all will have significant technical and commercial challenges:

- New Zealand (Conventional onshore discovered resources est. Oil/cond: 0.1 bbo, Gas 2.6 tcf). Main potential: Taranaki Basin and the rich Late Cretaceous and Early Tertiary source rocks in the East Coast basins of the North Island. Some dedicated wells have been drilled to test shale gas and oil potential (i.e. TAG Oil Ngapaeruru-1 well) with some encouragement. Issue exist with complex structure, adequate depth of the East Coast shales and potential environmental concerns.
- Myanmar (Conventional onshore discovered resources est. Oil/cond 1.0 bbo, Gas 3 tcf). Main potential: Tertiary basins.
- Malaysia (Conventional onshore discovered resource est. Oil/Cond 0.1 bbo, Gas 0.2 tcf). Main potential Onshore Sarawak i.e. Balingian Basin
- Philippines (Conventional onshore discovered resource: Minor gas <10 bcf). Main potential Cagayan Basin of Luzon Island.

Next steps
Building on the lessons from North America and our understanding of the region we offer the following recommendations and discussion on some key success factors for commercially viable unconventional plays:

- Target basins with proven conventional production and existing infrastructure.
- Focus on known, but undeveloped systems with tight reservoirs (hybrid plays) in close proximity to mature, over-pressured, rich source rocks.
- Leverage conventional exploration and production to cost effectively build knowledge/data (i.e. cores, 3D) and deliver early cash flow.
- Identify the best rocks and fluids focussing on over pressured high GOR oil / high BTU gas.
- Ensure appropriate overseas expertise is combined with extensive local knowledge.
- Industry/service sector co-operation is vital.
- Ready access to infrastructure.
- Gas plays must have viable, relatively unregulated local market.
- Engagement and buy-in with Governments and regional authorities.
- Good midstream contracts with Governments supporting market driven pricing.
- Countries that have in place specific contractual instruments that recognize the scale and timing of horizontal tight-reservoir plays.
- Even in the exploration-appraisal phase a multi-well program should be considered in order to allow rig and completion crews to climb to the plateau of efficiency.
- Good community relations are imperative. All stakeholders must benefit from the primary and secondary market. In the US, surface owners typically have some royalty interest in the production which creates a win-win situation with respect to surface access and operations.

Summary
We understand each basin and play is different and unique above and below ground challenges will

need to be managed to successfully unlock unconventional reserves. For example, some of the Tertiary rift basin strata presents challenges with non-brittle shales and waxy oil. However, we see in the US unconventional plays exist across for a broad spectrum of ages, depositional environment and tectonic settings. It is not a stretch, in our opinion, to imagine if some of this region's prolific onshore basins were located in the US they would already be successfully producing significant unconventional oil and gas. The relatively high gas prices in the Asian region provide a strong incentive and the challenge for explorers is to focus on the most likely plays, build the database to identify the sweet spots, test the concepts and work cooperatively with financiers, governments, service providers and communities to commercially develop the resources.

Speaker Biography

Kim Morrison has a successful 30 year career involved in many oil and gas discoveries working in senior technical and managerial positions with majors (including Marathon, Shell and Woodside) through to small cap companies in locations throughout the world. He graduated from The University of Sydney in 1984 with an Honours degree in Geology and Geophysics and also holds a Diploma in Applied Finance and Investment from The Securities Institute of Australia. Kim co-founded KRX Energy in 2010 and in 2014 this became part of ASX listed Lion Energy where he is currently Chief Executive Officer. He has been instrumental in establishing a dual conventional/unconventional strategy for Lion in Indonesia and has built a significant unconventional foot print through applications focussing on the prolific Central and North Sumatra onshore basins. Kim is a member of the American Association of Petroleum Geologists, Petroleum Exploration Society of Australia and SEAPEX.