Procurement of Non-reserve System Services

Assessment of interim options

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Executive Summary

We consider interim options for **non-reserve services** – inertia, reactive power and ramping margin. In the short term, we are constrained by current product definitions for these services – SIR, SSRP and RMX respectively.

SIR and SSRP are incompatible with moving to competitive procurement as they do not represent physical volumes reflective of the TSOs' requirements. Rather, they are best considered to be an ex-post payment scheme designed to incentivise supply of inertia and reactive power, primarily by modulating energy market outcomes. It makes no sense to set a 'volume requirement' for SIR or SSRP and then allocate this by auction, as there would be no guarantee that the TSOs' physical needs for inertia or reactive power would be met, let alone met at least cost.

Given this, the only feasible short run options for SIR and SSRP are to retain DS3 tariffs or to eliminate (or reduce) them. However, both tariffs have a useful effect. A rational bidder in the DAM or IDM should anticipate that it receives additional revenues for these services (to the extent that it supplies them) conditional on being synchronised. Therefore, the price offered through energy bids for units to turn on should be lower by the amount of these tariffs. This results in some modulation of energy market outcomes, slightly favouring those offering more of these system services in clearing, other factors equal. This rationale for DS3 tariffs can be found in the original 2014 Decision Paper that introduced them[1]. The tariffs also provide incentives for units that can synchronise at zero energy output and supply reactive power to do so.

Conversely, removing these tariffs leads to units increasing what they require to be paid to be turned on (though not subsequent increments to increase energy output, which are unaffected). This has the effect of raising the cleared price of energy by a small amount. It also reduces the supply of system services induced by the energy market. This reduction in inertia and reactive power delivered by energy market outcomes needs to be made up by bringing on additional units through non-energy actions (NEAs) at cost (the COD offers of those units). In turn, these NEAs result in additional supply of energy that needs to be rebalanced.

We have modelled the trade-off of cost and benefits from eliminating DS3 tariffs for SIR and SSRP using a stylised model, but actual energy market data from a sample of days. We find that the saving in not paying DS3 tariffs is dominated under reasonable assumptions by the increase in the energy price and the cost of making additional NEAs after rebalancing unwanted additional energy brought on by those NEAs.

These effects are highly variable depending on market conditions and exactly which units are close to the margin of being switched on or off. Therefore, in our view, there is a large degree of risk associated with elimination of DS3 tariffs in terms of what consequences there could be for system stability.

[1] See SEM-14-105, for example §14-§15.

We have not attempted to extend this model to ramping margins. This would involve significant additional complexity due to the service cutting across multiple periods of the energy market. However, we expect DS3 tariffs to affect the provision of ramping margin products in a similar way to inertia and reactive power. DS3 tariffs should modulate energy bids and energy market outcomes to favour selection of units at the margin that can also provide this service.

We offer initial views on possible alternative procurement methods for non-reserve services if product redefinitions were possible over the longer run. This analysis aims solely to identify likely candidate approaches and has not been assessed by EirGrid in terms of their effectiveness of meeting system needs or the feasibility of identifying target requirements ahead of real time. Consultation with suppliers would be needed to refine these suggestions.

1 Introduction

In response to a request by the RAs, EirGrid and SONI have asked us to undertake an economic assessment of alternative procurement methods for the following non-reserve system services:

- **inertia (SIR)**; and
- **reactive power** (SSRP); and
- **ramping margin (RMX)**.

1.1 Options considered

Long-run options

In the long run, there are a wide range of potential options for procurement of non-reserve services, including:

- a **DASSA-type daily auction**;
- the **Layered Procurement Framework** (LPF) with auctions on longer timeframes between weekly and annually;
- **long-term contracts** (for example annually for tranches of volume) awarded through a competitive process; and
- a **pre-determined fixed tariff**.

The first three options above involve various forms of competition to meet a quantity-based requirement set by the TSOs. The last involves some volume of supply being induced by a set tariff.

Limitations due to current product definitions

We demonstrate in Section 2 that **current product definitions** for SIR and SSRP do not correspond to physically meaningful services. Because of the non-linear relationship between SIR and inertia it makes little sense to define some quantity requirement for, say, SIR and then add up SIR contributions from individual suppliers to see if that requirement has been met. Similar issues arise for SSRP.

Rather, DS3 is better thought of as an **ex-post payment scheme**. It is intended to provide incentives for units to offer system services and to provide flexibility for the TSOs in meeting non-energy requirements (primarily through lower minimum generation levels - MINGENs).

Short-run options

Because of this fundamental limitation of the current product definitions, we are forced to distinguish between **short-run** and **long-run** options for procurement of non-reserve services. Introducing new product definitions needs time for the TSOs to ensure that operational requirements would be satisfied, to consult with suppliers and to roll out those new services.

During this transitional period, short-run options are limited to:

- **continuation of payments** under current DS3 arrangements;
- **lowering or rationing payments** but otherwise maintaining the current payment structure;
- **stopping payments** entirely.

In Section 3, we consider the question of what might happen if DS3 payments were eliminated for SIR and SSRP. Inertia and reactive power are interlinked, in that many types of plant can supply both inertia and reactive power. Therefore, a solution to shortage of either service will be to bring on and synchronise more plants (even if their energy is not needed). Given this, it makes sense to analyse these two services together. Issues with ramping services are somewhat different, which we defer to Section 3.9.

1.2 Evaluation criteria

If we were conducting a full analysis of long-term options, there would be multiple criteria relevant to assessing different procurement approaches:

- Whether **grid stability** requirements are met with sufficient certainty.
- The TSOs' requirements being met at least **cost to consumers**. This has several aspects:
    1. providers of system services should be **selected efficiently** (i.e. service requirements are split across suppliers to minimise total cost of supply);
    2. it should be possible for TSOs to set **volume requirements** ahead of real time, without TSOs facing undue risks to the eventual supply of services that give rise to an unnecessarily large precautionary element to those volume requirements;
    3. any procurement mechanism should as far as possible be robust to the possibility of **supplier market power**.

- There should be **stable price signals** to provide a basis for efficient **long-run investment decisions**.
- As system services are increasingly being provided by non-conventional units (and not necessarily co-produced with energy), procurement should be as far as possible **technologically neutral**.

However, in considering short-term interim options – retaining or removing DS3 tariffs – most of these considerations become largely irrelevant. Rather, the primary concern is which of these limited options can achieve the TSOs' **system stability requirements** in a **cost-efficient** manner.

Long-run investment incentives are of limited relevance here and primarily a question of what procurement approach for system services might be adopted alongside new product definitions. Nevertheless, we note in passing that removing DS3 tariffs without good reason would tend to undermine regulatory credibility, which in turn might affect willingness for new providers to invest even beyond the transitional period we are considering here.

2 Implications of current product definition

In this section we discuss the impediments to moving to competitive procurement without changes to the current product definitions of the three non-reserve services.

2.1 SIR

Definition of SIR

Inertia is equivalent to stored kinetic energy. For conventional plants, this is stored kinetic energy in rotors and turbines. System inertia is then (ignoring transmission constraints) a simple sum of the inertia of all synchronised units. System inertia determines the rate at which system frequency changes when faced with a rapid change in system load prior to modulating feedstock inputs (e.g. thermal input from gas) or drawing on long-term stored energy sources (e.g. opening a sluice gate in a hydro plant).

SIR is not a physical measure of inertia, but rather a non-linear function of inertia and characteristics of units. It is not interpretable as a 'quantity' of something to be procured and only indirectly links to TSOs' physical requirement, which is for inertia. For a given supply of inertia, SIR is larger if a unit's minimum output (MINGEN) is smaller.

Because SIR is a non-linear (quadratic) function of inertia, summing SIR does not have physical meaning. As we discuss below, a given system-wide total amount of SIR is compatible with a very wide range of system-wide total inertia.

Incentives created by current payment structure

The SIR volume that can be supplied by each unit is calculated from the inertia that the unit supplies and its MINGEN (the minimum output at which the unit can be synchronised). Units either supply their entire SIR volume if they are synchronised or none otherwise. There is no variation in the SIR (or indeed the inertia) supplied by a unit if its energy output changes provided it remains synchronised.[2] Therefore, any deficiency in inertia needs to be rectified by

[2] For a rotating plant (such a turbines and generator rotor) the stored energy is a function of its moment of inertia and its rotational speed. The moment of inertia is set by the physical characteristics of the rotating plant (the spinning mass and how far it is from the axis of rotation). The rotational speed is fixed by the system frequency once the unit is synchronised. Therefore, the stored rotational kinetic energy does not depend on the system output provided the unit is synchronised.

synchronising another unit rather than increasing energy output from units that are already generating energy.

As SIR volumes increase with lower MINGEN and larger inertia volume, so do SIR payments to units. These payments can be expected to be reflected in energy market bids, which would be lowered in anticipation of SIR payments if turned on. This means that units with relatively higher inertia and lower MINGEN can be expected to discount their bids further, increasing their chances to be selected for energy supply (and thus be synchronised and provide inertia to the grid).

Therefore, SIR payments promote the selection of suppliers that can provide more inertia with lower minimum output – this reduces the scope for displacing energy from other suppliers due to the need to have inertia on the grid.

Lower energy bids can also be expected to result in lower energy clearing prices, which allows for (at least partial) recovery of SIR (and SSRP) payment costs.

A unit's MINGEN and inertia are part of its technical characteristics and cannot easily be altered in the very short run. However, some units have choices over mode of operation that may affect their MINGEN. In the longer run, generators may be able to make technical improvements that reduce MINGEN. Therefore, in addition to their impact on energy market clearing, current SIR payments provide an incentive to reduce MINGEN where units have such potential.

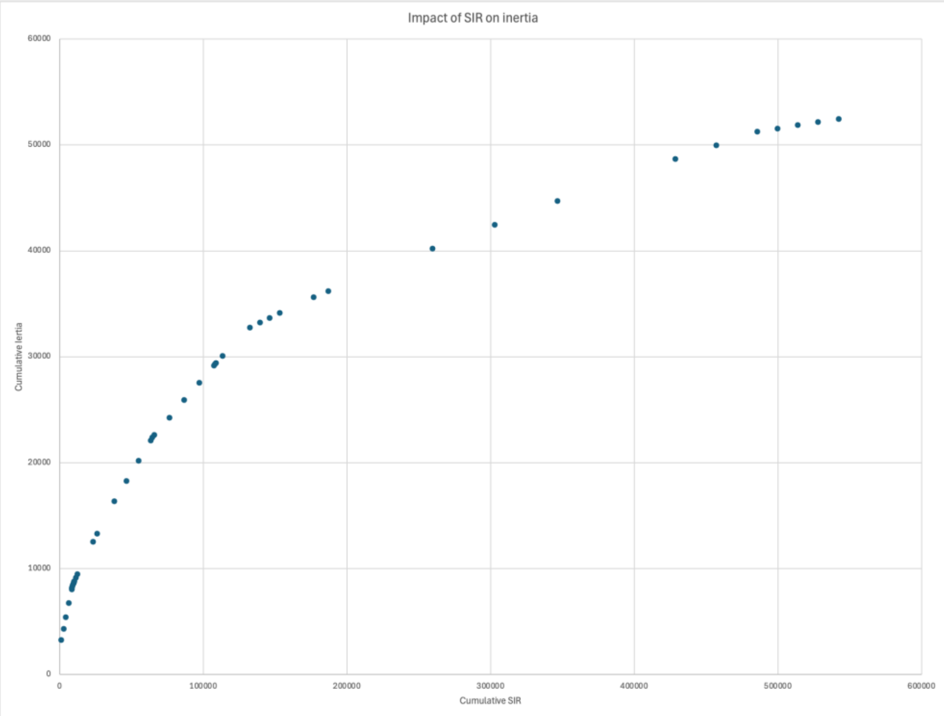
What if a competitive mechanism were used for SIR?

TSOs have a constant minimum floor requirement for inertia of 23,000 MVAs. This inertia requirement is not the same as an SIR requirement. Nor does it easily translate into an SIR requirement, as the amount of inertia supplied for a given level of SIR depends on supplier mix and the technical characteristics of individual units. Therefore, to account for this uncertainty, the TSOs would need to set a sufficiently large SIR requirement that the inertia floor would be achieved with sufficient probability given the potential for different supplier mixes. This would result in disproportionate over-procurement for most supplier combinations.

This is not a minor issue. The ratio of SIR delivered to the inertia delivered varies by two orders of magnitude across units, as shown in the box below.

Inertia and SIR volumes vary across units. The SIR determines the payment, but the TSOs have inertia requirements. For each unit, we calculate the ratio of the inertia supplied by that unit to its SIR payment. This ratio varies over a wide range from 2.5 to 0.02.

We sort units into decreasing order according to this ratio. To achieve a given inertia target at least cost in terms of SIR payments, we would choose the units with the highest ratios. This gives us a cumulative relationship between the inertia target (vertical axis) and the SIR volume on which payment is made (horizontal axis). This is highly non-linear.



The mix of units strongly affects the cost (in terms of DS3 tariff payments for SIR) of delivering a given volume of inertia. For example, the inertia floor of 23,000 MVAs could most cheaply be achieved by using units with the highest ratios, which implies a total SIR volume of 76,364MWs^2. At the current tariff of 0.0037, this costs €283 per trading period. This is the best case.

Conversely, if units with the lowest ratio are selected, the total SIR volume increases to 433,264MWs^2 and a cost of €1,603 per trading period. This is the worst case.

By comparison, the average SIR volume procured per trading period over July 2025 (the most recent month for which we have available data) is 368,318MWs^2, which at the current tariff costs €1,363. Compared to procuring the worst-case quantity of SIR, this involves a saving (at the tariff) of €240 per trading period.

2.2 Reactive power

SSRP presents very similar issues to SIR. As currently defined, SSRP is not a physical quantity related directly to the TSOs' need for reactive power. In addition, competitive procurement using current definitions would face additional complications:

- SSRP volumes do not distinguish between absorption (lead) and production (lag) of reactive power. This further increases the potential mismatch between SSRP (where the capability of absorption and production for a unit are added up) and the TSOs' requirement (which is defined separately for absorption and production).[3] This further exacerbates the need to over-procure SSRP to ensure that TSOs requirements are met if a target SSRP volume were set.
- Reactive power is highly localised and does not travel well across the grid. Therefore, absorption and production must be provided close to the locations that require it. This has two implications. First, requirements need to be identified locally. Second, this localisation severely limits the scope for competition between suppliers as only nearby units provide substitutable services. Suppliers at different locational nodes for reactive power do not supply substitutable services.

What if a competitive mechanism were used for SSRP?

As in the case of SIR, the actual volumes of reactive power absorption and production capacity for a given volume of SSRP depend on supplier mix and the technical characteristics of units. A wide range of outcomes for reactive power are possible from a given volume of SSRP.

With SSRP we have a further complication that the potential output of reactive power, though subject to minimums set by the grid code, may decline as plants approach their maximum possible energy output. This contrasts with inertia, where the supply is fixed in the short run by technical characteristics once a unit is synchronised.

[3] See page 61f of the DS3 System Services Agreement, available at https://cms.eirgrid.ie/sites/default/files/publications/Ire-DS3-System-Services-Regulated-Arrangements_final.pdf This defines the "Steady-State Reactive Power Range" as the sum of the declared leading and lagging reactive power. SSRP payments depend on the Steady-State Reactive Power and an RP Factor. The RP Factor (which is between 0 and 1) is a proportion the unit's registered capacity that is above its MINGEN. Therefore, other factors equal units with lower MINGENs receive large payments.

Furthermore, the TSOs' requirements are localised. A national requirement for SSRP would provide almost no certainty over whether reactive power requirements at a particular location would be met.

Given this uncertainty, if the TSOs were to set an SSRP volume requirement (as the basis for a competitive procurement), this requirement would need a very large precautionary buffer to ensure that sufficient absorption and production of reactive power would be available at all locations.

Even if SSRP were localised to try to remove some of this difficulty, with separate procurement of SSRP at different locations, we would still face a dichotomy of problems:

- With multiple suppliers, the achieved levels of reactive power for a given level of total SSRP depend strongly on which suppliers are chosen.
- Absent a multiplicity of suppliers, it will be difficult to run a competition procurement process because of market power concerns. A maximum (reserve) price might be set to contain market power, but this situation is not much different to using a pre-announced fixed tariff.

Therefore, in summary, similar problems arise as for SIR, but with SSRP we have the significant added challenge of localised requirements.

2.3 Ramping margin

Ramping capability within a power system is a function of the ability of generation and demand units to change their output/input across longer timeframes to manage net load variations. Net load variations can occur for multiple reasons, including forecast error related to demand and generation forecasts. The increasing volume of weather-dependent generation (e.g. solar and wind) and volume of embedded solar (which acts to reduce demand) increases the challenge of managing net load variations.

Ramping margin is supplied by units that are in a state allowing them to increase or decrease supply with relatively long notice well ahead of real time to respond to anticipated potential changes in energy demand or supply that might not be addressable through the balancing market close to real time.

The balancing market runs for 5 min periods settled every 30 minutes. The RMX products cover substantially longer periods:[4]

- RM1 requires a unit to provide additional supply within 1 hour of receiving notice and then maintain this for 2 hours;

[4] See page 76, ibid.

- RM3 requires a unit to provide additional supply within 3 hours of receiving notice and then maintain this for 5 hours;
- RM8 requires a unit to provide additional supply within 8 hours of receiving notice and then maintain this for 8 hours.

Therefore, ramping margins arguably give TSOs capability that is not directly available from the balancing market in terms of:

- ability to rebalance energy at an earlier time than can be achieved in the balancing market; and
- being able to do this predictably over multiple periods (especially RM3 and RM8).

Currently RMX payments are calculated and made after the event, based on outturn energy positions of suppliers. Whilst units face some risk if they try to pursue a sequence of PNs with a view to qualifying for a RMX payments, the current payment scheme nevertheless creates an incentive at the margin for units to be synchronised over multiple energy market periods and to offer flexibility (with an output strictly between minimum and maximum). This incentive effect is similar in principle to the impact of SIR and SSRP tariffs on energy market clearing.

Any system of competitive procurement based on existing product definitions would entail procuring RMX volume well ahead of time. For this to be a commitment from chosen suppliers, there would need to be some consequences for chosen units that subsequently fail to supply. In this case, units may face significant risk if they commit to supply an RMX service, as they need to obtain a compatible sequence of PNs. They might seek to manage this risk through making appropriate bids in the IDMs or BMs to achieve compatible positions, but the outcomes are not guaranteed. Whilst increasing any penalisation of a supplier failing to achieve compatible PNs would increase the commitment of suppliers, this would also load risk onto the supplier.

We expect that it would also be difficult for units to commit firmly to such sequence of PNs if they were chosen to supply RMX, as this would limit their options in the IDM and BM. However, although the effect of RMX payments on energy market bids is more complex than in the case of SIR and SSRP, the ex-post payments should still encourage units to lower their offer curves to be synchronised and with margins available to increase/decrease output.

Units may also be able to offer ramping capability by decreasing their output, which they could achieve through IDM or BM bids. Thus, anticipation of RMX payments may also provide incentives to reduce decrement bids. However, the materiality of this effect is difficult to assess, as ramping may require a sequence of compatible PNs rather than a single PN.

Notice that if TSOs instruct units through Non-Energy Actions, this would be remunerated through their Complex Bid Offer Data, which is part of their Commercial Offer Data (COD). We understand that bidders must base their COD on technical data and cannot lower them to reflect anticipated RMX payments.

2.4 Interim conclusions

Current DS3 payments are likely to influence energy bids, with the result that competitive procurement within energy markets indirectly leads to some procurement of system services. It also leads to some recycling of DS3 payments in lower clearing prices for energy.

Running a competitive procurement with current products does not seem to be a reasonable option, as this would result in grossly inefficient outcomes. This greatly limits the short-run options.

3 Quantification of SIR and SSRP effects

In this section we quantify the impact of eliminating DS3 payments for SIR and SSRP.

A key observation is that any shortfall of inertia or reactive power within the outcome of the unconstrained energy market (i.e. the DAM and IDMs) needs to be met by starting additional synchronised units. Such a shortfall cannot be rectified by the balancing market, which involves increasing or decreasing output of units, rather than starting up new units.

Given the start-up delays of typical plants, it would be too late by BM Gate Closure to start up additional plant. Furthermore, given the critical nature of these two services for grid stability, the TSOs need confidence sufficiently ahead of real time that system requirements will be met.

3.1 Model structure

In modelling the impact of removing DS3 tariffs we focus on the potential for the DAM to deliver inertia and reactive power through the effect of anticipated DS3 payments for SIR and SSRP.

We expect eliminating payments for SIR and SSRP to result in a chain of impacts:

- Because DS3 payments for SIR and SSRP are conditional on a unit being turned on, but not the volume of energy produced, the *total* price offer for any given (strictly positive) volume of output will increase by the lost DS3 payments. Therefore, whilst the marginal price offered by units for additional energy output *once turned on*, should be unaffected, rational bidders should reflect the loss of these DS3 payments in a higher price *to be turned on*, through higher average prices for the quantities offered. Bids in both the DAM and other energy markets should be subject to these changes if bidders behave rationally and absent any market power within these energy markets.
- The cleared energy outcome will be affected, as units with relatively greater supply of inertia and reactive power will tend to increase their energy bids by more. Therefore, sorting of units by offer prices within the energy market will

become relatively less favourable to those supplying more inertia and reactive power.[5]

- At present we expect wattless suppliers of Reactive Power to voluntarily synchronise to the grid to obtain DS3 payments. However, there would be no such incentive to synchronise in the absence of DS3 payments. Therefore, removal of DS3 can be expected to result in the loss of supply of Reactive Power from wattless units that have not been cleared in the DAM.
- If the unconstrained energy market delivers *less* inertia and reactive power, the TSOs need to make up any *additional* shortfall through NEAs. These involve acceptance of cost-reflective bids that units are required to offer through their complex offer data (COD). These bids are required to reflect short-run energy costs only, so (at least in theory) should not be affected by removal of DS3 payments. However, requiring more NEAs to rectify the additional shortfall in inertia and reactive power is costly.
- Starting up additional units to provide more inertia and reactive power leads to additional energy supply that may not be needed. Further rebalancing will typically be needed to neutralise this additional energy supply.

Therefore, we assess the following costs and benefits from eliminating DS3 payments:

- The immediate saving of DS3 payments for SIR and SSRP;
- Offsetting increase in the cleared energy price (and corresponding volume response);
- The additional costs of accepting COD bids through the TSOs' NEAs to restore the induced supply of inertia and reactive power lost from the unconstrained energy market; and
- Rebalancing related to neutralising additional energy supply induced by synchronising additional units through NEAs.

We have considered any possible longer-term effects of SIR payments in creating incentives to reduce MINGEN. This is an additional consideration that may be relevant if DS3 payments were removed. However, in the absence of data to investigate this possibility, we have not included it within our quantification exercise.

[5] We note that the 2014 SEM-C Decision Paper that decided to use regulated tariffs instead of competitive procurement acknowledges the incentive effects of these tariffs and the interrelation with energy markets. See SEM-14-105, for example §14-§15.

DAM only

We use a simplified assessment framework to consider the relative magnitudes of these various costs and benefits. This is sufficient to illustrate that there is little certainty that simply eliminating DS3 payments will yield a net benefit, as they do have a useful, if small, function in inducing additional supply of non-reserve services within the outcome of the unconstrained energy market.

To simplify the analysis, we have focussed on the DAM and used this a proxy for the average outcome of the unconstrained energy market, rather than additionally modelling the IDM. We consider this to be a reasonable simplification, as the DAM is responsible for roughly 90% of energy trading in the ISEM.

If new information is received after the DAM, the IDM then updates the cleared outcome. However, the DAM cleared outcome already includes all information available at the time DAM bids were made. Therefore, any subsequent update in the cleared outcome is essential random and, in any case, typically small. Therefore, *on average*, we would not expect different results from including the impact of the IDM in our analysis, but this would greatly increase the complexity of our modelling.

In any case, we understand that the TSOs need early clarity of any need to issue instructions to turn units on for system stability reasons. Given this, if the DAM were less successful in delivering part of the TSOs' requirement for inertia and reactive power, they would identify this through LTS runs and take action at the earliest opportunity to rectify this. They would not necessarily wait to see if the IDM fixed the deficiency.

COD bids and participation

Under the I-SEM, COD bids must reflect short run operating costs. Units are not permitted to take into account other revenue sources in making these bids. Therefore, we have assumed that the level of these bids would not change in response to removing DS3 payments.

However, some of the COD bids provide a zero cost for a unit turning on. Batteries are required to offer zero startup and no-load costs, which may not reflect actual costs, but be acceptable to these units in the expectation of any costs being offset by expected revenue from tariffs. However, in the absence of tariffs, batteries might be unwilling to synchronise unless they have an expectation to obtain some revenue through having non-zero output. In our base case we have assumed that such units would not participate if those tariffs were removed, by not making themselves available to be dispatched if they failed to clear in the DAM. However, as a sensitivity to our analysis we have also calculated the impact of removal of DS3 tariffs in the case were the TSOs may still instruct these units to turn on at zero cost.

3.2 Scenarios

We asked the TSOs to identify several typical days for the generating mix in terms of the contributions from wind and solar. We have been provided with six scenarios, summarised in the table below.

Table 1: Scenarios

		Operating generation (MW- all Ireland)				SNSP (All Ireland)	
	Date	**Average over day**	**Peak quarter hour**	**Average wind penetration**	**Average solar penetration**	**Average over day**	**Peak quarter hour**
Scenario 1	03/07/2024	4,075	5,551	50.5%	4.0%	61.4%	71.4%
Scenario 2	21/12/2024	4,934	5,596	76.2%	0.3%	71.8%	74.6%
Scenario 3	01/08/2024	3,674	4,087	16.9%	5.3%	39.3%	52.4%
Scenario 4	28/12/2024	3,765	4,674	18.2%	0.5%	34.5%	50.3%
Scenario 5	07/03/2024	5,074	5,764	67.4%	0.9%	67.5%	73.1%
Scenario 6	08/03/2024	4,979	6,285	33.4%	0.3%	41.7%	53.3%

3.3 Base case

Energy market clearing

For each of these scenarios, we have the set of DAM bids made for each hour of that day. These include both buy and sell orders. We clear these using a simplified merit order approach, assuming that all bids are simple bids without additional constraints. Therefore, the modelled outcome differs slightly from the actual outcome as we do not consider minimum revenue constraints on bid acceptance. However, given that to implement this the DAM clearing process simply removes bids for which such constraints are not satisfied, we would expect that ignoring these constraints will lead to greater acceptance of bids from suppliers of Non-Reserve System Services, which often will have a minimum generation output (MINGEN) reflected in such requirements – whilst with complex clearing some of these units may be left out if constraints are not met, our simplified model would still accept these units.

Our simplified clearing method yields a base case clearing price and volume for the energy market. The accepted sell orders determine which units would be turned on in this unconstrained market outcome (i.e. without application of system constraints).

In addition, we assume that suppliers of Non-Reserve System Services that can supply Reactive Power with zero energy output will also synchronise voluntarily to the grid to obtain DS3 payments. The volume of RP Lead and Lag contributed by these units varies over periods but is around 5% in scenarios 3 to 6, and around 10% in scenarios 1 and 2. This determines a base case level of inertia and reactive power.

Inertia shortfall

The TSOs have a constant inertia floor of 23,000 MVAs. In most hours, the DAM outcome delivers much less inertia than this requirement. This gives rise to an *inertia shortfall.*

We assume that the TSOs then select COD offers to turn on additional plants at their minimum generating capacity to meet the inertia floor. This entails additional cost as COD offers are paid at bid.

We also consider an alternative assumption that the inertia floor is reduced by 45% due to LCIS capacity coming online. This reduces inertia requirements in both the base case and the counterfactual case without DS3 payments.

Selection of COD offers

We use an optimiser to pick the additional COD offers to be accepted. This seeks to minimise the total cost in terms of:

- accepted COD bids being paid as bid (the cost of keeping the unit running at its MINGEN if the unit was already on in the previous hour, or both startup and running costs for the hour if the unit was not on); and
- the associated SIR and SSRP costs.

There is a constraint requiring the inertia shortfall to be made up from the accepted units additionally turned on.

This cost optimisation is performed separately for each hour, taking into account which units were already synchronised in the previous hour (after NEAs for that hour). We then post-process the results for the previous hour, requiring that no plant is turned off then turned on again an hour later (i.e. the minimum gap between being turned off and on again is two hours), when necessary revising the selection of CODs for the previous hour and updating costs (without re-optimising for the previous or current hours).

This optimisation model is overly optimistic in reducing costs of NEAs in several regards:

- in practice, whilst the TSOs would consider the costs of accepted COD bids, the process would be more manual and less optimised;
- there will be additional constraints arising from notice period for turning plants on and off that we have not considered.

For these reasons, we are likely to be underestimating the true costs of making up the inertia shortfall.

Reactive power

We do not have an explicit reactive power targets available from the TSOs. In any case, any such targets would complex, in that they would need to identify lead and lag requirements by location and according to system state. The TSOs have told us that requirements are unpredictable and in practice they are happy to take as much reactive power as is offered by synchronised units and that they typically need to issue dispatch instructions to obtain more reactive power capability at specific locations.

The inertia floor has the side effect of requiring additional units to be turned on, which typically also leads to additional supply of reactive power. Therefore, the inertia floor has the side effect of inducing supply of reactive power.

For simplicity, we have assumed that NEAs to achieve the inertia floor provides a minimum level of reactive power that TSOs require. From what the TSOs have told us, they typically require more than this, though there will be locational aspects to these requirements.

It would not be appropriate to respond to these uncertainties by setting an unrealistically high reactive power requirement. Any sufficiently high reactive power requirement within our model would force additional NEAs in both the factual and counterfactual cases, but in the counterfactual case we do not pay DS3 tariffs for the supply of reactive power. Setting any sufficiently high reactive power requirement would necessarily be more costly when there are tariffs to be paid.

Therefore, we have adopted the approach of first establishing a proxy reactive power requirement from the supply of reactive power achieved under tariffs. We then run sensitivities perturbing this requirement. Given what we are told by the TSOs, upward perturbation of the proxy requirement is likely to be a more reasonable reflection of the TSOs' actual operation behaviour. At the request of the RAs we have also considered a downward perturbation, but this would be inconsistent with what we have been told by the TSOs about actual system needs.

SIR and SSRP payments

Given the units identified as synchronised by our model, we determine payments for SIR and SSRP. These payments are functions not just of inertia and reactive power, but also plant characteristics.

SSRP payments have several scalars. We have not taken the performance, locational and temporal scarcity scalars into account. However, we have applied the product scalar to all generating units (as they are required by the Grid Code to provide AVR) and the wattless scalar to units with zero MINGEN.

3.4 Counterfactual case

Saving SIR and SSRP payments

In the counterfactual, we eliminate DS3 payments for SIR and SSRP. This has the immediate effect of saving the payments for SIR and SSRP identified in the base case.

Revised DAM bids

Next, we adjust the DAM bids to reflect the loss of anticipated SIR and SSRP payments conditional on a unit being turned on. A rational bidder would have reflected these in the price of offered to turn on, and netted these off its costs of turning on.

Bids consist of multiple price-quantity pairs, expressing not just a price for turning on a unit, but also incremental energy output. We have adjusted price-quantity pairs by:

1. Calculating the total payment that the bidder would receive for that quantity at the bid price;
2. Adding the missed SIR and SSRP payments to this amount; and
3. Calculating a new average price for the quantity, that would ensure that the bidder receives the same total payment.

This approach increases the payment required to turn on a plant, but the *incremental* payments required to increase energy output once a plant is already turned on are unaffected.

Energy price and quantity response

We clear the DAM with these revised bids. This leads to a higher clearing price in some periods. However, SIR and SSRP payments are small relative to energy market revenue, so the impact of removing these payments on the clearing price is typically small.

The DAM is a bilateral market with both buy and sell offers. Therefore, the demand side may respond to a price increase. A higher clearing price will be associated with a somewhat smaller quantity. However, again the effect is small as the price change is small.

There is a direct consumer loss associated with the induced increase in the energy price equal to the sum of:

- the price increase applied to the new, smaller volume;
- the surplus loss associated with the volume reduction (approximating half the product of the price change and the quantity change, assuming it reasonable to take a linear approximation given the small changes).

Because the price change is small, the surplus loss is tiny (quadratic in the change) relative to the price increase effect (which is linear in the change). Therefore, we can ignore the surplus loss for all practical purposes.

Impact on induced inertia and reactive power

Whilst the impact on clearing price and volume is typically small, removing DS3 payments will sometimes affect the units selected to be turned on. In some cases, depending on the mix of plants around the margin of acceptance from the clearing process, this may materially affect the volumes of inertia and/or reactive power lead and lag delivered by the unconstrained energy market.

For example, suppose that we had two units with closely similar energy costs, but one supplying more system services than the other. Suppose that both are close to the margin of being turning on or off in the clearing process and we only require one, but not both for energy reasons. With DS3 payments, the unit with greater supply of system services will be favoured in clearing due to it lowering its price to turn on in anticipation of payments. That preference in lost if DS3 payments are eliminated, so the cleared outcome may deliver a smaller volume of inertia and/or reactive power lead/lag.

In addition to this effect, we also assume that units able to provide reactive power at zero cost do not voluntarily synchronise to the grid, as there is no incentive payment to do so.

Given the revised DAM outcome, we can identity a potentially increased inertia shortfall and a new reactive power lead/lag shortfall. The revised inertia shortfall is relative to the fixed floor of 23,000 MVAs, whereas the reactive power shortfall is relative to the proxy reactive power target.

In the revised energy market outcome, we observe that the inertia shortfall is never smaller than the base case in which DS3 payments were present. Whether the shortfall becomes *strictly* greater, and the magnitude of such an increase, depends sensitively on the mix of plants that are close the margin of being switched on/off in the cleared outcome. Therefore, we expect – and find – that in some hours, but not all hours, we have an additional shortfall of inertia and reactive power to be made up.

Revised acceptance of COD bids

Next, we re-run the hour-by-hour optimisation of COD bid acceptance to minimise cost subject to the constraints of:

- making up the revised inertia shortfall;
- achieving proxy reactive power lead and lag targets.

Again, we post-process these hour-by-hour optimisations to keep units turned on who would otherwise be turned off and on again within an hour.

3.5 Zero COD bids

There are a small number of COD bids made with zero start-up cost in our data. This are almost exclusively from battery units, which are required by the bid code to make such zero COD submissions.

Whilst such zero bids may reflect a notion of these units very short run cost of supply, this is somewhat artificial and there will be some costs. First, units need charging to supply energy or reactive power. Second, if units are aiming to arbitrage the energy price across time, they need to maintain an appropriate charge state (to allow charging or discharging from that state); moving a unit away from this state will reduce the storage capacity available to execute arbitrage strategies and so have some (non-zero) opportunity cost.

Batteries with zero CODs and zero MINGEN

Within the somewhat artificial confines of our simple model, plants offering to turn on at zero cost (whether through offering a zero MINGEN or offering a zero turn on price to a non-zero MINGEN) are especially useful to achieve reactive power requirements through NEAs. Battery units offering zero COD bids have a zero MINGEN, which in the counterfactual case allows them to be brought on at literally zero cost.

Incentives to participate for wattless units

Within the confines of the model, we would have a situation in which units with zero COD bids would be available to augment system service volumes for no payment at all. This is unrealistic, as it is unclear why those units would even make themselves available for zero revenue. Indeed, this issue is recognised in the structure of DS3 payments for SSRP through the application of a wattless scalar doubling payments to encourage participation.

Absent the DS3 payment, these wattless units would have a reduced incentive to be available. Therefore, we cannot expect these units to remain available to the same degree without DS3 payments. Given this, we have assumed that these units making zero COD offers would not be available in the counterfactual case.

However, there might be an incentive for these units to be present to participate in the balancing market. Therefore, we also report results below under the alternative assumption where these wattless units all remain available.

In practice, the outcome is likely to be somewhere between these extremes. Nevertheless, our preferred assumption is that if these wattless units receive no payment for system services at all then we cannot rely on their presence when making non-energy actions. Whilst there may be some incentive for them to be synchronised to participate in the BM, this is highly uncertain and depends on their expectation of what might happen in the BM, which in turn will reflect unanticipated developments not priced into the energy market outcome.

3.6 Energy rebalancing

In both the base and the counterfactual cases, we typically need to bring on some additional units at minimum output (MINGEN) to provide inertia and reactive power. These non-energy actions typically cause additional energy supply beyond the DAM clearing volume. Subsequent rebalancing is needed, reducing output from some plants whilst maintaining the set of plants that are synchronised.

Generators may be willing to make a payment for a reduction in planned output to reflect their input cost saving, whilst still retaining the surplus associated with their accepted DAM bid (i.e. the difference between the DAM clearing price and their cost, we which assume is reflected in their bid). Therefore, *part* of the cost of the DAM cleared volume at its cleared price might be recouped to the extent that are these decremental cost savings are passed through.

We are considering the position when NEAs are taken by the TSOs to rectify inertia and reactive power shortfalls, we assume that the most expensive DAM bids would offer the most advantageous terms for decreasing output, offering to pay for any cost savings from reducing their output while maintaining their surplus from winning in the DAM. If we assume that there is competition to offer up these cost savings from reducing output relative to cleared DAM bids, we can calculate a simple proxy for these savings from the price at which suppliers selected in the DAM offered this reduced output in the DAM. Specifically, we use the DAM merit order and take the lowest price at which supply would have been sufficient to meet a revised quantity equal to the volume traded in the DAM less the additional volume brought on through NEA.

This approach clearly does not reflect the actual mechanisms by which a reduction in the quantity of planned energy output would occur and is very likely to overstate the potential saving that could be obtained for several reasons:

- We are implicitly assuming that DAM bids (in particular, the relative offers at different output levels) reflect the additional costs or cost savings from units adjusting output. However, if adjustments are made closer to real time, there may be frictions that make these adjustments more costly. In the case of cost savings from output reductions, these may be smaller than indicated by relative DAM bids made a day ahead.
- Only plants which are expecting to operate sufficiently above their MINGEN can offer output reductions, which is a subset of those plants who could have offered bids in the DAM. Therefore, there may be less competition for reducing output relative to the DAM outcome than for establishing the original outcome in the DAM.
- In practice, we observe imbalance prices to be considerably lower than DAM clearing prices when any reductions in output are needed after gate closure. (Indeed, imbalance prices are sometimes negative when exceptionally large reductions are needed.)
- We understand from the TSOs that very often dispatch down applies to renewable units. In such cases these units may not need to pay the full amount of their imbalance cost (CIMB) as a consequence for their output reduction, due to the CCURL and CDISCOUNT settlement mechanisms)

The factors above are significant in practice and our modelling approach very likely overestimates cost savings from rebalancing. In interpreting the eventual results, bear in mind that we have tended to understate the costs of NEAs by taking an optimistic view of rebalancing payments.

To reflect this, our preferred assumption is that rebalancing can recover the costs reflected in DAM bids on 80% of the energy volume that needs to be sterilised following NEAs. We also report under two alternative assumptions:

- Rebalancing can recover the costs reflected in DAM bids on all of the energy volume that needs to be sterilised.
- Rebalancing recovers the DAM clearing price on all the energy volume that needs to be sterilised. This represents a bounding case, as this represents the maximum possible amount that could be recovered.

3.7 LCIS and reduced inertia requirements

The Low Carbon Inertia Services (LCIS) programme has awarded long-term contracts for the supply of inertia by non-conventional plant. This supply would lie outside the framework we are considering above. Capacity under the LCIS programme is expected to be phased in from late 2027 onwards.

We have modelled the arrival of LCIS capacity through a reduction in the 23,000MVAs inertia floor by 45%. This has the effect of reducing the inertia shortfall in both the base case and the counterfactual case. This tends to reduce the costs of bringing on additional units to make up the inertia shortfall.

Some LCIS units will also provide additional reactive power as a side effect. Inertia is not locational, whereas reactive power is. We cannot assume that LCIS units that supply reactive power will be as effective in meeting our proxy reactive power requirement as they will be in meeting the actual inertia floor. Therefore, it would be unreasonable to assume that LCIS unit could contribute a similar 45% of the proxy reactive power requirement. In the absence of data, we have assumed that LCIS units might contribute to meeting 20% of the proxy reactive power requirement.

3.8 Results

Table 3 below shows a comparison of the change between the factual case and the counterfactual case for our base case and under alternative assumptions. The overall net effect of removing DS3 tariffs for our 6 scenario days is summarised graphically in Figure 1. The subsections below first discuss in turn the components of this overall net effect.

Energy price response

A significant part of any cost savings from removing DS3 tariffs is lost through higher energy prices (roughly 20-45% with the current inertia floor, and 25-65% when considering the lower inertia floor that can be expected upon introduction of LCIS). The impact on the energy price depends on the mix of units close to the clearing margin and how strongly these are affected by the removal of DS3 tariffs (i.e. the scale of SIR and SSRP supply relative to their energy offer). The impact on the cost of energy in the DAM and on consumer surplus is shown in Table 2.

Table 2: Impact of removal of tariffs on DAM cost of energy and consumer surplus

Scenario	Increase in cost of energy traded (EUR)	Loss of surplus due to reduction on energy traded (EUR)	Total consumer surplus loss (EUR)
Scenario_1	17,500	23	17,600
Scenario_2	10,200	8	10,200
Scenario_3	13,400	9	13,500
Scenario_4	10,200	3	10,200
Scenario_5	27,900	41	28,000
Scenario_6	19,100	14	19,100

Annex A illustrates the impact of removal of DS3 tariffs on the DAM clearing price and traded volume predicted by our model for each of the scenarios by period in the base case, as well as the resulting impact on consumer surplus.

Impact of DS3 tariffs on induced supply of inertia and RP

We also find that, even though the energy market operates on an unconstrained basis (with system stability requirements not explicitly considered when clearing), in some hours on each day there is an effect from DS3 tariffs in promoting supply of inertia and/or reactive power. This happens through units offering lower prices to turn on or synchronising despite having zero energy output as a result of anticipated DS3 payments. In some cases, this is sufficient to affect the merit order of units, boosting the supply of inertia and/or reactive power. The sensitivity of the induced supply of system services to the SIR and SSRP payments depends on a balance of:

- *differences* in SIR and SSPR payments and
- *differences* in energy costs

between units that are close to the margin of being turned on or off in the clearing process.

Whilst often the amount of inertia procured through the DAM may be unaffected, in some periods it might be up to 7% of the actual inertia floor. Procurement of reactive power is also affected, both through the merit order and by removal of incentives for wattless units to synchronise even if unsuccessful in the DAM. Annex B illustrates the loss in volume procured prior to NEA for each of the scenarios by period in the base case.

This result confirms the logic of the 2014 SEM-C Decision that introduced the DS3 tariffs. In addition to providing incentives for units to provide these services, the tariffs modulate energy market outcomes to provide somewhat more system services than would have been the case. This is helpful for the TSOs both because supply is put in place well ahead of real time and also because avoids costs associated with NEAs.

Costs of additional NEAs

We also find that there are costs of additional NEAs to make up shortfalls of inertia and/or reactive power in every scenario. The magnitude of this cost can vary significantly across scenarios (by a factor of roughly 4 in our case). These costs will vary with:

- the sensitivity of supply of system services induced by the energy market to the DS3 tariff;
- what units are still available to be turned on through NEAs (as some units will be on anyway due to the DAM outcome).

Unsurprisingly, these factors can vary significantly from hour to hour.

In addition, NEA will typically increase energy output as some units need to be dispatched to output their MINGEN. This involves a cost for managing imbalances between supply and demand for energy in each period. Such costs are typically higher in the absence of DS3 tariffs, as there is greater need to use NEAs to achieve the required volumes of inertia and reactive power.

Balance of costs and benefits

Under our preferred assumption that zero COD units are not available to make up any additional shortfall of SIR or SSRP, the costs of additional NEAs plus the higher energy price from eliminating DS3 tariffs for SIR and SSRP is greater than the payments made under those tariffs. This is true for every scenario considered in the base case. We do not even need to consider the additional costs of energy rebalancing to reach the conclusion that there is a net cost of eliminating DS3 tariffs for SIR and SSRP in the base case.

Sensitivity to the MUON operational constraint

In practice, the TSOs choose CODs to satisfy the MUON (Minimum Number of Conventional Units Online) operational constraint. This will contribute to increasing inertia and reactive power capability on the grid, as conventional units supply these services.

As an additional sensitivity we have also run our COD selection with this constraint, although reducing the number of required units in Northern Ireland to one (as we understand happened during the period covered by our analysis due to reduced availability of units, as some of these were undergoing maintenance and repair works).

Imposing MUON does not affect the overall conclusions. In most day scenarios, results are similar.

Reduced requirements due to LCIS

We have reduced the inertia floor by 45% to reflect the contribution of phase 1 LCIS units. We have also reduced the proxy reactive power targets by 20% to reflect some contribution from these units.

In one scenario, this is sufficient to flip the net cost of eliminating DS3 tariffs to a net benefit, but there is still a net cost in all other scenarios, albeit with a reduced magnitude. Therefore, our overall conclusions are largely unchanged.

Sensitivity to RP requirements

We understand from the TSOs that RP requirements are likely to exceed the levels achieved in the DAM and after procuring the necessary inertia. Therefore, we have run sensitivities to reflect a situation where the RP requirements would be 10% and 20% higher than the levels or RP lead and lag achieved after NEA to secure the inertia floor. This appears to increase costs from removal of tariffs in most cases.

At the request of the RAs, we have also run sensitivities with lower RP requirements, 5% and 10% below the levels achieved in the base case after NEA. Unsurprisingly, this reduces the benefits from tariffs in securing RP. These scenarios are inconsistent with what we told by the TSOs about system needs.

Sensitivity to zero COD participation

As a sensitivity, we have also shown calculations in which we make the alternative assumption that zero COD offers are all remain available to the TSOs to make up for the shortfall in reactive power. For reasons discussed above, we consider that this assumption is reflects an *unrealistic* polar case. In practice participation incentives for this units – who currently receive a wattless scalar – would be reduced, but it is not feasible to model this in detail for the current exercise. Therefore, we have look at this more extreme assumption as indication of the likely impact of only some units remaining.

Assuming maintenance of full participation by zero COD units is sufficient to shift to a slightly positive impact of removing DS3 tariffs, though the impact is still negative in one scenario. However, in practice we cannot expect all such units to remain, and this scenario needs to be interpreted accordingly. If we had *partial* participation of these units, we would obtain a result intermediate between the base case and this sensitive, which would likely again indicate an overall negative impact.

Overall conclusion

Figure 1 below illustrates the distribution of net cost calculations across the six scenario days for the different cases and sensitivities considered. The box-whisker plot shows:

- the median (vertical line within each box),
- the interquartile range (the box) and
- extreme values (whiskers/dots).

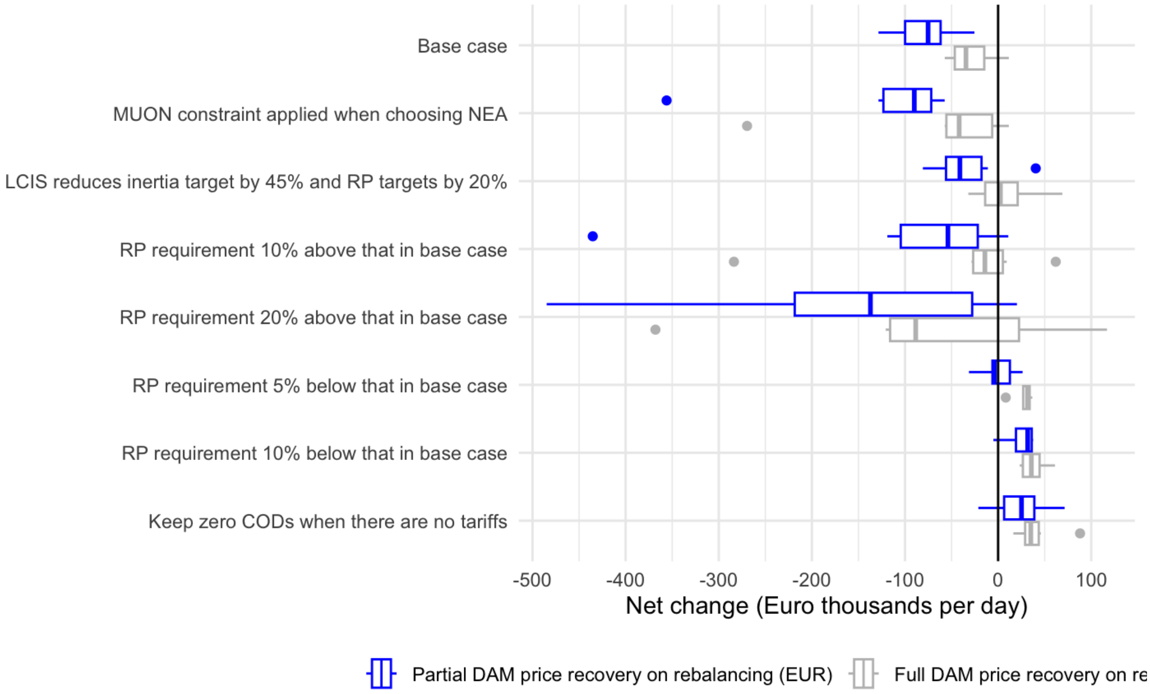
The blue boxes show the net change under our preferred assumption about rebalancing payments. The grey boxes show net changes under the most optimistic possible bounding case that rebalancing payments fully recover DAM clearing price payments to curtailed units. Our various alternative assumptions and sensitivities are listed vertically in Figure 1.

The results suggests that in most cases removal of tariffs risks a net cost.

The only alternative assumptions that yield a net benefit in a majority of scenarios involve either reducing the proxy reactive power target, which we are told by TSOs would not reflect actual system requirement, or assuming that removal of DS3 tariffs would not affect incentives for participation, which we consider unrealistic.

Notice that even in these cases, there are scenarios in which there are net costs. Therefore, even in these cases, there are situations in which DS3 tariffs are modulating DAM outcomes to reduce the need for NEAs.

Figure 1: Variation of net costs for different cases/sensitivities run



Overall, we conclude that eliminating DS3 tariffs would not lead to more cost-efficient procurement of the TSOs requirements and would likely increase overall costs to consumers.

This conclusion is perhaps unsurprising given the history of DS3 tariffs. They were introduced off the back of the 2014 SEM-C Decision not to use competitive procurement of these services, but rather to modulate energy market outcomes by providing incentives for units supplying these services to bid lower in their offers to turn on. These tariffs were set conservatively, so this modulating effect was unlikely to have been especially strong. Since then, nominal DS3 tariffs were decreased by roughly 25% in 2024 and there has been no adjustment for inflation. Therefore, this modulating effect on energy markets, inducing supply of system services, has been even weaker. Our findings above suggest that this situation is likely to be inefficient and that overall costs might be lower with somewhat larger DS3 payments, assuming these were reflected in energy bids.

Table 3: Estimated impact of removal of DS3 tariffs for SIR and SSRP

Case	Scenario	**Total savings on tariffs (EUR)**	Total consumer surplus loss (EUR)	Incremental cost of NEA to achieve inertia and RP target levels (EUR)	**Net change prior to rebalancing (considering tariff savings, consumer surplus loss from DAM and incremental NEA costs) (EUR)**	Change in revenue form rebalancing, assuming full DAM price can be recovered from full output reduction (EUR)	Change in revenue form rebalancing, assuming only part of DAM price can be recovered from full output reduction (EUR)	Change in revenue form rebalancing, assuming only part of DAM price can be recovered on 80% of output reduction (EUR)	Net change, assuming full DAM price can be recovered from rebalancing (EUR)	Net change, assuming only part of DAM price can be recovered from rebalancing (EUR)	**Net change, assuming only part of DAM price on 80% of output reduction can be recovered from rebalancing (EUR)**
Base case	Scenario_1	**63,200**	17,600	237,200	**-191,600**	183,100	142,400	113,900	-8,500	-49,200	**-77,700**
	Scenario_2	**49,300**	10,200	66,000	**-26,900**	-8,200	1,900	1,500	-35,100	-25,000	**-25,400**
	Scenario_3	**59,000**	13,500	317,300	**-271,800**	214,500	205,700	164,600	-57,300	-66,100	**-107,300**
	Scenario_4	**46,100**	10,200	177,200	**-141,200**	107,200	103,900	83,100	-34,000	-37,400	**-58,100**
	Scenario_5	**63,000**	28,000	132,000	**-97,000**	108,500	-39,400	-31,500	11,500	-136,400	**-128,500**
	Scenario_6	**63,200**	19,100	183,800	**-139,700**	89,300	83,700	67,000	-50,400	-56,000	**-72,700**
MUON constraint applied when choosing NEA	Scenario_1	**63,100**	17,600	229,000	**-183,400**	186,100	139,900	111,900	2,600	-43,600	**-71,500**
	Scenario_2	**48,000**	10,200	361,500	**-323,800**	54,200	-40,200	-32,200	-269,600	-364,000	**-356,000**
	Scenario_3	**59,000**	13,500	317,300	**-271,800**	214,500	205,700	164,600	-57,300	-66,100	**-107,300**
	Scenario_4	**46,100**	10,200	176,300	**-140,400**	107,100	103,800	83,000	-33,300	-36,600	**-57,400**
	Scenario_5	**63,000**	28,000	132,000	**-97,000**	108,500	-39,400	-31,500	11,500	-136,400	**-128,500**
	Scenario_6	**63,200**	19,100	183,800	**-139,700**	89,300	83,700	67,000	-50,400	-56,000	**-72,700**
Reduced inertia requirements due to LCIS (inertia 45% lower, RP 20% lower)	Scenario_1	**53,300**	17,600	212,500	**-176,800**	203,300	173,000	138,400	26,600	-3,700	**-38,300**
	Scenario_2	**45,700**	10,200	96,400	**-60,900**	65,100	1,200	900	4,200	-59,800	**-60,000**
	Scenario_3	**57,000**	13,500	173,500	**-129,900**	111,100	107,600	86,100	-18,800	-22,300	**-43,800**
	Scenario_4	**45,300**	10,200	88,600	**-53,500**	54,300	53,100	42,500	700	-400	**-11,000**
	Scenario_5	**52,100**	28,000	153,400	**-129,300**	97,300	60,500	48,400	-32,000	-68,700	**-80,800**
	Scenario_6	**61,700**	19,100	77,300	**-34,700**	103,700	93,900	75,200	69,000	59,200	**40,400**
RP requirement 10% above that in base case	Scenario_1	**64,900**	17,600	312,300	**-264,900**	257,700	182,300	145,900	-7,200	-82,600	**-119,000**
	Scenario_2	**51,800**	10,200	427,400	**-385,900**	102,100	-61,800	-49,500	-283,700	-447,700	**-435,300**
	Scenario_3	**59,300**	13,500	236,600	**-190,700**	169,500	161,900	129,500	-21,200	-28,800	**-61,200**
	Scenario_4	**46,400**	10,200	144,100	**-107,900**	79,300	76,600	61,200	-28,600	-31,300	**-46,600**
	Scenario_5	**65,000**	28,000	73,200	**-36,100**	45,400	28,200	22,600	9,200	-7,900	**-13,600**
	Scenario_6	**64,200**	19,100	166,800	**-121,700**	183,600	165,800	132,600	61,900	44,000	**10,900**
RP requirement 20% above that in base case	Scenario_1	**66,000**	17,600	430,000	**-381,500**	279,700	174,500	139,600	-101,800	-207,000	**-241,900**
	Scenario_2	**53,000**	10,200	498,800	**-456,100**	88,100	-35,900	-28,700	-368,000	-491,900	**-484,800**
	Scenario_3	**59,900**	13,500	317,300	**-270,900**	387,800	363,900	291,100	116,900	93,000	**20,200**
	Scenario_4	**47,000**	10,200	269,700	**-232,900**	112,200	106,400	85,100	-120,700	-126,500	**-147,800**

	Scenario_5	**66,000**	28,000	196,500	**-158,500**	83,400	40,200	32,100	-75,200	-118,400	**-126,400**
	Scenario_6	**64,500**	19,100	171,500	**-126,100**	181,200	163,900	131,100	55,000	37,800	**5,000**

Case	Scenario	**Total savings on tariffs (EUR)**	Total consumer surplus loss (EUR)	Incremental cost of NEA to achieve inertia and RP target levels (EUR)	**Net change prior to rebalancing (considering tariff savings, consumer surplus loss from DAM and incremental NEA costs) (EUR)**	Change in revenue form rebalancing, assuming full DAM price can be recovered from full output reduction (EUR)	Change in revenue form rebalancing, assuming only part of DAM price can be recovered from full output reduction (EUR)	Change in revenue form rebalancing, assuming only part of DAM price can be recovered on 80% of output reduction (EUR)	Net change, assuming full DAM price can be recovered from rebalancing (EUR)	Net change, assuming only part of DAM price can be recovered from rebalancing (EUR)	**Net change, assuming only part of DAM price on 80% of output reduction can be recovered from rebalancing (EUR)**
RP requirement 5% below that in base case	Scenario_1	**62,900**	17,600	172,600	**-127,300**	152,900	120,000	96,000	25,700	-7,300	**-31,300**
	Scenario_2	**49,300**	10,200	14,500	**24,600**	7,800	2,100	1,600	32,500	26,700	**26,300**
	Scenario_3	**59,000**	13,500	180,200	**-134,700**	168,900	162,600	130,000	34,300	27,900	**-4,600**
	Scenario_4	**46,100**	10,200	84,500	**-48,600**	85,300	83,100	66,500	36,700	34,500	**17,900**
	Scenario_5	**63,000**	28,000	30,600	**4,400**	26,200	-9,300	-7,500	30,600	-4,900	**-3,100**
	Scenario_6	**63,200**	19,100	97,500	**-53,400**	61,600	58,600	46,800	8,200	5,100	**-6,600**
RP requirement 10% below that in base case	Scenario_1	**63,200**	17,600	102,400	**-56,700**	79,900	64,500	51,600	23,200	7,800	**-5,100**
	Scenario_2	**49,300**	10,200	3,800	**35,300**	2,400	1,500	1,200	37,700	36,800	**36,500**
	Scenario_3	**59,000**	13,500	90,200	**-44,700**	105,900	102,800	82,300	61,100	58,100	**37,500**
	Scenario_4	**46,100**	10,200	44,200	**-8,300**	55,200	54,000	43,200	46,800	45,700	**34,900**
	Scenario_5	**63,000**	28,000	16,200	**18,800**	14,900	12,200	9,700	33,700	31,000	**28,600**
	Scenario_6	**63,200**	19,100	58,600	**-14,500**	38,700	38,100	30,500	24,200	23,600	**16,000**
Keep zero CODs in counterfactual	Scenario_1	**63,400**	17,600	137,300	**-91,500**	107,900	87,900	70,300	16,400	-3,600	**-21,200**
	Scenario_2	**49,300**	10,200	21,700	**17,400**	10,100	1,100	900	27,500	18,500	**18,300**
	Scenario_3	**59,000**	13,500	32,600	**12,900**	75,100	73,100	58,500	88,000	86,100	**71,400**
	Scenario_4	**46,100**	10,200	13,200	**22,700**	23,200	23,100	18,500	45,900	45,900	**41,200**
	Scenario_5	**63,000**	28,000	23,100	**11,900**	21,500	-11,700	-9,400	33,400	200	**2,500**
	Scenario_6	**63,200**	19,100	30,500	**13,600**	23,200	22,800	18,300	36,800	36,500	**31,900**

3.9 Implications for ramping products

We note that similar logic applies partially to DS3 payments for RMX products. At the margin, these payments provide an incentive for bidders to make energy market and BM bids that would increase the chances of review these payments. In particular, units need to achieve energy positions across multiple periods compatible with being able to be being ramped over all those periods.

However, we have not attempted to model this due to the significantly greater complexity involved. In particular, incentives to adopt an energy position compatible with achieving ramping payments depend on the probability of also being able to achieve compatible positions in other associated periods. Therefore, bidders are only likely to be able to exercise imperfect control on whether ramping payments are achieved. Given this, we are likely to see effects on energy bids smeared over multiple periods involved in qualifying for ramping payments.

Given this, we would expect that *at the margin* there may be a reduction in the supply of ramping achieved by energy markets, for similar reasons as for inertia and reactive power, discussed above. Given less supply of ramping for energy market outcomes, the TSOs then need to move units' energy positions to allow for flexibility to increase or decrease output over successive periods, again through NEAs. We have not sought to assess these costs.

4 Long-run procurement options

This report is primarily concerned with interim arrangements for procurement of the three non-reserve services. However, in this section will provide preliminary observations regarding long-run options for procurement of these three system services if redefinition of products is possible. We emphasise that these are preliminary views and that a more detailed understanding of the TSOs' operational requirements and the capabilities and preferences of potential suppliers would be needed to confirm and refine these comments. We only seek to identify clearly infeasible options and what remaining options might warrant further investigation.

Committed supply

We first note that the High Level Design[6] set out by the SEM-C envisages competitive procurement of system services on a 'firm' basis. By this we mean that a supply commitment is allocated to a supplier some time ahead of real time. If the commitment is breached and that supply is not forthcoming, the supplier faces some adverse consequence from non-supply (such as a need to make a compensatory payment, or application of a non-performance scalar).

Volume requirements

Given our preceding discussion of the infeasibility of using SIR and SSRP as a base for competitive procurement, we focus on product definitions that link direct to physically interpretable volumes. Such requirements at least have the logical possibility of being evaluated by the TSOs.

For inertia, we already have a current inertia floor (23,000 MVAs). We understand that the TSOs have a current tool for forecasting ramping margin needs.

For reactive power, identifying volume requirements is much more complex due to the localisation of these requirements and the variation in needs with composition of system load. We understand that the TSOs consider that evaluating volume requirements would be challenging. We have not considered the feasibility of such an exercise, but clearly it is a prerequisite for any quantity-based competitive procurement mechanism.

[6] SEM-22-012 System Services Future Arrangements High Level Design Decision Paper

4.1 Inertia

A redefined inertia service could be based simply on physical inertia (or equivalently kinetic energy). This would be procured on a committed basis, in that a unit supplying the service would be required to be synchronised, otherwise they would face adverse consequences. This approach would potentially allow for technologically neutral procurement, as there is a common basis for measuring quantities supplied by different units.

The current inertia floor suggests that it would be feasible to set a single national volume requirement.

Daily auction option

There are significant similarities with the approach to be adopted for reserve services, in which suppliers of reserve need to ensure compatible PNs otherwise they may face consequences from non-supply. Failure to supply could occur through TSO energy actions (i.e. instructing a unit to turn off). Therefore, further consideration of non-supply consequences would be needed to ensure that excessive risk was not being placed on committed suppliers of inertia. Subject to this provision, it appears feasible to use a broadly similar approach for inertia to that taken with the DASSA for reserve services.

Longer term auctions

Longer run competitive options – LPF or long-term auctions – are likely to be unattractive due to the strong interaction between energy market outcomes and the ability of units to supply inertia. Requiring units to commit far ahead to supply inertia places risk on suppliers that may not be synchronised at the required times. The further ahead commitment is required, the greater this risk.

If non-supply is consequential for committed suppliers, bids to supply the service will be increased to compensate for carrying this. Therefore, considerations both of cost efficiency and achieving system stability requirements reliable would appear better met by daily auctions than longer term alternatives.

Price-based procurement

A competitive quantity-based mechanism is not always preferable to a price-based procurement mechanism. Conclusions depend on the context.

Here we have the complication that all our competitive procurement options are based on setting a quantity requirement *in advance*. In some cases, the outturn requirement (at real time) is not known with certainty. Because a quantity requirement for an auction needs to be set in advance, it becomes necessary to include a precautionary buffer within that requirement. The greater this uncertainty, the larger this buffer needs to be to ensure that the outturn requirement is met with sufficient certainty. As a result, we will tend to over-procure quantity on average, but this is needed to limit the probability of under-procuring to an acceptable level.

In contrast, price-based procurement means setting a price in advance that is likely to induce sufficient supply of the service to meet the outturn volume requirement. In a simplistic view, if we know the aggregate supply curve, we pick the price to induce the quantity we want. In practice, we do not know this supply curve with certainty, and it may well be subject to shocks subsequent to having set a price. We will typically pick a single fixed price in advance that must cope with a variety of scenarios for both the TSOs' outturn volume requirement and the aggregate supply curve.

Perhaps surprisingly, there are circumstances in which price-based procurement can lower these risks and mean that we can reduce the average extent of over-procurement that can result. This can happen when the TSOs' outturn volume requirements are *positively* correlated with supply shocks. Put simply, if when the TSOs need more, then the suppliers tend to supply more at a fixed price. These circumstances can make price-based procurement more efficient than quantity-based procurement as on average there is less precautionary over-procurement.

On the basis of current practice, we see that the TSOs' have a constant inertia floor that does not vary. Therefore, these circumstances simply do not apply for inertia as there is unlikely to be any such correlation between shock on demand and supply sides.

In passing, we note that for *reserve* services we have the situation that there will tend to be greater need for reserve services when system load is greater and, consequently, supply of reserve services is diminished. Therefore, there is likely to be *negative* correlation between supply and demand shocks. This tends to disfavour use of a price-based mechanism as it makes demand and supply shocks reinforcing. Given this, moves to prioritise competitive procurement of reserve services have a justification. In comparison, inertia is similar in many ways to reserve services and admits a similar approach to the DASSA. However, lack of correlation between requirements and supply for inertia suggest that benefits of moving to competitive quantity-based procurement may be smaller than for reserve services.

4.2 Reactive power

Based on the TSO's physical requirements, we need service definitions based on either the production or absorption of reactive power at certain locations. Without substantial further analysis of the TSOs' needs, we cannot say much more about these localities. However, it is plausible that many tens of locations could be needed, based on the TSOs current practice of collecting statistical data on reactive power across 13 areas. We understand from the TSOs that these areas are likely to be too coarse to represent localised requirements, so only give a lower point on the likely requirements.

The TSOs need absorption or production depending on system conditions. High load conditions tend to need production of reactive power due to more inductive loads, and low load conditions to need absorption of reactive power. However, conditions can vary locally depending on the nature of loads and whether reactive power is being passed through one area to meet need in another. The overall situation is complex and capability for both absorption and production is likely to be needed.

Whilst it is possible that some auction designs could accommodate these features, they would be complex and involve 'black box' algorithms to select efficient winning outcomes from bids. However, this would still leave several major problems.

First, we expect localisation of reactive power requirements to lead to market power problems, due to the limited number of suppliers within these localities. Whilst there are some design features that might mitigate this, such as considering 'soft' boundaries and including the possibility of suppliers at different locations partially substituting for each other, ultimately it would probably require reserve prices to protect against high price outcomes. This leaves in a situation not much different to price-based procurement.

Second, to the extent that there is competition, we do not expect much competition. Market thinness may lead to volatile prices and lack of clear price signals for investors. Indeed, high prices may not necessarily attract entry, as investors may consider that these prices would not be sustained post-entry.

Third, there are TSO-led alternatives, such as building synchronous condensers (which can absorb or produce reactive power). These alternatives should limit the amount that the TSOs are prepared to pay for these services over the long run. However, setting a reserve price to reflect this is difficult, as in the short-run the TSOs need reactive power before such facilities can be built. In practice such investment decisions need to be driven by price signals, but these are likely to be poor.

Fourth, we are sceptical about whether it is feasible for the TSOs to define precise volume requirements for reactive power by locale.

These requirements depend on system load which is not entirely predictable. Also, measures to procure inertia to some degree interact with provision of reactive power. Inertia requirements may lead to more plants being synchronised than strictly necessary for energy needs. This can have the collateral effect of inducing additional reactive power. If the TSOs were trying to procure their entire reactive power needs through short term auctions, then this interaction with procurement of inertia services would need to be considered.

Short-term auctions

Overall, we consider that these problems are sufficient to consider that a short-term (e.g. daily) auction of reactive power services is infeasible.

Longer-term auctions

It is possible to image longer-term auctions of *tranches* of reactive power need through longer term contracts. The advantage of this approach is that such auctions can be run on a rolling basis and seek to meet part of the need in some area. This can avoid the need to precisely define the *entire* volume requirement that might be needed with short term auctions.

Where long term commitments to provide reactive capability are made, it may be difficult to do this off the back of making a generating unit available and synchronised across that period. Again, there may be risk of being turned off for energy market reasons that are difficult for the supplier to control. Therefore, competitive procurement of long-term contracts may better suit dedicated infrastructure such as synchronous condenser that can more easily commit to supply.

Under this approach, long-term contracts might not necessarily meet the entire reactive power requirement, as this may be difficult for the TSOs to determine with any precision. Therefore, there might still be a role for NEAs in making up shortfalls. Without this short-run flexibility, volumes procured through long-term contracts might need to be significantly higher to cover the worst case needs of TSOs.

Price-based procurement and mixed approaches

Suppose that some mixed approach were adopted, with competitive long-term contracts and some residual short-run 'swing' provision through NEAs. Would there be any role for DS3-type payments to induce supply of reactive power in energy market outcomes and reduce need for NEAs? Our analysis of short run options suggests that such tariffs might be cheaper than having to make additional NEAs. This is difficult to judge and needs further consideration, beyond the scope of this report.

4.3 Ramping margins

We have not sought to evaluate whether ramping margin services meet needs of the TSOs that could not be meet in other ways. Whilst in principle this is possible, RMX services provide guarantees that that balancing will be possible across multiple periods whereas using the BM relies on adequate BM offers being available in all the relevant BM periods as they occur. Therefore, arguably these ramping margin services can provide more certainty to the TSOs of their ability to meet demand shocks, especially where these shocks persist over longer time periods. They also allow the TSOs to ensure that there will be sufficient participation in the BM and mean that the TSOs are not at risk of having insufficient balancing capacity if the BM is thin.

Short-term auctions

In principle, there is no obvious difficulty in having an RMX-type service that entails a commitment to provide some volume of ramping (up or down) over some period. The complication is that it would be an ex-ante basis and entail some commitment to supply that service, which in turn depends on the unit's PN across multiple periods. Therefore, similar challenges arise as with reserve services in that we need to determine what happens if the supplier cannot meet its obligation due to TSO actions outside its control. If too much risk is placed on the supplier, this will simply lead to higher prices being needed to offer the service.

Clearly further consideration is needed of the risks created for suppliers that moving ramping margin services to an *ex ante* service that requires commitment over extended periods well ahead of real time. Whilst it might formally be possible using short-run auctions similar to the DASSA, imposing too much risk on chosen supplier will increase their costs, increase bids and reduce participation. Therefore, it is far from clear that daily auctions would necessarily be better than tariffs. Detailed quantitative analysis would be complex and beyond the scope of this exercise.

Long-term auctions

For similar reasons, we can largely rule out longer-term auctions. These would further raise risks facing suppliers not being able to meet supply obligations in the more distant future (where energy market outcomes are more difficult to forecast).

Price-based mechanisms

As indicated above, any quantity-based competitive mechanism involves a commitment to supply a service if the supplier is selected. If there are uncontrollable risks of not meeting this commitment – because of the need to achieve compatible energy positions over many periods – this needs to be priced into bids.

If this risk is large enough, it may be cheaper overall to use a price-based mechanism such as DS3 that make payments after the event if the service has been supplied. This provides a positive incentive for units to supply the ramping margin service, but does not face them with a negative consequence if they fail to supply (other than loss of the payment). However, this needs to be balanced with the difficulty in setting an efficient tariff due to lack of information. Therefore, it is far from obvious what the best overall approach might be and we cannot necessarily assume that short-run auctions would be superior without further analysis.

4.4 Interim conclusions

We emphasise this is a cursory analysis and conclusions are provisional only. We understand EirGrid is currently undertaking work on the potential design of new non-reserve products which has yet to conclude. We have not validated our initial observations on procurement design given above against this EirGrid workstream.

With these caveats, we find that:

- The use of short-term (daily) auctions for inertia appears feasible. Broadly similar issues arise as for reserve services (namely what the consequences of a supply commitment might be). Longer term auctions or price-based procurement appear less attractive.
- Reactive power is complex, with difficulty in defining localised requirements. This complexity makes it difficult to see how a daily auction of the entire requirement could be feasible. A more incremental approach of procuring tranches of long-term capacity may be indicated. However, even then some need for short-term provision of additional reactive power may be needed through NEAs, in which case some residual role for price-based procurement of some residual requirements might still be desirable to induce some supply through modulating energy market outcomes.
- For ramping margin, the main issue is how a commitment to supply should operate across multiple periods of the energy markets (and BM) and what consequences there might be from non-supply. They also involve missing out on payments for energy, so have a significant opportunity cost

for suppliers, who may then be unwilling to carry significant risks arising from non-supply consequences. Because ramping margins involve multiple periods, the risks facing committed suppliers are much more significant that for reserve services. This largely rules out use of longer-term competitive processes, as suppliers would need to commit to energy positions compatible with ramping margin supply too far ahead. A similar, but less severe, issue still arises for daily auctions. Therefore, whilst a daily auction might be feasible, it is far from clear that this would deliver better outcomes than tariffs.

Annex A Impact of removal DS3 tariffs on DAM outcome

Below we illustrate the impact of removal of DS3 tariffs on the DAM clearing price and traded volume predicted by our model by hour, as well as the impact on consumer surplus.

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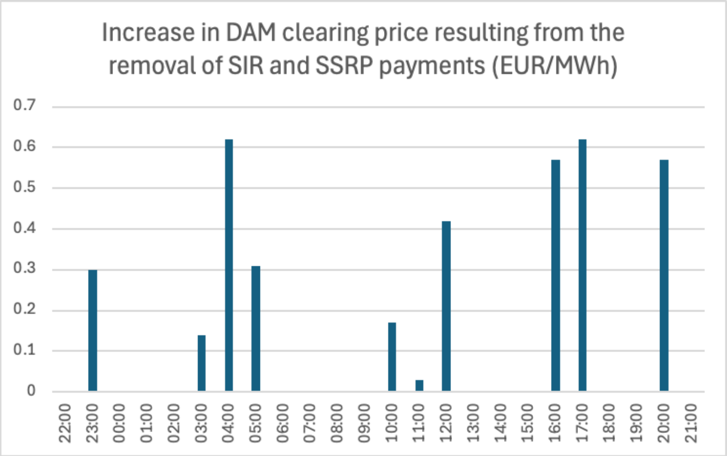

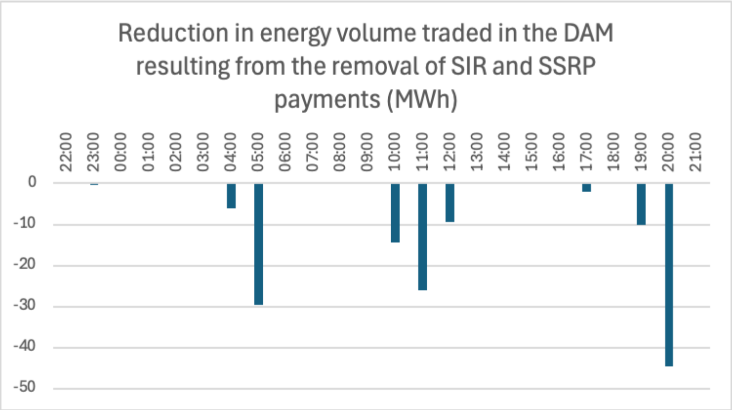

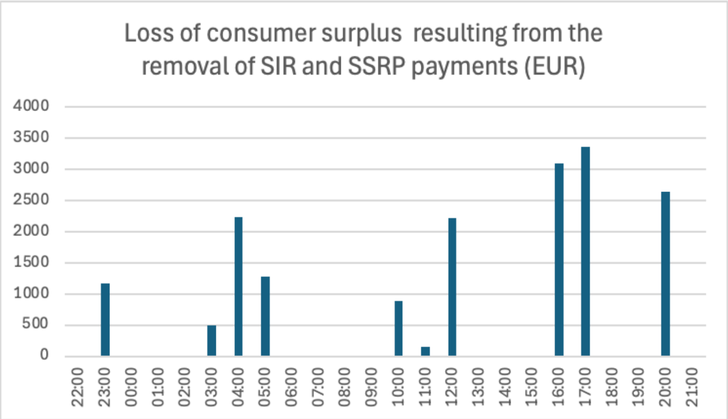

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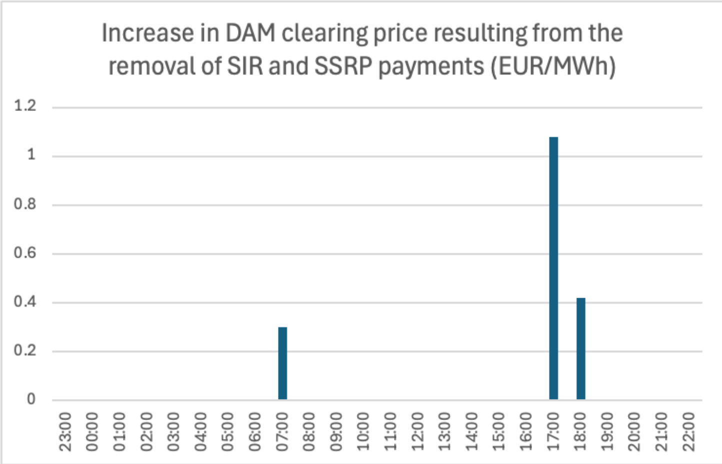

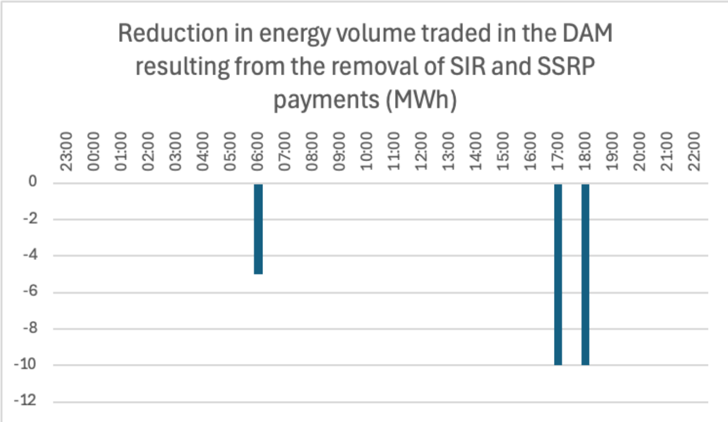

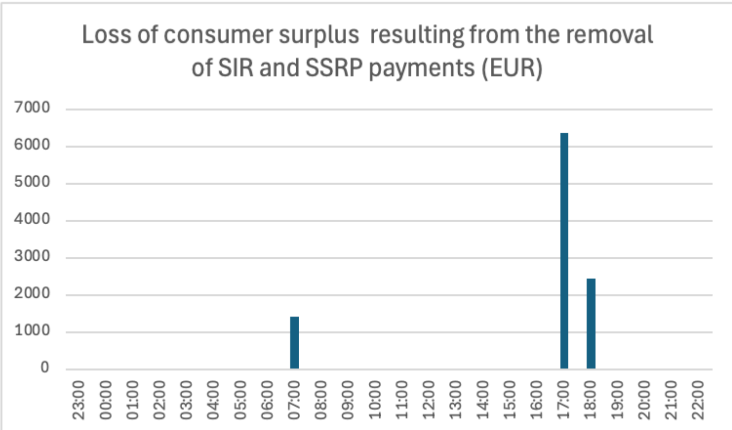

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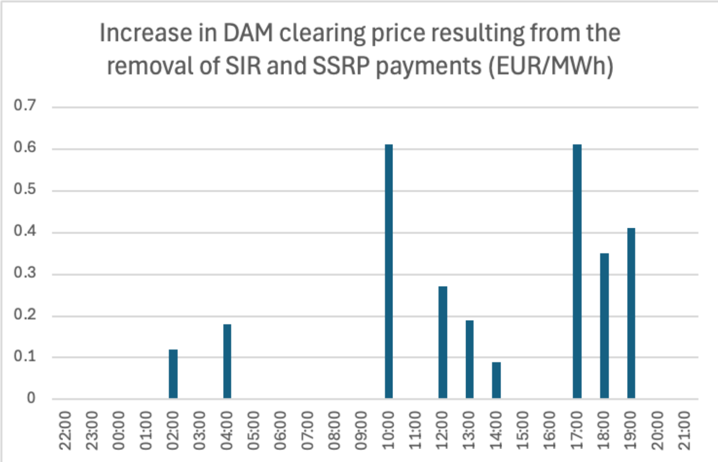

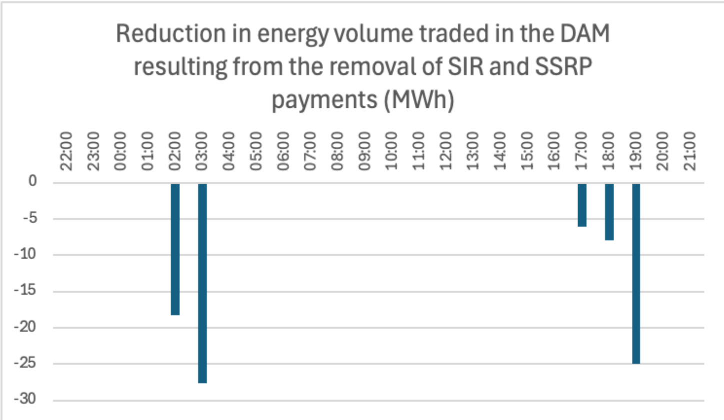

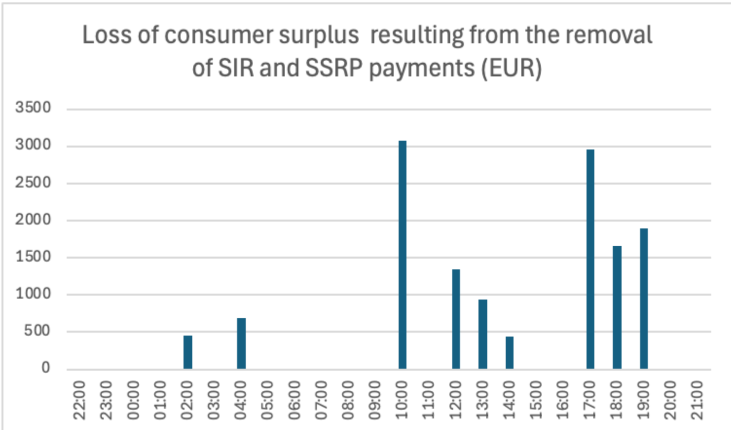

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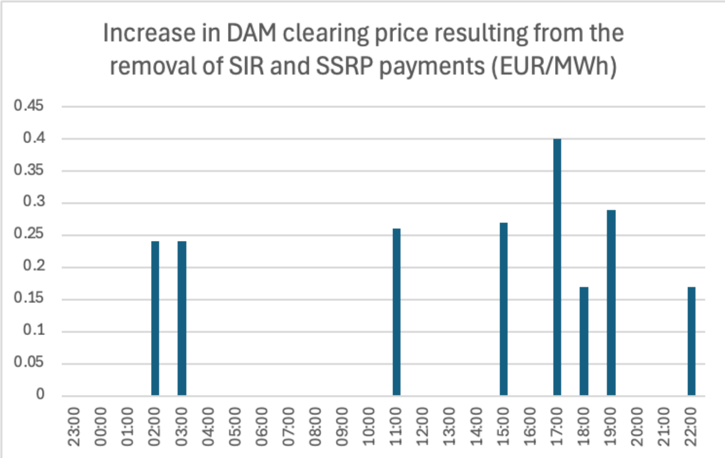

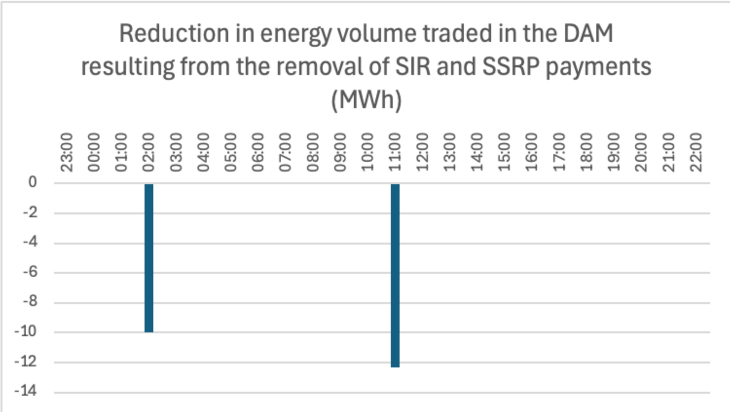

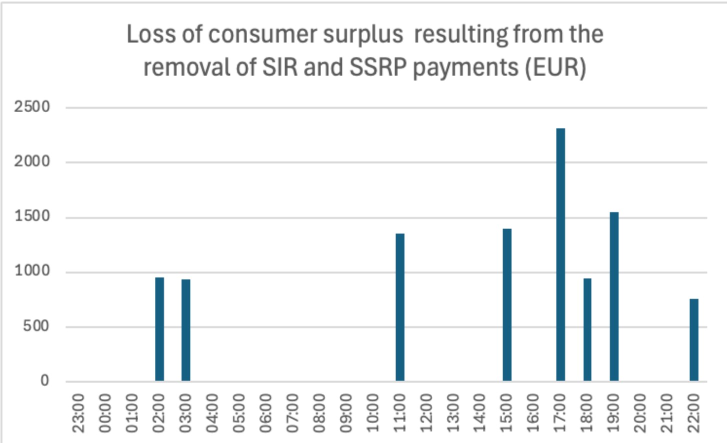

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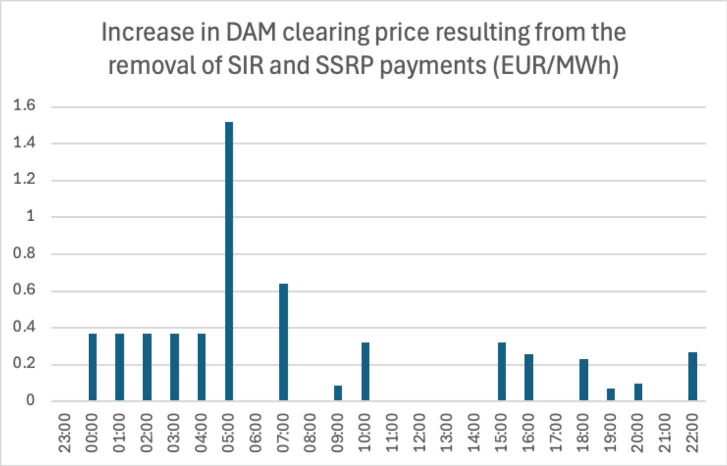
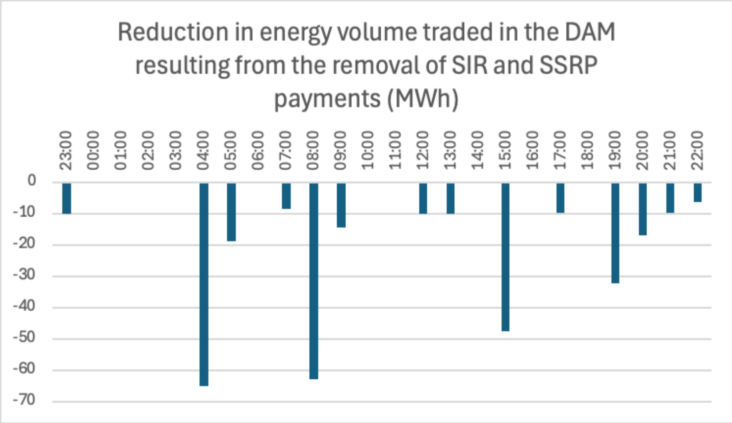
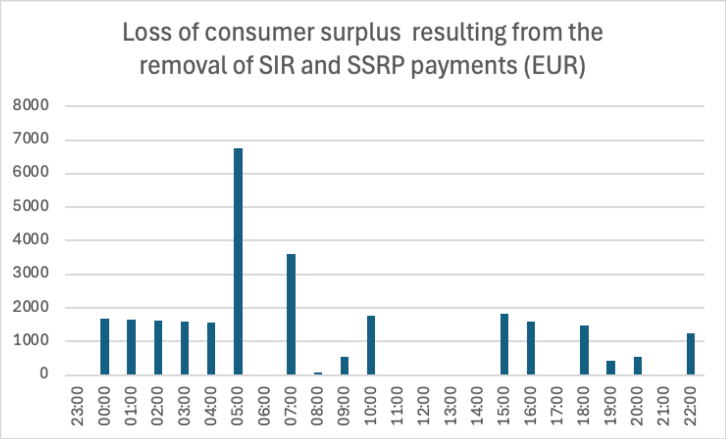
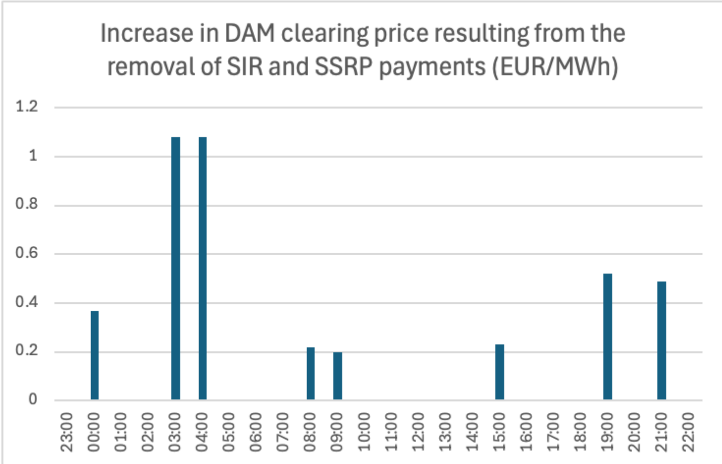
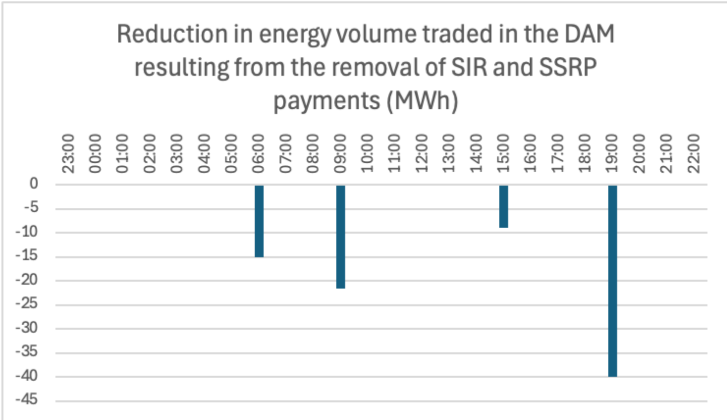


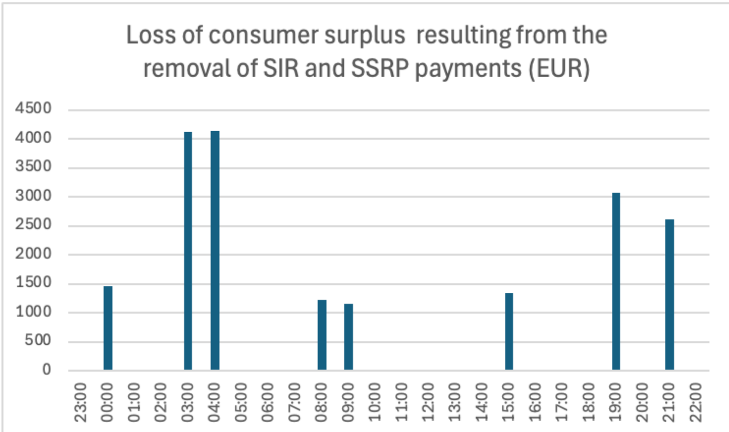




A.6 Scenario 6







Annex B Impact of removal DS3 tariffs on inertia and reactive power procured prior to Non-Energy Actions

Below we illustrate the impact of removal of DS3 tariffs on the volumes of inertia and reactive power procured prior to Non-Energy Actions predicted by our model for each of the six scenarios by period.

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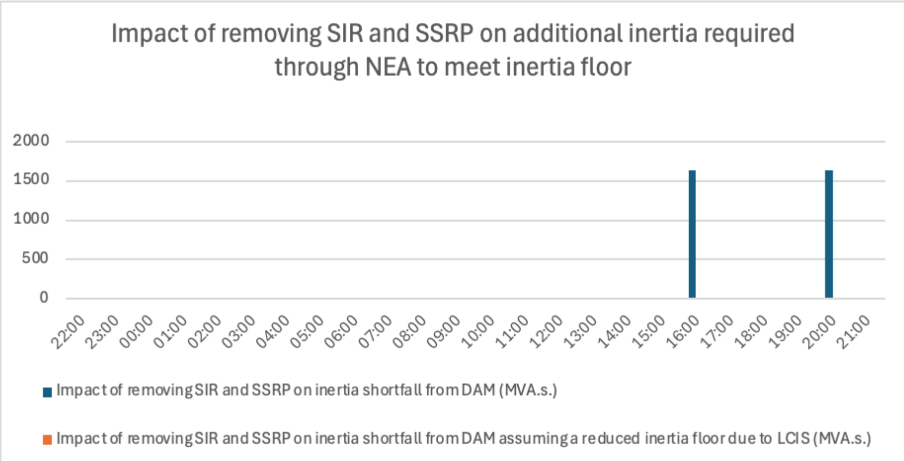

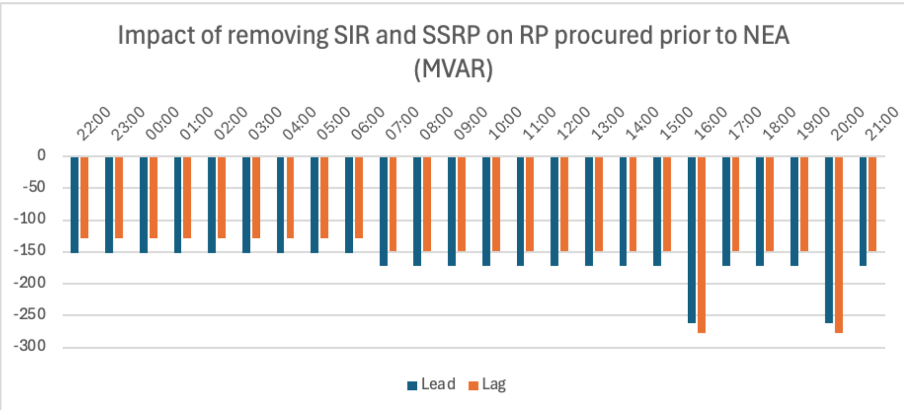

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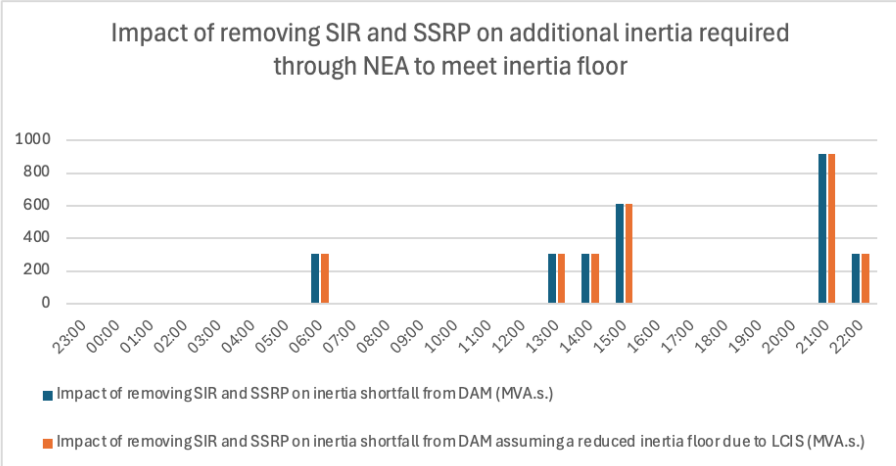

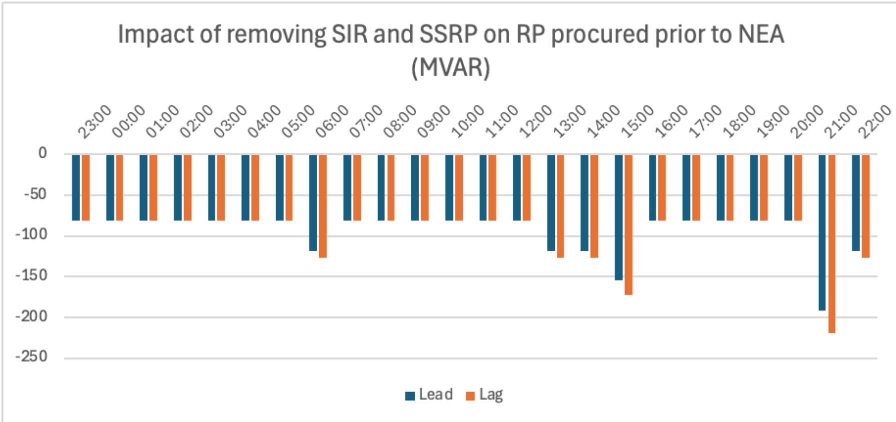

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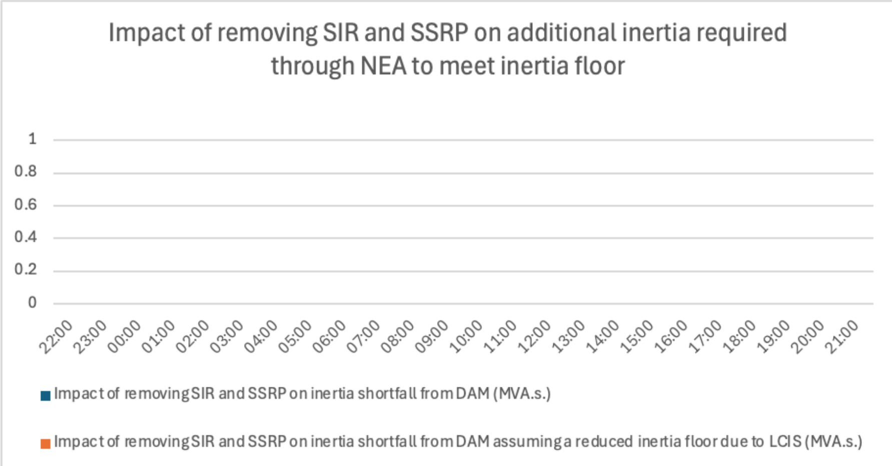

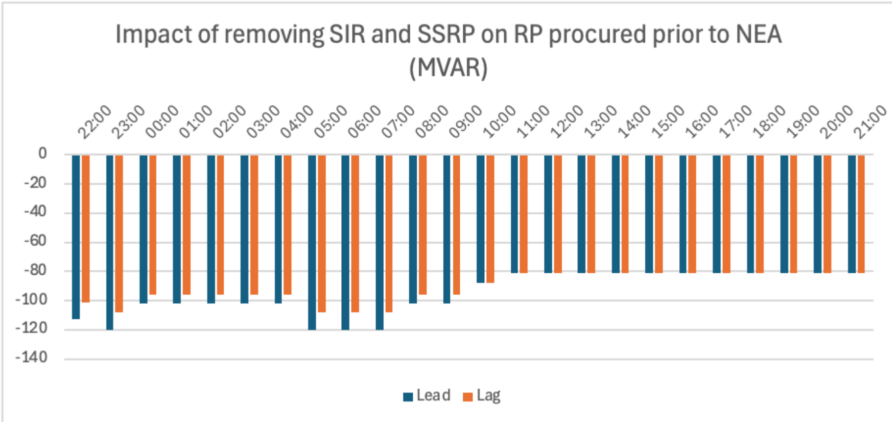

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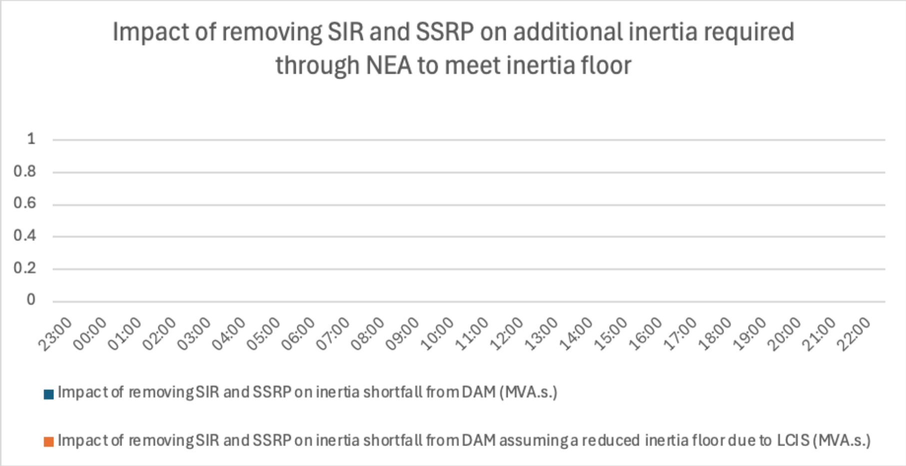

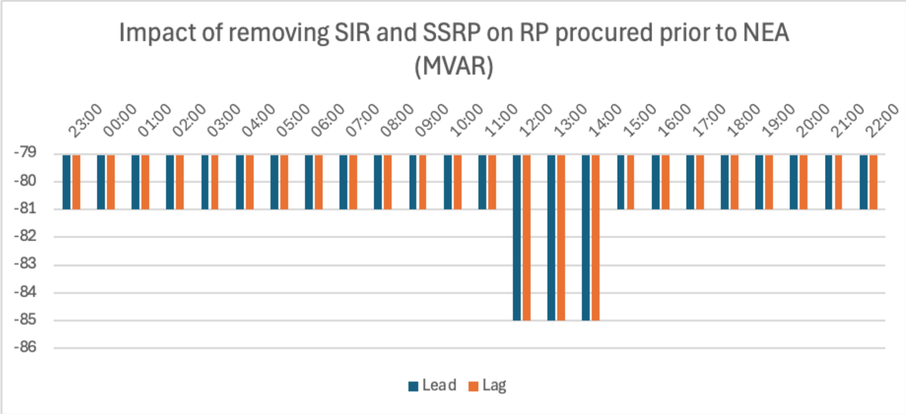

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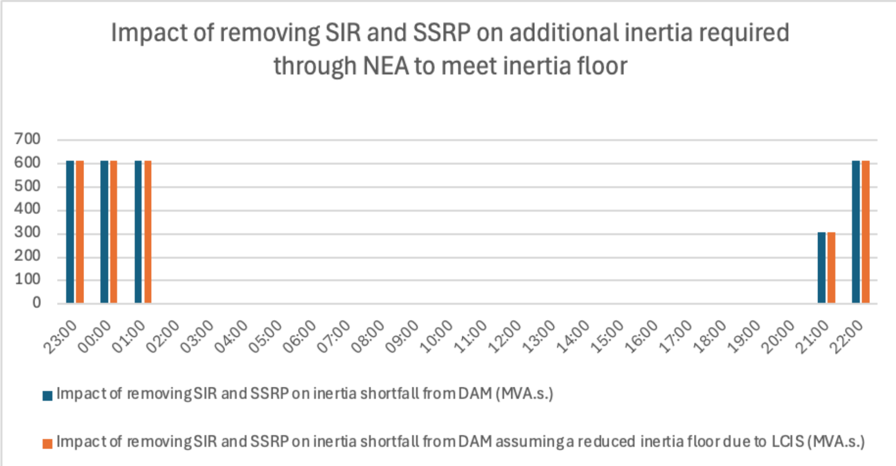

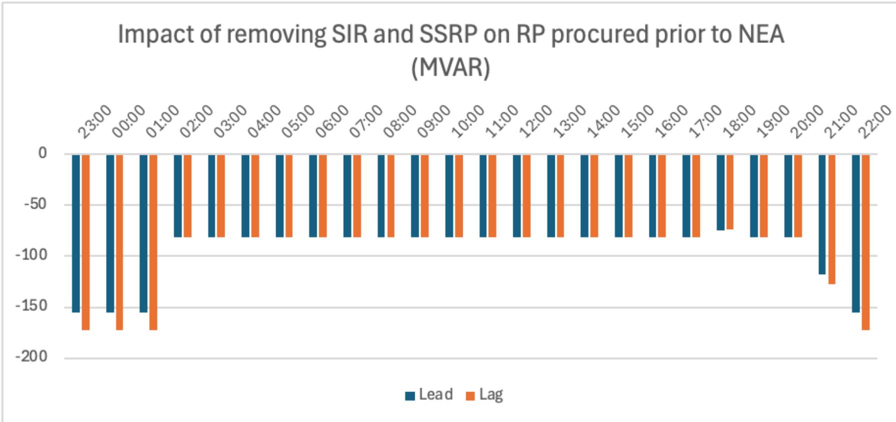

B.6 Scenario 6