Cuadrilla

Hydraulic Fracture Plan PNR 1/1Z

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Version	Section	Revision Information	Date	Reviser
0.1	All	Draft Publication	17/7/2017	Senior Geoscientist
1-6	All	Consultation with Environment Agency		HSE&P Manager
7	All	Update to Fault Reactivation	18/6/2018	HSE&P Manager
8	All	Update Fracture Modelling	22/6/2018	Senior Geoscientist
9	All	Clarification on critical stress and modelling	27/6/2018	Senior Geoscientist

Documents are reviewed as per proposed review date, or sooner if a significant change to the operation has taken place, to ensure relevance to the systems and process that they define.

Contents

1.0 Well Classification

Well Name:	**Preston New Road-1z**
Operator:	Cuadrilla Bowland Ltd
License:	EXL269 (for site location), PEDL165 (for lateral well)
Partners:	PEDL165 Cuadrilla Resources Ltd – 51.25% Centrica- 25% AJ Lucas – 23.75%
	EXL269 Cuadrilla Resources Ltd – 50.1875%; Centrica – 22.75%, AJ Lucas 22.0625%, Warwick Energy - 5%
Lateral Length [TVD]	782 m [2273-2341 m TVD]
Surface Coordinates:	Northing 432749.50 m Easting 337433.54 m [BNG - OSGB36]
	Lat 53° 47' 14.2827" N Long 02° 57' 04.0278" W [WGS84]
TD Coordinates:	Northing 432550.41 m Easting 335715.91 m [BNG - OSGB36]
	Lat 2° 58' 37.7166" W Long 53° 47' 07.0870" N [WGS84]

2.0 Faulting

a Local Faulting

Name	**Type | Distance to nearest injection point**	**Dip | Strike | Throw**	**Slip Tendency | Coulomb Stress Change | Stage | S_H[°N]**
Moor Hey	Reverse | 1600m	53ºE | 041º | 730 m	0.48 | 0.0011MPa | 41 | 035
Anna's Road	Reverse | 750m	40ºE | 061º | 650 m	0.87 | 0.0052MPa | 41 | 145
Haves Ho	Reverse | 1400m	50ºE | 044º | 1700 m	0.54 | 0.0018MPa | 41 | 060
PNR-1	Reverse | 550m	60ºE | 019º | 200 m	0.80 | 0.0247MPa | 41 | 070
Fault-2	Reverse | 1400m	85ºE | 032º | 30 m	0.52 | 0.0082MPa | 41 | 145
Thistleton	Normal | 2400m	68ºE | 030º | 850 m	0.90 | 0.0005MPa | 41 | 060

b Fault Reactivation

Fault reactivation is split into two assessments, risk to groundwater/permit boundary compliance and risk of induced seismicity. Respectively the Environment Agency (EA) assess the risk to groundwater/permit boundary compliance and the Oil and Gas Authority (OGA) assess the risk of induced seismicity.

c Groundwater/ Permit Boundary Compliance

Our assessment of hydraulic fracturing causing fault reactivation leading to a pathway from the Bowland shale towards and intersecting a groundwater bearing unit has been previously assessed within the PNR Environment Statement (ES), chapter 11 Hydrogeology and Ground Gas [(17)]. While hydraulic fractures could potentially intersect existing faults at depth within the shale, there is a very low likelihood of S-P-R (Source, Pathway, Receptor) linkage for fracturing fluid propagating outside the permitted boundary to a groundwater bearing unit. This is due to the short-lived pressures associated with hydraulic fracturing not enabling an upward migration of fluids over a significant distance and the contrast in geomechanical properties between the Upper Bowland Shale and the overlying Millstone Grit. At the Preston New Road Site, the Millstone Grit overlies the Upper Bowland Shale. Observations in section t "Well Observation" identify the Millstone Grit to be absent at the PNR1 well pilot hole location, however 3D seismic data shows the Millstone Grit present vertically above the lateral well (PNR 1z). As the lateral well PNR1z is drilled into the Lower Bowland shale the Upper Bowland is present above this lateral providing a further barrier between this well and the Millstone Grit. Consequently the assessment of the risk has not altered the conclusions reached in the Environmental Statement (ES) and the associated mitigation measures remain consistent with the previous ES assessment. Furthermore the distances noted in section a "Local Faulting" and section g "Seismic Discontinuities" have been verified and updated on analysis of the lateral wellbore PNR 1z. Consequently a direct discharge of fracturing fluid into the Millstone Grit remains a very low likelihood based on this updated assessment.

Critically stressed faults will be remodelled and a progressive stepped approach adopted during the hydraulic fracturing operation, e.g. using mini-fractures and previous fracture stage information, to verify that the risk remains very low. Detailed fracture modelling to assess this risk is described in section 4.k. The modelling performed demonstrates that in no single case does fracturing fluid migrate outside the permitted boundary. The risk remains very low for fractures to extend beyond the permitted boundary.

d Induced Seismicity

Cuadrilla is anticipating that the horizontal well bore, or the area intended to be hydraulically stimulated, will encounter a number of small local faults(8) within the shale rock. For the purpose of this assessment it is assumed that all faults within the area are 'critically stressed'. This is a conservative assumption as in reality not all faults will be critically stressed. Modelling a conservative assumption (direct injection into a predicted or unpredicted critically stressed fault) and using 2000 m^3 injection stages the upper bound estimate for the maximum induced seismic event magnitude possible, in the absence of any mitigating measures, would be 3.1 M_L(7). The likelihood of this upper bound event occurring is considered to be very low(9). The assumptions of the model will be updated as detailed in section 7.0 "Verifications Updates" of this plan and continued to be adapted during the hydraulic fracturing phase, by utilizing information from mini-fractures and previous fracture stages, to inform the decision tree in Appendix 4. Furthermore the embedded mitigation outlined in Chapter 12 of the Environment Statement will significantly reduce the risk of induced seismic events occurring.

e Slip Tendency Analysis

The data collected through extended leak-off tests and image logging in the PNR1 and PNR1z wells allows for a re-interpretation of the stress field. The updated stress gradients at reservoir level (at approximately 2,300 m depth) are as follows:

Sh = 14 ppg = 0.0164 MPa/m

SH = 27 ppg = 0.0317 MPa/m

Sv = 21.5 ppg = 0.0252 MPa/m

Pore pressure = 11.23 ppg = 0.0132 MPa/m

The orientation of SH rotates with depth. At reservoir level an orientation of 141° N is used. Using these geomechanical inputs slip tendencies have been calculated for identified faults and seismic discontinuities. The interpretation of absolute ST values is not straightforward since the strength of faults is generally unknown. With the simplifying assumptions of a regional stress field without lateral variations and no variations of fault strength, ST values can be interpreted in a relative sense. I.e. faults with the largest ST values are interpreted as potentially being critically stressed, whereas those faults exhibiting smaller ST values are considered to be stable. Analysis for the nearby Preese Hall (PH_Max) fault, which has been seismically activated gives. A maximum slip tendency of ST=0.78 for this fault.

Comparing absolute ST values to the slip tendency obtained for the Preese Hall fault, the following faults are considered as (potentially) being critically stressed:

- SD3
- Thistleton Max fault

- Anna's Road fault
- PNR max
- SD5
- SD6.

Additionally, SD1 and SD4 exhibit slip tendency values ≥ 0.7 corresponding to near-critical stress conditions when compared to the Preese Hall fault. The stress impact of the fracturing operations on the slip tendencies is calculated while systematically varying the orientation of SH between 25°N to 145°N in steps of 5°. The slip tendencies provided in this document are the worst case result from this SH variation. A significant increase of the ST value is obtained for the SD3 fault only. Due to potential fracture intersection, significant stress changes also occur on Fault SD5. These can be addressed with the extreme case simulations outlined in section d Induced seismicity.

f Coulomb Stress Change Analysis

Coulomb stress changes (DCS) associated with the planned hydraulic fracturing operations have been numerically simulated. For each fracturing stage, cumulative stress contributions from all previous stages were considered. Fracture models were simulated with a frack opening width of 40 mm(3). These simulations are repeated accounting for the modified stage locations and the refined fault trajectories. Orientation of SH which is varied between 25°N to 145°N in steps of 5°. The resulting maximum DCS values per fault and fracturing stage are presented within the fault and seismic discontinuities tables as the worst case result. The level of 0.1 MPa is considered to be a lower limit below which demonstrates that triggering of seismic events is considered unlikely. Simulated Coulomb stress changes (DCS) are presented for each fault and fracturing stage separately. For each fracturing stage, a single DCS value is provided, which refers to the 10 m x 10 m fault patch with the largest DCS. In all cases, the maximum DCS value is provided in the figure title together with the associated stage number and stress field orientation.

g Seismic Discontinuities

	Type | Distance to nearest injection point	**Dip | Strike | Throw**	**Slip Tendency | Coulomb Stress Change | Stage | S_H[ºN]**
SD1	Reverse | 850m	53ºE | 021º | 30 m	0.7 | 0.0084MPa | 41 | 085
SD2	Reverse | 800m	73ºE | 070º | 40 m	0.65 | 0.0092MPa | 40 | 025
SD3	Normal | 200m	75ºE | 150º | 25 m	0.96 | 56.248MPa | 41 | 145
SD4	Reverse | 300m	42ºE | 033º | 25 m	0.76 | 0.0868MPa | 1 | 125
SD5	Reverse | 100m	50ºE | 022º | 20 m	0.79 | NA |NA | NA
SD6	Normal | 500m	67ºE | 030º | 60 m	0.79 | 0.0707MPa | 5 | 135

Note: Although the SD3 feature is laterally adjacent it has not been observed in wellbore (Appendix 1).

The nearest seismic expression of SD3 is 200m from the nearest injection point. The model predicted a large DCS due to the input assumption of a direct injection into SD3 where the fracture directly intersects with this feature. This is modelled as a worst case scenario where no embedded mitigation measures are employed. However in practice the real time microseismic will be used to monitor fracture growth relative to the SD3 feature. If microseismic data indicates direct injection into the SD3, and that the SD3 feature does indeed appear to be a fault, then pumping operations will be modified to reduce the likelihood of further connectivity with SD3. Any noticeable seismicity risks will be further mitigated using the traffic light system.

h PNR1z Wellbore Identified Faults / Soft Sedimentary Structures

	Type / Distance along Wellbore MDRT	Dip | Throw	Slip Tendency | Coulomb Stress Change | Stage | S_H[°N]
1	NA | 2906 m	NA	NA
2	NA | 2958 m	NA	NA
3	NA | 3255 m	NA	NA
4	NA | 3363 m	NA	NA
5	NA | 3400 m	NA	NA

During drilling of the PNR well, five minor but identifiable structural changes were observed. These structural changes are identified using an azimuthal gamma tool that allows bedding dip to be estimated. It cannot be conclusively determined whether these structural changes shown by bedding dip changes are a result of soft sedimentary deformation, which is frequently observed in the PNR1 core or small scale faults. These structures intersected were too small to be resolved in the 3D seismic data. Orientation and extension of these structures are only loosely constrained by the depth in which they were observed. Therefore, these structures are not included in the specific sensitivity analysis due to the lack of analytical description available and instead are addressed with the extreme case simulations outlined in section d Induced seismicity. The structures are located between the fracturing stages and will most likely be intersected by a hydraulic fracture. However given the small dimension of these structures it is considered very unlikely that these structures could respond with noticeable induced seismicity.

i Fault Criticality Conclusions

This sensitivity analysis indicates that Coulomb stress changes due to the fracturing operations are in general extremely small (i.e. < 0.1 MPa), in particular all significant faults which can clearly be identified in seismic sections. Significant Coulomb stress changes are obtained only for the small fault-like structures SD3 and SD5. These structures are located in the immediate vicinity of hydraulic fractures and large Coulomb stress changes occur locally where the fractures reach or intersect the small fault structures. The worst case scenario modelling indicates that the highest DCS is associated with stage 41. This is due to stage 41 being the final injection stage in the well and the DCS calculations being modelled from the cumulative impact of all 41 stages. In reality stress build up will be dynamic, with stress redistributing in other areas or released through flow back between fracture stages, and not the static cumulative stress increase as modelled. However using a stepped progressive approach Cuadrilla will monitor any activity on features such as SD3 and SD5 and alter pumping operation accordingly to reduce the likelihood of stress build up occurring on these features. If these structures are truly faults then they will almost certainly slip in the course of the fracturing operations. However, given the small dimension of these structures and assuming that they are at least partially healed, we consider it unlikely that these structures will respond with noticeable seismicity. We also conclude these small structures pose a low risk of providing pathways for fluid migration outside of the permitted boundary due to their limited size and constraint. The same applies to the small fault-like structures intersected during drilling. In addition to the critical stress modelling demonstrating a low risk to fracture or fault growth outside the permitted boundary a number of mitigation measures will be employed while fracturing operations take place to further reduce this already low risk. These mitigation measures are detailed in section q "Permit boundary / Microseismic monitoring".

j Background Seismicity Results & Interpretation

A baseline of twelve months (Jan 2015 to Dec 2015) monitoring via 7 broadband seismometers has been conducted. No seismicity (events) were detected within the permitted boundary (19 events from 0.7-4.2 M_L were detected outside the permitted boundary with the nearest event at 36 km) and the data was provided to the British Geological Survey (BGS)[(2)].

In general, noise sources include mainly two types: instrument intrinsic noise and ambient or seismic noise. Seismic noise sources are often located at the surface of the Earth and caused by human-related activities such as traffic, factories, hydraulic treatment related noise, etc. and natural sources like wind, rain, water or waves. No current mining related noise activities have been identified in proximity to PNR activities, although the Lancashire coal fields and offshore East Irish Sea oil & gas production may provide background seismicity. This will be reported if occurring during the monitoring period. Below 10 Hz there is the Low noise and High noise models derived from broadband seismometers (Abercrombie & Leary, 1993)(16), so expectation is that background seismic noise level will fall between these two bounds. Above 10 Hz there is a fairly steep drop-off in terms of sensitivity of broadband instruments (seismometers) so geophones will likely be more sensitive. The above local noise sources are distinguishable from coherent downhole events with specific move-out. Noise reduction is achieved by applying pre-processing schemes such as predictive and adaptive filtering, stacking, and digital grouping/beamforming. For buried shallow-hole monitoring, noise is highly correlated with the pumping operations. Geophysical processes are able to distinguish coherent downhole events with a specific move-out from other coherent (or not) surface/cultural events.

3.0 Previous & Planned Operations

	Elswick-1	**Preese Hall-1**	**Preston New Road-1z**
Well Type	Vertical	Vertical	Horizontal
Fluid Type	Gelled-water with CO_2	Slickwater	Slickwater
Stages	1	5	Up to 41
Hydraulic Fracturing Fluid Volume per Stage	163 m^3 water 24.3 t CO_2	Maximum 2339 m^3	Up to 765 m^3
Proppant weight per Stage	58.5 t	Maximum 116.6 t	Up to 75 t
Seismic Monitoring		National BGS Network (10)	National & Local BGS Network Local real-time 8 station array Real-time downhole microseismic monitoring array
Pre Operational Investigations	2D Seismic Interpretation	2D Seismic Interpretation	3D Seismic Interpretation(11) Geomechanical study(3)
Historic Seismicity	None noted	1.5 & 2.3 (M_L) Induced (10)(4)	No events were recorded within the operational boundary during 12 months monitoring(2)

4.0 Proposed Injection Design & Fracture Modelling

	Including Slickwater | Sliding sleeve | Coil tubing
Injection / Stage	Up to 765 m^3 (Schedule 3 Table S3.2 EPR/AB3101MW)(5)
Proppant/ Stage	Up to 75 t proppant per stage | 100 mesh Congleton sand and 30/50 mesh Chelford sand(6)
Additives	Polyacrylamide based friction reducer (maximum concentration 0.05%) | <10% HCl up to 3 m^3 per stage| UV in event of reuse | (As required in Schedule 1 A5 (EPR/AB3101MW)(5)
Estimated Pumping Pressure / Rate	Surface 51.7 Mpa [7500 psi] - 3.6 m^3/minute

Maximum Pumping Pressure / Rate	Surface 65.5 Mpa [9500 psi] - 6.375 m^3/minute (Schedule 3 Table S3.2 (EPR/AB3101MW)) (5)
Wellbore Deviation Plan / Injection Points	See Appendix 3

k Fracture Modelling

Following completing drilling of PNR1z a static geomodel was constructed, combining seismic interpretation, well picks and azimuthal gamma driven interpretation. This geomodel comprised 12 horizons bisected by major reverse faults, segmenting the model into fault blocks. A Discrete Fracture Network (DFN) was created with 5 fracture sets representing the structures observed in PNR1z by the azimuthal gamma and bedding dip changes. These 5 fracture models were run at sleeve locations; 1, 8, 11, 27 and 41. They were chosen based on their representation of a section of similar geomechanical facies along the lateral and proximity observed structures. As such they represent the worst case scenario of direct injection into a structure which could be a sub seismic resolution fault providing the highest likelihood of creating a pathway for fracturing fluid outside of the permitted boundary.

The model was populated by combining fracture directions and intensity taken from borehole image interpretation in the PNR-1 pilot well, and combined with a “Distance to Fault” fracture driver. Geomechanical parameters including static rock moduli, formation pressure, and local tectonic stress field outlined within this document provided boundary condition into this model. They determine the critical well pressures required to initiate hydraulic fractures and they control the fracture growth.

The geomechanical model for the Bowland Shale formation was built by first estimating mechanical properties, pressures, and stress profiles near the pilot hole PNR-1, using the wireline logs acquired in that well. The properties were extrapolated along the stratigraphic horizons in the static geomodel. The fracture geometry (hydraulic height, width and length) is controlled by the geomechanical inputs (such as Young’s modulus, minimum stress/stress contrast, Poisson ratio, rock toughness), fluid leak-off and formation parameters (permeability, porosity, reservoir pressure) and imposed conditions such as fluid type, sand concentration and pump rate.

To estimate the magnitude and direction of the in-situ stress field and its variations within the Bowland formation, a numerical simulation approach was adopted. The results capture the natural stress variations that are associated with the suspected fault zones. Fracture simulation modelling for DFN scenarios was carried out using a Schlumberger proprietary modelling software, called Kinetix®. Fracture models were performed at the maximum allowable injection volume (765m^3) at the 5 sleeve locations aforementioned (1, 8, 11, 27 and 41). The Fracture models were performed 3 separate times to provide a sensitivity of fracture growth to the density of natural fracture within the matrix. At all 5 sleeve locations modelled with the 3 sensitivities to natural fracturing not one modelled fracture provided a pathway for fluid migration outside of the permitted boundary. In all cases the modelled fracture remained within the permitted boundary. Therefore the risk of creating a pathway for fluid migration outside the permitted boundary is considered very low. Additional mitigation measures detailed in section q will provide a real time ability to further reduce the risk of fracturing fluid travelling outside the permitted boundary. Fracture metrics can be found in the table below and graphics in appendix 5.

Kinetix 3D fracture simulation model of high density DFN based on PNR1z geology

Stage	Propped Width (mm)	Avg Fracture Height (m)	Avg Fracture Half Length (m)
1	227	154	64
8	95	66	211
11	367	55	193
27	232	44	189
41	310	25	313

5.0 Mitigation Methods and Monitoring

Including Traffic Light System (TLS) | Microseismic | Vibration			
Traffic Light System (TLS)	8 real-time seismometers installed[12]	Combination of broadband seismometers and 4.5 Hz, 3 component geophones. Minimum of 6 required for operational TLS[14]	Estimated detectability -0.5 (M_L), accuracy 300 m (X,Y) 300 m (Z) at estimated injection depth. Note microseismic array is the primary hypocenter monitoring array, not TLS. Estimate of location accuracy, including parameters, will be made available to the EA on request
TLS Monitoring Duration	Continuous real-time monitored 4 weeks before and 2 weeks after injection operations. During operations (24 hours)[12]. Real-time automatic event detection alert (SMS) and display online (seismic focal point web portal) within 60 secs. Manual re-processing (download data, load to software, manually pick and process) within 20 mins of alert (depends on multiple factors including event rate, noise level, event location, magnitude).		
TLS Array Location	Instruments installed in an array from 1.0 km to 3.9 km from the site and have been independently assessed as to quantity, location and redundancy [12].		
TLS Decision Tree	See Appendix 4		
Vibration Monitoring System	Minimum of 4 peak particle velocity (PPV) monitors active in addition to PPV data from 8 TLS stations		
Vibration Monitoring Duration	Monitored before and after operations (2 weeks). During operations (24 hours)		
Vibration Monitoring Decision tree	See Appendix 4		
Operational Boundary	Within the areal extent of the TLS, see appendix 3		
Microseismic Array & Fracture Mapping			

Real-Time Downhole Microseismic Monitoring Array with downhole recording within 5 minutes and all events displayed for validation. 12 slim hole, 3 component, 15 Hz Geophones.	Estimated detectability based on a simulation model given by the Contractor is given in the HFP, Velocity modelling for this estimate was based on Preese Hall logs tied to PNR-1z. Modelled assumptions are; • P picking error: +- 2 ms • S picking error: +- 4 ms • P azimuth error: +- 10 deg • S azimuth error: +- 16 deg • Noise Level: 1E-5 m/s2 • Qp = Qs = 100 Geophones will be verified once in downhole location. Loss in detection efficiency is not expected as long as the number of working shuttles in the array remains between 8 and 12 depending on array aperture. In the event of a loss in detection efficiency backup tools will be used to rectify loss and operations paused until efficiency is restored i.e. greater than or equal to 8 working shuttles. However there are potential scenarios where less than 8 working shuttles can still provide accurate data, however this will be agreed with the EA and can only be demonstrated once the array is downhole.	Estimated detectability -1.8 (M_L), accuracy 37.5 m (X,Y) 37.5 m (Z) at the toe of the well. Multiple pre-acquisition models were built for microseismic monitoring. Estimation of event detection is described in Raymer & Leslie 2011(15). These utilize Preese Hall well recorded velocity, sonic & density data and consider the planned PNR1z, PNR2 well profiles. The 37.5 m accuracy is a threshold, rather than a specific value. Microseismic monitoring will be able to detect fractures within the target reservoir and also into overlying strata. Modelling has been conducted to provide confidence of the detectability within the target formation to the depths of up to 1800m. With regard to the azimuth errors, these are estimations of the azimuth accuracy for each tool, and not final computed back azimuth accuracies. Estimate of location accuracy, including parameters, will be made available to the EA on request.

l Assumption Checking

Cuadrilla will, in collaboration with the appointed contractor, verify the velocity model using the furthest available downhole source from the array stations. See section 7.0 Verification Updates for model updates. If an identifiable seismic event is not recorded from an energy source, other means such as vertical stacking of successive records from repeat firing will be employed until an event is identifiable, or an alternate energy source will be considered. Assessment of the background noise will be performed at the beginning of data acquisition to fine tune the triggers and detection parameters assumed during modelling. In the event of significant decrease events detection during the job, a re-assessment of the background noise will be performed and a re-assessment of detection sensitivity and accuracy will be carried out.

m Microseismic Duration

Real-time monitoring throughout pumping operations with a minimum of 1 hour after the pumping operation unless agreed otherwise in writing with the EA.

n Operational Boundary

Within the areal extent of the TLS as per Appendix 3, the operational boundary is greater than the red line boundary as outlined within the Permit EPRAB3101MW. The purpose of the operational boundary is to provide a limit of detection for seismic events which can be detected to a high degree of certainty.

o Assurance

Microseismic monitoring will be installed and executed by a competent contractor specialising in microseismic monitoring. The contractor will follow its own quality assurance procedures for calibration and data gathering. A series of energy sources will be utilised to calibrate microseismic equipment. Any loss of geophone signal will be reported to contractor and subsequently rectified via their internal procedure as per section 5.0. If signals are lost from a sufficient number of stations such that the monitoring array is no longer able to perform as designed, then operations must be paused until real-time signals are re-established.

Contractors equipment will be checked on site before entering the well bore and again once in position using a downhole energy source. The energy source will confirm calibration and effectiveness of geophones. The contractor will conduct the calibration of downhole geophones in accordance with their procedure. Ray tracing is performed to compare the modelled travel time with the measured travel time. Interactive and automated model inversion methods provides a velocity model calibration.

An assessment of the array's effectiveness to monitor hydraulic fracturing operations will be conducted before pumping takes place. Waveforms will be monitored to further verify no tool string movement, which manifest as high amplitude noise across all channels. The waveforms will be used to assure and monitor the array operability. The individual sondes include a high side indicator sensor which measures the inclination and roll to verify non movement of sondes. A data acquisition system provides a series of indicators about the health of each downhole tool. High levels of background noise received downhole will reduce the signal to noise ratio and affect the location accuracy of detected events and detection threshold level. However multiple standard and proprietary geophysical processes which are used, subject to the specific noise filters, are able to distinguish coherent downhole events with a specific move out from other coherent (or not) surface/cultural events. These standard processes will be utilised in real-time and subsequently proprietary methodologies will be utilised after the events.

Elevated background noise will not lead to false event triggers. In the event of significant decrease of events detection during the pumping operation, a re-assessment of the background noise will be performed and a re-assessment of detection sensitivity will be carried out within the limits of detection.

p Microseismic Monitoring / Induced Seismicity Mitigation

The HFP applies an evolutionary approach, as described in the PNR ES Chapter 12[(9)], to risk assessment and mitigation (operational mitigation)[(9)]. This stepped progressive approach to hydraulic fracturing will consist of an initial mini-fracture stage and modest initial pumped volumes, building up to a maximum pump volume of 765 m^3 per stage. As this staged pumping process continues, an understanding of the performance of the reservoir during hydraulic fracturing is developed by;

1) Monitoring the extent of fracture growth using a real-time downhole microseismic array. If, during hydraulic fracturing, monitoring data indicates possible fault interactions with a preferential flow pathway, the pumping of fracturing fluid would be adjusted or terminated and the pumping schedule would be modified as necessary.

2) Implementation of the TLS. As long as the induced seismicity is <0.0 M_L (Green level) while pumping, operations will continue. If an induced seismicity event occurs in the range of ≥0 M_L to <0.5 M_L (Amber level) while pumping, the fracture stage can be completed. On completion of the injection the flowback procedure will be initiated. Pumping may then proceed with caution, possibly at reduced parameters. If an event occurs that is ≥0.5 M_L (Red level) while pumping, the fracture stage will be aborted and the flush and flowback procedure will

be initiated. Should seismicity occur at or above the red 0.5 M_L level then a vibration monitoring array will be utilised to assess the impact in accordance with BS7358-2. The measurement recorded by the vibration monitoring array and the TLS will then be used to assess the calibration of the ground motion prediction model(13) and amendments applied if required.

Cuadrilla is anticipating that the horizontal well bore, or the area intended to be hydraulically stimulated, will encounter a number of small local faults(8). Modelling a conservative assumption (direct injection into a predicted or unpredicted critically stressed fault) and using 2000 m^3 stages the upper bound estimate for maximum magnitude possible would be 3.1 M_L(7), which is considered to be a very low likelihood(9).

If surface vibration occurs in excess of 15 mm/s PPV (as referenced in BS7358-2) due to injection operations, which is assessed to be a very low likelihood, then future injection operations will be altered to mitigate below the PPV 15 mm/s level by adjusting fluid volume, rate, pressure, and or injection point. Where possible, TLS data will be co-processed with any available BGS data, event magnitude determination will be calculated using the BGS methodology. A trailing event with magnitude >0.5 M_L will require a well integrity check be performed and reported in the same manner as those events detected while pumping is taking place.

Fracture stages will be positioned or altered based on the knowledge of any disturbances identified in the microseismic monitoring, drilling and logging observations and from data acquired from previous frac stages, using the stepped progressive approach described in order to avoid direct injection into a significant fault. The plan to place a microseismic array in the build section of the well provides sufficient detectability and location accuracy. The final location will be confirmed to the EA when installed.

Utilising the frac sleeves and monitoring in the lateral is not standard operating procedure. Due to the internal profile of the frac sleeve, i.e. not being smooth, pushing the array along the frac sleeves runs the risk of it getting stuck or damaged along the lateral. If at any stage, not just the pumping phase, there is a loss of well integrity after a seismic event which poses a risk of fluid migration to groundwater we will stop activities and take action to maintain integrity of the well and contact the regulators without delay.

q Permit Boundary / Microseismic Monitoring

An evolutionary process as described in the PNR ES Chapter 12(9) will be employed to understand the performance of the reservoir during fracturing. This stepped progressive approach to hydraulic fracturing will consist of an initial mini-fracture stage and modest initial pumped volumes building up to a maximum pump volume of 765 m^3 per stage. As this process continues, an understanding of the performance of the reservoir during hydraulic fracturing is developed by monitoring the extent of fracture growth using a real-time downhole microseismic array.

If, during hydraulic fracturing, monitoring data indicate possible fracture growth with a preferential flow pathway towards the edge of the permitted boundary, the pumping of fracturing fluid would be adjusted or terminated and the injection programme would be adjusted as necessary to prevent future occurrences. If fracture fluid is interpreted to be outside of the permitted boundary injection will stop after flushing the well. If significant microseismicity continues to occur after the end of injection, then real-time monitoring will continue until it is clear that fractures are not extending beyond the permitted boundary. Future injection operations will be altered to comply with the permitted boundary by adjusting fluid volume, rate, pressure, and or injection point.

The operational boundary is greater than the red line boundary as outlined within the Permit EPRAB3101MW. The purpose of the operational boundary is to provide a limit of detection for seismic events which can be detected to a high degree of certainty. If significant events or cluster of seismic events occur outside the Permit boundary they will be detectable by Cuadrilla's monitoring inside the operational boundary. Any seismic events occurring outside of the operational boundary will be assumed to have a natural provenance except where there is a clear geomechanical link to faults, fractures or seismic event clusters within the operational boundary. The use of microseismic monitoring will track fracture height growth and length to monitor any relationship with seismicity outside the permitted boundary.

r Groundwater Monitoring

The Waste Management Plan (HSE-Permit-INS-PNR-006) details groundwater monitoring approach and protection measures. Further details have been submitted and approved in PO4 and PO7 which provides groundwater borehole installation and monitoring. The frequency of monitoring is outlined within the Permit EPR/ AB3101MW.

6.0 Reporting

TLS status will be reported in a timely manner on the Cuadrilla e-portal. TLS real-time automatic event detection alerts (SMS) and an online display are within 60 secs of an event. Manual re-processing (involving downloading data, loading, manually pick and processing) provided within 20 mins of an alert (depends on multiple factors including event rate, noise level, event location, magnitude). For the Downhole array all events will be displayed within 5 minutes. Other requirements will be reported to the EA upon request, e.g. geomechanical modelling parameters, including updates post drilling phase.

Morning Report	Post Frac Reporting
• Submitted daily during fracturing operations. • Injection depth, pumping chart, volumes and type of water, proppant, chemicals pumped. • Well integrity status. • Schematic of fracture growth, including the location, orientation and extent of the induced fractures, in relation to permitted boundary. • Associated seismic event location data after an event that dots are initially indicated to be outside of the sub surface permit boundary. This will be provided in a diagrammatic drawing. • Proposed mitigation measures, if required. • Induced seismicity of note. • Fracture modelling will be updated as new geomechanical data is acquired. • On completion of the initial mini-fracture Cuadrilla will provide stress magnitude.	• Hypocentre location data to be provided upon request to the EA. • End of Well Report as per PON9b+B61 • Quarterly report as per S4.1 (EPR/AB3101MW) • Microseismic data and geophysical data will be made available to the EA upon request

s Seismic Level Requiring Integrity Check & Reporting

If at any stage, not just the pumping phase, there is a loss of well integrity after a seismic event which poses a risk of fluid migration to groundwater we will stop activities and take action to maintain integrity of the well and contact the regulators without delay.

7.0 Verification Updates

The verification reports will be provided to the EA, OGA and HSE as required by their regulatory responsibility as soon as reasonably practicable or a minimum 3 weeks before the start of hydraulic fracturing and will continue to be updated during the hydraulic fracturing process.

t Well Observations

At the location of PNR 1 pilot hole the stratigraphic sequence went from Permian Collyhurst Sandstone directly into the Carboniferous Upper Bowland Shale. This boundary is at the angular unconformity known as the Variscan unconformity. The absence of Millstone Grit at this location is due to a high angle reverse fault pushing and folding the Upper Bowland higher than the surrounding structure and end Carboniferous erosional surface coming into contact with the Upper Bowland. Subsequently the red line permit boundary has been pushed upwards to approximately 1300/1400 m. Away from the PNR 1 pilot location and above the PNR 1z well, seismic evidence demonstrates the presence of Millstone Grit and thus does not affect the red line boundary (see Appendix 3). The subsequent observation has not changed the risk assessment or approach to hydraulic fracturing within the boundaries already established in EPR AB3101MW. The observations have been documented with an updated Appendix 2 cross section.

u Microseismic Model Update

Velocity models have been updated with application of data obtained from the already run sonic and density logs and from Vertical Seismic Profile (VSP) data. The operational plan is to use a downhole calibration energy source to update the velocity model. This model will include an estimate of the detectability magnitude at the furthest hydraulic fracture stage from the array. Best endeavours, i.e. moving the energy source as far into the lateral as possible without compromising the well integrity or potential to have equipment stuck downhole, will be made to get actual data to verify the velocity model at the furthest fracture stage from the array prior to hydraulic fracturing commencing.

8.0 Abbreviations

BGS	British Geological Survey
DFN	discrete fracture network
HD	high density
EA	Environment Agency
EMW	equivalent mud weight
ES	environment statement
ft	feet
HCl	hydrochloric acid
Km	kilometres
Lat	Latitude
Long	Longitude
m	metres
m^3	cubic metres
MD	measured depth
M_L	local magnitude scale
mm/sec	milimetres per second
Mpa	megapascals
OGA	Oil and Gas Authority
PH	Preese Hall
PNR	Preston New Road
ppg	pounds per gallon
PPV	peak particle velocity
psi	pounds per square inch
SG	specific gravity
SHmax	maximum horizontal stress
Shmin	minimum horizontal stress
t	tonnes
TD	total depth
TLS	traffic light system
TVD	true vertical depth

9.0 References / Related Documents

1: PNR Environmental Statement - Appendix L Fig. 12

2: http://www.bgs.ac.uk/research/groundwater/shaleGas/monitoring/seismicity.html

3: de Pater, H. & Baisch, S. 2011. Geomechanical Study of Bowland Shale Seismicity, Synthesis Report

4: Clarke, H., Eisner, L., Styles, P. and Turner, P. 2014. Felt seismicity associated with shale gas hydraulic fracturing: The first documented example in Europe, Geophysics. Res. Lett., 41, 23, 8308-8314.

5: Preston New Road Exploration Site Permit numbers EPR/AB3101MW

6: PNR Environmental Statement - Appendix B7

7: de Pater, C.J. & Baisch, S., 2011. Geomechanical Study of Bowland Shale Seismicity. Synthesis Report. For Cuadrilla Resources Ltd. 57pp. - Section 6.

8: PNR Environmental Statement - Chapter 12, para156

9: PNR Environmental Statement - Chapter 12, Summary

10: http://earthquakes.bgs.ac.uk/research/earthquake_hazard_shale_gas.html

11: PNR Environmental Statement - Appendix L10.2.2

12: PNR Environmental Statement - Appendix L10.7

13: PNR Environmental Statement - Appendix L8.3

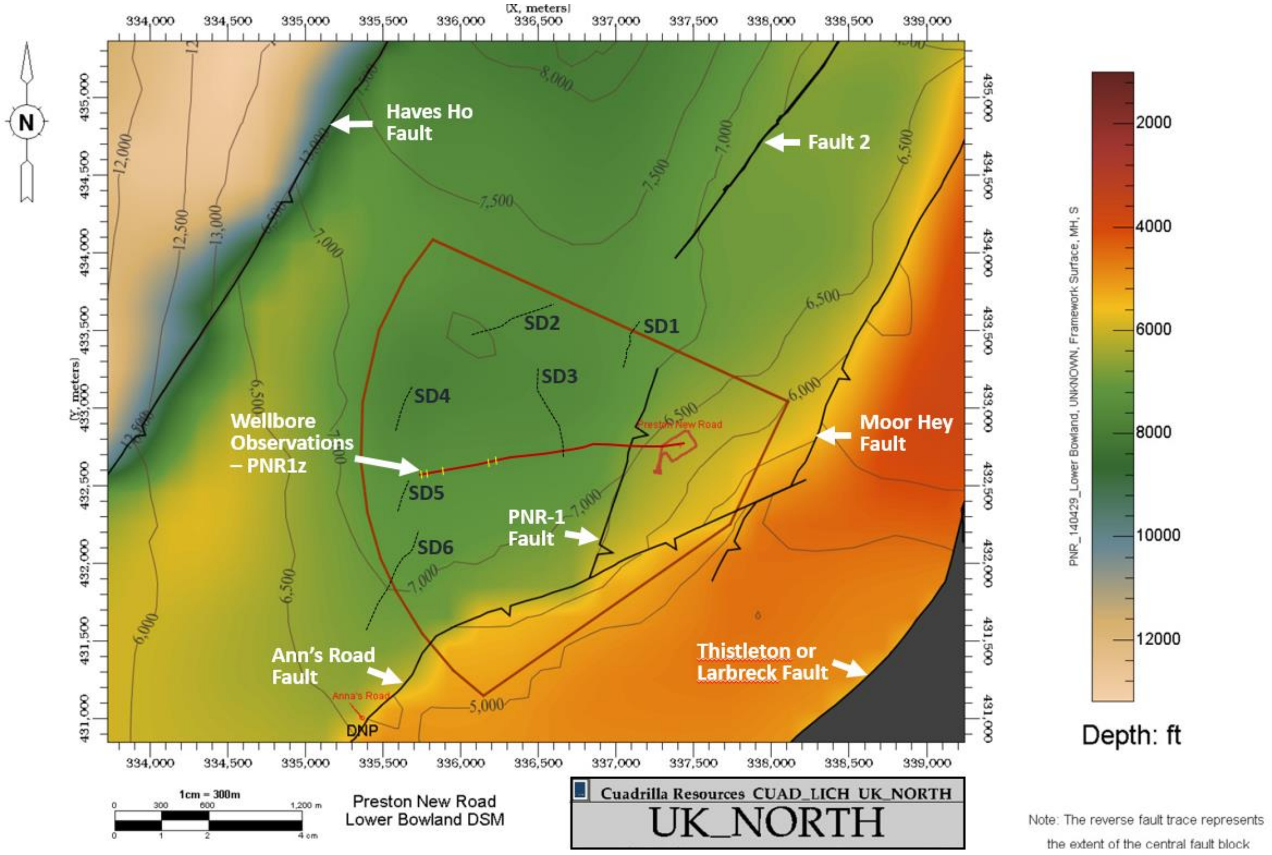
14: PNR Environmental Statement - Appendix L10.8.01

15: D.G.Raymer, H.D.Leslie, 2011. Microseismic Design & Case Studies. SPE, EAGE

16: R. Abercrombie, P Leary. 1993 Source parameters of small earthquakes recorded at 2.5km depth, Cajon Pass, southern California: Implications for earthquake scaling. Geophysics. Res. Lett., 20, 14, 1511-1514

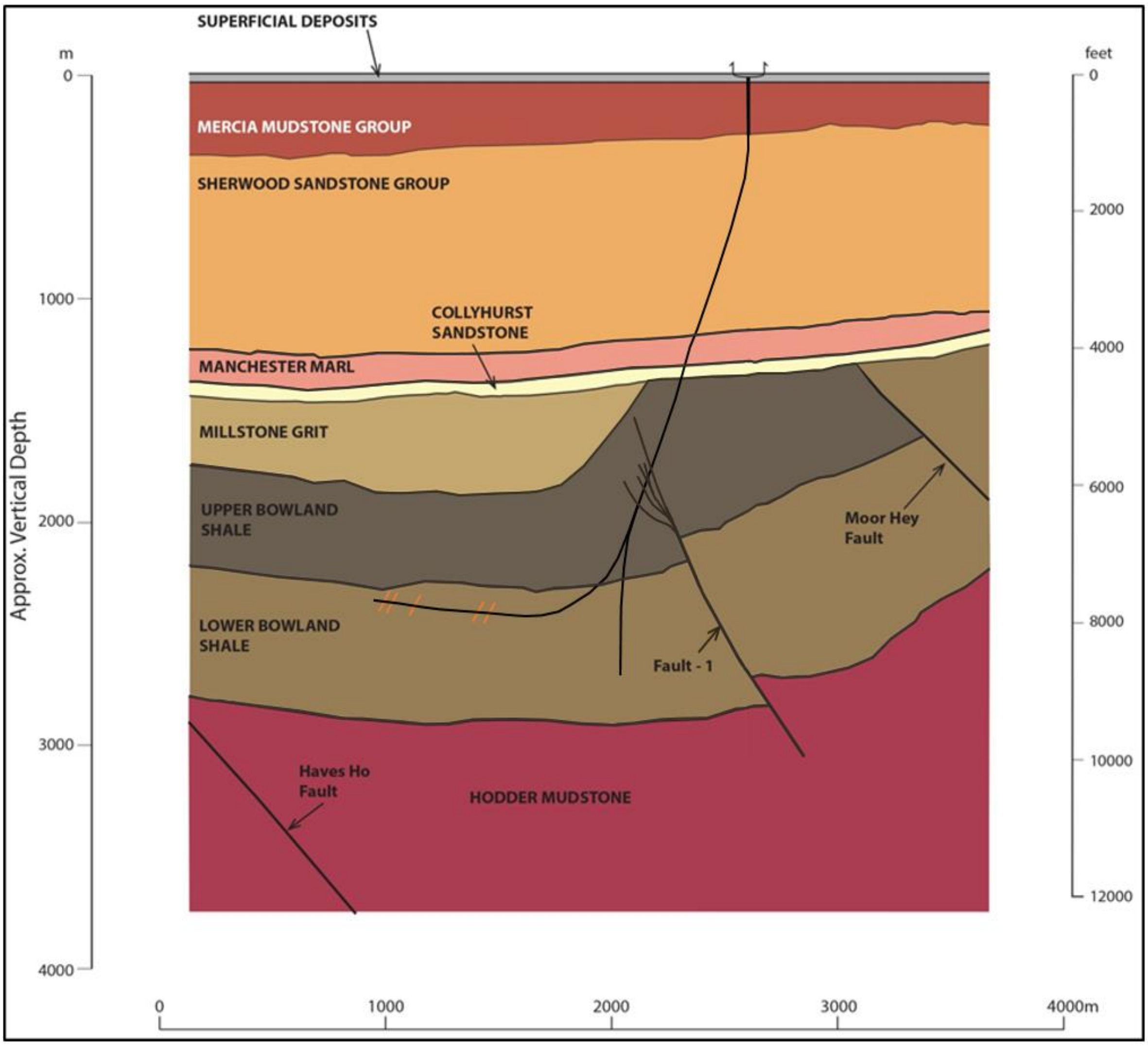
17: PNR Environmental Statement - Chapter 11 Paragraph 245-256, Page 318

Appendix 1: Lower Bowland Depth Structure Map

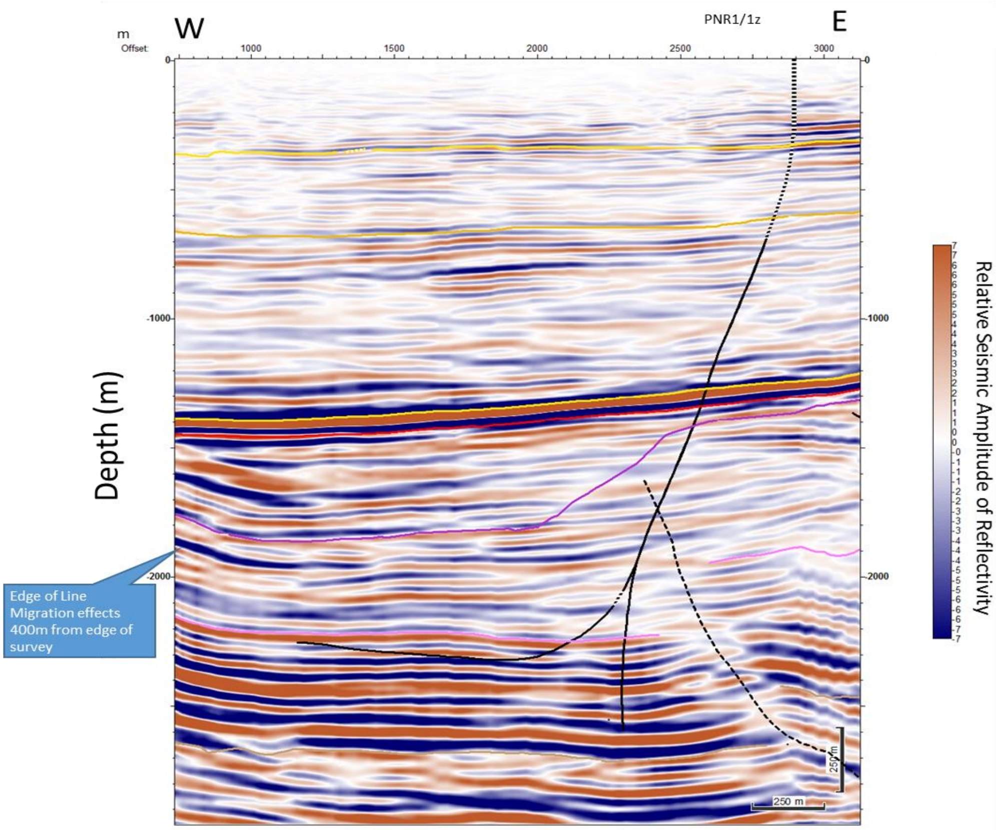


Appendix 2: Sub Surface Information

v Geological Cross Section PNR1



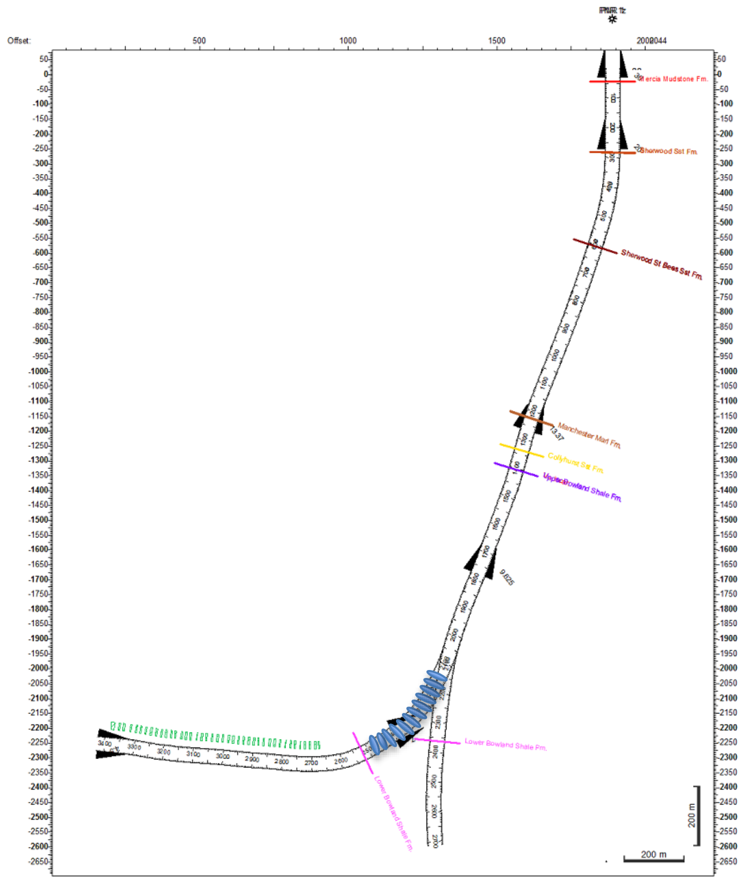
w Seismic Line PNR1z



The seismic discontinuities have no visible offset and therefore are not interpreted as a fault. However Cuadrilla anticipates that small faults exist at smaller scales than the seismic resolution and cannot rule out the possibility that the seismic discontinuities are potential faults, fracture swarms, depositional features, or seismic artefacts. However these small scale seismic discontinuities will not provide pathways to groundwater receptors because the target formation is isolated from the upper groundwater bearing units by the Manchester Marls Formation. The Manchester Marls Formation underlies the Sherwood Sandstone Group and is a mudstone unit containing primary and diagenetic evaporite minerals. These result in reduced permeability that effectively forms a barrier to upward flow of gases and fluids. For the purpose of this document we have described seismic discontinuities using fault variables, dip, strike, throw.

Appendix 3: Wellbore Profiles

- **Wellbore profile, hydraulic injection Locations, indicative microseismic array position**



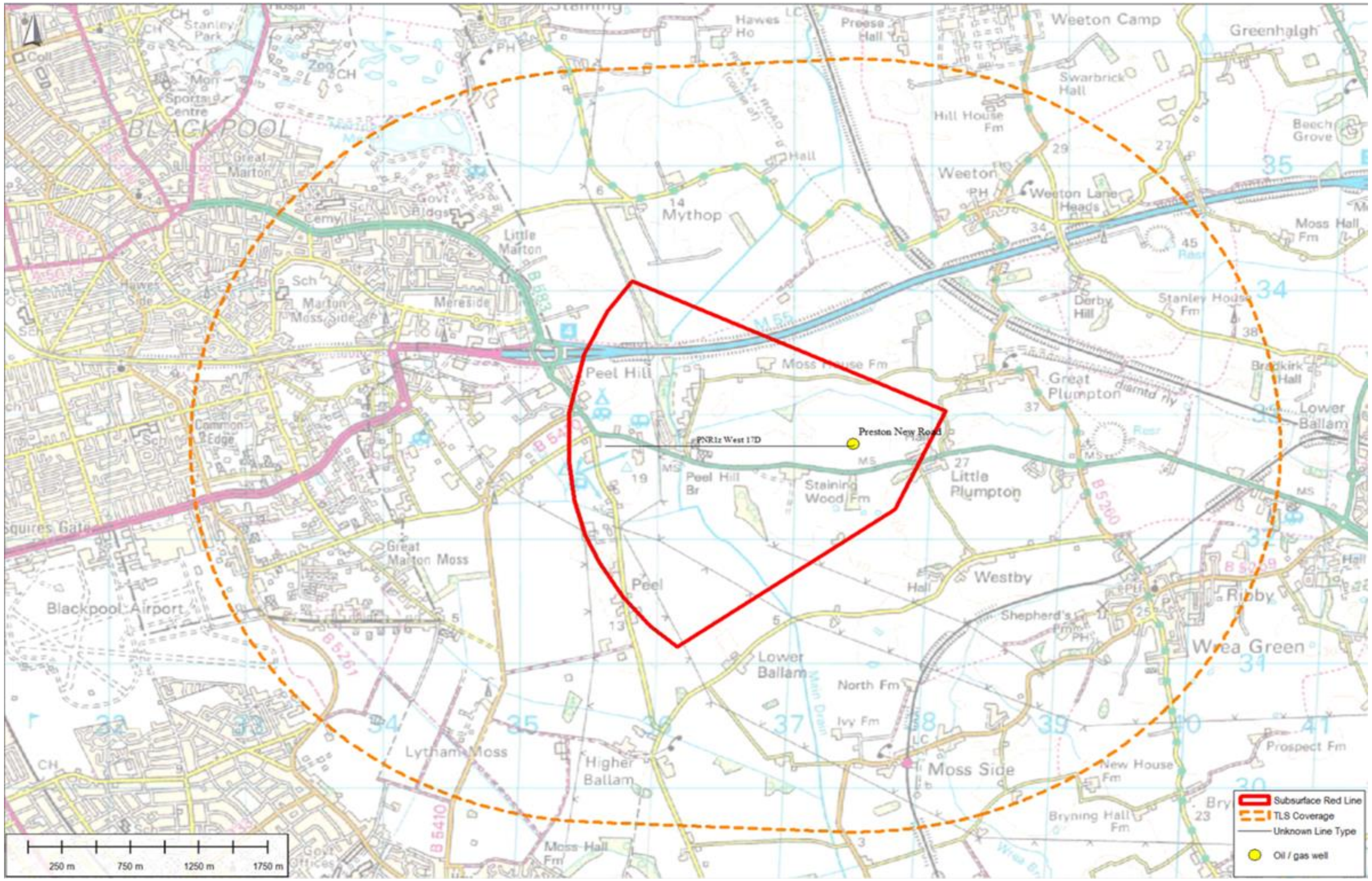
Key:

Green: Injection Points

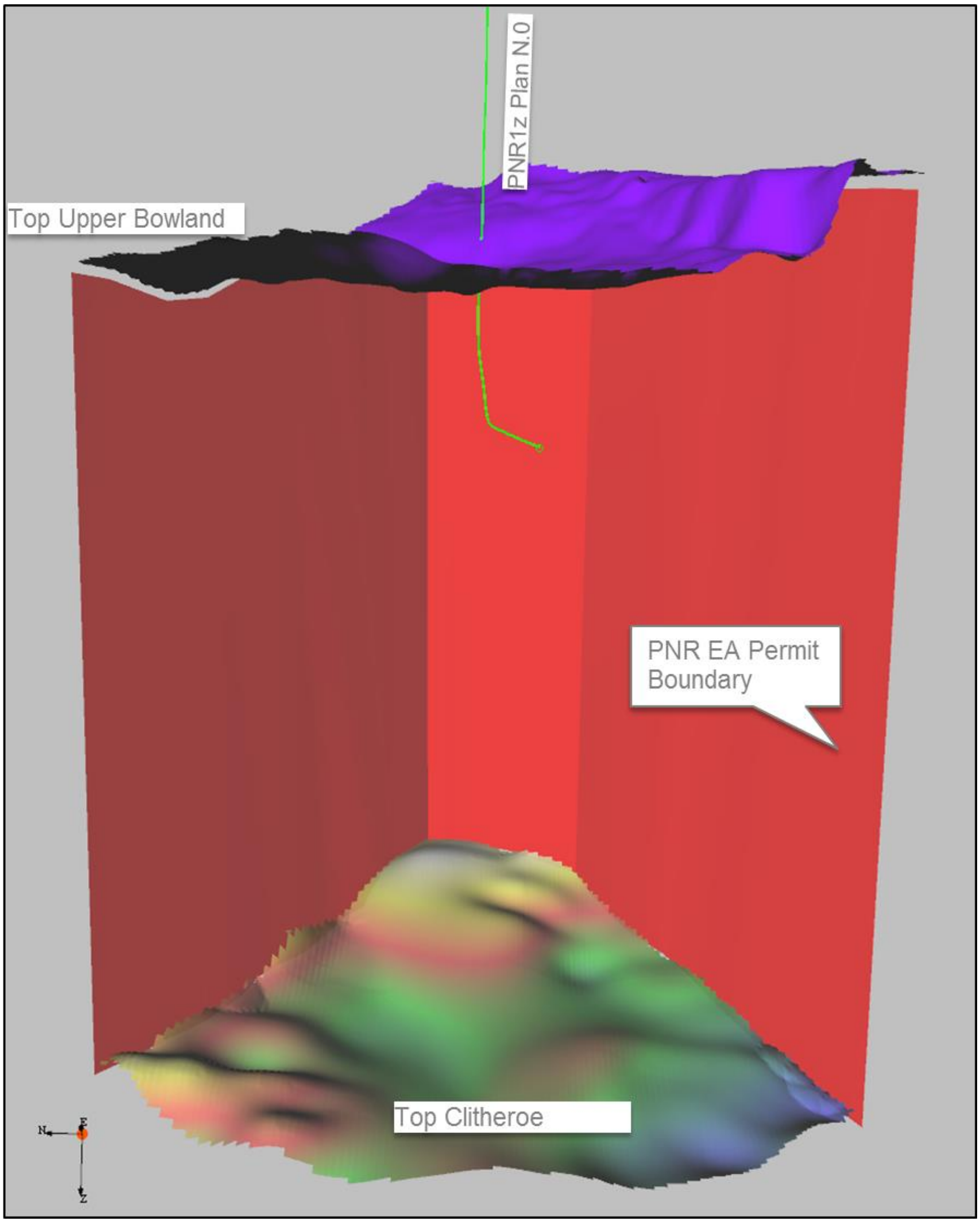
Blue: Downhole microseismic monitoring points

Note: microseismic monitoring will be performed from the observation well, not injection well.

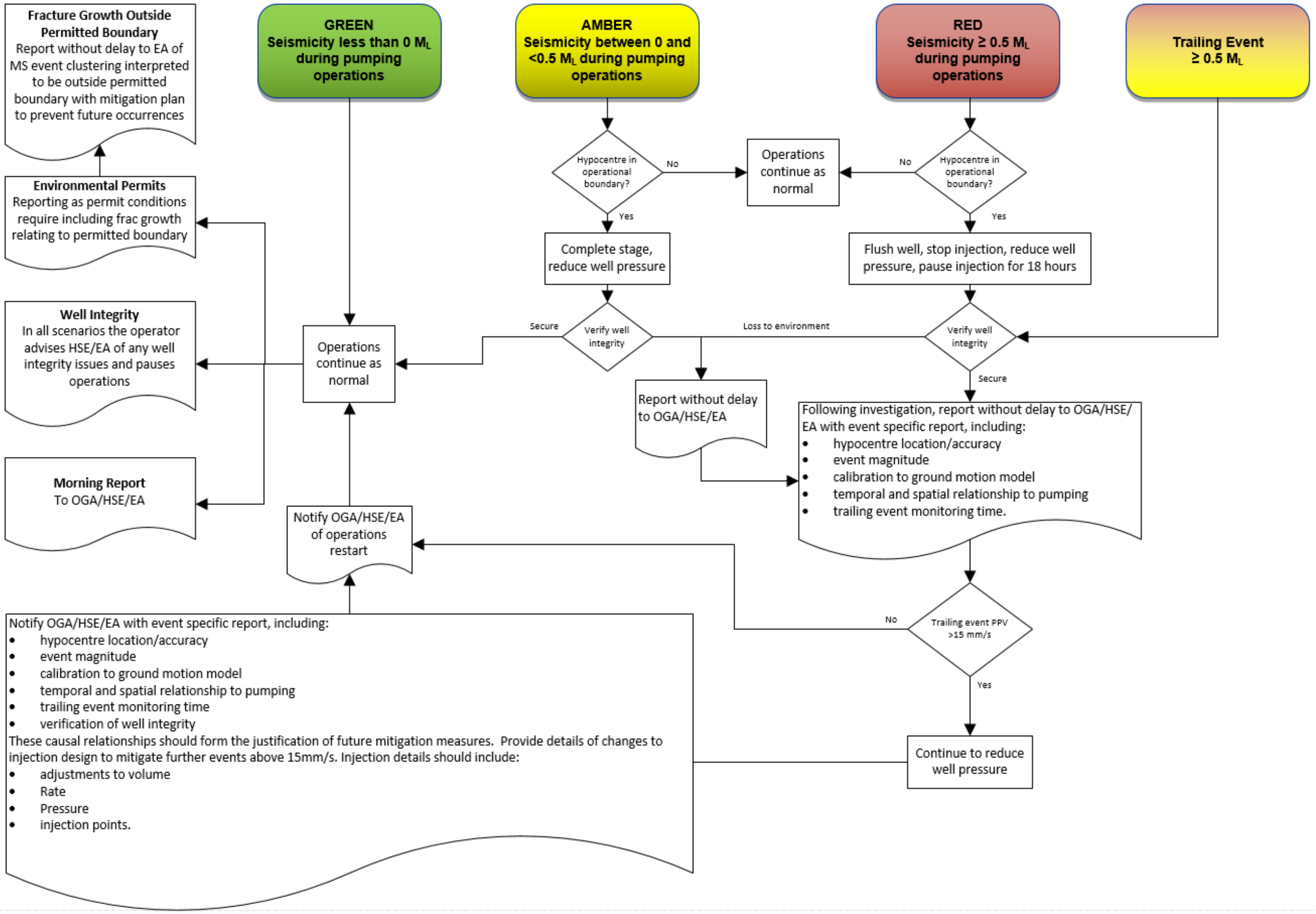
y Plan View showing TLS extent of coverage



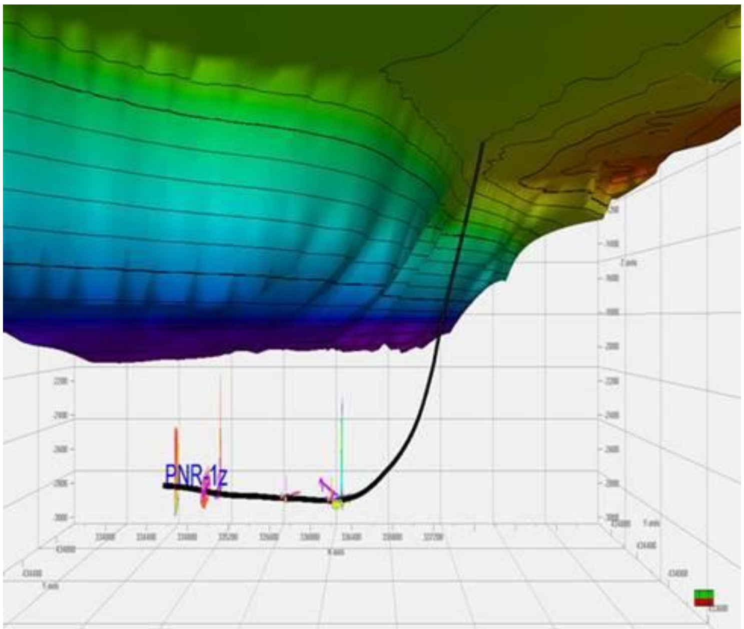
z 3D representation of EA boundary with wellbore profile



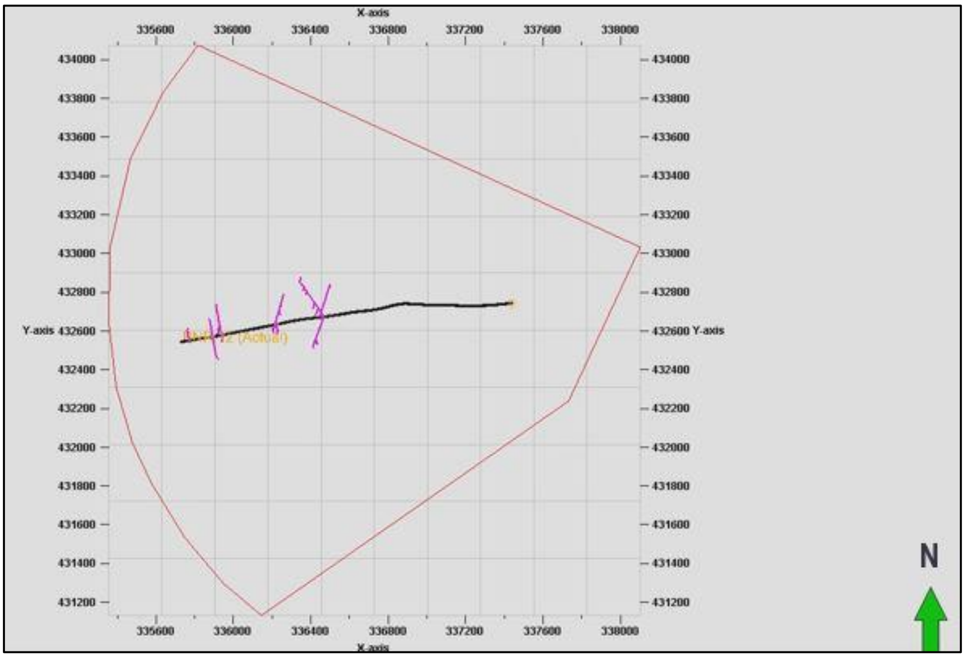
Appendix 4: HVHF Pumping Traffic Light and Surface Vibration System



Appendix 5: Fracture Model Graphical Representation



Cross sectional view looking due North across the PNR1z wellbore. The modelled fractures can be seen growing away from the well bore, this represents the complete fracture model not just the average fracture height. The upper limit of the permitted boundary is shown by the contoured horizon, blue representing deep moving into yellow at shallower depths. A grid is provided for scale, each box has a side length of 200m.



Map view of the permitted boundary, PNR1z wellbore shown in black and the hydraulic fracture models shown in purple.