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# Input Methodologies Review 2023: Draft Decisions

1. Transpower welcomes the opportunity to respond to the Commerce Commission's (the Commission's) 2023 Input Methodologies (IMs) Review draft decisions.
2. We acknowledge the Commission's considerable effort in reviewing the IMs, and we support several of the draft decisions including the Commission's draft decision to set the default discount rate at 5% for the Investment Test and the increase in the base capex threshold to $30m. We encourage the Commission to make decisions that are not specific to the RCP4 individual price-quality path determination effective immediately following the Commission's December 2023 determinations.
3. There are draft decisions that we disagree with. We are surprised at the Commission's draft decisions around the WACC percentile and its draft proposal to index our regulatory asset base (RAB). Proposing to reduce cashflows does not seem prudent at a time when significant investment in electricity transmission and distribution is required to achieve New Zealand's commitment to net zero emissions by 2050.
4. We share the Commission's concerns about affordability for end consumers and enhancing our social licence to operate is a key strategic objective for Transpower. However, short-term affordability gains can be quickly eroded through higher electricity prices in the long run if the incentive and funding to make the required infrastructure investments are removed.
5. We also consider that the Commission could have gone further in some areas, particularly regarding accelerating the major capex project process and resilience expenditure.
6. While we appreciate the workshop the Commission held on the Transpower Investment Test, we consider that the IMs review process can be improved with more workshops between the Commission and industry.
7. The rest of this submission is structured as outlined below.
    - Our key issues, and our support or otherwise for the changes proposed or not proposed:

i. Indexation of Transpower's RAB

ii. Major capex proposal processes

iii. Resilience funding

iv. Flexibility to introduce new uncertainty mechanisms

- A response to each of the following topic papers:

v. Transpower investment

vi. Financing and incentivising efficient expenditure during the energy transition

vii. Cost of Capital

viii. CPPs and in-period adjustments

## RAB indexation

8. We were surprised and concerned with the Commission's draft decision to index our RAB.
9. We appreciate that an indexed RAB approach might have some short-term affordability benefits, and the advantages for inflation protection and smoother prices in real terms. However, the cash flow implications for Transpower are significant.
10. We were surprised by the Commission's draft decision since our investment needs are arguably greater than in 2010 (when the Commission concluded Transpower should have an unindexed RAB), with a significant investment programme required to achieve New Zealand's objective of net zero emissions by 2050. The Commission appears to be rewriting its 2010 reasons for providing Transpower with an unindexed RAB.[1]
11. We are concerned that the draft decision to shift Transpower to an indexed RAB does not demonstrably better promote the section 52A purpose of Part 4. Indeed, the converse could be true given the "long-term benefits of consumers" contemplated in the section 52A purpose.
12. There are likely to be consequential impacts if a final decision is made to index our RAB. For example, we offer financing terms to some of our customers for new investment contracts (which we refer to as Transmission Works Agreements). We allow our EDB customers to choose longer term financing contracts not available to them from third party lenders. We expect to revisit these terms if our balance sheet is impacted to the extent expected by indexation of the RAB. The outcome is likely to be a reduction in the length of the contract terms we offer EDBs and our other customers.
13. Notwithstanding our strong preference for the status quo, if the Commission's final decision is to index our RAB, we consider a hybrid approach, where only the equity component of the RAB is indexed, better promotes the section 52A purpose of Part 4. This is because it better matches our revenue to the nominal interest payments we

[1] Input-Methodologies-Transpower-Reasons-paper-December-2010 page 29.

need to make on our debt.[2] A hybrid approach also better resolves for the debt compensation issue identified by the Commission.

14. A hybrid approach means the debt proportion of Transpower's rate of return is provided upfront as a nominal return. We have modelled the revenue reduction under this approach, and we estimate that the (nominal) revenue impact is ~$80m p/a compared to a ~$140m p/a reduction with a fully indexed RAB.

15. While the Electricity Authority has indicated to the Commission that the Transmission Pricing Methodology is 'future proofed' to indexation, there are potentially significant operational implementation challenges that we would need to work through with the Commission and the Electricity Authority.[3] These challenges may lead to additional costs and affect the proposed timing of implementation (for RCP4). We also expect amendments may need to be made to the Electricity Industry Participation Code to provide certainty and clarity of how indexation is expected to be reflected through the new TPM, which sets charges at asset-level.

16. Further details on our response to the draft decision on indexation are in RAB indexation section and attached to this submission is a report from Frontier Economics on the suitability of the 'hybrid approach' for Transpower.[4]

## Major capex proposals

### Proportionate consultation process

17. We consider an area of omission in the draft decisions is on our submission to "*Introduce a more proportionate approach to MCP applications based on the need and/ or size of the project. For example, to allow discretion on long-listing consultation requirements for some projects.*"[5]

18. The current rules require Transpower to consult on a long list of options and a subsequent short list of options to meet the investment need. We consider that the requirement to conduct two options consultations is not prudent or efficient for certain types of investments.

19. We consider a commensurate approach would permit discretion to:
    - consult only a short list consultation for projects that:
        i. are valued below $100m
        ii. are GRS investments under the deterministic limb
        iii. have limited technical and economic solutions to resolve the constraint or the technicalities has limited stakeholder interest
        iv. directly follow on from previously approved MCPs.

[2] This is on the basis of a notionally efficient entity.
[3] Commerce Commission, Draft-decision-Financing-and-incentivising-efficient-expenditure-during-the-energy-transition-topic-paper-14-June-2023, para. 3.84.
[4] Frontier Economics, RAB indexation, a report for Transpower, 13 July 2023.
[5] TP_Sub_2023_IMs_Review_Process_And_Issues_Paper_11July2022 page 9.

- seek offers for non-transmission solutions closer to (or as part of) the short list options when better specification of need and potential transmission solution is known.

20. The current IMs allow for the Commission to permit us to avoid a long-list consultation where it would be "unreasonable in the circumstances".[6] However, "unreasonable" is a high legal bar and would not allow us to consult only on a short list in the circumstances set out in paragraph 199. We consider that this leads to ineffective consultations and drives inefficiencies.
21. In Major Capex consultation and approval processes section, we provide specific examples of the type of investments where we consider a long list consultation does not add value, or in fact reduces effective engagement by increasing consultation fatigue.

## Scenario analysis

22. The Commission has clarified that the maximum number of scenarios we need to model for an MCP is five.[7] This draft decision would still require us to undertake modelling on all EDGS or their variations. [8] We do not consider that requiring a specific number of scenarios is commensurate with some of the investment contexts we analyse.
23. For example, national demand scenarios are often not relevant, and we are better using more regionally focussed EDB forecasts (particularly as they bear the costs under the new Transmission Pricing Methodology) rather than attempting to alter the national EDGS scenarios to fit.
24. We propose that the Commission should revise the policy to permit Transpower discretion to undertake the number and range of scenarios commensurate with the proposed investment need. We consider that this is in line with the Commission's 2012 policy intent.[9]
25. In Major Capex consultation and approval processes section, we provide examples of the type of projects we see this applying to.

## Resilience

26. We are concerned with the Commission's decision to not make explicit provision within the IMs for resilience expenditure. We consider that this draft decision is unlikely to demonstrably better promote the section 52A purpose of Part 4, for long-term benefits of consumers.
27. Resilience was not a topic of consideration for either the 2012 initiation of our Capex IM, nor the 2016 review. None of the IMs in any of the regulated sectors are explicit about resilience expenditure (excepting the Commission's proposed draft decisions for EDBs).

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[6] Capex IM, Clause I1 and clause 8.3.1 (2)(b).
[7] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 3.10.
[8] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 3.11
[9] See Commerce Commission, Transpower Capital Expenditure Input Methodology – Reasons Paper, January 2012, para.graph 7.4.48

28. We consider that the Commission has missed an important opportunity for itself and regulated suppliers to be able to meet requirements under the National Adaptation Plan, the resilience work associated with climate change (for example the consultation from the Department of Prime Minister and Cabinet (DPMC)[10] and the changes proposed for emergency management legislation.[11]
29. We do not consider that resilience can be solely related to enhancement and development type expenditure. We outlined in our RCP4 consultation that we were considering various resilience workstreams under base capex R&R that focuses on Response, Recovery, Risk Reduction and Readiness (the Four Rs for resilience) for major hazards.
30. We consider that identifying proactive resilience spend separately helps to improve transparency for our customers, consumers, the Government and the Commission of what we are doing to respond to our changing understanding of the impact of major hazards including as a result of climate change.[12]
31. We agree with the Commission that for some risk reduction investments, particularly large investments such as new lines and/or substations to improve resilience by adding redundancy, can and should be assessed using a probability times value of lost load assessment (i.e. economic reliability investment). However, there are several reasons why this is difficult or unreasonable for all the types of resilience expenditure we are forecasting into the future. For example, we do not know the precise probability of events occurring, we do not know consumers expected value of lost load under different major events, we do not know consumers' risk aversion or societal cost in relation to a catastrophic event, and we do not know the precise duration during an event due to many reasons including interdependencies of response.
32. As the DPMC has set out "*the focus to shift from the resilience of each distinct infrastructure asset, to how infrastructure assets and the networks between them can contribute to the resilience of the whole infrastructure system.*"[13] We need funding flexibility for work on our assets so we can collaborate with our customers to determine what their risk appetite is to major hazards. This includes undertaking risk reduction investments on assets where the life cycle replacement to modern standards is many years away. Managing these types of risks should not be dominated solely by actuarial tools and methods. A risk-based approach that allows for other risk criteria to enter and supplement those methods can deliver cost effective investments that are in the long-term interests of consumers.
33. Further details are in the Resilience expenditure section of this submission.

[10] Department of Prime Minister and Cabinet, discussion-document--strengthening-the-resilience-of-nzs-ci-system.pdf, June 2023.
[11] Refer Emergency Management Bill Overview of proposed changes » National Emergency Management Agency
[12] We improve resilience through our ongoing replacement, refurbishment, maintenance work and enhancement and development on the grid. The expenditure we are proposing for RCP4 is 'proactive' in that we are not waiting until the asset needs to be replaced or its to improve our readiness or recovery to major hazards.
[13] Department of Prime Minister and Cabinet, discussion-document--strengthening-the-resilience-of-nzs-ci-system.pdf, June 2023, page 23.

## No flexibility to introduce new uncertainty mechanisms

34. Our submissions to the Commission outlined that we considered that the IMs should have more flexibility to allow for uncertainty mechanisms.[14] We consider that the IMs should be more principles based with relation to uncertainty mechanisms rather than prescriptive. We consider the best place to set out the prescription for the uncertainty mechanisms is within the individual price-quality path (IPP) determination.

35. If the Commission considers that it is sensible and proportionate to introduce an uncertainty mechanism for a regulatory control period (RCP) it should be able to do this without needing to change the IMs. Put another way, if the Commission considers the uncertainty mechanism better achieves Part 4 objectives the IMs should have the flexibility to allow it in the first place.

36. We are proposing two new mechanisms for RCP4 related to resilience expenditure and helping our customers to electrify. We have proposed mechanisms which, in our view, deliver tangible and measurable benefits for our customers and consumers, balance risks between Transpower and consumers, and reduce the administrative burden. Further details are provided in Appendix A.

37. For the type of expenditure proposed we consider the existing uncertainty mechanisms in the IMs would not better promote the section 52A purpose of Part 4. While reopeners are powerful tools, the Commission has taken a prescriptive approach to the existing reopeners, so they would need to be amended to add flexibility. In addition, the reopeners that might apply are time limited and do not provide any certainty for recovery of expenditure made prior to the reopener being triggered.

38. For example, the Commission has indicated that it expects anticipatory connection asset (ACA) capacity expenditure to be included in our RCP4 base capex forecast. This is not realistic. As these investments are related to the type and location of connection requests, we are unable to forecast these ahead of need.[15]

39. We consider that relying on the E&D reopener is also not practical. The E&D reopener can only be triggered once. Without the assurance of recovering our costs we may avoid making the investment. In addition, even when we trigger the reopener, we may not have visibility of further ACA work towards the end of the RCP.

40. During its assessment of our RCP4 Proposal, the Commission’s may identify other areas where the use of an uncertainty mechanism may better promote Part 4 rather than including/ excluding it from the base capex or opex.

41. While we understand the Commission can alter the IMs after reviewing our RCP proposal, we believe having the certainty that the IMs allow the Commission to introduce uncertainty mechanisms, prior to our RCP proposals, better achieves section 52R of the Commerce Act. Therefore, we consider increasing the flexibility around the

[14] Transpower, Input Methodologies Review 2023: Draft Framework Paper and Process and Issues Paper, 11 July 2021.

[15] For the avoidance of doubt, we have not undertaken ACA investments before, we are not even sure if we will undertake any during RCP4, however we consider that it is appropriate that we have the option to do so.

introduction of the uncertainty mechanisms meet the IM Review decision-making framework.[16]

42. The rest of this submission responds to the Commission's topic papers.
43. We have endeavoured to review and respond to the draft decisions in their entirety as they relate to Transpower. However, in the relatively short five-week consultation period we have not been able to assess all the impacts the draft decisions may have on our operating practices and costs. If we subsequently identify further areas of concerns, we will provide formal notification to the Commission.
44. We also encourage the Commission to have a technical consultation on the determination to test that the final decisions are accurately reflected.

Please contact me [redacted]

Kind regards,

Joel Cook
Head of Regulation

[16] Commerce Commission, IM Review 2023 - Decision-making Framework paper, 13 October 2022, para. X21-X22

## Transpower investment

45. Transpower is supportive of several of the Commission's draft decisions. We consider the changes to be incremental and generally reflect modest improvements that should be made to the Capex IM.

46. Our view remains, however, that more substantive changes are warranted, specifically for a proportionate MCP consultation process commensurate with investment need, type and likely options, and for additional uncertainty mechanisms for resilience expenditure and connection assets. [17]

### *Demand and generation scenarios*

47. Transpower supports the draft decision to clarify that where Transpower varies an MBIE EDGS scenario, it is only required to model the varied scenario and not the original unvaried scenario.[18] We consider that this aligns with the Commission's original policy intent in its 2012 Capex IM reasons paper, that Transpower had flexibility to add, remove and alter scenarios. It stated then:[19]

> *Transpower may amend the scenarios (including the SOO scenarios) by adding, removing, or altering scenarios (and associated probabilities), including further developing scenarios or adding, amending or removing projects to ensure feasibility or to incorporate new information.* ***This should improve the appropriateness of the scenarios for the investment need that is being considered****. [emphasis added]*

48. The original intent is sound. As the Commission is aware, we have proposed a matrix approach to EDGS that would assist with our scenarios analysis in future.[20,21]

49. However, consistent with the original policy intent, there should not be a reference to the number of modelled scenarios Transpower must conduct. Transpower should have the ability to model only scenarios relevant to the investment need e.g., for reliability investments on the core grid to meet the deterministic limb of the GRS (i.e. N-1) fewer scenarios may need to be modelled as the option set is narrower.

### *The counterfactual scenario approach*

50. Transpower always uses counterfactual analysis. Nevertheless, the decision clarifies an approach for the counterfactual for an economic investment to assess how demand would need to be met absent transmission investment. We accept the Commission's decision that

### *Discount rate*

51. Transpower welcomes the draft decision to reduce the investment test discount rate used in the investment test to 5% with a sensitivity range of 3% to 7%.[22] By better

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[17] Transpower Draft Framework Paper and Process and Issues Paper, 11 July 2022.
[18] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 3.11.
[19] Commerce Commission, Transpower Capital Expenditure Input Methodology: Reasons paper, 31 January 2012, para. 7.4.48.
[20] Transpower, Updating Electricity Generation and Demand Scenarios, June 2023.
[21] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 3.11.
[22] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 3.42.

capturing the future benefits of long-lived transmission assets, the decision will support grid investment for achieving decarbonisation objectives.

52. As the Commission's view is that this reflects current financing rates, we consider that the introduction of the 5% default discount rate should not be delayed until April 2025.

### *P50 cost estimation and incentives for major capex*

53. Transpower supports the draft decision to implement the symmetrical incentive scheme using a deadband between P30 and P70 rather than around a point estimate of P50. We agree the use of the deadband "*will reduce the risk that there are early cost estimation inaccuracies and help manage cost uncertainties more efficiently*."[23]

### *Major Capex Projects (staged)*

54. Transpower supports the draft decision to clarify that "*subsequent stages of staged MCPs require Transpower to only submit updated supporting analysis and information, rather than carrying out the full MCP process*" and "*the level of consultation required for a subsequent project stage of an MCP (staged) will be commensurate to the materiality of any changes with reference to earlier project stages.*"[24]

55. These changes accord with our post workshop submission.[25]

### *Base Capex Threshold*

56. Transpower supports the draft decision to increase each of the base capex threshold, listed project threshold, base capex cost benefit analysis and consultation threshold, and base capex low incentive rate threshold to $30m. We also support linking the thresholds explicitly to the base capex threshold. We proposed the thresholds should be adjusted for inflation and agree "*maintaining the real value of the base capex threshold at a similar level to the 2012 $20 million (nominal) value, will allow the level of scrutiny to remain proportionate to the size of the projects envisioned when the Capex IM was set. This also avoids increasing the regulatory burden on Transpower.*"[26].

57. We support no change made to the current E&D capex reopener threshold at $20m (for at least two projects) as this matches our intent to use the reopener during RCP4.

58. If the Commission does not add flexibility into the IMs to allow for alternative uncertainty mechanisms, we propose an additional ground for the re-opener is resilience driven expenditure.

### *Listed projects*

59. Transpower supports the draft decision to expand the Listed Project mechanism to include base capex projects beyond grid R&R, greater than the proposed base capex threshold ($30m) and for which the Commission considers the Listed project criteria are met. We also welcome the draft decision that reconductoring projects primarily driven by condition can include options that increase capacity.[27]

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[23] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 3.75.
[24] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 5.4.
[25] Transpower, 2022 Capex IM Workshop Supplementary information, 12 December 2022.
[26] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 7.15.
[27] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 4.5.

60. Reconductoring is typically used to refer to reconductoring overhead line conductors. We would appreciate clarification from the Commission that it is reconductoring **and** cable replacement where we can increase capacity if the primary driver is condition.

61. We support the rationale for a simpler approval process with a single consultation, and that the evaluation process is also simpler and less time-consuming as it is based on the Capex IM Schedule A requirements for base capex, rather than the full major capex proposal approval process.[28]

62. While we appreciate the Commission extending the Listed Project criteria so that it could apply to our TransGo investment, as TransGo involves expenditure in RCP3, the Listed Project mechanism is not suitable[29] (we will use the low incentive base capex option.) The Listed project evaluation criteria implies most types of base capex, excluding E&D, can be proposed. For clarity, the simplest way to confirm this could be for the Commission to clarify the that the criteria includes all base capex excluding enhancement and development expenditure.

63. The Commission's proposed changes to the Listed project criteria[30] (proposed Capex IM clause 2.2.3(8)) explicitly narrows the uncertainty associated with listed projects to projects where the commencement date cannot be forecast with specificity. This change would prevent application of the listed project mechanism to projects like TransGO, as well as other R&R projects.

64. We consider that the Commission's determination should reflect the types of uncertainties contemplated in the RCP2 final decisions and reasons paper,[31] as timing, scope, and cost uncertainty.

*Clause 3.2.1 of the Capex IM – consistency with Net Market Benefit Test for base capex projects that exceed the Base Capex Threshold*

65. We disagree with the Commission that the economic assessment of replacement and renewal (R&R) investment – investments driven by condition – "should be" consistent with a net electricity market benefits test. The test was created by the Electricity Commission for evaluating capacity needs driven by demand and generation changes identified through the regulated processes of the Grid reliability report and the Grid economic investment report under the Code.

66. The Commission has however described its view of what "*consistent with a net electricity market benefits test*" means. It writes "*a cost-benefit analysis consistent with determining expected net electricity market benefit is one that applies an expenditure objective such that the proposed capex reflects the efficient costs that a prudent supplier of electricity transmission services would require to* …:"[32]

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[28] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023, para.. 4.10.2.
[29] Because the expenditure is to be incurred after the date of application on assets forecast to be commissioned within the regulatory period (Capex IM 3.2.3 (1)).
[30] Commerce Commission, Capex IM draft determination clause 2.2.3 (8).
[31] Commerce Commission, Setting-Transpowers-individual-price-quality-path-for-2015-2020-final-decisions-and-reasons-2014 para. D18.
[32] Commerce Commission, Setting-Transpowers-individual-price-quality-path-for-2015-2020-final-decisions-and-reasons-2014 para. D18.1

67. We propose that Capex IM clause 3.2.1 (a) be replaced with "*a cost-benefit analysis consistent with what a prudent and efficient supplier of electricity transmission services would undertake*". This keeps the Commission's intent intact but better aligns the requirements to the cost benefit analysis to the investment type.

68. The Fibre Capex IM provides useful precedent. The issues we raised about application of the net market benefit test for replacement investments driven by condition and asset management strategies would be addressed if the Commission adopted the fibre Capex IM prudent and efficient operator test.

69. The fibre approach would be consistent with the Commission commentary about Transpower providing analysis that "would give effect to the original policy intent that thorough and rigorous process is applied when testing the economics and engineering solutions of any base capital expenditure," to justify renewal investment."[33]

### *Clause 3.2.1 of the Capex IM: Consultation for ongoing programmes of work*

70. Transpower welcomes the draft decision to clarify that the current drafting of clause 3.2.1 of the Capex IM only requires Transpower to conduct consultation when the programme is first proposed and that there are no ongoing consultation obligations once the programme has commenced.

71. "First proposed" includes through the regulatory control period proposal consultation process. We strongly recommend that for supplier and consumer certainty under the statutory role for the IMs, the clarification should be expressed by appropriate drafting in the Capex IM. For example, new personnel at Transpower or the Commission may only read clause 3.2.1 and be unaware of the policy clarification in the reasons paper.

### *Anticipatory Connection Assets (ACA) capacity*

72. Transpower agrees with the Commission that consideration of ACA capacity capex scrutiny would logically fall under the Capex IM as the regulated cost recovery for the anticipatory capacity is via the TPM.

73. However, the proposal of the Commission to have Transpower propose anticipatory capacity investments at the regulatory proposal stage is currently unworkable.

74. The nature of ACAs is such that the timing and identification of the need will be determined by the (first mover) customer connection request. The connection investment requirements would be determined by the extent to which the customer (first mover) has agreed to fund the connection asset under investment agreements, and the additional investment Transpower considers is prudent and efficient to meet both current and anticipated future needs.

75. By design, the process is driven by a customer initiation. We do not forecast customer connection works in our regulatory proposal because the cost recovery is not via the TPM. ACA capacity investments would not be able to be included in base capex proposals, unless enabled via reopeners.

76. If the Commission is going to require approval of ACA capacity investments, the proposals would need to be able to be made at any stage of the regulatory control

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[33] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 12.31.

period to ensure first movers are not unduly held-up under their commercial (TWA) process.

77. We had proposed a connection capacity uncertainty mechanism based on "use-it-or-lose-it" such that the funds for any additional capacity could be accessed as needed to maintain an efficient Customer connection process [refer to the appendix for more detail].

78. We support the accounting basis that the connection asset cost recovered by investment contract would be assigned a nil value in our asset register, (and by inference, that the capacity of the connection asset recovered by the TPM is assigned a positive value in the asset register.) This approach is consistent with our proposed practice.

### *Major Capex consultation and approval processes*

79. The existing consultation process mandates two rounds of consultation on a long list and a short list. As indicated in the cover letter, we consider there is opportunity to create more commensurate consultation for investments that:

    - are valued below $100m
    - are grid reliability standard (GRS) investments under the deterministic limb
    - have limited technical and economic solutions to resolve the constraint
    - are technical in nature and have limited stakeholder interest.

80. We consider $100m reflects a level proportionate to which a short list consultation would be appropriate to gain an understanding of stakeholders' views. This would help reduce the consultation burden on stakeholders and better target the submissions that could have more meaningful impact on the investment option decision.

81. For example, the Henderson – Marsden line in Northland is a double circuit line, with one circuit duplexed for its entire length, and the other circuit duplexed for the southern 20%. Significant capacity could be enabled through duplexing the remaining single current section. There would be limited if any other technical solutions that could match the $/MW of this option.

82. Both the Waikato Upper North Island Voltage Management Stage 2 and Upper South Island projects follow on from previously approved MCPs. The previous MCPs included wide consultation to derive a preferred investment for the subsequent MCP. The preferred option is substation based, to be constructed on land already owned by Transpower and hence are likely to have limited interest from a technical consultation perspective.

83. The Commission considers the circumstances applying to Transpower have changed sufficiently to require a different approach for flexibility in the approval of major capex proposals.[34] Specifically, that "*In a rapidly changing decarbonisation and electrification environment, with uncertain demand growth and new renewables generation*

[34] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 8.23

*connections, the inability to change outputs while an MCP is being assessed may lead to MCP process inefficiency."*[35]

84. In this context, Transpower supports the draft decisions to:
    - *introduce a mechanism to allow Transpower to amend the project outputs in a major capex proposal after it has been submitted, but before the Commission has issued its draft decision on the proposal. The Commission may recommend Transpower reconsiders its proposal or Transpower may give notice of its intention to amend;* and
    - *clarify that the Commission may approve the proposed investment with some, but not all, of the outputs proposed by Transpower in an MCP – if the Commission considers that the proposed investment, with the inclusion of some of the outputs, does not satisfy the investment test. That is, in the event the Commission is satisfied that the removal of one or more outputs would increase the net electricity market benefit of the proposed investment.* [36]

85. We also strongly agree with the Commission's position that "*This decision does not extend to allow the Commission to amend any outputs or promote alternative outputs. That remains Transpower's role. We would only be deciding that, during our evaluation of the MCP proposal, a proposed output does not meet the investment test and therefore approving that investment does not promote the long-term benefits of consumers.*"[37]

### *Independent verification*

86. The Capex IM should follow the Fibre IM level of prescription for independent verification.

87. Transpower supports the draft decision for requiring that our base capex and opex proposals from RCP5 onwards (assuming Transpower is under an IPP)[38] are subject to pre-submission verification. The voluntary use of a verifier for RCP3 (and RCP4) has been beneficial and assisted Transpower in providing its proposal and has reduced the time and cost for the Commission to evaluate the expenditure proposal.[39]

88. However, we strongly disagree with any prescription for the Terms of Reference (ToR) and consider if any guidance is needed it should be at a principles level. The objective for the use of an IV for Fibre (also under an IPP) is higher-level. The Capex IM already contains the prescription for the evaluation of our base capex proposal, and the IV must apply that.

89. The level of prescription for the IV role in the CPP for EDBs is because the EDBs do not have a Capex IM. The Capex IM introduced in 2012 means the Commission complied with its statutory direction that the *extent of independent verification* condition was met (i.e. there was none). The Commission's evaluation role fulfilled the scrutiny requirement.

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[35] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 8.18
[36] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 8.10.1 and 8.10.2
[37] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para.. 8.34
[38] Commerce (Part 4 Regulation—Transpower) Order 2010 (SR 2010/268)
[39] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023

90. We consider the agreement of a ToR between the Commission and Transpower should be codified, but its form should be agreed as part of the lead-in to an RCP proposal. This approach removes compliance risk for Transpower and the third-party and allows for tailoring of review to the regulatory period in question. For example, for the ToR for RCP4 Independent Verification, the Commission and Transpower agreed several changes to the RCP3 Independent Verification ToR. We note that these changes are not reflected in the Commission's draft determination.

91. Transpower should not be at fault under the new rules should its search for an independent verifier yield no suitable party. The Commission is still able to perform its evaluation duties under the Capex IM (i.e. via Schedule A).

*Opex related to Major Capex and Enhancement and Development Projects*

92. Transpower supports the draft decision to amend:
    - the E&D capex reopener mechanism in the Transpower IM to allow non-transmission opex solutions as an alternative to capex (we note the term should be *transmission alternative opex* consistent with existing drafting for E&D); and
    - the Capex IM to allow that, in an MCP application, Transpower can seek approval for uncapitalised opex that is incurred because of that MCP.[40]

93. The draft decision to not allow opex in a listed project solution[41] would effectively remove any ability to consider *transmission alternatives.* Using the Listed project mechanism means no capex for these projects was in the base capex proposal, hence no forecast capex in the price path against which a transmission alternative opex solution can be assessed as being the cheaper option.

94. However, we note this decision may conflict with the current Transpower IM that a transmission alternative operating cost is classed as a *recoverable cost*.

95. In any case we propose removing the term "transmission alternatives" from the Listed project application. This amendment accords with the Commission's recognition that "*the much simpler listed project process requires Transpower to consult once and does not require it to consider solutions outside those associated with reconductoring transmission lines, such as transmission alternatives*"[42] and that the term is redundant for non-grid lifecycle projects.

*Cost allocation methodology*

96. We concur with the potential problem these rules are meant to resolve and note a regulated supplier should not be disincentivised from delivering demand side management as per s54Q of the Commerce Act 1986.[43] We agree it is possible for Transpower to restart a demand response programme.

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[40] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 11.3.
[41] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 11.3.
[42] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 4.10.2.
[43] 54Q Commerce Act 1986 The Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this Part.

97. Consequently, we support the 2% threshold to ensure cost allocation activity as "*not being so low as to impose significant regulatory costs on the regulated supplier for limited benefit, while at the same time not being so high that it could result in a misallocation of costs.*"[44]

### *Adding related party asset valuation (AV) rules for Transpower*

98. Given the limited extent to which Transpower is involved in unregulated activity, we query whether the extra compliance costs associated with adopting the related party AV rules from the EDB and GPB IMs into the Transpower IMs, subject to any required modifications, is warranted.

99. We note that when the matter of Related Party Transactions was considered in the last IMs Review the discussion did not include Transpower (presumably for the reasons above).

### *Treatment of capital contributions*

100. Transpower supports the draft decision to make no change to the Transpower IM in relation to the treatment of capital contributions. We agree that under our current accounting practices, the issue is presently restricted to a narrow range of capital contributions. Changing the IMs would be unlikely to justify the transitional compliance costs.

### *Transpower's proposal of making insurance payments a pass-through cost*

101. The increasing number of weather events have pushed insurance premiums up significantly. We expect these to continue to increase over time. Premiums typically increase after an event as insurers re-evaluate the probability and cost of an event.

102. We understand the Commission's reasons for its draft decision not to make insurance premiums a pass-through cost, however we consider that the current arrangements may not balance risk appropriately between regulated entities and consumers. While the Commission may not consider a straight pass-through to be appropriate, other approaches, such as uncertainty mechanisms or lower incentive rates on insurance premiums could be considered.

### *Minor clause issues resulting in change – information on transmission charges*

103. We support the draft decision to amend clause 7.5.1 of the Capex IM by deleting references to estimating increases in transmission charges based on per kilowatt of demand. This change is consistent with the new TPM which does not (directly) have per kilowatt charges.

## Resilience expenditure

104. Our submission remains that resilience outcomes as an expenditure objective should be allowed for under a base capex proposal.

105. Categorising resilience investments as "*either a major capex proposal (MCP) or as enhancement and development (E&D) capex in a base capex proposal*"[45] is too narrow

[44] Commerce Commission, Draft-decision-Transpower-investment-paper-14-June-2023 para. 10.38.
[45] Commerce Commission, CPPs-and-In-period-adjustments-topic-paper-14-June-2023 para. 9.94.

and the type of work we are proposing in our resilience programme does not align with this policy context. E&D and major capex needs are derived in the same manner from Grid Reliability Report and Grid Economic Investment Reports under the Code[46] - demand and generation changes are the investment drivers - and solutions typically deliver capacity.

106. The current drivers for the E&D reopener, as specified in the Transpower IM, would not allow us to propose resilience work.

107. Our capability in resilience planning has matured over the past 10-15 years. We now have a grid wide understanding of our vulnerabilities for most of our resilience threats, and the likely impact on service if they materialise. Our vulnerability assessments have informed our cost-effective risk-based pro-active investment plan in readiness and risk reduction for inclusion in our RCP4 proposal, supported by our Grid Resilience Strategy.

108. We accept using an evaluative approach applying "*likelihood of event* x *consequence*" approach is appropriate for some types of expenditure, as we did in RCP2,[47] but that does not make it the only approach going forward when the need for resilience is only increasing.

109. Internationally, regulators are using standards to drive resilience expenditure e.g. UK's work on flooding standards (ETR 138), and work in the US after the recent catastrophic events in Texas and Florida.[48] (For meeting standards, **cost effectiveness** assessment is also an appropriate approach, as allowed for under the Capex IM when we invest to meet the GRS on the core grid (the standard being N-1).

110. While recent experiences show new assets built to current standards perform well in major hazard events, many older assets reflect the lower standards and awareness at the time. While replacement and refurbishment cycles provide the opportunity to upgrade to appropriate standards, the timing may be many years away. We consider the risk is not acceptable now.

111. The Department of Prime Minister and Cabinet (DPMC) is consulting about strengthening New Zealand's critical infrastructure.[49] It identifies four main global drivers for **greater** resilience consideration through megatrends of: climate change; national security (e.g., espionage); economic fragmentation causing supply chain issues; and cybersecurity risks.

112. DPMC identifies the approach[50] the Commission highlights:

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[46] Electricity Industry Participation Code 12.76 and 12.114.
[47] Base E&D for HILP capex of $9.2M Setting-Transpowers-individual-price-quality-path-for-20152020-final-decisions-and-reasons-2014-NZCC-23-29-August-2014, page 75.
[48] Joint Federal-State Task Force on Electric Transmission | Federal Energy Regulatory Commission.
[49] Department of Prime Minister and Cabinet, discussion-document--strengthening-the-resilience-of-nzs-ci-system, June 2023 page 22.
[50] Department of Prime Minister and Cabinet, discussion-document--strengthening-the-resilience-of-nzs-ci-system, June 2023 page 22.

**These megatrends risk exposing the limitations of our current approach to resilience**

59. New Zealand's long-standing approach to regulating for critical infrastructure resilience has relied on the assumption that critical infrastructure owners and operators (or regulators) could accurately determine:

    a. the likelihood of a shock occurring

    b. know who or what would be affected by that shock

    c. estimate a shock's costs

    d. make rational choices about what investments to make to reduce those costs.

113. DPMC's view is "*this approach to ensuring resilience has historically served New Zealand reasonably well. However, it is not likely to be well suited to manage the complex challenges to come. For example, these four megatrends will make it more difficult to: a. forecast the likelihood of shocks, particularly those linked to a changing climate and state threats b. determine a shock's impact, as effects ripple through an increasingly interconnected infrastructure system…*"[51]

114. We agree with the DPMC characterisation of how the external context has changed. We have looked at ways to incorporate a greater range of resilience outcomes into our planning. Obtaining the information needed for a *likelihood* x *consequence* approach may not be possible for a number of reasons, including:

    - we do not know the value of resilience in a catastrophic event
    - we cannot yet know all the return periods and probabilities of the event occurring (e.g. climate change effects are changing existing understanding)
    - VOLL estimates do not include risk aversion or societal cost in relation to a catastrophic event. In addition, the VOLL estimate is not based on long duration outages.

115. On the third point, the Commission offers that we can propose our own VOLL, but the research literature[52] on the VOLL for wide-area long-duration outages (WALDO) is embryonic in arriving at any numbers. We consider we would have no basis to propose anything other than the VOLL derived for the usual context of ordinary unplanned interruptions.[53]

116. Strata's work on Wellington Electricity's CPP for earthquake resilience[54] discussed the VOLL for disaster situations, and noted there is no post-earthquake estimate of the VOLL. Strata considered that it is the unquantified benefits that are the primary driver of resilience investment for catastrophic earthquake events. Wellington Electricity's list of unquantified benefits showed benefits were sufficiently substantial to justify the proposed investments.

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[51] Department of Prime Minister and Cabinet, discussion-document--strengthening-the-resilience-of-nzs-ci-system, June 2023 page 22 para. 60.
[52] For example, the US Department of Energy (transmission) convened a workshop to "identify research needs and discuss potential avenues for methodological advances in the economics of widespread, long-duration power interruptions." Frontiers in the Economics of Widespread, Long-Duration Power Interruptions Proceedings from an Expert Workshop Larsen et al 2019.
[53] See our own commissioned research on VOLL [2016].
[54] Strata Energy Consulting, Assessment of Wellington Electricity CPP readiness expenditure, 18 December 2017.

117. We think the lack of information should not prevent resilience work from proceeding where there are clear risk mitigation benefits at relatively low cost for our customers. In fact our evaluative approach is not dissimilar to the role for *unquantified benefits* we are allowed to take account when assessing options in the Investment Test.

118. Our resilience expenditures are to mitigate the effects of, respond to, and recover from, hazards and threats to our critical infrastructure. Our economic assessments take a risk-based approach consistent with good asset management practice to achieve cost-effective and efficient solutions. The Commission has recognised cost-effectiveness as an evaluative criterion for our base capex proposal which means we are able to propose base capex on that economic premise. We are not proposing that an expenditure for resilience has no economic assessment.

## Expenditure for sustainability objectives

119. The IM draft review stated Transpower should *not* recover expenditure for the purpose of improving biodiversity.

120. Expenditure on biodiversity and sustainability are necessary for delivery of our transmission lines service. The Commission relates biodiversity to amenity benefits which sit outside the electricity net market benefits. We disagree that biodiversity only adds to amenity benefits, noting the current legal definition of 'amenity' does not include biodiversity.[55]

121. We consider that biodiversity is a key part of the environment that must be addressed in terms of managing impacts on the environment under Aotearoa New Zealand's resource management and conservation legislation, as well as playing a key role in climate change adaptation and mitigation.

122. Managing adverse effects is a key aspect of the RMA obliging a general duty to *avoid, minimise, remedy, offset or take steps* to provide redress for adverse effects. Existing national direction is making the requirement to offset more explicit, and mandatory (rather than something an applicant offers up to ensure they obtain consent). For example, the National Policy Statement on Freshwater Management[56] requires offsetting for biodiversity impacts, including containing two very detailed appendices about what must be achieved.

123. As an operator of nationally significant infrastructure and a critical utility, our network disrupts biodiversity in many ways. Disruption ranges from day-to-day removal of indigenous (and exotic) vegetation; severance of habitat from the construction of power lines and their access tracks; disturbance to water courses and areas of high use to native birds and bats; and ongoing impacts from routine maintenance of transmission lines and access tracks. We have 25,000 towers as part of our lines assets, with over 2,000 towers located in high conservation value areas (Department of Conservation-administered land and QEII Covenants), such as national parks some of which include areas of critical habitat for indigenous species. Many other lines assets, while located on

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[55] The primary legislation for managing amenity is the Resource Management Act 1991 or the RMA, which defines "amenity values" as: *"Those natural or physical qualities and characteristics of an area that contribute to people's appreciation of its pleasantness, aesthetic coherence, and cultural and recreational attributes."*
[56] National Policy Statement for Freshwater Management 2020.

private land, are located within or in close proximity to Significant Natural Areas regulated under the RMA framework, which also require careful management of biodiversity impacts.

124. Maintaining access involves construction and maintenance of culverts over streams and rivers, that ultimately restrict native fish passage upstream reducing catchment biodiversity. Whilst we strive in all we do to minimise these impacts on Aotearoa New Zealand's biodiversity, our activities will always result in biodiversity loss in some form or another.

125. Hence, like many organisations with biodiversity impacts, Transpower has committed to achieving a *net* indigenous biodiversity gain for our project work as part of our Sustainability Strategy. Not only is this to ensure we can maintain our social licence to operate, but biodiversity is increasingly important to our many stakeholders, landowners and particularly iwi and hapū organisations we interact with as part of our work or who we require sign-off from for resource consents. Our biodiversity commitments also reflect the growing international cognisance and resulting frameworks which recognise the importance of biodiversity, its maintenance, improvement, and its role in reducing climate-change risks.

126. Our proposed sustainability expenditure revolves around early development work on reducing our biodiversity impacts, and ultimately achieving *net* biodiversity gain through mechanisms such as culvert upgrades to meet fish passage requirements and indigenous restoration planting in impacted sites. This research and design work will be supported by expert ecologists' recommendations including assessing different options, together with the work required to and costs associated with securing resource consents, including associated consultation with stakeholders.

127. These initiatives will be crucial in responding to reform of the resource management system, which regulates the effects on Aotearoa New Zealand's biodiversity. In any event, Transpower as responsible state-owned enterprise will still be expected to "make good" in its impacts on biodiversity.

128. Our 2022/23 Sustainability Strategy is focused on improving the sustainability of our ongoing operations while driving long term change. It is underpinned by an extensive implementation programme to ensure that it is delivered across all divisions and teams within Transpower as well as with our service provider, supplier and community partners. Over the long term we are striving to drive behaviour change so that the sustainable way becomes business as usual.

**Table 1 Summary of Investment Paper draft decisions and Transpower response**

| Reference | Draft decision | Response / comment |
|---|---|---|
| X45 | Codify a requirement for Transpower to undertake an independent verification of its IPP proposal. | Support intent; however the level of prescription for the Terms of Reference is unnecessary, stifles evaluation flexibility and creates compliance risk from the many new pages of legal drafting. The role for the IV should be as presented in the Fibre IM but the mechanics of the verification process managed by non-codified ToR.<br><br>The Commission should also allow for the risk that there are no satisfactory proposals for the IV role. |
| X31 | Extend the categories of projects that can be listed to reduce the regulatory cost and complexity….to include transmission line reconductoring projects where the primary driver is conductor deterioration (but there may be incidental increase in capacity); and non-grid lifecycle replacement projects with estimated costs greater than the base capex threshold and a high level of uncertainty in cost. | Agree. For grid investment we consider the listed project mechanism should clarify it allows more investment types than just reconductoring, consistent with the Commission's evaluation criteria 2.2.2 (7) in the Capex IM.<br><br>We consider that the Listed project criteria should reflect all type of uncertainties as recognised in RCP2 final decisions and reasons paper,[57]which contemplates timing, scope, and cost uncertainty. |
| 3.103 | Reduce some of the unnecessary difficulties in estimating costs to the level of accuracy required by the P50 estimate. Our proposed amendment is to set a deadband around the P50 estimate for the Major Capex Allowance. The deadband ranges will be from the P30 and the P70 estimates. | Agree. |

[57] Setting-Transpowers-individual-price-quality-path-for-2015 - 2020-final-decisions-and-reasons-2014

| Reference | Draft decision | Response / comment |
|---|---|---|
| 3.11 | Amend the Capex IM to remove any ambiguity as to the extent of modelling that Transpower must carry out….It is our expectation that there will be a total of five scenarios (either EDGS or a variation) analysed. | Our preference is discretion on the number of scenarios, commensurate with the investment context. |
| 3.139 | No change to 10% difference between options | Accept. However, we note that while we can propose alternative percentages it creates an 'anchor bias' and there is limited rationale to the choice of the 10% anchor point. |
| 3.143 | No change to use of sensitivity analysis | Accept. |
| 3.148 | No change in respect of criteria for E&D and R&R base capex definitions, as they are flexible enough to support resilience expenditure proposals. | Strongly disagree. See cover letter and our response to the Transpower investment paper. |
| 3.26 | Clarify how the analysis of counterfactuals should be conducted. Transpower is able to develop and use a counterfactual scenario to quantify the economic impact of no transmission investment being justified to meet increased electrification demand | Agree, noting that Transpower always does do scenario analysis. |
| 3.26.1 | Not include a demand-side decarbonisation benefit in the Capex IM, because this effect is already factored into the analysis through the wholesale electricity price and demand forecasts. | Accept. Transmission investments are required to support decarbonisation objectives. Some investments maybe justified by wider economic benefits, and these may need to be driven by policy support/ direction from government. |
| 3.42 | The default discount rate reflects current market conditions…we propose to change the default discount rate to be used for the investment test to 5% with default sensitivities of 3% and 7%. | Agree. |

| Reference | Draft decision | Response / comment |
|---|---|---|
| 5.23 | Propose to amend the 'for avoidance of doubt' provision in clause 3.3.3(1) of the Capex IM to support the original policy intent (about project staging). | Agree. |
| 5.96 CPP and adjustments | Amend the IMs to introduce a 'reopener event allowance' recoverable cost in the EDB, GDB and the GTB IMs, which enables EDBs and GPBs to recover costs incurred as a result of any 'reopener event' up until the date the reconsidered price-quality path takes effect. | By not making this decision apply also to Transpower we assume the Commission has concluded this provision is already available to Transpower. Otherwise, Transpower should have this provision too.<br>If the Commission decides against the event being a reopener event, these (sunk) costs should still be recoverable. |
| 7.3.1 | Increase the base capex threshold to $30 million to account for inflation, until the next IM Review in 2030 (expected); also, refer directly to "base capex threshold" rather than a nominal value. | Agree. These changes should be effective from when the new IMs are gazetted. |
| 8.15 | Provide greater flexibility in the Capex IM regime in respect of Major Capex Outputs to provide partial approval for Major Capex Projects by approving some but not all outputs; a mechanism that allows Transpower to apply to amend individual outputs between the time it submits a major capex proposal and when we release a draft decision. | Agree. |
| 10.4. | Add the related party asset valuation rules from the EDB and GPB IMs to the Transpower IMs (including it is clear that GAAP applies on an arm's-length basis); require that the value of a commissioned asset Transpower acquired from another regulated supplier is at its RAB value. | Agree. |

| Reference | Draft decision | Response / comment |
|---|---|---|
| 10.4.1 | Require Transpower to apply Activity Based Allocation Accounting (ABAA) to adjust the total costs associated with supplying regulated services to take into account costs that are common to regulated and unregulated services. Threshold 2% cost. | Agree. |
| 10.4.1 | Require Transpower to adjust its **pass-through costs** to take account of those costs which are common to regulated and unregulated services; this requirement only applies if Transpower's common costs (costs not directly attributable) exceed at least 2% of its costs associated with regulated services. | Accept. |
| 10.4.1 | Require Transpower to adjust its **recoverable costs** to take account of those costs which are common to regulated and unregulated services, requirement only applies if Transpower's common costs (costs not directly attributable) are at least 2% of its costs associated with regulated services. | Accept. |
| 10.4.3 | Not amending the IMs in response to a potential problem with the accounting treatment of capital contributions Transpower receives | Agree. |
| 10.4.4 | No change to treat insurance costs as pass-through costs. | Accept, but note that as the volatility of insurance claims increase the Commission may need to revisit how insurance premiums are allowed for. |

| Reference | Draft decision | Response / comment |
|---|---|---|
| 11.16 | In a major capex project (MCP) application, Transpower can seek approval for uncapitalised opex that is incurred as a consequence of an MCP. | Agree. |
| 11.31 | To not allow for automatic price path adjustments as the Commission considers doing so would not provide the necessary scrutiny. | We consider the requirements under Transpower's IPP following a price path adjustment to be unnecessarily burdensome and add additional cost to consumers with zero benefit. We do not understand how this better promotes the Part 4 purpose.<br><br>The Commission states "*Additionally, when Transpower submits an MCP or listed project proposal for example, it can also submit the revenue impact information consistent with the requirements from clause 3.7.4(4) of the Transpower IM. No separate process is necessary.*"[58] However, under clause 30 of Transpower's RCP3 IPP, we are required to undertake a range of tasks to allow for an adjustment to our forecast MAR and SMAR, including an independent assurance report.<br><br>Each year the Commission requires us to audit our disclosure year to ensure that we have followed the requirements of the IPP and the Information Disclosures. Part of this requirement is ensuring that our reported, and recovered, revenues are correct.<br><br>We are incentivised against expenditure and not revenue. Revenue is a function of the approved allowances and any update to forecast MAR and SMAR will follow the same building block methodology established at the start of each regulatory period. We are audited against these building blocks as part of the annual regulatory audit. In the case of an MCP, the Commission only needs to determine what the allowed expenditure is. Our auditors, as appointed by the Office of the Auditor General, will then |

[58] Draft-decision-Transpower-investment-paper-14-June-2023. para. 11.30 [note the Commission's reference should be to clause 3.7.4 of the Transpower IM]

| Reference | Draft decision | Response / comment |
|---|---|---|
| | | provide assurance that we have correctly included our allowed expenditure when determining our annual revenue.<br>It seems reasonable that once the Commission has made a determination as to the amount of the allowed expenditure, Transpower should be able to update its revenue to reflect the allowed expenditure without an entirely separate (and burdensome) audit engagement that will be recovered from consumers. Additionally, our RCP4 revenue model will allow for in-period adjustments and this capacity will have separate assurance.<br>We acknowledge this may be more of an IPP issue than an IM, however we consider that it is appropriate to bring it to the Commission attention here given the additional costs it creates for consumers. |
| 11.3.1 | Amend the E&D capex reopener mechanism in the Transpower IM to allow non-transmission opex solutions as an alternative to capex; | Agree; but the term should be "transmission alternative opex" consistent with E&D as base capex (non-transmission solution is specific to major capex). |
| 11.3.2 | Not to amend the listed project mechanism in the Capex IM to allow opex solutions as an alternative to capex. | Agree. No need to amend because under the Transpower IMs (clause 3.1.3 (1) (c)), a **transmission alternative** operating cost is a recoverable cost. |
| 12.3 | Amend clause 7.5.1 of the Capex IM to remove reference to "per kilowatt of demand" when calculating transmission charge increases. | Agree. |
| 12.4.3 | No amendments to clauses 3.7.4 (When price-quality paths may be reconsidered) and 3.7.5 (Amending price-quality path after reconsideration) of the Transpower IM.<br>No change to the revenue-linked grid output measures to be amended following a catastrophic event, error, or | Despite the decision for no amendments being made, we note the draft Transpower IMs determination may have been inadvertently substantively amended. An existing provision that explicitly provides for the Commission to be able to amend the grid output measures following a revenue impact of a major capex or listed project, has been removed. Refer current clause 3.7.5 (2). |

| Reference | Draft decision | Response / comment |
|---|---|---|
| | change event, as provided for in the price-quality path reconsideration provisions in the IMs | Under a decision for no change, it is unclear that the new proposed clauses 3.7.11 and 3.7.12 include the existing policy provision for reconsideration of grid output measures following the revenue impact of a major capex and listed project. |
| 6.3 – 6.5 | Allow ACA investments to be made to address the Type 2 First Mover Disadvantage and ensure ACA investments are economically justified and tested under the Capex IM regime. In particular, we are proposing that: [précised]<br><br>When ACA capacity is being proposed under an MCP, Transpower: is only required to perform a shortlist consultation; when ACA capacity is being proposed in a base capex proposal as E&D capex, Transpower must identify those ACA capacity investments; | Unworkable in practice. Our base capex proposal does not include E&D on connection assets because capacity needs are managed by our investment contracting process and costs are not recovered by the TPM. This process is customer-led.<br><br>For that reason we proposed the role for an uncertainty mechanism to manage the specific situation. The E&D reopener will not work either as that would require at least one more project, an unlikely condition when depending on third party timing. |
| 12.4.1 and 12.4.2 | Retained the current clause 3.2.1 requirement that a cost-benefit analysis must be undertaken on a base capex project or programme involving forecast capital expenditure of greater than the base capex threshold; but clarify that Transpower is not required to undertake consultation for ongoing programmes of work that have already been consulted on; | Accept. The CBA is "consistent with" determining **expected net electricity market benefit** but this term is specific to the Investment Test applied for testing options for capacity increases driven by demand and generation changes identified by the GRR and GEIR under the Code.<br><br>Propose 3.2.1(a) clause is changed to the following:<br><br>• *a cost-benefit analysis consistent with what a prudent and efficient supplier of electricity transmission services would undertake*<br><br>If the rule is to remain then additional clause drafting is vital to confirm that Transpower is not required to undertake consultation for works that have already been consulted on through the base capex proposal and have been independently verified.<br><br>We will propose drafting, in the draft Capex IM determination. |

## Financing and incentivising efficient expenditure during the energy transition

129. The focus of this topic paper is on the tools and mechanisms, other than the cost of capital, that affect incentives for efficient investment and spending decisions.

### *RAB indexation*

130. The main decision is the proposal to index Transpower's RAB to inflation from RCP4 onwards. We address this issue[59] in our cover letter and have also appended an expert report from Frontier Economics on RAB indexation.

131. We acknowledge that an indexed approach might be preferable in certain circumstances. For example, an indexed RAB can provide suppliers greater protection against inflation and can result in smoother prices in real terms over time when compared to an unindexed approach.

132. Frontier Economics estimated that indexation of our RAB through RCP3 means Transpower would have been better off by $340m, being the difference between outturn and forecast inflation.[60]

133. We acknowledge the Commission's decision comes during a cost-of-living crisis and indexing will defer some cost recovery to the future. However, we note that Transpower makes up 10% of the average household's electricity bill and therefore the indexation of Transpower's RAB is unlikely to have a noticeable impact on consumers' electricity bills.

134. In its 2010 IM reasons paper[61], the Commission concluded that "*the higher cash flows that are associated with an unindexed approach in the first years following an investment were better suited for Transpower's investment profile going forward than CPI-indexation would be*" and that this "*was particularly important given the magnitude of Transpower's proposed investments, and the fact that the associated capex would often span multiple years prior to commissioning*".

135. The Commission maintained the unindexed approach as part of its 2016 IM review. The Commission's conclusion in the current context is at odds with its previous conclusion.

136. Transpower continues to forecast a substantial investment programme over the next 10-15 years. We are anticipating our closing RAB[62] in 2035 to be more than double our closing RAB in 2023 (nominally). This is an equivalent to the growth in the RAB observed from 2008 to 2020. As noted by Frontier Economics[63], and demonstrated by the Commission's modelling, the equity portion of Transpower's capex in RCP4 and RCP5 could be more than $2 billion during each of RCP4 and RCP5. This is significant

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[60] Frontier economics RAB indexation report for Transpower July 2022 page 12. (Frontier described the issue the other way, that consumers benefit by $340 million from not having 'protection against inflation' provided by the Commission over RCP3).

[61] Commerce Commission, Input Methodologies – Reasons Paper 2010, December 2010, para. 4.3.9.

[62] Unindexed, based on current forecast.

[63] Frontier Economics, RAB indexation, a report for Transpower, 13 July 2023.

relative to the equity component of the RAB at the beginning of RCP4. This presents a hugely significant equity-raising task over RCP4 and RCP5 which is further exacerbated by the transition to an indexed approach. Frontier consider that "*it is precisely this current point in time when the proposed change to RAB indexation would have the greatest impact on Transpower – just when capital investment of national significance in New Zealand's decarbonisation efforts is required*".[64]

137. Associated forecast capex, particularly that relating to major capital projects, will "span multiple years prior to commissioning."[65] Transpower accrues interest during construction during the build phase of these projects but inwards cashflows to cover the cost of capital are not provided until the projects are commissioned and have entered the RAB. With an indexed RAB, the disconnect between inwards and outwards cashflows relating to these projects is even larger, as only a real return is earned upfront.

138. We are concerned about the following effects this draft decision would have on Transpower operations:

- A possible reduction in Transpower's credit rating, increasing borrowing costs in turn
- Balance sheet implications which will impact Transpower's ability to continue to offer long-term financing to our electricity distribution customers
- Transpower's capacity to pay a dividend to the government as shareholder and potentially a need for equity injections (Separately, we are concerned with the Commission's position on financeability).

139. We agree with the draft decision to allow Transpower to apply for an alternative depreciation approach, should we be subject to indexation.

140. Notwithstanding our above position that we do not support the indexation of our RAB, if the Commission were to proceed with its position, we strongly recommend that it consider the 'hybrid approach' as suggested by EDBs during the 2022 IM Processes and Issues paper consultation.[66]

141. The approach involves the indexation of the return on equity component of the rate of return only. The return on debt proportion of the rate of return provides a nominal return. Therefore, better aligning cash flows in with those going out.

142. As the Commission has noted its draft decision as "*finely balanced*"[8] we consider this approach would balance supplier certainty and comfort for financeability, especially considering the upcoming investment profile, with the advantages of a fully indexed RAB.

143. We note the hybrid approach proposed is not the same solution as the Commission proposal to exclude the return on debt from the annual revenue wash-up. The Commission's draft decision deals with the difference between outturn and forecast

[64] Frontier Economics, RAB indexation, a report for Transpower, 13 July 2023.
[65] For example CUWLP and NZGP1 span 5+ years.
[66] E.g. see ENA Submission-on-IM-Review-Process-and-Issues-paper-and-draft-Framework-paper-11-July-2022.

inflation being applied to the cost of debt, whereas companies can hedge for this. The draft decision does not provide for nominal cash flows to match interest payments.

144. We need to consider more carefully the implementation issues of any proposed change, both for our RAB register and the role of the asset values for generating TPM charges (e.g. for establishing the costs to recover for a benefit-based investment).

*Remove the baseline adjustment term for Transpower's opex incentive calculation.*

145. Transpower strongly supports the removal of the baseline adjustment term and agrees with the Commission that it "*introduced significant levels of uncertainty to the IRIS mechanism which is proving detrimental to the predictability and effectiveness of the mechanism.*"[67] This is especially apparent when applying the RCP3-established methodology against forecast RCP4 inputs.

146. However, we do not agree that an "opex IRIS approach [like that] applied in the EDB DPP"[68] is appropriate for Transpower for the following reasons:

- our understanding is the Commission has misinterpreted our RCP4 proposal document.[69] In the proposal, we refer to updating numbers from 2021/22 to 2022/23 (or Year 2 to Year 3 of RCP4), instead of Year 3 to Year 4 as suggested by the Commission. We intend to use Year 3 as the base year for RCP4.
- we do not believe an opex IRIS approach like that applied in the EDB DPP appropriately manages temporary savings in the base year when a base-step-trend (BST) approach is used. This is because the overcompensation in the Year 4 IRIS carry forward is not offset by a lower allowance in Y6-Y10, as the allowance for the succeeding regulatory period is set using the BST and not Year 4 actuals.

147. Our understanding is AER's Efficiency Benefit Sharing Scheme (EBSS)[70] has mechanisms in place to appropriately compensate suppliers in this circumstance. We ask that the Commission review the EBSS and assess its appropriateness for Transpower for managing the above issue.[71]

[67] Commerce Commission, Draft-decision-Financing-and-incentivising-efficient-expenditure-during-the-energy-transition-topic-paper-14-June-2023 para. 4.243.
[68] Commerce Commission Draft-decision-Financing-and-incentivising-efficient-expenditure-during-the-energy-transition-topic-paper-14-June-2023 para. 4.250.
[69] Commerce Commission Draft-decision-Financing-and-incentivising-efficient-expenditure-during-the-energy-transition-topic-paper-14-June-2023 footnote 294.
[70] Efficiency benefit sharing scheme (EBSS) – November 2013 | Australian Energy Regulator.
[71] Required changes would be a Year 5 carryforward amount (determined ex-ante), an update to the base year adjustment term formula (referencing Year 3 as the base year instead of Year 4) and determination of base year non-recurrent efficiency gains.

**Table 2 Summary of draft decisions to Financing and incentivising efficient expenditure paper, and Transpower response**

| Reference in topic paper | Draft decision | Transpower comment |
|---|---|---|
| 3.102 | No introduction of any tools for altering the cashflow timing specifically for IRIS | Accept. We have not faced any issues managing cashflow timing of our own IRIS, however we note our IRIS is different to the EDBs in several ways, and so cannot comment on this issue with respect to EDBs. Our own IRIS cashflows are predictable (notwithstanding the baseline adjustment term) and known ahead of time. Additionally, the smoothing of our maximum allowable revenue mitigates any in-period revenue volatility that might be caused by IRIS carry forward amounts. |
| 3.276 | No financeability test in the IMs | Disagree. We support consideration of an introduction of a financeability test. |
| 3.4.3.1 | Index Transpower's RAB to inflation | Strongly disagree. We are concerned that the draft decision to shift Transpower to an indexed RAB does not demonstrably better promote the section 52A purpose of Part 4. Indeed, the converse could be true given the "long-term benefits of consumers" contemplated in the section 52A purpose. The decision is not appropriate given Transpower's upcoming investment profile to decarbonise New Zealand's economy and ensure a safe and reliable electricity supply. |
| 3.4.3.2 | Enable Transpower to apply for an alternative depreciation profile | Accept. This is appropriate should the Commission index Transpower's RAB to inflation. |
| 4.135 | Calculate the opex and capex incentive amounts based on IRIS allowances (adjusted for actual CPI) compared with actual expenditure | Agree. We support this change noting that this mechanism is already in place for Transpower (refer clause 33.3 of Transpower's RCP3 IPP).[72] Suppliers should not be rewarded or penalised for inflation outcomes they cannot control. |

[72] See Commerce Commission, Draft-decision-Financing-and-incentivising-efficient-expenditure-during-the-energy-transition-topic-paper-14-June-2023. para. 5.113.

| Reference in topic paper | Draft decision | Transpower comment |
|---|---|---|
| 4.162 | Maintain the current approach to the opex incentive rate being determined through the IMs | Agree. |
| 4.185 | Not change the current approach of applying the expenditure incentive mechanisms to all categories of opex and capex allowances. | Agree. Our expenditure allowances are intended to be fungible and to the extent opex is uncertain and/or uncontrollable then it should be represented as either a pass-through or recoverable cost. |
| 4.209 | Use the midpoint vanilla WACC for discounting opex savings and estimating the opex incentive rate | Disagree. Transpower appreciates that the midpoint ($50^{th}$) percentile might better represent the actual cost of capital at the time when discounting opex savings for the purpose of setting the standard base capex incentive rate. However, for simplicity we would prefer the Commission maintain the status quo.<br><br>We do not believe this proposed change better achieves the IMs purpose and instead creates more uncertainty for stakeholders because:<br><br>a. it is an additional, separate variable to an already complicated incentive regime; and<br><br>b. it creates a slippery slope where it might be argued that other areas of the price-path not directly linked to investment could be tethered to an alternative rate.<br><br>The actual WACC is not directly observable, the incentives only equalise if the WACC remains at its current level into perpetuity, and the change in the incentive rate from 23.5% to 21.6% is unlikely to alter supplier decision-making. |
| 4.221 | Maintain the current mechanism to account for the treatment of right of use assets/operating leases | Agree. Transpower supports this decision, however we are unsure if the incentive outcome is correct. We note that operating lease payments are excluded from the opex allowance but continue to be treated as opex for IRIS purposes. The effect of the IRIS is to balance the natural incentive. Without a natural incentive to balance, the retention factor for savings is not consistent across the duration of the regulatory period. |

| Reference in topic paper | Draft decision | Transpower comment |
|---|---|---|
| 4.239 | Remove the baseline adjustment term for Transpower's opex incentive calculation | Agree. Strongly support this decision. As we elaborate above, the IBAT introduced significant levels of uncertainty. However, we consider an appropriate alternative is needed to appropriately resolve for total savings in Year 4. |
| 4.27 | Maintain the current suite of expenditure incentive schemes for EDBs and Transpower as tools for mitigating capex bias due to financial regulatory incentives | Accept. While we consider the existing incentive schemes as working broadly as intended, we note that volumetric capex programmes (which appear to be more like maintenance), investor bias, capitalisation changes and subjective judgements, such as the baseline adjustment term (in its current form), can lead to actual or perceived incentives being unequal across opex and capex.<br><br>We ask that the Commission continue to monitor the application of the totex approach in overseas jurisdictions and use the significant lead time to the 2030 price-reset to assess the regulatory costs and benefits of both options on their own merits. We noted in our July 2022 submission that "[w]hile the costs of change will be created in the short term a future totex approach should create option value for the dynamic efficiency to be realised under technological change. Even if the timeline is too short to implement for 2025 then 2030 could be a good starting point for a changed regime."[73] |
| 4.94 | Maintain the current approach to expenditure incentive mechanisms for EDBs and Transpower | Accept. Transpower appreciates the Commission's decisions that respond to concerns we have raised about the IRIS baseline adjustment term (IBAT) and impacts of changes in GAAP on our expenditure incentive mechanisms.<br><br>However, as noted above, while the removal of the IBAT is welcome, we consider an appropriate alternative is necessary to correct for any overcompensation of savings in the penultimate year. |
| 5.4 | Maintain the status quo when forecasting CPI for the regulatory period | Accept. |

[73] Transpower-NZ-Ltd-Submission-on-Expenditure-incentives-EDB-workshop-06-December-2022, page 2

| Reference in topic paper | Draft decision | Transpower comment |
|---|---|---|
| 5.66.1 | Wash up allowable revenue for the first year of a regulatory period when inflation differs from expected inflation | Transpower supports this change for EDBs and, were Transpower to shift to an indexed RAB, would expect an inflation wash-up at the end of all years within a regulatory period. However, we note Transpower's building blocks, excepting the return of capital, are all naturally CPI-protected by Transpower's existing wash-up mechanism. We would need to undertake some analysis to understand how this would work in practice. Also note our preference to include within any annual wash-up an EV account balance recovery relating to the disclosure year two years preceding. Refer to Appendix B for more detail. |
| 5.66.2 | Exclude the return on debt from the annual revenue wash-up | Accept. This decision follows the underlying assumption that suppliers can hedge the risk-free component of the cost of debt for the duration of a regulatory period. Assuming a supplier can behave in this manner, then Transpower agrees that washing up the return on debt for actual inflation could produce windfall gains and losses to the extent that actual inflation does not follow forecast inflation.<br><br>We consider the 'hybrid approach' better manages the debt compensation issue. It also provides the cashflows at a more appropriate time (i.e. when the debt needs to be serviced). |

## Cost of Capital

148. We consider the Commission's approach to estimating the WACC parameters to be sufficiently robust and produce realistic outcomes. However, we note the Commission has not presented compelling evidence to support a departure from 67th percentile WACC estimates for price-quality (PQ) path regulation.

149. We also continue to support a "trailing average approach" for determining the risk-free rate.

*Disagree with using the 65th WACC percentile for EDBs and Transpower*

150. We agree with the Commission's position that a WACC percentile set above the mid-point estimate is appropriate, especially given New Zealand's decarbonisation and net zero commitments and the expected increase in reliance on electricity to follow. However, we do not support the Commission's draft decision to use the 65th percentile of the WACC for PQ regulation for EDBs and Transpower.

151. We do not consider the Commission has presented compelling evidence as to why the 65th percentile better promotes the Part 4 objective when compared to the status quo (the 67th percentile), especially alongside the second overarching objective for the IM Review being promotion of the IM purpose in section 52R more effectively.

152. The Commission engaged CEPA in 2022 to update Oxera's modelling with new data[74], with the Commission noting that "their update of the loss analysis model [pointed] to an optimal percentile between the 68th and 83rd for electricity."[75] We note CEPA observes that the "annualised cost of network outages resulting from underinvestment is uncertain and may be overestimated".[76] It seems that the Commission has not placed much credence on this study due to this observation.

153. Instead, the Commission notes "the range of percentiles based on the Oxera, ASCE, and CEG estimates are similar to the range that Oxera found in 2014".[77] The Commission selected the lower bound estimate for both the Oxera and ASCE at $1.0b and $1.1b, respectively. Oxera "considers the estimates of NZ$1bn-NZ$1.9bn from the ASCE 2011 paper to be more reliable for [its] assessment, and draw[s] insight from the lower bound of this estimate (i.e. NZ$1bn) in [its] analysis".[78] This suggests these two estimates are therefore (largely) derived from the same study and should not be used to substantiate each other. We also note the ASCE study was completed in 2011 and believe the dependence on electricity in New Zealand (particularly as we transition to net zero) is likely to be much higher than assumed in 2011. As such, we are unsure of the appropriateness of using the lower bound estimates given the significantly different context in present and future Aotearoa New Zealand.

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[74] CEPA-report-on-Commerce-Commission-IM-Review-Cost-of-Capital-29-November-2022
[75] Commerce Commission, Draft-decision-Cost-of-capital-topic-paper-14-June-2023.para. 6.25.11
[76] CEPA-Review-of-Cost-of-Capital-2022 -2023-Response-to-submissions-15-May-2023 para. 6.1.2
[77] Commerce Commission,Draft-decision-Cost-of-capital-topic-paper-14-June-2023 para. 6.72
[78] 27Big-Six27-EDBs-Oxera-report-Review-of-the-percentile-of-WACC-distribution-Submission-on-IM-Review-CEPA-report-31-January-2023 page 27

154. We also question the appropriateness of the reasonableness checks undertaken by the Commission. For example, included is an assessment that its WACC estimates "*are reasonable given they are below the long-term historical average returns of the New Zealand market overall… but above the post-tax returns on five-year government bonds… and five-year BBB+ bonds.*"[79] This is not a substantive test and note both the 5th percentile and 95th percentile post-tax WACC estimates for EDBs and Transpower fall comfortably within these bounds as well.

### *Maintain the current approach to estimating the risk-free rate*

155. The Commission's draft decision is to maintain the "prevailing approach", whereby the risk-free rate is estimated using a three-month average of the prevailing interest rates at the time of each PQ reset.

156. We continue to advocate for the "trailing average approach" noting that the Commission agrees that "the efficient debt financing strategy of a supplier is to issue debt with staggered maturity dates to minimise the potentially significant refinancing risk associated with having to refinance a large portion of debt at any one point in time".[80] The Commission also notes that it agrees that the "*trailing average approach… would support greater price stability between regulatory periods*".[81] While the Commission has discretionary tools to smooth prices at PQ resets, these tools only mitigate the transitionary impact between regulatory periods. The tools cannot alter the aggregate allowed revenue (in real terms) within a regulatory period. A trailing average approach can be a preventative tool to reduce price shock (between control periods) by protecting against any volatility driven by the determined risk-free rate.

157. The Commission's draft decision to exclude from the annual revenue wash-up the debt portion of the cost of capital is consistent with its assumptions underpinning its prevailing approach. Both decisions assume that the benchmark firm fixes its debt at the beginning of each regulatory period. However, we consider this antagonistic to the Commission's acknowledgement that the efficient debt financing strategy is a staggered approach. We hedge our debt at the beginning of a regulatory period because of the Commission's prevailing approach. If a trailing cost of debt approach was adopted, we would be able to follow a more efficient debt financing strategy.

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[79] Commerce Commission,Draft-decision-Cost-of-capital-topic-paper-14-June-2023.para. 7.17.1
[80] Commerce Commission,Draft-decision-Cost-of-capital-topic-paper-14-June-2023.para. 3.26
[81] Commerce Commission,Draft-decision-Cost-of-capital-topic-paper-14-June-2023 para. 3.45

**Table 3 Summary of draft decisions on Cost of capital paper, and Transpower response**

| Reference | Draft decision | Transpower comment |
|---|---|---|
| 3.114 | Maintain a spread premium of 7.5 bps for energy businesses | Accept. |
| 3.141 | Maintain a total allowance of 20 bps p.a. for a five-year regulatory period for debt issuance costs | Accept. |
| 3.166 | Maintain the current S&P long-term credit rating of BBB+ for EDBs and Transpower | Agree. |
| 3.8 | Maintain the current prevailing approach to estimating the risk-free rate | As we note above, we continue to advocate for a "trailing average approach" as it:<br>a) reflects more appropriately prudent debt management; and<br>b) acts as a preventative measure against price volatility between regulatory periods. |
| 3.9 | Maintain the current trailing average approach to estimating the debt premium | Agree. |
| 4.160 | Maintain a TAMRP of 7.0% for EDBs and Transpower | Accept, however we consider the rounding approaches adopted by the AER (10 bps) and Ofgem (25 bps) more appropriate. |
| 4.209 | Maintain the current approach of not including an equity issuance cost allowance | Disagree. If the Commission introduces an indexed RAB for Transpower then the Commission's modelling indicates that Transpower may require significant equity injections across RCP4 and |

| Reference | Draft decision | Transpower comment |
|---|---|---|
| | | RCP5. There are costs associated with equity injections. For example, Ofgem allows 5% for equity issuance costs.[82] |
| 4.21 | Update the equity beta estimate for EDBs and Transpower from 0.60 to 0.59 | Agree. We consider the Commission's approach sufficiently robust and statistically reliable. We agree with the selection of a large, international set of comparators. |
| 5.19 | Maintain the current approach to tax rates | Agree. |
| 5.26 | Maintain the standard error of the WACC for EDBs and Transpower at 0.0101 | Agree. |
| 5.5 | Change the leverage estimate for EDBs and Transpower - from 42% to 41% | Agree. |
| 6.2 | Use the 65th WACC percentile for EDBs and Transpower | Disagree. As we outline above, we consider there is insufficient evidence to support a change from the status quo. |

[82] Ofgem, RIIO-2 Final Determinations – Finance Annex (REVISED) (ofgem.gov.uk), February 2021, page 137.

## CPPs and in-period adjustments

158. This topic paper applies mainly to the Customised and Default price path regulation for EDBs but also covers the existing price-path re-openers for Transpower under our Individual price-quality path (IPP).

159. We present again our advocacy for flexibility within the IMs to add additional uncertainty mechanisms at the time of an IPP determination.

160. We respond to the proposed changes to the process and thresholds for reopening the price quality path for Catastrophic events, change events and errors. We support the changes based on the Commission's decision to align with the Fibre IMs re-opener provisions for "better clarity and consistency of the re-opener process".

### *Flexibility to allow for new uncertainty mechanisms*

161. The IMs are very prescriptive about the existing uncertainty mechanisms. We understand that the Commission considers it need to be specific as to the requirements to amend an IPP. However, we consider that more flexibility can be created by allowing the IPP to reflect the prescription with the IMs setting out the principles for an uncertainty mechanism that the Commission must consider.

162. The Commission's view is that rather than adding new uncertainty mechanisms, the existing ones may be used for the identified areas of uncertainty. We have considered this for RCP4, however we have identified areas of where the existing uncertainty mechanisms are not appropriate, for future transmission investments based on following reasons:

- The existing reopeners are linked to specific expenditure or triggers, these are not applicable to all of the areas of uncertain expenditure we are proposing for RCP4[83]
- The reopeners are typically administratively burdensome
- The E&D reopener is a once-only application, does not provide certainty that expenditure already incurred or for unforeseen costs towards the end of the period, can be recovered.

163. When we refer to 'uncertain expenditure' it is uncertainty at the time of submitting our RCP4 proposal in relation to scope of the work, costing, and/or timing.

164. Appendix A provides a few examples of the types of mechanism we are considering including in our RCP4 proposal. For the avoidance of doubt, while we have provided examples of our proposed new uncertainty mechanisms for RCP4, we are not seeking that these are prescribed in the IMs. Rather the IMs should allow for these to be prescribed in Transpower's IPP.

### *Re-opener events process*

165. We agree with the alignment with the Fibre IMs for following additional rules to create clarity and transparency for a reopener event process:

[83] An example is discussed in the resilience section.

- Define a ‘reopener event’ as an event, or series of related events that occurs within the twelve-month period before or during the regulatory period of the price-quality path determination [5.5.1.1]
- Require a supplier who nominates a reopener event to provide sufficient information [5.5.1.2]
- require the Commission to publish notice on its website after a significant step in the reopener process has been carried out [5.5.1.3]
- prescribe a list of factors the Commission must have regard to when deciding whether to amend the price-quality path [5.5.1.4]
- require the Commission to take into account the expenditure objective when determining the extent of any amendments [5.5.1.5]
- include a clause on the treatment of confidential information [5.7].

### *Proposed changes to thresholds*

166. We agree with all the changes proposed by the Commission:

- change the basis for establishing the threshold for the Catastrophic event reopener from an 'impact on revenue' test, to an 'incurred cost' test ($5m for Transpower) [7.8.1.3]
- change the basis for establishing the threshold for the Change event reopener, not relating to Generally Accepted Accounting Practice (GAAP) changes, from an 'impact on revenue' test, to an 'incurred cost' test (($5m for Transpower) [7.8.2.3]
- maintain the 'impact on revenue' test for the Error event materiality threshold, but change the threshold to be $100,000 [7.8.3].

167. For Transpower, the application of 'cost' tests rather than 'revenue' tests will result in thresholds being met at a lower level of expenditure, which is welcome.

**Table 4 Summary of draft decisions from CPP and adjustments paper, and Transpower response**

| Reference | Draft decision | Transpower comment |
|---|---|---|
| 5.5.1.1 | Define a 'reopener event' as an event, or series of related events that occurs within the twelve-month period before or during the regulatory period of the price-quality path determination. | "The twelve-month period before" the regulatory period of the price-quality path determination is the final year of the previous regulatory period, and means that historic events can be applied for (we agree).<br><br>And "during the regulatory period", means the event or series of events must be described relative to a one-year timeframe?<br><br>Assume can be more than one reopener event per RCP, as there are five 12-month periods. |
| 5.7 | Include a new provision on confidential information in the reopener process IMs. The drafting has been repurposed from the Fibre Capex IM.49 | Agree. |
| 5.5.1.2 | Require a supplier who nominates a reopener event to provide sufficient information | Agree. |
| 5.5.1.3 | Require the Commission to publish notice on its website after a significant step in the reopener process has been carried out | Agree. |
| 5.5.1.4 | Require the Commission to take into account the expenditure objective when determining the extent of any amendments | Disagree (or n/a to Transpower). "expenditure objective" is not a term used for Transpower regulation. |

| Reference | Draft decision | Transpower comment |
|---|---|---|
| 6.8 | To change how the impacts of GAAP changes are assessed in the change event reopener to remove the potential for windfall gains and losses. | Agree. |
| 7.56 | Change the threshold to be $100,000 for **errors** related to the price path for all entities...Our draft decision is to set this value as an impact on...forecast MAR for Transpower exceeding $100,000 when revised values are included in the appropriate price path model. | Accept. |
| 7.82.2 | Revise the impact on revenue test for **Change event reopeners** relating to GAAP changes to be based on whether changes had been in place at the time of the price path reset, there have been a different price path; **for Transpower,** the impact of the event exceeds $5 million. | Agree. |
| 7.8.1 and 7.8.1.3 | Change the basis for establishing the threshold for the Catastrophic Event reopener from an 'impact on revenue' test, to an 'incurred cost' test:...<br>for Transpower this will that be the total cost incurred in responding to the event exceeds $5 million. | Agree. |
| 8.33, 8.33.3 | Change the basis for establishing the threshold for the Change Event reopener (not relating to GAAP) from an 'impact on revenue' test, to an 'incurred cost' test:...<br>8.33.3 for Transpower, this will be the total cost incurred in responding to the event exceeds $5 million. | Agree. |

## Appendix A – Our proposals for an uncertainty mechanism

168. We are proposing two new uncertainty mechanisms for RCP4 to cover uncertainty expenditure on proactive resilience workstreams, and on bringing forward connection asset capacity or adding anticipatory capacity.

169. Below we provide a summary of the mechanisms, including flow diagrams, setting out how we think they may work in practice. The first is in relation to resilience expenditure.

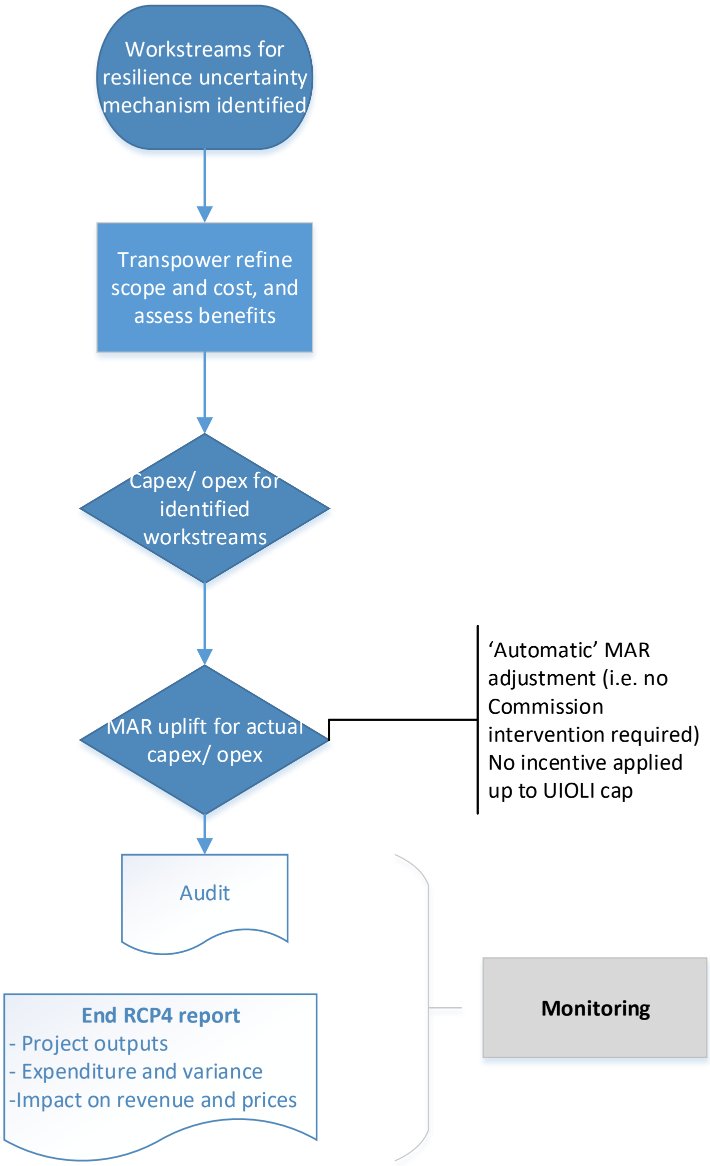
**Table 5 Proposed uncertainty mechanism for enabling customer electrification**

| **Uncertainty Mechanism: Resilience** | |
|---|---|
| Objective | Access to funds for selected resilience projects which will deliver customer benefits via risk mitigation from resilience threats, but their scope/size are uncertain at the time of the base capex proposal submission. |
| **Design** | |
| Type and size | Use-it-or-lose-it (UIOLI) mechanism – allowance would only apply to identified resilience workstreams. |
| Scope | The resilience uncertainty mechanism would only cover the workstreams identified in our resilience portfolio management plan (PMP).<br><br>We propose that the UIOLI allowance is fungible across these projects. We have estimated what we consider to be the minimum efficient scope and cost for these workstreams. This is set out in the Resilience PMP.<br><br>Currently, we have identified twelve resilience workstreams in total. If any of the workstreams we have proposed for base capex or opex are not approved by the Commission, we consider (subject to the Commission's reasoning) that these should then be included in the uncertainty mechanism. |
| Process | During RCP4, we will undertake further work to scope, and cost, the identified workstreams. If we are satisfied that the projects will deliver long term value to consumers, we will select the most efficient solution.<br><br>Our maximum allowable revenue set in the IPP will exclude the resilience UIOLI allowance. Expenditure incurred to deliver any combination of the projects up to the capped amount will be added to the RAB or expensed. In practice, this could be done either by an annual adjustment to our allowance or with the expenditure bypassing the capex incentive or opex incentive mechanisms.<br><br>Given the overall size of the resilience uncertainty mechanism. we are not proposing any in-period Commission reviews. Instead, we propose to publish an end of period report. |

| Uncertainty Mechanism: Resilience | |
|---|---|
| Incentive | The fund would not fall under the incentive scheme, expenditure would be added at actual cost.<br>Any expenditure on the identified resilience projects above the capped amount will be subject to the standard incentive rate. |
| Monitoring | Annual audit process – Our annual financial and information disclosures audits check whether we are allocating costs to the correct categories as per the resilience plan to ensure costs are only associated to the referred projects/programmes and only actuals are added to the MAR.<br>End of regulatory period report (new) – A report on the number of projects, project outputs, expenditure (variations from forecast and refined budget), reason for, pricing impact, and consumer benefit. This will create transparency for our stakeholders of the efficacy and efficiency of the expenditure under uncertainty mechanism.<br>We will annually report on the progress of resilience expenditure via our Asset Management Plan (AMP). |
| Cost recovery | We propose that the in-period adjustment will be applied automatically to RCP4 allowed revenue (i.e. no involvement from the Commission to approve). We will update the SMAR and MAR on an annual basis we propose to do this, either via an increase in the expenditure allowance for the actual spend or by bypassing the incentives applied to capex/opex. |

170. Below is a flow diagram summarising the above.

**Figure 1 Uncertainty mechanism for resilience expenditure**




171. The table below sets out our assessment of other options for our proposed uncertain resilience expenditure.

**Table 6 Resilience uncertainty mechanism option assessment**

| Option | Assessment |
|---|---|
| Base capex | Including an amount in base case is a viable alternative to our proposed option. However, while we have estimated probable scopes and costs for the identified workstreams, there is material uncertainty around both factors.<br>We consider that it is more appropriate for the risk to be dealt with via this mechanism. |

| Option | Assessment |
|---|---|
| Listed Projects | The resilience workstreams do not meet the required criteria. |
| Low incentive rate project | The resilience workstreams do not meet the required criteria. |
| Reopener | A reopener mechanism introduces significant administrative burden and uncertainty for planning and delivery. We do not consider that this administrative burden is commensurate with the potential level of expenditure and type of workstreams involved. |
| Volume driver | The workstream outputs are not comment, therefore an average unit cost cannot be applied. |

172. The second proposed uncertainty mechanism is in relation to enabling customer electrification.

**Table 7 Proposed uncertainty mechanism for enabling customer electrification**

| Uncertainty Mechanism: Enabling Customer Electrification (ECE) fund | |
|---|---|
| Objective | Provide $100m funding for Transpower to undertake works on connection assets that would otherwise be unfunded during RCP4:<br>• Bringing forward connection asset replacement at customer's request; and<br>• adding anticipatory connection asset capacity to new connections. |
| **Design** | |
| Process | The mechanism will be triggered by a New Investment Contract (what we refer to as a Transmission Works Agreement, TWA) process where that negotiation process is amenable to (i) bringing forward connection asset replacement from a future RCP or (ii) adding anticipatory connection asset capacity on the assets to be created under a TWA.<br><br>A key design objective is that the mechanism would have a low administrative burden to access the fund; no within-period regulatory determination necessary; and transparency as the expenditure would be visible via auditing and, a proposed, end-of-RCP4 report. |
| Incentive | The fund would not fall under the existing incentive scheme, expenditure would be added at actual cost, but efficiency incentives remain due to customer scrutiny and, if binding, the fund cap being limited ex-ante. |

| Uncertainty Mechanism: Enabling Customer Electrification (ECE) fund | |
|---|---|
| | We do not consider that this expenditure should be incentivised as we do not consider there is scope for out-/under-performance.<br>The customer(s), in agreeing to the TWA, scrutinise the prudency and efficiency of our proposed investment.<br>We propose that our MAR is adjusted based on outturn costs. |
| Monitoring | Annual audit process – Our annual financial disclosures audits checks whether we are allocating costs to the correct categories to ensure costs are associated with TWAs and only actuals are added to the MAR.<br>End of RCP4 report (new) – A report on the number of projects, expenditure, reason, pricing impact, and Asset Health Index impact (whether applicable).<br>Asset Health Index – Adjustment to the AHI to ensure we do not benefit via our service measures for expenditure associated with this fund The Asset Health Index also provides visibility to check that we are still undertaking the require work under our replacement and renewals programme. |
| Cost recovery | Bringing forward connection asset replacement – Costs will be recovered from the customer via the Connection Pool charging under the TPM. The customer will directly fund, via the TWA, any costs associated with writing off the existing asset and the incremental cost of the additional capacity.<br>New anticipatory connect asset capacity – 50% costs would be recovered from all connectee via the connection charge; 50% recovered from TPM via the simple method beneficiaries. Remaining ACA value would then be charged to subsequent connectees. |

173. Below are two flow diagrams summarising the above, respectively for, bringing forward connection asset replacements and anticipatory connection asset capacity.

**Figure 2 Uncertainty mechanism for bringing forward connection asset capacity**

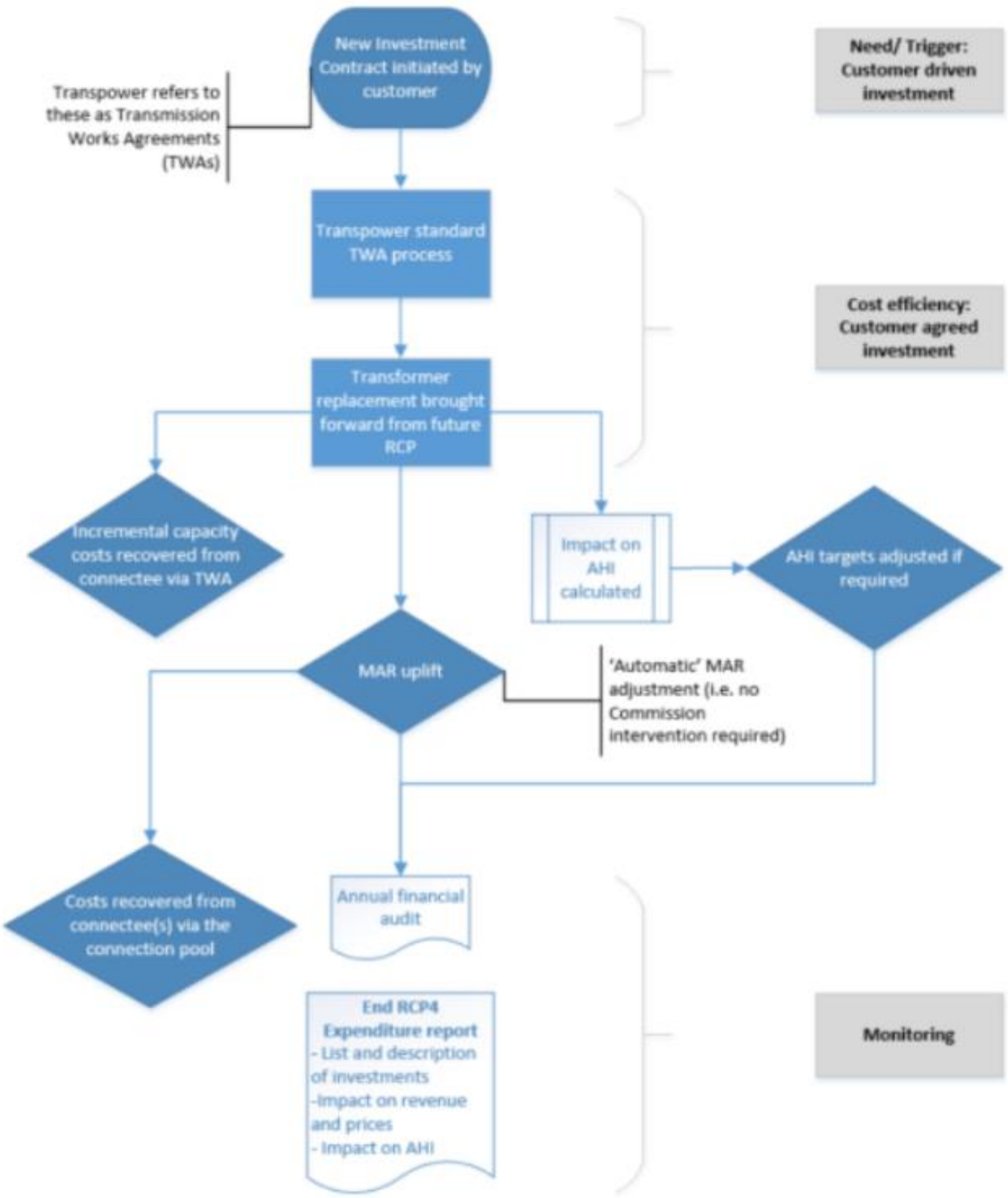


**Figure 3 Uncertainty mechanism for anticipatory connection asset (ACA) capacity**

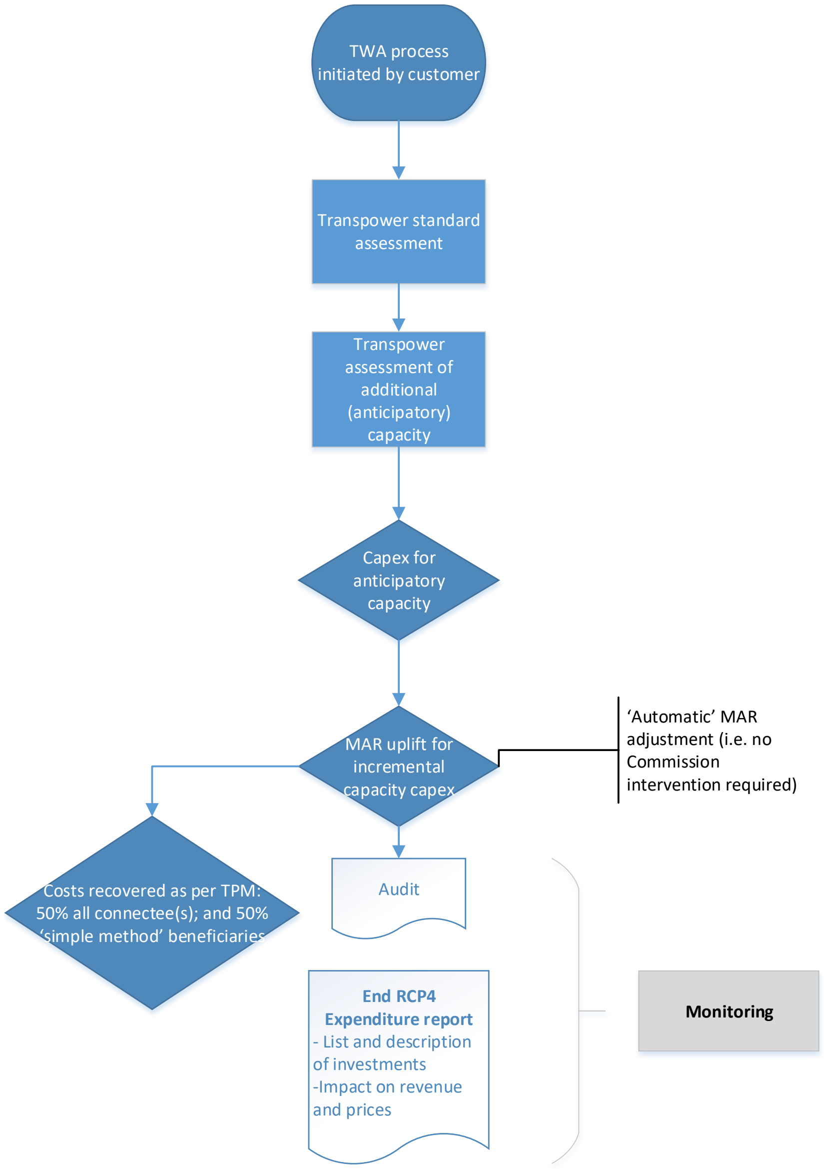



**Table 8 Enabling customer electrification uncertainty mechanism, option assessment**

| Option | Assessment |
|---|---|
| Base capex proposal | Including an amount in base case is a viable alternative to our proposed option. However, we estimate the number of transformer replacements brought forward during RCP4 could range from zero to five.<br>We do not have a forecast of the volume of anticipatory connection asset capacity work we will undertake during RCP4.<br>We do not consider it to be in consumers or Transpower's' long term interests to include an amount in base capex. |

| Option | Assessment |
|---|---|
| Listed Projects | We do not expect that a single project would exceed the base capex threshold and combining each transformer replacement and/or connection project would not meet the definition of 'programme'.<br>This is not a viable option. |
| Low incentive rate project | As per the listed project option. |
| Reopener | A reopener mechanism introduces significant administrative burden.<br>As the agreement of TWAs allow for direct stakeholder input, we do not consider the burden of a reopener mechanism is appropriate for these types of expenditure. |
| Volume driver | The unit costs between projects could vary materially therefore we do not consider a volume driver uncertainty mechanism would be feasible. |

# Appendix B – EV account balance recovery

174. As part of Transpower's RCP3 proposal, the Transpower IM determination was amended to explicitly allow for a balance in the Transpower EV account to be carried forward from one period to the next, and for that carried forward balance to be applied in setting Transpower's maximum allowable revenue for that next period.[84]

175. The EV account accumulates entries relating to Transpower's ex-post economic gain or loss, its capex incentive, and its service measures incentive. Interest is calculated on the opening balance using the post-tax prescribed WACC.

176. In RCP1 and RCP2, the price path was updated annually, and the EV account balance was recovered two years in arrears.

177. A change to a five-year wash-up was made in RCP3 to reduce *intra-period volatility* (year-to-year). With experience of the account balances during RCP3 and forecast for RCP4, we now consider *inter-period volatility* (RCP to RCP) a much larger concern.

178. We ask the Commission returns Transpower to an annual EV account wash-up (akin to its application in RCP2).

179. We outline why we consider inter-period volatility a larger concern below.

- With a five-year wash-up, we consider that long-term macroeconomic trends can have a compounding effect on Transpower's ex-post wash-up outcome. For example, the effect of significantly higher than forecast inflation in 2022 and 2023 is felt into 2024 and 2025, and outturn inflation consistently higher than forecast across the duration of a regulatory period has a compounding effect on each of Transpower's annual wash-up calculations. Additionally, this amount is not fully recovered from customers until 2030 – all the while accumulating interest at the prescribed post-tax WACC.
- We consider the effect of inter-period EV account balance volatility can be amplified by other differences in regulatory periods that have the effect of moving revenue in the same direction. For example, our forecast closing EV account balance for RCP3 is currently ~$150m. This amount is to be grossed up for tax, accumulate interest and recovered from customers across the duration of RCP4, equating to an increase in SMAR of ~$50m per year. This increase coincides with a significant change in the risk-free rate between RCP3 and RCP4 (1.12% to 4.31%[85]).
- In RCP2, our EV account balance closed at ($73m) to be returned to customers. After grossing up for tax, accumulating interest and spreading across RCP3, the reduction in SMAR in 2025 is (~$25m). We are forecasting a ~$50m increase in revenue in 2026 to recover ~1/5$^{th}$ of the closing RCP3 balance and so observe a ~$75m increase in revenue between 2025 and 2026 solely due to movements in the EV account.

[84] Proposed further amendments to input methodologies for TPNZ – draft decisions and reasons paper 18 July 2019

[85] Forecast at 1 March 2023.

- While we appreciate that the EV account could have an offsetting effect on other regulatory changes, we consider it prudent to mitigate outcomes that produce significantly large inter-period volatility[86] as opposed to smaller, “choppy” intra-period volatility.

180. We also consider while there will be compliance costs attached to an annual wash-up, we expect the benefits of the wash-up change to consumers will more than offset these.

[86] Such as the step-up we are observing between RCP3 and RCP4.