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EDITED TRANSCRIPT

FTS.TO - Fortis Inc Inaugural U.S. Investor Day

EVENT DATE/TIME: APRIL 01, 2015 / 12:30PM GMT

THOMSON REUTERS

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PRESENTATION

Editor

Webcast in progress.

Barry Perry - *Fortis Inc. - President and CEO*

-- CEO of Fortis. First thing I want to do is introduce my team here up at the panel. Karl Smith is the EVP and Chief Financial Officer of Fortis. Jim Laurito is the President and CEO of Central Hudson Gas and Electric. David Hutchens is the President and CEO of UNS Energy Corporation in Arizona. Gary Smith is the President and CEO of Newfoundland Power.

Newfoundland Power, just so you know, is the mother of Fortis, I'll call it and this year celebrates its 130th year of existence. So we've been in the business a long time. Gary actually is here sort of stepping in for Earl Ludlow who is the EVP of our Eastern Canadian and Caribbean operations. Earl could not make the event today. And finally John Walker at the end. John is EVP of our Western Canadian operations. Those are the operations in Alberta and British Columbia.

So forward-looking statement, I just want to caution we are providing a fair amount of forward-looking information today. Actual results will likely differ from assumptions that we are using in this presentation. I really would encourage everyone to read the forward-looking statement in detail.

I will also say that today in terms of numbers, we're a Canadian-based company. So unless there's a US dollar in front of a number, then you can assume that all the numbers you're seeing are in Canadian dollars.

I will tell you that the Canadian dollar exchange rate right now is $1.00 is equal to CAD1.27. A couple of years ago, we were at par. So there's been a pretty big swing in that sort of relationship over the last couple of years.

So Fortis has become a leader in the North American gas and electric utility market. Today, our balance sheet is CAD26.6 billion, Canadian again. We actually have nine utilities our business currently, representing about CAD24.7 billion of that balance sheet.

We are serving in our group 3.1 million electric and gas customers. The split is there on the slide. 93% of our assets are regulated assets. We do have also a non-regulated part of the business, representing about 7% of the assets. 4% of that is our hydroelectric business, and those are plants that mainly have long-term contracts in place.

The biggest plant, which John Walker will talk a bit about, is the Waneta plant that we're building in British Columbia. It's a CAD900 million investment, and that's the biggest part of that 4%.

We also have a hotel and real estate business that we are currently doing a strategic review on, and I'll speak about that in a minute.

So if we focus on our regulated assets, I'll give you a sense of the Company. Again, this is a split of that approximately $25 billion in assets. So starting with the US, we have two regulated businesses now in the US.

Central Hudson was our first acquisition. This is in the Hudson Valley area. It represents 11% of the overall company. UNS Energy is in Arizona. The biggest asset that UNS Energy owns is Tucson Electric Power, again representing about 30% of the Company.

The next biggest segment is FortisBC. FortisBC is the gas and electric business in British Columbia, Canada, our most westerly province in the country; 32% of the assets. Before we started on our US growth program, FortisBC would have represented more than 50% of the assets of the Company.

FortisAlberta in Alberta, Canada represents 14%. It's a wires business only distribution. A very good franchise. Eastern Canadian, we have three utilities, Newfoundland Power being the largest in that segment. Newfoundland, Canada, and Newfoundland is the most easterly province in Canada. You get a flight from St. John's to London in 4.5 hours. So we are way out there in the Atlantic.

We also own some small utilities in Ontario, and we own the utility in Prince Edward Island Canada as well.

And then the Caribbean, we have two businesses, regulated businesses there. We own the utility in Grand Cayman, and we own the utility in Turks and Caicos. So two beautiful places. If you haven't gone, you should visit.

So, how do we get here? This is CAD26.5 billion in assets. It's been an incredible decade for our company. If you look back in 2004, our balance sheet was CAD4 billion. And, frankly, in that year, we closed the acquisition and the two utilities in Western Canada, the electric business in Alberta and the electric business in BC, which we bought from an American company some of you might remember no longer in existence, Aquila. They had two jewels of assets in Canada, and when they got into trouble, we purchased those back in 2004 when we closed the deal. Fantastic acquisition for our Company.

We followed up with that in 2007. We bought the gas distribution business from Kinder Morgan in British Columbia. This was at one time a public company called Terasen. Kinder had bought that company mainly for its pipelines into the Canadian oilsands in Alberta. Did not want to own the distribution business, so we immediately started talking to Rich Kinder and his team and managed to do a bilateral deal to buy that distribution franchise back in 2007 from Kinder Morgan.

Through the period up to 2013, we would have looked at a number of acquisitions mainly in the US. We weren't successful during that period. We were close a couple of times. We did announce one deal called Central Vermont Public Service. You remember our friends at Gas Metro in Quebec came and topped our bid, which is very unusual in our sector. We immediately said thank you, collected our break fee and moved on.

We followed up, though, with Central Hudson, which was a fantastic purchase for the Company. Somewhat difficult approval process. It took 16 months to get the transaction approved in New York, but we stuck to it. We've delivered on every commitment that we agree to with the Commission here in New York and now are looking forward to having our rates reset finally here as of July 1. Jim and his team have negotiated the settlement there, which Jim will talk about in his presentation.

And then our largest acquisition ever was the purchase of UNS Energy Corporation in Arizona. We are very excited about doing business in Arizona. The regulatory approval there was very efficient. It took us about eight months to get the deal done. We've had a great experience so far in the state. We are looking forward to investing more capital in that jurisdiction.

So that takes us to today where the Company is now poised to really run this good portfolio of businesses that we own.

So let's look at performance over that period. So despite this acquisitive nature that we've been buying utilities in our core business, we've delivered good returns to our shareholders. On average, Fortis has delivered 12% annual returns over the last decade.

If you compare that to the various indexes, you look at the US indexes, the sort of S&P 500 utilities index is at about 10%, similar to the Dow. And then in Canada, our utilities index on the TSX is at 8%. So we've outperformed those three indices over that period of time.

We are very proud of this slide. Fortis has the record in Canada for a public corporation and increasing its dividend the most consecutive years. We've now done it for 42 consecutive years, and it's a very important record for our company. Really one that we want to keep going forward. There are a few American utilities, other businesses that probably have a record a bit longer than this, but in Canada there is no other public company, no bank and no other utility that's had this record as long as Fortis.

So let's talk about properties. This is a business we built from the ground up over the years, and last year we decided really we are going to focus solely on our core regulated utility business and long-term energy infrastructure, and we announced that we would conduct a review of this business. It is a good business. We have a management team in place that's running the business as it has in total about a couple of thousand employees, especially at the hotels.

It owns 23 hotels and 2.8 million square feet of office real estate in Canada. The hotels are spread out across the country, but the real estate is really concentrated in Atlantic Canada. Last year it had revenues of about CAD250 million, about CAD80 million in EBITDA.

We are looking at various options for the business, and we still believe we will have this announcement related to the conclusion of this review before the end of the second quarter of 2015.

So looking forward, really after this growth spurt we've had through acquisition, now looking forward to the organic growth that we have in front of us. And what we see is a capital plan is really generating about a CAGR over the next five years of 6.5% growth in rate base. And that's pretty healthy, I would think, for a North American utility.

We are as well pursuing a couple of projects in British Columbia in the sort of natural gas area, which John Walker will provide a fair amount of information on shortly. But these two projects, the expansion of our Tilbury plant in Delta, BC, which is just right next to Vancouver, and also the woodfibre gas pipeline expansion, could see us jump that growth rate over the next five years to about 7.5%.

So again, a pretty healthy growth rate. This is regulated investment, pretty vanilla kind of stuff, low risk, and I would think this by the end of this year, we will have made decisions on those two projects about whether they are going to proceed, and we today remain very optimistic that they will go forward.

So now we're going to head into sort of each of the presentations of the panel. I will tell you, we are trying to finish today by 10:30, and then we are allowing about 30 minutes for questions at that point in time. So we should be done by 11:00. We have a clock at the end of the room there that everyone is going to try to follow.

So Karl?

Karl Smith - *Fortis Inc. - EVP and CFO*

Thanks, Barry. Good morning, everybody. Picking up on Barry's point, my job is to impart a lot of numbers to you this morning. I have a very limited amount of time in which to do that. So if at some point it appears I'm going fast, it probably is because I'm going fast. But please bear with me on that.

And I wanted to start with a broad overview of some of the metrics of our business today and looking back a couple of years. One overriding comment I will make is that we've seen a significant increase in the size and scope of our business over the past three years. So I wanted you to take that away.

This table does include a number of non-GAAP measures. However, we think they are useful in your assessment of the Company or your understanding of the business. I have included a supplemental slide you'll see in your packet; that is slide 30. Don't bother to look at it now, but when you go home and if you have difficulty getting to sleep tonight, just take it out and read it.

I would like to draw your attention to several items in particular in regard to these measures. Earnings to common shareholders, basic earnings per share, EBITDA and FFO have all been adjusted compared to our published financial statements, and we've done that in order to eliminate the impact of several nonrecurring items. The most significant of these items is the exclusion of acquisition-related costs incurred in the acquisition of CH Energy and UNS Energy.

As Barry pointed out, the currency that we communicate in its Canadian dollars. When we do exchange US dollars in our presentation, we do it at the rate that Barry cited, CAD1.27. Most of the information would be in Canadian dollars.

When the guys from the US get up and talk about their CapEx program, that will be in US dollars. I'll mention that right now. And that's because that's their language, they can speak better in their own language in their own currency. And also it's better for comparative purposes for their sake.

I have included a 2014 pro forma column on this slide that shows what results would have been if we assume the acquisition of UNS Energy at January 1, 2014. Just to give you some idea of what a somewhat normalized year would have looked like in 2014.

Earnings per share is lower under this scenario that I just mentioned, and the main reason for that is a bit of a quirk is that we didn't actually issue the equity associated with the acquisition after 2.5 months post-closing.

With respect to earnings per share for the past three years, growth has been somewhat muted as we have absorbed those two significant acquisitions. I would point out, however, that in general there is a pattern of improvement in all of the metrics on this slide.

I wanted to show you the change in our market cap over the last several years, and as you can see, there are significant increases in both our market cap and our average daily volume. Our liquidity is significantly enhanced since the acquisition of UNS, and this market cap, I would suggest, establishes us as a solid mid-cap company even in the US market.

I wanted to show you what our segmented operating earnings look like. The other in this slide includes earnings from our Caribbean operations and also our non-regulated businesses. The portion of operating earnings that comes from the US will be larger going forward as it will include a full-year earnings from UNS.

With respect to our dividend payout ratio, you can see that it's hovered around 70% over the last three years. That's been a consistent pattern for us, and sitting here today we anticipate that that likely wouldn't depart much from that relationship going forward. The current dividend is CAD1.36 per common share.

With respect to our capital structure, we utilized both preferred equity and common equity in our capital structure. The percentage of debt is high at December 31, 2014, and that's due to debt still outstanding related to the acquisition of UNS.

Barry mentioned that we are in the process of a strategic review for our properties business. If we do sell that business, the proceeds will be earmarked to take out the debt that's outstanding on this acquisition.

We did target a capital structure that includes approximately 55% debt, and this should be sufficient in our view to maintain our current credit ratings.

In terms of our allowed returns, I just wanted to break these out for you on a weighted-average basis between the US and Canada. And as you can see, the returns are noticeably higher in the US, and that's part of the reason for our interest in acquisitions here. Our experience has been quite positive with the two acquisitions that we have made. And as you can see from this, it does boost our return on equity and also allows us to earn on a thicker slice of common equity, and we consider that very important as well.

Now, the big part of our story today is to give you some indication of what our capital spending program would look like over the next five years, and I'll do a high-level overview. The rest of the presenters will go into a bit more detail about what underlies the capital spending for each of their particular companies.

But our organic CapEx program for the next five years totals CAD9 billion, which is an average of CAD1.8 billion per year. Approximately 28% of the plan is expected to be derived from new customers, and I'll get into a breakdown of that a little bit later.

The obvious conclusion is that the growth rate declines in the outer years, as you can see, is partly an inherent attribute of the forecasting process and is typical of our past forecast.

Also typical is that new projects are identified as we get closer to the forecast in the year in question. Subsequent presenters, as I mentioned, will also discuss some growth opportunities that aren't included as of yet in our forecast numbers.

The next slide details our capital projects for the next five years -- our major capital projects, I should say. Our capital program is best characterized as having numerous small to midsize projects. As seen on the previous slide, a significant percentage consists of sustainment projects. These would be associated with lifecycle maintenance for example and the replacement of assets as you reach the end of their useful lives.

I've detailed the major projects included in our plan. As Barry mentioned, John Walker will talk about Tilbury 1A in detail in his presentation. Caribbean utilities will install a 40 megawatt diesel plant that will go into service in June 2016. The Pinal transmission project in Arizona is a 500 kv transmission line that will improve import from the Palo Verde hub to our load centers. And the FortisAlberta Pole-Management Program is a multiyear program to replace poles that have reached the end of their useful lives.

In 2015, UNS Energy will acquire a larger interest in the Springerville generating station and related coal handling facilities. And in 2017, they will buy out common facilities leased at Springerville.

The point I really wanted to leave with you with respect to this is that this is a low-risk capital program with a high degree of execution probability.

The fact that these are very low cost, numerous projects enables us to be able to execute on this quite readily. We don't have any other projects that would be larger than CAD50 million.

Now, as Barry mentioned, our capital programs I just talked about translates into a compound annual growth rate and rate base, and this is midyear rate base, by the way, of approximately 6.5%. When we include the projects that John will talk about later related to our LNG opportunities in British Columbia, the average CapEx increases to CAD2 billion a year for a total of just over CAD10 billion. And that would translate into a compound annual growth rate of approximately 7.5%.

I just wanted to talk about our funding strategy and our approach to funding that we take at Fortis. Consistent with our autonomous operating model, most debt is raised at the operating company level. We strive to maintain debt levels at the operating companies that are consistent with the approved regulatory amounts. Debt is raised generally at the long end of the curve, as most of you would be aware, if there's anybody here that doesn't invest in our bonds.

We do offer a dividend reinvestment plan that is based on a 2% discount to market price. Past participation has averaged about 30%, so there has been a tremendous amount of interest in our plan. And if that holds, approximately CAD100 million will be reinvested based on the current number of outstanding shares on an annual basis. And based on the capital plan that we are talking about, that would be sufficient common equity to fulfill that plan. In other words, we don't anticipate having to raise any additional capital in order to deliver on this capital plan.

We do target in a A- credit rating. I will show you our credit ratings in a subsequent slide. That's at the enterprise level. And as mentioned earlier, we are in a process to dispose of our properties business, and those proceeds would be applied to outstanding debt.

So let me talk about credit metrics for a few minutes. These are selected I think probably the most relevant credit metrics for the past three years. And, again, I provided a pro forma as well for 2014 because of the unusual nature of our year.

Generally speaking, they've been holding steady or improving slightly. With respect to funds from operations as a percentage of debt, in 2013 the decline relates to owning Central Hudson for only part of the year. In other words, we account for all of the debt but only a portion of the cash flow, and again that's just a unique nature of that particular year.

In 2014, the same phenomenon applies as a result of the acquisition of UNS Energy. As you can see on a 2014 pro forma basis, the results are more in line. For both years, there would have been a drag on cash flow due to the effects of the rate freeze at Central Hudson and the capital tracker proceeding at FortisAlberta. Both of these sources of drags will disappear in 2015.

I wanted to show you our debt maturities. Over the next five years, the average amount of maturing debt obligations is about CAD240 million, and we consider that quite manageable. Also, we do have long-term committed credit facilities of about CAD1.1 billion.

I will tell you, though, that the vast majority of those rolled over in 2016 and beyond. So we consider the next couple of years in terms of debt maturities quite manageable, and we should be able to handle that without too much difficulty.

Likewise, currently or at December 31, our liquidity position looks like this. We have unused credit facilities of about CAD2.3 billion. So, again, quite a bit of headroom there as well.

I mentioned the credit ratings earlier. At the enterprise level, S&P rates us A-, DBRS rates us A low. Of note is the recent upgrading, and this took place in October 2014 of Tucson Electric's S&P assigned credit rating to BBB+, and cited in that upgrade was the new ownership of Fortis Inc. Moody's also upgraded the company to A3 in February 2015, also partly because of the new ownership of Fortis Inc.

And the last slide is a busy slide, so I do encourage you to take this away rather than spend a lot of time on it right now. But it's meant to capture on one page the regulatory overview of our significant subsidiaries.

Not all our companies are on here, but I will tell you that over 90% of our business is represented on this slide. Included in the table is a summary of the regulatory models of our largest subs, as I mentioned, and I won't go through each specifically, but there are a couple of points worth making.

Most companies had agreements in place that go out several years. So, as we sit here today, we do have agreements in place that would take us over the next several years without having to go back to the regulator. BC and Alberta would be an example of that, and most companies have arrangements that permit them to earn above the allowed returns. And with subsequent speakers, you'll see some information with respect to how we have earned compared to our allowed returns in the various jurisdictions.

So I'm going to leave it right there and hand things over to Jim Laurito.

Jim Laurito - *Central Hudson Gas & Electric Corporation - President and CEO*

Thanks, Karl, and good morning, everyone. As Karl mentioned, I am Jim Laurito, President & CEO of Central Hudson Gas and Electric. And, as Barry had mentioned earlier, we were Fortis' first US acquisition in the States. So we sort of like to think of ourselves as Fortis' high school sweetheart. There will be many more to follow, but we'll always be the first, right? (laughter)

And I'm even more pleased to say that we are almost two years in now, and this merger has been everything that was advertised and more. We've met all of our merger approval commitments, in fact, exceeded a lot of those, and as a company, we are very excited because we are positioned for growth through some state and federal regulated utility investments that I'm going to touch on this morning.

So most of you know us in the room. Our service territory is located north of New York City in the beautiful Hudson Valley region, and the territory is split by the Hudson River with the majority of the population along that river where most of our combined electric and gas customers are located.

So in total, we have about 377,000 customers over a diverse 2600 square-mile territory between Metro New York City and Albany. And that includes areas as diverse as the Catskill Mountains, a lot of farmlands out to the east and some urban settings to the south of our territory. And in the Company today, we have approximately 950 employees.

Importantly, our rate base is really growing, and it's now reached the $1 billion mark for the first time since our post generation ownership history. So some really strong growth.

And a key attribute of our service territory I want to point out is its geographic position. We are the pathway for electric transmission from upstate New York to downstate and to the New York City area. And we are also a key gateway from the Marcellus gas shale gas region in Pennsylvania, Ohio, West Virginia, up into New England and New York markets. I point that out because it's key to our strategy, and I'm going to touch on it a little later.

If we turn to our regulatory environment, I would term New York as -- describe it as tough but fair. As Barry mentioned, our merger had a few interesting moments along the way, a few speed bumps in the approval process. But we got through it -- that's how we roll in New York -- and we made it through.

Industry restructuring occurred in the state in the late 1990s, and we've had competitive markets since then. A lot of ROEs are typically a little on the lower side versus the rest of the US, but we have above average risk protections that mitigate our risk in the business.

And three of those key risk moderators are revenue decoupling, which protects our downside risk on sales, we have full pass-through of purchased gas and electricity costs; and deferral treatment for pension costs and importantly our manufactured gas plant site remediation expenditures.

So on balance, I would say we have a supportive regulatory construct that favors A credit ratings and would point out that we have an extremely positive and constructive relationship with our regulators.

So we look at those regulators a little more closely, the Public Service Commission in New York is comprised of a chair and four commissioners, all of whom are appointed by the governor. They served six year terms, and as you can see, one commissioner's term has recently expired, but she is still serving. And a new commissioner has been appointed or nominated, but he has yet to be confirmed by the legislature.

And our new Chair, Audrey Zibelman, was appointed a couple of years ago. She's extremely dynamic, and she has laid out an ambitious and exciting agenda for new regulatory policy called Reforming the Energy Vision that many of you may have heard about. Affectionately, we call it REV, and that's garnered national attention.

It's another key part of our strategy and one of our key regulatory priorities that I'm going to delve into next.

So the top two regulatory priorities we have are our rate case that Barry mentioned and the REV proceeding, and they are both ongoing currently.

First, the rate case. Our two-year rate freeze period ended or it ends in June of 2015, and due to the 11 month statutory period, that meant we were required to file for new rates in July of 2014, which would then become effective on July 1 of 2015. So the proceedings started last summer, and in February of this year, we reached agreement on a three-year settlement with the New York PSC staff and several other key parties in the case, and that will provide certainty for us to run our business over the next three years.

I'll talk about this in more detail on the next slide, but suffice it to say, the case is currently under review by the PSC, and we anticipate an approval in June of this year.

So concurrently, the REV generic proceeding kicked off in April of 2014 and has been progressing through a two track process. A Track 1 order was issued this February, this past February, and Track 2 will continue through 2015 with a final order to be issued in early 2016. I'll give you more detail on that proceeding in a few minutes, but again we are working very collaboratively and cooperatively on this important proceeding.

So let's take a closer look at this important three-year settlement agreement that we've reached. The joint proposal was signed in February, and it includes electric and gas delivery rate increases of $55 million and $12 million, respectively, over the three-year period, which will end June 2018. The allowed ROE is 9% with an earnings sharing provision above 9.5%. So the first 50 basis points are for the benefit of shareholders, and we have a common equity layer of 48% in the business.

And also importantly, as Karl mentioned, related to capital investment, our program of over $450 million that we proposed was approved in its entirety. And it includes a number of important programs to upgrade our infrastructure, improve reliability, improve resiliency and support the direction of the REV proceeding, and that will make our system stronger, smarter and better.

And while the merger is closed, its benefits live on as we've used remaining financial benefits from the merger to mitigate the customer bill impact of the rate increase to a very modest level. Under this plan in the first year, electric customers will see only a $1.00 per month bill increase, and gas customers will actually see a slight decrease. And then in years two and three, the increases will be approximately $4 to $5 per month each for electric and gas, respectively. So we've really kept the increases and bill impact modest.

All the current risk mitigation protections remain with the added benefit of the creation of a major storm reserve, which eliminates the risk of major storm cost recovery. And also very importantly, we included four REV demonstration projects/proposals in the plan, which really made us a first mover among utilities in the REV space, which include a community solar project, demand response projects, micro-grids and a smartmeter opt-in project. These projects have been very well received and are being developed in conjunction with third-party providers.

So, as I said, this three-year plan is now being reviewed at the PUC with approval anticipated in June 2015.

So let's talk a little bit more about this REV proceeding that's garnered so much national attention as New York's version of utility of the future model. The goals are primarily to increase penetration of distributed energy resources in the distribution grid, primarily in our territory through solar. Increased demand response and increased energy efficiency and also to have the utilities both participate in and facilitate increased third-party involvement in these areas as the distribution system platform provider. Say that one 10 times fast.

The hope is that this will drive innovation and create new markets for products and services. So the desired outcomes here are greater distribution system efficiency, resource diversity, reliability and resiliency, as well as CO2 emissions reductions.

The Track 1 order was issued in February and determined that the distribution system platform provider will be us, the incumbent utilities, which very importantly means we will continue to operate and maintain the distribution grid as we have in the past, only creating these new markets with the proliferation of distributed energy resources.

Track 2 is important in that it will determine the ratemaking structure for the REV initiative, and the milestones currently include a staff straw proposal scheduled to be released this June with a final order early in 2016. So we're working collaboratively with the regulators, other utilities and over 300 parties to this case, but we really do view this as a great opportunity to enhance our engagement with our customers in new and different ways and our investments in the system.

And those system investments, make no mistake about it, are growing. This is a summary of our CapEx program over the five-year forecast period during which we'll invest over $800 million in the system. The key here is that you see growth in investments in all areas, all of which are designed to add value to our customers. Some key programs on the electric side include our distribution automation system project for $60 million, which is foundational to create those new markets in the distribution grid envisioned by REV, and it will reduce voltage delivery and customer usage by 3%. So it will essentially save customer usage without them having to change any behavior.

We also have four new substations and upgrades to others for $100 million, three major transmission projects over $100 million, and distribution system improvements totaling over $175 million. That's just on the electric side.

On the gas business, we are more than doubling the pace of our cast-iron bare steel pipe replacement program, investing over $80 million. I don't have to tell you the focus on the gas safety issues in the wake of the East Harlem incident, the San Bruno incident. We are also increasing our expansion of the gas system, investing over $75 million where we are adding two new franchise territories and converting many residential and commercial customers from oil to gas, even in these low oil prices at some significant savings.

We are also going to make significant investments in IT as well. Approximately $50 million to support our move to digital and self-service transactions, which we think will enrich our customer's experience. And importantly, I want to point out this forecast does not include any FERC-related transmission investments that I'm going to touch on later.

So the result of all this capital investment program is strong rate-based growth at slightly over 6% annually through the forecast period, again excluding those FERC-related investments.

So now turning to ROEs, our allowed ROE in the last three-year settlement that began in 2010 was 10%, and through solid execution, we were able to earn above our allowed return on the average over that three-year period. And, as I mentioned earlier, the term of the Fortis merger approval was that two-year rate freeze. And during that two-year period, we continue to invest about $250 million in the electric and gas businesses.

And you can see the effect of no return on that investment in the 2013 and 2014 years when ROEs dip below the previously earned levels. And so with the advent of this new settlement, we expect ROEs to return to the allowed levels.

So moving on now to some FERC-related transmission. As I said at the outset, our geography is a key attribute for both electric and gas transmission. On the electric side, the four investor-owned utilities in New York: Central Hudson, National Grid, ConEd, Iberdrola formed the New York Transco in the fourth quarter of 2014, and an affiliate of Central Hudson was formed at that time, Central Hudson Electric Transmission or CHET, which owns 6% share in Transco.

We filed the first three PSC-approved projects at FERC in December totaling $500 million, and we proposed additional projects as part of the PSC's AC transmission proceeding, which is part of the Governor's Energy Highway initiative totaling $1.2 billion. These projects could result in up to $100 million of additional investment opportunity for CHET at FERC returns and will result in a number of benefits for New Yorkers.

First, these projects are going to reduce transmission congestion from upstate to downstate in these two zones that cost customers about $1 billion per year in 2013 and 2014. They are also going to mitigate some increased supply costs to customers resulting from the FERC-imposed lower Hudson Valley capacity zone.

And lastly, by making more upstate renewable generation deliverable, it's going to help New York meet its current renewable energy goals and the EPA's new clean power plan goals. And so this transmission system is going to require significant ongoing investment over the years, and it'll all be upside to the forecast.

On the gas side, as I said, we are the gateway between the Marcellus region gas supplies and the constrained markets in New York and New England. So we're looking to take advantage of that proximity by developing a pipeline to bring lower cost gas to and through our region. If successful, this will result in benefits to our customers of increased reliability, increased supply portfolio diversity, lower gas costs.

So in addition, due to the increased amount of electricity generated from natural gas, electricity prices will decline as well, making this investment a clear win-win for customers and shareholders.

To get a sense of the price differential that exists, in the winter of 2014, peak gas prices reached $80 in New York. They reached $130 per MMBtu in New England, and on the other side of the constrain in Pennsylvania, they never exceeded $6. Even this past winter, prices were $5, $25 and $40. So prices were dampened this winter, but still quite a disparity; more infrastructure needed.

So to close, just want to say we are very focused on executing on our important priorities involving the rate plan, the REV proceeding and these transmission opportunities, and with the significant state regulated investments and the upside from FERC electric and gas transmission, we are excited about our future and positioned for growth in the years ahead.

And now I'll turn it over to Dave Hutchens, the President & CEO of UNS Energy. Thanks, everyone.

David Hutchens - *UNS Energy Corporation - President and CEO*

Good morning, everyone. Well, UNS Energy may not have been the first US acquisition. As Barry noted earlier, we are the largest, Jim. Just saying, I finally got to follow him after he said that.

I have a lot of material that's in your package here and I'm not going to go through every little gory detail on those slides. I will hit at a very high level, so if there are topics that you would like to hit them more detail, feel free to ask it during the Q&A session or feel free to catch me after and I will be glad to talk your ear off about distributed generation, clean power plan, and other things that I could talk your ear off but I'll save you from that today.

First, let me get on the right slide. First, let me give you an overview of UNS Energy. We are a holding company for three regulated utilities -- Tucson Electric Power, which is the largest 415,000 customers. A vertically integrated utility that serves that brown area that you see on that slide, which is the Tucson metropolitan area, that has a population of about 1 million people.

The other two utilities are served under the Unisource Energy Services umbrella. UNS Electric, again, a vertically integrated utility serving 93,000 electric customers shown in those two yellow areas up in Mohave County and Santa Cruz County in Arizona, as well as UNS Gas, a gas distribution company that serves 150,000 customers in the combination of those yellow and darker gray areas on the map.

We have a total combined rate base between three utilities of about $3 billion as of 2014 and we have 2,000 employees across the state of Arizona. Those three regulated utilities are regulated by the Arizona Corporation Commission which is a constitutionally created fourth branch of government in Arizona. They set the retail energy rates as well as related policy.

We are old-school cost of service rate making using historical test years. We have five commissioners that our elected statewide and they're limited to serve two consecutive four-year terms. And we have a very constructive relationship not only with the commissioners but with -- and as importantly, with the staff of the Commission.

And those constructive regulatory relationships have led to very constructive regulatory environment in Arizona, as well as constructive regulatory results and this slide here hits the highlight of several of those recent results. We have authorized ROEs across the three utilities ranging from 9.5% at UNS Electric to 10% at Tucson Electric Power. We have numerous adjuster mechanisms that help mitigate some of the risks that we face including purchase power and fuel adjustment clauses at all three of the regulated utilities.

We have a loss fixed cost recovery mechanism which is a partial decoupling mechanism to pick up fixed costs associated with distributed generation and energy efficiency. We have that in all three regulated utilities. We have an environmental compliance adjuster at Tucson Electric Power, and we have a transmission cost adjuster at UNS Electric. And we don't have any stay out or rate freeze provisions at any of the utilities as well.

And I think the next two bullets goes to show how responsive both our commissioners and their staff are to pending requests from utilities. And that is that in the last two rate cases that we filed, we've seen those completed in less than a year and as Barry mentioned earlier, we saw a very complicated transaction. Something that the Commission doesn't do very often, obviously. A merger transaction. That was completed in less than eight months.

And then the final bullet really hits on something that is key on the regulatory environment in Arizona and that's the Commission has recognized the need to open up new dockets to address things like rate design, net metering, and distributed generation and some of those issues that come along with those different policies. And that, to me, sends out the message that they get it. That they get that there is a changing utility landscape out there and regulations have to change to address it.

And we also are seeing and improving Arizona economy and it's mostly seen by some forecasts that we see from both good personal income in job growth going out into the future, as well as good population growth which is obviously one of the big drivers of utility growth is that population growth that obviously turns into customer growth. And Arizona has been historically one of the fastest-growing states, and guess what, we're going to be in one of those probably for a long time to come. We're coming out of that recession slowly but surely, but we see good numbers going forward.

At Tucson Electric Power, we also have a potential new mining customer, Rosemont Copper. And they are -- just had been recently purchased by HUD Bay Minerals out of Toronto. They're a large copper mine that we would serve when they -- they are in the process of getting their permits done. We're hoping those get done this year. When they are at full production, they'll be an 85 megawatt load for Tucson Electric Power, and that will be our single largest customer.

This slide shows our five-year capital expenditures which totaled about $1.8 billion and I'm showing in two different ways. On the left I want to show it because it breaks it down by the part of the business that we are investing in and I think it's very important to see that, when you look at that big blue part that's almost half of that pie, it's transmission and distribution. What I would call the safest and lowest risk investment that we can make as utilities. And then when you look at the right, we've got that broken down by the type of investment as far as growth, sustaining or other and you will see that fairly decent blip there in 2015.

Just so you won't ask me in the Q&A session, I will tell you what that's for and that's for -- Karl mentioned these two pieces in the CapEx slide, which is the Springerville unit one lease purchases as well as the transmission line that (inaudible) Central to Tortolita transmission line that he mentioned.

So we see a pretty decent rate base growth when you start from 2014 looking out the next five years. However, this slide is a little bit understating what our real growth potential is. Because 2014 was a very big CapEx year. And we are just coming out of a big CapEx spending cycle.

And so when you look at what is actually reflected in our rates across all three utilities, about $2.4 billion is currently reflected in rates. We have historical test years, so we have to go in and get permission to put those assets into rate base. So that necessarily leads to regulatory lag.

So if I was to look at this from a holistic perspective, I would look at this as we are starting today, as we sit here today, with $2.4 billion recovered in rates compared to that $3 billion that you see midyear 2014, which means there's $600,000 -- or $600 million that are still ready to be recovered in rates.

So when you look at this from a growth perspective, you take that $2.4 billion and look out a couple of years to 2016 and that $3.4 billion. That's a total of $1 billion that will have to go into rates. So that's how I would look at that growth perspective.

This next slide shows the UNS consolidated return on equity. These slides are always a little bit difficult to provide exact comparisons because the return on equity is weighted average of our regulated ROEs at the utilities from our Arizona Corporation Commission. And of course the achieved number is a GAAP ROE at the parent. So, there's a little bit of differences in those comparisons that you can notice in those footnotes. I just wanted to point those out, but we're seeing very good results from that parent level.

And it would also seen -- we have seen steadily improving balance sheet and capital structure at our utilities as well as improving financial metrics, Again as Karl had mentioned, we've seen upgrades at Tucson Electric Power from both S&P and Moody's and most recently, that Moody's upgrades puts all three of our regulated utilities at A3, which is a big achievement for us at UNS Energy.

And then of course we also plan on improving the capital structure across the organization as we go out into the future as shown by that projection there on the right. And that is mainly TEP, which has an existing capital structure in its rates of 43.5% and we plan on bringing that up to 50%. That's what brings the total equity to capitalization across the UNS Energy companies up to that 50% level over the next couple of years.

We also plan, over the next couple of years and longer term, to maintain our track record of containing our costs. Every utility, every business has had a lot of cost pressures over the past four or five years, but we've managed to limit those overall and have increases to about an average to 2% from 2010 to 2014.

This next slide shows what we're doing from the perspective of our generation portfolio and our diversification strategy specifically related to Tucson Electric Power. And a lot of pieces to this pie, but let me give you the takeaway. Tucson Electric Power is removing 500 megawatts of coal from its portfolio and replacing it with gas, renewables, and energy efficiency. So you see a much more balanced portfolio when you look at the right one and this is on the capacity basis than where we are now.

So we are pulling out that 500 megawatts of coal. And what that does is that's a third of our coal capacity that we have at Tucson Electric Power. Reducing coal capacity by one third. And in the end, that reduces our CO_2 emissions by 25% when you look at that timeline from 2014 to 2020.

This slide also has all the details of how we're doing that. I won't go necessarily into gory details. That's reductions at Springerville and San Juan as well as the replacement capacity of the Gila River combined cycle unit that we just finished purchasing last year, as well as a fuel switching down for a dual fuel plant that we have down in Tucson.

But one piece that isn't on this slide that I want you all to write down in your notes is that we bought that Gila River plant for CAD220 million, which is CAD400 a KW and I'm extremely proud of that purchase ticket. So that was quite a deal for our customers that we got on that.

So, I'm going to talk about -- just a little bit. I could talk for hours on the clean power plan, but this -- it's old news I hope to most people in this room. So I'm going to cover just a few very key items and how they relate to our business.

And the first is that the clean power plan requires state-by-state goals. The second is, Arizona got the worst deal out of any state. So, no matter how you slice it, Arizona has the highest unplanned coal reduction requirement of any state in the United States.

And the second is not only do we have that very drastic reduction requirement, but we got to get it all done by 2020. That's basically what the clean power plan has done to the state of Arizona. And that's what this slide shows here.

This is what the compliance schedule would look like as proposed -- now remember, heavy on the propose. It's a proposed rule at this point in time but that obviously gives us -- this gave us a lot of concern. Gave us a lot of concern, our corporation commission, Arizona Department of Environmental Quality, every stakeholder in Arizona lined up shoulder to shoulder and understands that this was going to be a huge issue for our state. Because if we had to meet that 2020 requirement, we would be required to shut down every coal plant that's under this rule in the state of Arizona and by 2020.

Obviously, that's crazy. And it would create all kinds of reliability issues. There isn't the gas infrastructure, there isn't the transmission infrastructure, there isn't the peaking capacity needed to replace those coal plants in place. So that is -- that was the biggest and still is the biggest issue that we face is making sure that we do not have that requirement in 2020.

So, one of the things that we've done is got that group of stakeholders that I mentioned before together and said, well, we've got to talk to EPA about these issues because not only is that cliff obviously the biggest problem we need to address but we're also getting pretty -- an unfair burden for CO_2 reduction imposed on our state compared to others.

And so, we got together and said, well, when you look at 111-D, which is where the Clean Air Act paragraph that this rule comes out of, and it says right in there that the EPA is supposed to consider remaining useful life of plants, well, we said we've got to use that. We've got to make sure that we go to the EPA and explain. We've got very -- in coal terms, very young power plants in Arizona. We have two -- this is not just ours, but in the state of Arizona that this applies to, we've got two that were built in 1985, we've got two that were built in 1990, we've got one that was built in 2006, and one that was built in 2010.

So we've got some pretty new coal plants. You've got to shut those things down right away. And so we went to the EPA and said, you know, this whole reasonable life issue in here, we need to address this. And what we think is appropriate is to say that coal plants should have a 40-year life before they're required to be re-dispatched to meet this requirement. And so far, the EPA has been pretty receptive of that idea.

And we also threw in another caveat that says remember, you're also requiring us to do a lot of things on coal plants related to regional haze and other EPA regulations. Well, we would also like that if we made a significant investment in these coal plants, that we get at least 20 years to recover those investments before they are required to re-dispatch.

So you take those two pieces, put those together, and this is what an alternative plan would look like which ends up with the lower end target and a much more reasoned glide path from 2020 to that 2030 compliance.

And we have -- we are cautiously optimistic. We've had a lot of conversations. The state folks had a lot of conversations with the EPA. We are hopeful we get traction. We're hearing good things out of EPA that the 2020 requirement will likely be loosened quite a bit.

So, we are cautiously optimistic that when the final rule comes out, that our state will not be -- well, let's just say that we are cautiously optimistic that it looks a lot more like that top blue line then the solid blue part.

So now I'm going to shift gears and talk a little bit about solar power. And let me start out by saying that Tucson Electric Power and our other affiliates are big fans of solar energy. But just like every resource that we have, we want to make sure that we get the best deal, the most cost-effective deal that we can get for our customers and that it's fair to everybody involved.

And to that end, we've put together programs -- this is back five years ago, we put together a program for community solar that was at that point in time pretty cutting-edge. And we also have put together another option for our customers, which is utility owned distributed generation solar program that just got approved last year and that we're going to implement here in the next couple of months.

Because solar has -- and specifically distributed solar has some challenges. And the first one is its cost. There is no quarrel that rooftop solar costs twice as much as utility-scale solar.

So if you want solar because you want to reduce CO2, you want to clean up the environment, you should want to get twice as much for your dollar than distributed generation -- distributed solar on your rooftop would provide. And there's also, on the fairness issue, there's the issue of net metering in our current rate design which basically shifts cost from people who have solar to those that don't.

It was okay and it might even have been appropriate when solar costs were much higher and we needed to get some solar installed. But now that's -- that was back when solar was three times the cost to put on your roof as it is today. And so, it's time to update these rules. There are system reliability as well as consumer protection impacts that are kind of a little bit in the background as well.

And the chart on the right -- it's not necessarily the numbers that are important because when you look at the total amount of distributed generation that's in our Tucson Electric Power service territory, it's about 2% of our load, but look at the shape of that curve. Exponential curves should start -- it should scare you. And this one --if solar continues to get cheaper and cheaper.

So the problem is shown here in graphical form related to rate design because our rates -- the cost to serve our customer -- about two thirds of that cost is fixed, but we only recover a very small amount of that fixed cost through a fixed charge. The rest of those fixed costs are recovered through volumetric rates. So if you combine that with net metering, as you will see in that second bar chart there, what happens if -- with net metering, with a full credit -- a full retail rate credit and the customer who appropriately sizes the solar system, they can have a rate design that looks like this, which means they don't pay barely anything towards the costs that are incurred to provide them service -- those fixed costs that are incurred.

And those costs end up being shifted to other customers. First, through our loss fixed costs recovery mechanism. Whatever is not caught there ends up going through the next rate case. So that's where that cost shift matters. And in others, there's ways of correcting this. You can lower that credit from a full retail credit, so that's one way to address it.

Another way to address it is looking at the bar chart on the right which is a different type of rate design where you recover more from a fixed portion on the bill as well as the demand and energy cost to reflect the amount that those customers are using in the system.

So there has been a lot of chatter for those of you who followed in the utilities in Arizona. Or actually, a lot of the states around the US around figuring out how to do an equitable rate design with distributed generation. In our neck of the woods, APS back in 2014 filed for increasing their fixed customer charge for solar customers. They asked for $50, they got $5. So making slow little baby steps. But everybody in that proceeding recognized the issue. Salt River project, they went all in and picked that far right three-part rate design and just implemented that just -- I think it was just last month.

Trico Electric is going at it a little bit differently. They are filing for a net metering change where, instead of a full retail rate credit, you get just their avoided cost and we have followed that up with our own filing related to net metering, which is very similar to Trico's with the exception that we aren't just using our normal avoided cost, which is basically set on a conventional generation, we're using what we call a comparable avoided cost which is the cost of what -- that we can get wholesale solar for right there in our distribution system. And we base that on a recent PPA, which, just for the record, is about $0.58.

Other rate proceedings that we will see, I talked about that pent-up rate demand that has built up over the past couple of years. Part of that will be relieved in the UNS Electric rate filing that we'll be making here month from today as well as TP. We're trying to figure out exactly what our test year will be, but we are working on that through the course of this year.

We have numerous growth opportunities that are not included in that CapEx slide that you saw. So we have nothing in there related to the Clean Power Plan because we don't know what that filing will really look like but that might provide additional investments related to diversifying our portfolio even further.

Distributed generation, we might -- we have that pilot program. We might be able to expand that for utility-owned residential rooftop solar. Of course, distribution investments are going to be big. We have to figure out how to operate our system more efficiently and allow all these distributed resources in the two-way flow that we see out there and provide additional reliability and service levels to our customers as well. Utility scale renewable generation, and of course transmission is always in play, especially related to the Clean Power Plan if there's any additional re-dispatch order to switch from coal to natural gas.

And our top priorities -- our number one top priority whenever you hear me talking is running the best utility that we possibly can. And that's what we call our operational excellence, making sure that our customers are happy and we've got satisfied customers, good customer service. We are providing great safety and reliability not just to our community, but to our employees as well and maintaining cost containment. We have to make sure that we're keeping our product as affordable as possible for our customers.

And of course, we will finish off executing our resource diversification strategies, looking at the Clean Power Plan and its final rule as well as opportunities for replacing an existing coal generation.

We're always looking for economic opportunities, no matter where they show up, and then executing those regulatory strategies, looking at rate design, filing our rate cases, looking at net metering. All of those things are in the queue.

So with that, let me turn it over to Gary Smith who will cover the Eastern Canadian versions.

Barry Perry *- Fortis Inc. - President and CEO*

Actually, we're going to break until 10 o'clock. So, appreciate there's coffee outside and be back sharply for 10 o'clock. Thanks, bye.

(BREAK)

Gary Smith - *Newfoundland Power - President and CEO*

Good morning. My name is Gary Smith and I'm President and CEO of Newfoundland Power. I just had to follow the format that was left before me. I guess my claim to fame with Newfoundland Power is that we are the original Fortis utility. So how is that? And John, maybe you'll have another one to beat that.

Okay, I'm going to start off doing a small geography lesson for you in that the utilities of the Eastern Canadian and Caribbean is spread out through the -- much across the globe as you can see it. There is a utility in Newfoundland, utility in Prince Edward Island called Maritime Electric, utility in Ontario, and two in the Caribbean in the Turks and Caicos and Cayman Islands.

The structure of these utilities I will speak to very briefly. Newfoundland Power and Maritime Electric are vertically integrated utilities. What that means is they have generation, transmission, and distribution assets.

However, the generation assets are somewhat limited and they do buy most of their electricity, they need to service customers from another supplier. FortisOntario, the utility, is a transmission distribution utility which purchases its energy. And utilities in the Caribbean are also vertically integrated utilities, but they produce 100% of the energy they need to service their customers.

These are mainly traditional cost of service utilities. There's 1,400 employees and then there's also some non-regulated generation assets that we have in Belize. Three small hydro plants on the Macal River.

To sort of give you an idea of the scale and the comparability between the utilities, Newfoundland Power is the largest of the five utilities. And then I will bring your attention on the customer side of the slide, where shows that the utilities in the Caribbean are basically 6% plus 3%, so 9% from a customer point of view, but from a midyear rate base point of view, they equal 31%. And again, that's because they have the generators to produce the electricity for the customers and that's why the rate base is a little higher compared to the other ones.

A few regulatory environment highlights. Newfoundland Power is to file a General Rate Application in June of this year. That's likely to be extended because the regulatory agenda is quite busy right now and I'll talk about that later. In Maritime Electric, there is the Energy Accord, which is a five-year arrangement, which expires in 2016. Under the Energy Accord, Maritime Electric's return on equity is fixed at 9.75% and they have prescribed annual changes in their electricity rates.

In Ontario, there's an incentive regulation model. And under that model, there is rebasing every five years, and annual adjustments to electricity rates based on a formula which is really inflation less productivity plus a stretch factor.

In the Turks and Caicos, there is a National Energy Policy being drafted which really focuses on renewable energy, wind, and solar energy. And our license agreements in the Caribbean utilities run very long times, typically 20 years plus.

On the five-year capital slide, of course, like Karl said in the beginning, you tend to see the increases in the beginning years with utility business. In the 2015, 2016, 2017 timeline, the increases in the growth category really come from some additional generation both in Maritime Electric, Prince Edward Island, and the two utilities in the Caribbean. Basically 100 plus megawatts of additional generation for about $160 million and those will be four different machines in those utilities.

The CAGR number is 5.7% and the capital program in these utilities focus in three areas. It's servicing new customers, it's improving reliability by replacing aging assets with stronger assets, and it's also about improving customer service mostly through technology platforms. Things such as additional automation in the substation distribution environment, more computerized work dispatch tools and outage management systems, and addition communication platforms to manage our communication with our customers.

Some of the return numbers for each of the utilities. So this is Newfoundland Power, where the achieved return is consistently higher than the allowed return. Again, a similar thing in Ontario. The achieved return is consistently higher than the allowed return. And in Maritime Electric, the achieved return equals the allowed return, and again, this is a function of the Energy Accord. And within the Energy Accord, the allowed return is pegged at 9.75% and any amounts above the 9.75% are refunded to customers.

A few comments about our non-regulated assets in Belize. It's 51 megawatts of hydroelectric plants. Three separate plants on the Macal River. The output of these plants is sold to Belize Electricity under a long-term power purchase agreement, the earnings contribution of approximately $23 million annually. These are relatively new hydro plants. Hydro plants last 100 years plus. These particular hydro plants are all less than 25 years old.

Just to take a minute to talk about some of the priorities. The first two bullets relate to Newfoundland and Labrador, and to explain those two bullets, I first need to explain the two utilities in Newfoundland and Labrador. So there's a government-owned utility which is primarily the bulk generation and transmission. And then there's Newfoundland Power, which has some transmission, some generation assets we are basically the delivery company the distribution company.

So the first bullet, which really has to do with rate pressures -- the government-owned utility in 2017 will bring online the Muskrat Falls project which is an 824 megawatt hydro plant in Labrador with an 1,100 kilometer line. It's a [$7] billion project. This project, when brought online will put some pressures on rates once you bring the $7 billion investment into the rates to be returned from customers, it will put some short-term pressure on rates.

Then there's the energy supply issue. And again, what this issue has to do with is last year in January, the government-owned utility had shortages in supply to provide to Newfoundland Power. And so, they had some difficulties with their generation on their system. And because of that, Newfoundland Power had 190,000 of its customers off in the middle of January.

The output of that was the regulator put together an investigation of what went wrong. And that continues to dominate the regulatory agenda in Newfoundland.

The third bullet down has to do with our utility in Prince Albert Island and Maritime Electric. It's a new submarine cable. These cables are very important in the reliability of supply to our customers of Prince Edward Island. The cables will be fully funded by the federal and provincial government. And this is similar to the existing cables that are there today that were put in the 1970s.

But from Maritime Electric's point of view, these projects are very important, because again, it's about reliability and supply to our customers. The other thing there for Maritime Electric is the installation of a new 50 megawatt combustion turbine and this is really about managing peak on the system and to provide a backup to the submarine cables.

The last few comments on the priority slides. In Ontario, there's two components to the opportunities, one is distribution, the other is transmission. On the distribution front, I guess the first thing I would say is our utility in Ontario is the only investor-owned distribution utility in Ontario and we've been there since 1996. This provides unique opportunity for acquisitions and mergers in Ontario. The provincial government commissioned the Clark Report in 2014 and the report identified benefits to the industry for consolidation at the distribution level.

So, Fortis is in an interesting position in Ontario with our history, in terms of if the government decides to move in terms of what it may do with the distribution assets in Ontario.

From the transmission point of view, there's a large project in northern Ontario and Fortis with a partner has been identified as a preferred bid in a competitive bidding process. This project is still very much in the early stages and is currently working through some regulatory and government approval processes.

And finally, the Caribbean. The economy in the Caribbean remains very healthy driven, of course, by tourism. And in the 2015 to 2017 timeline, we will be investing about [CAD]110 million in new generation to keep pace with load growth. So thank you very much. I'm going to turn it over to John.

John Walker - *Fortis Inc. - EVP - Western Canadian Operations*

Thank you, Gary. My name is John Walker, I'm the Executive Vice President, Western Canadian operations. My claim to fame as I was the very first full-time employee of Fortis Inc. Beat that. (laughter)

My sphere of influence right now is that I oversee operations primarily in British Columbia and Alberta. And you'll see from this map is that there's several utilities in Alberta. It's an all private area that's not a place with crown corporations, government-owned entities.

In BC, you'll see that we are the predominant gas provider. We have transmission and distribution there. We serve most of the gas customers except about 35,000 up in northern BC.

And you'll see from the hashmarks down in the southern corner here, that's where our electric operations are and we have some overlap of customers down in that particular area.

In Alberta, we serve the province through FortisAlberta. In BC, there are actually two companies. It's Fortis Energy Inc., which is our gas company, and Fortis BC Inc., which is the electric company. They are two separate regulatory -- regulated entities but we have a common leadership that oversees both of those operations as we go forward. But they serve -- when they apply, they apply for two separate rating agencies, ratings and rate bases.

The predominant company there from the electric side would be BC Hydro. They serve about 92% of the customers and we serve the balance from the electric point of view.

As I said, Alberta is a distribution utility. It's a wires only company. And has about 120,000 kilometers of distribution lines. It has a lot of -- a rural part of British Columbia. Sorry, of Alberta, it does not serve the primary urban centers like Calgary, Edmonton, or several of the other big communities that have their own municipals.

In British Columbia, the electric utility is vertically integrated. We have, as you can see, 7,200 kilometers of T&D lines and we own 225 megawatts of hydroelectric generation capacity, which serves about 40% of our energy requirements and about 30% of our capacity requirements directly from our own plants. I will talk later about the total amount of generation -- Hydro generation that we were involved in.

From the gas point of view, we have transmission distribution and LNG storage in some level of liquefaction to support that storage and over 47,000 kilometers of T&D pipelines.

We serve -- at the end of 2014, we served over -- almost 1.7 million customers between the three utilities in Alberta and British Columbia. Our midyear rate base was CAD7.3 billion, which, at the end of 2014, was approximately 50% of our total rate base and that has shifted around -- with the acquisition of UNS. But this is still the biggest part of operation in Western Canada from a Fortis point of view. We have over 3,300 employees.

In the regulatory environment, Karl went through this with a detailed slide up front, but we are under PBR mechanisms in both Alberta and British Columbia. The Alberta PBR runs from 2013 through 2017 and rates are set by formula. And there is a capital tracker mechanism for qualifying capital expenditures. And again, as Karl talked about this morning, we've just received a ruling on that which basically sets up and clarifies our capital mechanisms as we go forward.

In FortisBC, we received a six-year ruling basically covering 2014 through 2019 for PBR. That ruling came out in the fall of last year. It covers annual rate reviews and formula adjustments to revenue requirements. There's an earnings sharing mechanism that starts with the first dollar, 50-50 between customer and shareholder. Our regulatory relationships in both of these jurisdictions are reasonable and basically positive in the general sense.

One of the big stories, if you listen to anything about British Columbia and have any familiarity at all, British Columbia has become synonymous with the letters LNG from the Canadian context. Most of that context tends to be focused on northern BC up around Kitimat and Prince Rupert, where big players -- well known global names, Exxon, Shell, Chevron, Petronas -- all these companies are there. We're talking about very large projects up in that part of the world. They tend to be working on greenfields sites and massive pipelines to bring gas in from the northern -- gas in northern British Columbia and Alberta.

Where we are focused in British Columbia is that we have existing infrastructure obviously within our FortisBC gas operations. We own two LNG plants. Those plants have been around since 1971 in one case and 2011 is the newest plant, primarily set up for peaking and system disruption. So they are slow fill peaking operations, but they are very well-cited. We obviously have transmission infrastructure.

The other part about southern BC is that there are an awful lot of old brownfield sites that used to be pulp mills, logging operations, lumber mills, those sorts of things, and in a couple of cases, petrochemical operations.

We also have the advantage of being approximate to Asia and Hawaii. And Hawaii will come up in a moment. These projects and sites tend to be smaller in nature. Much more scalable, and manageable from a cost point of view and execution risk is a little lower.

We are clearly aligned with provincial government objectives in British Columbia which is really keen to see the development of the gas resources in northern BC. And the real market opportunity is export to drive that demand.

We have -- in our operations, it's very important around First Nations. Aboriginal rights are very strong in British Columbia and we have very positive relationships that go back 100 years just because of the nature of our operations in the electric and gas business where we have a lot of infrastructure working across aboriginal lands.

We are focused on what is basically a low risk tolling model. So it's a tolling plant. We take no commodity risk and we're focused on local and export demand.

The oldest of our plants is at a place called Tilbury. Tilbury is located at the mouth of the -- very close to the mouth of the Fraser River. It's a navigable river with ocean access. This plant has been around since 1971.

The existing plant is relatively small. As I said earlier, it's slow fill, 4,700 MMBtus per day, and the existing storage is just around a little over 0.5 Bcf. We are now in the process, as you can see from this picture, this is the foundation for the new tank, and basically we will expand our storage by 950,000 MMBtus per day. And our liquefaction is going up significantly, 34,000 MMBtus per day over and above the 4,700 that currently exists. We expect that this plant will be in service by late 2016. And all of this is going into our regulated rate base for our gas company in British Columbia of about CAD450 million -- CAD440 million that's currently included in the forecast.

The demand for this project has really been driven by regional demand requirements. We've moved into the transportation sector. We are seeing good growth in that, and we've also seen some growth in terms of remote communities for demand in terms of Yukon in the northern territories and those sorts of things. So it's an opportunity to deliver into that opportunity.

The second phase what we call 1B, talking about our scalable opportunities in LNG. This opportunity is to add an additional more liquefaction and no storage at this space is what we are currently looking at. It will be 133,000 a day of additional liquefaction. This would be also included in rate base, the estimated cost is CAD450 million. This has been basically directed through the provincial government to enable this to be -- our economic regulators, the British Columbia Utilities Commission, this has directed the Utilities Commission that this will be included in rate base as we move forward. So it's a way to expedite the process and the decisions that we are going along. And again, it goes back to the alignment with the government's broader agenda around gas and LNG specifically.

In order to enable this construction to start, it requires a long-term fixed contract for up to 70% of the liquefaction. Excuse me, and right now we have a conditional contract with Hawaii Electric that would meet these requirements. The primary condition right now is getting us through the regulatory approval process in Hawaii.

Tilbury, the actual site a Tilbury is larger, again, is a 35 acre site. As you can see from the schematic, we can put significant new storage on this site, and there's an opportunity for additional buildout for up to 300,000 a day of additional liquefaction. It would triple the total -- just about triple the total amount of output to 3.3 million tons from just under 1 million tons if we do a 1A and 1B. This site is zoned for LNG and has been in operation since 1971, as I said earlier, so we have a long history of operations in this particular location.

Again, continuing with the theme of LNG, but this is with an opportunity to serve a customer that wishes to build. They are looking to build an LNG plant, a smaller scale LNG plant, in what we call the Woodfibre site. This is actually again in the lower mainland. For any you have folks who have never skied in Whistler, this is going through Squamish, and it's just across the broad inland, just across from Squamish. Our opportunity here is to build additional compression and pipeline capacity to serve this plant. We are expecting to make final investment decision by December of this year with an in-service date in late 2018 or early 2019.

The estimated rate base addition, again, it's a rate base opportunity, is approximately CAD600 million and that is not currently in the forecast. This pipeline, again, was approved by what you would know as Executive Order. The provincial government stepped in here to support this facility and to ensure that timelines and delays to the regulatory process were not part of impeding this company's ability to move forward with the decisions to construct.

So, translating just a little bit, without Tilbury 1A -- or sorry, 1B, or the Woodfibre site, our operations in Western Canada are looking at approximately CAD800 million a year of capital expenditures, as you can see from this graph, for a total of about CAD4.3 billion over the next five years. As we look into what the opportunities could be if Tilbury 1B were to go ahead and Woodfibre were to proceed, we can see that those capital expenditures increased to CAD5.4 billion, or approximately CAD1.1 billion per year on average, so a significant opportunity. When we translate this into CAGR growth based on just our base case, we are seeing pretty good growth at 6.8% from 2014 through 2019. Most of this capital is highly executable and basically either were in progress or certainly approved to move forward. The CAGR growth increases quite substantially to 8.8% if we are able to get these other two projects moving in the time frames that we've been discussing.

The next three slides will really just talk a little bit -- you have seen this through some of the other forecasts about allowed versus achieved ROE. The first was FortisBC and our gas operations, and the trend you'll see that's consistent amongst all three utilities is that we've been able to consistently meet or exceed our allowed rates of return. Again, FortisBC Electric, and finally, when we look at it from the point of view of FortisAlberta. FortisAlberta has been benefiting over the last several years with the tremendous growth out there and an opportunity and having operated under PBR, they have been able to capitalize on that through 2013 and 2014 as demonstrated by these returns.

Barry mentioned earlier today about the Waneta expansion project. As this photo will show, what you see in the lower part of this photo is the expansion project. Adjacent to it is a plant called the Waneta plant. It's been in service since 1957. It's owned by Teck Resources and BC Hydro in partnership.

This Waneta expansion is a two-unit 335 megawatt hydro plant. The estimated cost on this plant is CAD900 million. It's 51% owned by Fortis Inc., so that makes it a non-regulated project. The other 49% are owned by two local quasi-government agencies, Columbia Power Corporation and Columbia Basin Trust. This plant has, while it's not regulated, has all the earmarks of regulated in terms of we have two 40-year power purchase agreements, one with BC Hydro for the energy offtake and the other with FortisBC Electric for capacity offtake. This plant is currently on budget and we are hoping a little ahead of schedule. We expect to go operational over the next few days. It started construction in October 2010.

When we complete this plant and build it in our portfolio, because it will be owned and operated by our FortisBC Electric subsidiary, we have over -- we will have over 1,500 megawatts of hydro generation that we either own and/or manage for third parties. So we are a very significant hydro operator, and several of those plants we actually take all the power from to serve our regulated electric entity.

When I look at the top priorities right now, obviously regulations are always at the top of the list in our regulated entities. Basically it's the PBR environments. We continue to manage in that. We just entered into this from a BC point of view. We have to continue to manage through it in Alberta.

We have cost of capital filings coming up for the years 2016 and beyond that will affect our utilities in Alberta and BC. All of them will be in that form as we get through later this year, making filings. A big part of it is to make sure we get Waneta commissioned and operational, so we do the run-in and work-up on that particular plant. It's a significant contributor to Fortis as we go forward. And the next really big part of it is how do we capitalize on these LNG opportunities either directly through our Tilbury site or through the opportunity to serve a major project at the Woodfibre site in Squamish.

And with that, I'll turn it back to Barry.

Barry Perry - *Fortis Inc. - President and CEO*

Thanks John. And we are on time, which I'm very impressed with.

So, just to wrap up, why invest in Fortis? Hopefully you've learned much more about our company over the course of the morning. Our focus is really on the low risk regulated utility business, and also on I would say long-term contracted energy infrastructure, looking at all of our franchise locations, trying to find opportunities to use our footprint to find more investment possibilities. And you see some of that especially in John's work in Western Canada.

We do have tremendous geographic and regulatory diversity across our group. We have I think some of the best experience management team in terms of dealing with regulatory matters in North America. I'm very proud of the team we have, and we always believe that that regulation part of our business will be front and center.

As you can see, we do have a pretty robust organic growth platform in our rate base, CAD9 billion of CapEx in our base plan, and possibly CAD10 billion when you include these other couple of projects that John is working on in Western Canada.

We do believe our utility acquisition model is very much now proven in North America, our sort of approach to owning substantially autonomous regulated businesses. And we have nine jurisdictions now, so we believe that regulators support our approach. We are a small head office, keeping operations local. And we do have I think positive discussions with regulators as we look at other potential opportunities.

The Company has got a strong balance sheet, as evident by the A low credit rating of the Corporation. There's only handful of utilities, especially holding companies like Fortis, that have that high of a credit rating in North America. Our approach is we like that A low rating. We like our large businesses to be in the A category and that's what we've achieved. When you see the ratings upgrades that our utilities have gotten post-post-Fortis buying them and from a credit perspective, that's very positive regulators like that.

We are very proud of our dividend record. We've increased it for 42 consecutive years. We believe our business plan over the next five years gives us ample opportunity to keep increasing that dividend. And that is a very important aspect of our sort of business model.

So, that summarizes our presentation this morning. We're going to open it up for questions for about half an hour here, and we will start. There's a microphone that we are trying to hand around. It might take a minute or two to get it over to you, but I think we will have one person in front, one in the back. So go ahead. Annette is bringing you a mic there. This is audiocast, so we are trying to have everyone who's listening in hear the questions.

QUESTIONS AND ANSWERS

Unidentified Audience Member

Hi, good morning. Just two questions. The first one is just on a potential Fortis listing in the US, what you are thinking on that. And then I have another question on that.

Barry Perry - *Fortis Inc. - President and CEO*

It's a discussion we continue to have. We've done a lot of homework on it. We've been on the Toronto Stock Exchange for a long time. It's pretty easy to buy the stock there. But we know that being on the New York Exchange is important. We will likely make a decision I would think before the end of this year on whether we will list or not.

Unidentified Audience Member

And again, it would just be as Fortis, not kind of like an [image roller] type of --

Barry Perry - *Fortis Inc. - President and CEO*

No, it would be Fortis Incorporated. We would have a dual listing similar to, say, a TransCanada or an Enbridge that are Canadian-based businesses with substantial US assets. They're listed both on Toronto and New York.

Unidentified Audience Member

And then just as far as the makeup of the Company going forward, I think you talked about -- I don't want to put any words in your mouth -- but kind of how much is Canada, how much is kind of outside of Canada, how much is US. Can you kind of talk about what your aspirations are there if you're kind of where you want to be or whether you want to grow a certain part bigger or get more even with let's say what you have in Canada. And then one follow-up to that.

Barry Perry - *Fortis Inc. - President and CEO*

In terms of ownership percentages of assets by country, I don't think it drives our business planning. But having a scenario over the next 5 to 10 years where Fortis would be half US, half Canada for example, I don't think is unrealistic, but it doesn't drive -- we are not sort of setting things up to make that happen.

Most of the opportunities from an acquisition perspective that we are pursuing, or the ideas we have, are US-based. There's just more opportunities. Most of what's left in Canada is owned by governments, and we don't see privatization as a thing that's going to be -- that is going to happen a lot over the next decade for example in Canada.

Unidentified Audience Member

And what is the landscape right now in the M&A market here in the US? Anything that you feel comfortable telling us? And then also what is your kind of digestion period if there is one?

Barry Perry - *Fortis Inc. - President and CEO*

I would say just general thoughts about the M&A market, there's been consolidation in the industry in the US. We are down now to 40 odd investor-owned utilities remaining. Only a few of those make sense for Fortis. Some are very large; some are very small; some are in multiple jurisdictions. These are the ones we are not interested in, so it's just a handful of companies. But I think, over a reasonable period of time, we'll probably have another look at one of those.

In terms of digestion, we do want to make sure that the integration of the utilities that we have acquired goes well. I think, because we benefited from strong management teams in place in those businesses, we're basically near done, done in New York and near done in Arizona. So we haven't put any Fortis people from what I call the prior business into these businesses. We have inherited the management teams that are in place and we are very happy with their performance. That model is our model, and so that helps with integration obviously. So we are really just about done on that at this point.

Unidentified Audience Member

A question for John. On the recent Alberta return on equity decision, I just wanted to know, maybe you don't have immediate impacts on you of that, given your rate plans, but how you see that affecting your results going forward and how you might manage that lower ROE.

John Walker - *Fortis Inc. - EVP - Western Canadian Operations*

Obviously, the lower rate of return is reflective in many ways of the sort of the interest rate environment that we find ourselves in. In terms of the immediate impacts, I think we will continue to perform very quite well, given that our performance-based rate environment. I think as we move down the road, if this were to hold, again, this goes back to 2013 through 2015, and we have to now refile for 2016 and beyond as I said earlier.

Karl Smith - *Fortis Inc. - EVP and CFO*

Let me jump in there as well Nancy. The nature of the PBR regime in Alberta is such that not all the revenue is affected by that decision. The capital tracker mechanisms are affected by that decision, but the revenue is associated with ongoing operation and maintenance because it's formula-driven based on an inflation factor, doesn't directly get affected by the lower ROE. So we estimate probably about 75% of our revenue was not directly impacted by that decision. Obviously, if you go far enough into the future and rates are reset, then it would be affected at that point in time.

Unidentified Audience Member

Do you see that decision bleeding over into other provinces?

Karl Smith - *Fortis Inc. - EVP and CFO*

I'd love to say no to that, but that's probably a bit naive.

Barry Perry - *Fortis Inc. - President and CEO*

We will go back to the slide that we had about the difference between Canada and the US, this sort of Canada being may be 100 basis points lower in ROE and 10 points lower on equity. I think that's going to continue, that scenario. 8.3% in Alberta, I would hope that's the low watermark in terms of -- that's the latest cost of capital decision that's out there based on the events that are in the market over the last year or so in terms of interest rates, and so hopefully that's the low watermark.

Unidentified Audience Member

Do you do some interest-rate hedging, for example, to adjust to the lower rates as they come into play?

Barry Perry - *Fortis Inc. - President and CEO*

We don't do hedging like that. In terms of -- the only area we look at or think about hedging is the relationship between our Canadian assets and US assets. We tend to naturally hedge by issuing capital in US dollars at the Fortis Inc. level in terms of debt capital, and that creates a bit of a natural hedge against our US exposure.

But from an interest rate perspective, the cost of debt at the utility level gets quickly built into rates anyway. And our customers in Canada have been benefiting from tremendously low interest rates as we build out the infrastructure that we've done in each of our jurisdictions.

Unidentified Audience Member

And then just one question for James, talking about the transmission and with electric and gas potential projects in New York. There's a lot of NIMBY obviously in the Northeast. And how are you -- do you have condemnation rights or how would you deal with that potential delay to your projects?

Jim Laurito - *Central Hudson Gas & Electric Corporation - President and CEO*

Great question. It is getting increasingly more and more difficult to build infrastructure out. But part of our geographic advantage is that we have a lot of rights-of-way that exist already, so the electric transmission projects we proposed fall within existing rights-of-way. They don't have to be widened and the structure heights are very minimal compared to the existing, so very low aesthetic impact there. In the gas pipeline project that we are considering, about 95% to 97% of that route would be on currently disturbed corridors, meaning electric or gas rights-of-ways. So again, we think those are advantages that FERC would really favor when they review any project that we put forward.

Unidentified Audience Member

Good morning. Just a few quick ones, and I apologize if these are kind of basic but I'm not that familiar with Fortis. Just in general though, when we look at Slide 17 and the debt and equity ratios that you guys provide, does the 34% common equity include goodwill? I think you guys have about CAD3.7 billion in that. Is that --

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Barry Perry - *Fortis Inc. - President and CEO*

Yes, that's the consolidated equity in our capital structure, so that would include the financing of the premium, which is the goodwill that we've picked up as we acquire utilities. Most of that premium has been financed with a combination of equity and pref shares, a little bit of debt but mostly with equity.

Unidentified Audience Member

Okay, I got you. And then with respect to just the treatment of goodwill in Canada, or I guess in the US, but is there any rate base -- excuse me, is there any -- you don't run on goodwill in Canada or the US, correct?

Barry Perry - *Fortis Inc. - President and CEO*

First of all, we are under US GAAP. We use US accounting in terms of our -- but the treatment is the same. We don't earn on the premium that we've paid to acquire businesses.

Unidentified Audience Member

Okay. And then in terms of the acquisition, just to follow-up on Andy's question, you mentioned 50-50 but that's not determinative. It's just you could see that happening. So what if there was an opportunity, just hypothetically, in which there was something that was in the US or something that was a game changer, so to speak? You guys have been very successful in M&A. Would you -- is there anything that would stop you from perhaps getting a little bit larger if there was an attractive acquisition? I'm wondering just to get a little more color.

Barry Perry - *Fortis Inc. - President and CEO*

I think the answer is no, there isn't. Obviously, we have to make sure it works for our company. We assess the jurisdiction. Hopefully we could create an accretive transaction to our shareholders. That's important. And there's no impediment. There's no -- we would be highly confident that we could get regulatory approval given our approach to the business, and so no, there isn't.

Unidentified Audience Member

Okay. And then just finally on the LNG deal in Hawaii, any idea about when that might be finalized? If you could give us a little more flavor.

John Walker - *Fortis Inc. - EVP - Western Canadian Operations*

The latest that we have from them is that we would expect that they would get through regulatory approvals by midyear next year, 2016.

Unidentified Audience Member

Okay, so that's when it would be finalized. Because that seems like it slipped a bit. Am I --

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John Walker - *Fortis Inc. - EVP - Western Canadian Operations*

Yes, it has slipped a little bit. Obviously, the acquisition with NextEra has gotten into the agenda a little bit as they review their process and they're trying to understand some things. But they are still very committed to an LNG solution.

Unidentified Audience Member

(inaudible - microphone inaccessible)

Barry Perry - *Fortis Inc. - President and CEO*

NextEra, I don't know if you guys are all aware, that they announced the purchase of HICO and they're going through an approval process in Hawaii to have that transaction done. Obviously, our arrangements were in place prior to the announcement of that project, so that now becomes part of the overall process basically in terms of the deliberations with NextEra, the commission in Hawaii, that it's not -- I don't think it should be unexpected that such a big initiative would become part of the strategy discussion between NextEra, HICO and the commission in Hawaii at this point in time.

Unidentified Audience Member

How much has FortisAlberta benefited from oil drilling there and are you seeing a decline in activity?

Barry Perry - *Fortis Inc. - President and CEO*

Karl or John? So you know, Karl ran FortisAlberta for seven years. He came in as CFO mid last year with my appointment as CEO. So I'll let Karl give you his sort of detailed understanding of how oil impacts our operation in Alberta.

Karl Smith - *Fortis Inc. - EVP and CFO*

It's difficult to assign a specific number to the question, but we have owned FortisAlberta for 10 years now. And the average rate base growth over that period of time is approximately 15%. As John described the geography of Alberta, a lot of the drilling, especially the new horizontal drilling and fracking, is in our service territory. So, over the last seven, eight years, that's been a big driver of our growth in Alberta.

More recently, obviously with the price of oil dropping down to where it is, there has been a slowdown and we are seeing some indication of a decline in the growth rate. We are still hooking up new customers, but I think, so far this year, the rate of new customer growth is about 30% off what it was last year. It's anybody's guess from here out as to what the length of that impact will be, but even at that rate, there is still a significant growth rate in experience in Alberta, but it certainly wouldn't be anywhere near 15% that we've experienced through a vendor.

Barry Perry - *Fortis Inc. - President and CEO*

And I will mention that our Alberta system is a very large network. We have over 1 million poles in our territory there. And one of the capital projects Karl mentioned was the sort of pole replacement program. That size of system requires a significant level of CapEx just to maintain it at the right standard. So we are still going to see growth in Alberta. It's just not as hot as it used to be.

Robert Kwan?

Robert Kwan - *RBC Capital Markets - Analyst*

I know it's early days in New York and especially Arizona, but just do you have some early feedback from the regulators about the clean approach you've taken on the regulatory front, examples not trying to jam rate payors with the corporate overhead cost?

Barry Perry - *Fortis Inc. - President and CEO*

I would say, Robert, we've ended up in a really good spot. Now the regulators in both jurisdictions don't see me. They don't see the head office folks. They are dealing with the local team, and that's how it should be.

Clearly, we were involved in the approval processes. We made commitments to obtain approval. We've delivered on every one of those and we have ensured that our local teams have done that. And I think that's satisfied what we needed to satisfy. And so our relationship in both these jurisdictions is positive at this point in time. And I think it will bode well as we think about where Fortis goes next over the next number of years in the US. We could call upon these jurisdictions as support for our approach. I'll give you an example.

In Arizona, the commission consumer advocate called New York. He didn't call Canada. We've been in Canada operating for 130 years, but they called New York and said how are these guys doing? You just closed the deal about a year ago and are they delivering on everything? And the answer was I think, yes. Because they didn't put any evidence to suggest otherwise. So having that local knowledge in the US about our model and our approach as we go forward from here is just going to add to our success, in my view.

Robert Kwan - *RBC Capital Markets - Analyst*

Just a follow-up on Alberta generic cost of capital. You touched on the base business not being impacted and that it will impact the K factor. Are there any other parts of the decision or other parts of the business as it relates to things like off ramps or earnings sharing?

Karl Smith - *Fortis Inc. - EVP and CFO*

No, there wasn't anything else affected. The one other thing you need to notice, Robert, was the common equity component dropped by 1 percentage point, so we're down to 40% in Alberta. Obviously, that's a slight negative, but everything else remained intact.

Robert Kwan - *RBC Capital Markets - Analyst*

But just in terms of -- so the 1%, is that -- that's K factor. Does it impact the base business? And then just with that lower ROE, does it change the thresholds is kind of what I was getting at.

Karl Smith - *Fortis Inc. - EVP and CFO*

No, I don't think -- it doesn't change the thresholds, or very immaterially if it does. And again, it doesn't affect the base business. It does affect the capital tracker applications that will be made on an ongoing basis because the cost of capital that's applied to those capital expenditures will be based on the 40% and the 8.3%.

Robert Kwan - *RBC Capital Markets - Analyst*

Thank you.

Barry Perry - *Fortis Inc. - President and CEO*

Back to the front if there's no one in the back.

Unidentified Audience Member

Thanks. For New York State, just with the Energy Highway and your transmission investment, I know there's been some debate around what that ROE should be. I think there's some concerns in New York as far as a FERC-regulated ROE. So maybe you can just expand on that and where you think that's going and where we kind of stand with that right now.

Jim Laurito - *Central Hudson Gas & Electric Corporation - President and CEO*

Right. As I said, we've already filed the first three projects at FERC, and we filed for a FERC regulated return with some incentives. Strategically, our point of view, and it's really core to the strategy at Central Hudson, is that any ROEs we will receive at FERC will be as good or better than state, and that's part of the diversification strategy. So we are not really too fixated on exactly what ROE we will get out of FERC. I think we will do fine there. Certainly, it could be challenged as they have done in New England, but on balance, I think we're going to do just fine.

Unidentified Audience Member

Is New York State okay with it being FERC-regulated? Isn't there some debate on that or am I mistaken?

Jim Laurito - *Central Hudson Gas & Electric Corporation - President and CEO*

They are okay with it being FERC regulated because they still retain citing jurisdiction in New York, so they are not giving up the rights for citing. They understand that this is bulk electric transmission and that it certainly falls within the FERC jurisdiction. But they can weigh in, and they have regarding some of the details around ROE as an intervener at FERC. So they will have an opinion, they will have input, but they clearly understand that the Energy Highway work is bulk electric transmission.

Barry Perry - *Fortis Inc. - President and CEO*

And is not being done in our utility central Hudson gas and electric. It's a separate entity that is the partner of the New York Transco. So I know some jurisdictions in the US use the extra return, like in Vermont I believe, the lower distribution rates. That's not what we are anticipating in this jurisdiction.

Unidentified Audience Member

And then just in Arizona, are there any -- I know Pinnacle is trying to build a line with AIX California and Arizona. Are there any transmission opportunities for you? And do you have any FERC regulated transmission? I'm not familiar.

David Hutchens - *UNS Energy Corporation - President and CEO*

Yes, we do have FERC regulated transmission about right around CAD400 million in TEPs rate bases as regulated by FERC. No big projects on the horizon that we are looking at. We're finishing up that one that we mentioned today that allows us more import capability from the Palo Verde generation hub, where most of the merchant plants are. Nothing near-term on our horizon. That being said, what's going on with the clean power plan will be the biggest driver. When you look at our state, all the coal plants are on the side of the state. All the natural gas plants are on this side of the state. Those natural gas ones are the ones we don't own, so we don't have transmission to them. The ones in place that we do have transmission rights to are those existing coal plants. So any drastic change in our mix of coal and natural gas will necessitate the need for import capability and transmission infrastructure in our state.

Unidentified Audience Member

Just to follow-up in New York, I think you guys mentioned that obviously there's a big constraint that's in the lower Hudson Valley. And it's somewhat political, and I think you guys are familiar with that pretty much. But I'm just wondering. With all this -- with the potential of you guys investing in transmission stuff, what do you see happening to that constraint? I know you guys don't benefit necessarily directly from the wholesale market but obviously it's an issue that your customers are impacted and obviously might give you guys some relief on rate increases and what have you in your own area. So just what do you see in the next two, three, five years in terms of what that basis -- that constraint -- how much do you see that changing?

Jim Laurito - *Central Hudson Gas & Electric Corporation - President and CEO*

I think it could change dramatically. I think, first, if you step back, FERC's action on implementing a new capacity zone has been under consideration for several years. And while it's not public, we think our intuition tells us that they were waiting for New York to build transmission, because they know transmission is the solution to relieving that congestion and alleviating the need for a new capacity zone.

So, what we think will happen once we build transmission is prices will begin to converge, and eventually that new capacity zone will be eliminated. And we have argued that point both in state and federal filings, so that we ask the ISO to actually put an off ramp in to define how that capacity zone could wind down eventually. They haven't done so yet, but we see transmission alleviating the need for that eventually.

Unidentified Audience Member

Any quantification on time, or when we might actually start to see a decrease in that capacity? When do you see that happening I guess is what I'm trying to figure out, and just how much, sort of how quickly could we see that?

Jim Laurito - *Central Hudson Gas & Electric Corporation - President and CEO*

I think the short answer is over the next several years because, strictly because of the time it takes to build transmission. So our first three projects that we've put into FERC we are hoping to receive approval on in December of 2015. And if we do, then we will start the citing and build process. So you're still looking at three or four years down the road.

I think one important point to mention is that, through the actions of Central Hudson already, we have reduced the impact of the new capacity zone for our customers in our service territory by about 50% through actions that we took with the ISO and the state PSC and FERC to get the Danskammer generation plant operational again. So that plant, as you know, was bankrupted under Dynegy, changed hands, was scheduled to be demolished, and then redeveloped -- the site redeveloped. But we saw an opportunity to bring that back into the market and assist the new owner in doing so. Having done that, we have essentially reduced the impact on our customers from what would have been about CAD100 million in additional supply vis-a-vis capacity costs per year, so already down to about CAD40 million to CAD50 million. So we've mitigated almost half that. Transmission we think will take care of the rest.

Barry Perry - *Fortis Inc. - President and CEO*

Any other questions? To the right.

Unidentified Audience Member

Just a quick follow-up on Arizona. What are you seeing in terms of load growth? Pinnacle West, for example, your competitor, says they are seeing modest load growth. If you look year-over-year, it's kind of flattish. What are you seeing in that part of the service territory?

David Hutchens - *UNS Energy Corporation - President and CEO*

We are seeing modest customer growth. And what we have in those slides, it goes from just under 1% this year to upwards maybe 1.2%, 1.3% in the further out years. Now, that customer growth is offset by things like energy efficiency and distributed generation, and so we are seeing just a very moderate or modest load growth over the next few years. Now, that's not to say that we are not still making investments. That just reiterates the needs for change in the rate design because that load growth and those customers that we are adding are still requiring the infrastructure needed to serve them. So it becomes more of a question not necessarily at looking solely at KWH type growth numbers, but looking at customer and infrastructure and rate base growth numbers, getting the rate design right, and getting that pushed through the commission.

Barry Perry - *Fortis Inc. - President and CEO*

Any other questions? In the back.

Unidentified Audience Member

I guess, on the transmission front, do you have any near-term desires to participate a little more broadly in some of the FERC Order 1000 opportunities across the states?

Barry Perry - *Fortis Inc. - President and CEO*

I would say no. We are really focused in the jurisdictions we operate in Arizona, in New York. If there are opportunities in those jurisdictions, we will be all over them. But we are not looking at going to a state that we don't own a utility in and just trying to invest in transmission. Up in Canada, the same thing. In Ontario, we are looking at some opportunities in transmission, but it's really because we have people on the ground that understand the jurisdiction and pursuing those opportunities. So, that's our model.

Unidentified Audience Member

Then just one quick clarification. On the need or the lack of need for new equity, does that include the LNG facilities?

Barry Perry - *Fortis Inc. - President and CEO*

If we are successful on the new facilities, we will have to do a little bit of equity to finance those, but that will be a great story.

Anything else? Thank you very much. We are very appreciative of your attendance and the questions. And if you want any follow-up, obviously call Karl or myself, any of the team members, and we'll be happy to answer your questions. Thank you very much.