Feedback on Stakeholder Submissions on *Setting Transpower's individual price-quality path for 2015-2020, Reasons for draft decision, 16 May 2014*

Issue	Stakeholder submission	Transpower Response
Expenditure Overview	**Pacific Aluminium** External reviews of detailed expenditure plans by regulators will tend to be conservative due to information asymmetry and concern about the consequences of cutting too deep, so driving the right behaviour initially is likely to lead to more effective outcomes. Transpower must increase its focus on minimising future capital and operating expenditure. **Contact** Proposed expenditure allowances are at levels which both promote and reward good asset management practices whist recognising the need to deliver electricity network services efficiently to consumers. Given that transmission costs represent a significant portion of a consumer's electricity bill, and are a significant driver of electricity bill increases, it is important that the impact on consumers is well considered in any final decision.	Regulators are properly concerned about the risk of cost reductions "cutting too deep" given the potential for negative long term impacts on consumers. To address this issue (and drive the right behaviour) the Commission has put in place incentive mechanisms that drive Transpower to continually pursue efficiency gains, and share those gains with consumers over time. It is important that cost reductions do not undermine the intended operation of the incentive mechanisms. We are very conscious of the cost of transmission services, and the impact of our expenditure plans on long-term costs. This is reflected in the robust processes we have used to develop our plans, and the challenging objectives we have set to lift performance while reducing overall expenditure. In particular: • We will continue to optimise our capital investments in RCP2 using improved risk management and increased asset utilisation. We expect this to reduce Base Capex by more than 14% compared to RCP1. • Using improved work management and targeted maintenance, we expect to reduce annual Grid Opex by 8% by the end of RCP2. • Achieving these asset management cost savings will require ongoing improvements in staff competency and our processes, which will put upward pressure on Corporate Opex. It is important to note that the Commission's task is to review our performance and expenditure plans with a view to the long-term interest of consumers, not to target any particular short-term revenue outcome.
	Major Electricity Users' Group Electricity consumers have difficulty with assessing the detail in the proposal by Transpower and the material published by the Commission to decide how far away from "world best practice" we are. Publication of a few dashboard type indicators would assist consumers understand if they should be concerned or not with the gap between and proposed rate of progress towards achieving "world best practice".	We agree with MEUG that it is not possible to establish whether a transmission operator is operating at "world best practice". There is no such standard, and there are no simple dashboard indicators that can be used. The benchmarking study of our operating expenditure cost performance against Australian transmission network service providers (TNSPs) by Parsons Brinckerhoff[1] demonstrates the difficulty of making international comparisons. These difficulties reinforce the importance of the incentive mechanisms that are in place to drive Transpower to continually pursue efficiency gains. These mechanisms, together with our performance targets and the information we disclose through our Annual Regulatory Report should provide consumers with confidence that the regulatory framework is operating as intended.
Grid Capex Overview	**Major Electricity Users' Group** Based on Transpower's proposal over the 10 years prior to and including RCP2: • the average annual compounding rate of increase in interconnection charges will be 6.3% per year, i.e. a total change over ten years of 85%; • no competitive business that it is aware of has been able to charge year-on-year increase prices at such a rate over a ten year span that included the GFC in 2008-09; and • with relatively flat and assuming productivity improvements, then unit prices should decrease.	As noted above, the Commission's task is to approve efficient expenditure as an input to setting revenues, not to 'goal seek' a desired short-term revenue path. That said, we do recognise that costs are important to customers and to the NZ economy, so we are very focused on pushing ourselves to pursue lowest total lifecycle cost. Prices have increased over the period cited as we have invested in strengthening the grid. Taking a longer-term view, as shown below, prices are actually only returning to 1993 levels (in real terms).

[1] CR01 – Operating Expenditure Benchmarking – Final Report 25 October 2013

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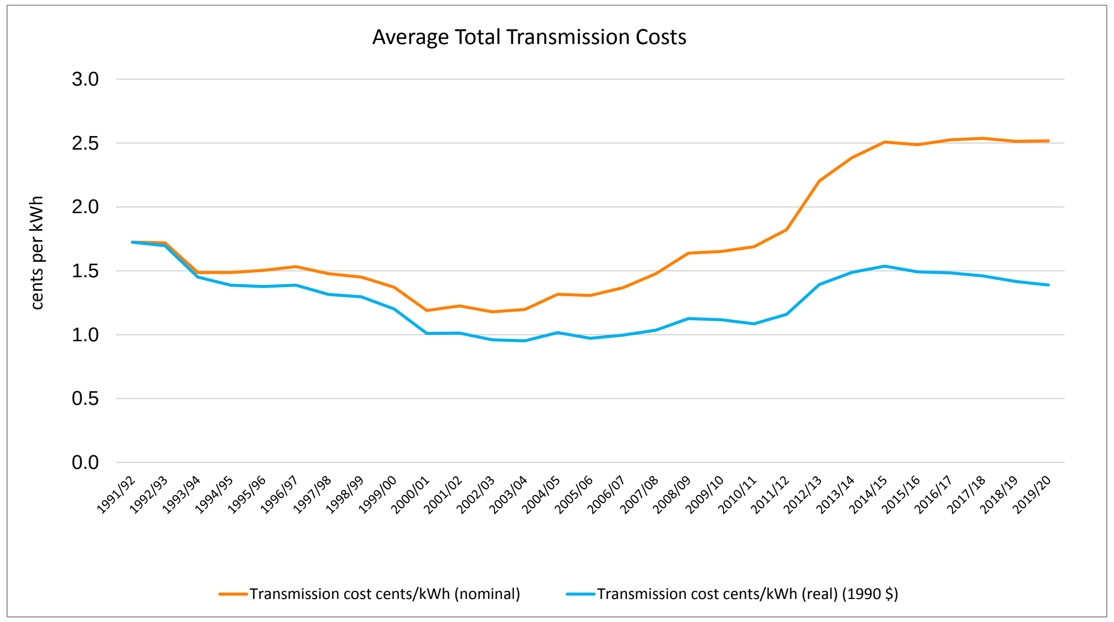
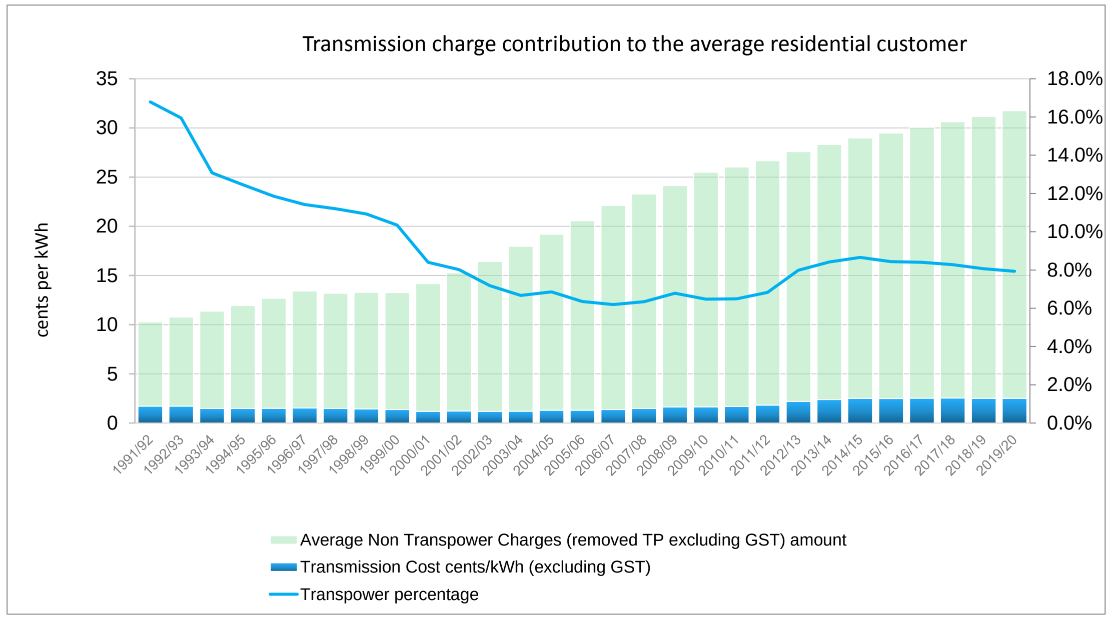
		 As a proportion of the average delivered cost of electricity, we expect transmission prices to again trend down, as shown below. It is also worth noting that, in addition to maintaining reliability, transmission investments place downward pressure on energy costs. By way of example, the HVDC Upgrade cost $670m and is expected to deliver market benefits of $920m over the next 30 years. That is, without the upgrade, the expected cost of wholesale of electricity would be $920m higher.  MEUG correctly identify that our draft revenue figures show a 14% increase in the interconnection rate from 2014/15 to 2019/20. We have updated our draft revenue figures based on our revised proposal (and updates to the other input assumptions) and will publish these on our website next week. The updated figures show an increase in the interconnection rate of 10% from 2014/15 to 2019/20. In constant 2014/15 dollars, the interconnection rate

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		decreases from $114.50 to $114.30 over the period. In response to MEUG's other comments we note that: • comparing charging trends between a regulated transmission business and a competitive firm does not provide any particular insight. Like other essential infrastructure businesses, transmission charges vary over long cycles due to the long economic life of the underlying assets; and • transmission charging cycles do not track economic cycles due to the long lead times for planning and delivering transmission assets, and the strong economies of scale for transmission investments.
Grid R&R Capex	**Pacific Aluminium** While Transpower's submission speaks of greater use of variable line rating, static VAR compensation and demand-side participation, we also observe significant expenditure proposals related to the relocation of substations indoors, greater undergrounding and construction of new corporate offices.	The need for all projects has been established on a case-by-case basis and have been reviewed by the Commission and its advisors. Grid Capex forecasts for RCP2 were developed through a robust process using the following stages: • Needs Identification • Options Analysis • Cost Estimation • Approvals • Integration and Optimisation • Multiple challenge rounds. Grid Capex is undertaken in response to a number of investment needs identified through various activities including condition monitoring, network studies, and safety reviews. Capex decisions take into account our operational activities to ensure that Capex and Opex are co-optimised. During RCP2, Grid Capex decisions will be primarily driven by: • safety; • asset criticality and service performance; • asset condition and health; • security and capacity; and • technology change. Detail of the Grid Capex forecasting process is provided in AM03 – Planning Lifecycle Strategy, and summarised in our Main Proposal, section 6.2. ICT capex forecasts are developed using a similar process but consistent with the technology. The governance and need identification is summarised in our Main Proposal, sections 8.2 and 8.3. Corporate capex projects are few and the need identified on a case-by case basis. All buildings eventually require repair, refurbishment, or replacing. Our Response (section 5.9) expands on the need to refurbish Transpower House without impact on productivity.
Grid E&D Capex	**Counties Power** Draws attention to the significance of the Bombay substation to their network, its age, anticipated load growth from the expansion in the greater Auckland and Waikato regions, and the limited ability to access additional demand response given current utilisation. Notes the discussions with Transpower on the potential development, and subject to obtaining advice from Transpower on the financial impact on Counties, offers qualified support for the option identified to expand the Otahuhu - Wiri transmission capacity.	We note Counties Power views on demand response and agree that we need to identify a solution to the limited Otahuhu-Wiri transmission capacity. Our Response, section 3.2, and revised POD (PD30) advance the justification for additional transmission capacity in the South Auckland region. The installation of an interconnecting transformer at Bombay remains the preferred option. We have consulted with Counties Power as indicated. We will continue to update and refine pricing information as we develop the preferred option.

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	Pacific Aluminium Transpower's demand forecasting methodology merits further consideration by the Commerce Commission (noting Strata's reference to Transpower's acknowledgment of deficiencies in its forecasting methodology). Supports the proposed reduction in E&D expenditure, and considers that the Commission's conclusion raises concerns about the robustness of Transpower's planning. The extent of the increase in capex due to the change in the major capex diminimus is not clear to Pacific Aluminium.	The matters raised by Pacific Aluminium have been addressed in our Response, section 3.2, and associated paper *Enhancement and Development Base Capex Response to Draft Decision*. In particular we have: • refined our demand forecasting approach resulting in an amended work programme, including the deferral of expenditure to RCP3; • revised our E&D Capex; and • raised specific concerns with the approach used to review the E&D Capex. Pacific Aluminium appears to suggest that our demand forecasting methodology affects our entire Capex proposal. However, of the 25 E&D Base Capex projects only five are necessitated through anticipated demand growth. These five projects comprise 3% of our proposed Base Capex. The needs for the balance of projects arise from asset condition, new generation, transmission constraints, risk management, or Code requirements. The impact of the change in threshold is discussed in our Main Proposal, section 6.4.
ICT Capex	**Meridian** Questions whether the Commission expect that Transpower would fund the development of a new TPM system through its general ICT capex allocation, should this be required during the 2015-2020 period?	We accept the Commission's proposal that this expenditure is excluded from our forecast. However, were this situation to change in RCP2 due to the decisions of the Electricity Authority (Authority), and a confirmed timeline and scope to emerge, we would seek agreement from the Commission to recover the required expenditure before committing any expenditure. We think this is a reasonable approach and will assist the Commission and the Authority in resolving funding arrangements.
Corporate Opex Overview	**Pacific Aluminium** Pacific Aluminium supports the Commission's draft decision to reduce Transpower's proposed opex for RCP2.	We refer to sections 2.2, 2.3 and 5 of our Response which explains our concerns regarding proposed reductions to Corporate Opex and provide additional information about the impact of the proposed reductions. We note that there is no new information or evidence provided by submitters that impacts on our Response.
	Vector The reason for the reduction in Corporate Opex is an expectation that Transpower can (or at least should be able to) reduce opex over the RCP2 period. However, neither the Commission nor its consultants appear to have been able to identify any particular inefficiencies that could be removed, rather there is a general assumption that something can be cut. The Commission's proposal appears to share efficiency gains with consumers before those efficiency gains can or have been identified by Transpower (or the Commission). Does not believe this would be appropriate or consistent with the principles underpinning price-quality regulation.	We agree with Vector's views that the Draft Decision does not identify any genuine inefficiency. We also agree with Vector's views on the appropriate approach for capturing future productivity gains. As set out in our Response, section 2.3, the approach suggested by Strata is contrary to the intended operation and purpose of IRIS.
Insurance	**Major Electricity Users' Group** Agrees that there should not be an allowance for indemnity payments required by the amendments to the Consumer Guarantees Act (CGA).	We agree with MEUG that we should not be "immunised" from exposure to the CGA. This is why we have proposed treating CGA costs as recoverable rather than pass-through. In particular, this approach: • does not diminish our incentive to minimise the compensation paid to customers; • manages the uncertainty associated with the CGA provisions by allowing cost recovery, subject to regulatory approval on an *ex post* basis; • provides us with a mechanism to recover efficient costs; and • preserves the incentive properties of the IRIS, as recoverable costs are excluded from the operation of scheme.

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		A more complete discussion of the treatment of our CGA exposure is provided in our Response, section 7.1.3.
Demand Response	**EnerNOC** Is of the view that: • Transpower's (demand response) DR programme should not be used for purposes other than transmission network deferral; • we should not approach retail consumers but instead develop DR capacity products and allow parties (aggregators, retailers) to supply them; • the Commission should reconsider its draft decision to disallow any DR programme costs, provided proposed programmes are supervised by the EA; and • EA coordination of Transpower's DR programme may identify projects that would enhance the efficiency of the Transpower system and also provide benefits for distribution networks and be to the advantage of consumers. **Major Electricity Users' Group** Before supporting funding for demand response as a transmission alternative MEUG wants to know there is an integrated plan to ensure providers are able to capture the benefits of providing DR in the wholesale electricity market (response to spot prices, dispatchable demand, provision of ancillary services), and as a distribution alternative.	In the same way that we continually pursue the most efficient cost for delivering transmission assets, we should pursue the lowest cost for using DR as a transmission alternative. To achieve this, we should not be precluded from approaching consumers directly. This does not mean we expect that aggregators and retailers won't have a significant role to play in delivering the most cost effective DR. The proposed development of DR, as set out in the companion paper to our Response, *Development of Demand Response as a Transmission Alternative*, is limited to DR as a transmission alternative. We agree with EnerNOC that the Commission should reconsider its draft decision to disallow any DR programme costs. We are also committed to working with the Authority to ensure DR is integrated and appropriately managed. This includes developing a DR protocol with the Authority as suggested in its April letter to the Commission. In response to MEUG, the purpose of our programme is to discover the price of differing types of DR. Our experience to date has revealed that the costs to enable participation are far lower than that suggested by aggregators prior to our open procurement process. If we restrict our contracting to aggregators, we cannot be confident that we are achieving the lowest possible costs.
Asset Health Incentives	**Pacific Aluminium** Considers that the additional performance measure proposed by Strata Energy - a network health measure – would be a useful addition to the Commission's proposed measures.	We agree that a network health measure should be a consideration for RCP3. During RCP2 we have proposed a set of asset health and volumetric based incentives in our Response, section 6.1, to address concerns raised about deliverability risks, removing the basis for the proposed reduction from R&R Capex.
	Vector The default VoLL under the Code is out of date, and in light of the Authority's recent findings is no longer a reliable representative of the value of unserved energy in New Zealand. The most appropriate VoLL value for the purposes of its Transpower IPP determination should be the Authority's national VoLL estimate of $50,031/MWh.	It is important to understand that VoLL values are not used to determine the incentive rate. Caps, collars and revenue at risk have been selected based on a range of design considerations and VoLL is used as one of several 'sense checks'. We agree that VoLL is inherently uncertain, but this is not a reason to alter the incentive settings.
Grid Performance Measures	**Carter Holt Harvey** Transpower should report the number of times it does meet planned finish times (an addition to OM8). The content of reports on unplanned interruptions should be scripted to include sufficient information so that customers may understand the likes of root cause and preventative measures (OM9). An output measure is developed to measure stakeholder satisfaction and engagement. **Contact** Supports the revised targets for customer focused quality measures.	We are continually seeking opportunities to improve our reporting to stakeholders, and will consider the enhancements we can achieve during RCP2 (over and above those we have already identified) in light of the final decision.
	Pacific Aluminium Stresses the importance that the regime is revenue neutral and targets are demanding.	The grid performance measures have been set to ensure we need to improve upon historic performance to achieve a financially favourable outcome.

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Other Measures	**Meridian** Supports the Commission's suggestion that Transpower develop processes to optimise the timing of planned outages taking into account their market impact. Encourages Transpower and the Commission to set clear targets for the development of market impact metrics, so that such a measure could be incorporated in any financial incentive regime from Regulatory Control Period 3.	We will continue to develop metrics to inform business processes in consultation with our stakeholders during RCP2. This work is also expected to identify the merits of including such metrics in the incentive regime developed for RCP3.
Business Improvement Initiatives	**Carter Holt Harvey** Regular reports on the progress made by the Voltage Disturbance Working Group. Implementation of dynamic line rating. Improve asset health models by obtaining statistically valid fleet data and combining all failure modes into the risk of failure used in each asset health models. Asset health data be made available to connected parties and customer specific quality standards developed. **Major Electricity Users' Group** Suggests that reports on the market impact of forecast vs actual outages be published on a monthly rather than annual basis.	Noting the July 2015 timing for a new set of initiatives, we will consider these suggestions in due course following the completion of the IPP process. We are currently trialling variable line ratings on six key circuits, four in the North Island and two in the South Island. Initial results indicate that variable line ratings are a cost effective means of utilising available line capabilities and will remain our focus for the medium term.
Economic Value Adjustments	**Contact** Agrees that no change be made to the legacy 2011 EV account balances for HVDC and HVAC that will run to the end of RCP2. **Meridian** Agrees that Transpower should have the ability to request approval to spread EV adjustments over more than one pricing year, in order to avoid price shocks. **Major Electricity Users' Group** Disagrees with EV adjustments being smoothed to avoid pricing shock effects ... Sees no reason why the HVAC and HVDC accounts need to be treated the same. **Pacific Aluminium** Disagrees with the Commission's previous decision to clear the legacy 2011 EV account balances by the end of RCP2. The revised transmission pricing methodology (TPM) proposed by the Electricity Authority will change the way that costs for the transmission system are recovered and from which parties they are recovered. Urges the Commission to shorten the period within which these balances are cleared.	The submissions on EV adjustments demonstrate diverging views amongst submitters. In our view, unless new evidence is provided, both EV balances should be cleared together during RCP2, as per the decision the Commission made at the outset of RCP1. The only "new" view raised in submissions is a reference to the TPM proposed by the Electricity Authority potentially changing the way costs for the transmission system will be recovered. In our view, this issue is appropriately within the scope of the Electricity Authority process. In this context we have supported the MEUG position that EV balances should not be reallocated if the TPM is changed.