TECHNICAL WORKING GROUP

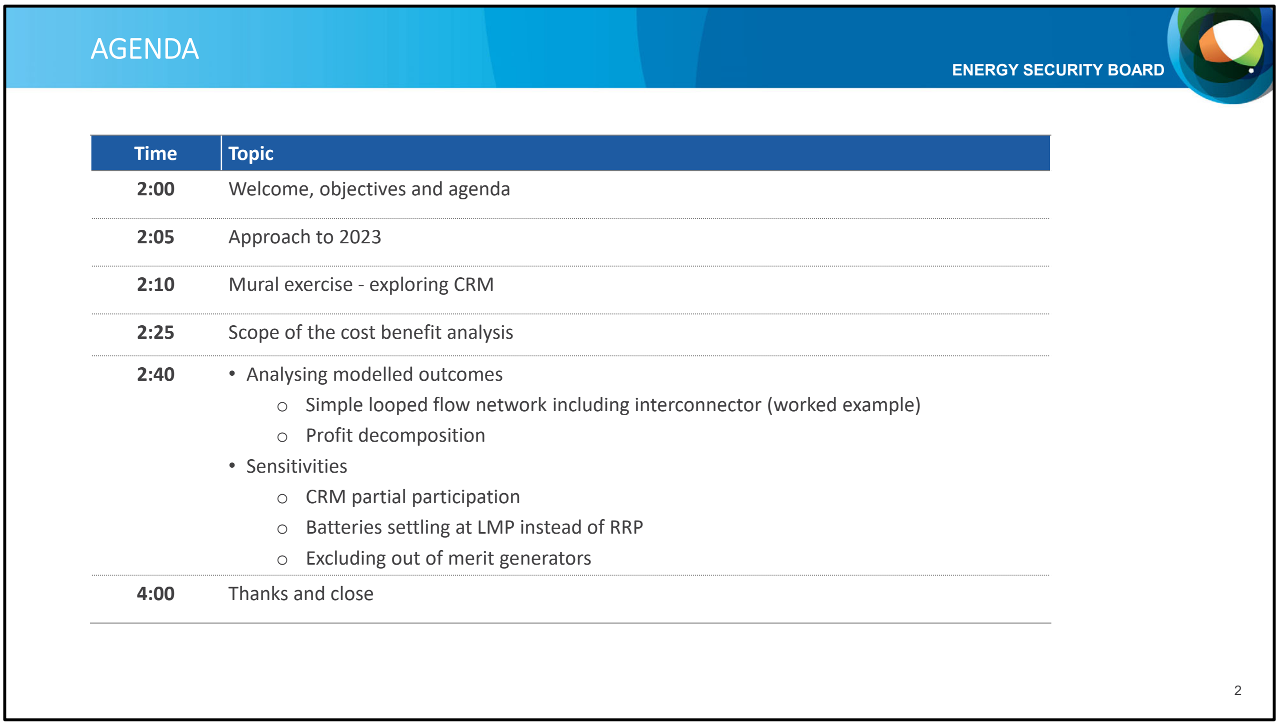
TRANSMISSION ACCESS REFORM

ENERGY SECURITY BOARD

1 DECEMBER 2022

The following slides are presentation materials shared with the ESB transmission access reform Technical Working Group (TWG) on 1 December 2022.

The Notes view is particularly helpful for readers to interpret slides 9-31.



AGENDA

ENERGY SECURITY BOARD

Time	Topic
2:00	Welcome, objectives and agenda
2:05	Approach to 2023
2:10	Mural exercise - exploring CRM
2:25	Scope of the cost benefit analysis
2:40	• Analysing modelled outcomes ○ Simple looped flow network including interconnector (worked example) ○ Profit decomposition • Sensitivities ○ CRM partial participation ○ Batteries settling at LMP instead of RRP ○ Excluding out of merit generators
4:00	Thanks and close

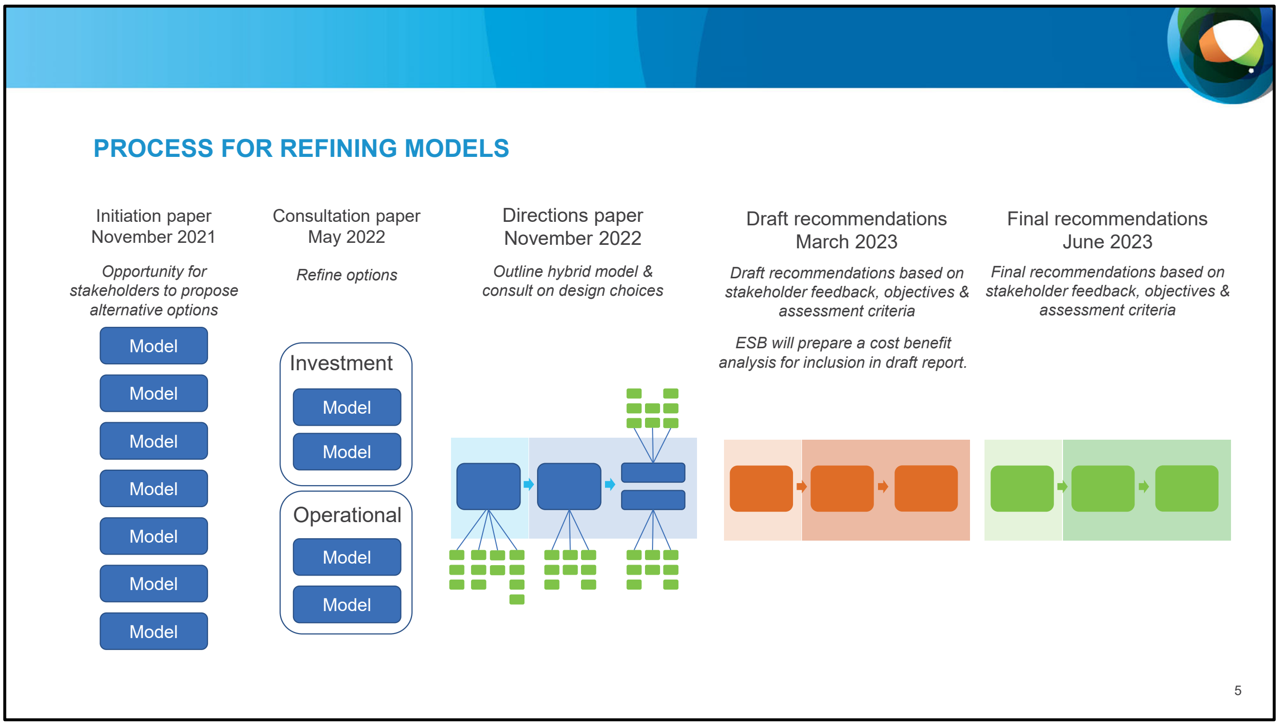
APPROACH TO 2023

NEXT STEPS

28 October Energy Ministers' meeting

Ministers committed to resolving congestion management as a key near term priority. Ministers noted that the ESB will issue a Direction Paper on a subset of the options under consideration. Ministers tasked Senior Officials to jointly undertake stakeholder consultations with the ESB on the full range of options, with recommendations to be considered at the first Energy Ministers' Meeting in 2023.

5 December	Technical workshop (webinar)
21 December	Deadline for submissions
25 January	Joint ESB/Senior Officials public forum
February 2023	Energy Ministers' meeting



PROCESS FOR REFINING MODELS

Initiation paper
November 2021

Opportunity for stakeholders to propose alternative options

- Model
- Model
- Model
- Model
- Model
- Model
- Model

Consultation paper
May 2022

Refine options

Investment
- Model
- Model

Operational
- Model
- Model

Directions paper
November 2022

Outline hybrid model & consult on design choices

Draft recommendations
March 2023

Draft recommendations based on stakeholder feedback, objectives & assessment criteria

ESB will prepare a cost benefit analysis for inclusion in draft report.

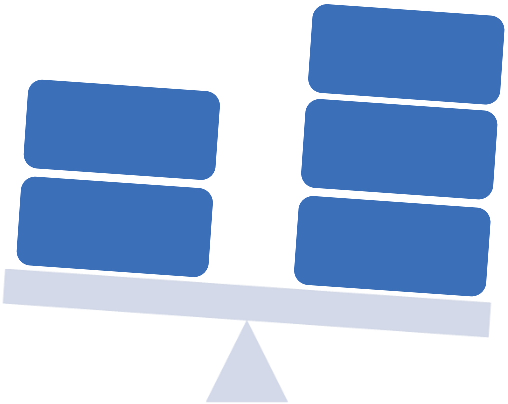
Final recommendations
June 2023

Final recommendations based on stakeholder feedback, objectives & assessment criteria

COST BENEFIT ANALYSIS

PROPOSED APPROACH TO COST BENEFIT ANALYSIS

- Cost benefit analysis to provide qualitative and quantitative assessment of options
- Key focus of cost benefit analysis to be use cases
  - Provide more tangible examples of how arrangements will change
- Supported by quantitative cost benefit analysis
  - Complexity of reforms and dynamic market environment means that a precise dollar impact is unrealistic
  - Rather, we seek to gain an understanding of trends, magnitudes, differences between the options



PROPOSED APPROACH TO COST BENEFIT ANALYSIS

Model element	Costs	Benefits
Congestion relief market	• AEMO implementation costs • Industry costs – assume industry participants only shift over if participant benefits>participant costs	• Improved dispatch efficiency – NERA modelling [supplemented by % improvement in dispatch efficiency based on international experience] • Change in cost of capital
Congestion management model	• AEMO implementation costs • Industry systems costs	• Improved dispatch efficiency – NERA modelling [supplemented by % improvement in dispatch efficiency based on international experience] • Change in cost of capital
Priority access	• Additional AEMO costs over basic CRM • Industry systems costs over basic CRM • Costs of holding auctions	• Change in cost of capital • % improvement in efficiency of capex spend [assumption based on international experience]
Congestion fees	• Ongoing administrative costs – AEMO and TNSPS	• Change in cost of capital • % improvement in efficiency of capex spend [assumption based on international experience]
Enhanced information	• Ongoing administrative costs – AEMO and TNSPS	• Qualitative assessment?

MODELLING

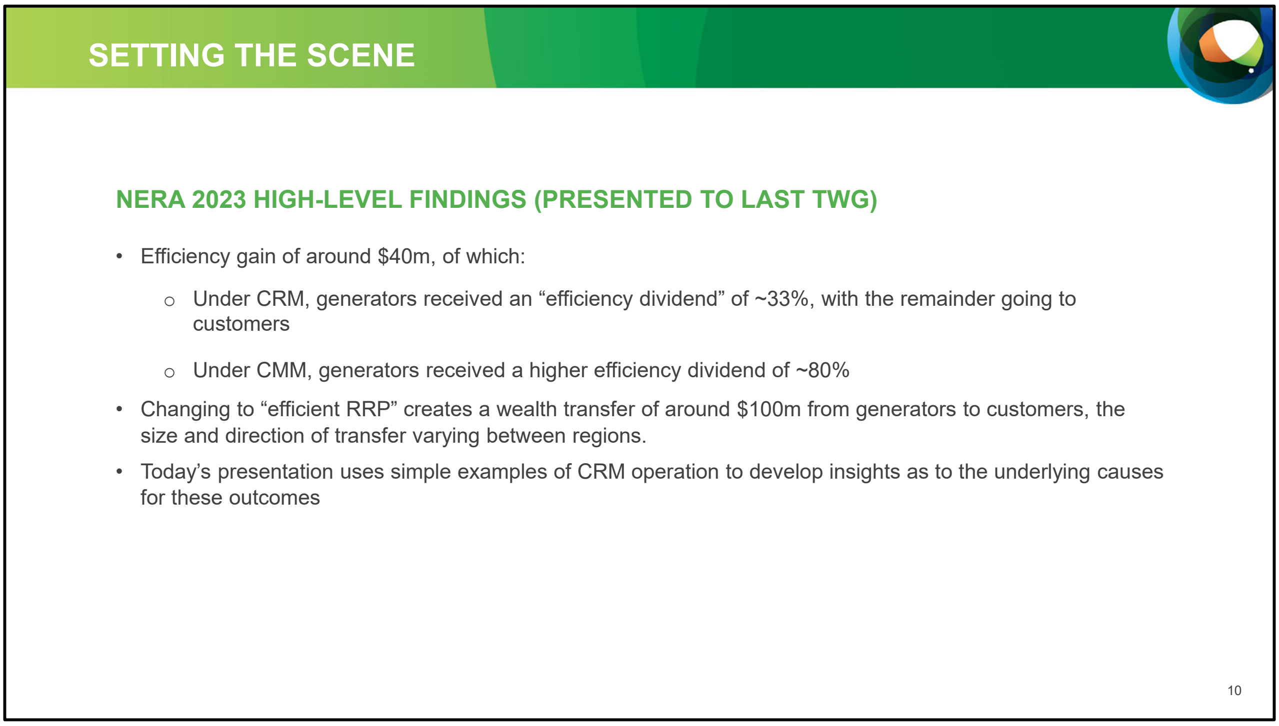
Analysing outcomes

This section builds on previous TWG materials shared on 17 November 2022.

The concepts and examples are still helpful as a standalone document to understand the CRM design in the context of inter-regional flows.

The Directions Paper introduced a worked example of the CRM design with a simple loop flow network with a single region and single load. This presentation gradually develops the reference scenario to examine two regions and two loads with interconnector limits.

This presentation includes alternative outcomes assuming bidding at cost and strategic bidding.



SETTING THE SCENE

NERA 2023 HIGH-LEVEL FINDINGS (PRESENTED TO LAST TWG)

- Efficiency gain of around $40m, of which:
  - Under CRM, generators received an “efficiency dividend” of ~33%, with the remainder going to customers
  - Under CMM, generators received a higher efficiency dividend of ~80%
- Changing to “efficient RRP” creates a wealth transfer of around $100m from generators to customers, the size and direction of transfer varying between regions.
- Today’s presentation uses simple examples of CRM operation to develop insights as to the underlying causes for these outcomes

There are two interesting aspects of the preliminary NERA modelling results for 2023 (draft results were presented to the TWG on 17 November 2022).

1. Whilst there is an efficiency gain (reduction in dispatch costs) of $40m, a proportion of this flows through to generators as an “efficiency dividend” with the remainder passed through to customers.
2. RRPs from efficient dispatch (representing future dispatch under transmission access reform) were markedly different from those from the “disorderly dispatch” (representing dispatch under today’s market design). This would create substantial wealth transfers, compared to the status quo, if RRP_{CRM} was adopted for settlement.

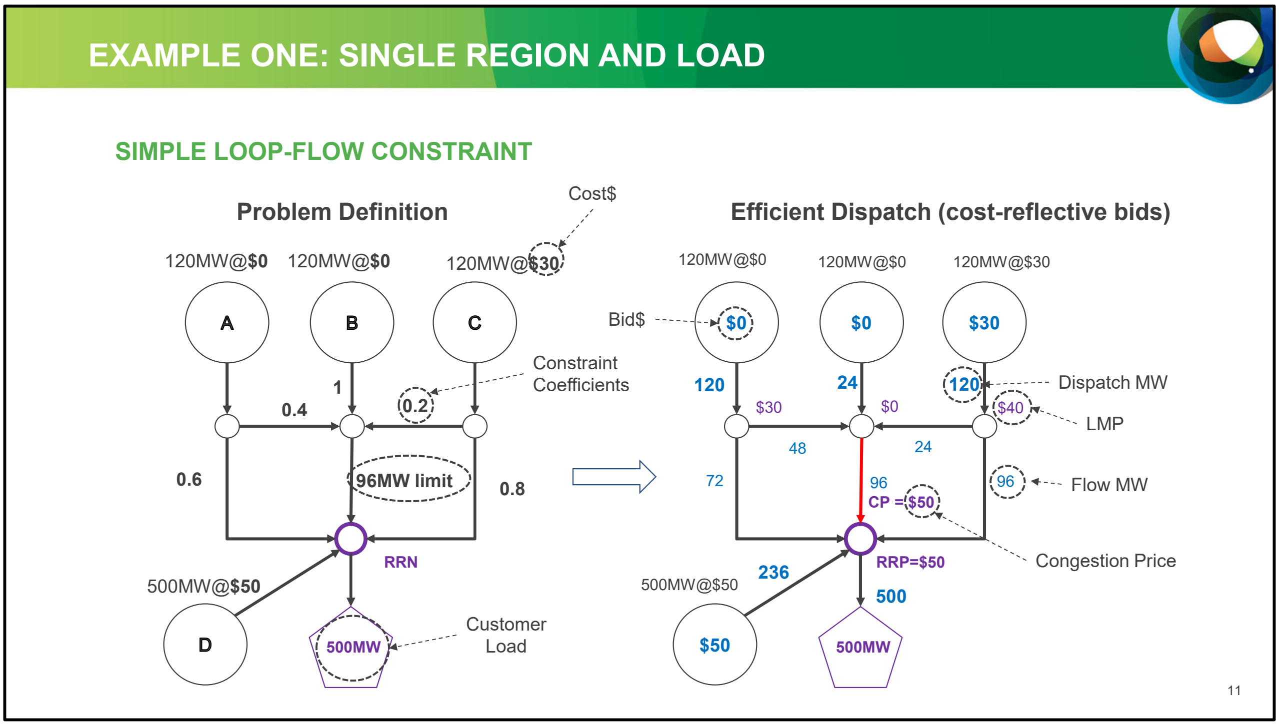
As discussed on 17 November 2022, the absolute value of the RRPs and quantum of the RRP changes should not be relied on given the model scope and limitations (no clamping for counter-price flows, no strategic bidding etc).

This presentation describes some simple illustrative examples that help to explain these outcomes and to develop insights as to the conditions where they are likely to arise.

The examples include:

- Example One – Single region, single load
- Example Two – Two regions, single load
- Example Three – Two regions, two loads (at cost and with strategic bidding)
- Example Four – Two regions, two loads, interconnector limits (at cost and with strategic bidding)

The examples introduce a consistent approach to decompose profit changes between status quo and the CRM design. The profit decomposition and concepts help to explain the draft NERA modelling results for 2023-2024.



EXAMPLE ONE: SINGLE REGION AND LOAD

SIMPLE LOOP-FLOW CONSTRAINT

Summary

The diagram provides a building block reference scenario that will be developed in this presentation.

Detail

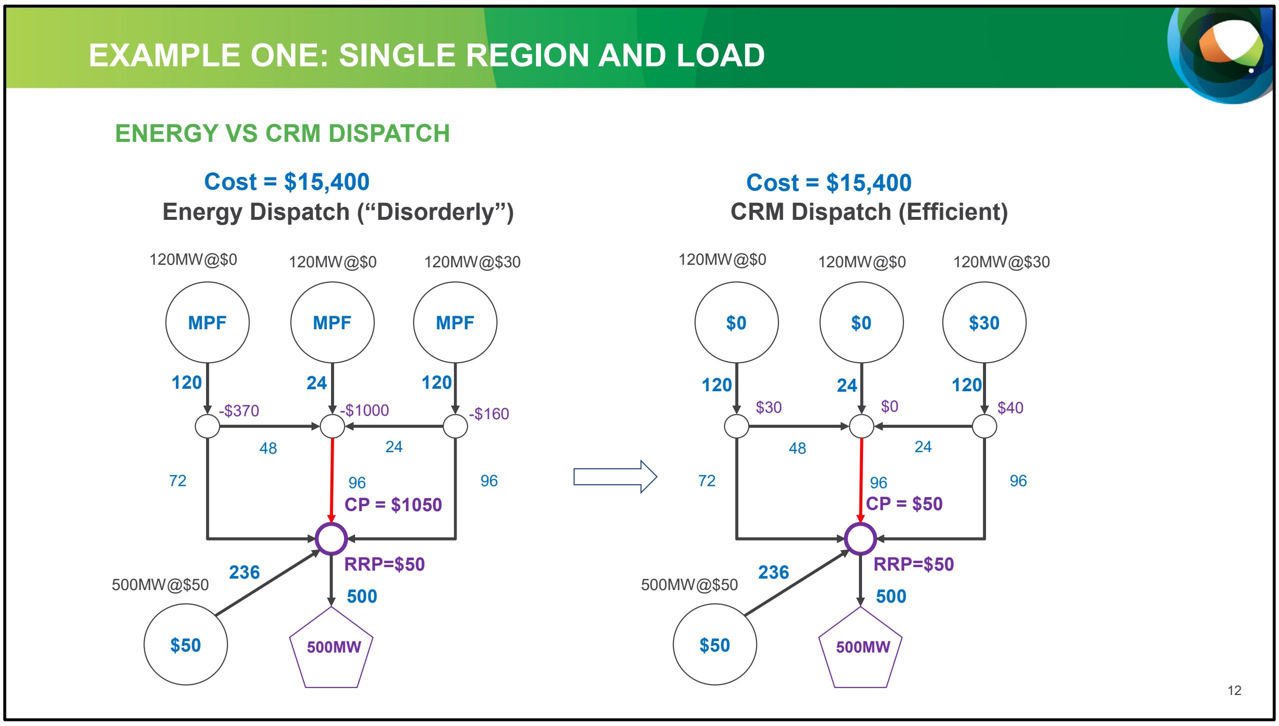
The first example is similar to earlier examples presented to the TWG. Three generators are located behind a constraint with a fourth located at the regional reference node (RRN) where the load is also located. The constrained generator have different costs and constraint coefficients, as shown.

The constraint coefficient represents the proportion of power output from each generator that flows through the constrained line: eg 20% of *C*'s output flows through the line, with the remaining 80% flowing to the RRN through a different path. The flow splits are seen in the right-hand diagram above.

In the efficient dispatch, generators bid at cost. Congestion arises between the 3 generators and the RRN, with generator *B* being constrained off, despite having a lower bid than generator *C*. This arises because of *C*'s lower constraint coefficient.

The LMPs in the dispatch are shown. Note that generators who are marginal (part-loaded) always have LMP at their local node equal to their offer price. Generators that have LMP above or below their offer price will be fully-dispatched or not dispatched, respectively.

Because generator *D* is marginal, it sets the LMP at the RRN, which defines the RRP for the region.



EXAMPLE ONE: SINGLE REGION AND LOAD

ENERGY VS CRM DISPATCH

Cost = $15,400
Energy Dispatch ("Disorderly")

Cost = $15,400
CRM Dispatch (Efficient)

Summary

In this specific example, the energy market (with disorderly bids) achieves the most efficient outcome (based on bids and constraint coefficients). There are no CRM adjustments.

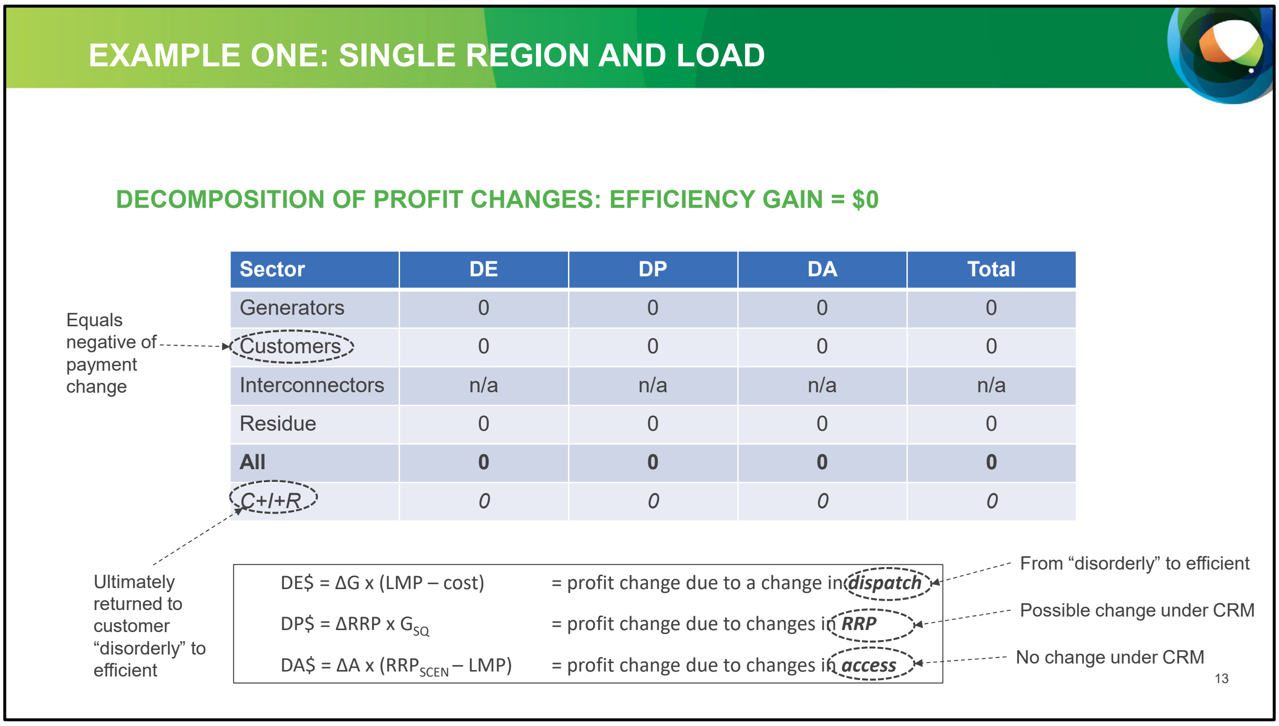
Detail

This slide compares disorderly dispatch from efficient dispatch. In the former, generators that are liable to be constrained off bid at the market price floor ("MPF" or -$1000/MWh), which is the case for the top three generators: offer prices are shown within each generator circle.

The CRM design consists of two dispatches: the *energy dispatch* where generators are likely to bid "disorderly" giving the dispatch outcome on the left; and the *CRM dispatch* where generators are likely to bid at cost, giving the outcome on the right. It is recognised that generators might bid away from cost in the CRM for strategic reasons, but bidding at cost is assumed in these examples for simplicity. Generators are permitted to opt out of the CRM but, for these examples, it is assumed that all generators participate.

Note that we are using the disorderly dispatch to represent two scenarios: the status quo outcomes under the current market design, and the energy dispatch outcomes under the CRM model. These outcomes are assumed to be identical in the NERA modelling and in these examples, although this might not be the case in practice.

It is notable that, for this example, the two dispatches are identical. This is because generators happen to be dispatched in order of constraint coefficients in the efficient dispatch, which aligns with the "winner takes all" outcome in the disorderly dispatch. This is not always the case, as is seen in the simple examples previously shared with the TWG. Note, though, that the disorderly bidding on the left has affected LMPs but it is not used for energy market settlement (G x RRP) so is only shown for completeness.



EXAMPLE ONE: SINGLE REGION AND LOAD

DECOMPOSITION OF PROFIT CHANGES: EFFICIENCY GAIN = $0

Sector	DE	DP	DA	Total
Generators	0	0	0	0
Customers	0	0	0	0
Interconnectors	n/a	n/a	n/a	n/a
Residue	0	0	0	0
All	**0**	**0**	**0**	**0**
C+I+R	*0*	*0*	*0*	*0*

Equals negative of payment change

Ultimately returned to customer "disorderly" to efficient

DE$ = ΔG x (LMP – cost) = profit change due to a change in *dispatch*

DP$ = ΔRRP x G_{SQ} = profit change due to changes in *RRP*

DA$ = ΔA x (RRP_{SCEN} – LMP) = profit change due to changes in *access*

From "disorderly" to efficient

Possible change under CRM

No change under CRM

Summary

Profit changes arising from CRM adjustments can be categorised according to a matrix of sector (generator/customer/interconnector/residue) and driver (efficiency gain, RRP change and access change). DP only arises if RRP_{CRM} is used for settlement rather than RRP_{NEM}. This slide sets the framework which will be applied to more complex examples.

Detail

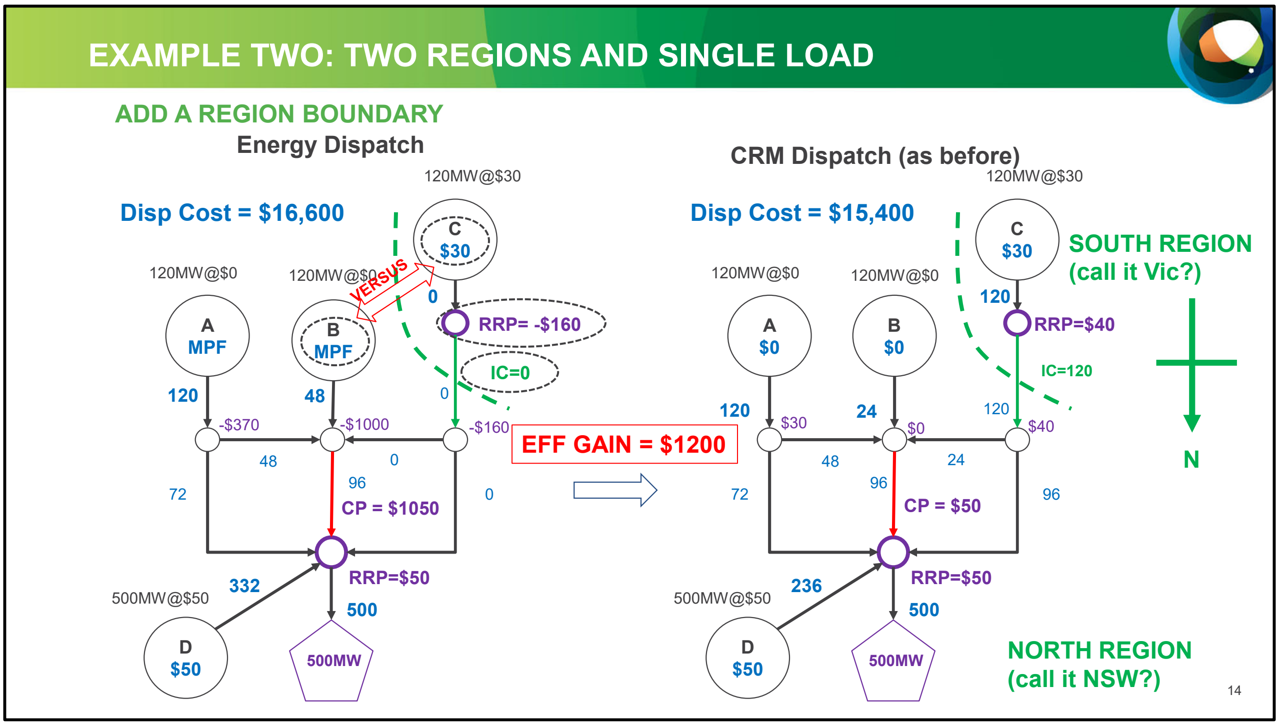
The NERA modelling estimates how the profitability of generators (spot market revenue minus variable generation costs) might change between the status quo and the CRM. The aggregate profit change can be split into three components, as shown above: DE, DP and DA. The table also shows profit changes for customers, interconnectors and settlement residue. Because the two dispatches are identical in this case, there is no profit change and the components and totals are all zero.

DE is the impact of the dispatch change (from disorderly to efficient) on profitability. For generators, this is also equal to the profit from trading in the CRM. The total of the DEs always equals the *efficiency gain*: ie the reduction in cost between disorderly dispatch and efficient dispatch.

DP is the impact of changes in RRP. As defined, this is a pure wealth transfer: ie the DP components always sum to zero.

DA is the impact of changes in access. Access is the MW quantity on which generators are paid RRP. In the CRM, access is based on energy dispatch, which is the same as the disorderly dispatch in the status quo. Therefore, DA is always zero for the CRM, but is included in the table for completeness. Note that DA is non-zero for the Congestion Management Model (CMM), but the CMM is not explored in this presentation.

Note that the profits allocated to interconnectors and "residue" (which are explained in later slides) are ultimately returned to customers, hence the "C+I+R" bottom line.



EXAMPLE TWO: TWO REGIONS AND SINGLE LOAD

ADD A REGION BOUNDARY

Energy Dispatch

Disp Cost = $16,600

CRM Dispatch (as before)

Disp Cost = $15,400

EFF GAIN = $1200

SOUTH REGION (call it Vic?)

NORTH REGION (call it NSW?)

Summary

The reference scenario is updated to include a regional boundary. The lower cost Generator C is now backed off in the energy market and does not achieve the most efficient dispatch. The CRM adjustments achieve an efficiency gain of $1,200.

Detail

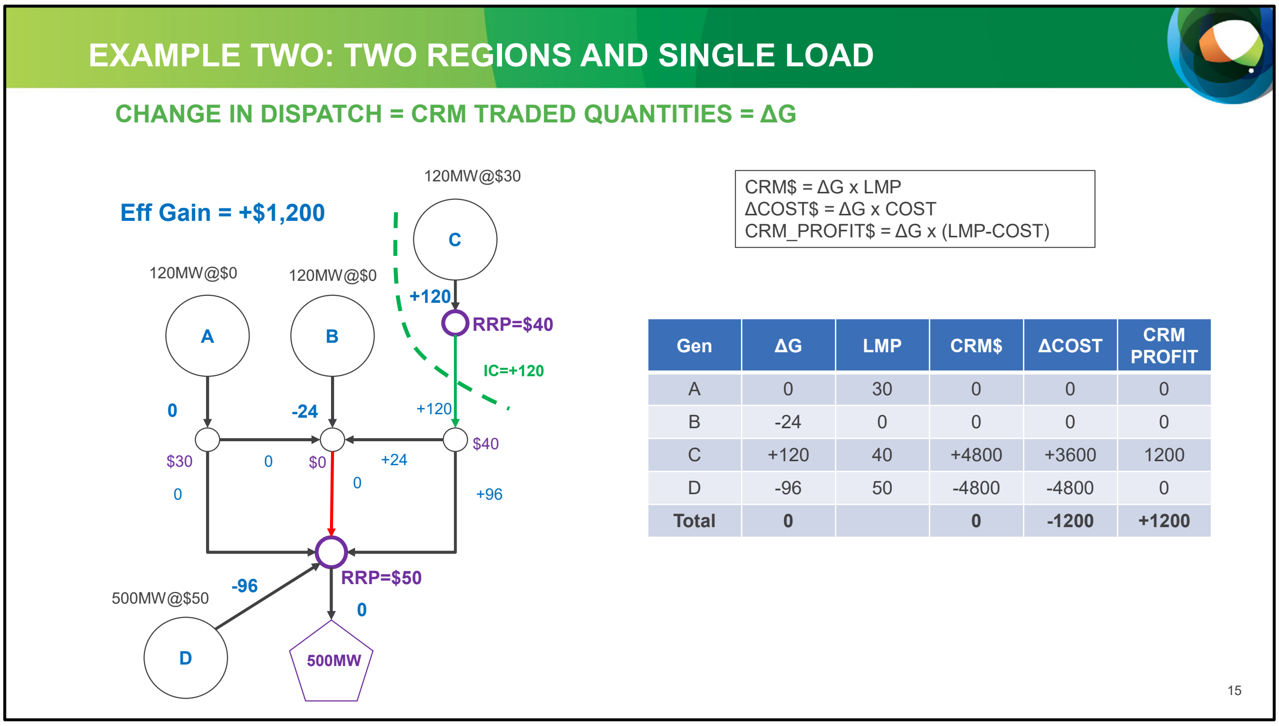
This is the second example, in which a region boundary is added to the first example, meaning that generator *C* is now located in a different region to the other generators. The new region is assigned a RRN, at the node where *C* is connected, the only node in the new region. With two regions, an interconnector is introduced. The flow on the interconnector is defined as the flow over the region boundary, which is equal to the flow on the line shown in green above.

Now that generator *C* is paid its local LMP/RRP, it is incentivised to bid at cost in the disorderly dispatch; continuing to bid at MPF would risk crashing the RRP to MPF and causing the generator to lose money. As it turns out, RRP is set very low in the energy dispatch of the top region, but *C* is not dispatched and so not exposed to this.

The large difference in offer prices between generators *A*/*B* and *C* drives a very different energy dispatch, with *C* now backed off to zero and its output replaced by increases (compared to the first example) in output from *B* and *D*. This substitution increases the cost of dispatch.

The efficient dispatch is unchanged from the first example, because the network topology and generator bids is unchanged. Therefore, there is now an efficiency gain in moving from disorderly to efficient dispatch.

The top and bottom regions are roughly analogous to Victoria and NSW, respectively, so they are referred to as “south” and “north”, which unfortunately makes the “map” upside-down.



EXAMPLE TWO: TWO REGIONS AND SINGLE LOAD

CHANGE IN DISPATCH = CRM TRADED QUANTITIES = ΔG

CRM$ = ΔG x LMP
ΔCOST$ = ΔG x COST
CRM_PROFIT$ = ΔG x (LMP-COST)

Gen	ΔG	LMP	CRM$	ΔCOST	CRM PROFIT
A	0	30	0	0	0
B	-24	0	0	0	0
C	+120	40	+4800	+3600	1200
D	-96	50	-4800	-4800	0
Total	**0**		**0**	**-1200**	**+1200**

Summary

In this example, the CRM payments net to zero and generators receive all of the efficiency gain (CRM profit of $1,200). Generators B, C and D have CRM adjustments but Generators B and D have zero CRM profits based on bidding at cost. Later examples introduce strategic bidding to redistribute profits between all CRM participants.

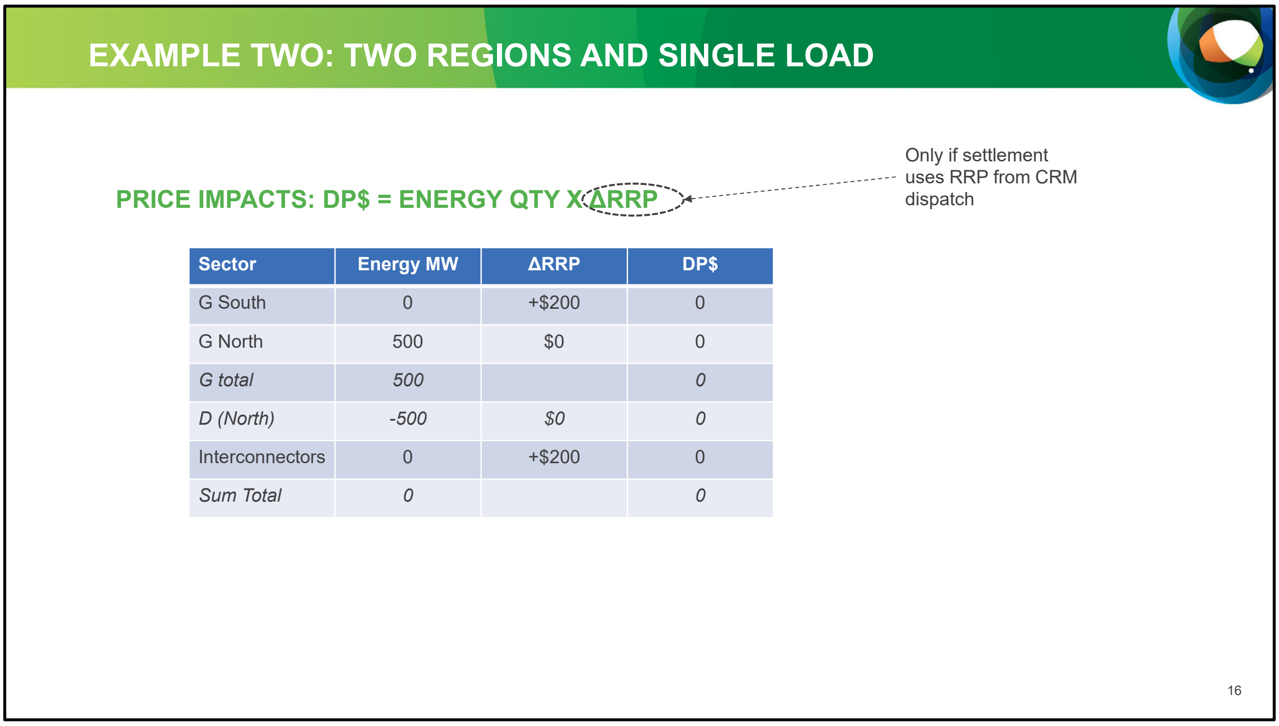
Detail

CRM trading is based on the difference between the energy and CRM dispatches. The diagram above shows these differences, with *C* increasing its dispatch in the CRM, *B* and *D* decreasing dispatch, and *A* unchanged. Note that demand is unchanged, so the pluses and minuses net to zero.

CRM quantities trade at the LMPs from the CRM dispatch, which are shown on the diagram. Generators are paid from the CRM if they increase dispatch and must pay into the CRM if they decrease dispatch. The change in dispatch implies a change in generating costs, and these are netted off the CRM payments to derive the change in profitability.

Note that the cost changes for the individual generators add up – by definition – to the change in dispatch cost, which is the negative of the efficiency gain. Note also that, in this example, CRM payments net out to zero; this is not always the case, as seen in a later example. Because CRM payments net to zero, the total CRM profit is equal to the efficiency gain. This means that generators receive all the benefits of the efficiency gain, whilst customers receive none. These shares of the efficiency gain are referred to here as the “efficiency dividends”.

Note that all of the efficiency dividend goes to a single generator, *C*. This is discussed further on a later slide.



EXAMPLE TWO: TWO REGIONS AND SINGLE LOAD

PRICE IMPACTS: DP$ = ENERGY QTY X ΔRRP

Only if settlement uses RRP from CRM dispatch

Sector	Energy MW	ΔRRP	DP$
G South	0	+$200	0
G North	500	$0	0
G total	*500*		*0*
D (North)	*-500*	*$0*	*0*
Interconnectors	0	+$200	0
Sum Total	*0*		*0*

Summary

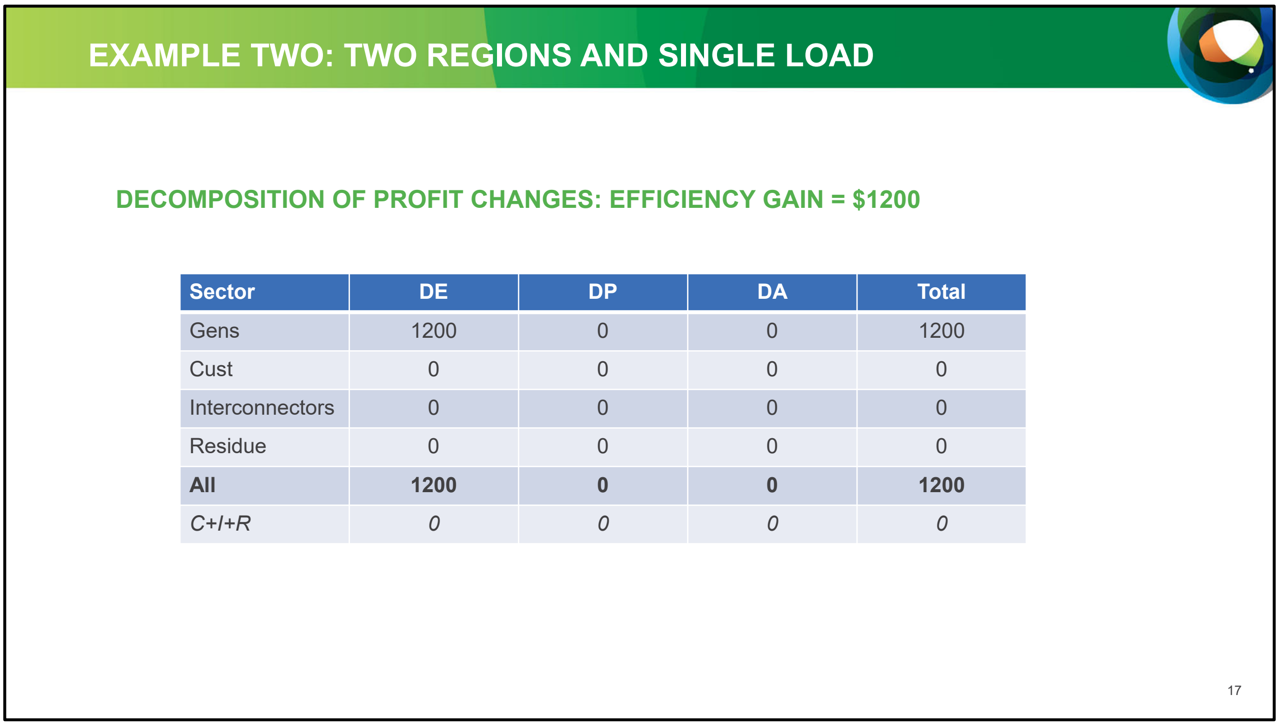
It is a design choice as to whether RRP is calculated based on the energy market dispatch (RRP_{NEM}) or CRM dispatch (RRP_{CRM}). If RRP_{NEM} is applied, there is no DP impact. If RRP_{CRM} is applied, there could be a DP impact although it is zero in this instance.

Detail

This table shows the profit impact, DP, that is caused by the change in RRP, based on generators' *energy* dispatch quantities. The change in RRP of $200/MWh relates to G South (-$160/MWh in the energy market vs $40/MWh in the CRM), as shown on slide 14.

Whilst there are RRP changes in the south region, there is no energy dispatch or demand in that region, so it does not give rise to any profit impacts. The definitions for these profit impacts are explained on a later slide.

Note also that, in the CRM, DP impacts only arise if RRPs from the CRM dispatch are used for settlement. If, instead, RRPs from energy dispatch are used, there is no profit impact, because these are the same RRPs as in the status quo. The choice of RRPs for the CRM design has not yet been decided.



EXAMPLE TWO: TWO REGIONS AND SINGLE LOAD

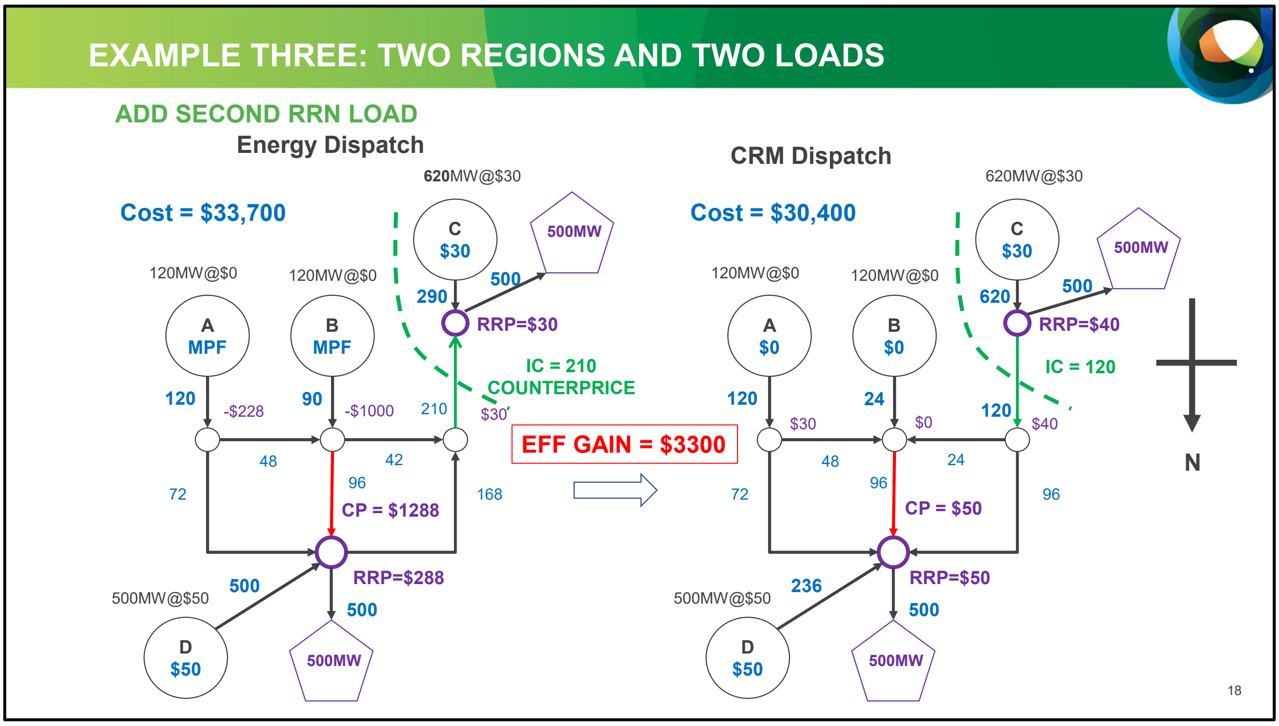
DECOMPOSITION OF PROFIT CHANGES: EFFICIENCY GAIN = $1200

Sector	DE	DP	DA	Total
Gens	1200	0	0	1200
Cust	0	0	0	0
Interconnectors	0	0	0	0
Residue	0	0	0	0
All	**1200**	**0**	**0**	**1200**
C+I+R	*0*	*0*	*0*	*0*

Summary

The table consolidates DE and DP results from previous slides. DA is always zero for the CRM. The total profit impact of $1,200 will always be equal to the efficiency gain.

The question is how this efficiency gain will be distributed, and whether there are any wealth transfers imposed on top. In this case, the efficiency gain is all allocated to generation and there are no wealth transfers.



EXAMPLE THREE: TWO REGIONS AND TWO LOADS

ADD SECOND RRN LOAD

Energy Dispatch

Cost = $33,700

CRM Dispatch

Cost = $30,400

EFF GAIN = $3300

Summary

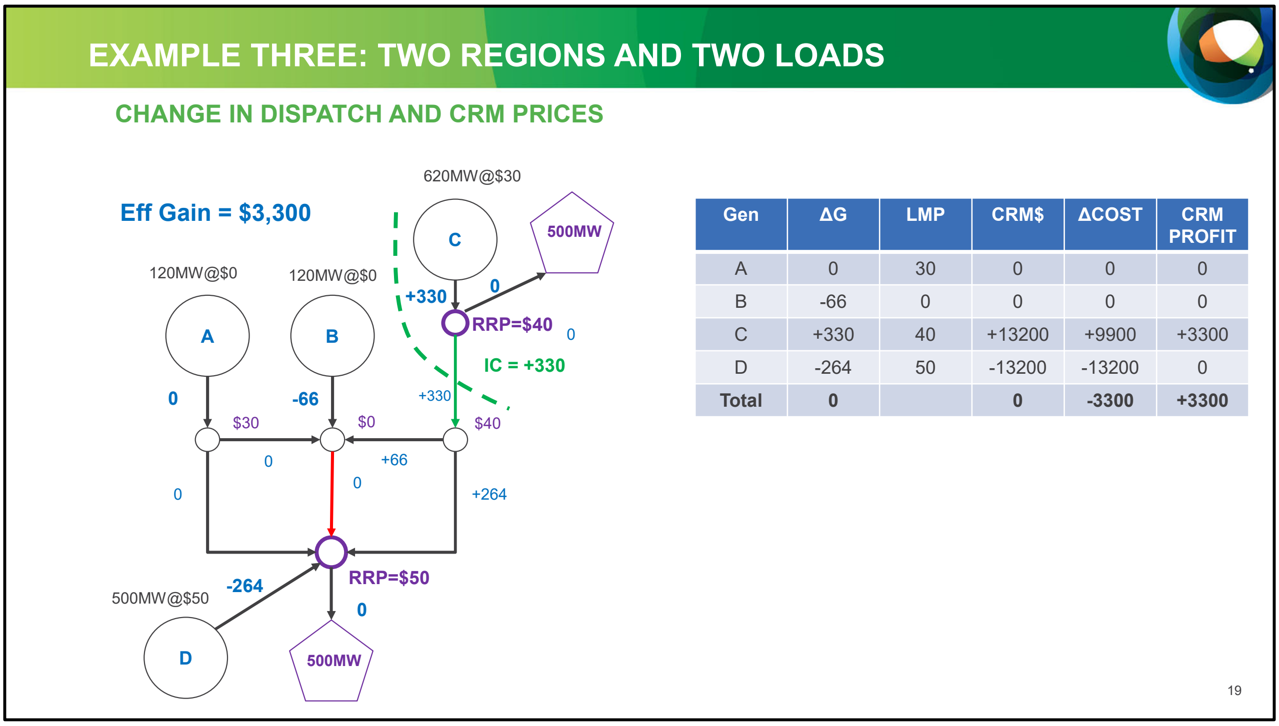
The scenario is updated to add load of 500MW to the southerly region and generator C’s capacity is accordingly increased from 120MW to 620MW. The energy market dispatch generates an inefficient counter-price flow (from north (generators B and D) to south). The CRM achieves an efficiency gain of $3,300 with an efficient interconnector flow from south (generator C) to north.

Detail

In the NEM, RRNs are located at load centres, so this third example adds load at the top RRN to add some realism. To retain the generation-demand balance from the earlier examples, the 500MW increase in demand is matched by a 500MW increase in the capacity of generator *C*, which is therefore able to supply the new demand whilst continuing to export 120MW to help serve the pre-existing load.

Whilst *C* could supply the entirety of the new demand, this does not occur in the energy dispatch, with 210MW of it instead being supplied by increases in output from *B* and *D* (compared to the previous example), and then transported via the interconnector which now flows “counter-price”: ie from the higher-RRP to the lower-RRP region. This counter-price flow is inefficient, adding further to dispatch costs.

In contrast, in the efficient dispatch, *C* supplies the new load and the interconnector flow remains “pro-price” in the direction of the higher-RRP region. The efficiency gain – the cost difference between the two dispatches – has further increased compared to the second example.



EXAMPLE THREE: TWO REGIONS AND TWO LOADS

CHANGE IN DISPATCH AND CRM PRICES

Gen	ΔG	LMP	CRM$	ΔCOST	CRM PROFIT
A	0	30	0	0	0
B	-66	0	0	0	0
C	+330	40	+13200	+9900	+3300
D	-264	50	-13200	-13200	0
Total	**0**		**0**	**-3300**	**+3300**

Summary

Compared to example two, example three settlement values are higher (same LMPs, higher CRM dispatch adjustments). As before, the CRM payments net to zero and generators receive all of the efficiency gain. Generators B, C and D have CRM adjustments but Generators B and D have zero CRM profits based on bidding at cost. Later examples introduce strategic bidding to redistribute profits between all CRM participants.

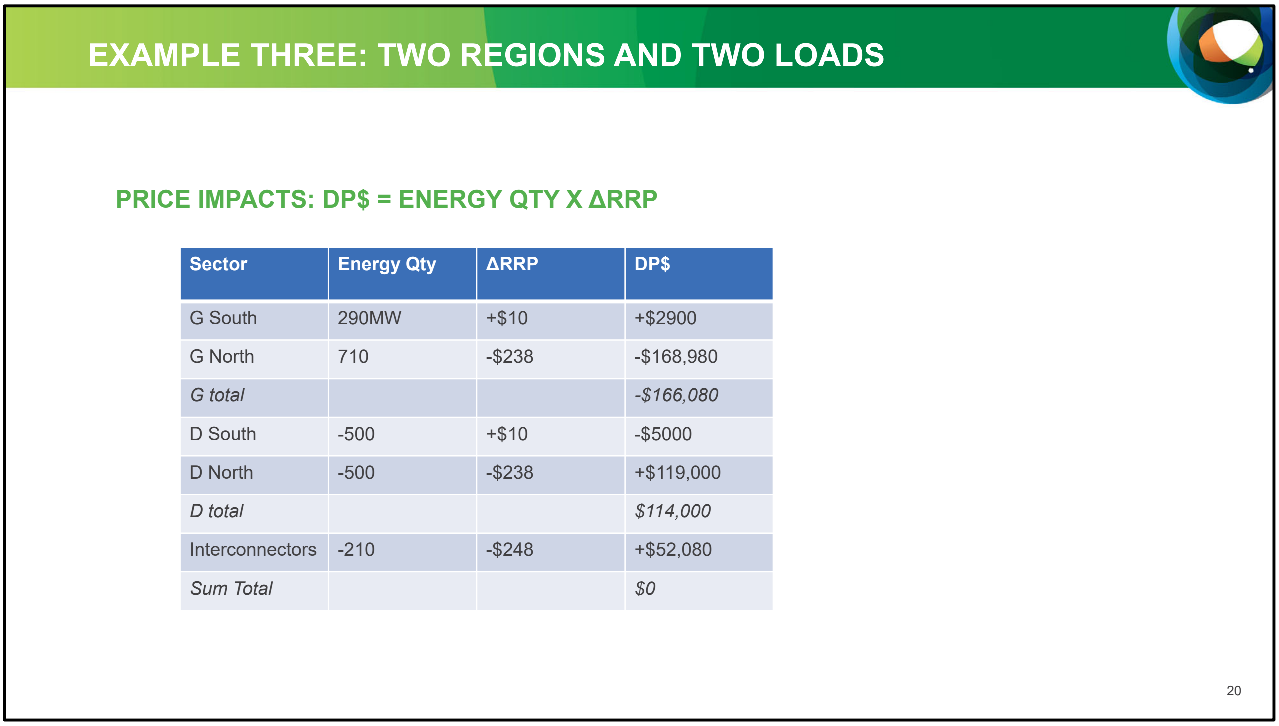
Detail

This slide presents CRM settlement outcomes for example three. Whilst the LMPs are the same as in example two, the traded quantities (ie changes in dispatch) are larger, giving rise to large dollar amounts. As before, the CRM payments net out to zero, meaning that the total profit equals the efficiency gain.

Once again, all of the profit is received by a single generator. This deserves some explanation given that, if only one generator benefits from CRM trading, the others may simply "opt-out", leaving the CRM unable to operate: obviously at least one buyer and one seller is needed to create a transaction opportunity. This outcome arises from two artificial aspects of the examples: that there are only a few generators; and that they bid at cost into the CRM.

Mathematically, if there are N binding constraints in a dispatch problem, there must be N marginal generators. In this example there are two binding constraints: the supply-demand balance constraint and the binding transmission constraint. Correspondingly, two generators are marginal in the CRM dispatch: *B* and *D* (see previous slide). As noted, for marginal generators, LMP = bid. Since generators are bidding at cost in to the CRM, LMP=cost for these two generators, meaning that their CRM profit must be zero. A third generator, *A*, is fully dispatched in both dispatches, so has no participation or profit in the CRM. This leaves just one generator to make a profit: *C*.

In reality, with more generators, and strategic bidding away from cost, the CRM profit is likely to be shared between multiple generators, and this group of winners will vary as dispatch conditions vary. This is illustrated in later slides below.



EXAMPLE THREE: TWO REGIONS AND TWO LOADS

PRICE IMPACTS: DP$ = ENERGY QTY X ΔRRP

Sector	Energy Qty	ΔRRP	DP$
G South	290MW	+$10	+$2900
G North	710	-$238	-$168,980
G total			*-$166,080*
D South	-500	+$10	-$5000
D North	-500	-$238	+$119,000
D total			*$114,000*
Interconnectors	-210	-$248	+$52,080
Sum Total			*$0*

Summary

Assuming RRP_{NEM} applies, there is no DP impact. If RRP_{CRM} applies, there would be significant DP impacts given the change to RRPs in both regions. Negative DPs for generators are offset by positive DPs for customers and interconnectors.

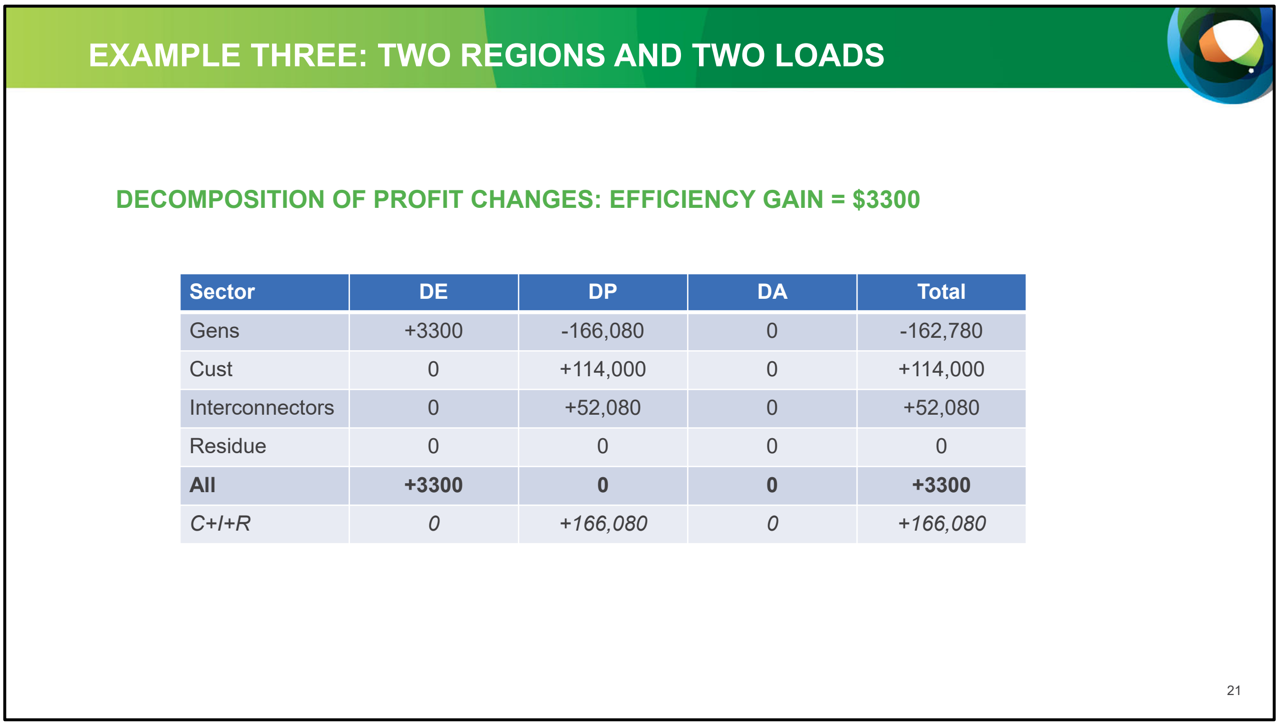
Detail

The substantial changes in RRP in both regions give rise to significant DP impacts, as shown in the table. As already noted, the impacts sum to zero across all sectors, including the Inter-regional Settlement Residue (IRSR) which is allocated to interconnectors and, ultimately, to customers.

Note the sign convention here. A rise in RRP will mean higher bills for customers, which will mean lower "profitability" (given that the value they obtain from electricity consumption is unchanged). So customers in the south region where RRP has increased show a negative DP. Correspondingly, when RRP decreases, customers have a positive DP.

Interconnectors receive the IRSR, so an increase in the IRSR leads to an increase in interconnector "profit" and so a positive DP.

As usual, the caveat applies that the DP arises only if the CRM RRPs are used for settlement.



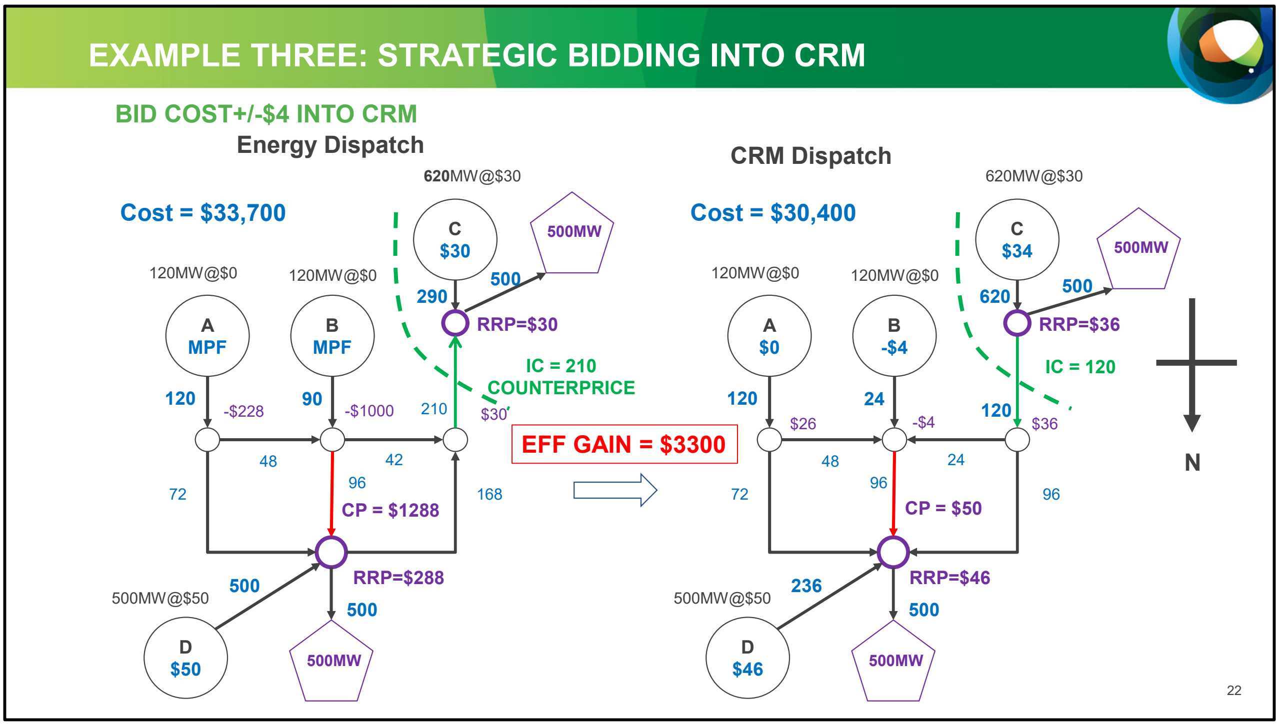
EXAMPLE THREE: TWO REGIONS AND TWO LOADS

DECOMPOSITION OF PROFIT CHANGES: EFFICIENCY GAIN = $3300

Sector	DE	DP	DA	Total
Gens	+3300	-166,080	0	-162,780
Cust	0	+114,000	0	+114,000
Interconnectors	0	+52,080	0	+52,080
Residue	0	0	0	0
All	**+3300**	**0**	**0**	**+3300**
C+I+R	*0*	*+166,080*	*0*	*+166,080*

Summary

Because the DE sums to the efficiency gain, the DP sums to zero and the DA is identically zero, the aggregate profit equals the efficiency gain, as always. Note how, in this case, the DP wealth transfers dominate the DE efficiency dividends.



EXAMPLE THREE: STRATEGIC BIDDING INTO CRM

BID COST+/-$4 INTO CRM

Summary

The scenario is updated to show the outcome of strategic bidding. The example carefully selects bids that maintain the same dispatch outcomes. In practice, strategic bidding may lead to a less efficient dispatch.

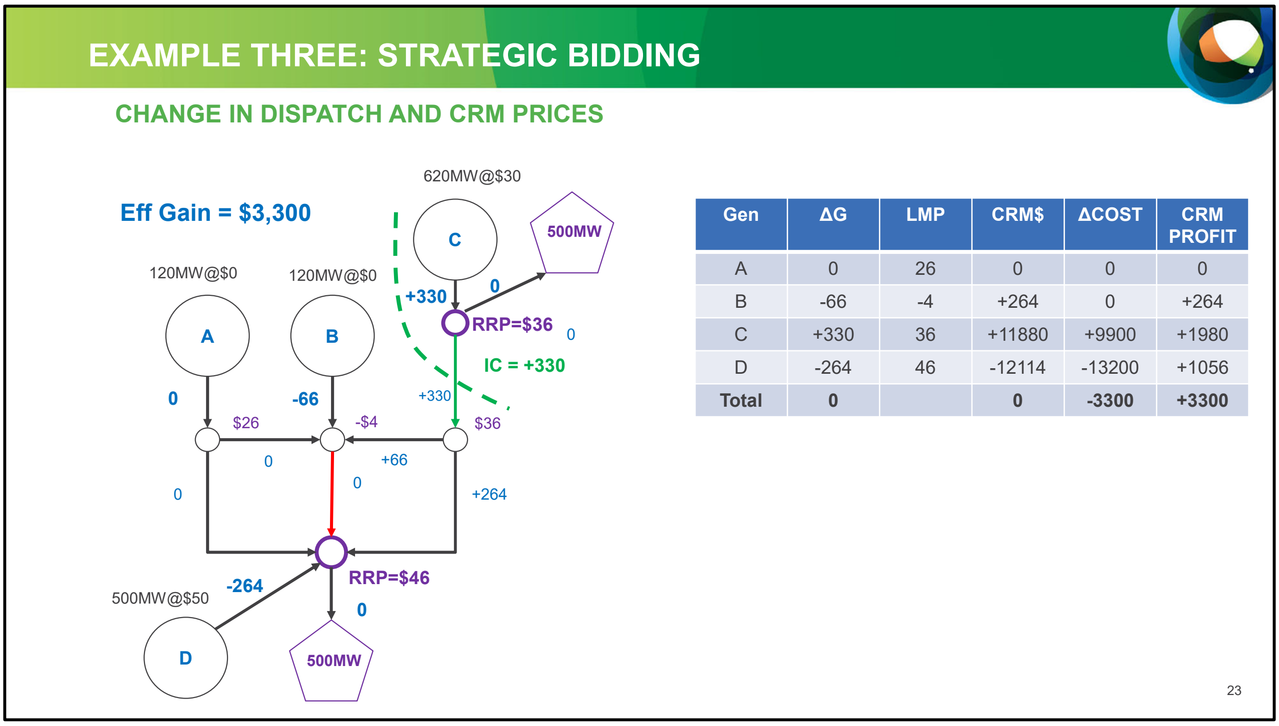
Detail

This is a new slide that wasn't presented to the TWG webinar but has been prompted by comments made there. In the original example 3, all of the efficiency dividend went to a single generator, C. It was explained that this "winner-takes-all" dynamic is because of the assumption that generators bid at cost into the CRM.

There is no requirement for them to do this, and the allocation of the dividend is likely to change if generators bid "strategically" away from cost. This is modelled in the revised example, where generators bid at *cost+/-$4*, depending upon whether they are expecting to sell into, or buy from, the CRM respectively. These revised bids are shown in the generator circles, as usual.

It is notable that these bid changes have not caused a change in CRM dispatch or, as a consequence, any change in the efficiency gain. This is not a general outcome. Strategic bidding might, in some cases, lead to a less-efficient dispatch.

The changed bids *have* changed the CRM LMPs and RRPs, however. Since this is an objective of changing the bids, this is represents a typical outcome.



EXAMPLE THREE: STRATEGIC BIDDING

CHANGE IN DISPATCH AND CRM PRICES

Gen	ΔG	LMP	CRM$	ΔCOST	CRM PROFIT
A	0	26	0	0	0
B	-66	-4	+264	0	+264
C	+330	36	+11880	+9900	+1980
D	-264	46	-12114	-13200	+1056
Total	**0**		**0**	**-3300**	**+3300**

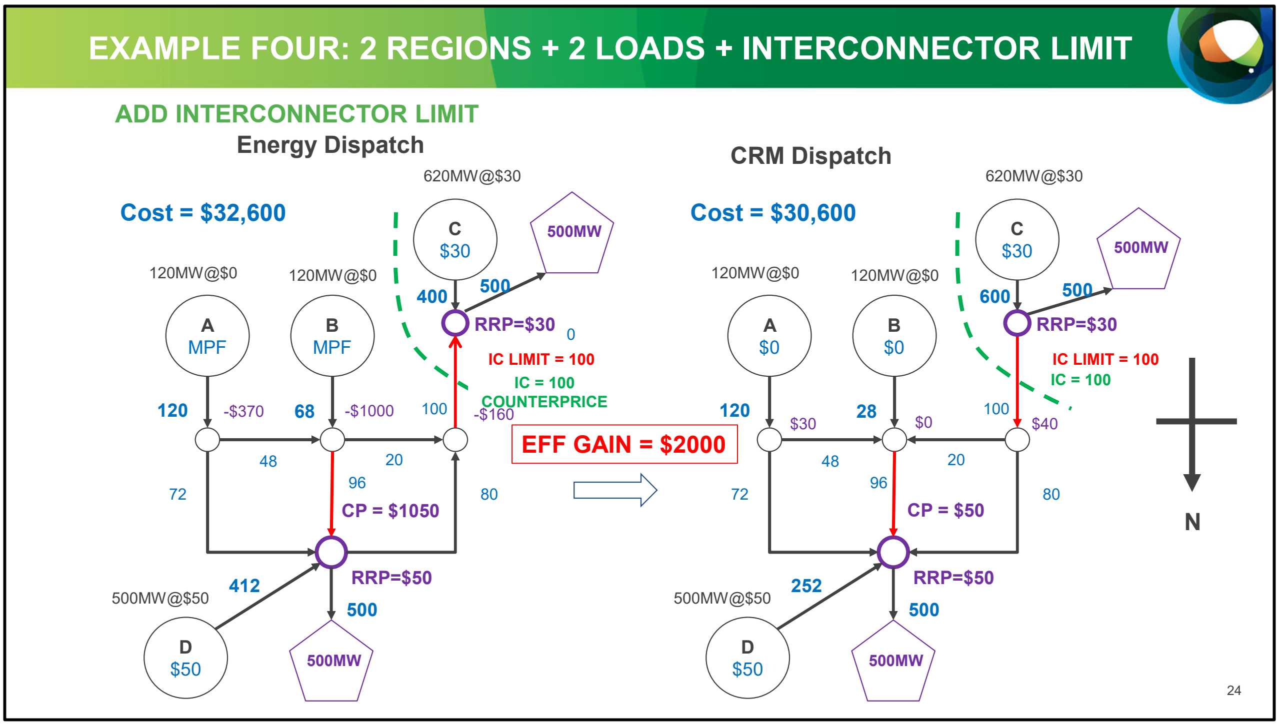
Summary

With strategic bidding, the example now demonstrates how the efficiency gain is shared between three out of the four generators (and hence why generators would be incentivised to participate in the CRM).

Detail

This is another new slide that presents the impact that strategic bidding has on the efficiency dividends. It is seen that the efficiency gain is now shared between three out of the four generators.

The consequential changes to RRPs could also create new wealth transfers (if the CRM RRPs are used for settlements) which could change the overall profitability of this bidding strategy, but this is not considered here for simplicity. This amended example also raises the question as to whether the RRN generators would bid strategically into the energy dispatch and what impact that would have on the efficiency gain and dividends. However, this question has not been explored here.



EXAMPLE FOUR: 2 REGIONS + 2 LOADS + INTERCONNECTOR LIMIT

ADD INTERCONNECTOR LIMIT

Energy Dispatch

CRM Dispatch

EFF GAIN = $2000

Summary

Clamping of interconnector flows can increase or decrease dispatch efficiency. In this example, clamping increases the efficiency of the energy market and reduces the efficiency of the CRM. The efficiency gain is reduced to $2000.

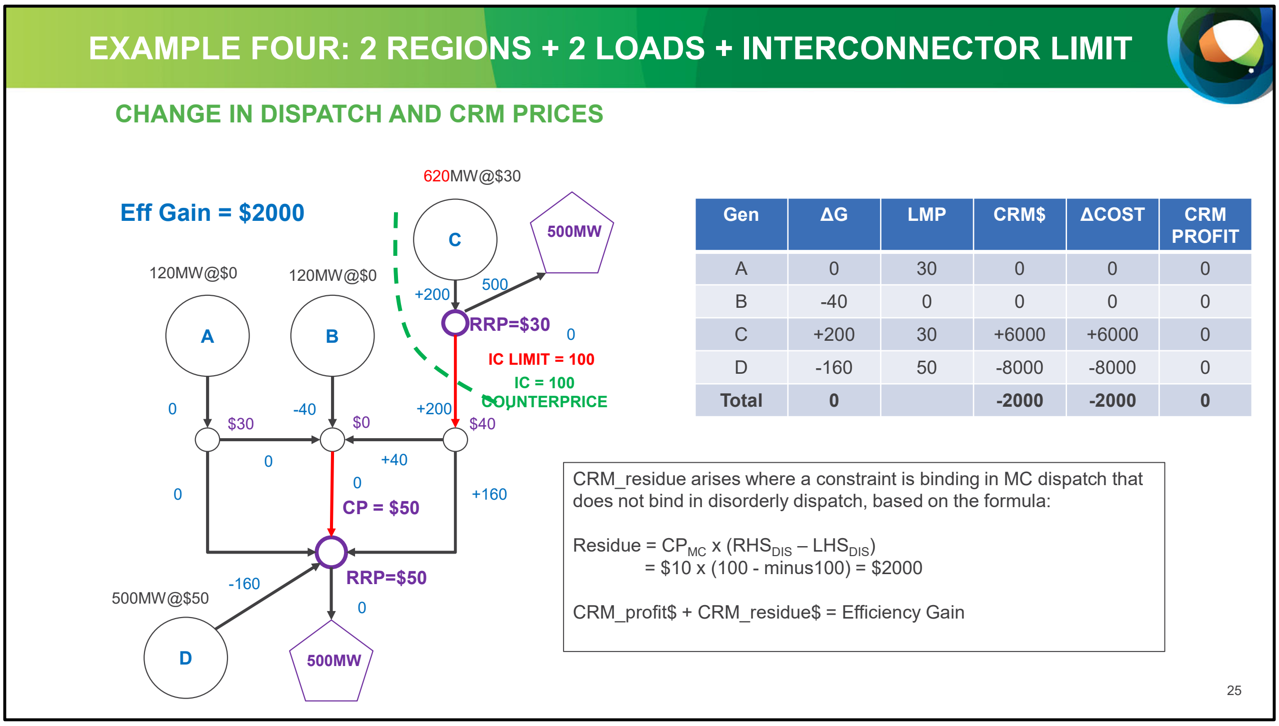
Detail

The final example adds a limit on interconnector flows to the previous example. It is modelled as a thermal limit, so the same 100MW limit applies to flows north and south. The limit binds in both dispatches, but in opposite directions, shown above by colouring the interconnector red.

In the energy dispatch, the limit constrains counter-price flows and so reduces the inefficiency of dispatch compared to the previous example. In practice, AEMO may actually clamp counter-price flows to zeros, further removing this source of dispatch inefficiency. However, NERA have not modelled this clamping in their analysis and it is not explored here.

The limit also constrains the efficient pro-price flows in the efficient dispatch, thereby increasing dispatch cost compared to the previous example.

Finally, the interconnector limit prevents either RRN generator operating at its limits in either example, so both – being now marginal – set the RRPs in each case and the RRP does not change with the dispatch change, eliminating any wealth transfers.



EXAMPLE FOUR: 2 REGIONS + 2 LOADS + INTERCONNECTOR LIMIT

CHANGE IN DISPATCH AND CRM PRICES

Gen	ΔG	LMP	CRM$	ΔCOST	CRM PROFIT
A	0	30	0	0	0
B	-40	0	0	0	0
C	+200	30	+6000	+6000	0
D	-160	50	-8000	-8000	0
Total	**0**		**-2000**	**-2000**	**0**

CRM_residue arises where a constraint is binding in MC dispatch that does not bind in disorderly dispatch, based on the formula:

Residue = CP_{MC} x (RHS_{DIS} – LHS_{DIS})
= $10 x (100 - minus100) = $2000

CRM_profit$ + CRM_residue$ = Efficiency Gain

Summary

CRM settlements may not always net to zero. In this example, the generators do not trade at a loss but the efficiency dividend (CRM profit) goes to settlement residue rather than to generators. This example is unusual. In practice, it would be more typical for the efficiency dividend to be shared in some way between generators and residue (rather than fully allocated to the latter).

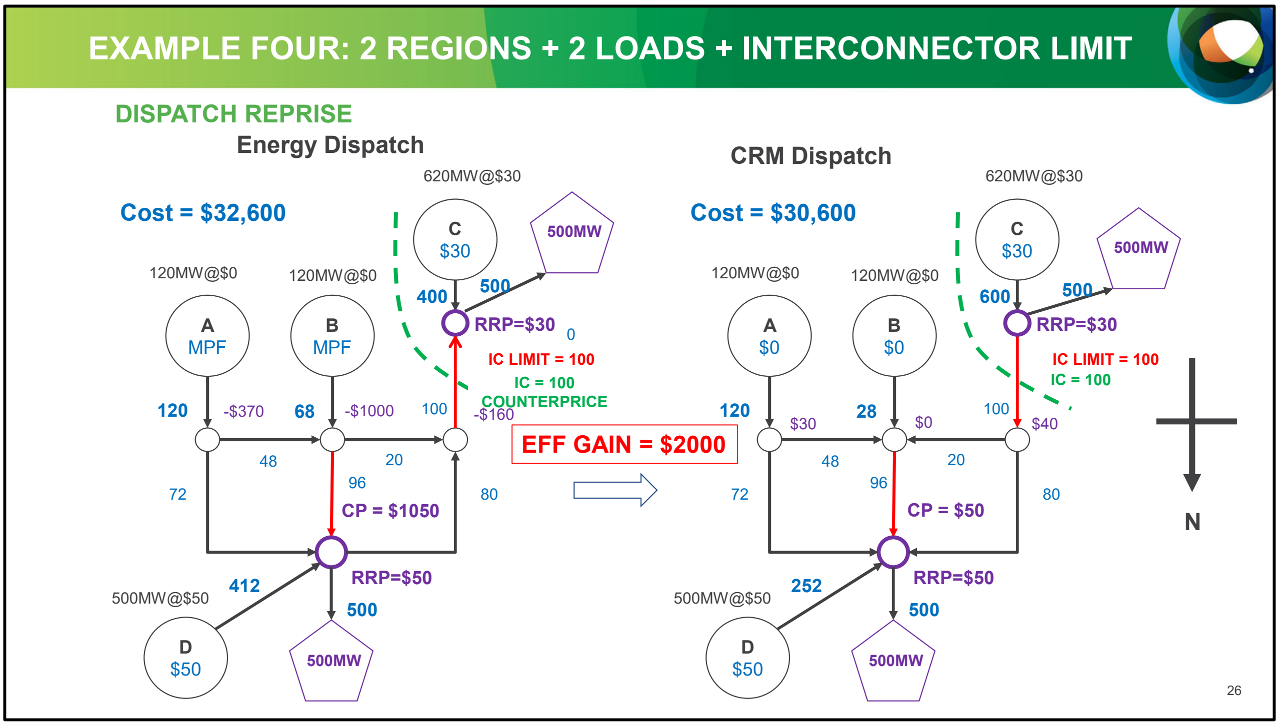
Detail

The usual algebra applies for calculating CRM settlement. In this case, unlike the other examples, there is a positive residue remaining in CRM settlement: the payments from buyers (ie *D*) exceeds the payments to sellers (ie *C*). The residue exactly offsets the efficiency gain, meaning the efficiency dividend goes to the residue rather than generators, who now receive no profit at all from CRM trading. Note that no individual generator ever trades at a loss (due to the cost-based bidding assumption), so there are no profits *or* losses for any generators.

This raises the obvious question as to whether there is something substantially different about this example which gives rise to residue here but not in the previous examples. In fact there is: the difference is that congestion now occurs in the CRM dispatch here at a point where there is no congestion in the energy dispatch. This is discussed on the next slide.

This slide shows the formula for residue, being based on the difference between the LHS and RHS in the energy dispatch for the constraint that is binding in the CRM dispatch but *not* in the energy dispatch. This difference is multiplied by the relevant congestion price in the CRM dispatch. In more complex examples, where there are multiple constraints with this characteristic, the residue terms would add together.

With the additional dispatch constraint, there are now 3 marginal generators for whom LMP=bid=cost, because of the cost-based bidding assumption and so CRM profits are not possible, The implications of strategic bidding in this example are explored in a later slide.



EXAMPLE FOUR: 2 REGIONS + 2 LOADS + INTERCONNECTOR LIMIT

DISPATCH REPRISE

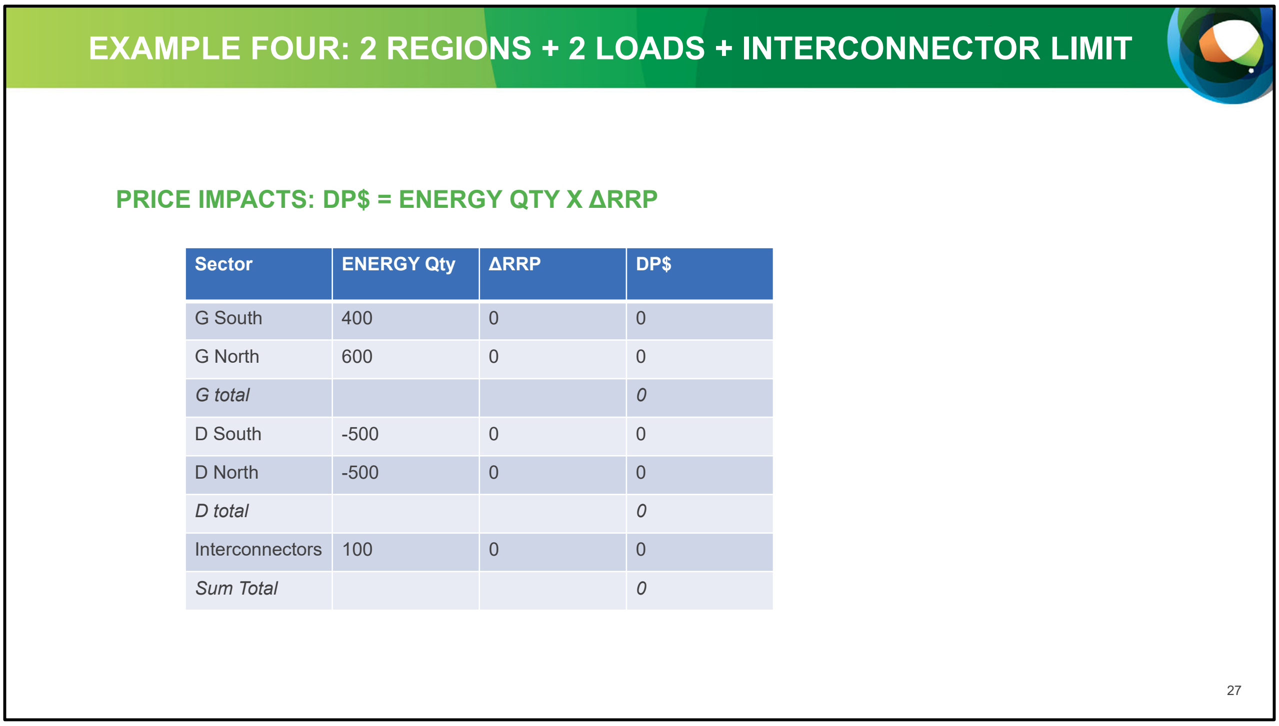
Summary

The settlement residue arises because the constraint does not bind in the energy market but does bind in the CRM.

Detail

This slides is an exact repeat of the previous but one slide, showing dispatch outcomes for example four. Note how the interconnector congestion moves from southerly to northerly between the energy and CRM dispatches. This means that the constraint that represents the interconnector's *northerly* limit is binding in the latter dispatch but not in the former, and this establishes the conditions for there to be a CRM settlement residue.

Whilst the CRM residue accounts for the entire efficiency gain in this example, this is not a general outcome. There will be many situations where the efficiency gain is shared between generation and CRM residue. An example of this is given in a later slide.



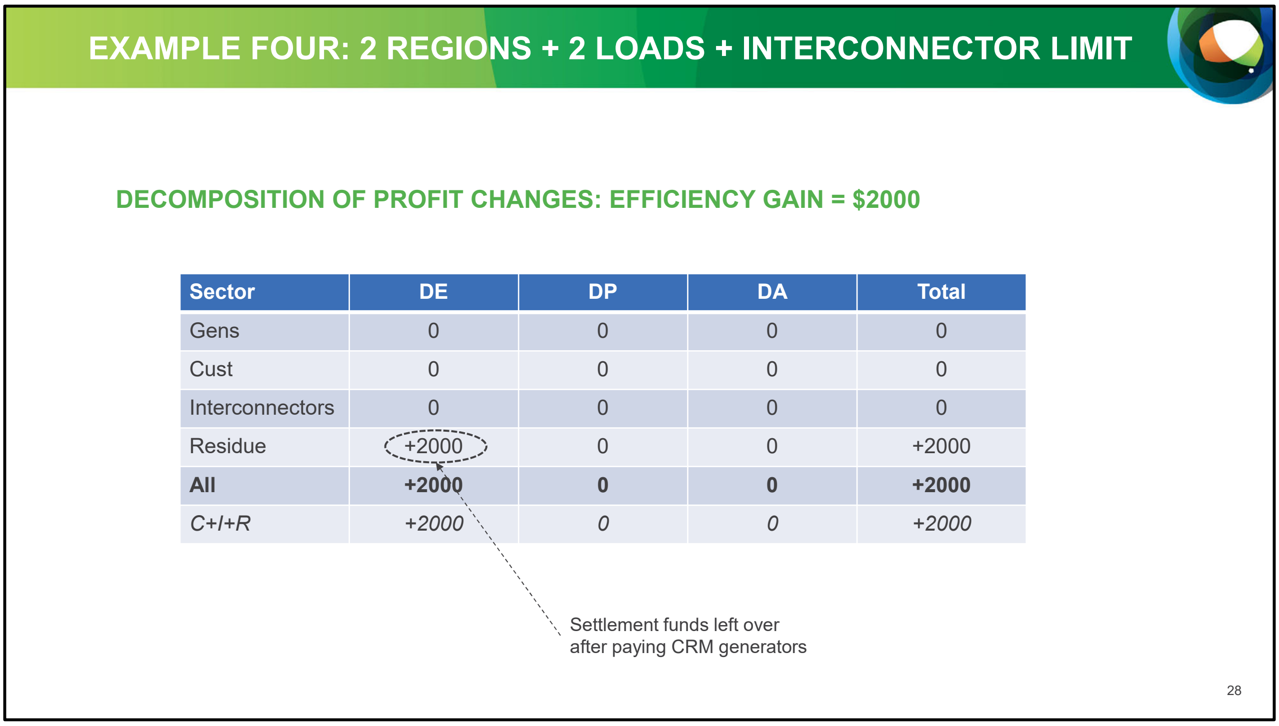
EXAMPLE FOUR: 2 REGIONS + 2 LOADS + INTERCONNECTOR LIMIT

PRICE IMPACTS: DP$ = ENERGY QTY X ΔRRP

Sector	ENERGY Qty	ΔRRP	DP$
G South	400	0	0
G North	600	0	0
G total			*0*
D South	-500	0	0
D North	-500	0	0
D total			*0*
Interconnectors	100	0	0
Sum Total			*0*

Summary

There are no RRP changes in this example, so no DPs.



EXAMPLE FOUR: 2 REGIONS + 2 LOADS + INTERCONNECTOR LIMIT

DECOMPOSITION OF PROFIT CHANGES: EFFICIENCY GAIN = $2000

Sector	DE	DP	DA	Total
Gens	0	0	0	0
Cust	0	0	0	0
Interconnectors	0	0	0	0
Residue	+2000	0	0	+2000
All	**+2000**	**0**	**0**	**+2000**
C+I+R	*+2000*	*0*	*0*	*+2000*

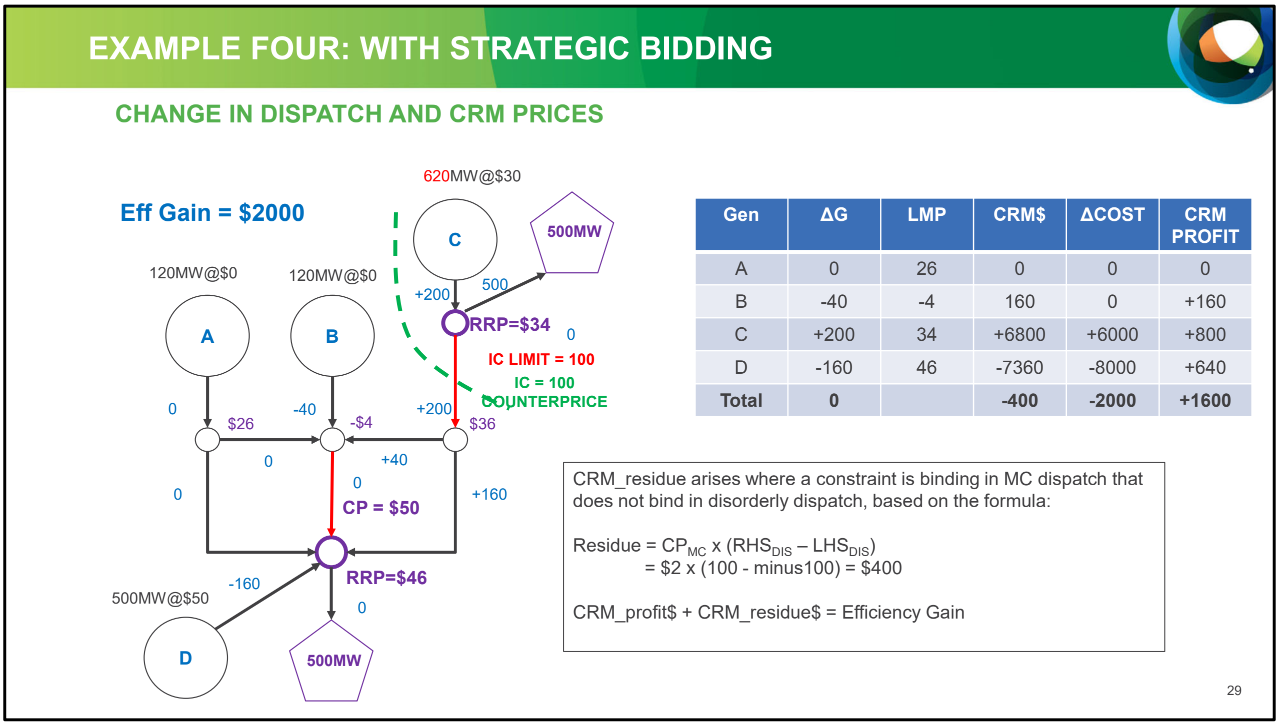
Settlement funds left over
after paying CRM generators

Summary
The mechanism and algebra for allocating the residue have not yet been developed, but are assumed to ultimately return to customers.

Detail
The CRM settlement residue is placed into this summary table in the “residue” row. This is to distinguish it from the interconnector profit: ie the IRSR. Technically, the CRM residue does not flow into the IRSR. Whilst, in this example, it is simple to attribute this residue to a particular interconnector (as there is only a single interconnector) this may not always be the case.

It is assumed that this residue will be ultimately returned to customers. However the mechanism and algebra for doing this have not yet been developed.

In summary, for this example, the entire efficiency dividend flows to settlement residue, and there is nothing for generators. This naturally raises the question as to whether this might encourage CRM opt-out. As in earlier examples, this “winner-takes-all” outcome arises from our cost-based bidding assumption. The next slide explores what happens when this assumption is relaxed.



EXAMPLE FOUR: WITH STRATEGIC BIDDING

CHANGE IN DISPATCH AND CRM PRICES

Gen	ΔG	LMP	CRM$	ΔCOST	CRM PROFIT
A	0	26	0	0	0
B	-40	-4	160	0	+160
C	+200	34	+6800	+6000	+800
D	-160	46	-7360	-8000	+640
Total	**0**		**-400**	**-2000**	**+1600**

CRM_residue arises where a constraint is binding in MC dispatch that does not bind in disorderly dispatch, based on the formula:

Residue = CP_{MC} x (RHS_{DIS} – LHS_{DIS})
= $2 x (100 - minus100) = $400

CRM_profit$ + CRM_residue$ = Efficiency Gain

Summary

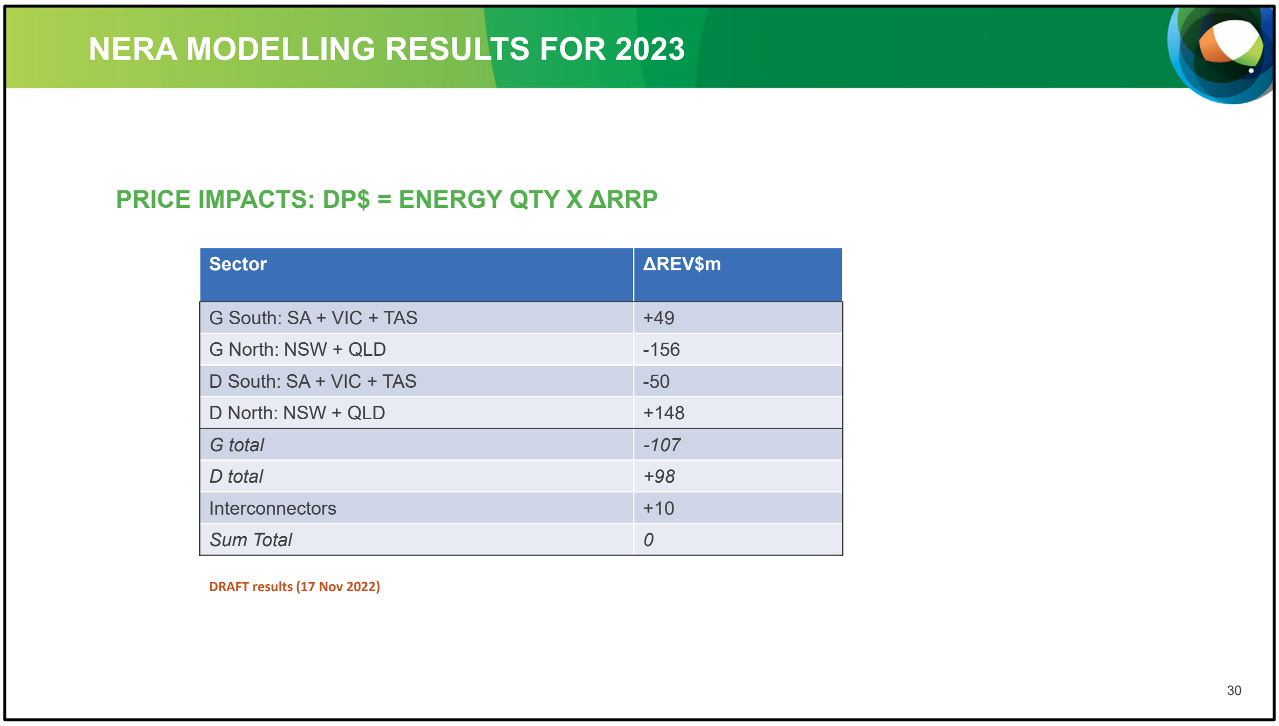
The example is updated to show the potential effect of strategic bidding. Out of $2000 efficiency gain, generators now receive $1600 and settlement residue of $400. The CRM profits are also shared between the 3 generators.

Detail

This is another new slide, not previously presented to the TWG, which explores the impact of strategic bidding in the CRM on efficiency dividends for example four. As with the previous example, bids are adjusted by +/-$4, depending upon whether the generator is selling into, or buying from, the CRM, respectively. As in the previous example, this bidding change does not result in any change to dispatch (so the relevant dispatch slide has this time not been included), but it does result in a change to LMPs and so to CRM settlement.

Unlike with the cost-based bidding outcome, this strategic bidding leads to the generators now earning a share of the efficiency gain: the lion's share, in fact, with generators receiving $1600 and customers just $400, the latter being the CRM settlement residue. As with the previous strategic bidding example, the generator dividend is shared between 3 generators.

Again, the additional complexities of RRP impacts and strategic energy market bidding are not explored here.



NERA MODELLING RESULTS FOR 2023

PRICE IMPACTS: DP$ = ENERGY QTY X ΔRRP

Sector	ΔREV$m
G South: SA + VIC + TAS	+49
G North: NSW + QLD	-156
D South: SA + VIC + TAS	-50
D North: NSW + QLD	+148
G total	*-107*
D total	*+98*
Interconnectors	+10
Sum Total	*0*

DRAFT results (17 Nov 2022)

Summary

The segmentation of DP is updated with draft modelling results from NERA (2023-2024). In total, it shows wealth transfers from generators to customers, with some underlying transfers in reverse for southern states. These wealth transfers only arise if RRP_{CRM} is used. Actual wealth transfers may be smaller given there is no interconnector clamping in the modelling.

Detail

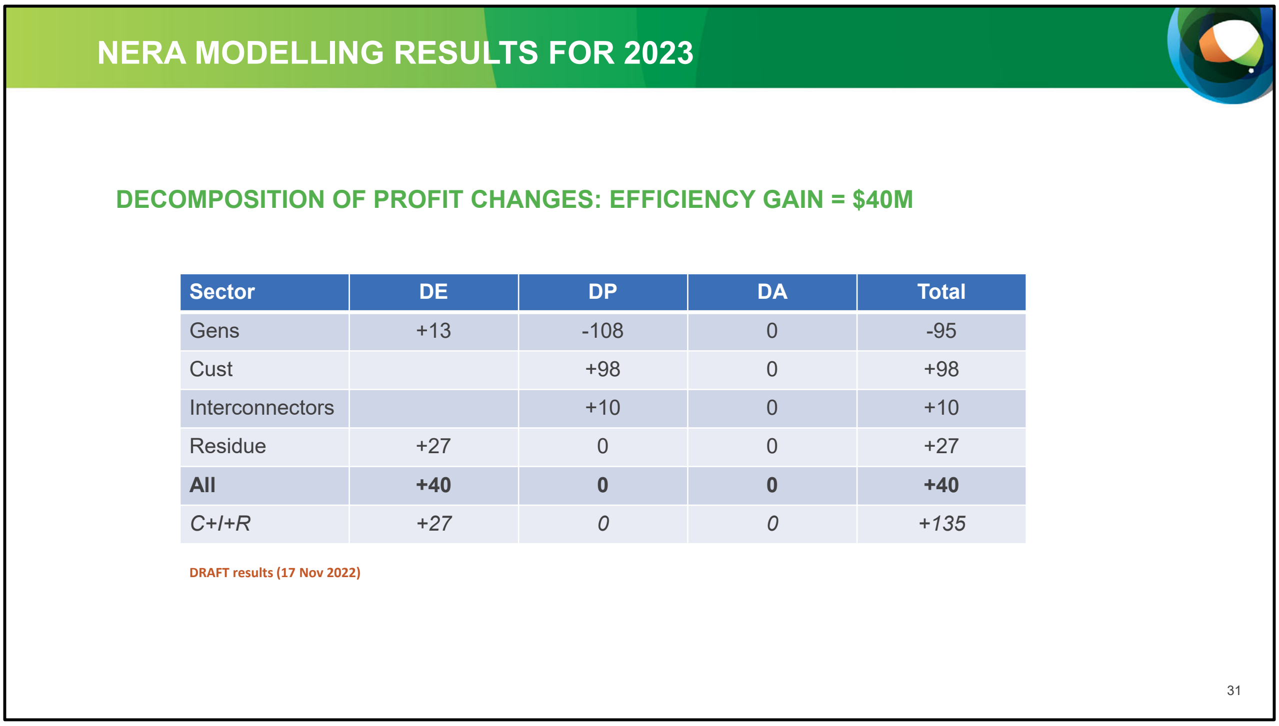
This table presents an update to the DP figures for the NERA results generators and further breaks them down into “northern” and “southern” generators. It also adds the corresponding figures for customers, together with the IRSR which, as always, is a balancing item which ensures the total DP is zero.

Note that whilst there is an overall wealth transfer from generators to consumers, in southern states the wealth transfer is in the opposite direction.

As usual, there is the caveat that these wealth transfers only arise if the CRM RRPs are used for settlement.

Note the similarity between the NERA results and the outcomes from the simple examples. This is deliberate. Whilst the simple examples are somewhat different to the NSW-Vic situation in the NERA modelling, the drivers and dynamics are similar. In particular, the reversal of inefficient counter-price flows on the NSW-Vic interconnector in the energy dispatch - to efficient pro-price flows in the CRM dispatch - gives rise to changes in RRPs which, in turn, give rise to these wealth transfers.

Because the counter-price flows seen in the NERA model outcomes would in reality be clamped by AEMO when material, the actual wealth transfers will likely be smaller than estimated by NERA.



NERA MODELLING RESULTS FOR 2023

DECOMPOSITION OF PROFIT CHANGES: EFFICIENCY GAIN = $40M

Sector	DE	DP	DA	Total
Gens	+13	-108	0	-95
Cust		+98	0	+98
Interconnectors		+10	0	+10
Residue	+27	0	0	+27
All	**+40**	**0**	**0**	**+40**
C+I+R	*+27*	*0*	*0*	*+135*

DRAFT results (17 Nov 2022)

Summary

Draft modelling results for 2023-2024 show a 2:1 split of efficiency dividend (DE) between settlement residue and generators. Total profit changes are dominated by the change in RRPs (assuming RRP_{CRM}) although there are significant caveats on the modelled outcomes for RRPs given the lack of interconnector clamping, lack of strategic bidding, and the limited cost assumptions for storage.

Detail

This table includes the wealth transfers from the previous slide and adds the DE efficiency gains. It is seen that around one third of the efficiency dividend flows to generators, which is slightly higher than in the earlier draft NERA results (shared 17 November 2022).

Whilst the examples presented here are not, in themselves, sufficient to explain this 2:1 split of efficiency dividend between customers and generators, they do at least illustrate how that split might arise. In particular, customers will receive some dividend in periods where congestion “moves around” between the energy and CRM dispatches, but not where congestion is static.

Note also how the DP wealth transfers dominate the DE efficiency gains in the NERA results, as was seen in example 3. This is due to the causal chain whereby intra-regional congestion affects interconnector flows which, in turn, affects RRPs and so DPs and overall profit changes. It is a feature of the NERA 2023 results that the main point of intra-regional congestion is in SW NSW (east of Darlington Point) and this has an impact on Vic-NSW flows that we have even seen in actual dispatch outcomes. It is not necessarily the case that all future congestion will affect interconnector flows, although it is plausible that the majority *will*, due to the topology of the NEM transmission network.

APPENDIX

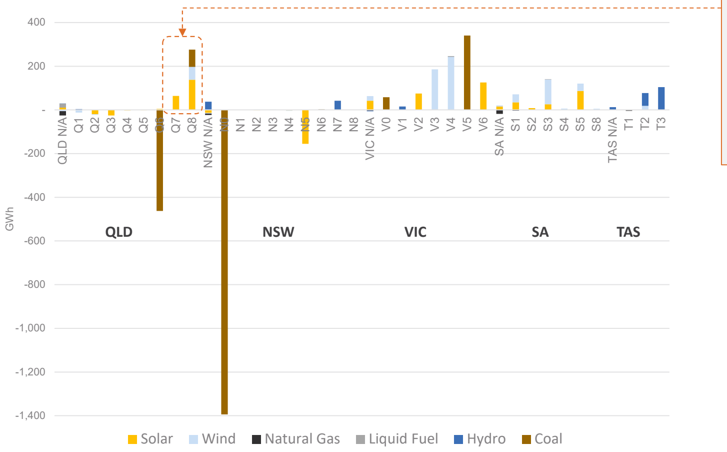
Modelling

Overview of sensitivities (2023-24)

CRM 100% PARTICIPATION – RESULTS

In 2023-24, modelling indicates CRM dispatch adjustments of +/- 2,300 GWh. Dispatch adjustments are broader than local transmission constraints and more interlinked as a result of changes to inter-regional flows; VIC/SA/TAS generation increases output and NSW/QLD generation reduces output.

CRM dispatch adjustments by technology and area (GWh)



Source: NERA analysis of PLEXOS outputs. Note: missing REZs (e.g. S6-S7) do not have any capacity installed in the year 2023/24 under the ISP 2022 Step Change assumptions

Model limitations

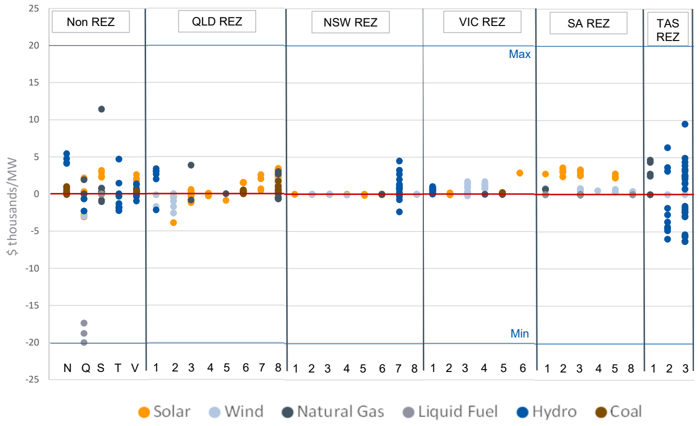
- Mismatches between the congestion price and LMP were identified in far north Queensland. LMPs have been adjusted for revenue calculations and derived from the congestion price (LMP = RRP – congestion price) but unadjusted LMPs still determine dispatch outcomes.

DRAFT results (16 Nov 2022)

CRM 100% PARTICIPATION – RESULTS

The total profit change for generators due to the change in dispatch is estimated at $13.4 million (draft, 2023-24). It is expected that there is no profit downside to participating in the CRM. Model limitations give rise to instances of profit decreases for some hydro (all states) and wind and solar (far north Queensland).

Profit differential due to CRM participation by technology and area (DE$)

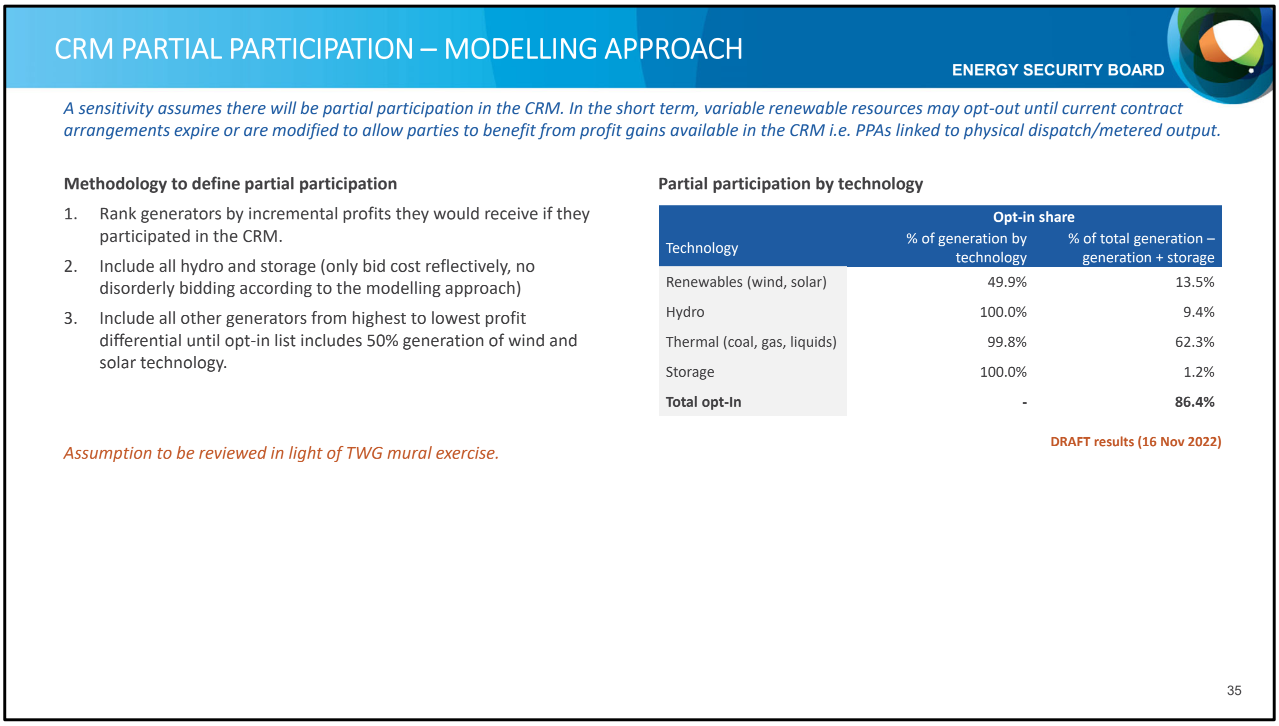


Source: NERA analysis of PLEXOS outputs. Note: missing REZs (e.g. S6-S7) do not have any capacity installed in the year 2023/24 under the ISP 2022 Step Change assumptions
DE$ = profit change due to a change in dispatch

DRAFT results (16 Nov 2022)

Model limitations

- Hydro modelling does not directly value the difference in use of water resources between the energy market dispatch (disorderly bidding) and CRM dispatch (cost reflective bidding), which could affect plants' costs in reality.
- Mismatches between the congestion price and LMP were identified in far north Queensland.



CRM PARTIAL PARTICIPATION – MODELLING APPROACH

ENERGY SECURITY BOARD

A sensitivity assumes there will be partial participation in the CRM. In the short term, variable renewable resources may opt-out until current contract arrangements expire or are modified to allow parties to benefit from profit gains available in the CRM i.e. PPAs linked to physical dispatch/metered output.

Methodology to define partial participation

1. Rank generators by incremental profits they would receive if they participated in the CRM.
2. Include all hydro and storage (only bid cost reflectively, no disorderly bidding according to the modelling approach)
3. Include all other generators from highest to lowest profit differential until opt-in list includes 50% generation of wind and solar technology.

Assumption to be reviewed in light of TWG mural exercise.

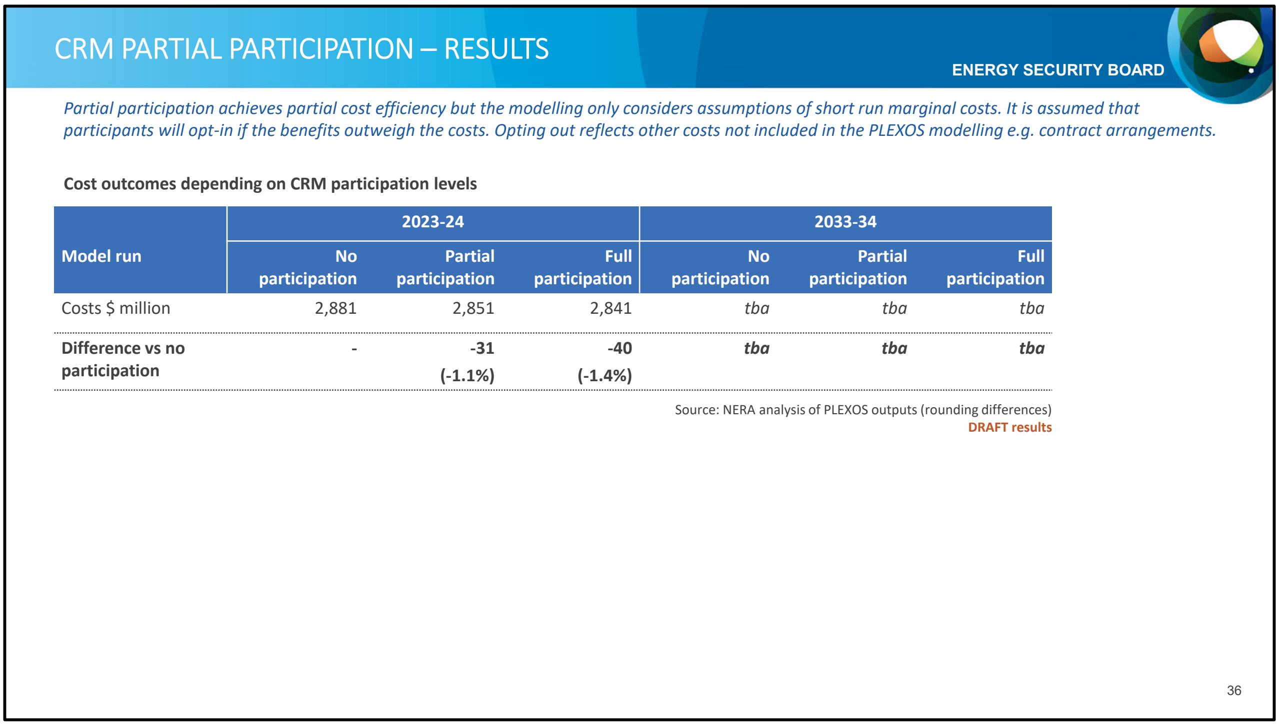
Partial participation by technology

Technology	Opt-in share	
	% of generation by technology	% of total generation – generation + storage
Renewables (wind, solar)	49.9%	13.5%
Hydro	100.0%	9.4%
Thermal (coal, gas, liquids)	99.8%	62.3%
Storage	100.0%	1.2%
Total opt-In	-	**86.4%**

DRAFT results (16 Nov 2022)

Mural queries:

1. Why wouldn’t a generator participate in the CRM?
2. Allowing for a period of adoption of the mechanism, in your view what would be the likely participation %?



CRM PARTIAL PARTICIPATION – RESULTS

Partial participation achieves partial cost efficiency but the modelling only considers assumptions of short run marginal costs. It is assumed that participants will opt-in if the benefits outweigh the costs. Opting out reflects other costs not included in the PLEXOS modelling e.g. contract arrangements.

Cost outcomes depending on CRM participation levels

Model run	2023-24			2033-34		
	No participation	Partial participation	Full participation	No participation	Partial participation	Full participation
Costs $ million	2,881	2,851	2,841	*tba*	*tba*	*tba*
Difference vs no participation	**-**	**-31** **(-1.1%)**	**-40** **(-1.4%)**	***tba***	***tba***	***tba***

Source: NERA analysis of PLEXOS outputs (rounding differences)

DRAFT results

BATTERY – MODELLING APPROACH

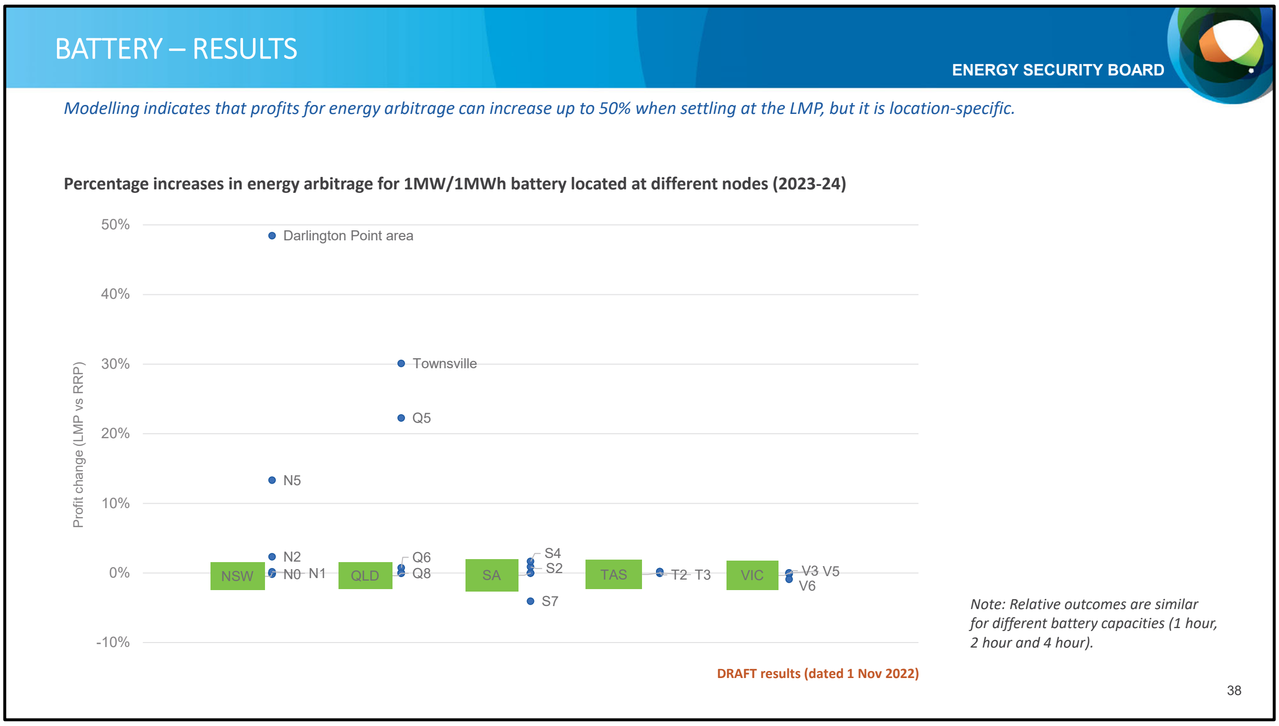
The theory is that batteries benefit from the introduction of the CRM with opportunities for higher profit arbitrage when charging at a lower LMP in the CRM (versus RRP in today's energy market). Modelling approach has been developed to calculate this profit increase.

Calculating profit difference for batteries settling at LMP

1. Identify half-hourly LMPs for a sample of nodes in the region
2. Model a simplified battery operation pattern using the LMPs (1 MW battery with 1 hour, 2 hour and 4 hour capacity, one cycle per day, 92% charging efficiency, 92% discharging efficiency)
3. Compare profit outcomes for selected nodes against a battery located at the regional reference node (where LMP = RRP).

Model limitations

- Battery profits are limited to energy arbitrage only (no other revenue streams modelled)



BATTERY – RESULTS

ENERGY SECURITY BOARD

Modelling indicates that profits for energy arbitrage can increase up to 50% when settling at the LMP, but it is location-specific.

Percentage increases in energy arbitrage for 1MW/1MWh battery located at different nodes (2023-24)

Note: Relative outcomes are similar for different battery capacities (1 hour, 2 hour and 4 hour).

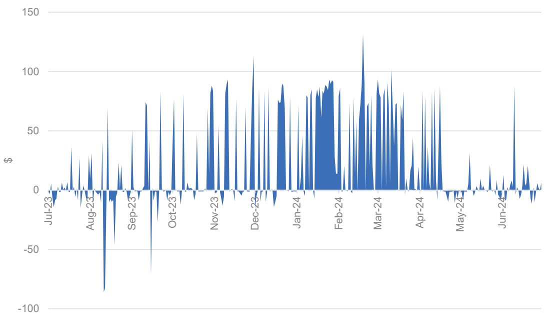
DRAFT results (dated 1 Nov 2022)

BATTERY – RESULTS

ENERGY SECURITY BOARD

The battery located near Darlington Point benefits from charging at a lower LMP during times of congestion. Over 50% of the profit variance was earned during the summer months.

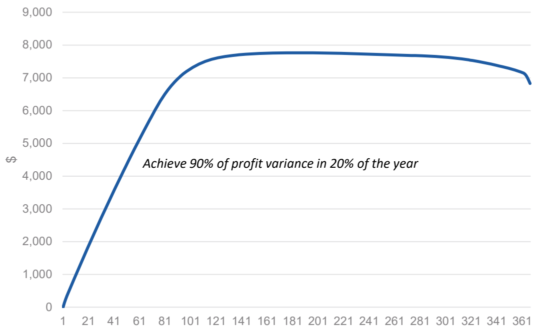
Daily profit variance for 1MW/1MWh battery located at NSW RRN versus near Darlington Point (settling at LMP) 2023-24



Source: NERA analysis of PLEXOS outputs.

DRAFT results (dated 1 Nov 2022)

Cumulative profit variance between 1MW/1MWh battery located a NSW RRN versus near Darlington Point (settling at LMP) 2023-24



Achieve 90% of profit variance in 20% of the year

DRAFT results (dated 1 Nov 2022)

OUT OF MERIT EXCLUSIONS - RECAP

Out of merit (OOM) describes generators with cost > RRP. Depending on the design of the CRM and CMM, there may be unproductive wealth transfers from in-merit to OOM generators. The Directions Paper proposes a number of design choices in response.

CRM

The CRM design introduces arbitrage opportunities between the energy market and CRM. Assume that:

- A generator is initially dispatched in the energy market
- The generator is not physically run after the CRM adjustments
- Generator is rewarded for its contribution to more efficient dispatch and is paid based on the difference between RRP and LMP.

The basic CRM design does not differentiate between in-merit and OOM.

OOM generators have a new opportunity to receive payments, despite not contributing to dispatch efficiency.

Arbitrage bidding in the energy market – scheduled and semi-scheduled generation

Coefficient	Merit position	Bidding incentives $/MWh		
		Today's energy market	Future energy market	Future CRM
Positive – causing congestion	In-merit	-$1000	-$1000	at cost
	Out of merit	at cost	-$1000	at cost

CMM

Out of the four rebate allocation methods discussed with the TWG, only one (inferred economic dispatch) would factor in costs to its method and exclude OOM generators from receiving an access payment.

The remaining three allocation methods could also result in unproductive wealth transfers to OOM generators:

- Pro-rata access based on offered availability
- Pro-rata entitlement based on a combination of constraint coefficients and offered availability
- Winner takes all based on constraint coefficients.

OUT OF MERIT EXCLUSIONS – MODELLING APPROACH

Given the logic applied, the CMM sensitivities for pro-rata access and pro-rata entitlements are the only modelled outcomes to quantify potential wealth transfers to OOM generators.

Quantifying wealth transfers to OOM generators

- Pro rata access and entitlement
    - Scenario assumes all generators qualify for access payments based on offered availability
    - Sensitivity excludes OOM generators from receiving access payments.

Other modelled scenarios do not quantify OOM issues

- Modelling logic applied for CRM and CMM 'winner takes all':
    - Generators will only disorderly bid if:
        - LMP < RRP by at least $1/MWh
        - Cost < RRP by at least $1/MWh

Hence modelling does not show strategic bidding by OOM generators to disorderly bid in the energy market and (a) trade in the CRM to avoid physical dispatch or (b) receive congestion rebates under the 'winner takes all' method.

In practice, OOM generators could receive payments under both of these scenarios.

OOM sensitivity for pro rata access and pro rata entitlement

OOM generators are awarded no access hence:

Revenue = A x (RRP – LMP) + G x LMP
Given A = 0
= G x LMP

Where

A	Effective access value (MWh)
G	Generation dispatch (MWh)
RRP	Regional reference price ($/MWh)
LMP	Locational marginal price ($/MWh)

Model limitations

- The modelling approach quantifies the 'windfall' profits if OOM generators are included in the CMM access allocation.
- However, to limit modelling complexity, it does not redistribute the access allocation from OOM to in-merit generators.
- In practice, the CMM design would redistribute access of OOM generators to in-merit generators.

OUT OF MERIT EXCLUSIONS – RESULTS

ENERGY SECURITY BOARD

Modelled outcomes show that 2 nodes are most affected by the OOM exclusion

Profit transfers as a result of excluding OOM generators from receiving access payments

	2023-24 Profit transfers $m		2033-34 Profit transfers	
Model run	**Pro rata access**	**Pro rata entitlement**	**Pro rata access**	**Pro rata entitlement**
Natural gas (NSW)	-6.6	-6.7	*tba*	*tba*
Hydro (NSW)	-1.2	-1.3	*tba*	*tba*
Other	-0.2	-0.3	*tba*	*tba*
Total	**-8.0**	**-8.3**	*tba*	*tba*

DRAFT results (received 27 Nov 2022)

Model limitations

- No strategic bidding
- Hydro and batteries are excluded from disorderly bidding (cost reflective only)
- Hydro modelling does not directly value the difference in use of water resources between the energy market dispatch (disorderly bidding) and CRM dispatch (cost reflective bidding), which could affect plants' costs in reality.

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