AGL Energy Limited
Half-year results webcast
Thursday 7 February 2019

Disclaimer: The following transcript has been edited and prepared by a third party on AGL's behalf. AGL cannot guarantee that it is accurate or complete nor that all or any errors it may contain have been corrected. You should not, therefore, rely on any of the information in this transcript. Anyone seeking to clarify content discussed in this transcript or the event to which it pertains should contact AGL's Investor Relations team.

Chris Kotsaris: Good morning and welcome to the webcast of AGL's 2019 Half-Year Results. We're pleased you could join us. This is Chris Kotsaris from AGL's Investor Relations team and in a moment our managing director and CEO, Brett Redman, will provide an overview of the results and an update on our business. He'll be followed by our interim CFO, Damien Nicks, who will present the results in more detail. Brett will then close with a market update and comments on our outlook. At the end of the presentation, we'll host a Q&A session. If you would like to ask a question at that point, please dial zero then one and to cancel dial zero then two.

I will now hand over to Brett.

Brett Redman: Thanks Chris, and good morning everyone. I'm delighted to be here presenting my first results as AGL's CEO. Joining me in the room is the entire AGL executive team. We look forward to taking your questions.

Let me begin by talking about key metrics in relation to safety, customers and AGL's people. I'm disappointed to say that our safety performance worsened during the period for both AGL's people and for our contractors. While the total injury frequency rate is relatively low by historic standards, 22 people were still hurt, seven of our employees and 15 contractors. That's obviously too many. In recent weeks, we have been reviewing key aspects of our safety culture to ensure we continue to drive towards zero harm.

Turning to customer, our key metric is net promoter score. While this reminds poor for the industry as a whole, it's encouraging to see an improved result of -16.9 for AGL. We are continuing to look for new ways to build customer advocacy and we're targeting a material improvement in our performance.

On people, it's clear that our employee engagement levels are not where they need to be. After two years without collecting data, we've conducted a survey in September which gave a score of 62%; that's materially below the high-performance benchmark to which we aspire. I've made improving our performance in relation to safety, customer and people are a key early priority of my tenure as CEO.

I'd like now to provide an update on some key areas of focus. During the half, despite continued supply cost pressure, AGL delivered lower standing electricity prices for household and small business customers in all states. We also led the market with our expanded scheme to reward our loyal standing offer customers with automatic discounts and to provide expanded debt relief to hardship customers.

In this period of high energy prices, policy, uncertainty, and technology transition, we recognise that building and maintaining trust is essential, and we know there is more that we need to do. We're investing more in the availability of our key thermal power assets, because the continued availability and reliability of these assets is essential to the community's confidence in the energy system as it evolves. And we are reviewing all our key customer and regulatory processes to understand how we can improve them to meet rising community expectations of companies like ours that provide an essential service.

There are currently $1.9 billion of new energy supply projects under construction along the east coast as a result of AGL’s direct investment for offtake support. We have another $1.5 billion of projects subject to feasibility, including the pumped hydro project at Bells Mountain in New South Wales we are announcing today. We're also committed to rolling out residential and small business battery solutions across our consumer base.

We continue to look to optimise our performance. Over the period just gone, we took the decision to increase operating expenditure in our thermal fleet to improve performance and increase our ability to capture value in future years. This has resulted in a revision of previous operating cost reduction targets, which were set relative to a weaker operating outlook at the time, but we continue to expect to reduce total operating expenditure this year and beyond. Our major systems investments of the past three years in customer experience transformation and enterprise resource planning are paying off and are becoming embedded in business-as-usual. We expect further efficiency gains from these programmes from the 2020 financial year onwards. Despite challenging conditions, we are tracking toward the midpoint of our guidance range for the full 2019 financial year for underlying profit after tax of $970 million–1.7 billion dollars.

Finally, we stated at our 2018 full-year results that we may resume share buybacks during this financial year in the absence of opportunities to invest in growth at scale, and that we would provide an update at these half-year results. We have in recent months completed a fundamental review of the growth options available to AGL and have concluded that there are compelling opportunities for AGL across three horizons, on which I'll expand in a moment. In addition, our current intention is to redeem our $650 million hybrid subordinated notes when they become available to call in June 2019, subject to material changes in market conditions, strategy, or funding needs. Given these plans and given the flexibility afforded by AGL’s strong financial performance at a time of policy uncertainty, we have determined that it is not appropriate to recommend share buybacks at this time, although we retain the flexibility to do so.

I will now give a brief summary of our first half financials. The key driver was again the strength of wholesale electricity markets, which impacts reported statutory profit and cash flow, but is the major driver of our continued strength in underlying earnings. And of course, the two impacts to our accounts are a positive lead indicator of future earnings.

Looking at our underlying results more closely, it was another strong period, with net profit after tax up 10% to $537 million and a corresponding increase in return on equity of 1.4 percentage points to 13.1%. You'll be aware that our first and second half split of earnings can be variable, and we do not expect to repeat this level of profit growth in the second half for reasons Damien will discuss later. We've declared an interim dividend of 55 cents per share, which is consistent with our practice of paying a lower interim than final dividend and of applying the 75% policy pay-out ratio across the total annual pay-out.

I now want to talk a little more about what I'm really focused on as CEO. Keeping it simple. I've set three strategic priorities and four operational goals. The strategic priorities are growth, transformation and social license. We want to accelerate our growth investment to meet evolving customer needs. We have a pipeline of energy supply projects in which we can invest, subject to the right policy settings. And one of my first actions as interim CEO last year was to conduct a fundamental review of growth options, as a result of which we are now actively working on material opportunities.

Under transformation, I'm immensely proud of AGL’s 180-year heritage, but we have to continue to reposition, refresh and reinvigorate the business for the modern world. Digital transformation will continue and we will look to adopt and embed best-in-class technology and data analysis whenever opportunity arises.

Now to social license, which is about meeting and exceeding rising community expectations. Our ongoing investment in energy supply, our actions to support vulnerable customers and our review of our response to key customer and community commitments are all integral to this, but we recognise that companies like ours have more to do. That's why we are so strongly committed to the energy charter, working across the energy supply chain.

Our four operational goals are clear and simple and will be reflected in remuneration objectives for me and the executive team. On safety, we are targeting a reduced total injury frequency rate. On customers, we are targeting improved net promoter score relative to our tier one competitors. On people, we are targeting improved employee engagement objectives. And our financial targets remain as published in relation to underlying profit, return on equity and relative total shareholder return. Exact outcomes relative to all of these objectives will be published with our full-year results.

This next slide provides more detail on how we are thinking about growth. Over the years, major investment in both brownfield and greenfield capital projects, as well as acquisitions, have been in AGL's DNA and provided the springboard for the strong wealth creation shareholders have enjoyed over recent years. Following a fundamental review of the opportunities available to us, we are confident of being able to deliver the next wave of growth, consistent with our historic disciplined hurdle rates across all three horizons.

The first is optimising our existing portfolio for performance and value. We remain committed to the transition of our portfolio away from coal to new sources of generation and storage which will ultimately be cleaner, more affordable and reliable. But our analysis indicates that, under almost any scenario, our thermal assets will be essential to this country's energy supply for decades to come. For that reason, we need to invest to ensure that they are secure, reliable, and flexible, especially as the way in which coal-fired power is despatched will change to support the build-out of more renewables. We've announced today a $25 million upgrade of the low-pressure turbines and feed water heaters at the AGL Loy Yang Unit 2 and are reviewing other similar initiatives across the fleet. That upgrade, like the upgrade to Bayswater that begins in early FY20, will not bring any increase in carbon emissions.

The second horizon for growth is evolving and expanding our core energy market offerings. The Crib Point LNG jetty has the potential to provide a new source of gas to the east coast and to support our storage and shaping strategy and our development of flexible peaking capacity. We remain committed to supporting the development of large-scale renewables and we are also getting serious about storage. Today, we've announced that we have secured a 250-megawatt pumped hydro project at Bells Mountain in New South Wales. Having commissioned the Dalrymple battery in South Australia last month, we're looking for more opportunities in grid-scale batteries too.

The third horizon for growth is creating new opportunities with the connected customer. Opportunities in distributed energy, spanning home storage, asset orchestration and e-mobility, arguably straddle both the second and third horizon. In the short term, we are focused on bringing to market our residential battery offering. We are also refreshing our options in relation to electric vehicles. Central to the third horizon is the ongoing expansion of the way customers think about energy, especially as energy and data value streams converge. Data plays an integral part in our day-to-day lives, much like electricity and gas. Customers expect and need a reliable provision of that service and see opportunities as the uses of data and energy become intertwined. We want to continue to go where the customer is going. We see many emerging growth opportunities in this space, early ones including broadband, e-mobility, smart home, and using data and energy to orchestrate our markets.

So when I say we're getting serious about storage, what do I mean? In residential batteries, live and propose government schemes are now presenting an opportunity for rapid growth. We intend to have the capability to deliver basic solutions in place by 1 July, and any customer can register their interest in this rollout on our website starting today. Our offering will be all about building capability and ramping up as government schemes do, expanding on what we've learned through our Adelaide virtual power plant, which is still the largest retail-led project of its kind in Australia. The current total market opportunity based on Victoria and South Australia's committed schemes alone is in the region of 50,000 batteries. That translates to a total investment across the market of $600 million–700 million based on current battery prices.

Pumped hydro is an equally exciting area of development. Having now secured the option of the Bills Mountain project, we are in the early stages of feasibility. Subject to certainty in relation to market design and our own ongoing scenario testing, this project will have a scale of 250 megawatts, representing an investment of about $450 million for the potential delivery in FY26. We see pumped hydro as potentially forming an essential component of Australia's firming capacity, and this option and others we are pursuing have the potential to add unique flexibility to our generation fleet.

Let's now look at some of the progress in the period on delivering fairness, simplicity and transparency for our customers. The price cuts for electricity customers in all states, expansion of the loyalty schemes and debt relief for our hardship customers were designed to help relieve cost of living pressures for as many customers as possible. New products like AGL Essentials, which was 34% of all internal sales in January and 21% of total sales, are also making a difference, giving customers access to simpler, more transparent products.

The middle chart on this slide shows the progress we have made with getting customers off non-discounting standing offers, which account for just 5% of all customers. Post the changes and expansion of the safety net effective 1 January, it is now just 3% of customers. Our ombudsman complaints are actually up slightly versus the prior half in absolute terms driven by the Power of Choice reforms, but you can see AGL's share of total complaints continues to fall and it is disproportionately lower than our market share of customer accounts.

Our key indicators of market activity tell a solid story on a comparable basis. Market activity remains intense across the board. Churn has increased and acquisitions and retentions also remain elevated. Despite these intense conditions, we've improved our churn spread to market since June and retentions have also decreased with more customers switching to lower-priced products in the prior year. And consumer accounts in a highly-competitive market are actually up slightly. This is helped by our continued growth in Western Australia, where we now have 30,000 customers and a broadly flat outcome in all other states. We remain interested in growing our Western Australian business.

The customer experience transformation programme has been a contributor to our solid customer metrics. We increasingly think of the project as part of our business-as-usual as we enter the last months of the associated capex uplift and shift our focus to driving customer adoption and continue to enhance the experience. Total digital registrations are now almost 1.2 million customers, and we're seeing encouraging outcomes in areas like total digital sales, e-billing, adoption of the energy insights tools and digital net promoter score, which is strongly positive. Digital interactions have increased substantially over the period, up 76% since FY17, with core volumes dropping slightly amid intense market, media and government activity.

We set our targeted opex savings from the programme of $30 million–40 million dollars per annum at full run rate and customer adoption post the 2022 financial year. The current annual run rate of cost savings and cost avoidance, noting the big uptick in market activity that has occurred since the programme began, is in the region of $20 million, and further savings will crystallise in future years.

Meanwhile, we are continuing to invest in the great portfolio we have to make it as resilient, efficient and flexible as we can, as pressure increases on the aging existing coal fleet throughout the NEM. This slide shows planned and unplanned outages versus availability at AGL's thermal portfolio on the left, and total generation mix on the right. Amid supply constraints and solid demand, we have consciously shifted our focus at the big coal-fired plants away from short-term cost reduction that might increase in new profit, to expenditure that contributes to short-term costs, but will enhance value in current and future years. The higher level of unplanned outages in the FY19 first-half period reflected those we experienced in the first quarter at Bayswater and Loy Yang.

The right-hand chart shows how in recent months our wind and hydro assets have increased their generation, offsetting some of the pressure from reduced coal activity and again emphasising the strength of a diverse portfolio. It's worth stressing: the portfolio comprises both physical and financial assets, including insurance products. As we always say, we have up days and down days. It's worth noting that we expect to emerge from the extreme heatwave in late January with no earnings impact, despite being slightly short to our sold position because of unit outages.

I'll close this section with our project development map, which reflects our desire to grow as our core energy market offerings evolve. This is becoming increasingly busy, but there is no question that policy and regulatory uncertainty is contributing to delays in both executing and approving projects. Completion of the two big wind farms we are currently constructing through the Powering Australian Renewables Fund – Silverton and Coopers Gap – as well as the Barker Inlet gas-fired peaker, have been slowed by how AEMO is applying rules governing how generators connect new assets to the grid. We're working with AEMO to ensure these projects can still be delivered, but this highlights the extent to which policy certainty and joined-up planning is required throughout the system to ease constraints on new development. Similarly, our ability to proceed to a final investment decision on the Newcastle power station has been hindered by non-progression of the national energy guarantee and the federal government's so-called big stick legislation, which is creating new risks and uncertainties for the market.

Despite the challenging policy environment, as a result of AGL's direct investment or off-take support, there are currently $1.9 billion of energy supply projects under construction on the east coast. We have a further $1.5 billion of projects in our development pipeline.

I'll now hand over to Damien and talk about the numbers.

Damien Nicks: Thanks Brett and good morning everyone. I'll start by quickly explaining the reconciliation of statutory profit to underlying profit in the half. In significant items there were gains on sales of national assets and the development rights of the Yandin Wind Farm in Western Australia. These were largely offset by the impairment we took when we closed our residential solar installation operation in September. The loss in fair value of financial instruments of $251 million in the period, compared with a gain of $127 million in the prior corresponding period, reflects movements in wholesale prices.

Now let's look at underlying profit across the Group in more detail. The result reflects the breadth and flexibility of our portfolio and strong wholesale markets, which enabled us to deliver 10% profit growth at the same time as we deliver customer affordability initiatives and increased expenditure on our generating plant, consistent with our refreshed focus on optimising our existing assets for performance and value.

The period-on-period increase in profit was $50 million, reflecting a strong result in wholesale electricity and eco markets. This more than offset continued margin compression in customer markets from the impact of customers switching to lower-priced products, customer affordability initiatives, and a decline in large business customer volumes. Higher cost in Group operations were as a direct result of our deliberate decision to increase operating expenditure in our key thermal fleet to maintain plant availability and support value delivery now and in the future. Higher depreciation is occurring as forecast as we undertake a short-term step-up in sustaining capital expenditure on major outages and life attainment activities on assets nearing the end of their life. Also to note on this slide, net finance costs were down because of lower average net debt and the increase in income tax simply reflects higher profitability.

Our first to second half earnings can vary between the years, and this year we expect a weaker second half, driven primarily by lower gas volumes due to seasonality and the decline in large business sales, margin compression from lower-priced products, and the impact of price cuts in Victoria. In addition, we will see higher input fuel costs across the portfolio as legacy contracts roll off.

Now let's look at operating expenditure in more detail, and the key point I want to make here is that we have deliberately increased costs above our original forecast to ensure we are delivering performance today and setting ourselves up to deliver future value. After taking inflation into account, we delivered a small reduction in real cost for a minor nominal increase in first-half operating expenditure. The increase in costs reflected the customer affordability initiatives, as well as the emphasis on optimising plant availability, and additional costs from increased well activity at the Moranbah joint venture.

The $49 million of business efficiency savings included lower labour costs as a result of the Loy Yang transition and the reorganisation programme and, in customer markets, lower campaign and advertising spend associated with the entry into WA and brand transformation in the prior year, and savings arising from the customer experience transformation programme. While we expect to deliver real savings in the full year of about $60 million, this is about half of our previous target of $120 million. The revised target reflects the emphasis on value over cost at our key operations, as well as further increases in Moranbah costs, increased marketing costs and other seasonal costs.

However, this is in the context of a strong first half result that has us tracking to the midpoint of an unchanged guidance range, which demonstrates the value we are generating from our decisions we are taking. A lot has changed in the market and at AGL since we set the original target last August. Our decisions to increase expenditure at our plants have been very deliberate to optimise the portfolio for performance and value and to drive improve results now and into the future. This is essential not only for community confidence, but also to maintain strong earnings. We will continue to drive operational cost improvements on a year-on-year basis; however, we will ensure we are making well-informed cash and opex decisions that are ultimately linked to value. We've recently completed detailed diagnostics in both Group operations and customer markets that identified cost out and other value-enhancing initiatives that will enable us to continue to drive toward future savings.

Now turning to our electricity portfolio performance. You will note that the generation broadly matches our customer demand; despite the outages during the period at some of our key thermal sites, the breadth and the flexibility of our portfolio ensure we were able to generate at comparable levels to prior years. Total generation volumes were flat, and in this period there was relatively little change by customer type. Weather impacts were negligible; in consumer, a decrease in average customer numbers and lower average consumption due to a change in customer mix reduced volumes slightly. Large business sales continue to decline in a competitive market, although the decrease was less steep than in the recent prior periods. There was no significant change to the wholesale customer base in the period.

We have commented previously we are somewhat indifferent how generation is cleared through lower-margin channels. Turning to electricity margins, the trend remains positive for AGL, reflecting higher wholesale prices and lower compliance costs for green certificates. Consumer margin was down as we experienced increased churn across the portfolio and the continued flow on impact of customers switching to lower-priced products, and a decline in consumer market volumes. Large business margin was also down due to the decline in volumes I've already mentioned. The eco market's improved as the as L Ret? market price decreased, and we had high generation from our hydro and other renewable assets.

The Group operations cost increase reflects the opex and the depreciation trends I've previously discussed. The gas volume reduction is consistent with recent trends, with a continued decline in large business volumes due to the loss of low-margin business customers in continued tight supply conditions. Milder weather in Victoria contributed to a reduction in consumer volumes, and wholesale volumes were up slightly due to customer acquisitions. Our focus continues to be on clearing available supply at terms that represent good value.

The next gas margin slide shows that higher market prices for gas resulted in higher margins, despite a reduction in sales volume driven by a supply-constrained market. This was evident in both consumer and wholesale margins.

Let's now turn to cash flow. As shown on the left table, the major variance in the period was the increase in cash outflows for margin calls, similar to what we saw in FY17. This is due to the impact of higher wholesale forward electricity prices on our futures market contract position. Because we manage our net long physical generation position through taking a net short contracting position, as prices rise, our positions lose value. This means there is a negative mark-to-mark impact in statutory profit line and a negative cash outflow for March in calls. But the net long generation position means we stand to recoup this impact over time, starting in the second half of the financial year, subject always to any change in the futures market. This is because higher wholesale electricity prices drive strong cash flow and earnings, and negative margin calls generally reverse through cash receipts as positions unwind. Other operating cashflow items were largely unchanged. As shown in the chart on the right, the major change in our use of cash compared with the prior corresponding period was the retirement of debt in the first half of FY18.

Our capital expenditure in the first half of $406 million was broadly consistent with our expectations and we continue to anticipate full-year expenditure of about $1 billion. We have pulled out sustaining capex in our core thermal assets – shown here in the darker blue – from broader sustaining capex across the Group, to highlight the level of investment we've been making in these assets. Sustaining capex on those assets was $217 million in the first half in preparation for summer and will be about $373 million for the full year. We expect this capex to decline in later years as we complete major mid-life investments.

Our growth capex in the second half largely relates to the delivery of the Barker Inlet Power Station, shown here in yellow, with some expenditure continuing into FY20. Our current capex plans assume we'll start constructing the Newcastle gas peaker in FY21. However, as Brett has mentioned, our ability to proceed to a final investment decision on this project has been hindered by ongoing policy uncertainty. You can see here in the bright blue colour the major capex uplift supporting the digital transformation programmes is finishing this financial year.

Now moving to our balance sheet, the strength of which is a real advantage in the current political and economic environment. The chart shows in the pink the hybrid, which we currently intend to redeem in June subject to any material changes in market conditions, strategy, or funding needs. We have a great deal of flexibility as we think about funding and capital management thereafter. We are well-placed to secure new bank debt at competitive rates, either to fund growth opportunities or, if they do not eventuate, to consider share buybacks consistent with our capital allocation principles.

I'll now hand back to Brett. Thank you.

Brett Redman: Thanks Damien. I'll close with some comments on the outlook for the market and for AGL. It's clear from electricity price trends that volatility remains; although forward prices have rallied strongly in recent months, the curve is still in backwardation. We see the reasons for the rally as follows: lower non-AGL hydro generation due to recent drought conditions; delays in renewable projects coming online; gas and coal costs remaining high; and tight market conditions over recent summer months. Having said that, the longer-term backwardation reflects expectation that fuel costs may moderate over time, that the volume of renewables supply will increase, and that the market will respond to these tight conditions and higher prices on either the demand or supply side. Trading beyond FY20 remains illiquid

Moving to renewables, there has been considerable commentary on the outlook for LGC prices as the build-out towards the 2020 RET target continues. Certainly the LGC spot price has declined, but irrespective of short-term market trends, AGL expects underlying demand for renewables development to continue to be strong. As the chart on this slide suggests, any market that is expected to grow between three and five times presents opportunity, and green schemes of some form are likely to continue to form part of the value streams for AGL.

Regardless, the PARF assets will provide new streams of value as they come on stream in coming months. We continue to see the PARF-type structure, with shorter-term PPAs and drawing on infrastructure fund support, as an attractive model for developing these kinds of assets.

The situation in gas remains challenging. The AEMO data shows that east coast gas demand is already exceeding supply and, beyond 2023, the situation deteriorates. AGL's strategy in wholesale gas remains to benefit customers by mitigating supply uncertainty and provide optionality. The Iona gas storage services contract comes on stream in FY21 and will supply AGL with additional storage and swing capacity, and we continue to progress our plan to import LNG into Victoria by the gas import jetty at Crib Point. We now anticipate making a final investment decision in FY20, given there will now be a requirement to provide an environmental effects statement. We met a key milestone in December 2018 with the execution with Hoag of the contract for the supply of floating storage and regasification unit for the project. We continue to make progress on securing long lead time assets for construction.

Finally, to our guidance. We are tracking towards the mid-point of the range for underlying profit after tax of between $970 million and $1.07 billion. This is the result of our strong portfolio performance offsetting the impact of increased operating expenditure and coal plant outages. The second half will be lower than the first half and the prior second half; that's because of lower gas volumes due to seasonality and lower large business customer volumes, continued consumer margin compression due to lower-priced products and the impact of the Victorian price change that took effect last month, and higher import fuel costs.

As always, our guidance is subject to normal trading conditions and policy and regulatory uncertainty. In FY19 and beyond, policy certainty remains critical to the energy sector. AGL supports policy reform that addresses the identified issues and drivers of increased prices and creates an environment of certainty for investment. We are developing $1.9 billion of projects and assessing a further $1.5 billion of projects, all of which can contribute to lower energy prices and increased system security and which we could execute faster with more certainty.

Our investment in our plant, in customer systems and our continued commitment to a safe, reliable and low-cost generation fleet are all designed to support the delivery of a cleaner, more affordable and more reliable energy. Despite industry uncertainty, our business is performing solidly and we are focused on delivering our strategic priorities of growth, transformation, and social license, and we are optimistic about the future.

We will now take your questions.

Chris Kotsaris: Thanks Brett. A reminder that if you'd like to ask a question, please press 0 then 1 and 0 then 2 to cancel. And also, if you wouldn't mind limiting it to one question; you can re-queue for further questions at the end.

Our first question is from James Byrne at Citi. Please go ahead.

James Byrne (Citi): Morning everyone. I guess really for me, the most important question is just clarity around capital management. So when you say you retain the flexibility to be able to buy back shares, should we think about your balance sheet as being able to support both growth capex and buybacks in parallel, assuming you take FIDs on the pipeline of growth assets that you think you have in front of you?

Brett Redman: I think, James, what we're saying by saying we retain the flexibility to revisit share buyback is saying that that's a conversation that will never stop. So, it's something I expect we will address almost monthly, weekly, daily and every time we present our results. To what extent that in a future presentation we talk about share buyback is interrelated to the amount of growth projects that we do. But what we're saying here today is that we're making our priority the growth pipeline that we see, and so we're putting more to one side a share buyback conversation,. but we retain the flexibility, if you like, to revisit it in the future.

James Byrne: Got it. I appreciate it's just one question but really, to follow up: like, how do you think about the current headroom that you have on your balance sheet after paying down that hybrid when we the market want to think about how much flexibility you have to buy back shares?

Brett Redman: Again, I think it's perhaps at this point better answered through the lens of what's our flexibility to fund our growth aspirations. So, the projects in the pipeline that we're presenting here today – a good chunk of which is managed off balance sheet, so without going through it all, we retain the investment discipline in our approach to how we make these investments. But we've got the balance sheet headroom to fund what you see, as well as there's capacity there to go on to do the other things that we're starting to develop internally as new growth ideas.

James Byrne: Okay, great. Thanks, Brett.

Chris Kotsaris: Thank you James. Our next question is from Pete Wilson from Credit Suisse. Please go ahead, Pete.

Peter Wilson (Credit Suisse): Thanks Chris. If I could ask about eco markets, can you drill down a little bit more into the $55 million increase versus PPP and what you're doing there with the inventory build?

And then also, given that spot prices are $40 now versus the $70–80 that they were last year, when do you expect to start passing that through to customers and hence when should we start to see that flow through your earnings?

Damien Nicks: Thanks Pete. Look, as we flagged at the August results, we flagged that we anticipate the eco margin being up period on period. What's been a big generator this year for us has been higher renewable generation, but also lower compliance costs. And what we've flagged in the past is there is differences between when we're setting our prices and when some of the compliance prices get set as well, so that's driving some of that variability between the periods.

I might get Richard to talk to just a view on LRETs into the future.

Richard Wrightson: Hi Pete. Just in terms of where the LRET is going, we're already projecting that come 2020 the scheme will be met, which does put downward pressure on the LRET price. But we're also highlighting that under either colour of government next election there is an increase in demand of renewables, yet how that gets funded through the system is not yet defined. So, whilst the LRET scheme might go backwards, some of the opportunities for growth in the renewables area and expanding out the renewables, a 50% target on the federal waiver is actually quite an aggressive growth target. So renewables still have value, albeit declining from the LRET scheme.

Peter Wilson: Okay, thanks Richard. I was actually more interested in like the pass-through to customers. So I mean, if the prevailing price is $40, I assume that's lower than the bundled price that most of your customers are paying now. So when does that actually get passed through to customers and hence flow through to your earnings? More so than the direction of the LRET price.

Damien Nicks: Right, so customer pricing we set twice a year; we set it obviously once in 1st July, also 1st January for Victorian price customers. When we bundle up all of our pricing, this gets taken into account as part of that positioning when we're considering our customer pricing. So if you can imagine, you know, we've just had the Victorian pricing, the view on whatever that price was at that point in time gets built into customer pricing as we set the prices.

Peter Wilson: Okay, thank you.

Chris Kotsaris: Thank you Pete. Our next question is from Rob Koh at Morgan Stanley. Please go ahead, Rob.

Rob Koh (Morgan Stanley): Thanks guys. Just a question in relation to the cost reduction targets. It was previously expressed as a nominal FY21 target of $1.364 billion and that hasn't been repeated in this presentation. You have talked about a future cost reduction, so just can we clarify: are we abandoning the previous nominal target, or how should we think about it?

Damien Nicks: Rob, Damien Nicks here again. Look, the way to think about that is we've made some active decisions this year to really focus on our plant, our availability, and ensure we've got the generation there when we need it. So we made that decision, you know, during this period. As a result, we had additional costs, and what you're starting to see now is some of that value flow through and you'll continue to see it flow through the books. What we're not putting up in the half year is a view of what that three-year target looks like, so we need to continue to look at how we think about the optimisation of that fleet and we will continue to do that over the next six months.

Rob Koh: Okay, great. Thanks Damien. Can I maybe just sneak in another one, if that's not too cheeky, Chris? So, one of your competitors highlighted that if retail price re-regulation in some form or another were to come in, the gross impact would be in the order of $60–120 million EBIT before mitigation measures. Just wondering if we should be thinking a similar order of magnitude for your customer book?

Brett Redman: Hi Rob. We debated whether we should put out a similar number or a similar calculation, expecting this question. The reason we didn't was because the competitor who put that out, they put it out in the context of the day, where there's an element of when you do the calculation, it's versus what? So the calculation that was published previously was versus the expected 'what' of the day, but that continues to change and move up and down. So we kind of thought about it and thought if we try and put any number out, we'd struggle.

The one thing I'd say is from 1st January we've now only got 3% of customers on pure standing offers and so the exposure that we have there is somewhat limited. It's not nothing, but it's somewhat limited because virtually every customer now is on some form of discount or lower price through our Essentials channel.

Rob Koh: Okay, understood. Thanks very much, Brett. Appreciate it.

Chris Kotsaris: Thanks Rob. Our next question is from Ian Myles at Macquarie. Please go ahead, Ian.

Ian Myles (Macquarie): Hey guys. The outages you've had in the half – and particularly the February outage just recently – how does that influence your approach to how much of your capacity you want to have in spot markets versus actually hedging up on a go-forward basis? It does seem that the coal plants are getting less reliable as they get older.

Richard Wrightson: Hi Ian, it's Richard here. I'll take that question. First of all, January was probably our more stressful period, Ian, through that hot weather when we had the outages in that period. What we're trying to reflect in here, we do have a very strong diversity of fleet, so even when we do lose our large coal unit, we have a lot of flexibility in fleet – and particularly during those periods, we actually had eight Torrens units running through that period. We also had flexi-generation. But also it goes down to what sort of insurance products we can buy, both from things such as weather derivatives, but also with our customers – there's a lot of things we do with our customers around demand management and control. So there are no hard and fast rule there. We do constantly look at the position, look at the insurance products we have in the market and try and optimise those to compliment the fleet that we have, also bearing in mind that within the fleet it is a very, very flexible fleet that we can do different things with to ensure we cover those outages. Obviously on very, very high-demand days like that when you do lose large units, you do push everything you have in the portfolio, but as Damien said, those two days – despite the loss of the Loy Yang unit – were relatively neutral.

Brett Redman: Maybe just to build on that too, earlier on in this financial year we made the deliberate decision that, if you like, rather than having to get into a discussion, as we saw the fleet under a little more pressure, 'Should we back off a little bit in a contracting sense,' what we thought was a better pathway forward and a deliberate decision forward is to spend a little bit more money on maintenance and to hunt for value that way, rather than defend a little bit of a decline. And so I think you see the impact of it coming through in a little more opex and potentially a little more capex as we keep the fleets at a good level of maintenance, rather than a shift in our contracted strategy.

Ian Myles: Okay, and just one final segue into that. LRET, are you going to – with the February settlement, are you planning to go short the LRET market as the government's sort of encouraging?

Brett Redman: Look, we are loosely square. So – the devil is always in the detail, but we're not running an active strategy of trying to be short to that requirement.

Ian Myles: Okay, thanks.

Chris Kotsaris: Thanks Ian. Our next question is from Joseph Wong at UBS. Please go ahead, Joseph.

Joseph Wong (UBS): Hi guys. The question from me is regarding the economics for the new hydro power station. If you can provide any more details on what your rate of return metrics are and if Snowy Hydro 2.0 is considered when you do your base case assumptions.

Brett Redman: So, the return metrics that we expect continue where, if you like, the minimum hurdle for all the significant capital projects we do is the 12% IRR post-tax nominal. So, that stays the same. Some projects, if we assign more risk to them, we may expect to do better, but that's your minimum threshold. So the pumped hydro project, where it is somewhat early days as we're trying to model out exactly how that will operate within the market, we would expect it to at least pass that hurdle, given in a practical sense that I wouldn't expect that we would reach an FID point on that project until after it becomes somewhat more crystallised in terms of are we going ahead or not. I think we will know has Snowy got its contracts in place and its funding approval in place to proceed before we need to make that decision. Right now, given that the current federal government seems very intent on pursuing that project – and speaking to the opposition, they seem somewhat supportive, without putting words into their mouths – you'd have to lean into it as being a more likely base case that Snowy will get there rather than not. A little bit of a debate on the timing, is probably more about what we think about.

Joseph Wong: Okay, thanks guys.

Chris Kotsaris: Thanks Joseph. Our next question is from Baden Moore at Goldman Sachs. Please go ahead, Baden.

Baden Moore (Goldman Sachs): Good morning, Brett. I was wondering, you made the comment from a growth capex perspective that your thermal generation assets in the portfolio today will be there for generations to come. Should we expect you also to start investing in I guess longer-term fuel supply that might be cheaper than an export parity price, or is that something that's a long way down the track for you?

Brett Redman: I think in terms of the timing of our thermal fleet, we spend a lot of time publicly talking about the lives of our coal-fired in particular and to the extent we've got gas-fired there as well; 'A' Station is obviously coming towards the end and 'B'. is an older plant as well. So there's no shifting in timelines, if you like. In terms of the security of fuel, if you think about it, Loy Yang owns its own coal mine, and the engineers would have a better way of saying it, but it has about a million years of coal there I think. Don't quote me with that number, but it has all the coal it would ever need throughout its useful life. Black coal, we published again in this pack an outlook for Macquarie Power Station and black coal supplies there. So gas becomes the more interesting discussion and our particular focus right now is really trying to support whole in market, focused on Crib Point about trying to open up new sources of supply for gas. So there's no a real change in our thinking about time horizons for securing fuel, and it's somewhat plant-specific on coal and somewhat market-driven in the case of gas.

Baden Moore: Okay, thanks Brett.

Chris Kotsaris: Thanks Baden. Ian Myles is on the call again; please go ahead with your question, Ian.

Ian Myles: Thanks. Just about your batteries, you're talking about moving into the retail space and are making a bit more of a noise about it. Can you just maybe give us some colour on what your strategy is there, if you plan to own the batteries or you want the consumers to? And also within the broader business where I guess the industry is increasingly becoming capital white with infrastructure-based businesses owning generation, do batteries fall in that same category, given they work on a cycle approach?

Brett Redman: I think if I distinguish between grid-scale batteries and household batteries, grid-scale batteries to the extent we're starting to look at those opportunities is probably on balance sheet simply because of what you're alluding there: they're driven by cycles rather than time, they're a much harder thing to move off balance sheet because you want to be able to manage them or operate them very flexibly. That may evolve in the future, but the starting point is probably leaning towards being on balance sheet. At a household level, what we're setting out to target is to either meet or exceed our natural market share. So in any market we have a natural market share of residential customers, so we would be targeting to do that or more of whatever number of batteries are then put into that market, so it will pace according to technology costs and government incentives. We're seeing a lot of government schemes starting to come out.

The operating model you use and how you fund it, I think to begin with it'll be a bit like what we did with digital meters where things were on balance sheet. And a lot of that was because we wanted to make sure that we developed our propositions, if you like, in an environment where we could be quite flexible as we came to understand the operational needs and the customer needs, but later on you may change your funding method if it becomes clearer that there's a better benefit to customer or a better benefit to us by moving it around. So digital meters was an example that after some years, and successfully building a new business at scale, we then moved it off balance sheet into somebody else's hands. We continue to put in digital meters for our customers, but at terms that really work for us and the customer.

Household batteries I think will initially be more likely to be on balance sheet, but you may see funding models evolve a little bit like solar panels, where some customers will want to get financing and own them directly. There will be a whole debate, I think – I know I'm running on a little bit on this question – but a whole debate will start to emerge around how much value does the customer directly get in terms of moving energy around within their home and how much will we supply through new revenue streams with doing things like orchestrating those batteries and fund the customers.

So I think it's going to be quite dynamic on balance sheet initially, but many pathways as we get to learn and evolve.

Ian Myles: That's great, thanks.

Chris Kotsaris: We have another question from Rob Koh at Morgan Stanley. Rob, please go ahead.

Rob Koh: Ah, thanks Chris – appreciate the second chance, probably the third chance. Brett, I think you mentioned that you still are interested in Western Australia, and just wondering if you could give us a sense of your strategy for Western energy or Perth energy in that context.

Brett Redman: Well, we have a policy, I suppose, of never commenting on any potential active M&A. All I would say is, in a broader sense, Western Australia continues to be a market of interest of us. We've created a foothold with gas, residential customers; we're now a buyer or procurer of gas in that market. We're starting to think about a long-term future that may evolve on the electricity side, although obviously a lot of that's driven by whether deregulation emerges or not. And in the meantime, a really interesting potential there that, as things like solar panels and batteries and energy management which are not regulated in the same way, we can take products that we develop on the east coast across to the west.

So I think Western Australia in its own right over the next couple of years may not move the dial, but it's a nice piece of growth to supplement our east coast business and we'll continue to carefully move forward in that market.

Rob Koh: Okay, cool, sounds good. Thanks a lot.

Chris Kotsaris: Thanks Rob. Our next caller is Kate Burgess from Acuris. Please go ahead, Kate.

Kate Burgess (Acuris Global): Hi. I just wanted to ask another question about the Bells hydro project. Assuming you do go ahead with that project, I'm just wondering: could a part of it or could the project be spun into the PARF once it's developed and externally funded, or are you more likely to fund that internally with net debt?

Brett Redman: Again, it's a little bit like battery description that I gave. It's an asset that, at least initially, is more characterised by being a flexible asset, and by that I mean every day, every hour, you're making a decision about how to run it and you may run it quite differently one day to the next just depending upon what prices are doing in the market or your levels of water storage or the like. So because of its active nature, initially at least it certainly suits better being on balance sheet. That's not to say in the future it may not move off, but if you think about it, the hydro assets which are somewhat similar to what we've got down in the more southern parts of the east coast, we kept all of those on balance sheet because they are the sort of assets that we do a lot of different things with.

So, if you were trying to forecast for that one, I'd guide you towards keeping on balance sheet without saying that that's a forever future. Things may change.

Kate Burgess: Okay, thank you. And just sneaking in a second question: would you say the same thing about the Dalrymple battery? Has that been funded internally, just based on what you were saying about storage?

Brett Redman: That one is being funded by – I'm trying to remember which agency it is…

Damien Nicks: ElectraNet.

Brett Redman: ElectraNet, sorry. That one is being funded by ElectraNet, so that's off-balance sheet. We facilitated the build of it and I think we're helping with running it – I'm just looking it up. Damien is nodding. So, we're helping with the ongoing running of it, so that's off-balance sheet. So that was one where ElectraNet, from memory, put out an expression-of-interest-style process which we were successful with, and we thought it was a great opportunity to learn. The big value of that one is as a learning opportunity rather than a – you know, we make I suspect a small margin on it, but it is not a profit-driven decision if you like, it's a learning-driven decision.

In the future with grid-scale batteries, I think there is a revolving push and pull between distributors and generator retailers like us about who are the natural owners of grid-scale batteries, where are they best placed and what's the right funding models. If we were to build a grid-scale battery, my gut tells me it's more likely to be taken on balance sheet because it is a flexible asset and it's one where we want to retain full flexibility on how hard or soft we run it, depending on the conditions of the day. But it's not to say that you couldn't see a future funding model emerge to push it off.

Kate Burgess: Okay, got it. Thank you.

Chris Kotsaris: Thanks Kate. Our next question is from Michael Morrison at Deutsche Bank. Please go ahead, Michael.

Michael Morrison (Deutsche Bank): Thanks Chris. Brett, your FY19 guidance back in August included a comment that wholesale markets earnings were to peak as electricity market prices began to decline. You've not included that in your half-year guidance, notwithstanding you said it's unchanged. Can you just give us some comments around your thoughts on the wholesale market earnings?

Brett Redman: I think, the way to consider that is the mid-point of our guidance points towards profit that's not significantly different to last year – it's up a little bit, but not significantly different. As we look into the future, some of the lead indicators of profitability like the wholesale electricity prices are pointing to a flatter to slightly lower future. So, without trying to get into the more emotive words of peak or the like, we are at a point where it's not like over the last three or four years where we were seeing a forward outlook of materially high prices year on year on year. We're seeing a much flatter outlook as we start the period into the future.

Michael Morrison: Okay, thank you.

Chris Kotsaris: Thanks Michael. We have a few questions online. The first one is from Max Vickerson at Morgans Financial. He asks, 'Can you provide some colour on how you would describe AGL and the industry's relationship with the Labor opposition?'

Brett Redman: Interestingly enough, we had a senior member of the shadow cabinet in visiting us and the board yesterday. I describe it as quite good – as I would on the government side as well, perhaps to pre-empt any questions at a personal level. We are constantly in contact with the federal opposition and we seek to make sure that they're updated on our plans, as we seek to make sure that we're fully-briefed on understanding what their thinking is. So I think that there's a good two-way flow of information and an ability to work with both sides of the House.

Chris Kotsaris: And another question from online; it's from Joseph Jacobelli at Bloomberg Intelligence. Joseph asks, 'Do you have any way of quantifying the return on investment from the $400 million of digital transformation programmes undertaken in FY17 to '19?'

Brett Redman: I think what we guide towards in terms of things like the CXT project were, as with all investments we make, we expect them to exceed our hurdle rate. So, it's that same 12% IRR post-tax nominal, so the business case for that project certainly laid it out over time and that's what we would expect to do. We signalled today that, post I think it was FY20 or FY21, the full run rate of cost savings on that project should be approaching $40 million-odd. This year we're at about the $20 million-odd mark, and so it is more or less progressing in the way that we would expect and so we would expect as we go forward that we start to see improved costs coming from it, but also better customer experience.

The last comment I'd make on that is some of the customer stats that we presented earlier on that we're holding up pretty well in what is quite a ferocious environment from a – both a policy setting and a competitive setting. We are going through that in pretty good fashion. Some of that I certainly attribute to the investments we've been making in our systems, which make us much better to engage with from a customer point of view.

Chris Kotsaris: Thank you. There are no further questions, so with that, we'll end this conference call. Thanks everyone for participating.

Brett Redman: Thanks all.