EDITED TRANSCRIPT

Q1 2018 ATCO Ltd. (TSX: ACO.X, ACO.Y) and Canadian Utilities Limited (TSX: CU, CU.X) Earnings Calls

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Q1 2018 Earnings Call

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OPENING COMMENTS

Dennis DeChamplain *ATCO Ltd. and Canadian Utilities Limited – Senior Vice President and CFO*

Good morning,

Before we start with your questions I just want to take a couple of minutes to make a few opening remarks if that's alright with you.

As usual, Anthony Maher, Katie Patrick and Myles Dougan are with me today.

We had a really busy quarter on the capital investment side of things. ATCO invested $772 million in capital growth projects in the first quarter. 98 per cent of this capital was invested in assets that earn a return under a regulated business model or are under commercially secured long-term contracts. This amount includes $112 million for the acquisition of our long-term contracted, 35 MW hydro power station based in the state of Veracruz, Mexico. We also invested $250 million in our regulated utilities.

But the largest portion of our capital was invested in Alberta PowerLine for the 500 kilometre Fort McMurray West electric transmission line. We invested $368 million in this project in the first quarter, which generated higher earnings for this business under service concession arrangement accounting. The robust capital activity on APL was mainly due to land preparation, tower foundation installation and tower assembly proceeding ahead of schedule. The target energization date of June 2019 remains on track.

But the quarter wasn't without its challenges. We recorded lower earnings in large part from the rate re-setting process in the PBR distribution utilities and in our electric transmission business. The regulatory environment incents us to find cost improvements and we were successful in doing just that in the last PBR period for the distribution utilities and in the last GTA period for electric transmission. Over time, as we become more efficient and lower costs, our customers get the benefit of these efficiencies that flow into customer rates. However, that means our earnings also reset when we enter a new rate setting period, which is where we are today. But we're confident in our ability to find new and innovative ways to implement additional cost savings in the future - not just in the utilities, but in all of our businesses.

In our unregulated businesses, we remain busy looking for new growth opportunities in select global markets. In Structures & Logistics, we negotiated a contract extension for the LNG Modular Structures project in Louisiana. The original 29-month contract for 1,900 beds was coming to an end next month, but we renewed the contract for 750 beds to the end of 2018 with an option to extend the contract to April of 2019.

Structures & Logistics is also building a new manufacturing facility in Santiago, Chile. We expect that the new facility will be operational later this year. This step further cements the business foundation we are re-establishing in South America.

This quarter, we also announced a new long-term contract to build and operate a 26-megawatt cogeneration power plant in the state of Durango, Mexico.

Closer to home, in our Power business, we completed work on our Battle River unit 4 coal power plant to enable the unit to co-fire with natural gas. Natural gas can now be used as the fuel to generate approximately half of the unit's 155 MW total electricity generation capacity. This will both lower the overall emissions from the plant and allow it to be a more competitive merchant electricity generator in the developing Alberta power market.

And in our storage business this quarter, we completed construction on the last two of four long-term contracted hydrocarbon storage caverns near Fort Saskatchewan, Alberta. This which will double our storage capacity to 400,000 cubic metres.

In all, we have been busy in these first few months of 2018. We will continue driving forward to find innovative ways to generate new business, in new markets, while staying on the path to lower our overall cost structure.

Now I’m sure you have some specific questions so I will turn the call back to you.

QUESTIONS & ANSWERS

Regulatory Developments

In the Regulatory Developments section of the MD&A under Utility Asset Disposition, what is meant by the recovery of prudently incurred costs?

Prudently incurred costs are costs that have been scrutinized in a public proceeding and found by the regulator to have been spent prudently (reasonable decisions were made in light of the circumstances known at the time). Once costs pass the prudence test, they are to be recovered from customers by including them in rates as established in the Electric Utilities Act and Gas Utilities Act.

How might the recovery of prudently incurred costs be amended under the Government of Alberta's recently proposed Bill 13?

The discretionary powers created under the Alberta Utilities Commission Act, or AUCA, override the prudent cost recovery protections in the existing Electric Utilities Act and Gas Utilities act. The AUCA prevails where there is a conflict or inconsistency between it and the Electric or Gas Utilities acts. This means that the investor protections found in these acts that ensure the reasonable opportunity to recover prudently incurred costs can be overridden at the discretion of the AUC under the proposed clauses of the AUCA.

What is the issue you have with the language in Bill 13 about utility asset dispositions?

Bill 13 treats the sale of surplus assets the same as the sudden destruction of assets, for example by wildfire or floods or ice storms. ATCO's concerns relate to uncertainty created for the cost recovery for prudent investments and retroactive ratemaking, not to the treatment of surplus assets when they are sold.

What is the problematic language about retroactive ratemaking in Bill 13 that you are referring to?

Bill 13 includes language that grants the AUC the ability to deny the utility full recovery of its costs, including capital investments, that arose in a prior period, whether or not rates have been finalized for that period.

What do you mean by Bill 13 gives "the AUC the authority to make decisions on a case-by-case basis"?

Bill 13 does not set out any principles or a policy framework for the AUC to follow, rather it grants full and unfettered discretion for the AUC to make decisions on dispositions and on cost recovery for assets prudently invested in. This lack of policy direction is what gives rise to regulatory uncertainty.

What are the next steps in the process?

The second reading of the bill is expected in a week or two. We are in discussions now with the Government of Alberta regarding recommended changes to the current draft bill.

What levers to do you have at your disposal to achieve better than the regulated approved ROE in PBR2?

In the first couple of years of PBR2 we are unlikely to make the same levels of ROEs we made at the end of PBR1 because we are now passing substantial operating cost savings onto customers.

The main change we see is the re-setting of O&M costs to the lowest O&M costs in any year between 2013 and 2016, which was 2016 for us. That lower deemed revenue for O&M expenses in PBR2 has had a material impact on our Q1/18 earnings.

That said, we are confident in our ability to find productivity improvements and earnings enhancements. Our ROE track record certainly shows that we have successful in achieving better than approved ROEs both in the cost of service regime and in PBR.

PBR is set up to incent us to find efficiencies, and we have been able to do that and will continue to work on finding efficiencies which is good for our shareowners and good for the customer.

We will leverage innovation and technology in order to keep lowering costs. We think we can continue to provide additional cost savings through continued IT improvements, procurement improvements, and the centralization of administrative activities.

The productivity factor in PBR 2 of 0.30% is less than in PBR 1 at 1.16%, which means the offset to the inflation factor is lower. That means that operational improvements and efficiencies have a larger potential impact on the bottom line.

We also get a 50 basis point add to our base ROE for the second generation of PBR for 2018 and 2019 because of our success with the first generation of PBR. That will be helpful to earnings out of the gate in PBR2. Not all of our Alberta utility peers received this 50 basis point incentive.

Finally, regarding capital, the revenue calculation for return on and return of capital is based on average capital spent during 2013-2016 (or approximately $300 million per year per utility). To be clear, we make our capital investment decisions with providing safe and reliable service to our customers. With that being said, if we invest less capital in PBR2, we actually have the potential to improve earnings for our shareowners, at least during the current PBR period. For example, if the approved capital spent was approximately $300 million per year, spending $250 million would result in potentially making about $2 or $3 million per year more in adjusted earnings in the first year of PBR2. The calculation would be $50 million times 37% equity thickness times 8.5% ROE.

What is the latest update on the timing of the various regulatory proceedings under way?

The current General Cost of Capital or GCOC proceeding will establish the capital structure and return on equity for 2018, 2019 and 2020. The hearing stage has ended now and we have written arguments to file and reply. We expect a decision in 2018. In its current form, Bill 13 creates additional uncertainty for the utilities and raises business risk. We are in discussions with our Alberta utility peers about how Bill 13 may require re-opening of the GCOC proceeding. And as we discussed, the second reading of Bill 13 is expected next week and we are in discussions with the Government of Alberta regarding recommended changes to the current draft bill.

For electric transmission, the hearing for the 2018 and 2019 General Tarif Application will probably take place in the third quarter of 2018. So we'd hope to the record the impact of the decision in the fourth quarter of 2018.

For our gas transmission utility, we expect to file our 2019 and 2020 General Rate Application in the second quarter of 2018.

Electricity

Could you provide insight regarding the decrease in adjusted earnings for Electricity Transmission?

About half of the quarter over quarter decrease in adjusted earnings for Electricity Transmission is due to entering a new period for the General Tariff Application, with the other half primarily resulting from lower interim rates approved by the Alberta Utilities Commission. We will true up our earnings once we receive the final decision on the application.

Do you plan to participate in the next Renewable Electricity Program auctions in Alberta?

On February 5, 2018, the Government of Alberta announced the next two auctions totaling 700 MW; one for 300MW and one for 400MW.

REP 1 was highly price competitive which gives us reason to be cautious going into these auctions and we think looking for other advantages in the auction process is the way to go.

For example, the REP2 400MW auction will have an indigenous participation component, which we think is promising, and is an aspect of our business culture we consider a strength. These kinds of qualifying features may present some additional opportunities for us to work with indigenous groups on some proposals for REPs in the future.

It looks like the 300MW REP 3 auction will be structured similar to REP 1 making wind as the most likely successful technology.

What are your thoughts on the second version of the Alberta Capacity Market?

The Alberta Electric System Operator (AESO) released the second version of its Comprehensive Market Design for the capacity market on April 24, 2018. The capacity market design remains a work in progress, with the potential for changes up to the planned release of the final market design in mid-2018.

The latest market design signals some positive movement with respect to the availability and penalty framework and determination of capacity values. The capacity commitment period remains one year, with a three year forward period. We will continue to evaluate the details and to work with the AESO and market participants to refine the design. Generally, though we see the current capacity market design as favoring incumbent electricity generators.

What was the capital expenditure related to the co-firing of Battle River 4 and how will you use this facility?

The capital expenditures to convert Battle River unit 4 to a co-firing unit with natural gas was minimal. We already had an existing natural gas supply line and just had to change some of the burners in the unit. It will be a mid merit unit that we will look for market opportunities to dispatch.

When do you expect the turn back of the Battle River 5?

We're in discussion with the Balancing Pool about the turnback, and there has been no indication that it will be delayed beyond September.

What will be your plans for Battle River unit 5 if it is turned back to ATCO?

ATCO is actively investigating opportunities to run the asset as part of its merchant portfolio as a natural gas fired facility. The final capacity market design will be a part of that decision-making and we should have more clarity on that market design this summer before BR5 turnback happens.

To fully convert to a natural gas-fired plant we would need additional natural gas supply. We are actively working on engineering design and plans in the meantime.

What is the timing on APL spending and construction through 2018?

We have been in construction for almost 9 months and have demobilized for spring breakup. We expect Q2 and Q3 capital spending will be lighter and ramp back up in Q4 2018 and Q1 2019. Our construction schedule is dependent on winter arriving for construction conditions to begin. If we finish early on the construction, we can add "bonus" time to our contract revenue, however, this is capped at 3 additional months.

Pipelines & Liquids

For your hydrocarbon storage facilities in Alberta, are there additional development and expansion opportunities?

We have four caverns under contract today with two in-service now and two being brought into service in the next few months. We have completed construction on Cavern 3 and 4 which are expected to begin contributing earnings in the second quarter of 2018. We also have over 30 caverns of additional development potential in the same area.

What additional pipeline investment opportunities exist if further coal to gas power plant conversions are announced?

We think we offer a competitive solution to our customers for new connections. There are several opportunities within our service territory for us to provide new pipelines to connect converted plants in the Wabamun area.

What is the update on your Mexican storage partnership discussions?

We are still working on potential JV agreements regarding partnership on storage and midstream opportunities with Cydsa.

Structures & Logistics

What should we expect for ASL earnings going forward?

A similar year to 2017 seems likely unless we announce new contract wins.

For Modular Structures major projects, the lower capital spending profiles for many of our natural resource customers means we will see lower major project activity levels, particularly in Western Canada. That being said, we are looking at a number of opportunities in other markets, not to the size of a Site C or a Wheatstone, but with potential.

Our goal is to continue improving space rental utilization and securing additional long-term services contracts with customers in the natural resource sectors. Expansion will be focused in select global markets, including Canada, Australia, South America, Mexico and the U.S. Non-traditional modular markets such as public education facilities, high density urban residential housing and correctional facilities also offer development opportunities.

Will you look at acquisitions for Structures & Logistics growth?

Yes, we consider acquisitions as part of our growth strategy. Typically, for ASL, these are bolt-on size acquisitions that provide us with access to a new market or region. The 2016 Chile acquisition for 50 per cent ownership of ATCO-Sabinco is an example of that type of acquisition. That acquisition was for about $25 million so that the type of size we would consider as a bolt-on acquisition.

How does your Structures & Logistics project lead list look? What about potential for a workforce housing LNG project in BC?

We have a decent lead list of projects we are looking at for 2018 and hopefully we can secure our fair share or more of those. But the size of each project is smaller than in years past.

In 2018, we have seen an increase in leads in the natural resource sector, mainly in Alberta, BC and the US. We are also building a decent lead list of high density urban residential modular housing leads.

While natural resource sector leads remain our largest sector for leads, the percentage change in the lead list that is in infrastructure, education and urban residential housing sectors has grown at a much faster rate in the last year.

Corporate & Other

What is your growth outlook for your Alberta asset base?

There continues to be liquid rich development in NW Alberta. We see the potential for increasing opportunity relating to water and storage. With the Capacity Market favoring incumbents of coal to gas, we see coal to gas opportunities. Our lead list for modular structures and logistics opportunities has also improved since last year. Electric Transmission experienced large build in recent years, but going forward rate base growth in the business is expected to moderate. The other Alberta utilities are expected to continue growing driven mainly by new customer connections and infrastructure replacement.

How has the implementation of IFRS 15 impacted earnings?

We restated each quarter's adjusted earnings for 2017 and included it in the Quarterly Information section of the Q1 2018 MD&A. For the remainder of the fiscal year, we will use these restated amounts as our comparative figures. Additionally, we have increased our disclosures around revenues, which can be seen in Note 6 of the Q1 unaudited interim consolidated financial statements.

Overall, the impact of IFRS 15 restatements at Q1 2017 was not material, with a net impact of approximately $2 million at Canadian Utilities, and $1 million at ATCO.

What are your plans for dividend increases going forward?

We will continue to review our performance, long range prospects, balance sheet strength and credit metrics as part of our thinking on dividend rates. We review all of that in conjunction with our track record of annual dividend increases.

As far as performance goes, we do view our non-regulated ASL and Electricity Generation businesses at the bottom of their cycles and expect higher returns from these businesses in the medium term.

Could you provide some insight regarding your go forward financing plans?

In general, we will stay the course with our usual financing options of funds generated by operations supplemented by the CU DRIP, and debt and preferred share issues if needed.

The debt refinancing discussions are already underway with our lending syndicate in Australia for our utility debt of approximately ~$700M.

In 2018, we have no debt maturities at CU Inc. However, we do expect to be active in the debt markets with incremental financing at a similar level of new issuance to last year for CU Inc's continued growth.

In 2019, we have $480 million of debt maturing in two tranches. One tranche for $180 million matures in January, and the other tranche for $300 million matures in August. So we will have some debt re-financing to do in 2019 on top of the incremental financing we expect for CU Inc's continued growth.