Level 5 Woodward House
1 Woodward Street
PO Box 10 045
Wellington 6011
www.concept.co.nz

+64 (21) 906 027

Confidential

12 October 2021

Doug Watt
Manager Market Monitoring
Electricity Authority - Te Mana Hiko
Level 7, ASB Bank Tower, 2 Hunter Street
Wellington 6143

By email: doug.watt@ea.govt.nz

Dear Doug,

Review of discussion paper on 'Inefficient price discrimination in the wholesale market – issues and options'

The Electricity Authority (Authority) is reviewing the wholesale electricity market. It has prepared two papers: an empirical paper that is diagnostic in nature; and a discussion paper that explores the potential responses to an issue that the first paper has identified.

A - Scope of opinion

The Authority has asked Concept Consulting Group Ltd (Concept) to review the discussion paper, and to specifically comment on:

1. Is the problem definition precise and does it reflect the evidence?
2. Are the criteria the right ones, could any be added or subtracted?
3. Is the option set complete?
4. Is the assessment robust?

In the following sections we review the draft discussion paper (version sent on 7 October 2021) in relation to each of the items 1-4.

Our evaluation takes account of the document's status as a discussion paper which the Authority will release to elicit feedback. Hence, we focus on whether the document provides a robust basis for stakeholders to comment on the identified problems and options and provide meaningful feedback.

We have relied upon the information provided by the Authority, including some information supplied by certain market participants to the Authority on a confidential basis.

Consistent with our brief, we have not undertaken a full audit of the analysis or independently verified all inputs or materials cited in the paper. Instead, we have largely relied upon the correctness of factual and other material provided by the Authority and have undertaken only limited separate analysis.

In the course of preparing this letter we have benefited from discussions with Pat Duignan of Munro Duignan Ltd (which is also undertaking a review for the Authority). However, the opinions expressed in this letter should not be interpreted as representing the views of any party other than Concept.

Except as expressly provided for in our engagement terms, Concept and its staff shall not, and do not, accept any liability for errors or omissions in this letter or for any consequences of reliance on its content, conclusions or any material, correspondence of any form or discussions, arising out of or associated with its preparation. This letter remains subject to any other qualifications or limitations set out in the engagement terms.

B – Is the problem precise and does it reflect the evidence?

The issues paper focuses on the potential for economic efficiency losses to arise from price discrimination, particularly allocative inefficiency effects including from the sale of electricity at prices below the economic cost of supply.[1]

In our view, the problem statement is clear. Importantly, the paper notes that price discrimination is not inefficient per se.

As regards evidence, the paper presents analysis of the Tiwai contracts to show that the concern can plausibly arise in practice and is not merely theoretical in nature. The overall analytical framework is set out in Appendix B of the paper. The framework is then used to calculate numerical estimates of potential efficiency impacts, based on input parameters derived exclusively from public sources.[2] The resulting efficiency estimates are set out in Table 2 of the paper.

We consider that the general framework described in Appendix B of the paper is conceptually sound as a basis for analysing electricity sector efficiency impacts. As regards the application of the framework, the reliance on public data to inform the input assumptions does constrain the analysis to some extent.

We note the baseline mid-point potential efficiency loss estimate in Table 2 of the paper is $87 million per year. We consider this estimate to be reasonable – indeed it may be an under-estimate. Our reasoning is as follows:

a. our analysis which draws on confidential information estimates the efficiency loss impact from the production subsidy to be $[redacted] million in annualised terms (i.e. $[redacted] million over the 40 month contract period – see appendix of this letter for more information).
b. there will also be an efficiency loss associated with foregone electricity use by consumers other than NZAS. For illustrative purposes we conservatively assume this will be zero.
c. there will be a potential efficiency gain associated with the increase in consumer surplus for NZAS if its willingness to pay exceeds the contract price.
d. the baseline efficiency loss estimate in the Authority's analysis is $87 million per year. For a+ b+ c to be $87 million, the consumer surplus gain to NZAS would need to be $90 million per year. For this to be correct, NZAS's willingness to pay at the time the contract was struck would need to exceed the contract price by about [redacted] $/MWh. That is more than 50 percent above the level that was finally negotiated. We are aware of no evidence to show such a proposition is realistic.
e. based on these factors, we think the magnitude of baseline total deadweight efficiency loss reported in Table 2 of the paper is defensible.

Table 2 of the paper reports the estimated efficiency losses for a set of sensitivity cases. While we support the purpose of sensitivity testing, we query whether the reported results necessarily achieve this because the framework may not capture some important factors. For example, the sensitivity case relating to stranded water indicates that "the efficiency gain for generators on stranded water is estimated to be the

[1] Paragraphs 5.1 to 5.8.

[2] The principal exception is the reference in paragraph 5.24 to work undertaken by Concept, which in turn is based in part on confidential documents provided to the Authority by Meridian.

contract price less avoidable cost (on the order of $8/MWh given South Island Mean Injection charges from Transpower and operating and maintenance costs)". We query whether there would be a material change in the total South Island Mean Injection charges payable in this sensitivity case, given that the total revenue requirement for the high voltage direct current link is fixed. In our view, there are good grounds to rely on the baseline estimate to demonstrate the credible potential for material efficiency effects to arise, and to discuss the other sensitivity cases in qualitative terms.

C – Criteria used for evaluation

The evaluation criteria are set out in Table 3 of the paper and are reproduced below.

Table 1: Evaluation criteria included in paper

	Criterion	Description
Efficiency	Highest value use of electricity	• Electricity is provided to consumers that value it most highly and value it more than the cost of production
	Transparency	• Provides assurance (to public and Authority) that electricity is efficiently allocated
	Confidence	• Minimises risk premiums
	Flexibility	• Supports bespoke transactions that create value, including the allocation of risks to parties that are best able to bear
	Addresses inefficient discriminatory pricing	• Addresses root cause of inefficiency and any competition concerns
Competition	Reduces potential for price mark-ups over cost	• Reduces consequence of market power
	Incentives to invest in new generation	• Supports price signals for efficient investment in generation and electrification
Practicality	Within Authority mandate	• Feasible policy actions to achieve outcomes consistent with Authority's legislative mandate
	Timely	• Can be addressed before any further contract negotiations between generators and large consumers
	Benefits outweigh costs	• Satisfies usual cost-benefit analysis required by s39 of Act, including implementation and compliance costs

Source: Electricity Authority paper

We consider the evaluation criteria to be sound. Our only suggestion is to add an explicit reference to reliability. This would tighten the linkage to the Authority's statutory objective with its three distinct limbs. We consider a reference to reliability to be especially relevant in the current environment, with the need to mobilise investment capital to help meet growing power demand and accelerate decarbonisation efforts.

D – Completeness of option set

As per our brief, we have not evaluated the individual options. Rather, we have reviewed the set of options to identify any others which might possibly address the identified problem, or options which appear not to be linked to the problem.

We have not identified any options within the Authority's power which should be added or omitted.

E – Robustness of options assessment

The draft paper includes a list of pros and cons in tabular form for each option that could be implemented via a Code change. Given that the assessments are in summarised form and there is no indication of the weights to be accorded to various factors, it is not possible to review the robustness of the options assessment in detail.

Having said that, our understanding is that the Authority has chosen this high level approach to obtain submitters' views regarding the options. These views would then be an input into the Authority's decisions on how to move forward, including more detailed analysis on options which are proposed for adoption. On this basis, we consider the options assessment to be at a suitable level for a discussion paper.

In addition, we support Pat Duignan's suggestion that cross-submissions be considered as part of the wider information gathering process and options refinement process.

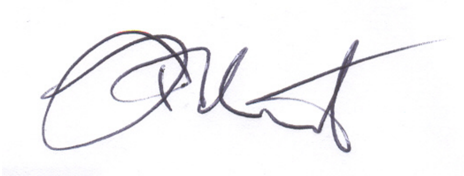
F - Conclusion

In our view the problem statement is clear. We consider the general analytical framework described in the paper to be conceptually sound. As regards the application of the framework, the reliance on public data to inform the input assumptions does constrain the analysis to some extent. Having said that, we consider there is sufficient evidence to show that the concern can plausibly arise in practice and is not merely theoretical in nature.

We have not identified any options within the Authority's power which should be added or omitted. We consider the evaluation criteria to be sound. Our only suggestion is that the Authority consider adding reliability impacts to the set of criteria. We consider the options assessment to be at a suitable level for a discussion paper.

Please let us know if you would like to discuss any of the issues covered in this letter.

Yours sincerely,



David Hunt

Director

Concept Consulting Group Ltd

Appendix

Effective strike price for additional CFD volumes

While the 'headline' price recorded in the NZAS Meridian CFD agreement is [redacted] \$/MWh[3], the effective strike price for the additional CFD volumes provided between 1 September 2021 and 31 December 2024 is less than this figure. This is because the new agreement provided for the reduced price to be backdated to 14 January 2021 (noting supply under the previous agreement did not terminate until 31 August 2021). This price reduction is akin to a rent rebate provided on an expiring lease, to encourage a tenant to sign a lease extension. The rebate effectively lowers the rental price for the new lease period.

The value of the rebate is calculated by multiplying the difference in strike prices between the old and new agreements by the CFD volume in the period 14 January 2021 to 31 August 2021. The new price is [redacted] \$/MWh and we understand the pre-existing CFD was priced at [redacted] \$/MWh.[4]

The value of the rebate is therefore \$[redacted] million.

Table 2: Calculation of value of rebate

Value of rebate in period 14 January 2021 to 31 August 2021		
Price under pre-existing agreement	\$ [redacted]	\$/MWh
Price under new agreement	\$ [redacted]	\$/MWh
Price difference	\$ [redacted]	\$/MWh
Duration when rebate applied	230	Days
CFD volume receiving rebate	572	MW
Total CFD volume in period	3,157	GWh
Value of rebate in period	\$ [redacted]	\$m
tiwai efficiency effect calcs.xlsx		

In economic terms, this rebate should be amortised over the incremental CFD volume to be supplied[5] under the new agreement – i.e. in the period 1 September 2021 to 31 December 2024.

The maximum volume to be supplied under the new agreement is 16,721 GWh. The implies a rebate of [redacted] \$/MWh and an effective strike price of [redacted] \$/MWh.

The minimum volume supplied under the new agreement will occur if NZAS exercises the option to reduce the CFD volume from 572 MW to 400 MW effective from 1 July 2022.[6] In this case the rebate will equate to [redacted] \$/MWh and the average effective strike price will be [redacted] \$/MWh. This figure incorporates the effect of the rebate and separate price reduction (to [redacted] \$/MWh in headline terms) for supply from 1 July 2022.

The table below sets out the relevant calculations and results in detail.

[3] (Clause 5.2 c). This price is for the full 572 MW commitment. If NZAS elects to reduce the CFD volume to 400 MW in July 2022 the strike price drops to [redacted] \$/MWh from that point.

[4] Meridian Board presentation, July 2020, page 6.

[5] The agreement is structured as a CFD so there is no supply of physical electricity. We use the term as shorthand to refer to the contractual volume covered by the financial swap arrangement.

[6] This assumes the agreement is not terminated before 31 December 2024, and that Meridian does not invoke the smelter demand response provisions to reduce CFD volume which it is permitted to do if hydro storage falls below defined levels.

Table 3: Calculation of value of rebate

Scenario 1 - NZAS takes maximum volume	Duration Days	Relevant capacity MW	Additional CFD volume under new agreement GWh	Rebate value ($[redacted]m) amortised over new volume $/MWh	Headline strike price $/MWh	Effective strike price $/MWh
Full 572 MW from Sep 2021 to Dec 2024	1,218	572	16,721	$ [redacted]	$ [redacted]	$ [redacted]

Scenario 2 - NZAS takes minimum volume	Duration Days	Relevant capacity MW	Additional CFD volume under new agreement GWh	Rebate value ($[redacted]m) amortised over new volume $/MWh	Headline strike price $/MWh	Effective strike price $/MWh
1 Sept to 30 June 2022	303	572	4,160	$ [redacted]	[redacted]	[redacted]
1 July 2022 to 31 December 2024	915	400	8,784	$ [redacted]	[redacted]	[redacted]
Total/weighted average	1,218		12,944	$ [redacted]	[redacted]	[redacted]

Subsidy provided to NZAS under the new Tiwai agreement

We have been asked to estimate the size of any subsidy that NZAS receives under the new supply agreement. If there is a subsidy, the size will be relevant to quantifying the overall economic efficiency impact of the new supply agreement. The assessment of efficiency effects is discussed further in Mr Duignan's letter.

Basis for assessing subsidy

We have compiled our assessment based on information about the contract provided on a confidential basis by the Authority, public source information available at this time, and our own analysis. If material new information were to become available in the future we may wish to revise our estimate.

In economic terms, prices are defined as subsidy-free if they lie between the incremental and stand-alone costs of supplying the relevant service.[7] In the present context, we have focussed on whether the price paid by NZAS is *below* the incremental cost of supply as that would indicate a subsidy is being provided.

Smelter closure from 1 September 2021 is the baseline

In essence we calculate prices and incremental economic costs for the additional energy supplied under the new agreement, as compared to a baseline of smelter closure after 31 August 2021

Importantly, the expected incremental cost is estimated based on information prevailing in late 2020/early 2021. That is the appropriate timeframe because the subsidy information will be used to quantify the *expected efficiency effect when the new agreement was concluded*.

Average price payable under new supply agreement

The average price for the additional supply is the change in total charges under the new agreement divided by the change in total volumes. As noted in the previous section in this appendix, the average price will depend on whether NZAS triggers the right to reduce CFD volumes to 400 MW after 1 July 2022.

The total charges, CFD volume and average price will therefore lie in the ranges shown in Table 4. For completeness, we note these calculations assume that the CFD volumes are used to underpin equivalent physical electricity demand at the Tiwai smelter. This contention appears reasonable even though the agreement is in the form of a CFD. This is because the agreement allows Meridian to terminate the CFD if smelter demand falls below an average of 540 MW for more than one quarter.[8] Meridian would likely have strong financial incentives to make such a termination unless expected market prices were below the strike price. We note that this provision allows NZAS to reduce its average quarterly demand at the smelter by up to 32 MW without risking early termination. It has a financial incentive to make such demand reductions if the hedge settlement proceeds will exceed the value of associated aluminium production. To the extent such demand reductions occur, they would be expected to *lower* the effective net charges paid by NZAS for

[7] For example, Commerce Commission, Input Methodologies (EDBs & GPBs) Reasons Paper, 22 December 2010, paragraph 7.2.5.

[8] Clauses 6.6 and 12.8B(b) of the agreement.

electricity supply. Having said that, we have not sought to estimate any such impact because we understand the smelter (at least historically) has had limited operational flexibility.

Table 4: Incremental supply under new agreement – total charges, volumes and effective prices

Period 1 September 2021 to 31 December 2024	Total charges payable by NZAS	CFD volume	Average effective price
	$m	GWh	$/MWh
Scenario 1 - NZAS takes maximum volume	$ [redacted]	16,721	$ [redacted]
Scenario 2 - NZAS takes minimum volume	$ [redacted]	12,944	$ [redacted]
tiwai efficiency effect calcs.xlsx			

Expected incremental costs arising from new Tiwai agreement

The incremental cost of supply under the new agreement is the economic cost of generating the electricity to enable smelter operation after August 2021.

The continuation of smelter demand beyond 31 August 2021 means that more supply would be required compared to the baseline of smelter closure. We expect the additional supply to be met from a mix of:

1. Increased generation from various thermal power stations in the North Island.
2. Increased utilisation of renewable generation which would otherwise be 'spilled' (i.e. water which would be literally spilled over a dam, or feathering of wind turbines to 'spill' some of the available wind energy).
3. Reduced transmission losses noting that some of the energy produced by renewable generation in the lower South Island would be lost if used to serve demand which is electrically more distant from generation than the smelter.

In our analysis we have focussed on item 1 and treated items 2 and 3 as free resources for New Zealand. This will bias the cost estimate downwards because spill is not free and will have a positive (though relatively modest) economic cost.

While the increased thermal generation costs are not incurred directly by Meridian (it does not own any thermal stations), thermal costs are nonetheless relevant to the analysis because our focus is on national economic costs – i.e. the incremental resource cost to society of supplying power to the smelter after August 2021. Furthermore, while it might be argued that Meridian's incremental cash cost of supply from renewable resources is close to zero in the short run,[9] if the smelter continues in operation Meridian foregoes the opportunity to sell to other users the electricity that the smelter consumes. The thermal costs provide a measure of the opportunity value of those foregone sales.

Effect of transmission losses and constraints on thermal generation volumes

The first step in calculating cost effects is to estimate how much extra thermal generation would be required due to the continued operation of the smelter. We estimate this by undertaking a 'hindcast' simulation. This calculates how much thermal generation would have changed in the past if the smelter demand had not been present after accounting for transmission constraints and losses.

The analysis uses six years of historical data and is undertaken using half-hourly generation patterns. Multiple years are used to assess the effects of wet and dry periods and other system variations. We believe that system behaviour over this period is a reasonable approximation for the 'smelter continues' case. The system was fairly stable over that period with minimal new generation being developed and minimal demand growth.

[9] If we ignore completely the need to earn a return on invested capital and replace equipment as it wears out.

While some new generation is expected to come online in the period 2021-2024 much of this was committed after the smelter agreement was announced. In relation to new generation that was already committed, its output broadly equates to growth in the demand for non-NZAS users. Accordingly, we expect the non-NZAS demand growth and previously committed new projects to more or less cancel out.

In modelling transmission limits, we considered two distinct states: before the Clutha and Upper Waitaki Lines Project (CUWLP) upgrade in the lower South Island and after. We also consider two distinct Tiwai operation scenarios: full Tiwai operation and a partial operation 400 MW from July 2022.

Our modelling considers the transmission constraints on the inter-island high voltage direct current (HVDC) link, and between the lower South Island (LSI) and the rest of the electricity network. Our analysis assumes an HVDC northwards receipt limit of 1000 MW.[10]

We do not explicitly model instantaneous reserve requirements. However, we assume that an investment in additional battery capacity would have been required if the smelter had closed to facilitate northward transfers on the HVDC. We discuss that issue further below.

Our analysis estimates lower South Island constraints by comparing supply and demand in the region and assuming that any excess supply is exported northwards. We assume an export limit of 600 MW on this for the 'no CUWLP' scenario and 1000 MW in the 'with CUWLP' scenario.[11] Our approach implies that the 600 MW constraint is regularly breached in the current network, suggesting that our modelling approach is conservative (i.e. it overestimates the impact of the constraint and under-estimates thermal generation cost impacts).

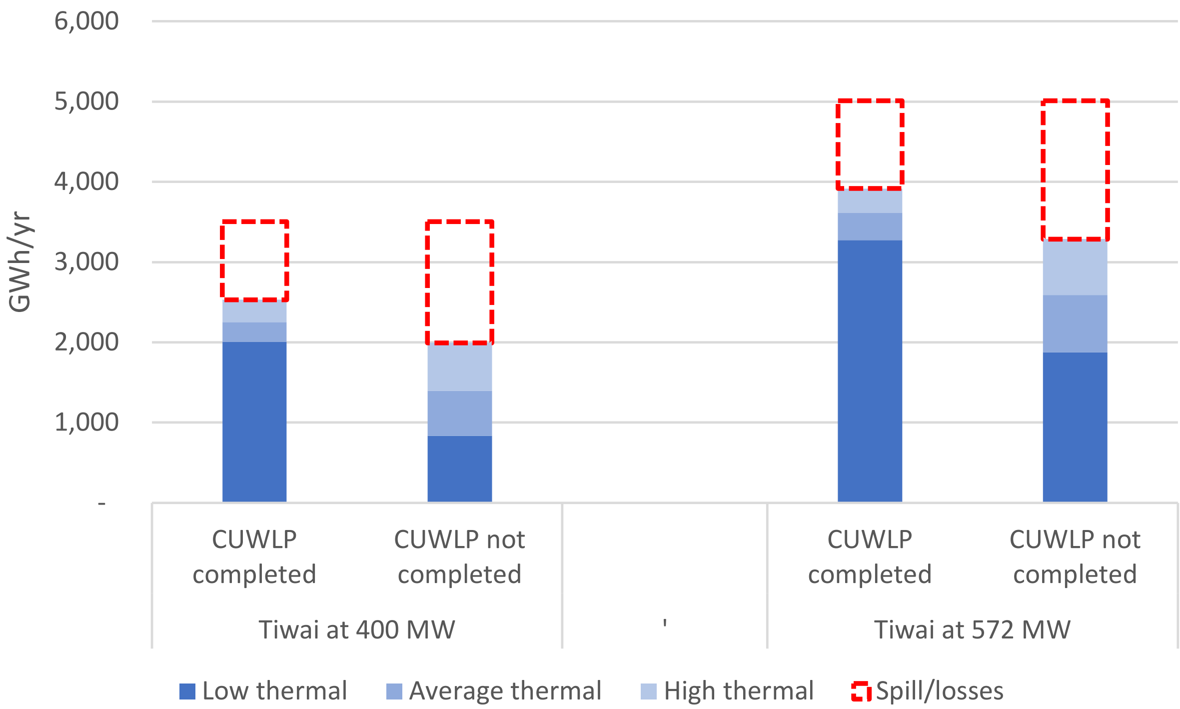
Similarly, there would be changes (typically increases) to losses due to increased HVDC northwards flow. For estimating the increase in HVDC losses, we use an average loss approach based on the loss curve approximation for the HVDC used in SPD. We then multiply this increase by two to approximate the effect of increased losses on the HVAC (high voltage alternating current) transmission network.

[10] While the HVDC can nominally transfer 1200 MW of power northwards, it rarely exceeds 1000 MW due to reserve requirements.

[11] These values are based on "Clutha Upper Waitaki Lines Project. Invitation to comment on proposal to progress remaining projects" – Transpower May 2020.

Figure 1 shows the results of the analysis. It indicates how a change in Tiwai demand would be expected to affect thermal generation, and how much would be lost to increased spill and/or losses.

Figure 1: Extra thermal generation required to supply Tiwai smelter



To interpret the graph, consider the "Tiwai at 572 MW + CUWLP not completed" scenarios. The Tiwai smelter consumes about 5,000 GWh a year when operating at 572 MW, as shown by the combined height of the rightmost bar. The dark blue section of the rightmost bar shows that about 1,900 GWh of this would be met by thermal generation in the lowest of the modelled years. The other shades of blue show the highest and average amounts. In the highest year about 3,300 GWh of extra thermal generation would be required, and on average about 2,600 GWh. The dotted red box shows that about 1,700 GWh of the generation to supply Tiwai would be met by reduced spill and losses, even in the driest year (i.e. when the most thermal generation is needed).

Before the completion of CUWLP, there is much larger variation in the quantity of thermal generation required. This is because the effect of the lower South Island constraint varies greatly depending on hydrology. Currently, during dry periods the region can be a net importer of electricity, meaning that even were Tiwai to leave there would be minimal constraints on exporting power. However, currently, during wet periods the export constraint can bind at times even with Tiwai smelter demand. After 1 June 2022[12] the impact of the LSI constraint is substantially reduced.

The chart also shows that were the Tiwai smelter to operate at 400 MW, a lower proportion of its demand would be met by thermal generation than were the smelter to operate at 572 MW. This is because without any Tiwai smelter load, there is a large amount of LSI spill, and so the first MWs of demand are much more likely to result in reduced spill, rather than an increase in thermal generation.

Effect on thermal generation costs

We have estimated the short run marginal cost (SRMC) of thermal plant based on an assumed gas price of 7.3 $/GJ, an assumed coal price of 5.5 $/GJ and a carbon price of 50 $/t. These values reflect our view of

[12] This date reflects the information that available when the new Tiwai agreement was signed. See https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/2020_Dec_Part%20A%20Executive%20Summary.pdf

expected average prices in late 2020/early 2021 for the coming 3-4 years. We also include an allowance for other variable costs of operation which vary by plant type.

Table 5 - Assumed SRMC for thermal displacement

	Whirinaki	Rankine	CCGT	OCGT
SRMC ($/MWh)	$ 297	$ 125	$ 77	$ 105

By way of comparison, Contact in early 2021 stated publicly that its thermal plant had expected fuel and carbon costs of 81 $/MWh.[13] This estimate excludes variable operating costs which we estimate at 5-10 $/MWh depending on plant type. Another point of comparison is Genesis which reported that its weighted average thermal fuel generation cost was 98.88 $/MWh in FY 2021.[14] Again this figure excludes other variable operating costs which we estimate will vary between 5-20 $/MWh depending on plant type.

The analysis estimates the change in thermal dispatch at a plant-type level – noting that these vary in their cost of generation depending on fuel conversion efficiency, fuel type and other operating costs. Our base case uses a strictly efficient "reverse dispatch" approach whereby the most expensive thermal is switched off first. The means that Huntly Rankine units are switched off first, followed by open cycle gas turbines (OCGTs) and then finally combined cycle gas turbines (CCGTs). This is slightly unrealistic as it is unlikely that the most efficient solution will always eventuate.

A non-perfect scenario of turning off OCGT plant ahead of Rankine units results in a reduction in costs of $9m if Tiwai reduced demand to 400 MW in 2022, and a reduction of $3m if Tiwai consumed at 572 MW. The 572 MW scenario is lower because it is more likely that all OCGT and all Rankine generation is displaced, and so the order does not matter as much.

Additionally, in some half-hours during the hindcast period there is less than 572 MW (or 400 MW)[15] of total thermal generation in operation. In those half-hours we have limited the change in thermal generation to the maximum which was running. In reality this might result in the dispatch of less hydro generation in that particular period, allowing more hydro generation in another period (with correspondingly less thermal). We have ignored this time-shifting effect, and instead assume that if all excess generation cannot be removed by scaling back thermal generation in the particular half-hour then it is lost as spill. This is expected to be conservative – i.e. bias the efficiency cost downward.

We also have not accounted for minimum thermal generation limits when scaling back thermal output. In reality, instead of running a CCGT at below minimum load it's likely that an OCGT would be utilized instead, and the impact of this for a very small amount of generation is minimal.

We have assumed that Huntly Rankine units operate on coal, but there is negligible difference in SRMC between operating on gas or coal using our fuel and carbon cost assumptions above. We perform this assessment using the thermal dispatch patterns and HVDC flows for the six years from 2015 to 2020. We stress that all historical years use expected SRMCs in late 2020 (i.e. the period when the agreement was negotiated). It is only the market behaviour that is used from earlier years. The expected impact reflects the average observed effects over the six year hindcast simulation period.

---

[13] This is based on historical thermal plant operation and carbon + fuel costs in January 2021. See also https://contact.co.nz/-/media/contact/mediacentre/presentations/tauhara-investment-and-capital-management-plan-presentation.ashx?la=en. Contact estimated its gas plant to have a fuel and carbon cost of 81 $/MWh in FY2021.

[14] https://gesakentico.blob.core.windows.net/sitecontent/genesis/media/content_2020/investor/pdfs/fy22/genesis-energy-fy21-results-presentation.pdf

[15] These figures are quoted before adjustment for transmission losses. In the model we estimate that a change of 572 MW at Tiwai results in an average change of about 500 MW in the upper North Island.

Smelter demand response provisions

The new agreement maintains the provision in the pre-existing contract which allows Meridian to reduce the CFD volumes for a period if hydro storage falls below pre-defined levels.[16] Our calculations do not explicitly account for this provision. To do so, we would need to calculate a probability weighted average of the economic cost of supply for two cases: where demand response is invoked; and where it is not invoked.

The calculations set out above implicitly cover the former case because they are based on a six year 'representative period' during which Meridian did not invoke the smelter demand response provisions. While the CFD volume would be lower in the alternative demand response case, we expect that effect would be more than offset by the higher economic cost of supply for the remaining volumes. This is because Meridian cannot invoke the provision unless hydro storage is very low – in which case supply costs are expected to be well above the values based on average thermal SRMCs. Hence, we consider that not including the effect of smelter demand response provisions is likely to understate the expected economic cost of incremental supply.

Incremental cost savings arising from new Tiwai agreement

As noted above, shortly after the Tiwai smelter closure announcement in mid-2020 Meridian and Contact were reported to be considering investment in a 100 MW battery in the North Island to provide more instantaneous reserve cover and facilitate northward energy transfer on the HVDC.[17] This project was shelved when the Tiwai contract extension was later signed.

We assume that a battery investment would have been required in the absence of the contract extension. We estimate the economic cost avoided in the relevant period would have been $21 million. This is based on the battery cost estimates used in the Authority's consultation paper on trading conduct rules issued in early 2021. We assume the costs are incurred for the period July 2022 to December 2024 and that the battery provides no other benefit.[18] The latter assumption is likely to be conservative, and if relaxed would reduce the incremental cost savings from not investing in the battery.

Overall summary – comparison of prices and incremental costs

Figure 2 summarises the overall results of the analysis. The chart considers two cases: full smelter operation at 572 MW until 31 December 2024; and reduced operation at 400 MW from 1 July 2022 to 31 December 2024.

In the case where the smelter operates at 572 MW until December 2024 the additional charges payable by NZAS are $[redacted] million compared to expected incremental costs of [redacted] million. This results in an expected subsidy to NZAS of $[redacted] million.

In the case where the smelter reduces its demand to 400 MW from July 2022 the additional charges payable by NZAS are $[redacted] million compared to expected incremental costs of $[redacted] million. This results in an expected subsidy to NZAS of $[redacted] million.

[16] Clauses 4.1 to 4.11 of agreement.

[17] See Energy News article on 27 August 2020.

[18] See https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/consultations/#c18781

Figure 2: NZAS charges and incremental cost of supply

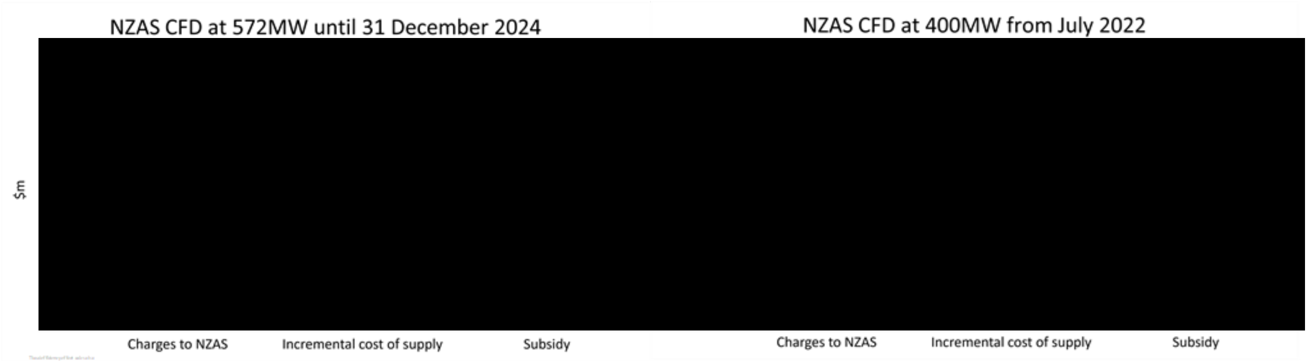


Figure 3 shows the same information expressed in $/MWh terms. In the case where the smelter operates at 572 MW until December 2024 the additional charges payable by NZAS are on average [redacted] $/MWh compared to expected incremental costs of [redacted] $/MWh. This results in an expected subsidy to NZAS of [redacted] $/MWh.

In the case where the smelter reduces its demand to 400 MW from July 2022 the additional charges payable by NZAS are on average [redacted] $/MWh compared to expected incremental costs of [redacted] $/MWh. This results in an expected subsidy to NZAS of [redacted] $/MWh.

Figure 3 - Tiwai breakeven price