URTeC: 2688694

Timely Understanding of Unconventional Reserves through Rate Transient Analysis – a Vaca Muerta Case Study

John M. Thompson*, David M. Anderson, Daniel Nakaska; Anderson Thompson Reservoir Strategies, Matias Fernandez Badessich; YPF, Cameron T. Boulton; McDaniel & Associates

 DOI 10.15530/urtec-2017-2688694

This paper was prepared for presentation at the Unconventional Resources Technology Conference held in Austin, Texas, USA, 24-26 July 2017.

Abstract

The Securities & Exchange Commission requires that 'reliable technology' be used to estimate reserves, but no method can truly be considered reliable when the data does not yet exist to validate it. This is the case for shale wells with modern completions and limited production history, which is exacerbated in newer shale plays, such as the Vaca Muerta. In order to achieve reliability from our reserves evaluation methodology, the authors suggest that a multi-faceted approach is required.

Although Rate Transient Analysis (RTA) has been previously introduced as a reserves evaluation technique, it has not become mainstream, primarily because it is more cumbersome than rate-time decline curve analysis (DCA). Nevertheless, in the presence of valid supporting data, RTA is certainly defensible. In comparison to DCA, RTA captures more performance behavior elements of unconventional reservoirs through physics-based reservoir modeling. It can accommodate changes to the reservoir, well and fracture properties, while also accounting for differences in operational practices (e.g. draw-down controlled wells).

In this study, wells with truncated production datasets in the Vaca Muerta are evaluated and forecasted, using two fundamentally different approaches- i) *RTA workflow*- which focuses on detailed modeling of the underlying physics of fluid flow with the end objective of individual well forecasts under prescribed constraints and ii) *Standard reserve evaluator workflow* – which focuses on delivering a repeatable and scalable forecasting methodology whose reliability is measured in the aggregate, rather than by individual well samples. The evaluations are validated by comparing short-term well forecasts against the withheld well production, in a blind experiment. Our results show that RTA provides useful insight into what drives production, but does not always result in a better forecast. The results also demonstrate that RTA provides an excellent complement to the standard evaluator workflow when data is both limited and sparse – helping to understand the potential impact of recovery on future field development considerations (well spacing) as well as individual well operating conditions.

Introduction

The motivation for this work comes from the authors' recognition of the widespread disconnect between the worlds of RTA, which focuses on reservoir modeling, and conventional reserves evaluation, which typically relies on (multi-segment) decline curve analysis (DCA). Both contribute to the understanding of the big reserves picture, but in very different ways. It is the authors' opinion that inclusion of RTA in a reserves evaluation workflow can (sometimes significantly) improve the depth of understanding, particularly when the data is sparse and/or time-limited (i.e. green-field) and the reservoir is complex (e.g. an abnormally-pressured shale play). The Vaca Muerta is just such an example. The primary purpose of this paper is to demonstrate this idea through a blind study, where three wells with limited production history are evaluated and their forecasts are compared against their actual production updates. As we will see, each well selected by the operator provides hidden surprises.

Vaca Muerta Play Background

Geological and geographical details for the Vaca Muerta are already well summarized by Fernandez Badessich and Berrios (2012). Since November 2010, when its very first shale oil well was brought on production, YPF has drilled and completed more than 400 vertical wells and 100 horizontal wells with remarkable success. It continues to be considered a highly prolific, world-class shale play, spanning highly undersaturated black oil to dry gas systems, with everything in between.

Reserves Evaluation Workflow

The standard reserves evaluation workflow for an actively developed unconventional resource relies on a statistical data set, from which clear trends and correlations can be extracted. This allows the evaluator to develop dynamic type well decline curves that can be adjusted based on well design parameters, location, vintage, cardinality and other categories that may influence well performance. The influence of undeveloped versus developed locations is also a major consideration in the workflow, which contains three components-

1. Performance analysis of producing wells – This is done using a three-segment decline curve, incorporating (in sequence) transient (super-harmonic), stabilized (approximately harmonic) and exponential, respectively. The three-segment approach has been shown to capture the salient behavior of the vast majority of long-term unconventional production histories. The transition to exponential occurs at a prescribed limiting decline rate, usually based on production simulation or analog play experience.
2. Type curve analysis – Arguably the most important, this step is designed to rank well performance by multiple categories across the study area, such that new wells or wells with limited production history can be fitted with a suitable set of decline curves to capture production forecasting uncertainty.
3. Overall recovery factor (RF) check- This step is important, particularly when infill development at optimized well spacing has not yet occurred. In these cases, RF will likely be a significant function of well spacing, and will be inextricably connected to the stabilized B and limiting decline rate, which we will illustrate later in this manuscript. Thus, the big reserves picture is somewhat dynamic, and individual well production forecasts will be influenced by assumptions of future well spacing as the field develops.

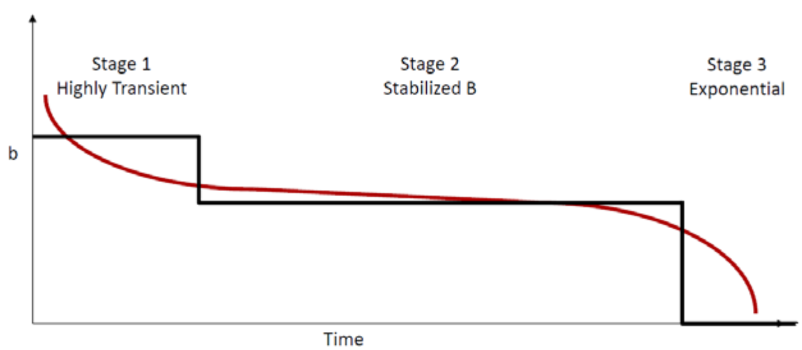

Figure 1: Illustration of three-segment decline to capture entire well performance profile (dark red: actual b behavior, black line: three-segment b approximation)

Single Well RTA Workflow

Rate transient analysis (RTA) is used to understand dominant drive mechanisms and characterize dynamic reservoir and completion parameters in a producing well, based on detailed analysis of rate and pressure.

The RTA performed in this study includes diagnostic plots, which yield bulk reservoir parameters as well as qualitative descriptions of flow regimes and production drive mechanisms. The bulk interpretations are validated with a history match of the well performance data, based on representative reservoir models. The models are then used to forecast future production under assumed operating conditions.

A more comprehensive summary of standard RTA techniques, models and conventional workflow is presented by Anderson and Mattar (2003). An RTA methodology for shale wells is provided by Anderson et al. (2010).

Diagnostic Plots

Diagnostic plots are used to identify dominant production mechanisms and quantify bulk reservoir and completion characteristics. There are three diagnostic plots used in this study, the Log-Log plot (with dimensionless Type Curve), Linear Flow Specialized plot (normalized pressure vs. material balance square root time or linear flow superposition time) and the Flowing Material Balance.

The Log-Log plot is primarily a qualitative diagnostic for identifying dominant flow regimes- transient, transition or boundary dominated flow. Matching production data to a suitable type curve can also provide bulk characteristics such as effective permeability, fracture half-length and drainage aspect ratio. These parameters are useful for seeding a history match model.

The Linear Flow Specialized plot is a good objective indicator of completion effectiveness, based on early well performance data (both rate and flowing pressure). This plot identifies transient linear flow and quantifies the product of total connected fracture area and square root of matrix permeability($A\sqrt{k}$). It also quantifies the apparent fracture conductivity, which can be influenced by propped fracture conductivity, convergence skin, fracture face skin, proppant embedment, fines migration, phase trapping and other phenomena.

The Flowing Material Balance (FMB) analysis (Mattar and Anderson 2005) focuses on the late-time boundary dominated flow behavior, quantifying the contacted Original Gas in Place (OGIP) or Original Oil in Place (OOIP). In ultra-tight reservoirs, this analysis is usually indicative of the hydrocarbon pore volume in contact with the productive fracture network – often called the stimulated reservoir volume (SRV).

Dynamic Reservoir Modeling and History Matching

The Enhanced Fracture Region (EFR) model by Stalgorova and Mattar (2012), shown in Figure 2, has proven to be a suitable model for simulating production from a vertical well with a single fracture or a multi-stage fractured horizontal well in an ultra-tight reservoir. This model assumes uniform, planar parallel hydraulic fractures that are perpendicular to the horizontal lateral. Each primary hydraulic fracture is surrounded by a limited region of enhanced permeability that can be used to simulate fracture complexity. The flow capacity and volume of the enhanced region are usually defined through the history matching process. It should be noted that, in this study, all production modeling was performed using a numerical (finite difference) model to account for multi-phase flow in the reservoir.

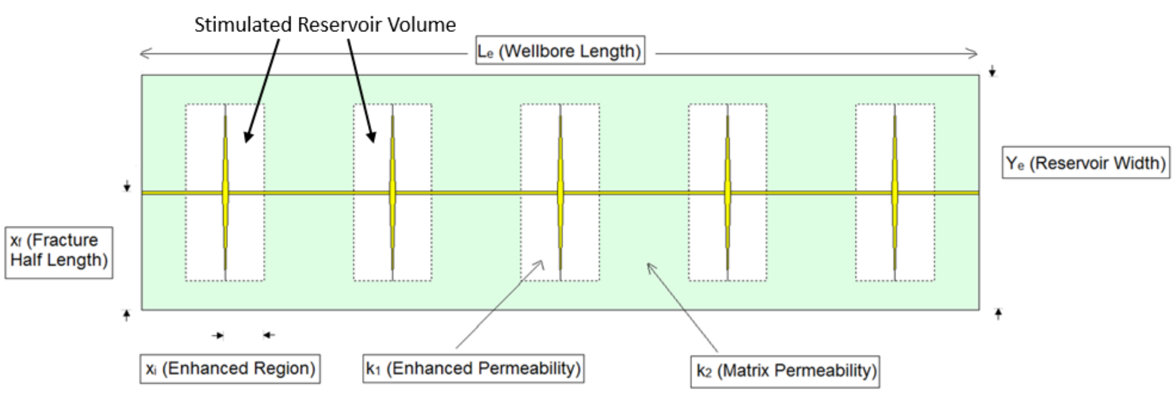

Figure 2: Enhanced fracture region model (Stalgorova and Mattar, 2012)

Pressure Dependent Permeability Considerations

The Vaca Muerta is highly over-pressured (0.9 psi/ft) and thus there is an expected dependence of rock compressibility and permeability on stress. Core laboratory tests confirm and quantify a dependency of fracture conductivity on confinement stress, which is shown in Figure 3. This can serve as a proxy for the dependency of effective permeability to effective stress. However, this core data cannot be easily translated into a relationship between rock properties and pore pressure for practical production modeling.

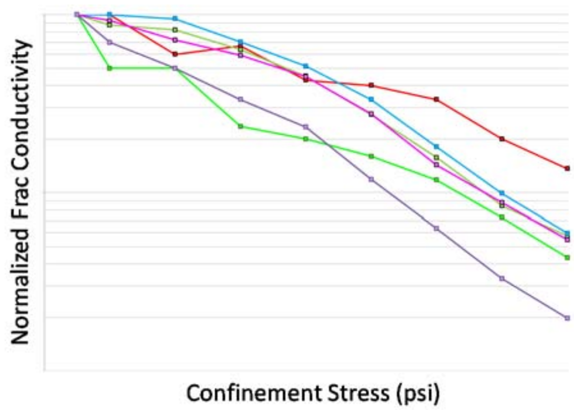

Figure 3: Laboratory measured fracture conductivity as a function of confinement stress

Although the impact of pressure dependent rock properties on well production can be easily modeled, its signature is not always clearly evident in the data itself. Therefore, the parameter representing pressure dependent rock properties in RTA (the gamma function) is set as an assumed value, based on the evaluators' previous experience in dealing with Vaca Muerta wells, as well as with over-pressured reservoirs in other basins (e.g. Haynesville, Eagle Ford, Duvernay, etc.). As we will show, some data sets will require adjustment of this value to obtain a satisfactory history match, while with other data sets the gamma function is somewhat non-unique. Thompson et al. (2010) and Okouma et al. (2011) provide details for identifying stress-dependent permeability in abnormally-pressured shale well production data sets, provide a workflow for calibrating the pressure-dependent permeability relationship (from build-up data), and demonstrate its impact on production forecasting and reserves.

Well Examples (Case Studies)

In this study, three wells were analyzed. Reservoir, wellbore and completion parameters are presented in Table 1.

Table 1: Reservoir, wellbore and completion parameters

	Well A	Well B	Well C
Well Type	Vertical	Horizontal	Horizontal
Primary Fluid	Oil	Oil	Gas
Lateral Length (ft)	N/A	2,330	3,900
TVD (ft)	9,900	9,700	8,860
Completion Type	Plug-and-Perf	Plug-and-Perf	Plug-and-Perf
Stages	5	8	15
Perforation Clusters / Stage	2	8	4
Proppant / Stage (lbs)	300,000	500,000	450,000
Total Frac Fluid / Stage (bbl)	6400	11,200	7,900
Fluid System	Hybrid	Slickwater	Hybrid
Initial Reservoir Pressure (psi)	8,735	8,850	7963
Reservoir Temperature (°F)	222	221	222
Net Pay (ft)	610	131	110
Total Porosity (%)	9.5	7.0	9.0
Initial Water Saturation (%)	32	34	40
Oil Gravity (°API)	38	38	N/A
Gas Gravity	0.78	0.78	0.67
Saturation Pressure (psi)	2,800	1,900	N/A

Well A-

Well A was one of the first wells drilled in the Vaca Muerta. It is a vertical oil well with a five stage plug and perf completion with over 600 feet of total connected net pay. Raw production data for the well is presented in Figure 5. Over the period from February 2011 to June 2013 the well exhibits an initial steep decline transitioning to a much shallower decline under naturally flowing conditions. Continuous flowing bottomhole pressure (FBHP) was measured with a downhole gauge up to September 2012. Two additional FBHP measurements were taken in 2013 from flowing pressure gradient surveys.

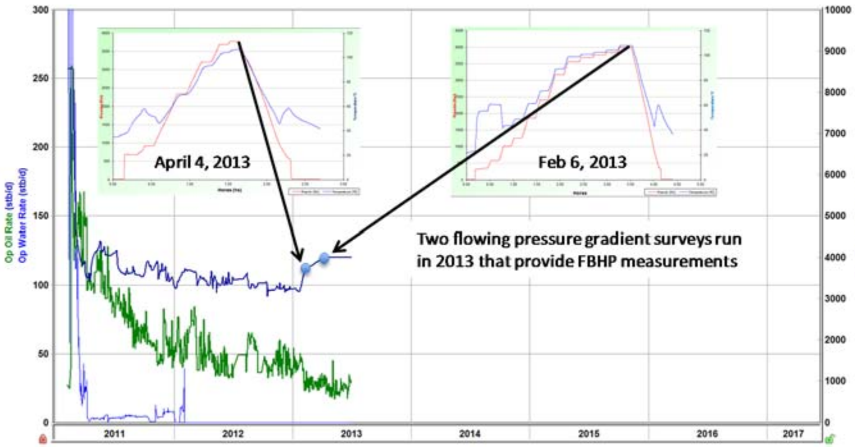

Figure 4: Raw production data – Well A

Reserves Evaluation

From a reserves evaluation perspective, one of the key observations to be made from the data is that the oil production rate suddenly drops to under 30 stb/d in February 2013 from an average of nearly 50 stb/d in the preceding 12 months. The production rate stays depressed, suggesting that the well will require artificial lift. This is supported by the observed increase in FBHP during this time. An inflow performance relationship can be generated using the production and pressure data available to estimate the initial rate based on the installation of a pump. To capture the uncertainty of future flowing pressure conditions, ‘low’ (conservative), ‘best’ (most likely) and ‘high’ (optimistic) production forecasts were generated.

Each production forecast was generated with a three-segment decline curve, with terminal decline rate consistent with the confidence level for a low, best and high estimate, respectively. Decline parameters for each segment are presented in Table 2.

Table 2: Reserves evaluation multi-segment decline parameters – Well A

Arps Parameter	**Segment 1**			**Segment 2**			**Segment 3**		
	Low	Best	High	Low	Best	High	Low	Best	High
Initial rate (stb/d)	27.2	27.2	27.2	Continued	50	60	Continued from segment 2		
b-value	1.2	1.3	1.4	0	1	1		0	0
Decline rate (%)	80	75	70	8	25	22.5		8	7
Length of segment (yr)	7.1	0.5	0.5	8.0	8.6	9.9		12.8	17.0

The resulting range in EUR for Well A is 112 – 225 Mstb. A quick RF check reveals very conservative recovery, with a 1-3% RF for a 40-acre drainage area (A_d); the A_d provided by the operator. This result indicates there may be infill potential. The forecasts have been compared to the actual production history that was withheld in figure 5.

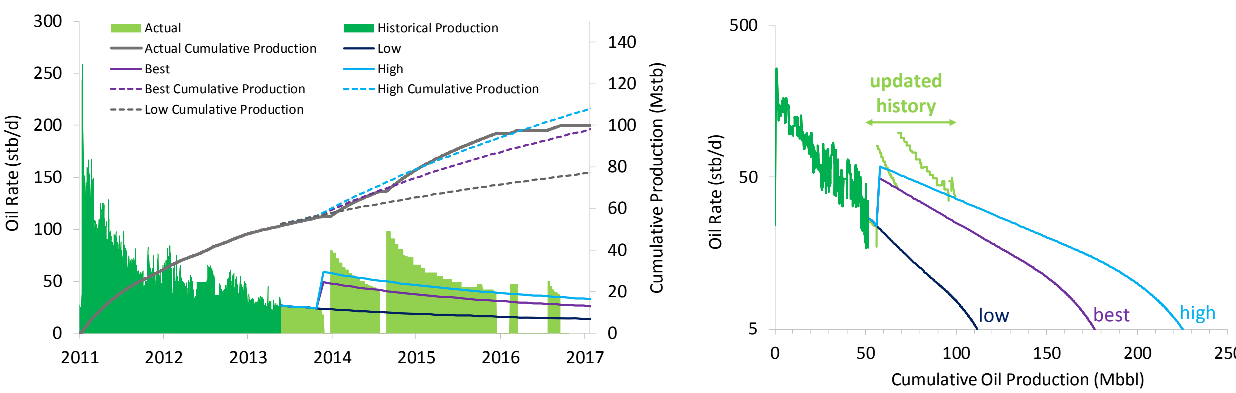

Figure 5: Reserves evalutor production forecasted oil volumes compared to actuals – Well A

Despite the forecasts being unable to accurately predict the peak rate and flush performance periods in 2014, we do observe that the late-time historical performance is coming back onto predicted trend and the actual cumulative production falls between the best and high estimates; those that considered a pump installation.

It is unclear to the evaluator why the well is producing only intermittently throughout 2016 and why it has been shut-in for so long. Before providing a production forecast and EUR update, in a case like this, the evaluator would need more information from the operator.

RTA Evaluation

The diagnostic RTA for Well A is shown in Figure 6, featuring linear flow specialized analysis (6a) and FMB analysis (6b). From the specialized plot, the well appears to be in late linear flow-to-early transition flow. Oil material balance square root time was used as it is the preferred time function for analyzing variable rate and pressure data (Liang et al. 2011). Estimated permeability and fracture half-length are 500 nd and 466 ft, respectively. The FMB analysis indicates a contacted drainage area of about 5 acres after 2.5 years of production. Since this well has an assigned drainage area of 40 acres, its long-term forecast is unlikely to be constrained by total volumetric oil-in-place (OIP).

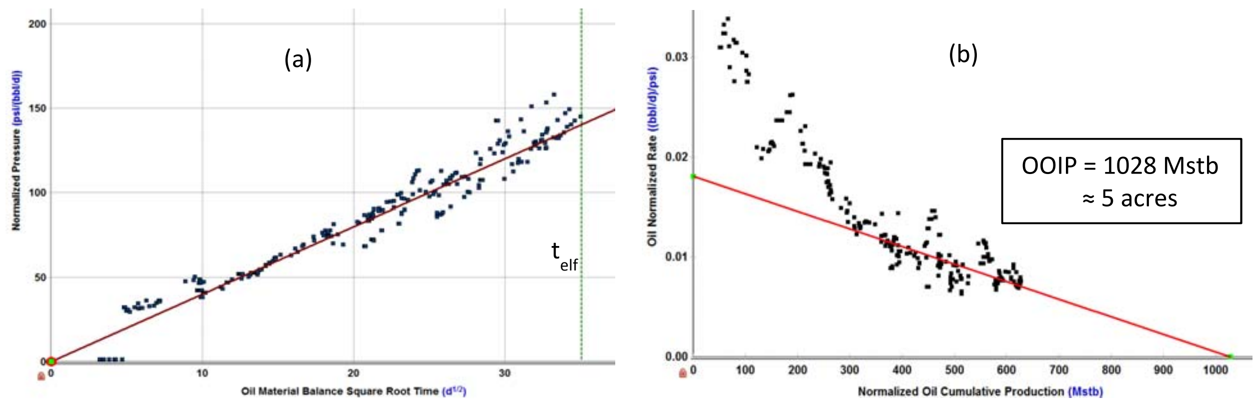

Figure 6: Diagnostic RTA – Well A

Blasingame elliptical flow type curve analysis (Figure 7) provides an alternative analysis to the straight-line methods. The type curve match yields estimated reservoir and completion parameters which are used to seed the history match model. The numerical model history match of Well A's performance is shown in Figure 8.

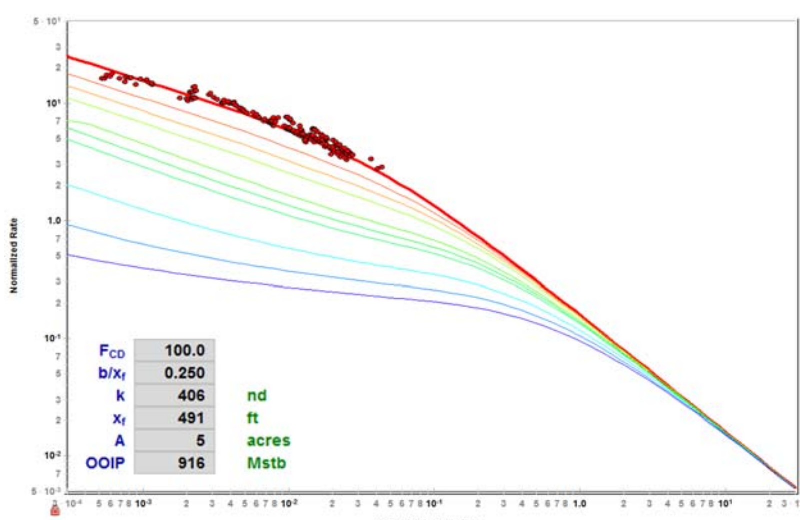

Figure 7: Blasingame elliptical flow type curve analysis

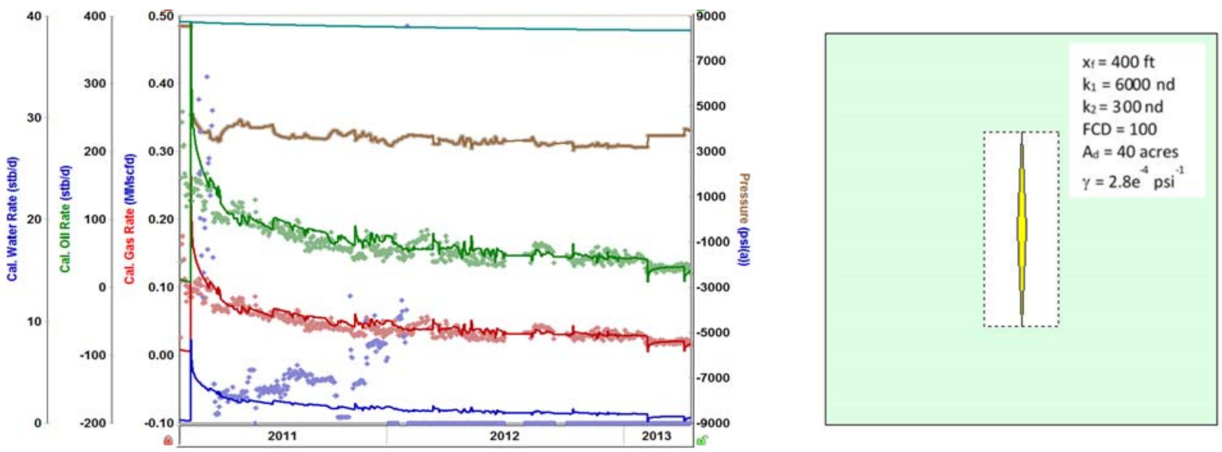

Figure 8: Truncated model history match – Well A

The model match confirms the contacted drainage area from FMB analysis. Pressure dependent rock properties (e.g. permeability) are not necessary to obtain a satisfactory history match of this data. As previously stated though, our experience with the Vaca Muerta and other over-pressured shale plays (> 0.75 psi/ft), along with the known lab data, suggests that pressure dependent permeability should be a dominant drive mechanism, and thus it is included in the model.

To be consistent with the reserves evaluation, three production forecasts are included for Well A, representing the range of uncertainty for future flowing pressure. Also included for comparison purposes is a simple decline curve (harmonic), based on the best fit of the historical data. These forecasts are compared to the actual production history that was withheld (Figure 9).

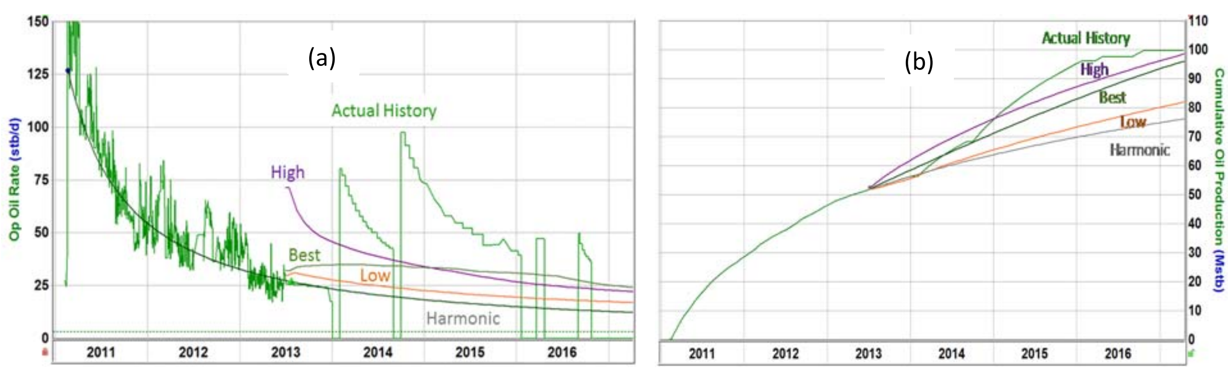

Figure 9: Production forecasts with comparison to actual production history – Well A

A cursory comparison of the high RTA forecast (constant p_{wf} of 1000 psi) with the actual well performance indicates a close match in total cumulative production at the end of history (Figure 9b); a result very similar to the one obtained by the reserves evaluator's approach. Indeed, the operator confirms that the well was placed on artificial lift shortly after the start of the withheld data segment. Interestingly, closer inspection reveals a significant amount of downtime (8.7%) in the withheld production history. Clearly, this is something that could not possibly have been predicted by the analyst, and therefore the comparison is not straightforward.

A secondary RTA forecast, simulating this downtime, clearly indicates that the RTA model under predicts well performance, even at maximum drawdown conditions (Figure 10). This suggests that the model is missing some component of physics that is critical to simulating long term recovery. This is an important lesson about how critical it is to have the right model in place to obtain a reliable forecast. Without consideration of downtime, the original (high) RTA model passed the "sniff test" (the cumulative productions matched), but it will almost certainly under predict long-term performance and EUR.

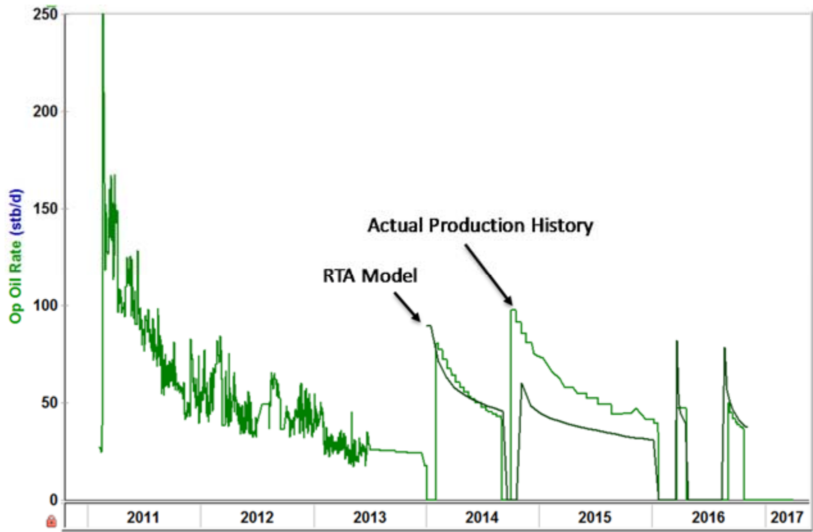

Figure 10: RTA model forecast assuming artificial lift and simulating downtime compared to actual production history – Well A

We sought to find out what the RTA model was missing by re-matching the total production history response. This task was complicated by the fact that the FBHP during artificial lift (the withheld production period) are unknown. To overcome this difficulty, we used the known production rate during the full history as the model constraint and generated a bottomhole pressure profile that matched the known pressure history, but also ensured that simulated pressures didn't fall below a minimum of 1000 psi during the withheld production segment (Figure 11). As it turns out, the only way to obtain this history match was to remove the pressure dependent permeability from the model. This illustrates the danger human bias can play in model-based forecasting (Rajvanshi et al. 2012).

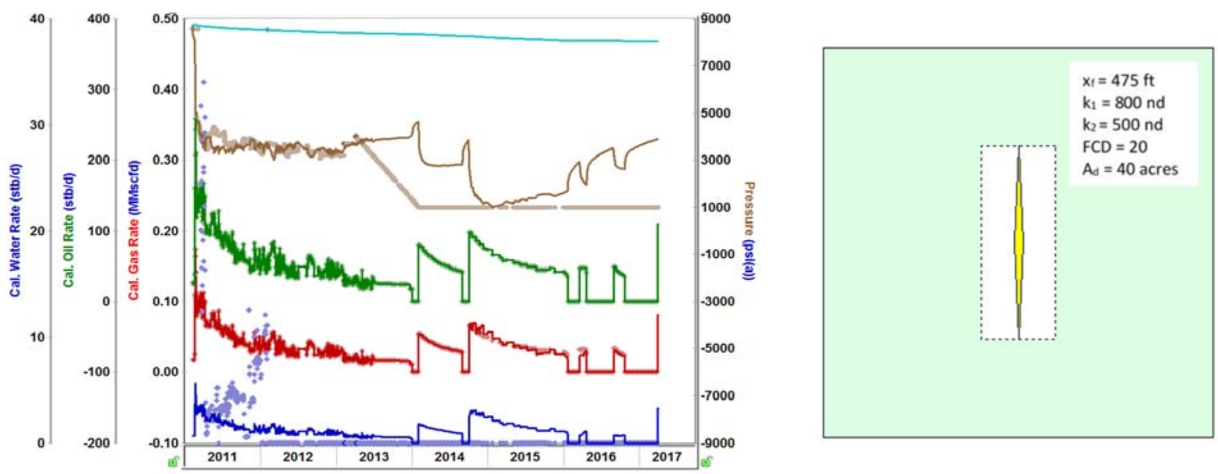

Figure 11: Corrected model history match (full history) – Well A

The production forecast from the corrected model (Figure 12) matches the withheld production history exactly, and predicts a 30-year EUR 74% higher than that of the 'high' forecast from the original model. Is this more reliable than the original RTA forecast? Likely, because the model that generated the original forecast was not capable of matching the full production history. Having said that, the updated model forecast has some inherent optimism, in that it assumes there is constant reservoir properties (e.g. permeability, pay, etc.) to the reservoir boundaries; boundaries that extend far beyond what the well has contacted with no productivity loss from geomechanical effects.

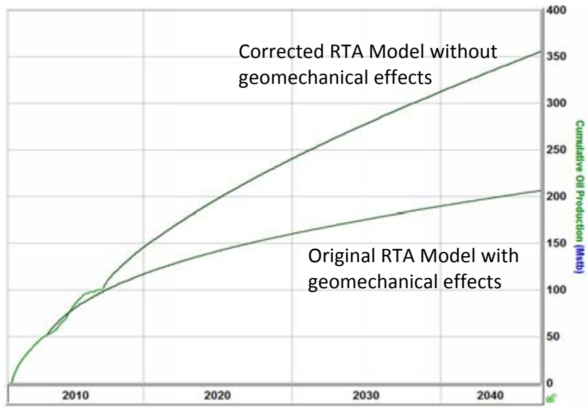

Figure 12: Comparison of forecasts generated from original and corrected RTA models – Well A

It should be noted that, although the model was based on a 40-acre drainage area, there is no improvement in the 30-year EUR above 20 acres. This is illustrated in Figure 13, which presents EUR and RF results for a series of numerical modeling runs at different drainage areas.

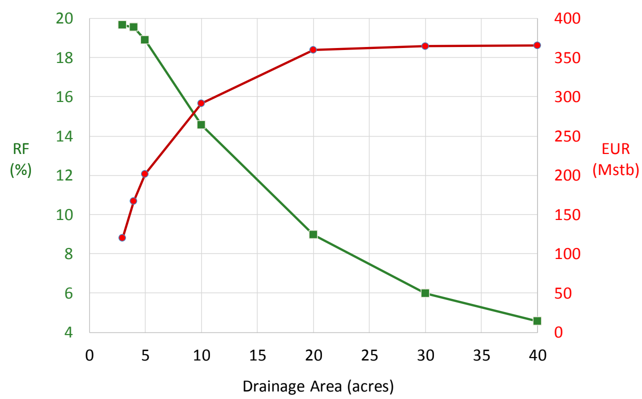

Figure 13: Correct RTA Model EUR and RF results as a function of drainage area – Well A

Well B-

Well B is a horizontal shale oil well with an 8 stage plug and perf completion with roughly 131 ft of *estimated* net pay with no other wells in its vicinity (an unconstrained drainage area). Raw production data for the well is presented in Figure 14.

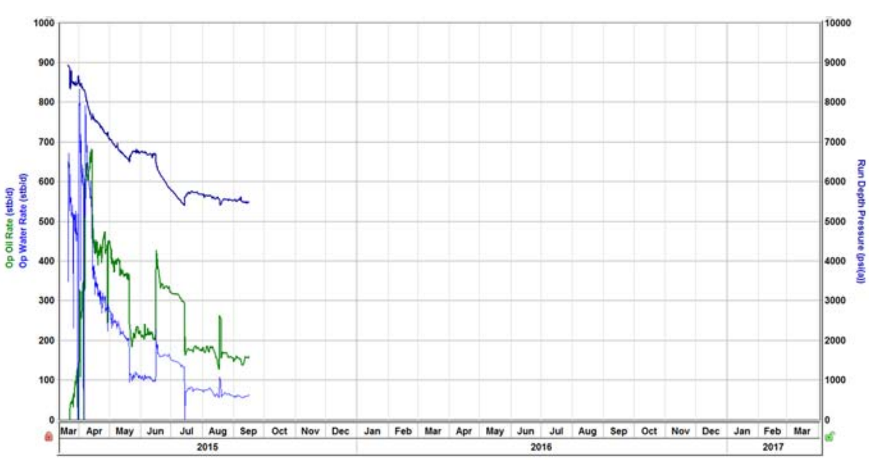

Figure 14: Raw production data – Well B

This well example, with its erratic production rate, looks like it was carefully selected to trick the evaluator! However, the flowing pressure and production data tell a consistent story. Once again, FBHP was measured with a downhole gauge.

Reserves Evaluation

Like the previous example, a key uncertainty here is the future flowing pressure condition. The (3-segment) production decline parameters for each case (low, best, high) are presented in Table 3, reflecting the forecast uncertainty. The low case assumes continued operating practices (i.e. no pump), while the other cases assume a drop in flowing pressure.

Table 3: Reserves evaluation multi-segment decline parameters – Well B

Arps Parameter	Segment 1			Segment 2			Segment 3		
	Low	Best	High	Low	Best	High	Low	Best	High
Initial rate (stb/d)	175	225	235	Continued from segment 1			Continued from segment 2		
b-value	1.2	1.3	1.4	1	1	1	0	0	0
Decline rate (%)	80	75	70	Continued from segment 1			8	8	7
Length of segment (yr)	0.5	0.5	0.5	10.8	10.6	12.3	8.5	13.7	16.7

A RF check is also difficult for this well given that the well is in an isolated area and the future field development program is unknown. Based on an assumed drainage area of 60 acres (for a 700m lateral), the recovery factor ranges from 8-14%; a reasonable result.

All three forecasts are shown and compared to the actual production history that was withheld in Figure 15.

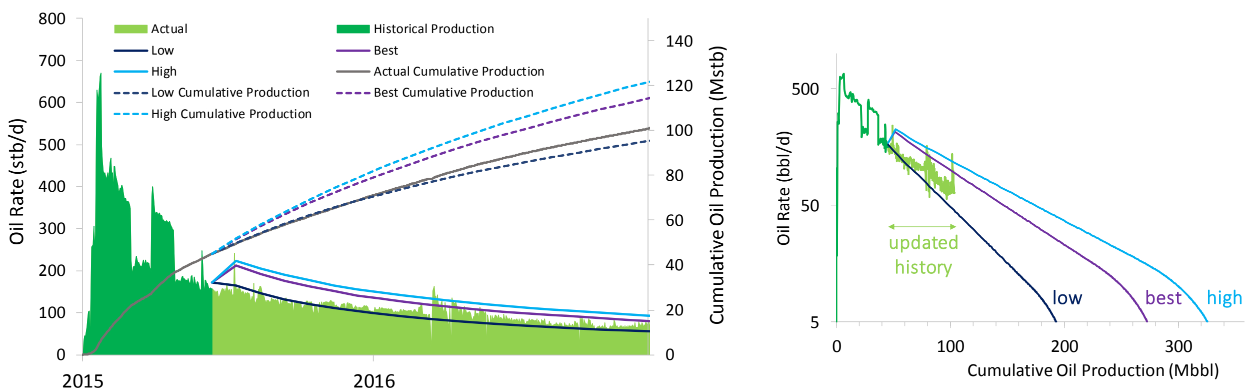

Figure 15: Reserves evalutor production forecasted oil volumes compared to actuals – Well B

Unlike the previous example, the operator appears to have stayed the course with operating conditions. The low forecast initially looks good when compared to the actual updated rate history, but it does not predict its late-time behavior. The other cases were optimistic because they assumed a significant early reduction in flowing pressure.

RTA Evaluation

The diagnostic RTA for Well B is shown in Figures 16 (Specialized and Flowing Material Balance Analysis plots) and 17 (Compound Linear Flow Type Curve analysis). In contrast to Well A, Well B transitions out of linear flow very early, exhibiting what we would call transitional flow (Liang et al. 2012). This is not surprising, as Well B is a horizontal well with multiple stages, laterally spaced at 276 ft, for which early inter-stage interference would be expected. Estimated permeability and fracture half-length are 2800 nd and 136 ft, respectively. Upon first inspection, this permeability appears too high for shale, and exceeds the range for permeability provided by the operator. However, this effective permeability represents the initial condition and decreases significantly during production (by an order of magnitude). The Flowing Material Balance analysis indicates a contacted drainage area of about 44 acres after 2.5 years of production.

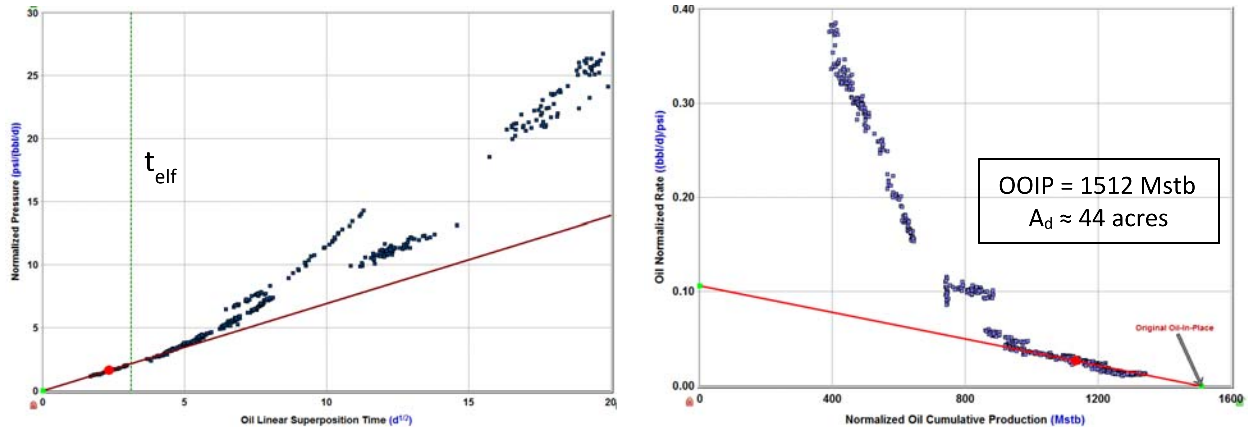

Figure 16: Diagnostic analysis – Well B

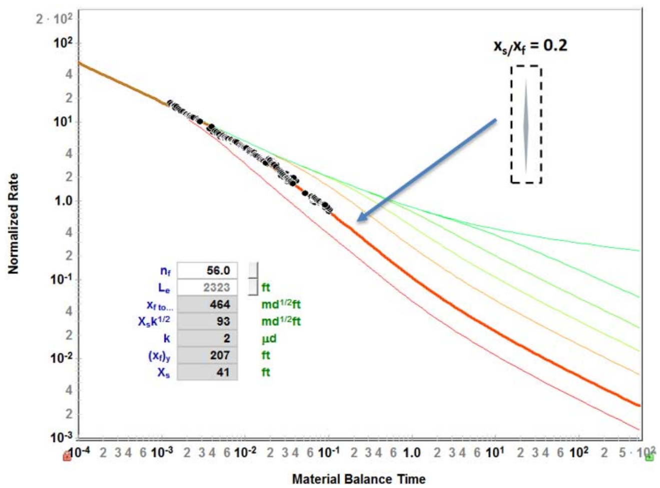

Figure 17: Compound linear flow type curve analysis – Well B

A model history match of Well B's performance is shown in Figure 18. In contrast to Well A, the model for Well B requires the influence of pressure dependent permeability in order to obtain a satisfactory match of the data. Figure 19 shows the results of a similar model, but without pressure dependent permeability. Close inspection of the history match demonstrates the model's inability to track the flowing pressure peaks and valleys.

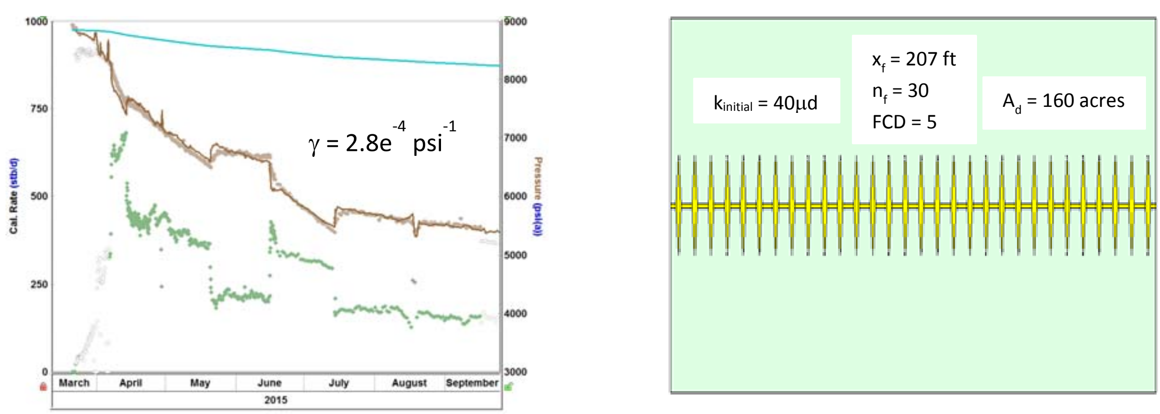

Figure 18: RTA model history match with geomechanical effects – Well B

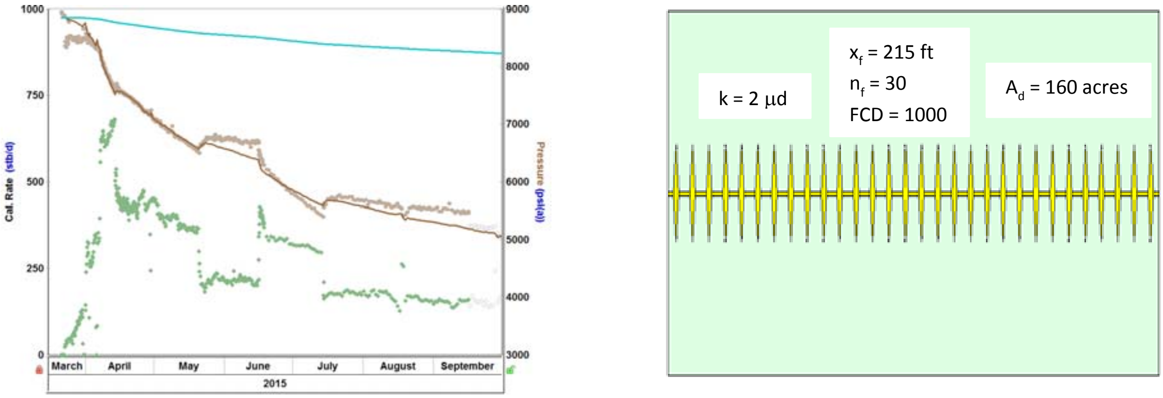

Figure 19: RTA model history match without geo-mechanical effects – Well B

Two production forecasts representing constant (low) and declining (best) flowing pressure profiles are shown for Well B in Figure 19 and compared against its withheld production history. These RTA forecasts appear to bookend the true production response. It also shows the withheld flowing pressure history compared with the assumed pressure history for the most likely forecast. As evident from the plot, the forecasts agree fairly well during the period where the flowing pressures match. At the point where the model pressure drops below the actual pressure, the most-likely forecast begins to exceed the actual production, which is an expected result.

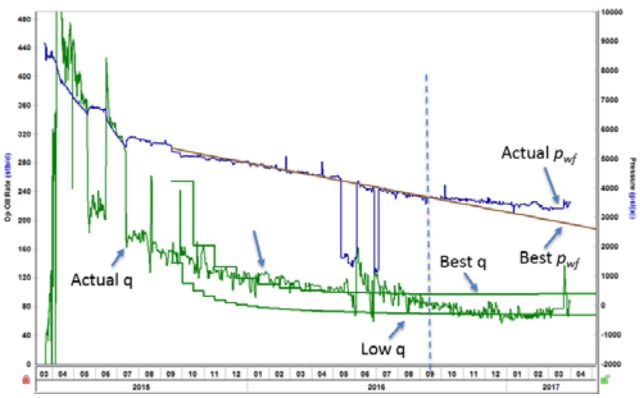

Figure 19: Model history match including withheld data – Well B

Unlike Well A, comparison of Well B's withheld data to the forecast provides validation of the original model and major corrections to the model are not required (some minor fine tuning adjustments were made). The model 30-year EUR for Well B is 400 Mstb for an 80 acre drainage area.

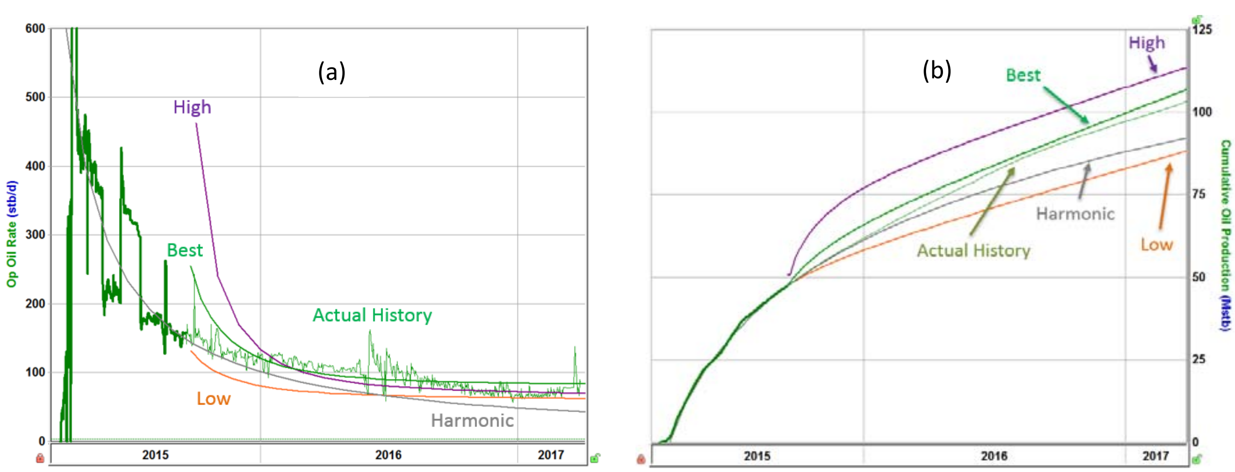

Figure 20: Production forecasts with comparison to actual production history – Well B

It should be noted that, although the model was based on a 160-acre drainage area, there is no improvement in the 30-year EUR above 80 acres. This is illustrated in Figure 21, which presents EUR and RF results for a series of numerical modeling runs at different drainage areas.

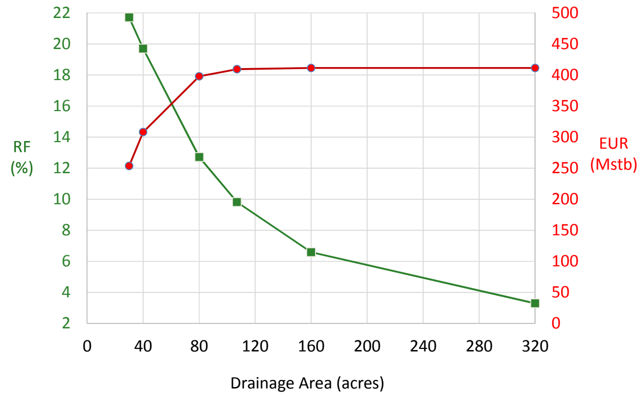

Figure 21: Corrected RTA Model EUR and RF results as a function of drainage area – Well B

Well C

Well C is a horizontal dry gas well with a 15 stage plug and perf completion with roughly 110 ft of *estimated* net pay with offset wells 1000 ft (300 m) away, constraining its drainage area. Raw production data for the well is presented in Figure 22. This well appears to have a more established production profile with steady flowing pressures over the past few months.

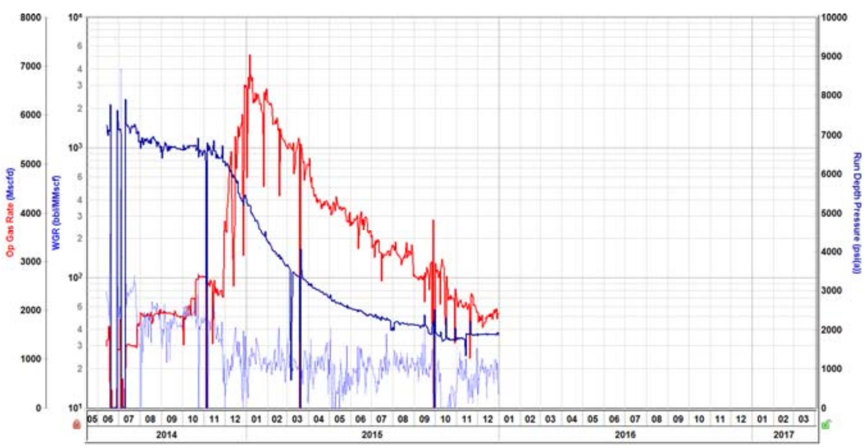

Figure 22: Raw production data – Well C

Reserves Evaluation

From a multi-segment DCA perspective, this well appears to be already exhibiting second segment (i.e. near harmonic) behavior. For this reason, segment one decline parameters are not provided in Table 4. The second segment therefore represents the start of the production forecast.

Table 4: Reserves evaluation multi-segment decline parameters – Well C

Arps Parameter	Segment 1			Segment 2			Segment 3		
	Low	Best	High	Low	Best	High	Low	Best	High
Initial rate (Mscf/d)				2074	2074	2074	Continued from segment 2		
b-value				1	1.1	1.2	0	0	0
Decline rate (%)				55	50	45	8	8	7
Length of segment (yr)				10.7	9.6	10.1	17.6	21.6	27.1

A RF check is perhaps easier for this well, as its drainage area has been defined by the existence of producing offset wells (≈ 107 acres or 5 wells/section). Based on this drainage area, the recovery factor ranges from 50-65%. All three forecasts are shown and compared to the actual production history that was withheld in Figure 23.

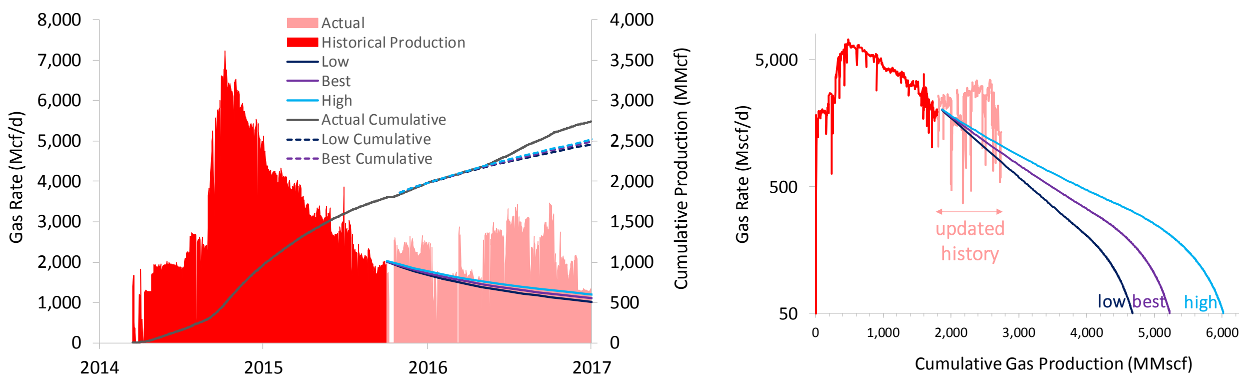

Figure 23: Reserves evalutor production forecasted gas volumes compared to actuals – Well C

RTA Evaluation

The diagnostic RTA for Well C is shown in Figure 24. It suggests linear flow with an early transition, similar to Well B. However, Well C's performance is complicated by several discontinuities in its diagnostic signature.

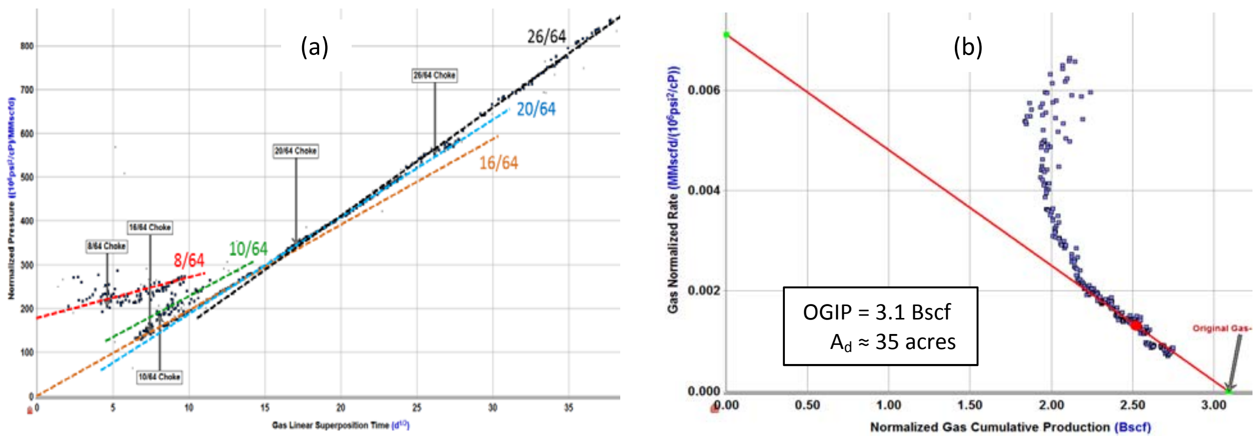

Figure 24: Diagnostic RTA – Well C

Upon closer inspection, Well C exhibits successive increases in slope on the Linear Flow Specialized plot coincident with three separate choke adjustments. The discontinuities appear to indicate a reduction in total productive frac area when the choke size is increased, which is an expected result of strong pressure dependent rock (and/or fracture) properties. Estimated permeability and fracture half-length are 237 nd and 206 ft, respectively. The Flowing Material Balance analysis indicates a contacted drainage area of about 35 acres after 2.8 years of production. A numerical model history match for Well C is shown in Figure 25. The model includes pressure dependent permeability, as confirmed by the diagnostic plot.

The updated production history (Figure 26) outperforms the model prediction by a significant margin. There are two reasons for this- i) This well has a 2400 ft standoff distance between end of tubing (2-7/8″) and total depth and therefore is likely suffering from significant liquid loading. Thus, the true bottomhole flowing pressures are likely much higher than those calculated by the model. ii) The spikes in gas rate and water that occurred during the withheld segment of the data suggest frac hits from offsets which provide an additional influx of pressure support into the system. The combination of these two factors leads to a significant under prediction of the model.

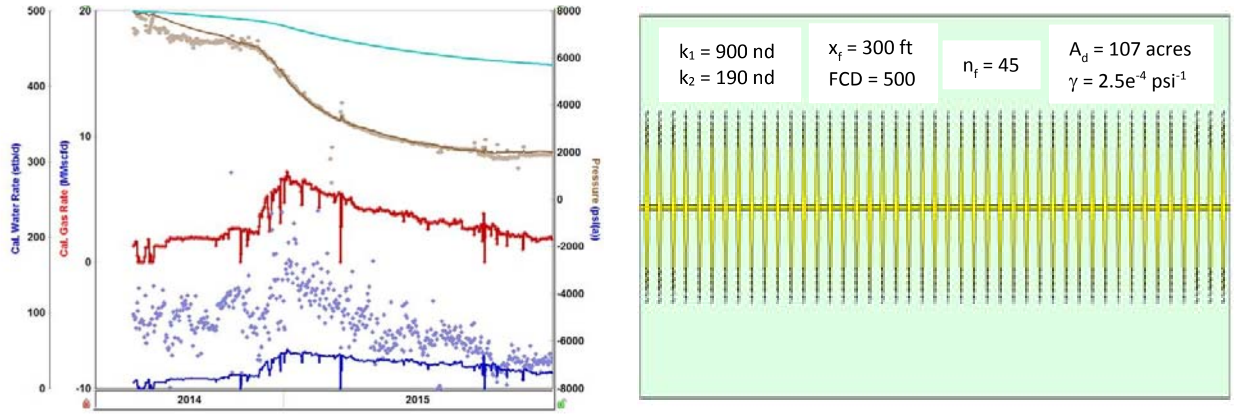

Figure 25: RTA Model History Match- Well C

Figure 26: Production forecasts with comparison to actual production history – Well C

Figure 27 shows a corrected model, taking into account the likely influence of liquid loading. This model yields a more realistic long term forecast (Figure 28).

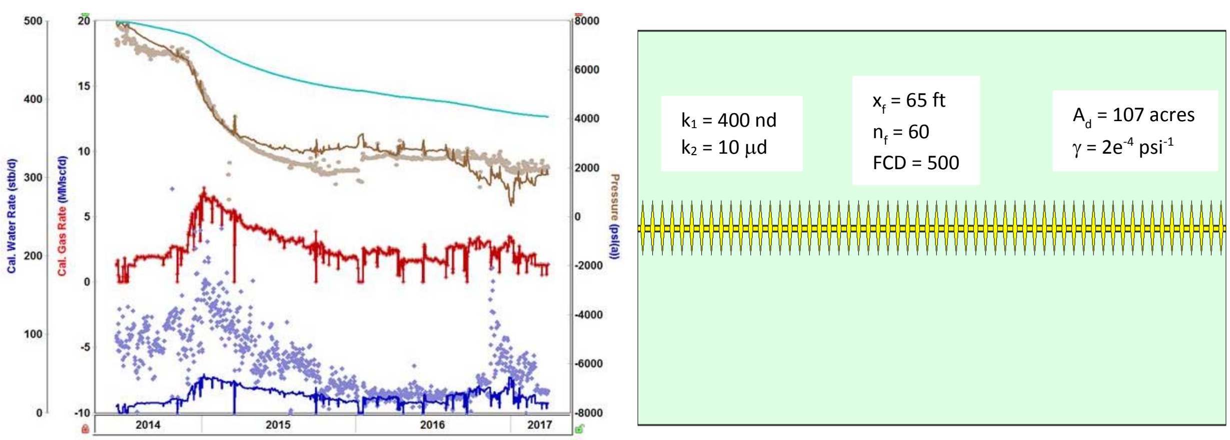

Figure 27: Corrected History Match – Well C

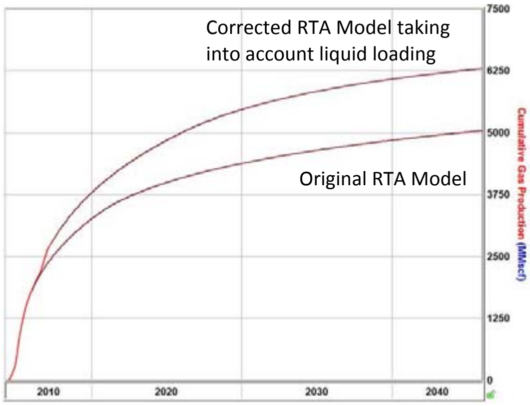

Figure 28: Corrected Model Forecast vs Original Model Forecast – Well C

Figure 29 shows the dependence of recovery factor and EUR on drainage area (well spacing). One way to interpret this plot is to say that drilling two wells at 80 acres/well will recover 12 bcf, whereas drilling a single well will recover 9.5 bcf. Thus, the two well case only recovers an incremental of 2.5 bcf (1.25 bcf / well). This suggests that significant interference takes place 80 acre spacing – an unusual result for shale gas. This stands in stark contrast to the reserves picture for Well A, which shows that two wells drilled at 80 acre spacing yield an EUR very close to 2X that of a single well at 160 acres. The primary reason for this discrepancy is permeability – Well C has 10 μd (initially), whereas Well A has 500 nd.

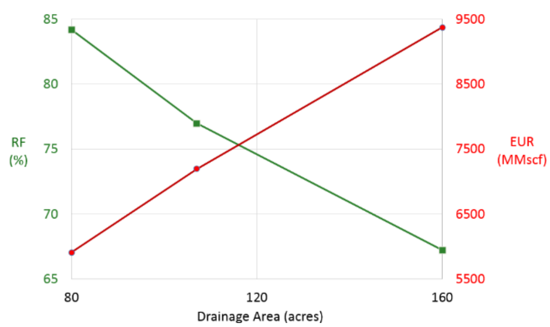

Figure 29: Corrected RTA Model EUR and RF results as a function of drainage area – Well C

Figure 30 provides a "bridge" to the reserves evaluation workflow, in that RTA provides a defensible terminal decline rate (d_{lim}) as a function of drainage area. These limiting decline rates should be used in the reserves evaluators' 3-segment decline curve workflow, once the drainage area for each well has been determined, based on a particular well spacing scenario. It should be noted that all forecasts declined with a b-value of 1 before transitioning to terminal decline (b-value of 0).

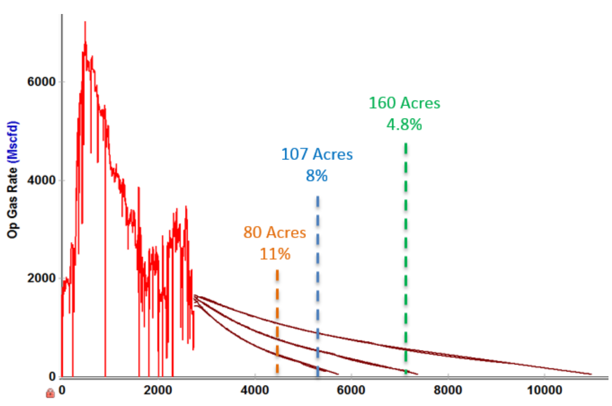

Figure 30: RTA model forecasts illustrating terminal decline (d_{lim}) as a function of drainage area – Well C

Results

Table 5: 30-year forecasting results based on a 20-acre drainage area – Well A

	DCA (b-value = 1) Truncated History	Reserves Evaluation Truncated History			Original RTA Model Results Truncated History			Corrected RTA Model Forecast Full History
		Low	Best	High	Low	Best	High	
EUR (Mbbl)	118	112	176	225	188	197	206	360
OOIP (Mbbl)	4019	4019	4019	4019	4019	4019	4019	4019
RF (%)	3	3	4	6	5	5	5	9

Table 6: 30-year forecasting results based on a 60-acre drainage area – Well B

	DCA (b-value = 1) Truncated History	Reserves Evaluation Truncated History			Original RTA Model Results Truncated History			Corrected RTA Model Forecast Full History
		Low	Best	High	Low	Best	High	
EUR (Mbbl)	188	193	272	325	328	328	372	368
OOIP (Mbbl)	2336	2336	2336	2336	2336	2336	2336	2336
RF (%)	8	8	12	14	14	14	16	16

Table 7: 30-year forecasting results based on a 107-acre drainage area – Well C

	DCA (b-value = 1) Truncated History	Reserves Evaluation Truncated History			Original RTA Model Results Truncated History			Corrected RTA Model Forecast Full History
		Low	Best	High	Low	Best	High	
EUR (Bscf)	4.64	4.67	5.23	6.00	4.99	5.04	5.04	7.29
OGIP (Bscf)	9.38	9.38	9.38	9.38	9.38	9.38	9.38	9.38
RF (%)	49	50	56	64	53	54	54	78

Table 8: Comparison of actual cumulative volumes against forecasted volumes – all wells

	Actual Cum Volumes	DCA (b-value = 1)	Reserves Evaluation			Original RTA Model Results		
			Low	Best	High	Low	Best	High
Well A (Mbbl)	100	77	77	98	108	82	96	99
Well B (Mbbl)	103	91	97	117	124	88	107	114
Well C (Bscf)	2.74	2.40	2.46	2.49	2.52	2.42	2.44	2.55

Discussion

It is worth noting that the reserves evaluation and RTA workflows were conducted entirely independently of one another by practitioners with different skill sets and different preconceptions about how oil and gas data ought to be evaluated. Upon review of the process and results, we can see some similarities, but also some major differences.

Reserves evaluators focus on the reliability of the aggregate system forecast, without worrying too much about individual samples. This is necessary because their projects often encompass very large properties containing hundreds or thousands of individual well samples. This study was perhaps unfair, as the reserves evaluator was not provided any of the supporting information they usually require, only the detailed well data for the three wells (in very different geological areas of the Vaca Muerta). In contrast, rate transient analysts focus explicitly on individual samples, requiring a rich supporting data set for each well that is analyzed. As such, this study was more aligned to the RTA practitioner's way of thinking than that of the reserves evaluator. In RTA, neighboring wells in an asset are often treated (almost) entirely independently, even if reservoir characteristics are similar. When reserves evaluators generate a forecast for an individual well, there is a strong overprint of the "type well" in which is embedded statistical intelligence for the field. Consideration for operating conditions is usually limited to the highest impact wells. RTA forecasts rely heavily on the individual well operating conditions, completion characteristics and production signature. Despite the differences, the methodologies yielded forecasts that were not dissimilar, and both evaluators had similar observations about the well data that they were analyzing.

Conclusions

The reserves evaluation and RTA methodologies yielded three forecasts for each of the three Vaca Muerta examples- Low (assuming pessimistic operating conditions and/or decline characteristics), Best (assuming most-likely production characteristics) and High (assuming the most optimistic operating conditions and/or decline characteristics). These were compared against a baseline, constructed using an easily repeatable harmonic decline curve, based on a best fit of the (truncated) production history. The resulting EURs are shown in Tables 5-7.

The two approaches provided forecasts that were directionally consistent with one another (there were no major disconnects). However, the reserves evaluation approach consistently yielded a larger range between low and high EURs than that of the RTA approach. This suggests that the RTA methodology leads to the evaluator having higher confidence in their results than does the standard reserves evaluation approach. This is not surprising, as RTA requires more data, specialized expertise and effort for the evaluation of an individual well and therefore practitioners will undoubtedly have greater confidence in their forecasts than if a simpler method were used. The validation component of this study, using the withheld data, suggests that this confidence may very well be overstated as the RTA results were no better than the results provided using the standard reserves evaluation workflow (Table 8). The premise of overstated confidence derived from expert analysis is a well-documented psychological product of the human condition known as evaluator bias (Rajvanshi et al. 2012).

In addition to demonstrating greater confidence, the RTA forecasts also appear to be consistently more optimistic, on average, than their reserves evaluation counterparts. This is an interesting result, and is also not entirely unexpected. RTA is model-based and is therefore relies on an idealized perception of the well, reservoir and future producing conditions. Often the reality of long-term production contains a great deal of non-ideal variance from those models, usually in the downward direction. An experienced reserves evaluator, having likely seen long-term production profiles from many more wells than the typical RTA practitioner, will implicitly include this previously experienced realism in their evaluation.

So, does RTA add any value to this process? Indeed it does. The inclusion of RTA in a reserves evaluation workflow, particularly in cases that have limited production history in a green field scenario, and/or complicated reservoir and producing conditions (all of which are present in our case study) allows the evaluator to understand what drives production and how recovery will respond to changes in the system, both at the well scale and at the larger field development scale. As we saw with Well A, understanding how production responds to different operating conditions is at least as important as being able to predict future production volumes. Another benefit provided by RTA was its ability to predict how recovery is impacted by well spacing. Without these (and other) learnings, the evaluation of reserves could become static and unresponsive to changes in well design, completion technology and field development strategies. It may be a good predictor for one snap shot in time, but requires the evaluator to be in tune with how an asset or play is evolving. A workflow that includes RTA allows the evaluator to have a dynamic understanding of reserves with a far greater texture than one that does not, particularly when there just isn't a sufficient statistical sample size. Unfortunately the Achilles Heel of an "RTA-only" approach is the previously mentioned evaluator bias, leading to overconfidence in forecasting. However, if the experienced reserves evaluator and the RTA practitioner work closely together (in this study, they did not!), the benefits of both of their skill sets can be brought to bear on the difficult problem of understanding unconventional reservoirs in a green field scenario.

Nomenclature

A_c	=	*total cross-sectional area to flow, ft*^{2}
A_d	=	*drainage area, acres*
c_t	=	*total compressibility, psi*$^{-1}$
d_{lim}	=	*terminal decline rate*
ϕ	=	*porosity*
FBHP	=	*flowing bottomhole pressure*
FCD´	=	*dimensionless apparent fracture conductivity*
FMB	=	*flowing material balance*
G_p	=	*cumulative gas production, MMscf or bcf*
h	=	*net thickness, ft*
k	=	*permeability, md or nd*

N_p	=	*cumulative oil production, Mstb*
OOIP	=	*original oil in place, Mstb*
OGIP	=	*original gas in place, MMscf or bcf*
P_i	=	*initial reservoir pressure, psi*
p_{wf}	=	*bottomhole flowing pressure, psi*
q	=	*flow rate, stb/d or Mscf/d*
RF	=	*recovery factor*
SRV	=	*stimulated rock volume*
t_{elf}	=	*end of linear flow*
x_f	=	*fracture half length, ft*

References

Anderson, D.M. and Mattar, L. 2003. "A Systematic and Comprehensive Methodology for Advanced Analysis of Production Data". SPE 84472 presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, 5-8 Oct

Anderson, D.M., Nobakht, M., Moghadam, S. and Mattar, L. 2010. "Analysis of Production Data from Shale Gas Wells". SPE 131787 presented at the SPE Shale Gas Production Conference, Pittsburgh, Pennsylvania, 23-25 Feb

Fernandez Badessich, M. and Berrios, V. 2012. "Integrated Dynamic Flow Analysis to Characterize an Unconventional Reservoir in Argentina: The Loma La Lata Case". SPE 156163 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, 8-10 Oct

Liang, P., Mattar, L. and Moghadam, S. 2011, "Analyzing Variable Rate/Pressure Data in Transient Linear Flow in Unconventional Gas Reservoirs". CSUG/SPE 149472 presented at the Canadian Unconventional Resources Conference, Calgary, Alberta, 15-17 Nov

Liang, P., Thompson, J.M. and Mattar, L. 2012. "Importance of the Transition Period to Compound Linear Flow in Unconventional Reservoirs". SPE 162646-MS presented at the Canadian Unconventional Resources Conference, Calgary, Alberta, 30 Oct – 1 Nov

Mattar, L. and Anderson, D.M. 2005. "Dynamic Material Balance (Oil or Gas-in-Place Without Shut-Ins)". CIPC 2005-115 presented at the Canadian International Petroleum Conference, Calgary, Alberta, 7-9 Jun

Okouma, V., Guillot, F., Sarfare, M., Sen, V. Ilk, D. and Blasingame, T.A. 2011. "Estimated Ultimate Recovery (EUR) as a Function of Production Practices in the Haynesville Shale". SPE 147623 presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, 30 Oct – 2 Nov

Rajvanshi, A.K., Gmelig Meyling, R. and ten Haaf, D. 2012. "Instilling Realism in Production Forecasting: Dos and Don'ts". SPE 155443 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, 8-10 Oct

Stalgorova, E. and Mattar, L. 2012. "Analytical Model for History Matching and Forecasting Production in Multifrac Composite Systems". SPE 162516 presented at the SPE Canadian Unconventional Resources Conference, Calgary, Alberta, 30 Oct – 1 Nov

Thompson, J.M., Nobakht, M. and Anderson, D. 2010. "Modeling Well Performance Data From Overpressured Shale Gas Reservoirs". SPE 137755 presented at the Canadian Unconventional Resources and International Petroleum Conference, Calgary, Alberta, 19-21 Oct