THURSDAY 30 MAY 2013

(Conference resumed at 10.03 am)

CHAIR: Good morning ladies and gentlemen and welcome to the second day of the Electricity Authority's TPM Conference. So my first reminder is to speak into the microphone as though you are a jazz singer. As long as you are close to the microphone the stenographer will be able to hear. Don't talk too fast. And please identify yourself before you talk so they can attribute whatever you say to the correct place. So we don't have a dispute about who it was who made particular comments.

The same procedures as yesterday will be followed. Individual Members of the Board will ask questions to the parties to whom they have questions up to the front table. There are microphones available at the front table. I noticed they've multiplied by a factor of two overnight, so that there are now four of them on the table. And that will give an opportunity for people to come up and answer any significant questions and there will be an opportunity for other Board members, and members of the staff and usually if appropriate there will be a chance to make other comments.

We will try and keep it as informal and as constructive as we possibly can. This is not a litigatious or adversarial event on this occasion, it's for the benefit of the Board to be able to dig into some of the submissions and cross submissions you've put so much work into and provided to make sure that they fully understand them. But also to test out some of the preliminary conclusions that they've drawn and analysing your submissions in terms of what you're actually saying. So I'll just introduce people at the front table for the benefit of those who are new; I notice we do have some new faces, I didn't expect our crowd to swell, I thought it would shrink. Welcome along Simon.

David Bull, Elena Trout, Susan Paterson, Roger Sowry and I am Brent Layton.

Susan Paterson it going to lead off the questions today. This is appropriate, it is her birthday.

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SUSAN PATERSON: I'm not actually going to lead off, I'm going to let Roger lead off. There's a lot of questions on SPD so I'm going to let Roger start.

CHAIR: My apologies. Roger's going to do the first part.

HON ROGER SOWRY: The first questions are around the submissions that were made on the HVDC and the sunk cost reallocation; we did have some discussion yesterday on sunk costs so we will be a bit of re-litigation on some of those issues, but hopefully there will be some new stuff as well.

So can we ask - I don't know whether Northpower are here, but the questions are for Northpower, CEG or Transpower, Contact, Mighty River, Unison, Norske Skog Meridian and TrustPower and Vector. If they could come to the table please?

FEMALE: Can I just clarify Mighty River's not here today. I work for them, but they were unable to come today.

CHAIR: Yes I am aware of that. So we'll just read their questions.

HON ROGER SOWRY: So the first question is for Northpower, I will read it to get it on the record and they will be given a chance to respond in writing.

The question was you submitted that new investment projects that are already approved and either completed or substantially completed prior to 2014 are now sunk costs and that changes the behaviour by beneficiaries but will not change those investments at all.

And you also submitted that we should be encouraging the maximum use of these new projects to maximise the benefits of those investments. And the question was do you consider that there is a risk that encouraging the maximum use of assets will bring forward the date by which a new investment would be needed? And how will spreading the costs of assets to non-beneficiaries promote efficient investment in relation to these assets?

So those were the Northpower questions.

So if we just move then to CEG, they're not here, but Transpower and Ross, are you happy to take the question?

ROSS PARRY: I'm happy to take the question and I will see whether I can respond.

HON ROGER SOWRY: So CEG submitted that there can be no dynamic efficiency benefits associated with applying a beneficiaries pay approach to reallocating the sunk costs of past investments. So first question, we kind of did traverse this a bit yesterday, but I think it is worth traversing, which is why do you consider that the costs of past transmission investments are fully sunk? In particular, why can't transmission assets be unbolted from their platforms and transferred to other sites? We started this yesterday.

ROSS PARRY: You are right we did have a little bit of a discussion about this yesterday. I mean, I don't really have much to add to the discussion yesterday other that I think we talked about the difference between substation assets and transmission line assets and in the cases of substation assets, a reasonable portion of the value is around the electric components, the transformers and the like and that those do have some redeployment value. Obviously some significant portion of the value tied up in substation assets is also in other substation infrastructure that you can't pick up and move somewhere else, particularly the civil civil site works and the like, as well as some of the other building work and the like.

I think when it gets to transmission lines I don't have a large sample of direct experience but from the projects I've seen tends to be the dismantling costs are larger than the salvage value, so we tend to when we're removing a transmission line offset some of the salvage costs, sorry, the dismantling costs with the salvage proceeds, rather than the other way round.

HON ROGER SOWRY: Can you please just also comment on whether or not more efficient operation of the existing assets can lead to a delay in the requirement for future investments?

ROSS PARRY: I think - I think the point about this trade off between the static and dynamic efficiency, is that you've got a definite risk of upsetting dispatch efficiency. So - of producing an out of merit dispatch solution every half hour, to the extent that you're influencing people's bidding behaviour and off take behaviour through a price signal around transmission.

In the long - in the long run I suppose there's some interplay between how much you - I guess it's true to say if you deter to the use of a transmission line that was built, you may also defer the future need to upgrade that transmission line. But I'm not sure that those two things are in a proportion sort of order of magnitude, if you like, that the certain risk - ongoing risk of deterring maximum use of the transmission line to achieve a more optimal dispatch pattern and consumption pattern across the grid every single half hour is a far bigger risk than in the long run when periodic transmission upgrades happen every 30 years or 60 years or whatever it is, that you might have some influencing around the margin on the timing of that.

HON ROGER SOWRY: So in the same light - or same line, would more effective price signals alter the investment decisions for generators?

ROSS PARRY: I think that's - again yes they would at the margin have some influence on the decisions that generators make around where they locate and that's certainly part of the crux of the argument around the HVDC $30 million PV inefficiency. But you know, at the same time generation location decisions are made primarily on the basis of where the resources are available and that's a big constraining factor on where generation location decisions are made. So it's sort of at the margin sometimes, the transmission cost impact might be enough to shift you from - to shift the merit order - the long run merit order in terms of generation expansion.

HON ROGER SOWRY: And yet when we go around and visit generators, particularly in the South Island, they've been telling us, certainly from my time on the Authority and before that the Commission, that they won't invest in what they would see as the next most viable project in the South Island because of the price signal that they're receiving with the HVDC, so how does that – I mean it sounds to me it's a bit more than marginal I would have thought?

ROSS PARRY: Look, I think you have an information problem there and it would be very hard for the regulator to to have full information to know to what extent the HVDC charge shifts the long run merit order for transmission. The best estimate you have of that is the GEM based modelling that you've done - that the TPAG's used and that Transpower and the EC or EA it might have been, have had a go at since then. Certainly, you know, Meridian has stronger views about the impact on merit order of expansion. And other people have other views about whether the plant that they're proposing would be the next merit order plant anyhow. So I think it's certainly it does have some influence - it can have some influence on merit order where the merit order is otherwise so closely spaced that the transmission charge is enough to shift the next preferable plant.

I'd be a little - I guess it's a little bit more clear cut in a case where you have the likes of the HVDC charge which is applied to all generators across the South Island deterring investment in a portion of the South Island that's a net importing region. I think that that becomes a bit more clear cut.

ELENA TROUT: Ross, just to go back to sunk cost and by way of an example of you saying that the transmission assets are sunk. In the situation where NIGUP was actually installed and there was a significant continue of transmission assets that were replaced and taken down, can you explain what happened to those assets, particularly the transmission lines and how, for instance, the Clevedon valley and around Te Huna were they just put in a hole and disappeared or were they sold to other organisations or scrapped?

ROSS PARRY: I was not personally involved in that project and can't give you a detailed response, so I'm happy to follow up in writing as to what exactly happened to those assets and perhaps to quantify the dismantling costs compared to the salvage value.

DAVID BULL: I have an amplification I would like. You are suggesting that it's only at the margin that generation investment is affected. My understanding is that Contact, for instance, does not offer full capacity of their plant in the South Island because of the charges, so it's not only new investment, it is existing investment that is potentially under utilised.

ROSS PARRY: I forget the PV value, but yes that's another one of the PV values identified by TPAG in the another analysis around the inefficiency of the HVDC HAMI charge. And so you know, certainly it does, I think it might be 5 million, it's a much smaller magnitude number, and I guess if there was a real shortage of peaking capacity in the South Island that the energy price signal would outweigh the HAMI signal, but it's certainly - the margin has some influence on the offering of that extra capacity.

HON ROGER SOWRY: Okay. The next question I've got is to Contact. In your submission you state the decision regarding the majority of the $2 billion worth of transmission investments were made in the past and There is no potential for sufficient gains to be made in relation to that investment. Yet you also state that the HVDC cost allocation needs to be changed. So I'm wondering how you reconcile the apparent inconsistencies of those two positions?

BOYD BRINSDON: Boyd Brinsdon, Contact Energy. Unfortunately I'm probably not the right person, I'm from an operational background in Contact, to answer that question, but we can take it and reply in writing.

HON ROGER SOWRY: Okay. So now the next part was in what circumstances would a reallocation of costs of historic investments be warranted?

BOYD BRINSDON: Same answer applies.

HON ROGER SOWRY: Okay. The next question was to Mighty River, and they aren't here. But I will read out their question again to get it on the record. So to Mighty River, you state in your submission that the following: "We consider the inclusion of sunk assets is a poor regulatory practice, the immediate impact of which will be to send a clear messages that regulatory decisions are retrospectively reversible, and moreover, that the value of investments made in good faith can be destroyed or materially diminished. The question was could they please explain the relationship between that submission and their statement that Mighty River Power can see no compelling evidence in the Authority's analysis to suggest the 2011 TPAG majority proposal was not a proportionate and pragmatic solution to the HVDC issue. The TPAG proposal would have involved altering the pricing for what they consider sunk assets. So we will send that to them.

The next question is to Unison; I think Unison are here? They registered for the day. No, they're not. So, the Unison question, again for the record, was you submit that sunk costs should be recovered in a least distortionary way. Why do you consider that the costs of historical investments are sunk? If there was a technological change that meant historical transmission investments were no longer needed wouldn't changing parties that made no use of those assets nor received any benefit from them lead to distortions? Yep, sorry, charging parties, yeah. So that will go to them.

And Norske Skog aren't here. So we will read their one. They submitted that South Island generators have been paying for the HVDC since the late 1990s and at that time the prices they paid for their assets, or their opening balance sheets in the case of the baby ECNZ companies, reflected the expectation of paying HVDC charges to perpetuity. They recommended that new South Island generators should not have to pay any HVDC charges and this would overcome any real or perceived generation investment inefficiency. So the question was do you think that assets such as the Manapouri extension - that the Manapouri extension should not be subject to the HVDC charges? The second one was what charges should new assets be subject to? Do they have a view as to whether or not this will distort competition in favour of new South Island generators? And how will this provide incentives for efficient generation investment in the South Island? And the third question arising out of their submission was did they believe that the Authority should make this change to avoid generation investment inefficiency even though they submitted that there hasn't been a change in circumstances material enough to warrant a total re-write of the TPM. So they will be forwarded to them for response.

The next question therefore is to Meridian who are here. So what is what’s your response to the NZIER's comment that there is an issue with inclusion of HVDC Pole 2 in SPD because the likelihood that the HVDC HAMI charge has already been factored into South Island generator's assets values?

GUY WAIPARA: We disagree that that any HVDC charges have been factored into anyone's asset values, they've been in dispute for a long time and that's pretty well known.

We actually think that it's okay to keep Pole 2 and Pole 3 consistently in the same mix. We do get that running an SPD methodology with Pole 2 out is going to be kind of challenging for how you solve your model. But I think it's really important that all assets are treated consistently.

HON ROGER SOWRY: Okay. Yep. So you want Contact to comment on that?

ELENA TROUT: Yes please.

BOYD BRINSDON: On the same question? So the question of whether Pole 2 should be included, or the general question of whether they are deemed an asset values in their understanding of the current TPM or both?

ELENA TROUT: Both.

BOYD BRINSDON: Both. Yeah, I share Guy's view that my understanding is that I can't imagine for any minute that current asset values use for South Island generation assets assume any assumption that TPM would be in the purview. And in regards to Pole 2 I agree, if Pol 3 is to be included in the calculation for SPD then a) it would be difficult to implement it without Pole 2, and b) we couldn't see any logic for doing so.

HON ROGER SOWRY: Alright. So the next question then is to Contact. You recommend in your cross submission that the Authority consider incremental options such as the HVDC charge being changed from HAMI to megawatt hours. How will this promote efficient utilisation and investment of the HVDC?

BOYD BRINSDON: Well as has been mentioned five minutes ago, Contact does operate a regime now where there is approximately a hundred megawatts of generation capacity not offered to the market in anything other than an emergency situation where it would be. But we believe the current HAMI charge does send the wrong generation signal and the wrong net benefit signal and that that generation would be made available to the market if charges were based on megawatt hour rather than megawatt capacity.

HON ROGER SOWRY: Okay, so again to Contact, why would that approach be superior to the SPD model or method for the HVDC?

BOYD BRINSDON: I think you will find that Contact has actually generally supported the concept of beneficiary pays. I think the context of Contact's submission is that we are far from convinced that SPD determining beneficiary is less than proven and it is not a matter that we believe it would be better or worse than the current regime for charging with HVDC. We just don't think the work is evolved enough to prove that case.

HON ROGER SOWRY: So so in your submission are you suggesting that if the option of moving to the megawatt hour approach was taken that the HVDC would continue to apply to South Island generators only, although expanded to include all South Island generators above 10 megawatts, including embedded generators.

BOYD BRINSDON: I think there's quite a few facets to that question, one is that Contact isn't supporting the HVDC regime with a megawatt hour charge rather than a megawatt charge. The submission that we've made for inclusion of embedded generation is that we don't see embedded generation should be treated any differently under any charging regime. Be that HVDC charging or RCPI or any other mechanism for charging beneficiaries. So there's quite a few questions in there and they're actually - you know, there is an interplay between them. So no I don't think it is fair to say Contact is suggesting moving to a megawatt hour charge and leaving the current HVDC charge as it is, no.

CHAIR: So your point is if there is an HVDC charge you'd prefer it to be on a megawatt hours rather than a HAMI?

BOYD BRINSDON: Sorry if there is an HVDC charge in its current form?

CHAIR: Yes, if there was an HVDC charge continuing on South Island generators you would prefer it was an a megawatt hours basis rather than a HAMI basis, is that what you are saying?

BOYD BRINSDON: That would be Contact's preference with a covenant that Contact doesn't prefer an HVDC charge, no.

CHAIR: Nobody likes eating poisoned spinach.

BOYD BRINSDON: No. Poison spinach.

CHAIR: A billion dollars of charges a year?

BOYD BRINSDON: I think it's only 180 million for the HVDC.

HON ROGER SOWRY: Now you have commented earlier in response to a supplementary question from Elena Trout around the NZIER comment around the taking into account the value, but I've just got a question here that I will read out. So you refute NZIER's comment that it is likely that their HVDC HAMI charge has already been factored into the South Island generator's asset values and you state in fact that you can only comment in relation to Contact and advise that this is incorrect. So you do that in your cross-submission.

The question is why is this cost not incorporated into Contact's asset value since it was a cost on Contact prior to the purchase of Contact in 1999.

BOYD BRINSDON: Unfortunately it's very difficult to find anyone at Contact you know, that has that length of history. I should probably be included because I've been there but wasn't involved. I think probably the answer could be that those arrangements were deemed and understood to be temporary in nature in charging the HVDC at the time. And I probably would think that Contact was of the expectation that given they think they are actually probably an unjust form of charging that they wouldn't be there.

But as I'd say, it would be better if that question was put in writing to Contact so the appropriate person within our industry- within our organisation could answer that.

HON ROGER SOWRY: All right. We will do that. Does anyone else have any follow up questions for Contact? Yes, Alistair.

ALISTAIR DIXON: Yes Alistair Dixon, from the Electricity Authority. I have both a question for both Meridian and Contact around this asset values question.

So if the HVDC charge affects the returns that you can receive from your generation, why is that not impacting on your asset values? Do you want to both answer that please?

GUY WAIPARA: It's pretty much the same as I've already mentioned. We've always seen the HVDC charge as a temporal thing and it's always been disputed. So we've never really allocated that concept to the value of South Island generation assets per say. I think they're disconnected.

GILLIAN BLYTHE: If I can perhaps also add, Gillian Blythe, Meridian. At the time Meridian was set up there was an 02 Heads of Agreement on transmission, which was fully acknowledged by shareholdings ministers at the time, that there was going to be an opportunity for Meridian and Transpower to sit down and to discuss and if necessarily go to Court on their charging for the HVDC.

BOYD BRINSDON: Mine are all very short, in that is my understanding as well, but again please direct that question to somebody more appropriate within Contact if you could.

CHAIR: My follow up question is, so is your proposition that potential shareholders and existing shareholders deciding whether they will buy or quit your shares are not taking into account the current charging regime on the HVDC when making the decision as to the price they think is acceptable and appropriate for the value of your business?

BOYD BRINSDON: Personally I don't know what the decision make processes of our shareholders, no. Again, please direct the question to Contact and we will see if we can find an answer.

CHAIR: And for Meridian, should you ever be listed, do you think that the share price that will trade in the market will reflect the costs that you are subject to including transmission costs, and your be ability to pass them on?

GUY WAIPARA: What I can say -

CHAIR: Or inability to do so?

GUY WAIPARA: What I can say is, we're drafting a prospectus right now, is that the transmission, the regulatory regime and in particular a section on transmission is going to fully outline all the risks to investors so that they can make a call on that with their eyes wide open.

BRUCE SMITH: Thank you, Bruce Smith, Electricity Authority. I have a question that arises from a comment made by Ross earlier on. You mentioned that one of the problems with transmission pricing is it could lead to static inefficiency, in particular out of merit order dispatch. I just want to test a view with you that I have that it tends to be overestimated in New Zealand. In fact, that inefficiency I think could be quite low and the reason is that we have hydro storage, so out of merit order dispatch will lead to water either being stored that would have been used or the reverse. So it's a multi temporal problem. Provided no water is actually spilt, no wind is spilt, there's very little cost from out of merit order dispatch, could you comment on that view and perhaps also Meridian could comment as well?

ROSS PARRY: I guess I think the spot market's a relatively important feature of our electricity system and it seems to underplay the importance of this, the wholesale electricity spot market to me. I can follow up with a more fulsome response if you like but I think Guy might have a view.

GUY WAIPARA: There's probably a short and a long term answer to that. So you could probably get your head across that being close to correct in the short term. But if in the long term you've got companies like ourselves with standing instructions to withhold capacity due to a HAMI charge and then that brings forward, in some someone's else’s view the need to invest in a peaking station, then there are really costs in dynamic efficiency in letting that accrue from operating constraints that we all live within.

CHAIR: If it was the case, and this is a question to Contact, that your current share price reflects the matter that you are currently subject to the HVDC charge on the South Island generators, if that was the case, and there was a change made, would that lead to a windfall gain for Contact Energy, in your opinion? Or is it going to be dissipated somehow - some other way?

BOYD BRINSDON: Sorry Dr Layton, is if the question if the TPM is implemented as proposed will that lead to a windfall gain?

CHAIR: Well given the current TPM charge to the South Island generators for the HVDC, and if one did accept, and I'm not saying you have accepted this, but if you did accept that it was in there, and we then changed the regulatory regime, would that lead to windfall gains for Contact? Do you accept that proposition or - which is a theoretical proposition.

BOYD BRINSDON: I think Contact's work is that if the HVDC charging was changed as proposed by the TPAG to be across all generators, is that, no, Contact wouldn't expect a windfall gain. It is likely that Contact would pay a greater share than it does currently. But Contact has always argued for an even playing field. So, no, my understanding, again probably not the right person within Contact to give you a full answer, is that, no, it wouldn't result in windfall gain.

CHAIR: But TPAG proposed that all of the interconnection charge, including the HVDC, fall upon load. So it wouldn’t be, it would be a reduction in transmission charges under TPAG to Contact. Do you think that would lead to a rise in the price of their shares?

BOYD BRINSDON: If transmission charges were reduced to Contact then you would naturally expect that would benefit Contact shareholders.

CHAIR: Can I ask the same question of Meridian?

GUY WAIPARA: Can you run that by us once more?

CHAIR: If the transmission charges were changed so that the transmission charges to be paid by Meridian were less than they currently are, and you were listed on the stock exchange, and this came as a surprise to everybody, would the share price - you expect the share price to be higher after that event than it was before?

GUY WAIPARA: It's quite hypothetical considering we're going through a process, this is pretty transparent so - and we are going to disclose everything about this process that we can talk about, the proposal also has - if it goes through in its entirety a 50/50 split of the residual to generators so our actual transmission costs go up, not down. But they are allocated much more on a level playing field. So it's not entirely clear what the market would make of that, and in particular, generators' ability to pass those full costs on to consumers.

CHAIR: I was essentially saying the hypothetical situation where we changed it, so the current charges were changed so that you paid less would you expect the value of your business to be higher in the market place than it is now?

GUY WAIPARA: So this is a different option to your proposal.

CHAIR: I'm just trying to tease out the impact of the HVDC on the current value?

GUY WAIPARA: So okay in theory if you have a company with a series of cashflows going forward and you reduce operating costs in some way, so that you've got more cash in the bank, then that is going to have an impact, you would think, of investors' view of your market cap. I would have thought.

CHAIR: Thanks.

HON ROGER SOWRY: Okay, I just move to TrustPower. So TrustPower submit that the Authority's proposal reallocates the costs of a large number of transmission cost that have already been built or are approved, without the parties who are proposed to pay for these assets being aware, at the time of the investment approval, of their future payment obligations. So they indicate also their support for the TPAG majority proposal. So the question is, do you have a view about whether the proposal might cause the same issues for consumers?

PETER CALDERWOOD: Yeah Peter Calderwood from TrustPower. When you look at the analysis that went in - that's gone into transmission - the TPAG proposal, but also the analysis that the Authority is doing with the existing, wealth transfers are generally seen as a second order effect and so if we were looking at from a more of an economic purity. Any transmission - any change in transmission pricing or any pricing will - in any part of the industry will involve some wealth transfer.

So yes the TPAG majority decision would - did involve some increase in - to consumers over the transition period as it came in. But on the other side the analysis, which of course was not totally agreed with in TPAG, but the analysis also showed that there was a net consumer benefit from those changes.

HON ROGER SOWRY: Okay. To Vector, your submission, in your submission you recommend that the HVDC charge should not be changed. The question is how would this promote static and dynamic efficiency?

ROBERT ALLEN: Not changing something would have no change in the static or dynamic efficiency compared to the status quo by definition.

The point that we've made in our submissions is that the alternatives that have been proposed would not be to the long term benefit of consumers, it would make consumers worse off which is why we haven't seen through the EA propose any consumer supporting - consumers paying for the HVDC link.

HON ROGER SOWRY: Okay. Do any other Board members have questions? Staff? Alistair?

ALISTAIR DIXON: It's Alistair Dixon, from the Electricity Authority.

I've first got a question for TrustPower around this question that was - that Roger just asked on the reallocation of costs and the fact that this was done in a way that parties weren't aware of. And, and then of course TrustPower indicated support for the TPAG majority proposal. So if you had - if the Authority put in place a similar transition provision to the TPAG proposal and that - and TPAG found that mitigated the issue for consumers, would a similar transition provision mitigate the issue with the Authority's proposal?

PETER CALDERWOOD: Yeah Peter Calderwood from TrustPower. No. We are really comparing apples and oranges.

The TPAG two solutions, was one was status quo and of course the majority was a move to a full postage stamp which was a simple understood methodology. The proposal being forward by the Authority is unknown, volatile and is going to cause additional risks to all parties. So I don't think you can compare those two and just say by putting in a transition to the new proposed, and predominantly SPD-type base of methodology can be compared, can be compared equally.

And, so, our main concern about the new methodology is round some of the new untested methodologies being put into place.

ALISTAIR DIXON: Can I just follow up on that? So, are you saying that if - if a period of time is given for parties to adjust their contracts, take into account this new charging regime, that there wouldn't be benefit from that, that parties could adjust their positions to to take into account that impact and that wouldn't beneficial?

PETER CALDERWOOD: Yeah Peter Calderwood from TrustPower again. Yeah I reiterate, it's actually the fundamental methodology that we are concerned about. Obviously a transition will always help. But we're still transitioning to something we don't think is sustainable.

HON ROGER SOWRY: Okay. Does anyone else have any comments they wish to make on this section?

All right. Thank you.

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HON ROGER SOWRY: I now want, if we can have to the table Genesis, TrustPower, Pioneer Energy, Castalia, Contact, Meridian and the Auckland Energy Consumer Trust who I don't think are here?

So this this section covers submitter and cross-submitter suggestions around alternative methods and if I can start off please with Genesis and and Castalia. So you suggested a straw-man which you refer to as the "simplified SPD approach" in your cross-submission on page 9 from Genesis. Castalia on your behalf also suggested a straw-man which it titled ex-ante GIT and it was in their cross-submission.

The question is which should the Authority prefer and why?

JEREMY STEVENSON-WRIGHT: Jeremy Stevenson-Wright for Genesis Energy. I think in answering that question, and I will actually ask Ben or Alex from Castalia to respond in more detail following this, but in answer you need to also consider that part of the reason why we gave two options was also to identify to the Authority that there's other alternatives within the so archetype of the SPD model proposed that can have a different level of benefits and costs to the one proposed in the Authority's original paper. So, in that regard we've put forward two proposals. One a simplified method which involves a, from memory, a longer SPD period for calculating, but calculates over a longer average period of time, and therefore takes the volatility out of the signal yet still provides an incentive for participants to participate in investment decisions for the construction of new assets. And the simplified approach - sorry, and the alternative from Castalia's perspective also involved a more closer interaction with the Commerce Commission testing on the GIT test and I might just pass over to Ben on that one.

BEN GERRITSEN: Thanks Jeremy, Ben Gerritsen from Castalia. Yeah, so that's - right in our cross-submission we conducted a high level evaluation of both of these alternatives, so the simplified SPD approach and also an ex-ante, I think what we call the ex-ante GIT approach which has that more direct link to the transmission investment approval process. And, you know, firstly just reiterating what what Jeremy said, we really saw the value of doing that as providing the Authority with our high level evaluation of how we would expect different options might evaluate under a bottom up approach to cost benefit analysis and we had a really good discussion yesterday about the value of bottom up approaches to cost benefit analysis and we clearly maintain our view that that would be a useful addition to the evaluation of changes in this area.

When we conducted that high level analysis of those different options, what we found was that the simplified SPD option evaluated better than what the Authority had proposed in those five kind of components of a bottom up analysis that we had identified of providing efficient signals for transmission investment, for generation investment and load investment, and also providing for the efficient operation of wholesale and retail electricity markets. And essentially the - I won't repeat the full analysis, but I think that finding that a simplified SPD approach which takes into account a longer timeframe for considering the allocation of - sort of identifying beneficiaries and then fixing that charge for a longer period of time, I think the reason that evaluates better, or is likely to evaluate better, in our opinion, is because of the trade-off that you are trying to strike between the flexibility of a transmission charge that reflects changing underlying market dynamics and this was a point Honourable Sowry, Mr Sowry that you mentioned yesterday that really don't you want a transmission charge that is flexible enough to recognise underlying changes in the market such as the closure of of the aluminium smelter at Tiwai Point. And I think you know, there is agreement that there is benefit in that. On the other hand, you are also trying to have a transmission charge that is sufficiently stable and predictable that people can make investment decisions now on the basis of some known quantity, that they know that their investment decisions are in fact going to lead to a profitable situation for them because of the known charge. And so you are trying to strike that balance between flexibility to respond to changing circumstances and whilst having stability, so less volatility and a simpler charge to understand.

And so we really felt when we looked at the bottom up components of a cost benefit analysis that that would be, that that balance would be better struck by an SPD charge that was fixed over a longer period of time and that more clearly identified the true beneficiaries of transmission investment. So our analysis of that simplified SPD methodology was that it would evaluate better under a cost benefit analysis than the Authority's proposal.

HON ROGER SOWRY: So can you then, because we did ask the question of Transpower yesterday, how do you cope with major change in the player? So a new player emerging or a large player exiting from the market? How do you cope with that under your simplified SPD proposal?

BEN GERRITSEN: I think you would clearly need to have rules developed for those situations and those are foreseeable situations. I think you also have that problem under the Authority's proposals already in that even if it's an ex post monthly charge, someone may go bankrupt in the month and you have no-one to allocate that charge to. Presumably you just - that’s a smaller issue and so you smear it across the remaining participants in the market. But yeah, you would need rules.

ALEX SUNDAKOV: Perhaps if I could just add at maybe a slightly higher level? I mean, I don't think it's a question of the Authority sort of looking at the specific proposal that Genesis presented in its cross-submissions, specific proposal that we kind of outlined in our cost benefit analysis. I think it's more that we were looking for a type of solution. And I think underlying our thinking was the idea that we really could not see any benefit from the ex post volatility of the regular re-runs of the SPD model. We could see a lot of value in kind of in the logic of saying let's use the model to identify the beneficiaries and bring that into the ex-ante decision making. But we just really struggle to understand what is the benefit of this, kind of, additional volatility that can't be hedged in the market and really doesn't add very much to the efficiency incentives.

So, the solution lies somewhere around fixing the allocation of beneficiaries, using the SPD model ex-ante but allowing for a set of reviews. Now, clearly then it becomes a question of well how often do you review it? Do you do it like a kind of a regulatory every five years, or do you do something else? I don't think we've gone to the kind of detail to really think about this. But all of that is a type of solution.

HON ROGER SOWRY: Just in that answer Alex you comment that it can't be hedged in the market, the proposal, surely a financial instrument could be developed that would cover that risk?

ALEX SUNDAKOV: Well, I think it was raised yesterday, it's hard to see whose the natural counterparty.

So you can hedge it; the way you would hedge is it by basically charging - setting prices that will recover your expected value within the significant variation. So you should always be trying to over-recover, if you like, that's kind of a natural hedge that I think a firm would have to go for.

HON ROGER SOWRY: Okay. In terms of the - so I just want to get - so I just want to go back to make sure I've got this clear, so what Genesis is saying we shouldn't - you don't want us to prefer one option over the other, ie your option or Castalia's option, you just delivered those so that we could see that there are at least different options?

JEREMY STEVENSON-WRIGHT: Jeremy Stevenson-Wright for Genesis Energy. Yeah, going back to the purpose of those options is to demonstrate there are better options within the same model that was proposed by the Authority's paper that don't deliver the disbenefits and the costs that the Authority's current proposal does.

In terms of the similarities between the simplified and Castalia's GIT model, naturally the GIT model requires a greater alignment with the Commerce Commission processes and that in itself may require some form of statutory alignment; that might not be achievable. Therefore, a simplified approach might be the option you need to take or consider.

I would stress, in our view, both of those options would be preferred over the current model on the table from the Authority's paper.

HON ROGER SOWRY: So under the ex-ante GIT approach how would-should we treat investments that were made prior to when the TPM comes into force?

BEN GERRITSEN: Ben Gerritsen, Castalia. I think our view of that was, you know, the ex-ante GIT approach responds to the concerns that were raised by many parties that this is essentially a sunk cost and that there are no dynamic efficiency gains from reallocating sunk costs and, therefore, another you know, another methodology would need to be applied for addressing past investments such as a postage stamp for past investments and then an ex-ante GIT approach for future investments. So clearly an ex-ante approach can't apply to projects that have already gone through the GIT, already been invested and approved.

ALEX SUNDAKOV: I mean, I think as the Commission itself has stated - sorry the Authority itself has stated in its documentation, the choice for investments that have already been undertaken the choice of the starting date is purely arbitrary. And it's that - so it's kind of very difficult to come up with an analytical model for an arbitrary choice. I think, as Ben said, I think what you need to be thinking about is kind of trading-off two considerations, one is that for the investments that have already been undertaken, really the efficiency that you are looking for is now static efficiency; they have been - those investments are in place, it makes no sense to discourage the utilisation of those assets. On the other hand, you also probably want to make sure that that's the pricing regime that will apply to forward looking investments, that will be coordinated with the grid investment test, doesn't, doesn’t collide too much with the smearing of past costs. So you maybe kind of looking at some-some kind of practical compromise between the two. But I do think that what you do with the historical investments is essentially arbitrary. And I sort of think that it's easy to get carried away here by wanting to put more into the SPD charge just because if you only do it on a forward looking basis there may be very little involved in that, and it kind of doesn't sound interesting enough. But I don't think that should be the guiding principle.

HON ROGER SOWRY: So would you put Pole 3 , would you put Pole 3 into the ex-ante approach?

ALEX SUNDAKOV: Well I think – you know it's a good question, I don't think so, but -

HON ROGER SOWRY: So we draw the line some time in the future?

ALEX SUNDAKOV: You draw the line from the day of the implementation of the policy. I think if - I mean, if you want to have a kind of a really principled approach which says this is about influencing new investment decisions then it would need to be for for new investments.

HON ROGER SOWRY: It kind of cuts across the Meridian and Contact view that the current pricing mechanism was somewhat temporary.

ALEX SUNDAKOV: Right, but that's exactly why I think the arbitrary decisions will need to be made.

JEREMY STEVENSON-WRIGHT: Just on that, I mean to some degree the Pole 3 and HVDC debate has drawn a line around those particular assets, so at least it has isolated that debate to some regard. So that boundary has been drawn, it might make the Authority's decision around there, make it easier for them to distinguish between those assets.

HON ROGER SOWRY: So what does that mean - tell me what that means, does that mean you would put it in?

JEREMY STEVENSON-WRIGHT: I'm just saying when it is comes to the arbitrary decisions making around what date you would apply the SPD method to, you may have - well you could arguably see that those assets have been part of an ongoing debate around their value for some time.

HON ROGER SOWRY: Yep.

JEREMY STEVENSON-WRIGHT: There has been some work done in the past around those specific assets. You might arguably say that maybe the new methodology could be applied to them, but at the same time I think you would have to honestly recognise that you are not to get the dynamic efficiency benefits from the methodology being applied to that.

HON ROGER SOWRY: So I don't want to put words in your mouth, but - so if we were to put Pole 2 and 3 in, but not put you know, NIGUP or any of those other major projects in you would see that as justifiable on the grounds that the the HVDC debate has been ongoing and that that's the issue that was trying to be solved.

JEREMY STEVENSON-WRIGHT: I think I'd probably put it another way and say that --

HON ROGER SOWRY: I'm sure you would.

JEREMY STEVENSON-WRIGHT: -- the ongoing debate around HVDC means that there is an issue around those assets that needs to be probably finalised and brought to a conclusion to give certainty to the industry overall.

HON ROGER SOWRY: Yeah. All a bit arbitrary isn't it?

JEREMY STEVENSON-WRIGHT: Unfortunately yes, it is.

HON ROGER SOWRY: Has anyone got any other?

DAVID BULL: I was at the Pole 3 conference, bit like this, and at that conference there was a commitment made from the Electricity Commission which we've inherited I think, that there would be a review of the transmission pricing methodology so wouldn't it be logical with that being signalled that at least from that date new investments, including Pole 3, because that was what was being discussed, should be included in the revised system?

JEREMY STEVENSON-WRIGHT: No. Sorry Jeremy Stevenson-Wright for Genesis Energy. I mean, first of all unfortunately I wasn't at that conference so I wasn't aware of that statement.

Furthermore, I suppose an undertaking to review the methodology doesn't necessarily change the fact that you still rely upon the current methodology. I think what we're suggesting in the principled approach is to take the SPD method, or take the new methodology and apply it to those future assets. I think that's an investment or a regulatory change that I think investors would understand.

I think retrospectively going backwards to a date at a conference where it was given an assurance around there would be a future review at some stage, I don't think that provides you with certainty.

ELENA TROUT: Sorry, Elena Trout. Just to clarify for me your understanding, so the debate about the transmission pricing and the commitment that was made by the EC to a number of parties in regard to the investment of Pole 3, are you suggesting to me that Genesis were not aware of that? I just want to make sure that we're on the same page here on why we are here and why we've actually opened up this debate.

JEREMY STEVENSON-WRIGHT: Just to clarify, I was not personally at the conference. I would have to take that and go back on writing and see who was for Genesis Energy at that conference, you may recall who was in attendance for Genesis Energy then.

In terms of our position we were aware of the ongoing debate around transmission pricing and specifically in terms of its isolation around the HVDC.

DAVID BULL: Clearly that commitment included the DC for Pole 3, there's no doubt about it, that it was intended that it included the Pole 3. And there was agreement from the five major gentailers that that would be so.

JEREMY STEVENSON-WRIGHT: Thank you.

ALEX SUNDAKOV: Perhaps if I can just make one comment on that, I think that - I mean I'm absolutely in no position to comment on any commitments that have been made or haven't been made, but I think just - one thing that's important to be absolutely clear, it has no efficiency implications. So the only thing that has efficiency implications is forward looking investment. Everything else is really an arbitrary choice about what you think is fair or is not fair.

CHAIR: I want to pick up on that point Alex, because what your proposition would end up with is two different methodologies for valuing assets that were invested in at roughly the same time. One group like NIGUP that were bitterly opposed by MEUG as is well on the record and they are here and can say if it's wrong; another by - in relation to the Pole 3. So you are going to end up, aren't you, with a situation where parties are going to say we have been unfairly treated, and particularly consumers who are going to say these investments have all been undertaken, there's been an exception made for the HVDC but not made for the assets that we are now ending up paying for. That in itself will lead to ongoing disputes. That in itself will have efficiency effects. So there is an efficiency consequence, I would suggest to you, from in fact us not sorting out a rational and clear way of doing it. And we know how much is being spent today at this conference. We know how much was spent in reasonable quantum in preparing the huge stack of papers I have at home and the megabytes I have in my thing and the consulting charges, so it's not a free good us actually not settling the thing in a reasonably coherent manner across the board. There are efficiency effects, I put it to you.

ALEX SUNDAKOV: Look, that's a fair point. I mean I think that's - I mean you're right, that there clearly is inefficiency costs from not putting this issue to bed. It's been around for far too long and has cost far too much in endless debates. So in a sense that's a judgment that you would need to make as kind of what needs to be in, what needs to be out to keep various people happy. But given there's always going to be lots of people unhappy whatever you do. I'm not too sure. Good luck to you, I'm glad I'm on this side of the table.

HON ROGER SOWRY: Do we have any questions from staff? Alastair?

ALISTAIR DIXON: Yes, Alastair Dixon, Electricity Authority. This is just a question for Castalia. So if we take an ex-ante approach- or it seems to me your rationale for an ex-ante was primarily around efficient incentives or providing efficiency gains around transmission investment. But, but it seems to me though that there's also other efficiency - investment efficiency gains that you could get around promoting more efficient investment in other parts of the industry. So, for example, if we changed the charging basis as it's proposed for the SPD charge around, for example, the HVDC that would change incentives around investment, for example, in the upper South Island which is basically an importing region. Wouldn't that be helping to promote more efficient investment? And - and in order to get that gain we'd actually have to apply it to transmission investments that were currently in place.

ALEX SUNDAKOV: I think that so from the point of view of generation and incentives to invest in generation, I mean I think that once the transmission investment is in place you clearly don't want to disincentivise new generation from utilising the transmission capacity. But you also want to make sure that you don't reach the peak capacity too early. And the way that the SPD model is going to be applied by averaging benefits to - you know, effectively calculating average, how far benefit is effectively ignoring those peak issues anyway. So it's kind of, you know, a six of one and half a dozen of the other. Because you - I can see how you could say well perhaps a more continuous application of the model could send a slightly refined - more refined signal for generation investment. On the other hand, the model is a fairly gross approximation anyway. To me, the additional volatility more than gobbles up any of those benefits.

BEN GERRITSEN: Yeah see I think there is another - there is a real issue about the relevance of transmission pricing for generation and load investment decisions and I think this was something that the Electricity Commission took a close look at and and I think we provided a reference in our paper or the Genesis Energy submission on some work that the EC did on this, essentially concluding that really the transmission pricing signal in terms of decision making for generation and load is very weak, so you'd have to convince yourself that you were actually likely to change investment decisions for generation and load by sending this more refined signal. I haven't been convinced of that yet.

CHAIR: If I understood Alistair right, I think he was referring to the fact that if you alter the way in which transmission charges are allocated, then you will alter the extent to which particular firms and businesses and consumers actually bear those charges. And in the cases of firms, at the margin you could expect it will alter their cost structure and hence have some impact upon their decisions about whether to, at the margin, invest or not invest and it will be across the whole sector, so there is a not only my suggestion that there's a dynamic efficiency benefit out of us not all spending time at these conferences chewing our hair up, but also there is a benefit, albeit small for an individual firm, but still spread across a wide range that could occur as a result of altering the allocation, which is an investment affect.

ALEX SUNDAKOV: Could I clarify, do you mean investment affect beyond investment in electricity generation? You mean in terms of where the load is going to be located?

CHAIR: Or whether people decide to invest or not. If you go back to say an airport example which is one that you and I are very familiar with, you know the landing charges do influence what investments Air New Zealand and Emirates and so forth actually make. It does have an affect. And that's a sunk cost, or it could be argued that there are elements of that involved in it, and there are elements that are involved in it. It doesn't mean to say that one shouldn't worry about how the charges for those assets are actually allocated, because it does affect the rest of the economy.

ALEX SUNDAKOV: I think as a matter of principle I certainly don't disagree with you, but I think it's when you start getting down to detail and you think about first of all what is the quality of the incentive that is being sent from the application of the SPD model, given just how approximate that that benefit calculation is, given the assumptions around model. Plus the issue that Ben has just raised about you know, all the other factors of the influencing the investment decision. And on top of that take the offsetting affect of the additional volatility and the cost that's imposing. It's just - it's not obvious at all that there is net benefit, you know, it's - you have got influences pulling in both directions.

CHAIR: So if you actually think of some of the people who have turned up here from the demand side, some of them have very significant proportions of their cost structure involved in electricity and are bearing, under the current pricing regime, a significant part of that transmission cost. And I would put it to you that at the margin there of some of their investment decisions will be shaped like that, they're here, they can comment whether that's true or not true. But it's not just the energy costs, it's - they look at the transmission cost as well, which for them since they don't pay GST and they don't pay distribution and the the metering is usually provided by themselves, they are a very large proportion of their particular electricity bill.

ALEX SUNDAKOV: And as I said, I'm not necessarily disagreeing with that, what I'm questioning is the strength of that signal, just how positive it is and how useful it is versus the side affects, you know - I mean to me, and it really takes us back to our discussion yesterday about the bottom up cost benefit analysis, that's really the level of detail one needs to get into the cost benefit analysis of whether the unintended consequences of the medicine outweigh the benefits of the medicine.

PROFESSOR LEW EVANS: I just have a couple of comments, so thanks for the opportunity, Lew Evans is my name.

First of all there's been the discussion of the arbitrariness of the particular assets being in particular ways and a lot of it has to do with simply that we have an arbitrary pricing of assets that relate to the HVDC; that if we were to be agreed that we had a common pricing methodology for the network as a whole that included the HVDC then the discussion would move on. But even in the discussions here this morning there's a lot of the arbitrariness comes about because we actually - are we talking about the transmission pricing methodology that exists today or the one without the HVDC being corrected or whatever? So I just - that's a general comment that I would make.

Secondly, certainty is really important in these things, so the arbitrariness is unfortunate in a way if it's to persist. It has to be held out now and considered in the light of the change in transmission pricing methodology and it does seem to me that if you're going to make a significant charge, if there are costs that are on the table that can be improved such as being established by - regarding the HVDC and some others, that it should be treated and treated now. But then there's the question of obviously what the optimal strategy is from that point. And the two alternatives seem to me to be since we're in the section on alternatives, the model where we have some form of the SPD as proposed by the Electricity Authority, plus the postage stamp. And, if I was to read the submissions that people have made on that, which I got to at 2 o'clock yesterday morning thanks to the delivery of the summaries, that people seem to think that the RCPD, together with a megawatt charge for injection have a lot going for them as alternative sort of - or models for a postage stamp.

Right, so let's think about then what's the value then of the SPD model. Well, it is that it induces people to think about the next investment. It induces them to be interested in future investments. That's basically its value. There are two elements to the EA's approach that provide this value. One is its SPD model. The other is charging generators for injection. And I think there is a good argument to say that generators should be induced to participate in these, more strongly perhaps, in these investment decision making by regarding the network. And both SPD and the injection charge do that.

The SPD, does it add anything over that? I think not. But that's my view. But it does - it's one of two legs of inducing people, market participants to be in the interests of examining future investments.

CHAIR: Thank you.

HON ROGER SOWRY: Do we have any other - I think Alistair you had a question?

ALISTAIR DIXON: I actually had a question on an alternative that – Its Alastair Dixon from Electricity Authority. I just had a question on an alternative that was raised by TrustPower in their submission.

HON ROGER SOWRY: Well Alistair we'll come to that, because we've got a whole range of other alternatives that I'm just about to come to. But it was whether anyone wanted to finish off on this or make any comments at all?

JOHN STEPHENSON: John Stephenson, NZIER. I just want to clarify something on a point of economic principle when people have talked a little bit about postage stamp and that goes straight to something which is fairly core in economics around efficient taxes. And I think we just need to be clear that in rough ascending order the most efficient tax if you want to recover a cost is lump sum tax, something which possibly looks like the loss in asset value that - if it is true that HVDC charges are in the asset base of South Island generators, then that's essentially a lump sum tax and that is highly efficient. The second is differentiated charges what we would call Ramsey pricing. That is effectively what the SPD method does, particularly with respect to the HVDC when its, when flow is going south consumers in the south will pay in, when it's going north if the opposite is true and you'll get a - and therefore there's a benefit in one direction and not the other, and people would be willing to pay for that benefit, and therefore you can differentiate on the basis of that benefit and you have a more efficient tax regime less distortionary revenue recovery mechanism. And third on the list is the smear approach. And we need to be very clear that that's the order of efficiency and it's not true that smearing is always the best approach.

HON ROGER SOWRY: All right. I have got now a question for TrustPower. In your submission you suggest that efforts could be made to reduce the volatility of the charges. The question is how would you suggest this be done?

PETER CALDERWOOD: Yeah Peter Calderwood from TrustPower. I think this is one of these questions that would have been a lot more useful to have known prior to the conference so that we could prepare, so we'll take that one away and respond in writing.

HON ROGER SOWRY: Okay. All right. Now we have got a number of parties at the table at the moment, Pioneer, Contact, Meridian and TrustPower, have all made suggestions for improvements to the Authority's proposals and I guess I'd just like to get you, and maybe we should start with Meridian, we want to know whether you - do you consider that your suggested approach would better promote the Authority's statutory objective than retention of the status quo? And if so, why?

GUY WAIPARA: In short we do - we believe it does. So if I answer that in two parts, firstly what are the principles and secondly, I think there's design stuff that we've been talking to you about and commented on.

So in a principled - at the principled level we do think a), the proposal really breaks down a long term and really unconstructive process and debate about who pays. We do think that flexibility's a good thing and its ability to be changed to market conditions lends it to be a bit more durable than counterfactuals. And thirdly, we do think that the SPD approach - we've done our own market modelling and directionally it's saying the same thing, you know, who are the parties who benefit from transmission? So we think at a principled level the design looks pretty good.

The principle refinements we've got I'd characterise as design changes around that. So firstly, we think - I mean for us volatility is not really an issue, we see it as a 10% times a 10% problem if you look at SPD, transmission is 10% of delivered your energy bill and SPD starts out quite small. And compared to the energy market, and we've got FTRs coming in there's a lot more volatility that you manage as a business day in day out. But, we have a lot of other players that think the volatility and complexity is a problem and that includes our subsidiary Powershop and within that business Ari's the only guy who gets this, so whether it's real or perceived I think there's a problem there.

So, what we've come up with is a number of refinements just to take the volatility out, and we think that can be done a number of ways, but you could set prices for the future, based on what happened for the year or the two years before and that means all retailers across the country have got certainty of their transmission cost input. And I think that does deal with your concerns around competition on the retail platform.

The second part of our proposal is we do think that half hourly capping of benefits is too sharp. If you think of transmission as in the early years anyway as an insurance product, it's there for high impact, low probability events, you really need it when you really need it, and those are likely to occur in the odd trading period. So to cap benefits at a half hourly basis I think underplays the benefit transmission really brings to all participants. So we're suggesting that you spread that out over a longer period.

And thirdly, and this is going to sound very arbitrary, because it is, is that practically someone's got to run this process and that's Transpower and having been there, I do get that even the existing TPM does take a little bit of work, but that's not the reason not to change. So we should give the guys there the chance to experiment on a smaller set of assets at the start and get comfortable with that and make sure that all of us get to understand how this works. Because it will minimise - I think that will minimise transaction costs. So, we've suggested paring back the number of assets that you put into an SPD process from somewhere around 60 to, you know, just the handful of big assets where most of the value is. And again, it is an arbitrary thing but we think pragmatics does have some place in economics.

HON ROGER SOWRY: Just as a follow up, you said "to start with", so would you envisage paring back to the big assets and staying with them or would you envisage paring back, running a system and then over time adding in the other assets?

GUY WAIPARA: What we've suggested is is in a forward looking sense.

HON ROGER SOWRY: In a forward way.

GUY WAIPARA: Yep.

HON ROGER SOWRY: Okay.

GUY WAIPARA: You start to look at big assets. I don't know that you're going to get a lot of benefit out of putting 10 million dollar assets through this kind of process and then carving up those costs across numerous players across the network. I don't think the value's there.

HON ROGER SOWRY: All right, thank you. Contact?

BOYD BRINSDON: Can I just ask you to give me the question again. Guy's answer was quite lengthy.

HON ROGER SOWRY: In your submission you made suggestions for the improvements to the Authority's proposal and the question is do you consider that the suggested approach that you made would better promote the Authority's statutory objective than retention of the status quo?

BOYD BRINSDON: I think to be clear, Contact didn't make suggestions for alternatives, other than to suggest much in the same lines as Guy's just answered that this is an extremely complex solution for transmission pricing methodology and I think Pioneer Generation made the point yesterday that possibly only the four large generator retailers could get their head around it. I can assure you, speaking for Contact, we don't. And we don't believe that the bottom up view of the wider proposal is being considered and the interplay between RCPI, the reduced effectiveness of RCPD, whether SPD actually does derive the right signals and in fact Contact supports the view that the volatility in our SPD might not be great enough in order to discourage peak use of the transmission system and in context with that, the reduced affect of RCPD, and I think most people in this room probably share the view that peak load is what drives you know, peak transmission investment. And we don't think that the bottom up view is being successfully undertaken to actually ensure that there isn't perverse outcomes and we are very much of the view that it will change participants behaviour and there's been no sensitivity testing of that at all. So that is a view that we have. But I don't think Contact is promoting an alternative.

HON ROGER SOWRY: Okay. Have you - you just made the comment about the complexity of the issue and that you haven't been able to get - I think your words were you haven't been able to get your head around it, have you been - I mean, have you been able to model the proposal?

BOYD BRINSDON: We've, on page 26 of our submission we've submitted the output from some modelling which would suggest our concern, probably our key concern for Contact is that the modelling we undertook under the SPD benefit analysis would suggest that Otahuhu power station actually is a larger beneficiary of transmission than Taranaki combined cycle. Really in pragmatic terms we find this difficult to believe that you would want to disincentivise a power station in the middle of Auckland that is never in an exporting region and our analysis suggests under the SPD, which we've put before the Electricity Authority and asked to be verified and to have, to my understanding, sorry, not directly involved in modelling, but have had no contrary view to that.

That those simple modelling examples using historical information would suggest that there is a fundamental flaw in the methodology that disincentivises a combined cycle power station of similar size. It disincentivised it being in Auckland.

HON ROGER SOWRY: Okay. Pioneer Energy?

REBECCA OSBORNE: Yeah Rebecca Osborne from Pioneer Energy. I'd just like to say their Mary Ann and I are here today also representing Pioneer's subsidiary, Energy for Industry; also Energy 3, and one of our major customers Auckland District Health Board. And the reason we're doing that is because none of those other parties have got the resource to be here, but they are all concerned about this proposal. And I think there's a couple of key fundamental reasons for that and they are reflected in the alternative straw-man we've put up, and that is in terms of the demand side - and the retail and demand side the complexity is massive. I mean I have spent a bit of time thinking about this, I certainly haven't devoted the last six months to it or anything and I can't say I've a hundred percent got my head around what the SPD is. It terrifies me thinking about how we would incorporate that methodology into our investment decisions because we don't understand the implications of it; we don't know whether we're going to face SPD charges on generation; we can't - don't know how to calculate what the SPD charges on load will be. We also believe, quite strongly, that the most efficient use of big lumpy assets like transmission is to make sure that the capacity life of those is as long as it possibly is, so we think this methodology moves away from placing quite a large emphasis on managing peak demand into the future. And I don't think you can suddenly change signals when you start worrying about the capacity - when you're starting to get towards the capacity limit on those assets. I think if you've given them away for 20 years or whatever you're going to struggle to get them back again. So I guess that's a big part of it too.

That the other aspect from the embedded generation side is, as we mentioned yesterday, we don't believe that the unintended consequences of the embedded generation parties has been considered or was considered prior to issue of the proposal documents. We - as we said yesterday, we don't actually know whether we'll face SPD charges or not, so we - even if we were in the position to have modelled the cost for ourselves, we wouldn't know what the answer was; we don't know what the impact on our business will be, we know there will be one. We're also concerned obviously about the ability to continue the ACOT revenues that embedded generation receives from the network companies that are enshrined in the Code in Part 6 and the convention has become to base those on the RCPD charge which will be reduced under the proposal. But the Code actually requires network companies to pay the avoided and avoidable costs both operating and capital that are as a result of the embedded generation. And it's just become convention to use RCPD. In fact, the strict interpretation that I think the Code says is that any and all transmission costs or capital costs that are avoided by the network company as a result of the embedded generation generating should be paid to the embedded generation. So - and that means you have to reproduce the calculations that Transpower do and the complexity of the proposal makes that mind boggling really.

MARY ANN MITCHELL: Mary Ann Mitchell for Pioneer Generation. Just in terms of the alternatives that we proposed, the components that were discussed by Meridian, we support those, but in addition to that we are suggesting that a threshold for generation to be included in an SPD is above 10 megawatts. This is consistent with the approach in the wholesale market. And if- if Pioneer Generation's assets which are all less than 10 megawatts became visible under SPD, the modelling for transmission cost, it's likely that the system operator would use its discretion to be - to use those assets in SPD modelling for the wholesale market as well and require dispatch and additional cost for the- our business.

REBECCA OSBORNE: Just very quickly, I think we all know that the parties that ultimately pay for any cost in this industry are the consumers. And I think it's important to remember that the industry is made up than a lot more than just the parties that are in this room and that we need to remember to think about how this is affecting small retailers who aren't here; how it's - whether it's going to introduce extra barriers to new entrants coming into the industry, and we believe it does, this industry is already really complicated and this is making - adding a whole new level of complication and I think you can only make sure you're achieving or promoting your statutory objective by thinking about the industry end to end.

HON ROGER SOWRY: TrustPower?

JAMES TIPPING: James Tipping, from TrustPower. Just wanted to make the point that we, we didn't actually put forward a straw-man alternative to the proposal as such. Our preference is for a number of options to be worked up to the same level of detail as the SPD method proposal, preferably in a - be in a working group and then assessed on sort of common set of criteria. So we haven't put forward a straw-man as such. We did suggest some potential amendments to the proposal made by the Authority -

HON ROGER SOWRY: Yeah, that's what I was meaning.

JAMES TIPPING: But even with those amendments we're not convinced that it would necessarily be better than the status quo.

PETER CALDERWOOD: Yeah Peter Calderwood, TrustPower. I just add to that, yeah - and I think that's not just a status quo but also our preferred alternative which was always the TPAG majority proposal and I think in working up any of those alternatives that sort of emphasises the need that they would have to be evaluated using a bottom up cost benefit analysis because the top down approach just would not work with that, because you would get the same answer for all alternatives.

CHAIR: I had a question for Pioneer Energy, and you are proposing that there be a de minimus for 10 megawatts for the charging for generators, there's a 10 megawatt de minimus for the requirements to essentially notify the system operator, but this is about charges. Don't you think that could lead to inefficient decisions around the size of generator that people will choose? So that they would be - I'm just reminded that when I was a young student I did a study of tax on sheep, and the tax was two shillings per a hundred, or part thereof, and it was amazing how many farmers had 98, 97, 96 sheep and then when the tax was removed that disappeared. Now I think part of that was tax evasion, but I think part of it may have also been that people actually adjusted to that and you ended up - where maybe an efficient plant would be 12 megawatts but they decide to do 9.9 and hence we have an investment inefficiency as a result of that de minimus charge. Do you see that as a problem or not a problem?

MARY ANN MITCHELL: I think the problem already exists in the wholesale market with the threshold of 10 megawatts and the system operator has the discretion to require generators of less than 10 megawatts to be involved in the wholesale market, so -

REBECCA OSBORNE: I think there's always going to be a threshold too, it's an arbitrary decision. The 10 megawatts has become the convention. If you make it lower then you're just going to start - there's always going to be somebody who's smaller, so where do you draw that threshold? And are you just- at some point you just start adding complexity to the wholesale market without, you know, really getting any benefit from it.

MARY ANN MITCHELL: The other point I'd like to add is that there seems a motivation for part of this charge is to incentivise parties to be involved in decision making around transmission investment and an organisation like Pioneer Generation and other smaller embedded generating companies just don't have the resource to commit to those types of decisions.

HON ROGER SOWRY: Any other questions? Staff? All right. Does anyone have any comments on this that they wish to make? Anyone else in the room?

ALISTAIR DIXON: Alastair Dixon from the Electricity Authority. I just had a question for Contact, and I was just - just wanted to remind you of your proposal which was incremental modification including implementation of the Kvar charge, modification of the HVDC charging regime, so changing I think to a megawatt hour charge and removal of the subsidy for embedded generation. I was just wanting to just check that did you have a view that if we made those changes would that better achieve - would that be an improvement over the status quo or would your preference be retention of the status quo?

BOYD BRINSDON: I think those suggestions were improvements to the proposed TPM, I don't know how they can be in reference to the current TPM. Have I understood the question correctly?

ALISTAIR DIXON: Well, it was certainly my reading of them was it was more around, I mean, basically what you are advocating I think in your submission was just incremental modification, rather than sort of a major step change along the lines of the SPD method, that was at least how I understood what your submission said - this is your cross-submission, rather than your submission.

BOYD BRINSDON: I think it's probably fair to say that Contact has made it quite clear that they have a general concern with the proposals as it stands into its complexity and we've gone over that many times. And the other point we'd add, that I didn't ask, was that we don't believe it will introduce lobbying to a degree at all, we just think the lobbying will move from the EA to Transpower, because part of the problem with the wider design is that so much of it is left up in the and left to Transpower to design, around the RCPI - RCPI and all the other facets of it. I think it would be probably amiss and non-productive for Contact to have not made any comments past the first point saying that it's overly complex and difficult to understand. So I think for the purpose of trying to aid the process we might have made those suggested changes. But, remembering in the wider context of our, you know, genuine concern over the proposal in its totality.

HON ROGER SOWRY: Molly?

MOLLY MELHUISH: I think DEUN should be on record for supporting the comments by Pioneer Energy that the extreme complexity cuts many people out of even thinking about, much less participating in the market. And I'm thinking about small retailers who might support some types of conditions.

This discussion of whether transmission costs are sunk and should perhaps most efficiently be charged via postage stamp charges, this whole thing is making me recall when consumers met the Authority Board and got the idea that power prices are rising in significant part due to transmission pricing. And we just think that domestic - and we were told that domestic consumers are very largely the causer of the peak demands and we're looking for whether it's worth pricing to incentivise reducing peaks or whether the sunk costs are so big that peaks don't matter any; there's, you know, plenty of capacity in the transmission lines. So we find that the economic level of discussion is not crystallising into the concepts that domestic consumers know and always knew. And it's hard to form an opinion on efficient pricing when domestic consumers who are the big causers of peaks are not coming into the discussion at all.

ALAN EYES: Alan Eyes from New Zealand Steel. If you'll just let me make a comment perhaps also supporting what Pioneer Energy said and, in particular, that what I believe needs to be kept in mind at the end of the day, whatever formula is arrived at, it's the end consumer that pays the charge. And coming back to something you said earlier Brent in terms of what it actually means on the demand side, in New Zealand Steel's case the 10% that Guy talked about of transmission charges is actually nearer 20% for New Zealand Steel when we look at our external costs for electricity. One of the big factors there is having a formula where we can manage what we do within our business, manage our electricity loads and peaks, to help try to moderate ever increasing costs of running the business. And to do that we've got to be able to understand the formula. Despite all the tutoring from my MEUG colleagues and Bruce Alistair & Co down there, I would have to say my understanding is at this level; not at the detailed level to actually how the SPD would work. And, you know, with an ex post model and all the issues of alignment of forecast and settlement prices I think need to seriously look at whether the SPD model is again to allow us as the end consumer to be able to predict accurately what these charges are and manage our business appropriately.

HON ROGER SOWRY: Any other comments?

PETER CALDERWOOD: Yeah Thank you, Peter Calderwood from TrustPower. I wasn't involved in some of the earlier questions, so I think I just probably confirm where TrustPower's - and it's in our submission, but fundamentally we support beneficiary pays principles for new assets and when I say new assets that's assets that have not yet committed.

But we've made the comment about the beneficiary paid principles that's been looked at in the past and it's really been looked at right back to the late 1990s probably 1998 or not even before then, back into the late 80s even, beneficiary based principles have been looked at for transmission pricing. And I think we've just got to remind ourselves that the successive regulators and those involved have actually decided over that time that it has just not been efficient or practical to put them in, put those in place. So I just think we just do have to be very careful and that comes back to that whole making sure we do have any cost benefit analysis right in relation to that.

HON ROGER SOWRY: All right, no other comments? All right we've got one further question in this session and they aren't here, it was to the Auckland Energy Consumer Trust, I presume they're not here? So I will read their question for the record.

DAVID DE BOER: Their consultants are.

HON ROGER SOWRY: NZIER are, they are, that's right, yeah, well they can answer the question then if they feel if they feel up to it.

So yes, NZIER on behalf of the Auckland Energy Consumer Trust suggested that the SPD charge should potentially be only applied to future investments, ie, investments that are made after the TPM comes into force. We want to consider the examples of a significant transmission investment in the upper South Island and why would it be appropriate that the beneficiaries of this investment are subject to the SPD charge and that they also contribute to the costs, for example, of the North Island grid upgrade and the north Auckland to Northland project through say an RCPD charge and how will that promote efficiency?

DAVID DE BOER: Can I take that back to my colleague and get him to consult with his client?

HON ROGER SOWRY: Does anyone else want to comment on the question?

GILLIAN BLYTHE: Gillian Blythe, Meridian. I think one of the questions that is at the heart of that - one of the issues that is at the heart of your question is durability and it's durability in terms of geography whether it's North Island to South Island; durability in terms of contact counter party; whether it's different types of consumer groups or different types of generators, or whether it's existing assets or new assets. And there are always going to be boundaries that need to be drawn, whether you know they are arbitrary, it's still - it's a line in the sand. And one of the factors that went into our recommendation that you refine the number of assets that you have in the SPD, and keep it at the top 5, which captures the major value of the 2 billion plus investments that have been made since 2004, was that you were able to retain some that were North Island assets such that you had a beneficiary element that was able to see South Island consumers reflecting a smaller benefit to them of the NIGUP NAaN proposals, and so you had that sort of - that more durable outcome. And the same thing will be true if you look at the investments that are going to be considered by the Commerce Commission shortly, I think one of the ones is the Bunnythorpe Haywards, there a decision due on that, now that will affect different parties in different ways. And I think one of the issues you will have is someone who is feeling aggrieved by an SPD charge that reflects that new investment to come of turning around saying well, just a moment why didn't you have one from last year or the year before? And you will end up with a - with a dispute in terms of that sort of boundary line. So that's I think one of the issues that's absolutely critical that it's seen to be a durable outcome.

HON ROGER SOWRY: So would you see that boundary line, because you've got two ways of drawing it, one way you've got is by time, which has been suggested. So we say well anything from here forward or anything - or the other way to do it is to do it by size of asset and we say well anything over X size. Which way would you prefer, if any?

GILLIAN BLYTHE: I think I would probably add a different principle into it, in that when we all receive our invoices we need to be able to understand what we're receiving. And when you have more and more assets - so if you go from the 5 to the 63, it gets more and more complex to understand, if only intuitively why you're being charged 1 million for this, or you know, 500,000 for that. If you get - if you're talking about flows going into Auckland on NIGUP and NAaN you can understand roughly why you might be considered a beneficiary. But

I think as you go to a smaller set of assets that are all in the core parts of - you know, deep enmeshed in the grid it becomes less able without -without significant expertise to be able to dig down into why you've got a bill for $10,000 on a particular asset. So I think there's different pragmatism that I would - I think you need to introduce into it.

HON ROGER SOWRY: I guess what I'm trying to get at is, and it may be that others may wish to comment as well, is how much of the mischief in the proposal is in participants' minds due to the fact that the SPD model being proposed captures too many assets, so it goes to maybe too low a level, back too far, how much it is complexity around too many assets? And we've had I think it was Contact alluded to that earlier on. Or how much of it is - is it just look you know, we're going to get hammered by the new HVDC charge so therefore we're going to fight this to the death? I don't expect you to answer the second one because you're not going to tell me that. But in terms of the first one is there a point where you can say well, actually there's only these last - there are these 10 or there's these seven that fit the model that would make it a much more simpler process.

GILLIAN BLYTHE: Size does matter. I think the - I guess what I would say - and we reference a paper by Bill Hogan in our submission, when he said in a paper in 2011 "the challenges to find approximations that honour the beneficiary pays principle without imposing a standard of perfection". You get most of what you need by having the top five. I don't know why we need to have all the others in. You achieve most of it.

HON ROGER SOWRY: Yeah, okay. Do others have a comment on that?

ROSS PARRY: Ross Parry from Transpower. I think you've got a pretty good sketch of some of the design parameters here; I just wanted to introduce two other considerations. One is in terms of the absolute number of investments that you have subject to the SPD method ultimately over time. I think the more assets you have in there, the more you get the situation potentially where people's consideration of the next investment and the merits of that next investment are influenced by the reallocation of the costs of the existing assets, because there's an interaction on whenever you construct a new asset on the apparent benefits of the already built assets. The more assets you have in the club, if you like, the more that that becomes a feature of the decision making and the influence on how people think about. So, in a sense that, I guess, corrupts the signal you're trying to get to, the more assets you have.

Just the other point I thought it worth raising that nobody's - and I don't know if you're planning to ask about this later is just about the choice of counter party on the purchase side. And for us we certainly see the shift to a retailer counter party as being a significant and not essential design choice.

HON ROGER SOWRY: Okay.

BRUCE GIRDWOOD: Bruce Girdwood from Vector. I think some of this discussion has sort of delved down into the detail but if we just raise it up to a high level which is around how decisions - investment decisions are made and we've spoken about this quite a lot. We've got the Commerce Commission Part 4 which essentially goes through - well, the transmission investment decisions are made at that point and the question then, in, in my mind, is when you look at past investment decisions which were made on the basis of a set of rules and then you change those rules going forward to that investment decisions so it creates a huge amount of uncertainty and if you create those rules looking forward and you are clear about them that enables people to make their decisions knowing full well the consequence of those decisions. And that goes back to our end consumers that have spoken today where that huge amount of uncertainty could possibly lie.

So I think it's really clear that that clear line should be drawn and that line should separate past investment decisions and future investment decisions, so that there is real clarity.

HON ROGER SOWRY: So where would you draw the line now?

BRUCE GIRDWOOD: I would simply say that if you are going to implement a new set of rules from that day forward any decision should be based on the new set of rules and everybody should know what those rules are, so that they can, they can make their own business decisions on the basis of known quantities.

HON ROGER SOWRY: Contact?

BOYD BRINSDON: I haven't probably thought this answer through as well I probably should have, but I think if the Board were going to consider reduction of assets to five, then they should also consider a reduction of those assets to one, being the DC, given that it's a general feeling of concern.

I think your question Mr Sowry that you were going to put through NZIER is a well thought out question in that it's a genuine concern that the upper South Island grid, and upgrade would be required, I mean it's quite clear that's probably the next and there is an inconsistency in that. But I think the beneficiaries of the HVDC, they are in dispute, but I think it's clear that in different hydrological conditions they're different in each year and that's probably an appropriate measure and probably the least disputed one for determining who the beneficiaries are because there is no interconnection and no - no interplay with other assets. There is a definitive source in the sink.

HON ROGER SOWRY: Okay.

REBECCA OSBORNE: Just wanted to come back to your original question Honourable Sowry, which I think was what part does complexity play, play in how we feel about this proposal compared to what we feel about the HVDC charges being lumped in the way they have been.

Complexity is huge and we have - we have no issue with the HVDC being included as other assets are. As somebody who has kind of been on the periphery of the industry for a while, I've never understood why the HVDC is treated separately because the market doesn't work without it.

HON ROGER SOWRY: Okay. Any other comments?

All right, we are going to wrap up this session then. I will hand it back to the Chair. Because the next piece we're moving on is going to be chaired by Susan.

CHAIR: Lunch today is scheduled to start in 15 minutes. I think we'll probably have an opportunity to get through question 45, but we'll call a line at that. So we've got 15 minutes on a question which is at NZIER and MEUG.

So Susan is going to deal with the next lot of SPD questions so I hand-over to her.

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SUSAN PATERSON: Thank you, so if I could speak to MEUG and then NZIER that would be useful, are you able to come forward to the table?

Thank you, so this is for NZIER and MEUG. You suggest that the unorthodox calculation of consumer benefits had the impact of over stating consumer benefits. And in paragraph 163, page 44, of your submission you suggest a more prudent approach would be to use long run demand elasticities for the beneficiaries pays procedure as it applies to sunk assets already in existence. You go on to suggest in your submission on page 44 that for future grid investments a short run elasticity could apply. I'm interested in how you would suggest that the Authority estimates these elasticities, and when you say that the approach is more prudent do you mean more widely accepted or some other definition of prudent?

JOHN STEPHENSON: This might be one we have to take away. John Stephenson, NZIER.

I will just restate your question just so I understand, you want to know about how you go about understanding the short run demand curves? And the long run?

SUSAN PATERSON: Yeah, I mean how would you estimate those demand elasticities in practice?

JOHN STEPHENSON: Right, okay. So, I'm going to assume that you don't want a treatise in econometrics or- or that kind of analysis. But, broadly speaking, you have a couple of options. The first would be to treat the entire entire market on its own and simply to run an econometric analysis to determine what the short or long run elasticities are. There's several techniques that I could run through. I won't, just to spare you some time, but if you want me to I can elaborate. Or, rather than treating the market as a single market you can certainly observe the behaviour of individual load centres in response to price over time. I think we've got a wealth of data which we probably under utilise in trying to understand these different demands. But, you know, contrary to what I think a lot of people will say about the inelasticity or unresponsiveness of demand, in actual in actual fact we see enormous amounts of evidence of quite elastic demand and I think we've got some nice examples from the recent period of rather high prices in the wholesale market which seem to have been, by my cursory assessment, seem to have been alleviated to some extent by a demand response. So we can certainly go through those events and look at who is responding and at what prices and you could pull together your own evaluation of certainly short to medium term elasticities based on that actual observed behaviour.

And then you can actually go to a much - probably a third option is actually to look at certainly industry-by-industry load-by-load investment response, that's the very long run - the very long run demand responses. Again, using fairly standard techniques.

It would probably be the case that if you were to use differentiated demands you'd probably want to remain reasonably general in your evaluation of those demands. So as to avoid people quibbling over the you know, very small differences in parameters and techniques of evaluation. But you'd want to definitely differentiate according to particularly very large - very large load. And, you know, ultimately I think we mentioned in our - I think we mentioned in our attachment or our submission - our report to MEUG that ultimately what you want is the market to deliver that demand function for you. And that means resolving other work programmes that I understand the Authority has underway in terms of demand side responsiveness, demand side bidding.

SUSAN PATERSON: So just to clarify you would do those demand elasticities your suggestion is on a regional basis, that you'd do them? How finely would you go down to the customer segments?

JOHN STEPHENSON: I think broadly speaking you'd want to do it by GXP. I don't see - the information is there. We know that load profiles are very different. We know that price levels are very different. You know, price level really matters to people in a world of constrained income and so you want to take account of that variation. It sounds complex but I don't actually think it is, it's just the replication of the same equation two hundred times. Not that complex. But whether or not you say "we", whether or not "we" should do something like that is perhaps a different question, but there is certainly entities, independent entities -

CHAIR: It's not an advertorial.

JOHN STEPHENSON: In fact I was going to wave my hand at - yeah, this is not an advertorial, I was going to wave my hand at the existence of the likes of MBIE to be a somewhat independent party in that kind of assessment.

I appreciate too that the Authority is independent but it's another option for evaluating these things.

SUSAN PATERSON: And just to follow up that question around why you see it as more prudent?

JOHN STEPHENSON: The long run elasticity is more prudent?

SUSAN PATERSON: Mmhmm.

JOHN STEPHENSON: Because ultimately if you overstate the benefit you'll overcharge. And if you overcharge you'll chase away demand. And I think so that's ultimately the risk that we see and I think that everybody sees it transmission pricing, is ultimately that inefficient demand response. So broadly speaking it would be most prudent, most conservative to actually take a long run elasticity when evaluating benefits, we tend to downplay the benefit and reduce the likelihood of overcharging?

SUSAN PATERSON: Other Board members have comments or queries?

CHAIR: I don't know the answer to this, that's why I'm asking you, but I think it's a question - is it the demand for electricity that you want to estimate or the demand for transmission? The elasticity of those?

I'm happy if you want to come back.

JOHN STEPHENSON: Let me say, in principle, you are correct, you'd want to evaluate - when understanding the benefits of transmission you'd want to evaluate the demand for transmission, I think that's- that’s true.

The practical implications of that when - in the context of an SPD model I'm not sure of. So I'll take that away and come back to you.

CHAIR: And just a follow up to your previous point that you made that was about taxes and the efficient allocation of taxes. Do I take it that your view is that if we don't get a beneficiary pays charges and we have to go on to an administrative charges using our hierarchy, having failed to get a market solution and exacerbator pays, if we didn't impose a beneficiary pays charge then we should be looking for more charges that are like the current HVDC charge that are just straight out lump sum taxes on people? As the most efficient next option, instead of a spreading arrangement?

JOHN STEPHENSON: I think that - I think it actually depends on how you go about that. So it's worth bearing in mind that the reason that taxes aren't charged in general in the world on a lump sum basis is because it's extraordinary difficult and so we write it off. We don't even - we don't do the differentiated tax, it's the Ramsey style thing, we try to get to it, but even that usually is written off. So there's always practical implications. I haven't worked through the practical implications of what you would on a lump sum basis on the - certainly on the load side. You know, what would be the relevant base for levying that tax?

But it is entirely reasonable to consider a differentiated, differentiated lump sum administrative tax. Differentiated by generation and load. So it is conceivable on first principles to levy a tax on you know a name plate basis, capacity rating for generation, for example. That is - that's conceivable, while still having a residual - while still having a charge on load which is smeared in some other fashion, so you could mix it up. The balance of whether you want to mix up smear and - with a lump sum and differentiated by load and generation is really an empirical question as to how practically it would work and the costs and benefits of doing that. But it shouldn't be beyond the realms of consideration. I think politically it probably is but economically it makes sense to have it in the mix.

CHAIR: Well we're looking for the efficient economic solution, not taking into account wealth transfers which we don't worry about in the end unless they have efficiency affects. So if we did end up with a residual charge having to replace all of the SPD charge. Then my logic is - my understanding of your logic is, we should be looking for fixed capacity based charges that are basically a tax on on generators and practical purposes would lead to a smearing arrangement on load, is that - what do you think is the tax efficient solution? Not talking about the practicalities.

JOHN STEPHENSON: Yes I think it should, it would be in the mix, yeah, absolutely.

SUSAN PATERSON: Thank you very much. Sorry, Carl go ahead.

CARL HANSEN: Just to follow up on that, it's Carl Hansen from the Authority, in a dynamic world where you have investment choices that are influenced by regulatory risk, is there any such thing as an incentive free charge? I've had quite a background in tax and one of the issues with the lump sum tax is quite a strong dispute about whether in fact they are incentive free in the wider context of the incentives for decision making, not just on the particular taxed activity, but the implications for all sorts of other investors.

JOHN STEPHENSON: Yes, so no tax is perfect, and I mentioned that we only have it in principle order and practicalities do get in the way.

I'm trying to think whether or not I'm answering a question which is to the proposal and actual issues on the table, or the previous hypothetical about whether or not even, you know, lump sum taxes should be in the mix. I think - I say two things, one they have to be - they have to be in the mix. There seems to be a tendency in these discussions to set certain pricing options off the table all together and to presume certain features of the market which personally I think is a little bit restrictive, for example, the appeal to sunk costs, smearing is not a very sophisticated discussion, I mean, you want to at least have these things on the table of course. Speaking to the practical implication of say like a lump sum tax, in the context of the current proposal I think my earlier observation from the floor was more around the fact that we may have accidentally imposed a lump sum tax in the past. And to be very clear, I actually think that if that is the case, if we have de facto imposed a lump sum tax on South Island generators, you want to ring fence that, which would mean not extended any HAMI charges to new generation, and that to a large - because otherwise you've still got that potential generation inefficiency.

So, it's a way of saying, you know, whether or not in practical terms we can actually get a lump sum tax that would actually work, is something we need to - you know, you'd need to actually work through in quite some - quite carefully, but it may be that we've stumbled on imposing one in the past and we should take advantage of that.

SUSAN PATERSON: Thank you very much.

CHAIR: Okay lunch.

(Conference adjourned from 12.11 p.m. until 1.05 p.m.)

CHAIR: Susan, over to you.

SUSAN PATERSON: Thank you very much, Chair. I've still got some questions around the SPD and this section is around identifying beneficiaries. So, the people that I still have some questions for are TrustPower, Vector, Waipa, Powerco and Orion, so if those people are here it would be good to -

My first question is for TrustPower. You suggest that VOLL shouldn't be $3,000 in your cross-submission, page 13. What do you consider the cost of non-supply should be for the purposes of the SPD charge; and then secondly, NZIER suggest using elasticities of demand, which we discussed before lunch, to ensure transmission charges do not overstate benefits to consumers. Is that something that you had considered, and do you any views on that approach?

JAMES TIPPING: James Tipping, from TrustPower. I think, firstly, as we were stating, we have issues with any use of real market outcomes to determine transmission pricing, and going along with that there's sort of fabricated counterfactuals where you're just removing a line and assuming nothing else changes along with that. And the VOLL is quite, and sort of implicitly linked with how those counterfactuals work. So, I think our high level issue is more with the fact that there's the real market outcomes being used in the short term basis, rather than the sort of more traditional beneficiaries pays model, which is a long-term analysis, which you wouldn't, the VOLL wouldn't be as crucial to that.

SUSAN PATERSON: Do you have idea or - I mean, if we were to- to proceed in the way that we have proposed, any other views on what level VOLL should be set at?

PETER CALDERWOOD: Yeah Peter Calderwood, from TrustPower. Look, we actually haven't done the analysis to support that, we could possibly come back in writing with a response. But I think in basic terms, we don’t - just don't believe fundamentally that the whole methodology works with a VOLL in a fabricated-type solve off the SPD.

JAMES TIPPING: And the choice of VOLL and the impacts it has on the identification of beneficiaries, and the size of those benefits, is so crucial to the whole thing, it's such a material impact that it's just a really good example of the sort of issues that you will have if it were implemented in terms of cost allocation, wealth transfers, durability and all those kind of issues. So, that's why, again, we suggested going to the more traditional long-term approach rather than the short-term half hour by half hour approach.

SUSAN PATERSON: Thank you.

BRUCE ROGERS: Sorry, can I just add something to that? Bruce Rogers from Orion. I guess it's a very good point because the transmission system, when you take out the asset to do the calculation leads to a non-supply situation and therefore VOLL, it doesn't seem like an even remotely sensible counterfactual. I mean, I don't think we would have built an alternative system that meant a significant part of the country got no supply. So, I think that just reinforces TrustPower's point.

ROBERT ALLEN: Yeah And that's also submitted in Vector's submission, where we argue you need to take a longer-term perspective and ask, if that asset wasn't there what would have happened in the counterfactual, and agree with Orion, that the counterfactual wouldn't not be non-supply, it wouldn't be a diesel generator either.

JAMES TIPPING: James Tipping again. Just to clarify, to our knowledge there's no other application of beneficiaries pays that takes this short-term half hour by half hour approach. Everything else has been proposed on a long-term, so a proper counterfactual. So, if you didn't build the line, how would the supply side evolve as a result of not having the line there, how would the generators change an offering behaviour as a result of that line not being there, as opposed to let's just strip a line out and leave everything else the same on a half hourly basis.

SUSAN PATERSON: Okay, thank you. If I move on now to a few questions to Vector. In your submission, cross-submission, it's clear you don't support either the beneficiaries pays approach or the SPD method, considering both to be fundamentally flawed, and that was in your response to question 25 and also in your cross-submission on page 2. However, you suggest one justification for maintaining the HVDC charge is that benefits to HVDC, including pole 2 and 3, already exceed costs.

We also note you advocate for exacerbators pays as follows: If the Authority wants to send dynamically efficient pricing signals, they need to reflect the long-run costs that network usage impose, ie exacerbator pays rather than beneficiaries pays.

Does your concern with beneficiaries-pay relate to issues with accurately identifying beneficiaries, or do you consider the concept itself is flawed?

ROBERT ALLEN: That's a long question so if I miss anything please pick me up on that. A lot of what's said in the consultation paper is talking about having more efficient transmission investment, but the problem is that beneficiaries-pay doesn't signal the cost of new transmission investment, so it's not sending a dynamically efficient signal forward that might result in deferred transmission investment. Instead, it seems that the EA's proposition is relying on the efficiency occurring not through people's behaviour in terms of usage of the network, but rather in the way that they engage with the Commerce Commission, and there's been a lot of question marks about the merit of that.

In terms of the issues, concerns that we have about beneficiaries pays, there are any number of different forms of beneficiaries pays, and the fact that you can use the HVDC, you could use beneficiaries pays argument in relation to the HVDC just reflects that some forms of beneficiaries pays is less sophisticated than some others, like the SPD which is very very complicated.

I'd also stress that the arguments around HVDC don't hang on beneficiaries-pays but there's any number of reasons why you might stick with the status quo. That's only one potential argument.

In terms of the problems with beneficiaries pays, as it's presented by the EA in the form of the SPD method, there are a number of problems with it, that changes that you could make would help to ameliorate, and we've discussed some of that in this current round and some - some of it in the earlier session. But in terms of the counterfactual example, you go from a simple situation of cranking the handle to calculate an SPD method, to a situation where you're having to do a whole lot of, we would say, necessary hypothetical subjective evaluations about what would have happened if this asset had never been built, and it starts to get very complicated and it starts to get a lot of arguments about what would have happened because it has such major impacts for how much each party will end up paying. But even if you do a lot of the changes that have been talked about, we fundamentally believe that the SPD method will result in substantial gaming problems, similar to pay as you bid; what would happen if there was pay as you bid with generators seeking to avoid the transmission charges, and we've had some of the generators expressing the same view, which I take to assume, I take to mean that they would expect that they would engage in such behaviour.

SUSAN PATERSON: Thank you for that. I'll stick with Vector because I've just got a few questions, if I can, just to clarify around that. In your early submission on the decision-making and economic framework paper you had suggested that full locational pricing would satisfy that framework, and that the existing approach recouping HVDC charges is consistent with this. Is that still your view?

ROBERT ALLEN: Yes, that's correct, and if you go back to the decision-making framework consultation paper and the discussion there - and in the – in the current consultation there's a lot of talk about the outcomes that you would expect in a competitive market include prices varying by location, and I quote here from the EA, "in highly competitive markets prices vary by location". I think it's quite clear that in a market like - that locational pricing is a market like approach, and we would say that if locational pricing was based on long-run marginal costs, which presumably it would be, then that is consistent with exacerbator pays also, both of which are higher in the hierarchy of the decision-making framework than the SPD in beneficiaries-pay that the EA is proposing.

SUSAN PATERSON: Okay. And so round if locational pricing is your preferred approach, do you consider the current HVDC charges are optimal in terms of locational pricing approach, and if not how can they be improved; and then second one, how can the interconnection charges be modified to reflect the long-term locational pricing approach that you advocate?

ROBERT ALLEN: We - sorry, I should qualify the statement that we consider locational pricing to be optimal. What we have said is we consider it ranks higher on the EA's decision-making framework, but ultimately whether locational pricing should be introduced is a matter that should be tested with the same rigour as we have argued that the EA's own proposal should be tested, and there are a number of factors that may mean locational pricing is a good idea and there are other reasons that it may not be, it depends on the circumstances. And in our submission we talked about some of those circumstances.

For example, if the transmission network has plenty of capacity, demand growth is low, or minimal, there's little likelihood of need for much future transmission investment, then locational pricing wouldn't offer great dynamic efficiency benefits compared to a situation where there was very high demand growth and a lot of need for future transmission investment. It very much depends on a case-by-case situation depending on the country and the country's circumstances. And I think there were some other questions but I apologise, I can't remember what they were.

SUSAN PATERSON: The other one was, how could the interconnection charges be modified to reflect the long-term locational pricing approach you advocate, and how does it relate to market-like exacerbator pays beneficiaries pays or alternative?

ROBERT ALLEN: There's potentially a number of ways you could do it and that's probably a discussion for a future day, but in our submission we talked about, talked of a postage stamp being an example of a way that you could - a simple form of locational pricing but there would be, I'm sure, other options with differing degrees of complexity.

SUSAN PATERSON: And just to follow on with other things in your submission. You recommend exacerbator pays as a pricing principle. What does this imply for charging for the North Island grid upgrade project and North Auckland and Northland project?

ROBERT ALLEN: I'm not sure we advocated exacerbator pays, we noted it was higher in the decision-making hierarchy compared to beneficiaries-pay. If you were going to go down an approach of long-run marginal cost or you're going consider those options, you would be probably looking at it across the board, not specific to a certain region.

SUSAN PATERSON: Okay. If I just give you a little background around this because it comes again from submission. You state with respect to the Authority's proposal to apply SPD charges to post 2004 assets but not pre 2004 assets, which was in your submission. "To use the Authority's market gardener analogy, the signal that would be sent is that the truck should use the old pre 2004 roads to deliver the potatoes from Oamaru to Pukekohe" -

ROBERT ALLEN: I think it's spinach now.

SUSAN PATERSON: "Even if the use of the new roads would provide a more productive, quicker efficient route".

Are you suggesting the SPD method be altered to apply to the whole grid to address this problem, assuming the problems identified could be addressed, or are you suggesting an alternative approach should be applied?

ROBERT ALLEN: We express that as a problem per se with the SPD method. We weren't necessarily suggesting that there was a resolvable solution to that beyond not pursuing the SPD method.

SUSAN PATERSON: Okay, thank you. My next question's Waipa. Have we got Waipa here? We haven't, oh dear, this is a bit of a long question. Shall I still read this out, Chair?

CHAIR: Yes, and somebody else might like to answer it.

SUSAN PATERSON: Okay. So, the question that I had for Waipa was that on page 5 they submitted that "all new core grid assets should be paid for by generators. Only in this way they will receive the full effect of locational price signals".

The question was, isn't it possible that generators do not benefit from some core grid asset investments, for example, assets in some areas directed at providing reliability benefits for load. If so, why should generators pay for those assets and how would that promote efficiency?

They also considered that SPD charges should not be capped, which was on page 4 of their submission.

The question was to ask them to clarify whether an uncapped SPD charge would be acceptable if the SPD charge also applied to load, or would this only be acceptable if generators were identified as the sole beneficiaries.

And then secondly, how did they consider core grid assets that are not used should be charged?

They also submitted, "The transmission pricing proposal would be the same as capping a peak generator's charges at the average operating costs as if it were a base load generator, a base load generator with 100% availability. Under these circumstances there would be no peak generator in the market".

So, we were interested in why they would consider that to be the case and why should this be the case if, as is proposed, the peaking generator were only subject to SPD charges when it operated and received a benefit from the wholesale market?

On page 7 they also submitted that "there's no reason to split residual charges between generators and loads and every reason not to. Generators have no ability to manage customer demand, generally this lies with the distributor where RCPD charges align with network capital investment signals and connection transformer signals".

And so the question was, could they clarify why they considered that the residual charge should be just RCPD with no RCPI, and how does this reconcile with their comments that costs of new core grid assets should be allocated to generators.

I don't know whether anybody else wishes to pick up some of the answers to those questions?

CHAIR: They may have heard how many generators were here and decided that -

THERESE THORN: I'm Therese Thorn, I'm from TrustPower for the next two days, and I think the point that they raise about generators only requiring a lower level of security from the transmission grid than load does, is one point I would like to pick up on. And we know there are a number of examples across the grid where a generator, for example, might have a run back scheme to go off, so they're actually only getting N security there, load quantity N-1. Typically a generator might have one transformer whereas load would have two.

So, those are examples where generally across the grid load requires a much more secure grid then then generators do, and you could argue that a generator in fact were only asking for an N secure grid but a load wants N-1. So, when going for the SPD model perhaps we should change it to be N secure for generators and N-1 for loads. Thank you.

SUSAN PATERSON: Therese, why don't you stay there because other people - does anybody have any supplementary questions with regards to that for Therese? John, would you like to follow-up?

JOHN STEPHENSON: Sorry, on a matter of principle I wanted to address what I think is a misnomer, certainly from the point of view of the economics around the demands for reliability and who benefits from that.

The -It may well be true that as a technical solution, load requires a different degree of reliability or demands a different degree of reliability in the network than generation, but it's a misnomer to think that that means that generation doesn't benefit from that additional degree of reliability. Generation, after all, only makes its money and gets its return on load and consumption, and insufficient reliability is a cost on load which would reduce demand, which would reduce returns to generation. So, from an economic point of view, in fact, its not the case that reliability is solely a load benefit.

THERESE THORN: However, the benefit is not equal, not even close to equal. A generator's avoided cost is $80-$100 a megawatt hour and, as we know, load is around $10,000. So, just from an economic perspective, the two are just not balanced at all.

CHAIR: But Therese, under the SPD charge, the benefit will be calculated for a generator as the increase in price they receive times the volume that they actually sell. So that they are- that is the benefit that is calculated for them.

THERESE THORN: But the asset -

CHAIR: If you just wait, under a smearing charge you may try this argument but the smearing charge is an administrative charge, it's not a beneficiaries-pay charge. So, I've seen this comment by lots of generators but they have failed to recognise, in my view, that the after we go beyond SPD we're no longer trying to charge beneficiaries, we're trying to charge in an efficient manner a tax. We decided not to have a fixed charge, we decided that the next step of a Ramsey pricing was probably not also acceptable as well, and went to a smearing charge, but the question about benefits is really about that one and it's not that one that is in fact a beneficiaries-pay charge. Do you understand my point? Do you have a response to that?

THERESE THORN: I suppose it's the size of the money that you are applying would be different under - from a generator's perspective. A billion dollars is the grid we've got, which is the N-1 secure grid. What grid size would generators require?

CHAIR: They're going to be paying on the SPD for the actual benefit, or a proportion of the benefit that they receive. So, that, I don't see how that arises. The question really is in the RCPD.

THERESE THORN: Perhaps it's something that we could write to you about and leave it at that, thank you.

CHAIR: Okay.

BOYD BRINSDON: Boyd Brinsdon, Contact Energy. My point was just to reinforce Therese Thorn on a technical basis for N-1 security, understanding your question, Dr Layton, the Board gets that so we'll leave it at that.

SUSAN PATERSON: Thank you. The next issue that arose and I've got questions for NZIER, Norske Skog and Energy For Industry. So, if any those would like to also come forward. Oh sorry, stay with us, I've turned two pages as once. So I've missed that one.

So, sorry Powerco - I'm sorry about that. You submitted on page 3 of your submission that SPD doesn't measure the value of insurance or option benefits. I was interested in why this is the case given the SPD method incorporates the cost of non-supply under the proposal, and do you have suggestions for how costs relating to insurance or options should be allocated?

ROSS WEENINK: Ross Weenink from Powerco. Our view is that the SPD but 4 method achieves beneficiaries, or identifies the beneficiaries of the grid only partially, because it's effectively a spot estimate of the benefit every half hour, and maybe you look at what the price is with the grid, the real grid there, and then take an asset out and recalculate the prices, and the difference determines your - who your deemed beneficiaries are. But, of course, if the assets that you've notionally taken out were actually taken out, then the behaviour of the market participants would be quite different particularly if some of the larger assets were taken out. So, in which case the difference between the price with the assets in and without would be different and I think that's a point that needs to be taken into account.

Then there's also the fact that some assets under the SPD butf 4 method wouldn't show any benefit at all because if you took them out there would be no change in the prices. But we’re not sure that means that those assets don't actually have any value, because they may have an option or insurance value if the demand changed slightly or just still have the same demand but the pattern of demand across the grid changed slightly, those assets might actually be brought into play and, of course, we all know that transmission assets can't be conjured up just when you need them but it is - it's still valuable to have that, just having those assets there confers an option value or an insurance value.

I think one way of looking at it is to think about what the value of insurance is. If I've got a life insurance policy, Bruce Smith might say that he's taken my pulse every half an hour and I'm still alive, so therefore the policy is not worth anything but I'd contend that it is.

SUSAN PATERSON: Have you got any other thoughts on how you'd - how the costs relating to insurance and options be allocated?

ROSS WEENINK: We didn't really think about that in-depth because we think that the status quo is actually the better way of pricing, but we did think that the fact that we - well, in our view the – the way that the SPD but 4 method would calculate or identify beneficiaries is incomplete. There's a fundamental flaw in the sort of line of reasoning that has been adopted by the Authority, because unless it is accurately identifying the beneficiaries, then you're not going to get the beneficiaries, the true beneficiaries fronting up to the Commerce Commission to lobby for a better capital expenditure decision for new transmission investment.

And we thought that the - there was a problem with the way that the charge would recover sunk cost because - well, sunk or fixed costs, we don't think the analysis really changes very much whether the costs are sunk or fixed. We think that a non-distortionary approach and a reasonably fixed charge is the best way to do that and, of course, the SPD but 4 method creates quite a volatile charge, and we don't think that it - well, you could say, okay, that's static efficiency, we don't think it achieves static efficiency, does it achieve dynamic efficiency; are you - does it identify the long-run marginal cost of new transmission investment? We don't think it does that but of course the mechanism that is claimed to achieve dynamic efficiency is the, you know, the accurate identification of the beneficiaries and, therefore, the lobbying of the Commerce Commission are better to capex decision-making and we think it only partially achieves that at best.

SUSAN PATERSON: Okay, thank you. Orion, on page 4 of your submission you suggest that the reliability benefits provided by assets like NIGUP and NAAN were "non-monetary" and won't be captured by SPD.

Just interested in why you think that's the case given the counterfactual solve under the SPD method models the situation with removal of the asset and assigns a cost in the event of non-supply?

BRUCE ROGERS: Bruce Rogers, Orion. You may just be indicating that I didn't fully understand your proposal but I think in that paragraph 16 I was quoting the paper, saying that the paper acknowledges a number of significant recent investments were reliability investments. So, my own view when I was looking through the whole SPD thing is that if you take out a reliability investment, how does it affect the market outcome, and I wasn't sure how it could. So, if an investment is done for reliability purposes, so effectively a reserved circuit, if you like, and you remove it, I think the market outcome is the same, but I could easily be wrong.

CHAIR: It's actually going to have some benefit, it has to change the probability you do have outages, doesn't it -

BRUCE ROGERS: Yes but the question is does the SPD resolve method actually pick that up or not, and I guess that was in the general context of a concern that the way the paper was put out, effectively there was a table that really pretty much, if you took it at face value, demonstrated that all of these recent investments that New Zealand has made in the transmission system were bad ones, and it comes down to, is the benefits calculation out of the SPD thing a partial estimate of the net economic benefits, which is what the Commerce Commission is trying to do when it goes through its process, or is it comparable for benefits thing. So, you're actually saying you've got it wrong and I don't really think it is the latter, it's just that the SPD calculation is incredibly partial and probably quite unreliable. So, the conclusions that are drawn about the the quality of the investment decisions are actually very poor ones, and so all we're doing really is setting up the SPD method as a way to beat ourselves up around making bad decisions. On the other hand, if the SPD method is the right way to do this economic benefits analysis, then I think we should take it across town, give it to the Commerce Commission and ask them to use it as their investment test method. I don't think we should have two different systems trying to work out benefits when they're not actually consistent. If we've found the right method, then let's give it to them and let's use it.

SUSAN PATERSON: We'll take that as an interesting suggestion. If I move back to Powerco, on page 3 you submitted that the most economic interconnection charge would be one that achieves non-distortionary recovery of sunk costs and also signals the long-run marginal cost of new investment when demand is increasing. You submitted the current "RCPD charge moves some way towards signalling LRMC" but not the SPD proposal.

ROSS WEENINK: Mmm.

SUSAN PATERSON: If the current RCPD charge is broadly efficient, why are transmission charges increasing by over 60% in areas where there's no significant transmission investment, such as the lower South Island, and how does that promote efficiency?

ROSS WEENINK: Ross Weenink from Powerco. Well, we said that the RCPD method was sort of a nod in the direction of signalling the long-run marginal cost of new transmission investment. I don't think anyone suggests that it actually does that or that it's ideal, there's certainly room for improvement there. But we don't think that the SPD Part 4 method actually achieves that any better, that it's not intended to signal the LRMC and it doesn't do so. So, we're not saying that the RCPD is perfect. It does – it aims to flatten the peaks and avoid the need for some new transmission investment where demand is increasing. If you're concerned about regions that may be paying for new investments that shouldn't be, then you could go to something like what's known as a license plate interconnection charge so that - rather than the method that we've got at the moment, where the charge is allocated across the whole country, albeit it with four regions with different N numbers. So if there's a slight balance or a slight tilting of the charge in favour of the northern regions, you could identify a separate interconnection revenue for the four different regions. That's known as license plate as opposed to a postage stamp.

SUSAN PATERSON: Sure. Okay, have any of the other Authority Board Members got any other questions? What about any of the other - sorry, I'll come back in a sec - any of the other Authority staff; Alistair - sorry, Bruce?

BRUCE SMITH: Okay, Bruce Smith, Electricity Authority. Question for Powerco. So you talked about these sorts of insurance or options values. So, at the time the regulatory test is applied for an investment, so I'm thinking of the grid investment test, these things are taken into account. Does that mean that you would - you have some, you know, you view favourably the suggestion, I think it was from Genesis, that you'd look at the grid investment test application and use that to identify beneficiaries?

ROSS WEENINK: Ross Weenink for Powerco. I would have some sympathy for that idea. That's not something that we've considered in any detail.

SUSAN PATERSON: Anyone want to make a further comment?

JAMES TIPPING: Yeah Just one further comment, James Tipping from TrustPower. In relation to Bruce's comment before about, and the comment that's just been made about interaction with the grid investment test and new investment decisions, my understanding is a lot of the benefits are predicated on getting the right information out at investment time and making the right investment decisions with relation to transmission investment. The issue I have, or the problem I have, and I'm trying to work it out, is the SPD method as proposed is based on observed market outcomes. So, how if were getting- if we had a proposal for a new transmission investment would we actually forecast what those charges are and relate them to the benefits and work out whether it's a good investment to make? May be an open question.

SUSAN PATERSON: Any comments?

CHAIR: As I said at the very beginning and the reason I didn't respond to Bruce was we're not answering questions, we're asking questions, so --

JAMES TIPPING: I'll rephrase.

CHAIR: -- we'll answer the questions when we come with our next proposal.

JAMES TIPPING: I'll rephrase. I see this as a big problem. There's no way to forecast charges with the SPD method.

SUSAN PATERSON: Thank you, we'll take that on board.

BRUCE ROGERS: Sorry, Bruce Rogers here. Maybe I could expand on that. I think it also raises the problem that I suspect people will have to try and forecast those charges, if it comes to this, if they are going to try and lobby the Commission around its decision-making, and in a sense that's the same problem as the, using the SPD method perhaps, or some other beneficiaries pays method, to do a longer term approach to this as opposed to doing it half hour. So I think one way or another, if it's going to be useful it has to be long-term irrespective of who actually does the long-term analysis. Whereas knowing in the first half hour after the asset has been built that it costs you $10,000 as much that it's interesting and, as Gillian alluded to, you might have trouble explaining the invoice, but it really has no economic benefit at that point.

CHAIR: There is just one comment I would make which is a comment and observation, is that the Authority did at the request of a number of parties actually calculate what the SPD charges were likely to be on the pole 3, and pole 3 only started last night.

JAMES TIPPING: James Tipping, TrustPower. The response to that would be is it's a sort of fabricated market outcome with no adjustment generators offers. So, you're sort of de-stressing the grid rather than predicting outcomes that might actually happen.

REBECCA OSBORNE: Can I just make a comment on this? Rebecca Osborne from Pioneer Generation. There's been a lot of talk about price signals for investment decisions. I think it's important to remember that we already have very strong price signals for investment decisions from the spot market and the spot market prices do signal where constraints in transmission issues are. I think introducing another variable charge to try and give a price signal there is actually just going to distort those prices, not give a stronger signal.

SUSAN PATERSON: Okay, thank you for that. I am now up to my right page and I'm going to move on to the costs under the - whether the costs under the SPD method, whether they should be capped. So, my first question was for NZIER.

You suggest that there are a number of structural flaws in the SPD model that will lead to unintended outcomes, for example half hourly capping which you consider will limit the extent to which benefits can be identified.

So, my first question there is, won't increasing the capping period shift much of the costs of SPD on to load; and then, secondly, what do you consider the most appropriate capping period, whether that's weekly, monthly or another period?

JOHN STEPHENSON: John Stephenson, NZIER. So, capping, if it is the case that extending the capping period leads to more benefits to load and higher charges to load, we would have no problem with that. If that's where the benefits lie, that's where the charges end up, so be it and certainly in terms of getting the optimal capping period right we haven't run the numbers, the number of candidate options is very large. What we would say is that having a very long period of cap which could have the result of having charges largely determined in a handful of periods is potentially problematic simply because of the problems with accidents, error, charges could swing on a single, on a handful of periods. So, you don't want to go too wide in the number of periods that you consider. But I think, as we pointed out in our report to MEUG, you don't have to go to that many periods to start to get a much greater degree of charging through the SPD method, and so absolutely the half hour looks like a sub-optimal approach.

SUSAN PATERSON: Do you tend towards sort of weekly, monthly, do you have a feeling for actually what that next length of period should be?

JOHN STEPHENSON: No, we haven't -

SUSAN PATERSON: You haven't done the modelling?

JOHN STEPHENSON: Haven't done the work.

SUSAN PATERSON: That's fine. And my next question is for Norske Skog, they're not here. Let me read that out for you.

In page 12 of their submission they suggest that "the main reason why the SPD method is so ineffective in charging beneficiaries arises from the Authority's intention to calculate benefits from every single trading period". They also go on to suggest that "transmission investments are built to meet peak demand so the best beneficiaries-pay charging method is to allocate costs according to beneficiaries- to party's benefits at peak times".

They then go on to say that "if the charge was applied to only a few periods of the year, then the incentives for generators to avoid the charge would be high".

And They go on to say, on the other hand, "consumers' bids would all be represented by a price of $3,000 a megawatt hour", which was on page 12 of their submission.

I was interested to clarify whether they consider that the cap should be extended out to allow the allocation of costs to peak periods, and ask them whether this would not, according to their arguments, incentivise generators to avoid the charge. So, I don't know, would anybody else like to comment on those issues raised?

BRUCE ROGERS: Bruce Rogers from Orion. I guess the key thing about capping is that given the way presumably the revenue requirement will be set for the year, every time you cap you reduce the relationship between the total costs for the year and the alleged benefit. So, you're effectively making it impossible for the benefit calculation to be greater than the cost. That's what capping does, unless --

SUSAN PATERSON: Sure.

BRUCE ROGERS: -- it just so happens that the method is the same in every half hour. I think it's quite important because again, it goes back to that thing, we are sort of in a number of places having a table that says these investments were bad, and the reason they're bad in those calculations is because we've decided to cap the benefits, partly.

SUSAN PATERSON: Okay, thank you. You're here for Energy For Industry? So, in page 4 of your submission you suggest that the SPD cap should be changed to a longer period, either weekly or monthly, and also suggest that the SPD charge is too volatile.

Have you considered that increasing the cap period would increase the variation of charges from half hour to half hour, and do you consider this is a problem, and also how would you address it?

And, secondly, increasing the cap period will significantly increase SPD charges and reduce the residual charges, and just a question as to whether you're comfortable with that?

REBECCA OSBORNE: Rebecca Osborne from Energy For Industry here. Can I ask that we be given the opportunity to respond to that question in writing, please.

SUSAN PATERSON: Sure, that's fine. Has anybody got any other comments that they wish to make with regards to capping of the charges for SPD?

ROSS PARRY: Ross Parry from Transpower. We did a lot of the analysis I think that helped sort of flesh out this question about capping in the first place, and I mean we really did that just to illustrate that there's design choices to be made that significantly influence the allocation of wealth. I don't think there's really - two points, one is I don't think there probably isn't an optimal answer in terms of, are we talking about a day, a week, a half hour, a month; and the second is just the observation that it seems a bit incongruous to be having that conversation in the context of what the ground we've covered before here, where I think there's more work to be done, really, about the validity of the approach as a whole before we kind of get to the point where we can have a productive discussion about detailed design parameters like half hour, a day, week, month.

SUSAN PATERSON: Okay, thank you. Do any of the other Board Members have any questions they wish to ask? Any of the Authority staff?

ALISTAIR DIXON: I actually have some questions from slightly earlier. I was actually just wanting to ask a question actually going right back to Vector, so if that's all right.

So, it was just in relation to this analogy, the market gardener analogy and the post 2004 asset point, and the fact that it would provide incentives basically to use back roads rather than State Highways. So, I guess my question is really, if we follow that approach, I mean I guess if we take your advice, what approach should we be taking? Should we be say applying the SPD method to say the 220 network, or something like that; is that what you're suggesting we should do, or is there some other approach you think we should be looking at?

ROBERT ALLEN: If you're going to persevere with the SPD method and you wanted to, and you were looking at addressing the effect of having discrimination between pre and post 2000 assets, one solution would be to take a broader approach to what assets are included in the charge but that of course would raise issues because you would be, as discussed before, you would be introducing assets into the SPD method that were already approved by the Electricity Commission or the Commerce Commission and what are you actually achieving by measuring the benefit of those assets that are already there and are fixed and/or sunk. But we would say the main problem with the SPD method isn't the discriminatory treatment of pre and post 2004 assets and people driving around back roads to deliver their potatoes or spinach. It’s The main problem is the problem that generators would have strong incentives to game the regime as a form of tax avoidance or evasion.

SUSAN PATERSON: Thank you for that. If I just, and I know it's already been partly discussed, but just sort of delve a little further on the cost of non-supply. I've got questions, I’ve got questions for Contact, Pacific Aluminium and Fonterra.

So, the first question is for Contact Energy. You suggest on page 29 of your submission that $20,000 a megawatt hour is an appropriate value for the cost of non-supply in the SPD method, yet load parties suggest $3,000 a megawatt hour is too high and it reflects a short-term solution. How would you reconcile your position with that of load parties, and why do you consider that your position best promotes efficiency?

BOYD BRINSDON: Again I would probably, at the risk of repeating myself, like to reserve the opportunity for Contact to answer that in writing but my understanding of Contact's position is that it's formed from the view that that is the deemed value of VOLL and that is the value of VOLL used in previous grid investment tests, but, as I've said, we'd prefer to give a full and a written answer to that question.

SUSAN PATERSON: Okay. So my next question for Pacific Aluminium, you're Pacific Aluminium, Ray, aren't you? You suggest 3,000 is too high for the cost of non-supply as it reflects a short-term solution and doesn't reflect what a long-term solution would be. So, I was interested in what your rationale for preferring a cost based on the long-term solution was?

RAY DEACON: Ray Deacon, Pacific Aluminium. That's quite right. When you're looking at investments in the transmission system you're taking a long-run perspective, and if a transmission, particular transmission investment wasn't made and it was going, and the alternative was going to be the alternative of non-supply actually wouldn't be the correct counterfactual, the alternative would be some other form of generation and I don't believe it would be a diesel generator set either, it would be something else. And, therefore, I think the-the appropriate price in the counterfactual would be something like the long-run marginal cost of the next tranche of generation, so much much lower than the $3,000.

SUSAN PATERSON: Okay, so other Board Members, would you like to have queries?

CHAIR: This is for Ray. Wouldn't it be more realistic to think that, rather than your answer that it's always going to be less than 3,000, that it would depend upon the expected frequency of non-supply; that if non-supply was going to be a very rare and occasional event, once every say three or five years, then it might be reasonable to assume that VOLL is the appropriate charge because that's actually what would happen. If it's going to happen more frequently, let's say every six months or so, there would be some point in which you would find it beneficial to have a generator driven by diesel sitting there and the costs of capital and of the running costs of that given the expectation with which it would be able to be operated would be the figure, and if you thought it was going to happen very frequently without this transmission line, you may look at a long-term generation solution which could be putting in another hydro plant. So that, in fact, it really depends upon the frequency that one would have to set this figure.

RAY DEACON: Ray Deacon, Pacific Aluminium. Yes, I would agree that there would be a trade-off and you're quite correct, Mr Chairman, that depending, the least cost solution might actually be a diesel GEN set but that certainly wasn't apparent to me in working through that paper.

SUSAN PATERSON: Do any of the other Authority staff have questions?

ELENA TROUT: Excuse me, Susan, could we ask New Zealand Steel to share their views of a lesser value for VOLL?

ALAN EYES: Alan Eyes from New Zealand Steel. Maybe I'll answer it in the form of where do we - what's the level that we trade off production for the cost of electricity, and that's not a straightforward question because the nature of our operation is a vertically integrated mill and so the value of producing product out say of our paint line is totally different to producing molten iron, and it also gets very complex when you feature in our waste heat and waste gas co-generation possibilities. But when, you know, you start talking figures of $20,000 for example, you know the question really is how quickly can we shut everything down safely without causing plant damage or safety aspects for the staff. In other areas it's even figures of approaching $1,000, once again, just how quickly can we get everything shut down. I'm not sure whether that's precise enough, Elena, for your questions?

SUSAN PATERSON: Other Authority staff, questions?

ALISTAIR DIXON: I actually had a question for Vector.

SUSAN PATERSON: He's just got a mouthful but if you make it a long question he'll be finished.

ALISTAIR DIXON: It actually is a reasonably long question. So, Rob, you can finish your mouthful hopefully and I can extend it, if you like. So, just in your submission - so this is paragraph 72 on page 13 - you state, "The Authority's short-term approach" -

ROBERT ALLEN: Which paragraph?

ALISTAIR DIXON: So your sub-in your submission, and it's paragraph 72 on page 13 of your submission. You state, the Authority's short-term approach to determining consumer surplus is akin to determining the person should pay up to hotel rates for renting a house on the basis that if the house was removed, for example if it was burnt down, they would need to stay in a hotel and you're saying that's equivalent to the assumption that a transmission line would be removed, supply would come from a diesel generator, but you're saying, and I think this is similar to Pacific Aluminium's point, that if a long-term perspective was taken the value would be determined by the best alternatives, so renting another house, and that would result in a substantially lower consumer surplus calculation, and so therefore the price should be based on the type of generation investment that would have occurred in the absence of transmission capacity.

I'm just wondering, given all of that, and you indicated that really what the Authority should be preferring is exacerbators pay rather than beneficiaries-pay, so I'm just trying to reconcile or how do you reconcile this position with your perspective that we should actually prefer exacerbators pay and therefore we should be actually focused on sort of the long-run marginal cost assets?

ROBERT ALLEN: I'm not sure there is anything that needs to be reconciled here. Paragraph 72 and the surrounding material is talking about the problems with the SPD proposal, and the suggestion in 72 about what you could do to ameliorate some but not all of those problems is predicated on if the EA is going to persevere with the SPD method, it's not saying that if you do what we suggest in 72 we will support the SPD method necessarily, because, as we stated before, there are some intractable problems that we see with it.

So, I don't see any consistency of Vector saying that exacerbator pays is superior to beneficiaries-pay, though if that is an inconsistent perspective that would be interesting in terms of the EA's proposal, because the decision-making framework says the EA should prefer exacerbator pays to beneficiaries-pays, but the EA's proposal is for beneficiaries-pays.

SUSAN PATERSON: Thank you for that. That kind of wraps up the end of our questions around SPD. I mean, certainly from the Electricity Authority, we are extremely keen to make sure that we do fully understand all the issues that people have with the SPD model. So, I am happy just to throw it open to the floor in case there are any other points that anybody else feels need reiterating, or any other different aspects of the SPD model that people would like to make us aware of, if there are other factors that you think we should take into account that haven't either already been raised in the submissions or, you know, made clear for us here today. If you could state your name first, would be great thank you.

JEREMY STEVENSON-WRIGHT: So, Jeremy Stevenson-Wright from Genesis Energy. Just going back to a question that was asked of Energy For Industry, and thinking through that over the last ten minutes or so. Now that question, as I understood, related to the inherent volatility that the Authority acknowledges is in the SPD method, and in particular at the way that the current proposal attempts to address that volatility through the capping methodology.

Ultimately, I guess, our concern with that capping approach that's suggested in the proposal is it really does limit the beneficiaries-pays aspect of the SPD method as an attempt to reduce that volatility, and I think our concern really there is that there's other ways to manage that volatility rather than do so via the capping method.

So, in our strawman methodology, for example, we suggested that one way of managing the volatility per se is to run it on a five yearly basis, and that although the individual within I suppose year volatility, that actually the method calculates would still remain, the actual volatility that the end payer sees or the end consumer sees is actually relatively steady and flat and a known quantum. So, I just wanted to address that and made sure that we made that point clear to you.

SUSAN PATERSON: Can I just ask a supplementary question to that. A lot can change I guess in five years, and I was just interested in why the selection of something like five years versus one or two, which would give a lot of stability but then would also allow for new entrants, exits and changes in the industry?

JEREMY STEVENSON-WRIGHT: Sure, and I think to some degree this question has already been canvassed earlier today and also yesterday in terms of, there are parallels in five year periods being set for transmission investments, in terms of the current process we have in place. So, it's that five year period is I would say relatively standard for this kind of investment. But in terms of those special events that may trigger a reconsideration, I agree, and we have said this earlier, that you would need to think of what are the extreme events that would trigger a reassessment, what's the material level of event that would require you to rerun the SPD allocation.

SUSAN PATERSON: Okay, thank you.

ROBERT ALLEN: In terms of the open to the floor, there was just one additional point we would like to make, and looking at the EA's consultation paper, you have concern about an uncapped SPD method on the basis that it may mean parties have greater incentives to act so as to avoid the charge, a concern that we share, and the EA's consideration of other beneficiary methodologies such as economic models, flow tracing, zonal beneficiaries-pays, made similar comment that had concerns, that the likely costs of this option, or these options, are incentives on parties to alter their use of the grid in order to minimise their exposure to the charge which may be inefficient, but in terms of the SPD proposal the EA appears to say the opposite, and its the EA has said believes it will try to structure their offers to the spot market to reduce the estimation of their private benefits. It then goes on to say, rather than being a problem, the Authority believes this is a positive attribute of the proposal.

So, one thing Vector wasn't sure about is why gaming is a good thing for the SPD proposal but is a bad thing for other versions of beneficiaries-pays, but I'll leave that as an open question, not a question for the EA.

SUSAN PATERSON: Thank you. Ray?

RAY DEACON: Ray Deacon, Pacific Aluminium. I just wanted to elaborate a bit more on my earlier answer and I agree with the Chair's point, and it wasn't clear, for me anyway, from the consultation paper that that was a consideration. So, I would request that in any future specification, that the use of VOLL is constrained by the number of times it applies to a particular grid exit point. Because the issue for me is, if the absence of a particular piece of transmission system meant that an infeasibility was created at a GXP, or a number of GXPs, a repeated number of times then you would get to a point where using the cost minimisation approach, you wouldn't have a diesel generator in there, you would actually have alternative generation. So, that I think that needs to be specified in the model.

SUSAN PATERSON: Thank you for that. Peter, you've got a further point?

PETER CALDERWOOD: Yeah, Peter Calderwood from TrustPower. Look I have just been listening through this debate around VOLL, and I'll probably retract because I don't think we will be able to come back and tell you what we think VOLL is going to be because it is so complicated, and I think it's one of the key things which is driving why this ex post SPD method is not going to work. The only way you're going to sort out VOLL is for every single line you have to say, what happens when that is taken out of service, if it results in a cost to supply what's the next best alternative, and as we add more and more investments into SPD, this is just going to get more and more complicated. So, you'll have to have a, I suppose, a bespoke VOLL for every single asset that you are taking in or out of SPD, because it is so material, particularly if you end up with loss of supply, on what the outcome is going to be on the SPD charges. So, yeah, it just tweaked to me listening through that debate, it just adds to that complexity about ex post SPD versus some form of ex-ante beneficiaries-pay.

SUSAN PATERSON: Thank you. John, did you have a point you wanted to make?

JOHN STEPHENSON: John Stephenson, NZIER. I just want to make another point of general principle and it comes from the point of view of people who we- I think we've got a reasonable handle on the SPD method and we think it's a good one and I just - a good general approach - I just want to address what's often termed the nirvana fallacy in policy and making decisions, and that's the comparing of something which is good against something which is unachievably perfect, and I think we're falling into that trap a little bit in looking in the SPD method sometimes with our criticisms. For example,you know we can be concerned that it's not a perfect assessment of benefit but it's certainly significantly less subjective than charging on the basis of last year's 12 half hourly regional coincident peaks, which frankly are extraordinarily hard to forecast precisely, and more so than understanding what charges would be under an SPD method. So, you have to be very careful about perfect being the enemy of the good, and certainly the desire to have the perfect being the friend of the even less good. Just a general point of principle.

BOYD BRINSDON: Sorry I'm Boyd Brinsdon. Just looking at the generators, other than to clearly dispute the point that we believe it would be far more difficult to forecast the outcome of the SPD modelling as it's suggested, as suggested as opposed to forecasting the outcomes of coincidental peaks. And I think it was reasonably easy to forecast the outcome of coincidental peaks two nights ago, and generators and load responded to it. The sort of response that I don't think you'll get from an SPD methodology because no-one will see those signals.

And probably on a point of clarification, too. I may be getting a bit precious here but I'd like to point out that it is genuine that generators will be disposed to managing their offers to minimise SPD charging. I don't see that it's gaming, I see that as no different to networks rightly managing their off take charges through RCPD now. And, I think Contact has made that point, and I do think that that will derive inefficient outcomes for generation when a million in my operational role needs to consider in a complex nature how we manage SPD charges and how we - I won't be doing my role properly if I don't seek to avoid them for the benefit of Contact.

SUSAN PATERSON: Thank you.

REBECCA OSBORNE: Sorry Rebecca Osborne from Energy For Industry. I would just like to come back to the point about RCPD peaks as the gentleman over here said they're not easy to predict when they're going to be; I thoroughly disagree with that statement. We have - we actually earn quite a bit of revenue from doing exactly that and one of our sites, that the savings we make from doing that are about 7% of, or can be 7% of the total electricity cost.

SUSAN PATERSON: Thank you for that point. Alistair, did you have a point that you wished to raise?

ALISTAIR DIXON: Well, it was actually around this question of forecasting RCPD peaks, so I'm just intrigued about this. So, are you saying that you can forecast when the RCPD periods are set, that you can do this, say, at the end of whenever it is, say it's at the end of December but there's going to be a cold snap on 28 May and that you can avoid that then, or is that is that easier to do than forecasting that on the basis of last month's SPD charges we have this amount, and so that last month might provide us some information on what this month's SPD charges are? I'm just trying to get an understanding of the comparison between the two.

SUSAN PATERSON: Anybody like to answer that for Alistair?

THERESE THORN: Therese here and I would like to make a comment. I think, probably this is a slightly more general comment, I think there's a difference between cost allocation and pricing and I think, I'm not sure whether we're calling this cost allocation or we're calling it pricing.

We know the price of our coincident peaks set 12 months ago, so we now how much effort we need to put in to managing that price. What we're talking about here is cost allocation and we don't know until after the event how much that cost will be using this current methodology. So, it's quite a different allocative method, and I've done pricing in this industry for nearly 20 years in different forms and I've probably priced almost every different transmission pricing methodology that we've had over that last 20 years, and we are now used to getting from Transpower three months before we set our next 12 months' worth of pricing to our consumers, what that price- what that price is going to be. We don't know exactly how much capacity we're going to remove but we know what the costs of the capacity is so it's certain to us and we can charge that, we can pass that price through to our consumers accurately. So, if they make that benefit, they get the benefit of it.

Whereas the proposed methodology is extremely uncertain for us to be able to reliably pass that benefit through to our consumers in a robust way, because we can't reprice all the time. Our pricing sequence is a whole 12 months.

Now, if you guys came up with a cost allocation methodology in whatever way you do, but you say to Transpower, look guys, this is how we're going to do it but you're allowed to set those prices 12 months in advance so that then the industry can actually price them through to consumers accurately I think we'd be a lot happier. So, I'm actually saying we need an ex-ante pricing methodology cost allocation, whatever way you like. Thank you

SUSAN PATERSON: Thank you. I think that - oh sorry, Alan?

ALAN EYES: Yeah Alan Eyes, New Zealand Steel. Just to add to that. We're taking decisions if not half hourly at least two hourly in advance, but I guess it's a similar argument to what Therese is saying. Monday night, the team - we knew how much it was going to cost for the peak demand, the team had to make a judgement call, is that going to be one of the North Island regional peaks for the year or isn't it, and manage our load accordingly. When we moved to – if if you're going to continue with an SPD charge and it's going to be on a half hour basis, we raise exactly the issues that we raise now in terms of it being an ex-post model which all of the issues that arise with the deficiencies and the settlement, the forecasting and settlement pricing, we can't take decisions in terms of our production levels based on whether the information that we're being told through WITS is going to be accurate or not. And so to compound the issue by having some of our transmission charges based on those same issues that haven't yet been resolved within the wholesale market, becomes a real issue for us.

SUSAN PATERSON: Thank you. Ralph, have you got a further point you would like to make?

RALPH MATTHES: I think probably this is - sorry, Ralph Matthes from Major Electricity Users Group. I think this has been quite an interesting debate but it, I think to shed some light on it, really needs some analysis. The Authority has already done some initial analysis about the impact on end consumers up and down the country. I mean, as I recall, currently interconnection charges are around $108 a kilowatt. For the average consumer in Auckland I think you are probably getting down to maybe $90 a kilowatt, or something like that, on average for a number of scenarios. In other words, all consumers would be benefitting from introduction of the proposal as you had it. But to me the question was, that's an average and some years prices might go above the 108 and other years might be substantially below 90. So, I think that's the issue around getting some more metrics around the volatility and what's the average price over a year that counts. Thank you.

SUSAN PATERSON: Thank you for that. Okay, I'll wrap up this session and pass back to the Chair.

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CHAIR: Well, thank you very much, Susan. We are scheduled to go on till 3 o'clock and so we'll move on to the next topic, which is the RCPD charge.

Of the 33 people I was going to call - the first 33 I was going to call, only three of them are here which is a commentary upon the incentives upon distributors to make submissions on a charge that they have pass through, I think. But the people I want to call are ENA, which I believe is represented by Powerco; Nova; and then I wanted any distributors but they're - so anybody else who's a distributor, Orion, Vector and with Powerco I think that's it; Pan Pac, they're not here; NZX, they're not here; Vector, they are there; Meridian; next one was Northpower; NZ Geothermal Association; TrustPower, Mainpower; and Powerco.

This is a session about the residual charge, the RCPD/RCPI, and I'll start with some background.

The Authority proposed a residual charge to recover HVDC and interconnection costs that are not recovered through the connection charge, LCE charge, kvar charge, or the SPD charge. The residual charge is designed in the Authority's proposal to impose a broad-based low-rate charge that minimises distortions in the use of the grid. It involves recovering 50% of the residual costs through a regional coincident peak demand charge to load through distributors; recovering 50% of the residual costs through a regional coincident peak injection, charge to generators; the RCPD and RCPI aspects should be designed so that parties subject to the charge have sufficient incentives to avoid peak use of the grid in the region in which they are located; and, distributors could elect to opt out of the residual RCPD charge at any node to the extent they do not benefit by offering to or purchasing from the wholesale electricity market, subject to consulting with retailers at that node. If distributors opt-out, the charge would apply to the retailers at the node.

So, my first question is actually to Fonterra, which I missed out of my list. Anyway, they're not here either so I'll read the question.

Fonterra submitted that the Authority needs to ensure that no gaming occurs post implementation as generators will alter their offer behaviour to minimise transmission charges, which will have the risk of "charges to consumers incorporating a greater proportion of transmission costs than they do currently".

And the questions were, can you clarify what you mean by this given that the interconnection charges are currently all met by load through an RCPD; and, does your concern relate to HVDC charges or are you referring to an impact on household prices?

So, we'll send them that question.

The next question was for MRP which you're aware is not here either and gave an excuse for not being able to answer questions today.

The question to them is, for the record, you do not favour charging generators, citing distortionary effects and submitting that generators are not "causers".

If consumers pay for the transmission costs of generators' location decisions, doesn't this amount to consumers subsidising the costs of generators? If not why not? How does this promote efficiency?

Are you concerned about charging generators "leading to increased distortions to wholesale and retail market prices and added risk premiums" common to all options for charging generators or just the Authority's proposal? If these concerns apply to charging generators, do they also apply to the examples of farmers paying transport costs of getting their goods to market or airlines paying landing charges? Do they also apply to the HVDC charge on South Island generators, and if so, why?

MRP had noted that these distortions were "not seen as beneficial to the long-term interests of consumers".

But suggested in its cross-submission, page 8, that among other core elements of the proposal that could be consulted on more widely, the Authority could investigate trialling the concept of beneficiaries-pay on the HVDC.

Does your suggestion of trial beneficiaries-pay for HVDC include generators as beneficiaries?

How do you respond to suggestions from some submitters that charges to generators are in the long-term interest of consumers if generators cannot pass transmission costs or a portion thereof to consumers?

What is your position on generators being subject to a locational signal such as that from the current HVDC charge?

Next question is to - you're representing ENA, Ross. You mentioned in your submission that ENA might be supportive of an RCPI charge dependent on design.

How would you suggest an RCPI charge could be specifically structured to minimise distortions and make the charge stick?

ROSS WEENINK: Ross Weenink on behalf of the Electricity Networks Association. I'm a little bit torn here because Powerco's position is that the RCPI design is not a good one.

CHAIR: We accept that you're having to represent a group that you may not agree with.

ROSS WEENINK: Yes, but I think the ENA view was that provided the incentive that the charge provides doesn't lead to our generation being inefficiently withheld, then it could be satisfactory.

So, if you had an RCPI with a relatively large N rather than just one peak, then that could be a way around that problem. I think that was the essence of it.

CHAIR: And do you think that would make the charge stick?

ROSS WEENINK: It could do, yes, because the larger the N, the closer you get to per megawatt hour. So, it's a compromise really.

CHAIR: And the follow-up is to what extent you consider making generators subject to residual charges would reduce incentives to engage in load control? "You" being ENA.

ROSS WEENINK: ENA, yes. I think Yes I'm just trying to remember what the problem was there actually. If you could remind me what was the point raised in the submission?

CHAIR: I think the argument is that if you have an RCPI, then there's going to be less in the RCPD and that will lower their incentives to avoid --

ROSS WEENINK: Oh, I see. Yes, right. Yes That's right. Yes

CHAIR: -- the peak and hence lower their incentives to operate their load control, whether efficiently or inefficiently.

ROSS WEENINK: Yeah Yes, I can see that. So, if you spread the - the charge across a wider base and therefore the RCPD signal isn't as strong, I suppose you could - you could reduce the N number, that would make it stronger. But I don't- I don’t remember ENA actually coming to a view about what the solution was.

CHAIR: And a further follow-up is, do you consider, or does ENA consider the Authority should provide a detailed design of the charge rather than leaving the detail designs to Transpower, which has been the subject of quite a number of submissions?

ROSS WEENINK: Yes, I think it would be better for ENA to provide the design rather than leave it to Transpower.

CHAIR: I could be wrong in this but I thought that in the current methodology the design was initially done by Transpower, of the RCPD.

ROSS WEENINK: Yes. The - the guidelines required a methodology to be proposed and Transpower proposed the RCPD method, yeah.

CHAIR: So, why is it that, since that worked the last time round in 2008 the thought is now that Transpower has lost that capability to do that design?

ROSS WEENINK: I don't think that it's lost the capability, it's just that I think as a general principle it's better for the – the Authority to be more prescriptive in terms of the design. So I remember - I mean, I don't expect that we'll get back into this situation again, but there was a, we got to the point where there was something of a stand-off between Transpower and the then Electricity Commission about whether the AMD method should be maintained or a coincident peak method should be adopted, and eventually a compromise was reached but I don't think that that the exercise really achieved anything constructive.

CHAIR: We won't speculate on which party was on which side --

ROSS WEENINK: No, no.

CHAIR: -- I think we've got a fairly good idea. And so you just see it that it would be better if those issues weren't repeated on this occasion?

ROSS WEENINK: Yes. That there wasn't actually any discretion and that the Authority had considered all the submissions and come to a conclusion and then decided what the correct approach should be.

CHAIR: Thank you. Do my colleagues have any questions?

ELENA TROUT: Just interested if Orion has got any view on that last question, the last question in terms of the Authority providing greater detail rather than allowing Transpower -

BRUCE ROGERS: Since I've picked up the microphone I'll back you up a bit. I think there was confusion there between the decision to have the residuals split 50/50 and then how that might be recovered, and I think one of the questions was, how does that affect incentives. Well, I think the arithmetic is pretty straightforward, the more that is put into the generator bucket, the less will be in the distributor - let's say the load bucket, and therefore the price signal must be smaller. So that’s, I think it's a pretty straightforward piece of arithmetic and we don't need to go too much further on that.

But for me the - the more important question is where does 50/50 come from, and I know I'm not allowed to ask questions of the Authority but it is one of the important questions I think that needs to be resolved. I think a number of people have expressed sort of conceptual views, like I think our view was well we think it should probably be more load than generation because of reliability value and I think Meridian came up with 75/25 possibly pulled from a similar place as the 50/50, who knows, but – but it seemed a bit better. Yeah, so I guess that's my perspective on the question.

CHAIR: But do you have any questions - comments on the questions that have been asked to Powerco?

BRUCE ROGERS: No, I think Ross was representing ENA at this meeting.

CHAIR: And what about Vector as another - are you a member of ENA or?

ROBERT ALLEN: Yes, we are. We don't have anything to add.

CHAIR: And any of my colleagues want to ask questions? Staff? Alistair, what a surprise.

ALISTAIR DIXON: Alistair Dixon. Sorry. I'm just interested in the impact on incentives for load control if we're broadening the base and applying, introducing RCPI. So, if that reduces the amount on distributors but distributors can pass through charges, I'm just interested - and pass through RCPD charges, how is - given that pass through how is a reduction in the charge going to alter incentives? Presumably the incentives for load control are just responding to a signal. Presumably is it price that's causing that response or is there some other sort of more sort of benevolent reason why there's that load control sort of going on? Or is it perhaps a commercial reason in the distribution business itself?

ROSS WEENINK: Ross Weenink for ENA. I think it's just the - well, most distribution companies do pass on the charges to retailers and it's the retail customers. If the retailers then pass those, pass any reductions that result from load control on to their customers, then the incentive is obviously dependent on the volume of the reduction. If you're dealing with direct connects, then obviously they see the incentive directly.

ALAN EYES: Alan Eyes and a non-New Zealand Steel observation. Am I allowed to make one of those?

CHAIR: Absolutely, Alan.

ALAN EYES: With the - If the RCPD is going to be halved, in effect, for the distributors, I would have thought there's still a strong incentive there in terms of managing investment and control within their own networks because, generally speaking, I would expect that peak demands on the local distribution networks will be at the same time as the regional peaks, with a few exceptions.

BRUCE ROGERS: Bruce Rogers from Orion. Yes, that's true, and I guess it's important to note that we're talking about more than a halving here. The residual is what's left after you do the SPD benefits calculation, and if it just so happens that the transmission system actually happens to provide significant benefits to New Zealand, which I hope it does, you could be talking about a very small amount because I think you're taking out loss and constraint excess as well. So, who knows what the number will end up being, and it sort of reinforces Therese's point four, in a sense we're going to find out after the event how much this is going to be whereas at the moment we know in advance what the dollars per kilowatt is and that's what we translate into pricing. I would point out, and this has been made in probably about 3,000 Orion submissions, that we at least tried to do load management in the interests of consumers and there is no commercial benefit to us from what we do, either on our own network on in the upper South Island. We do it because we believe that investing against that price is something that we effectively in our systems and consumers can do, particularly larger customers, and effectively 50,000 residential customers in Christchurch have a hot water cylinder that we can control and we think that benefits everybody, but it doesn't benefit Orion's business, in fact it makes our business smaller.

CHAIR: So, if that's the case can the Authority assume that there are incentives for load control that come from RCPD upon - that come from RCPD rather than their philosophy of life as a result of that charging to actually load control, or is it entirely dependent on their philosophy of life?

BRUCE ROGERS: Bruce Rogers, Orion. Again, I'm not sure I get that philosophy of life bit but the point is that at the moment it's nearly $100 a kilowatt, which is the pricing that we see and that we build into our pricing that people respond to. It could be - we don't know what it will be in this new method but let's suppose it's $25. To the extent that the number built into the price that people respond to is a lower number, I think you'll get less response. Now, that might be more efficient, I don't know, but if people think that what happens at the moment is a good thing for consumers, there is going to be less of it.

CHAIR: But do I understand you correct, that it's actually - load control is not in Orion's business interests, it just happens to be something that they think they should do for their customers?

BRUCE ROGERS: Yes.

CHAIR: And does that apply in your view to other distributors?

BRUCE ROGERS: I mean I should point out that we do all that in conjunction with the other South Island distributors and we have a joint arrangement where we try and manage the RCPD. So, everyone is involved in that using similar resources and capability. We just happen to host the system that manages all of it.

CHAIR: So, I think the corollary of that is that the RCPD doesn't provide the incentive for your behaviour, it's your own view about what's good for customers?

BRUCE ROGERS: That's certainly part of it but I would point out that we have a significant number of major customers who invest in a lot of diesel generation against a price that we set. That price is around about $160 per kilowatt per year. If the RCPD goes away, that price will fall to $100 per kilowatt per year and I think that could make a difference to either the investments they have already made or the investments they might make in the future, because that's quite a big change. It may flow through the other parts of the market, that is a possibility, but what it won't do is flow from us. And we've been able to set that price consistently over a long period so people can invest against it. Whether something is volatile what we might end up with is as consistent a signal that people can build on is maybe still up in the air.

CHAIR: Thanks. Are there any other parties that want to make - let's move on to the next question. Unfortunately I now have a string for people who are not present so you're going to have the boring experience of me reading them out.

The first question is for Nova who I'm pretty sure is not here.

In response to the Authority's residual proposal Nova noted, "we have serious concerns over the value impact of a RCPI charge and its effect on wholesale electricity prices".

The question is why would Nova expect the RCPI charge to have an effect on wholesale electricity prices? If the RCPI charge were in practice a megawatt hour charge because there were no regions in which it would be efficient to signal avoidance of peaks by generators, would you have the same concerns?

Nova also suggested in its submission at page 3 that SPD charges should be capped at 25% of total HVDC and IC charges on the basis of their observation that reliability assets should be met by residual charges. This would ensure that most of these charges would fall in the residual. Then for possible solutions to the residual problem, Nova suggested at page 3 of its submission, the remaining 25% should be allocated via another charge:

RCPI charges to South Island generators; generator connection charges; and, a postage stamp demand charge based on dollars per megawatt hour.

Did you really mean 75% should be allocated to the residual, ie 25% plus 25% which equals only 50%?

What proportion of the charges do you suggest should be attributed to each of the RCPI charges on South Island generators, generator connection charges and a postage stamp demand charge based on megawatt hours- dollars per megawatt hour?

Is the RCPI charge intended for HVDC only?

Why would an RCPI charge be workable for South Island generators and not North Island generators?

The next question I have is for all the distributors. We've got three, Powerco - I presume you're 28 as well, are you?

ROSS WEENINK: Yes.

CHAIR: So, I was quite wrong before, 28 turned up and embodied in yourself.

ROSS WEENINK: That's right.

CHAIR: And Orion and Vector. To what extent do you consider including generators in residual would disincentivise you to engage in load control? This is a continuation of the same question I've been following up with.

So, we've heard from Orion, that it's not so much the residual as it's the effects it will have on direct connect customers and upon their ability to price to them. Vector, do you have a view?

ROBERT ALLEN: Rob Allen, Vector. That's not a matter that was covered in our submission. If you would like us to come back to you, we would be happy to.

CHAIR: That would be acceptable, thank you. Ross?

ROSS WEENINK: Ross Weenink for Powerco. For the reasons that we've just discussed, just the volume of the residual, the amount to be allocated, the incentive would be bound to be lower. I think in practice Powerco does see some commercial advantage to itself from load control, from controlling hot water to enable the RCPD periods to be reduced because there are some areas around our network that need reinforcement and if we can avoid or defer the need for that, then there's some commercial advantage to us.

That incentive is still there, of course, even if the residual was lower. So, what we focused on in our submission was whether the RCPI approach was an appropriate way of - of recovering the residual. I presume that's a question you're going to come on to in a minute.

CHAIR: At some point, yes. I've got another question for the distributors and then I'll open it up to others. That is the RCPD charge is based on regional coincident peaks, obviously; 12 in two regions and 100 peaks at another two regions, and the general intention of it is to try and discourage people from using electricity distribution and line charges - transmission charges, at the time that one has peak demand. But it's a bit like a charge analogy that somebody has suggested to me. It's a bit like charging people who get on a bus depending on whether the bus is actually at peak use of the bus as opposed to whether there is not much spare capacity in the bus, that is that you will end up with a charge based on peak demand but it may well be that you are maybe nowhere near capacity and if you'd spent

$5 billion on transmission charges you may be a long way from - on transmission investments, you may be a long way from peak even though - a long way from capacity, even though inevitably you will always have a peak.

So, how good a signalling method of avoiding actually capacity shortages, and the requirement and the need to invest in extra capacity, do you think the RCPD charge is compared with other possibilities, and have you thought about other possibilities for those charges?

So, Bruce, do you want to start or shall I start with Ross? Do you understand the question? I'm exploring issues that have arisen as we've analysed all of your submissions. I'm not asking you to introduce new material.

BRUCE ROGERS: Okay, Bruce Rogers again. I'm rather tempted to take the 5th on this but since I guess you're introducing new material, so can I introduce some new answers. But I think the key point is that, as everyone probably admits, no pricing arrangement is perfect and we haven't thought a great deal about alternatives to RCPD. I guess we think that we sort of do the right thing and the regulatory regimes come and go, pricing comes and goes but you can still keep doing the right thing and maybe the regulatory regime will align with the right thing at some point, perhaps even by chance.

But I'm not going to answer the alternatives one but I guess the RCPD for us, we do see it as a long-run marginal cost signal and absolutely it isn't perfect, and it isn't the way the numbers are worked out, the numbers are worked out by dividing Transpower's revenue requirement for that bit by the number of megawatts, that's the way it's worked out, but it's sort of in the ballpark and that doesn't seem too bad for us. But what we're trying to do is we understand that the key driver for future investment in the upper South Island will be demands until at some point Transpower goes, hang on a minute, we need some more capacity, and so us managing demand every year to try and keep it as low as possible while maintaining service levels to consumers, which is an important constraint, is a good proxy for managing that. It doesn't mean that in any year, and in fact I think in the last two years we've actually managed to reduce the upper South Island demand. The capacity on the network hasn't changed, I agree with that completely. The capacity is probably 200 megawatts north of the amount that we actually use at peak. That's just a feature of the model, we get to game effectively other parties. If other parties in New Zealand do not respond to RCPD and we do, we gain and that goes through to consumers, that's a good thing for those consumers. Yes, there's problems with it but if you take the longer-term view I think it works reasonably well and it there is a risk that will be lost under the proposal that the EA has put forward.

CHAIR: Can ask a couple of follow-ups because I think this is a very important issue that's been sort of - it's arisen in my mind through reading all of your submissions and cross-submissions, so it's arisen out of the submission process. The point you've said is, yes, it's gamed. We know that Transpower, what's got to be paid to Transpower in total under the current regulatory regime is sort of fixed. Transpower gets its WACC whether it deserves it or not, but it gets its WACC. And so the RCPD can at most reallocate money between different groups, and it reallocates it from those - so it doesn't actually relate to a capacity relationship, it relates to, in fact, transferring it around and the parties who in the end, because this has all got pass-through, that there is one lot of end consumers or another lot of end consumers, and that depends then upon how good the people who are doing the prediction in their region are, and how proactive and motivated by non-RCPD issues, largely; talking about ordinary domestic consumers, are - are shifting that cost from one to another. But there's no efficiency gain here, it's just shifting.

ROSS WEENINK: Ross Weenink for Powerco and ENA. I don't think that's quite right, Brent. I think that there is an efficiency gain. It's a little bit like the prisoner's dilemma gain where it would be better for the prisoners themselves to cooperate but the optimal, the nature of the gain is always for them to default. So, because of the way RCPD works, everyone's really incentivised to control, because if you don't you'll end up being hit with an extra WACC of transmission charge, and so unless you cooperate and you've agreed beforehand to cooperate and not control, which the Commerce Commission might have something to say about, I think there is an incentive to control there. And I think in the upper South Island, in particular, you can see that there has been, that that control has been applied very well, and the other load control initiatives that have been applied there have actually deferred the need for transmission investment.

But when the RCPD method was originally developed, it was envisaged that when major new investments went in, in the upper regions, that the N=12 mark might be reviewed, because N=12 is supposed to be designed to provide a substantial incentive to shave peaks and defer investment, and because if significant investment's gone in then you've got a big overhang of capacity, there's not the same argument to continue with that, and I think that's one of the things that was thought to be possibly a material change in circumstances, but only in relation to that element.

CHAIR: So, we have had all this big investment which should have altered capacity and hence should have altered, if this was a signal that was good beforehand should mean it's a signal that's no longer efficient. But if we are controlling load even up in the upper North Island 200 megawatts shy of the maximum capacity, in general that's what

I understood you to say, the question the Authority then has is this an efficient arrangement? Is this RCPD providing an efficient signal?

BRUCE ROGERS: Bruce Rogers again. I guess again it goes back to the short-term versus long-term thing. So in a particular year, yes, there's a whole bunch of gaming going on, nobody can argue with that. We are to some extent taking money from rich North Islanders and giving it to the poor people of the South, but it doesn't always work out quite that way. But long-term, Transpower does drive its investment planning off actual observed demands. It has quite a big buffer in there as well for its planning because it wants a buffer, you know, to deal with unexpected events, but what we want to be able to do when Transpower comes a calling saying, look, we think you need to upgrade the upper South Island link is say well here's some points on a graph and what we can show you is, you know, demand is consistently around here for the maximum demands measured for an RCPD, or whatever method, and that we know that they are being managed as well as they can against a proxy for long-run marginal cost of new transmission investment. So that when the transmission investment is needed, it is the right thing to do.

CHAIR: Although we have heard Transpower say they don't want the number of things to be changed. We heard that, I believe, earlier. I'll give you a chance to respond and Molly is bursting here, her arm is to respond. After you.

MOLLY MELHUISH: Thank you, Brent. DEUN has consistently since the framework exercise over a year ago, asked if we could have a what we think is a more efficient way of dealing with peaks, which is a critical peak pricing. And I would like you to ask whether this isn't a sort of alternative charging mechanism.

Now, you would have to incentivise retailers to offer a critical peak pricing. They don't seem to want to and, indeed, they don't seem to want consumers to be, small consumers to be price responsive at all. And we've also asked for that to be an ex-ante signal.

Now, we've had a lot of discussion today about ex-ante versus ex post pricing and it's just that some of us domestic consumers would like to see ex-ante pricing which would forecast when the prices were big enough to make a real difference, and then maybe we wouldn't be having to pay for the sunk costs when demand is nowhere near where it really matters.

CHAIR: Thank you, Molly. And Jeremy do you have something you want to add? Ross?

ROSS PARRY: Thank you. Just a comment on Molly's point there. I think we are at a juncture where we're starting to see a lot of retailers talk about split tariffs coming in the course of the coming year. It's interesting to think about what an SPD-type volatile charge might do to that type of retail innovation if it were to come along.

To go back to the question that- that prompted my grabbing the microphone. You talked about our view on the reviewing the number of N, the N number for us. If you do, - We hadn't talked about that at this conference. We do mention that in our submission, about that question of reviewing the number of peaks that we measure in the upper North Island post the major investments, and I'll get to that in a second.

I think just on the discussion about RCPD I'm sort of drawn to John's comment over there about the Utopian fallacy and the point that you know we shouldn't let the perfect be the enemy of the good, and I think the RCPD charge is a good example of that.

I think another point is that when we're dealing with transmission pricing there's a whole lot of imperfect options and we need to be pretty clear that the version where, the bit that the grass appears greener really is a lot greener. In other words, that there’s I think there's a big hurdle to change. You need to be pretty clear that you're going to something better.

On the N, returning the number of peaks that we measure. I think the other thing to bear in mind when thinking about that is that load control can't switch on and off and that price signals are most effective when they sort of tune up and down over a period of time, rather than sort of disappear, or either come about really quickly or disappear really quickly.

We've put in our submission that perhaps a way to deal with this tension would be to explicitly have a mechanism in the pricing methodology that set out how – how and under what sort of criteria you would review the number of peaks, you know, around the change in circumstances, like post investment. So, I think it would be, in a sense, kind of a negative thing for us to do, to suddenly and without much warning change the number of peaks that we measure against to be much larger very quickly, as in to de-tune the signal post investment when a lot of people have you know made investments against that signal. But at the same time, there is a logic to de-tuning the signal gradually post investment, and I think a, sort of a mechanism for weighing that decision up that's reasonably predictable and structured would be the right way to do that rather than to, sort of, make a decision now that we think we should change the N to some other number.

I'd just talk about one other point as well that was mentioned earlier which is around - it sort of comes up here and is relevant to this as well, is the allocation of responsibilities between Transpower and the Electricity Authority about design choices such as RCPI and RCPD regions and numbers of peaks.

In the RCPI thing I think there's a particular you know difficulty that for me I would see that - I'm not very clear that the RCPI is a good idea and that there's a good basis for doing an RCPI charge, so it would be quite an invidious task to have to design the thing, from that point of view. But as a guiding principle I think the structure of the framework that we have for developing the transmission pricing methodology splits the responsibility between the Authority and ourselves. You've got to think about the rationale for that in the context of having a you know fully worked-up pricing methodology now in the sort of situation where we're at now, which is quite different from the last time the methodology was written. I think there's a case to say that the sort of contentious or difficult policy decisions best sit with the Authority through its processes, and that the operational decisions about making the thing work efficiently better sit with Transpower. And that might not be an absolute sort of distinction but I think that's a helpful thing to bear in mind when thinking about which parameters are decided in which forum. We certainly don't think that it's sensible to - to leave Transpower in charge of contentious policy decisions.

CHAIR: I'm sure you're well aware that Vector submitted at considerable length that the Authority had gone way beyond what it should have done and Transpower's was treading on Transpower's role in that regard. We'll have a quick response because we're in afternoon tea time.

ROBERT ALLEN: I'd clarify there that what Vector said was, what we suggested was that the EA had gone beyond what the Code envisaged the EA could do, going beyond the Code envisages that the EA would produce guidelines and Transpower would produce the methodology. That begs the question about whether the Code is appropriate, and Ross makes some good points that suggests that the Code may need to be looked at, but the point we were making was we considered that the EA was in risk of breaching its own Code, rather than commenting on whether the Code was desirable or not.

CHAIR: We'll break now but when we return, if anybody has any comments they want to make on this particular issue before we move on to the next question to a non-attender, is very welcome to raise it when we resume. We're going to have 15 minutes, so we'll come back at 22 minutes past 3.

(Conference adjourned from 3.04 p.m. until 3.25 p.m.)

CHAIR: Welcome back everybody to the afternoon session of day –day 2. When we broke for afternoon tea we were discussing the efficiency or otherwise of the current RCPD charge and I said I'd give other parties an opportunity if they had a pressing need to talk about this. I notice Peter has got himself armed with a microphone, that suggests something going - I thought Therese was going to do all the talking for the next two days since she's retiring. Peter?

PETER CALDERWOOD: Yeah, thank you very much. Peter Calderwood from TrustPower. Yeah, I'll start off and I think Therese will probably continue on if I don't cover the points that I wanted to make.

Look, again, I think I'd like to take this whole RCPD discussion up a level and just why some of the concerns that we would have about some - any radical changes to both the level, particularly the level but also maybe the number of periods that it's averaged over.

And, first of all, first of all I would like to go back to, Brent, your buses and I don't know actually how bus tickets in Wellington work but maybe - but if you catch a train or a bus in Sydney after 9 o'clock in the morning they are cheaper, and so that is actually some form of peak demand charging which they are applying for, you know, coincident peaks and of course, as we all know, if you catch a plane to Wellington at 7 o'clock in the morning it's a lot dearer than one at midday, and if you want to go back to Auckland at what 10.30 at night you can get one for $39, or something like that. So, this is not unusual to have congestion or peak-type charging to try and level out demand, but I think, I think the key thing is we need to go back, and some form of coincidental or peak-type charging has been in existence basically I think forever within the electricity industry in New Zealand, and you can probably go back to the 1950s where I understand that there was only a peak demand charge, there was no energy charge at all because it was all based on how much hydro generation had to be built. But even since I've been in the industry there has always been quite, a very strong transmission demand-based peak demand charge, and my thesis there is that's flown through to exactly the whole way that we have designed and operate the whole system.

Now, I don’t - this is not necessarily about saying we look in the past and we don't change things but I think, again, we need to be really really careful of step changes in something which drives a whole lot of the way both distributors but also right through to end use customers do react to that, and we have always had some form of demand charges flowing through to end use customers, be it lower prices for hot water control or - if I remember in the past where we've, we’ve had specific peak, off-peak type charges, in our days a distribution network targeted at cool stores to -to turn off at peak times, and they were all predicated on the basis of both - what had to happen within their own distribution network, but also the charges which were flowing through from Transpower and its predecessors, and on the basis that it's only logical that if you can flatten your demand you're going to get more efficient use of the transmission network.

Now, as I say, I'm not saying we don't change over time and, look, I don't know whether the signal is too great or too little but what I want to caution against is a too big a step change, and this would be the biggest step change in the level of - the relative level of peak demand charges imposed on the industry that I would have actually, would have seen in my whole , in my whole 30 plus years within the industry. So, I think it's actually, we need to be careful about unintended consequences

ELENA TROUT: So, could I just clarify there, Elena Trout to TrustPower. So, is your concern more about making a change or the significance of the change irrespective of whether what we've got is correct, well, is the most efficient way of pricing, or not?

PETER CALDERWOOD: Yes. I think the key thing is, yeah, it's it's that step level of change. If you came to the conclusion, yeah, and you can do all the modelling in the world and say, well look, maybe it's not efficient, but if you don't actually, if you do that sort of change and do it in one step you will get unintended consequences and we have seen it before with even some subtle changes to the way that sometimes moving from, where we've moved from AMD to RCPD, or coincidental or vice-versa, there was some period back I think in the 90s where there was a fixed two-part type charge for peak and off-peak. All of those things change significantly the shape of the load within distribution networks, and in most cases when those changes were done they were actually undone quite quickly because there were unintended consequences, and I don't think we actually - we probably don't understand the amount of demand response that's actually out there.

CHAIR: So, you're arguing that demand is actually quite elastic?

PETER CALDERWOOD: What I'm arguing is demand is not elastic in probably total energy, it is elastic on times of demand and a lot of demand can move from one time period to another and level. So, not from that energy point of view but from when that energy is used.

CHAIR: Thank you. Other - Ralph and then Rebecca.

RALPH MATTHES: Ralph Matthes from Major Electricity Users Group. Brent, you asked the question, is the current RCPD working? In MEUG's written submissions we kicked for touch and said we'd wait and see what the distributors and retailers had to say but just we're still in that position, just want to make a couple of observations from what's been said today.

The first one is about Orion's charges. As I understood Bruce, what he said is that the very largest users get charged $160 per kilowatt at peak, whereas the actual interconnection charge is more like 108. I think that just points to the fact that when the

RCPD charges are passed through by Orion, they're completely distorted in the favour of households contrary to the very largest. So, yeah, in that case I don't think it's working at all.

The other observation is that had Vector had a proper RCPD type pass-through, perhaps even had a good citizen approach like Orion, we may not have had NIGUP.

CHAIR: The next person is Rebecca and then we will allow both Orion first and then Vector to respond to the comments of Ralph and possibly Rebecca.

REBECCA OSBORNE: Rebecca Osborne from Pioneer Generation. I would just like to bring us back to the statutory objective which was a long-term benefit of customers, of consumers rather, and I think in order to achieve that you need to at all times be thinking from one end of the industry right to the other, so all the way from generation through to the- the place of consumption, and that doesn't just include the transmission, it includes the network charges, all of which are legislated to provide a return on investment, and that's a return on capital spend.

I think in my- relation to the RCPD charge here, is that it provides a strong signal to manage peak demand which doesn't just benefit Transpower, it also benefits the network companies and allows the network companies to avoid investing in extra assets, and that minimises charges, on-charges to consumers. So, if all of a sudden you provide less motivation to the network companies to manage peak demand, it allows them to justify additional investment in the networks which just ultimately ends up costing the consumers more. So, you know, it - you might not think it's an efficient way of charging for the transmission grid but you have to think all the way to the – to the point of use.

ROBERT ALLEN: I was just going to make the comment that I don't consider it appropriate to be making - using a TPM conference to make negative comments about a distributor's pricing and we reserve the right to respond at a future time but this isn't the appropriate forum for that.

BRUCE ROGERS: Bruce Rogers from Orion. I guess my response to Ralph is that first point is read the Orion pricing methodology which is available on the website because that's the only way you'll really get a good grasp of what we're up to. The prices I was talking about, was the overall price that a major customer sees, that's a combination of the distribution and the transmission components. And what I was saying was that if the transmission component was removed, the total price signal that the major customer may be investing against goes down by a great deal, you'll probably get less demand response from them. But we do not have a pass-through of a peak transmission component which is greater than the RCPD dollars per kilowatt that Transpower charges us. So, I'm sorry if I misled you in that respect.

CHAIR: I've got a question for Rebecca. You're very welcome to come to the front if you wish, or stay there. The RCPD charge on distributors at the moment, they have full pass-through for, so where does the incentive come from in that RCPD charge on them to either alter their grid , their distribution investment or to signal to you other arrangements?

Your requirement under which you operate at the moment is that you are paid for the avoided and avoidable transmission and distribution costs, and at the moment it is tied with the RCPD but it's not actually legally based on that, as you pointed out previously. So, you were arguing that there was an incentive here but I just can't see that there is an incentive because distributors have pass-through.

REBECCA OSBORNE: Well, I think distributors, like everybody else in the industry, are under constant pressure not to increase charges to consumers any more than they absolutely have to. One of the ways that the RCPD signal passes through to consumers can be through direct pass-through of transmission costs to consumers. So, we have customers who we manage their site import level to minimise their overall electricity cost by reducing their peak demand, and they get a return from that through direct, direct pass-through of transmission charges from their distributor. So, that's one example but there are numerous other ways it occurs. I mean, the ACOT thing is another and the value of the RCPD method to that is that it is relatively easy to predict how you should behave but it's also relatively easy to administer with your network company.

CHAIR: I can understand how if they pass through including the effects of the RCPD to a party such as yourself, that the RCPD provides you with incentives to behave. What I can't understand is your claim that it provides them with incentives about their investment because they, if you look at the regulated ones, they have full pass-through, they have their regulator, it doesn't alter their allowed return, they're guaranteed a return on their WACC and so they don't actually have any economic incentive at all to alter their investments from this mechanism, they may have others but not this mechanism, as far as I can see. But that's the question, what is that mechanism?

REBECCA OSBORNE: I guess you would have to ask the distributors that. I think the comment from Orion earlier was more or less in agreement with my argument, that it does provide them a signal to manage demand, and it also, perhaps the benefit might be that it is a simple way of encouraging - of structuring charging to consumers to help them act to manage peak demand, and I think somebody mentioned before that you're probably not aware of the level of demand response that goes on and I think that's certainly true. We – we submitted in our submission that we would like, we'd suggest that EA reruns the SPD with and without all the embedded generation in the model. I don't think that's a particularly easy thing for you to do because you don't actually know how much of it is out there and what - how well it's responding.

CHAIR: So, you haven't seen our publication this week of the volumes of distributed generation?

REBECCA OSBORNE: I have and I think an awful lot of that volume in terms of energy is related to new large distributed generation such as Tiaku and Mahinerangi.

We don't consider ourselves to be in the same bucket as that with all our generation being less than 10, 10- well less than 10 megawatts, I don't think we've really got anything that's even 5. It’s - We're connected within the network because that's where we are and it doesn't make any sense to connect to the grid. We're not connected there to avoid paying charges to Transpower.

CHAIR: I think we'll just have to disagree about what our data shows because -

REBECCA OSBORNE: I think you know the volume of connections, I think you've got some 450 new connections at less than 10 kilowatts and that is probably the likes of Photovoltaics on housing. I think that's a different argument all together.

CHAIR: Yes, we have our distributed generation - but that's a bit beside the point. My understanding from Bruce, and he'll correct me if I've got it wrong, I thought eventually it was not the RCPD that was motivating your sending on these signals but your public policy stance, is that correct?

BRUCE ROGERS: Well, I guess in a room which appears to be largely full of economists it's a bit dangerous to say people might do the right things for other than commercial benefit. I mean, it's actually relatively low cost for us to do it.

CHAIR: Are there any other – oh we had Ray and then -

RAY DEACON: No, I'll pass now.

PROFESSOR LEW EVANS: I would just like to make the comment, Lew Evans speaking, that congestion charges of the sort of RCPD are very efficient in many settings, including road congestion and various other places. They induce behaviours that internalise externalities, and I could go back to the bus case that Brent has prompted this discussion, and I think it is a good discussion to have because of all the elements on the table with respect to TPM. But when you think about the bus getting fuller and fuller over time and the charges, and then putting in congestion charges as people enter the bus so you end up with people with their legs sticking out the windows and just jam-packed as you would - might do in Japan on a train, and then you think, well, I'll just add a little bit and if I add a little bit to the charge the loss and constraint rentals that go with that bus plus a little bit gets me to buy another bus and expand capacity. And So, that's , that's the kind of thing that the congestion charges use, and we can think of actually the -the increasing price at any node is actually a congestion charge of a form , of a form that has to do with pricing the network.

And getting back to the issue about the good citizens here who are managing the network, and independently of their, of their ownership. I wonder whether if I had a cooperative I would like my lines company to actually have a proper trade-off between investing in local oil generation or whatever, versus taking the power from the grid. And so I would say that that would be, you know, the owners I imagine of cooperative companies would appreciate these actions being taken

BEN GERRITSEN: Thanks, Ben Gerritsen from Castalia. I think the other thing to bear in mind is how the regulatory regime for setting prices for distributors works. Brent, you've described it as a straight pass-through, distributors get their WACC.

I think in reality the incentive-based regulatory regime that we now have in New Zealand sets a forward-looking price path for distributors and they have very strong incentives to manage their costs below that price path. So, in this situation, whilst I accept that transmission costs are a pass-through item within that regulatory regime, the commercial imperative for distributors is to manage their actual capital spend below their allowance, their capital allowance, and obviously that capital spend is dictated by network peaks. So, it's not surprising that you see distributors acting in a way to manage their network peak, which happens to be RCPD, which then has a flow-on effect for the amount of transmission costs that are allocated to that network. They may not be doing that for the benefit of, of lower transmission prices but they're doing it for the benefit of actually increasing their returns above WACC. If they can do that efficiently, the Commerce Commission is happy for them to keep that- that efficiency saving.

CHAIR: So, you don't see that coincident peak is - is a poor, a potentially poor measure of actual capacity constraint? Because you're always going to have a peak, even if you've only got three people ever getting on the bus, three would be the peak -

BEN GERRITSEN: I take your point, yeah I think that's a fair point. There, I think, you know, it is very much a situation where you don't have a perfect measure of - of peak. This is the one we currently have. I think there would be an onus to show that you would be moving to something better with any change. Yeah, but I guess I just wanted to explain that –that I wouldn't see distributors seeing peak demands on their network as being just purely a pass-through because of that correlation between investment needs at the network level where they have an opportunity to increase their returns, and RCPD charges. That - Again, that correlation probably isn't perfect but they both, both mechanisms provide incentives to manage network peaks.

CHAIR: But after you've spent the thick end of $5 billion on transmission upgrades, surely you would think there would be some extra capacity and that the margin between the coincident peaks and the actual scarcity of capacity would have changed and that you should rationally be changing the N if you - or looking for some other measure of being squeezed on capacity?

BEN GERRITSEN: I don't disagree with that, I think that's a fair point, yep.

CHAIR: Alan Eyes?

ALAN EYES: Really a non-New Zealand Steel comment again. I think what's got to be borne in mind, that there's no direct connection between how the distributor sees their charges and how it ends up to most of the end customers because it's a repackaged situation. So, I mean there unless you happen to be a consumer of the – of the lines company or you've got a separate contract with your local lines company, for the vast majority of consumers they're getting a repackaged deal at the time it passes through the retailers. So, whatever signal might be coming down from transmission charges to the lines company, and however the lines company may calculate their own demand component versus energy component, there's no guarantee that that same signal ends up in my bill as a domestic customer because it's been repackaged.

SUSAN PATERSON: Alan, can I just ask you with regards to that, is that an issue that we need to look at as to what are those price signals that the consumer's actually seeing on transmission, and, and maybe distribution although we're not discussing that here, as far as what actually appears on a consumer's bill?

ALAN EYES: I can only answer that in a personal capacity, not a New Zealand Steel capacity. Perhaps I'll answer it by making the point, I asked the facetious comment at the downstream conference in March, is the retailer an unnecessary middle man for the future? And it's much wider than just, it’s much wider than just demand, although that is part of it. And particularly now as we move into time of use metering it becomes much more practical for the end consumer, for me as a domestic consumer if I want to, to look at true pricing signals right from the wholesale market and also what those pricing signals may be in a demand component.

CHAIR: Ray, were you..? Do any of my colleagues have a question?

GUY WAIPARA: Just a real quick one, Brent. We're all used to peak demand charges and I think by and large they've worked pretty well. It is a bit risky generalising, saying $5 billion spent might mean we can change because it's been spent in specific places, so it might change parts of the network but there's still a lot of parts of the network where a congestion-based charge may make a lot of sense. If there's only 200 megawatts, for example, head room in the South Island and a transmission planner's outlook on life, that's not actually that much, and then we could get quite complacent about say supply into Auckland. But all you would need to happen is for a few things to happen such as the retirement of a couple of thermal plant and then you will find yourself back into where you were close to being quite a few years ago.

So, I just thinking you need to be pretty careful around how you think about the efficacy of a peak demand charge and whether or not that should change.

CHAIR: Just to clarify, my questioning hasn't been about having a peak demand charge, it's about whether the current charge, that is actually a peak demand charge, that's the best option we could have. That's the - what I've been asking to try and tease out people's views about. Are there any other questions? Bruce has a question about transmission alternatives.

BRUCE SMITH: Oh yes I have a question. Sorry Bruce Smith, Electricity Authority. I have a question for Orion. So, if you imagine that the RCPD charge was quite significantly reduced, then you would send- be sending through to your customers a lower charge, therefore there would be less response so your -you could imagine that your peak demand would be growing at a faster rate and that may lead to Transpower proposing to the Commerce Commission earlier than it would have, you know, their next significant investment, so it might be a new line into Christchurch.

In that scenario could you not at that point propose to the Commerce Commission or to Transpower a transmission alternative, a demand response alternative, using the same mechanisms as we've been talking about, but in this case the charges that you could signal through to your customers would be very accurate because they would be related to Transpower's option and the date at which it was going to go in, so therefore you would be able to accurately signal to your customers deferment value.

So, my question really is, can you imagine yourself doing that, can you do that and could you make up any lost ground?

BRUCE ROGERS: Bruce Rogers from Orion. I suppose I can imagine myself doing it. One of the things we've learned over the years, though, is that customer demand response is something you build up and it can be easily lost. So, if you go out with six months' notice to say can you give us that 20 megawatts back, you might struggle to actually get it.

I would also point out that network peak demands and transmission peak demands are fairly well-aligned. Getting back to the 12 half hours things in the upper South Island, we manage load for probably generally around about a hundred hours a year and don't get perfect coincidence with the 12 peak half hours. So, that's an untractable number, so but the two are reasonably well aligned. So, we will be managing load in any case on our network for our own reasons and it just happens to feed through to the transmission. We just have the transmission in there because of the upper South Island coordinated development that we try to do. But I think the key point there is that if you give it away, you might struggle to get it back. I don't think consumers invest in that way.

BRUCE SMITH: But with a new line you might have 7 or 8 years to try and make up lost ground. Do you not think you might be able to pick up most of any demand response that you'd lost over a period of several years?

BRUCE ROGERS: As I say, I don't think it would make - if we weren't responding at all or trying to respond on consumers' behalf to the RCPD, I'm not sure we would actually change our network load management that much, and you can't manage load for network peak purposes without affecting transmission demands.

BRUCE SMITH: I'm a bit confused now. You seem to be saying that there isn't, there wouldn't be much loss. I mean, if you just reduce your signal from a 160 down to 60 -

BRUCE ROGERS: What I'm trying to say is if – if major customers, who are probably one of the key people here, the sort of people who put in generation on site, often they have it for back-up reasons and they just happen to run it in response to our price signals, but they make those investments and the point is that they get used to doing this sort of thing and they do it every year, and if you take the signal away one year and so we say next year, look, transmission pricing has changed, and of course under this proposal if the opt-out remained I think the Orion and most distributors would opt out because it just looks too bizarre or just too uncertain for us, particularly from regulatory perspective, but we have found if people stop doing stuff it can take a while to get them back into the, back into the play.

BRUCE SMITH: And yet there has been a successful upper South Island demand response trial by Transpower, there's another one in Auckland, isn't there? So, they've done the 400 kV, now they're doing the demand response. So, it seems to me, why not do it in the reverse order in Christchurch?

BRUCE ROGERS: Well, I think the Transpower demand response trial is a slightly different topic and I think you'd find that Orion's perspective on the success of the demand response trial in the upper South Island was slightly different to I think yours. I believe what they – what they discovered was the existing demand response.

CHAIR: Well, thank you very much everybody. I don't think there are any other matters on that. I have a question now for Pan Pac who are not here so to get it on the record I will read the question out.

Pan Pac supported Norske Skog in its position that the residual charge should not be allocated to generators because under the RCPD charge they are able to respond to peaks.

How will a residual charge to generators affect the ability of Pan Pac to respond to peaks under the RCPD charge, is the first question.

Second question to them is, would you support a residual charge to generators if the charge was designed so as to limit their ability to pass through the charge into wholesale prices?

The next question is for NZX who are also not present. They submitted in their submission on page 9 that the RCPD:RCPI split could be determined by the previous year's SPD charge.

The question for them is, why would that approach be efficient given that the residual charges are not intended to be beneficiaries-pay charges like the SPD? Wouldn't this approach increase incentives on parties to take action to avoid the SPD charge creating inefficiencies?

The next question is for Vector. You suggested on page 44 of your submission that the RCPI charges will be more difficult for generators to pass through than megawatt hour charges. Why do you think this to be the case?

ROBERT ALLEN: If you are charged a megawatt hour charge for transmission, that becomes part of your marginal cost and will be reflected in the higher, higher bid price is our assumption.

CHAIR: You think it's just easier to variablise, in short?

ROBERT ALLEN: Yeah, exactly. You're converting a fixed and/or sunk, depending on your view, transmission cost into a variable charge, and a variable charge will be easier, more avoidable than current charges.

CHAIR: Thank you. Anybody else want to ask questions of Vector? I think that might be your last one for the day too, we might have to dream up a new one.

Oh, sorry, Alistair. What a surprise. You're a bit slow, Alistair. You're going to have to speed up over there.

ROBERT ALLEN: I might suggest we introduce an arrangement of questioner pays.

CHAIR: Oh, but we have a new transmission pricing methodology which is called proportionate to submission length, and our variant on that is proportionate to fees paid to consultants.

ALISTAIR DIXON: Just to follow-up on that. So, are you suggesting - this is for Vector, are you suggesting that the RCPI charge should be preferred because it's more efficient, or in fact are you suggesting it should be preferred? I mean that's the first question, and then I guess why?

ROBERT ALLEN: Preferred to what?

ALISTAIR DIXON: Preferred to, say, a megawatt hour charge.

ROBERT ALLEN: Yes, we are, we don't support variabilisation of transmission costs.

ALISTAIR DIXON: So, what's the reason? I mean, okay, so you don't support variabilisation, so why?

ROBERT ALLEN: That would present an allocative led inefficient pricing signal to avoid a fixed and/or sunk transmission cost.

CHAIR: Any follow-ups? Next question is for Meridian and in your submission you, and I quote, argued that "any efficiency loss associated with the RCPI component of the proposed charge, disincentivising the peaking generation sector of the market, should be minimal with good design, while the avoided costs of additional peaking generation and transmission lines are much greater, potentially several $100 million. Yet, in your cross-submission you recommend on page 4 changing the RCPI charge to a megawatt hour charge.

Are these two submissions in conflict, and if so are they able to be reconciled in some way? If not, how are they reconciled?

GUY WAIPARA: Guy Waipara from Meridian. I'm pretty sure we've said the same in both, which is we believe that the generation part of the residual charge should be on a megawatt per hour basis, and we've already had experience with what a peak megawatt injection charge does under the current regime of HAMI and we do think that you'd have real design challenges with getting that right.

So, for example, not all zones across New Zealand are always importing, sometimes they're importing, sometimes they're exporting. So, what do you do when you want generation somewhere like Manapouri when Southland is dry or then suddenly decide that you want to export it?

So, we think you can get something quite wrong with an RCPI and think variablising it is probably the right sort of tax when you're at the bottom end of your framework.

CHAIR: Thanks Guy. Next bit of my question is that you actually recommend that the RCPI be 25% of the total residual charge and not 50% of the residual charge, and you do this on the basis of some rough calculations around what you think SPD is going to allocate between load and generators. But given that the charge, the residual charge isn't intended to be a beneficiaries-pay charge, do you have some other rationale as to why those proportions should be 25% generators instead of 50% to generators?

GUY WAIPARA: We actually think you should open your mind to the idea that the administrative charge could have a component with beneficiaries-pay to it, so we don't think that you should be closed off on that. We do think that demand benefits more from transmission than generation. If you look at the recent suite of new investments across the country, most, not all, have been made to supply demand to meet reliability standards. All you need to do is walk into a sub-station that supplies load and you'll see everything is duplicated. If you walk into a sub-station where a generator's connected, there's no duplication because the economics don't justify it. So there are a number of examples where you can see physically that demand values transmission more than generation.

Thirdly, we had a scan internationally and what - what seemed to be the centre of gravity around any kind of split between generation and demand roughly equated to 75/25 and that tended to also sit quite nicely with running your own model for the beneficiaries-pay methodology, which is SPD. So, to avoid being accused of being arbitrary, we thought well why not run your own model and see what the answers are and then use that as the starting point for an allocation between load and generation.

CHAIR: Do you think that the moving from 50% to 25% to generators will increase the incentives on them significantly to try and gain the SPD charge, because now their RCPD will be over time dependent upon their share of the SPD, or are you suggesting the 25% sit there forever?

GUY WAIPARA: I'm not convinced that a lot of gaming is going to go on with SPD. There's lots and lots of other trade-offs to be made when you're trying to decide what to do with the generation portfolio. So, it’s not- that's not a done deal for me in my mind.

If you look at what you're trying to achieve with your whole package, which is to achieve scrutiny, there's certainly enough skin in the game at a 25% level for companies like ourselves to sharp and scrutinise all aspects of transmission, whether it be new investment or revenue resets, or even what's your average weighted cost of capital, I think we'll be there.

GILLIAN BLYTHE: If I can perhaps also add that if you've shifted it to an ex-ante calculation and if it's over a year or over two or three years, we won't be focusing on what we're going to be paying in three years' time through a residual charge, we'll be focusing on what we need to do in the wholesale market.

CHAIR: Thank you. Anybody else got questions of Meridian on this issue? My colleagues? Alistair?

ALISTAIR DIXON: If I'm allowed. So, Alistair Dixon for the Electricity Authority. I just- So we just heard before from Vector that they don't favour a megawatt hour charge because they consider it's archaically inefficient so I just wondered, Guy, whether you had any response to that perspective?

GUY WAIPARA: Other than we disagree.

ALISTAIR DIXON: Well I just- I mean So, are you suggesting that basically a megawatt hour charge is more efficient than an RCPI charge, and I guess I would like to understand why that might be the case?

GUY WAIPARA: If you think we're at the bottom of your framework so we're into how do we get this tax sheeted home in a least distortionary way, I think setting up peak injection charges for generation is quite problematic in lots of locations in this country and you might find yourself in unintended consequences land, and I do think a megawatt hour charge seems a lot simpler and easier to handle. So, it's a combination of pragmatics plus avoiding situations like we currently do with HAMI.

CHAIR: Yes, Susan?

SUSAN PATERSON: Can I just ask, and I guess it's a general question. So, following on from what you've just said, Guy, does that mean, and do people agree that you could have a megawatt charge on the residual, you could have a megawatt charge on injection and an RCPD on the demand side, on the load side I mean? I mean is that, are there any reasons why that wouldn't work?

GUY WAIPARA: We don't think there's any reason why, the way it can't work at all, so I'm interested to see what others think.

PETER CALDERWOOD: Yeah Peter Calderwood from TrustPower. Yeah, there's absolutely no reason why that wouldn't work. We have other reasons why the megawatt hour charge is - that follows on why it it shouldn't be charged on generators, but that's probably a different question.

CHAIR: Ray?

RAY DEACON: Ray Deacon, Pacific Aluminium. Yeah, I agree, I think that would work really really well for the generators because they would be able to run those costs straight through into their offers and there would be 100% pass through to consumers, so it would defeat the purpose of allocating costs to the generators.

ROSS WEENINK: I mean -, sorry okay. Ross Weenink for Powerco. Our view is that there's not really much point in having an RCPI charge because I think all the generators would know that they're at risk of being caught by an RCPI period over the winter months and they would adjust their offers accordingly, and in fact they might add a little bit extra just to account for the risk. So, it will end up being a megawatt hour, per megawatt hour charge borne by all load anyway. So, you might as well just go straight to the per megawatt hour, if that's the way you want to go, in order to have a tax that's broadly spread.

GUY WAIPARA: Just on the point about pass-through. I mean, the starting point in my view is that if transmission investment has been efficient, then ultimately consumers need to pay for that, because that's all part of showing the true marginal cost of what it costs to supply each, each unit out of electricity between A and B. So, you've got two choices; one is a megawatt hour choice and one is a megawatt choice, and if everybody sees megawatts then somehow all parties are going to want to convert that into a variable charge, and there will be overs and unders around that and it's quite possible that that charge will be in excess of what's been allocated to you because you put a risk margin on whether or not you'll get that back. So, that's not obvious to me that it's inferior.

CHAIR: Carl - or Contact and then we'll have Carl.

BOYD BRINSDON: Boyd Brinsdon, Contact Energy. I think it's probably appropriate to say that I think there is observation that something that resembles an RCPI charge now is a HAMI and Contact's view would be that it does distort incentives and we can show that on the Clutha and it has done for the last five to ten years.

I think it's equally fair to say that I'd like the Commission to ask how they believe a station like Whirinaki would be offered and how it would be considered under an RCPI. I think it's likely that Contact would actually not be able to offer Whirinaki because the price that they would need to recover for something like a 0.5% utilisation factors would run into tens of thousands of dollars.

It is equally very difficult to comment on the RCPI because it hasn't been designed and I think that's the fundamental flaw here. We're talking about a method of allocating charges that hasn't been designed yet. But I - I'm a very practical person, think in practical terms, and maybe that's the thing for the Electricity Authority to consider, plants like Whirinaki, plants like Stratford Peak, they won't be there and they very much do contribute to meeting demand and meeting security of supply. And we've given thought under the proposal to how we'd offer Whirinaki, and with many people looking at it we haven't worked it out yet.

CHAIR: Carl?

CARL HANSEN: Thank you, yeah. A question really for Meridian. I guess if you think a megawatt hour charge for generation is pragmatically efficient, then would you hold the same view for load, that is, would it be better to have a megawatt hour charge for load rather than peak demand?

GUY WAIPARA: I still believe that peak congestion is what - is how demand should be charged and in the long run what you're trying to avoid is, or defer is new transmission build, and there's value in that, in that the way you signal that is to signal the cost of use at peak, which is what generally derives new transmission apart from, you know, interconnection stuff like the DC. So, I think it's actually okay to have a demand charge which is different than for generation.

PETER CALDERWOOD: Yeah Peter Calderwood from TrustPower. Just to make a comment on that, on the per megawatt hour charge. I think the other thing that will happen if you end up with a per megawatt hour charge is the RCPI is naturally it will flow through into offer prices and the consequence of that will be that for one of the river hydro and intermittent wind, and other uncontrollable generation, you will end up with spill, because that will be a marginal cost of operation.

I think megawatt hour charge is the only way you can have an RCPI because otherwise you'll get the other disincentives, but you are then, you will have additional run of the river hydro and wind spill, and other intermittent generation, probably including perhaps solar as well.

CHAIR: Can I just comment that both your response and Contact's response have assumed an inefficiency in the design of the RCPI, and our proposition was that we would only introduce one if it was efficient to do so. So, to assume that it was going to be what we said it wouldn't be, it may be that it is an inefficient regime but then that's the default. So there's been quite a lot of submissions that have assumed, they've forgotten the little tag that we always inserted in, it was inserted this morning, about the efficiency of it. So, you're just really arguing that it's very difficult to get an efficient RCPI charge I suspect?

PETER CALDERWOOD: Yeah Absolutely and yeah we can't understand how you could have an efficient, an efficient one, so we're interested to see what you come up with.

CHAIR: Well we will rely on Transpower to do that under our guidelines, they're the smart boys around here. Next question, unless anybody else wants to carry on with that, is for NorthPower.

They submitted that the present time is the right time to change the hundred highest regional peaks in the upper North Island and I think they probably meant the 10 - the 12, but that's what I've got written down here.

And so the question to them was to provide more detailed information about why they should consider this would promote efficiency. Well, actually they argued that it's the time to change to a hundred, which is correct.

The next question is for the NZ Geothermal Association. I know they had a listed person down here but I don't know if they actually have anybody present. The question is, you submitted that integrated retailer/generators would be in a better position to pass on generator costs at the retailer end while a merchant generator of the type many Maori Trust investors will be will not have the same ability to pass on these costs.

Can you explain your position with more detail?

Does Mighty River Power, TrustPower, Contact, Genesis have a view on this? So, Mighty River Power are not here so TrustPower, Contact and Genesis. Ah, so Peter?

PETER CALDERWOOD: Could you actually just repeat the question because I fell asleep because it wasn't for me.

CHAIR: It was a bit of a trick, it didn't tell me it was for you either. So, it's basically saying that these people submitted that the integrated retail generators are better off in passing through generator costs at the retailer end where the merchant generators, like many of the Maori Trust investors are in geothermal and smaller plants, will not have that same ability to pass through costs. And what we asked, really, was them to explain fully their position. I think they're thinking about geothermals who are often in the circumstance of, who have contracted, and the question that is really to you is what's your view of this particular position?

PETER CALDERWOOD: Yeah Peter Calderwood, TrustPower. Look, I can't talk about specific contracts because they're confidential, but I think that you're probably hitting on the right area there. There will be existing contracts in place and, of course, any regulatory change will change those contract positions, yeah because fundamentally bidding into the market there should be no difference but - and I think that's another thing to be really careful about. As we do such a major change, there are a lot of long-standing contractual arrangements between parties with existing plant and, you- as much as you try and cater for future provisions, change in law and those sort of things, you never get it always right, and so, yep.

CHAIR: Peter, the parties I've talked to, and I certainly haven't talked to all of them, have tended when you ask them this question have ended up with contracts that go not much more than three years at the most. Is that your experience or are they significantly longer than that, without an ability to reset on the basis of, say, pricing at the GXP rather than pricing on some other basis which may be the current contract.

PETER CALDERWOOD: Yeah, contracts are of a varying length and probably that's commercially sensitive information I can't disclose.

CHAIR: Contact? Genesis?

JEREMY STEVENSON-WRIGHT: Jeremy Stevenson-Wright for Genesis Energy. We actually did raise the impact of volatility overall from a proposal on retail competition in our submission at paragraph 77, and just reading there, "the logic is if a market participant can secure both retail and generation, this is likely to weaken the total volatility of the overall charge, for example, increase in load allocation will be at least partially offset by decreases in the generation allocation".

So, that's the logic behind why a vertically integrated, or why this proposal would encourage retailers and generators to be vertically integrated where they can be. I suppose a further risk is they may try to be locational more regionally based as well.

CHAIR: Thank you. And Does Contact have a view?

BOYD BRINSDON: I'm sure Contact does have a view but unfortunately, again, I'm not the right person to share it so we'll give it in writing to the Board, thank you.

CHAIR: Thank you very much. Any follow-up questions from my colleagues? From staff other than Alistair? From Alistair?

All right, next question is for Mighty River Power who are not here. In their cross-submission on page 4 they wrote that, "The prevalent view expressed across a range of submitters was that the allocation of SPD and residual charges to generators and potentially retailers would lead to increased distortions to wholesale and retail market prices and added risk premium reflecting the volatility of charges".

If the SPD charge and residual charge were designed in a manner that minimised volatility, would you continue to hold the view that it is inappropriate to apply residual charges to generators? If so, why?

We now get on to the final topic for the day which is distributor opt-out and TrustPower has submitted on page 38 of its submission that the opt out clause could result in higher transaction costs and the potential for disputes in the opt out process?

JEREMY STEVENSON-WRIGHT: Excuse me, Mr Chair, it's Jeremy Stevenson-Wright for Genesis here. Just on that question around the, the question to MRP regarding retail, well, the effects of volatility on the retail market and the risk premium.

CHAIR: You want to make a comment?

JEREMY STEVENSON-WRIGHT: I was getting to that, yeah, I'm asking for permission to make a comment?

CHAIR: Yes.

JEREMY STEVENSON-WRIGHT: Thank you. I mean, Genesis Energy in our submission have - and cross-submission have emphasised our view that this proposal will increase retail prices and that is primarily due to the risk premium that retailers will place on managing this particular type of cost. In effect, we also see that effect probably occurring in the wholesale market as well as wholesale generators attempt to manage manage volatility by effectively trying to hedge themselves by putting in a higher price.

CHAIR: So you don't actually have an answer to the question, it's just a statement about volatility.

JEREMY STEVENSON-WRIGHT: It is a statement about volatility but insofar as, I suppose, if your question, you would like to know the detail about why we think retail prices will increase due to this risk?

CHAIR: No, we had a question about whether - because we understand your submission, it's their submission actually had some conclusions and other points which have led us to ask the question, so. But I've understood that you think it's going to add to costs.

JEREMY STEVENSON-WRIGHT: Okay.

CHAIR: And others have too, so --

JEREMY STEVENSON-WRIGHT: Thank you.

CHAIR: -- that's not the issue that we're questioning.

So, TrustPower, page 38, the opt out clause would result in higher transaction costs and potential for disputes in the opt out process. Could you provide more detail on how you see this happening, Peter?

PETER CALDERWOOD: Yeah Peter Calderwood from TrustPower. Yeah I mean In our submission we've highlighted a number of issues where additional costs that could come as a result of that. I think the key thing here is, again, it's very dependent on the final detail, and that's I think if you look at our 27.10, we say "TrustPower requests further information on these matters so it can understand how the Authority's proposal will impact its retail business".

But the sort of things that we've put in our submission there is in relation to the additional transaction costs and also some costs just generally in the industry around potential. So, I really can't answer your question in any more detail than we've got, until we know the detail of what is being proposed.

CHAIR: In relation to the opt out?

PETER CALDERWOOD: Yeah, in relation to the specific yeah - specific additional costs other than what is in our submission.

CHAIR: Which aspect of the opt out are you unclear about? Which aspect of our opt out proposal are you unclear about, or is it the RCPD you're not clear about or are there other charges?

PETER CALDERWOOD: I think we might be better to take that one back and respond in writing.

CHAIR: It was just a question about the opt out and how that might affect, and the opt out only applies to the RCPD component, not even the RCPI, so it's about that.

Sorry, I've got another one from my cross submission – from your cross-submission. You stated that, the "Authority's analysis of the effect of distributors opting out is incomplete and that this material - this is material to its overall evaluation".

Can you advise what further analysis you think needs to be undertaken?

PETER CALDERWOOD: Peter Calderwood from TrustPower. I think, again, we'll take that one on notice and respond in writing.

CHAIR: Thanks. The next question is for Mainpower, who are not here, and they submitted at page 2 of their submission that if a distributor opted out, the distributor "would not even be paying for any benefit at all", which would be "inconsistent with the principles of beneficiaries-pay that the EA proposed in the methodology".

As the opt out proposal was in regard to the RCPD charge which isn't a beneficiaries-pay regime, please explain why your concern is about beneficiaries-pay and why this is relevant; how do distributors benefit from transmission; what methodology would you suggest for calculating benefits to distributors; and, given distributors' regulated ability to pass on transmission charges, what would be the rationale for charging distributors on a beneficiaries-pay basis even if they do benefit from the grid?

The next question is for you, Ross, unless there's anybody who wants to -

SUSAN PATERSON: No, I was just interested if any of the other distributors wanted to answer that question?

BRUCE ROGERS: Bruce Rogers, Orion. I think Guy made a really good point before that maybe we need to think a bit more widely and maybe it's not quite as pure as people think in terms of the different components, maybe there is some benefit that can be in the residual. So, maybe Mainpower had wee bit more going for them than in the way you presented the question.

CHAIR: What about Vector? Powerco?

Next question is for Powerco and it is in your you appear to have been qualified in your support for the opt out clause on the basis that it would "mitigate residual charge volatility risk".

Would you still support the opt out clause if changes were made to the proposal to significantly reduce the volatility and uncertainty of residual charges?

ROSS WEENINK: Ross Weenink for Powerco. If the volatility were able to be reduced, then yes, that would make the proposal more attractive. I can't say for sure whether we'd support it or not, we'd need to see the detail. The main problem with what seems to be being proposed at the moment is that the residual would be quite variable because the the amount recovered via the SPD method would be variable and it's what's, it’s what’s left over -

CHAIR: And the LCE?

ROSS WEENINK: Yes that, that as well.

CHAIR: But that already exists now, doesn't it?

ROSS WEENINK: It does exist but it's dealt with separately. You probably know that under the default price path arrangements that we're subject to by the Commerce Commission, that the it's the uncertainty of the pass through and recoverable costs that represent the main risk of breach for distributors. And so if transmission charges, which are obviously the largest pass through, are going to become much more uncertain, then there the- the risk of breach would rise astronomically. And so we'd see that if that were the case, that we'd be virtually forced to - to opt out, there wouldn't actually be a question about - there wouldn't be an opting question at all, so. But – but if, as you say, the volatility could be removed in some way, then we need to look at it more closely.

CHAIR: That raises, you know, your reply in our interchange raises a question that I've been thinking about which isn't on the list of questions but I'll ask it at any rate, and that is, my understanding is that Transpower passes through to the current people paying transmission charges the loss and constraint excesses proportionate with their payments for those transmission charges with the HVDC separate from the charge on to the AC network, and that that can vary from year to year, vary significantly. The result of that is that your actual transmission costs, your actual transmission costs in the year ex post actually are highly variable because ex-ante you don't know what those loss and constraint excesses are that are going to fall into your pocket. Yet, we've heard lots of submissions about any volatility ex post in the charge is an extremely difficult thing.

ROSS WEENINK: Mmm.

CHAIR: That raises in my mind, which is always slightly suspicious, that the real concern about volatility is not so much about volatility, which you could probably manage because there aren't hedge loss and constraint excess losses either in an existing market, but is actually about the ability to set charges in a way that you could be sure that pass through is fairly complete. Is that an unfair proposition?

ROSS WEENINK: Yes Ross Weenink from Powerco. Yes, I think it is because the at the moment the loss and constraint rentals are not treated as transmission charges. The transmission charges are - are fixed ahead of time and then the rentals are - are treated separately.

CHAIR: But there's an offset.

ROSS WEENINK: There's not exactly actually because the methodology used to rebate the loss and constraint excess doesn't exactly mirror the transmission pricing methodology because it's done by the flow of energy over particular arcs on the grid, and the TPM doesn't use that method.

CHAIR: But it still is an offset to -

ROSS WEENINK: It is an offset, yes.

CHAIR: But not one that we've had in submission, that this is a basic problem with the current methodology, the volatility of your net costs that you currently face, and I'm surprised because we've had huge numbers of submissions about the potential volatility it might be creating, not one submission about the existing volatility. So, isn't this a bit odd?

ROSS WEENINK: No, because, as I say, the - as far as the Commerce Commission is concerned the rentals aren't transmission charges, so they're not, they’re not treated as part of the DPP regime. So, it's that that causes the problem for us. If you were to - another way of dealing with the volatility would be to get the the Commission to look at how the DPP is set.

CHAIR: But does that not illustrate my point, that the actual issue is your ability to pass through --

ROSS WEENINK: Mmm.

CHAIR: -- not the fact that it's volatile, because under the current regime, of course, they're considered to be outside of the regulated returns; correct?

ROSS WEENINK: Yes, but we need -

CHAIR: So there isn't an issue about breaching. So, that you can actually pocket them if they are large and pocket them if they are larger. It causes variability in your net transmission costs effectively, because these are related to the costs of transmission, but people are not up in arms about this because essentially it doesn't interfere with their ability to pass through charges where in fact the current, what we're proposing they perceive may do so; is that correct or have I got it all wrong?

ROSS WEENINK: No we, we need to forecast what the pass trough's and recoverables are and if we run over we still, we can potentially breach. At the moment transmission charges don't represent a risk. The main risk is that the - the Authority's and the Commerce Commission's levies might change and that's actually a risk for us. That's the reason that we actually don't set the charges to exactly match the notional allowable revenue. There's about a 0.1% difference.

CHAIR: What about other distributors and then more generally generators?

PETER CALDERWOOD: I can make a comment from a generator/retailer. Peter Calderwood from TrustPower. I think we've got a couple of things with LCE to understand, is first a lot of distributors do pass their LCE back through to retailers, and so the retailers are taking that volatility on. But I think the important thing is, and it's a little bit like the comment I was making yesterday about hedging, LCE is inherently a natural hedge against high prices, because generally when you have a high LCE price you have high spot prices. So, from a financial instrument point of view, or from a risk point of view, you can deal with that, and in fact it's slightly positive.

CHAIR: Ah, but an SPD is designed that it will be only high when you get a higher price. So, what's the problem?

PETER CALDERWOOD: It's when - you're paying more when you pay a higher price.

CHAIR: You can still - the same cost.

PETER CALDERWOOD: It's totally, it's exactly the opposite.

CHAIR: But you're surely only going to be paying for the transmission when it's higher. If you're not making an extra benefit out of the transmission, you're not going to pay in the SPD charge; right?

THERESE THORN: Can - sorry, it's Therese Thorn here.

CHAIR: It's about the benefit you get, so you would be getting higher prices for your generation.

THERESE THORN: We're looking at this as a -

CHAIR: If you pay as a generator.

THERESE THORN: This is a retailer risk management strategy. That loss rental rebate is not paid to generators, it's actually paid back by the network companies to the retail business.

CHAIR: And they will only be paying some of the SPD if they're getting a lower price because of the transmission than they would otherwise be getting, so it's still volatility.

THERESE THORN: But because of the way the wholesale market works, the cost, the spot cost to a retailer is offset to a degree by the return of those rental rebates, and therefore it's managed as part of a retailer's hedge management strategy because it's a mitigating risk. But one of the things about the SPD methodology that's been proposed is that when the load flow's going south, so South Island prices are really high, you're actually charging under the SPD methodology those South Island retailer loads - so this is the top of the South Island - more when the price is high, whereas the other methodology you get more money back when the prices are high. So, one's a mitigating risk and one's an exacerbator on your retailer risk management strategy.

BOYD BRINSDON: Boyd Brinsdon, Contact Energy, and quite happy to be shot down in flames on this one by someone who might know better than me, but I'm not convinced that you will actually have high prices at the receiving end because we're dealing with the factual and the counterfactual, and the counterfactual calculation will be what derives the benefit. I don't think it's necessarily the case that you'll receive high prices. My understanding of the SPD logic is that you'll have a flow in a direction, be it south to north, and in the counterfactual equation you take those assets out and it hypothesises what the price will be.

So I do - again, willing to be shot down, but I don't necessarily agree that you will actually see an LCE type disconnect.

CHAIR: Any other suggestions?

BRUCE ROGERS: Bruce Rogers, Orion. I can confirm that the volatility in the LCE does not cause any problem for us from a compliance perspective in terms of the price path. So, if all of the new transmission stuff, if you talk to the Commission about this, if you suggested that it be changed so that all of the transmission costs could be treated in that way, that would be fine, but the way the regulation is written at the moment, volatility in the new transmission costs that would come through under the proposed TPM would create a compliance risk for us, both a compliance risk on one side and an under recovery risk on the other side.

And just since I've got the mic I'm going to add that in terms of the natural hedging thing, it seems pretty obvious to me that a single party should get the bucket of LCE, SPD and residual because at least that volatility is all taken out and you're only left with the residual volatility perhaps in the total amount. So, it seems to me that distributors opting out would be efficient in the sense that it would help the retailers manage the risk of the volatility that they will definitely get from the SPD and the LCE components because obviously the volatility of a sum which is a single number must be less than the volatility of the components.

CHAIR: So, what I would find useful is if retailers and distributors that feel - because this I think is quite an important issue, who feel that there is a problem in my analysis or I seem to have got the wrong end of the stick, could derive a simple explanation as to why ex post LCE volatility in their buckets, now I understand about retail distributors who pass it on, but other people actually receive it, while that ex post volatility is not something that you have criticised and sent submissions in, about the current arrangement where you have been very vigorous in your submissions about the volatility of something which looks to me to be something even significantly smaller in volatility than that item in terms of movements from year to year. So, it's the rationale logic of why this is not the case and what is the reason, it's a question to have.

BRUCE ROGERS: I guess I urge the Authority Bruce Rogers again- I urge the Authority to read the DPP determinations. That will explain to you why there's a problem. There isn't a problem with variability in loss and constraint excess. There is a problem with creating variability in transmission cost that is not loss and constraint excess. It's just the way the regulation is written. Regulation is never perfect, as you're rapidly finding out.

CHAIR: It's not the retailers, I've already said I understand your line business, yes.

ROSS WEENINK: Just to reinforce that - Ross Weenink from Powerco, that the way the Part 4 regulation is written, loss and constraint excess charges are not treated as part of transmission charges, so therefore the volatility doesn't cause a problem for us in terms of compliance.

CHAIR: I didn't write the latest version but I wrote the version before and there are some carry-through and I understand what the logic of those are. Yes, there have been changes but I'm just still a little puzzled about the strength of submissions we got about volatility and it seems to me like loss and constraint excesses for some parties in the industry cause volatility and maybe that they have natural hedges, I just want an explanation.

PETER CALDERWOOD: Peter Calderwood from TrustPower. Just from a process point of view, if you could put that to us in writing so we understand what the question actually is and we'll come back in writing.

CHAIR: No trouble at all. Anybody?

GILLIAN BLYTHE: Gillian Blythe, Meridian Energy. If I can just go back, though, to the question about distributor opt out. If the Authority makes their change to make this transmission pricing proposal more of the December-type notice, so do the ex-ante type of arrangement, not the ex post, that ought to address the uncertainty the distributors have over the bulk of the transmission charges. So, the problem that they are describing in terms of the DPP should not exist. Now, if that doesn't exist, I think from a go-forward perspective having distributors in the mix is a better outcome, you're likely to maintain signals that Orion and the certainly the upper South Island distributors are responding to on behalf of consumers, you're likely to reduce the need for Transpower to have to have, I think at the last count or last look at the participant register, an additional 34 benchmark agreements with the retailers, reduce the need for retailers to have to necessarily put in place additional prudential arrangements with Transpower, as well as the prudential arrangements they need to have with the clearing manager for wholesale arrangements, plus you'll remove the need for retailers to have to have some form of arrangement under the Part 6 arrangements, presumably in terms of embedded generators when they're going to try and want the avoider costs transmission. It just seems to me that the current contract counterparty arrangements is a far smoother, more straightforward way of addressing these issues.

CHAIR: Thanks, Gillian.

We do have one further question because I saw Vector were disappointed that it was the last. We've got one more for them.

You submitted in favour of the proposal for distributors to opt out of a residual charge in your page 43, though you suggest that residual charges on retailers should be compulsory.

How do you respond to concerns expressed in submissions that imposing residual charges on retailers will increase costs because of factors such as higher prudential costs and less competition from distributed generation?

ROBERT ALLEN: We suggested opt out be compulsory because we thought it would make sense and would be better for retailers if they have consistent arrangements across all of the line businesses and over time didn't think it would be helpful for retailers to, in some network areas, to have to deal with opt out and others opt in, and in some network areas potentially changing over time. Gillian, Meridian correctly raised that there are issues and costs of dealing with Transpower under the TPM proposal and those costs are something that would need to be reflected in the EA's assessment of the proposal.

CHAIR: Any supplementary questions? Alistair?

ALISTAIR DIXON: I'm sorry, I actually had a question for Gillian. So, Gillian, I mean the various costs that you raised, I mean under the proposal, the proposal was that the SPD charge would apply to retailers on the load side. So, if we were going to introduce that, then we'd need to introduce all of those - you know, we'd basically need to do things like establish prudential arrangements, deal with benchmark agreement, those sorts of things.

So, therefore, I wonder whether your concerns around opt out, is that, you know, if we were going to do that, do your concerns about opt out around residual charge, do they still apply, particularly if we for example did what you suggest and had ex-ante charging?

GILLIAN BLYTHE: I think the critical matter is that of the refinements that we've put forward, the most important one is to make this an ex-ante signal. If you do that you might not have all the retailers that were there in the time period that you're next wanting to charge. So there might be some retailers that have exited the business and so you need to make sure that you've got a counterparty that's there. So, on that basis, even your SPD bit that you want to charge to retailers, I think that's misplaced. I think you need to continue to do that to –to a party that will be there. Vector will be there tomorrow, Orion will be there tomorrow, so if you charge them as an agent at that point for the customer, then you have the - a continuous link in your chain.

CHAIR: Any other questions that people have? There appear to be none. I'll call today's session to a close and once again thank you very much for your attendance and also for your answers and suggestions.

Tomorrow we start again at 10 o'clock and we start with distributed generation and we have questions for Energy 3, Pioneer Generation, Clearwater Hydro, New Zealand Steel and Contact Energy. So they can steel their nerves overnight. Thank you very much.

(Conference adjourned at 4.48 p.m.)

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