MARK CHYC-CIES: Good Morning.

RESPONSE: Good Morning.

MARK CHYC-CIES: I'm very happy to welcome everyone to Veresen's 2016 Investor Day. My name is Mark Chyc-Cies. I'm the Director of Investor Relations and Corporate Planning. And joining me today are Don Althoff, President and Chief Executive Officer; Theresa Jang, Senior Vice President of Finance and Chief Ex—Financial Officer; Betsy Spomer, Executive Vice President, President and Chief Executive Officer, Jordan Cove LNG; Darren Marine, Senior Vice President, Business Joint Ventures; Dave Fitzpatrick, President and Chief Executive Officer, Veresen Midstream; and Paul Eastman, Senior Vice President Operations.

Don will begin the presentation today by providing a brief overview of our strategy, but most of the time today is set aside to talk about our businesses in detail. We will begin by highlighting the business that generates most of our cash flow today before taking a short break. After which, we'll talk about the businesses that are going to drive our future growth: Veresen Midstream and Jordan Cove LNG. We'll conclude our discussion today with our funding strategy and our balance sheet. In order for us to remain on schedule, I would ask that you please hold your questions to the end.

Now, before we begin, I will have to remind you that some of the comments made today, and certain statements contained in the presentation, are forward looking in nature. Forward-looking information is subject to risk and uncertainty, and consequently, actual results may differ materially from what is indicated. We caution all participants not to place undue reliance on this forward-looking information. Also, certain financial information may not be standard measures under U.S. GAAP and may not be comparable to similar measures presented by other companies. These are considered to be important measures used by the investment community, and should be used to supplement other performance meas—measures perform—prepared in accordance with GAAP in the U.S. For further information on non-GAAP measures, please refer to our most recent MD&A and financial reports. Now, I will turn it over to Don.

DON ALTHOFF: Well, thank you Mark. And welcome everybody. I had mentioned to few people today, this is Veresen's first Investor Day. So, I guess, from our heritage as Fort Chicago, it's only taken us sixteen years. So, hopefully, it's—it's worth the wait. And—so—and thanks for joining us. I'm—I'm just delighted to—to be kicking it off.

We've spent—I—I've spent a lot of time on the road with investors lately and have really been really trying to talk about a few key messages about where Veresen is at. We—we've really, I think, fundamentally transformed Veresen's business model, our asset base and the management team over the last five years. It's a very different company from the days of the income trust and Fort Chicago. We've created a strong base and—and have grown it in a focussed way. It's still anchored by Alliance Pipeline but it's more diverse and it connects some of the best resource basins in North America with the premium markets.

The strong foundation is underpinned by long-term take-or-pay contracts and diverse of counter-parties. With these changes, we've also strengthened the balance sheet and lowered the overall risk of the company. I think it's fair to say today that our base business is among the best in our peer group. Based on the business we've put in place today, I'm confident of the sustainability of the dividend. We know it's important to our investors, and the dividend will continue to be a core piece of our value proposition.

We’ve also developed and implemented a strategy that creates a compelling and differentiated value proposition for our comp—for our customers. And it’s working. Veresen currently has $1.4 billion of projects under construction, which is relative to our market cap. is best in class in our peer group. I believe that we’re positioned to continue to secure significant new growth in the future, largely through our Veresen midstream platform. Based on where we’ve positioned the company today, we now see ourselves, fundamentally, as a growth company.

Finally, we’ve put in place a strong management team. They have a proven track record and deep industry experience. The management team we assembled have been key contributors on our journey, and I’m confident they will deliver future success. And, of all the significant accomplishments we’ve had over this last four years, getting the right management team in place, I think, was the most important.

So, let me tell you a little bit about the journey we’ve been taking. When we converted the corporation from the trust era, the company was still largely as it was when we created it a decade prior. Although the company did acquire one new asset, the Alberta Ethane Gathering System, or AEGS, and several development power projects, roughly 85% of our distributable cash came from Alliance and Aux Sable. And only 75% of the dividend was covered by take-or-pay contracts. With strong frac margins at Aux Sable, sus—although strong frac margins sustained the dividend at the time, we also understood that the cyclical nature of the cash flow wouldn’t sustain the dividend long term. In order to diversify our cash flows and our historical dependence on Alliance and Aux Sable, Veresen acquired Hythe/Steeprock assets from Encana in 2012. This marked Veresen’s entry into the Western Canadian Midstream. It was our first step in implementing the strategy.

Continuing with the diversification strategy, Veresen acquired a preferred interest in Ruby Pipeline in 2014, adding another highly contracted, long haul pipe to the portfolio. With the Ruby acquisition further strengthening our cash flows, we expanded our Midstream footprint as we formed Veresen Midstream in 2015. It's currently producing a half a billion cubic feet/day of gas in—in the Montney for processing, and has the potential to invest up to $2.5 billion in capital growth projects net to Veresen. This build out also establishes a platform in the Montney to secure additional third-party growth. And we still see Veresen Midstream as the growth engine, going forward.

We just recently announced the sale of our power business, which will allow us to turn off our DRIP, and to fully fund our current growth without accessing the equity or debt markets. That means top-line growth will also translate into per share growth. With the sale of power business closing in the first half of 2017, our focus will be solely on building and managing infrastructure and the gathering, processing and transportation of natural gas and natural gas liquids.

Once the three gas plants at Veresen Midstream are online, on a distributable cash basis, we will be roughly one-third Alliance, one-third Ruby, and one-third Veresen Midstream. It's important to note that we've also made significant progress over the last several years in maturing Jordan Cove into one of the best projects on the West Coast of North America.

With the trends we are seeing in the industry today, I'm confident that our strategy of being focussed on natural gas and NGL infrastructure in our geographic footprint will prove to be a winner. As I mentioned earlier, with $1.4 billion in projects contracted and under construction, relative to our size, we offer best in class growth. More importantly, we are not pursuing growth for the sake of growth. We are focussed on translating top line growth into increasing distributable cash per share. We will manage our balance sheet prudently and make sure we maintain the financial flexibility to execute our business plan and take advantage of opportunities. And maintaining an investment grade credit rating is also important to us and critical to the execution of the business plan. Our strong-based business, our growth, and our balance sheet underpin our current dividend. The dividend is an important part of our value proposition and remains a priority.

Our business today is well positioned to take advantage of two key North American trends in the natural gas and NGL infrastructure space. First, production growth is largely coming from regions that lack the infrastructure to support producer's aspirations, even at these reduced natural gas prices. And, the growth in these regions is changing the flow and the pricing of natural gas and NGLs across North America, leading to increased pressure for export to customers on other continents. In particular, we see the Montney as the to—top North America play, with volumes expected to grow by 50% in the next five years. Through Veresen Midstream platform, we are positioned to be central to the build out of the gathering and processing infrastructure. The increased drilling in the Montney is also driving up the amount of NGLs that are being produced in the Western Canadian basin. With weak NGL prices in Alberta, as well as a wide basis differential between ATCO and Chicago, we are seeing very strong demand for Alliance and Aux Sable's services. In Alberta, we own the only ethane transportation business. The business is critical to the province's petrochemical industry, and we've been able to source additional growth opportunities through our ownership in AEGS.

Our—our footprint in the Pacific Northwest also supports these favourable dynamics. The Ruby Pipeline was placed into service five years ago in order to help diversify the supply of gas to Northern California. Supportive factors over the medium and long-term include: demand growth in Northern California, limited available storage, and accelerated retirement of power generation. All of these factors in—increase reliance on gas-fired generation and spur gas demand in the region.

Outside of North America, we are equally well positioned for growth. There is significant gap in the next decade between LNG supply and demand, particularly in the Asia-Pacific region. We know that North America has attractive LNG supply region, due to the scale of the resource, the low cost of supply, and the existing infrastructure network. Our Jordan Cove LNG project is well positioned, on a supply basis, to capitalize on the dynamics and remains the most advanced project on the West Coast of North America. Jordan Cove represents a valuable and potentially transformative longer-term option for the company.

To provide you with more insights on our business and our plans going forward, I'd like to introduce my leadership team that has made it all possible. I'll introduce them in the order that they'll be presenting.

Darren Marine has deep experience in Canadian Midstream industry, and a trading background. I can't think of a more ideal background for leading our joint venture businesses, including: Alliance, Aux Sable, Ruby, and AEGS. Darren was formally the President of SemCAMS.

Paul Eastman is an engineer's engineer. And, when I shared that with Paul, he wanted to know what I meant. I'll—I'll tell you what I meant. He's an operator. He's the guy that just loves to see the plants run smoothly and hum. I think, when you see the safety performance that we've achieved over the last three or four years, Hythe/Steeprock is running at 99.5 at all-time records. He has a strong background in—in Operations, and—and just loves the passion of—of the business. He's—he's an exceptional leader. Responsible for our operating assets and our shared service. Paul began his career in Dow, and has—has been with Veresen now for eight years.

Our—our strategy is to become customer-centric. So, I think it makes perfect sense that we recruited Dave Fitzpatrick, an oil patch veteran, to lead Veresen Midstream. He brings an important producer perspective and the start-up experience in leadership to develop and bring Veresen Midstream to the top of the pack. Dave has run a number of companies in his career. Most recently, he led and was the cofounder of Shiningbank Eng—Energy.

Betsy Spomer heads up the Jordan Cove project and is recognized in the industry as a leader in the LNG space. I didn't fully appreciate what that meant until Betsy and I were at a medi-conference, when one of our largest customers came up to me and said, "You hired a great person. That Betsy's a rock star." Well, she's just Betsy to us but she bec—in—especially because I know Betsy from her days. She started off as a landsman with Amoco in Wyoming and has worked her way up through Amoco, BP, and then ten years of running business development for BG Group before she joined Veresen.

And our CFO, Theresa Jang, who most of you know, is really knows the inner workings of Veresen better any—than anybody else in the firm. She is the glue that holds it all together. And we keep coming up with big, new, innovative ideas, and she keeps finding ways to fund it; and—and that's very important. Over the last two and a half years, Betsy—or Theresa has raised over $4 billion to fund our growth projects. Theresa began her career, as many, in Calgary at TransCanada and has been with Veresen for over 10 years now.

So, I didn't go through the years. Unfortunately, I'm the only guy with 30+ next to me. But you'll notice that it's a very mature and seasoned group, but it's still a group that's full of passion and energy and I think you'll find that today. So with that, I'll now step aside and let the team walk you through the business. Darren, over to you.

DARREN MARINE: Thanks Don, and good morning. I'm very excited to have this opportunity to talk about our Alliance, Aux Sable, and Ruby assets. At over 40% of our earnings, Alliance represents our largest stream of cash flow. As Don pointed out, the pipeline and Aux Sable's Channahon fractionator that sits at the end of the pipe were the genesis of the company.

It's worthwhile to quickly talk about how and why the pipe was—was built, as many of the details are still valid today. The concept was conceived back in the mid-1990s. At the time, producers were facing a restriction of both natural gas and natural gas liquids coming out of Western Canada. And they were looking for an alternative to TransCanada, which dominated the market. A group of Canadian producers recognized that Chi—that the Chicago market had ample appetite for both their NGLs and natural gas. So, it—it was an innovative idea, building a very long and expensive, liquids-rich gathering system and putting a giant fractionator at the other end to sell pipeline spec, natural gas, and natural gas liquids.

Today, Chicago remains an attractive destination for Canadian gas. It's a relatively large market connected to other gas and NGL markets; all of which are significantly stronger than Alberta. I would also note that liquids pricing is becoming increasingly important in driving well economics for producers. Recently, leading up to the end of the original contract tenures, we were able to effectively sell all firm capacity available on the pipe. The new contracts have an average tenure of five years, which is standard for a pipe coming off its initial terms. Now, new in 2016, we now benefit from selling additional capacity through our interruptible and seasonal firm services. We also retain the savings from optimizing pipe operations, as—as well as reducing overhead. As you can see from the map, Alliance is well situated as it runs through the Montney, Duvernay, and the Bakken, and it provides a competitive outlet for producers of gas and NGLs in those basins.

Now, let's turn to fundamentals for a minute. The successful re-contracting of both Alliance and Aux Sable reconfirms our strong view that there is too much natural gas and natural gas liquid supply in Western Canada, and that we need new markets to balance and fundamentally support Alliance and Aux Sable's competitive position. In fact, it's the exposure to the Montney, Duvernay, and the Bakken that makes the outlet for the pipe quite strong.

Many people take a cursory look at the production in—in Canada and conclude that the basin won't be able to compete. While many studies project Canadian production staying flat, the actual makeup of the gas in—in Western Canada is changing rapidly.

Most all new supplies, and most supplies in Western Canada over the next decade, are expected to come from the Montney and, to a lesser extent, the Duvernay. The Montney has already seen incredible growth increasing from over one BCF a—from—just under 1 BCF/day in 2010 to over 4 BCF/day in 2016. And it is expected to grow by an additional 50% over the next five years. At that point, it will represent over 40% of total WCSB production. Even looking on a North American basis, the Montney is simply a top play.

We see a lot of people—we see—we saw a lot of different reports about relative economics, but the constant is that the Montney is at or near the top. Perhaps, a more tangible indicator is to look at where the ri—the rigs are still turning. It's now expected that about as many rigs will be drilling in the Montney this year as in all of the Northeast U.S. With the tremendous growth that has been seen in the Marcellus, the majority of available low-cost infrastructure additions in—in the area have already been exploited. As a result, the Montney and Marcellus gas are now at a point where it's roughly an even match, from a transportation basis. Since the Marcellus gas would need additional pipe capacity to push into Chicago market, we remain confident in Alliance's relative positioning.

Longer term, the Duvernay is also a very exciting play. Today, it's at its early stage of development relative to the Montney, maybe five to seven years behind the Montney. That said, based on what we're hearing from producers over the last twelve to eighteen months, we think there's been a—a major change in the development and the Duvernay may, in fact, exceed current expectations.

NGL fundamentals also support Alliance. A shift continues in Western Canadian gas as it becomes richer, resulting in more natural gas liquids looking for a home. Given that we are currently in the low part of the commodity cycle, as crude prices recover, we would expect producers to continue to increase drilling in NGLs. We believe that this NGL story will continue to be one of Alliance’s competitive, primary, competitive advantages, offering producers an option for their gas and NGLs without expensive capital investment in the field.

Ultimately, through Alliance, producers can get their liquids to a high-value market at a cost far below rail and, ultimately, offer the best netback on all-in basis. While the anticipated improvement in NGL margins will continue to support Alliance, the greater impact will likely be on margins at Aux Sable. In particular, we expect the seven Efteling crackers that are expected to be coming online in the U.S. over the next several years will significantly improve demand for ethane. Additionally, we expect the growth in U.S. water-borne exports to continue to improve both propane and ethane margins in the Gulf Coast.

While the fundamentals for the pipe are very strong, we also know that there was a lot of concern in the market about our ability to re-contract the pipe. For nearly ten months—with nearly ten months under our new service model, we—we—we think the pipe is doing very well and that’s been reflected in strong seasonal, firm volumes and rich gas services. When we were last re-contracting the pipe, it was clear from our producers that there was little appetite for a ten or fifteen year long-term commitment. A—a contract of that size would be a large commitment for many small to mid-size producers and could strain their flexibility. What we did find out is that it was, generally, the producers who expected significant growth in their production basis, but took the longer-term view and were more motivated to find egress out of Western Canada for their production. Given how public Seven Gen has been about their space on Alliance, I think it’s fair to say there's a prime example of this, as they took seven years of transportation space, as well as escalating volumes over t—over time.

In looking at Alliance's contracted volume profile, we wanted to highlight a couple of important observations. Most importantly, we know there are shippers whose firm capacity over the next few years either decreases or ends entirely. Some of these companies were using Alliance as a bridge until BC LNG comes on-stream. In any event, we project that these—that—that—that the impact is—is positive for seasonal services and interruptible services for Alliance over the medium-term.

Secondly, in terms of re-contracting the pipe past 2020, Alliance will have an incumbent advantage, in many cases, particularly with the shippers who are committing increasing volumes over time. There's an element of integration, particularly due to the unique arrangements shippers have, due to the NGL transportation angle. So, in a way, the larger the volume you get, it's—it's harder for them to switch.

While the fundamentals are strong and we are very positive about our ability to re-contract the pipe in the future, we know the market can change and we need coverage for those possibilities. Today, Alliance capacity is held by a diverse group of over thirty shippers that includes producers and marketers, with the weighted average contract term of five years. Approximately, 60% of receipt capacity is held by shippers with investment grade credit as of Q2. Seven Gen is the largest single shipper. While they're not investment grade today, yet, they have been recently upgraded.

Also, as a normal course of business, Alliance requires security from counterparties that are below investment grade. We also continuously monitor the health of our shippers, and we believe they're in fairly good shape right now. The other key—the other key protection we have today is that the service we provide is deep in the money and in high demand. If we see a shipper default on their obligations today, we would expect that they could de—they could immediately—Alliance could immediately re-contract with another counterparty.

Now, let's turn our attention to the growth story. Given the strength of Alliance today, and the expansion of other systems in the basin, we're asked fairly regularly about when is an expansion coming? I can tell you it's not something that we're actively pursuing right now. When we look at the options on the slide, our primary are—area of focus in the short to medium term will be to extend the term of the agreement on the pipe. Alliance is an import—is an important part of Veresen's distributable cash, and our preference would be to extend the terms of the agreements for as long as possible. We've already had expressions of interest in extending contracts for a very significant period of time. We would consider debottlenecking projects, ancillary service additions, and gathering system expansions if the appropriate commercial conditions existed.

Thinking a bit bigger than that, we could look to expand the entire system. From a technical perspective, it's certainly feasible through the increased number of compressors on the system, as well as an expansion at Aux Sable to handle the increased NGLs at Channahon. However, from a commercial perspective, what it would take in our view is extending the tenure of the existing pipe, plus contracting the incremental volumes with credit-worthy counterparties under take-or-pay agreements, similar to what we have today, for a term that would return capital costs of the expansion. We're simply not willing to meaningfully change our business model for the sake of expanding the pipe.

For Aux Sable, NGL margin recovery can have significant upside, driving increased profitability for Veresen. We get a lot of questions about how to think about an impact of NGL recovery on Aux Sable. As you know, we have an agreement with BP that limits our downside exposure. This agreement also limits our ability to provide specific details on the mechanics of Aux Sable. Under the agreement, NGLs at Channahon are marketed by

BP. BP pays Aux Sable a fixed annual fee and a per—a percentage share of the net margins in excess of the fixed fee. The percentage share of net margins varies and depends upon specified thresholds being reached. BP compensates Aux Sable for all associated operating and maintenance costs, and costs incurred to source feed stock gas supply up to a certain point. And some capital costs with the Channahon facility.

Given these structures, the potential performance ban, at a given margin level, can vary quite—quite wild—wildly as it is subject to many other factors. It also creates an inflection point, at which we gain more torque to a potential recovery, which we would suggest occurs at a margin level roughly twice what we saw in the first half of 2016.

So I know I'm not going to be able to get away without talking about the—the TCPL proposed exp—expansion out—out East. I had a number of questions at—at the break. So, TransCanada's recent announcement to offer discounted long-haul service on the mainline, from Empress to Dawn, has certainly garnered a great deal of attention. We believe Alliance is competitive relative to all scenarios that have been discussed to date.

First off, the Chicago market is—is larger and more liquid than Dawn. It's clear why a proposal like this is coming up. If Nexus and Rover are built and push Marcellus gas into Dawn under long-term contracts, it's going to be difficult for WCSB production to get that market share back. And it's likely to drive Dawn pricing down, and decrease Western Canadian prices as—as well.

At the same time, if the proposal is successful, it's not clear how Dawn pricing will behave over the proposed ten to twenty year term of the agreement. The additional volume could drive down Dawn pricing, negating any benefit. Furthermore, if Nexus or Rover are eventually built, despite the success of TransCanada's proposal, operating capacity in the new lines would push down Dawn prices materially.

The dynamics in the Chicago market are a bit different. Based on the pipe commitments Marcellus producers have already made, which doesn't even get them to Chicago, Marcellus producers are already paying as much for egress as Montney producers are on Alliance. To actually get new Marcellus gas into Chicago would require additional tolls. So, we think the Montney supply will continue to be competitive with the Marcellus in the Chicago market.

Alliance has also looked at competitiveness of other basins into Chicago. And again, we think Alliance is well positioned. NGL transport also stands out as a major differentiator for the pipe. While most people tend to compare Alliance on a lean gas basis, it's the liquid advantage that—that—that certainly holds a—a lot of value for producers. Alliance also has the benefit of being a fairly new pipe. Its reliability is recognized and highly sought after by producers. And with over fifty receipt points in Canada, it's not looking to build out its system right now. Meaning, better shippers do not need to be concerned about either a [indiscernible 32:37.5] system to facilitate construction or potential rate increases to cover the build out for the services.

We expect the NGTL rates—system rates could significantly increase given the expense of their proposed gathering system expansion. Finally, we believe the long-term contract tenure of the TCPL pro—proposal and the regulatory hurdles will materially impact the success of the uptake. In summary, we think Alliance and Aux Sable assets are well positioned, and their services will be in strong demand well into the future.

Now, let's switch gears to Ruby. Veresen succe—successfully expanded its footprint into the Pacific Northwest and added significant and accretive cash flow through the acquisition of Ruby Natural Gas Pipeline in 2014. It's structured to help diversify Northern California gas supply. Ruby went into service in 2011. The pipe is supported by a very strong mix of investment grade shippers. PG&E is the anchor shipper, and uses Ruby in order to diversify their supply portfolio. Veresen has the preferred interest in the pipe and receives $91 million US, or $120 million Canadian per year. This attractive structure provides strong downside production while preserving the upside. Additionally, Veresen holds an option to convert the preferred interest into a 50% common ownership.

While Ruby has take-or-pay contracts in place for approximately 1.1 BCF/day that protects earnings, the impacts of changing supply and demand balances are being seen operationally. In the second quarter, we saw actual volumes at about half the firm commitment levels. Cheap Canadian supply in recent months is driving this underutilization of capacity at Ruby. Fortunately, our position remains strong. The first series of our long-term contracts do not expire until 2021. And the PG&E agreement extends five years beyond that. With our earnings secure for the medium term, our strategy will be to wait and collect a preferred dividend over the next few years.

When we look at the fundamentals into the next decade, we do see positive signals that fundamentals will continue to support a successful re-contracting of the pipe. Rockies' overall production will likely remain stable over the next decade. However, increases in commodity prices are expected to stimulate renewed interest in the region, with associated gas and unconventional plays expected to be a larger contributor to Rockies gas supply going forward. Quick price recovery will be particularly relevant.

Just as important as production rising and pushing supply West will be the demand side of the equation that—that will draw Rockies' supply. Forecast predicts that Northern California will be increasingly dependent on Rockies' gas supply. Canadian gas, which is direct—directly competing with Rockies' supply today will gradually be absorbed by upstream US markets in the Pacific Northwest, creating the gap that will need to be filled by the Rockies' supply. Moreover, continual structural changes in California power industry are expected to grow natural gas demand for the region. As an early adopter of strong, environmental policy, California has and will continue to be aggressive in finding cleaner and safer sources of energy. Growing gas demand is the result. Coal to gas switching and early retirements of nuclear facilities will continue to push increase in gas demand in California. Finally, exports will also influence Ruby at Malin, with increased demand for gas to flow south to Mexico. In addition, Jordan Cove LNG will significantly increase the de—demand for gas in Malin.

As I mentioned, in the interim we will rely on our preferred interest to receive our distribution, paid out before common distributions. Our partner, Kinder Morgan, receives $40 or $50 million US a year in common distributions, which provides a buffer for our preferred interest payouts. In fact, based on the cost structure, the income derived from our investment grade shippers alone would be sufficient to cover Veresen's preferred distribution.

Looking further out, the changing debt structure will add flexibility. As the pipe debt is amortized over time, the cost of financing will continue to decrease. For example, today's debt service costs are about $200 million a year on a gross basis. With about half of that debt maturing over the next five years, we will have additional cushion for our preferred distribution with each passing year. Reducing debt service costs will also put the pipe in a better position for re-contracting in 2021.

To summarize, we think that Alliance, Aux Sable, and Ruby are all well positioned to continue to provide Veresen with long-term, stable cash flows. Just as importantly, these are critical pieces of infrastructure and, as we have all seen, pipe in the ground is becoming increasingly more valuable. Now I'll turn the presentation over to Paul Eastman to discuss the AEGS system and the Burstall project.

PAUL EASTMAN: Thanks Darren. And good morning. Have you ever wondered where Ziploc bags come from?

RESPONSE: No.

[LAUGHTER]

PAUL EASTMAN: I started my career in the petrochemical business with Dow Chemical many years ago making those Ziploc bags, or at least making the polyethylene that—that goes into the Ziploc bags. One of thousands of plastic products that make life more convenient today.

How does this relate to Veresen's AEGS business, you might ask? Well, the Alberta Ethane Gathering System, or AEGS, is the only spec ethane system in Alberta, and it's the backbone of today's petrochemical business in the province. And, ethane is used by the Dow's, the NOVAs, and the Exxon's to create ethylene and then polyethylene, which goes into making those Ziploc bags, and milk bags, and a number of other things.

The AEGS pipeline was built in the '70s as part of Alberta government's initiative to nurture the budding petrochemical industry in the province. Very successful too. The very productive part of Alberta today was NOVA now building a second polyethylene manufacturing facility as we speak.

And now over to the diagram. The West side of our AEGS system runs along the Western part of the province, down to the—the southern—sorry, Southern Alberta down to the Shell Waterton complex at the very Southwestern corn—corner of the province. And the East leg takes ethane from the straddle plants on the TransCanada mainline at Empress, near Alberta-Saskatchewan border. This is also the point where Pembina's Vantage Pipeline ties in to bring ethane from North Dakota. Both these legs take ethane to Joffre, which is near Red Deer, roughly where the South and East legs meet with the Northern leg. At Joffre, we find the NOVA—NOVA Chemical facility, which is one of the two main end users of the system. The North leg can flow in both directions, and at the end of it sits the Dow Chemical facility in Fort Saskatchewan just Northeast of Edmonton.

Since Veresen bought AEGS in 2004, it's been a source of steady, predictable cash flow. The existing take-or-pay contracts have been in place since 1998 and run through to 2018, and we're sure that the re-contracting will be an opportunity for us. The existing agreements do not have a cost escalator provision and most comparable pipelines, which generally have higher tolls than AEGS does today. Re-contracting the system will ensure that AEGS remains a steady source of cash flow. However, other than a few smaller scale expansion opportunities, we don't expect there'll be significant growth in the ethane demand, and in the—in the Alberta petrochemical industry in the near to medium term.

Where we do expect to see opportunities is in incremental projects that leverage off of AEGS, such as our Burstall Storage project. We're constructing it for NOVA near the end of the East leg of the AEGS system. Burstall is being built under a twenty-year firm lease with NOVA and will provide valuable operation stor—operational storage to help NOVA mitigate potential supply disruptions at the Joffre facility; sort of like adding a shock absorber to the system to keep NOVA's production online and smooth as it can take up to two days for NOVA to restart production after an interruption.

Burstall has a—a capacity of one million barrels of ethane, and is expected to cost $140 million to construct. The project has an in-service date to the third quarter of 2018 and construction remains on time and on budget for us, with an approximately—with approximately one quarter of the total cost of the project incurred to date.

And, we think the Burstall project's important to Veresen for a couple of reasons. First of all, it's the perfect reflection of our strategy to leverage our footprint and build a connected network of assets. Our ownership of the AEGS system and our long-term work and relationship with NOVA created the Burstall investment opportunity. And we also believe that the 8 and 9X EBITDA investment model is attractive, while still providing a low risk contractual structure. And NOVA's investment in the Burstall project reinforces their commitment to AEGS over the long-term. These are really the kinds of investments we want to generate from our asset base.

And the second point I'd like to make is that Burstall is a project that levers Veresen's existing development, construction, and operating capabilities. Over the last four years, we've built and successfully placed into service over three-quarters of a billion dollars of projects. Veresen can build.

As you can see from the slide, while we really cut our teeth on the power business, we've already transferred those capabilities into our Midstream space with the construction of the Hythe Liquids Recovery Project Phase 1, that just went into—just was completed and went into service in June, and the ongoing construction of the Burstall project. We are selling our power business but we are definitely holding on to these internal capabilities within our organization.

And, when we talk about building and constructing, there are many systems and capabilities required to support this muscle. Over the past several years, we've developed depth in critical support areas like environment, health, safety and regulatory, supply chain and procurement to buy the equipment and services needed to build, project controls to schedule and measure our own performance, and community relations to make sure that we build relationships in the areas that we build and operate. And these capabilities are not off the shelf. They're very Veresen-specific, and they're designed to match our customer's needs, our own can-do culture, and their location is—they are also location-specific to support the communities that we operate in.

So my point is the supporting capabilities must be grown and developed through experience. You just can't buy or hire off the street. You also need to integrate these functions, both between each other and across the rest of the company. It's true it's taken us quite a few years to get where we are today.

And, when I think about a report card to demonstrate our ability to operate, safety and environmental performance results are usually a good indicator of where a company is at. When we looked at our numbers a few years ago, we really weren't when—where we needed to be. And how—and—and you can see our numbers have really been improving over the last few years. We've basically turned a geographically scattered set of plants and operations into a cohesive and synergistic operating portfolio, and created a one team culture around safe, reliable operations. In the process, creating results that are both based on a culture of keeping each other safe and also processors to help us produce repeatable results.

So, what I would like to leave you with today is an operating culture that we built at Veresen is something I and we are really proud of. We're now leveraging this capability, including on behalf of Veresen Midstream. That's right, KKR trusts us to build with their dollars as well. And, as Dave will tell you after the break, we expect that our construction and operating capabilities will be critically important as we leverage that platform in the future. Thanks, and back to you, Mark,

MARK CHYC-CIES: Thanks, Paul. With Darren and Paul now having covered our base business, we're going to take a fifteen-minute break. When we resume, Dave and Betsy are going to talk about our growth projects, which are Veresen Midstream and Jordan Cove LNG. So we'll see you in fifteen minutes here.

[PAUSE]

MARK CHYC-CIES: All right, I believe we are ready to get going again here. The second half of our presentation will be about our growth opportunities. So we'll talk about Veresen Midstream and Jordan Cove. So with that, I'll turn it over to Dave to talk about Veresen Midstream.

DAVE FITZPATRICK: Well, thank you Mark, and good morning ladies and gentlemen. I understand the team gets a lot of questions about Veresen

Midstream and, really, how it all works, what it's about. So, let me with my producer background start, likely no surprise, with the description of the asset base.

We tend to think of our assets as two areas. First, let me start with Hythe and Steeprock gas plants to the Southeast portion of—portion of the map sheet. Hythe in Alberta. Steeprock on the BC side. Both currently processing gas. The two gas plants form a complex that has the functional capacity to process just over one half of a billion cubic feet of gas/day. To give you an idea of the scale of the complex, we are the largest delivery point—gas delivery point on the TransCanada system. We also own all the gathering and compression assets that feed both plants.

The first train at Hythe was built over thirty years ago, with the most recent of our five trains. When I say trains, think of—as a processing unit added in 2008. Two trains at Steeprock were built in 2006 and 2008. Originally, these plants were intended to process production from the Doig, the Cadomin, and later, some of the very early dry gas Montney wells. Importantly, these two plants, Hythe and Steeprock, are operated by Veresen and have been since they were purchased from Encana in 2012.

The second part of the footprint is Dawson, the area to the North and West—West of Hythe/Steeprock, as shown on your slide. This is where we are currently building the Sunrise tower and Saturn gas processing facilities, at an approximate cost of $2.5 billion to Veresen Midstream, to add an incremental 1 BCF/day, billion cubic feet/day, of natural gas proce—processing. We also own, in this complex, all of the gathering and compression that feed the plants.

The Dawson area is where we expect to see the majority of our capital opportunities. Our agreement with Cutbank Ridge Partnership, or the acronym CRP, stipulates that we are their Midstream partner for all future gathering and compression opportunities in this area. Recall that Darren talked about how the Montney is one of the lowest supply cost plays in North America. The acreage we are talking about here on this slide is at the heart of that play. What that means is that wells drilled in this area, typically, have higher NGL yields; condensate in particular, and strong gas rates, which meaningfully improve the economics to the producer. For that reason, we believe that this area of mutual interest, pertaining to our joint venture, can compete with gas supply anywhere in North America.

Turning to the commercial side of our agreement, bear with me as I summarize some of the statistics. Cutbank Ridge Partnerships, CRP, was formed in 2012 when Mitsubishi purchased a 40% stake in the assets in exchange for $1.45 billion in cash upfront, plus a commitment to pay 50% of Encana's future development costs for a total additional $1.45 b. This means that Encana pays half of their remaining 60% ownership, in other words 30%, and Mitsubishi pays the rest, 70%. This results in very favourable economics to Encana, as, of course, they receive 60% of the revenue for 30% of the capital costs.

Veresen Midstream is a partnership between Veresen Inc. and KKR. KKR's initial interest was held half in Class A units, which pay cash distributions, and half in Class B PIK units which pay dividends-in-kind in the form of new Class A units. No additional Class B PIK units are being issued. Capital calls are all in Class A cash dividend units, meaning that the Class B PIK units make up a shrinking proportion of the capital base of Veresen Midstream over time. If you thought I'm doing a Midstream version of Abbott and Costello's "Who's on First," wait, I have more. Starting at the end of Q1 2019, either party can trigger the conversion of Class B PIK units into Class A units. At that time, Veresen will also have the opportunity to equalize its interest in Veresen Midstream back to the original 50%. Veresen currently expects that its interest in Veresen Midstream in '19, before equalization, will be the low to mid-40s.

We have an agreement to provide all required Midstream services to CRP. In that agreement, total investment is capped at $5 billion, but that, of course, would be waved for the right economically attractive incremental opportunity.

In terms of Veresen Midstream as an organization, we have an operating team of fifty-eight employees and fifteen Head Office staff who are largely focussed on business development, production accounting, engineering and construction, health/safety and—and the environment, financial, and—and legal.

Back to the resource again. Before committing to the $5 billion infrastructure partnership, Veresen did a lot of work to make sure this was the right resource and, equally important, the right producer to joint venture with. I can tell you from our front row seat, we are witnessing the very strong well results and the compelling economics of this particular area of the Montney. Well economics are incredible. I can tell you from, certainly my E&P days, to achieve triple digit IRRs, of course, particularly in this commodity price environment, is rare. And that's before the Mitsubishi carry. If you look at the graph, you'll see the bump up net to Encana. IRRs generated North of 200% from most of the drawing opportunities. Well results also continue to improve. Drilling and completion costs have come down by a third, relative to last year's average cost, while the rates from these wells continue to increase on both a raw gas rate, but probably economically more important, higher NGL yields, as well. These assets will attract capital. Encana's recent equity raise last week, in fact, the week before, provides them a stronger balance sheet to fund the growth of this play.

As part of our relationship with CRP, we review their budgets and have a great idea of how the play's expected to develop over the next several years. When we look at Encana's recent investor materials, it's very clear that they are bullish on the play. In addition to hosting an Investor Day in May of this year in New York to champion their Montney assets, they've also begun to provide public guidance as to how they see the play developing longer-term. Importantly, they point to more than one billion cubic feet/day and 50,000 barrel/day of NGL, natural gas liquids, net to Encana by 2018, which is more than double current rates. Longer term, they see the play tripling from current levels. Those rates clearly exceed the capacity of the infrastructure and the build out that is currently sanctioned.

One important factor that differentiates the Montney from most of the resource plays we've seen in North America over the last several decades is the sheer size of the resort—re—the sheer size of the prize and the resulting well inventory. This is not a play that will be drilled up in five, ten, or even fifteen years. And, equally important, these plants are also built to endure the longevity of this resource. The reason for this longevity is that the Montney is typically a package of three stacked plays, totalling up to a thousand feet in net pay. To officially access this resource, Enc—Encana anticipates drilling wells at three different levels, meaning that on a historical pad—drawing pad where four locations would have been drilled historically, Encana now looks to drill twelve plus wells on that same plaid—same drilling pad. And ultimately, up to twenty-four locations on that same well drilling pad.

While we do believe in the strength of this resource and the robust economics, both are compelling reasons for CRP to retain an aligned interest with us, we also have a full suite of contractual provisions. Because there are two separate transactions for Hythe and Steeprock and Dawson, of course, we have two separate transactions—two separate structures. Hythe/Steeprock, the plants that are currently processing gas and were initially acquired by Veresen in 2012, are governed by a take-or-pay contract that is in place for another sixteen years. We take no volume risk at Hythe/Steeprock, and future capital projects in the area are also subject to take-or-pay arrangements. Operating costs are also flow-through to Encana as long as they remain within a reasonable operating band.

The structure at Dawson is different. It is a twenty-eight year, fee-for-service deal. Fees for each individual facility are set at start-up by taking the estimated capital cost of the facility, a utilization forecast over time, and the target rate of return we negotiated on signing of the contract. You calculate a rate per MCF and true up over time to that rate of return.

There are a couple of key provisions, which provide us protection to ensure we earn that suitable return. We call this structure our fee-for-service plus. First, risk is partially mitigated by fee true-ups at set points in time. On compression and processing facilities, it's after the first year, so as to create a strong incentive for the producers, Encana and Mitsubishi, to fill the plants day one. On gathering lines, it is spread out over time to better account for the variances you would typically see across a producing field.

The second provision, that helps reduce risk over time, is the requirement that CRP ensure we've got all of our capital back for each investment after eight years of use. In the event that we have not, they're required to provide a cash payment, we call the simple payout or top-up, to provide us full capital recovery. Allowing us, of course, to de-risk the investment and underpin our financing. As a—as a side note, an 8X EBITDA investment multiple on new builds is strong, especially relative to the multiples we're seeing out there in the Midstream A&D market.

Construction, or capital risk, is nullified as fees are set on actually costs, be they higher or lower. Operating costs is born by Cutback Ridge Partnership, following Encana's operating in the period following start up, and remains flow through once we assume control – but is subject to escalating caps. These caps are intended to cover controllable operating factors, and items such as: electricity costs, property tax, remain flow through.

One last thought before I—I change gears on our contract structure. While some of our competitors may downplay the merits of a fee-for-service contract, I can tell you, from the numerous discussions we have with our customers, the E&P community, that several of those same competitors are relatively quick to hand out term sheets that look very similar.

So, assets, structure, contracts – check, check, check. Let's talk about growth, profitable growth. We currently have $2.5 billion of projects under construction that will roughly triple the EBITDA of Veresen Midstream over the next eighteen months. The platform concept, that I'll talk about, is essential to understanding our business model, because it is what will drive our returns higher, our multiples lower. To establish our initial footprint, we needed to pay approximately 12X EBITDA for the Hythe/Steeprock take-or-pay model, but because we are now investing in multiples in the range of 8 to 10X, we are significantly driving down that investment multiple, returns driving up over time.

We would expect to grow beyond the numbers you see on the table in front of you on the slide. There is still approximately $1.7 billion remaining on the $5 billion original commitment with CRP, and there is significantly more infrastructure investment required, as I mentioned earlier, to get to the levels that Encana publically stated they will go, ultimately.

In the near term, additional gathering lines will be needed to get the gas from the wells that will fill the three plants under construction. Also, natural gas liquids yields continue to increase, driving the need for more liquids handling capacity than initially contemplated; all for good reasons, driven by economics. The Hythe Liquids Recovery project that we built and brought online at Hythe in June of this year is a great result; a great testament to this. I absolutely expect that, given the need for significant additional liquids recovery and storage, we will see, in fact, several $100 million of additional NGL projects to be sanctioned over the next six to twelve months by CRP.

A other project that we are advancing in Veresen Midstream is a proprietary pipeline to interconnect the three gas plants currently under construction: Tower, Sunrise, and Saturn. This will allow Veresen Midstream to move third-party gas between the facilities, allowing maximum production and run time flexibility. This allows us to avoid using the Encana CRP proprietary dedicated pipeline infrastructure. Additionally, our agreement with CRP only requires us to pay the incremental costs on capital projects if we piggyback on other work that is currently ongoing. It's important to under—understand that. Meaning that, for this particular example, on this pipeline trunking that I'm talking about, our build out costs will be significantly lower than a Greenfield opportunity, and significantly advanced in terms of timing, due to permits that are already in place. We expect this pipeline project will pay back solely on the ability to ship volume between the plants during turnarounds, however it's true long-term value will be in giving us greater flexibility to bring third-party volumes into our complex.

This same piggyback principal is also being executed at the Tower gas plant, the Northernmost of the three plants, where we are installing proprietary liquids handling and storage to, again, attract nearby third-party volumes. Both the interconnect and the proprietary liquids at Tower are—are excellent examples of our ability to leverage the footprint at truly low incremental capital costs. In a sense, much of the additional third-party development work we are advancing is largely paid for, and commercially backstopped.

And, when we look at the players in our zip code, on the map sheet on the slide, we know the producers in this community. We talk to them on a regular basis. Those are our third-party potential customers. Perhaps the most straightforward opportunity for us is to bring third party plants—third-party gas into the plants, after they are constructed. If you look at the distance on the map, it is not all that far at all. Each square on the plant is only six miles. We will structure either short or long-term arrangements with those third-party producers.

We believe there are other opportunities to debottleneck existing facilities, or expand. The likelihood of fitting 50+ million cubic feet/day into a 1 BCF/day gas complex, I would suggest is very high. As Midstreamers, that is what we do. In either case, be it debottlenecking or expanding, these, again, will be at much lower costs than building new stand-alone facilities. We will lever off our existing liquids handling infrastructure and interconnection with NGL and gas lines to avoid duplication of infrastructure, resulting in lower costs, higher netbacks to the producer community – our customers.

I know that several producers in the area have a strong preference for building and owning their own infrastructure. However, let me leave you with a couple of concepts. We believe there are three principles that really underpin our value proposition to those producers.

First and, likely most important long-term, producers tend to have a higher cost to capital, and capital spent on infrastructure isn't going into their core business, into the ground, drawing and completing wells to add volume. Imagine the impact on Encana had they spent all this facility capital up front in the complex?

Two, as a Midstream company, our focus is to keep our facilities full. And we are positioned to approach, in aggregate, the producers around our plant to offer lower, long-term, fixed operating costs.

Finally, to sustainably operate these plants also requires – and—and Paul referenced this in some of his section – another skill-set that often isn't a core value, a core focus of the E&P producer community. I'm talking about reliability and safety. Look no further than our Hythe/Steeprock complex, where the plants run at a 99+% reliability, and we haven't had a safety incident since taking over operatorship of the facilities.

Overall, we are confident in our strong partnerships with Encana, with Mitsubishi, and with a number of the other producers in the Northeast BC and Northern Alberta areas. We take a very producer-centric mantra to our business development, and we are a service company. We believe that sets us apart in the Midstream world. That provides the cornerstone for our long-term infrastructure build out.

Thank you, on behalf of all my colleagues up here. Thank you on behalf of Verisen Midstream. It's my distinct pleasure now to introduce Betsy Spomer, our Jordan Cove secret weapon, our Veresen rock star…

BETSY SPOMER: I'm not sure.

DAVE FITZPATRICK: …up to the podium. Take it away, Betsy.

BETSY SPOMER: I think we need to, kind of, calm all that down a little bit. I mean…

[LAUGHTER]

BETSY SPOMER: …whew. Anyway, I want to thank you, Dave. It—it's a real pleasure to be here today and it's a pleasure to talk about Jordan Cove. I joined Veresen two years ago, in recognition that Jordan Cove was a unique US West Coast project that could happen. I actually thought we would be towards the end of the first US development cycle. For various reasons, I remain confident that we will be at the beginning of the next one. And I'd like to share with you some of my reasoning for that.

Most observers – and I want to talk a little bit about this glut, supply glut, that one hears so much about. Because I think, when you peel it back a little bit, you find out it's much more transitory and much more typical of cycles in this space. I think most observers agree that the current market's oversupplied; however, there were about 60 million tonnes, or 8 BCF +, of new LNG supply in 2014 to 2016, and the market continues to clear on the day. So you hear all these projections about stranded US capacity, turn down this, turn down that. I’ve seen this song and dance before, and it occurred when the Gatari’s [phonetic 1:10:28] ramped up their big trains in ’09, ’10, and ’11, and all that LNG was going to come washing into the US, since the LNG market of last resort. And guess what – it never made it. And there’s a good reason for that. It’s because the elasticity response to low prices absorbed all that supply as it passed through the Mediterranean.

And, although there 80—another 80 million tonnes of post-FID cumulative capacity that’s coming online – that’s post-FID capacity – this graph is post-FID capacity. I think, any kind of profile that tries to pick winners at this point in time is—is—is probably a fool’s errand. But, most of this new supply coming from the completion of the Australian build out and the new US projects, is spoken for in end-use markets. But, nonetheless, due to this supply ramp up, low oil prices, and the resulting low US—I mean, low LNG spot prices, new products are being deferred or cancelled. There’s only been one FID in 2016 – that was BP’s Train 3 at Tangguh, and I think it’s instructive that 75% of that was contracted to the Indonesian domestic market, which is a theme you’re going to hear some more about. Because I think, as we know in the energy business, nothing solves low prices like low prices.

But with capacity and new supply projects, the fact that there are very few making it past the FID hurdle over the last twenty-four months, and strong demand growth, driven by India, China, and Southeast Asia, the market is expected to not only rebalance by 2023, but to almost double by 2030; requiring an additional incremental 150 million tonnes of new supply by the end of the decade. This graph is based on what Mackenzie data, but I’ve seen it validated by several other pundits with a very similar conclusion. And, where is this new supply going to come from? I think sophisticated buyers are already concerned.

And I also believe that most of this—a lot of this demand growth, and why you're not going to see stranded cargos on the water, is front-end loaded, because low prices are driving a predictable demand response. Egypt signed up for its third FSIU. Pakistan just signed up for their second. Bangladesh—Bangladesh just signed up for their first. So, I mean, we're seeing the reaction to low prices as—as we speak.

And there's another factor that I think is under-reported, and—and important, is Southeast Asia. Asian demand is expected to grow at a compounded annual growth rate of greater than 16%, from 2016 to 2030. And growth in India, Pakistan, and China is expected to exceed a 10% annual growth rate. And this—that's what—that's what's inside this—this demand projection. And Southeast Asian demand is not only GDP growth and urbanization, but is also triggered by declines in domestic gas production and pipeline supplies. And that—and that's a big difference. Singapore, Indonesia, Pakistan, Vietnam, Thailand, Malaysia, and Bangladesh all face domestic and pipeline supply declines over the next decade. This fact is important because in each of these markets natural gas infrastructure is already in place. That's why you can contract an FSIU, hook it up eighteen months later, and start importing LNG. The barriers to market entry have come down tremendously.

Just as an anecdote, Thailand has doubled its LNG production last year to just about 3 million tonnes. Indonesia is expected to be a net LNG importer by 2023. Pakistan, which, you know, may be not the most desirable market in the world – thank God there are people—thank heavens for the Gatari's [ph] – faces a 4.5 BCF/day supply deficit by 2021. And that equates to 33 million tonnes of LNG. I'm not suggesting that they'll be importing 33 million tonnes of LNG by 2021, but I think that just demonstrates the—the size of the problem. China, which has underperformed over the last two years, slashed domestic prices in November by 28% and saw a surge in LNG imports this summer, as low-cost imports undercut the price of domestic production. Imports grew 38% in August, year-on-year, and exceeded those of South Korea for the first time.

And, as we've seen across all markets, low prices are deferring and leading to project delays. There are uncertainties to this outlook. The trajectory of US gas prices will impact the relative competitiveness of US LNG imports. You know, we've gone from $4 forever to $3 forever. We're about $2.99 today, so, you know, we'll—it'll be interesting to see how we test that level.

Timing of new non-US LNG supplies. I think, especially, East Africa. Although I think, once again, you know, they require a certain scale that's going to be difficult in today's market. And then, LNG demand in the mature Asian markets of Japan, South Korea, and Taiwan. And this—this—these mature markets, demand uncertainty is primarily a function of the future energy mix and government policy. And I think I'll use the Japanese market as—as a—as an example of this. This is—Japan is a very good example of some of the uncertainties facing the mature markets as they grapple with nuclear energy, cost, and greenhouse gas emissions. As the largest LNG market in the world, what happens in Japan matters; regardless of the possibility that demand declines to pre-2011 levels. Under no scenario through the 2030's does Japan relinquish its largest LNG market statistic.

As shown on this first graph, 25% of Japan's long-term contracted spires between 2020 and '25, and buyers are recognizing the need to support new supply projects. On energy mix, in April 2014, the Japanese Ministry of Economy, Trade, and Industry approved its Strategic Energy Plan, culminating in its best mix of energy sources planned for 2030. Now, it's important to remember the context of this, because Japan was reacting to the 2011 earthquake and tsunami and the resulting nuclear shutdown, which dramatically increased imports of hydrocarbons at historically high commodity prices.

But this new plan, which came out last summer, is ambitious. CO2 emissions are to be reduced by 22%. Electric energy efficiencies to be increased by 17% - I don't know how many of you have been in a meeting in Tokyo in August, but another 17% of energy efficiencies scares me to—a little bit. And then, renewable energy is to be—to be increased by 12%, to 22 to 24%. Of that 12%, 9 is hydro – and they pretty much have exhausted their opportunities for—for adding hydro. Solar is 2%. And a question is: can a country, a very highly populated island country, with limited land availability, deliver this kind of renewable growth?

And I think, more controverse—controversially, this mix requires a significant restart of nuclear power plants, from 0 in 2013 to 20 to 22% of total electrical power production by 2030. And, to date, the restart program has been stymied by the courts and a very negative public opinion. Given the uncertainty on the pace and quantum of nuclear restarts, most market participants believe that Japan will struggle to meet these targets. And, as you reduce nuclear and renewable, by definition you have to decrease coal if you're going to maintain compliance with your Paris commitments, which the Japanese take very seriously. And, needless to say, there's only one fuel that can bridge the gap, and that will be LNG. And this is commonly discussed by, you know, sophisticated Japanese utilities, but many, you know, was in a bunker mentality in 2014 and it's going to take them a while to revise and reanalyze this.

Nuclear policy is also fundamental to LNG demand in Taiwan and South Korea. The new Prime Minister of Taiwan ran and won on a platform of phasing out nuclear power by 2025. Taiwan's problem – they don't have any place to store the nuclear waste, and they're looking for ways to offload it.

Equally important though, I think from the industry perspective, is repositioning LNG from being perceived as a premium fuel, which certainly, in the 2014 $16 to $18 MMBTU time frame, it was viewed as to a fuel that can compete on a base-load cost basis, and contribute to a low-carbon future. I believe, we believe, that US LNG exports is an important enabler to this, and is—and—and this repositioning is underway.

So, if you look at the next slide – now, this is, kind of, a hodge-podge of analysis. I borrowed it from Shaneer [phonetic 1:20:57], but it's based on when Mackenzie Data Company filings investor materials. This cost of supply curve assumes breaking prices are based on an unlevered, after-tax return of 10% over construction, plus twenty years of operations, and a Henry Hub price of $3.00. And, I think, what's very clear here, and which I confirmed in all of my wanderings, is that US LNG exports, if not the lowest, are clearly in the lowest quartile of delivered costs globally. So, you can see, you know, $8 to $9 dollars delivered, in a world where we're looking at today's spot prices of $5.75 to $6. But we know that pricing will have to signal these type of levels to pull incremental supply, and the lowest cost supply is—is—is coming from the US. And—and I'm not going to say anything negative about the Canadian opportunity, but I'll speak a little bit about what differentiates the US opportunity – and it really is existing infrastructure.

I mean—and the reason we believe that US exports will continue to remain competitively advantaged is just the size and scope and quality of the resource. You've heard a lot about the Montney today. It's phenomenal. It's bigger than the Marcellus and just as low-cost with liquids. We've got transparent market indices that determine the cost of feed gas. Buyers like that. They like to feel like they're getting a fair deal, and that somebody's not, you know, screwing away excess rent. And, I think, one of the biggest things is that the market size and depth allows the desegregation of Midstream and Upstream developments. Projects are much smaller, you know. No one has to go develop Dawson Creek to export LNG from Jordon Cove, and that really reduces scope and cost.

And US infrastructure developers, and Canadian infrastructure developers, are willing, in exchange for a lower risk profile, to take a lower return on capital, which—than our—than our IOC, integrated, Upstream brethren, such as Exxon Mobile, BP, and Shell. And then, it cannot be underestimated how important the existing pipeline infrastructure is to making all this work.

The other big advantage: we have deep labour and capital markets. I think you all can attest to that. I think the US Gulf of Mexico construction projects are proceeding very well. Concerns about labour costs and availability have proven to be, you know, not relevant. And we—and the US is going to continue to push liquid faction costs lower. When you look at the US Gulf of Mexico projects, they're pretty undifferentiated. And that's why I think Jordan Cove is such a great project. Because we are on the West Coast. We're only nine days to Tokyo. No Panama Canal. No hurricane risk. And—and very distinctive.

Then, to talk a little bit about – that's a rendering of—of the project. Basically, it's 6 million tonnes refilled Phase 1; that's about a BCF/day. We have a 400-acre site and it's expandable, easily expandable, on the basis of the installed common facilities to 12+ million tonnes. The Pacific Connector gas pipeline starts from the Malin Hub, which is on the—in Southern Oregon at the Northern Canadian border, and is a 232-mile, 36-inch, 1+ BCF/day initial design capacity pipeline; also expandable to—to twice that.

I mentioned infrastructure. One of Jordan Cove's biggest advantages is not only the West Coast location, but the existing long-haul large diameter pipeline systems that serve the Malin Hub. We've got the TransCanada NITs and GTN system, from Western Canada, and our Ruby pipeline, coming from the Rockies. However, unlike projects in the Gulf that are competing for natural gas with a number of end-users, the Western Canadian Rockies producers are looking for new gas markets. As anyone's looked at our docket, after our FERC decision, you'll see letters from Congressional delegation in Utah, Wyoming, Colorado – and there's a good reason for this. Through Ruby, we are aligned with these Rocky producers to get that gas to market. Both of these systems also have low-cost expansion opportunities and little local competition in Southeast Oregon for gas supply. We're not going to have a lot of basis problems in this project.

Another key element to the project, and a major reason for its long, strong local support, is the international port of Coos Bay. I know it looks kind of sleepy in this picture, which I think is a pretty good syst—symptomatic of what's—what's happened in—in Southwestern Oregon. It was once the largest timber and wood products port in the world. This was it. It's over three to four hundred ships calling per year. Today, it's primarily used for exports of wood chips – primarily to Japan – at thirty to forty ships per year. The decline in timber and wood products has hit the region and Southwest Oregon very hard. The community, through the Port Authority, has been looking for an anchor project to revitalize both the local and regional economy, and has embraced the Jordan Cove project, because of the things we can bring to do that.

The other key differentiator I'd like to mention is our announced market support from two significant Japanese buyers. The first is Jera, a joint venture between Tokyo Electric and Chubu Electric, the first and third largest electric utilities in Japan. The second is—was with Itochu, the second largest Japanese trading house and most profitable in the current year.

It's worth a few key words…I'd like to make a few—say a few words on these key term sheets that we signed in March and April. The key term sheets we executed and announced with Jera, Itochu, are fully priced with all other key commercial terms agreed; sufficient that there was a meeting of the minds between the project and the buyers, that there was the basis for a commercial transaction. And that was critical, because Jera doesn't put their name publically on much. In fact, I think we're the only supply project, since they were formed in April of last year, that they've actually allowed their name to be publically associated with. Itochu is the same thing. So, whereas, you know, heads of agreements with unnamed parties are ubiquitous, these are quite—quite different.

We continue to make progress with Jera, Itochu, and other buyers. These are complex agreements. We've got equity considerations, project equity, pipeline arrangements; however, we are making good progress, and I think the timing and outcome of a final FERC decision has created a bit of a lack of immediacy, due to uncertainty on what the final project schedule will look like – and I'll talk about that next.

As those—as those of you know, who have been following our progress – or lack thereof – on March 11th FERC denied our applications for Jordan Cove and the Pacific Connector Pipeline. To say that it was unexpected would be a—a gross understatement, and it was equally unprecedented, and I think really surprised most observers. FERC denied our applications on the basis that we had failed to demonstrate that the pipeline served the public convenience and necessity, due to lack of transportation contracts. The key issue was a lack of evident market support to justify the imposition of the—the potential imposition of eminent domain on effected landowners. They do not have to est—they do not have the requirement to establish market support or public benefit on the LNG plant, but they turned down the—they—they denied the LNG plant application because without the pipeline it could not function.

On April 8th we filed a Request for Rehearing. Fortunately, in spite of the FERC denial, we were able to announce the Jera and Itochu key term sheets. And, I must say, hats off to Jera, because that March 22nd date had been locked and loaded way in advance, and—and they blinked, but not seriously, with the FERC denial. A little frenzy of—of conference calls.

Coincident with the Request for Rehearing, we also submitted transportation agreements for 77% of the pipeline capacity, including one with the local—the distribution company, Avista, to serve local communities in Southern Oregon along the pipeline route. And I think that's important to show public benefit. FERC did grant our Request for Rehearing on May 9th, but is under no statutory deadline to make a final decision. So, people ask, "When are you going to hear from FERC?" We—we really don't know. Precedence from other Requests from Rehearing – none of which, by the way, are analogous to this situation, indicate that we should hear something by the end of the year.

In our Request for Rehearing, our primary argument is that FERC should reverse its denial on the basis that we have now submitted pipeline agreements for 77% of the pipeline, that are sim—very similar to those that FERC has accepted in the past. We also provided FERC with two other alternatives, in case they weren't prepared to go that far, to condition the use of eminent domain of the subsequent submission contracts, and to keep the docket open and allow us additional time to conclude commercial negotiations. Regardless, the FERC denial was made without prejudice to our ability to refile. We have a comprehensive Environmental Impact Statement that concluded there were no technical or environmental impacts from the project that could not be adequately mitigated. There were no showstoppers from a technical or environmental perspective, and so that's made—made this whole incident so—so unbelievable.

But, I think it's also important to note, at the State level we continue to make progress. The State of Oregon has been good as gold in giving us fair opportunity. We got our Air permit, which is one of the big two last summer, and progress continues to work—and progress continues on our other permits.

We also, as—have all of our Coos County Land Use permits, which is, as you recall with another Oregon project, was a fatal flaw. So, that is a key differential and, I think, very much demonstrates the local stakeholder support. We also had a tremendous outpouring of support in reaction to the FERC denial. The State of Wyoming filed its own Request for Rehearing, on the basis that we were timed out without sufficient notice. You know, we remain cautiously optimistic.

Then, to just sum up, we know that Jordan Cove is competitive on a delivered basis with Gulf of Mexico Brownfield costs. And that's important because we might win a tie, but we can't cost any more. We're right sides to the current market conditions, at 6 to 7 million tonnes. I think that's what slowed East Africa; the lack of infrastructure requires greater scale than—than—than the market can bear. We've got executed and announced term sheets for a minimum of 50% of the throughput. We are nine days from Tokyo. No canal or hurricane risk. Large gas supply from two large gas regions, served by easily expanded, large diameter pipeline systems, and very strong stakeholder support. So, I can't say when. I can't—I can't say—I can't say when, but I know it will happen, and I remain very confident of that. Thank you very much. I'm going to turn it over to Theresa.

THERESA JANG: Thanks Betsy. It's really hard to follow her up, especially with the stimulating conversation on the balance sheet and funding, but I'll—I'll do my best to keep you—to keep you informed on this.

Now, I hope what you've taken away from my colleagues this morning is that now we're very excited about the way our businesses are situated, and we're very confident that we're positioned for success. We're equally confident in our strong financial position, and that it will allow us to fund our capital growth, to continue to service our debt, and to maintain our dividends.

And, when we talk about being in a strong financial position, we believe that our highly contracted cash flows, as well as the diversity of our counterparties play into that. The chart on the left here shows you the diversity of our counterparties, and you can see that within our top-ten largest counterparties, nine are investment grade or have an investment grade parent. And, our top three counterparties, starting at the top in the grey, are: Encana, and then moving clockwise: Seven Generations, and PG&E. And, importantly, no single counterparty contributes more than 13% of our cash flows in 2016. On the right, we've proven—presented a different view, and it shows you that under the makeup of our current dividend of $1/share, that all of this is supported by our businesses that have take-or-pay contract structures.

So, as you'll recall back in August, we announced our enhanced funding strategy, under which we are now pursuing the sale of our power business, and our intention is to redeploy the proceeds from that sale into our contracted growth in Midstream. This plan allowed us to suspend our DRIP in August, and we had previously been using the DRIP to fund the equity component of our Midstream growth.

And then, in early September, we announced that we'd secured an additional $650 million of credit facilities within Veresen Midstream. And this is really significant, for a couple of reasons, but what I say to you is that: as we were going through the process of completing this debt financing for Veresen Midstream, all of our vendors had the opportunity to do what many of you can't do, which is to go underneath the Midstream agreements, that Dave talked about in as much detail as we could today. And, through that due diligence process, all of our vendors stepped up and said, "You know, we affirm the business model that you have for Veresen Midstream." And all increased their commitments. And that was really significant for us. So, between the power sale of Veresen Inc. and this additional funding at Veresen Midstream, our growth is fully funded without the need to access equity or debt capital markets at this point.

In terms of our payout ratio, we expect to close out 2016 in the low-90's, and, depending on the timing of when we close the power sale, we do expect 2017 to remain high. But we have a line of sight to significantly higher cash flows in 2018, when the Veresen Midstream plants come into service and start flowing. And, at that time, we do expect that our payout ratio will drop significantly. And it's important to note, as well, that when we think about our payout ratio, we look at it after the deduction of amortized debt scheduled to be repaid.

This funding strategy will strengthen our balance sheet and improve our—our already strong liquidity position. Today, our leverage, on a proportionally consolidated basis, is about 5X EBITDA. But, if you carve out the debt in there that's supporting our $1.2 billion capital growth program, our leverage would be closer to about 4X EBITDA. And, if you look at each of our businesses, we believe that leverage within each of them is very appropriate, with, of course, the outlayer being Veresen Midstream at 8.7X. But, again, once those cash—those plants are flowing in 2018, that debt to EBITDA will decrease significantly.

Importantly, each business has a healthy level of debt service coverage, providing confidence in the cash distributions that come up to Veresen. The proceeds of the power disposition will further strengthen our balance sheet by reducing our leverage, and there will be a permanent reduction of about $400 million at the power asset level.

With additional proceeds, we'll use that to pay down our revolver, at the Veresen Inc. level, and we'll draw on the revolver as we fund our Midstream growth over the next year and a half. And when the projects come online, we expect that our debt will be within our target range of 4 to 4.5X EBITDA.

In terms of the power divestiture process, we have been working very hard on preparing for the launch of the sale. We've been pulling together all this information for our data rooms, engaging independent engineers to do their studies, looking at preparing market studies, and really anticipating to have a very good data room to formally open in the coming weeks here. It would be our anticipation that we have something to announce in the 1st quarter, and to have this closed by the middle of next year. We've seen very strong interest from a number of players around our assets, both strategic and financial players, and we've indicated that our objective is to maximize value for all of our stakeholders and, therefore, we will look at either selling the asset on block, or at the asset level.

And I know that you all want to know what these assets will fetch for us. We have a range in mind, but we're not prepared to share with you yet what that range is. We would tell you, though, that just based on responses, and looking at comparable transactions in the market, that the market is firm. And we are fully confident that we will transact on this sale.

So, in summary, all of our existing growth is fully funded. We're well positioned to maintain our dividend. Our credit rating remains very important to us and we'll continue to protect our balance sheet to assure that we remain solid investment grade. And with that, I'll turn it back to Don.

DON ALTHOFF: Thanks Theresa. So, we've—we've promised that we'd provide a lot of detail, and—and I don't think we've let you down there. But I would—before we conclude and—and go to Q&A, I would like to provide a few concluding comments.

I think, what—what I'd like to leave you with today is that we've fundamentally transformed Veresen from a one asset company with re-contracting risk and no clear growth, into a focused set of diversified business with significant growth under construction, and visible growth into the future. The business we have in place is as sound as any in the sector. The quality of the assets, the contract structure, and the diverse set of counterparties provides us stable and predictable cash flows for many years to come.

Our clear and compelling growth strategy is focused on natural gas and natural gas liquid infrastructure, linked with great resource basins, and end markets. It's produced $1.4 billion in growth under construction so far, which is best in class, relative to our peers; and there's more coming. We have a number of projects, which leverage our footprint, under development and I believe we will sanction before the end of the year.

And, not only do we have a great business and a great basin, we've got a great amount of growth under—under construction, but I also think there's a lot of upside potential. NGL margins will improve over time, and Aux Sable profits will return. Back in 2011, our share of Aux Sable profits were $100 million US. I'm not sure the market will ever get back to that level, with the amount of NGLs that we see in the market, but you can see there's material upside. And there will be demand for LNG projects, and—and the ones on the West Coast in North America, I think, are well positioned to capture that growth, in Jordan Cove.

And, lastly, I hope you've witnessed today we've got the experience, the ingenuity, the passion, and the Leadership team to deliver on a very bright future. I will throw one other piece in. We have our values at the company. One of the value statement is: "We take our work seriously, but not ourselves." I think you can see that we've got a great group of folks. I probably pushed the "rockstar" bit a little too far today, but Betsy will get even with me at some point down the road. It was a true statement, by the way. That—that actually did happen. So, now, I'm going to turn it back to

Mark. We're going to open it up for Q&A and—and—and hear what's on your mind. So, Mark.

QUESTION AND ANSWER SESSION

MARK CHYC-CIES: Fantastic. So, that concludes our formal part of the presentation. But, so that everyone in the room can hear and so the folks on the web cast can hear the questions, and we don't have to repeat them, Dave and Ross will be walking around with hand-held mics. If you'd like to ask a question, please just raise your hand. They'll come over to you, and ask away. So, where can we get our first question from?

ROB CATELLI [PHONETIC]: Hi. Rob Catelli [phonetic] from CIBC World Markets. I'll start with a couple questions on the Veresen Midstream and then one on Alliance. I—I believe I heard you, Dave, say that there—there are terms to equalize the ownership at Veresen Midstream upon conversion? Can you give us some indication on what the terms are? How that pricing would work? If it's based on cash flow or book multiples, or something else?

DON ALTHOFF: I mean, look, one of the things that we were going to do was…let—I'm going to MC it, so let me take a first whack at that and then—and then I'll let Dave throw a bit in. Although, I will say, this is—the terms for repurchasing of the PICs was agreed, and the partnership agreed, that it is based upon a—an analysis of what the—the business is worth. That is relatively standard and predictable in the industry. We have not told the market or provided any other specifics beyond that, but it—it wouldn't…I mean, the—the repurchase of the—of the PICs will be inline with the value of the market—of the business, when we go and do that. And that's all been pre-described in the—in the partnership agreements. Missing anything there, Dave?

DAVE FITZPATRICK: No. Theresa commented in—in her presentation that we effectively went as far as we could talking about the—the MSA, the Ministry Service Agreement, with our—our valued partners. Don is right. It's typical for us, standing up here, to not go much beyond that and much more detail. So, that—that's the right answer at that level.

ROB CATELLI [PHONETIC]: And, just again on that Veresen Midstream – sort of a higher-level question here, but early days. Do you have any thoughts on how the Enbridge/Spectra merger might impact competition in the—in the Montney for—for new growth opportunities?

DON ALTHOFF: Let me—let me take a first whack at it and then I'll—I'll turn it over to any other colleagues. I—I mean, I think, you know, and I—I'm ex-Amoco VP. I mean, I understand what it's like to—to undertake a big piece like that. So, I suspect…and Enbridge has said that they are going to sell some assets. So, one is: you know, one reason that Enbridge likes Spectra so much was their gas assets up in the Marcellus and up in the Northeast. I think, you know, what I've read and heard so far, that'll be a focal area for them. Enbridge has expressed a desire to grow in the Western Canadian Basin, but for Veresen, you know, whether Enbridge is, you know, 90 billion or 165 billion, you know, it—you know, our—our ability to compete has really been around our ability to be nimble and our ability to be customer-centric and customer-focussed and innovative. And I don't think that changes one bit during the process.

So, I—I don't think, from our growth perspective, we still think we're going to grow off our footprint, as a fundamental starting point for it, which gives us a cost of capital, which gives us an understanding of the producers better than anybody else in the market. I think that'll be where we grow. I—I don't think that the—the—the acquisition of Spectra will really have any impact on our growth at all. Dave, additions?

DAVE FITZPATRICK: Yeah, it doesn't change our business model at—at all. As Don said, core to our strategy is this producer-centric focus that we bring to the mat. We talked about it earlier on—on Midstream.

Also, just one other bit of colour on the merger. Enbridge is already in our backyard; doesn't change our plan. Spectra, on the other plan, historically has not participated in much of the expansion or development, new development, in Northeast BC. So, I would also suggest that if Enbridge bumps up their game, on a—on an expansion of the Spectra system, in fact, over time, it will help egress out of Northeast BC, and we'll benefit from that with our GNT business.

ROB CATELLI [PHONETIC]: And then, moving on to Alliance. My last question. You know, you talk about the re-contracting a little bit but, you know, now with the shorter portfolio, contract portfolio life is conceivably always in re-contracting discussions at this point. So I wonder if you can characterize how active things really are? And whether or not you're addressing the—the shipper group as a group, or individually?

DON ALTHOFF: Well, high level is there—there is a shipper task force, and that's always important. The—the producers and the marketers need to have a voice in the conversation; that—that's very important to us. You know, what—what we wanted to do with Alliance and Aux Sable were to get this new business model in place. It's a very different business model than a cost-of-serve model.

And, we wanted to be absolutely focused on delivery of this new business model, and maximizing the value of the assets on startup. So, now, we're—we're almost ten-eleven months away from starting it up. I think we feel really good about the base business, and we've begun to shift our focus to re-contracting. And we've had a number of producers come back to us and talk about it. I'll—I'll kick it over to Darren to provide a bit more colour around where we are.

DARREN MARINE: Yeah. Rob, I think it's fair to say that we're approaching this re-contract team, further out – almost as from an individual basis. So, when you look at some of the producers in the WCSB that are constrained, you've got some individuals that are more motivated than others, based on how much capacity they have to get out of—out of the basin.

So, one thing's for sure – I think you've got to have a plan to get the resources out of Western Canada, if—if this last round has taught us anything. It's—so, a little bit from a one-off perspective, but we've been very pleasantly surprised by both the—the number of people and the names that have come to us to say, "Hey, we want to think about something longer."

ROB HOPE [PHONETIC]: Hi. Rob Hope [phonetic] from Scotia Bank. Just on the Alliance and Aux Sable theme, once again. Just, in terms of your upcoming discussions on re-contracting, has any thought been given to potentially giving producers an increase in share of the NGL barrel and, thus, turning up Aux Sable into a fee-for-service asset?

DON ALTHOFF: Well, I—I—I think there's two pieces. Just a bit of context – when we first began the re-contracting process, NGLs were worth almost as much in Edmonton as they were in Mont Belvieu, and the basis differential between ATP—or ATCO, in this case, in Chicago is about $0.40. So, we found that in the early days the producers were pretty—pretty bullish on the fundamentals being in their favour around piece. And, so, we didn't really, actually, think that was the way the market would go, but we also knew an MP type was a problem. So, I think, fundamentally, you know, we—we really like—we really like the pipe, and we thought the basis would open up. We thought the drilling of—of—of all of the Montney and the Duvernay would really flood the market with NGLs, and the basis would move back to the Gulf Coast. Both of those have come true. I would argue we have more leverage today with producers than in the past. I suspect NGL-sharing will become more favoured towards us.

I—I also will tell you that all of the incremental volume that's come on Alliance and Aux Sable has come with no NGL-sharing. And, so, you know, I—I think, fundamentally, you know, I—I like where the—the market is—is positioning, and that was really the context for where we are. I—I'll let Darren, kind of, finish up with, you know, where we think the rest of it will go and how that will play out.

DARREN MARINE: Yeah, I—I would say, generally, that the fundamentals were not in our favour, if we go back three or four years, when we were first re-contracting the pipe. Fortunately, the fundamentals have materially moved into our favour, which is why we want to continue to extract the economic trend of a very wide ATCO Western Canada to Chicago basis that existed today. So, yes. We'll capitalize on—on that opportunity.

In terms of fee-for-service, that would be—that is our aspirational goal in some point in time, is—is to have everything locked down and—and nailed down for a long period of time in a fee-for-service type of nature. But, NGLs, I think, is really…the amount of sharing of the NGLs, I think, is really just another part of the re-negotiation of the agreements that are going forward, and that'll depend on the end pieces.

ROB HOPE [PHONETIC]: All right. That—that's helpful. And then, just moving on to Veresen Midstream. In the past you talked about the potential to vend in other assets into Veresen Midstream, such as AEGS and I would imagine Burstall. Are there any updated thoughts here with the—with the power sale process going on and the change in funding strategy?

DON ALTHOFF: Well, I think—let me just start high level. I mean, we—we have, in the power sale down, said that we'd be interested in buying—somebody buying it all, buying part. We've also said that an asset swap would be on the table, and people can bring that forward. I mean, Veresen Midstream is the growth profile and—and where the platform will grow, over time. We want to integrate this all together. We want to optimize it and get more value out of the whole supply chain, than that—that piece. I think, when it comes to, you know, how we're thinking about funding, you know, I—I'd ask Theresa to add a bit on that, but, you know, I think that's the high level piece.

THERESA JANG: Yeah, really, when we talked about potentially putting other assets into the partnership, it has been around, you know, what alternatives we may have for funding. With the power sale, that, sort of, takes care of our immediate funding requirements. And, so, you know, I wouldn't think that an AEGS drop down is, kind of, top of the list but it will remain as an option.

And I think one of the other things we think about is—is timing, with the AEGS re-contracting coming up, I think it would make sense for us to really get through that re-contracting process and enhance the value of that asset before we really contemplated anything more.

DON ALTHOFF: And Burstall. And Burstall.

BEN PHAM [PHONETIC]: Hi. Ben Pham [phonetic], BMO Capital Markets. On the Alliance pipeline, could you attach some volume figures to debottlenecking sit—option, as well as the expansion to 30%? And could you also comment on if there's permit requirements cross border?

DON ALTHOFF: Well, the—the—I mean, high level, the—I think, the way that Darren laid it out is there's some debottlenecking of the…one way to think about Alliance is it's really two sets of pipes. It's got a big gathering system. Actually, one of the more material gathering systems in Western Canada, going through the Montney and—and the Duvernay. I think, when you saw some of Dave's pictures you could see where the pipe runs.

And then, there's this bullet line from, you know, Central Alberta all the way down to Chicago. And I think we think about it in that line. And so, you know, in that context, you know, Darren – why don't you talk a little bit about the size and—and scope?

DARREN MARINE: Yeah, you know, I think—I think the sky can be the limit with respect to, you know, any of the assets. And, in particular, of course, as I mentioned, we need to have the—the proper underpinning from market to make sure the—the deal makes sense. But, you know, it's almost a—a series of smaller debottle—debottlenecking-type projects that, you know, might be in the, you know, \$1,500 million…sorry, 50 to 100 million/day range. You know, if you were to expand the system all the way from Northeast BC to Chicago, of course you're talking about some compression and—and some pipe looping, which is a pretty material capital event. We don't see that in the cards today, but some of the smaller ancillary-type benefits, whether it's storage or additional compression to alleviate some of the congestion that currently exists in, sort of, the Montney and Duvernay Northeast BC area, that's certainly possible.

DON ALTHOFF: And—and, I like to think about – I mean, there's small debottlenecking projects. The next big would be to add compression on the pipe, which could add pretty material volumes, and then looping – and that's how we'd look at it. We'll take the low-hanging fruit that has, you know, quick paybacks and relatively low costs that I think producers are comfortable with signing up for today, and we'll look at compression expansion, or looping projects, down the road. But I—I do think those are out of it, so.

BEN PHAM [PHONETIC]: Any colouring on the permitting side?

DON ALTHOFF: You know…sorry, can you rephrase it, rephrase the question, please?

BEN PHAM [PHONETIC]: Just if you were to expand the Alliance pipeline, is there any additional permits that could be gained factor for this to occur?

DON ALTHOFF: Yeah, I think that it would really depend on, you know, what part of the system you're—you're expanding, in terms of the permitting. You know, we—we've, kind of, have all been following along on what's been happening on the, you know, cross border United States side of the equation. But, I think, if the project made sense, and we had the—the right backing by industry, I think, in due course, we'd find the—the building permits taken care of.

BEN PHAM [PHONETIC]: Ok. Ok. My second question – you talked about power monetizations and redeploying that cap into Midstream, it seems like a no brainer, just power 12X and redeploy 8 to 10. But, how do you think about it, from a levered IRR-basis? And also when you think about the risk profile differences between power and Midstream, you know, counterparty differences? And with the KKR situation, the take on the back end is probably a bit of an upward revision to your book value, when you take that back. So there's a bit of groundage in the back end. And—And, so, do you need to see some developments occur with respect to your other non-power businesses, to move forward the power asset sale?

DON ALTHOFF: Well, let me start high and then I'll—I'll toss Theresa the hard part of that question. Just—just a reminder about the power business. So, when, you know, it's—it's a terrific business. It's got great counterparties. It's got long-term contracts. They're easy—easy assets to run. The—the thing, for Veresen – let me start strategically why we would even put those assets up for sale.

You know, fundamentally, we see a very clear line of sight to a differentiated growth strategy that can win in the market in our Midstream gas business. We don't see the same on power. Power's a very different business. The—what it takes to develop those projects: the development costs, and the resource base, and the funding, the cost of capital for us – that—that didn't look like a business that we can grow, especially when you look at internally, now, we've got so many growth projects with great returns; it was just tough for it to compete for cost of capital. So we've been pretty clear to the market; we didn't plan on growing our power business. It's—it's a great cash cow and—and we liked it for that.

That said, there were a couple of things that worried us. One was, by 2018 power is 5% of my business, and—and management's attention to that very important operating asset was going to become more and more of an issue as we grew the other parts of the business pretty materially. So, it is a funding source for us that we thought about it.

And we thought about two things, when we decided on timing about selling. One was: we wanted to be absolutely clear about the fundamentals and the earnings potential for Alliance and Aux Sable. So, nine months under our belt; we felt great about that. Two is: we wanted to be sure that the new gas plants were on time, on budget, and there was gas being drilled to fill them up behind them; and we're very comfortable about that. The third piece for us is: is that this is probably a bit naïve on my part, but I do think interest rates are going up at some point, and, therefore, our power business will be worth less. It's an annuity, over time, as interest rates go up. So we actually felt like there was never a better time to monetize the value of those power—of the power business than today.

So, fundamentally, we're moving on it for those fundamental reasons. And, as we think about our—our balance sheet and the way we think about funding and projects, going forward, I'll—I'll turn that over to Theresa to provide some clarity.

THERESA JANG: Yeah. I mean, just to go back to the comments I made earlier from a no problem/effort standpoint, you know, selling the power assets will—will help us make an improved metric around what our leverage looks like. There's $400 million of debt on the power assets that are going to come off of our—our balance sheet permanently.

And then, you know, we're projecting, depending on what divestment of proceeds looks like, to have a great position on our revolver to draw from it, and—and go forward. So, you know, a target of 4 to 4.5X EBITDA is where we think our—our debt is going to be after the sale of the power assets, and when the Midstream assets come on. And we're, you know, we're confident that we're going to be able to get there with the sale.

I—I think, you know, just as far as counterparties go, you know, there is no doubt that, you know, ISO and BC Hydro are fantastic counterparties to have. But, as Don mentioned, really become a shrinking part of our portfolio. The tradeoff, for us is, you know, can't underscore enough a couple of things around Veresen Midstream. One is there tends to be this focus on Encana and Mitsubishi is A-rated, and we really like that. I think that's an important element of who our counterparty is on—on that Midstream arrangement.

The other piece around that is—is, you know, that Encana has been, you know, from what we can see, doing, you know, all the appropriate steps to strengthen its assets and capital. You know, their big equity raise last week helped tremendously. And, from a—from an ongoing perspective, as we look at their overall business and the view that we have, and—and Dave can maybe help me with this, but their focus on the Montney and seeing the most economic area of their business, really helps to drive our confidence that these assets will get built out and get used to the extent we think. So, from a counterparty perspective, we're—we're quite comfortable with that tradeoff, if you want to call it that, for—for those reasons.

DON ALTHOFF: Yes, Robert.

ROBERT KWAN [PHONETIC]: Thanks. Robert Kwan [phonetic], RBC. Questions on Alliance and then Midstream. Just starting with Alliance. Can you just talk about how you think about your—or your desire and contracting strategy going forward? You've got the certainty of efficacy versus you've gotten quite well on seasonal firms and IT service. And, especially, with some of the modest roll offs that you've got, how you think about wanting to—to look at your contracting going forward? As—as well, thinking about term. So, locking in, you've done very well on the OPEX side of things, trying to lock down—how long do you want to lock down the FT and try to keep yourself away from any pressure on—on a cost-of-service-type of application?

DON ALTHOFF: Well, I'm going—I'm going to throw this one to Darren, but the one thing about the pipe is it is an at-risk pipe with negotiated rates and tolls. And so, the regulators look at our—our returns on the pipe and they—they factor that in with the—the fact that—that we are at risk on it and, therefore, you know, cost-of-service or return types of numbers are interesting but not all that important in the way that we do it, going forward.

I'll—I'll throw it to Darren to talk a little bit about the—the logic and the rational for re-contracting, going forward, that it builds on it, but I think negotiated rates is because of the service of the pipe, I think, is probably fundamentally where we're going.

DARREN MARINE: Robert, we're—we're very pleased with the uptake and the ability to translate positive market fundamentals in Western Canada up to the pipe, with respect to getting the revenue today. And we think we're—we think, for sure, the medium term above market on the seasonal service and—and IT perspective of the pipe.

It would be our preference to extend out, for as long as humanly possible, as a toll that made a lot of sense to—to us, as investors. And, so, that's—that certainly is a strategy, is to capture the opportunity of a positive fundamental [indiscernible 2:06:12] that exists in the market today, to play forward that—that gain.

ROBERT KWAN: And then—and then, in terms of your volumes, do you have the numbers of how much the volumes in Alliance are direct connected versus needing NGTL service?

DON ALTHOFF: I'm sorry?

ROBERT KWAN: Do you have a percentage of your Alliance volumes that are direct connected into the pipe versus needing NGTL service?

DON ALTHOFF: I don't have that—that off the top of my head, Robert.

ROBERT KWAN: Just looking at the Midstream side of things, the Interconnection project – and there was some talk, Dave, or you were talking about that being largely to serve third—third parties, and then some…it sounded like you might have some contracts in place? Can you just talk a little bit more about that? And I don't know if you can talk within your—your CRP contracts, whether those margins are creditable? Again, for cash flow through?

DON ALTHOFF: I'll just pitch that one to you, Dave?

DAVE FITZPATRICK: The answer is yes to all of the above.

[LAUGHTER]

DAVE FITZPATRICK: And—and more specifically on—on the contract, although I can't, of course, divulge too much detail for proprietary reasons. I'll just say there's a sharing mechanism in place, that if our prime counterparties, in fact, allocate specific capacity to us and we, as a proprietary system, there is a sharing mechanism in place that both—all parties benefit. I'll say that much, contract aside.

From a business development standpoint, there is nothing like interconnecting three gas plants that process a billion cubic feet a day of natural gas. I have never seen, in my entire career, three gas plants, all within a span of approximately thirty miles in distance, that had exactly a resource base that generates 400 million cubic feet/day, 200 million cubic feet/day, and 400 million cubic feet/day. Geology doesn't work that way. So, we take the extra step, as a Midstreamer, to run this trunk-line project to connect all three, to allow us the ability, our counterparties the ability to move volume between the plants when one is down or one is mismatched with its supply basin, to a plant that is undersupplied or undernourished. #1.

My #2, it is perhaps the best example of our ability to go in to third party producer offices and say, "We're connected. Let's find a way to fit you, Mr. E&P, into this incremental 50 million cubic feet/day." (I used in my—my podium example) to process that third party gas through the existing complex that we have today. This line, looks like it'll be up and running when the plants are functional.

DON ALTHOFF: And—and just one more point. I mean, Dave talked about that we've got the biggest interconnect on the NGTL system. We're also connected to Alliance and to the West Coast system. So, the—the CR—the piece of Veresen Midstream, actually, has some of the best egress out of the region. We can get into the NOVA system. We can get into the West Coast system, and we're also connected to Alliance. So, a lot of great egress, which is a very important piece to a lot of producers.

ROBERT KWAN [PHONETIC]: And just so I'm clear, when you were doing your discussion around the payback, are you taking into account that, effectively, all you're doing, though, is swapping time value in terms of getting that cash out front, if it is creditable, against what would have been a balloon payment in eight years?

DON ALTHOFF: Fair comment. Run your own profile. Suffice it to say that the original plant that came on-stream a little over a year ago now, Saturn Phase 1 – the first build out of Saturn – has been flowing at approximately 80+% of capacity from the one start up. So, sure you can do the math however you wish. My 8X example was truly a simplified version, but the multiple still stands, in time.

ROBERT KWAN: Ok, thank you.

MARK CHYC-CIES: Do we have any other questions at this time?

DIRK CLAYBORE [PHONETIC]: Dirk Claybore [phonetic] with Alta Corp Capital. First question will be continuing on the Midstream side. And, David, you were talking about tripling the volumes. There's an awful lot of liquids that comes with that and, right now, you're really just working on—on the separation of the liquids. What opportunities do you see further down, on the liquids side, as to the helping of marketing and finding new market for those liquids?

DON ALTHOFF: Let—let—let me share one quick piece, because Dave is really the right guy to answer. I will say that one part about the asset base that we own is although they are not necessarily connected physically, or necessarily commercially, the one thing that's actually quite helpful in the asset portfolio that we've got is that we understand the NGL business pretty well. Aux Sable processes 130,000 barrels/day of liquids and—and we do a lot of work with producers on their economics of whether they'll produce them in Western Canada or bring them down to Chicago and have them fractionated there. So, that's an insight and some wisdom and some market intelligence I think helps us in this process. Brings something to the table over and above the Western Canadian view. But, Dave, do you want to talk a little bit more about the Western Canadian side?

DAVE FITZPATRICK: Higher level, we are always looking at integrating our footprint, expanding our footprint to take advantage of the value chain. Period. Full stop. What is really exciting, in terms of the size of the prize, is generally, the historical Montney production, Montney drilling, targeted reserves that were approximately 20 barrels of condensate – I'll call it 20 barrels of NGL – per million cubic feet and lower. The drilling results the last six to twelve months have typically all targeted NGL rates of 90+ barrels of condensate – or NGL – per million cubic feet. That is a staggering uplift. Do the math on a BCF/day of incremental gas processing—processing, and that is a sizeable prize.

So, to—to your question: do we have a sanctioned project today to look at the downstream implications of that? No. Not yet. Is it within our radar? Absolutely.

DIRK CLAYBORE [PHONETIC]: Ok. When—when we're looking at your partner on Veresen Midstream, KKR typically has a time horizon with the various pools of funds that they have. What should we be thinking about as their time horizon as a partner?

DON ALTHOFF: Well, KKR opened up a new infrastructure fund about a year before Veresen Midstream was put in place, and the marketing on that fund was eight to ten years. So, you know, how will they want to come in and out? It's—it's not perfectly clear. But I think we're pretty confident that they're in it for a while and—and are interested in growing the—the—the—the business more than just the CRPs. So, I suspect they'll be our partner for quite a while.

DIRK CLAYBORE [PHONETIC]: Ok. Switching over to the Jordan Cove project, and Betsy had put up, effectively, a cost curve for us to look at. And—and, I'm curious, when you look at the cost curve, I mean, the US is clearly the lowest on the curve. How important, then, is the economic rent – because your US-based lower interest rates, relative to—to other countries? And, clearly, the other side of the contract also matters on the economic rents. So, how much does that play into it?

BETSY SPOMER: Well, I mean, clearly, that's part of what makes the US low cost. But, you know, it takes a little bit of capability to fully utilize that.

You've got to have a gas dest that can…you know, you're either going to need someone to manage your gas supply and pipeline transportation or you need the capability to do that. But—but, clearly, when we negotiate costs with buyers, we're looking at that market according to our financial advisor. Construction costs. All those things, which all contribute. I mean, I think at one point people though the US would be high cost relative to labour. But, you know, relatively speaking, that's proven to not be a concern. And, in fact, it's going—an advantage.

DON ALTHOFF: I'd also add that, you know, the—the—the buyers know that you need to get a reasonable return on the project or people won't develop them. I think, for Jordan Cove, the other piece of element that it's—it's a good returning project is that most of the buyers that we've been speaking with want to take an equity position in the project, as well. So, I think, you know, for infrastructure projects, I'd put it on the high end of the return basis. And the producers are ok with that, because that clears the market, and they'd like to be an owner of it, as well.

DIRK CLAYBORE [PHONETIC]: Ok. And, if I could switch now to the Alliance side of it? Given the short reserve life now with the modern wells, how realistic is it to get really long-term contracts down to Alliance? Isn't it just going to continually be short-term contracts, unless you've got somebody that has got huge capital behind them and very large base? Otherwise you're just going to be continually smaller-term contracts that will always back in. And, in fact, the case, how did we ever get to a point where expansion trigger gets pulled? And, if that expansion trigger gets pulled, then there's an obvious—you've got to expand down to Aux Sable. So, how do those tie in?

DON ALTHOFF: Well, I—I mean, I think that there's two pieces. Because it's not just a natural gas pipe, but it's an NGL pipe, and—and people are, instead of using their capital to build fractionation facilities in Western Canada, they're just leveraging ours down in Channahon. I think that drives, maybe, a little longer-term view of the world. I think, for producers to get comfortable with signing longer-term contracts, they need to get more comfortable with where they think ATCO and Chicago pricing and Henry Hub pricing are going, long-term.

I think, you know, we're a year or two from really starting to see that stabilize out and get to the right place. So, we are—are speaking to some that are actually looking at some pretty long extensions, more driving by NGL economics than—than methane economics. And so, you know, I think, you know, it'll depend on the producer. And they have to be pretty big. We are seeing the smaller producers want the—the shorter pieces of it. You know. And I think, you know, from an economic point of view, we'll need the producers to feel comfortable with longer contract lengths before we do expansions, as Darren—Darren mentioned, because we're going to look for some certainty on returns, and—and they're not going to be willing to stand up and do that until they get more comfortable with where the bases are going. So.

DIRK CLAYBORE [PHONETIC]: So, that would mean that, too, in order to then expand – when you're looking at expansion of the Alliance, you have to also expend Aux Sable, otherwise you're going to have lean out the gas.

DON ALTHOFF: We—we do. I mean, the—the front end of Aux Sable has two terminal expanders that can do 1.1 billion cubic feet each. So, we have the ability to go up to 2.2 billion cubic feet/day on the pipe. We only have about 130,000 barrels/day of fractionation capacity, which, by the way, is the lower-cost piece to add. We could expand it and just put dry gas on the pipe, and—and—as one option to get methane out. But if you did want liquids capacity, we would have to pair that with—with an expansion of the…

DIRK CLAYBORE [PHONETIC]: Well, certainly, given your earlier comment that you guys were looking at it from the liquids side, it's unlikely they'd want to run it lean, right?

DON ALTHOFF: No, I think, that's right. I think, fundamentally, that's right. It's just an option and, you know, Darren had laid it out. I think the first step is looking at some debottlenecking. We think, over time, the market will start to sort itself out, as far as where bases are going long-term, and with these new basins coming online. And—and, as that look—as that happens, we'll look at the more expensive—expansions, because I think then producers will be willing to backstop. Would you add anything?

DAVE FITZPATRICK: I would, Don. I think, just on the NGL front. One of the great advantages that Alliance and Aux Sable have – if you look at 131,000 barrels/day of liquids that flow right past the petrochemical complex in Alberta. In some point in time, if the wind of the—the conditions exist where there's a major cracker expansion, a huge source of both methane and—and propane and—and some butane that go right by the doors. So, you know, if—if the conditions existed in the future, you could certainly see the possibility to taking some liquids off in Western Canada, you know, with the fractionations facility.

And, with respect to the longevity of the reserves you were asking about, I think it's certainly early, from a Duvernay perspective, to prove up those reserves before people start to swing for the—you know, for the right field of the fence on the tenor of the agreements. But, what we're finding with the Montney, is—is it's world class. I—I think people get more comfortable with it every day, with respect to proving up the reserves. You know, I think they certainly got the reserve base for the facilities that we're talking about here. And the CRP, are, you know, not going to get, you know, proved out or—or be done drilling for—for ten, fifteen, twenty plus years. So, I think the—the future looks—looks right.

MARK CHYC-CIES: Being mindful of time, I think we have time for two—two more questions here.

DON ALTHOFF: Ok.

QUESTION: Hi. I just have a question on LNG costs. You've got US Gulf and West Coast at $8 to $9 cost. I just—can you differentiate between the two and give the assumption on the delivered cost of gas, either from Rocky user or from Western Canada, in that assumption?

BETSY SPOMER: Sure. I mean, what—what we have at Jordon Cove is: one) a permutable project, which, I think, is unique on the US West Coast, for sure. And that has a nine-day shipping to, you know, let's say use Tokyo base, as an example, versus twenty-two out of the Gulf. That's a significant shipping differential that really, essentially, bridges the gap between Greenfield and Brownfields with a larger pipeline.

A lot of the projects, you know, are a little bit different. You know, Freeport's Electric draws. You've got to think about what you're going to think the electrical price is going to be, going forward, which is a pass through. But, that—that $8 to $9 at a $3 Henry Hub price is a pretty good number, and I—I would argue it's a really low risk number for us, with—because we're not wearing a lot of the basis risk that a lot of the producers are wearing in—in the Gulf of Mexico.

On the Montney, I mean, we can get from Dawson Creek to Malin for about $0.55. So, you look at, you know, FX. You look at ATCO versus Henry Hub versus Malin and, you know, there's quite a bit of value there. The problem, I think, for the Western Canadian projects is they have to build a GTM. They have to build a Ruby. If we had to do that, we would not be economic.

And, it's our ability to leverage the existing large diameter pipe that really is what makes all the difference. And that—and that's true for the Gulf of Mexico. And, to a certain degree, even Cove Point, because they expanded such a large import capacity, so they had a lot of big diameter pipe to—to reverse the other way.

QUESTION: [Indiscernible]

BETSY SPOMER: Rockies gas. It's—I've been watching it very closely. The basis is actually held up better in the Rockies than one might have thought, what with Rockies Express being reversed. But, when you look at Rocky—Opal, which is the relevant hub for Ruby, versus Malin, and our ability, post-2021, to be commercial on Ruby with re-contracting, I still think there's a lot of opportunity there.

It's difficult to get inside the TransCanada box on GTN, because, you know, I know what we can do on Ruby, as far as low-cost expansion. There is a—a limit to GTN capacity. And—and—and I'm not suggesting that Ruby is only, you know, in second place, but there are very few buyers who want to put all of their eggs in either Western Canada or the Rockies. And, we've had such phenomenal support. We've had field trips to producers on the Western slope of Colorado, detailed tours and presentations on Peon space and economics. They just upgraded the Peons from something like 40 TCF/day—40 TCF to some huge number of over 100 TCF/day. So—so there's a lot of gas and it's getting less and less expensive, as people climb the unconventional drilling curve.

DON ALTHOFF: And the thinking is, I mean, the economics Betsy shared were: A) they were—there an assumption that the Gulf Coast would be expansion, so they don't have to put in tanks and a jetty and all of the things that come with it, and—and we do. But it—because it's delivered into Tokyo Harbour, the shipping piece.

The other thing, for us, is we've use Henry Hub as the price. I think, over time, we're going to see Malin price drop under Henry Hub. Certainly, ATCO's been under Henry Hub for quite a while. And—and I think that the buyers see both Opal and ATCO as being—trading at a discount. But that's not how we've done the numbers; the numbers are based on Henry Hub, because we wanted to put it on an apples to apples space. But I think it will shift, over time.

BETSY SPOMER: I mean, I think that's absolutely right, Don. I would expect Henry Hub and [indiscernible 2:26:00] to become – they essentially are today – the premium price point in North America.

DON ALTHOFF: It'll be interesting because we've seen some credible volume balances that showed Texas is a net importer of natural gas, which is almost mind boggling. But, you've got 8 BCF/day of LNG projects got a good start up in the next couple of years. You've got 3 BCF/day of gas going into Mexico. You know, we hear numbers like three more coming. So, I think Henry Hub is going to be the premium price in North America. I think our buyers see that as well, and I think that really gives us an outlet for Western Canadian gas and—and US Rockies gas. Ok. Anything else?

MARK CHYC-CIES: All right. Well, at this point we'll wrap up the discussion. Management will be around if you have any additional questions for us. For those of you on the web cast, please just feel free to email us at investor-relations@veresoninc.com and we'll get back to you. So, thank you for joining us, everybody, and thank you for your continued support of Veresen.

DON ALTHOFF: Yes. Thank you very much.

[APPLAUSE]

[END OF TRANSMISSION]