FESCO, Ltd.
Petroleum Engineers

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May 18, 2015

Mr. Steven Nations
Pinnergy, Ltd.
111 Congress Avenue, Ste. 2020
Austin, Texas 78701

Re:	Well:	Hwy 67 SWD 1
	Field:	Newark East (Barnett Shale)
	Location:	Johnson County, TX
	Prod Interval:	9341 – 11878 ft
	Formation:	Barnett Shale
	Test Date:	May 12 – 15, 2015

Dear Mr. Nations:

FESCO, Ltd. performed the following test procedure on the subject well:

1. Well Status = Shut in.
2. MIRU slickline trailer unit.
3. RIH with 1.25" weight bar and tagged an obstruction at 11659 ft. POOH.
4. RIH with tandem electronic memory gauges making static gradient stops.
5. Suspended gauges at 9300 ft for the duration of the test.
6. Conducted a 36 hr Reservoir Pressure Injection Test by pumping disposal water into the formation.
7. Conducted a 24 hr Reservoir Pressure Falloff Test by stopping the pumps and shutting in the well at the wing valve.
8. POOH with tandem electronic memory gauges making static gradient stops to surface.
9. Secured wellhead and well site.
10. RDMO.

The attached report contains the data collected during the above test procedure and a pressure transient analysis of the tests.

Injection Test:
The water injection rate during the subject test was 2.5 STB/minute (3600 STB/d). The injection period length (36 hrs) equaled 150% of the falloff period length (24 hrs). **Figure 1** shows an overview plot of the injection and falloff test data. **Figure 2** shows a **Cartesian** plot of the data. The injecting reservoir pressure "broke over" 7.65 hours after the injection period began and remained essentially stable at slightly above 5510 psia for the remainder of the 36 hour injection period. **Figure 3** is a **log** plot generated to identify flow regimes. Minimal wellbore storage effects indicated by the unit-slope line distorted all data occurring before approximately 0.006 hours. Radial flow occurred between 0.007 and 0.80 hours (as evidenced by the zero-sloped pressure derivative data). Reservoir linear flow (evidenced by the 0.50-sloped pressured derivative) occurred between 0.80 and 7.65 hours. Linear flow in a well that has not been hydraulically fractured is most often caused by reservoir flow between two parallel

boundaries. Therefore, a radial homogeneous reservoir model and a parallel no-flow boundary model were used to model the data before 7.65 hours. Data after 7.65 hours was flat or decreasing for the remainder of the test and could not be matched. Since radial flow occurred, reservoir properties could be uniquely determined via conventional semilog analysis and confirmed via nonlinear regression type curve matching.

A **semilog** analysis was conducted in **Figure 4**. The slope of the line drawn through the radial flow region identified in **Figure 3** was used to calculate the corresponding values of permeability to water (K), skin factor (S), flow efficiency (FE), and delta pressure due to skin (dpS). Nonlinear regression type curve matching techniques were used with a radial homogeneous reservoir model and a parallel no-flow boundary model to estimate reservoir parameters. A good visual and statistical type curve match of the data before 7.65 hours resulted. The computed semilog and type curve analysis results are summarized below.

Log Type Curve Match Results
K = 30.011 md
S = -5.0492
dpS = -124.84 psi
L1 Boundary = 316 ft
L3 Boundary = 418 ft
Channel Width = 734 ft

Semilog Analysis Results
K = 30.287 md
S = -4.8911
dpS = -119.85 psi
FE = 2.0394
Radius-of-Investigation = 2803 ft

Figure 5 is a linear flow plot. The reservoir linear flow period (identified on the log plot of **Figure 3** and having a pressure derivative slope of 0.50 psi/log cycle) is evidenced by the linear data occurring between 1 and 2.7 square-root time hours. The slope of the line drawn through this data region predicts a channel width of 718 ft and equidistant parallel no-flow boundary distances of 359 ft from the wellbore. These values are consistent with the type curve match results recorded above.

The reservoir and surface injection pressures recorded at the end of the 36 hour injection test were 4911.25 psia and 650 psig, respectively. The calculated overall injection fluid density (pressure gradient) between surface and 9300 ft is as follows:

Fluid Density = [4911.25 – (650 + 15)] / 9300
Fluid Density = 4246.25 / 9300
Fluid Density = 0.4566 psi/ft

Falloff Test:
Figure 6 shows a Cartesian plot of the data. The reservoir pressure during the falloff test decreased until about 6.5 hours into the test. The reservoir pressure between 6.5 and 9.0 hours was essentially stable. The reservoir pressure during the remainder of the falloff test increased. **Figure 7** is a log plot generated to identify flow regimes. Wellbore storage indicated by the unit-slope line distorted all data occurring before approximately 0.03 Equivalent Time (ET) hours. The expected radial flow regime that occurred in the injection test between 0.08 and 1.00 hours did not appear in the falloff test. Instead, the data between 0.08 and 3 ET hours has a pressure derivative slope of 0.8123 psi/log cycle. This could either be a storage response or a possible multiple boundary response. The boundary response possibility seems unlikely since the parallel no-flow boundary response in the injection test occurred at about 0.80 hours and this response started a log cycle earlier at 0.08 hours. Stationary no-flow boundaries should occur at the same approximate time in any pressure transient test. Therefore, the data between

0.08 and 6.0 hours seems best explained as an extended wellbore storage response. The pressure derivative after 3 hours begins decreasing as the pressure stabilizes and disappears as the pressure during the falloff test starts increasing. (NOTE: The pressure derivative data disappears because its value on a falloff test becomes negative with increasing pressure and negative numbers cannot be represented on a log plot.) In conclusion, the falloff data could not be matched using a homogeneous reservoir model and a parallel no-flow boundary model.

Static Gradient Surveys: FESCO conducted a static gradient survey at the beginning (5/12/2015) and end (5/15/2015) of the test procedure. Both surveys indicate a water level at surface. The reservoir fluid density at 9300 ft on 5/12/2015 and 5/15/2015 was 0.4657 psi/ft and 0.4582 psi/ft, respectively. These values compare well with the value (0.4566 psi/ft) calculated at the final reservoir and surface pressure during the injection test (see Injection Test discussion above).

FESCO, Ltd. appreciates the opportunity to work for Pinnergy, Ltd. Please call me if you have any questions concerning this report.

Thank you,

FESCO, Ltd.

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