Peyto Exploration & Development Corp.
President's Monthly Report

October 2011 | From the desk of Darren Gee, President & CEO

The end of September marks the eighth straight quarter of profitable production growth at Peyto. What a run it has been, doubling production over the last two years! Thankfully, it has been the perfect environment to be aggressively investing in new natural gas development projects. Service costs have remained at reasonable levels, with only modest inflation in service rates, while at the same time we've been able to more than offset those increases with reduced drilling times and lower overall costs. I suspect service inflation will stay reasonably low for a while yet if these latest oil prices hold.

As in the past, this report includes an estimate of monthly capital spending, as well as our field estimate of production for the most recent month (see Capital Investment and Production tables below).

Capital Investment

*2011 Capital Summary (millions$ CND)**

	2010	Jan	Feb	Mar	Q1 '11	Apr	May	Jun	Q2 '11	July	Aug
Land & Seismic	18.5	-1	2	5	6	0	1	1	1	1	7
Drilling	140.5	15	16	20	51	13	10	9	32	17	14
Completions	65.3	12	11	10	33	8	4	5	18	8	10
Tie ins	30.3	2	2	3	7	2	1	1	5	4	3
Facilities	19	3	3	2	8	4	4	8	16	4	6
Drilling Credit Used	-7.6	0	0	0	0	-1	0	-2	-3	0	0
Sub Total	**266**	**29**	**34**	**41**	**104**	**26**	**20**	**22**	**69**	**33**	**40**
Rem. Drilling Credit	-4.1	0	0	0	**0**	0	0	0	**0**	0	0
Total	**262**	**29**	**34**	**40**	**104**	**26**	**20**	**22**	**69**	**33**	**40**

****This is an estimate based on real field data, not a forecast, and the actual numbers will vary from the estimate due to accruals and adjustments. Such variance may be material. Tables may not add due to rounding.***

Production

*2010/11 Production ('000 boe/d)**

	Q4 09	Q1 10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11	Jul	Aug	Sept	Q3 11
Sundance	15.9	16.5	18.5	20.1	24.6	28.0	30.2	31.2	32.1	33.8	32.7
Kakwa	2.4	2.8	2.7	2.6	2.6	2.6	3.2	2.9	3.1	3.1	3.1
Other	1.1	1.3	1.1	1.0	1.1	1.1	1.1	1.0	1.0	1.0	1.0
Total	**19.4**	**20.6**	**22.3**	**23.8**	**28.2**	**31.7**	**34.4**	**35.1**	**36.2**	**37.9**	**36.7**

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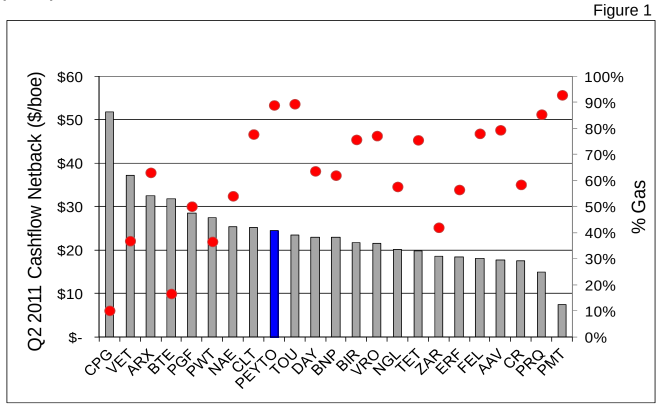
A Test of Materiality

I just returned from presenting at an industry conference down east and was amused by the HSBC signs in the airport terminal advertising *Perspective*; a picture of a high healed shoe and a chili pepper to illustrate one person's pain is another's pleasure, and vice versa depending on their perspective. It made me think about how important perspective is when looking at all the data we do, on a day to day basis, whether we're evaluating an investment, reviewing a drilling result, or judging a company's performance.

Even just looking at a cross section of the industry's cash netbacks (Figure 1), we see substantial variance and the need for many data points to put any one number into perspective.

Figure 1



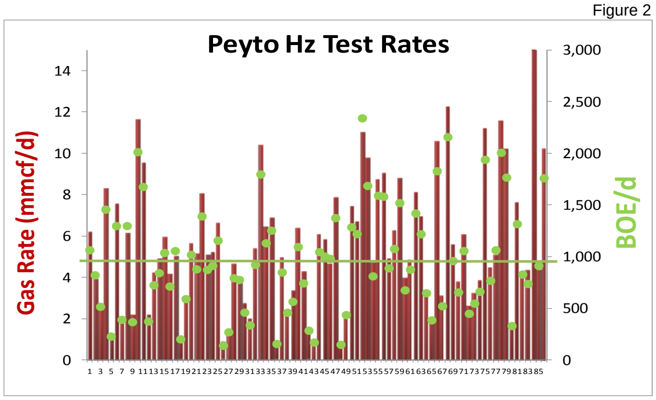
At times though, perspective alone isn't enough. Often times we also need context to make sense of the information. In the case above, for instance, knowing the % of oil or gas that makes up a company's production base, puts the netback into context.

Sometimes context is forced upon the distributor of the information. Like in the case of reserves or resources, National Instrument 51-101 requires that disclosure must put reserves information in context by providing things like effective date, evaluator, evaluation method, materiality and so on.

It's too bad that the same type of context isn't required for other information that is disseminated these days, like well test rates. Too often, we are reading about operational updates that include test results from individual wells without perspective or context.

For instance, a 10 mmcf/d gas test rate from a new well in Alberta used to be a big deal. That's because our perspective was from an average well of a few years ago that was less than 1 mmcf/d. Now, with all the horizontal multi-stage frac wells being drilled, a 10 mmcf/d test rate is quite commonplace. Have a look at Peyto's test results over the last year and a half using that exact well design. Figure 2 shows the first 86 horizontal MSF wells that Peyto has drilled and their corresponding test rates, both gas and total boe/d. For some context, these test rates were taken at the end of the cleanup flow period (typically 2-3 days) when the wells were generally producing inline to sales. Because we were able to sell the tested gas, you know there was very little Nitrogen or Carbon Dioxide, used in the frac fluid, remaining in the gas stream.

Figure 2



You can see that Peyto has tested wells anywhere from 1 mmcf/d up to 17 mmcf/d with many testing in excess of 10 mmcf/d. When you include the liquids, the average well tested close to 1,000 boe/d. From a historical perspective, these are impressive numbers. But the question we should really be asking is, "How material are these results in today's world?" Within the context of the very early time in the well's life, the capital cost of the wells, the size of the resource base they are going to produce from, and the costs to take this production to sales, are these test rates worthy of disclosure and do they make a material impact on the value of the companies disclosing them? At Peyto, we have always taken the approach that they are not material.

When you read that a Montney well, for instance, was testing at 15 mmcf/d with 50 bbl/mmcf of NGLs in some company's operational update, and that's all the information you get, you really have to discard that information as meaningless. There are just too many questions left unanswered that are required to put that test into context. Consider, for example, the following:

1. A multi stage fracture of a typical horizontal well can use 5,000-6,000 kilowatt hours of energy to put the frac into the formation. How long before that artifically enhanced drive is gone and the true reservoir drive is experienced? Sometimes its actually the poorest reservoir quality that initially flows back the fastest.
2. Of the fluids tested, how much is fracture fluid; either water or oil? Do the rates include the N_2 and CO_2 that is added to the frac fluid for energy? Often times the early time data is mostly frac fluid (or gases) coming back.
3. What is the flowing pressure of the well relative to the reservoir pressure and abandonment pressure? In other words, is the well producing at it's maximum capability or just a fraction of it.
4. How quickly will that near wellbore flow rate decline to reach a steady state flow rate, as supported by the surrounding reservoir rock?
5. What is the captial cost to drill, complete, equip and tie in that well relative to any other well?
6. What are the op costs/royalties the well will have to pay?
7. What components of the production need to be removed and disposed before sales? What is that cost?
8. What is the typical drainage area that the well can be expected to drain and how much recoverable reserves are in that area?
9. How long will it take to get the well tied in and on stream, producing revenue?
10. How long to recover the capital investment and what is the value left to recover after that payout?

The amount of context required to make any flow test data meaningful is significant. Even when all is said and done, and you've determined that say, for every well like this the company has built a $10 million dollar asset for a $5 million dollar capital investment, now you still have to decide how material it is. Relative to the company's size, a few of these wells a year could be material or could be immaterial. Or if the company has hundreds of these in inventory, the pace at which they can or cannot develop them now determines materiality.

I think investors should demand that enough context be disclosed if a company wants to share well test results, so they can assess whether the tests really mean anything. Barring that, perhaps it will be the securities regulators that have to draft disclosure rules so investors get what they need to judge whether a single well test is material or not.

Activity Update and Commodity Prices

Oil prices have backed off again, and with it the Canadian dollar. Its good news for us, as a lower Canadian dollar, relative to the US, improves the AECO natural gas price. At the same time, a lower oil price slows down the oil sands and conventional oil activity in Alberta which drives down oilfield service costs. Hopefully this environment will continue for at least another year.

Figure 3