TRANSCRIPTION OF THE DIGITAL RECORDING

OF THE PRESENTATION

OF

TERRANCE McGILL

MR. McGILL: Tony, thank you. And with me on my left here is Tracy Barker who runs our investor relations group. If anybody at the end of this wants to be on the mailing list, because Lord knows you don't get enough emails on announcements and things with the company, pass your card over to Tracy and he will make sure that happens. And again, thank you very much for being here today.

I am president of the managing partner of Enbridge Energy Partners, so I have all the United States assets for Enbridge. Enbridge, Inc., is our general partner, and then hopefully in the short 20 minutes you'll get a story of the partnership of income, safety and growth that we believe our company provides to investors.

Enbridge, Inc. -- and we trade, by the way, under the EEP symbol for the limited traditional Class A limited partnership shares. We trade also under EEQ for our I-shares, which are at the time designed for institutional holders. Basically they pay out distributions in additional shares and OK warrants.

Let's see. Get this straight. I know you haven't seen this yet today, so to cover for everyone else, the legal notice on forward-looking statements, so please get one of our handouts from out front and you'll be able to read that.

Enbridge, Inc., is our general partner as I mentioned. 52 year history. Its main claim to fame is running the world's longest oil pipeline from the Alberta oil sands all the way down across the Great Lakes and into eastern Canada as well as a little touch of western New York there. It's a big diversified energy company, large cap with a split rating of A and a high B, which is triple B, triple B plus, whatever that is, and it's certainly as a 52 year company in for the long haul with an annual compounded growth rate of 13.2 percent, so it's certainly been around a long time and has provided very good investment to those investors.

It has three legs: the long oil pipeline as I mentioned from Alberta all the way down to the United States, a distribution company in Toronto, a couple other little areas, New Brunswick and Newick, but Toronto's distribution is 1.7 million customers and the largest distribution company in Canada. And on the bottom of our slide, well, there's a long line, the Alliance pipeline, brings gas from western

Canada down to Chicago, the partnership or the general partner owns 15 [50?] percent of that, and everything to the south is a gathering of processing assets with the offshore assets that were purchased from Shell about three years ago I believe just last month, three years ago last month.

So I've put that up there so you could see the next one, which is the Enbridge Energy Partners, traditionally an EEP symbol. We have two main businesses, which has the fourth quarter or 50/50, so the oil pipeline in blue, the Lakehead system, which was the original asset of the partnership, moving crude oil, about 1.6 million barrels as it stands today, down to Chicago, it splits the Great Lakes, and we had a couple other acquisitions, the North Dakota system which I'll touch on later up there to the top and the Ozark system which goes from Cushing to Patoka, and that brings with them -- that was purchased from Shell also. That brings with it 17 million barrels of storage at the Cushing terminal.

The green pipelines are owned by the general partner and we depict them only to show the linkage as they connect the partnership's oil assets. To the south we purchased Midcoast Energy, oh, that would be five to six years ago now, rolled it into the partnership, and these are the gathering of processing assets that we have in our partnership.

Very simple the math, and you'll see where this presentation is somewhat going, we're 50/50 oil and gas in our partnership. On the oil side, the Lakehead system is about 80 percent of that, and on the gas side, Texas is 90 percent of our gas business. So we'll kind of focus on those two things, and that's also where our capital growth and our greenfield projects are coming from.

We were built like a lot of MLPs through acquisitions. Enbridge did not play in any of the arenas of fiberoptical and the pipelines, or marketing and trading at the time, so it came out of the early 2000s with plenty of dry powder, but wanted a presence in the United States, wanted a presence in the Gulf Coast, and that lead to the purchase of Midcoast Energy. From that, we purchased -- and then purchased a coke system in east Texas, Davin[phonetic] gathering system in North Texas, Cantera up in Barnett shale, as I mentioned the Shell assets at Cushing, so we were able to buy assets at 7, 7 and a half times even doc, but as time's going on, private equities come in, other parties come into the space and you see the multiples jump up on acquisitions, but we were blessed by having then enough critical mass in our areas with rising oil prices to be able to go into organic growth, which I'm sure you've heard plenty of folks wanting to be in the organic growth field.

And the yellow kind of depicts that acquisition model we had at the beginning, and as we've morphed into more of the organic growth model and you see the tremendous capital expenditures going out as we're building the infrastructure to move predominantly Canadian oil down to the United States.

Crude oil markets, the strategy is pretty simple. It's harder to execute. There's 174 billion barrels in Canadian oil sands. It's a fascinating process and two story -- dump trucks the size of two story houses. It takes a ton of sand for a barrel of oil and they move a million barrels a day out of that.

We move 65 percent of the oil out of

Alberta, and the goal is as the oil sands grow, we've served 85 percent of the Minneapolis refineries and 100 percent of Superior, Wisconsin, 50 percent of Chicago, the BP Whiting facility, but as additional oil is coming down, it's clear that the pad two, that upper midwest area, is going to have more Canadian crude oil than it can possibly handle not withstanding additions and refurbishments to existing -- or expansions really to existing refineries.

So the goal was how to turn those red dots which -- the red dots which depict Canadian crude or refineries served by Canadian crude and kind of move that down to those yellow dots which do not have Canadian crude, and how do we get -- so there's kind of three parts of this. The upper midwest is used to Canadian crude, not a problem. The midwest, or the center section in there, has gotten local production, four small lines coming up from the Gulf Coast. And of course down to the south, the Holy Grail for Canadian oil producers is to get down to those refineries in the Houston-Beaumont area that can handle the heavy crude, such as the Venezuelan heavies, the Mexican Mayans, and get down and compete with the waterborne crudes.

So it's very simple strategy, how do we get this crude oil down from Canadian into the United States as we try to handle our appetite for crude oil. The execution part is always hard in building pipelines and the government regulations, permittings and all the things that come with that.

Our first project or the first bottleneck that we had to resolve is what we call the southern access pipeline. We move 1.6 million barrels of crude oil. We have several lines coming down from Canada and crossing the border. They drop off into Minneapolis and places like that.

In Superior, Wisconsin, is our bottleneck. We can move 940,000 barrels of crude oil south from Superior to Chicago. The balance of the crude oil goes on the north side of Lake Michigan and moves over to eastern Canada, but that's not where the growth is. We need to have more capacity going south to handle the additional crude oil volumes.

So southern access is designed to handle that. It's a 42-inch pipeline to be built from Superior, Wisconsin, down to ultimately Delavan, Illinois, where it can go south of the Spearhead or back up to Chicago, and there's other pipelines in that area.

It's a $2.1 billion project. The first tranche of that, 190,000 barrels of it, comes on line here in April of '08. The second tranche comes on in April of '09 which will be another 210,000. Oil pipelines generally are 36-inch pipes that can handle 400,000 barrels, kind of rule of thumb. Extra pumping stations can get you a little bit more, but what we needed is more capacity than that, so the partnership took the risk to upsize the pipeline to a 42-inch which will be able to move additional crude oil volumes.

This project is about as MLP friendly as we could come up with in that it does not -- it doesn't have supply risk, and I'll explain that in a second. What we get as the partnership is a 9 percent real return plus inflation plus tax. We true up every year. We move fewer volumes in the first year. The tolls go up in the second year. If we move higher, the tolls go down lower, and the cost is spread over all 1.6 million barrels. All the barrels that go through there picks up the cost of this expansion.

And I mentioned, well, how did we get this levy on supply risk, and in April of '08 when we come on line, we will be paid whether there's an incremental barrel of oil ready to come on at that point or not. And the key is in the Alberta oil sands there's almost $100 billion committed or haven't been spent to develop these sands, and a $2.1 billion pipeline is just not a big deal in the scheme of things with the Alberta oil. They would much rather have the pipelines there early rather than there late. They get such a -- they're going to get such an uplift in their prices, it more than pays for this expansion. So the supply risk is not an issue for this project, and again it's a very, very MLP friendly type of project.

Now, I mentioned a 42-inch. 42-inch, I'm up now to 800,000 barrels, and now it's got another problem as the southern access fills up in that I can't get enough capacity to Superior. I can take more away from Superior than I can get to Superior, so that led to Alberta Clipper which is a much longer build because it's going from Edmonton in Alberta all the way down to Superior, Wisconsin. The partnership will pick up the U.S. fees, $1 billion in 2007 dollars, to add 450,000 barrels a day of capacity.

The similar -- I mean no supply risk. Similar kind of a structure to it, no supply risk. We use the National Energy Board, the Canadian group multi-pipeline rate, plus 2 and a quarter percent plus tax, and once that comes on in July of '10, now the pod's right in that you have enough capacity to handle the incremental production from Edmonton and bring it all the way down south, south of Chicago into that area.

So again, I've given you three dates, April of '08 for the first tranche of southern access, April '09 for the second part of southern access, July of '10 for Alberta Clipper. And then -- and the oil comes, but again, as an investment in the partnership without the supply risk, we'll get paid to wait if we have to wait.

North Dakota. I mentioned -- I touched on North Dakota's system. Quite the opposite of maybe some of the royalty news you've read out of Alberta where they were raising the royalties. The North Dakota legislature including the governor has advocated drilling incentives for the BOC in play.

And we have the oil pipeline up in there that was purchased '9 -- when was it, 2000? -- something like that, and so we've had two expansions, one we just completed, a 30,000 barrel a day expansion, and the next one is about a 50,000 barrel a day expansion that should be completed by early next year.

Same kind of regulatory construct in that those costs are rolled in and all barrels will pick up the cost of the expansions. We've just compressed the time period into five years for the first expansion, seven in the second. So again, we'll get -- certainly get our money back plus a good return, just in a much shorter time period.

So we see growth in the western North Dakota/eastern Montana area. There's a tremendous amount of activity going on up there, certainly at the oil prices as they are today.

So I've talked about a couple things, where's this oil coming from, and what we've done is we go out and talk to all the oil sands producers and we're a very optimistic bunch. And we kind of tempered it down a little bit with labor and refinery developments and pipe constructions and things and come up with an Enbridge forecast of what we think incremental production will be, and this graph depicts just incremental production from today.

Lay on top of it a grid of what we believe to be a pipeline construction, including Keystone there in the middle, it's a $5.2 billion pipeline from Edmonton over to Patoka, and you start to see where the pipes will be there before the oil, but that's fine, oil producers are paying folks to be there before the oil, but you see an incremental 2.1 million barrels of capacity will be needed. 1.8 million barrels of it will be for crude oil, 300,000 barrels of it will be for diluent constant that will be shipped up to Edmonton to cut the heavy crude so the stuff will actually flow. It's not the most viscous of crude oils that's coming down the line. So we do see tremendous growth and we see tremendous upsize in this area. It's a very, very long life reserve area that again we're moving 65 percent as we sit right now with available capacity as the oil comes on.

So I've touched on the producers doing their part with $100 billion and the pipelines doing their part with the investments to go to infrastructure and that leaves the refineries. And this is a list of the refinery developments, either announced or under construction, of refinery expansions and refurbishments to be able to handle the Canadian crude in the existing area. The biggest one will probably be at Whiting. So we see the demand, Foothills in Minneapolis, and Superior -- the Murphy refinery in Superior will probably double in size, so we see the refineries getting ready for this big chunk of crude oil that will be coming downstream.

So even with that, we'll have more crude oil than the upper midwest and the midwest can handle. How do we get down to the Gulf Coast? There's been a couple of attempts at this and one of them is by Enbridge, the general partner, in buying the Spearhead pipeline, which was I believe a 20-inch line moving from Cushing to Chicago that was owned by BP. Bought it, reversed it, so we can move Chicago to Cushing, and doing 125,000 barrels a day and it's currently being expanded up to 200,000, so it'll be 200,000 total.

Exxon Mobile took the Pegasus line and reversed it from Patoka to course from Canada down to Houston and it's currently moving 70,000 barrels. The problem is these aren't very big diameter pipes. Trying to get heavy crude through a 20-inch line is sucking malt through a straw. So that's lead to Exxon Mobile and Enbridge working on a joint venture to build a 36-inch pipeline to move 450,000 barrels down from Patoka generally following the Pegasus right-of-way to get down to the refineries, certainly the Exxon refinery and other source in the United States.

So you'll see that the map has been complete from the oil sands all the way down to the Gulf, and yes, the basis differentials clearly support this additional transport cost. The farthest I've seen the basis drop is probably $50 back from WTI up in the Alberta oil sands. That's probably a record. Generally it's 22 to $27, so it's working out pretty well.

On the gas, pretty simple story on the gas since most of it's from Texas around here or down here, and if you go on to Dallas, you see the wells being drilled at the Dallas-Fort Worth Airport or TCU campus. We've seen 27 percent growth in our supply areas in the Bossier sands, in the east Texas and in the Anadarko area, so we see continued growth.

And pipeline construction, a lot of which you heard from other companies today, but it's a tremendous asset that's being explored here in the state. We see growth in certainly the Barnett shale, probably -- I think it's probably 2.3 BCF a day now moving up to 4 to 6, and the east Texas area just north of Houston is doing a lot of exploration and tremendous production out of that area. We're just finishing up our Clarington project. We're already down to -- we've got pipe all the way down to Beaumont and that's currently moving about 300 million a day.

Again, getting gas out of Texas, Texas produces about 9 BCF more than it consumes and this gas has to hit the borders to try to find the east coast, the southeast, the mid Atlantic states to be able to serve the demand out there.

Our funding requirements, I mentioned on that chart about $5 billion is needed over the next three years. We've prefunded. We're running probably 47 percent debt now with a combination of A units, C units, hybrids, zero coupons, you name it, we've probably got something like that in there, but we're looking at probably $970 million of equity requirements over the next three years, notwithstanding our liquidity that we have which is almost -- which is about $2 billion in a combination of credit lines, reporting features and general partner commitments, so we do have the liquidity, but we are going to need equity investment over the next three years.

The debt, we're -- we don't have as much debt. We're going to have to add some more debt to that, but we do follow a 50/50 debt/equity structure.

So let's see. I'll go to this one, the risk. We do take commodity risk in our gas business. We hedge it out 70, 50, 40, 30, 20 over the next five years. We don't go up as fast as some folks. We don't go down as fast as some folks. We don't think people buy as many energy units to take -- making bets on gas prices or fract spreads. So we follow a cash flow risk model instead of an earnings risk. We keep a 7 and a half percent cash flow risk limit, we're probably at 6 percent today, and that will come down as hedges get put on and things move off into the future.

So investments in Enbridge Energy Partners. We do think it's a good combination of income, safety, certainly as I mentioned one of the very first MLPs with a strong general partner, and we do have growth. The oil sands, it's not a question of if, it's a question of when, and right now the pipes will be ready, you know, start generating cash in April, and oil sands workers are working very, very hard to get all of that crude oil coming down. And as far as I can tell, there hasn't been any abatement in demand for crude oil in the United States, so it's going to be a supply source for a long, long time in this country.

So with that, I wrap up, Tony. Thank you all very much.

* * * * * * * *

STATE OF ILLINOIS)
) SS
COUNTY OF FORD)

I, JUNE HAEME, CSR, RMR, CRR, do hereby certify that I am a court reporter doing business in the City of Champaign, County of Champaign, State of Illinois; that I transcribed the digital recording of said hearing; and that the foregoing is a true and correct transcript of said digital recording.

JUNE HAEME, CSR, RMR, CRR
NOTARY PUBLIC

"OFFICIAL SEAL"
June Haeme
Notary Public, State of Illinois
My Commission Expires:
September 27, 2008