March 13, 2017

PLS

CANADIAN SCOUT

E&P

Serving the Canadian upstream industry with information, analysis & prospects for sale

Volume 26, No. 04

Regional Activity

February Top 10 Alberta Operators by Permit Count	
Fort Hills Energy Corp	36
Canadian Natural Resources Ltd	34
Tourmaline Oil Corp	29
Peyto Corp	24
Long Run Exploration Ltd	23
MEG Energy Corp	21
Devon Canada Corp	17
Seven Generations Energy Ltd	15
Cenovus Energy Inc	13
Cenovus FCCL Ltd	13
Total	225

Permits by Formation

Permit by Zone	Feb	Jan	Dec
McMurray Fm	64	45	49
Montney Fm	46	53	72
Wilrich Mbr	28	36	9
Viking Fm	27	75	27
Quaternary System	21	-	-
Mannville Grp	20	9	10
Lloydminster Mbr	18	16	24
Cardium Fm	16	46	42
Notikewin Mbr	15	7	11
Other	147	173	266
Total	402	460	510

Source: PLS Research

Canada oil sands become less foreign

Canada's oil and gas sector is starting to recover, but not all parts are being revived equally. **Canadian Natural Resources Ltd.'s** $12.7 billion acquisition of a 17% stake in **Shell** and **Marathon Oil's** oil sands assets was the latest instance of foreign oil companies scaling back their costly oil sands portfolios, following **Statoil's** sale to **Athabasca Oil Corp.** earlier this year. Shell sold its entire 60% WI in the Athabasca Oil Sands Project project, 100% WI in the Peace River Complex in-situ assets, including Carmon Creek, and 100% WI in the Cliffdale heavy oil field, as well as several undeveloped oil sands leases in Alberta ranging from 60-100% WI.

Statoil, Shell & Marathon sell down.

In the second deal, Shell and **CNRL** will pay **Marathon Oil** US$1.25 billion each to jointly acquire and equally own its Canadian subsidiary **Marathon Oil Canada Corp.** (MOCC), which holds 20% non-operated WI in AOSP.

Continues On Pg 18

Chevron positioning for big Duvernay Kaybob buildout

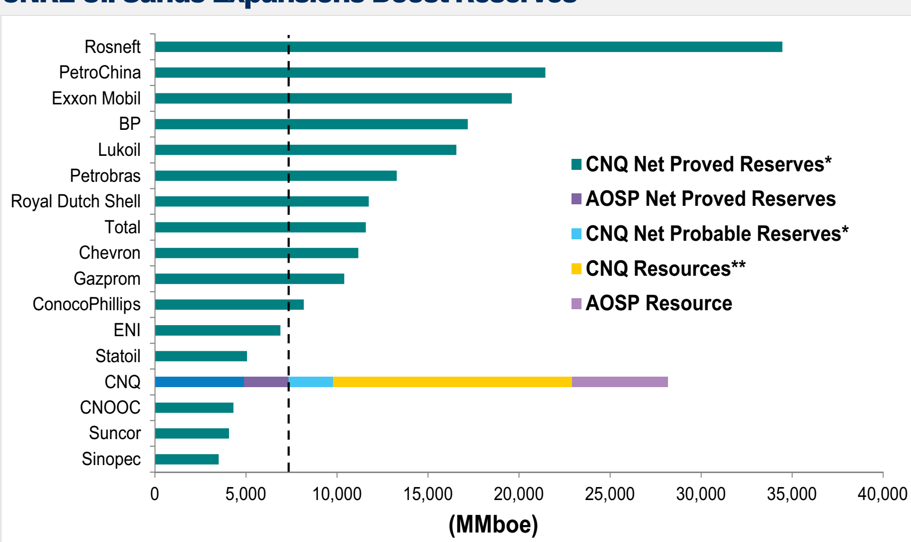
Chevron is taking steps to develop its substantial holdings in the liquids-rich Duvernay Kaybob play near Fox Creek, Alberta, by putting in place a midstream agreement with **Pembina Pipeline Corp.** Under the deal, Pembina will have the right to construct, own and operate gas-gathering pipelines and processing facilities, liquids stabilization facilities, and other supporting infrastructure should Chevron go ahead and develop its assets in the play. Chevron did not indicate when it might move on the project, but given industry trends it could be soon.

Agreement with Pembina builds on May deal for an initial 100 MMcf/d plant.

Chevron's agreement with Pembina is similar to one put in place between **Encana** and **Veresen** in the BC Montney, where Encana plans to drill wells to boost its gas liquids output to 70,000 bbl/d in 2019. Like the Duvernay, the Montney is poor in infrastructure and one of the more expensive places to drill horizontal wells in Canada.

Continues On Pg 4

CNRL Oil Sands Expansions Boost Reserves



* Company net proved and probable reserves as at December 31, 2016 .

** Company net best estimate contingent resources other than reserves as at December 31, 2013.

Source: CNRL March 9 Presentation via **PLS docFinder www.plsx.com/finder**

DEALS FOR SALE

SASKATCHEWAN NONOP SALE

2-Key Units. ~6,026-Net Acres
WEYBURN & MIDALE AREAS.
Marly & Vuggy Zones
~3-10% NonOperated WI Available
Net Production: 1,202 BOPD
Exp 2017 Net Income: ~$1,191,666/Mn
2016 Proven Reserves: 6,058 MBOE
Net Proven PV10: $81,776,000
AGENT WANTS OFFERS MARCH 2017
PP 13555DV

PP
~1,200 BOPD

WESTERN CANADA ASSETS

73,326-Net Acres.
ALBERTA & SASKATCHEWAN
Producing From Mannville Group
93% OPERATED WORKING INTEREST
Current Production: 2,063 BOED
Est 2017 Cash Flow: $1,450,000/Month
Total Proved Reserves: 5,101 MBOE
AGENT WANTS OFFERS MARCH 2017
PP 13187DV

PP
~2,000 BOED

Drilling & Production

Crew finds condensate-rich window at West Septimus

Delineation of **Crew Energy's** BC Montney lands continued in 2016 with successful results from new stratigraphic intervals and confirmation of an ultra-condensate-rich window in the West Septimus area that holds six times the condensate Crew has found elsewhere in the play. The company's initial two wells produced 740 boe/d (46% condensate) and 700 boe/d (51% condensate) after 90 and 145 days, respectively, leading to a significant reserve addition at West Septimus.

Two West Septimus wells in NE BC see condensate load range 46-51%.

These well results contributed to the booking of 41 undeveloped ultra-condensate-rich drilling locations at West Septimus with a combined 37.5 MMboe 2P EUR (26% condensate).

Given the capital cost for each of these two delineation wells was $4.3 million, including a 40-stage open-hole completion using two tonnes of sand per meter, Crew is eager to pursue more work in this area. It is planning to construct two six-well pads here in mid-2017, which could lead to up to 165 such locations eventually being booked.

Initial 2-wells lead booking 41 locations, but up to 165 ikely to be booked.

Crew's 4Q16 and full-year production at Greater Septimus totaled 17,300 boe/d and 17,800 boe/d, respectively. Volumes were 59% higher than in 2015 and 21% higher than 4Q15 due to continued drilling and completions activities focused in the ultra-condensate-rich region, which are very economical given current prices. These volumes were achieved despite an eight-day full system shutdown of the Alliance Pipeline, which resulted in all of Crew's Montney operations being shut-in, leading to a loss of 1,750 boe/d.

Crew also continued to see increases in condensate production in proportion to other liquids output, as total NGL volumes in 2016 were 33% higher than in 2015. Operating costs at Greater Septimus also declined 7% from 3Q16's $3.34/boe as a result of improved economies of scale and continued cost reduction initiatives.

CanadianAcquirer Feb. 21

Crew selling heavy oil assets in Alberta & Saskatchewan

Painted Pony rethinks 2017 plans on uncertain prices

Uncertainty over the direction of future commodity prices led **Painted Pony Petroleum** to rethink its 2017 capex and drilling program. Guidance from late last year indicated Painted Pony would spend $319 million in 2017 to drill and complete 61 wells, which would help generate 288 MMcfe/d. Now, Painted Pony says it will send $288 million—10% less than the previously announced $319 million—to drill 58 wells and complete 51. This reduction in activity will impact both 2017 production and plans for 2018.

The revised capex puts Painted Pony on course to produce 260 MMcfe/d. Although 28 MMcfe/d less what was planned under prior guidance, 2017's projected volume will still be an 87% YOY increase over what the company averaged in 2016. Painted Pony also reduced its estimate of what it will do next year as well, noting preliminary thinking on its 2018 capex sees the company drilling 37 wells instead of 42 and spending $216 million as opposed to $385 million. Production in 2018 is in turn expected to now be 360 MMcfe/d.

Canadian Rig Count as of 03/10/2017 (by Province)

	This Wk	Last Wk	Last Month	Last Qtr	6 Mos Ago	Last Year	Change	% Change
Alberta	218	227	246	155	84	61	157	257%
British Columbia	32	32	32	24	13	25	7	28%
Manitoba	5	10	10	3	3	1	4	400%
New Brunswick	0	0	0	0	0	0	0	0%
Newfoundland & Labrador	0	0	0	0	0	0	0	0%
Newfoundland & Labrador Offshore	1	1	2	2	0	3	-2	-67%
Nova Scotia	0	0	0	1	0	0	0	0%
Saskatchewan	59	65	62	45	34	8	51	638%
Quebec	0	0	0	0	0	0	0	0%
Total	315	335	352	230	134	98	217	221%

Source: Baker Hughes

ABOUT PLS

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A tale of two oil industries

Q1 earnings season and release of government data by AER **(PG. 18)** shows that two different Canadian oil and gas industries are emerging from the downturn. The first consists of small-to-mid-sized companies that have staked their future on short-cycle projects that focus on conventional plays, tight formations and shale. Companies like **Raging River (PG. 5)**, **Bellatrix (PG. 9)**, **Painted Pony (PG. 2), TORC (PG. 6)**, **Whitecap (PG. 11)** and **Blackbird (PG. 7)** are using opportunities provided by improved technology, lower costs and, most of all, quick rollout to use the limited upward movement in prices to their advantage.

IN THIS ISSUE

Higher prices lead shale players into growth while oil sands remain moribund.

The situation in Canada's other oil and gas industry is far less optimistic, however. Oil sands and SAGD producers are being squeezed by prices that largely remain too low to justify increased investment, leading to an exit by the big international oil companies. **(PG. 18)** This leaves bitumen production mostly Canada's domestic firms, of which a few, like **Pengrowth (PG. 3)** and **BlackPearl (PG.1)** have announced plans to increase production or expand existing projects. Most are standing pat, however, and spending on synthetic oil production from bitumen is slated to fall 11% this year. **(PG. 18)**

Future of Canadian oil may not be found in bitumen as long supposed.

Although bitumen continues to dominate Canadian production for now, just how long this will remain the case is unclear given widespread uncertainty over prices. A clue may be found in the plans of **Chevron**, which like **Encana**, has signed a major midstream agreement to underpin its future growth in Canada's shale patch. **(PG. 2)** Those plans have yet to be articulated, but if they look like **Shell's (PG. 5)** and **ExxonMobil**'s dive into shale, then the future of oil and gas in Canada may increasingly be found outside of its bitumen deposits.

Drilling & Production

CNRL's Horizon reaches new highs but overall output flat

Canadian Natural Resources' Horizon project tallied record synthetic oil output of 178,000 bo/d during 4Q16, driven by strong performance from existing operations and the continued ramp-up of Horizon Phase 2B. Horizon's volumes as a whole now stands at 202,600 bo/d, or 11% more than the development's design capacity. This is slated to go higher still once Horizon Phase 3, which is slated to increase synthetic oil production at by 80,000 bo/d, starts producing later in Q4.

Volumes from Horizon development now 11% above design capacity.

CNRL also saw record annual production at its steam assisted gravity drainage project at Kirby South, where volumes grew 28% YOY to 37,700 bo/d in 2016. Meanwhile, at Pelican Lake production dropped 9% from 2015 to hit 47,600 bo/d. This decline was limited by the continued use of polymer flood, however, and CNRL as a result has not had to drill there for the past two years. Elsewhere, North American light oil production was once again flat YOY even as heavy oil volumes outside oil sands and SAGD project also fell.

Horizon Phase 3 will increase synthetic oil production at project by 44%.

Overseas, CNRL's production grew 20%, led by strong results in Africa where output at Espoir and Baobab fields in Cote d'Ivoire grew by 37% to 26,100 bo/d despite the occurrence of strikes protesting layoffs. North Sea volumes in turn improved by 6% to 23,550 bo/d due to waterflood optimization at some fields. Altogether, CNRL produced in line with guidance in 4Q16 at the rate of 859,600 boe/d (68% oil and NGLs), up 17% from 3Q16 but otherwise flat YOY from the 855,800 boe/d recorded in 4Q15.

This steady output was in part achieved via a 2016 drilling program that saw 206 gross production, exploration and appraisal wells drilled—35 more than in 2015. Net, CNRL drilled 190 wells across its assets, 50 more net wells than a year prior. The increase was a result of accrued cost efficiencies in drilling operations and the stabilization of oil and gas prices during 2H16, which allowed the company to increase its program as the year progressed.

Pengrowth boosts Lindbergh Phase 2 by 10,000 bo/d

Falling costs at **Pengrowth's** Lindbergh SAGD project in Alberta are leading the company to increase how much oil it expects Phase 2 to produce. Pengrowth received environmental approval for Phase 2 in May 2016, which would have boosted nameplate capacity by 17,500 bo/d to a total of 30,000 bo/d. In late February, Pengrowth amended these plans to allow for Phase 2 to increase output by an additional 10,000 bo/d to 27,500 bo/d total, pushing aggregate volumes at Lindbergh to 40,000 bo/d.

Capacity expansion was made possible by an overall 27% reduction in Phase 2's projected capital cost since May 2015 to an estimated $620 million. In addition to using this $230 million in freed-up capital to engineer more production from Lindberg Phase 2, the savings also allow room for the planned optimization of Phase 1 during 2017. This will consist of drilling seven new well pairs and two infill wells and emplacement of associated infrastructure. This should boost Phase 1 volumes to 18,000 bo/d.

Savings allow for uptick in Phase 1 & Phase 2 volumes to 40,000 bo/d.

By YE17, Pengrowth expects Phase 2 design work to be 70% complete and ready to be executed as funds become available. Company-wide, production this year will average 50,000-52,000 boe/d, which translates into a 9-12% decrease YOY from 2016's 57,000 boe/d and a 17-20% fall in production from 2017.

CanadianCapital Feb. 8

Pengrowth's $125MM plan based on conservative outlook

Drilling & Production

Chevron positioning for Duvernay buildout

Continued From Pg 1

This makes swift roll out of gathering and handling capacity crucial. Encana solved this problem by partnering with Veresen, which will build on its existing midstream assets to support growing Encana production.

Pembina's agreement with Chevron looks to be much larger, however, and could end up translating into a multi-billion-dollar spending program over several years. The arrangement also builds off a deal Pembina made with Chevron in May 2016 to build a 100 MMcf/d shallow-cut gas plant in the Duvernay that will serve as a field hub for the supermajor. The plant, to be in service in 2H17, includes condensate, gas and water field handling, a gas gathering trunk line and a fuel line for a total expected capital cost of ~$130 million.

No FID yet but preliminary midstream plan points to eventual Chevron sanction.

The supermajor re-entered the Fox Creek area in 2009 after divesting in 2004 legacy assets that the company had held since 1957. Today, it owns rights to 330,000 Duvernay shale acres. In 2011, Chevron started a shale exploration campaign at Fox Creek that resulted in 16 horizontal wells drilled, of which 13 were completed using multi-stage fracs. More recently, Chevron commenced a pad drilling program in 2H14 to evaluate production rates and reservoir performance. Chevron owns 70% working interest, with the remaining 30% retained by Kufpec.

Holds 330,000 Fox Creek acres and has been working on pilot pad drilling.

Conoco reports 1.2 Bbo decline in oil sands reserve

ConocoPhillips has followed **ExxonMobil** in writing down a significant amount of Canadian oil sands resources due to new US SEC reporting requirements. The company reduced its developed and undeveloped reserves of bitumen by half to just 1.2 Bbbl. The delisting of these resources accounted for 70% of Conoco's total resource write-off in 2016 of 1.75 Bboe. However, like Exxon, Conoco said it will likely relist the reserves once prices improve.

Conoco made the reserve reductions at its operated Surmont project, where it is partnered 50:50 with **Total**, as well as at the Foster Creek, Christina Lake and Narrow Lakes developments that are operated by **Cenovus**. Total, like Conoco, followed suit in writing down the value of its Surmont reserves, but Cenovus did not as it reports its reserves under Canadian, not US, rules. The difference means that while Conoco was forced to reduce reserves, its 50:50 partner Cenovus' total proved reserves rose 5% YOY.

US reporting rules means Conoco must follow Exxon in oil sands writedown.

Surmont lies 60 km southeast of Fort McMurray and covers 548 sq km. The $1.4 billion SAGD development extracts bitumen from deposits via 146 wells. Phase 1's 30,000 bo/d came on stream in 2007, while Surmont Phase 2—the largest single-stage SAGD project ever undertaken—began producing in September 2015 and is slated to add 120,000 bo/d. Production was on course to reach 150,000 bo/d by the end of 2017, but the 2016 Alberta wildfires forced a delay and as of October Surmont had only reached 100,000 bo/d.

Surmont to hit 150,000 boe/d by YE17 as Phase 2 nears full ramp-up.

Meanwhile, oil sands aren't the only Canadian resource play to be getting less love from Conoco. The company has also decided to sell several of its conventional natural gas assets in the country, and should announce a formal sales offer in the coming weeks. The sale could potentially bring in $2.0 billion and will likely offer assets in the Deep Basin, Clearwater and Kaybob-Edson plays. Conoco does not plan to sell its oil sands assets nor will it sell its Montney properties.

■ **Hemisphere Energy** spent only $2.4 million in 2016 but was able to add 823,000 boe to its 2P reserve base. This puts the company's total 2P position at 4.6 MMboe, split between its assets in south and southeast Alberta. During 2016, the company also produced 585 boe/d. Looking to the rest of 2017, Hemisphere will begin developing the Atlee Buffalo oil pool, which the company discovered in September.

■ **Point Loma Resources** will resume drilling horizontal wells in H1, targeting the West Cove Nordegg oil pool and the Upper and Lower Mannville in Alberta's Paddle River region. The company will also optimize production at its newly acquired Judy Creek asset, which is now producing 400 boe/d. Point Loma is now averaging 900 boe/d, but this will grow to more than 1,000 boe/d once a Thorsby Glauconite well is tied in.

■ **Zargon Oil &Gas's** 4Q16 production was 2,449 boe/d (80% liquids), a 33% drop from 3Q16 due to divestiture of the company's southeast Saskatchewan and Killam, Alberta properties. Production in Q4 was just under Zargon guidance of 2,500 boe/d, which is also the company's full-year 2017 target rate. Zargon's 2P reserves decreased 38% YOY to ~13 MMboe (87% liquids). Capex in 2017 will be $7.8 million—enough to maintain current volumes.

Drilling & Production

Raging River's ERH program exceeding expectations

Raging River Exploration drilled 94 Dodsland Viking wells during Q1, with about a third of them being extended-reach horizontals featuring 1,600-m laterals. These are expected to be big producers for the company given prior results from ERH wells. So far Raging River has a total of 55 ERH Viking wells with more than 30 days of production in its inventory, and on average they have been producing at twice the rate of comparable offsetting 800-m horizontal wells—significantly more than estimated pre-drill.

ERH, waterflood & asset buy should lead Raging River to exceed guidance.

By the end of Q1, Raging River will have brought 106 wells on production, leaving 26 drilled but uncompleted wells left to be put to sales during Q2. Based on YTD field estimates, this program is on track to let the company exceed its announced 2017 guidance of 22,500 boe/d. This trend will likely continue once Raging River's waterflood expansion at Beadle, Plato, Forgan and Gleneath is completed, which will put on stream another 1,300 bbl/d of light oil.

Raging River bought Dodsland Viking property for $58.3MM.

In Q4 Raging River realized sales of 20,450 boe/d (92% oil), a 38% increase YOY from 4Q15. E&P expenditures for the quarter were $76.7 million, resulting in a total of 106 Viking wells being drilled. Raging River also closed on a deal to acquire a Dodsland Viking property for cash consideration of $58.3 million. The buy added ~620 boe/d (97% light oil) of production as well as 24 net sections of land prospective for Viking light oil.

PLS CanadianAcquirer A&D

CanadianAcquirer Jan. 11

Raging River acquires Viking assets for $58 million.

Shell files for pilot SAGD well-pair in Peace River area

A few days after **Shell** announced it would pump part of a $2.0-3.0 billion 2017 shale capex into its liquids-rich Fox Creek assets, Shell submitted an application to Alberta Energy Regulator for an SAGD pilot project consisting of two well pairs and a cored observation well to be drilled at its Peace River property. The three-well pilot project will be drilled from a well pad inside Shell's already approved Peace River project area, but AER needs to sign off on a target bottom hole location that sits in an unapproved area. Shell estimates that the proposed wells will intersect an area containing 4.6 MMbbl of bitumen, but how much might ultimately be recoverable in this part of the Bluesky reservoir is unclear.

Bluesky bitumen tinkering continues even after $2.0B Carmon Creek fiasco.

If successful, the pilot could unlock a great deal of Peace River oil, but Shell's efforts so far have not been encouraging. The company has been working on the problem since the 1950s, and in the last two decades sunk several SAGD wells into the Bluesky reservoir that all performed poorly. However, Shell says the reason these earlier efforts failed was due to poor understanding of the reservoir's geology and the less-than-optimal drilling and completion techniques that were used at the time.

In 2010, Shell thought it had gained enough experience in the play to justify a large-scale project—the 80,000 bo/d Carmon Creek development—and by 2014 was moving to put it into production. The price collapse subsequently scuttled these plans, forcing Shell to debook 418 MMbbl of bitumen and write off nearly $2.0 billion as a result. The half-built oil sands plant at Carmon Creek was then sold to **Kineticor** and **OPTrust** in February.

Sees poor well design & sub-optimal completion as reason for earlier failures.

Shell's expensive experience at Carmon Creek might have turned the supermajor off thermal work entirely, but there is just too much oil locked up in the Bluesky sandstone to give up trying altogether. In 2007, Shell estimated the Peace River play could contain a gross 155 Bbbl of bitumen, mostly contained in the Cretaceous Bluesky formation's clastic, 20-30 m-thick deposits.

Husky steaming at new pad in Tucker development

Husky Energy is moving on projects announced in Q4. At the Tucker development, steaming is underway at a new eight-well pad with first production expected in 2Q17. Also at Tucker, drilling started at a 15-well pad that should see first oil in 2H18. Tucker production averaged 20,800 bo/d in 4Q16—a 38% increase from 4Q15. The new pads being built are expected to boost Tucker volumes to 30,000 bo/d by YE18.

Outside its thermal assets, Husky is focusing on fewer, more material plays. Husky's portfolio in Western Canada is now more than 70% gas-weighted, providing a natural hedge for the company's energy requirements at its thermal projects. A 16-well program is now underway targeting the Wilrich formation in the Ansell and Kakwa areas. The work will increase volumes by 6,000 boe/d, pushing total output from Western Canada non-thermal assets to 36,000 boe/d.

Two new well pads adding a total of 23 wells will be on stream in 2H18.

Husky averaged 327,000 boe/d in Q4, or 30,000 boe/d less than 4Q15. This was due to divestitures in Western Canada, natural declines and planned turnarounds, partially offset by growing thermal production and increased volumes from the Liwan gas project in the South China Sea. In particular, the Edam East, Vawn and Edam West Lloyd thermal projects averaged 28,500 bo/d. This surpassed their combined design capacity by 15%.

Husky's 2P reserves stood at 2.8 Bboe at YE16, while the company's five-year proved reserves replacement ratio, including acquisitions and dispositions, was 121%. Taking into account acquisitions and dispositions, which included a reduction of 86 MMboe of proved reserves in Western Canada, the 2016 proved reserves replacement ratio was 19%.

Drilling & Production

Cenovus to drill 50 wells at conventional Palliser Block

Cenovus will drill some of the 700 locations it has identified at its Palliser conventional oil block in southern Alberta in 2017. The company set aside $160 million to drill 50 horizontal development wells and 60 stratigraphic test wells at the property. The goal, said CEO Brian Ferguson, is to "generate short-cycle cash flow to support continued growth in our oil sands assets." In December, Cenovus said 70% of its $1.2-1.4 billion capex in 2017 will go to sustaining oil sands production, with much of the rest will going to growth targets like Palliser.

Mirrors larger industry trend to focus on cheaper, short-cycle investments.

Cenovus isn't the only company to spend money on conventional wells. Alberta Energy Regulator predicts that overall spending on conventional, tight formation and shale oil and gas will increase in 2017. This type of spending fell 41% in 2016 to $10 billion, but this is expected to increase by about 20% in 2017 to hit $12 billion. The surge is coming as a result of increased prices and greater interest in relatively inexpensive, short-cycle investment of the type Cenovus will carry out in Palliser.

BlackPearl maps out course to quadruple production

BlackPearl Resources sanctioned Phase 2 of its flagship Onion Lake heavy oil project in Saskatchewan. CEO John Festival called Onion Lake a company cornerstone, and Phase 2 will add 6,000 bo/d. The build will double Onion Lake's volumes to ~12,000 bo/d at a cost of $180-185 million. Construction of a central processing facility and well pads is expected to take 12-15 months, which will be followed by a 9-12-month ramp-up period. Phase 2 first oil in slated for mid-2018.

Onion Lake's thermal production to double to 12,000 bo/d.

Phase 2's speedy rollout has been facilitated by early legwork that saw the company sign contracts for long lead items ahead of project sanction. Onion Lake Phase 2 will comprise the bulk of BlackPearl's $200 million 2017 capex—a total that was well above analyst expectations of $85 million. Although the company can fund Phase 2 internally, a $75-100 million loan may be secured to ease cash flow.

However, if a loan isn't forthcoming, BlackPearl will prioritize Onion Lake Phase 2 over conventional E&P work.

Onion Lake Phase 2's capital costs will come in at $30,000 per daily barrel of oil, or nearly 14% lower than that for Phase 1, which was built on time and budget for a total cost of $225 million and is now producing above capacity at 6,100-6,300 bo/d. Given Onion Lake's operating costs of $10-15/bo and a breakeven price of less than $25/bo, BlackPeal sees room for a follow-on Phase 3 that, like the two prior phases, will add another 6,000 bo/d to Onion Lake—pushing volumes eventually to 18,000 bo/d.

The 80,000 bo/d Blackrod development receives government greenlight.

BlackPearl also received permission from Alberta to develop the company's Blackrod SAGD project. Blackrod will be built in phases with Phase 1 to put 20,000 bo/d on stream. Phase 1 will cost up to $800 million, which works out to $37,500-$42,000 per bo/d—or 25-40% more expensive than Onion Lake Phase 2. Also in the works is restart of Blackrod's Mooney conventional heavy oil project in central Alberta.

Onion Lake Phase 2 and 3, Blackrod Phase 1 and Mooney's ASP flood will transform the company once completed via the addition of a combined 37,000 bo/d. This is more than triple the 10,080 boe/d that the company averaged in 2016, which was a 21% increase over 2015's 8,030 boe/d. In 2017, BlackPearl estimates production will remain steady between 10,000-11,000 boe/d as it works on Onion Lake Phase 2.

TORC O&G ends 2016 on a production high note

TORC Oil & Gas produced a record 19,600 boe/d (83% oil and NGLs) in Q4, or 1,000 boe/d more sequentially and 8.4% more than the year prior quarter. On an annualized basis, TORC's 2016 volumes were up 20% compared to 2015's average of 15,588 boe/d. This production was in part generated from a 2016 capex plan that saw 39 wells drilled and completed across its assets in southeast Saskatchewan and the Alberta Cardium.

Over the past year, TORC also reduced well costs at its Torquay/Three Forks in Saskatchewan play by 10-15%, primarily through operational efficiencies. As a result, TORC increased the Torquay/Three Forks capital allocation in 2017 and plans to drill 15 wells. Meanwhile at its conventional assets in the southeast part of the province TORC will drill 38 wells to maintain production and maximize free cash flow. In Alberta, TORC will drill a total of 12 Cardium wells.

Company record of 19,600 boe/d comes of 2016 capex of just $82MM.

Reduced cost of Torquay/Three Forks means more work for this play in 2017.

Company capex in 2017 is pegged at $130 million, $48 million more than TORC's 2016 E&P budget of $82 million. These investments will lead to 2017 production averaging 19,900-20,600 boe/d with volumes at YE17 being at the top of that range. TORC's 2P reserves stand at 99.6 MMboe (83% oil and NGLs), which is 10% above where they were at YE15.

Drilling & Production

Strategic adds new Muskeg Marlowe producer

Early in Q1, **Strategic Oil & Gas** tied its Marlowe Muskeg 14-35 step-out well to sales via a 4.0-km pipeline. After 24 days, the well averaged 885 boe/d (50% oil). The performance of 14-35 is similar to the 14-12 and 2-13 Muskeg wells, both of which were brought on production late in Q4. Well 14-12 tested at 810 boe/d (59% oil) over four days, while Muskeg 2-13 flowed at 1,057 boe/d (54% oil) over seven days.

New north Alberta well is flowing ~443 bo/d after 24 days.

Strategic will spend $30 million on capex during 1H17, which includes drilling six Muskeg horizontal wells. So far, Strategic has drilled three wells and the fourth is underway, with all being placed in the fairway between the 14-35 and 2-13 wells. Once all six wells have been drilled, completed and tied to infrastructure, Strategic believes the north Alberta property will be capable of 4,000 boe/d.

Average cost for new Muskeg wells fell 3% YOY to just $3.0 million/well.

In 2016, Strategic increased its 2P reserves YOY by 53% to 19.6 MMboe. The company's finding and development costs averaged $9.83/boe for 2P reserves on capital expenditures of $29.3 million. Meanwhile, future Muskeg development costs per well dropped by $100,000 to $3.0 million at YE16 despite the increase to 20 completion stages and a corresponding increase in well length compared to prior years.

Blackbird ramps Elmworth/Pipestone assets past 1,500 boe/d

Blackbird Energy is pleased with the initial ramp-up of its Elmworth/Pipestone Montney assets, which came on stream in late January. Production as of mid-February was 1,938 boe/d (53% liquids) and H2S levels were at approximately 5.5%, which is under Blackbird's contracted amount of 6.0%. However, operations were suspended temporarily for about a week in February due to a mechanical failure at a third-party gas handling facility. This third-party outage was expected to be resolved by March.

Enters into transport & handling deal for up to 90 MMcf/d of production.

Meanwhile, Blackbird entered into a non-binding transport and handling agreement with an unidentified midstream company for up to 90 MMcf/d of production from its Pipestone/Elmworth lands. The agreement is contingent upon the midstream company sanctioning construction of a gas-handling plant and building a pipeline gathering and compression system linking the plant with Blackbird lands to the north and south of the Wapiti River. The deal also requires Blackbird to obtain takeaway service from the proposed plant.

Peyto lets up on gas choke as it heads to 660 MMcfe/d

Peyto Exploration began 2017 running a total of nine rigs in Alberta, four of which were operating in the Brazeau area and five near Sundance. Since January, these nine rigs have drilled 32 wells, 23 of which have been rig released. Peyto

has completed and brought on stream 18 wells so far in Q1, including several left over from 4Q16. The company has 17 more wells it plans to complete and tie to sales before spring break-up. At Sundance, Peyto is eying a four-rig program using pad drilling through breakup.

Volumes flat from a year prior but will drill 12-24% more wells in 2017.

Peyto added 239 MMcfe/d (92% gas) of production capacity in 2016 at a total cost of $469 million, making the year's spend to increase volumes the lowest cost—at $1,800 per Mcfe/d—to build new production in Peyto's 18-year history.

The company exited 2016 producing 576 MMcfe/d, down 2.6% YOU. The reason for the relatively flat rate of production in 2016 was Peyto's decision to defer putting new volumes on stream from wells drilled in late 2015 and early 2016 in order to maximize returns.

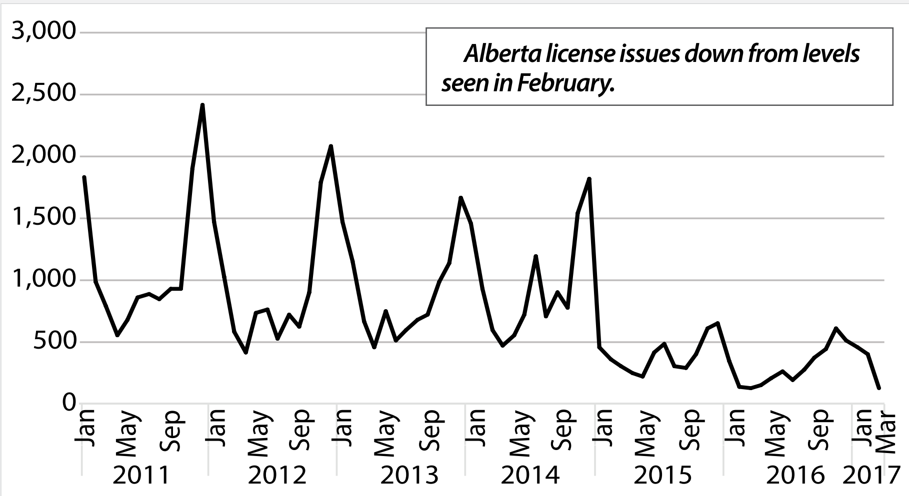
Peyto will make up for this by boosting production to 658 MMcfe/d by YE17. To get there, the company will spend $550-600 million to drill 145-160 liquids-rich horizontal gas wells, 16-36 more than 2016. The drilling will be focused on the Wilrich formation across its Deep Basin lands, in particular in the Greater Sundance and Brazeau areas. Peyto will also increase its gas processing capacity by 120 MMcf/d by putting its Brazeau East gas plant online, which will increase the company's total by 15% to 955 MMcf/d total.

New gas plant will lift Peyto's handling capacity 15% to ~950 MMcf/d.

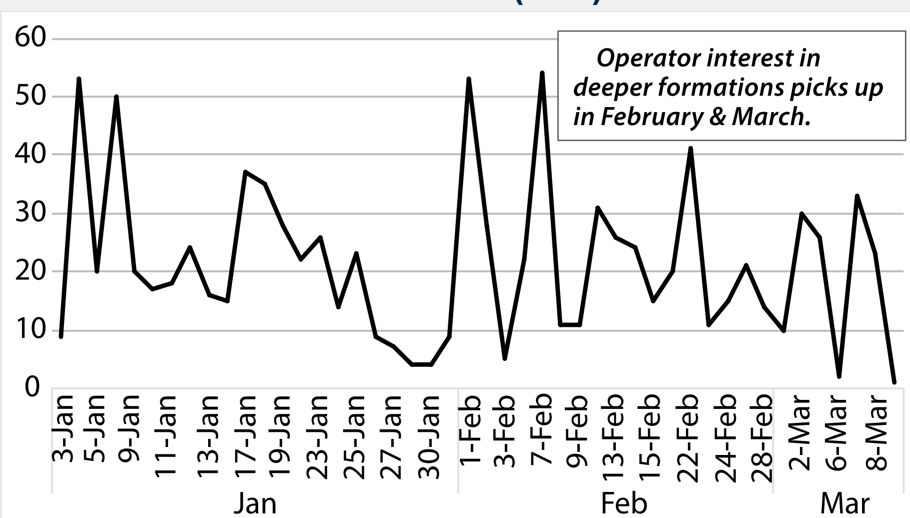
Peyto's cost per completed stage is now about $145,000, while drilling time for an average Sundance Wilrich horizontal well is now 16 days—a gain of three days from 2015 and about a 29% reduction in the cost to complete a stage from the year prior. These costs trends helped push Petyto's finding and developing cost for new proved and producing reserves in 2016 down by 12% to $1.44 per Mcfe. As a result, for every well drilled Peyto found 1.9 new undeveloped 2P drilling locations, increasing the YE16 2P reserves 11% YOY to 3.9 Tcfe.

Peyto's 2P reserve increased to 3.9Tcfe, up 11% YOY.

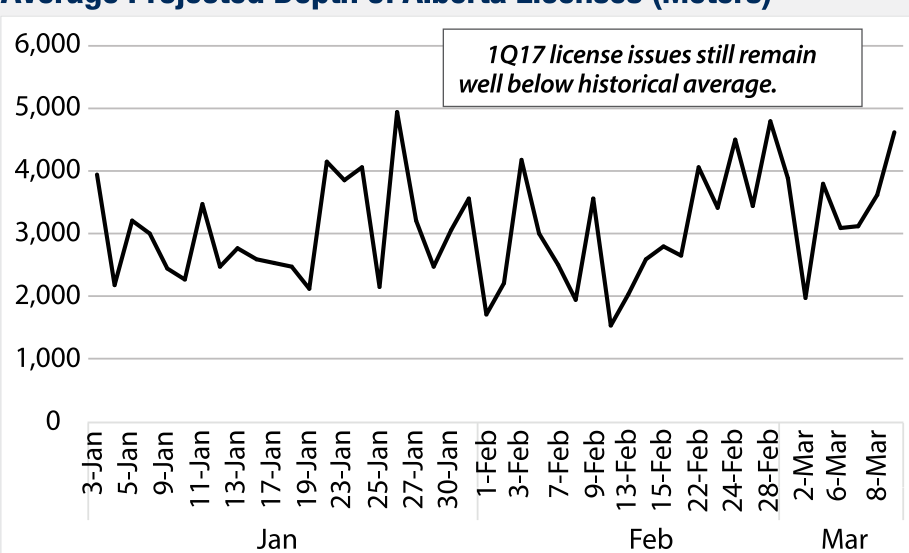
Number of Alberta Licenses Issued (Last 5 Years)



Number of Alberta Licenses Issued (2017)



Average Projected Depth of Alberta Licenses (Meters)



Source: PLS Research

CENTRAL ALBERTA

ALBERTA OPPORTUNITY

26.25-Sections of Land. 16,800 Acres.
WASKAHIGAN / KAYBOB T59-65.
Duvernay Land Rights.
Unencumbered Crown Lands.
Seismic Data & Stratigraphy Available.
100% WORKING INTEREST FOR SALE
CA Required To View Data Room.
ORIGINALLY Q3 2016 SALE
CONTACT AGENT - POST BID STATUS
L 11247DV

L

FOR SALE

CALL PLS FOR INFO

ALBERTA PROPERTY

2-Producing Wells. 1-Water Injection Well.
PEMBINA.
Nisku Oil Pool.
1-Water Potential Injector Well And ---
---Associated Pad Facilities.
3D Seismic Data Available.
46.875% OPERATED WI FOR SALE
Gross Production: ~1,500 BOED
Original Oil-In-Place: 8.2 MMBBLS
ORIGINALLY Q4 2016 SALE
CONTACT AGENT FOR UPDATE
PP 11179DV

PP

~1,500 BOED

BUYERS! NO COMMISSIONS

ALBERTA PROPERTY SALE

1-Producing Property.
NITON / MCLEOD AREA T54-56.
Production From Cardium, Wilrich--
--And Lower Mannville Formations.
OPERATED WI FOR SALE
Recent Net Oct 2016 Prod: 195 BOED
Recent Net Operating Income: $90,000/M
Est, Net PV10 Value: $26,200,000
Total Proved Reserves: 3,208 MBOE
Proved Plus Probable: 5,195 MBOE
CONTACT AGENT FOR UPDATE
PP 11275DV

PP

195 BOED

DEALS FOR SALE

CENTRAL ALBERTA ASSET SALE

~37,458-Net Acres.
MICHICHI & BANFF AREAS
Proven Light Oil Opportunity
71 Potential Locations Identified.
3D Seismic & Geotechnical Data Available
Avg ~97% OPERATED WI AVAILABLE
Q3 2016 Production: ~820 BOED
Production Is 57% Liquids.
Total P+P Reserves: 7,606 MBOE
Total P+P PV10: $72,200,000
100% Owned & Operated Gathering Facilities.
CONTACT AGENT FOR MORE INFO
PP 13621DV

PP

~820 BOED

Drilling & Production

Tamarack on course to hit 20,000 boe/d by end of Q1

Since the start of 2017, **Tamarack Energy** has brought 15 new wells on production including 11 Viking light oil wells, two extended-reach horizontal Cardium light oil wells, one Notikewin liquids-rich natural gas well and one heavy oil well. Current volumes are 19,000 boe/d—putting Tamarack on course to exceed its H1 guidance of 18,500-19,000 boe/d.

Tamarack has been able to meet this goal despite numerous factors negatively impacting operations. This includes non-operated production curtailments, a third-party gas plant curtailment, earlier-than-expected road bans due to warm weather and delays stemming from the lack of availability of fracking crews. Based on the three rigs now running, Tamarack will bring an additional 15 Viking and four Cardium wells on stream by the end of March.

Tie-in pace means Tamarack will likely exceed Q1 guidance by 1,000 boe/d.

These wells will assist the company in reaching an estimated 1Q17 exit rate of 20,000 boe/d. Looking ahead to Q2, Tamarack will bring nine Viking wells and one Cardium well on stream that had been drilled in Q1. Tamarack has budgeted $165-175 million in 2017 to drill 140-150 wells, of which 122-130 will be Viking oil wells. This compares to the 22 wells that the company drilled in 2016.

In 2016, Tamarack achieved strong organic reserve growth due to the success of its drilling program, enhancements to completion techniques and well performance improvements. The company increased 2P reserves 26% YOY to 56.5 MMboe, with oil and NGLs weighting across all reserves categories increasing to 60% compared to 2015 weightings of ~50% PDP, 52% 1P and 54% 2P.

January 15, 2015 • Volume 06, No. 01
PLS CanadianCapital
Serving the marketplace with news, analysis and business opportunities

CanadianCapital Jan. 20

Tamarack gets borrowing base boost to $220 million.

Bellatrix running three rigs ahead of spring breakup

Bellatrix Exploration launched its 2017 drilling program with two rigs in January, but decided to add a third in February in order to ensure completion of H1 goals ahead of spring breakup. These goals consist of the drilling of nine wells, including two high-impact Cardium prospects. Results are encouraging so far, and Bellatrix believes that it may have flexibility to balance infill development drilling with step-out appraisals designed to increase its reserve position and drill location book.

Spirit River well drilled in Jan. recorded 18.1 MMcf/d after 30 days on stream.

Of the nine wells drilled or to be drilled before spring breakup, Bellatrix has production data back from four. All were 1,600-m wells drilled in the Spirit River area of Alberta, and they averaged 14.5 MMcf/d after an average 16 days of being on stream. Of these wells, the longest to be producing was 100/1-30-44-09W5, from which Bellatrix recorded an IP30 rate of 18.1 MMcf/d. Bellatrix also drilled the 1,600-m 100/1-30-45-09W5 Cardium well in the Alder Flats area, and completed it in 25 stages using a 625-tonne slickwater frac.

Estimates over 390 liquids-rich drilling locations are at Spirit River.

Bellatrix exited 2016 producing 31,500 boe/d and is aiming to produce 33,500 boe/d over the course of 2017 with a YE17 exit rate targeted at 35,000 boe/d. If achieved, this will put the company in striking distance of reaching its goal of producing over 42,000 boe/d in 2019, sourced mostly from its Spirit River assets. The region has become increasingly important to Bellatrix, and since 2010 has grown to account for over 50% of the company's production from less than 25% at the start of the decade.

Aims to produce 33,500 boe/d over the course of 2017

Bellatrix exited 2016 with 2P reserves of 229 MMboe (25% oil and NGLs), or about 3% more YOY. This translates into the company owning 90 2P Spirit River drilling locations, but Bellatrix estimates that up to 303 unbooked locations are also contained in its 262 gross sections there, giving it 393 Spirit River drill sites in total. Bellatrix estimates that development of just 14% of this booked and unbooked inventory could maintain company output in the 30,000-35,000 boe/d range until 2020.

Bellatrix's Spirit River Competitiveness

BXE SPIRIT RIVER COMPETITIVE WITH TOP TIER MARCELLUS OPERATOR F&D COSTS AND EFFICIENCIES		BXE Spirit River Type Curve	Marcellus Type Curves			Blended SW PA 50% Wet 50% Dry
			SW PA Super rich	SW PA Wet	SW PA Dry	
Total gross well costs (DCE&T)	US$/well	$3.1	$5.9	$5.8	$5.2	$5.5
Year 1 production	MMcfe/d	4.7	4.4	7.0	8.3	7.7
3 Year expected recovery	Bcfe	3.0	3.7	5.6	5.9	5.7
5 Year expected recovery	Bcfe	3.7	5.2	7.7	7.6	7.6
EUR	Bcfe	6.0	16.0	20.6	17.6	19.1
Natural gas	% of EUR	76%	46%	49%	100%	74%
F&D costs (3 yr recovery)	US$/Mcfe	$1.04	$1.60	$1.04	$0.89	$0.96
F&D costs (5 yr recovery)	US$/Mcfe	$0.84	$1.12	$0.75	$0.68	$0.72
Year 1 capital efficiency	US$/boepd	$3,952	$7,960	$4,971	$3,747	$4,306
EUR recovered in first 10 years	%	78%	50%	55%	59%	57%

Source: Bellatrix January 4 Presentation via **PLS docFinder www.plsx.com/finder**

CENTRAL ALBERTA

CENTRAL ALBERTA PROPERTY
5-HZ Producers. 6-InActive. 25,000+ Acres.
HUSSAR/ROSEBUD AREA
Pekisko Formation.
Proprietary 3D Seismic Data
100% OPERATED WI AVAILABLE
Net Production: ~87 BOED
Net Operating Income: ~$47,500/Month
Total Prov+Prob Reserves: 114 MBOE
Net Prov+Prob PV10 Value: $1,800,000
ORIGINALLY Q4 2014 SALE
CONTACT AGENT FOR STATUS
PP 11727DV

PP
87 BOED
CALL PLS FOR INFO

PARKLAND. T52.
7-Oil Wells. 1-SWD. 2-Shut In.
PEMBINA AREA - 5.5 Sections
Mannville Formation. 1,800 Meters.
Wells Completed In Ostracod Formation.
100% OPERATED WI FOR SALE
Net Production: ~30 BOPD & 200 MCFD
Net Cash Flow: ~$80,000/Month
Prefers Trade For NonOp AB/SK Property.
CONTACT SELLER FOR DETAILS
PP 12899DV

PP
MANNVILLE

EAST ALBERTA

VERMILION. T50.
PLS
33-Active Wells. 6-SWD. 1-Suspended.
Sparky Formation.
Additional Upside P&NG TBO Mannville.
Production To Date >95% Oil.
66.66% OPERATED WI AVAILABLE
Net Production: ~50 BOED
Total Cumm'd Production: ~3.46 MMBOE
Asset Has LLR of ~0.9.
PP 11120DV

PP
50 BOED

WEST ALBERTA

ANTE-CREEK AREA. T63-T65.
12,160-Gross Acres.
PNG Rights: Below Base Of Bluesky-
Bullhead To Base Of Triassic & Below
Base Of Nordegg To Base Of Triassic
100% WORKING INTEREST AVAILABLE
FOR SALE OR FARMOUT
CONTACT SELLER FOR MORE INFO
L 13602FO

L
BLUESKY

GREATER PINE CREEK AREA
PLS
700+ Potential Locations.
115,000 Net Acres-HBP.
Second White Specks Trend.
Well Defined Oil Window.
Drilling Depth: ~6,500 Ft.
MAJORITY OPERATED WI
Crown Royalty Is 5% BPO; 25% APO
Estimated OOIP: ~45 MMBO/Section
Budgeting Or Looking To Raise $30MM+
DV 12009

DV
HBP ACREAGE

WEST ALBERTA

WESTERN ALBERTA PROPERTY
5-Key Areas.
PROGRESS/VALHALLA, SPIRIT RIVER,
POUCE COUPE, BONANZA & JOSEPHINE
Doig, Charlie Lake, Montney, Halfway &
Varying Working Interest Available
Aggregate Production: 190 BOED
Expected 2017 Income: ~$123,167/Month
Total Proved Reserves: 787 MBOE
AGENT WANTS OFFERS APR 6, 2017
PP 13658DV

PP
190 BOED

NORTHERN ALBERTA

FAIRVIEW / WORSLEY AREA. T80-87.
~177,900-Undeveloped Acres.
PEACE RIVER ARCH
Charlie Lake, Kiskatinaw & Wabamun.
Trade and Proprietary 2D Seismic Data
100% OPERATED WI AVAILABLE
CONTACT AGENT FOR UPDATE
DV 13393L

DV
CHARLIE LAKE

NORTHWEST ALBERTA ASSETS
145,924-Gross Acres. 115,151-Net Acres.
DEEP BASIN, PEACE RIVER ARCH &
WABASCA AREAS.
83-Horizontal Development & Infill Drilling.
Waterflood Upside Targeting Light Oil.
Net Production: 2,618 BOED (56% Liquids)
Total Proved Reserves: 6,412 MBOE
Probable Reserves: 9,760 MBOE
NPV10: $58,295,000
ORIGINALLY Q4 2016 SALE
CONTACT AGENT - POST BID STATUS
PP 13072DV

PP
2,490 BOED
BUYERS! NO COMMISSIONS

RAINBOW / ZAMA AREA. T106-111
51,872-Undeveloped Acres (82-Sections)
Muskwa Oil (Duvernay Equivalent)
Trade and Proprietary 2D Seimic Data
100% OPERATED WI AVAILABLE
CONTACT AGENT FOR UPDATE
DV 13394L

DV
MUSKWA

SOUTHERN ALBERTA

LARNE AREA. T28.
1-ShutIn Well. 320-Net Acres.
Sulphur Point. 4,080 Ft.
50% OPERATED WI AVAILABLE
Proved Reserves: 1.1 BCF
CONTACT SELLER FOR MORE INFO
PP 13121DV

PP
SULPHUR POINT

SOUTH ALBERTA ACREAGE
Acreage For Sale.
NEVIS & LEDUC AREAS. T29-T52.
Varying Fee Simple/Freehold Interest
FOR SALE OR FARMOUT
CONTACT SELLER FOR MORE INFO
L 13603FO

L
ACREAGE SALE

SOUTHERN ALBERTA

MULTIPLE AREAS. T14-T48.
>9,600 Total Acres.
Aphrodites, Centron, Hartell, High River,
Leduc, Long Coulee, Okotoks, Shouldice,
Turner Valley, Vulcan, & Watelet Areas.
Varying PNG Rights Area To Area.
FREEHOLD UNDEVELOPED MINERALS
CALL SELLER FOR MORE INFO
M 15555

M
VARYING PNG

ALBERTA NON-CORE PROPERTIES
2-Producing Properties.
CHIN COULEE & CLARESHOLM
Sawtooth & Barons Sand Formations.
Data Room Opens January 16, 2017
100% WORKING INTEREST FOR SALE
Comb. Production: 61 BOED
Chin Coulee Net Value: $1,800,000
Claresholm Net Value: $277,372
Chin Coulee Total Proved: 118 MBOE
Claresholm Total Proved: 38 MBOE
CONTACT AGENT FOR UPDATE
PP 20100DV

PP
~61 BOED
DEALS FOR SALE

DEL BONITA AREA. T1-4.
~58,500-Acres. 2-Standing. 3-Susp. 2-Abd.
UNDEVELOPED LAND
Second White Specks, Banff, Exshaw,
-- Bakken and Big Valley Horizons.
Trade and Proprietary 2D Seismic Data
100% OPERATED WI AVAILABLE
CONTACT AGENT FOR UPDATE
DV 13391FO

DV
ALBERTA BAKKEN

GADSBY. T37.
PLS
2-ShutIn Wells. 1,280-Acres.
Viking. ~3,700 Ft.
Mannville. 4,600 Ft.
100% OPERATED WI AVAILABLE
PP 11461DV

PP
VIKING

PINCHER CREEK AREA. T4-9.
~57,250-Undeveloped Acres (~89-Sect.)
SECOND WHITE SPECKS & CARDIUM
Al Rights Surface to Basement.
Trade and Proprietary 2D Seismic Data
100% OPERATED WI AVAILABLE
CONTACT AGENT FOR UPDATE
DV 13392FO

DV
ALL RIGHTS

SOUTHEAST ALBERTA ASSET SALE
7-Total Wells. 640-Acres.
CRESSFORD AREA.
Producing From Mannville Pool
Rights From Surface To Base Of Mannville
6 UnBooked Drilling Locations.
100% OPERATED WI AVAILABLE
Current Production: 20 BOPD & 80 MCFD
PDP Reserves: 107 MBO & 225 MMCF
PDP PV10: $2,814,000
CONTACT AGENT FOR MORE INFO
PP 13272DV

PP
MANNVILLE

Drilling & Production

Whitecap nearly halfway to 2017 drilling goal

Whitecap Resources drilled 72 wells so far this year after mobilizing 11 rigs during the first two months of 2017. This is four more rigs than the company had running in 4Q16 and leaves Whitecap with just 20 more wells to be drilled before reaching its Q1 goal of 92. Although Whitecap has since reduced its rig count to eight, the company believes it is on course to meet its Q1 target. Once met, this leaves the company 97 more wells to drill to reach its YE17 target of 189 wells.

A brisk 11-rig program during the first two months of 2017 drills 72 wells.

This builds on 2016, during which Whitecap achieved very low-cost organic reserve growth. Finding and development costs reached a record low of $2.34/boe, including changes in future development capital, and resulted in a recycle ratio of 11.3. Combined with $486.2 million in acquisitions, Whitecap increased 2P reserves by 28% in 2016 to 355 MMboe. However, this is likely to increase due to strong production results in both southwest Saskatchewan and Boundary Lake that were not included in this estimate due to lack of data.

Boosts 2P reserves 28% to 355 MMboe & sees F&D cost average $2.34/boe.

Whitecap has so far not experienced any service cost increases and believes it is well positioned to meet the company's 1Q17 production target of 55,000-56,000 boe/d. This is 4,400-5,400 boe/d more than what Whitecap produced in Q4. For full-year 2017, Whitecap's production goal remains at 57,000 boe/d, and the company is confident it will be met.

Stage completes Blackbird Upper Monteny well in 3 days

Blackbird Energy was able to complete a 56-stage frac in record time using **Stage Completion's** Bowhead II collet-activated fracking system. Stage deployed the system at Blackbird's Pipestone Montney operations near Grande Prairie, Alberta, where it completed Upper Montney well 3-28 in 56 stages using 1.87 tonnes of sand per linear meter in just 80.25 hours, or 3.34 days, including maintenance downtime.

Stage completed 56-stage lateral with 2,765 tonnes of proppant in 80.25 hours.

This is the fastest completion ever conducted in a 4.5-in. monobore Montney well without coil tubing assist utilizing the Stage System. Without the downtime devoted to carrying out maintenance on the frac pump heads, the completion of well 3-28 would have taken only 54 hours to complete. The 3-28 well also represents the highest tonnage intensity used by Stage's system for a wellbore of this type.

Nearby wells using alternative methods took up to 17 more days to complete.

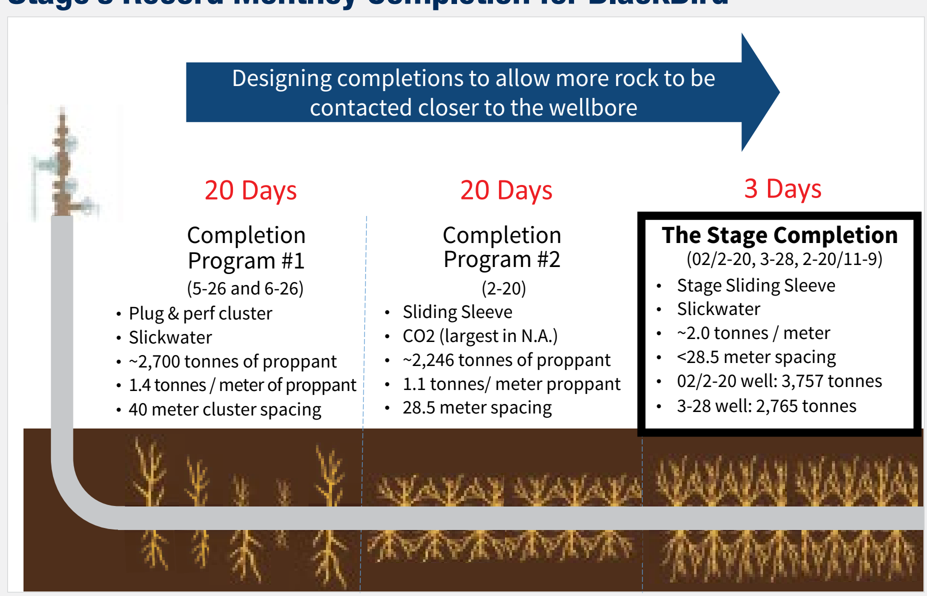
In comparison, completion of nearby Blackbird wells 5-26 and 6-26, which used a plug and perforate method using 2,700 tonnes of proppant, and well 2-20, which used a sliding sleeve and 2,223 tonnes of proppant, all required 20 days to complete. The record completion time was accomplished due to Stage's use of a dissolvable ball on collet that activates sliding sleeves, and it features a constant ID wellbore that is cementable in place.

As result, collet/sleeve engagement can be accomplished within minutes of finishing the previous stage, allowing for each stage to be completed in under an hour. Stage's system also includes a technology that provides pinpoint fracturing capability to operators, which increases ultimate recovery, improves water management and gives continuous operations with deployment under pressure capability.

Collet/sleeve engagement happens within minutes of the previous stage.

Since rollout of the system in May 2016, Stage has deployed it in 114.3-mm wells at 65 bbl per minute and 139.7-mm wells at 100 bbl per minute per stage—rates unachievable with coiled tubing activated sleeves. Over the next 60 days, Stage expects to deploy more than 750 stage sleeves/collets in Canada, the US and internationally. This is in addition to the 192 stage sleeves/collets deployed over the previous 30 days.

Stage's Record Montney Completion for BlackBird



Source: BlackBird February 21 Presentation via **PLS docFinder www.plsx.com/finder**

SOUTHERN ALBERTA

SOUTHEASTERN ALBERTA FARMOUT
~18-Sections.
DRUMHELLER & CRESSFORD AREAS
Producing From Ellerslie Formation
Targeting Ellerslie, Banff & Glauconitic
Well Logs & 3D Seismic Data Available
Varying Operated WI Available
Drumheller Current Production: 29 BOED
Total Proved Reserves: 226 MBOE
Total 2P Reserves: 579 MBOE
Total Proved PV10: $1,585,000
CONTACT AGENT FOR UPDATE
FO 13511PP

FO
FARMOUT
CALL PLS FOR INFO

MULTIPLE ALBERTA

ALBERTA PROPERTY SALE
6-Producing Properties.
GARRINGTON, VIKING, BUCK LAKE--
--PEMBINA, SKARO & MEYER LAKE
Glauconitic, Ellerslie, Elkton, Cardium--
--And Other Formations.
OPERATED WI FOR SALE
Recent Oct 2016 Production: 440 BOED
Monthly Net Operating Income: $250,000
PV10 Value: $33,200,000
Total Proved Reserves: 2,311 MBOE
Total Proved Plus Probable: 3,976 MBOE
ORIGINALLY Q4 2016 SALE
CONTACT AGENT FOR STATUS
PP 11126DV

PP
440 BOED

CANADA LEASEHOLD SALE
151.5-P&NG Leases & 93 Oilsands Leases.
VARIOUS ALBERTA AREAS
Cold Lake, Driftwood, Athabasca----
Enchant, Claresholm, Atlee Buffalo,-----
-Milkwan, Turner Valley, Chip Lake, Gunn-
-Blueridge, Goose River, Shadow, Nipisi-
-Woking/Rycroft & Worsley.
WORKING INTEREST FOR SALE
CA Required To View Data Room.
ORIGINALLY Q4 2016 SALE
CONTACT AGENT FOR UPDATE
L 11116DS

L
FOR SALE

CANADA OPPORTUNITY
Multiple Producing Properties.
VARIOUS AREAS OF ALBERTA
Glauconitic Sandstone, Edmonton Sand-
-Belly River, Horseshoe Canyon And--
--Other Various Formations.
Joint Venture Drilling -
-- Upside Opportunities.
WI FOR SALE OR FOR FARMOUT
Production: 1,885 BOED
Total PV10 Value: $53,148,000
Total Proved Reserves: 11,025 MBOE
ORIGINALLY Q4 2016 SALE
CONTACT AGENT FOR STATUS UPDATE
PP 11119FO

PP
1,885 BOED

SASKATCHEWAN

LUCKY HILLS. T30.
800-Acres. 2-Vertical Wells.
P&NG From Surface To Base Of ---
--The Viking Formation.
50-100% OPERATED WI FOR SALE
CONTACT AGENT FOR MORE INFO
DV 11197

DV
FOR SALE

SOUTHWEST SASKATCHEWAN LEASES
2,210-Gross Acres.
MOOSOMIN AREA. T14-T15.
Target Formation: Red Jacket
Avg 50% Working Interest Available
L 13615

L
RED JACKET

BRITISH COLUMBIA

BRITISH COLUMBIA LAND SALE
~40,000 Net Acres. 76-Natural Gas DSUs
AKUE CREEK AREA
All Rights Surface to Basement.
Trade and Proprietary 2D Seismic Data
50-100% OPERATED WI AVAILABLE
CONTACT AGENT FOR UPDATE
DV 13396L

DV
ALL RIGHTS
BUYERS! NO COMMISSIONS

NORTHEASTERN B.C.
8,171-Net Acres. 37-Natural Gas DSUs.
ESKAI AREA
Surface to Base of Jean Marie Formation.
Trade and Proprietary 2D Seismic Data
30-33.33% NonOperated WI Available
CONTACT AGENT FOR UPDATE
DV 13395L

DV
JEAN MARIE

ALTARES & ATTACHIE AREAS
~42-Net Sections. ~26,506-Net Acres.
Montney Formation Potential
Upside In Doig & Gething CBM Formations
COMPANY FOR SALE
Total Proved Reserves: 1,764 MBOE
Total Proved PV10: $154,000,000
2 Gas Plants, Transportation & Facilities
AGENT WANTS OFFERS MARCH 2017
CO 13228L

CO
STRATEGIC ALTERNATIVES

NEWFOUNDLAND

WEST NEWFOUNDLAND
1-Permit. 43,000-Acres.
One Identified Prospect.
Water Depth: 1,500 Ft.
SEEKING JV PARTNER FOR FARMOUT
Reserves: 2,000 MMBO & 5,000 BCF
CONTACT PERMIT OWNER FOR INFO
DV 11236FO

DV
OFFSHORE

MULTIPLE AREAS

ALBERTA & BRITISH COLUMBIA
352,640-Acres. 37-NonOp Gas Drill Units
IMMEDIATE UPSIDE POTENTIAL
Montney, Charlie Lake, Kiskatinaw, --
Wabamum, Muskwa Oil Development, --
Second White Specks & Cardium Potential.
30-100% NonOp & OPERATED WI
CONTACT AGENT FOR UPDATE
DV 13390PKG

DV
UNDEVELOPED

ALBERTA & BRITISH COLUMBIA
545,894-Gross Acres.
Montney, Mannville, Cardium, Viking --
--Nisku, Keg River Oil & Other Formations.
2D & 3D Seismic Database Available.
OPERATED WI & ROYALTIES FOR SALE
2015 Avg. Comb. Prod: 9,603 BOED
Comb. 2P Est. Reserves: 42,437 MMBOE
CA Required To View Data Room.
ORIGINALLY Q1 2016 SALE
CONTACT AGENT - POST BID STATUS
PP 90667DV

PP
~9,600 BOED

ALBERTA & SASKATCHEWAN ASSETS
~95-Total Sections.
HARDY & RETLAW AREAS
BAKKEN FORMATION
Glauconitic, Ostracod, Lower Mannville,
Suburt, Belly River, Second White Specks
& Ellerslie Formation Upside
98.5% OPERATED WI AVAILABLE
Net Production: 236 BOED
Currently Cash Flow Positive.
Total Proved Resveres: 482 MBOE
PDP Resveres: 409 MBOE
Total Proved PV10: $5,323,000
ORIGINALLY Q4 2016 SALE
CONTACT AGENT FOR UPDATE
PP 13620DV

PP
~235 BOED
DEALS FOR SALE

CANADA COMPANY STAKE SALE
1-Producing & 4-NonProducing Properties.
SASKATCHEWAN & MANITOBA
6 unbooked horizontal locations.
Viking, Jurassic & Mississippian Fm.
Offsetting Production From All Prospectives.
WORKING INTEREST FOR SALE
Recoverable Reserves: 43.7 MBBls/Well.
Confidentially Agreement Required.
CONTACT AGENT FOR MORE INFO
PP 11227DV

PP
FOR SALE

CANADA LAND POSITION
>390,000-Undeveloped Acres.
ALBERTA & BRITISH COLUMBIA
Del Bonita, Pincher Creek, Fairview--
--Worsley, And Rainbow/Zama Areas.
Easkai & Akue NE British Columbia.
SOME LANDS HAVE BEEN SOLD
Operated & NonOperated WI Available.
CONTACT AGENT FOR UPDATE
DV 11245FO

DV
SALE OR FARMOUT

PLS PetroWire Database

Canada
wire.plsx.com

Date	Location	Abstract
Offshore Eastern Canada		
Mar. 3	West White Rose	Project sanction for **Husky Energy's** West White Rose development may occur in H1.
Mar. 3	EL 1144 & 1150	**CNOOC** was awarded 100% working interest in the two blocks.
Feb. 25	White Rose	**Husky** will drill two infill wells at White Rose in 2017.
Feb. 15	Hebron	Construction of the gravity-based structure for the field has been completed.
Feb. 13	EL 1070	**Enegi Oil** must achieve a successful flow test from one or more wells in the block by December 2018.
Feb. 12	Shelburne Basin	**Shell** has failed to find significant hydrocarbons with its Monterey Jack and Cheshire deepwater exploration wells.
Feb. 8	Flemish Pass	**Statoil** is planning to carry out a two-well campaign in the area starting in mid-2017.
LNG		
Feb. 21	Steelhead	The Huu-ay-aht First Nations will hold a referendum on the project on March 25.
Feb. 16	Pacific Northwest	British Columbia reached multiple agreements with several First Nations related to the project.
Feb. 13	Pacific Northwest	**Petronas** said it would relocate the project if the Canadian authorities find the move necessary.
Feb. 7	Woodfibre	The National Energy Board accepted an application for a 40-year export license for the project.
Oilsands & Heavy Oil		
Mar. 9	Athabasca Oil Sands Project	**Marathon Oil** has agreed to sell its 20% stake in the project.
Mar. 2	Horizon	During 4Q16, average production of syncrude hit a high of 178,063 bo/d.
Mar. 2	Kirby	4Q16 production averaged 39,415 bo/d.
Mar. 2	Pelican Lake	During 2016, production averaged 47,636 bo/d.
Feb. 28	Lindbergh	**Pengrowth** filed an application with regulators to increase design capacity by 10,000 bo/d to 40,000 bo/d total.
Feb. 28	West Ells	The project has started up and is currently producing 60% of its 5,000 bo/d capacity.
Feb. 23	Onion Lake	**BlackPearl** has started construction of Phase 2.
Feb. 23	Blackrod	Average production during 4Q16 was 523 boe/d.
Feb. 22	Christina Lake	**ConocoPhillips** has revised down over a 1 Bbbl of oil sands reserves because of low prices.
Feb. 22	Kearl	**ExxonMobil** has debooked the entire 3.5 Bbbl of bitumen reserves at the Kearl as a result of low oil prices.
Feb. 21	Great Divide	Since start-up in 2007 to YE16, production has totaled 34.8 MMbbl of bitumen.
Feb. 17	Carmon Creek	**Kineticor** and **OPTrust** have acquired the partially constructed 690 MW cogeneration at the project.
Feb. 16	Foster Creek	**Cernovus** plans to resume investment in its Phase G expansion.
Feb. 9	Hangingstone	Production during 4Q16 averaged 8,300 bo/d.
Feb. 9	Fort Hills	**Suncor** has increased cost and capacity estimates on its Fort Hills oil sands project to $12.5-12.9B and said oil production was on track to start up in late 2017.
Feb. 9	Leismer	Near term development plans include start-up of four pre-drilled infill wells on Pad L5, infill opportunities on pads L3 & L4 and regulatory approval to expand pad L2.

See more at wire.petrowire.com

MULTIPLE AREAS

CANADA SALE PACKAGE

Multiple Producers. 3-Core Areas.
ALBERTA, SASKATCHEWAN
& BRITISH COLUMBIA
Varying OPERATED & NonOp WI
Feb 2014-Jan 2015 Net Income: $428,458/Mn
Total Proven Reserves: 6.6 MMBOE
ORIGINALLY Q4 2016 SALE
CONTACT AGENT FOR UPDATE
DV 13283

DV **~1,650 BOED**

DEALS FOR SALE

WESTERN CANADA PROPERTIES

~60-Net Wells. ~153-Sections.
ALBERTA & BRITISH COLUMBIA
Spirit River, Charlie Lake, Wabamun,
Montney, Halfway, Gething, Paddy &
Dunvegan Potential
Varying Working Interests & Royalty Interest
Current Net Production: 814 BOED
100% Owned & Operated Infrastructure
AGENT WANTS OFFERS MAR 22, 2017
PP 13304DV

PP **~800 BOED**

MONTANA

BAKKEN & THREE FORKS

16,100-Net Acres.
Secondary Targets: Madison, Charles,
Mission Canyon & Ratcliffe Formations
Target Depths: 6,500 - 6,800 Ft.
100% OPERATED WI; 80% NRI
Offset Production: 50-150 BOPD
Potential Recoverable Rsrvs: 60 MBO
CONTACT AGENT FOR MORE INFO
L 3756

L **BAKKEN**

CALL PLS FOR INFO

CONVENTIONAL OIL

41-Wells. 4-SWD. 11,532-Net Acres.
Charles C & Nisku Formations
Acreage Is 76% Held By Production
31 Total Shallow 3P Locations Identified
100% OPERATED WI AVAILABLE
Est Feb 2017 Net Prod: 160 BOPD
Estimated 3P Reserves: 2.9 MMBO
Estimated 3P PV9: $26,400,000
AGENT WANTS OFFERS MARCH 2017
PP 2100DV

PP **CONVENTIONAL**

WILLISTON BASIN

10-Potential Wells. 3-Prospects.
MULTIPAY PROSPECTS
Red River. 11,300 Ft.
Mission Canyon & Others. 7,500 Ft.
Seeking Ground Floor Partner to Lease --
-- and Drill on 3D Defined Prospects
60% OPERATED WI; 48% NRI
Expected IP (Red River): 375 BOPD
Expected IP (Mission Canyon): 162 BOPD
Well Reserve: 300 MBOE/Well
Project Reserves: 3.0 MMBOE
Drill & Completion Cost: $3,350,000
DV 3851

DV **MULTIPAY**

NORTH DAKOTA

BAKKEN - THREE FORKS

6-Producing Wells. 1-NonProducing Well.
4-Middle Bakken Wells. 3-Three Forks Wells.
17 PUD Locations Identified.
Varying NonOperated WI & NRI
Gross Prod: 1,877 BOPD & 4,341 MCFD
10-Mn Avg Net Income: $15,159/Month
CONTACT AGENT FOR UPDATE
PP 2365DV

PP **NONOP**

NORTH DAKOTA

DIVIDE & WILLIAMS CO., ND

197-Total DSUs. 282-Producing Wells.
123,790-Net Contiguous Acres.
905-Gross & 471-Het Undeveloped Locations
Expansive Subsurface Data & 3D Seismic
Varying Operated & NonOperated WI
Current Net Production: 10,419 BOED
Proj'd 12-Mn Cash Flow: ~$7,250,000/Mn
Avg Original Oil In Place: ~18.3 MMBO
Net PV10: ~$299,000,000
AGENT WANTS OFFERS APR 26, 2017
PP 2971DV

PP **10,400 BOED**

MCKENZIE, WILLIAMS, DIVIDE, STARK,

~392-Net Mineral Acres. 20-25-Leases.
BURKE, BILLINGS & MOUNTRAIL COS.
Objectives: Bakken & Three Forks
Acreage Held By Production.
Leases Can Deliver 76.25-79% NRI
CONTACT SELLER FOR INFO
L 3944

L **BAKKEN**

BUYERS! NO COMMISSIONS

MIDALE & NESSON

100+ Potential Wells. 22,300-Acres.
Target Depths: 5,950 Ft. - 6,010 Ft.
Recompletion & Lateral Drill-Out Options
Subsurface Geologic Data Available
22.5% Working Interest; 18% NRI
Expected IP: 350 BOPD
Est Well Reserves: 300 MBO/ Well
Est Project Reserves: 18 MMBO & 66 BCF
DHC: $1,300,000; Compl: $1,600,000
DV 1663

DV **MIDALE**

MOUSE RIVER PARK

1,220-Net Acres.
Madison Formation Objective.
1-HZ Well Awaiting Completion.
30.5548% NonOperated WI AVAILABLE
CONTACT SELLER FOR MORE INFO
PP 2664DV

PP **MADISON**

WILLISTON BASIN

1-Unit. 50,000-Acres.
CEDAR HILLS ANTICLINE
Red River C & D Benches
Development Has Been Conventional.
OPERATED WI AVAILABLE
CONTACT SELLER FOR MORE INFO
L 2710PP

L **ROCKIES**

Drilling & Production

Spartan 16% done with its drill program for 2017

Spartan Energy is running a four-rig program in Q1 and has three rigs operating in southeast Saskatchewan while the fourth is working in the west-central part of the province. So far this has resulted in the addition of 20 wells, including eight open-hole wells, three fracked Midale wells, eight Viking wells and one vertical stratigraphic well. Field conditions remain favorable, and Spartan believes it will be able to complete its Q1 program before spring breakup.

Intends to drill a total of 126 wells across its core assets in Saskatchewan.

In 2016, Spartan drilled 40 open-hole wells and fracked 11 Midale wells. The company also brought on stream six previously drilled Viking wells, drilled six test stratigraphic wells and recompleted three others. The drillbit delivered 2P reserve additions of 8.1 MMboe, which when combined with acquisitions increased overall 2P reserves 260% YOY to 109 MMboe (91% oil). Estimated production during 2016 was 11,760 boe/d.

Field work and acquisitions increased 2P reserves by 260% over 2016.

Spartan will drill a total of 126 wells in 2017 and will increase production by 9,380 boe/d to average 21,080 boe/d. About $60 million will go to drilling 81 open-hole Mississippian producers in southeast Saskatchewan, while $27 million will be spent drilling 18 wells on the Midale fairway. Elsewhere, Spartan will drill 10 Ratcliffe light oil wells at its new Oungre property; three wells targeting the Torquay/Three Forks play; and 14 Viking light oil wells in west-central Saskatchewan. Total E&P capex in 2017 is expected to be $145 million.

Drilling & Production

Crescent may revise 2017 production estimate upward

Crescent Point Energy looks likely to beat its Q1 guidance of 170,000 boe/d. In a market update, the company says strong performance at its south Saskatchewan and Williston Basin assets may lead a to revision of its annual guidance following spring breakup. Under plans announced in December, Crescent Point said it will drill 670 wells across Canada and the US, generating 172,000 boe/d in 2017 and pushing its YE17 exit rate to 183,000 boe/d.

In 4Q16, Crescent Point averaged 165,097 boe/d and exited the year producing more than 167,000 boe/d. Step-out drilling added 1,000 new internally identified drilling locations last year, bringing the company total to over 8,000. On a 2P basis, Crescent Point replaced 137% of 2016 production and increased reserves to 958.5 MMboe (90% oil & liquids). This is a 2.5% YOY increase from the 935.5 MMboe recorded in 2015.

PrairieSky sees more than 500 wells drilled in 2016

PrairieSky Royalty reports 140 wells were drilled on company lands in 4Q16, bringing the company's annual total to more than 500 wells as compared to more than 650 wells in 2015. Drilling and licensing activity focused on the Viking light oil play in western Saskatchewan as well as light oil in the Mannville in central Alberta, the Alberta and Saskatchewan Bakken, and multiple liquids-rich resource targets in the Deep Basin, including the Montney and Spirit River formations.

Average 4Q16 royalty production was 23,978 boe/d (46% liquids), while full-year 2016 royalty production averaged 23,308 boe/d (47% liquids). This is substantively unchanged from the 23,050 boe/d (46% liquids) that the company produced in 3Q16. During Q4, PrairieSky spent \$367 million to acquire additional lands and sees opportunity for additional purchases of land and royalty rights as it heads into 2017.

Granite plans to drill 10 Alberta Bakken wells in 2017

Granite Oil drilled and completed its first three Alberta Bakken oil wells of 2017 for an average all-in cost of ~\$1.25 million per well, marginally above last year's costs. Granite will spend \$13.5 million in 2017 drilling and completing 10 EOR Bakken horizontal wells and expanding EOR through conversion of three producing wells into gas injectors. The remaining \$3.0 million of its capex will be directed toward the drilling of high-priority exploration targets.

In 2016, the company successfully drilled and completed 10 Alberta Bakken oil wells and produced 2,866 boe/d. Volumes ticked upward during Q4 to 2,978 boe/d. Granite expects to produce 3,050 boe/d in 2017, or about 6.5% more than what it averaged last year. Reserves as of YE16 were 18.6 MMboe (83% oil), 5.4% above YE15.

Two Bonavista wells test at rate above expectations

During Q4, **Bonvista Energy** drilled its first pair of extended-reach horizontal wells at its Ansell property in Alberta's Deep Basin in a northwest-southeast configuration. This two well pad has producing for three days as of March 2 and is currently being tested in-line at a combined rate of 35 MMcf/d—meaningfully above Bonavista's pre-drill expectation for the pair. Bonavista has six other wells drilled and awaiting completion at Ansell, which should be accomplished prior to spring break-up.

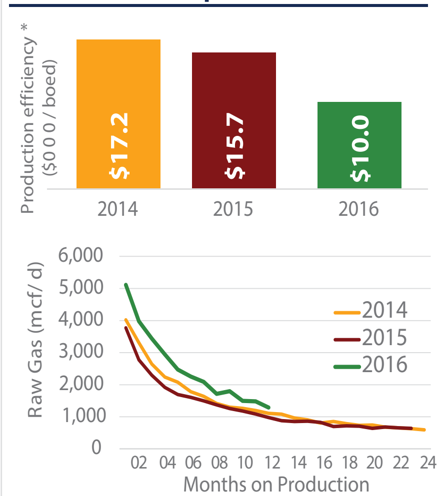
Orientation change for Ansell well pair produces up to 35 MMcf/d in Deep Basin.

Last year, Bonavista drilled 18 horizontal wells in the Alberta Deep Basin, which helped to produce 19,270 boe/d from the play—or about 28% of total company production of 70,000 boe/d. Most of this activity was focused on the Spirit River area, where Bonavista drilled 13 horizontals, eight of which were drilled in Q4. Six of these have already been tied to sales with more to follow once Bonavista's Ansell facility is expanded by 40 MMcf/d to 100 MMcf/d total by the end of March.

Bonavista maintained its target of 70,000 boe/d throughout 2016 despite a 51% reduction in YOY capital spending and divestiture of 5,000 boe/d. Although output in 2017 will only be 9-10% higher, volumes from the Deep Basin could surge by 40%. Much of this growth, up to 90%, will be handled by Bonavista's own facilities, generating higher margins as a result. Capex in 2017 will nearly double to \$280-300 million, leading to a total of 43 wells drilled—26 in the Deep Basin and 27 in the west-central region.

Extended Reach Horizontals Enhance Efficiency At Ansell Willrich

Year over Year Improvements



Well Characteristics

	Ansell Wilrich		
	2017E	2016	% variance
Drill & complete capital ($mm/well)	★ \$4.2	\$4.1	2%
Wells drilled (net)	17.0	13.0	35%
Average lateral length (m)	2,075	2,200	-6%
IP12 (boe/d)	450	450	0%
\$/boed *	\$10,165	\$10,000	2%

★ Averaged **\$4.1**mm on 4 wells 2017 YTD

** Capital used represents average drilling and completion costs and \$400k for equip and tie in costs*

Source: Bonavista March 8 Presentation via **PLS docFinder www.plsx.com/finder**

Drilling & Production

Sunshine Oilsand brings West Ells to 2,200 bo/d

Sunshine Oilsand's West Ells SAGD project in the Athabasca region of Alberta started commercial operations and is producing at 60% of its 5,000 bo/d design capacity, or about 2,200 bo/d. The company put all eight of Phase 1's well pairs on steam injection in August and by mid-2016 began initial production from five wells as it geared up for a commercial start in 2017, and by December all eight of the well pairs were producing. Sunshine plans to build a second 5,000 bo/d phase at West Ells but hasn't indicated when that might occur.

Commercial ops start as a possible expansion to 10,000 bo/d considered.

Oil sands leases could eventually produce up to 1.0 MMbo/d.

West Ells is believed to contain enough bitumen to allow for up to 130,000 bo/d of synthetic oil production, development of which is Sunshine's goal. However, the company said last year that it would operate West Ells at an initial loss as it works out production kinks while waiting for prices to improve. In the meantime, the company will mind its significant regional holdings, which cover 1.0 million acres across Alberta's oil sands patch. Sunshine's best estimate is that these leases could eventually produce up to 1.0 MMbo/d.

Storm to grow production by more than 35% by YE18

Storm Resources drilled five Umbach horizontal wells, completed five others and turned three over to sales during Q4. This brings the total number of horizontal wells the company has drilled in the liquids-rich BC Montney play to 58. YOY, the number of producing wells at Umbach has increased by nine, while overall sales volumes, which stood at 12,945 boe/d (15% liquids) increased by 21% compared with 2015. Umbach is now producing 17,000 boe/d, but Storm sees production going much higher over the next two years.

Longer completions & 30 frac stages will boost Umbach Montney volumes.

As in previous years, Storm's frac stage and lateral lengths experimentation has supported growth. For the wells completed in 2016, D&C costs declined 22% on a per-stage basis and the IP-90 rate improved by 13% to 5.3 MMcf/d, all while frac stages increased by three to an average of 25 per well. Although lengths averaged 59 m shorter than in 2015, at 1,301 m 2016's lengths are still 111 m longer than Storm's first Umbach wells.

Compression capacity at 115 MMcf/d but can quickly expand to 150 MMcf/d.

These results are informing Storm's drill plans for 2017, and the company believes that the majority of future Umbach horizontal completions will now extend greater than 1,600 m and have more than 30 frac stages. By the end of Q1, Storm plans to have drilled six more Umbach horizontals and completed four others. These additions will feed Storm's third compression facility, which started up in January.

Storm's facility can be expanded to 150 MMcf/d for just $7.0 million.

Storm's compression capacity now stands at 115 MMcf/d, a 44% increase, which allowed throughput in January and February to reach 90 MMcf/d—32% more than in Q4. However, the new facility can be expanded to double its current size for about $7.0 million, meaning that Storm will ultimately have capacity to handle 150 MMcf/d once that is greenlighted. Doing so will support plans to grow total volumes to 27,000 boe/d by YE18.

At the end of 2016, Storm's 2P reserves stood at 104.1 MMboe (14% liquids). Although reserve additions replaced 195% of production for proved developed producing, 175% for total proved and 172% for total proved plus probable, the company's total 2P reserve tally was up just 3% from 2015's 100.7 MMboe.

People & Companies

- **Bellatrix Exploration** appointed *Brent Eshleman* as president and CEO, a position that he has held on an interim basis since November when *Raymond Smith* announced his retirement. Smith held these positions since 2009. Eschleman joined Bellatrix's board as EVP in July 2012 and was named COO in September 2014.
- **Blackbird Energy** hired *Paul Goodman* as manager of completions and production. He was previously responsible for multi-pad completions programs and Blackbird's fracking business in the Alberta Montney. Additionally, *David Mills* was named Blackbird's manager of facilities engineering. Mills has held senior positions with companies such as **ConocoPhillips**, **Imperial Oil**, and **Qatar Liquefied Gas Co**.
- **Imperial Oil** VP and general counsel *W.J. Hartnett* retired on Dec. 31, 2016. He will be succeeded by *P.M. Dinnick*, who most recently served as Imperial's assistant general counsel of upstream from May 2012 to December 2016.
- TSX-listed **North Sea Energy** appointed *Ian Lambert* as interim CEO and CFO following the departure of *J. Craig Anderson* and *Petya Popova* from these respective roles. Lambert is the former president and CEO of **Trade Winds Ventures**, and served as that company's CEO for the past 10 years and as chairman for the past two.
- **Parex Resources** chairman *Norman McIntyre* and reserves and operations committee chair *John Bechtold* will retire from the board at the company's May 11 shareholder meeting. *Dave Taylor*, Parex's current president, will assume the CEO role following the retirement of *Wayne Foo*, who will become chairman of the board.
- *Daryl Gilbert* resigned from the board of directors of Calgary-based, Europe-focused **PRD Energy**, of which he became an independent director in 2010. In June, PRD completed the review of its strategic alternatives process and decided to commence the orderly liquidation and dissolution of the company, which began in late August.

Crown Land Sales

BC Feb. land sales sees more interest in Montney

British Columbia's February land sales netted $3.69 million, driven by industry interest in the Montney formation. A total of 8,177 hectares were sold at an average price of $451.33 per hectare. The sale follows the very successful January offer in which BC took in $39.62 million in bonus bids, largely due to **Plunkett Resources'** $35.13 million bid for a 2,331-hectare license that included sections 28 and 33 at 77-14W6 and sections 3, 4, 9-11, 15 and 16 at 78-14W6.

Stomp Energy was the most active BC buyer this time and bought a 792-hectare parcel for $1,407.98 per hectare covering sections 29, 24 and 28. It also got a 1,113-hectare parcel for $675,591 with land from units 60 and 70. Stomp has prowling Alberta and Saskatchewan, where in February it won Alberta parcel B0155 for $7.99 million and a 194.25-hectare Saskatchewan parcel within the Viewfield Bakken for $165,262.

People & Companies

- *Doug Baker* will retire from the board of directors of **RMP Energy**. He was chair of the audit committee and member of RMP's Engineering, Health and Safety Committee and the Governance and Nominating Committee. The board now consists of *Josh Young*, *Andrew Hogg*, *Jim Saunders*, *Craig Stewart* and *Lloyd Swift*.
- **Suncor Energy's** chairman, *James Simpson*, retired. Replacing him will be *Michael Wilson*, who was appointed to the board in February 2014.Wilson has management experience in the petrochemical sector, including as former CEO of **Methanex Corp**.
- **TransCanada** appointed *Stephan Cretier* as new independent director, effective Feb. 17. Since 1999, he has been chairman of the board, president and CEO of **Garda World Security**, the world's largest privately owned security company, and CEO of **Rafale Capital** from 1999-2001.

Drilling & Production

Pine Cliff plans to drill 13 natural gas wells this year

Alberta gas producer **Pine Cliff Energy** will spend $18.5 million in 2017 to drill a total of 13 wells, of which nine will be drilled at its Edson property while the remaining four will be Viking producers near Kinsella. Pine Cliff will also recomplete up to 40 other wells across its three main operating areas in the province. This work will help generate 117-119 MMcfe/d (93% gas)—essentially flat from Pine Cliff's Q4 flows of 118 MMcfe/d (93% gas).

Expanded capex will be enough to keep production flat at ~117-119 MMcfe/d.

The 2017 budget is nearly double what Pine Cliff spent on E&P work 2016. Due to the company's small program last year, its 1P reserves dropped 10% to 295 Bcfe (94% gas) from 2015. In turn, 2P reserves stood at 389 Bcfe at YE16, a 9.0% drop YOY from what Pine Cliff registered last year. Although reserves have dipped, Pine Cliff still has over 900 gross drilling and recompletion locations, of which only 34% are needed to maintain current output until 2022.

Vermilion's strategy focuses on Canada in 2017

Vermilion Energy will be most active in Canada in 2017, where it will drill 45 wells. In the West Pembina play, Vermilion will drill or participate in the drilling of nine Cardium wells, up from just two in 2016. The company will also drill or participate in the drilling of 23 West Pembina and Ferrier Mannville wells in 2017, three more than last year. In southeast Saskatchewan, it will drill or participate in 13 Midale wells, six more than in 2016.

Will see 45 wells drilled across Vermilion's Western Canadian base.

Outside of Canada, Vermilion will carry out debottlenecking operations at Wandoo field offshore Australia to increase capacity there by 600-700 boe/d. This follows a two-well sidetrack campaign in 2Q16 that increased capacity by 4,300 boe/d. Meanwhile, in the US' Powder River Basin in Wyoming, Vermilion will drill and complete three wells.

In France, Vermilion will tie in four Champotran wells drilled in Q4 and continue a waterflood program that will push the Paris Basin field's volumes from ~3,500 boe/d as of YE16 to nearly 5,000 boe/d by YE20. At Neocomian, also in the Paris Basin, Vermilion will drill the first four wells in a five-year, 20-well campaign that will increase production from 1,000 boe/d to 1,750 boe/d by YE21. Near Bordeaux, a recompletion and waterflood campaign will maintain Cazaux volumes at 1,500-2,000 boe/d.

Production to rise 10% YOY in 2017 to average at nearly 70,000 boe/d.

Elsewhere in Europe, Vermilion will drill two onshore exploration wells in the Netherlands during 2017 after drilling the same number in 2016. Vermilion will keep its German output steady at 2,000 boe/d as it looks for way to increase production at its first operated asset in the country, acquired from **Engie** in June.

This activity will cost the company $295 million in 2017, or 23% more than was spent on E&P work last year. Production in 2017 will average 10% higher YOY at 69,000-70,000 boe/d. Looking ahead to 2018, Vermilion believes it will be able to hit 75,000-76,000 boe/d based on current plans.

Developments & Trends

Cost & price forcing an oil sand exodus Continued From Pg 1

CNRL's new assets had average production of 160,000 bbl/d in 2016. CNRL estimates that its total production will be 1.07 MMboe/d after closing, nearly equivalent with Algeria, for context.

Shell's turn last month to shale and away from big oil sands developments is part of a larger trend away from high-cost projects that started at the outset of the 2014 price collapse but is continuing even as oil has moved to more than $50/bbl. Since the start of 2017, **ExxonMobil** and **ConocoPhillips** have written down a combined 4.7 Bbbl of bitumen, representing a loss of $250 billion worth of reserve potential.

Shell the latest in string of big names heading out of Canada's oil sands patch.

Statoil left the oil sands in December after selling off its Athabasca area assets to Athabasca Oil and taking a $500 million loss. **Koch Industries** meanwhile canceled a major oil sands project at Muskwa late last year, and **Devon Energy** now seems to be backing away from its proposed 105,000 bo/d Pike project that up to now had been on course for a sanction nod later this year. In all cases, the high costs of greenfield oil sands projects has been cited as a reason for the pullback.

Pike is a good project, but offers lower returns than the company's well-oriented programs, says Devon CEO Dave Hager. Analysts say that unless costs come down, very few large projects will be sanctioned. In 3Q16, IHS Markit estimated that new oil sands fields require US$85-$95/bbl to be economical—or 55-72% higher than current prices. If this is the case, then it isn't likely many will be greenlighted soon as **BOFA Merrill Lynch** believes prices won't sustainably breach the $70/bbl market until at least 2022.

Alberta regulator's data shows diverging industry trends

Alberta Energy Regulator expects oil and gas investment across Alberta to rise by just $200 million in 2017 to total $26.2 billion. Although this is basically flat YOY from 2016, it is clear that there are two very different Albertan oil and gas industries emerging out of the 2014 price collapse. On one hand are the conventional, tight formation and shale drillers who are positioned for strong growth. On the other are the oil sands operators who need prices to go much higher in order to justify new investment.

AER predicts that for conventional, tight formation and shale drillers total spending in Alberta will increase by 20% to $12 billion. The increased investment is coming as a result of prices moving off their downturn bottoms and continued interest in the Cardium and Lower Mannville oil and the Montney and Upper Mannville natural gas plays. The rapidity with which these short-cycle assets can be rolled out is attractive to companies still struggling under low prices and great uncertainty over which way prices are headed.

Oil sands spending to drop 11% to $14.2B but conventional to jump 20%.

The $12 billion that will be spent on conventional, tight formation and shale is still $5.0 billion less than what was spent on these kinds of plays in 2015, but the $2.0 billion jump stands in stark contrast to the still moribund oil sands sector where big players like **ExxonMobil**, **Shell** and **ConocoPhillips** have dramatically reduced their exposure to these capital-intensive, long-cycle projects. AER sees oil sands spending dropping 11.2% to $14.2 billion in 2017 from about $16 billion last year.

This trend is creating a divergence away from Canada's oil and gas status quo. Producers may increasingly be wary of sinking capital into oil sands, but Alberta and Canada as a whole are still dependent on synthetic oil production. AER data shows that more than 60% of Canada's output in 2016 consisted of marketable bitumen, while in Alberta bitumen accounted for over 50% of the province's energy production. Bitumen remains on top for now, but with fewer companies willing to invest in it how much longer that will be so is an open question.

Exxon confident oil sands projects will resume

Despite **ExxonMobil** writing off 3.5 Bbbl of bitumen reserves at its Canadian oil sands assets in February, the supermajor isn't looking to abandon such projects altogether. At the company's analyst day in New York, CEO Darren Woods said Exxon was examining ways that it could increase efficiency in oil sands operations, focusing especially on technology. "We got a lot of opportunity to do that," said Woods.

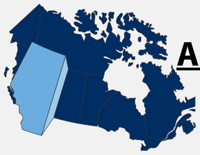
Kearl's op costs have dropped by more than 50% over the past two years.

So far Exxon has brought down operating costs at its flagship Kearl development by more than 50% since 2015, but technological improvement in extracting oil from bitumen is seen as key to making oil sands viable again under US accounting rules. Wider application of techniques like solvent-assisted steam assisted gravity drainage, which increases oil yields by 25-40% and is used at Exxon's Aspen in-situ thermal project could be used to achieve this.

Phases 3 & 4 to increase Kearl capacity by 125,000 bo/d but have been delayed.

Exxon averaged 169,000 bo/d at Kearl during 4Q16—down 16.7% from 4Q15's 203,000 bo/d. This was due to planned and unplanned maintenance, but without costs coming down it is unlikely that either Kearl Phase 3 with a capacity of 80,000 bo/d and Kearl Phase 4, which will increase capacity by 45,000 bo/d, will be revived soon. Both were due to start up in 2016 and 2017, respectively, but have been put on hiatus due to low prices.

CROWN LANDS



Alberta

136 Lots

Crown Land Sale of PNG Rights consisting of **136 Lots** (Leases/ Licenses) Is Planned For April 05, 2017, and A Crown Land Sale of PNG Rights consisting of 104 Lots (Leases/ Licenses) Is Planned For April 26, 2017.

If you would like to be added to distribution for these sales, please contact Jennifer.Esquieres@gov.ab.ca or call 780-422-9432

Saskatchewan

44 Lots

A Crown Land Sale of **44 Lots** (Licenses/Leases) PNG Rights Is Planned For April 11, 2017.

If you would like to be added to distribution for these sales, please contact landsale-subscribe-request@list.gov.sk.ca or call 250-952-0333.

British Columbia

11 Lots

A Crown Land Sale of PNG Rights consisting of **11 Lots** (Leases/ Licenses) Is Planned For April 19, 2017.

If you would like to be added to distribution for these sales, please contact PNGTitles@gov.bc.ca or call 250-952-0333.

Canadian Farm-Outs

Location	Acreage	Interests	PLS Listing Code
Big Bend Area. T67.	1-Active Gas Well. 632-Gross Acres.	47.35% NonOperated WI Available	FO 13662PP
Calling Lake Area. T71-72.	2-Active Gas Wells. ~10,121-Gross Acres.	25% NonOperated WI Available	FO 13729PP
Chisholm Area. T71-72.	1-Gas Well. 3-Sections.	100% Operated WI Available	FO 13625PP
Dawson. T81.	320-Gross Acres.	100% Operated WI Available	FO 14922
Ferrier. T42.	640-Gross Acres	100% Operated WI Available	FO 11899
Gunn Area. T55.	3-Gas Wells. ~2,530-Gross Acres.	43-51% Operated WI Available	FO 13624PP
Judy Creek Area. T64.	1-Oil Well. 64-Gross Acres.	55% Operated WI Available	FO 13614
Kaybob Area. T65.	1-Gas Well. 256-Gross Acres.	25% Operated WI Available	FO 13568
Kaybob. T59-T60.	2,304-Gross Acres.	Working Interest Available	FO 11514
Little Smoky. T66-T68	5,760-Gross Acres. 16-Sections.	100% Operated WI Available	FO 15045
Niton. T50-54	6,560-Gross Acres.	100% Operated WI Available	FO 14924
Northville. T52-T53.	1,792-Gross Acres.	10%-50% WI Available	FO 11466
Obed. T52-55	10,880-Gross Acres.	100% Operated WI Available	FO 14938
Pembina Area. T48.	1-Oil Well. 128-Gross Acres.	25% NonOperated WI Available	FO 13617PP
Senex Area. T94.	1,120-Gross Acres.	100% Operated WI Available	FO 13591
Swan Hills Area. T71-72.	800-Gross Acres.	100% Operated WI Available	FO 13563
Westerose. T44 & 46.	1,600-Gross Acres.	100% Operated WI Available	FO 14816
John Lake Area. T55.	1-Active Gas Well. 632-Gross Acres.	100% Operated WI Available	FO 13592PP
Lloydminster. T50 & T52.	2,200-Gross Acres. 2-Sections.	100% Operated WI Available	FO 14289
Radway Area. T59.	1-Gas Well. 632-Gross Acres.	50% Operated WI Available	FO 13627PP
Viking Kinsella. T49	640-Gross Acres.	100% Operated WI Available	FO 11091DV
Gilby. T35 - 43.	18,996-Gross Acres.	100% Operated WI For Sale	FO 14136
Multipay Opportunity	56,646-Net Acres. 85.4-Sections.	100% Operated WI For Sale	FO 14134DV
Hotchkiss. T94.	640-Gross Acres.	100% Operated WI For Sale	FO 15094
Strachan. T38.	2,560-Gross Acres.	100% Operated WI Available	FO 15123
Carrot Creek Area. T50-54.	17,000-Gross Acres.	100% Operated WI Available	FO 13486PP
Mikwan. T37	160-Gross Acres.	100% Operated WI Available	FO 14965
Nanton. T16-T17.	2,112-Gross Acres.	50% Operated WI Available	FO 11984DV

Source: PLS Research

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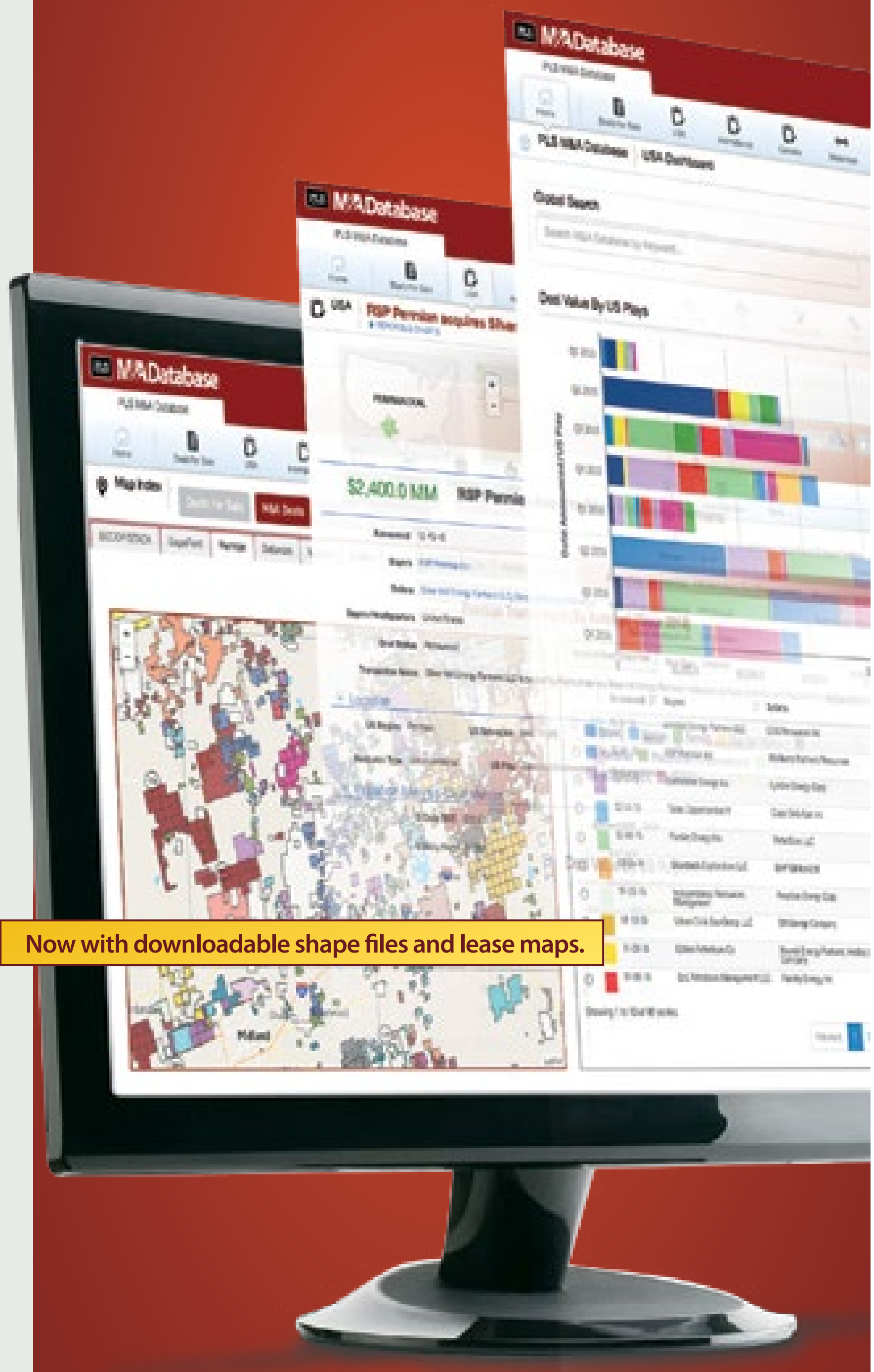

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