TRANSCRIPTION

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Mike Roan: Tena koutou, Good morning, everyone, and thank you for joining us for Meridian Energy's Results Announcement for the Financial Year through 30 June 2025. I'm Mike Roan, Meridian's Chief Executive, and I have with me our acting Chief Financial Officer, Helen Peters.

For those that are new investors, I sat in that seat at our interim results announcement back in February. So at the very least, I bring continuity and given the environment the business is navigating right now, my experience, and the experience housed throughout our business, is more important than I would have imagined a year or so ago.

And while we were challenged by the perfect storm this year, I'm incredibly confident about the future of the business and its ability to both support and grow the economy while rewarding shareholders for doing so.

As I'll talk to soon, there are some challenges immediately ahead that require attention but when we properly harness the natural bounty that this country has to offer, I believe the electricity sector will underwrite the economic growth of the nation, and I want Meridian to be a driving force behind that.

This will require an evolution of where we've come from and some change. I have an immense respect for what people have done to get Meridian to where it is today, but I also have a clear idea of what's required for us to continue to succeed as we move forward.

First, I want to further accelerate our development of renewable energy. While we're well on track to deliver seven new developments in seven years, that was framed before the gas sector collapsed. So we need even more clean energy to realise the ambition. And as we do this, I want us to go back to our roots.

Sixty-odd years ago, the Waitaki Power scheme was devised and built in the Mackenzie Basin. It remains the country's largest hydro scheme and the backbone of Aotearoa New Zealand's electricity system. But it has so much more to give. There is more water to be accessed, more megawatts to be achieved from existing assets and a fundamental shift in the role stored hydro plays.

At a time when politicians and others are calling for a solution to the firming issue, I say look to hydro for a lower cost and lower carbon solution. In my view, the route to global competitive advantage for our economy can only come if we harness more water within that and other existing hydro catchments. We need to be bold and we are.

We've recently established a hydro development team to explore opportunities in the Mackenzie Basin and in Fiordland. We worked with the Waiau Guardians to create more flexibility and storage in that catchment, and we've just received Ministerial approval to have our application for access to Pūkaki contingent storage head through the Fast-Track process.

Second on my list of priorities, I want us to get even closer to our customers - that's where we've set our compass. Like every business, you're only as successful as the customers that you serve, so as well as evolving at pace to help customers thrive in the future, we are highly tuned into how we can support industrial and residential customers in the current tough environment.

But back to today. There's no question that underlying financial performance was poor last year. From a financial perspective, the business struggled to get out of first gear and even had to hit the brakes hard at one point. Now that result has been well-signalled and every Kiwi knows that when it doesn't rain, it's tough to make hydroelectricity and turn that into profits.

The second half of the year was better than the first, but only just. EBITDAF was $100 million more but the January to March period was the driest on record, and the rebound from April to June brought only average inflows. The result? The lowest earnings for our business in a decade.

Our business is always going to take a hit in a drought, and this year, we had two, and both of them one-in-90-year droughts. And when gas was switched on to replace hydro, that also failed. There's no historical precedent for this series of events, none.

Despite these challenges, there was no loss of supply and 99% of Meridian's customers were entirely unaffected. And they were unaffected because we sheltered them from the high wholesale prices, even though we didn't have that surety ourselves. As a result, we lost money in our retail business last year. But that's the advantage of a vertically integrated business. We can and will continue to navigate the challenges on behalf of our customers.

I think the 2025 financial year will be defined by Meridian putting the country's security of supply first, keeping power flowing for homes and businesses and the financial hit we took because of that. I understand that people are calling for generation to help bring prices down and ensure that we have enough electricity for the future. I want these things, too, but there's babies and there's bathwater.

The New Zealand electricity system is robust, possibly more so now than before the events of August 2024. The same cannot be said of the gas sector. The failures evidenced in August 2024 are now playing out more widely in that sector with customers facing higher gas costs, businesses having to put up prices to cover these costs, and the worst instances, shutting up shop because they can't get the molecules.

The electricity sector uses gas too, but we can't fix the problem of declining gas production. We can, however, work around it. As the Huntley Strategic Energy Reserve agreement signals, the electricity sector is switching away from gas as well. Executing that agreement was a very challenging decision for everyone at Meridian, given our commitment to decarbonisation and renewable energy.

But the economy needs fuel and our job is to support that economy and ensure homes and businesses have the power they need, so we had to enter into a pragmatic solution. The good news is that so long as Pūkaki contingent storage gets fast track approval, the Strategic Energy Reserve arrangement, alongside NZAS demand response, should see the electricity sector through the disruption.

My key point is that the country's energy supplies have been challenged, so we have adapted, not perfectly yet, but things have certainly stabilised. And if I bring things back to the company level, the Strategic Energy Reserve also signals that your management team has reset Meridian's portfolio settings to manage future risks. And despite these challenges, we've been able to provide a stable dividend to shareholders.

We can't deliver our strategy without the confidence of shareholders who will always endeavour to reward for their loyalty. Furthermore, our business needs the support of those shareholders if it is to invest, and we have been, and are, investing billions. At least a quarter of all electricity generation has been replaced over the past 15 years, costing $12 billion and that wouldn't have happened without big businesses like ours. Fifty-four cents in every dollar of the dividend that Meridian makes is returned to the government and that money, approximately 300 million this year, is used by the government to fund health, education and roading.

A further 25 cents on the dollar goes to and mum, dad and youthful Kiwi investors. So in total, 79 cents of every dollar we make stays right here in New Zealand supporting Kiwis.

And while the numbers we post are invariably large, shareholder returns have been incredibly reasonable. So a stable steady dividend is very important and it provides evidence of the strength of the business, and that strength is now being leveraged to grow.

Not only did we deliver the $450 million Harapaki Wind Farm and the $186 million Ruakākā battery last year, but we obtained five consents for new developments, including the $227 million Ruakākā Solar Farm, which is starting construction next month; Mount Munro Wind Farm, Te Rere Hau, another battery near Palmerston North, and the Te Rahui Solar Farm, a joint venture with Nova.

We don't just focus on today, we're focused on tomorrow and delivery of our strategy, and I'm going to move on to that strategy now. As this slide shows, the strategy is straightforward. Invest in new renewable generation and firming assets to accelerate decarbonisation of the economy, deliver cheaper energy to customers so they can unlock value in their lives and businesses, strive to deliver more from the operating business, and grow the capability within the team so we can do better every year.

It's aligned with where I want to take the business, it's clear for our teams and it connects directly with our purpose, and it will grow shareholder value.

Now, despite the challenging operating environment and conditions and intense industry scrutiny, Meridian continues to attract and retain engaged staff.

In my view, that's because smart, capable people want to make a positive impact, and they can here. It's one of the reasons why I've spent 17 years of my life here - the people are terrific, and they're also terrifically motivated. They also have the courage to do what needs to be done to make us better, a lot of it. I'll provide a little more colour on this a bit later.

We've also overhauled the well-being strategy, and the overhaul was pleasantly straightforward. If we focus on leaders providing leadership and we take the dross out of daily tasks, people will have space to look after themselves, and it's working.

Employee engagement remains strong, with our latest survey showing three quarters of the people that we work with are engaged and want to tackle the challenges ahead. Now, that puts us in an upper echelon of New Zealand businesses.

The safety metrics reflect the complexity of our operations, but we're committed to making sure that people are armed to make decisions regarding their safety as they go about their daily tasks.

I talked to some of what's on this slide earlier, but the two one-in-90-year seasonal droughts, May to mid-August 2024, and again from January to April 2025, were unprecedented, and inflows into the hydro catchments reflect this. They were 64% and 57% of average in each period respectively.

While the hydro lakes look large, the reality is that they only hold up to 16 weeks of water at best, so they're in fact quite shallow. We have to remember that they were designed to meet expected electricity consumption in the 1970s, not the 2020s or 2030s.

The financial impacts of lower physical generation flowed into the monthly energy margin figures that are shown on the top right graph. The August through October impacts were exacerbated by the loss of gas and the impact of freeing up more from Methanex.

We also asked NZAS to do more than contemplated last August, and they did. The second drought saw NZAS provide even more support to the electricity system, which was appreciated, but as with all commercial arrangements, that 50-megawatt deal costs money, and it reduced energy margin by a further $40 million.

Now, if you want to understand what the electricity sector has been through, look no further than NZAS, that will finally be back to full load later this week after more than a year supporting the electricity system. So, thank you to the NZAS team. You've become a bigger and more important element to the electricity sector than either we or you may have imagined only 18 months ago.

And in another ‘that was then this is now’ story, the green bar on the top graph shows that energy margin has reverted to pre-drought levels. As for gas, I've talked to that story. For one reason or another, and I don't have the answer for it, but gas has not been able to keep up with the needs of a modern economy, or be the transition fuel to this country's low carbon future. Instead, its demise is putting the electricity sector and the economy through the wringer.

Looking ahead, and based on what we know today, the graph on the right of the slide shows that dry year risk in the electricity sector has been stabilised so long as the Pūkaki contingent storage Fast Track application is approved before winter 2026.

The combination of the strategic energy reserve, NZAS demand response, and critically, that contingent storage, provides enough energy to manage a drought should it occur. This combination is important as it buys time for Meridian, and other businesses, to accelerate the investment in renewable generation.

We're targeting $2 billion of capital spend in the next three years and our renewable development pipeline allows us to do that as it's strengthened over the past five years. Te Rere Hau may have slipped by up to 12 months, but construction of the 130-megawatt Ruakākā Solar Farm is underway.

Stage 1 of the Te Rahui 200-megawatt Solar Farm is about to hit financial close, possibly as soon Friday, and we'll make decisions on the Manawatu battery, a solar farm in the Waikato and Mt Munro in the next 12 months as well.

That would represent 1,800 gigawatt hours of new energy being delivered and $1.6 billion more capital deployed this decade with more to come. Our PPA for the Tauhei 150-megawatt solar farm enables that asset to be commissioned in 2026 as well.

So we're cooking ‘without gas’ and the benefits of these developments will flow through to shareholders in the country quite quickly. You'll also see that the pipeline has a higher concentration of solar development than wind or batteries.

While solar is valuable to us, it is not correlated with wind or hydro inflows, our core development competence remains in building wind farms, and there are some material prizes in that space so expect the pipeline to move over time.

The Electricity Authority and Commerce Commission Task Force provided further insight into its 'Level Playing Field' measures last week. It's hard to offer much commentary other than to say that we're up for any change that reduces cost for our customers.

What is creating uncertainty, and considerable noise, is the fact that no one has any real idea what the government intends to do as a result of the Frontier report.

And while I know government is carefully assessing what to do, if anything, evidence from offshore interventions and electricity markets suggests that they typically increase rather than decrease prices for consumers.

Now we're prepared for whatever might play out. The Minister is talking about a surgical intervention. It's certainly not the time for an amputation. I say that because the underlying issue, not only the electricity sector but for the wider economy, is the lack of gas. It's this that's driving up prices everywhere, and that, in my view, is what requires attention.

If I was making surgical calls, I'd be considering the following:

- some form of funding to help gas customers convert to electricity or biomass, and quickly
- deferring the Commerce Commission approved increases in distribution and transmission costs, as this is what's driving above-inflation cost increases for electricity consumers
- and combining the Gas Industry Company and the Electricity Authority to improve regulation and disclosures across the energy sector.

Each would have an immediate benefit, and I'm hopeful that this is where the government focuses its response to the Frontier report.

The reality is that the electricity market works (and it did its job last August signalling gas shortage) - Gentailers did not earn excess profits. The EA report of March 2025 and this result are proof of that and investment is pouring into the sector to remedy problem that loss of gas created. And while the overall cost of living pressures on households are big right now, electricity costs,

although a factor, have as a percentage of average household incomes, been reduced over the past 10 years.

And there are only five countries in the OECD with better industrial pricing than New Zealand. Of course, we can and we must, do better. But where we're at today is a very strong starting point for a remote country without that many people.

Now I want to change gears for a minute. Specifically, I want to talk about emissions as, while not front of mind right now given the overall cost of living challenge that people are facing, climate change is still a thing. And reducing emissions, especially as the sector is likely to burn more coal in the short term, is important.

Meridian reviewed its Half-by-30 framework during the year and while the target to have Scope 1 and 2 emissions by 2030 has been retained and is tracking well, the Scope 3 target has been revised, given we're now in a period of material sector growth and investment.

It's unrealistic to expect our supply chain emissions to half from 2021 levels in this capital-intensive environment, so we've reset that target to focus on a 51% reduction in Scope 3 emissions based on a per megawatt installed capacity basis. That is, we've changed it to an intensity target, a target that reduces the intensity of Scope 3 emissions as we grow.

Now some have noticed but in case you haven't, Meridian is now the highest-ranking utility in Asia Pacific region on the Dow Jones Sustainability Index, again not bad for a utility in a small country.

Before handing to Helen, I want to talk to the efforts of the Retail team over the past 12 months as decisions they are making and the outcomes they deliver will create considerable value for shareholders over the long term. They'll also support customers.

Customer numbers lifted by 35,000 over the year and Meridian now has 405,000 customers, excluding Flick. That's an important marker of customer support for what the team is doing, but as importantly, the Retail team has begun to offer products to reduce customer costs.

The first being a product that offers $10 off a customer's monthly bill if they hand over control of their hot water cylinder to us to reduce peak demand. Now

that product already has 18,000 customers so it is popular. The team also added 60 new EV chargers to the Zero network and reset the entire team structure, dropping 45 roles in the process or close to 15% of that team before the change. And after that change was complete, the team moved to select a new operating platform, Kraken to support the business into the future. The first customer has already been migrated to that platform.

Of course, the Retail team also runs an award-winning fund to support customers who decarbonise their businesses and a proper hardship practice to support our vulnerable customers. And when I say Retail, it is people that make those tough calls and have to roll up their sleeves to make them work, and they did.

They were outstanding last year, and I'm proud of the courage shown and the achievements to date as they're all designed to make energy cleaner and cheaper for our customers, the people who pay the bills and work hard themselves.

Helen, over to you.

Helen Peters: Thanks, Mike. Before we dive into the numbers, I do want to take a moment to recognise Mike Roan on his appointment as our Chief Executive. Mike, we're all genuinely thrilled to have you at the helm. And I do have to thank you for passing the acting CFO baton to me, just in time to talk about our most financially character-building year in over a decade. So let's get started on the financials.

FY25 was a year where nature really tested us. As Mike mentioned, two record droughts, one in winter, one in summer, combined with low wind, declining gas availability, a wet spring and low prices, all created extremely challenging conditions to manage.

As you can see, our operating cash flows have taken a significant hit, down 52% on last year. At $318 million, this is the lowest level we have reported since 2009. That's a tough number to stand in front of and I want to acknowledge that upfront.

There are a few key drivers behind the result. Reduced physical generation from the back-to-back droughts; low wind generation and the cost of risk products, including the NZAS demand response calls, saw energy margin drop by 23% to $982 million.

This really reflects the cost of keeping the lights on when hydro and wind were scarce. We leaned heavily on derivatives and demand response during the year and those tools did their job, but they came at a cost.

So in summary, operating cash flows fell by $349 million, driven by energy margin dropping $294 million and the increased tax of $35 million.

This also all flows through to EBITDAF, which fell 32% to $611 million. What's important here is that our balance sheet held firm. We've actually built it to withstand dry years and FY25 proved that our structure works.

Now on to dividends. Despite the financial pressure and current year cash flows, the Board has declared a final dividend of 14.85 cents per share, bringing the full year dividend to 21 cents, which remains unchanged from last year. To support this, we drew on over $300 million of debt headroom.

That's the equivalent of a reasonably sized new wind farm. That's not something we do lightly. We have also always carried conservative balance sheet settings to manage the business impacts of droughts.

As a renewable and predominantly hydro generator, it is neither practical nor cost effective to try and hedge away all the tail risk to our portfolio. So extreme droughts will have an earnings impact. We're also being realistic.

If we face similar droughts in future years, we may or may not need to review our dividend levels to provide flexibility and maintain our existing BBB+ credit rating. The dividend reinvestment plan remains in place with a 2% discount.

Let's now look at EBITDAF. The biggest driver behind our decade low EBITDAF was the $294 million drop in energy margin. That's the direct result of lower physical hydro generation and significant derivative and demand response costs and I'll talk more about that soon.

The winter 2024 drought broke in a hurry and the spring that followed proved to be the second wettest Spring ever. And while $800 wholesale prices through a small number of August 2024 trading periods got plenty of headlines, the $1 prices that came with the Spring inflows didn't quite grab the same attention.

Managing those large inflows into our catchments meant we ran hydro hard, realising very low generation prices. Other revenue has a couple of one-off items in it this year, including a new metering contract benefit, insurance proceeds from cyclone damage at the Harapaki Wind Farm and the operating

revenue from our joint ventures and Flux. Transmission and distribution cost increases are also now flowing through.

Energy margin fell to $982 million, down from $1.276 billion last financial year. The impacts of the drought show up in physical energy margin with hydro volumes more than 1,000 gigawatt hours or 10% off the 10-year average.

In fact, you have to go back to 2012 and 2013, which were back-to-back drought-affected financial years to see our hydro output at less than 11,000 gigawatt hours. These conditions also affected wind generation with calm periods coinciding with the droughts, particularly in winter and summer.

Despite that, we've had almost a full year of production from Harapaki Wind Farm and it performed exceptionally well, achieving a 35.5% capacity factor in its first 12 months. However, to manage the volatility, we did spend $300 million on derivative purchases and demand response calls.

And while they worked, they were expensive and drove a $460 million reduction in financial energy margin compared to last year. Now, I do want to take the opportunity to address the common misconception that high wholesale electricity prices are somehow a windfall for Meridian. That idea is simply not the case.

High wholesale prices are a signal, a signal of fuel scarcity. That's how the market is designed to work. During the year, we became a substantial net buyer of electricity derivatives, at those elevated prices. Aad those prices were compounded by gas scarcity.

The sector's traditional backup fuels were simply not available in the volumes or at the prices we've relied on in the past. So, while wholesale prices were high, they reflected a stressed system and for us that translated into higher costs, not higher profits.

Now, let's talk about our Retail business. Retail really was the bright spot this year and it's where we're seeing the most visible transformation. We ended the year with over 405,000 customer connections, a 10% increase from last year. That's more than 35,000 new connections across our Meridian and Powershop brands.

We saw a 2% increase in sales volumes across our mass market segments, excluding agriculture and a 6% lift in net average sales price, delivering a $32

million increase in revenue. In the corporate segment, volumes were flat, but pricing strength drove a $36 million uplift or 7% growth in revenue. And while agricultural volumes declined, down 13% on last year, these can move around year-to-year based on the irrigation season.

But our growth is clearly being led by residential, SME, and the large business segments. Overall, this is a standout performance from the Retail business, and it positions us well as we roll out our new Kraken platform and the digital customer experience.

Moving on to generation. At first glance, inflows came in at 98% of average, which sounds pretty solid but that headline hides the extreme volatility we experienced. FY25 brought the kind of variability that is incredibly difficult to manage, and it resulted in our lowest hydro generation since 2013.

The Harapaki Wind Farm delivered its first full year of generation, producing 549 gigawatt hours. That contributed to a 26% increase in wind generation year-on-year. We've also made progress on our generation upgrade programme, restoring 29 megawatts of capacity at White Hill and Te Āpiti, and an additional 8 megawatt uplift at Aviemore and Ōhau B and C. This all links to the 112 megawatt of new hydro capacity we are chasing from our existing assets.

We've also faced challenges. At Manapōuri, we've been dealing with issues related to seven transformers, originally supplied in 2015 and 2018. Two of these were removed from service in 2023 due to elevated gassing. A third was installed at the end of 2024. Two new transformers from a different provider are expected to arrive by early 2026. We've made the decision to proactively replace all five over the next two and a half years.

At West Wind, a prolonged transformer outage took 45 megawatts out of the system, reducing capacity to 98 megawatts for most of the year. We did secure a loan transformer from Transpower in late 2024, which restored that lost capacity, and the permanent replacement has now arrived and is sitting on the Wellington Wharf. So we're on track to have the new one operational before the end of October this year.

Let's now move to operating expenses. This year, opex came in at $289 million. A 3% increase on last year, and importantly, below our revised market

guidance of $298 million. Now, that sounds like a modest rise, but there's a key reason behind it.

In short, this year we didn't meet our short-term incentive financial benchmark. This contributes to a cost reduction of $7 million. This means that our people received a small proportion of potential incentive payments, and our senior people received no payment.

That's a tough outcome, but it's a reflection of how closely our remuneration is linked to performance. Beyond incentives, we also sealed operational changes to our Retail and Flux business units. These round out the $11 million of staff cost reductions and reflect the new Flux structure, which now has 29 fewer roles.

At the same time, we're invested in transformation. We've brought in contract support to help deliver the Retail transformation and DigiGEN, our digital generation programme. These costs are reflected in the $8 million increase in contractor spend.

We've successfully completed the implementation of our new Oracle finance system on time and on budget. These one-off costs show up in the $6 million ICT line. The cost line also includes the addition of Harapaki's operating costs. And finally, like everyone else, we have also encountered higher Council rates across our generation assets.

Now on to capital expenditure. In February, we revised our guidance and indicated that we might spend between $220 million and $250 million. We landed at $193 million, down 45% from last year and below that guidance. It's important to note that this lower spend simply reflects timing changes and not a slowdown in strategic investment.

FY24 included milestone payments for Harapaki and the bulk of the Ruakākā BESS investment. In contrast, FY25 fell between the tail end of Harapaki and a later than expected start to the construction of the Ruakākā Solar Farm. Consent for that project was initially lodged in September 2023. It took just over a year to secure initial approval in September 2024.

That decision was then appealed. It took another five months to reach resolution and final consent in February 2025. Stay in business capex also lifted this year, driven by two key investments. The replacement of our SCADA

generation control system and upfront costs for the new Manapōuri transformers.

Looking ahead, our investment programme is accelerating, including the five new consents that Mike talked about earlier.

Now we jump to talking about FY26, where we want to continue to provide guidance on our operating and capital expenditure.

Operating costs first. We are looking at spending between $311 and $316 million next year, which represents an uplift of up to 9% on last year. What's driving that increase is not just inflation or overheads, it's investment in the future.

One of the biggest contributors is our retail platform transformation. In FY26, we'll be running two billing platforms, Flux and Kraken, as we transition customers across, temporarily doubling up on costs.

Once we're fully on Kraken, we expect to remove $15 million of annualised Flux expenses from our cost base by FY28. So, this is a short-term transition cost for the long-term gain. The other driver is our expectation that we'll meet our short-term incentive financial benchmark next year. This means that we expect to pay a higher level of short-term incentives than we did in FY25.

Now turning to capital expenditure. We have allocated between $330 and $360 million next year. As you can see from the graph, growth capex is largely driven by the completion of the Ruakākā Solar Farm. On this day in business capex, the more generation assets you build, the more likely you are to see asset maintenance costs rise. We're also continuing the transformer replacement programme at Manapōuri that I talked about earlier.

The $10 million cost of the two new transformers in FY26 is also included in the asset maintenance bucket. So in summary, costs are going up, but they're going up for the right reasons. We're investing in platforms, people and infrastructure, and we're doing it with a clear view of the long-term benefits.

Let's now look at the results below EBITDAF. These graphs clearly show a massive swing in our reported profit. Net profit before tax fell $671 million, and net profit after tax dropped $881 million.

Even our preferred non-GAAP measure of underlying net profit after tax was down $303 million from last year. So what's driving these movements? The key

factor was a $1.247 billion loss from the fair value movements of our energy hedges. This number includes realised and unrealised losses. $901 million of that total loss relates to NZAS, and is driven by the accounting treatment of the new electricity agreement, which came into effect in July 2024.

Under the new structure, the NZAS contract is treated as a financial instrument, or a derivative for accounting purposes, a 20-year contract for difference, or CFD, rather than a standard revenue contract. This means it's now carried at fair value and remeasured at each reporting period, with the main driver of any value change being movements in the long-term electricity price forecasts.

In FY25, the unrealised loss on the NZAS contract was $465 million. This loss does not reflect actual cash flows. We also recognised a $33 million impairment on the Flux platform, following our decision to transition to Kraken as a retail technology platform. Depreciation increased by $113 million, largely due to last year's $3 billion asset revaluation across our generation sets.

Again, this is a non-cash adjustment, but it does affect reported profit and with another $2 billion uplift in asset valuation this year, depreciation will increase again in FY26.

Our generation assets get revalued each reporting period based on the same long-term electricity price forecasts as electricity derivatives.

All of that washes through to a statutory loss of $452 million. Our underlying NPAT, which adjusts for the non-cash items was just $56 million, down $303 million from last year. That movement is largely explained by the $294 million drop in energy margin, with the higher depreciation expense offset by the negative tax expense on the current year's statutory loss.

So while the headline numbers are poor, it's important to understand that these are largely accounting-driven impacts, not operational ones. Our underlying business remains strong. We continue to invest in growth, maintain our dividend and support customers through the energy transition.

Net debt increased 18% to $1.505 billion and our net debt to EBITDAF ratio rose to 2.5x, up from 1.4x last year. We have $658 million of undrawn facilities, all under our green finance programme, with a diversified funding mix. And while Meridian's debt to EBITDAF has increased, this is due to the dry year EBITDAF, rather than a large increase in leverage.

S&P do take a multi-year view of our debt to EBITDAF and have affirmed a stable outlook as at July 2025. We have ample liquidity available to support our balance sheet through debt facilities. We're also considering a $300 million green bond issue, which would extend our debt maturity profile and support strategic investment.

Our capital structure remains robust and we're well positioned to fund our growth agenda. Finally, a quick look at July. The good news is that we're seeing signs of recovery and we are well past the drought impacts of last financial year. Inflows for the month were 89% of average. Waitaki storage was also sitting at 89% and snowpack was 76%.

Hydro storage is significantly higher than this time last year and generation volumes are tracking well. That's a solid foundation heading into the new financial year. Customer connections grew 1.4% in July and are up 11.2% year-on-year. Retail sale volumes were up 9.4% and generation was up 9.6% compared to July last year.

These are further strong indicators that earnings reversion has happened and operating conditions are stabilising. August will also see the final fees paid on the largest smell to demand response call we made last year. The ramp-up is almost completed and ends as a nearly back to full consumption.

The annual premium fee for the demand response continues, but the temporary call has now concluded. Looking back, that demand response call was critical. It underpinned security of supply through the extraordinary droughts we faced last year and it's a great example of how customer flexibility in the system can support resilience when it's needed most.

So, in summary, while FY25 was financially poor, we're heading into FY26 with a strong balance sheet, lots of momentum, and a more stable operating environment. Back to you, Mike.

Mike Roan: Thanks, Helen, and thanks for the plug, it was a nice touch. Tough experiences build character and last year, it certainly did that for us. It was tough financially, and it was very tough for customers, but it would have been a lot tougher for them without us and we are proud of the support we've provided, and will continue to provide them.

We realise that we have to prove ourselves to investors all the time, even more so when things don't go to plan. And we are. Delivery of the Harapaki Wind

Farm and Ruakākā battery alongside consent and current construction of the accompanying solar farm at Ruakākā mean that we're growing.

With Te Rahui, Mt. Munro, Te Rere Hau, the Palmerston North battery and the PPA supporting Tauhei, that growth will continue. The meaningful progress within the Retail and Generation teams and the Flick acquisition will make a difference as well. And a stable dividend should allow investors to look through last year's challenges and focus on the future.

With that in mind, I'm pleased that operating conditions have returned to normal and with a new mix of risk management products on hand, the business is well equipped to navigate the next few years. So the majority of the damage that the sudden collapse and gas suppliers caused is behind the electricity sector.

Absent more unhelpful news, any remaining uncertainty has been driven by concerns that the government may intervene. My observation is that they know the cost of doing that would be high, and so we're taking the time to assess whether it's worth it or not.

Regardless of what they do, it will be up to us to navigate the course, and I'm ambitious for the company as I know that we're busy unleashing the renewable bounty that New Zealand has.

And as that happens, the country will gain a sustainable competitive and cost advantage that other countries will not be able to match. We intend on providing a little more insight into this at an Investor Day that's scheduled in November.

But right now, we can move to questions, and we'll start with questions from anyone here in the room. Hugh, we'll go to you.

Hugh Lockwood: Hi, I'm Hugh Lockwood from Forsyth Barr. Thanks, Mike and Helen. Just a couple of questions. Firstly, are you able to provide a bit more colour on the dividend commentary and maybe talk to what net debt-to-EBITDAF gearing ratio the Board would be comfortable with, looking at a sort of normalised hydro earnings basis?

Mike Roan: Yes. I mean, it's exactly what it said, Hugh, is we have paid a stable dividend over a year where cash flows haven't sustained that. So all we're trying to say to people is we're mindful that, that has consumed a piece of the balance sheet. And if we have another drought in the future, we'll look at it.

Other than that, we expect normal business, which is what we hope for as well. Net-debt-to-EBITDAF is driven by the S&P ratios really. As you look, we had a spot ratio this year that was 2.5 this year. Last year, it was 1.6. We expect that to normalise as we head into next year as well. So we just -- we're looking at the 2x to 3x as the range for net debt to EBITDAF.

Hugh Lockwood: Okay, and my second question is on the pipeline. So you mentioned that Te Rere Hau's timeline has been pushed out but you've got the target for three projects to commence in FY26. And it sounds like a lot of projects might reach FID in the next 12 months. So can you talk to what other projects might be part of that three? And also if there's maybe the potential for more than three next year?

Mike Roan: Well, we're hopeful that there might be more than three, but the three that I've mentioned, the first one is Te Rahui. I mentioned that next couple of days, we expect that it will reach financial close. The team is working really hard on the battery in Palmerston North and Mt. Munro Wind Farm as well.

And while Te Rere Hau has slipped by up to 12 months, there's a lot of work that's going on to see whether we can't bring that forward as well. So time will tell. Development, as everybody knows who's in the development game is tough. You find things out that you just didn't expect, but we have a lot of people working really hard to deliver those outcomes.

Hugh Lockwood: Great. Thank you.

Mike Roan: Jonty?

Helen Peters: Nice to see you.

Jonty Nattrass: Good morning. Jonty Nattrass from Octagon Asset Management. Thanks for the presentation, Mike and Helen. My first question, obviously, with FY25 kind of fresh in the minds, just wondering if you could provide a bit more context on the portfolio positioning. How you see your length? You mentioned the Waitaki contingent storage as part of that wider security theme. Does that play into your -- the thoughts on there? And how does the HFO kind of feed into that?

Mike Roan: Yes. It's having gone through, as you say, '24 or '25, it allows you to look really carefully at business settings. And we're on this trajectory to not only buy a bunch of risk management products that supported us but decarbonise the

marketplace more effectively. We've had to sit back and look at that again, Jonty.

And the two things that have gone on within the business is we set an optimal portfolio for our business based on the opportunity in front of us and the risk that that we face, and we've backed that off a touch. So we've dropped the optimal levels a touch as we head into 2026.

We've also reset the risk management products that we have within the business. The way that I presented is we have about 300 megawatts worth of swaptions or demand response sitting within the business, given the transactions that we've written, which are -- it's a lot more than we had as we headed into '24, and we knew, we found out in '24, that some of that insurance didn't work out so well.

So we feel really good about looking at 2026. We don't know whether it's going to be wet or dry or normal yet, but we've certainly positioned the portfolio, given the experience that we had.

Your piece on contingent storage is, the way we see that is it's just incredibly important for New Zealand energy security is all the analysis -- that graph shows hopefully gives people some insight into how the strategic energy reserve, the NZAS transaction and contingent storage line-up to cover dry year exposure from a country perspective. And so security of supply, as well as moderating costs for customers, is really what contingent storage will help with.

Jonty Nattrass: Cool. Thank you. And my second question is just on the hydro development that you mentioned. Mike, I know that was a key focus of coming into the top seat. I was just wondering if you could talk a bit more about, is that on top of the work being done within the generation team to expand, obviously, the transformers expand capacity, the Waitaki, is that looking at further expansion of those two schemes?

Mike Roan: Yes, it is, Jonty. So I kind of mentioned that we're going back to our routes where trying to redevelop a skill set that was manifested in the '60s and '70s within the business. And so it will take us time to develop the internal capability and then identify the options that work.

But it's kind of simple in one way, as you lose access to gas and storage that provides that firmness is we have to get it from somewhere else as a country if

we want affordable energy. And when you look around the resource that we have that other countries don't have is we have hydro.

And so we will be careful about it. We'll work with stakeholders to move our way through that process. But if there's ever a time that the country needs someone to be looking at it, it's now.

Jonty Nattrass: Thank you.

Mike Roan: I don't think we've got any more questions in the room. So why don't we move to the phones?

Operator: Thank you. Your next question comes from Joshua Dale with Craigs Investment Partners.

Joshua Dale: Morning, team. Just on the Te Rere Hau project. Now you've acquired New Zealand wind farms. I think in the past, you had signalled the cost of that project was $500 million to $600 million. What does the incremental cost look like now, do you think?

Mike Roan: So I reckon it's going to cost us more than 600, Josh, is probably the best that I'd give you. But the economics of that project, it is one heck of a project. The average capacity factor on that wind farm, it looks superb. I'd love us to be able to push the go button on it.

But we've got one challenge at that site and it's an important challenge to resolve, which is there's an airways tower that sits there and helps air traffic in New Zealand navigate the skies and we've got to move that off-site successfully.

So that's really, really important. We've got to get it right and we will, but it's just taking more time than we'd contemplated. But that is an incredibly valuable property.

Joshua Dale: Got it. Thank you. And just on your balance sheet settings, you've talked a little bit about this. Traditionally, the range seems to be 2x to 3x net-debt-to-EBITDAF, but we're in an environment now, obviously, with gas back up getting harder to rely on. We've just had evidence of what your exposure can be to a dry year and then you've got $2 billion of capex coming through.

I appreciate you'veended to manage the balance sheet to a bit more conservatively than that 2x to 3x range, but has there been any change in your

thinking or perhaps changes to the phasing of that capex to provide you more capacity going forward?

Mike Roan: I mean, the simple answer, Josh, is no.

Helen Peters: I was going to say the same thing, so that's good.

Mike Roan: You come back to the country needs energy and our job is to provide that energy and we've got the consents that are coming through our pipeline and we've got the balance sheet to deliver it. There's no question about our intent moving forward.

I think what you've seen for our business is, I hesitate to say you've seen floor earnings because the future is really uncertain, but you've got a sense of what can really happen to our business when things are extreme. Two 90-year droughts and the loss of gas in one year for a business that relies on hydro energy and then thermal when it doesn't rain, that's a pretty tough thing to get through.

So I don't have any concerns I look at the financial forecast for the business and our capacity to both deliver investment and stay within that net debt to EBITDAF range that you mentioned. Helen.

Helen Peters: And I think coming back to that capex spend, the key driver of any changes to the amount we spend in a financial year is the impact of the development pipeline and any delays to that pipeline and you saw that in the amount of capex that we spent in FY25.

So while we give guidance and we model that of where we think we're going to land with capex, any delays in that development pipeline will have an impact to that debt level.

Joshua Dale: Okay. Thank you. The last question I had was, if I'm a customer sitting at home, logging into your website in say 12 months' time, you've got the Kraken platform implemented. Are there any changes to your product offering that I may see?

Mike Roan: Yes.

Helen Peters: That’s the plan.

Mike Roan: Absolutely. Well, Josh, the benefit of technology is it allows you to both connect with your customers more effectively because you get to know them better

through the use of technology and it allows you to expand your products and services to them. Now, Kraken is incredibly efficient and effective at what it does.

It wasn't easy for us to step away from Flux, but we have. So that gives you a sense of the discipline that we've got and our commitment to delivering outcomes for our customers as well as shareholders. So, yes, you will.

Joshua Dale: Any early sort of insights on what customers may see in a product offering sense?

Mike Roan: The simple answer is no, Josh, but not because you've asked it. I'm just not giving away to our competitors.

Joshua Dale: No, totally fair. Thanks very much, guys.

Operator: Your next question comes from Andrew Harvey-Green with Forsyth Barr.

Andrew Harvey-Green: Morning, Mike and Helen. Just a couple of questions from me. Are you able to remind us, I think the contingent storage volume that you're looking at is around about 600, 650 gigawatt hours and how much of that, assuming it comes through, do you think you'd be able to access in sort of an average year in terms of what would your average hydro generation volumes change by if you had that available?

Mike Roan: Hi, Andrew. So it's 545 gigs that's available through that contingent storage. And you're right. On average, we will generate harder. I don't have a number for you. Owen's kind of singling three or four something. We will let you know. But the key point is as you increase access to hydro storage, you are able to generate more because you got access to more water on average.

And the way that we have talked to it previously is we see the financial benefit to customers being in the order of $500 million a year. And improvement in our earnings base being in the $12 million to $15 million per year. So we think the leverage outcome for customers is brilliant but there is an improvement in our own financials as well. So I don't have the gigs for you but given probably what you wanted to know anyway.

Andrew Harvey-Green: Yes, all good. And just sort of following on from that, I mean, you -- I guess, applied for emergency access to that storage for 2025 and Transpower turned you down. Going through the fast-tracking consent process -- I mean, how is

that going to, if I assume you're more confident of being successful through that and presumably the aim is to get that in place for 2026?

Mike Roan: Yes, it is. So the aim is to get it in place before winter '26. And I think about it like we think about consenting is you've got to choose a number of routes if you want to improve the odds of success. And so we were hopeful that working with Transpower, that we would get confidence for Winter '25 access to that storage but we didn't. In the meantime, while we were going through that process we lodged a fast track application.

And we do have, I'll say, reasonable confidence, we haven't been through that process before, but certainly, the effort that we're putting in and bring it back to what I said before, when you look at charts or talk to people about Winter 2026, security of supply is going to be driven by access to it. So there's a national need as well as a company outcome.

Andrew Harvey-Green: Yes, great. Okay. And just last couple of questions. Just sort of looking at the Kraken implementation and just understanding is I'm getting the opex right going forward. So you've got elevated opex for FY26, and I'm right in saying in FY27 as well before we see things reduce. Helen, you talked about, I think, $15 million reduction in opex after that. Is that just the one-off costs dropping out or is that in addition to one-off costs?

Helen Peters: So the $15 million dropping out is essentially the operating cost of the Flux business. So once we've fully moved over to the Kraken platform, then those costs will come out of the business. And that's why we've said that, that should happen by the end of FY28. But there'll be a gradual reduction in that over those financial years.

Andrew Harvey-Green: Yes, okay. And in terms of the elevated level of cost per annum as you implement Kraken? What are the Kraken costs?

Mike Roan: They're in the same order, Andrew. So that that lift Helen presented, they're in the $12 million to $15 million range. So you kind of -- the challenge for us over next couple of years, as Helen said, we're running two retail billing platforms. And as we migrate to Kraken, we'll be able to reduce the cost and impact of the Flux platform, by '28, we should have unwound it entirely.

Andrew Harvey-Green: Okay, I understand that. No, that's great. That's all for me. Thank you.

Operator: Your next question comes from Grant Swanepoel with Jarden.

Grant Swanepoel: Good morning, all. Just I wasn't quite clear on the answer, there. So there's $12 million of extra cracking costs related costs this year, that drops out and you get just a $3 million extra reduction in costs by 2028?

Helen Peters: So I think we'll probably be looking at -- probably a $3 million to $5 million drop.

Grant Swanepoel: Okay. Thanks. My next question is just on your maintenance capex. So that's been creeping up every year and we understand why it's been creeping up. But our valuation obviously links to a long-term maintenance capex expectation. What is the long-term expectation for ICT costs and asset maintenance?

Helen Peters: Yep. Drawing on the asset maintenance cost and what I tried to pull out in the presentation is that as we continue to add new generation assets, they do need to be all maintained, so you will see higher levels of stay-in-business capex in relation to asset maintenance, just due to the fact that we'll have more assets to maintain.

On the ICT side, costs over the next couple of years are all related to the digital transformation that we're doing across Retail. So that's in that Kraken space and then also in DigiGEN, which is a digital transformation of our Generation business.

Mike Roan: Grant, how we used to talk to $65 million of annualised capex was kind of the number, and then we actually only spent about $50 million of annualised capex. I think what we'll do is we'll give you an update at the Investor Day in November on capex because those numbers still feel reasonable. But what we're seeing is a bunch of one-off replacements, whether it's the SCADA environment or the transformers. And of course, they flow through multiple years. So I think we do owe it to people to come back and re-baseline that underlying state business capital forecast.

Grant Swanepoel: Mike, that's very helpful because your estimated maintenance costs have risen from $24 million to $65 million over two years, quite eye-watering.

Mike Roan: Yes, yes.

Grant Swanepoel: So it's good to know it's going to revert back to normal.

Mike Roan: Yes, I can't see why it doesn't, Grant.

Grant Swanepoel: Thanks. And in terms of the HFO cost that you've taken on now, how do those relate to your historical type of demand response costs and general swaptions that you used to? Is it a bit elevated because of the 10-year contract?

Mike Roan: They're okay. I shouldn't say that, it's in front of the Commerce Commission, I guess they'll make the ultimate call. But I think at one level, you could say that the cost base for that contract is higher than some of the demand response and swaptions that we'd enter -- the gas backed swaptions that we'd had, but not unrealistically or unreasonably so.

The Strategic Energy Reserve agreement, it feels like a reasonable approach compared to the alternates, whether that be demand response or trying to find some other measure. So not unreasonable, but we don't mind paying less.

Grant Swanepoel: Thanks, Mike. And a final question, you guys might not answer it so I'll lowball it anyway. The consensus is sitting well above $1 billion. Are you happy with that on an EBITDAF forecast to at least beat $1 billion if hydro plays a role?

Mike Roan: I think I'll leave that to you, Grant, for that forecast. You know, we don't provide forecasts.

Grant Swanepoel: But cognisant of where consensus sits and not too uncomfortable with that?

Mike Roan: Yes, I think that, Grant, there are obligations on businesses to provide updates to the extent consensus and internal forecasts very materially and we're really mindful of those.

Grant Swanepoel: Thanks, Mike. Thanks, Helen.

Operator: Your next question comes from Vignesh Nair with UBS.

Vignesh Nair: Hi. Good morning, Mike and Helen. Thank you for the presentation. A couple of questions. Firstly, sort of pointing to in the presentation, we've seen two one-in-90-year events from a hydrology perspective this year. I think anecdotally, you're hearing such events getting more and more frequent. Do you think there's a pattern emerging or a structural change in terms of hydro volatility in the business?

Mike Roan: So I'd tell you the interesting thing is no. All our modelling shows that as climate change has a bigger, bigger -- a bigger impact on the country, that the catchments in the south, inflows received more water in bigger doses. So that's

what all the forecasts, whether it's NIWA or any of the climate scientists, that's what they'll forecast and show. That's the advice that we get.

It just -- sometimes it happens, Vignesh. We know the risks. I think that's the key thing with our business. We know the risks. We know droughts are inevitable, ultimately. And so we manage the business with the balance sheet and a portfolio position that can manage them. That bit that really hurt us this year was the fact that, that insurance, those swaptions that we bought, they failed. And that, as Helen presented, I think I did the same thing at interims is that costs a lot of money…

Helen Peters: 300 million.

Mike Roan: Yes. So I go back to my simple answer, Vignesh. No.

Vignesh Nair: Okay. Perhaps it's just recency bias. I suppose this second your question was just a clarification on capex over the next couple of years. I think last year you talked 3 billion in growth capex between 2024 and 2030. Firstly, is that still an appropriate assumption?

Mike Roan: Yes, and sorry for any confusion in there, Vignesh. When I talk to 2 or 1.6, I use a couple of numbers in there. The ambition is still through 2030 to land $3 billion worth of capital. My numbers were just different periods.

Vignesh Nair: That's just purely growth, not stay in business? It's just -- and so given that backdrop, sort of implies your guidance into next year, positive result this year and last year a spend of about $700 million for the three and a half years leading into 2030. Is that still fair?

Mike Roan: Yes. Although some of the developments, you know, that don't all come, they're not all equal, Vignesh. When you look at developments like Te Rere Hau, you do have to land a couple of big ones in there to get to those sorts of numbers.

But look to those bigger developments that are flowing through our books and through the pipeline, you can easily see where that money comes from or that forecast comes from.

Helen Peters: And the big one next is Te Rere Hau.

Vignesh Nair: Yes, that's very clear. And finally, is the balance sheet still structured in a way in which to support, I suppose, flat dividends for two dry years I think was the

previous, I suppose, standard? Is that still going to be the case through this phase of elevated capex?

Mike Roan: I think our reference to May in the statements is we would look at it carefully, Vignesh, if we saw another drought emerge in the short term. Like every balance sheet, you need to restore it. So, that's what we were trying to get to was we know what we have the capacity for, but when you do draw on that balance sheet, you don't have infinite capacity. And we've got this incentive and drive to invest while maintaining our credit rating.

So, we were just saying to people, if we had another big drought on our hands, we have to look at that big drought. But otherwise, we restore the balance sheet, build these assets and get on with business, which is what we're forecasting to do.

Vignesh Nair: Amazing. That's all from me. Thanks, guys.

Helen Peters: Your next question comes from Stephen Hudson with Macquarie Securities.

Stephen Hudson: Hi, Mike and Helen. Thanks for the presentation. Just a few from me, just the revaluation. I just wondered if you could call out any changed assumptions there underpinning that $2 billion revaluation this year?

Helen Peters: I can take that one. The increase for the generation assets is largely driven by the change in the wholesale market outlook price for the future. The only one change that we did have to our assumptions, which we've included in the financial statements, is that we did change our depreciation from accounting to tax depreciation. And there's a small note of that in our financial statements. But other than that, it's the same calculation and the same methodology that we've had in prior years.

Stephen Hudson: And the wholesale price change, do you have a number at hand there, Helen?

Helen Peters: Offhand, I don't have it. I'm just looking to Owen. I don't have that, but we can get it to you.

Mike Roan: Yes. And remember, we presented at our last Investor Day, we gave like a price range and we've updated that since that's the latest variation of wholesale market outlook has popped a little bit. Not materially so, but again, we'll give you an update on that very openly and transparently, as we did at the last Investor Day in November.

Stephen Hudson: Yes, very good. And then just talking of Investor Days, I think last year, the team sort of talked about the potential for a new power station on the Waitaki chain. I just wondered if you had an update on that potential.

Mike Roan: So it's sitting in the pipeline. Is the best I can say is we're trying to align that with the work that we're doing on wider storage options in the Mackenzie. And obviously, if you're looking at your structures and storage, any new power station that you might add to your structures has got to align with development of those options, and so it's connected to that work.

In the meantime, what you might have picked up on today, and I can't remember how more widely we've referenced it, but as the Waitaki power station upgrade, that's underway. And where you'll see a capacity uplift for that power station.

Stephen Hudson: Very good. And just on contingent hydro, I think you mentioned the 545 number. There's a release and an urgency release component to that, sort of 330 and 210 roughly. You've gone for the full 540 in your Fast-Track application?

Mike Roan: Yes, we have. But it's a great reminder that it is, from a physical perspective, just water flow, is the lower that lake gets, the less water flows down the canal. It's just friction slows water flow down, and so the deeper you go into that storage, the less water actually passes through the canal.

So first 300 gigs is straightforward operationally for us. The remaining couple of 100 gigs is -- no one's been there before and so it just is harder to deliver. Our engineers are confident that we can. The release of that water would be slower than what you would see under normal operations. So it's a great reminder, Steve.

Stephen Hudson: Do you have any clues on what's happening with the Tekapo contingent storage? Do you know if that's subject to a Fast-Track allocation as well?

Mike Roan: We don't. Transpower are looking at updating their SOSFIP as well again at the end of the year. And I should be clear. While we have tabled a Fast-Track application for contingent storage, is we're supportive of contingent storage for the same reasons that we laid out for others, whether it's Tekapo or down in Clutha is you want a low-cost clean energy system to support the economy. The way you get it is you develop your hydro resources and that contingent water is just sitting there and available to us.

Stephen Hudson: Yes, makes sense. Thanks Mike. Just two more quick ones. It sounds like NZAS are in market for 100MW to bring back Potline 4. Can you confirm that at all and give us any clues as to what they intend to do beyond Potline 4?

Mike Roan: So I think they're in the market for 50MW for Potline 4, so Potline 4 is a 50-megawatt addition. We're working with them...

Stephen Hudson: It's 50 plus is what I've heard, yes?

Mike Roan: Yes, look, they would love to expand that Potline and make it a full Potline. They'd love to get it to 180 megawatts if they could. The reality is you've got to balance that increase in consumption with the development of your asset base.

And so what is slowing them down is the same thing that has impacted the electricity sector. Is we felt good about the renewable investment going in to the market as being able to accommodate new growth. But when we lost access to gas, another fuel is we've had to recalibrate and so the development that's going on is to replace gas for existing users.

And so we're working with them to try and find an economic solution to them but that aligns with the development pipeline that we've got. And I'm sure other people are doing the same thing as we've only got capacity to support them for a portion of that increase.

But we know they're in market talking to people about it. And we're keen to support it because it's economic growth, but we've got balance that opportunity against making sure we deliver for people who are already here.

Stephen Hudson: Yes, makes sense. And just last one. We've seen one of your competitors sort of start to talk a little bit more openly about developing off balance sheet. I just wondered if you had some early views on whether or not we could see a similar change for you?

Mike Roan: Yes, Steve, I mean, we already are. So Te Rahui is a development. It's a joint venture development, majority project finance. I think the total cost is $370-odd million for Phase 1. It's a 400-megawatt development. It's in 2 stages. Stage 1 is 200MW. I think that, first, as I said, the cost is about $370 million but most of it is project financed.

You'll have seen our work with NZ Wind Farms. That would have been a joint venture and we've got a PPA in place with Tauhei, the joint Clarus-Harmony Solar Farm as well. So we're open for business. And what that means is our

balance sheet, structuring with others, in whatever way that makes sense for them and for us.

Stephen Hudson: Makes sense. Thanks, Mike and Helen.

Operator: There are no further questions at this time. I'll now hand back for any closing remarks.

Mike Roan: Thank you. Only closing remark is to close. Thanks, everybody, for your time this morning. Appreciate you being here and on the phones and for your questions, though are excellent. Thank you.

[END OF TRANSCRIPT]