Peyto Exploration & Development Corp.
President's Monthly Report

April 2012 From the desk of Darren Gee, President & CEO

Predicting weather (sorry, *"climate change"*) on this planet has to be one of the most challenging jobs of all. The only solace being, that you can be completely wrong and nobody holds you accountable. This was never more evident than this past winter where all the predictions were for cold in the NW portion of North America and tons of snow along the east coast. Now that winter is over (11 BCF of natural gas injection last week makes it official) these predictions couldn't have been further from the truth. My friends in Toronto and New York still have dust on their snow shovels, the ski resorts in Western Canada received all the snow they could handle and it was Europe that got all the cold weather. Sadly, we are not yet in a position to send Europe our natural gas to heat their homes so instead we've got way too much gas in storage heading into the injection season. This supply/demand imbalance has tipped the scales and caused gas prices to plummet, creating very little incentive to bring on new flush production this spring. Thankfully, as with the weather, this too will change. Figure 1 shows Peyto's daily production trend versus the past and currently forecasted Alberta gas price.

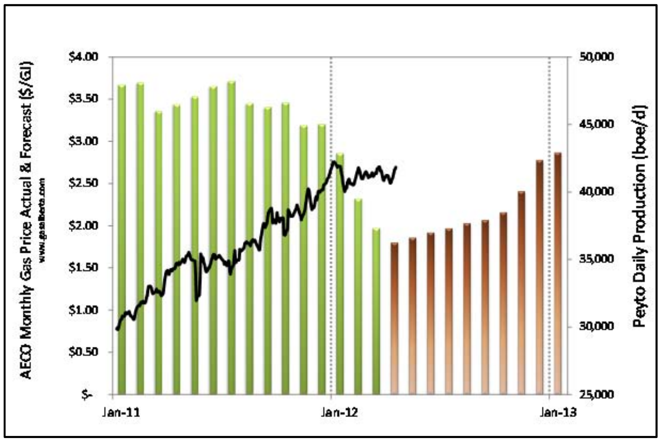

Figure 1 Source: Peyto, www.gasalberta.com

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

*2011/12 Capital Summary (millions$ CND)**

	2010	Q1	Q2	Q3	Oct	Nov	Dec	Q4	2011	Jan	Feb	Mar	Q1 '12
Land & Seismic	18.5	6	1	14	6	0	1	7	28	2	0		
Drilling	140.5	51	32	46	15	19	15	49	178	20	19		
Completions	65.3	33	18	26	11	9	8	28	104	10	11		
Tie ins	30.3	7	5	10	4	2	5	10	32	2	4		
Facilities	19	8	16	16	0	0	0	0	40	1	3		
Drilling Credit Used	-7.6	0	-3	0	0	0	0	0	-3	0	0		
Total	**262**	**104**	**69**	**112**	**35**	**30**	**29**	**95**	**379**	**35**	**36**		

****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

*2011/2012 Production ('000 boe/d)**

	Q1 11	Q2 11	Q3 11	Oct	Nov	Dec	Q4 11	Jan	Feb	Mar	Q1 12
Sundance	28.0	30.2	32.3	34.5	34.9	35.9	35.1	35.7	35.7	34.8	35.4
Kakwa	2.6	3.2	3.0	3.1	3.2	3.9	3.4	3.6	3.7	4.0	3.7
Other	1.1	1.1	1.0	1.0	1.4	1.5	1.3	1.7	1.8	2.5	2.0
Total	**31.7**	**34.4**	**36.4**	**38.6**	**39.5**	**41.3**	**39.8**	**41.0**	**41.2**	**41.3**	**41.1**

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Last Man Standing

Being one of the lowest cost producers of natural gas in North America means we are constantly looking for ways to keep costs down. That means looking at what many of our low cost competitors are also doing. The challenge is identifying those competitors when everybody is claiming to be low cost. Is it the play they're in that's low cost or is it what they are doing corporately? That's why its important to look for pure play companies, to see the real cost structures in those plays manifested in the company's financial performance. When the question becomes the reverse, who are the high cost producers, the same methods can also be used.

Lately, with natural gas prices so low, the market and the industry are all looking to see when the high cost production starts to be shut in. As much as low prices will drive less drilling activity and bring on less new supply, it is *really* low prices that will drive the shut ins and correct the glut of storage that the warm winter has created.

According to the most recent storage figures, there is some 835 BCF of gas in storage today that usually isn't there. Which means getting back to normal is going to require the industry to shut off the valve for a while.

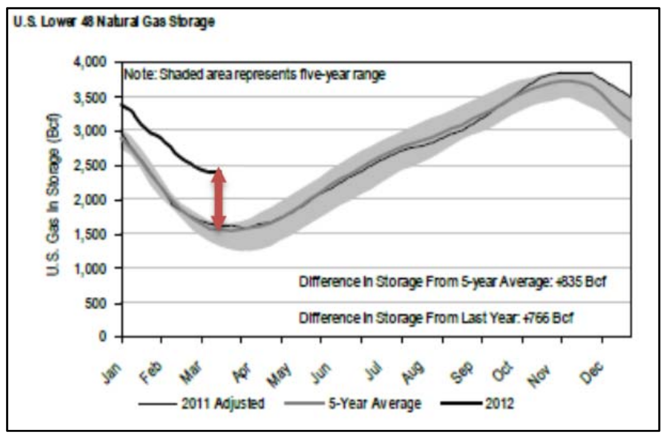

Figure 2, Source: CIBC

If, for example, we saw 10 BCF/d shut in for 83 days, then we should be right back to where we normally would be. That is, right back to the $3.50/GJ AECO and $4/mmbtu NYMEX gas price world that we had last year. Conversly, if we had 6 BCF/d more demand from power generation, than we normally have, which is what is currently happening, then we'd only have to shut in 4 BCF/d for those same 83 days.

So the big question in my mind is, who's 4 BCF/d is it? Logically, it's the 4 BCF/d with the highest cost and lowest revenue. But every gas producer in North America is saying that's not me, it must be him and pointing the finger outward.

If proportionately, the Western Canadian Sedimentary Basin, has to take its share of shut ins, or around 18% (14 BCF/d in Canada out of 78 BCF/d in N.A.), we can likely deduce where the first 0.75 BCF/d (18% of 4 BCF/d) should come from. The NEB summarizes the different regions of gas production in the following map, on which I've highlighted four areas: NE BC, NE AB, SE AB and Central AB,. These areas make up around 2.3 BCF/d of the 14 BCF/d in the WCSB.

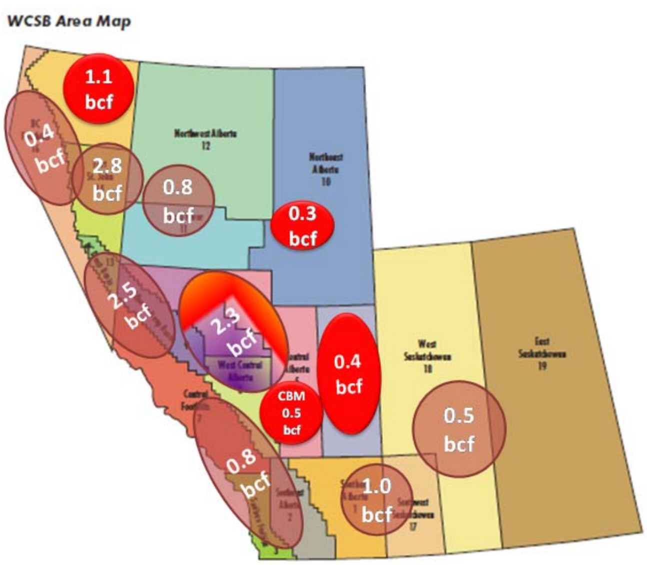

Figure 3: Source NEB

These four areas traditionally have higher cost production, either due to low pressure or high transportation and processing costs, and they have lower revenue due to a lack of NGL content in the gas stream (ie. pure Methane). I would suspect these four areas are the first to go. In addition, the sour gas portion of Central Alberta falls into the high cost bucket.

If we look for pure play producers in those areas and analize their cost structure we quickly see that today's natural gas price has put them under water.

Unfortunately, most of the production in these areas is controlled by large integrated major producers, so the shut ins will likely occur without a lot of fanfare.

When February and March 2012 prices start to show up in lease operating statements run in April and May, the shut ins should start to materialize in significance. The same goes for the other 82% of North American production in the US. There needs to be another 3.25 BCF/d out of 64 BCF/d down south upon which the valve also closes. Then we can really start to chip away at the storage excess.

Activity Update and Commodity Prices

Breakup has begun with spring weather beginning to thaw the roads and ground in Alberta. County road bans are preventing heavy traffic from 10 AM to 10 PM which causes delays and extra cost for most drilling, completion and pipelining operations. This last round of Peyto wells that have recently been drilled will have to wait until after breakup to be completed and brought onstream. That's okay, as the prices we receive for the gas will likely improve by then too, if the forecast in Figure 1 actually happens. Third party tie ins on some of our emerging plays can wait until then too, since the processing fees will be higher. And the bottom hole chokes that we were going to pull, to increase the production from some of our higher productivity wells, can just stay put. There's no point in exposing more flush production to even lower natural gas prices.

I would not be surprised to see the gas rig count drop to virtually zero during breakup this year. With gas prices at circa 1999 levels, seeing the gas rig count drop to 26 rigs like it did in 1999 would tend to correlate.

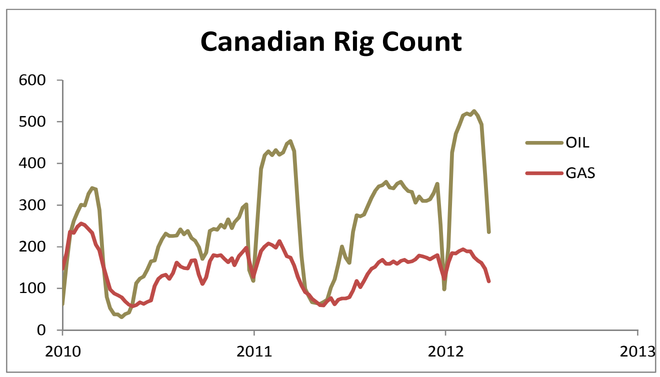

Figure 4 Source: Baker Hughes