Meridian Energy FY 20 Results Announcement – 26 August 2020 – LIVE TRANSCRIPT

NEAL BARCLAY: Good morning and welcome to Meridian's 2020 Annual results call

Good morning and welcome to Meridian's 2020 annual results call. I'm Neal Barclay, Meridian's Chief Executive and I am appropriately physically distanced here in Wellington from Mike Roan, Meridian's CFO.

The result that we are about to present is a particularly strong one especially as we managed to shade the FY19 EBITDAF outcome and FY19 was one out of the box. And whilst I know most people on this call probably can't wait until we get to the NZAS bit, you're just going to have to humour us, as there is a lot that has occurred in the last 12 months that we want to talk to.

That said, we aren't getting carried away with ourselves as conditions have moderated in the second six months and clearly there are a couple of sizable challenges on the horizon.

Whilst EBITDAF was up, reported net profit was down by 48%, largely driven by non-cash fair value adjustments of hedging instruments. Mike will get into this in more detail, but it does not reflect the underlying strong business performance.

Here are a few of the highlights. EBITDAF is up 2% and it is the quality of the result that I'm most pleased with, particularly when compared to the prior year.

Our FY20 outturn was driven by a significant lift in the volume and pricing of contracted retail sales on both sides of the Tasman. We delivered strong growth across all customer segments. Our customer retention rates improved, and the Meridian brand sets the benchmark for retention in New Zealand. Our cost to serve per customer also continued its downward trend.

Hydro conditions were favourable in New Zealand, but the Team did exceptionally well getting away a record amount of generation, given the HVDC was heavily constrained during Q3. It cost a reasonable amount of money to hedge that outage but even so, we materially outperformed our expectations during the event.

The continuing drought in Australia significantly impacted our hydro generation which was around 40% of average and we saw wholesale prices soften materially during the second half of the year. However much of our position was well hedged and the business was largely immune from falling wholesale prices. FY21 will be more challenging for MEA but the silver lining is our hydro catchments are filling up fast so hydro generation should recover during the next year.

My sense is the electricity sector in New Zealand and more generally NZ Corporates have responded well to the Covid pandemic to date and genuinely put customers first. I'm proud of how our Team reacted and given we are still a long way from out of the woods you can expect us to continue to support our customers where we can.

What worries me most in our business, is keeping our people safe and clearly our safety performance needs to improve. We had eight LTIs during the year and three of those resulted in serious injuries. But worrying about it doesn't make it better, so we remain very focussed on making tangible progress evolving our workforce safety culture. I am confident that the lag injury rate indicators will start to improve in line with the work we are doing to manage all aspects of what we do safely.

Like most Kiwi and Aussie businesses, escalation of COVID alert levels forced us to quickly find new ways of working, while continuing to deliver essential services to customers who themselves are facing significant disruption. The response of our people was awesome frankly and I couldn't have been proud of them. Mental wellness will continue to be a focus for us, and I'd like to acknowledge our Team in Melbourne who have been working from home since March and continue to do a great job.

Some of our gender balance targets remain stubbornly hard to shift and we are disappointed not yet to achieve our target of 40% of women in senior leadership roles. We need to do better but I'd love to get investors out to some of our generations sites as we have some awesome women leaders now working in what have traditionally been male dominated teams.

Retaining skilled, engaged staff must be a key goal for every business and so we are committed to the NZ Skills Pledge. This will bring further investment in technology and training to help better futureproof our workforce.

Lastly, as you can see from the chart the Meridian Team remain well engaged with our business, our customers and our purpose.

While our strategic direction is largely unchanged and hopefully familiar to you. Obviously, responses to COVID and NZAS exit are now part of our future. Over the next few slides, I will cover off some highlights and some of the challenges in front of us.

We remain absolutely committed to demonstrating sustainability leadership and to our purpose of Clean Energy for a Fairer and Healthier World. Operationally we have many more runs on the board in terms of our emissions footprint, climate and carbon reporting and we have achieved changes in the certification of our financing and customer propositions.

At a more strategic level, debate on the merits and consequences of pursuing a 100% renewable electricity grid continues. We concur with virtually every study done that the current industry settings and pure economic fundamentals will deliver a largely renewable electricity system within the next 10 to 15 year. Eeking out the remaining 5 or so % of gas firming, will likely drive up the cost of electricity and reduce the incentive to electrify transport and industrial heat and that is where the real decarbonisation opportunity lies. Our strong view is government policy initiatives should focus on stimulating demand for electricity not supply.

I'd also suggest that a strong transmission grid is the single largest enabler of generation competition, renewables growth and ultimately lower prices to consumers. So, policies that support Transpower to continue to sensibly enhance the grid are also very important.

I joined this industry in late 2008 and since that time, collectively, the sector has delivered a more secure and more renewable electricity system. And most importantly, Kiwi's are paying less in real terms for electricity, than they did back then.

But energy hardship remains a real issue for many New Zealand households. COVID has in some cases exacerbated that as well as negatively impacting the cashflow and viability of many businesses.

We have responded by providing a greater level of support for our customers. As you will know, in 2018 we stopped clawing back PPD from customers who were late paying and during the pandemic, we have offered customers individualised payment solutions, we created a targeted credit fund for customers in real need, we implemented a blanket 'no disconnections' policy for Covid related debt and we suspended late payment fees. There is a cost to this, and we are carrying a higher level of debt provision as a result, but it remains the right thing to do.

We also wanted to do more to help families facing hardship, so we matched the $1M donation other generous kiwis made to KidsCan. With that additional money Kidscan are able to give children in hardship a handup and the best chance of an education, and hopefully help break the cycle of poverty.

We've shown support for our suppliers by shortening up our payment cycle to help support their cash flows.

And in recognition of the new challenges our staff faced during lockdown, we supported them with a working from home allowance.

As I said earlier, I'm proud of how our team have responded and more generally I think New Zealand businesses are playing their part where they can.

There was enough pre COVID organic demand growth to offset the short and dramatic hit to demand that came during the L4 lockdown. But it is difficult to get any kind of gauge on future demand, given the uncertain economic outlook ahead and the future exit of 5,000GWh of NZAS load from the system.

It is interesting to note that the sharp drop in demand during Alert L4 is of a similar quantum to what we expect to happen when NZAS closes.

To have a final TPM decision now in place is a welcome last milestone in a very long process. The Electricity Authority's estimates show Meridian's likely future cost reductions. However, it is worth noting these cost levels assume NZAS remains as a market participant. With their exit, we expect our share of HVDC costs to be higher than this FY24 estimate, but it is difficult to ascertain by how much at this stage.

On the negative side of the regulatory ledger, it is fair to say we were blindsided by the Authority's preliminary decision of an undesirable trading situation, relating to unprecedented flood events of December 2019.

Our focus at the time was on managing an enormous amount of floodwater through our catchments. It's not readily appreciated how well hydro generators do this. For a comparison you can look at the flood damage that occurred on the uncontrolled Rangitata River during December, which included nine of Transpower's pylons being wiped out.

The true level of avoidable spill during the flood is in the margin of error and the customer impacts are small. Clearly a few parties who speculate on FTRs and take exposure to the spot market missed an opportunity to profit during this time, but given prices throughout December were on average the lowest for the calendar year, it is hard to see how anyone can credibly claim to have been materially out of pocket.

At a technical level we believe the basis for the decision is incorrect as nothing occurred that is outside the past observed normal operation of the market. The preliminary decision also contradicts decisions made by the Authority in previous investigations and effectively re writes the rules for what defines a UTS including a new test that "prices need to be what the Authority would expect to see". Which is a very low bar.

Clearly, we don't think this is the Authority's best work, but we acknowledge there is a wide range of views on the matter. And we also believe that the Electricity Authority is a capable and constructive regulator, so being at odds with them on such an important issue is not where we want to be.

We would prefer to work with the Authority to find a sustainable solution and we believe that should involve using the code reform process, supported by consultation and appropriate cost benefit analysis to establish the need for change and how to best implement any change.

These views have gone into our submission to the Authority and we will see later this year what the final decision is.

On a much more positive note, the coalition government's climate programme is moving forward with the strengthening of the ETS. Caps, containment and industrial allocation phasedown will result in stronger price signals and that will enable more efficient investment decisions in emissions reduction. New Zealand has plentiful renewable electricity resources available to support this country's decarbonisation and I applaud the government's climate change response.

Also, it was great to see the Government's water reform programme, to improve water quality, sensibly recognises the role New Zealand's large hydro schemes will play in a better future for this country.

These reforms also put the concept of Te Mana o te wai (the mana of water) as the central concept of future water planning. The perspectives and value of iwi will be rightfully more important than in previous resource management processes.

And so to NZAS. To be clear, we are working to an August 2021 smelter closure date. There is dialog with Rio Tinto on a possible staged exit and I believe they are having further discussions with Government in relation to transmission costs. But I don't have anything further to provide on that currently.

Last month we outlined the steps we will take to respond to their exit. The list of potential mitigations is growing, and we are getting traction in some key areas.

Most importantly, Transpower have confirmed a May 2022 or earlier completion of the Clutha Upper Waitaki Lines Project. This project will allow all of the energy from the Manapouri and Clutha schemes to be exportable from the Lower South Island by at most nine months after the smelter's scheduled closure, and possibly even sooner.

In potential partnership with both Contact and Transpower, we are moving forward on our North Island battery development that will then further increase the economic capacity on the HVDC and allow export of more of the energy to the North Island.

We've taken the decision to defer the build of our Harapaki windfarm in Hawkes Bay. The project itself is shovel ready and economically viable, even with the smelter's hard closure scenario playing out. So, we will review the build decision as the uncertainty around the smelter exit starts to dissipate, but Spring 2021 would be the earliest possible commencement date.

Whilst we cannot save our way out of the near-term revenue reduction from the smelter exit, it does create the opportunity and imperative to further optimise the business cost structure. And in light of the likelihood of restricted Manapouri generation between August 2021 and May 2022, we are reprioritising asset management work which will lead to some near-term cost savings.

We are also fielding plenty of enquiries from parties who would like to establish alternate industries and take advantage of the renewable electricity available in the South Island. Some of these parties are very credible but any development is likely to be around three to five years away, so we are not relying on it as part of our immediate portfolio response.

Continuing the momentum we have established over the last two years growing our retail business is also a key mitigation measure. I've read some industry analysts calling out concerns around heightened retail price competition emerging. I think that is just the nature of the competitive market we operate in.

We've also noted comments made by the other large generators about how things may play out after an NZAS exit. It's clear we've got slightly different views on the risks and opportunities that our respective businesses face. And that's not too surprising.

From our perspective there are many moving parts and the worst of the news is certainly now out there. But I'd make the following overall observations:

Transmission is the enabler of competition and must be prioritised. Being a long generator in a market with excess supply is not likely to be a winning strategy. Hence you can expect Meridian's mitigations will focus on bringing our position into balance. In this regard helping to facilitate new load in the South Island, hands down, is the most valuable play for our business - followed by growth in retail market share.

Large volume inter generator deals have a part to play as they enable parties to better manage their risks through the changes ahead. But I would not expect them to have any real bearing on the economic fundamentals that will drive generation retirement and new development decisions.

In summary, an NZAS exit was not something we would have chosen, but at the same time it was kind of inevitable. In the mid to longer term we are in the unique position of holding a 5,000GWh renewable energy advantage and I am confident we will execute on our mitigation strategies and build an even more resilient business.

During the year we worked out how to gain access to the full consented range of Lake Pukaki. I know we have talked about it on a couple of investors calls previously but for completeness I wanted to touch on this again because it was a very successful initiative delivered by our hydro team during the year.

In simple terms we now have access to another 367GWh of fuel. That's the equivalent to a new medium sized wind farm for around $15m.

The additional GWhs also create greater flexibility to balance out storage and production, particularly where there are constraints on the HVDC. We have modelled that in the order of $10-$15M p.a. of energy margin uplift.

The next 5 slides provide an update on Meridian's operating units.

Our Customer Team's performance during the last year was awesome. We added over 1,100GWh of contract load in FY20 at improved average prices.

Brand strength, service accuracy, higher retention rates and reducing cost to serve have all supported growth across all customer segments, something we have continued to see during July and August.

As I said earlier, maintaining this momentum is massively valuable going into a future without NZAS. But we are also very aware that the competition isn't going away, so we'll need to get appreciably better to continue to win.

We hit record generation in New Zealand – in both wind and hydro. And whilst we enjoyed above average hydro inflows, the Wind Team managed to lift wind farm availability and our Wholesale crew navigated the significant period of interruption to the HVDC flows. So, I think on balance, we got the very most we could have out of the generation fleet this last year.

The strong generation volumes obviously helped offset the expected softening in wholesale prices, which saw our average generation price fall 28% in the year.

The forward curve suggests the gas scarcity that has led to elevated prices over the last couple of years is going to be overtaken by the likelihood of NZAS closing next year. A period of soft wholesale prices is probably inevitable.

Like in New Zealand our Powershop Teams in Melbourne and Masterton continued to deliver the goods. Electricity customers and sales volumes are up around 24% and our carbon neutral Victorian gas offer is gaining real momentum.

Our retail margins remain solid, but headline prices have fallen in line with wholesale price reductions.

The Australian market isn't without its COVID impacts either. Lower industry churn rates have slowed our acquisitions in recent months. We've also boosted our doubtful debt provisions significantly.

We still see plenty of upside growth potential for Powershop in Australia.

The now familiar NSW drought conditions persisted through FY20. However, in what is hopefully something of a circuit breaker, storage is improving quickly, and we are now have the novelty of near seasonal average storage.

Generation prices were well off during the year with record domestic gas production and less LNG exports ultimately driving lower electricity prices. Our Team got ahead of the softening market and hedged a large proportion of our generation to both Black and Green prices but the outlook for FY21 will be certainly be more challenging.

However, over the medium to long term the trading conditions still look favourable as Australia comes to grips with their decarbonisation challenge and as the aging coal fired generation fleet marches toward their inevitable retirement.

So, we continue to actively seek generation development and firming options to support our planned growth of Powershop. Most recently, we completed feasibility work on the 130MW Rangoon wind farm development option and we have made good progress on a firming battery option, adjacent to our Hume hydro station.

Mike will talk to the project to migrate the Meridian customers to the Flux platform shortly. I'll just make some overarching comments. It is taking longer than we expected and will cost more but not to a material degree. Most importantly we are still confident in the benefits that drove the business case and we've migrated over 100,000 customers now with very little fuss.

Flux's continuing relationship with Powershop UK is uncertain though. Powershop UK are owned by npower and npower has now completed its merger with E.ON. Both npower and E.ON have announced their intention to move their customers to the Kraken platform (owned by Octopus Energy), but as yet there is no decision about the Powershop UK customers.

So on that not so cheery but also not too surprising note, I'll now hand over to Mike to talk to the Financials in more depth before I round up at the end. Thanks Mike.

MIKE ROAN: Thanks Neal, we have just had another tremendous year.

And the results that I will talk to in a minute are driven by a very talented and committed team in New Zealand and Australia that not only delivers in the current environment but has been testing how it might overcome the set of challenges that closure of the Tiwai aluminium smelter might bring.

So alongside taking pride in the outcomes from FY20, if that plays out the team is looking forward to proving to you, our shareholders, that we can create more value than we would have, had it stayed.

Time will tell whether the smelter does go of course but competition is a wonderful thing and there is plenty of value to unlock looking forward. But back to the year that was.

As you all know, the financials were solid. While accounting measures like Net Profit After Tax were well off last years run rate, non-cash items drove that reduction and we tend to look at EBITDAF as both a comparative measure across energy businesses and across time.

And the small lift in EBITDAF this year to $854m is very satisfying.

If I dive into that figure a little, and as I stated during our interim announcement, this outcome was driven by outstanding execution in NZ, where EBITDAF lifted by $20m, while Meridian Energy Australia more than held its own as the team there lifted EBITDAF by $2m .

The reduction in transmission expense in NZ that started to flow through in April didn't hurt either but our increased costs, while being well signalled, brought us back a touch. All in all, and as I say very satisfying.

Alongside EBITDAF, I tend to look to operating cashflows as my measure of underlying performance. And here again, we had another strong year with net cash from operations at $605 million. If I compare this to operating cashflow from two years ago, it is up a whopping 42% or $178 million. That said, it is $30m lower than last year but largely because cash tax was $43m higher in FY20.

And this strong cashflow is crucial, not only given the change coming at us, but also as it has helped maintain a strong balance sheet while letting us support our people, customers and suppliers during the first lockdown due to COVID. It also meant that financing needs were well down on last year, even as we lifted the ordinary dividend.

As a result, net debt only lifted $52 million over the year and the key S&P ratios that support our BBB+ credit rating, "net debt/EBITDAF" and "EBITDAF Interest Cover", at 1.8 and 10.3 times respectively, did not move substantially during the year.

Which is a perfect segue to dividend flow.

On July 10 we announced the cessation of the capital management program so that does not factor into the conversation today. However, given the strong year, and our healthy cash flow and balance sheet, we have decided on a final ordinary dividend of 11.20 cps.

This means the total dividend for FY20 is 19.34 cps.

While this represents a fall of 9% on last year, that fall is driven by the cessation of the capital management program. With this in mind, the lift in ordinary dividend of 3% is pleasing.

And to save on valuable question time, we recognise that there is uncertainty about future earnings and cashflows of the business, but we won't be moving away from our policy of not providing earnings and dividend guidance today.

So on to NZ performance. As you may recall we had a strong first half year in NZ. The best first half ever in fact.

While the second half wasn't as strong, the teams navigated a three-month HVDC outage expertly and without fuss (as I suggested they would), COVID and towards the end of the year, the beginnings of a drought that has extended into August.

At the same time, I can categorically say that we have a Customer business with strong momentum. In Neal's earlier slide you would have seen that customer numbers, volumes and prices were all up on 2019. Here you can see how that momentum translated into value.

Contract sales across our customer segment lifted by $142 million year on year and that in turn delivered an $18 million lift in Energy Margin for the Customer team. At the same time, strong generation volumes supported higher wholesale derivative sales but as prices fell year on year, the value of those derivative sales fell by $17 million.

The wholesale team also did a stellar job of managing risk during the 3 month HVDC outage where they bought over 500GWh of derivatives and 150MW of FTRs over the past four years to make sure our position remained sound. And these hedges contributed to the $43m lift in the cost of derivative purchases.

I won't focus on COVID specifically as while it did have a material impact on electricity consumption in April, the effect was shorter and smaller than expected. Overall, NZ Energy Margin lifted by $14 million.

That may not sound like much and it is down from the H1 uplift of $76m but I can tell you that retailing and wholesaling electricity is very competitive and improving results takes considerable coordination, discipline and grit. So both teams have done a tremendous job.

And while we are on NZ, as you know we are contesting the Electricity Authority's preliminary findings that there was a UTS in December 2019. While we do this, we have booked a $5 million provision in case the regulator maintains its position. We do not believe that would be the right outcome of course, so time will tell whether this is a reasonable call to make or not.

Moving on. As you can see from the graph, the customer story in Australia is similar, strong retail performance with electricity and gas customer numbers and contracted sales lifting. The wholesale story is similar too, with wholesale prices falling materially during the year.

It can be a bit tough to pick this apart from this side of the ditch but the volume growth across both electricity and gas businesses drove the $29 million lift in contracted sales shown here whereas the price falls held this lift in check. And while wholesale prices did fall materially, with VIC FY20 futures trading $110MWh in November 2019 but falling to $73MWh by June, as can be seen the position was well hedged and those derivatives added $9m to the teams result.

We also had a significant benefit from having hedged our LGC sales, which settled in February, at much higher prices. We gained A$14m from this but unfortunately that gain will not be repeated in FY21.

At the same time, Meridian Australia's retail electricity prices, net of distribution, fell by 8% over the year. And the reason they fell, is that there are two regulated price frameworks in Australia, one for Victoria, Victoria Default Offer or VDO, and another for the rest of the National Electricity Market, Default Market Offer or DMO. As wholesale prices fall, both VDO and DMO track with them and as customers can access VDO and DMO offers from retailers, all prices tend to fall or rise alongside those frameworks. While I won't do the calculations justice here, both use wholesale prices as a component of their calculations, and therefore they both fell and retail prices went with them.

And before someone says we should deploy this here, there are plenty of pitfalls in both and given volatility in underlying wholesale prices in NZ, I doubt customers here would accept the price swings that would bring.

At the same time, the Australian drought that I talked about this time last year, continued. For the full 12 months of FY20, the Green State hydro assets only produced 113GWh, down from 203GWh the previous year and a full 175GWh off their average generation levels.

The good news is that while the above dynamics were in play, Meridian Energy Australia managed to lift its Energy Margin contribution by $4 million. This is a solid outcome, given at Interims the team was down $1 million on last year and I noted that should the drought extend, our second half performance might be challenged.

As we sit here today, there is some further good news, in that the drought has broken and hydro storage lakes are filling nicely. But this is tempered by the fact that wholesale prices remain low. So, the Australian business is in for another bumpy ride in FY21.

At last years results announcement, we looked to set expectations in terms of cost by introducing a range for both opex and capex.

At that time, we said that FY20 opex was likely to fall in a range of $280 to $286 million. I'll come to the waterfall chart in a minute but FY20 opex actually landed at $294 million so well above the top end of that range. At first blush, that is not flash. But, as with most things, it is explainable. To do that, I first want to talk to the table that provides a legend for the waterfall chart.

In FY21, we have moved Electricity Metering expenses into Direct costs. We have done this as Electricity Metering expenses tend to move up if customer numbers are growing, and down if they are not. So, by removing this category, you should be able to gain further insight into operating expense movements generally.

Therefore, to provide a comparison between FY20 and FY19 we need to deduct Metering expenses from operating costs for both years. We also need to adjust for IFRS16 that I talked to at our Interim results – simply put, implementation of that accounting standard drops operating costs by $6million Year on Year, and of course lifts EBITDAF by the same amount.

Having made both adjustments, the FY19 operating cost base was $243 million and in FY20 it lifted to $258 million. This lift in cost was due to the following elements.

A provision that we took for holiday pay of $6 million. The reason for this is there is a risk that Meridian has to pay holiday pay on incentives and this matter is currently before the courts. We thought it prudent to capture this year, just in case.

There was also a $3 million lift in asset cost that is largely due to the Ohau refurbishment program, while we are also in the closing stages of a 3 year remediation program at Te Apiti windfarm that brought that farm back to respectable levels of availability and that program cost a little more than expected.

I will talk to our NZ asset maintenance program further at Interims as with the Tiwai exit in front of us, we will likely reset our work program for Manapōuri, White Hill and the Waitaki assets. If we do do this, it will reduce our FY22 and 23 opex materially and as we near FY23, we will also begin to see the benefits of the Customer teams transition to Flux. Both arrive at the right time. But I will talk to that when we present our interim statements next February.

The Australian asset cost increase was driven by Senvion, who provided O&M services at the Mt Mercer windfarm, being placed into receivership. I mentioned this at our Interim announcement where I said that we were able to leverage wider relationships to manage this failure. We did this and as a result, we now have Siemens as our O&M partner at Mt Mercer. This outcome did cost us some coin, as you can see here, and while most of this was legal cost related to the receivership and renegotiation, there was about $0.5m that represents an ongoing cost, as opposed to a one off.

Insurance costs are an ever increasing, but important, nuisance and Neal talked to the COVID impact – here we simply frame up the costs across outstanding leave balances, working from home benefits and KidsCan, who did and do incredible work by the way.

And while it isn't captured as a cost item here, we did lift our provisions for doubtful debts from $5 million in FY19 to $15.7 million in FY20 given the risks COVID poses for the wider NZ and Australian economies. We haven't experienced any erosion in the quality of our debtors to date, so we will see in time whether this was overly cautious or prudent.

So $258 million in opex came around pretty quick but when you strip out the FY20 one offs like COVID and holiday pay, our opex lifted by $8million year on year to $251 million.

Looking forward, we expect to spend between $261 and $266 million in FY21 or between $10 and $15 million more than FY20 when removing those one offs. The lift largely comes from growth initiatives that I don't want to lay out today for competitive reasons, but I will provide insight on them in time, either as this year progresses or as they deliver fruit. As I said right at the outset, we can see opportunities to unlock value given Tiwai's nearing departure in NZ but we can also see them in Australia.

As mentioned earlier, Net Profit After Tax fell by a sizeable 48%. But when you add the fair value movements in electricity and treasury hedges, impairments – that I will talk to in a minute - and the tax effect of those adjustments; the non-GAAP measure, Underlying Profit After Tax, only fell by 5% year on year, but was still well up on 2018.

As for those impairments, last year we signalled that we were likely to take further impairments on our Australian wind farms given forecast revenue streams for those assets fell faster than the depreciation expense associated with them.

Back then we took a $5 million impairment on Mt Millar. This year that lifted to $33 million and the fall in Australian futures curves, saw us impair Mt Mercer wind farm by $24 million as well.

And finally, in a note to the financial statements, we have provided an indication of the impact that an NZAS exit might have on the valuation of our generation assets, should the smelter shutdown in August 2021. While that impact will become clearer in time, we consider that it could be an accounting devaluation of between $690 million and $1.3 billion.

As I note, the actual outcome is uncertain and we will update it again when we present our interim statements, but if it proves accurate, this is similar to the uplift in value written into last years financial statements.

Not much to talk to here really. We spent $64 million of capex in FY20 which was below our forecast range of $70 to $80 million. We will roll that same range into FY21.

In saying this, we might need to lift that forecast during the year as we expect significant progress on the project that is moving our customers over to the Flux platform. That initiative has been making good progress, but as captured in our Integrated report, it has been re-baselined. The original schedule had completion of that transition by December 2020, and a total cost for the initiative of $31 million. We now expect it to be complete by September 2021 and total costs have lifted to $48 milion. And while those changes drop the net benefit of the initiative, those benefits still remain strongly positive and they continue to tell us that the Flux engine has real value moving forward.

So, if we do revise that range upwards it will be because that initiative is making sound progress.

I have already talked too much of this slide so I only wanted to cover one thing. And as well as unveiling our annual results today, something else we are unveiling is Meridian's new Green Finance Programme.

You will be aware, as a company we are deeply committed to sustainability. It is at the heart of our purpose, and one of the key reasons we only generate electricity from renewable resources. We know how important it is for us to play our part to help combat climate change, and recognise the critical role renewable energy plays in driving decarbonisation of the wider economy.

Meridian has a deep understanding of how climate change can impact its business, now and in the future. We were the first company in New Zealand to prepare and publish a climate risk disclosure report. In addition, Meridian reports to the Carbon Disclosure Project and the Dow Jones Sustainability Index, and is committed to the Sustainable Development Goals 7 and 13 which have been integrated into our business and our business reporting. As part of Meridian's ongoing commitment to sustainability, we are adding this green finance program to those initiatives.

Our overarching goal is to reach a wider community of likeminded investors, and to do this we need to keep building our credentials with those who may not know Meridian Energy directly, but are looking to place their money with businesses like ours. The Green Finance programme should help us do that.

It will also be used to finance or refinance projects and assets that deliver positive environmental outcomes.

As of tomorrow, all of Meridian's existing funding will fall under the umbrella of this program and our Retail bonds listed on NZX will be designated as "Green bonds". We believe this will benefit investors by providing an opportunity to invest in a broad range of accredited green debt instruments. I'd like to thank Westpac for their help in implementing the Programme and you can check out our website for more information.

So, alongside a great result, this is a nice addition to unpin the fact that we remain one on NZ's largest and most sustainable businesses. Neal, back to you.

NEAL BARCLAY: Thanks Mike.

So I think today draws a line under a remarkable couple of years of financial performance. Based on forward wholesale prices, I wouldn't expect to see that level of performance replicated, at least not until the market fully transitions away from the loss of NZAS. That said I can assure you that Management and the Board remain strongly focused on managing the business and our balance sheet in a way that delivers a competitive dividend to our shareholders.

The ongoing effects in both New Zealand and Australia of a lasting global pandemic is still highly unknown. The economic contraction and the lasting loss of business activity must ultimately weigh on electricity demand.

But if I take a 'half glass full' perspective, we now have certainty an NZAS exit will happen, if not in a year then certainly within the next 4. The mitigations that we and many others in the industry are now turning our minds to, most notably Transpower, will make more renewable energy available more quickly than was the base case assumption prior to 9 July. I believe Meridian's low-cost asset base, strong retail brands and our exposure to Australia still leaves us strategically well positioned to lead the sector.

We've certainly got some near-term headwinds, but beyond that, the Meridian valuation and the sector's fundamentals strong. We are at the start of a great opportunity to reshape our business, our sector and drive New Zealand's decarbonisation. And that is something we will all benefit from.

Thank you, so that's our presentation. We're now available to take some questions.

>> Thank you very much sir. Ladies and gentlemen, if you would like to ask a question, please press 0 followed by 1 on your telephone keypad and wait your name to be announced. That is zero followed by 1 on your telephone keypad.

>> Your first question is from the line of Grant Swanepole from Jarden. Please go ahead, sir.

GRANT SWANEPOLE: Good morning Neal and Mike. Couple of questions. Firstly, on Harapaki. You delayed your decision. I was under the impression that you didn't have the ability to extend your resource consent. Can we just start on how far you have been able to extend that consent until?

NEAL BARCLAY: Grant, the consent lasts until 2023. We would have to have a meaningful project underway sort of late '23 to - you know, the live within the existing consent conditions. We have a few years of time to work with.

GRANT SWANEPOLE: So that means you have a 6-month window to pull the trigger. Is that correct?

NEAL BARCLAY: No, no, 2023 Grant. We can pull the trigger effectively earlier in that year.

GRANT SWANEPOLE: Oh, OK. Thanks. On Flux, can you remind us what the benefits were you mentioned about a year ago? Was it about 10 million a year?

NEAL BARCLAY: Yeah, about 80 million over a 10 period. So - and we have already actually taken some of them onboard with the restructure of our ICT group a year-and-a-half ago. With the additional cost on the actual project delivery, those benefits are reduced by about 15 million. But we're still looking at about 70 to 75 million over the term of the - life of the asset, if you like.

GRANT SWANEPOLE: Thank you. The UTS outage, the $5 million - is that the max penalty do you believe? If it's not, what do you reckon the range of impacts and the timing of when you might have to pay up?

NEAL BARCLAY: I think the - it's interesting. UTS isn't a penalty regime in itself. So, if the EA want to restate prices, if that's where they go, then it is quite a complicated process, because you'd have to restate prices for about 3,000 separate trading periods, which creates some complexity in its own right. But when we have worked through and assumed a very low price, like around $6 or so, $5 million would be the maximum impact on our business.

GRANT SWANEPOLE: Thanks. Genesis in their results presentation mentioned that they would be looking for a long-term PPA with yourselves. Can you talk to the trade-offs that you see in terms of putting one of those in place to give yourself some earning certainty in the near-term, against what you might give up in the longer term, by putting in a 10-plus year contract with them?

NEAL BARCLAY: Yeah. It was interesting to see that from Genesis Energy because we certainly haven't agreed with a 10-year plus contract with them. We are interested in talking to them on a range of issues, and other party for that matter. Certainly we would be looking at a, if possible, we would be looking in transition hedges, so maybe out to five years.

We have also got the virtual asset swaps that start to wind down in 2023, and we would like to talk to both Mercury and Genesis about extending those transactions. They worked well. They are market linked, so they don't leave anyone exposed and outside of the market for a long period of time. We will always - as a South Island hydro generator, be interested in talking to parties about peaking or firming load in the North Island. So there is a range of options to discuss with our competitors. You would have got the message earlier that our strongest - from a Meridian perspective - our strongest option is to grow load in the South Islandm and beyond that to continue with the momentum that we have got in our retail side of our business. So, a long-term hedge would have to be balanced off against those aspirations.

GRANT SWANEPOLE: Thanks. Nice segue to my final question - can you give colour on the demand response in the South Island that you were talking too earlier, other than dairy that we were all expecting something to happen in.

NEAL BARCLAY There is a range of parties that want to talk to us, and talk to other folk as well. I don't want to get to the details on any of them, because the conversations are commercially confidential to a certain extent but you would have heard talk of data centres, hydrogen facilities, carbon capture facilities. There is a range of industries and some pretty credible players behind them that are pretty keen to engage.

GRANT SWANEPOLE: Thank you very much, Neal. That's it from me.

NEAL BARCLAY: Thank you Grant.

>> Thank you very much. Your next question is from the line of Andrew Harvey-Green from Forsyth Barr. Please go ahead, sir.

ANDREW HARVEY-GREEN: Good morning Neal and Mike. Couple of questions from me, following on from Grant. First, just in terms of your ability to retail on the North Island and then your sort of confidence levels about being able to do that successfully, given the South Island basin and dealing with the basis risk?

MIKE ROAN: Thanks Andrew. We are very confident to run our retail business in both the South and North Island. There are products we need to purchase to be able to do that, but the team has been well aware of this risk, and understands that risk pretty well, given we do retail in the North Island today. So, they have either bought a number of products and will continue buying a number of products to help manage those exposures. But I think the key message, Andrew, is we're confident our capacity to grow that position and manage the risk associated with it.

ANDREW HARVEY-GREEN: OK. Thanks. And following on, around the Genesis question and what Genesis is saying, so they made it pretty clear that they weren't interested in the short-term contract. I suspect five years might be viewed by them as too short term. How comfortable are you about operating without any agreement with Genesis? Is that a plausible scenario?

NEAL BARCLAY: I'll tell you one thing I'm not comfortable about is having a negotiation on intergeneration hedge in public. We will probably... (LAUGHTER) We will probably park that there. But, like I say, for us - I understand their position. But our position is different. You know, these things, you tend to work through and try and find a middle ground. And we're not only talking to Genesis about the sorts of cover we're looking for for the future.

ANDREW HARVEY-GREEN: Sure. OK. And last question from me was just around transmission costs. So, I think you provided some guidance around the DC cost expectations for FY '21. I'm assuming the other connection charges will be dropping as well. Are we sort of looking at around about 70 million-odd all-up for transmission costs as a reasonable assumption for FY '21?

MIKE ROAN: Yeah Andrew. Slightly higher, but in that ball-park.

ANDREW HARVEY-GREEN: OK. That's great. Thanks.

NEAL BARCLAY: Thank, Andrew.

>> Thank you very much. Your next question is from the line of Stephen Hudson. Please go ahead.

STEPHEN HUDSON: Good morning, Neal and Mike. A couple of quick ones from me. Firstly, I wondered if you could have a stab at estimating the cost of the HVDC outage over the second half. Secondly, I think Standard & Poor's estimated that your trough EBITDAF hard exit would be around about the $470 million mark. I wondered if you can give us a comment on if veracity of that number. Thirdly, can you give us an update on the Waitaki region consenting and what, if any, risks surround that process. And then just lastly, if you can sort of sweeping back to NZAS, give us the feel for how the $50 to $70 million step out in your offer actually behaves and why there is that step up?

NEAL BARCLAY: I will cover the last two, you cover the first two.

MIKE ROAN: Yeah. Hey Stephen, the cost of the HVDC outage hedging, I mentioned in my notes that we bought about 500 gigs of derivatives and about 130 odd megs of FTRs to cover that position. But they were brought over a reasonable period of time. You would have noted that our overall cost derivatives lifted by 43 million over the year. Much of that was due to covering the HVDC outage. In terms of the S&P forecast for EBITDAF, I think you mentioned 470 mil. You know we don't provide guidance on that but we're probably a bit more optimistic in our opportunities as we approach that year. So, that would be my response to that number specifically.

NEAL BARCLAY: Stephen in terms of the Waitaki region consenting, that process has been going well. We have had a strategy in play for three years. We are maintaining strong relationships with all the key stakeholders, particularly those that we think will be critical in the end decision. And I'd call out Ngai Tahu, the Department of Conservation, and ECAN obviously. I point to the changes in the fresh water consenting - well, fresh water regulations that the Government's announced. They do actually point to the importance of maintaining flexibility for those major hydro schemes around the country. So that supports our position in the reconsenting process as well. So yeah that is tracking well. No real red flags. But it is a big process. It will go right to the 2025 deadline, I suspect.

In terms of the step-up in the NZAS offer that we had on the table before they decided to exit New Zealand, I think that's what you're referring to. It is kind of moot at this stage Stephen. It isn't part of the transaction going forward in terms of the staged exit deal that we have got on the table. It had a number of components, but the reason why it stepped up between now and 2023 is we had a demand response part of the package on the table and that would replace, or a component of, if not most of the existing swaption that we have the Genesis that winds down in 2023. And there's been no secret that Contact have provided some support for the offers that we've had in place and the nature of their pricing changed a wee bit as well. That sort of led the offer to improve over time. The other bit that was part of it was potentially a transmission underwrite. But, again, that's all kind of moot and history because that's not what we ever talking about with the staged exit offer.

STEPHEN HUDSON Clear. Thanks, guys.

NEAL BARCLAY: Thank, Stephen.

>> Thank you very much. Once again, zero followed by 1 on your telephone keypad. Wait your name to be announced. That is zero followed be a1 on your telephone keypad. Thank you.
Your next question is from the line of Nevill Gluyas, from Jarden. Please go ahead. Sir.

NEVILL GLUYAS: Good morning, team. Just a few questions from me. Just in terms of demand stimulation ideas you have on the South Island, what's the sort of earliest time frame you think we could see some material growth there? Are we talking three years to 500 gigawatt hours? 3 years to 200? Just to set some envelope around our expectations.

NEAL BARCLAY: That's really hard, Nevill. I would expect - you know, maybe a thousand gigawatt hours... Depends on the nature and who actually gets their business case up and what actually ends up happening. Three years would be the earliest for a material chunk of load, I think, and probably within five years - hopefully - you know, we would have filled the entire gap.

NEVILL GLUYAS: Great. And what sort of gap size do you think that is?

NEAL BARCLAY: Well, we're losing 5,000 gigawatt hours with the NZAS exit. There's the potential to grow demand to that level and beyond, to be frank.

NEVILL GLUYAS: Right. OK. That's great. Thank you. Next question - just on the UTS. You suggested maybe a code change might be the better way to address the issues, that the EA is concerned about in the UTS decision. Preliminary decision. Can you suggest what sort of code changes you think would be best?

NEAL BARCLAY: What we have put in our submission is that we would be up for talking about some sort of code change that went to spill pricing. It seems to be...

NEVILL GLUYAS: Gotcha

NEAL BARCLAY: ...an issue that they are concerned about. Like I say, I don't think we have done anything inconsistent with practice previously adopted by ourselves and other generators. But it is a concern for the Electricity Authority. We should address that head-on, I think.

NEVILL GLUYAS: OK. That's useful. Thank you. In terms of Flux out in Europe, if - do you have an option to withdraw from the scheme? Can you - I guess I'm wondering whether or not you can take the Flux idea to other potential partners over there if Eon is going to move on with Kracken.

NEAL BARCLAY: We had an exclusivity arrangement with nPower. But that expires at the end of this year, if they don't hit certain customer targets. And it appears they won't at this stage. So we're locked in. We do have a 2-year term nation right on the contract as well. With the chunk of fixed revenues associated with that. So, we have a wee bit of time to work our way through it but as I say, we don't really have any clear guidance from nPower or Eon at this stage in terms of what they want to do with the Powershop UK customer base.

NEVILL GLUYAS: Thank you. Very useful. The last question from me was just in relation to your Flux conversion here in New Zealand. I suppose it's a difficult time, given what we think might be happening with the retail market, competition increasing, to be changing your billing platform. Are you comfortable that you're sort of in a good position to compete for new customers and potentially elevated levels of churn as you go through that transition?

NEAL BARCLAY: Yes. I mean, it's running slower than we would have liked. But it should be completed by September next year. We already have 100,000 customers on it. We will have most of the mass market customers on it before the end of this calendar year. And really the time delay is down to the complexity in developing the product to manage the CNI segments.

NEVILL GLUYAS: Great. OK. That was very useful. Thank you very much.

NEAL BARCLAY: Thanks Nev.

>> Thank you, sir. There are no further questions at this point. Mr Barclay, please continue. Thank you.

NEAL BARCLAY: Thank you, all, for your attendance. We will wrap it up there. Have a good rest of the day. Thank you.