SDP response to IPART Draft Report and Determination

Prices from 1 July 2023 to 30 June 2027

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SDP response to IPART Draft Report and Determination

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Executive Summary

Overview

SDP welcomes the opportunity to comment on IPART's Draft Report and Draft Determination on SDP's maximum prices from 1 July 2023 ('draft decision'), as well as supporting consultant advice provided to IPART by Atkins and Marsden Jacobs Associates (MJA) ('Atkins draft report').[1]

SDP's response to IPART's draft decision is guided by our overall objective for the 2023 Determination period to increase Greater Sydney's water supply resilience through dynamic utilisation of the Sydney Desalination Plant (the Plant). The long-term interests of customers will be promoted by ensuring SDP can fulfil its expanded role under its Network Operator's Licence and support the broader objectives of the GSWS.

SDP broadly supports the draft decision because, as discussed below, IPART recognises the implications that SDP's new role has for its efficient costs, risks and incentives.

As summarised in Table ES.1 below, SDP agrees or accepts with minor modifications most of IPART's draft decisions, even in circumstances where IPART's approach differs from our 2023-27 Pricing Submission. This is because on most issues the draft decision recognises the implications that SDP's new role has for its efficient costs, risks and incentives and promotes the long-term interests of customers.

However, for a small number of issues we propose that IPART change its draft decision based on the evidence and justification provided in this response. The areas in which we propose changes are draft decisions:

- that do not fully reflect the operating and cost implications of SDP's expanded role under its Network Operator's Licence and do not support the broader objectives of the GSWS;
- where IPART has failed to consider material submitted by SDP;
- where there is an inconsistency or misalignment between elements of IPART's draft decisions;
- where the draft decision appears to depart from previous IPART decisions (including recent decisions and guidelines) without a clear justification; or
- where calculation errors need to be corrected. In reviewing the underlying financial modelling for the Draft Determination, we identified several apparent calculation errors including incorrect entry of draft decisions or incorrect formulae within spreadsheets. We note that approximately half of the change to revenue/price forecasts suggested by this response to IPART's Draft Decision relate to these apparent calculation errors, with the remainder driven by revisions proposed by SDP.[2]

As discussed below, the three draft decisions of most concern to SDP relate to:

1. **The costs incurred by SDP to keep the Plant in a state of readiness,** which the Atkins draft report concluded were *variable* costs required for periods when no desalinated water is being produced".[3] These costs are *fixed* and incurred at all levels of production and should be included in the fixed Plant service charge rather than in the Sydney Water zero production charge;
2. **Inadequate allowances for energy usage and treatment costs** which the Atkins draft report recommended be based on historical data. This historical data does not reflect expected movements

[1] Atkins and MJA, Sydney Desalination Plant (SDP) Expenditure Review, Consultant Report, Draft Report, April 2023.

[2] We would welcome the opportunity to discuss these with IPART prior to the Final Determination to ensure all decisions are being applied correctly in the financial modelling.

[3] IPART, Draft Report, p53.

in treatment costs, including the increase in chemical prices that has occurred in global markets, and does not reflect the requirements to operate the Plant sustainably under SDP's new Network Operator's Licence in line with good industry practice;

3. **Asset life assumptions for the pipeline and membranes** that do not properly reflect the expected economic life of those assets as required by Pricing Principle 3 of the ToR.

Each of these issues is summarised briefly below.

The costs of keeping the Plant in a state of readiness are fixed

IPART's draft decision recognises that 'availability costs' including the costs associated with process water and associated treatment costs, will need to be incurred to keep the Plant in a state of readiness. However there appears to be a misunderstanding of *when* these costs are incurred based on the findings of the Atkins' draft report which concluded that these are "variable costs required for periods when no desalinated water is being produced".[4] On this basis, the draft decision was to allow SDP to recover these costs through a 'Sydney Water requested zero production charge'.

As we detail in this response, however, availability costs are incurred at all levels of production below full capacity (and to some extent even at full capacity) not only during zero production days. Specifically, costs are incurred to maintain assets appropriately (e.g. process water is used to ensure reverse osmosis membranes do not dry out, but the cost of this water cannot be recovered because it is not supplied to Sydney Water), maintain asset availability and reliability by asset rotation (i.e. ramping modular elements of the plant up and down to maintain efficacy) and to comply with our environmental licences (i.e. maintain outfall diffuser velocity). The costs of keeping the Plant available to meet the levels of service required under SDP's Network Operator's Licence and envisaged under the GSWS should therefore be treated as *fixed*, rather than variable. We understand from our engagement with Sydney Water, that it supports this position.

SDP submits that the costs allocated to the "Sydney Water requested shutdown charge" be instead included in SDP's fixed O&M operating expenditure allowances and factored into the fixed Plant service charge. This will better promote the cost-reflectivity of prices and consistency with Pricing Principle 4 & 6 of the ToR.

The allowances for energy usage and treatment costs based on 2021-22 data do not reflect the costs of sustainably operating the Plant

SDP's flexible full-time role will require different operational practices than historically required under its previous Network Operator's Licence. In the context of setting Routine Asset Maintenance (RAM) allowances, IPART recognises that "*a sustainable operating regime under the new operating licence is not the same as the emergency response role under which SDP has been operating since March 2020.*" On this basis IPART's draft decision increased Atkins' recommended costs for RAM. This important point extends to other cost components including the allowances for energy usage and variable treatment costs – both of which have been primarily based on historical costs.

The draft decision on energy usage is based on Atkins' analysis of the Plant's historical energy use plus a modest increase for membrane aging. While Atkins did not recommend further efficiencies, IPART's draft decision added a continuing efficiency factor of 0.7% p.a. SDP's concern is that energy usage during the 2017-23 regulatory period was based on the Plant's emergency response role, where the three most efficient Reverse Osmosis (RO) trains were used preferentially on a temporary basis until the Plant was expected to shut down.[5] With the Plant now set to operate on a flexible full-time basis this is not a sustainable approach. To meet good industry practice, we will need to undertake normal asset rotation across the Plant's 13 RO trains. In the absence of additional capital investment, this will increase

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[4] IPART, Draft Report, p53.

[5] These three RO trains have impellors (the rotating component of the pump) that are trimmed, which means they use less energy but may not be able to produce water when sea water quality is poor.

the Plant's energy use during the 2023 Determination period relative to historical energy usage. This issue could be addressed by either Atkins' adjusting their recommended energy use allowances or IPART removing the continuing efficiency factor applied to energy volumes to improve alignment between IPART's related decisions to reduce SDP's proposed capex on RO membranes and our proposed treatment costs.

The draft decision on treatment costs, mainly comprised of chemical costs, is based on the Plant's treatment costs in 2021-22. During the expenditure review process, Atkins acknowledged that there had been a material increase in chemical prices in global markets in recent years. However, Atkins appear to have concluded that these market movements had been incorporated into the contract prices agreed between SDP and Veolia and the resulting treatment costs incurred in 2021-22. SDP's concern is that [redacted] the increase in global chemical costs was not fully reflected in our treatment costs in 2021-22. The costs incurred by SDP over the 2023 Determination period will not align with the costs incurred in 2021-22 because they will need to adjust to prevailing market prices for chemicals. We have developed a revised treatment cost forecast that incorporates feedback provided by Atkins during the expenditure review and includes prevailing market prices for chemicals obtained by Veolia leveraging their buying power to minimise cost to customers. IPART's draft decision notes that "SDP and Veolia as global leaders in water treatment are well positioned to provide robust forecasts of future chemical costs." [6] SDP submits that our revised treatment cost forecast should be included in the final decision to ensure usage charges reflect the "variable underlying resource costs"[7], consistent with IPART's approach to other building block allowances. This will ensure SDP is financially indifferent as to whether it supplies water as per Pricing Principle 4 of the ToR, and better promote the cost-reflectivity of prices and consistency with Pricing Principle 7 of the ToR.

The draft decisions on pipeline and membranes do not reflect their expected economic lives

We submit that the pipeline asset life should be set to 100 years, reflecting its economic life. In SDP's circumstances, the pipeline's expected economic life cannot exceed its design life. It appears the draft decision has failed to consider:

- The evidence provided by SDP in expert reports from KBR and Frontier Economics, which expand on these issues and justify SDP's proposal for a 100-year pipeline asset life. This evidence clearly states that the 100-year design life of the pipeline, as specified by the designers of the pipeline, does ***not*** represent a minimum or lower bound estimate of the physical life of SDP's pipeline. Rather there are specific factors that threaten the pipeline's ability to achieve an economic life longer than the design life, including the aggressive marine environment under which a majority of the pipeline resides, no ability to inspect certain components of the pipeline, no cross-connections, no ability for SDP to supply water if the pipeline requires remediation and the risk of obsolescence beyond the 50-year term of SDP's Water Supply Agreement with Sydney Water; as well as
- IPART's 2019 and 2022 decisions on WaterNSW's Broken Hill Pipeline which reaffirmed the principle of setting asset lives in line with the asset design life (as specified in design documentation).

IPART's decision in the 2017 Determination was anchored to assumptions about the potential economic life of Sydney Water's pipeline assets. While there may be factors to suggest Sydney Water's portfolio of pipeline assets could achieve an economic life greater than 100 years (some factors that suggest Sydney Water's assets could last longer than SDP's pipeline are listed in the KBR pipeline asset life report). There are no reasons to suggest this could be the case for SDP's pipeline. If anything, SDP's pipeline is more like the Broken Hill Pipeline, for which IPART has assumed an asset life of 100 years, consistent with its documented design life.

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7 IPART, Draft Report, p147.

We also submit that IPART should maintain an 8-year asset life assumption for membranes. The Atkins draft report has recommended an 11-year asset life based on a novel concept of "production-weighted" asset life that has not been supported with any evidence as to how this is consistent with the regulatory precedent or requirements of the ToR. It is incongruous for the regulatory asset life of membranes to be increased relative to the 2017 Determination given:

- there is no clear reason why the underlying principle of setting the design life [redacted] 8 years should change;
- [redacted] This is the upper limit on which manufacturers will guarantee performance of the membranes;
- Prudent and efficient asset rotation will mean all membranes are likely to be used more in the future than they were in the past, meaning there is very low possibility the membranes could be placed in preservation to extend the life beyond 8 years.

Addressing these issues in the final decision will ensure consistency with the economic life of those assets as required by Pricing Principle 3 of the ToR.

Other concerns with the Draft Decision

In addition to the key issues listed above, SDP has identified several other issues that we submit are necessary to ensure the Final Determination promotes the long-term interests of customers as well as regulatory certainty, stability and transparency. These include:

- **The cost of debt true-up:** It is in customers' long-term interests that SDP's prices are annually updated for changes in the trailing average cost of debt so that it can meet benchmark efficient credit metrics. Our analysis in this response explains why an annual cost of debt update would have an immaterial impact on customer bills over the 2023 Determination period, but it would ensure that SDP's cash flows and credit metrics are not subject to inefficient stress within a regulatory period. This is particularly important to SDP as a relatively small, privately-owned infrastructure business that raises its own debt in global capital markets which as standard practice, impose strict debt covenants on companies like SDP that are measurable every six months. We understand from our engagement with Sydney Water that it remains prepared to support an annual cost of debt update for SDP consistent with its previous views expressed during the 2018 WACC Guideline process.
- **Catch-up efficiency factors**: Not applying compounding catch-up efficiencies of 0.5% p.a to opex and above 1.5% p.a. to capex. SDP submits that it is efficient, and the draft decision notes the Plant's operator, Veolia, are "global leaders" providing cost savings and other benefits to our customers. We do not consider that Atkins has demonstrated SDP's distance from the efficiency frontier nor the specific limitations that IPART has noted are "incumbent on the consultant to justify" [8], particularly given Atkins' admission that "the specific nature of SDP's business does not allow us to benchmark with confidence".[9]
- **Land tax and council rates**: In the absence of providing cost pass-through for these uncontrollable costs, SDP submits that IPART should at least adopt SDP's revised estimates of land tax and council rates, which are informed by expert evidence and exclude ongoing efficiencies on the basis that these costs are clearly outside of SDP's reasonable control, as has been accepted by IPART in other contexts.[10] We note that Atkins has failed to consider the expert report we provided on this cost item.

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[8] IPART, Our Water Regulatory Framework, Technical Paper. November 2022, p50.

[9] Atkins, Marsden Jacob Associates, *Sydney Desalination Plant Expenditure Review Report*. April 2023, p55.

[10] For example, IPART states its Water Regulation Handbook that non-controllable costs include costs such as regulatory fees and other input costs including Sydney Water's bulk water costs determined by IPART. IPART, Water Regulation: Handbook, April 2023, p42.

- **GGRP costs**: Incorporating a formal end-of-period true-up for subordinate GGRP costs i.e., those costs incurred by SDP under the GGRP contracts that are in addition to the cost items recovered through the benchmark price, to ensure fulfilment of Pricing Principle 7A of the Terms of Reference, or alternatively providing a cost pass-through for these items. We have provided an expert report from Energetics that outlines both the likely materiality of these costs and the prudence/efficiency of ensuring SDP is able to recover these costs.
- **Financeability test**: Considering the evidence SDP provided relating to the benchmark test. SDP has proposed a benchmark test that recognises that a benchmark efficient firm would face nominal interest costs. This differs from IPART's benchmark test which assumes incorrectly that a benchmark efficient firm would face real interest costs over the 2023 Determination period – which is infeasible for almost every corporate borrower in Australia, including SDP. [redacted]

In addition, we note one other area where the draft decision misinterprets the operating and cost implications of SDP's new role. Sydney Water controls the sequencing of the Annual Production Request through ongoing production requests at a daily, weekly and monthly level. SDP does not have control over production decisions that would enable it to respond to expected movements in energy charges and does not agree with the draft decision's conclusion that SDP is best placed to manage the risks associated with these costs. Additionally, if SDP was to control the sequencing and make operational production decisions based on expected movements in energy market costs this would greatly erode the flexibility of operations sought by Sydney Water and envisaged under NSW Government policy objectives as set out in the GSWS, as well as introducing additional risks to achieving consistent and reliable operation over the long term, which would not be in the best interests of customers.

Appendix A of this response details calculation errors as well as the revisions to forecasts we have identified for IPART to address in its Final Determination.

Most aspects of the draft decision reinforce SDP's incentives for good performance

Apart from the small number of areas of concern identified above, SDP considers that IPART's draft decision largely recognises the significant change in the scope of SDP's service under its new Network Operator's Licence in the cost, risk and incentive framework administered by IPART, which will support the NSW Government's policy objectives as set out in the GSWS.

For example, the draft decision:

- improves the operation of the efficiency carryover mechanism (ECM), which provides a financial incentive for SDP to pursue ongoing improvements in operating expenditure where permanent efficiency savings can be demonstrated and better aligns it with the new operating regime;
- allows many of SDP's proposed increases in expenditure (such as the increased costs of managing operational co-ordination, insurance, cyber security, and sustainability) which enables SDP to respond to the challenges of the future;
- acknowledges that SDP faces strong incentives for good performance including through its Network Operators' Licence and avoids the risk of imposing a new outcome delivery incentive (ODI) scheme before the outcomes of SDP's new operating regime is fully tested;

- establishes a single operational 'mode' for pricing purposes;
- promotes the efficient allocation and management of risk in several areas, particularly:
  - by accepting SDP's proposed insurance costs, IPART has enabled SDP to appropriately manage certain risks on behalf of its customers via efficient commercial insurance
  - some changes to the energy adjustment mechanism (EAM) reduce SDP's exposure to risks outside of its control to some extent (e.g., reducing the core band to 2.5%)
  - retaining pass-through of energy network costs recognises that SDP cannot manage risks associated with such an exogenous cost
  - by applying the 2018 WACC methodology, IPART has appropriately compensated for systematic risk borne by SDP.

Summary of SDP's response to each of IPART's draft decision

Table ES.1: Summary of SDP's response to IPART's draft decisions for the 2023 Determination period

Section of this response	IPART Draft Decision	IPART decision reference	SDP response to draft decision
2 Scope and form of regulation			
2.1	Length of determination period	1	Agree
2.2	The form of price control (price caps)	25	Agree
2.3	Production levels for prices	2,3	Accept with qualification
3 Incentive and risk management framework			
3.1	Service Level Incentive Scheme (SLIS)	39,40	Agree
3.2	Efficiency Carryover Mechanism (ECM)	41-44	Accept with qualification
3.3	Energy adjustment mechanism (EAM)	45-48	Accept subject to minor modification
3.4	Energy network cost pass-through	33	Agree
3.5	Risk management mechanisms for uncontrollable costs	31, 32, 34	Accept with qualification
3.6	Re-opener of determinations	35	Accept with qualification
3.7	Guiding principles for future Plant Expansion determination	38	Accept with qualification
4 Operating expenditure			
4.2	Fixed O&M costs - Plant	6,7	Accept subject to minor modification
4.3	Variable O&M costs - Plant	6,7	Disagree
4.4	O&M costs - Pipeline	6,7	Disagree
4.5	Energy costs: energy price	5	Accept with qualification
4.6	Energy costs: energy volumes	4	Disagree
4.7	Corporate costs	6	Accept subject to minor modification
4.8	Insurance costs	6	Accept subject to minor modification

Section of this response	IPART Draft Decision	IPART decision reference	SDP response to draft decision
5 Capital expenditure			
5.1	Actual capex over 2017 determination period included in RAB	9	Agree
5.3	Plant +Pipeline capex (incl. membranes, periodic maintenance, pipeline and corporate)	10	Accept with qualification
6. Allowance for a return on assets, regulatory depreciation, tax obligations and other revenue			
6.1	Opening value and roll forward of the Regulatory Asset Base	9,10	Accept subject to minor modification
6.2	Rate of return	11	Accept (subject to correction of calculation errors)
6.3	Application of a cost of debt true-up	12	Disagree
6.4	Depreciation methodology	13	Agree
6.6	Asset lives: Pipeline	13	Disagree
6.7	Asset lives: Periodic maintenance	13	Agree
6.8	Asset lives: Membranes	13	Disagree
6.9	Asset lives: Other	13	Agree
6.10	Return on working capital	15	Accept subject to minor modification
6.11	Tax costs	16	Accept subject to minor modification
6.12	Revenue adjustments: required by the TOR: EAM	17	Accept subject to minor modification
6.12	Revenue adjustments: required by the TOR: ECM	18	Agree
6.13	Revenue adjustment for 2022-23 deferral year	19-20	Accept (subject to correction of calculation errors)
7 Proposed prices			
7.1	Pricing structures	24-26	Accept with qualification
7.2	Cost sharing and proposed application of prices	29	Accept with qualification
7.3	Negotiated agreements	25, 26	Accept with qualification
8 Impacts on customers and SDP			
8.1	Customer impacts	Chpt 10.1-10.2	Agree
8.2	Financeability analysis	Chpt 10.5-10.6	Disagree
8.3	Meeting service standards	Chpt 10.3	Accept with qualification
8.4	Implications for the environment	Chpt 10.8	Accept with qualification

1. About this response

1.1 Background

In September 2022 SDP submitted a comprehensive pricing submission for the period 1 July 2023 to 30 June 2027 (**2023 Determination period**) for review by IPART (**SDP pricing submission**). Our pricing submission sought to define a pricing, risk management and incentive framework aligned to SDP's role under its new Network Operator's Licence and the NSW Government's policy objectives as set out in the Greater Sydney Water Strategy (GSWS).[11] At the same time our pricing submission proposed to deliver services prudently and efficiently so as to promote the long-term interests of customers.

After receiving SDP's pricing submission, IPART released an issues paper, sought feedback on consultant reports, conducted a public hearing and has now released its draft report and determination on SDP's maximum prices from 1 July 2023, as well as its Draft Methodology Paper on the Energy Adjustment and Efficiency Carryover Mechanisms (**draft decision**).

This submission sets out our response to this draft decision (**SDP response**).

1.2 Our approach to developing this response

SDP's response to IPART's draft decision is guided by our overall objective for the 2023 Determination period to increase Greater Sydney's water supply resilience through dynamic utilisation of the Plant. The long-term interests of customers will be promoted by ensuring SDP can efficiently fulfil its expanded role under its Network Operator's Licence, and support the broader objectives of the GSWS.

We have reviewed IPART's draft decision (including its consultants' reports), and in doing so, we have engaged with the NSW Government, Sydney Water and stakeholders to discuss their priorities and preferences for our services over the 2023 Determination period. We have:

- Structured our response around IPART's draft decisions for ease of reference;
- Provided revised modelling inputs by exception where we consider it relevant to IPART's final decision (summarised in **Appendix A**);
- Provided supporting detail in appendices, and where possible avoided unnecessary duplication by providing clear references to relevant information rather than restating information already provided. This includes referring to information contained in SDP's pricing submission and SDP's response to IPART's Issues Paper (**response to Issues Paper**).

For each constituent draft decision, we have stated where we:

- **Agree** - where we agree that the draft decision promotes our customers' long-term interests in the context of the new operating environment and circumstances expected to prevail over the 2023 Determination period ('green light')
- **Accept with qualification** - where we consider that the draft decision could more fully promote our customers' long-term interests in the context of the new operating environment but are accepting it for the 2023 Determination or proposing only minor refinements or conditions (grey or 'amber light' where minor modifications are proposed). Where possible we have accepted IPART draft decisions even if we are not completely aligned in our (SDP and IPART) respective approaches.
- **Disagree** – where we do not agree that the draft decision promotes customers' long-term interests in the context of the new operating environment and the impacts are likely to be material and/or the decision is not consistent with sound regulatory principles or practice ('red light').

[11] SDP's Network Operator's Licence and Retail Supplier's Licence under the Water Industry Competition Act 2006 (WICA) set out Operating Rules developed in response to the Greater Sydney Water Strategy (GSWS) take effect from 1 July 2023

1.3 Our responses to IPART's specific questions

IPART has raised three specific questions for stakeholder comment.

1.3.1 Recovering the costs of insurance to manage force majeure risks:

IPART's draft decision asked SDP to consider whether prices should reflect the costs of recovering from force majeure (FM) events through third-party business interruption (BI) insurance. Specifically, it requested:

"1. Should prices reflect the costs of recovering from force majeure events through third-party business interruption insurance? Or alternatively, should these costs be avoided via Sydney Water's continued payment of a service charge during force majeure events?"

We have discussed the two options described in the draft decision with Sydney Water, and it remains of the view that SDP should maintain full BI insurance cover that includes funding the costs of recovering from FM events. SDP and Sydney Water consider this would be in the long-term interests of customers. This is because BI cover provides valuable insurance in the face of more frequent and severe natural disaster events, increased risks from more frequent operation and customers' greater reliance on SDP going forward. SDP has cost effectively built this capacity in the Australian insurance market over time, which customers would continue to benefit from under this option. To ensure that customers can obtain maximum benefit from BI insurance funded in SDP's allowed prices, Sydney Water and SDP will incorporate a mechanism into their Water Supply Agreement (WSA) to reduce SDP's fixed charges by the extent to which insurance coverage indemnifies SDP. Sydney Water has strong incentives to ensure that SDP maximises insurance claims, including because IPART will provide oversight of what occurs in practice when assessing Sydney Water's ability to recover costs from end-use customers.

We also considered whether it would be in the long-term interests of customers to exclude the costs of recovering from FM events from our BI insurance. Our efficient insurance costs includ[redacted] insurance policies with a BI component - SDP's Industrial Special Risks (ISR) Policy, [redacted] Veolia's Professional Indemnity (PI) Policy. These BI policies are procured in the global insurance market that provides access to cost-efficient standard insurance products that do not allow the insured to pick and choose events that will be included or excluded in the BI component. Standard BI policies cover not only FM events but also non-FM events – that is events that are not force majeure in nature such as an operational failure of or latent defect in a pipeline, in the case of ISR insurance. These non-FM events can have as long a duration as FM events and duration is a key driver of BI limits within insurance policies. Typically, [redacted] Veolia's Professional Indemnity insurance [redacted] carry a BI component in their limits, are triggered by non-FM events, so the exclusion of FM events from these policies do not change the risk profile of the policy, the limit or the premium cost. This means that the premium cost for all three of the insurance policies with a BI component would not change even if FM events could be and were excluded from them.

The report from insurance experts AON attached at **Appendix D** further explains the impact of FM events on BI insurance and supports the position discussed above.

As a result, SDP is submitting insurance cover which has a full BI component (i.e. includes cover for FM and non-FM events). The premium cost was previously provided to IPART as Package 1 in our September 2022 Proposal to IPART and is reflected in the table in Section 4.8.

1.3.2 Setting a Sydney Water requested zero production charge

IPART's draft decision asks:

"2. Is our approach to setting a Sydney Water requested zero production charge appropriate? Are there any unintended consequences that may occur that we should consider?"

SDP proposed that the costs of availability including process water– which are incurred to the greatest extent whenever production is below full production of 250 ML/day to ensure SDP can respond to changing production requests – are recovered through the fixed Plant service charge consistent with Pricing Principle 6 of the Terms of Reference. IPART's draft decision recognises that costs are necessary to keep the Plant in a state of readiness.

However there appears to be a misunderstanding of *when* these costs are incurred based on the findings of the Atkins' draft report which concluded that these are "variable costs required for periods of when no desalinated water is being produced".[12] On this basis the draft decision was to allow SDP to recover these costs through a 'Sydney Water requested zero production charge'.

As we detail in this response, availability costs are required at all times that the Plant operates at less than full production to keep the plant in a state of readiness for full or increased production (e.g. in response to a water quality or system outage emergency) not only during zero production days (see Section 4.2). Specifically, costs are incurred to maintain assets appropriately (e.g., reverse osmosis membranes), maintain asset availability and reliability by asset rotation (i.e. ramping modular elements of the plant up and down) and to comply with our environmental licences (maintain outfall diffuser velocity). SDP submits that the costs allocated into the "Sydney Water requested shutdown charge" be included in SDP's fixed O&M opex allowances and factored into the fixed Plant service charge. We understand from our engagement with Sydney Water, that it supports this position.

IPART's draft decision not to accept SDP's proposal to include these costs in the fixed Plant service charge and instead include some of these costs in a requested zero production charge would mean SDP is not financially indifferent as to whether it supplies water (as per Pricing Principle 4 of Terms of Reference) and would be incentivised to run at full or no production, because outside of these scenarios SDP would not recover the costs of making the Plant available. Not enabling SDP to recover these costs in the fixed Plant service charge would impede SDP's ability to regularly change Plant production levels as requested by Sydney Water under SDP's Network Operator's Licence, as required to maintain a strategy of asset rotation, and to meet the flexible operations objective of the GSWS.

1.3.3 Cost sharing between Sydney Water and other purchasers

IPART's draft decision asks:

"3. Is our approach to sharing costs between Sydney Water and other purchasers appropriate?"

SDP considers the draft decision's cost sharing framework to be simpler and more transparent than the 2017 Determination. However, should the emergence of another customer become a realistic possibility in future regulatory periods, more detailed consideration would need to be given to the proposed cost sharing arrangement to ensure that it does not itself become a barrier to third party supply and outcomes that are in all customers' long-term interests.

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12 IPART, Draft Report, p53.

2. Scope and form of regulation

Table 2.1: Scope and form of regulation: Summary of SDP's response to IPART's draft decisions

Issue	IPART draft decision	IPART decision reference	SDP response to draft decision
Length of determination period	• A 4-year regulatory period from 1 July 2023 to 30 June 2027.	1	Agree
Form of price control (price caps)	• Retain 'building block' revenue requirements to estimating the efficient costs of providing SDP's monopoly services in line with its requirement to operate on flexible full-time basis in accordance with SDP's Network Operator's Licence • To set maximum prices (i.e. price caps) that SDP can charge for providing these monopoly services at all times	25	Agree
Production levels for prices	• To apply a representative average production level, equivalent to 68.4%, for SDP's capital expenditure and depreciation profiles • To not set any 'fixed' minimum level of production, and allow SDP and Sydney Water to flexibly negotiate a minimum production level on an annual basis	2,3	Accept with qualification

2.1 Length of determination period

SDP **agrees** with IPART's draft decision. In our view a regulatory period from 1 July 2023 to 30 June 2027 best balances the need to have funding certainty with learning how the business responds to its new operating regime and reviewing regulatory settings based on this.

SDP supports longer, 5-year, regulatory periods in the future. However, there are several unique circumstances that support a shorter 4-year pricing determination for this regulatory period.

2.2 Form of price control

SDP **agrees** with IPART's draft decision to retain 'building block' revenue requirements and the setting of price caps in line with SDP's requirement to operate on flexible full-time basis in accordance with SDP's Network Operator's Licence (i.e., removing mode-based distinctions).

These decisions are in the long-term interests of customers because:

- Price caps based on a revenue requirement provide appropriate incentives for SDP to incur and recover only the efficient costs associated with supplying whatever level of water production it is requested to provide.
- Setting a single set of prices that apply at all times (i.e. removing the previous mode-based sets of prices) is consistent with SDP's new Network Operator's Licence, which requires SDP to operate on a flexible full-time basis.

2.3 Production levels for prices

SDP **accepts with qualification** IPART's draft decision to not set any 'fixed' minimum level of production and allow SDP and Sydney Water to flexibly negotiate a minimum production level on an annual basis, subject to IPART:

- ensuring that the fixed service charge reflects the prudent and efficient costs of making the Plant available including the costs of process water (see Section 4.2). These costs are incurred at all levels of production but are more evident at lower production levels, or when changing production as detailed in Sections 1.3.2 and 4.2.

- removing the ‘Sydney Water requested zero production charge’ and reallocating the costs of making the Plant available into the fixed Plant service charge to ensure:
  - The fixed Plant service charge reflects the fixed costs of providing services as per Pricing Principle 6 of the ToR;
  - SDP is indifferent as to whether it supplies water as per Pricing Principle 4 of the ToR; and;
  - The Plant is able to change production levels flexibility to meet Sydney Water production requests and the flexible operation objectives of the GSWS (see Sections 4.2 and 7.3).

3. Incentive and risk management mechanisms

Table 3.1: Incentive and risk management mechanisms: Summary of SDP's response to IPART's draft decisions

Issue	IPART draft decision	IPART decision reference	SDP response to draft decision
Service Level Incentive Scheme (SLIS)	• Not accept SDP's proposed SLIS • Remove the abatement mechanism on the basis that SDP's Network Operator's Licence provides sufficient incentive to ensure good performance	39-40	Agree
Efficiency Carryover Mechanism (ECM)	• Remove the mode-specific distinction in the efficiency carryover mechanism (ECM). • Not accept the proposal to calculate efficiency savings as the difference between forecast and actual costs. • Amend the ECM to calculate efficiency savings in two components for fixed and variable costs separately, to address SDP's concerns about the operation of this mechanism under differing levels of water production. • Apply a financial incentives cap of 2.5% of fixed plant charges, noting that it is now only applied to the ECM.	41-44	Accept with qualification
Energy adjustment mechanism (EAM)	• To remove the mode distinction in the EAM, reduce the core band from 5% to 2.5% but retain the sharing ratio of gains and losses on the sale of surplus energy outside of this core band • To remove ex post prudency assessment of SDP's energy trading strategy • To commence the 2023 EAM application period from 2022-23	45-48	Accept subject to minor modification
Energy network cost pass-through	• Retain cost pass-through of network component of energy costs and remove the temporary Fixed Network Charge cap	33	Agree
Risk management mechanisms for uncontrollable costs	• Not accept SDP's proposed end-of-period true-ups for specific existing subordinate GRRP energy costs (i.e. ancillary service charges, market fees, and network loses), new fees that may be introduced by energy market regulators and material movements in land tax, council rates, chemical costs and insurance • Not accept SDP's proposed cost pass-through of generator compensation, unaccounted for energy (UFE) and Reliability and Emergency Reserve Trader (RERT) charges but propose to consider any generator compensation charges incurred by SDP during the 2023 Determination period at our next SDP price review	31 32 34	Accept with qualification
Re-opener of determinations	• Clarify the type of events that constitute re-opener events, but for IPART to retain discretion over whether it will re-open the determination rather than setting an explicit materiality threshold as proposed by SDP	35	Accept with qualification
Guiding principles for future Plant Expansion determination	• To not accept SDP's proposed guiding principles for expansion determination, and instead provide guidance on the principles that IPART would have regard to in any future expansion determination	38	Accept with qualification

3.1 Service Level Incentive Scheme (SLIS)

SDP **agrees** with IPART's draft decision to remove the abatement mechanism which applied under the 2017 Determination, on the basis that under SDP's new flexible role, the abatement mechanism is no longer fit for purpose and no longer aligns with its new flexible role. We note that this position is also supported by Sydney Water.

SDP also **agrees** with IPART's decision to rely on the incentives created by financial penalties within SDP's new Network Operator's Licence for the 2023 Determination. As noted by IPART, SDP will also have strong reputational incentives to reliably respond to Sydney Water's production requests. More experience within SDP's new operating environment is needed to inform if further incentives are required and, if they are, what these incentives should target to deliver in the best long-term interests of customers.

3.2 Efficiency Carryover Mechanism (ECM)

SDP **accepts with qualification** IPART's draft decision to retain an ECM that allows SDP to carryover demonstrated efficiency savings, net of efficiency losses, in operating expenditure for four years following the year in which the efficiency saving was achieved, and to remove the mode-specific application of the cap.

SDP also **agrees** with IPART's draft decision to remove the mode-specific application of the ECM given SDP's full time flexible operations.

SDP supports the principle of incentive regulation and concurs that the ECM should allow SDP to retain permanent efficiency savings for a fixed period, regardless of when they are realised, before these savings are passed on to customers through lower prices. This ensures there are equal financial incentives to pursue efficiency gains throughout the determination period.

IPART's draft ECM seems to adequately account for the impact of SDP's variable (year to year) supply volumes on its efficient costs (and therefore the calculation of marginal, year to year, efficiency gains/losses to be carried forward). However, the ECM should exclude costs beyond SDPs control (e.g., movements in land tax & council rates, subordinate GGRP and energy network costs) to avoid windfall gains and losses. This would be consistent with IPART's expectations that controllable and uncontrollable costs will involve different forecasting techniques and regulatory treatment with the potential for 'carve-outs' of uncontrollable costs from efficiency mechanisms.[13]

SDP also **agrees** with IPART's draft decision to accept SDP's proposal to set an annual cap on financial rewards or penalties under the ECM of 2.5% of SDP's plant fixed charges.

3.3 Energy Adjustment Mechanism (EAM)

Overall SDP **accepts with qualification** IPART's draft decisions on the EAM.

SDP **accepts with qualification** IPART's draft decision to expand the scope of the EAM to remove the mode distinction and include all of SDP's surplus energy. However, we are concerned that this is subject to SDP being compliant with the relevant provisions of its Network Operator Licence. IPART notes that:

> *If SDP is deemed to not be in compliance with the relevant terms of its Network Operator's Licence for part of a financial year during the application period, any energy relating to that period may be excluded from the EAM.*[14]

SDP is concerned that a non-compliance with its Network Operator's Licence could be unrelated to the application of the Energy Adjustment Mechanism. A failure to provide reports as required by the licence, for example, should not affect the application of the Energy Adjustment Mechanism. There is already a mechanism to penalise general licence breaches. We propose therefore that the relevant condition read:

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13 For example, IPART states in its Water Regulation Handbook that non-controllable costs include costs such as regulatory fees and other input costs including Sydney Water's bulk water costs determined by IPART. It notes that IPART has agreed to allow carve-outs from the CESS so that costs that are uncontrollable can be excluded from the scheme while the schemes are new. IPART, Water Regulation: Handbook, April 2023, p39-42.

14 IPART, Draft Methodology Paper, p15.

"*The Energy Adjustment Mechanism will not apply to any surplus electricity that is available to SDP as a result of SDP breaching its Network Operator's Licence (for example, a failure to produce the quantity of water required under the licence).*"

This would be consistent with the requirements set out in Pricing Principle 8(iii) where the EAM only applies at times when SDP complied with its requirements to maintain and operate the desalination plant as set out in SDP's Network Operator's Licence (note these requirements are set out in clause 1 of schedule A of SDP's new Network Operator's Licence).

SDP **agrees with** IPART's draft decision to reduce the existing 5% core band to 2.5%. This reduces somewhat SDP's exposure to windfall gains and losses from the sale of surplus energy.

SDP **accepts with qualification** IPART's draft decision to retain the 80:20 sharing ratio of gains and losses on the sale of surplus energy outside of the core band. In doing so, we reiterate that SDP has no ability to manage these windfall gains and losses because:

- SDP's Network Operator's Licence is clear that SDP has obligations to meet production volumes and timing that are within Sydney Water's control. This is likely to be consistent with the WSA whereby Sydney Water can control the sequencing of the APR through ongoing production requests at a daily, weekly and monthly level. For these reasons SDP cannot sell energy entitlements until they are known to be surplus;
- Additionally, if SDP was to control the sequencing and make operational production decisions based on expected movements in energy market costs this would greatly erode the flexibility of operations sought by Sydney Water and envisaged under the GSWS, as well as introducing additional risks to achieving consistent and reliable operation over the long-term, which would not be in the best interests of customers;
- forward premia are completely uncertain so SDP cannot expect to get a better or worse price for the sale of surplus energy by selling forward or settling at prevailing spot price once energy is known to be surplus;
- The Plant is not capable of rapid changes in production levels to respond to short term energy market price movements.[15]

SDP intends to engage with Sydney Water on the cost and benefits of reducing Sydney Water's flexibility to vary production sequencing in the management of Greater Sydney's water security to enable SDP to respond to movements in energy market costs, while remaining compliant with its Network Operator's Licence to meet production requests. Sydney Water's Decision Framework for SDP operation[16] endorsed by the Minister for Lands, Water, Hospitality and Racing outlines the ministerially endorsed process and factors Sydney Water must consider when making production requests. Creating incentives for SDP and Sydney Water to seek savings in energy-related costs gains may send conflicting signals between the policy and regulatory framework.

SDP **agrees** with IPART's draft decision to exclude forward selling surplus energy from the test of "the prudence of SDP's energy trading policy and activity". SDP supports the EAM amounts being calculated as *actual* gain/losses (e.g., volume of surplus energy* actual-contract price) with no consideration of *hypothetical* gain /loss.

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15 In addition, SDP's GGRP contracts require that any energy gains associated with an exercise of interruption rights are to be shared 50% with its retailer Iberdrola. That is, if SDP provides interruption rights to Iberdrola, and Iberdrola exercises those rights (which results in surplus electricity and gains being made by selling that surplus electricity on the spot price), then 50% of those gains would be retained by the Iberdrola, and SDP would have to pay 80% of those gains (outside the updated 2.5% core band) to customers pursuant to the EAM. This means that more than 130% of the gain would need to be paid out. The only way for SDP to avoid this consequence is by not providing interruption rights to Iberdrola. This will limit SDP's incentive to deliberately reschedule production loads to take advantage of high energy prices, as suggested by IPART in its draft decision.

16 Sydney Water, Decision Framework for SDP Operation, June 2022.

3.4 Pass-through of energy network costs

SDP **agrees** with IPART's draft decision to retain the cost pass-through of the network component of energy costs.

SDP has no ability to manage network costs, either through an ability to vary production schedules to respond to short term movements in costs such as network prices, or by negotiating with Ausgrid to reach more commercially advantageous terms. Network prices cannot be forecast because neither SDP, nor Sydney Water, can reliably forecast water production needs which are subject to highly variable weather patterns, water quality variances, system outages and complex water usage decisions by end-use customers. Electricity network charges are no different to IPART determined bulk water prices, which IPART states are examples of uncontrollable costs faced by Sydney Water in its Water Regulation Handbook.[17]

Energy network charges are also independently reviewed and approved by the Australian Energy Regulator (AER) based on its review of their prudence, efficiency, and cost-reflectivity. The AER process promotes the long-term interests of customers and so the ultimate network charges approved by the AER should be passed through in SDP's prices into the future.

Retaining the cost pass-through of the network component of energy costs is a continuation of the arrangements that apply in the 2017 determination period. IPART has previously noted this cost pass-through arrangement meets its cost pass-through principles. IPART and other regulators have always passed through network costs when setting regulated retail electricity and gas prices.

SDP **agrees** with IPART's draft decision to remove the temporary Fixed Network Charge cap. The Fixed Network Charge cap was a temporary arrangement put in place to ensure network charges were set at a level consistent with shutdown in response to storm related re-instatement works and was applied until SDP was called into operation mode. Now that the Plant has returned to operation, it is no longer required.

3.5 Risk management mechanisms for uncontrollable costs

SDP **accepts with qualification** IPART's draft decision on risk management mechanisms for uncontrollable costs.

As noted by IPART, SDP incurs several energy market charges under the GGRP costs and these costs are highly uncertain[18]. However, expert advice from Energetics suggests these costs are likely to be material over the 2023 Determination period.[19] In addition, as noted in Section 3.3, to remain compliant with its Network Operator's Licence to meet production requests and respond to movements in these energy market costs, SDP's Water Supply Agreement with Sydney Water would need to constrain Sydney Water's flexibility to vary production sequencing. SDP does not accept "SDP is best placed to manage the risks associated with these costs." This would not promote the long-term interests of customers nor the objectives of the GSWS[20] Like electricity network charges, and land tax & council rates, these are by definition uncontrollable costs[21] incurred in providing SDP's services and should be reflected in the prices of providing SDP's monopoly services. These uncontrollable costs should also be removed from the assessment of efficiency gains and losses under the ECM (see section 3.2).

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17 For example, IPART states its Water Regulation Handbook that non-controllable costs include Sydney Water's bulk water costs determined by IPART. IPART, Water Regulation: Handbook, April 2023, p42.

18 IPART, Draft Report, p45.

19 Energetics, *'Other' electricity market charges*, An overview of 'other' regulated charges applicable to Sydney Desalination Plant over the RP3 period, 28 April 2023.

20 IPART, Draft Report, p123.

21 For example, IPART states its Final Handbook, that non-controllable costs include regulatory fees and other input costs including Sydney Water's bulk water costs determined by IPART. (IPART, Water Regulation: Handbook, April 2023, p42).

SDP accepts the draft decision with the qualification that energy market charges introduced and levied on SDP through the GGRP contracts should be included in IPART's draft decision (#34) through an ex-ante commitment in the final decision to an end-of-period true-up for these costs. This is both because these costs are prudent and efficient, and given the potential materiality of these subordinate GGRP costs as demonstrated through Energetics' report (See **Appendix C**). This would also ensure the fulfilment of Pricing Principle 7A of the Terms of Reference to IPART, which states: "The price determination should consider SDP's ability to recover all costs it incurs in complying with the GGRP and the GGRP Contracts {…}".

Although it does not affect this Determination, we consider that the draft decision incorrectly links SDP's proposed risk management mechanisms with the compensation that SDP receives through the WACC allowance for the reasons explained by Frontier Economics in **Appendix F**.

3.6 Re-opener of determination to manage material movement in efficient costs resulting from unforeseen events

SDP **accepts with qualification** IPART's draft decision. SDP concurs that retaining provision for a re-opener is an important risk management mechanism to address costs that are unknown prior to the determination.

While SDP's pricing submission included a materiality threshold, in SDP's view IPART's draft decision goes some way to providing greater certainty by stating (p.125) that IPART would consider reopening the determination of SDP mid-period when an event has the following characteristics:

- the event is exogenous and cannot wait for a true-up of efficient costs, and a cost pass-through has not already been set.
- the event materially affects SDP's ability to deliver water or results in prices set during the determination period being no longer cost-reflective.
- alternative risk management measures are not appropriate to mitigate or prevent the impact of the event.

However, SDP considers that the impact on SDP's financeability should be a key factor in IPART deciding whether a re-opener is appropriate because a utility "cannot wait for a true-up of efficient costs" following an event. Section 8.3 and **Appendix G** provide further detail on the financeability test.

3.7 Expansion cost recovery principles

SDP **accepts with qualification** SDP's draft decision. While setting out clear expansion cost recovery principles now would provide additional clarity, SDP acknowledges that these should not conflict with any future ToR.

SDP accepts the draft decision with the qualification that some of the guidance in the draft decision could potentially:

- compromise the intent of future government policy decisions and their timely implementation with regard to expansion. SDP's expectation is that it would receive an Expansion Notice from the NSW Government that requests SDP to plan for an expansion through a pre-existing contractual agreement. The purpose of IPART's expectation for SDP to develop a business case based on a strong understanding of its customers (both direct and end-use customers) including their preferences and willingness to pay for the expansion is unclear. We would expect the NSW Government to ensure an Expansion ToR provides this supporting guidance to IPART.
- expose SDP to significant cost-recovery risk relating to Expansion costs particularly if IPART seeks to undertake benchmarking analysis which could impact the competitive contracting and financing of such an expansion. We note IPART's concern that "the timing that cost information is shared with IPART would not allow IPART to assess the prudence or net benefit of this expenditure until after

binding contracts have been signed", however SDP's intent would be that contracts would not be signed with a preferred tenderer until after the IPART review and Government final approval.

- be inconsistent with IPART's precedent such as accepting the tendered construction costs for the Broken Hill Pipeline in its 2019 Determination after reviewing the robustness of the competitive tendering process. IPART noted that it engaged consultants to advise on the prudence of the tendering process.[22]

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22 IPART's final report notes: "In assessing the prudence of WaterNSW's capital expenditure over the pre-commissioning period of the Pipeline, Synergies reviewed WaterNSW's procurement process for the Pipeline. Synergies' found that WaterNSW conducted a detailed and robust tender process for the Pipeline within an overarching compressed timeframe for pipeline construction and commissioning. Synergies found that most of the costs associated with the Pipeline's design and construction, as well as future operations and maintenance, have been driven by the outcomes of competitive tender processes administered by WaterNSW; and that this process was well-designed and executed having regard to good procurement practice. As a result, Synergies concluded that WaterNSW's procurement process resulted in costs for the D&C and O&M contracts that reliably reflect a competitive market outcome." IPART, Murray River to Broken Hill Pipeline, Final Report, May 2019, p42.

4. Operating expenditure

Table 4.1: Operating expenditure: Summary of SDP's response to IPART's draft decisions

Issue	IPART draft decision	IPART decision reference	SDP response to draft decision
Determining and applying efficiency factors to opex allowances	• Operating expenditure allowances incorporate various scope efficiency adjustments, a catch-up efficiency factor of 0.5% p.a. from 2023-24, and a continuing efficiency factor of 0.7% p.a. These efficiency factors are largely based on advice from Atkins	6-8	Disagree
Fixed O&M costs – Plant	• Not accept' SDP's proposed fixed O&M costs for the Plant and instead adopt Atkins recommended allowance, with the exception of routine asset maintenance, and incorporating catch-up efficiencies of 0.5% p.a. and continuing efficiencies of 0.7% p.a.	6,7	Accept subject to minor modification
Variable O&M costs – Plant	• Not accept SDP's proposed variable O&M costs and instead adopt Atkins recommended variable O&M costs incorporating scope adjustments, but with the addition of a 0.7% p.a. continuing efficiency factor	6,7	Disagree
Fixed O&M costs - Pipeline	• Not accept SDP's proposed O&M costs	6,7	Disagree
Energy costs: energy price	• Set energy prices based on market-based benchmark of efficient energy costs	5	Accept with qualification
Energy costs: energy volumes	• Not accept SDP's proposed benchmark energy volumes and instead adopt Atkins recommendation and add to this a continuing efficiency adjustment of 0.7% p.a.	4	Disagree
Corporate costs	• Accepted many of SDP's proposed increases in corporate costs • Applied efficiency factors to all corporate costs, including uncontrollable costs	6	Accept subject to minor modification
Insurance costs	• Accepted SDP's proposed increase in insurance costs (plus efficiency factors) but tailor the allowances to the incentive schemes	6	Accept subject to minor modification

4.1 Determining and applying efficiency factors to opex allowances

SDP **disagrees** with both IPART's estimation and application of efficiency factors in its draft decision.

4.1.1 Scope efficiency adjustments

Atkins defines scope efficiency adjustments as "inefficiencies within proposed changes to a utility's specific programs".[23] These adjustments are made before any catch-up and continuing efficiency adjustments. Given this definition, these adjustments are relevant to SDP's proposed step changes.

In summary, Atkins recommended:

- no scope adjustments to SDP's proposed insurance costs (i.e. accepted SDP's proposed step changes for insurance costs);
- some scope adjustments to SDP's corporate costs (i.e. accepted some of SDP's proposed step changes for corporate costs);

[23] Atkins, Marsden Jacob Associates, *Sydney Desalination Plant Expenditure Review Report*. April 2023, p 17.

- substantial scope adjustments to SDP's proposed O&M costs for the Plant (i.e. accepted almost none of SDP's proposed step changes for O&M costs for the Plant which largely relate to additional costs under SDP's expanded role under its Network Operator's licence – and instead based most of its recommendations on FY22 expenditure).

Atkins' scope adjustments for O&M imply that it considers SDP's expanded role is essentially the same as the current emergency response role, and that the efficient costs of operating in this expanded role are reflected in full within the contractual payments for these activities to the Plant operator in a single year - FY22. IPART's draft decision, however, was to increase the routine asset maintenance component of O&M above Atkins' recommendation, noting that:

> *Our view is that a sustainable operating regime under the new operating licence is not the same as the emergency response role under which SDP has been operating since March 2020.*[24]

SDP supports IPART's draft decision to increase RAM costs above Atkins' recommendation and its recognition that the new operating regime for the Plant imposes additional costs. The new operating regime is also a driver of increased costs for other components of O&M and energy volumes, as outlined below.

4.1.2 Catch-up efficiency factor 0.5% p.a.

Atkins recommends, based on its experience, that catch-up efficiency adjustments of 0.5% p.a., growing to around 2% p.a. in 2026-27, are appropriate for SDP. The catch-up efficiency adjustments within the Draft Report are largely based on a view that "Having operated the plant across a range of volumes for a number of years, SDP and Veolia should now be in a better position to optimise operations and make efficiencies".

SDP submits that it is an efficient business. There is very limited evidence provided to justify the catch-up efficiency factor applied in IPART's draft report to opex, nor is this consistent with the 2017 Determination. Neither the Atkins draft report, nor IPART's draft decision, identify:

- The "efficiency frontier" for SDP's circumstances. That is, a desalination plant transitioning from long-term shutdown, to maximum production in drought response mode, then to flexible, full-time operation. SDP has exceeded expectations in responding to the unprecedented series of challenges in its recent history delivering exemplary customer outcomes through drought and flood emergencies, and there is no evidence (benchmark or anecdotal) that it should have delivered these services in a more efficient manner;
- SDP's distance from the efficiency frontier. Atkins itself notes, "the specific nature of SDP's business does not allow us to benchmark with confidence"[25] [26] yet states clearly that its application of these factors does not mean SDP will have arrived at the frontier by the end of the 2023 Determination period;
- The uncertainty related to the specific catch-up efficiencies recommended by Atkins and accepted by IPART given there is no quantitative analysis produced on the efficiency frontier or SDP's distance from the frontier, nor discussion of how this uncertainty could be reflected through a "range of efficient expenditure, rather than an exact figure."[27]

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24 IPART Draft Decision, p 48.

25 Atkins, Marsden Jacob Associates, *Sydney Desalination Plant Expenditure Review Report*. April 2023, p55.

26 Noting that other regulators like the AER have a quantitative transparent framework around this and IPART has committed to taking steps towards this. IPART notes it intends to streamline information returns to support greater use of benchmarking and working with the businesses to develop predictive models of longer-term capital expenditure needs to support expenditure reviews. IPART, Our water regulatory framework – Technical paper, November 2022, p47.

27 IPART, Our water regulatory framework – Technical paper, November 2022, p50.

SDP is concerned that not only does it appear arbitrary as to how the catch-up efficiency factor was determined, it is also unclear how much further SDP have to go to reach the frontier. In SDP's view it is unreasonable to conclude that SDP is below the cost efficiency frontier and apply significant cumulative catch-up efficiencies growing to around 2% pa in 2026-27 to all opex elements:

- based on observed practices and historical cost information that have not yet been adjusted to reflect our new Operating Rules, which only come into effect from 1 July 2023; and
- without robust evidence on SDP's specific and changing circumstances. An assessment of whether catch-up efficiencies are reasonable can only be made once the costs of operating under the new regime are incurred and compared to other comparable benchmark entities. Such an assessment can only be made once SDP's new Network Operator's Licence has come into force (after 1 July 2023) and after operational experience under the new Network Operator's Licence.

Further, the limited rationale provided by Atkins regarding the evidence on catch-up efficiencies does not appear to identify any areas that would impact on insurance. In 2017, Atkins recommended, and IPART approved, the removal of any catch-up efficiency factor to corporate costs (which included insurance costs):

> *We have therefore accepted the deletion of the 0.5% pa cumulative efficiency. The 0.25% continuing cumulative efficiency is retained and has been accepted by SDP*[28]

It is not clear what has changed since this point, and it is not clear what Atkins is recommending that SDP would need to do to reach the level of a best-practice or cost efficiency frontier.

In our view, we do not consider that:

- Atkins has demonstrated that its proposed catch-up efficiency factors are relevant to SDP's circumstances (including the references to efficiency factors applied to very different network/retail water and wastewater utilities), nor addressed IPART's expectations for acknowledgement key uncertainties and "other specific limitations – incumbent on the consultant to justify" in recommending a range of efficient expenditure ("rather than an exact figure")[29]
- IPART has recognised the limitations of the Atkins analysis and the challenges that SDP could face in meeting its new Licence requirements and the objectives of the GSWS if the draft decision on catch-up efficiencies was retained (see Section 8.2).

SDP submits that catch-up efficiency adjustments of 0.5% pa be removed from SDP's opex allowance.

4.1.3 Continuing efficiency factor of 0.7% p.a.

IPART's draft decision states it has applied:

> *A continuing efficiency factor of 0.7% pa (cumulatively) from FY24 onwards, in alignment with IPART's usual approach to continuing efficiency for other regulated businesses. The 0.7% continuing efficiency factor is based on the Australian Productivity Commission's multi-factor productivity analysis*[30]

SDP notes that neither Atkins nor IPART has responded to SDP's proposal for a 0.3% p.a. continuing efficiency factor which we consider to be more appropriate for the reasons set out in SDP's pricing submission.[31] The continuing efficiency factor should only be applied to SDP's controllable costs. While

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28 Atkins, Sydney Desalination Plant - Expenditure Review: Supplementary Report, May 2017, p6.

29 IPART, Our Water Regulatory Framework, Technical Paper. November 2022, p50.

30 IPART, *Sydney Desalination Plant Pty Ltd Review of prices to apply from 1 July 2023 - Draft Report*, April 2023, p 47.

31 For details see section 9.1.3.1 of Appendix to SDP Pricing Submission, September 2022.

SDP considers energy costs are controllable, we have set out later in this response our reasons why in this instance IPART should not add a continuing efficiency adjustment to energy volumes which were not recommended by Atkins, and which come on top of substantial reductions to SDP's proposal.

SDP submits that IPART:

- exclude the continuing efficiency factor from land tax and council rates, given that the continuing efficiency factor should only apply to controllable costs.
- exclude the continuing efficiency factor from energy volumes given these are already incorporated into energy volumes as set out in sections 4.6 below.

4.2 Fixed O&M costs for the Plant

SDP **accepts with qualification** IPART's draft decision on **fixed O&M costs for the Plant.**

IPART's Draft Decision is based on accepting Atkins recommended fixed O&M costs for the Plant, with the exception of routine asset maintenance, incorporating catch-up efficiencies of 0.5% p.a. and continuing efficiencies of 0.7% p.a.

SDP supports IPART's draft decision to increase the level of routine asset maintenance (RAM) above Atkins' recommendation which was based on data in FY22. Atkins' recommendation is not reflective of an efficient level of routine maintenance required for the Plant under SDP's expanded role and would pose material risk to SDP's ability to meet levels of service under the GSWS and WSA.

IPART's draft decision recognises this:

> *Our view is that a sustainable operating regime under the new operating licence is not the same as the emergency response role under which SDP has been operating since March 2020. By extension, the level of routine asset maintenance undertaken by SDP during emergency response may not translate to a sustainable level of maintenance going forward. As such, our view is that the use of FY22 as a base year for cost setting purposes may not provide an accurate reflection of the actual level of routine asset maintenance required by the plant going forward*[32]

While below our proposed RAM costs, which reflected sustainable maintenance requirements under SDP's new Network Operator's Licence requirements, SDP supports IPART's draft decision to increase RAM costs above Atkins' recommendation. We also note that SDP expects to incur, for the first time, additional costs for asset replacement of a large volume of predominantly instrumentation and control assets that will reach end of life in the 2023 Determination period. The timing for replacement of these individual assets will be monitored and assessed for efficiency with the aim to safeguard the Plant against equipment failure that would otherwise compromise service levels. These costs are not included in our proposed capex/periodic maintenance as they were included in proposed RAM costs.

SDP also submits that IPART include in the fixed O&M costs for the Plant, the additional costs of keeping the Plant available under the same premise "*that a sustainable operating regime under the new operating licence is not the same as the emergency response role under which SDP has been operating*". SDP's proposal included a step change to reflect the additional costs [redacted] related to process water[33] and associated treatment processes, and adequate resourcing to adapt to production requests that may change at any time.[34] Atkins' draft report did not include any step change to fixed O&M but did recommend $0.7m p.a. relating to 'variable costs in non-production mode'.

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32 IPART, *Sydney Desalination Plant Pty Ltd Review of prices to apply from 1 July 2023 - Draft Report*, April 2023, p.48.

33 Process water is water produced by SDP to maintain availability and readiness, preserve assets or processes and/or meet environmental approvals that is not used to make drinking water (i.e., not sold to Sydney Water).

34 Appendix 9.2.1 of SDP's proposal provides detailed information on the costs of remaining available under the new Operating Rules.

It is important to clarify that the costs of keeping the Plant available are incurred at all levels of production below full capacity (and to some extent even at full capacity as asset rotation continues and process modules are ramped up and down). Specifically, these costs are incurred to maintain assets in an operational state (e.g. reverse osmosis membranes) and comply with our environmental licence conditions (i.e. additional bypass flow to outfall), but also to maintain the Plant per good industry practice while meeting customer expectations.

Atkins noted "*Given the flexible full-time operational regime over the 2023 determination period. SDP would likely face operational limitations in meeting the proposed periodic maintenance program*". SDP agrees it will need to be flexible in how it delivers both its efficient periodic (capital) and routine asset maintenance. This will require us to run at zero production or reduced production when convenient to Sydney Water and, per recent experience, to reschedule our agreed maintenance zero production periods from time to time to suit the changing operational needs of our customer. SDP will incur additional costs to provide this flexibility, but such maintenance shutdowns, reduced production periods, or rescheduling are not clearly defined as 'zero production requests from Sydney Water'.

SDP proposes these 'costs in non-production mode' be included as fixed O&M costs. While SDP does not agree with Atkins' approach to estimate these costs, nor its characterisation that they are 'variable', we submit that a $0.7m allowance be included as part of our fixed O&M allowance to ensure we are best placed to work with our customer to deliver optimal customer outcomes while remaining indifferent to production volumes requested. Inclusion of these costs in the fixed O&M allowance is not only more cost-reflective, it would also avoid the need for a separate 'Sydney Water requested zero production charge' (see Section 7.1). We understand from our engagement with Sydney Water, that it supports this position.

In summary, SDP's qualifications are that:

- the additional costs of keeping the Plant available under our new Operating Rules as recommended by Atkins ($0.7m pa) be included in the fixed O&M allowance as these costs are incurred at all levels of production when the Plant is not at full capacity (or when changing production level including moving to and from full capacity) not just when the Plant is at zero production.
- IPART addresses our comments on catch-up efficiency adjustments as outlined in section 4.1.2.

4.3 Variable O&M costs for the Plant

SDP **disagrees** with IPART's draft decision on **variable O&M costs for the Plant**, which was to not accept SDP's proposed variable O&M costs ($218.8/ML avg across the 2023 Determination period) and instead use Atkins recommended variable O&M costs incorporating scope adjustments and a 0.7% pa continuing efficiency factor ($158.3/ML avg).

IPART accepted Atkins' recommendations which incorporate substantial scope adjustments to SDP's proposed treatment costs. Atkins' approach for recommending treatment costs is based on 2021-22 costs with a small and progressive allowance for membrane ageing over the 2023 Determination period which is completely offset by the continuing efficiency applied in IPARTs draft decision. As set out in the table below, Atkins' recommendations were substantially lower than an earlier version of its draft report that SDP was provided to review and comment on.

The variable O&M costs for the Plant in the draft report:

- limit the ability of SDP to respond to the range of operating conditions defined in the original design envelope for Plant,
- do not provide sufficient allowances to maintain water quality to customer requirements under expected performance of aging membranes, and
- do not reflect current chemical market prices nor allow for uncertainty in future market prices.

Together this constitutes a risk to efficient cost recovery for the service provided, which in turn may incentivise SDP to operate the Plant too aggressively and inadvertently reduce service levels (e.g. delay membrane chemical cleaning during a period of low production requests and then need to reduce output to clean membranes during a period when our customer requests higher production).

In response to IPART's draft decision, SDP has revised its forecast treatment cost. Our revised forecast applies the same bottom-up methodology applied in our original proposal (and used as the basis of the 2017 Determination) but updated to reflect Atkins' recommendations in its recent draft report. In summary, our revised forecast:

- adopts Atkins' approach of using 100% actual, historical inlet water quality data for forecasting chemical dosing rates, rather than SDP's original proposal of using actual (75%), good (5%) and poor (20%) inlet water quality (noting that this does not align with the original design of the Plant and does not provide SDP with allowance for any deterioration in inlet water quality which is outside SDP control),
- adopts Atkins recommendations for alternate treatment chemical options which may be feasible, but in our view may provide a sub-optimal outcome,
- adopts Atkins view on the severity of reverse osmosis membrane aging effects, and reduce the cleaning frequency and dose rate assumptions accordingly,
- includes updated chemical unit prices based on the outcomes from Veolia's current national tender process (taking advantage of Veolia's scale as operator of multiple treatment facilities),
- adopts Atkins view on other variable costs (OVC),
- adopts Atkins' approach of phasing in the impact of membrane aging on chemical dosing in equal steps from 2023-24 to 2026-27, and
- incorporates a continuing efficiency challenge.

The above revisions reduce our initial forecast costs and result in SDP managing greater risks (for example: inlet water quality risk, future chemical price risk, membrane aging performance risk) over the 2023 Determination period thus setting a stronger efficiency challenge.

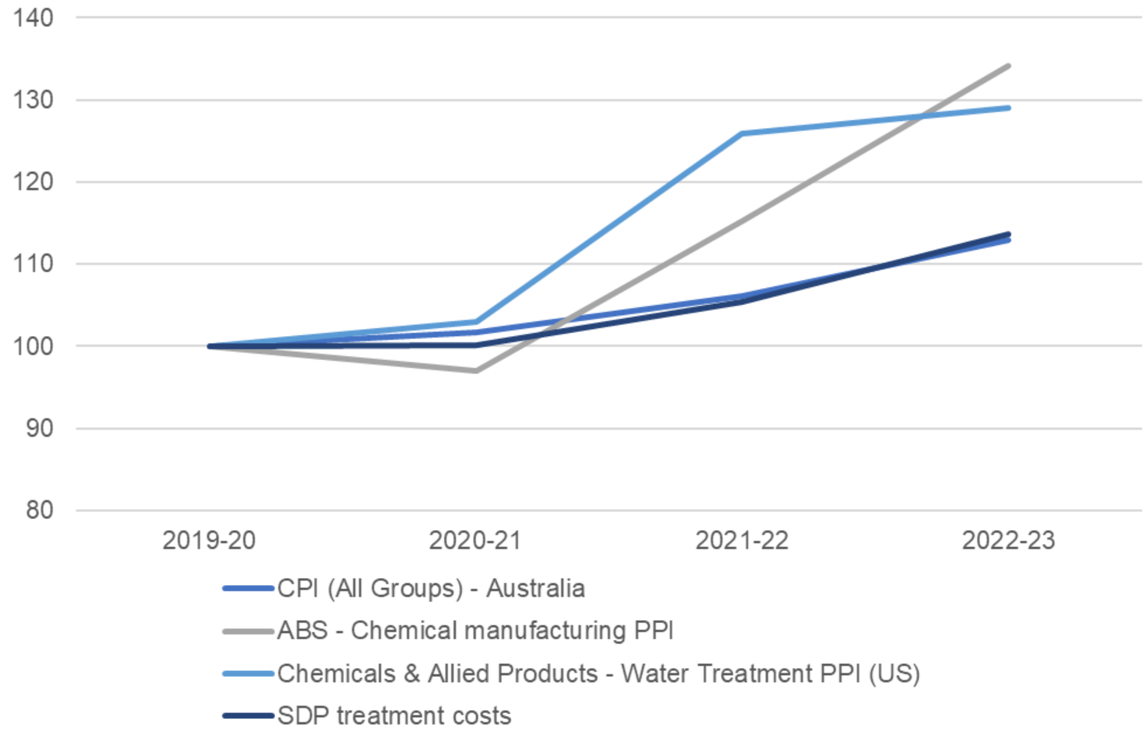
SDP disagrees with the draft decision to base variable treatment costs on data from 2021-22 as these reflect prices below current chemical market prices. Veolia undertakes a periodic national chemical tender process [redacted] The chemical prices incorporated in variable tariffs that SDP paid to Veolia in 2021-22 were reflective of unit prices set [redacted] in 2019-20. [redacted] COVID related supply chain constraints and other geopolitical factors which led to increases above standard [redacted] indexation during this period. [redacted]

Chemical price increases are summarised in Figure 4.1 below. This figure shows the movement in two major chemical producer price indexes (PPIs) from both the Australian Bureau of Statistics and the US Federal Reserve, compared to an index of SDP's actual treatment costs through its contractual interface with Veolia and the CPI. It shows that:

- since 2019-20, chemical PPIs have risen by around 30% whereas SDP's treatment costs incurred (per ML) have only increased by around 14%
- SDP's actual treatment costs in 2021-22 were yet to reflect the full extent of global chemical price increases [redacted]
- using 2021-22 costs as the basis for treatment costs in the 2023 Determination period is not reflective of current market prices and would result in usage charges that do not reflect the "variable

underlying resource costs”[35], which would be inconsistent with IPART’s approach to other building block allowances and Pricing Principle 7 of the ToR[36]

Figure 4.1: Index of chemical cost movements vs index of SDP’s actual treatment costs (2019-20 = 100)



Note 1: CPI and PPI data for 2022-23 is for the 9 months until March 2023.
Note 2: SDP’s treatment cost is calculated as $/ML of water sold, with 2019-20 water volumes adjusted for Plant restart.
Source: ABS Producer Price Indexes, Basic chemical and chemical product manufacturing; ABS Consumer Price Index, Australia; Federal Reserve Economic Data, Producer Price Index by Commodity: Chemicals and Allied Products: Water-Treating Compounds, SDP AIR/SIR.

SDP and customers gain substantial benefits from Veolia's national procurement process and buying power. [redacted] The outcomes indicate that market conditions have moderated in 2023, albeit reflecting a sustained increase in underlying chemical prices. Our revised forecast treatment costs reflect these current market prices (April 2023), which SDP submits represent a prudent and efficient benchmark.

IPART’s preference is to set allowances based on market prices, for example in energy where IPART noted that:

…a market based estimate is best regulatory practice, because:

- *It represents the best available estimate of the efficient cost of procuring energy in a competitive open market;*
- *It provides the incentive for SDP to procure its energy efficiently within the next determination period.*

35 IPART, Draft Report, p147.

….therefore, where there is sufficient benchmark data from competitive markets…, we consider it to be regulatory best practice to apply these benchmarks for pricing purpose.[37]

SDP submits that IPART amend its draft decision on variable O&M costs for the Plant toreflect SDP's updated treatment cost forecasts including current chemical prices and continuing efficiency as summarised in Table 4.2. with further detail including workings and assumptions provided in an Excel spreadsheet at Attachment B. This will ensure SDP is financially indifferent as to whether it supplies water as per Pricing Principle 4 of the ToR, and better promote the cost-reflectivity of prices and consistency with Pricing Principle 7 of the ToR.

Table 4.2: SDP's revised proposal for treatment costs in the 2023 Determination period ($/ML, $2022-23)

	2023-24	2024-25	2025-26	2026-27
SDP proposal (SDP Pricing Submission)				
[redacted]				
Total	**219.75**	**219.09**	**218.43**	**217.78**
Atkins' initial assessment (initial draft report)				
[redacted]				
Total	**218.11**	**207.36**	**196.75**	**186.28**
Atkins' revised assessment (draft report) in IPART draft decision				
[redacted]				
Total	**156.24**	**157.61**	**158.95**	**160.27**
SDP response to draft decision				
[redacted]				
Total	**169.53**	**171.06**	**172.56**	**174.03**

Note: All figures presented are post-efficiency adjustments.

4.4 Fixed O&M costs for the Pipeline

SDP **disagrees** with IPART's draft decision on fixed **O&M costs for the Pipeline** to not accept SDP's proposed ($0.5m pa avg) and instead adopt a lower allowance including incorporating catch-up and continuing efficiencies ($0.2m pa avg allowance over the 2023 Determination period).

Atkins' report largely accepted SDP's proposed fixed O&M costs for the Pipeline, although it applied its own catch up and continuing efficiency adjustments. On page 53 of its report, Atkins states in a footnote that:

SDP has explained that the key driver for the proposed increase in O&M for the Pipeline is an increase in Routine Asset Maintenance and that this is based on a revised preventative maintenance program identified, following a detailed condition assessment of the Pipeline which culminated in the 2020 Pipeline Asset Management Plan (PAMP). We challenged why

[37] IPART, Sydney Desalination Plant Pty Ltd Review of prices to apply from 1 July 2023 - Draft Report, April 2023, p.43-44.

the increase was only projected from FY23 onwards given that the PAMP has been in place since June 2020. In RFIs 124 and 125 SDP was able to explain that it is only being increased once certain key renewals have been completed. This appears reasonable to us and we have recommending SDP's proposed increase due to the criticality of the pipeline.

Atkins' recommended efficient O&M costs for the Pipeline of around $0.5m pa.

IPART's draft report notes that it agrees with most of Atkins recommendations for fixed costs but allowed only $0.2m pa for fixed O&M costs for the Pipeline. There is no discussion from IPART on why it departed from Atkins' recommendation, and on this basis SDP assumes this is a transcription error in the draft decision.

The Pipeline is a critical element in providing SDP's services, and not maintaining this asset appropriately could affect SDP's ability to meet required levels of service under the GSWS and WSA.

SDP submits that IPART amend its draft decision on fixed O&M costs for the Pipeline to reflect Atkins' recommendation on fixed O&M costs for the Pipeline.

4.5 Energy prices

SDP **accepts with qualification** IPART's draft decision on energy prices.

IPART found that "*the benchmark approach would, to the extent reasonably foreseeable, also allow SDP to recover its costs in relation to the GGRP and GGRP contracts*". As a result, IPART was able to conclude that using a market-based benchmark "*accounts for the costs that SDP is expected to incur in complying with the GGRP and GGRP contracts – therefore fulfilling Principle 7A of the Terms of Reference*".[38] In the event that benchmark prices fall below a certain level, a benchmark approach would not fulfil Principle 7A of the Terms of Reference.

SDP remains of the view the energy price allowance should be based on the cost per unit of energy incurred by SDP under the GGRP Contracts. As set out in SDP's proposal, SDP considers that this approach reflects SDP's legal obligation under New South Wales planning law to purchase electricity through the GGRP Contracts, is consistent with SDP's commercial imperative to purchase through long-term contracts and delivers prices that are based on prudent and efficient contract prices (this is because the GGRP Contracts were entered into following the completion of a well-considered and competitive tendering process).

SDP notes that IPART's market-based estimate of energy prices includes allowances for some of the costs incurred under the GGRP Contracts including energy (together with the costs of contracting), losses, green schemes (including SDP's obligation to purchase 100% renewable energy), ancillary services costs, market fees, metering costs and a retail margin. However, IPART's market-based estimate of energy prices does not include several other energy costs that SDP will likely be exposed to over the 2023 Determination period under the GGRP Contracts. These other costs include the costs of unaccounted for energy (UFE), Reliability and Emergency Reserve Trader (RERT) and the NSW Peak Demand Reduction Scheme (PDRS).

In response to IPART's rationale that these costs will necessarily remain "relatively minor", SDP sought expert advice from Energetics, which we have attached to this response which highlights these costs are likely to be material over the 2023 Determination period.[39]

SDP disagrees that it has a "degree of control" over these costs. The Atkins/MJA draft report clearly states that energy users such as SDP will pay for these costs either through a higher retail margin levied by energy suppliers and/or pass through of these costs to energy users – neither of which IPART has

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[38] IPART Draft Decision, page 43.

[39] Energetics, *'Other' electricity market charges*, An overview of 'other' regulated charges applicable to Sydney Desalination Plant over the RP3 period, 17 April 2023.

incorporated in the draft decision. As noted above, SDP also does not have control over production decisions that would enable it to respond to these charges. SDP does not accept "SDP is best placed to manage the risks associated with these costs."[40]

SDP submits that IPART's final decision should provide a clear regulatory mechanism for SDP to recover these costs, as discussed in Section 3.5.

4.6 Energy volumes

SDP **disagrees** with IPART's draft decision to not accept SDP's proposed benchmark energy volumes over the 2023 Determination period (fixed 34.7 MWh/day and variable 3.67 to 3.73 MWh/ML) and to instead adopt Atkins recommendation and add to this a continuing efficiency adjustment of 0.7% p.a. (fixed 28.8 to 28.2 MWh per day, variable 3.47 to 3.39 MWh/ML).

IPART's draft report notes that there are technical and engineering limitations to energy consumption savings for the Plant. However, IPART considers that SDP can achieve efficiency savings elsewhere. IPART notes:

> *…any limitations to the reduction in SDP's energy consumption could be offset by greater efficiency improvements in other areas of the business.*[41]

SDP does not agree that the imposition of a 0.7% pa continuing efficiency factor to Atkins' recommendation represents a "realistic, yet challenging, target"[42] given that:

- Atkins recommendation (and IPART's draft decision) does not allow any uplift or step change for increased energy volumes under SDP's expanded role (apart from a minor uplift for membrane aging). Instead, the draft decision is based on a line-of-best-fit using energy consumption from the 2017-23 regulatory period. SDP's concern is that the energy use during the 2017-23 regulatory period was based on the Plant's emergency response role, where only the three most efficient Reverse Osmosis (RO) trains were preferentially used on a temporary basis until the Plant was expected to shut down.[43] With the Plant now set to operate on a flexible full-time basis this is not a sustainable approach. To meet good industry practice, we will need to undertake normal asset rotation among the Plant's 13 RO trains. In the absence of additional capital investment, this will increase the Plant's energy use during the 2023 Determination period relative to historical energy usage. Either Atkins' adjusting their recommended energy use allowances or IPART removing the continuing efficiency factor applied to energy volumes will address this issue and improve alignment between IPART's related decisions reducing SDP's proposed capex on RO membranes and our proposed treatment costs.
- Atkins recommendation is also below SDP's proposed benchmark energy volumes, because Atkins considers the design of the Plant (that relies on operational valve throttling to adjust pressure to the membranes) means that aging membranes will not have as great an effect on energy consumption as SDP proposed. SDP submits that this view only applies to RO trains without trimmed impellors. However, as noted above three out of 13 (23%) of the Plant's RO trains operate on trimmed impellors, which do not adjust pressure via operational valve throttling.

40 IPART, draft decision, p123

41 IPART, Draft Decision, p 41.

42 IPART, Our water regulatory framework, Technical Report, Nov 2022, p26.

43 These three RO trains have impellors (the rotating component of the pump) that are trimmed, which means they use less energy but may not be able to produce water when sea water quality is poor.

- Atkins' recommendation did not apply the continuing efficiency factor to energy volumes despite continuing efficiency adjustments being applied to all other aspects of their expenditure review. In our view without a technical basis provided this is likely because of substantial scope adjustments already made with further limitations in SDP's ability to reduce energy consumption.[44]
- SDP's proposed energy volumes align with our proposed capex on RO membranes, however IPART's draft decisions which reduce energy volumes and capex on RO membranes is not aligned and internally inconsistent.
- SDP is a single asset but energy intensive business, which naturally reduces the diversification benefits IPART assumes can be found across our business to enable SDP to achieve an "'average' improvement to efficiency".

SDP submits that, to improve alignment between IPART's decisions reducing both SDP's proposed capex on RO membranes and treatment costs, either Atkins' adjusts their recommended energy use allowances or IPART removes the continuing efficiency factor to energy volumes.

SDP and Veolia monitor the performance of RO membranes (including related chemical and energy consumption/costs) and make decisions to replace membranes (incur capex) in order to minimise overall opex and capex costs while endeavouring to meet levels of service. This is consistent with IPART's expectations to optimise between opex and capex, which was recently reiterated in principles 7 and 8 of IPART's new 3Cs framework.[45]

IPART's draft decision to impose a 0.7% p.a. (compounding) continuing efficiency factor on top of Atkins' recommended benchmark energy volumes results in benchmarks that would be equivalent to the Plant's current, average, energy consumption by the end of the 2023 Determination period. SDP submits that these targets are unrealistic given the increased energy requirements of the Plant including ageing membranes over the 2023 Determination period, the uncertainty of requested production volume and schedule, and the expectation of flexibility to respond in a timely manner under the new Network Operating Licence conditions (with resultant additional process water requirements).

IPART's additional efficiency adjustment to energy volumes creates a situation where:

- allowances for capital expenditure, treatment costs and energy volumes are not internally consistent. This means SDP may need to undertake additional capital expenditure to keep energy and treatment costs within the allowance, or risk not meeting its required levels of service;
- any deterioration in operational conditions, such as a divergence from Atkins' assumption of average inlet water quality, over the 2023 Determination period would create further risks to SDP meeting service standards. This would not provide SDP with the "organisational resilience to absorb cost impacts arising from changes in the operating environment.[46]"
- variable usage price allowance being below the "variable underlying resource costs"[47] of supplying water. It also risks sending inefficient price signals to Sydney Water when making its production requests.

SDP submits that IPART amend its draft decision on energy benchmarks to:

- reflect Atkins' recommendation on fixed and variable energy benchmarks and remove its application of a 0.7% pa continuing efficiency factor (see section 4.1.1).

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44 During the expenditure review process, Atkins recognised that due to the ageing of the Plant and membranes combined with increased asset rotation to meet the new requirements in our Network Operator's Licence, SDP would need to undertake capital expenditure to meet pre-efficiency energy allowances. This is likely why Atkins' did not recommend a continuing efficiency factor.

45 IPART, Our water regulatory framework, Technical Report, Nov 2022, p19.

46 IPART, Our water regulatory framework, Technical Report, Nov 2022, p20.

47 IPART, Draft Report, p. 147.

4.7 Corporate operating costs

SDP **accepts with qualification** IPART's draft decision for all corporate operating costs <u>other</u> than land tax and council rates. We consider that IPART's final decision should adopt an allowance for land tax and council rates that includes four key updates:

- Having regard to the evidence presented in its property market expert [redacted] report on forecasts of the underlying land value used to determine land tax. In its draft report, Atkins stated that it is not clear that SDP has justified that land tax and council rates will increase above historical rates in real terms. However, Atkins' comments in Appendix E of its draft report indicate that it has not reviewed the evidence presented in SDP property market expert's report when developing its recommendations. We provided this report to IPART as part of SDP's September 2022 Pricing Submission. We consider that IPART and Atkins should consider this evidence in their final recommendations and decisions. SDP's property market export report clearly sets out the justification for increases in land tax above historical rates in real terms. It recommended forecasting unimproved land value based on a [redacted] long-term historical growth rate of [redacted] in nominal terms. Using a long-term historical average to forecast values that fluctuate from year to year is an approach commonly taken by many regulators including IPART to ensure that prices are set in the long-term interests of customers. The expert report is attached as **Appendix H**.
- Accurately reflecting Revenue NSW's calculation of land tax using a 3-year average of the NSW Valuer General's land valuation. Atkins recommendation to maintain land tax at the 2021-22 expenditure would mean that its forecasts do not reflect the mechanics of Revenue NSW's calculation of land tax. Even if Atkins and/or IPART did not accept the evidence presented in its property market expert's report for [redacted] growth rate and adopted a 0% growth in the land valuation, we would expect a real increase land tax above 2021-22 expenditure levels based on the three-year land values included in the most recent land tax assessment notice issued by the NSW government which was provided to Atkins.
- Incorporating actual costs for 2022-23 for both land tax and council rates when forecasting efficient costs. Atkins draft report states that it has recommended maintaining the 2021-22 expenditure level plus the increase in land tax seen in 2022-23. However, IPART's allowances in its Draft Report do not reflect this increase. This appears to be a transcription error so should be corrected in IPART's Final Report. In addition, we also have information on the most recent council rates for 2022-23 (including rates associated with the land that our pipeline occupies at Sydney Airport) and have incorporated this into our updated forecast.
- Removing catch-up and continuing efficiencies applied to land tax and council rates. SDP does not have a "degree of control" over these uncontrollable costs as they are set by Revenue NSW and Sutherland Shire Council. Neither Atkins or IPART have addressed how SDP would be expected to achieve catch-up or continuing efficiencies in these areas. These costs are akin to the 'category specific forecasts' that the AER excludes from its base-step-trend calculation to forecasting efficient operating costs for energy network businesses. For example, the AER's 2022-27 determination base-step-trend model for Ausnet treats its land tax as a category specific forecast which is not subject to the AER's forecast productivity (or efficiency) change and is excluded from the AER's incentive mechanism for operating expenditure.

We note that IPART's Water Regulation Handbook proposes that:

> *Where a cost item is:*
>
> - *non-recurrent (including cyclical, such as regulatory submission costs), or*
> - *non-controllable (e.g., bulk water costs – where prices are set by IPART – and regulatory licence fees),*

we would expect the businesses to provide separate forecasts for these items as variations to the BTS forecast. The business may also wish to provide separate forecasts for particular cost items where the business expects to see significant real change in input prices over the forward determination period, such as for the cost of insurance of dams or the cost of grid electricity.[48]

We have developed an updated forecast of land tax and council rates incorporating these four key updates and provided a spreadsheet setting out the calculations (see **Appendix E**). In our view these updated forecasts reflect the efficient costs of land tax and council rates that Atkins and IPART should include in their final recommendations and final decision.

4.8 Insurance costs

IPART's draft decision adopts SDP's total proposed insurance costs, with the addition of catch-up and continuing efficiencies. However, IPART notes that the insurance cost allowances outlined in Table 5.4 of the Draft Report are preliminary only and that some insurance policies need to be tailored to its proposed changes in incentive schemes.

The draft decision included several qualifications:

- It is expected that between the release of IPART's Draft and Final Report, SDP is to obtain from its insurance broker a quote for ISR insurance that is tailored to the draft decisions on incentives.
- It is assumed that SDP and Sydney Water will together assess the efficient costs of SDP recovering from a force majeure (FM) event. If both parties are agreeable to Sydney Water paying a service charge during FM events, then it is expected that SDP's ISR quote will exclude coverage for Business Interruption related to FM events. It is also expected that SDP will demonstrate if and how this outcome aligns with the long-term interests of customers.
- If SDP and Sydney Water determine that third-party Business Interruption (BI) insurance reflects the most efficient cost of SDP recovering from a force majeure event, then it is expected that SDP's ISR quote will include coverage for business interruption related to FM events. It is also expected that SDP will demonstrate if and how this outcome aligns with the long-term interests of customers.

IPART's draft decision also sought comment on:

> *Should prices reflect the costs of recovering from force majeure events through third-party business interruption insurance? Or alternatively, should these costs be avoided via Sydney Water's continued payment of a service charge during force majeure events? (**Question 1**)*

SDP **accepts with qualification** IPART's draft decision on insurance costs. We consider that IPART's final decision should adopt an allowance for efficient insurance costs based on:

- Updating the level of insurance coverage so that it reflects the cost of full BI insurance to cover a range of plausible scenarios (**<u>including</u>** FM and non-FM events).
- Removing catch-up efficiencies applied to SDP's and Veolia's insurance, consistent with the 2017 Determination.

Further details on these two areas are set out in the sections below.

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48 IPART, Water Regulation: Handbook, April 2023, p42

4.8.1 Updating the level of insurance coverage so that it reflects the cost of BI insurance to cover a range of plausible scenarios (**including** FM and non-FM events)

SDP's efficient insurance costs include three insurance policies with a BI component - SDP's Industrial Special Risks (ISR) Policy, [redacted] and Veolia's Professional Indemnity (PI) Policy.

In response to IPART's Draft Report, we considered several alternative levels of BI cover for these policies:

- Option 1: BI insurance to cover a range of plausible scenarios, **including** FM and non-FM events, where SDP is unable to supply drinking water with a commensurate reduction in the fixed service charge for insured events (i.e., the status quo under SDP's existing insurance policies).

  This would require the WSA to include terms clarifying when and how the fixed service charge would be reduced. For example, if an event occurs that results in SDP receiving a payment under its BI or equivalent insurance policy, any fixed charges payable to SDP will be reduced by the amount of that payment. The costs of this option are akin to Package 1 set out in our September 2022 Proposal to IPART.

- Option 2: No BI insurance with payment of fixed services charges **guaranteed** in all circumstances. Under this option, Sydney Water would continue to pay the fixed service charge in all circumstances (including FM events) and IPART **would specifically include this guarantee** in its Final Determination to ensure there were no misunderstandings or potential disputes between SDP and Sydney Water in the event the Plant became inoperable for any reason and was unable to produce water.

  This would require IPART's Final Determination and the WSA to state **expressly** that the fixed service charges are always payable, without adjustment, even if the plant or pipeline are unavailable, unless otherwise agreed between SDP and Sydney Water.

- Option 3: BI insurance to cover a range of plausible scenarios, **excluding** FM events, where SDP is unable to supply drinking water with a commensurate reduction in the fixed service charge for insured events.

  IPART has asked SDP to prepare a forecast on this basis.

  Insurers do not offer a BI component of ISR policies that specifically exclude FM events. Insurers offer a standard policy that covers a range of risks (including FM and non-FM events), with the level of coverage determined by the length of time that SDP would be unable to supply drinking water for an insured event.

  SDP has undertaken analysis with its insurance broker – AON – to understand the impact of excluding FM events from the BI component and associated insurance cost. We found that there are several non-FM events that would still result in a lengthy period where SDP would be unable to supply water. For example, we identified failure modes in the pipeline and inlet/outlet tunnels that would result in SDP being unable to supply water for more than four years. This means that there is no reduction in the insurance policy limit or the insurance premium to effectively exclude force majeure events.

  In addition, the other two other insurance policies which carry a BI component (Veolia PI insurance [redacted] are not triggered by FM events. FM events are a feature of the ISR policy. The Veolia PI [redacted] cover can be triggered by other events, for example the Veolia PI insures against an operational error which makes the plant inoperable. This means that excluding FM events from these policies would again not reduce the premium cost and so would not benefit customers.

  Like Option 1, this would require the WSA to include terms clarifying when and how the plant fixed service charge would be reduced. For example, if an event occurs that results in SDP receiving a payment under its BI or equivalent insurance policy, any fixed plant charges payable to SDP will be reduced by the amount of that payment.

AON's expert report on the impact of BI insurance cover on SDP's insurance policies is set out in **Appendix D**.

We consulted with Sydney Water on these alternative levels of coverage. Sydney Water remains of the view that SDP should maintain full BI insurance cover that includes funding the costs of recovering from FM events. SDP and Sydney Water consider this would be in the long-term interests of customers. This is because BI cover provides valuable insurance in the face of more frequent and severe natural disaster events, increased risks from more frequent operation and customers' greater reliance on SDP going forward. SDP has cost effectively built this BI insurance cover capacity in the Australian insurance market over time, which customers would continue to benefit from under this option.

The cost saving over four years related to SDP not taking out BI cover and having Sydney Water pay its plant fixed charges in all events when the plant becomes inoperable is about $7-8 million in nominal terms. This compares to the payment of plant fixed charges of over $650 million over four years in the event that the plant or pipeline became inoperable and SDP stopped producing water in an extended FM or non-FM event. SDP believes therefore it is more cost effective for customers to pay the additional premium cost to allow SDP to be covered for BI insurance rather than have to pay plant fixed charges in the event the plant or pipeline is inoperable. The money saved by Sydney Water in the event the plant is inoperable while insurance covers SDP's revenue loss, could be used to provide alternative water sources to customers when SDP has an extended water production outage.

To ensure that customers can obtain maximum benefit from BI insurance funded in SDP's allowed prices, Sydney Water and SDP will incorporate a mechanism into their WSA to reduce SDP's plant fixed charges by the extent to which insurance coverage indemnifies SDP. Sydney Water has strong incentives to ensure that SDP maximises insurance claims, including because IPART will provide oversight of what occurs in practice when assessing Sydney Water's ability to recover costs from end-use customers.

SDP is submitting insurance cover which has a full BI component (i.e. includes cover for FM and non-FM events). The premium cost (including Veolia's insurance) was previously provided to IPART as Package 1 in our September 2022 Proposal to IPART and is reflected in the following table.

[redacted]

4.8.2 Removing catch-up efficiencies applied to SDP's and Veolia's insurance costs .

We consider that our approach to forecast efficient insurance costs is consistent with a best practice or frontier company and with the Water Industry Competition Act (WICA) requirements administered by IPART. Therefore, we recommend that no catch-up efficiencies should be applied to insurance costs.

As noted in SDP's Pricing Submission, SDP's insurance arrangements were developed using a detailed approach that carefully considered all key principles set out in IPART's insurance guidelines for WICA licensees and the additional principles IPART outlined in section 4.3 of IPART's Issues Paper. We also provided further information on the key steps in this approach in several expert reports from our insurance broker Aon. For example, Appendix 9.17 of our September 2022 proposal contains Aon's report describing the detailed risk profiling and insurance gap analysis we undertook. This analysis mapped our insurance program against our risk register to ensure that we select the most efficient option based on our operating environment.

In addition, Atkins scope for catch-up efficiencies do not identify any areas that would specifically impact on insurance, rather they are generic statements that could presumably be related to a range of activities undertaken by any water or other business. It is unclear what has specifically changed to SDP's operations since the 2017 review when no catch-up efficiencies were applied, nor what Atkins is recommending that SDP would specifically need to do to reach the level of a best-practice or frontier company in these areas (i.e. how it would use new technologies and procurement to make efficiencies in these areas).

5. Capital expenditure

Table 5.1: Capex: Summary of SDP's response to IPART's draft decisions

Issue	IPART draft decision	IPART decision reference	SDP response to draft decision
Actual capex over 2017 determination period included in RAB	• To accept SDP's actual capex as prudent and efficient and roll forward of the Plant and Pipeline RAB for the 2017 determination period based on this historical capex.	9	Agree
Determining and applying efficiency factors to capex allowances	• Capex expenditure allowances incorporating a catch-up efficiency factor of 1.5 to 7% p.a. over the 2023 Determination period, and a continuing efficiency factor of 0.7% p.a. based on advice from Atkins.	10	Disagree
Plant + Pipeline capex (incl. membranes, periodic maintenance, pipeline and corporate)	• To not accept SDP's proposed capex of $81.0m for the Plant for the 2023 Determination period. • Set a Plant capex allowance of $46.44m based on accepting Atkins recommendations.	10	Accept with qualification

5.1 Actual capex over the 2017 Determination

SDP **agrees** with IPART's Draft Decision on efficient capital expenditure and roll forward of the RAB. It is in the long-term interests of customers for SDP to recover its prudent and efficient costs (noting Atkins' assessment was that actual capital expenditure for the 2017 Determination period was efficient).

5.2 Determining and applying efficiency factors to capex allowances

SDP **disagrees** with IPART's estimation and application of catch-up efficiencies and continuing efficiency factors in its draft decision.

5.2.1 IPART's continuing efficiency factor

Our comments on continuing efficiency are summarised in section 4.1 above.

5.2.2 Catch-up efficiency factor

SDP notes that while IPART refers to catch up efficiency of 0.5% pa in its draft report, the Atkins draft report includes capex-related catch-up efficiency adjustments starting at 1.5% and rising to 7% (2026-27).

While SDP accepts IPART's draft decision on capex (pre-catch-up efficiencies), we do not consider that Atkins has demonstrated that its catch-up efficiency factors for capex, which are even larger than the factors applied to opex, are justified as per our detailed comments in Section 4.1.

SDP submits that:

- SDP is an efficient business;
- There is no quantifiable evidence provided that SDP is below the efficient frontier;
- Catch-up efficiency adjustments should be removed from SDP's capex allowance.

5.3 Forecast capex over the 2023 Determination period

SDP proposed an increase in capex over the 2023 Determination period including an ongoing industry standard membrane replacement program, increased periodic maintenance, specific projects that improve reliability and resilience of the Plant and upgrading our systems to ensure our critical infrastructure is secure from cyber-attack.

SDP **accepts with qualification** IPART's draft decision on forecast capex, with the following qualifications that:

- SDP will demonstrate the prudence and efficiency of its capex decisions made during the 2023 Determination period, in particular membrane replacement decisions based on actual Plant performance for IPART's ex post review during the next price review.
- Based on IPART's draft decision there is a reasonable chance that capex above IPART's draft allowance for the 2023 Determination is required to ensure SDP can meet service levels, particularly related to membrane assets given:
    - Atkins approach involving estimation of an "effective age" for membranes in reviewing the membrane replacement program;
    - IPART's draft decision to apply efficiencies to energy volumes and chemical costs. Given the opex-capex trade-off, further capex may also be required to lower the average membrane life to achieve compulsory water quality standards imposed under our Network Operator's Licence (as the lower the membrane age, the more efficient the membrane in terms of use of energy and chemicals).
- IPART addresses our comments on efficiency adjustments including removing catch-up and continuing efficiency adjustments (as outlined above in section 4.1).

With regard to membranes, IPART's draft decision was to accept Atkins' recommendation. Atkins reprofiled SDP's proposed membrane replacement program for first and second pass membranes, whereby the 2023 Determination period would require no replacements for second pass membranes, and a one-off replacement for first pass membranes in FY24.

SDP's proposal for membrane replacement was based on targeting an average membrane age of:

- 4 years for the first pass membranes, and
- 6 years for the second pass membranes.

Atkins has agreed with SDP's approach to adopt the above membrane ages but has introduced the novel concept of an "effective age" for membranes based on utilisation, rather than calendar year age. SDP does not agree with this approach. In our view this concept understates the deterioration of membranes even when the Plant is not operating at full capacity and is inconsistent with guarantees of performance provided by manufacturers [redacted] It therefore understates the rate of membrane replacement that will be required in the 2023 Determination period. See related discussion on membrane asset lives in section 6.8.

SDP recognises that IPART's framework of incentive regulation provides incentives for utilities not to overspend allowances. However, SDP may need to invest in new membranes earlier than predicted by Atkins depending on actual energy usage, chemicals usage and other treatment costs, as well as prudent management of supply chain constraints. Further, making no allowance for spare membranes to address the long lead times for membrane procurement (approximately 1 year) puts at risk SDP's ability to meet the levels of service defined in our Network Operator's Licence and the outcomes desired under the GSWS.

In line with good operational practice, SDP will make decisions to replace membranes based on the actual performance of the membranes. We note that IPART's Water Regulatory Handbook states that actual capex is rolled into the RAB at the commencement of the next regulatory period, with "ex-post expenditure reviews by exception"[49]. We would be willing to make "supporting information available to IPART on request, such as business cases" and other materials developed as part of our standard decision-making processes to justify the expenditure.[50]

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[49] IPART, Water Regulation: Handbook, April 2023, p13.

[50] IPART, Water Regulation: Handbook, April 2023, p41.

6. Allowance for a return on assets, regulatory depreciation, tax obligations and other revenue

Table 6.1: Allowance for a return on assets, regulatory depreciation, tax obligations and other revenue: Summary of SDP's response to IPART's draft decisions

Issue	IPART draft decision	IPART decision reference	SDP response to draft decision
Allowance for a return on assets, regulatory depreciation, tax obligations and other revenue			
Opening value and roll forward of the RAB	• Opening value of the RAB including rolling-forward the RAB for actual capex, depreciation and indexation over the 2017 determination period	9,10	Accept subject to minor modification
Rate of return	• To set a real vanilla WACC allowance of 3.6% for 2024-25, which is based upon: • a nominal WACC allowance of 6.4% applying its 2018 WACC methodology; and • an inflation forecast of 2.7% based upon a five-year geometric average and usings the RBA's 1-year ahead (to the end of June 2024) CPI inflation forecast as published in the RBA's February 2023 Statement of Monetary Policy.	11	Accept (subject to correction of calculation errors)
Movement in the cost of debt	• To apply an end-of-period true-up to account for movements in the cost of debt (rather than cost pass-through as proposed by SDP)	12	Disagree
Depreciation methodology	• To calculate the allowance for depreciation using a straight-line depreciation method	13	Agree
Asset lives: Pipeline	Adjust the regulatory asset lives for the Pipeline from 120 to 116 years	13	Disagree
Asset lives: Periodic maintenance	• Adjust the regulatory asset lives for periodic maintenance from 30 to 6.6 years	13	Agree
Asset lives: Membranes	• Adjust the regulatory asset lives for membranes from 8 years to 11 years	13	Disagree
Asset lives: Other	• Retain all other regulatory asset lives consistent with the 2017 Determination	13	Agree
Return on working capital	• Use IPART's current methodology for determining the allowed return on working capital	15	Accept subject to minor modification
Tax costs	• Set a tax allowance using a tax rate of 30% and IPART's standard methodology, reflecting benchmark forecast tax liabilities.	16	Accept subject to minor modification
Revenue adjustments: required by the TOR: EAM	• Set the EAM amount for the period 2016-17 to 2021-22, consistent with intent of the 2017 methodology and covering all surplus energy	17	Accept subject to minor modification
Revenue adjustments: required by the TOR: ECM	• Not to include an efficiency carryover adjustment for the 2023 Determination period based on applying the 2017 methodology	18	Agree
Revenue adjustment for 2022-23 deferral year	• Include an adjustment to account for the impact of the one-year deferral of the determination (2022-23) • Adjust SDP's notional revenue requirement to account for an over-recovery of $5.9 million accrued over the year	19 20	Accept (subject to correction of calculation errors)

6.1 Opening value and roll forward of the Regulatory Asset Base

SDP **accepts with qualification** IPART's Draft Decision on roll forward of the RAB, subject to IPART updating the calculations in the final decision to account for 6 months only of depreciation on membrane capex in 2018-19 ($1.8m in $16/17) rather than the assumed 12 months ($3.6m in $16/17) in the draft decision. This is because membrane capex was commissioned (and membrane service charged levied) in January 2019 rather than July 2018 (i.e. SDP received 6 months of revenue from this charge).

6.2 Rate of return

SDP **agrees subject to correction of calculation errors,** with IPART's use of the 2018 WACC methodology to determine the nominal allowed WACC, and IPART's inflation forecast of 2.7%.

SDP has identified three apparent calculation errors in the implementation of the WACC model used by IPART to derive the real WACC allowance of 3.6% presented in the draft decision:

- When selecting the sampling period to be applied to historical tranches of debt in IPART's WACC model, IPART appears to have selected them as if the prevailing tranche was to be sampled during FY2022 rather than FY2023.
- The Draft Report states (p. 170) that the sampling date that IPART used for FY2022 (to determine allowances for FY2023) was to the end of May 2022 (in line with SDP's proposal). In fact, this sampling date has not been used in IPART's WACC model. Use of this date for Tranche -1 (which corresponds to the debt tranche in FY2022) would need to be implemented directly in Table 17.1 of the 'Trailing average' tab of the IPART WACC model.
- Under the 2018 WACC methodology, the current cost of debt allowance is subject to a transition over the 2023 Determination period. IPART confirmed in written guidance to SDP that this transition would occur over five years commencing on 1 July 2022 and ending on 30 June 2027.[51] This means that by 30 June 2023, SDP would be one year into the five-year debt transition. Under IPART's debt transition, the current risk-free rate and current debt margin for FY2024 should be determined by giving 80% weight to Tranche -1 and 20% weight to Tranche 0. However, in IPART's WACC model, the current risk-free rate and current debt margin for FY2024 was determined by giving 20% weight to Tranche -1 and 80% weight to Tranche 0. This mathematical error in the implementation of the debt transition is inconsistent with the debt transition set out in the 2018 WACC methodology.

SDP submits that these three errors in the implementation of IPART's WACC model should be corrected. Doing so would result in:

- a nominal vanilla WACC allowance of 6.6%;
- an inflation forecast of 2.7% (consistent with the Draft Report); and
- a real vanilla WACC allowance of 3.7%.

For this reason SDP submits that IPART's final decision should use a real WACC estimate of 3.7% for FY2024. However, we accept that IPART will update the market parameters prior to the publication of its Final Report.

For future determinations where a delay may occur, SDP considers that a clear approach for how to set the regulated WACC should be developed (e.g. sampling periods that are nominated ahead of time to enable efficient refinancing/hedging activities). We accept that the 2018 WACC Guideline did not explicitly consider what should occur in the event of a determination delay and so this could be an issue for consideration at IPART's next WACC review.

[51] IPART, RP3 WACC approach, letter dated 21 April 2022.

6.3 Cost of debt true-up

SDP **disagrees** with IPART's draft decision to not accept SDP's proposal for annual updates to prices to reflect annual changes in the cost of debt allowance.

SDP submits that the application of annual updates to SDP's prices as proposed in our Pricing Submission would:

- Align with the fundamental rationale for the trailing average approach—which is to provide the closest possible match between the regulatory allowance and the efficient cost of debt. This approach would produce a cost of debt allowance that could be matched effectively by a benchmark efficient firm that managed its debt portfolio in a prudent and efficient way.
- Align IPART's approach to the approach used by every other regulator that has adopted the trailing average approach—including the Australian Energy Regulator (AER), the Economic Regulation Authority of Western Australia (ERA), the Queensland Competition Authority (QCA), the Independent Competition and Regulatory Commission (ICRC), the Essential Services Commission of Victoria (ESCV) and the Essential Services Commission of South Australia (ESCOSA).
- Fulfill the commitment in the 2018 WACC methodology that IPART would assess whether prices should be adjusted annually or whether a cost of debt true-up should be applied on a case-by-case basis, without either of these approaches being treated as the default approach.
- Ensure the following efficient and desirable outcomes:
  - Customers would pay the efficient cost of delivering services in each year – no more and no less. If the efficient cost of debt were to decline over the regulatory period, that benefit would be passed through to consumers immediately, without having to wait until the next regulatory period for the implementation of the cost of debt true-up;
  - Because customers, such as Sydney Water and end-customers would be paying the efficient cost of delivering the regulatory services, they would receive efficient price signals in making their respective source supply (i.e., production requests) and consumption decisions respectively. This would be consistent with IPART's final decision on the Water Regulatory Framework in which IPART concludes that cost-reflective pricing is essential to promoting efficient consumption, supply, water security and intergenerational equity;[52] and
  - SDP would receive an allowance in line with the efficient cost of delivering regulated services, thus eliminating cash flow mismatches that might otherwise create or exacerbate financeability problems.

These points are echoed by Frontier Economics in **Appendix F.**

Frontier Economics notes that there have been periods in which the market cost of debt has increased rapidly and unexpectedly (e.g., during financial crises and periods of high inflation). For example, Frontier Economics notes that the yields 10-year BBB Australian corporate bonds increased by 410 basis points between October 2021 and October 2022—a period of just 12 months.

If SDP were to face a major increase in the efficient cost of debt over the regulatory period (for instance, due to another financial crisis that is beyond SDP's control), the resulting deterioration in financeability could not be managed by a privately-owned company such as SDP. This is because—as was set out in SDP's pricing submission[53]—SDP does not have the State support enjoyed by the State-Owned Corporations (SOCs) regulated by IPART. Unlike SOCs, it is standard for privately owned and financed companies like SDP who are required to procure debt finance in global financial markets without the

52 IPART, Our water regulatory framework: Technical Paper, November 2022, p109.

53 SDP Pricing Submission, September 2022, p178-79.

support and guarantee of a state government, to be subject to strict debt covenants including meeting the Debt Service Coverage ratio (DSCR) which is measured every six months.

A mismatch in cash flows triggered by a steep increase in interest rates that is not matched immediately by an increase in revenues can lead to those covenants like DSCR not being met. The consequence of not meeting an interest coverage ratio like DSCR would put a company like SDP in breach of its financing arrangements, with serious negative consequences for that company. We understand that the SOCs regulated by IPART do not face these financial strictures and so are better able to manage a mismatch in cash flows in a way that private companies like SDP cannot. Hence, while other water business regulated by IPART may be able to weather such events, SDP cannot.

[redacted]

We have discussed this matter with Sydney Water and confirmed that it remains prepared to support to annual adjustments to SDP's prices. This is because SDP's costs represent approximately 10% of the end-customer bill and is already likely to vary annually depending on the volume of water requested by Sydney Water as well as variances each year for CPI inflation. Sydney Water could accommodate annual adjustments to our prices through existing pass-through mechanisms without incurring any additional administrative burden and without additional risks being transferred between SDP and Sydney Water. Our recent engagement with Sydney Water indicates that it supports SDP receiving an annual change to prices to reflect the annual update to the cost of debt allowance.

For the reasons set out above, SDP maintains its position that IPART should adjust prices annually within the 2023 Determination period to reflect changes to the trailing average cost of debt allowance, rather than apply the draft decisions' cost of debt true-up approach.

6.4 Depreciation methodology

SDP **agrees** with IPART's draft decision to continue to apply straight-line depreciation. We agree with IPART's view that this method is superior to alternatives in terms of simplicity, consistency and transparency.

6.5 Summary of regulatory asset lives

SDP **agrees** with IPART's draft decision on regulatory asset lives for several asset categories on the basis that these reflect the economic lives of these assets, as set out in Table 6.2.

However, SDP **disagrees** with IPART's draft decision on regulatory asset lives for the pipeline and for membranes. IPART has failed to consider most of the information that SDP provided in support of its position in relation to the economic life of SDP's pipeline.

Table 6.2: Standard asset lives for the Plant and Pipeline: Summary of SDP response to draft decision

Asset category	IPART 2017 Determination	SDP pricing submission[54]	IPART draft decision	SDP response
Plant	30.0	30.0	30.0	Agree
Intake Infrastructure	90.0	90.0	90.0	Agree
Outlet Infrastructure	100.0	100.0	100.0	Agree
Pumping Station	25.0	25.0	25.0	Agree
Pre-operations Payment	20.0	20.0	20.0	Agree
Project Development	44.0	44.0	44.0	Agree
Periodic Maintenance	30.0 (part of Plant)	7.6	6.6	Agree
Membranes	8.0	4.5	11.0	Disagree
Corporate	5.0	5.0	5.0	Agree
Pipeline	120.0	100.0	116.0	Disagree

The Terms of Reference specify pricing principles which require that "return of assets (depreciation) is to reflect the economic lives of the assets".[55]

As explained in detail on SDP's Pricing Proposal, 'economic life' represents the period of time over which a regulated asset is expected to generate economic returns. The expected economic life of an asset can be equal to, or shorter than its design life. The design life represents the period of time over which a regulated asset is designed to be physically operational and is typically specified in the design documentation associated with the specific asset. In some circumstances the economic life of an asset may be shorter than its design life (e.g., where declining demand for the output of the asset or it becomes uncompetitive relative to alternative technologies).

Critically, however, the economic life – and thus the regulatory asset life - cannot exceed its expected design life. Standard regulatory practice is to assume that the expected economic life is equal to the design life unless there is evidence that the asset is unlikely to be able to generate economic returns for the full design life of the asset. If there is no such evidence, the question then turns to how to appropriately establish the technical or design life of each asset.

6.6 Regulatory asset life - Pipeline

IPART's draft decision (Decision 13) is to adjust the regulatory asset life for the pipeline from 120 to 116 years). IPART states that it has chosen 116 years on the basis that:

- The rationale for adopting a 120-year pipeline asset life in the 2017 Determination is still relevant, subject to updating with the data provided by SDP on the percentage of the pipeline that is undersea.
- The design life of 100 years represents the minimum life expected for pipelines and that setting the asset life based on the expected minimum might not represent good value for customers.

SDP **disagrees** with IPART's draft decision on asset life for the pipeline.

SDP's proposal was that the pipeline's asset life should be 100 years. This was based on the following:

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54 SDP Pricing Submission, September 2022, p190.

55 The TOR underline the key principle that SDP would be unable to recover the full efficient cost of its regulated assets if the economic life of those assets is shorter than the asset life assumed by IPART when setting the regulatory depreciation allowance.

- The standard regulatory principle that (unless there is evidence that the economic life of the asset is shorter than the design life), the period over which the capital costs of an assets are to be recovered should be set in line with the *design life* of the specific asset – not benchmarked against other "generic industry practice in determining an expected service life for the pipeline".[56]
- KBR's opinion that the *design life* of SDP's pipeline is 100 years. KBR has outlined that this design life does ***not*** represent a minimum or lower bound estimate of the physical life of SDP's pipeline, but its actual design life of the pipeline.[57] This was based on the following:
  - the parts of the pipeline which are undersea are located in aggressive marine environment and an asset life of 100 years is an appropriate design life for that environment;
  - the pipeline should be treated as a singular asset and not be averaged using the land-based section. To this effect, KBR outlined: "*Unlike Sydney Water's assets, the SDP pipeline is a single whole entity and if any part of the pipeline is damaged or removed from operation, be it land based or under-sea, then the whole pipeline would be out of service. If any part of the under-sea sections are lost, then the whole of pipeline would be out of service for an extensive unknown period and the plant cannot supply water";*[58] and
  - the sub-elements of the pipeline that sustain it—including cathodic protection, pipe wall thickness, protective coating and lining, joint design—were designed to achieve a 100-year design life for the whole pipeline. The design for these sub-elements would have been developed for a greater period if the appropriate asset life was 116 years

The draft decision has not addressed key evidence put forward by SDP. In particular, it has not addressed the expert report from KBR in any meaningful way, despite KBR being uniquely qualified to express an expert opinion, as it was a part of the Sydney Water's Water Delivery Alliance which designed and constructed the pipeline in 2010.

The draft decision has failed to address Atkins' finding that SDP's proposal to set the asset life assumption of the pipeline in line with its design life of 100 years is "valid".[59]

Instead, the draft report appears to justify the decision by reference to the decision to adopt a 120 year pipeline asset life in 2017. However, the 2017 Determination was not based on evidence on the design life of SDP's actual, in situ pipeline but the regulatory asset life assumed for a portfolio of pipelines of another regulated water company. This approach is at odds with Atkins' latest advice to IPART, which explains that the design life of each regulated asset should be assessed on the basis of the specific circumstances of that individual asset, rather than some other unrelated asset.[60]

For the reasons explained by KBR, SDP's pipeline differs fundamentally from Sydney Water's pipeline assets.[61]

- Sydney Water's pipelines form part of an extensive, interconnected network that offers flexibility to divert supply between systems to allow parts of the network to be shut down temporarily for repair and maintenance that would extend asset life. By contrast, SDP's infrastructure consists of a single delivery pipeline with no redundancy or ability to divert when the Plant is operating.

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56 AECOM, Expenditure Review of WaterNSW Broken Hill Pipeline, Report to IPART, May 2022, p23.

57 KBR, Sydney Desalination Plant Pipeline Design Life – Technical Memorandum, 16 August 2022, p. 9.

58 KBR, Sydney Desalination Plant Pipeline Design Life – Technical Memorandum, 16 August 2022, p. 15.

59 Atkins, Sydney Desalination Plant ("SDP") Expenditure Review Consultant Report, 2 April 2023, p. 121.

60 Atkins, Sydney Desalination Plant ("SDP") Expenditure Review Consultant Report, 2 April 2023, p. 121.

61 KBR, Sydney Desalination Plant Pipeline Design Life – Technical Memorandum, 16 August 2022, pp. 8-9.

- Furthermore, unlike Sydney Water's pipelines, 86% of SDP's pipeline is inaccessible for routine condition assessment and maintenance due to being either undersea or constructed at depth in tunnel.

Therefore, the regulatory asset life applied to SDP's pipeline should not be benchmarked to the regulatory asset life applied to Sydney Water's pipeline assets. This also implies that setting the regulatory asset life of SDP's pipeline equal to a design life of 100 years should have no implications for the asset life assumptions that IPART should adopt in relation to Sydney Water's pipeline assets.

The draft decision states that "the design life of 100 years represents the minimum life expected for pipelines" and concludes that "setting the asset life based on the expected minimum" might not represent good value for customers. This appears to be a misunderstanding of what the design life of SDP's pipeline represents as addressed in KBR's report. The 100-year design life of the pipeline, as specified by the designers of the pipeline, does ***not*** represent a minimum or lower bound estimate of the physical life of SDP's pipeline. KBR addressed this point directly in its August 2022 report.[62]

SDP's pipeline was not designed to operate more than 100 years. If SDP were required to recover its pipeline costs over 116 years, but the existing pipeline is renewed after 100 years, then consumers at that time would be paying for recovery of the original pipeline and its replacement for sixteen years. This would result in intergenerational inequity with consumers over those sixteen years unnecessarily paying more than the efficient cost of delivering the regulated services.

SDP also notes that in previous decisions for other regulated businesses, IPART has adopted the approach that we have proposed in relation to the SDP pipeline—namely, to adopt an asset life assumption in line with the design life of the asset, as specified by its designers. For instance, in the 2019 review of prices for the WaterNSW's Broken Hill Pipeline, IPART concluded it was appropriate to use the design life as this: '*would lead to greater accuracy and therefore more cost reflective prices*'.[63] This approach was reaffirmed by IPART and its cost consultant AECOM in the 2022 review of prices for the WaterNSW's Broken Hill Pipeline.[64]

SDP submits that IPART should adopt a 100-year asset life assumption for SDP's pipeline on the basis that this would:

- Be consistent with Atkins' draft advice to IPART that setting the asset life assumption for SDP's pipeline in line with the actual design life of the pipeline is valid;
- Be consistent with the evidence provided by SDP, including the expert evidence provided by KBR, the designers of SDP's pipeline; and
- Resolve the inconsistency of approach and reasoning adopted by IPART in its asset life decisions in relation to SDP's pipeline and the Broken Hill Pipeline (which are appreciably different to Sydney Water's portfolio of pipelines).

To adopt an asset life that exceeds the design life despite the advice of Atkins, the expert report of KBR and the fact that a simple, point to point, pipeline is involved, would be a clear error.

6.7 Regulatory asset life – Periodic maintenance

SDP **agrees** with IPART's draft decision on asset life for Periodic maintenance on the basis that this now reflects the weighted average approach for periodic maintenance where the asset life reflects the economic useful life of the asset weighted using the estimated periodic maintenance cost during the Determination period.

62 KBR, Sydney Desalination Plant Pipeline Design Life – Technical Memorandum, 16 August 2022, p. 9.

63 IPART, WaterNSW: Murray River to Broken Hill Pipeline, Final Report, 2019, p. 63.

64 AECOM, Expenditure Review of WaterNSW Broken Hill Pipeline, May 2022, p23.

6.8 Regulatory asset life – Membranes

SDP **disagrees with** IPART's draft decision on asset life for Membranes on the basis that this does not reflect the economic life of these assets. IPART's draft decision reflects advice by its consultant Atkins, who stated that:

> *The asset life of the membranes has been calculated by running two potential membrane replacement scenarios for both the first and second pass membranes and the representative average production. These suggested that half of the first pass membranes would be replaced by either year 9 or 10 after installation and half of the second pass membranes by year 13 or 14.*

Weighting these results by the number of first and second pass membranes suggests an average asset life of 11 years (rounded to the nearest year).

Atkins has introduced a new methodology that heavily favours estimates of average production (rather than considering calendar age and the membrane warranty) in considering the economic life of the membrane assets without seeking to:

- justify the change in methodology (i.e., why is an 'effective production age' methodology based on assumed average production preferable in setting the economic life of the membrane assets for the 2023 Determination given an alternative methodology was used in the 2017 Determination);
- explain its consistency with the ToR requirements; or
- transparently articulate the risks in this approach to establish an assumed average production that is an input to establishing an effective production age and the ongoing implications of IPART making a new decision on membrane asset lives at each subsequent determination when there is a change to expected production volumes.

The change in approach to the asset lives for membranes introduces regulatory risk given that in the 2017 Determination IPART's expenditure consultant, Atkins, stated that:

> *The main change is the addition of a new asset group for membrane replacement with a life of eight years.*

This design life was set in line with [redacted] Indeed, in its 2017 report Atkins noted:

> *The membranes have a* [redacted] *We suggest a life of eight years based on our experience of membrane use in established desalination plants...*
>
> *...After a few years, there will be a range of ages for the membrane elements in the pressure vessel, with the oldest element* ***eight years old*** *[emphasis added] and the youngest less than one year old.*[65]

These asset life assumptions also supported Atkins recommendation, which IPART adopted, to provide for a full membrane replacement on restart given the assets were older than 8 years, including significant time in preservation. IPART noted:

> *In line with our expenditure consultant's recommendations, we have allowed for the costs of a full set of membranes on the first restart of the plant. This is because the plant has been in a prolonged period of shutdown (since July 2012) and the stock of membranes will be reaching the end of its asset life* ***(8 years)*** *[emphasis added] during the 2017 determination period.*[66]

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65 Atkins, Sydney Desalination Plant – Expenditure Review, Final report to IPART, February 2017.

66 IPART, Sydney Desalination Plant Pty Ltd: Review of prices from 1 July 2017 to 30 June 2022, Final Report, June 2017, p4.

Further IPART explicitly noted the importance of the manufacturer's warranty, and its relationship to age rather than production, to performance:

> *The manufacturer extends warranty on membrane conditions if membranes are preserved in shutdown using the agreed protocol…Atkins Cardno noted that even following the storage protocol, the condition of the membranes cannot be ascertained past* [redacted] *eight years…*
>
> *We recognise that membrane replacement costs are critical to the plant's production and supply of any desalinated water…if SDP experiences operational issues due to faulty membranes over the 2017 determination period, it should be covered by the manufacturer's warranty.*[67]

Thus, the methodology used to set the membrane asset life in the 2017 Determination did not include assumptions relating to assumed average production. Rather they were based on the design life of the assets set in line with [redacted] [68]

SDP has [redacted] if membranes are put in a state of preservation (which is not planned for the 2023 Determination because it is unlikely to be prudent and efficient given SDP is expected to be in flexible full-time operation). This is the upper limit on which manufacturers will guarantee performance of the membranes.

For this reason, it is incongruous for the regulatory asset life of membranes to be increased relative to the 2017 Determination given:

- The design life set in line with the [redacted] has not changed;
- The membranes are likely to be used more in the future than they were in the past, meaning there is very low possibility the membranes can be placed in preservation to extend the life beyond 8 years.

SDP therefore proposes that IPART should revert to the 8-year asset life for membranes as established in the 2017 Determination for the purposes of setting the regulatory depreciation allowance.

It would better ensure:

- consistency in the application of the design life principle for both the pipeline and membrane assets being the upper bound of the economic life of the assets in accordance with Pricing Principle 3 of the Terms of Reference.
- reduce unnecessary, complex and uncertain changes in the regulatory depreciation to be applied to these assets in each determination in line with the principle of simplicity, consistency and transparency which underpins IPART's use of the straight-line depreciation method (see section 6.4).

6.9 Regulatory asset life – Other assets

SDP **agrees** with IPART's draft decision on asset lives for all other assets on the basis that these reflect the economic lives of these assets.

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67 IPART, Sydney Desalination Plant Pty Ltd: Review of prices from 1 July 2017 to 30 June 2022, Final Report, June 2017, p86-88.

68 IPART, Sydney Desalination Plant Pty Ltd: Review of prices from 1 July 2017 to 30 June 2022, Final Report, June 2017, p88. Similarly, Atkins did not suggest that the life of new membranes once replaced on restart could be significantly extended beyond 8 years even though it was highly unlikely that the Plant would be operated at full production for 8 years given its "drought response measure in accordance with the NSW Government's Metropolitan Water Plan."

6.10 Return on working capital

SDP **accepts with qualification** IPART's draft decision on return on working capital, subject to IPART utilising an assumption of 48 days for the number of days for receivables in arrears in the calculation of working capital, and accounting for changes to prepayments to reflect updated (pre-paid) insurance costs. Further detail is in **Appendix A**.

SDP notes that 48 days closely reflects the contractual terms contained in the Water Supply Agreement with Sydney Water and the standard duration for the billing/receivables cycle which SDP experiences.

6.11 Tax costs

SDP **accepts with qualification** IPART's draft decision on tax costs, subject to IPART addressing calculation errors related to the nominal RAB (for calculation of notional interest costs) and updating the tax depreciation forecasts to reflect revised capital expenditure allowances for the 2022-23 deferral year and the 2023 Determination period. Further detail is in **Appendix A**.

6.12 Revenue adjustments required by the ToR

SDP **accepts with qualification** IPART's draft decision on EAM revenue adjustments, subject to IPART clarifying the draft decisions' use of a 1% real financing rate being consistent with the 2017 methodology to use the RBA corporate bond series and the latest available RBA 1-year inflation forecast to generate:

- a nominal financing rate series using monthly observations over the relevant years of the application period
- a nominal interest rate using available months of data for the review year
- a real interest rate based on the nominal rate used for the review year, the RBA's most recent 1-year inflation forecast, and the Fisher equation, to be used to calculate an annuity over the adjustment period, and
- a real interest rate based on the nominal rate used for the review year, the RBA's most recent 1-year inflation forecast, and the Fisher equation, converted to a six month interest rate to discount the annuity values (end of year values) to EAM allowances (mid-year values).

Based on our review, the draft decision appears to use:

- a 12-month average as at February 2023 to obtain the 3-year BBB corporate bond rate.[69]
- the forecast of inflation to June 2023 from the RBA's February 2023 Statement on Monetary Policy (6.75%).[70]
- a 3-year geometric average of the RBA forecast and 2 years of inflation at SDP's proposed inflation forecast (2.8%).[71]

SDP proposes that IPART update the real financing rate to reflect the 2017 methodology. This increases the real financing rate to 1.86% and increases the payments to customers for their share of gains from the sale of surplus energy over the period 2016-17 to 2021-22.

SDP **agrees** with IPART's draft decision not to include an efficiency carryover adjustment for the 2023 Determination period based on applying the 2017 methodology.

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69 The EAM methodology specifies that available months during the review year (FY2023) should be used (see p17 of IPART's 2017 methodology paper), i.e. using bond rates from July 2022.

70 The methodology states that the RBA's most recent 1-year ahead forecast should be used (see p18 of IPART's 2017 methodology paper), thus the RBA forecast of 3.5% should be taken.

71 The methodology does not specify such an approach, instead specifying using the RBA's most recent 1-year ahead forecast and the Fisher equation. Therefore, SDP understands that the corporate bond rate should be converted into real by using the RBA forecast of 3.5%.

6.13 Revenue adjustment for the 2022-23 deferral year

SDP **accepts with qualification** IPART's draft decision on the revenue adjustment for the 2022-23 deferral year.

As explained in SDP's pricing submission (p.195), SDP continues to believe that no such adjustment should be made, as the 2017 Determination clearly provided for existing prices to continue in the event of a deferral. Reviewing all prices and costs ex-post creates undue uncertainty, which can adversely impact incentives for efficiency. If a revenue adjustment is to be made in the future as a result of delay, SDP requests that greater clarity is provided ex-ante so that businesses have appropriate guidance to efficiently manage operations during a period of delay.

For the purposes of the 2023 Determination, SDP agrees with IPART holistically considering key building block components and comparing actual revenue (based on 2021-22 prices and actual volumes) with IPART's calculation of hypothetical revenue (based on estimated efficient costs for 2022-23, updated 2022-23 prices and actual volumes) for the deferral year. However, SDP has identified apparent calculation errors in the implementation of the IPART's revenue adjustment for the 2022-23 as summarised in **Appendix A**. Should IPART make a final decision to include a revenue adjustment for the 2022-23 deferral year these apparent errors should be corrected.

SDP also **agrees** with the approach presented in Table 7.9 of IPART's Draft Report, where the revenue adjustment is made as an annuity payment spread evenly over the 2023 Determination period. The impact on Sydney Water and its end-use customers is NPV-neutral, but a smoothed approach assists SDP in managing cashflow impacts.

7. Maximum prices for SDP's services

Table 7.1: Allowance for a return on assets, regulatory depreciation, tax obligations and other revenue: Summary of SDP's response to IPART's draft decisions

Issue	IPART draft decision	IPART decision reference	SDP response to draft decision
Pricing structures	• To accept a simplified two-part price structure consisting of – a. Fixed water service and pipeline charges (expressed as $ per day) and – b. Volumetric water usage charge (expressed as $ per ML) • To apply the 2-part price structure at all times • To set a Sydney Water requested zero production charge	24 25 26	Accept with qualification
Cost sharing and proposed application of prices	• To provide for prices which ensure SDP's customers pay a share of costs, including any customers other than Sydney Water	29	Accept with qualification
Negotiated agreements	• Not accept SDP's proposal to allow negotiated agreements over the 2023 Determination period.	25, 26	Accept with qualification

7.1 Pricing structures

SDP **accepts with qualification** IPART's draft decision on pricing structures such that the simplified two-part price structure applies at all times, subject to removing the "zero-production day charge" and ensuring the prudent and efficient costs of making the Plant available are included in the fixed service charge. These costs are a core means of meeting SDP's new Licence requirements, the objectives of the GSWS and are incurred whenever the Plant is operating below maximum production—rather than only at zero production.

IPART's draft decision sought specific comment on:

> *Is our approach to setting a Sydney Water requested zero production charge appropriate? Are there any unintended consequences that may occur that we should consider?* (**Question 2**)

In our view, IPART's draft approach to setting the Sydney Water requested zero production charge is not appropriate. This approach:

- Mischaracterises the costs incurred in making the Plant available. These costs are unrelated to production levels and are incurred whenever the Plant is operating below maximum production (see Section 4.2)
- IPART's draft decision to exclude these costs from the fixed Plant service charge and include (some) of these costs in a requested zero production charge:
  - creates an incentive for Sydney Water to request production volumes just above zero production as it avoids the costs of making the Plant available;
  - creates an incentive for Sydney Water to request zero production for a period of time that does not fully cover the period from midnight to midnight (as in this case the charge would not be levied), or would mean that SDP would not be compensated for the costs of providing this flexibility under this situation;
  - creates a misalignment between the calendar day under which the charge can be levied (midnight to midnight) and the billing day which covers a period 8am to 8am;
  - means SDP is not financially indifferent as to whether it supplies water, as it will not recover the costs of making the Plant available and impede its ability to meet the service levels agreed with DPE and Sydney Water under SDP's Network Operator's Licence.

SDP's proposed refinements to the draft decision will ensure:

- SDP and Sydney Water are provided with appropriate incentives to negotiate minimum production levels;
- The fixed Plant service charge reflects the fixed costs of providing services as per Pricing Principle 6 of the ToR.
- SDP is financially indifferent as to whether it supplies water as per Pricing Principle 4 of the ToR and has appropriate incentives to meet the service levels agreed with DPE and Sydney Water under SDP's Network Operator's Licence. See Sections 1.3.2 and 4.2.

7.2 Cost sharing and proposed application of prices

IPART's draft decision is to continue to define cost sharing principles to ensure SDP's customers pay their fair share of costs and establish a simple sharing based on pro-rating fixed charges based on shares of daily volumes supplied, rather than a complex formula which previously applied in the 2017 Determination.

IPART's draft decision also asked:

> *Is our approach to sharing costs between Sydney Water and other purchasers appropriate? (**Question 3**)*

SDP **accepts with qualification** IPART's draft decision on cost sharing principles.

Currently, SDP has only one customer (Sydney Water), and it is highly unlikely SDP will supply a third-party customer in the foreseeable future given SDP's Network Operator's Licence and the need to flexibly respond to meet Sydney Water's needs in or outside of drought. For this reason, the cost sharing principles and their application are unlikely to have any material impact over the 2023 Determination period.

SDP's response to IPART's to **Question 3**:

IPART's draft approach to establish a simple sharing arrangement is more transparent than that which applied under the 2017 Determination. However, should the emergence of another customer become a realistic possibility in the future, a more detailed consideration would need to be given to the proposed cost sharing arrangement to ensure that it does not itself become a barrier to third party supply and outcomes that are in all customers' long-term interests. This is because:

- It is not clear that setting a charge which levies (a potentially significant) share of the fixed capacity costs based on pro-rating daily volumes is either fair or efficient, given that such a customer would (as recognised by IPART) be receiving an inferior non-firm or opportunistic product (i.e., not be receiving a firm share of the capacity) and which may render the service uneconomic relative to other options available to that customer.
- Any charge to a new customer above the incremental cost of supply should leave Sydney Water (and end customers) better off and be more likely to be economic relative to other options available to that customer. Rather than seeking to recover a significant share of the fixed service costs – which are incurred to ensure the Plant is available to meet Sydney Water production requests – this situation is much more amenable to a negotiated agreement which could leave both Sydney Water and other customers better off (see Section 7.3).

7.3 Negotiated agreements over the 2023 Determination period

7.3.1 IPART draft decision

SDP **accepts with qualification** IPART's draft decision on negotiated agreements over the 2023 Determination period.

SDP proposed negotiated agreements given the difficulty in attempting to estimate costs associated with meeting all possible levels of service in a way that is consistent with the Terms of Reference. This proposal sought to provide flexibility in dealing with unknown scenarios and confidence to Sydney Water and IPART that there was sufficient regulatory oversight through a 'deferred regulation' framework.

However, SDP:

- acknowledges that Sydney Water is likely to continue to be SDP's only customer over the 2023 Determination period;
- agrees with IPART that under the GSWS it is highly unlikely that an alternative level of service, such as a prolonged shutdown "appears low… and would diminish as we progress through the Determination period".[72]

For this reason, SDP accepts the draft decision to continuing to set maximum prices that apply at all times for SDP's monopoly services is in the best interests of customers and is appropriate for the 2023 Determination period.[73]

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[72] IPART, Draft Report, p91.

[74] IPART, Draft Report, p106.

8. Impact of maximum prices

Table 8.1: Impact of draft decisions: Summary of SDP's response

Issue	IPART draft assessment	SDP response to draft decision
Customer impacts	• Impacts on Sydney Water and end-use customers would be very small	Agree
Meeting service standards	• Allowances are sufficient to enable SDP to meet service standards	Accept with qualification
Remaining financeable	• IPART found that the draft decisions would allow SDP to remain financeable over the 2023 Determination period, and did not identify any financeability concern for SDP that needs to be addressed in this review;	Disagree
Implications for the environment	• Allowances are sufficient to enable SDP to meet environmental obligations	Accept with qualification

8.1 Customer impacts of prices

IPART's draft decision found that found that the impacts on bills for both Sydney Water and end-use customers will be very small:

- Under IPART's draft decision, Sydney Water's annual bill would increase by 1.5% in 2023-24, after inflation.
- Given that the cost of SDP's services makes up less than 10% of a typical Sydney Water customer bill, IPART's draft decisions would result in a small increase of around $2 per year in a typical bill.

SDP **agrees** with IPART's draft assessment that the customer impacts of prices under IPART's draft decision are minimal.

8.2 Meeting service standards

IPART finds that (Chapter 10, section 10.3) that its draft decisions on SDP's operating and capital expenditure would enable it to operate efficiently and to implement infrastructure repairs and investments to meet service standards at or above those expected by customers and required under its licences over the 2023 Determination period.

SDP **accepts with qualification** IPART's draft finding that its draft decision enables SDP to meet service standards if SDP proposed amendments are accepted in the areas of O&M Fixed and Variable costs, energy volumes, insurance costs, pipeline costs and if Pricing Principle 7A of TOR is fulfilled.

8.3 Remaining financeable

SDP **disagrees with** the way in which IPART has conducted its financeability analysis.

The Draft Report misconstrues the financeability test proposed by SDP as "basically combining the benchmark and actual tests."[74]

[74] IPART, Draft Report, p106.

SDP's proposed financeability test is not a hybrid of IPART's benchmark and actual tests. Rather, the financeability test that we have proposed is a more realistic version of IPART's benchmark test[75] that recognises that a benchmark efficient business issues nominal debt and, therefore, faces nominal interest expenses. IPART's benchmark test assumes unrealistically that a benchmark efficient business would face real interest expenses. IPART's test is therefore likely to find no financeability problem because the debt service obligations faced by the benchmark efficient firm are understated.

IPART's draft decision is not to change the ratios used for the financeability tests including declining to incorporate SDP's proposal to include the Debt Service Coverage Ratio (DSCR) as part of the benchmark test. In its 2018 Final Report on the review of its financeability test, IPART determined that it would not include the DSCR as a standard ratio in its financeability tests because it considered it was not clear how to establish a target ratio for a benchmark efficient business. However, IPART committed that when conducting financeability tests during future price reviews, it would consider all issues and submissions put forward by stakeholders on this matter.

Having regard to that commitment, SDP submitted analysis by independent debt advisory expert [redacted] on an appropriate target DSCR ratio for a benchmark efficient business in SDP's circumstances, and the evidence underpinning that target benchmark ratio. This is an important financeability/debt metric for debt raising firms like SDP that are subject to limited term concessions.

SDP is concerned as the draft decision has failed to consider material submitted by SDP and appears to depart from previous IPART commitments to consider this issue as part of the price review process.

[redacted]

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75 SDP's proposed financeability test is a benchmark test because it assumes that the benchmark efficient business:

- always maintains a benchmark level of gearing of 60% (rather than SDP's actual level of gearing);
- pays just enough dividends to maintain the benchmark gearing level (rather than SDP's forecast dividends);
- incurs benchmark interest costs in line with the (nominal) cost of debt allowance (rather than SDP's actual interest costs); and
- incurs benchmark corporate tax obligations.

8.4 Implications for the environment

SDP **accepts with qualification** IPART's draft finding that its draft decision enables SDP to meet its environmental and other obligations as long as Pricing Principle 7A of the TOR is fulfilled.

Appendices

Glossary

Term	Definition
2017 Determination	IPART determination on the maximum prices SDP may charge from 1 July 2017 to 30 June 2023 (including the 2022-2023 deferral year) .
2017 Determination Period	The period from 1 July 2017 to 30 June 2023.
2023 Determination	IPART determination on the maximum prices SDP may charge from 1 July 2023 to 30 June 2027.
2023 Determination Period	The period from 1 July 2023 to 30 June 2027.
Abatement Mechanism	Applies to the 2017 Determination period. A pricing mechanism intended to create a financial incentive for SDP to maximise its production of drinking water when required under the 2017 Operating Rules.
Annual Production Request	A request made by Sydney Water by 1 May each year for the supply of water from the SDP over the following financial year, of the type referred to in section 4.2.2 of the Decision Framework, and includes a six-monthly modification of such a request and any other request agreed between SDP and Sydney Water from time to time, provided that the modification: complies with the Decision Framework; and is notified by the Sydney Water to IPART and SDP, in writing, before it takes effect.
Annual Production (period)	This refers to the applicable financial year when the Plant is responding to an APR requested by Sydney Water to produce a defined annual volume of water in accordance with SDP's Network Operator's Licence. Regulated charges apply at all times during this period, with a nil usage price for supply in excess of 110% of APR as per SDP's Network Operator's Licence.
Average Membrane Lifetime	The expected mean length of time since installation of first and second pass reverse osmosis membranes respectively to maintain warranty coverage and meet operational requirements (potable water quality, required output volume and differential pressure) before replacement is required.
Base Service Charge	Daily fixed charge included in the 2017 Determination to reflect the costs of making the Plant available in water security (shutdown) mode. SDP has not proposed a Base Service Charge for the 2023 Determination period. Rather all fixed Plant costs would be recovered through the fixed Plant Service Charge
Building Block	IPART's standard methodology to establish notional revenue requirement.
Capacity of the Plant and Pipeline	The capacity of the existing Plant is 250ML per day measured as a rolling average over 365 days. The capacity of the Pipeline is an annual daily average of up to 500ML per day.
Capital Asset Pricing Model	A model used to determine a theoretically appropriate required rate of return on an asset, to make decisions about adding assets to a well-diversified portfolio. The model describes the relationship between the expected return and risk of investing in a security. It shows that the expected return on a security is equal to the risk-free return plus a risk premium, which is based on the beta of that security.
Capex	Money spent by a business or organization on acquiring or maintaining fixed assets, such as land, buildings, and equipment. In SDP's case this includes relevant expenditure on the Plant, DWPS and Pipeline and associated assets, including Periodic Maintenance, Specific Capital Projects and RO Membrane Replacement.
Consumer Price Index	The Australian All Groups Consumer Price Index number (Weighted average of eight capital cities) published by the Australian Bureau of Statistics.

Term	Definition
Cost of Debt Allowance	The minimum rate of return required by debt investors in a benchmark efficient regulated business.
Cost Pass-Through	A change in price of the products or services supplied following a change in the efficient costs incurred in producing them following a defined event.
Customers	Residential and small business water customers in Greater Sydney.
Debt Service Coverage Ratio	Ratio of operating income available to debt servicing for interest, principal and lease payments.
Decision Framework (Sydney Water)	The 'Decision Framework' document prepared by Sydney Water and endorsed by the Minister that sets out the framework for when Sydney Water will request water from SDP so as to align with the 2022 Greater Sydney Water Strategy.
Water Regulatory Framework	IPART, Water Regulatory Framework: Delivering Customer Value – Technical Paper, November 2022.
Water Regulation Handbook	IPART, Water Regulation: Handbook, April 2023.
Drinking Water Pump Station	Transfers water from the Plant's drinking water tank via the Pipeline into Sydney Water's distribution network at Erskineville.
Efficiency Carryover Mechanism	Financial incentive for service providers to pursue efficiency improvements in operating expenditure.
Electricity Supply Agreement	The agreement between SDP and Infigen Energy Markets Pty Limited (now part of Iberdola Australia) dated 28 July 2008 for the supply of electricity to the Plant, as amended from time to time.
Emergency Response (Period)	This refers to a period when the Plant is operational and SDP agrees to a request from Sydney Water to produce a specified volume of water at short notice in accordance with SDP's Network Operator's Licence, the Decision Framework and WSA. SDP must use best endeavours to comply with this request. Regulated charges apply at all times during this period.
Emergency Response Notice	This refers to a notice issued by Sydney Water and agreed to by SDP to produce a specified volume of water in a specific timeframe (likely at short notice) in accordance with SDP's Network Operator's Licence, the Decision Framework and WSA. The volume of water that is produced in accordance with an ERN is not included in the Annual Production Request cap.
Energy Adjustment Mechanism	As per the Terms of Reference, the energy adjustment mechanism is to provide for the carryover and pass-through to SDP's customers of gains or losses, outside a core band, associated with the sale of surplus electricity and RECs.
Energy Saving Scheme	NSW Energy Saving Scheme; financial incentives to install energy efficient equipment and appliances.
Expansion Determination	Part of the expansion planning process; IPART's determination of prices for the expansion of the Plant.
Financeability	The capacity of a business to finance its activities – including its day-to-day operations and its capital investments to renew and expand the infrastructure required for these activities.
Fixed Network Charge	Fixed component of cost pass through from electricity costs. Based on regulated network prices and actual maximum demand.
Full-Time Equivalents	Measures how many full-time employees or part-time employees add up to full-time employees a company employs.
Funds from Operations	The actual amount of cash flow generated from a company's business operations.

Term	Definition
Good Industry Practice	The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a prudent desalination plant operator acting in accordance with SDP's Network Operator's Licence, the Decision Framework and WSA good industry practice and applicable Australian and internationally recognised standards having regard to the Capacity of the Water Infrastructure, its duty, age and technological status.
GGRP Contracts	The Electricity Supply Agreement and Renewable SA contracts between SDP and Iberdrola Australia (previously Infigen) for the purchase of electricity and Renewable Energy Certificates (specifically Large-scale Generation Certificates, LGCs) and the development of the Capital Wind Farm that are described in the Greenhouse Gas Reduction Plant.
GGRP costs	All charges SDP is required to pay Iberdrola Australia pursuant to the GGRP Contracts.
Greater Sydney Water Strategy	The NSW Department of Planning and Environment's strategy to deliver sustainable and resilient water services to Greater Sydney for the next 20 to 40 years. The Greater Sydney Water Strategy replaces the Metropolitan Water Plan.
Greenhouse Gas Reduction Plan	A strategic plan for the management, minimisation and off-set of greenhouse gas generation associated with electricity supply for the Plant required under s75J of the EP&A Act 1979 (NSW).
Incremental Service Charge	Daily fixed charges in 2017 Determination in Plant Operating Mode over and above the Base Service Charge in water security shutdown. SDP has not proposed an Incremental Service Charge for the 2023 Determination period.
Industrial Special Risks	Business insurance that provides coverage for high-value physical assets and business interruption.
Interest Coverage Ratio	Debt and profitability ratio used to determine how easily a company can pay interest on its outstanding debt.
Intermediate Permeate Tanks	Used to store and buffer the reverse osmosis First Pass rear permeate before feeding it into the RO Second Pass Process. IPTs are made of glass fused to steel panels with silo bolts.
Large-scale generation certificate	A large-scale generation certificate created pursuant to the Renewable Energy (Electricity) Act 2000 (Cth). One LGC can be created per megawatt hour (MWh) of eligible electricity generated by a power station. Registered LGCs can be sold or transferred to entities with liabilities under the Renewable Energy Target or other companies looking to voluntarily surrender LGCs.
Membrane Service Charge	Set by IPART in the 2017 Determination as a separate daily fixed charge to recover capital costs of membrane replacement. This has been incorporated into the Plant Service Charge for the 2023 Determination period.
Metropolitan Water Plan	Originally developed in 2004 and updated in 2006 and 2017. Has subsequently been replaced by the GSWS.
Monthly and weekly phasing	Water produced in response to an APR will be, where possible, delivered progressively over the year to meet the needs of Sydney Water in accordance with SDP's Network Operator's Licence, the Decision Framework and WSA. The timing of this water delivery over the year or over a shorter period is termed 'phasing'.
Minimum production	This refers to a period when the Plant is operational and is requested by Sydney Water to minimise annual production, subject to remaining ready to respond to production requests in accordance with SDP's Network Operator's Licence, the Decision Framework and WSA. Regulated charges apply at all times included when the Plant is producing minimum volumes.
Negotiated Agreements	Covering services, incremental costs (or cost savings) and prices within a clear set of approved pricing principles for water supplied in response to an alternative level of service requested by Sydney Water.
Network Operator's Licence	SDP's Network Operator's Licence (No.10_010) granted under the WIC Act on 9 August 2010, as varied on 19 September 2022. SDP's Network Operator's Licence takes effect on 1 July 2023.
Next Regulatory Period	2023-2027 regulatory period from 1 July 2023 to 30 June 2027.
Operating & Maintenance (O&M) Costs	Expenditure incurred in facilitating the functioning of the Plant line with Good Industry Practice, as required under SDP's Network Operator's Licence.

Term	Definition
Operating Expenditure	Ongoing cost for running a product, business, or system. Expenditure required by SDP for the Plant's functioning in accordance with SDP's Network Operator's Licence, the Decision Framework and WSA.
Operating Rules (New)	The operating regime reflected in SDP's Network Operator's Licence as amended in 2022 to align with the 2022 Greater Sydney Water Strategy and operationalised in the Decision Framework, Terms of Reference and WSA.
Periodic maintenance	Periodic maintenance refers to significant expenditures to replace, renew and/or refurbish the Plant's mechanical, electrical and other assets to ensure they reach their economic lives and maintain the reliability and required level of service for the Plant. Periodic maintenance is like routine asset maintenance but is less frequent and involves major works that are capitalised.
Pipeline	The pipeline system running from Lot 2 in DP 1077972 in the suburb of Kurnell up to, but not including, the connection valve at Shaft 11C on the City Tunnel at Bridge Street in Lot A in DP 365407 in the suburb of Erskineville and consisting of the following infrastructure: (a) an overland pipeline running from the drinking water pumping station at the desalination plant to Silver Beach; (b) a marine pipeline running from Silver Beach to a point 800 metres offshore from Silver Beach; (c) twin marine pipelines running from 800 metres offshore of Silver Beach to Cook Park, Kyeemagh; and (d) an overland pipeline running from Cook Park, Kyeemagh up to the connection valve at Shaft 11C on the City Tunnel at Bridge Street, Erskineville.
Pipeline Service Charge	Separate daily fixed charge for SDP's pipeline.
Plant	The Sydney Desalination Plant located at Kurnell, including the Drinking Water Pump Station.
Plant Service Charge	Single fixed charge to recover the fixed costs of operating and maintaining the Plant.
Plant Expansion	The potential future expansion of the Plant to facilitate capacity for an additional 250ML per day of production.
Production Request	A request made by Sydney Water to SDP to produce water in accordance with SDP's Network Operator's Licence, the Decision Framework and WSA.
Regulatory Asset Base	An accumulation of the value of asset investments that a service provider has made in its network.
Reliability and Emergency Reserve Trader	Function conferred on the Australian Energy Market Operator to maintain power system reliability and system security using reserve contracts. The costs of RERT interventions are recovered from market customers (typically retailers) as ancillary services charges.
Renewable Energy Certificate	An REC is equivalent to one MWh of electricity generation. SDP purchases RECs in order to fulfill its obligations under the GGRP. REC is used as a general term covering both Small-Scale Technology Certificates and LGCs.
Renewable Services Agreement	Contract with Iberdrola Australia (previously Infigen) which provides SDP with LGCs and enables SDP to meet its obligation that the Plant be powered by 100% renewable energy.
Retail Supplier's Licence	SDP's Retail Supplier's Licence (No.10_011R) granted under the WIC Act, as varied on 19 September 2022.
Revenue Requirement	The amount of revenue that SDP can recover from the provision of regulated water supply and water security services (equal to the sum of the building block components).
RO Membrane Replacement	Capex on new reverse osmosis membranes to replace used membranes in the reverse osmosis system. It includes removal of used membranes and installation of new membranes.
Routine Asset Maintenance Costs	The costs of maintaining the Plant's mechanical, electrical and other assets. This includes preventative, corrective and breakdown maintenance activities. This expenditure is an essential part of good asset management practice, helping to ensure our assets provide reliable service and achieve their economic lives.
SDP's Monopoly Services	SDP's declared services referred to IPART under the Terms of Reference are: (a) the supply of non-rainfall dependent water to purchasers, and (b) the making available of the desalination plant to supply non-rainfall dependent drinking water.
SDP's Water Supply Services	Services declared by the Minister under section 51 of the WIC Act.

Term	Definition
Security of Critical Infrastructure Act 2021 (C'th) (Critical Infrastructure)	Security of Critical Infrastructure Act 2021 (C'th).
Specific Capital Projects	Specific Capital Projects include all capex other than Periodic Maintenance, RO Membrane Replacement or Corporate Capex. It includes the replacement of existing assets with new assets (either like for like, or alternate assets to provide a similar function) and the addition of new assets including major modifications to existing assets.
Subordinate GGRP costs	These include all costs incurred under the GGRP Contracts other than the costs for energy and RECs which have a specified price in the contracts (i.e. a subset of GGRP costs). These costs are driven by market forces or decisions which are outside of SDP's control. Examples of subordinate GGRP costs include ancillary service charges, market fees, network losses, UFE charges, RERT charges and generation compensation fees.
Submission (This)	SDP's response to IPART's Draft Report and Draft Determination
Supplier's Licence	SDP's Retail Supplier's Licence held under the WICA.
Sydney Desalination Plant	Sydney Desalination Plant Pty Limited
Sydney Water (Corporation)	SDP's direct customer and counter-party under the WSA.
Tax Asset Base	The amount deductible for tax purposes against any taxable economic benefits that will flow to an entity when it recovers the carrying amount of the asset.
Terms of Reference	Terms of Reference for Referral of SDP to IPART under Section 52 of the Water Industry Competition Act, dated 16 June 2022.
Unaccounted for Energy	Residual losses of electricity in the system, and includes technical losses, commercial losses and estimation errors. AEMO is responsible for determining and publishing UFE which allocates the costs of UFE to retailers
Uncontrollable Costs	Specified costs driven by market forces or decisions which are outside of SDP's control. These include Subordinate GGPR costs, land tax and council rates and insurance over the 2023 Determination period. This does not exclude any uncontrollable costs that might be the subject of a re-opener event.
Variable Network Charge	Variable component of cost pass through from energy costs. Based on regulated network prices and benchmark energy volumes.
Water Industry Competition Act 2006 (NSW)	Water Industry Competition Act 2006 (NSW).
Water Industry Competition (General) Regulation 2008 (NSW)	Water Industry Competition (General) Regulation 2008 (NSW).
WaterNSW	WaterNSW is the organisation responsible for managing raw water supply across NSW by bringing together the Sydney Catchment Authority (SCA) and State Water Corporation (State Water) (at 1 January 2015).
Water Supply Agreement	Between SDP and Sydney Water; facilitates purchase of water by Sydney Water from SDP.
Water Usage Charge	For supplying non-rainfall dependent drinking water. This charge reflects SDP's efficient variable operating costs when the Plant is operating and applies for all water supplied to Sydney Water.
Weighted-Average Cost of Capital	Weighted average of debt and equity costs required for a benchmark efficient business to invest in necessary infrastructure.

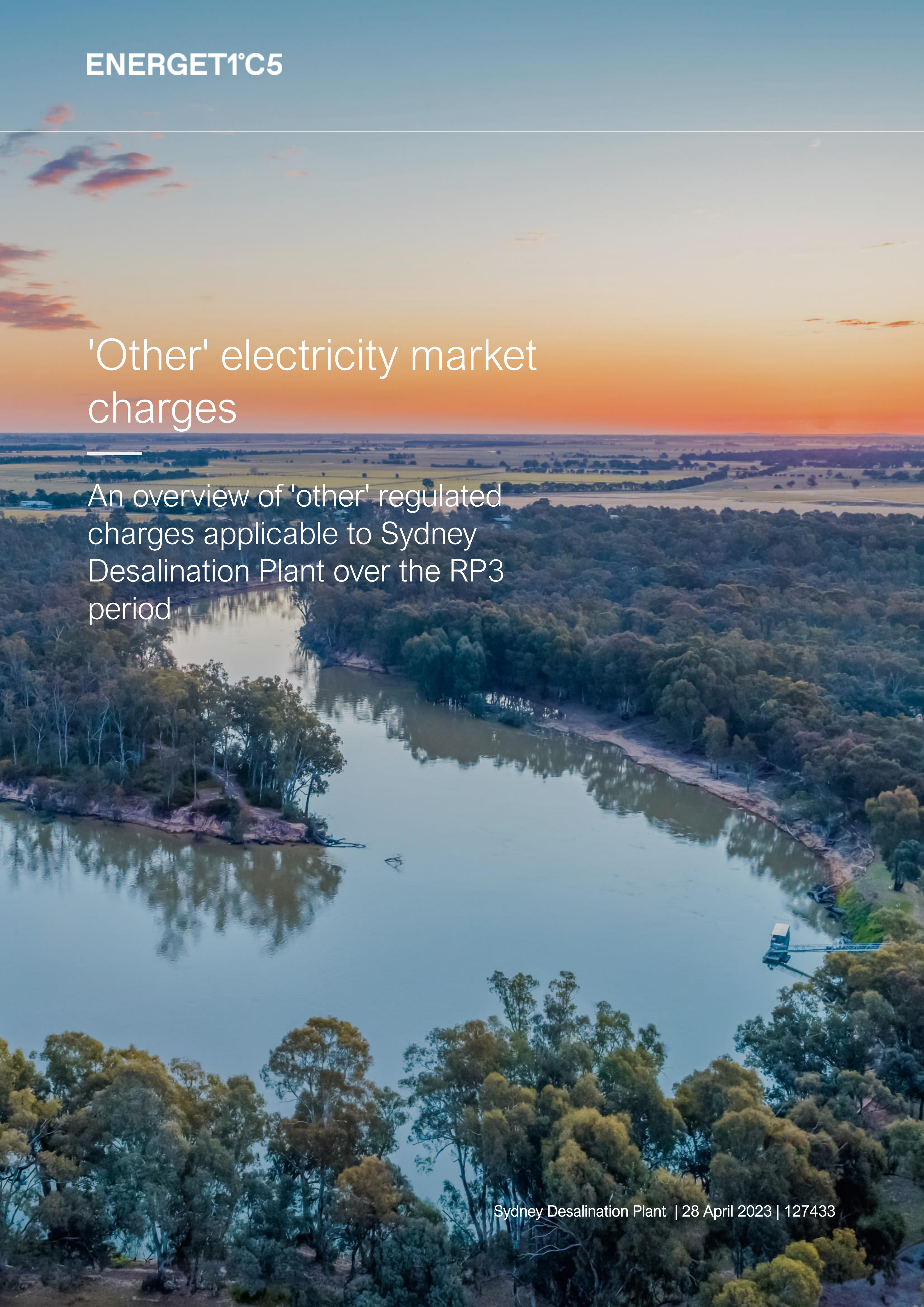
Abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIR	Annual Information Return
AML	Average Membrane Lifetime
APR	Annual Production Request
BAU	Business as Usual
BI	Business Interruption
Capex	Capex
CAPM	Capital Asset Pricing Model
CDR	Consumer Data Right
CGS	Commonwealth Government Securities
CoD	Cost of Debt
CPI	Consumer Price Index
D&C	Design and Construct
DER	Distributed Energy Resources
DPE	Department of Planning and Environment
DSCR	Debt Service Coverage Ratio
DWPS	Drinking Water Pump Station
EAM	Energy Adjustment Mechanism
ECM	Efficiency Carryover Mechanism
EPL	Environment Protection Licence
ERN	Emergency Response Notice
ESA	Electricity Services Agreement
ESG	Environmental, Social and Governance
ESS	Energy Saving Scheme
FFO	Funds From Operations
FM	Force Majeure
FNC	Fixed Network Charge
FTEs	Full-Time Equivalents
GGRP	Greenhouse Gas Reduction Plan
GL	Gigalitre
GSWS	Greater Sydney Water Strategy
ICR	Interest Coverage Ratio

Term	Definition
IPART	Independent Pricing and Regulatory Tribunal of NSW
IPT	Intermediate Permeate Tanks
ISR	Industrial Special Risks
kL	Kilolitre
kV	Kilovolt
LGC	Large-scale generation certificate
LRET	Large-Scale Renewable Energy Target
ML	Megalitre
MWh	Megawatt hour
MWP	Metropolitan Water Plan
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
NRR	Notional Revenue Requirement
ODI	Outcome Delivery Incentives
O&M	Operating and Maintenance
Opex	Operating Expenditure
PFI	Project Finance Initiative
RAB	Regulatory Asset Base
RAM	Routine Asset Maintenance
RBA	Reserve Bank of Australia
REC	Renewable Energy Certificate
RERT	Reliability and Emergency Reserve Trader
RFR	Risk Free Rate of Return
RO	Reverse Osmosis
RSA	Renewable Services Agreement
SDP	Sydney Desalination Plant Pty Limited
SIR	Special Information Return
SLIS	Service Level Incentive Scheme
SOC	State Owned Corporation
SRES	Small-Scale Renewable Energy Scheme
SWC	Sydney Water Corporation
TAB	Tax Asset Base
ToR	Terms of Reference
VNC	Variable Network Charge

Term	Definition
WACC	Weighted-Average Cost of Capital
WICA	Water Industry Competition Act 2006 (NSW)
WSA	Water Supply Agreement

ENERGETICS



'Other' electricity market charges

An overview of 'other' regulated charges applicable to Sydney Desalination Plant over the RP3 period

Sydney Desalination Plant | 28 April 2023 | 127433

Executive summary

Sydney Desalination Plant (SDP) has engaged Energetics to provide a forecast benchmark rate for 'other' regulated electricity charges which would be applicable to SDP over its next regulatory period, 1 July 2024 to 30 June 2027 (RP3).

These 'other' charges are levied on end-users in addition to the typical retail electricity, environmental and network charges, and are considered regulated and not subject to negotiation within a typical retail electricity contract. This report provides an overview of these regulated charges and details how they are derived. In summary:

- Unaccounted for Energy (UFE): UFE is the difference between all adjusted metered energy entering a local area, compared to all adjusted metered energy consumed within the local area. The Australian Energy Market Operator (AEMO) apportions these additional costs to retailers for their customers (based on the prevailing wholesale spot market price).
- AEMO market intervention: Any costs associated with the AEMO intervening in the electricity markets to ensure system security are passed on to retailers, who then pass these on to their customers. Market intervention charges vary substantially in form and in magnitude depending on the type of intervention applied to secure the power supply system. In the case of a Market Suspension or implementation of the Administered Price Cap (APC), these are both seen as a last resort, and it is not seen as appropriate to include them in any benchmark forecasts for SDP.
- The Reliability and Emergency Reserve Trader (RERT): RERT is a function conferred on the AEMO to maintain power system reliability and system security using capacity reserve contracts. AEMO financially compensates the providers of this reserve, and it is this cost that is then passed back to retailers, who in turn pass it through to customers who had consumed electricity in that region, at that time. The supply-demand balance in the NSW power system is expected to be much tighter through RP3 due to the closure of Liddell power station in 2023, and the expected closure of Eraring power station in August 2025. For this reason, there is increased risk of the RERT mechanism being utilised more often during the coming years.
- Ancillary service charges: Ancillary service charges cover various non-energy costs associated with maintaining a stable and secure electrical power system in real time from an engineering and operational management perspective. These charges include Frequency Control Ancillary Services (FCAS), Network Support and Control Ancillary Services (NSCAS) and System Restart Ancillary Services (SRAS). The AEMO manages the payment and cost recovery of these services and passes these on to customers.
- AEMO market fees: These regulated fees are passed on to market customers to recover costs associated with the management and operational services that the AEMO provides to safely manage the electricity grid.
- NSW peak demand reduction scheme: The NSW Peak Demand Reduction Scheme provides financial incentives for businesses and households to reduce their consumption during periods of peak demand through the provision of tradeable certificates. Retailers and large energy users are legislated to purchase or create a specified number of Peak Reduction Certificates (PRCs) from eligible activities to meet the scheme's percentage target (which increases annually).

In addition, this report aims to provide:

- An overview of the possible implications of the Retailer Reliability Obligation (RRO) on SDP's retail charges. When triggered by the Australian Energy Regulator (AER), the RRO places an obligation on retailers to demonstrate that they have procured sufficient contracts to cover the peak demand of their respective customer loads. It is not anticipated that this will have a direct impact on SDP's energy charges.

- estimates of retail operating margins. Retailer operating costs refer to expenditures involved with servicing, marketing to, acquiring and retaining customers. Retail operating costs are inherently retailer specific, but generally do not vary materially across jurisdictions.

The vast majority of these charges are regulated and inherently uncertain. Furthermore, these charges are not considered contestable[1], and would be applied consistently to a customer such as SDP regardless of who their retailer would be. It is Energetics view that the most efficient means of incorporating these charges into SDP's regulatory framework is to consider them equivalent to electricity 'network charges' such that they be passed through at cost.

Despite this view, to support SDP's regulatory submission, Energetics has been engaged to develop a forecast benchmark rate for each of these components. Table 1 consolidates our forecast rate for each of these. Note that AEMO market intervention charges (i.e. market suspension or APC) have not been included in this table as they are viewed as a last resort and not appropriate for inclusion in a benchmark rate for the RP3 period considering the high level of uncertainty that apply to their likelihood and their magnitude.

Table 1: Forecast of 'other' charges over RP3 (in real 2023 $ per MWh)

Type	Charge	Units	FY23[2]	FY24	FY25	FY26	FY27
Regulated, non-contestable charges	Unaccounted for Energy[3]	$/MWh	-0.62[4]	3.89	3.89	3.89	3.89
	Reliability and Emergency Reserve Trader	$/MWh	1.05[5]	2.11	1.05	3.16	3.16
	Ancillary service charges	$/MWh	0.55	0.38	0.38	0.38	0.38
	AEMO market Fees	$/MWh	0.99	1.05	1.05	1.04	1.12
	NSW peak demand reduction scheme	$/MWh	0.36	0.38	1.13	2.07	2.83
	Total	$/MWh	2.33	7.81	7.50	10.54	11.38
Other charges	Retail operating margin	$/MWh	N/A	3.34	3.34	3.34	3.34

[1] With the exception of 'Retail operating margin'
[2] Actual 'year to date' charges for the period 1 July 2022 – 31 March 2023
[3] Based off a spot price outcome in line with the FY23 YTD P75. Assuming the P90 spot price outcome would result in a benchmark rate of $7.11/MWh
[4] Actual credit of $127,226 divided by actual 204,398MWh consumption
[5] Actual charges of $168,654 divided by forecast 160,000MWh/year volume (See Table 7)

Contents

1.0 Introduction

1.1 Background

Sydney Desalination Plant (SDP) is finalising the determination for its third price review period with IPART covering the period 1 July 2023 to 30 June 2027 (RP3). The regulatory framework aims to provide SDP with a regulated income stream equal to the efficient cost of its operation. Setting an accurate benchmark price for electricity as part of this determination process is therefore critical in ensuring SDP can recoup its costs.

1.2 Scope of report

In addition to typical retail electricity, environmental and network charges, there are a series of 'other' electricity market charges which can be levied on end-users that are considered regulated and not subject to negotiation within a typical retail electricity contract. Generally, these fees and charges are established by the Australian Energy Market Operator (AEMO). These charges include:

1. Unaccounted for Energy (UFE),
2. Generator compensation fees for AEMO market intervention,
3. Reliability and Emergency Reserve Trader (RERT) charges,
4. Ancillary service charges,
5. AEMO market fees, and
6. NSW Peak Demand Reduction Scheme (PDRS) pass through charges.

In addition, an overview of the Retailer Reliability Obligation (RRO) as well as a benchmark rate corresponding to the typical electricity retailer operating margin, are also provided to support the forward benchmark price estimates for RP3.

For each of the charges above, this report provides:

- an overview of the charge,
- how it is typically calculated, and
- our approach and forecast charge for each financial year over the RP3 period.

2.0 Unaccounted for Energy

2.1 Overview

UFE is the difference between all adjusted metered energy entering a local area, compared to all adjusted metered energy consumed within the local area. The differences between the two are typically caused by factors such as:

- energy theft,
- inaccurate or faulty meters,
- estimation errors associated with unmetered devices (such as council street lighting),
- profiling of reads to the trading interval (5 minute) level, or
- errors or variance in the static distribution loss factor (DLF) allocated to a site for a year compared to the actual losses in the distribution system due to dynamic loading conditions including seasonal and diurnal effects.

The National Electricity Amendment (Global Settlements and Market Reconciliation) Rule 2018 introduced in May 2022 requires AEMO to determine the amount of UFE for each local distribution network area. UFE charges have existed since the start of the National Electricity Market, however prior to May 2022 were borne solely by the “local” retailer for the distribution network. AEMO’s settlement processes now apportions UFE costs to every retailer who is financially responsible for customers in a specific distribution network territory based on a pro-rata share of total customer load. Retailers are now passing through these apportioned costs to their customers.

2.2 Typical calculation approach

Because UFE is the difference between all adjusted metered energy entering a local area, compared to all adjusted metered energy consumed within the local area (as measured at the transmission connection point), UFE must be calculated at the local area level, rather than at the Transmission Node Identifier[6] level.

The calculation for determining UFE for each 5-minute settlement interval is:

$$UFE = TME - DDME - ADME$$

Where from the distribution network perspective the values are:

- TME: Transmission Metered Energy – all energy flowing at each transmission network connection point into the local area
- DDME: Distributor to Distributor Metered Energy – all adjusted energy flowing at a distribution connection point into the local area which is connected to an adjacent local area

[6] Transmission network node that is characterised by the transmission loss factor and/or transmission use of system charge for a connection point. TNI codes are used to identify a virtual transmission node or transmission network connection point.

- ADME: All Adjusted Distribution Metered Energy flowing at a distribution connection point within the local area which is assigned to a TNI or Virtual TNI

UFE is **allocated** (UFEA) to each connection point based on the share of that connection point's DME of the total DME of the local area. The calculation for allocating UFE is therefore:

$$UFEA = UFE \times (\frac{DME}{ADMELA})$$

Where the values:

- UFE: Unaccounted for Energy for the local area
- DME: Distribution Metered Energy flowing towards the connection point for each settlement interval.
- ADMELA: the sum of all Adjusted DME for the Local Area for each settlement interval.

For convenience of calculation, the UFE and ADMELA are calculated at a local area level per interval and then converted to an Unaccounted-for Energy Factor (UFEF) by using the formula:

$$UFEF = \frac{UFE}{ADMELA}$$

The UFEF can then be directly applied to a customer's metered consumption data and multiplied by the Regional Reference Price (RRP) to determine the UFE charge value per interval. Importantly, the UFE factor for a given settlement interval within a local area may be a positive *or* negative value.

While the intent of Global Settlement UFE processes is to apportion UFE (unaccounted) based on pro-rata (accounted for) metered consumption, there are fundamental limitations in how AEMO and retailers can achieve accurate and reliable UFE charge amounts. The core sources of variability for UFE calculation, and hence limitations in settlement are:

- Type 7 unmetered loads,
- Non-contestable unmetered loads,
- Profiling methodologies used to allocate Type 6 accumulation meter data, 30-minute meter data, and 15-minute meter data to 5-minute interval data,
- Fixed annual Distribution Loss Factors (DLFs) which do not reflect real distribution system losses, particularly at times of peak network demand.

The limitations are discussed by AEMO in detail in the UFE trends report[7].

2.3 Forecasting UFE charges for SDP through RP3

Sydney Desalination Plant is located in the Ausgrid network area. The range of Ausgrid specific UFE factors has been directly applied to SDP metered consumption data and multiplied by the applicable RRP (i.e. NSW electricity spot price) to determine a UFE value per interval aligned to AEMO and retailer settlement processes[8].

As UFE is calculated specific to the local distribution area, we have analysed the Ausgrid distribution area historical UFEF and associated NSW RRP and demand data[9]. SDP is directly connected to Ausgrid's 132kV sub-transmission system with a DLF for the period FY23 of

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[7] Available at: ufe-report-june-2022.pdf (aemo.com.au)

[8] Note that Timing differences between the AEMO weekly settlement calendar and monthly retailer billing necessitate a reconciliation of final UFEF and metering data monthly in arrears over a period of 6 months.
[9] AEMO settlement processes allow for periods of up to 6 months before final validated meter data and UFE factors are made available to financially responsible market participants.

1.00150. The applicable TNI for the SDP connection is the Sydney South Bulk Supply Point (NSYS).

Based on weekly preliminary settlement data provided by SDP's retailer, the daily average range of UFEF values for the Ausgrid distribution area for the period May – October 2022 was between -3.5% and 4.6%, with a median value of 1.37% and an upper quartile value of 2.37%. Noting that for the purposes of setting a forecast benchmark price the upper quartile UFEF has been assumed, as values for UFEF are positively correlated to NSW regional demand and price, tending to increase the total value of UFE in times of higher regional demand.

Based on these historical values, and the prevailing NSW spot price, the range of possible UFE charge outcomes applicable to SDP for the FY23 period are detailed in Table 2. As shown, the total value of UFE for SDP in FY23 is forecast to remain in the range from $0.62M to $1.14M per annum depending on the final spot price outcomes.

Table 2: UFE observations for FY23

Item		Unit	Wholesale spot price scenario	
			FY23 RRP (P75)[10]	FY23 RRP (P90)[10]
Volume	UFEF Range	%	–3.5% to 4.6%	
	UFEF Upper Quartile	%	2.37%	
	Estimated SDP consumption	MWh/year	160,000	
Regional Reference Price (RRP)		$/MWh	$164.00	$300.00
Estimated annual UFE charges		$/year	$0.62M	$1.14M
Estimated UFE		$/MWh	$3.89	$7.11

Forecasting a benchmark price for UFE applicable to SDP through RP3 is inherently difficult due to the uncertainty on both the UFE volume and forecast spot price outcomes over the forecast period (particularly in periods of peak evening demand). For the purposes of estimating the incremental cost through RP3, it has therefore been assumed that UFEF volumes will remain in the upper quartile, and the RRP will settle in the P75-P90 range (based of FY23 year-to-date). This forecast is detailed in Table 3.

Table 3: Forecast UFE benchmark charges for RP3 (Real $2023)

Benchmark rate for UFE	Unit	FY24	FY25	FY26	FY27
Assuming P75 RRP[10]	$/MWh	3.89	3.89	3.89	3.89
Assuming P90 RRP[10]	$/MWh	7.11	7.11	7.11	7.11

[10] The P75 and P90 level depicts the UFE calculation based on the actual 75th percentile and 90th percentile NSW wholesale electricity regional reference price (RRP) outcomes observed during FY23 YTD period (1 July 2022 – 30 March 2023).

3.0 AEMO market intervention

3.1 Overview

The intervention price provisions of the National Electricity Rules (NER) form an important component of pricing in the National Electricity Market (NEM). These are most commonly applied during periods when AEMO intervenes by issuing a direction to a market participant in accordance with NER clause 4.8.9 to secure the power system.

In accordance with NER clause 3.9.3(b), AEMO must set the energy and ancillary service prices during market intervention at the prices that would have applied had the intervention not occurred. This provides a basis for market settlement processes to continue operating, and provisional intervention charges may be levied on market participants within the standard settlement week processes.

Other forms of market intervention less frequently implemented by AEMO include RERT (as discussed in Section 4.0), the application of an Administrative Price Cap (APC), and a Market Suspension.

When a market intervention event occurs in a NEM region, AEMO can direct generators to increase supply where possible, as well as requesting large commercial users to significantly reduce load or fully curtail their load. In return, AEMO financially compensates those generators for remaining on or increasing supply, and, if applicable large commercial users for reducing their consumption. The form and process of assessing the compensation amount payable to market participants during the period of market intervention is summarised in Table 4 below.

The costs associated with market intervention are typically passed back to retailers and other financially responsible market participants via settlement, who then pass the cost to those customers who consumed electricity in that region, at the time of the event. AEMO market intervention charges differ depending on the region, and customers are charged based on the region their supply is connected to. All market intervention events are listed on the AEMO website[11].

3.2 Typical calculation approach

Market intervention charges vary substantially in form, frequency and magnitude depending on the type of intervention applied by AEMO to secure the power supply system. Table 4 describes the key parameters for each relevant type of market intervention that was observed in NSW during 2022. RERT charges are addressed separately in Section 4.0.

[11] See: *https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/market-event-reports*

Table 4: Key parameters of AEMO market intervention processes

Item	Direction	Administrative Price Cap (APC)	Market Suspension
NER12 Rule basis	3.15.7	3.14.6	3.14.5
Determined by	AEMO	Australian Energy Market Commission (AEMC)	AEMO
Guideline	Intervention Settlement	Compensation	Intervention Settlement
Compensation	90th percentile pricing Net direct costs (Fuel, variable operating costs, start cost)	APC ($300/MWh) Net direct costs inclusive of fixed operating costs PLUS opportunity costs	Compensation = Deemed costs – Provisional settlement amounts
Price basis	$300/MWh	APC of $300/MWh[13] Additional amounts methodology per 3.14.6 of NER	Benchmark value for generation = Benchmark cost times 1.15 where: Benchmark cost = Fuel costs x Generation efficiency + Variable operating cost
Additional compensation claims	Direct costs only	Direct costs plus opportunity costs	Direct costs only per NER 3.14.5B but cannot double count if also directed
Timetable	AEMO Intervention Settlement is released within ~100 days from event Additional claim by generator may be lodged up to 15 days after event	Participants claim notice within 5 days end of suspension. AEMC publishes claim AEMC decides within 45 days	Participants claim notice to AEMO within 15 days AEMO determination is made in accordance with intervention settlement timetable

3.3 Forecasting market intervention charges through RP3

Market intervention charges for SDP through 2022 have varied substantially in form and in magnitude related to the type of intervention applied by AEMO to secure the power supply system. The nature of AEMO's out-of-merit order interventions make specific charges for intervention services difficult to forecast, however all charges have been transparently supported with settlement data as it becomes available. In many cases, for generator compensation under the APC and Market Suspension, final compensation amounts are yet to be finalised. Known total costs for the NSW region as a result of 2022 market interventions are shown in Table 5.

[12] National Electricity Rules
[13] In November 2022 the Australian Electricity Market Commission (AEMC) agreed to a temporary increase of the APC to $600/MWh from 1 December 2022 to 30 June 2025.

Table 5: NSW Regional costs of market intervention through 2022 (exclusive of RERT)

Item	Unit	Directions compensation	Administrative Price Cap (APC)	Market Suspension
Total NSW cost	Total	$5.02M	$10.7M	$37.9M
Average rate	$/MWh	$2.05	$15.50	$4.38

The operational flexibility required by Sydney Water Corporation limits SDP's ability to dynamically respond to electricity market conditions, and specifically the ability to avoid any market intervention. Any other off-market intervention charges imposed on SDP on a pass-through basis by its electricity retailer will be directly proportional to SDP's directed operating mode at the time of the intervention event.

It is our view that market intervention charges are not appropriate for inclusion in a benchmark rate for the RP3 period. These costs reflect actions undertaken by the AEMO as a 'last resort' to ensure system security and are therefore highly uncertain in terms of frequency and magnitude of cost impact. As such, the most efficient approach to manage these charges through a regulatory framework is to treat them as a pass-through charge, similar to network charges.

4.0 Reliability and Emergency Reserve Trader

4.1 Overview

The Reliability and Emergency Reserve Trader (RERT) is a function conferred on AEMO to maintain power system reliability and system security using reserve contracts[14].

AEMO continuously assesses whether forecast electricity usage is likely to exceed available generation on a given day, for example if very hot weather is expected. If AEMO forecasts a shortfall, it will take action to activate previously agreed contracts to provide a capacity reserve. Typical examples of reserve that can be procured for RERT include:

- Unscheduled load that can be curtailed and restored on request from AEMO. This can be large industrial load or a group of aggregated smaller loads, and
- Unscheduled generation assets (such as standby diesel or batteries).

AEMO financially compensates the providers of this reserve, and it is this cost that is then passed back to retailers, who in turn pass it through to customers who had consumed electricity in that region, at that time. RERT charges are generally separately itemised on retail electricity invoices, however some retailers may elect to bundle RERT charges together with other AEMO market fees.

4.2 Typical calculation approach

Following a RERT event, AEMO will calculate the cost of the event based on the quantity of energy sourced through the RERT mechanism, and the pre-agreed contract rates with each respective provider. This cost is apportioned across electricity retailers who then pass this on to consumers (i.e. SDP) based on their MWh consumption. All RERT events are listed on the AEMO's website[15]. As an example, the costs of some recent RERT events in NSW are detailed in Table 6.

Table 6: Example of NSW Region RERT costs (14th – 17th June 2022)

Date	Region	Energy (MWh)	Gross cost	Unit cost (per MWh)	Intervention start	Intervention end
14/06/2022	NSW	900	$21,600,000	$24,000	18:05	21:05
15/06/2022	NSW	1,484	$30,077,727	$20,275	17:30	23:30
17/06/2022	NSW	1,417	$29,910,699	$21,111	20:00	18/06 04:10

[14] See: https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert
[15] See https://www.aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting

4.3 Forecasting RERT charges through RP3

RERT charges for SDP over 2022 varied substantially in both the duration and volume of RERT intervention support applied by AEMO to secure the power supply system. The nature of AEMO's out-of-merit order RERT interventions makes specific charges for capacity difficult to forecast, however all charges are transparently supported with settlement data as it becomes available.

To support a view on the expected likelihood and duration of the application of RERT, Energetics have used the reliability assessment from AEMO's 2022 Electricity Statement of Opportunities (ESOO) update released in February 2023. AEMO measures reliability as Expected Unserved Energy (USE) as a percentage of energy demand. The expected trend in NSW is illustrated in Figure 1 below by the solid light blue line.

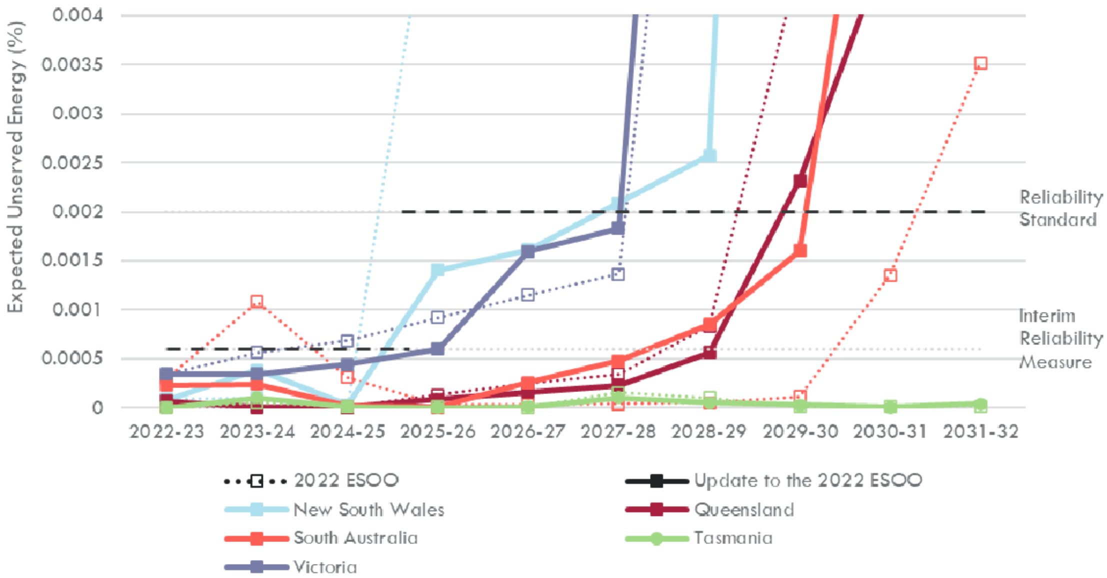

Figure 1: Reliability and indicative reliability forecasts, all regions, 2022-23 to 2031-32 (Source: AEMO, Update to 2022 Electricity Statement of Opportunities, February 2023)

As illustrated, the expected USE experienced in NSW is forecast to increase over the 4-year forecast period, particularly in FY26 and FY27. This increase is largely in line with the expected reduction in dispatchable generation capacity reserve (i.e. the closure of Eraring and Vales Point power stations), as well as the increase in peak demand. To forecast future RERT charges applicable to SDP, we have therefore used the historical CY22 RERT charges levied on SDP and extrapolated these based on the increased Expected USE over the RP3 period. Table 7 provides more detail of this approach.

For the purposes of forecasting increases in RERT dispatch, it is assumed that replacement generation will be built to keep Unserved Energy in line with the Interim Reliability Measure (IRM). The objective of keeping USE below the IRM is expected to prevail over the RP3 period: the AEMC initiated early March 2023 a consultation process seeking an extension of the IRM to 1 July 2028[16]. As such, a figure of 0.0006% has been used for USE in FY26 and FY27.

[16] AEMC, Review of the Interim Reliability Measure – Draft report, 9 March 2023

Table 7: Forecast RERT benchmark charges (Real $2023)

Financial Year	Unit	CY22[17]	FY24	FY25	FY26	FY27
Approximate Expected USE	%	0.0002	0.0004	0.0002	0.0006	0.0006
Actual RERT charges applicable to SDP (YTD)	$	168,654	-	-	-	-
Forecast RERT charges applicable to SDP	$	-	337,310	168,655	505,965	505,965
Forecast volume	MWh	160,000	160,000	160,000	160,000	160,000
Forecast benchmark rate	$/MWh	1.05	2.11	1.05	3.16	3.16

[17] Based off actual charged RERT through June 2022.

5.0 Ancillary services charges

5.1 Overview

Ancillary services charges cover various non-energy costs associated with maintaining a stable and secure electrical power system in real time from an engineering and operational management perspective. There are several ancillary service types which AEMO procures, including:

1. Frequency Control Ancillary Services (FCAS) are used by AEMO to maintain the frequency of the electrical system (within the prescribed range of 50 +/- 0.15 Hz). There are eight unique FCAS markets which serve to procure frequency stabilisation services to both increase and decrease the frequency over varying time frames.
2. Network Support and Control Ancillary Services (NSCAS) are procured by AEMO to maintain power system security and reliability, and to maintain or increase power transfer capability of the transmission network. There are two types of NSCAS:
   a. Reliability and Security Ancillary Services (RSAS), and
   b. Market Benefit Ancillary Services (MBAS)

   Importantly, AEMO only procures NSCAS where it has identified an NSCAS gap over the coming five-year period, and it considers that the gap will remain after receiving advice from transmission network service providers about their proposed arrangements to address the gap.
3. System Restart Ancillary Services (SRAS) are used in contingency situations to provide power station “black” re-start services in the rare event of a partial, or full system black event (power blackout).

5.2 Typical calculation approach

Payment and cost recovery for ancillary services vary by the service types.

- FCAS is enabled via the NEM Dispatch Engine (NEMDE), with calculation for price discovery occurring via the bid stack process in a similar manner as wholesale spot energy pricing.
- NSCAS and SRAS are procured under long term bilateral contracts between AEMO and the participating service providers.

FCAS are recovered from the relevant market participants (market customers or generators). Lower contingency FCAS costs and regulation FCAS costs not attributable to generators on a causer pay basis are recovered from market customers.

NSCAS costs are recovered by AEMO from market customers in proportion to their energy consumption in the relevant requirement region.

SRAS recovery is shared equally (on a 50/50 split basis) between market customers and generators.

5.3 Forecasting ancillary services charges through RP3

Ancillary services charge projections from RP3 have been extrapolated from historical values recorded during the CY18-CY22 period as illustrated in Figure 2. FCAS costs vary with market conditions, with the potential for materially higher FCAS costs in the event of a statewide separation from the NEM (such as experienced in South Australia and Queensland over recent years). Importantly for the RP3 forecast period, the risk of separation in NSW is reduced given interconnections to both Victoria and Queensland.

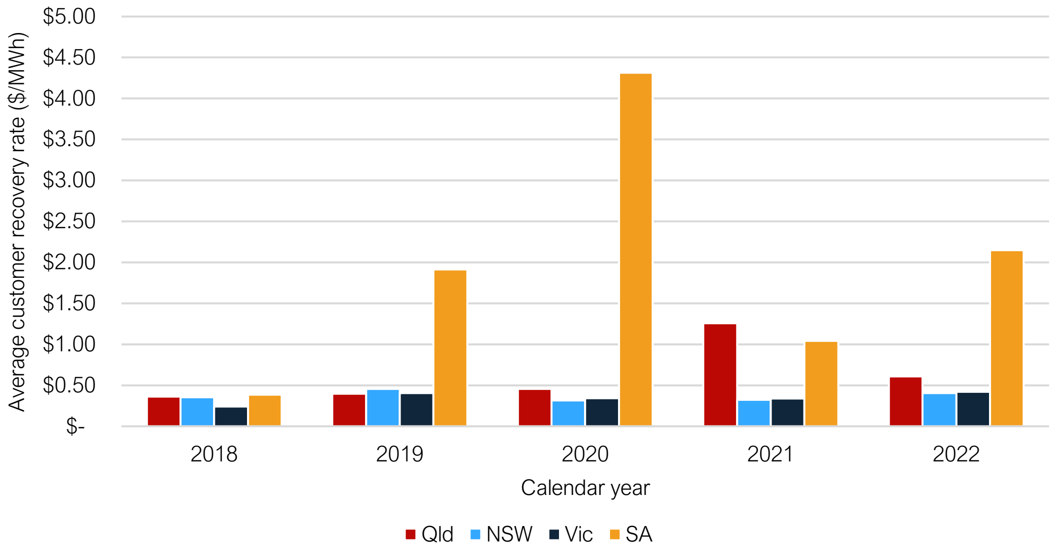

Figure 2: Average annual ancillary services recovery rates[18]

We have carried forward average rate through CY2018-2022 NSW regional specific costs over the forecast FY24-FY27 horizon to establish estimates for the charge (in $ per MWh) that may be recovered from SDP.

Table 8: Forecast ancillary services charges over RP3 (Real $2023)

Item	Units	FY23	FY24	FY25	FY26	FY27
Ancillary services total	$/MWh	$0.38	$0.38	$0.38	$0.38	$0.38

[18] Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/ancillary-services-data/ancillary-services-payments-and-recovery

6.0 AEMO market fees

6.1 Overview

AEMO charges market fees to market participants (retailers and generators) to recover costs associated with the management and operational services that AEMO provides to safely manage the electricity grid. Such costs largely pertain to staffing, IT systems, office leasing and other typical centralised corporate organisational costs.

AEMO establishes the total recoverable costs as a revenue requirement through a user pays, fee-for-service system. These recoverable costs are established via a budgeting process in consultation with market participants. The total recoverable costs are then allocated, depending on the cause or source of the costs, to either market customers (i.e. end consumers via retailers), or wholesale participants (i.e. generators) at a rate respective to their usage. For most costs, the total recovery amount is then amortised across annual NEM wide operational consumption to establish a $/MWh fee.[19]

The fees charged to market customers (i.e. SDP) are categorised by AEMO as:

- **Market Customer Fees:** These fees cover a broad range of operational, strategic and supervision services that AEMO provides. Each year AEMO publishes its annual revenue requirement to cover the costs of market operations, long-term energy planning and wholesale settlements and prudential supervision. Market Customer Fees are typically split as:
    - General fees, paid entirely by market customers, and
    - Allocated fees, specifically allocated to market customers
- **IT upgrades and 5-minute settlement (5MS) compliance:** AEMO introduced an additional fee class for IT upgrades for 5MS compliance in FY22. The 5MS compliance fee was introduced to cover the cost of implementing the 5-minute and global settlement rule upgrades to IT systems for the NEM.
- **Distributed Energy Resources (DER) integration:** The DER integration fee was also introduced in FY22 to recover the costs associated with integration of Distributed Energy Resources (DER) into the NEM.

Collectively, the 5MS and DER integration fee classes have contributed to a $30.5 million (55%) step up in total AEMO market fees recovered from Market Customers since FY22.

6.2 Typical calculation approach

AEMO's annual budget consolidates expected costs for providing services related to the above categories[20]. The required revenue for each component is then divided by the total forecast consumption of the NEM in order to develop a per-MWh charge that can be spread across all relevant participants.

[19] Some costs, particularly those allocated to generators are apportioned on a capacity basis, rather than on a total generated energy basis.
[20] 2022-23 AEMO Budget and Fees, Section 2 – Fees, pg. 13, 2022-23-aemo-budget-and-fees.pdf

As the charges are ex-ante in nature, changes to the realised level of grid consumption and any unplanned costs that AEMO must incur for market operations can result in a surplus or deficit being recorded based on the prevailing market conditions. AEMO's budgeting cycle allows for these "unders" and "overs" to be recouped (or clawed back) in the following years. As at 30th June 2022, AEMO has carried forward a core operating deficit of $103.6m which is planned to be recovered over the FY23-25 period.

AEMO published its FY23 budget in June 2022[21]. As illustrated in Figure 3, market customer benchmark fees have increased significantly year on year, especially in FY22 and FY23, due to the combination of operating expenditure increases and a revised strategy to recoup previous year's deficits.

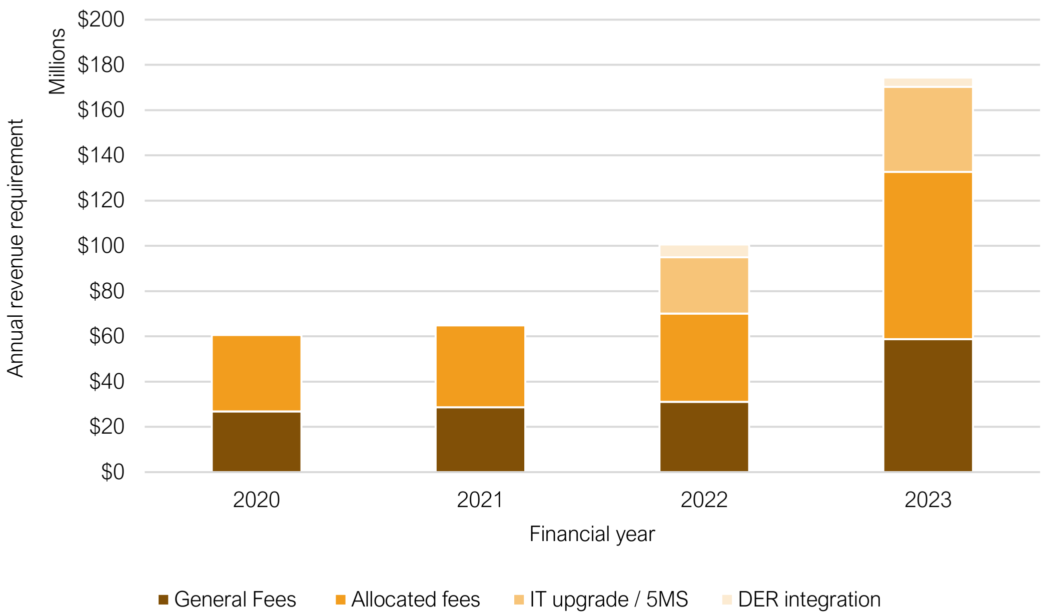

Figure 3: Historical AEMO market fees

6.3 Forecasting AEMO market fees through RP3

Table 9 details our approach to forecasting each of the respective market fee categories for the RP3 period.

Table 9: Forecasting approach to AEMO market fees

Market fee type	Forecasting approach
Market customer fee	The primary contributor to excess operating costs in FY23 were labour expenditures, system and process upgrades and financing costs. We expect the factors driving these costs to persist and so the excess operating costs are kept flat for the duration of the forecast. The debt recovery strategy has a clear 3-year timeline, so diminishes after the operating deficit is cleared. The unplanned costs were the result of energy market volatility, requiring additional resourcing within AEMO and broader economic and labour inflation experienced through FY22. Energy market volatility through the renewable energy transition is expected to persist, whilst labour requirements and costs tend to be sticky (i.e., we anticipate AEMO's

[21] Available at: https://aemo.com.au/-/media/files/about_aemo/energy_market_budget_and_fees/2022/2022-23-aemo-budget-and-fees.pdf?la=en

Market fee type	Forecasting approach
	workforce to remain stable at minimum). As such these elevated costs are expected to persist over the RP3 period.
5MS benchmark fee	The 5MS fee has applied since FY22, where $24.8m was included in the budget. For FY23, this has increased to $43.1m. with AEMO providing comment in their budget that the increase is largely accounted for due to higher technology and cloud support costs ($11.5m) as well as IT equipment depreciation ($6.9m) plus other minor items. It is reasonable to assume that AEMO will experience an ongoing requirement to maintain and re-invest in operational IT infrastructure and staffing to support the 5MS requirement. As such, this cost line item is escalated at the CPI rate over the forecast period.
DER benchmark fee	The DER fee first appeared in FY22, with $5.7m being budgeted, this reduced slightly to $5.2m for FY23. AEMO provides some commentary in terms of the movements and drivers of this fee (largely IT related). As behind the meter distributed resources in the form of rooftop PV and distributed batteries continue to increase their penetration, the requirement to forecast, monitor, control or orchestrate and generally incorporate considerations of their output will accordingly increase. The DER fee has been escalated over the forecast period in relation to the average cumulative growth rate of solar PV installations in the NEM.

In line with the above assumptions, our forecast of AEMO market fees across the RP3 period are detailed in Table 10.

Table 10: Forecast AEMO market fees (Real $2023)

Financial Year	Unit	FY24	FY25	FY26	FY27
Market customer fee	$/MWh	0.81	0.80	0.77	0.85
5MS compliance fee	$/MWh	0.21	0.21	0.21	0.21
DER integration fee	$/MWh	0.030	0.038	0.047	0.059
Total fees	**$/MWh**	**1.05**	**1.05**	**1.04**	**1.12**

7.0 NSW Peak Demand Reduction Scheme

7.1 Overview

The NSW Peak Demand Reduction Scheme (PDRS) provides financial incentives for businesses and households to reduce their consumption during periods of peak demand through the provision of tradeable certificates.

The scheme was introduced in 2022 by the NSW Department of Energy as part of the NSW Electricity Strategy and is nominated to be effective between the 1st of November and the 31st March each financial year between the hours of 3:30PM and 9:30PM AEDST. One certificate is generated for every 0.1kWh of peak demand that is reduced during this window, with the aim of reducing demand pressure on wholesale electricity prices across NSW and the risk of power outages in summer.

The scheme mechanics operate in a similar manner to existing environmental certificate schemes. Retailers and large energy users, classified as scheme participants, are legislated to purchase a specified number of Peak Reduction Certificates (PRCs) annually, based upon factors such as:

- the individual entity's average demand during the 3:30-9:30pm (AEDST) period on designated Peak Days[22];
- NSW Operational Demand on those days; and
- the percentage target for the Scheme in a given year.

Certificates are subsequently created through the undertaking of eligible activities to meet the scheme's target, which begins at 0.5% peak demand reduction in 2022, increasing to 10% by 2030. Various industrial equipment and processes are eligible, such as HVAC, power systems and refrigeration.

7.2 Typical calculation approach

Participant's liability within the scheme is determined by a formula deriving the volume of electricity sourced during the compliance period (from metered and non-metered sources). The scheme's purpose is to reduce peak demand and so the target rate sets how much demand is to be reduced during a given financial years compliance period. The formula for an individual entity's liability is below[23].

Individual liable demand:

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[22] Four Peak Days are established retrospectively based upon the four days which experience the highest Operational Demand in NSW over the Compliance Period (1st Nov – 31 March) for each year.
[23] See: *Individual liable demand | IPART (nsw.gov.au)*

$$= \frac{Electricity\ purchased\ by\ consumer\ in\ NSW\ during\ compliance\ period\ (MWh)}{4\ \times number\ of\ hours\ in\ peak\ demand\ reduction\ period} \times 1000$$

A participant must purchase or create enough PRCs to offset this liability. A larger percentage target translates to a higher liable demand for each participant, increasing the demand for certificates and their market price (assuming supply is held constant). As shown in the following section the target rate set for the scheme, along with the traded certificate price, influences the pass-through cost charged to the consumer.

The Individual liable demand is then used to establish Individual certificate targets as follows:

<u>Individual certificate target:</u>

$$= \frac{individual\ liable\ demand\ (MW)}{scheme\ liable\ demand\ (MW)} \text{ x scheme certificate target}$$

The scheme liable demand is the sum of all participants individual liable demand (expressed in MW) and is established retrospectively after all participants have reported their liable demand.

The scheme certificate target is established in advance, and is based upon the PDRS percentage target, and the 10% summer probability of exceedance (POE) peak Operational Demand for NSW. The Scheme Certificate Target for FY23 is 3,911,112 certificates and is expected to increase proportionately with the PDRS percentage target.

7.3 Forecast NSW Peak Demand Reduction Scheme charges for RP3

The PDRS is a recent initiative, and the market is immature. The certificates are traded through direct contracts. There are no standardised contracts or an exchange to facilitate trades. This makes forecasting an accurate market price difficult.

We have used the scheme's penalty rate in lieu of sufficiently representative historical data for certificate prices. The penalty rate, set at $2.35 is the price per certificate that a participant must pay if they do not acquire sufficient certificates to cover their liability, acting as a ceiling price on the market.

The penalty rate[24] and the peak demand reduction targets[25] are legislated in the Electricity Supply (General) Regulation Act 2014 – REG 60. We have assumed SDP's Individual Liability demand is based upon the plant operating at maximum capacity at the time the four Peak Days are established, i.e. at 40MW. Furthermore, consistent with Section 2, we have assumed annual plant consumption of 160,000 MWh. The SDP liability is calculated by multiplying the SDP certificate liability, with the PRC penalty rate, and subsequently dividing the total annual liability by the annual consumption forecast to establish a $/MWh rate.

[24] ELECTRICITY SUPPLY (GENERAL) REGULATION 2014 - REG 62 Scheme penalty rates (austlii.edu.au)
[25] ELECTRICITY SUPPLY (GENERAL) REGULATION 2014 - REG 60 Peak demand reduction targets (austlii.edu.au)

Table 11: Forecast NSW PDRS charges (Real $2023)

Financial Year	Unit	FY24	FY25	FY26	FY27
PDRS Target	%	1.0	3.0	5.5	7.5
Forecast SDP certificate liability	# certificates	25,647	76,940	141,056	192,350
PRC penalty rate	$/certificate	2.35	2.35	2.35	2.35
SDP total liability	$	$60,269	$180,808	$331,482	$452,021
Forecast volume	MWh	160,000	160,000	160,000	160,000
PDRS cost applied to electricity	$/MWh	0.38	1.13	2.07	2.83

8.0 Retailer Reliability Obligation

8.1 Overview

The RRO was introduced on 1 July 2019 to support reliability in the National Electricity Market (NEM). The scheme meets this objective by making liable entities (i.e. energy retailers) accountable for the reliability of electricity sourced to meet their requirements when a potential supply shortfall is forecast.

The RRO relies on modelling undertaken by the AEMO as part of their annual Electricity Statement of Opportunities to forecast reliability gaps in each NEM region over the coming five-year period. If a reliability gap is forecast three-years and three months (i.e. 'T-3' Reliability Instrument) from the identified gap, then the AEMO will then request that the AER trigger the RRO.

When triggered, the AER then require liable entities (e.g. electricity retailers) to demonstrate that they have procured sufficient qualifying contracts related to covering peak demand[26] for their respective electricity requirements during the identified gap. Where an entity is found to have insufficient qualifying contracts, the AER is empowered to pursue financial penalties.

For the avoidance of doubt, the RRO is not an explicit new, additional charge. Rather, it incentivises wholesale market customers (i.e. mostly electricity retailers) to enter into firm wholesale contracts with generators. Such forward contracting should in turn support investment in dispatchable generation and improve the long-term reliability of the NEM. A well-hedged retail structure would already include the cost of such contracts and reflected in the retail rates it offers its customers.

8.2 Forecasting the impact of the RRO for RP3

As it stands, there is a single 'T-3' Reliability Instrument which has been issued in NSW for periods during RP3. Specifically, this period is the from 1 December 2025 to 28 February 2026 inclusive for trading intervals between 2:00pm and 9:00pm[27]. The result of this is that there will be an increase in demand from Liable Entities to source qualifying contracts during this period. The impact of this Reliability Instrument will therefore already be reflected in the price of underlying wholesale forward contracts.

Furthermore, it is our view that SDP should not be impacted by the RRO or any Reliability Instrument in NSW as its retail agreement with Iberdrola is already backed by physical generation from the Capital Wind Farm and was secured on the basis of the retailer servicing a block load of ~40MW.

[26] Specifically, a one-in-two year peak demand event.
[27] Available at: ***https://www.aer.gov.au/node/83764***

9.0 Retail operating margin

9.1 Overview

Energy retailers face two major cost categories when building up their pricing for electricity supply to end customers. These are:

- the cost associated with the electricity supply itself (cost of goods sold), and
- the cost to service customers

The cost of goods sold (COGS) relates to the cost of bulk energy procurement and hedging of customer risk through various financial and physical channels (such as contracting with 3rd party generators or making spot electricity purchases).

Retailer operating costs refer to expenditures involved with servicing, marketing to, acquiring and retaining customers. These costs are inclusive of aspects such as maintaining a customer management system and IT platform, web-based customer access portal, call centres as well as management and provision of the prudential credit requirements from AEMO, amongst others.

Energy retailers face these same costs irrespective whether their customer bases are comprised of mass market customers (household), small businesses, or large market customers. In each case, the retailer bears these overheads, although large (and therefore more complex) customers typically require greater service effort. Retail costs are accordingly higher on a total dollar's basis for large customers such as the Sydney Desalination Plant, but generally substantially lower on a $/MWh basis given the 10-100's of GWh pa consumption, compared to less than 10MWh pa for average mass market customers.

9.2 Typical calculation approach

Retail operating costs are inherently retailer specific, but generally do not vary materially across jurisdictions. While various regulatory bodies such as the Australian Competition and Consumer Commission (ACCC) and the Australian Energy Regulator (AER) routinely report on the state of retail competition within electricity markets[28], their remit and focus tend to be residential mass market and small business customers.

There are three common definitions for energy retail margins, calculated in the following manner:

- Gross margin: revenue – COGS
- Operating margin: revenue – (COGS + retail service costs)
- EBITDA margin: revenue – (COGS + retail service costs + central expense allocation)

Margins may also be expressed as EBIT margin (after accounting for the Depreciation and Amortisation).

[28] State of the energy market 2022 - Chapter 6 - Retail energy markets.pdf (aer.gov.au), and Inquiry into the National Electricity Market (accc.gov.au)

9.3 Forecasting retail gross margin for RP3

While the ACCC can compel retailers to provide access to management reporting detail they may not otherwise make public, the focus from both the ACCC and AER has largely been on small customers. Accordingly, there are fewer whole of industry reports or data sources from regulatory bodies comparing retailer margins relating to large commercial or industrial customers.

The only ongoing source of public information regarding the retail margins from large electricity customers lies within the segmentation analysis of AGL's financial and operating disclosures as detailed in Table 12[29]. Origin Energy, which as a listed entity is also required to provide public disclosure of its financial results, does not separately segment the gross margin between large and small customers in the same way (although does report sales volumes separately). Further, the other major energy retailers operating in the NEM are either subsidiaries of foreign companies (e.g. Energy Australia, Engie, Alinta) or are Government (Snowy Hydro) or privately owned and therefore no such public segmentation financial disclosure exists.

Table 12: AGL's margin for commercial and industrial customers

AGL C&I customer margin	Units	FY19	FY20	FY21	FY22
Large market customer volumes	GWh	9,780	10,560	10,200	10,500
Large market gross margin	$m	34	36	34	33
Gross margin	**$/MWh**	**3.48**	**3.41**	**3.33**	**3.14**

AGL reported gross margin on sold electricity volumes to large market customers has averaged $3.34 per MWh (or ~4% of revenue) over the last 4 years. This is consistent with Energetics' observations over multiple years of undertaking large market customer procurement exercises, and benchmarking against observed ASX futures quoted prices.

[29] Available at: ***https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/media-centre/2023/230209-appendix-4d-and-fy23-half-year-report.pdf*** (See pages 4 and 13)

10.0 Benchmark rates for 'other' charges through RP3

Table 13 consolidates our forecast rate for each of the respective charges outlined in this document. Note that AEMO market intervention charges (i.e. market suspension or APC) have not been included in this table as they are seen as a 'last resort' market mechanism and it is our view that these costs are not appropriate for inclusion in a benchmark rate for the RP3 period. Rather, any future AEMO market intervention charges that may apply during the RP3 period should be most efficiently recovered by SDP via an ability to pass these through via water user charges.

Table 13: Forecast of 'other' charges over RP3 (in real 2023 $ per MWh)

Type	Charge	Units	FY23[30]	FY24	FY25	FY26	FY27
Regulated, non-contestable charges	Unaccounted for Energy[31]	$/MWh	-0.62[32]	3.89	3.89	3.89	3.89
	Reliability and Emergency Reserve Trader	$/MWh	1.05[33]	2.11	1.05	3.16	3.16
	Ancillary service charges	$/MWh	0.55	0.38	0.38	0.38	0.38
	AEMO market Fees	$/MWh	0.99	1.05	1.05	1.04	1.12
	NSW peak demand reduction scheme	$/MWh	0.36	0.38	1.13	2.07	2.83
	Total	$/MWh	2.33	7.81	7.50	10.54	11.38
Other charges	Retail operating margin	$/MWh	N/A	3.34	3.34	3.34	3.34

[30] Actual 'year to date' charges for the period 1 July 2022 – 31 March 2023
[31] Based off a spot price outcome in line with the FY23 YTD P75. Assuming the P90 spot price outcome would result in a benchmark rate of $7.11/MWh
[32] Actual credit of $127,226 divided by actual 204,398MWh consumption
[33] Actual charges of $168,654 divided by forecast 160,000MWh/year volume (See Table 7)

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Description	Prepared by	Reviewed by	Approved by	Approval date
Initial draft for SDP's consideration	Dr Patrick Booth Lachlan Goodland-Smith Andrew Pintar	Mark Asbjerg	Gilles Walgenwitz	03/04/2023
v2 – addresses comments from SDP	Andrew Pintar	Mark Asbjerg	Gilles Walgenwitz	17/04/2023
v3 – additional commentary in executive summary following comment from SDP	Mark Asbjerg	Gilles Walgenwitz	Mark Asbjerg	28/04/2023

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Re: Opinion on certain WACC issues in IPART's Draft Decision

Our instructions

IPART published its Draft Decision on SDP's regulated prices for the 2023-27 regulatory period on 14 April 2023.[1] You have asked us to provide our opinion on two specific aspects of the Draft Decision that relate to the allowed Weighted Average Cost of Capital (WACC):

1. IPART's proposal to apply a cost of debt true-up to SDP rather than update SDP's prices annually during the 2023-27 regulatory period to reflect changes in the trailing average cost of debt allowance; and
2. IPART's linking of the WACC allowance to various risk management mechanisms proposed by SDP.

Key conclusions

On IPART's decision to apply a cost of debt true-up to SDP, we conclude that:

- IPART has failed to apply its 2018 WACC methodology, insofar as it relates to decisions about whether a cost of debt true-up should be applied. The 2018 WACC methodology commits IPART to considering, for each decision on a case-by-case basis, whether prices should be adjusted annually in line with year-on-year changes in the trailing average cost of debt allowance or whether a cost of debt true-up should be applied. The 2018 WACC methodology also commits that neither of these approaches would be considered the default approach. However, in every decision since the

[1] IPART, Sydney Desalination Plant Pty Ltd Review of prices to apply from 1 July 2023, Draft Report, April 2023 (IPART Draft Report).

publication of the 2018 WACC methodology, IPART has applied a cost of debt true-up, regardless of the circumstances of the business in question. IPART now justifies that approach on the basis of price stability for consumers—a general consideration rather than one that is specific to the circumstances of each regulated business. Thus, the cost of debt true-up approach *has* effectively become the default approach, contrary to the 2018 WACC methodology in which IPART committed to consider this issue on a case-by-case basis.

- This clear departure from the 2018 WACC methodology, without consultation or explanation, undermines the stability, certainty, replicability and predictability of IPART's regulatory framework.
- The cost of debt true-up approach is not consistent with the primary rationale for the trailing average approach—which is to ensure the closest possible match between the regulatory allowance and the efficient cost of debt. This means that, in any given year:
  - Consumers may pay more or less than the efficient cost of debt. The trailing average cost of debt allowance has fallen consistently since 2018. IPART's policy of applying a cost of debt true-up in every decision since 2018 (rather than updating prices annually) has meant that consumers have not received the benefit of these declining costs through immediate price reductions. As IPART itself has explained recently, if regulated prices do not reflect efficient costs, that would blunt the price signals for efficient consumption and sourcing of water supply and water security; and
  - SDP's regulatory allowance may be higher or lower than the efficient cost of debt. This can result in cash flow mismatches that could potentially cause a material deterioration in the financeability of the business. SDP has submitted modelling to demonstrate this, but IPART's Draft Decision does not mention or respond to those submissions. It is therefore unclear to us whether/how IPART has taken that material into account.
- In our view, the most efficient outcomes would arise if IPART were to set prices in line with efficient costs in each year of a regulatory period. Such an approach would be consistent with annual updates to SDP's prices to pass through year-on-year changes to the cost of debt allowance.

On IPART's linking of the WACC allowance to various risk mechanisms proposed by SDP, we consider that the Draft Decision is incorrect to suggest that a reduction in the "volatility of SDP's earnings", as a consequence of adopting SDP's proposed risk management mechanisms, would lower SDP's exposure to systematic risk. The risks that SDP seeks to manage via the proposed mechanisms appear to be highly firm-specific in nature rather than being market-related/systematic. In order to sustain the position adopted in the Draft Decision, IPART would need to demonstrate convincingly that adoption of the risk management mechanisms proposed by SDP would lower the covariance between SDP's returns and the returns on the market as a whole. No such evidence or analysis has been put forward by IPART. And there seems to be no good reason to suppose that should be so. Indeed, there is no evidence that IPART has given any consideration at all to the extent to which the relevant risks are systematic versus firm-specific.

The Appendix to this letter elaborates on these points further.

[redacted]

Director, Frontier Economics Pty Ltd.

Appendix – Detailed discussion

Cost of debt true-up

The Draft Decision rejects SDP's proposal that its prices be updated annually over the 2023-27 regulatory period to reflect changes in the trailing average cost of debt allowance and instead proposes to apply a cost of debt true-up. Under IPART's proposed approach:

- SDP's cost of debt allowance would be fixed at the start of the regulatory period; and
- Any difference between the cost of debt allowance in a given year and the allowance fixed at the start of the period would be rolled forward to the start of the next period and 'trued-up' by adjusting next period's prices in an NPV-neutral way.

We note that we addressed the weaknesses of the cost of debt true-up approach in our September 2022 report to SDP.[2] The Draft Decision does not address or respond to any of the points we raised in relation to the shortcomings of the cost of debt true-up approach in that report. Therefore, it is unclear whether, or how, IPART has taken the points we made in our report (and which SDP referenced in its original revenue proposal) into account in the Draft Decision.

The remainder of this section set out our comments on IPART's proposal in the Draft Decision to apply a cost of debt true-up to SDP for the 2023-27 regulatory period. A more fulsome exposition of our views on IPART's cost of debt true-up is presented in our September 2022 report, and the opinions expressed below should be read in conjunction with that report.

IPART has not adhered to the 2018 WACC methodology. This undermines the stability, certainty, replicability and predictability of IPART's regulatory framework.

IPART's 2018 WACC methodology states that IPART would assess the application of the cost of debt true-up "on a case-by-case basis", and assured stakeholders that when deciding whether to use the true-up approach or to adjust prices annually within the regulatory period, "neither option would be considered the default."[3] However, in every decision since IPART published its 2018 WACC methodology, IPART has only applied the cost of debt true-up, regardless of whether the regulated business in question:

- Supported the use of a cost of debt true-up;
- Proposed annual price adjustments within the regulatory period (e.g., to avoid mismatches between the regulatory allowance and the efficient cost of debt); or
- Made no submission on the matter at all.

Effectively, IPART *has* treated the cost of debt true-up as the default approach because in every instance that a regulated business has proposed annual updates, that proposal has not been accepted. There are no examples of IPART adopting annual updates. This one-size-fits-all approach is difficult to reconcile with IPART's commitment in the 2018 WACC methodology to assess the application of the cost of debt true-up on a case-by-case basis.

[2] Frontier Economics, The allowed rate of return for SDP, 9 September 2022, section 3.

[3] IPART, Review of our WACC method, Final Report, February 2018, p. 38.

In our view, it is very clear that IPART has failed to adhere to its 2018 WACC methodology insofar as it relates to decisions about whether a cost of debt true-up should be applied.

Given that the approach IPART has taken on this issue is so at odds with the commitments it made in the 2018 WACC methodology, IPART should explain the precise circumstances in which it *would* apply annual price adjustments (rather than a cost of debt true-up).

In the absence of such clarification, stakeholders can only conclude that IPART has decided to depart from its 2018 WACC methodology without explanation or consultation, and that the cost of debt true-up is now in fact IPART's default approach (contrary to the published 2018 WACC methodology). This would, in our view, seriously undermine regulatory "stability, certainty, replicability and predictability"—which were key objectives in IPART's 2018 WACC methodology review.[4]

Moreover, as we explain in more detail below, IPART has not adopted the true-up approach after considering the particular merits of the case at hand, but rather justifies that approach by appealing to the "benefits to aligning the approach between utilities, especially when they are part of the same integrated water system."[5] This reasoning is antithetical to the case-by-case consideration that IPART committed to in its 2018 WACC methodology.

The application of IPART's cost of debt true-up undermines the rationale for the trailing average approach adopted in the 2018 WACC methodology.

The first reason IPART cites in favour of the cost of debt true-up is that it promotes within-period price stability for consumers. This is obvious since the cost of debt true-up approach involves fixing the WACC allowance for the duration of each regulatory period. However, this results in mismatches between the regulatory allowance and the efficient trailing average cost of debt. This, in turn, results in inefficient outcomes within each regulatory period because in each regulatory year:

- Consumers may pay more or less than the efficient cost of delivering the regulated service; and
- SDP may recover more or less than the efficient cost of delivering the regulated service.

We note that the trailing average approach has now been adopted by nearly every regulator in Australia. IPART adopted this approach during its 2018 WACC methodology review.

The primary rationale for the trailing average approach cited by regulators when adopting it is that it ensures the closest possible match between the regulatory allowance and the efficient cost of debt. This results in:

- Consumers paying the efficient cost of debt in each year of the regulatory period—no more or less;
- The minimisation of cash flow mismatches faced by regulated businesses that could otherwise cause financeability problems; and
- A cost of debt allowance in each year that is commensurate with the prudent staggered debt management approach that regulated and non-regulated infrastructure firms adopt to minimise refinancing risks.

The cost of debt true-up undermines this rationale by permitting the regulatory allowance in each year to diverge from the efficient cost of debt.

[4] IPART, Review of our WACC method, Final Report, February 2018, p. 3.

[5] IPART Draft Report, p. 68.

No other regulator that has adopted the trailing average approach applies a cost of debt true-up of the kind proposed by IPART.[6] This is for the simple reason that a cost of debt true-up is at odds with the very rationale for the trailing average approach.

Moreover, it would be impossible for any firm (regulated or non-regulated) to manage its debt portfolio in such a way that would result in a cost of debt that matches the regulatory allowance implied by IPART's cost of debt true-up. An approach that cannot be implemented by any business cannot reasonably be described as prudent or efficient.

In our view, the most efficient outcomes arise when the regulatory allowance is set equal to the efficient cost of delivering the regulated service in each year. If regulated prices do not reflect efficient costs, that would blunt the price signals provided to Sydney Water to promote efficient water sourcing decisions. IPART explains in its final decision on the Water Regulatory Framework that setting regulated prices to reflect costs is essential to promote efficiency and intergenerational equity:

> *Through the 3Cs framework, we are becoming less prescriptive in pricing structures, but businesses will need to show they are sending cost reflective price signals. This is particularly important when thinking about intergenerational equity and the need to send signals to promote a secure water supply.*[7]

The imposition of a cost of debt true-up would result in SDP's prices in each regulatory period being less (not more) cost-reflective and would therefore be at odds with a key part of IPART's regulatory framework to send efficient price signals to water users.

The cost of debt true-up approach could result in consumers paying more than the efficient cost in each regulatory period.

Furthermore, IPART has no way of foreseeing how prevailing market rates or the cost of debt may evolve over the regulatory period. As such, it cannot rule out the possibility that market rates (and, therefore, the efficient cost of debt allowance) would decline over the 2023-27 regulatory period. In these circumstances, consumers would need to wait until the next regulatory period to receive the benefit of those cost reductions via lower prices.

This is not simply a theoretical possibility. As **Figure 1** below shows, the trailing average cost of debt allowance produced by IPART's 2018 WACC methodology has declined significantly (by over 220 basis points) since 2018.[8] Since IPART has applied a cost of debt true-up in every decision since it adopted the trailing average approach, in every such regulatory determination consumers have had to wait a whole regulatory period (typically four years) before receiving the benefit of these lower rates through lower prices.

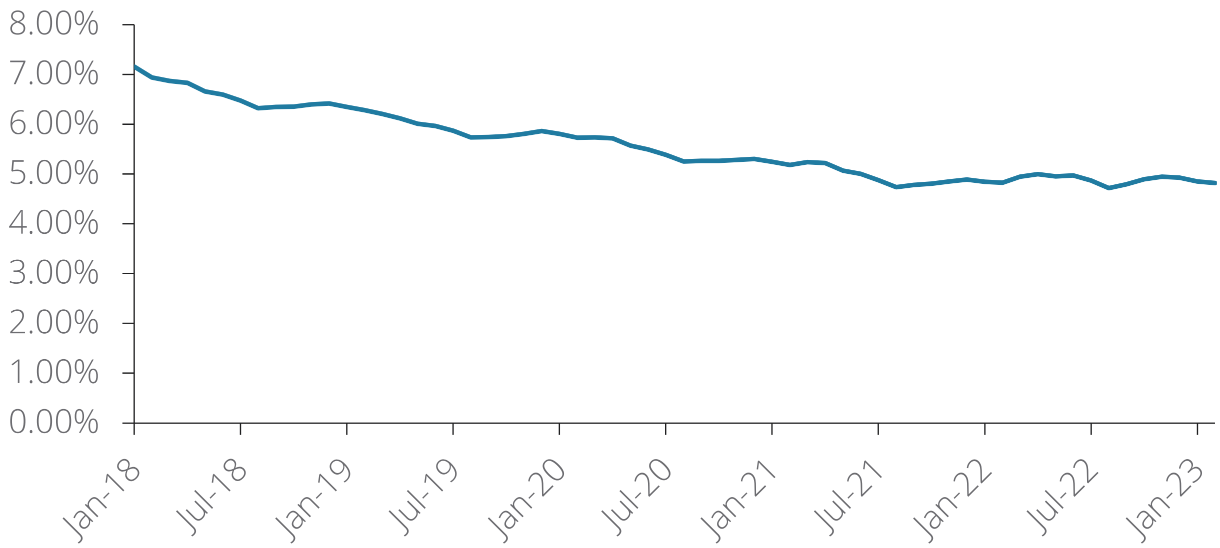
[6] The regulators that have adopted some version of the trailing average approach include the Australian Energy Regulator (AER), the Economic Regulation Authority of Western Australia (ERA), the Queensland Competition Authority (QCA), the Independent Competition and Regulatory Commission (ICRC), the Essential Services Commission of Victoria (ESCV) and the Essential Services Commission of South Australia (ESCOSA). None of these regulators have adopted a cost of debt true-up of the sort IPART has adopted.

[7] IPART, Our water regulatory framework: Technical Paper, November 2022, p. 109.

[8] From 7.16% in January 2018 to 4.93% in March 2023.

Such an outcome could have been avoided by adjusting prices each year within the regulatory period (as SDP has proposed) to reflect changes in the efficient cost of debt. It is not clear to us why IPART prefers an approach that has resulted in consumers paying more than the efficient cost of debt in past decisions, and that could result in consumers paying more than is necessary over SDP's 2023-27 regulatory period, when there is a viable and implementable method that would avoid such outcomes.

Figure 1: Trailing average cost of debt



Source: Frontier Economics analysis of RBA data.

Note: For simplicity, this figure presents the long-term cost of debt allowance under IPART's 2018 WACC methodology, which reflects a 10-year trailing average of historical yields.

IPART has not reflected in its Draft Decision evidence submitted by SDP on the materiality of cash flow mismatches and the associated financial impact on SDP.

While IPART agrees that the cost of debt true-up may impose cash flow mismatches on SDP, IPART asserts that the financial impact on SDP "may not be high." IPART provides no evidence to support this assertion.

By contrast, SDP's pricing submission presented expert financial modelling and analysis by [redacted] The Draft Report does not mention or acknowledge this analysis. It is therefore unclear whether or how the analysis has factored into IPART's conclusions in relation to the potential impact of cash flow mismatches caused by the proposed cost of debt true-up.

Implicit in IPART's assertion that that the financial impact of cash flow mismatches on SDP may not be high seems to be an assumption that financial market conditions will remain relatively stable over the 2023-27 regulatory period. In reality, neither IPART nor regulated businesses can foresee how financial markets will turn out in future.

[redacted]

For instance, IPART did not, and could not have anticipated that:

- the yields on 10-year BBB Australian corporate bonds would rise by:
    - 535 basis points during the during the peak of the 2007-08 Global Financial Crisis;[10] or
    - 124 basis points over February and March in 2020, the initial months of the Covid-19 crisis; or
    - 410 basis points between October 2021 and October 2022; or
- the yields on 10-year Australian Government bonds would rise by 300 basis points since their nadir in November 2020.[11]

IPART cannot rule out the possibility of such events occurring over the 2023-27 regulatory period. Simply assuming away such outcomes, as the Draft Report seems to do, exposes SDP to a lottery, whereby SDP could face a very material deterioration in financeability if the prevailing cost of debt were to increase sharply, while the regulatory allowance remains fixed at the 2023-24 level. As noted above, an administratively simple annual cost of debt update akin to the annual CPI updates applied to SDP's prices could mitigate these risks, which would be in the long term interests of water users.

SDP has updated the financeability modelling presented in the [redacted] assuming that SDP's allowances for the 2023-27 regulatory period are set in line with the Draft Decision, and reflecting the following scenario:

- Per the cost of debt true-up approach, the cost of debt allowance would be fixed for each year of the 2023-27 regulatory period at [redacted], the allowed cost of debt for 2023-24, (light blue curve in [redacted]; but
- The true market cost of debt increases from current levels over the 2023-27 regulatory period in the same way rates increased during the 2007-08 GFC (dark blue curve in [redacted]

[10] From 8.5% in December 2007 to 13.9% in December 2008.

[11] From 0.84% in the 40 days to 30 November 2020 to 3.84% in the 40 days to 31 October 2022.

[redacted]

[12] SDP's modelling has presented nominal metrics, rather than the real metrics used in IPART's benchmark test, because a benchmark efficient business in SDP's circumstances can only raise nominal debt and therefore faces nominal debt service obligations.

[redacted]

As a relatively small, privately-owned infrastructure company, SDP would not be able to manage such a material deterioration in financeability (e.g., due to another financial crisis that is beyond SDP's control). This is because, as SDP has explained in its original pricing proposal, it does not have the Government support enjoyed by the State Owned Corporations (SOCs) regulated by IPART. Unlike the SOCs, it is standard for privately owned and financed companies like SDP that issue debt finance without the support and guarantee of a State government to be subject to strict debt covenants.

These debt covenants require the borrowing firm to report key financial metrics, such as the Debt Service Coverage ratio (DSCR), every six months. A mismatch in cash flows triggered by a steep increase in interest rates that is not matched by an increase in revenue can lead to key financial metrics such as the DSCR falling short of the thresholds established in the firm's debt covenants. The consequences of breaching such debt covenants may be very serious. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Such outcomes could be avoided by IPART setting the cost of debt allowance for SDP in each year of a regulatory period equal to the efficient cost of debt (as determined by the trailing average allowance).

IPART's own analysis implies that the purported benefits to consumers of price stability are overstated.

IPART considers that price stability within each regulatory period is an important reason to favour the cost of debt true-up approach. The Draft Report also argues that any financial impact on SDP as a result of cash flow mismatches under the cost of debt true-up approach may not be material because annual changes in the trailing average cost of debt allowance are likely to be small:

> *...we note that the impact on an annual basis may not be high. This is because, under the trailing average cost of debt approach, only a small proportion of the debt is refinanced each year...*[13]

If IPART believes that the annual changes to the trailing average cost of debt allowance are likely to be small, then it follows that the resulting volatility in prices is likely to be low. If that is true and prices are only likely to be marginally more stable under the cost of debt true-up approach, then the purported benefits to consumers of the cost of debt true-up approach—in terms of greater price stability—would seem to be overstated.

[13] IPART Draft Report, p. 68.

If, on the other hand, IPART considers that consumer prices would be significantly more volatile without the cost of debt true-up approach, then it follows that the cash flow mismatches faced by SDP (and the associated financial impacts) would be large.

It is untenable and internally inconsistent to claim simultaneously, as the Draft Report does, that:

- The cost of debt true-up approach would result in materially more stable prices to consumers; *and*
- The cash flow mismatches imposed on SDP by the cost of debt true-up approach are likely to be immaterial.

IPART has used circular reasoning to justify the cost of debt true-up approach.

The second reason IPART gives for favouring the cost of debt true-up approach is that "there are benefits to aligning the approach between utilities, especially when they are part of the same integrated water system."[14] This reasoning is circular because, by this logic, the application of a cost of debt true-up to Sydney Water would justify the application of a cost of debt true-up to SDP, which would in turn justify the application of a cost of debt true-up to Sydney Water, and so on. Circular reasoning is not a sound basis on which to make good regulatory decisions.

This path dependent approach—whereby the decisions applied to one regulated business are contingent on previous decisions applied to other regulated businesses—is also at odds with IPART's commitment to assess the application of a cost of debt true-up on a case-by-case basis, examining the specific circumstances of the regulated business in question.

There is no evidence that annual price updates would impose a disproportionate administrative burden on Sydney Water or SDP.

The third reason that IPART cites in favour of the cost of debt true-up approach is lower administrative burden and shifting of risk from one regulated entity to another.

We are advised by SDP that in its discussions with Sydney Water about this matter, Sydney Water has indicated it remains prepared to support annual adjustments to SDP's prices and considers that this is likely to be immaterial in the context of SDP's total bill to Sydney Water. This is because SDP's costs represent approximately 10% of the end-customer bill and is already likely to vary annually depending on the volume of water requested by Sydney Water as well as variances each year for CPI inflation.

Moreover, IPART's Water Regulation Handbook notes that Sydney Water already updates its prices annually to pass through to customers the difference between forecast SDP costs (included in prices set in the Sydney Determination) and actual SDP costs.[15] The Draft Report notes that "Sydney Water passes through changes in SDP costs to end-use customers following a 12-month lag."[16] These pass-through mechanisms were included in Sydney Water's 2020 Determination to manage a range of uncertain operating and capital costs.[17]

The annual adjustments to SDP's charges to reflect year-on-year changes in the cost of debt allowance could be accommodated readily within these existing cost pass through mechanisms and would involve no material additional administrative burden for Sydney Water.

[14] IPART Draft Report, p. 68.

[15] IPART, Water Regulation Handbook, April 2023, p. 55.

[16] IPART Draft Report, p. 103

[17] IPART, Water Regulation Handbook, April 2023, p. 55.

Nor has Sydney Water raised concerns that the application of annual price adjustments would transfer risk from SDP to Sydney Water. This is also not surprising given the cost pass through mechanism available to Sydney Water to pass actual SDP costs onto customers, and the fact that SDP's costs are a small fraction of Sydney Water's overall charges, as noted in the Draft Report:

> *The costs of SDP's services to Sydney Water make up around 10% of a typical Sydney Water end use customer bill. Therefore, a 1.5% increase in the prices SDP charges to Sydney Water would translate about a 0.12% increase in end-use customer bills. For a typical Sydney Water customer bill of about $1,300 per year, this would amount to about a $2 increase in the bill.*[18]

In our September 2022 report, we presented modelling results that indicated that that Sydney Water's revenues would differ by a maximum of only $6 million in a given year, as between the annual updating and cost of debt true-up approaches.[19] This would represent just 0.2% of Sydney Water's total allowed revenues, which demonstrates that even a worst case variance is still eminently manageable for Sydney Water as compared to SDP .

If Sydney Water were to pass through changes in SDP's prices to consumers annually, there would be no need for Sydney Water to 'store up' those price changes over a regulatory period and, therefore, no transfer of risk from SDP to Sydney Water.

Link between WACC and risk management mechanisms

SDP's original revenue proposal proposed a number of risk management mechanisms, including:

- Expanded cost pass-through mechanisms for costs that are beyond SDP's control (e.g., new taxes);
- A new end of period true-up for other uncontrollable costs;
- Mid-period re-openers for events that are exogenous to SDP; and
- Symmetric changes to certain incentive mechanisms that would result in consumers sharing more of the difference (both positive and negative) between SDP's actual operating costs and the regulatory allowance.

The Draft Report rejects these proposed risk management mechanisms. In doing so, IPART erroneously links the risks that SDP seeks to manage through these proposed mechanisms to systematic risk. Specifically, IPART suggests that adoption of these proposed mechanisms would lower SDP's exposure to systematic risk that this would warrant a reduction in SDP's WACC allowance.

Only systematic risk is compensated via the beta allowance used to determine the cost of equity allowance. IPART makes this very point in 2018 WACC methodology:

[18] IPART Draft Report, p. 103.

[19] Frontier Economics, The allowed rate of return for SDP, 9 September 2022, p. 20.

> *...only systematic risk affects the expected return required by the marginal equity investor (who determines the price of equity). This is because the marginal investor would hold a well-diversified portfolio of equities, and a diversification strategy can remove firm-specific risk.*[20]

IPART contends that the introduction of the proposed risk management mechanisms would reduce SDP's exposure to systematic (and non-systematic) risk. However, IPART provides no evidence that the adoption of these mechanisms would affect systematic risk borne by SDP. IPART simply contends that the adoption of the mechanisms proposed by SDP would "reduce the volatility of SDP's earnings and so reduce both SDP's systematic and non-systematic risks."[21]

This statement implies that any reduction in the volatility of a firm's earnings would reduce its exposure to systematic risk. This is incorrect.

In the framework of the Capital Asset Pricing Model (CAPM), which IPART uses to determine the cost of equity allowance for regulated businesses such as SDP, systematic risk (as measured by beta) is defined in terms of the correlation between the returns of the firm in question and the returns on the overall market, and is represented formulaically as follows:

$$Beta \equiv \frac{\mathrm{Cov}(r_i, r_m)}{\mathrm{Var}(r_m)},$$

where:

- r_i represents the returns of the individual firm;
- r_m represents the returns on the market as a whole;
- $\mathrm{Cov}(r_i, r_m)$ is the covariance between the returns of the individual firm and the returns on the market as a whole; and
- $\mathrm{Var}(r_m)$ is the variance of the returns on the market as a whole.

Note that the variance of the individual firm's earnings (which is presumably what is meant when the Draft Report refers to the "volatility of SDP's earnings") does not appear anywhere in this formula. Hence, it does not follow (mathematically or as a matter of economics) that a reduction in the variance of the firm's returns results in a reduction in its exposure to systematic risk—as the Draft Report contends. This is a misunderstanding of the CAPM and the concept of systematic risk.

Any event that merely changes the variance of the firm's returns (i.e., $\mathrm{Var}(r_i)$) but that has no effect on the *covariance* between the between the returns of the individual firm and the returns on the market as a whole (i.e., $\mathrm{Cov}(r_i, r_m)$) would have no impact on systematic risk. Such events are firm-specific and would only affect the business's exposure to non-systematic risk.

There is no convincing reason we can see why any of the risk management mechanisms proposed by SDP would alter the *covariance* between SDP's returns and the returns on the overall market. For instance, there is no credible reason to think that the costs that SDP seeks to manage via the proposed

[20] IPART, Review of our WACC method, Final Report, February 2018, p. 48.

[21] IPART Draft Report, p. 128.

mechanisms (e.g., land tax, greenhouse gas reduction plan (GRRP) costs, the cost of generator compensation, unaccounted for energy (UFE) and reliability and emergency reserve trader (RERT) charges) should be low when the Australian stock market is up and high when the Australian stock market is down.

If IPART considers that there is a systematic component to these risks, it would be incumbent on IPART to explain clearly—with evidence—by what mechanism those risks are systematic in nature. It is not sufficient to simply assert that these risks are systematic, particularly when there is no *a priori* reason to suppose that they are.

IPART and other regulators have previously noted that use of risk management mechanisms for sharing or transferring firm-specific risks (e.g., via insurance or pass throughs) is not relevant in setting the WACC allowance and, in particular, the cost of equity allowance. For example, in the context of managing some business specific risks through insurance, IPART noted in its 2017 Determination for SDP that changes in the allocation of firm-specific risk does not affect the required rate of return:

> *We consider SDP's coverage for business interruption insurance would be sufficient given the proposed changes to the abatement mechanism. As this increased risk is firm-specific in nature, it should also not lead to an increase in the permitted rate of return to SDP. Only systematic risk is reflected in the Capital Asset Pricing Model that underpins our estimate of the WACC.* [22]

We agree with the conclusion IPART reached in the quotation above from its 2017 determination for SDP. The application of consistent reasoning would rule out any link between the mechanisms to manage firm-specific risks proposed by SDP and SDP's exposure to systematic risk.

Finally, we note that even if IPART were convinced that there is a systematic element to these risks, there would be no way to reliably and empirically quantify the adjustment that would need to reflect the reduction in systematic risk that would be commensurate with the adoption of the proposed risk management mechanisms. Any arbitrary adjustment to beta that was not based on empirical evidence would undermine the excellent work IPART undertook during its 2018 WACC methodology review to develop a structured, predictable and replicable approach to estimating beta.

[22] IPART, Sydney Desalination Plant Pty Ltd, Review of prices from 1 July 2017 to June 2022, Draft Report, March 2017, p. 33.