Tamboran's exploration and appraisal of the Velkerri shale unconventional gas play, Northern Territory, Australia

Donny Loughry[1,2]

Introduction

Following more than a decade of very low activity, the Beetaloo Basin's Velkerri shale unconventional gas play has gained much attention in recent years. Activity in the basin has never been higher, with multiple operators racing to deliver the first gas ever to be sold from the ~1.4-billion-year-old formation as early as this year. This indicates that the exploration phase is beginning to wind down, the appraisal phase is in full swing, and for some, pilot development is even occurring.

Tamboran's exploration and appraisal program is largely built on learnings from more than two decades of unconventional development in US shale resource plays such as the Marcellus, Eagle Ford, Wolfcamp and Barnett. Because of this, a legitimate claim can be made that, in many respects, exploration and appraisal in the Beetaloo Basin has far outpaced that of the US plays. For example, in the world-class Marcellus Shale play of the Appalachian Basin (**Figure 1**) there are currently more than 16 000 horizontal wells producing ~28 billion cubic feet of gas per day (BCF/d) from the shale (**Figure 1b** and **c**). However, prior to the onset of horizontal shale-drilling in the basin in 2007, more than 200 000 vertical well penetrations had occurred dating back to 1970 (**Figure 1a**), many of which intersected the Marcellus formation. Even with paradigm-shifting technological advancements like hydraulic fracture stimulation techniques, the first meaningful volume of gas (1 BCF/d) was not reached until 2011. Moreover, more than a thousand additional vertical wells were drilled and logged between 2007 and the present to evaluate the reservoir quality of the Marcellus Shale, and to make appraisal and development decisions. One could make the case that exploration and appraisal in the Marcellus Shale has been ongoing since before 2007.

In the Beetaloo Basin, Tamboran has benefited from intimate knowledge and experience in the US shale plays and has jumped the exploration and appraisal learning curve quickly, allowing a relatively fast progression from appraisal to pilot development. By leveraging this experience Loughry (2025) demonstrated how many early decisions can be made in a shale basin with comparatively far less data, so long as the information is of sufficient quality and type and is spatially distributed in a way that matches the scale of observation. For example, in the exploration and appraisal phase of a shale play, the scale of observation is necessarily at the basin level, as threshold properties used to define the play bounds vary most obviously at the basin scale of observation. Therefore, it is much better to have

[1] Tamboran Resources USA, Addison, Texas, USA
[2] Email: donny.loughry@tamboran.com

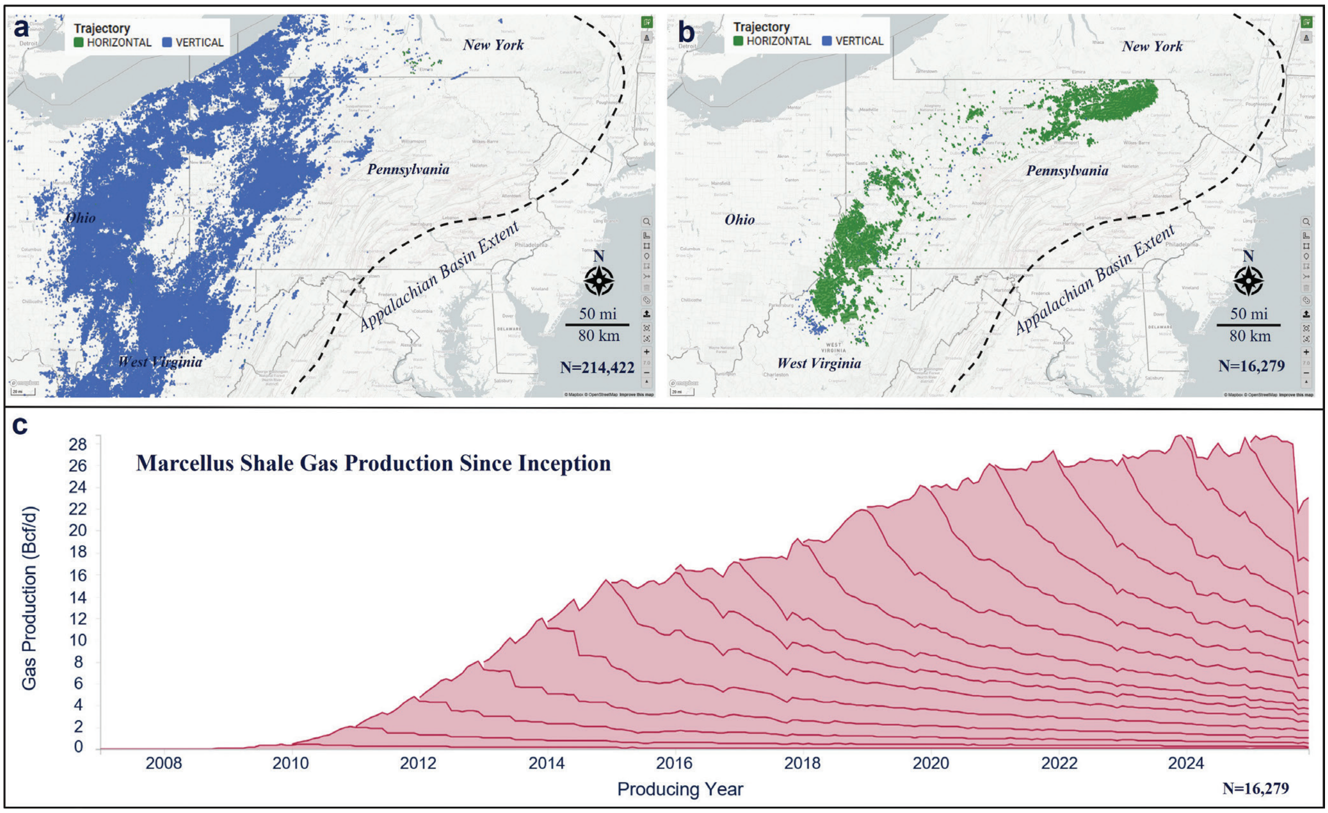

Figure 1. Spatial distribution of well development in the Appalachian Basin, USA. (**a**) Well development prior to horizontal development of the Marcellus Shale. (**b**) Present-day horizontal well development in the Marcellus Shale play. (**c**) Average daily production through the first 15 years.

even spatial sampling of the formation in question across the basin by fewer wells, than to have clustered and uneven sampling of the formation with more wells. **Figure 2** compares the spatial sampling of the Marcellus Shale and the Velkerri shale within their respective basins at the onset of appraisal for horizontal development. Even though there were more than 1500 wells intersecting the Marcellus Shale that could be used for shale evaluation (**Figure 2a**), very few well data points existed within what is now known to be the Core Areas for production. Because the shale was spatially under-sampled, it took additional years of drilling to identify the sweet spots for well performance (**Figure 2b**). Conversely, the even spatial sampling of the Velkerri shale in the Beetaloo Basin has allowed quick identification of likely production sweet spots (**Figure 2c**), confirmed by the above average well performance within the areas (**Figure 2d**).

Exploration and appraisal phases

As initial exploration and appraisal of unconventional resource plays necessarily require scoping at the basin scale of observation, it is important to acquire the proper datasets early. Not all datasets are equally important at this stage. **Figure 3** provides an indicative timeline for acquiring and integrating data types for shale plays. Importantly, open hole evaluation logs and core will be used early to define the play bounds and fairway (Loughry 2025) through the development and integration of a core-calibrated petrophysical model. Thus, acquiring these data types in pilot holes with proper sampling of the basin is imperative. Typically, one pilot hole having a robust suite of open hole logs per 100 km^2 is adequate during appraisal, as shale plays are continuous, and transitions in reservoir properties from one area to the next are gradual. Pilot hole logs, once integrated with existing or acquired 2D seismic datasets, allow for the generation of depth maps of key surfaces or intervals for planning additional appraisal locations. Well tests are necessary during the appraisal phase to calibrate well performance to mapped rock and reservoir properties. Pressure data is a critical dataset to collect at all appraisal sites, as it is a widely recognised primary driver of well performance. Diagnostic fracture injection tests (DFITs) and pressure build-up tests (PBUs) provide good estimates of the reservoir pressure within the formation. Since they are performed at different times (DFITs prior to well stimulation; PBUs during well testing), independent estimations can be integrated into a robust solution.

One of the peculiarities of unconventional shale plays is that the wells must be completed with a hydraulic fracture stimulation to create the necessary permeability pathways within the reservoir and back to the wellbore. In most plays, this is performed with proppant- or sand-laden water

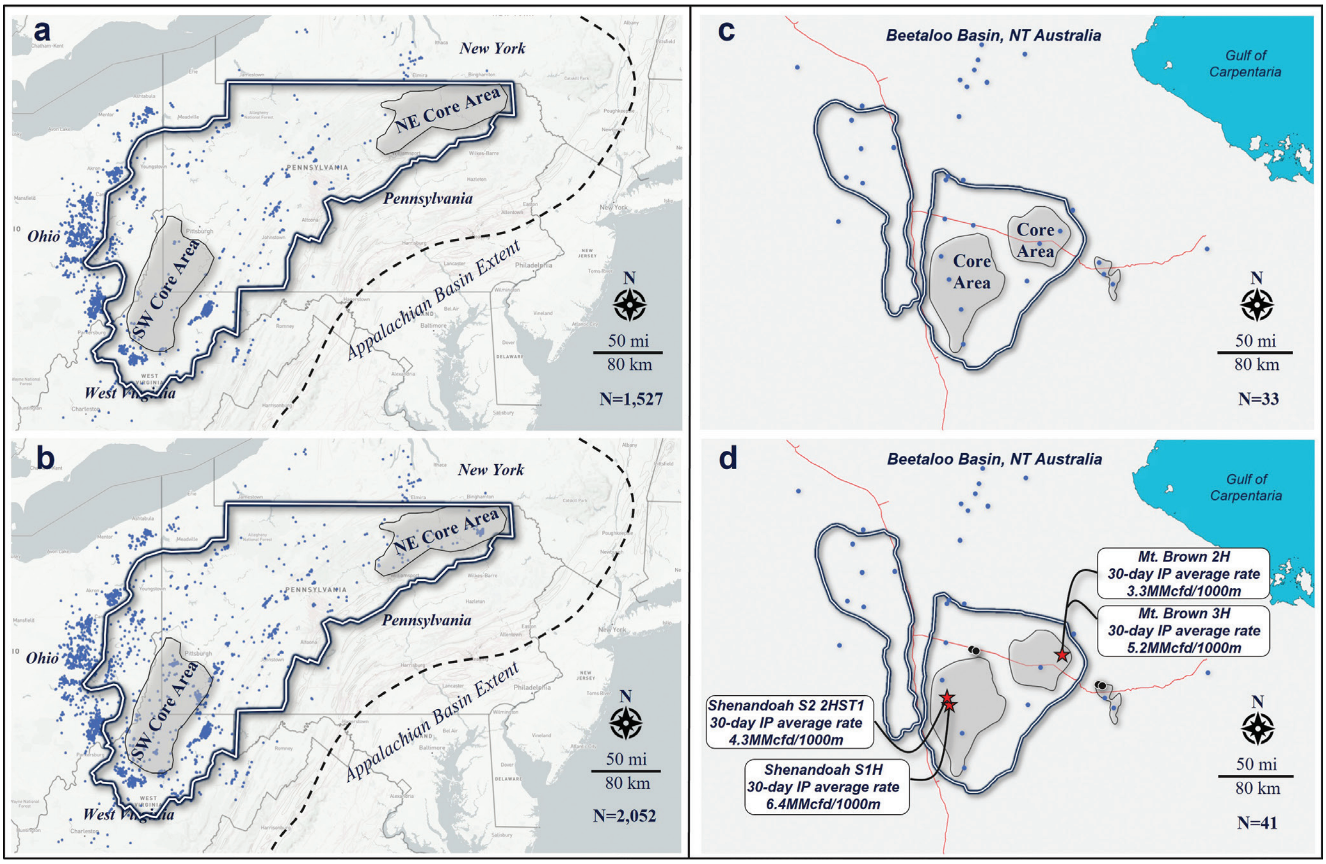

Figure 2. Spatial distribution of well evaluation data. (**a**) Marcellus Shale well control distribution at the onset of horizontal appraisal phase, ca 2007. (**b**) Same area at present day. Wells shown are vertical (blue dots), have total depths greater than 6000 ft, and contain the minimum log suite required for basic shale reservoir evaluation. (**c**) Velkerri shale present-day well control distribution showing comparatively better sampling of the emerging Core Areas of the play at onset of appraisal phase. (**d**) Four highest-rate horizontal well tests to date shown (red stars). Black dots are lower rate well tests outside the Core Areas. Well test data from ASX and NYSE announcements. MMcfd/1000 m = million cubic feet per day per 1000 m of completed lateral length. N = number of wells. USA map data source: Enverus PRISM® 2026.

at high enough pressures to generate a propped fracture network in the reservoir. Upon flowback of the well, some proportion of the water used for stimulation flows back to surface for treating and re-use. This is referred to as the 'clean-up' phase of flowback. The ease with which the well cleans up and produces at peak rate is directly related to the reservoir pressure, or energy, of the formation. The water column imparts a downward pressure at the bottom of the well, and the reservoir pressure imparts an upward pressure. The greater the fluid pressure difference at bottomhole, the easier it is for the well to clean up on its own, without the use of artificial lift systems. Since water is ubiquitously used for the stimulations across a given resource play, areas of higher reservoir pressure generally produce at higher rates than areas of lower reservoir pressure. These areas are the ones that eventually become known as Core Areas. By integrating the datatypes discussed above during appraisal, basin area trends emerge that help inform the location for future pilot development (**Figure 4**).

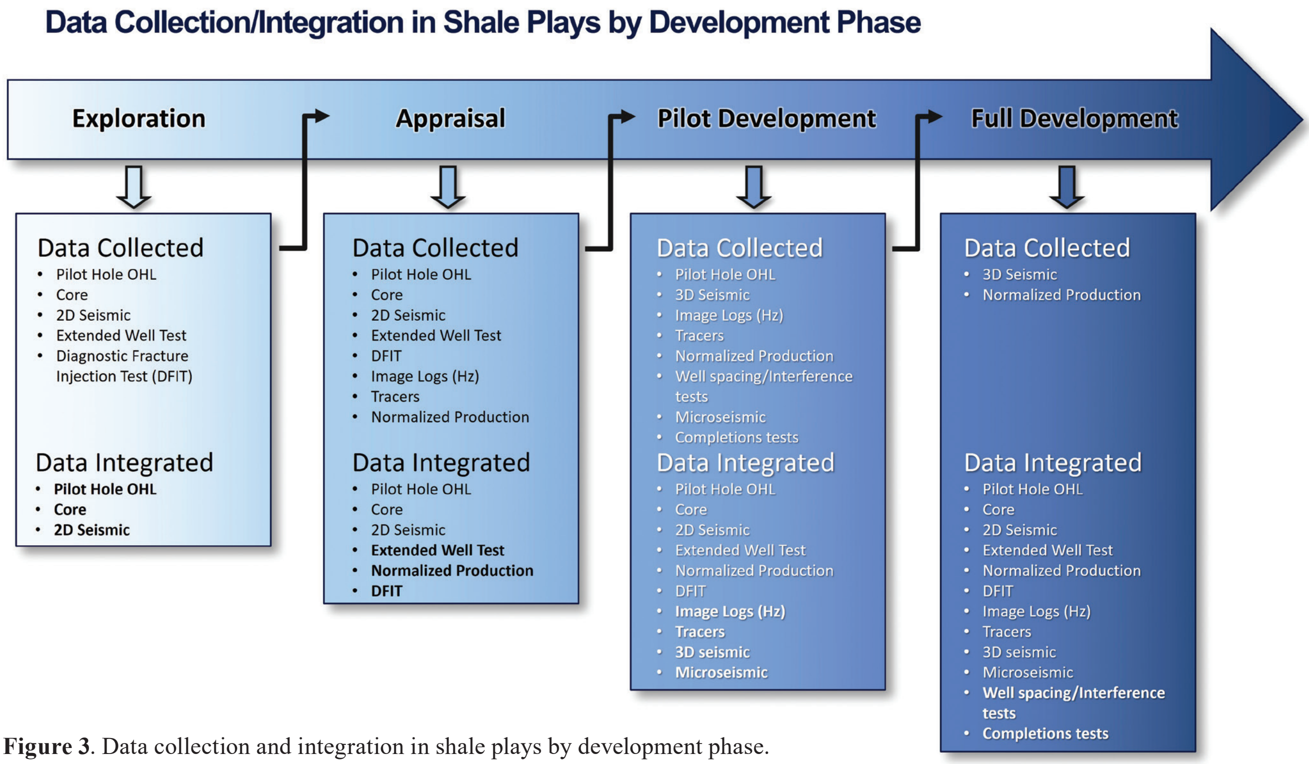

Figure 3. Data collection and integration in shale plays by development phase.

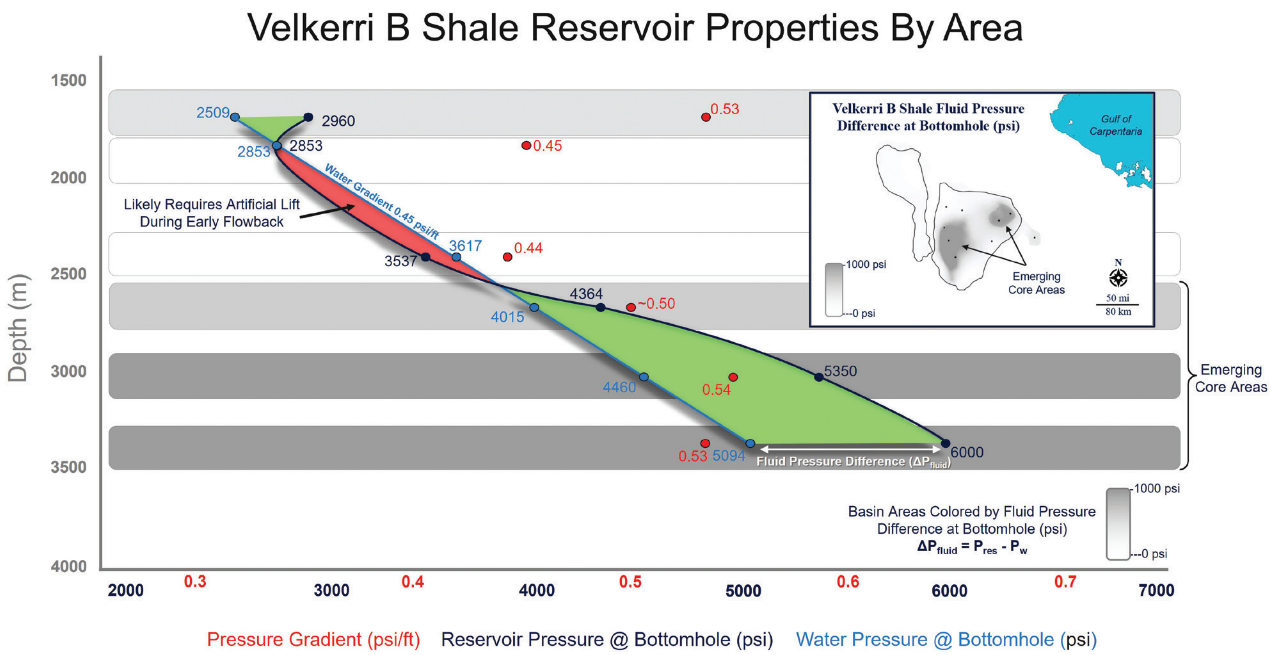

Figure 4. Velkerri B shale reservoir properties by basin area. Over-pressured conditions (green shading) relative to water gradient result in areas with well performance above basin average. Under-pressured or normally pressured conditions (red shading) result in areas that have lower well performance. Although still often commercial, early time flowback operations in these areas may require artificial lift during the clean-up phase. ΔP_{fluid} = fluid pressure difference at bottomhole conditions; P_{res} = reservoir pressure at bottomhole conditions; P_w = water pressure at bottomhole conditions.

Pilot and full development

As the pilot development phase begins and transitions to full development, new data types supplant earlier ones in importance. Earlier datasets will still be acquired as needed to fill data gaps, but the questions that need answered during these phases require more specialised information. These questions centre around well planning, field development, and well optimisation. Three-dimensional (3D) seismic datasets are necessary to identify drilling geohazards such as faults, karst collapse features, or shallow gas hazards during the planning phase. Microseismic fracture stimulation monitoring measures the small, sub-seismic scale acoustic cracks and pops of the formation during the stimulation and is integrated with a velocity model from a nearby pilot hole log suite to position the microseismic events in space relative to the wellbore location. This is one of the very few datasets that gives a direct measurement of hydraulic fracture geometries. These models, along with other reservoir engineering-based models of fracture geometry, are synthesised to inform well spacing distances within the area. Well spacing and well interference tests can then be performed to fine-tune the well spacing in each area to be applied to the full development plan. Completions tests will be performed to optimise the hydraulic fracture stimulation. Often, chemical tracers that bond with hydrocarbons or water are pumped in completions stages to obtain direct evidence of flow from a given stage for comparison to different hydraulic stimulation types. Finally, no dataset tells the story quite like production. The productivity of the wells in the area, properly normalised for lateral length, stimulation type and geology, gives the final feedback necessary to drive important field development decisions.

Acknowledgements

Acknowledgements to the Tamboran Resources exploration, drilling, and completions teams.

References

Enverus PRISM®, 2026. Available at <https://www.enverus.com/solutions/energy-analytics/ep/prism/> [accessed February 2026].

Loughry D, 2025. A hierarchical application of 20+ years of learnings from North American unconventional exploration and appraisal activities to delineate a 1MM-acre 'sweet spot' in the Beetaloo Basin shale gas play, Northern Territory, Australia. *Australian Energy Producers Journal* 65. doi:10.1071/EP24134