TRANSCRIPTION

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[START OF TRANSCRIPT]

Neal Barclay: Tēnā koutou katoa. Good morning, everyone. Welcome to Meridian's profit announcement. I'm Neal Barclay, Meridian's Chief Executive. I have with me our Chief Financial Officer, Mike Roan. We'll talk through aspects of the financial results for the last year and we'll also provide perspective and context for the current market conditions.

On balance, we think the business performed strongly during FY24 across the board and we knocked off several major milestones. The top of that list was the long-term deal struck with the New Zealand Aluminium Smelter, or NZAS. The two standout features of the deal were firstly the 20-year term. That has removed massive uncertainty for the sector and allowed us to reset both our dividend policy and renewable build programme. And secondly, the Demand Response Agreement, and we're seeing just now how valuable that has turned out to be.

We delivered the Harapaki Wind Farm on budget and on time. The wind farm is now fully operational and early wind yields are absolutely fantastic. And we've well progressed on our grid scale battery at Ruakākā in Northland. I'll talk about our renewable pipeline shortly, but at a headline level, we have a line of sight now to $3 billion investment in renewable projects and we intend to make that through the remainder of this decade.

We've also lodged our re-consent application for the Waitaki Hydro Scheme. This will be the largest consent ever granted under the RMA in New Zealand. We have support for the key affected parties, and we are confident in the outcome and that is essential to this country's low-carbon future and security of supply. And we've made the decision to put on hold our Southern Green Hydrogen project, or SGH.

Global inflationary pressures have presented significant headwinds for SGH and we will not progress to detailed design until the economic prospects for the project have improved. All up though, financially it was a great result. And over the course of the year, we continued our excellent momentum in customer sales and hydro inflows turned up with almost impeccable timing throughout the year. That was obviously too good to last and that is my segue into some comments on the current conditions.

Now, droughts are insidious things. They come on slowly, but then the effects start to compound rapidly as they extend. As shown on the top right graph, between May and mid-August, inflows were the lowest on record across the two catchments that we manage. That has led to unprecedented low storage levels in the Waitaki Scheme. The story is similar in all other hydro catchments across the country and that's turned into quite a challenge for the sector.

But the reason why wholesale prices have been so high in recent weeks is because of the scarcity of gas, which is a key backup fuel for when the system is short on hydro. There is just not enough domestic gas available for either gas users or electricity generators at present. And what is available is very expensive.

Prices peaked three weeks ago in the electricity market and they reflected the fact that the diesel generator at Whirinaki was running during that week. But the industry is clearly responding and several significant actions have been taken in recent weeks. These include creating the opportunity for early access to contingent hydro storage if we need it, buying gas off Methanex to use in electricity generation and calling demand response options with NZAS so they reduce consumption and make that energy available to the market.

Meridian is investing heavily in each of these actions to ensure security of supply. As a result, we've slowed the drawdown on the hydro lakes and wholesale prices have moderated, although they are still hovering between $200 and $300 per megawatt hour on average.

For Meridian C&I customers who have or are coming off contract between July and the end of October, we are rolling their contract pricing through to 1 November. Hopefully some of the heat will have come out of the wholesale market by then. We're also offering extended duration contracts with levelised fixed prices to take the sting out of the current prices when customers do recontract.

So we're doing all we can to insulate our customers from wholesale volatility. We still believe wholesale prices will soften considerably over the next few years as more renewable projects come to market. And clearly current market prices do not impact the vast majority of our mass market customers as our internal transfer price has built up over a number of years.

Back to the position today. The inflow deficit over the last few months amounted to about 1,000 gigawatt-hours compared to average and Meridian's combined storage presently sits around 710 gigawatt-hours less than average. The rain events over the last week have brought welcome relief, but we still have work to do to restore the lake levels and we're relying on the ends of demand response and financial contracting to do that.

The hedges we have invested in total around 800 gigawatt-hours, so if we get anywhere near average inflows from here, they should do the job. Now, the average cost of those hedges is around $258 per megawatt-hour and that will impact our bottom-line over the next few months.

Lake Pūkaki is New Zealand's largest hydro storage lake by far. Contingent storage represents up to five metres of water for Meridian or 545 gigawatts of energy. This is material and at this stage we're not likely to have to use it, but we do have a plan in action in case we do. That plan includes layering in 26,000 tonnes of rock to armour the lower reaches of the Pūkaki High Dam as we drop into the contingent zone. We've previously stockpiled most of the necessary rock near the dam for this eventuality and we have the team on standby.

I think FY25 will be a battle of inches. A few of us in the business have seen something like it before and we are well prepared for it. And of course, everything changes if we get a decent amount of rain.

Now, when we signed the demand response agreement for NZAS in May, we did not expect we'd be asking them just one month later to reduce electricity consumption by the maximum amount and the team at the smelter certainly weren't expecting it either. So, I would like to acknowledge the NZAS team, because operationally it's a considerable task to turn off a pipeline. They managed it well and in fact, they managed it faster than was contractually required.

We have agreed with NZAS that they will make an additional 20 megawatts of demand response available. So, they are leaning in heavily to help manage the effects of this drought. All up, the amount of curtailed demand at the smelter will be around 650 gigawatt hours and that's material in the context of the current energy challenges. Obviously, we don't want to make a habit of this and the historic weather patterns suggest we won't. But this is a great example of the value that well-organised and well-compensated demand response can bring to the market. This arrangement makes financial sense for the smelter, as they are compensated for the reduction in demand.

No one is losing their jobs. In fact, their employees and suppliers are busier than ever and the electricity system will rely less on gas and coal to fill the energy gap.

And from Meridian's perspective, as a risk management tool, customer demand response can be more reliable than thermal swap type agreements. Thermal swaps typically have suspension clauses that cover instances where fuel is not available or plant failure occurs. So, we're working with other customers who can flexibly manage their demand to strike similar demand response agreements.

We've embarked on considerable operational change at Meridian over the last couple of years. We've reshaped the operating model in our generation business, and we're in the process of adopting a more agile operating model in retail. But putting the buzzword bingo to the side, what we're really trying to achieve is speed to market, speed of decision-making and ultimately more efficient outcomes that benefit our customers.

The change can create uncertainty for people, so it has been pleasing that staff engagement continues to steadily trend upwards, and that reflects our focus on creating an inclusive, high-performing and safe work environment for our people. On this slide, we've highlighted a few areas of focus and improvements to our approach to wellbeing and our overall health and safety management systems.

At our June Investor Day, our Chief Customer Officer, Lisa Hannifin, unpacked the retail opportunities we intend to pursue. That evolution will enable a fundamental shift, we believe, in the role customers can play in our industry. Where customers can shift their demand to less congested parts of the day, or year as it turns out, we can pay them for that flexibility and save them money.

We can also point to good progress on operational outcomes, like our Energy Wellbeing Programme, new demand through process heat conversions, and sales of renewable energy certificates. But right now, our customer focus is on the impact of these high wholesale prices.

Spot-exposed consumers have experienced significant price increases and that is hurting them, the employees and the communities where they operate. But spot prices during extended droughts tend to be high, and these are sophisticated businesses who have assessed the risk and chosen to take exposure to the spot market.

The Electricity Authority requires businesses who take spot exposure to complete a financial stress test each quarter to demonstrate their resilience to high prices. The stress test case for this current quarter was assuming a $400 average price for three months.

That's probably higher than what will actually transpire. Fortunately, 99.9% of our customers are on fixed prices and this demonstrates the value that a vertically integrated business like Meridian can offer. We remove risk for our customers by managing wholesale price volatility over time.

And today that is very clear and present for most of them. And as I mentioned earlier, where we have C&I customers whose contracts are ending, we've chosen to support them by rolling their contracts through to 1 November this year. The thing that will put most pressure on retail prices in the near term is the significant uplift the sector faces in transmission and distribution costs.

The Commerce Commission are determining a significant increase in costs from 1 April 2025. While increased network investment is one factor in that, much of the forecast uplift is driven by the increased cost of capital due to high inflation and interest rates that we're all experiencing. The ComCom's draft proposals include smoothing to reduce the extent of a step change in any one year.

But even so, the average distribution cost increase for our customers next year equates to around 9% of their total bill. The ComCom will finalise its decision in November. We are working through what that means for customers, but I think we will see the prolonged period of sub-inflation price increases coming to an end, or at least paused until the next ComCom regulatory pricing period for the monopoly parts of the system also comes to an end.

This year we published our first climate-related disclosures under the newly mandated reporting standards. That contains more detail than is probably helpful. But if I boil it down, we remain sharply focused on our Climate Action Plan, which delivers a significant renewable pipeline, customer decarbonisation, and manages our own emissions reductions as we do it. In the year ahead, we will build out how we deliver on our new net-nature-positive commitment.

While our existing approach to mitigating the impacts of our operations is already robust, we will better define and enhance our contribution. And this work should enhance the consenting processes by giving communities confidence in us as a leader in sustainability and a developer of new renewable generation. And on that score, we are making good progress on our battery at the Ruakākā BESS, and we expect it to land it inside our original budget.

The delay in Transpower's work programme is likely to push commissioning to the first quarter of 2025, but it will be in place well before next winter for sure. We've also progressed the consent of our Manawatū battery project, and we note our competitors are now also seeing value in grid scale batteries, and I think that's good for everyone. The sector does seem to cop criticism for a lack of investment in new generation.

That is a story that is entirely baseless and flies in the face of facts. The facts are there's been no real or sustained demand growth in New Zealand since 2010, and so the electricity system is the same size as it was then. But in that time, around $10 billion of new generation investment has occurred, and virtually all of that has replaced ageing coal and gas-fired plant.

In 15 years, the industry has replaced around a quarter of current capacity, mostly through geothermal and wind developments. In a sense, all of that investment has just got us to the start of the energy transition, but to suggest the sector has not invested is just plain wrong. Also, as a country, we only took up the challenge of zero carbon by 2050 in 2019, but well before that, the electricity system was evolving rapidly towards 90% plus renewables, and we'll hit that milestone this decade.

Because of the intermittent nature of renewables, and this country's relatively low hydro storage capacity, we will have periods where we will still have to rely on coal and gas like right now. Wholesale prices will be high during those periods, but the trend towards a highly renewable and lower cost system will happen.

If we look at the recent past, the last five years alone, Meridian has invested $1 billion on existing new renewable assets, and we will increase that level of investment threefold by the end of this decade, creating renewable energy as our core business, and it's a great business to be involved in with huge growth potential. But the competitive nature of the market has ensured that investment returns are modest and stable. Since listing in 2013, Meridian has delivered an average return on assets of 3% and return on equity of around 5% per annum.

Now I've talked plenty about the long-term investment required by the sector to deliver New Zealand's low-carbon future. It's that imperative that underpins our development pipeline at Meridian. We continue to prospect and develop a set of options that will ultimately double the size of the generation capacity we have today.

And finally, before I pass over to Mike, I'll quickly talk to our decision to pause work on our hydrogen option. SGH is a unique opportunity to leverage Aotearoa's renewable resources and support global markets to achieve their carbon reduction commitments. But the economics of green hydrogen have become challenged over the last couple of years.

And globally, markets have been slow to resolve the gap between the cost of producing the product and the potential customer's willingness to pay for it. So SGH will go on hold, and we've agreed to conclude our partnership with Woodside. We have built up considerable IP in green hydrogen, however, and we will continue to actively monitor our target markets in case the prospects improve.

I'll now hand over to Mike to delve into the numbers.

Mike Roan: Nga mihi nui and Kia ora koutou. Thanks for joining the call this morning. As you now know, we had one heck of a year last year delivering $667 million of operating cash and $905 million of EBITDAF, both records for our business. And the timing of the result is fortunate, as the last couple of months, and most likely the next couple have been tough by comparison.

In fact, the only analogues that come to mind to describe the challenge the industry is working through right now are 2012, and before that maybe '91, '92. While the story of 2024 has yet to be finalised, there are some very unfortunate outcomes for those who took spot exposure. These large businesses may be sophisticated and will have understood the risk they were taking, but that

certainly doesn't help their employees, their suppliers and the communities caught up in the situation.

It's times like these that being a customer of a business like ours is really valuable, because not only can you rely on the fixed prices that we offer, but if you're unfortunate to come off contract right now, we will see you through, given the commitment you've made to us over the years. But enough of that for now. I'll come back to the current conditions as I close, but I want to unpick the financial year '24 result, as it deserves some attention, even if it was so last year.

As this slide shows, it was another year of strong performance, and the first for some time where the weather didn't interrupt our plan until near the very end. In fact, way back in February, I noted that we had a chance to deliver stronger second half performance for the first time in five years, and that is exactly what the operating teams did.

Alongside the result, and as Neal mentioned, we had a couple of pretty other special things happen during the year as well. First, we delivered the Harapaki project, and it's now producing 176 megawatts of renewable energy while adding a new and in my view graceful dimension to the ridgeline above Napier.

And, of course, the NZAS contracts. They are important as they brought certainty for the smelter, the electricity sector, Southland, and our nation. Certainty is a new thing for our industry, and I think that some may have forgotten that, but it's very important as it unlocks investment. And now that we have it, that is what we'll do, invest faster.

As Neal noted, we're already out of the blocks, having committed over $1 billion to new renewable energy assets, but certainty is also supporting new entrants invest in our sector. While collectively our traditional competitors have also committed another 2 billion to new renewable generation assets, others like New Zealand Windfarms have arguably the largest wind farm development that New Zealand has seen in front of them at Te Rere Hau.

We're helping out there, but the team at New Zealand Windfarms is doing some very heavy lifting, and we're pleased to see that through fast-track legislation, the Aoketere consent has been granted, subject to conditions, and this should result in a larger wind farm being developed.

Ka pai team. And Nova, Lodestone, Final Solar, Ranui Generation and many others are tapping into New Zealand's solar generation resource and building at scale. In fact, 69% of committed and actively pursued developments in the Electricity Authority's investment pipeline are being pursued by new entrants to the sector. My rough estimate suggests that combined, they've committed to or proposed to invest upwards of 1.6 billion across their sites.

My point is, the market is working to encourage both traditional and non-traditional investors to invest in our sector. And given the scale of the challenge through 2050, there's plenty of space for everyone. And the investment is not one-dimensional. We're also investing in non-traditional relationships that will reduce the impact of dry years.

The new demand response agreement with NZAS is just the start and while I've heard suggestions that asking businesses to temporarily shut production lines when energy supply is tight is a poor outcome, I think that sentiment is misguided.

My conversations suggest that these types of arrangements improve the financial wellbeing of those businesses as they get paid to reduce consumption and only enter into such agreements to the extent these payments add to their bottom line. Demand response products may not be for everyone, but we're talking to plenty of customers looking for additional revenue streams right now, so I can see a bright future for these types of products.

If I was to summarise the last couple of minutes, it'd be to say that certainty is a good thing for investment and for customers, which gives me a perfect segue to dividends, as certainty is good for investors as well. For the last three years, I've said that we'd review both dividend levels and the dividend policy when Rio Tinto makes a clear decision on the smelter's future. It's done that emphatically.

So, the lift in final and full year dividend shouldn't be a surprise, but I do hope it's satisfying as you, our investors, have been patient. This morning, we're declaring a final ordinary dividend of $0.1485 per share. This is a 25% lift on the financial year '23 final ordinary dividend, and brings the full year dividends to $0.21 per share. And we're lifting the dividend reinvestment plan discount from 0% to 2%, as we're hopeful that this new era of certainty will accelerate development plans. The final ordinary dividend will be imputed at 80% and paid to shareholders on the 20th of September.

We're also adjusting the dividend policy. Specifically, we're moving that policy to an operating cash flow-based measure to make sure dividend payment levels align fully with operating cash flows. Other elements of the dividend policy remain, the key ones being payouts will be between 80% and 100% of operating cash flows over time, after assessing wider business needs and the Board's commitment to a BBB+ credit rating.

On to EBITDAF. You would have seen on Slide 14 that both EBITDAF and operating cash flows continue to grow as our teams improve performance. As you can see from the graph here, the 16% year-on-year lift in EBITDAF was largely driven by increases in energy margin, even as lifts in operating expenses offset some of that gain. And while I'll talk to the net profit after tax figure that comes later in the pack soon, as it's driven by large non-cash movements, it doesn't offer useful insight into operating performance.

So EBITDAF and operating cash flows remain the key performance metrics for our business, and they both show that our operating teams delivered superbly last year. If we jump over to the energy margin slide, you can see that the lift in performance was once again driven by our retail team. Well, that may not be as easy as I just stated, but to help you get to the same answer, I'm going to do some on-the-fly math gymnastics to help out.

If you deduct the cost to supply customers from increases in generation spot revenue and then remove the cost of derivative purchases from the value of those derivatives, you'll get a net number of negative 9 million. That is, the portfolio of wholesale, physical and financial sales and purchases were reasonably balanced. So, what really drove the uplift again this year was retail team performance.

I'm not saying the wholesale and generation teams didn't do a superb job. They did, as they generated enough energy to meet customer needs while securing financial cover that managed risk. It's just that when you compare their performance to financial year '23, the result was similar or similarly excellent. And thus our expectations of their performance during the current drought are also very high.

But the retail team stole the show again and they continue to work hard to secure and grow valuable relationships across customer segments. And you can see some of that mahi here. Total sales volumes continue to grow across

mass market channels and pricing improved as well. But the team balanced this growth by holding corporate sales volumes steady even as they lifted price.

I've said it before, I'll say it again. We're very fortunate to have the best retail team in the sector and they improved their performance again while continuing to grow our business. Now I mentioned our generation team a little earlier. And as you can see from the bottom graph on this slide, financial year '24 was not particularly wet. In fact, inflows were the lowest on average in seven years. And as a result, hydro generation volumes were down on financial year '23. However, wind generation made up for that reduction.

Now the generation team don't make the wind blow or influence rainfall patterns, but they do make sure the generation fleet is available for use by the wholesale team. And as financial year '24 wholesale prices were more than double those in financial year '23, that job was particularly important. And while they did their job admirably, we had two disappointments during the year, both related to transformers.

The Manapōuri transformer challenges continued and we lost one of the two transformers at West Wind. Interestingly, with low inflows, the Manapōuri transformer outages did not impact generation volumes or energy margin delivery at all. However, the West Wind constraint cost $6 million in lost energy margin during the year.

The good news is that the West Wind constraint will be unwound in October as Transpower is lending us a transformer for 10 or so months, after which a new transformer will have been installed and the situation at Manapōuri will improve in March '25 as the new transformer is brought to bear down that way.

As the Manapōuri transformers have been a challenge for our business since 2011, the generation team will buy a spare for Manapōuri. But with global demand for transformers high, that spare and the transformer for the seventh unit aren't expected until September 2025. And then we'll need 12 weeks for installation and commissioning.

We laid out most of the above information in our recent Investor Day, but the key point is that the generation team is tireless in its efforts to make sure we have maximum generation available while tackling the transformer challenges that have confronted us for some time.

Now, I'm not sure whether anyone truly appreciates this slide, particularly the top graph that shows increases in costs for all the reasons I've previously explained. But it's here to provide transparency on what we spend investors' money on.

The first thing I'll note is that operating costs fell within the guidance range presented in February. And while they say explaining is losing, the second graph shows the elements that drove the uplift in operating costs. Rem increases drove a 6% uplift in salaries and recruiting a new staff was focused primarily on Flux's growth, Meridian's development pipeline, and properly resourcing our team that supports vulnerable customers.

While I expect Flux staffing to fall this year given the change in strategy for that business, the growth within the development team now means that it will be able to construct at least two new assets at any one time. That's not something Meridian has achieved historically, but it's a sign of the times and it does signal that we continue to prepare for substantial investment in the coming years.

The increased contractor spend was also driven by a development team in Flux. I'd make the same comment for Flux as I did a minute or so ago, and I expect development team costs to stabilise this year. The increase in ICT spend was driven entirely by the new finance system that's being introduced into the business. In total, that will cost us approximately $17 million, the majority flowing into financial year '25.

I'll finish with insurance. As while costs lifted again last year, we did adjust our insurance programme, and those changes will see costs held flat in financial year '25. To be clear, we didn't reduce insurance coverage, rather we found new insurance products that will work for us.

On to capital costs. At $349 million, capital costs landed at the bottom of the forecast range. This is down on initial estimates as we were unable to secure a consent for the 130-megawatt Ruakākā solar development within the window that had been expected. That was disappointing for our business, and no doubt to those of us who also worry about energy security.

There's a reasonable backstory to this consent, but we don't have time to present it here, so to steal a phrase from Neal, it looks like it will take longer to get that consent than it will to build the asset. That said, we did deliver Harapaki, and the development team is progressing a number of initiatives

outside of Northland, some of which have been announced and some that have not.

Stay in business capex was also reasonably elevated, with the new office that we're broadcasting from being built out during the year and being captured as a component of the workplace facility spend. If I jump to the next slide, you can see the level of investment that's directly in front of us. You can also see how challenging it is to navigate new investment consenting. Now, realise that this slide is a bit of a word salad, but that's the point.

I mentioned certainty earlier in my talking points and how that supports investment, but as you can see here, there's little certainty in regards to consents or the best pathway to obtain one. In simple language, there are eight paths you can take to consent new investment, and we're using five of them to move seven development projects that collectively cost $3 billion forward. Each process has different requirements, timeframes, and costs, and they each have different risk profiles.

There's no certainty that we'll obtain a consent from any pathway, which is part of the reason we diversify the approach. That's why we welcome this Government's intention to remove the regulatory barriers to support investment and get the job done. If we're able to achieve consent inside 12 months for projects that meet environmental and economic hurdles, then that will be a material accomplishment.

But back to more solid financial ground. As presented in this slide, I expect operating costs to land between $302 million and $308 million this financial year. That suggests operating costs will lift between $21 million and $27 million. This is the third successive year of large operating cost increases, but there's always good reason for them, and the waterfall chart shows where we intend on investing that cash.

Salaries will continue to lift or be under half the rate of last year. There's another slug of cash being spent on the finance system deployment, and now that Harapaki is finished, the operating contract has been crystallised, and that lifts generation maintenance costs.

Finally, we continue to expand our development activities. The increase you can see here is twofold. First, it is money we're investing in Te Rere Hau and the New Zealand Windfarms joint venture.

Second, it was money set aside for Southern Green Hydrogen. Given we've put Southern Green Hydrogen on hold, some of that cash will not be spent, but the team on that project are now focused on other activities. A couple of other notes from this slide.

I'm also forecasting total capital expenditure of between $295 million and $325 million this financial year. That largely reflects cash being invested in the battery at Ruakākā, as well as anticipated cash supporting a solar farm at that same site. But it's also driven by lift and stay in business capex, given there's a generation control system replacement project that is getting underway.

We need to pay for the transformers I mentioned before, and there are a couple of other generation projects, including gravel removal at the Manapōuri Lake Control Structure, and replacement of the electrical and automation technology at Manapōuri Power Station. So, Manapōuri will continue to be a busy site probably through 2028. I will, of course, update you if anything changes.

The graphs on this slide show the difference between net profit after tax and underlying net profit after tax. The reason we present both is that underlying net profit after tax removes items like unrealised fair value movements on derivatives, as they are not cash costs, whereas net profit after tax is a gap measure that by definition includes these elements. As you can see, the difference between the two can be stark.

So, understanding why that difference plays out each year is really important to those who put our performance in perspective. To help you with this, Slide 50 of this pack shows the reconciliation, and while we don't put that up on this slide, a positive $98 million fair value movement in the unrealised portion of derivatives, and an $18 million impairment in Flux are those drivers. I tend to suggest investors look beyond net profit after tax when it comes to operating results, but both measures have value.

What the underlying net profit after tax chart shows is that business performance lifted again last year. The net profit after tax graph simply shows that unrealised gains and losses on derivatives change materially year-on-year. The above differences are also a key part of the reason why I've elevated the conversation on operating cash flows and why we change the basis of the dividend policy is working through accounting measures can be a bit like mumbling at people and hoping that they get it at times.

I like to present measures that are simple and that reflect business performance and it's hard to look past operating cash flows. Last but not least, there was a $3.15 billion lift in the value of generation assets over the year. You might say this deserves more than just a cursory bullet in the presentation, but all it really reflects is that the accounting value of assets is catching up to the market value of those same assets and the reason for this is NZAS decided to stay in New Zealand.

Now, this slide continues to show that our balance sheet remains flexible. Net debt to EBITDAF -- net debt has lifted on financial year '23, but the key S&P rating metric net debt to EBITDAF remains well below the bottom of the BBB+ threshold of 2x. The reason for the lift in net debt is that we issued a new $300 million green bond during the year as an existing $150 million green bond expired. This cash was used to support delivery of Harapaki.

We have another $200 million green bond expiring this year. And it's likely that we'll replace that one as well. If we can accelerate the development programme in some way, it could be that we enter debt markets twice in financial year '25. Of course, that would be a positive if it plays out.

As I don't have too much more to add, I'll finish where I started. Financial year '24 was a strong year, but we're currently focused on navigating the drought. This makes for tough operating conditions for a renewable energy business. But droughts are inevitable. And while they can be tough, you learn a lot from them as well.

As investors, you know our business well enough to know that we carry balance sheet headroom specifically to cover these types of events. And while operating cash flows will vary, dividend stability will and can be maintained. And to our residential and small business customers out there, you don't have exposure to the high wholesale prices, your electricity prices are fixed.

You can see the impact of the drought in the storage graph on the right. National hydro storage has never been as low at this time of year as it is now. So, the generation, wholesale and retail teams have work to do to navigate a tricky period. But that's why they get out of bed. There will likely be a financial year '25 financial impact.

But with near term ASX prices having peaked on the 5th of August and since fallen by approximately $190 a megawatt hour, it could be that the worst is

behind us. I'm not saying it has and prices remain elevated. But if markets are right, then we'll turn our attention to winter 2025.

It is going to take quite a bit of rain to return New Zealand's hydro lakes to more normal levels. And our job ultimately is to satisfy shareholders while delivering energy security for this fine land we live in. And while we navigate these challenges, the lift in both the dividend and the dividend reinvestment plan discount suggest that the business is in good health and focused on investment.

I'll hand back to Neal so he can make a few closing comments of his own.

Neal Barclay: Cheers, Mike. In many ways, the focus for FY25 is continuing the momentum we have built over the last couple of years. And that includes getting development projects through the consenting processes and into the build phase, delivering the transformer replacements of both Manapōuri and West Wind, as well as adding incremental generation from our existing assets.

Adding to our customer demand flex and process heat tally. And we will continue to develop our team capability and culture, focussing on digital maturity, diversity, wellbeing and safety. And Mike has a very new and expensive financial system to deliver, it turns out.

Plus, we'll begin the chunky work involved in replacing our existing generation control system. So, there's plenty to do, but the entire team are aligned behind a clear strategy and a sound plan. So, to wrap up, FY24 was a successful year for the business. We got a very significant strategic issue resolved and made good progress on the other key aspects of our strategy.

As we've discussed, the FY25 is shaping up to be a different challenge entirely, at least at an operational level. Every hydro catchment in the country has received much lower-than-normal inflows over the last four months. That situation has started to abate over the last week or so, but the lakes remain at very low levels.

Meridian is investing heavily in hedge arrangements with the smelter and thermal generators, and that is incentivising physical responses that are helping to manage security of supply. We've also advocated for better access to contingent storage, and we've been listened to.

There are unfortunately some large businesses or more importantly the people who rely on them for their livelihoods, badly affected by direct exposure to current wholesale prices. That is not an outcome that anyone wants, but the vast majority of consumers do not have that same wholesale market exposure, and the Meridian customer team is making sure our C&I customers coming off contracts are being supported through this high price volatility.

All up, I'm confident we're doing all we can to support system security and to insulate our customers from the current high wholesale prices. But the key issue remains that there's simply not enough domestic gas available to meet either the needs of gas consumers or gas electricity generators and as a sector. We need to solve that problem and we need to solve it quickly.

LNG import may be the fastest and best way to ensure we have adequate renewable firming fuels available when it doesn't rain much, and the upfront infrastructure investment seems very manageable. So Meridian is engaging directly in this opportunity through the gas security response group.

Delivered LNG will not be cheap, possibly more than $20 a gigajoule or between $200 and $300 a megawatt hour. So, it is not a replacement for domestic gas consumption nor is it a base-load electricity generation option, but it does lend itself to seasonal electricity firming. It will be reliable, flexible, and diversifies system risks.

It'll also likely increase competition for firming options, and hopefully help improve transparency in the gas sector in New Zealand. If you're not intimately involved in the gas industry, it can be very challenging to understand exactly what is going on.

For example, understanding when gas-backed hedge arrangements may be in danger of being suspended. If the sector invests in the infrastructure to enable LNG imports, but never has to use it, it will still reduce risk and ultimately prices. And in my view, it'll be money well spent. The government's announcement on Monday to support the consenting of a project is very good news.

Looking to the long term, the solution is the deployment of more diversified renewable generation throughout the country. That will ultimately reduce the reliance on South Island Hydro and whilst we will still see low hydro sequences in the years ahead, they will become less impactful.

For those of us old enough to remember, when the lakes were last this low in 1992, the country saw rolling brownouts and that was not acceptable. In 2008, the lakes were nowhere near as low as they are now and yet we had a public savings campaign. This is certainly not where we're at today, and I think the sector deserves some credit for that.

And lastly, these near-term challenges are not blunting our intention nor our effort to drive our development pipeline forward and enhance our customer product set.

So that's it from us. Thank you all for your attention. We can now move to some questions, and I think we'll start with questions from anyone here in the room this morning. Okay, so we've got a microphone.

Analyst: Tim Mowbray, Macquarie, Asset Management. Just one question for me. If you – there's the announcements yesterday kind of from the government, there's a few bullet points. One of them in there was the transmission line companies being able to potentially develop generation.

Just more of a broader question kind of leading from that, in terms of if you think about New Zealand's requirement to build generation, is capital actually a constraint or do you think there's constraints more in other places like consenting supply chains, people etcetera is bringing more capital and other players actually benefit?

Neal Barclay: Well, having more players involved doesn't hurt, but capital is not the constraint. There's plenty of money globally looking for high-value renewable projects. We've got a well-positioned balance sheet to contribute most of the other gentailers have. But as Mike indicated, we've seen other parties come into the sector as well. So capital is not a constraint, yes. The key constraint in this country at this moment time is your ability to get things consented in a timely and efficient manner and that's been worked on clearly by the government. So the improvements in that consenting regime from a New Zealand perspective, I think will be the key catalyst to unleashing investment at a faster rate than what we've seen today.

Analyst: And so just a follow-on question. In terms of your current pipeline?

Neal Barclay: Sorry, I should probably add to that, when we look at the growth required between now and 2050 to decarbonise the country, we don't have enough people in the industry at the moment. There's a lot more engineers, Wintec,

trade staff, eroding construction teams that will be required to meet that demand lift. So that's a challenge.

That's something we're very mindful of as a sector, but -- and I'm not calling it out as a constraint but it's probably more of an opportunity actually for the people of New Zealand to really climb into this in great careers in a sector that's going to grow dramatically from this point.

Analyst: There's my follow-on question which was if your current pipeline about 2030, when you think about that, is that kind of based on what you know now with consents? Or is it assuming some kind of improvement in that if content issues resolved, could that bring the pipeline forward? Are those kind of issues talked about people potentially?

Neal Barclay We've got two of the projects that are in part of the pipeline are on -- we've put them on the fast-track consenting list, don't know if they've been accepted yet. but it would be helpful if they got a relatively quick consent through that process, and that would enable us to get on and get them built. Anyone else in the room? No? Okay. Well, I think we can open up the phone lines.

Operator: Thank you. If you'd like to ask a question, please press star one on your telephone and wait for your name to be announced. If you'd like to cancel your request, please press star two. If you are on a speakerphone, please pick up the handset to ask a question.

Your first question comes from Grant Swanepoel from Jarden. Please go ahead.

Grant Swanepoel: Good morning, Team. Mike, this question is for you and I know explaining is losing, but 14%, 13% deference and an 8% to 9% increase in opex. Are we getting close to a cost out program? $308 million is the midpoint. It seems quite eye-watering. Or is there something that $308 million that has one ICT costs coming down?

Mike Roan: I think you see it flatten ground. That's what I was alluding to. I think you'll see ongoing lifts and salaries. There are -- we're always trying to run the business as efficiently as we can. But our focus -- if you go back over those last three years, where that money has gone, has gone into the development team and really trying to accelerate our investment pipeline. Outside of that, the corporate costs of largely, and outside of salaries as the corporate costs have held reasonably flat.

So, I think you'll see it plateau grant as opposed to coming back, but I do agree. Those cost increases have been significant over the last three years. That's why I point them out to people, but they've been for a very good reason. You come back to what we're talking about generally today is being able to, and actually investing in, new facilities, there are concerns, which is typically the holdup, but as Neal mentioned, we need good people to deliver those assets. And so we've invested in that capability to make sure that we can do it.

Grant Swanepoel Next one, on stay in business capex. So still well above, I think it's $55 million is your long-term guidance. When does that revert back to a $55 million type number?

Mike Roan: That's a great question, Grant. I know that this financial year '25, you can see it sitting at $100 million. Financial year '26 some of those programs that we -- that I mentioned will roll into '26. So I would expect that you'll start to see that reversion 27, 28 as we come out of the implementation of the generation control system.

Well, I don't have the numbers up there and we haven't run up by our Board. The costs of that initiative are substantially larger than what we've spent in the past. And it takes about three years to run through that cost profile. So, I think once you get through that, that happens once a decade sort of stuff, is then you'll start to see those standard business capex costs come back to the levels that we've seen historically.

Now, the only thing that I'd add to that is, of course, we're adding new wind farms to our business. We're adding, hopefully solar arrays and, we've got a battery coming at us. So, there will be capex requirements for those new investments as well, but I'll be sure to point them out, as we step forward.

Grant Swanepoel: Thanks, Mike. And then at your strategy day, you had three or four projects that you're moving towards FID on. Have you got any updates for us on cost to build those projects? Are you still on track your [$150 per megawatt real wholesale power prices real wholesale prices over the next 15 years?

Mike Roan: Yes, Grant, we're still working those projects through. There's no real new info that we've got since Investor Day. We're -- touch wood on some of the consenting process. I feel like we're pretty close on the solar development up Northern way. There's a lot of hard yards being put into Mt Munro over in the

Wairarapa. And we're working through the construction costs and programme for Te Rere Hau, but again, all going well there. We're approaching FID middle of the year -- next year.

So, I guess no real update on what you did here back at Investor Day, either in terms of cost profile or ability to accelerate those projects. But what I did note, and you heard us talk to is there are plenty of new entrants looking at the sector. And so, we're not just exploring the activities that we might undertake. We're looking to support and accelerate plans that others might have. So, if we do get any good news on that front, we will let you know.

Grant Swanepoel: Thanks, Mike. My final question, just a question on clarification. When you talk about hydro inflows being done 1,000 gigawatt hours, is that from May or from the 1st of July?

Neal Barclay: So that was from May, Grant. So, May, June, July, through August, mid-August, I think, was when we took that measure.

Grant Swanepoel: And at 800 gigawatt hours of cover, is that also from May or is that from 1st of July?

Neal Barclay: That's kicked in more recently, yes, from about July.

Grant Swanepoel: And can you just give us an idea of what hydro inflows are down from the 1st of July?

Mike Roan: Not off the top of my head. They're the lowest on record, Grant. And they're on that slide. There's a slide that we've got in the pack.

Neal Barclay: That's from May through. So, we can give you more concentrated recent hydro inflows, if you'd like, but we'll give it to you after the meeting. Sorry, Owen was just calling out 70% odd, Grant.

Grant Swanepoel: Thanks.

Operator: Thank you. Your next question comes from Stephen Hudson from Macquarie Securities. Please go ahead.

Stephen Hudson: Morning, Neal. Morning, Mike. Just a few from me. Just firstly on Harapaki. Can you give us an update on what you're expecting the capacity factor for that farm

to land at? Seems to be travelling a little bit ahead of the numbers that you were getting sort of a year or two back.

Neal Barclay: It's early days, so we wouldn't revise the business case assumptions, but what we are seeing is that wind farm maxing out capacity in recent times. So, it is performing exceptionally well. In the nick of time, I might add. So yes, the signs look good, but we wouldn't call a change in our long-term assumptions around that until we've actually seen some, at least a year of real-life experience.

Stephen Hudson: Okay, and my numbers may be old, but I think I've got in there sort of 35% or something like that?

Neal Barclay: Well, it's looking well north of that, but, we have seasonal, things to take out of, so. We'll keep an eye out, but we're pretty optimistic the way it's playing out.

Mike Roan: Steve, if you're not above 40%, then change your numbers.

Stephen Hudson: That's my margin of error. Contingent hydro -- just on contingent hydro, obviously, there's some temporary relief in the offering, but I just wondered whether or not you foresee any permanent change at the trigger levels there?

Neal Barclay: Yes. Well, look, the government called that out in their announcement earlier in the week, and we need to work with the consenting authorities. But, from my perspective, Lake Pūkaki is a hydro lake. It was created purely for hydro generation. It's not used for any social amenity. We can actually stretch the like -- it's currently got a standard operating range of 14 meters.

But if we can extend that to create an extended operation range of around 19 meters, it will mean on average, we produce more hydro generation in this country. And that will also go towards reducing price pressures over time. So, I think there's a strong case to normalising the consented level and bringing the contingent back into the standard lake levels.

So that's the conversation we want to progress with – we're not only consenting authorities but also government to the extent that they can help facilitate that end outcome.

Mike Roan: I think the only thing I'd add to that, Huddy, is in the absence of gas that we expected to show, I think Neal's point is more important than it would have

otherwise been. And so, normalising the use of that contingent storage, particularly in the short term, while we look at whether LNG as a longer-term opportunity or domestic gas arrives, is something that is within the control of the country.

And as Neal said, it's a hydro storage facility, and that storage looks like its increasingly valuable as compared to where we were even a year ago. So, I think if you were prioritising it as something to do, it would be a good one to have near the top of the list.

Neal Barclay: And you might take a different approach with contingencies around Hawea, for example, which does have more of a social impact or so but Pūkaki we think needs looking at.

Stephen Hudson: Very good. Thank for that. Just two more quick ones, sort of boring accounting on this, unfortunately. I think you're alluding to a change in the Option premium accounting to take that cost above the line. Mike, if that's the case, can you confirm that? And what would a sensible number for FY25 be noting that I think FY24 was about 23 million. Could we use sort of 30 million, 35 million for FY25 as Broad estimate?

Mike Roan: Yes. Thanks, Steve. So, one, yes, we've changed the accounting treatment of the option premiums, they sit below EBITDAF, and now we've moved them back into energy margin. So, it's, I think, a useful change. This year is a funny one. And that if you look deeply at those ends contracts, we only pay the premium for the demand response beginning the first of January 2025. So, we're only paying half of the option premium. And I think heard you say '23, Steve, I think if you cut that number in half, you're not going to be far from the mark.

Stephen Hudson: Thanks, Mike. And sorry, last one for me. Just on the re-val, I know you've said sort of the accountants catching up with the market. Can you just break down the $315 into, I don't know wholesale price or WACC or just some sort of broad buckets?

Mike Roan: Wholesale price and cost to capital. Those would be the three pieces. So, a small change in cost of capital, Steve, but it really was, I mentioned -- and I think we've said it before, is we've used index price path for the valuation of our generation assets to date and that we wouldn't make that change until contracts

were struck. So, what you have seen is that we've changed the price path that we use. So, the majority of it is wholesale price.

Stephen Hudson: Very good. Thanks, team.

Operator: Thank you. Your next question comes from Peter Wakeman, a private investor. Please go ahead.

Peter Wakeman: Good morning. I was just wondering if there's been any warranty issues with transformers or anything like that and how things are shaping up on that require bearing in mind how long it takes to replace these items, first question.

Neal Barclay: Yes, Peter. I mean, we're looking at the warranty relationship around all the transformers that have failed, and that's an ongoing conversation with the providers of those transformers.

Peter Wakeman: And so that hasn't been concluded yet?

Neal Barclay: Not, entirely no.

Peter Wakeman: Right. And with respect to the government fast tracking, have they given you any idea when they will come up with such a decision?

Neal Barclay: I'm not better informed than anyone else, Peter, on that. We'll see the bill go through the parliamentary process in due course. And what we're interested in, as I mentioned earlier, has seen a couple of our key and very significant projects are on that first list, so they can be considered by the expert panel and hopefully, consented at a rapid pace.

Peter Wakeman: Right. And with respect to insurance, what sort of -- for example, as the government ever offered you or have you ever asked the government for insurance in the sense that when 9/11 happened, the government provided an insurance to Air New Zealand because of the private industry wouldn't do it. And I just wondered if the government would insure Meridian an event of an Alpine fault or Wellington fault or whatever it happens to be a whatever. Have you had any sort of agreements because I think if again would it actually lower the cost of insurance or how significant would that be for balance sheet?

Mike Roan: So, Peter, the answer is no. We don't ask for government support as it relates to insurance. What we do, do is we ensure our properties against the events

that you mentioned. So, we do take our insurance cover. But as the costs have lifted over time is what we've done is we've explored new products from an insurance perspective.

Typically, we've gone to the global reinsurance market. But we've actually entered into arrangements with a new entity for us in any event that provides insurance called Everen. And they effectively consolidate a number of companies, insurance, not just in New Zealand but across the globe, and as a result, can provide premium to us that reduces our overall cost. So what I'd say to you is we like to explore further arrangements similar to that with Evren and other types of insurances as opposed to stepping back to the government and asking for support from that perspective.

Peter Wakeman: All right. And the last question has to do with the some panels and their degradation over time and what age and technology are they for Whangarei?

Mike Roan: Peter, have those questions might be beyond my technical means. I'm not sure about Neal.

Neal Barclay: We haven't contracted them yet, Peter. We're working with various suppliers understanding is they've got at least a 20-year life frame. But we could provide a bit more information. In fact, we will provide more information when we get the project to financial close, and we announce it as a committed project that we're getting on with.

Peter Wakeman: Okay, well, thank you very much.

Neal Barclay: Thank you, Peter.

Operator: Thank you. Your next question comes from Cameron Parker from Craig's Investment Partners. Please go ahead.

Cameron Parker: Morning, guys, and congrats on a really strong performance. Just wondering if you could talk to the transmission and distribution price increases we're expected to see come through and also the impact on your underlying customer increases, and also in the context of what your intentions are in growing into the North Island, given your supply arrangements are growing in that geography as well.

Neal Barclay: Well, Cam, I mean, we've laid it out in the pack. The ComCom are looking at distribution pricing across the whole sector. They've come out with a proposed -- set of proposals that see those costs increasing reasonably dramatically. And

in fact, the increases into next year on the current proposals look like about 23% on average across our customer base. It will depend on who your customers are, but that's how we've modelled it.

Now they do have a smoothing mechanism because those cost increases would be more rapid than that if they didn't smooth it. But when we take that 23% and spread it across the whole customer bill, the increases are between north of 8.5% to 9%. So that's pretty, I mean that's significant.

We haven't quite worked out exactly how we're going to manage that with our customers. Obviously, we're doing a lot of work on new product sets and Lisa will be talking a bit more to the market about that in the coming days, but we do have products coming to market or they're actually being trialled in market today that if customers can provide a bit more flexibility and shift their usage and the demand around we can actually help them save money overall, not only on the distribution side of the bill, but also the energy component.

So, we're doing everything we can to drive minimise the impact of those costs as they flow through. In terms of our position in the North Island, yes, as we grow our position and we get access to not only more generation in the North, but also through PPAs and other hedge arrangements, we're still focused on growing the size of our retail business.

Most of the customers in New Zealand are in the North Island. So, we will continue to actively seek out growing our market share in the North as well. We understand the risk, obviously, and we manage those through various instruments and product types.

Cameron Parker: Yes, great. Okay. Then just the last one for me is just around gas risk and gas-fired swaptions at the moment that you have. Are you able to talk to that. Any detail?

Neal Barclay: Well, I guess, and I alluded to this in the presentation, but as these gas issues emerged, it's very difficult to get a handle on them. And what I can tell you is all the gas-backed swaptions that we had to some degree were suspended and in relatively short order. So, we had to do a lot of work behind the scenes to get that hedge position back into some sort of shape and that's why we were leaning on the NZAS demand response quite heavily.

We also bought hedges on the back of Whirinaki and we've been right and behind the Methanex deals as well. So took a bit of work. I guess the thing that

concerns us most is just the line of sight a customer those hedge transactions has through to the fuel source and when it's running scarce and visibility or transparency in that regard is poor I would put it, absolutely poor for our sector in that that scenario we do need to improve.

I think quite interested in the -- and I've just had a quick read of it, but the government review into the electricity sector. I think we welcome that. I think it's appropriate. I do wonder whether they've missed the point a touch because they've indicated that the high prices are driven by low hydro inflows. We know that and gas availability.

But the gas that's about the last time it's mentioned in the scope for that piece of work. So, I think we'd all benefit if the scope of that review was extended to include regulation in the gas sector and how that impacts through to electricity prices. I think it's a must-have and it's a bit of a missing in that scope at the moment, but we'll be giving that feedback.

Cameron Parker: Great stuff. Cool. Thanks Neal.

Operator: Thank you. Your next question comes from Andrew Harvey-Green from Forsyth Barr. Please go ahead.

Andrew Harvey-Green: Morning, Neal and Mike, just a couple of questions from me. First of all, in terms of typical structure going forward under the new dividend policy, do you have a particular sort of EBITDA – net debt ratio that you're looking at, so we can have the – it's now that you finalised?

Mike Roan: Andrew we would like to get back into BBB+ territory. So between 2x and 3x net debt to EBITDAF is where we would look to trend. It's probably the simplest estimate that I'd have. I think we felt we're trending that way, although our operating performance has been as strong as you've seen. So that EBITDAF figure from last year means that that net debt to EBITDAF ratio is a little lower than we expected it might have been, but that's the track we're headed towards is between two and three times.

Andrew Harvey-Green: Yes. Great. Okay, thanks. Next question is just around the Manapōuri transformers, and I guess those of us that were able to go and see them a couple of months ago. Are you able to give us any update on progress in terms of finding out what the actual issues are? And I think there was a suggestion you're going to be pulling them apart to have a closer inspection. Has that actually thrown up yet?

Neal Barclay: We're still working through the process to do that, Andrew. But, yes, we will be pulling the two that are out of service apart. We're just trying to work out the arrangements between the original manufacturer and how we do that effectively without having to ship them back off to Australia.

And we will have the right level of expertise involved in that process so we can get to the root cause. We've got another – of those two, there was another two Transformers that were in part of the same batch. They are not mis-performing at all, but we certainly need to understand the root cause just so we can get comfortable around their likely longevity. In the meantime, though, we've committed to and we've got a new transformer. It should hit the water later this month and be installed well before Christmas. We're looking at two others which will leave us with a spare for delivery sort of backend of next year.

Andrew Harvey-Green: Yes. Great. Thanks. Next question is just around demand response and the opportunity there. And then I guess we've seen what the smelter's been able to do, which has been great and very well-timed. Can you give us a sense of sort of the target for yourselves?

I assume it probably relates to some of the South Island demand that's transforming load away from coal potentially. But are you able to give us a sense of the size of demand response you might be able to get?

Neal Barclay: Look, not clearly, but we're working with at least two milk processing businesses in the South Island for a decent chunk. You're talking sort of potentially between the two of them 50 to 75 megawatts. And I think that's...

And we're only just starting this conversation. I mean, I noticed Pan Pac through this whole process has slowed down operations. I mean, if they had a demand response agreement with someone like us through this period that would actually make that a profitable exercise for them. So, there is a lot of demand, we think around the country that can be tapped into. But we're too early in the process, Andrew, to call out exactly how much. But we think it's significant. And you're talking hundreds of megawatts.

Andrew Harvey-Green: Yes. And last question, just to follow on from Steve's questions, I guess, around the contingent hydro. So, if we were to move that contingent hydro into standard operations, I assume you'll probably still look to keep a chunk down there as a reasonable contingency. But what sort of uplift in annual generation, hydro generation, could we be looking at?

Neal Barclay: We'd have to run that through all the models. And we haven't done that yet because we don't have that agreement. But we'll provide a bit more insight, Andrew, if we actually get that change through to the sort of the consent processes.

Mike Roan: Yes. And there were announcements, Andrew, that we made. I can't remember the year but they're on our website around that contingent storage utilisation. So the range from 518m to 516m reasonably easy to access and operate other than the 26,000 tonnes of rock that you need to put into Pūkaki. Beyond that, it gets tougher given the configuration of Ōhau A power station. And you've got to be careful around how you actually run water down the Pūkaki Canal.

So you've got a couple of metres, I think of water that would be reasonably easy to operationalise. And then the other storage, it's about three metres of additional water lower, would need to take more time and effort if we were to use that. And that two metres is an additional couple of 100 gigawatt hours. So as Neal says, we have to run it through our modeling, but that's the type of storage that's down there that's -- I'll say, reasonably easy to access.

Neal Barclay: I just add, sorry, Mike. But the engineers are doing more work, and we think we can get into those -- the meters below those two as well, reasonably productively. That's why I was sort of hesitating to give you a number because we've still got to work that through -- but it's a chunk. It's a decent chunk of generation.

Andrew Harvey-Green: That's great. Thanks. That's all from me.

Operator: Thank you. Unfortunately, that does conclude our time for questions today. I'll now hand back to the presenters for any closing remarks.

Neal Barclay: Well, thank you all for your attention. Hopefully, that was informative, interesting times, clearly. We're all very, very busy, and we will catch up with as many investors in the coming weeks as we can in person as we tap. So, thank you all for your attention, and good morning.

[END OF TRANSCRIPT]