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ENBRIDGE WINS SUPPORT FOR $7B PIPELINE REPLACEMENT PROJECT

Shippers agree to surcharges to raise capital to upgrade 1,660-km line from Alberta to Wisconsin

Calgary-based Enbridge and Enbridge Energy Partners say they have shipper support for a $7-billion investment in their mainline system running between Edmonton and Superior, Wis.

The Line 3 replacement program will complement the existing Line 3 segment replacement program and include all remaining segments of Line 3 between Hardisty, Alta., and Superior, the two companies announced Monday.

The L3R program, subject to regulatory approvals, is targeted to be completed by the second half of 2017.

"Mainline shippers have agreed to support surcharges on all barrels moving on the mainline to provide an appropriate return on the additional capital required," the companies said in a news release.

Enbridge CEO Al Monaco says the Line 3 replacement program will be the largest project in the company's history. (Associated Press)

Under the L3R Program, all segments of the line between Hardisty and Superior will be replaced with new pipe using the latest available high-strength steel and coating technology.

Long-term integrity costs to maintain the line will be substantially reduced and the reliability of service will be enhanced, they said.

"The Line 3 Replacement Program is an important project for our customers and for Enbridge and aligns very well with our strategic priorities," said Enbridge CEO and president Al Monaco.

"You can think of this project as a buffer, to deal with unplanned disruptions and maintenance and additional scheduling flexibility that shippers need," Monaco said Tuesday on a conference call with investors.

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"That's very critical from our shippers' perspective because it ensures producers have highly reliable access to the best markets so they can get full value for their crude."

Biggest project in company's history

"The L3R Program will be the largest project in our company's history and will serve to significantly extend our industry-leading earnings per share growth rate well beyond 2017."

Initial development work is already underway to support the regulatory applications that will be submitted in late 2014, Enbridge said.

"This includes an extensive public consultation process with landowners, aboriginal and native American communities, municipalities and counties and other stakeholders along the Line 3 right of way. Further information on the project will be shared with the public in the near future through mailouts and public meetings."

The Canadian L3R Program, between Hardisty and Gretna, Man., currently is estimated to cost approximately $4.2 billion and will be undertaken by Enbridge's wholly-owned subsidiary, Enbridge Pipelines Inc.

The U.S. L3R Program, between Neche, North Dakota and Superior, is estimated to cost approximately $2.6 billion US. The U.S. Program will be undertaken by Enbridge Energy Partners, L.P. with funding provided jointly by Enbridge and EEP at participation levels yet to be finalized.

The program will result in the elimination of $1.1 billion of Line 3 integrity capital, which would otherwise be required by 2017, as well as elimination of additional post-2017 integrity capital.

Guy Jarvis, president of liquid pipelines for Enbridge, said the L3R program provides a very attractive solution to Enbridge and its shippers.

"In the long run it is the most efficient way to maintain the line," Jarvis said. "It also improves the reliability of the system, with less down time for inspections and repairs and more operating flexibility."

Mark Maki, Enbridge Energy Partners president, said the U.S. Line 3 replacement program would provide a significant attractive investment opportunity for EEP, enhancing distributable cash flow growth rate.

Line 3 is a 1,660-kilometre, 34-inch diameter pipeline that has been in operation since 1968.

CNRL WANTS TO START HIGH-PRESSURE STEAMING NEAR ACTIVE SPILL SITE

The company whose northern Alberta spills have been oozing bitumen for 10 months nonstop has asked the province to let it start high-pressure steam operations less than a kilometre away from one of the spill areas.

More than a million litres of bitumen have spilled so far from Canadian Natural Resources, Ltd.'s Primrose sites – but it's hard to tell because that's lower than what the company said had spilled several months ago. (CNRL says that's due to "reconciliation" in its numbers; the Alberta Energy Regulator doesn't collect its own figures)

Either way, that makes this one of Alberta's top five bitumen spills in 40 years. And the leaks show no sign of stopping.

Canadian Natural applied last month for permission to start high-pressure steam operations at a Primrose South site. The closest well is about 500 metres away from the one-kilometre exclusion zone the province set up last summer around one of the spill sites.

This would be the same kind of high-pressure cyclical steam stimulation CNRL used where these spills occurred: Inject extremely high-pressure steam into a vertical hole in rock; then suck all the heated bitumen out as the high pressure forces it up through the same hole in the rock.

CNRL says it knows what started the leaks in the first place: It blames old wellbores deep within the rock that should have been capped with cement but allowed bitumen to escape.

"We are confident as to the cause and the step we can take to prevent it happening again," spokesperson Zoe Addington said in an email.

Others aren't so sure.

"It's kind of strange to me they're sort of approving steaming in the absence of knowing officially what went wrong," said Keith Stewart, climate and energy campaign coordinator with Greenpeace Canada.

"If they start injecting here it could reheat and cause the other one to keep spilling or it could, depending what's cracked, it could widen cracks more. It certainly won't make things better."

Regulator spokesperson Bob Curran said they're reviewing the application and there's no set timeline for how long that will take. "As a general policy," he said in an email, "we do not discuss specifics of applications that are under review."

But "if CNRL hasn't proven they can ensure it won't happen again and if the regulator doesn't know it won't happen again, it should be considered a high-risk application," said Pembina Institute analyst Erin Flanagan.

When the spills were just a few months old, CNRL said there was no way to stop the seeping bitumen until the pressure pushing it up from underground subsided. It appears it still hasn't, although it remains unclear how much has actually spilled: In September, CNRL said about 1.2 million litres of bitumen had spilled; this week, it said about 1.77 million, chalking the discrepancy up to reconciled numbers.

The company also said the amount spilling now is almost "imperceptible" – about 1,000 litres a month from all spill sites.

Kevin Timoney doesn't buy it: The Treeline Ecological Research investigator published a detailed report into these spills, figuring that, if previous volume reports were accurate, the real amount of bitumen spilled so far is probably closer to 2 million litres.

"Both AER and CRNL fail to provide accurate, complete, and timely information to the public," Timoney's report reads. "Without independent oversight of reported hydrocarbon release and recovery volumes, the public may never know the true volumes spilled or recovered."

The spills are expected to come up in CNRL's conference call with investors following its fourth-quarter earnings announcement Thursday.

CNRL's application to start high-pressure steaming says it has done a risk assessment on all wellbores within a kilometre of the proposed site, and plans to implement "an enhanced monitoring and reporting protocol" within that area.

Others aren't so sure wellbores are the answer: The Alberta Energy Regulator would say only that it "continues to make progress is its investigation, and will release its findings once the investigation is complete."

Environmentalists point out it seems statistically unusual for several wellbores in different locations to suddenly fail at once, and strange for one failed wellbore to cause spills surfacing several kilometers apart.

They say it could be that the steam's just too high pressure – it's cracking the caprock, creating fissures in the stone where bitumen can escape.

If that's the case, it could mean trouble – not just for CNRL's operations at Primrose, but for anyone extracting bitumen by injecting high-pressure steam into the ground. And the number of in situ operations doing that is slated to grow. What happens if it turns out companies don't know as much about doing that safely as they thought they did?

The regulator's investigation into a similar CNRL spill in 2009 suggested problems with rock and pressure, but was ultimately inconclusive as to what caused the large spill.

It's possible the broader implications of such a finding could be holding the regulator back from suggesting the problem lies in the extraction method itself.

"It would be a very brave bureaucrat in Alberta who said, 'We have a problem with in situ technology' because it is the future of tar sands development," Stewart said. "This is why I think they need to make their reviews public and they need to be reviewed by independent experts."

ALBERTA REGULATOR CRITICIZES PIPELINE COMPANY FOR 2012 OIL LEAK

Alberta's energy regulator is criticizing a pipeline company in a report into a 2012 pipeline leak that dumped nearly half a million litres of oil into a major river.

The Alberta Energy Regulator says operator Plains Midstream failed to inspect the line often enough. The line cracked open in the Red Deer River when the stream flow was unusually high.

The regulator also says the company didn't pay attention to high streamflow advisories, which might have enabled it to limit the damage.

The spill affected about 1,700 people, including businesses and summer cottagers at a reservoir lake downstream.

The regulator has told the company to update its emergency response plan.

DEVON DEAL SHOWS CANADIAN NATURAL'S IMPROVED OUTLOOK FOR GAS PRICES

Signalling a change from its previously bearish outlook for natural gas prices, Canadian Natural Resources Limited has agreed to pay $3.13 billion for the bulk of Devon Energy Corporation's western Canadian assets.

Oklahoma City–based Devon says proved reserves associated with the divestiture totalled about 170 million barrels of oil equivalent exiting 2013.

The blockbuster deal will give Canadian Natural assets producing 86,633 barrels of oil equivalent per day in western Canada, with six owned and operated gas plants and four oil batteries. Excluded from the deal were Devon's thermal bitumen, conventional heavy oil and Horn River shale gas assets. The target closing date is April 1 with an effective date of Jan. 1, 2014.

"This is a gas-weighted acquisition—about 70 per cent is gas," says Steve Laut, Canadian Natural president.

"And the metrics on the gas we think are very reasonable and fair," he says, noting North American gas storage is down significantly this year and the forward strip pricing is positive.

"We think it'll take quite a bit of time here to get the storage filled up. So 2014 and potentially into 2015 looks like pretty strong gas pricing and that helps the metrics of this deal," Laut acknowledges.

"But that's not the driver of the deal," he emphasizes. "It's the assets themselves—and our ability to integrate those assets, achieve operating costs and [general and administrative] synergies and just develop some of the light oil properties and liquids-rich natural gas…that drive the acquisition."

Canadian Natural says the 2013 estimated operating costs for the Devon assets averaged about $1.79 per thousand cubic feet equivalent.

Asked whether the acquisition will significantly change how the company allocates capital, Laut says it won't slow the development pace of its Horizon oilsands mining project.

The current Horizon expansion is running about 10 per cent below the cost estimate, he says.

"I wouldn't see the allocation of capital [within Canadian Natural] changing too much," Laut says. "Although I will say now with a little bit of lift in gas prices, you know we have a lot of liquids-rich gas that does compete with some of our oil properties. So as we shake out the capital allocation and rank everything based on return on capital, it's possible you will see more liquids-rich gas drilling into the portfolio in the second half of the year or into 2015. But we still haven't done that allocation yet."

At present, Canadian Natural expects to spend roughly $150 million on the Devon properties during the remainder of 2014.

This is the second recent move by Canadian Natural that could signal increased confidence in gas.

In the first quarter of last year, Canadian Natural began looking for buyers or joint venture partners for 380 net sections of its Graham Kobes area Montney lands in the liquids-rich fairway of northeastern British Columbia. However, the company has since decided to hang onto that acreage.

In its own press release, Devon says it will "immediately repatriate the proceeds to the U.S. for use in the repayment of debt incurred to finance its Eagle Ford acquisition" once the deal closes.

"This agreement represents a significant step forward in the execution of our non-core divestiture process," says Devon president and chief executive officer John Richels. "This tax-efficient transaction provides for a clean exit from our Canadian conventional business at a value of nearly seven times 2013 [earnings before interest, taxes, depreciation and amortization], a substantial premium compared to Devon's current trading multiple. Furthermore, the timely execution of the largest piece of our non-core divestiture process accelerates the refocus on core assets."

CONNACHER RECORDS DROP IN RESERVES

Connacher Oil and Gas Limited reported an overall reduction in reserves in 2013 despite an increase in proved producing reserves.

Estimated proved reserves totalled 212.06 million bbls of bitumen as of Dec. 31, 2013, a decrease of one per cent over year-end 2012 volumes of 214.01 million bbls, as evaluated by GLJ Petroleum Consultants Ltd, independent qualified reserves evaluators. The present value of future net revenue, discounted at 10 per cent annually, is $900 million, down from $1 billion the previous year.

However, proved producing reserves grew by 13 per cent to 22.53 million bbls from 19.93 million bbls in 2012 with the inclusion of the recently drilled infill wells and well pairs at Pod One. Production totalled 4.3 million bbls in 2013.

Estimated proved and probable reserve volumes are 446.38 million bbls of bitumen, down one per cent from 451.4 million bbls a year earlier. The 10 per cent present value declined by four per cent to approximately $1.69 billion, due to GLJ's estimates for future capital and operating costs, slightly lower future commodity prices, and the timing of the Algar expansion.

Connacher has been successfully piloting the proprietary SAGD+ process for three years. Based on its success and recent Alberta Energy Regulator approval for a commercial project, GLJ assigned 2P reserves at Algar reflecting implementation of that process in addition to steam-assisted gravity drainage (SAGD). The company plans a commercial project using the SAGD+ process at the Algar facility in 2015.

Pod One and the Algar expansion areas do not have SAGD+ process reserves assigned at this time. These areas are assumed to continue to have infill wells in addition to SAGD in the 2P reserves category.

Connacher's first SAGD project at Great Divide, Pod One, has been producing bitumen since late 2007, with commercial production commencing March 1,

2008. Bitumen production at Algar began in August 2010, achieving commerciality Oct. 1, 2010.

Approximately 21.3 million bbls of bitumen have been produced from Great Divide since start-up through Dec. 31, 2013, and have been deducted from earlier estimates of proved reserves prior to the calculation of reserves as at Dec. 31, 2013.

The year-end 2013 report was prepared using assumptions and methodology guidelines outlined in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101.

CANADA OFFERS TO WORK WITH US ON OIL POLLUTION IN KEYSTONE XL LETTER

The Canadian government has sent the Obama administration a letter making its case for the Keystone XL pipeline.

The letter argues the merits of the pipeline on environmental, economic and energy-security grounds.

It expresses a desire to work with the Americans on oil and gas issues, without wading into specifics.

The three-page note is signed by Canada's ambassador to Washington, Gary Doer, and addressed to Secretary of State John Kerry.

Kerry is leading a regulatory review of the pipeline proposal and is accepting public comments during a 90-day national-interest determination phase.

Once that's over, the Obama administration must decide whether to allow the pipeline to cross the border and connect to an existing leg in the southern U.S.

The president has reportedly told state governors that he expects to make a final decision in the next couple of months.

It's the fifth time the Canadian government has submitted public comments in the multi-step, years-long Keystone XL regulatory process.

DOCUMENTS SHOW FRACKING IS SOARING IN ALBERTA

Alberta New Democrats say newly released documents show fracking has become an unregulated free-for-all in the province with no regard for the impact on groundwater or on people's health.

NDP Leader Brian Mason presented information Tuesday provided under freedom-of-information laws that shows the number of hydraulic fracturing licences granted by the province soared 647 per cent last year to 1,516.

Mason said the amount of water allocated and used for fracking has increased even faster.

"Most Albertans don't realize that fracking in Alberta is almost completely unregulated," he told a legislature news conference. "And it is increasing on a dramatic scale without any understanding of what the potential consequences will be."

He said the water loss alone is sobering, with more than 17 million cubic metres used in 2013.

"This is an enormous amount of groundwater. It's pumped into the ground, it's polluted by chemicals and it's never seen again."

Fracking blasts pressurized water and chemicals into underlying rocks to release trapped natural gas and oil.

It has changed the game on North American resource extraction in the last decade — fuelling an oil and gas boom in North Dakota and delivering a 15 per cent overall production increase south of the border, according to Alberta government data.

It has also resulted in a backlash from environmentalists and from homeowners who live near fracking sites. Their main concern is polluted groundwater and aquifers.

In Lethbridge, homeowners and city council are fighting an application by Calgary-based Goldenkey Oil to drill three wells using vertical hydraulic fracturing within city limits and within one kilometre of where people live.

The legislature members for Lethbridge — Progressive Conservatives Bridget Pastoor and Greg Weadick — have told residents they are making sure concerns are heard. Mason said they two need to go farther and actively fight the development.

"They're mealy-mouthed hedging on the whole question."

Fracking has brought with it controversy in other provinces. Newfoundland and Labrador, Nova Scotia and Quebec are re-evaluating its benefits versus the consequences of environmental damage.

Mason said it's too late for a moratorium on fracking in Alberta.

"The horse is kind of out of the barn. It's a mainstream activity now."

He suggested Premier Alison Redford's government should undertake an independent scientific review of hydraulic fracturing and use independent groundwater monitoring before further projects get approved.

Environment Minister Robin Campbell disagreed with Mason. He said in a news release that "Alberta has strict regulations that apply to all oil and gas development regardless of the technology being used."

Campbell also said concerns of environmental damage have not been borne out.

"To date, there has not been a documented case of hydraulic fracturing fluids contaminating a domestic water well in Alberta. For anybody to claim that the water supply is at risk is completely false," said Campbell.

"All water licence applications are carefully reviewed to ensure no significant impacts to our environment or other water users."