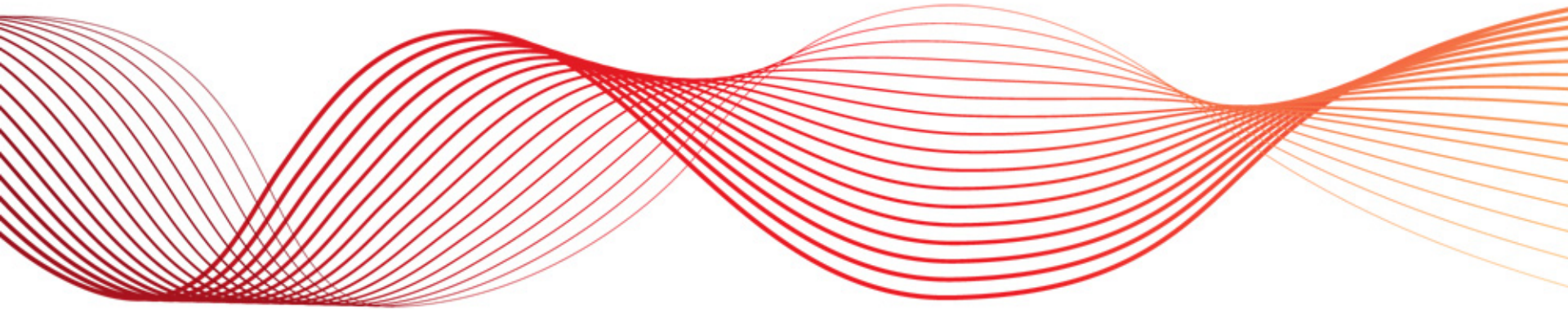
WA MARKET REFORM PROGRAM

SETTLEMENTS FORUM – MEETING 2

23 NOVEMBER 2016

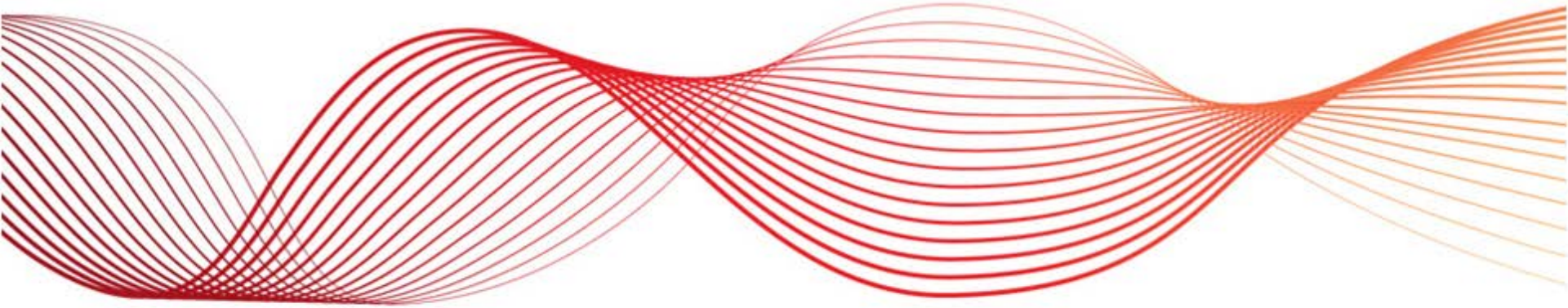


AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

AGENDA

1. Welcome and confirm agenda
2. Recap on actions previous meeting
3. Causer pays
4. Break
5. Full runway pricing
6. Approach to registration
7. Market fees
8. Next meeting and closing

RECAP ON ACTIONS PREVIOUS MEETING



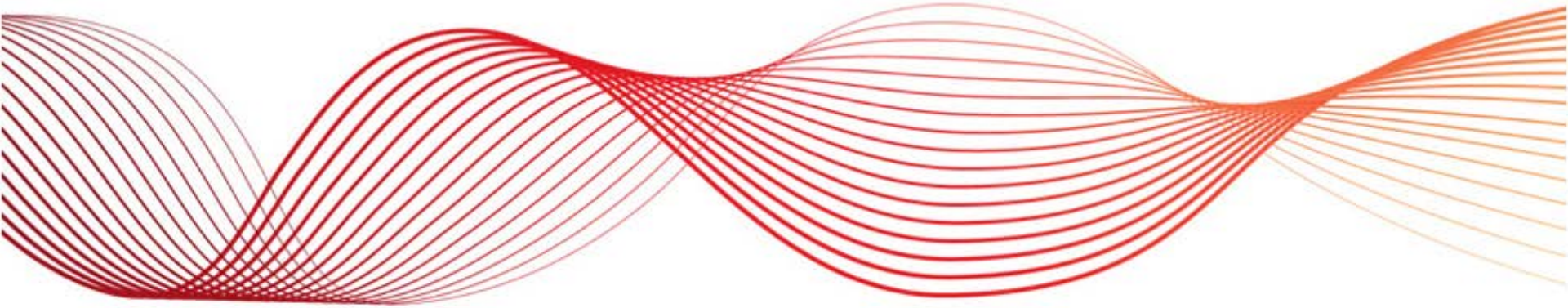
TOPICS COVERED

- Introduction to settlements
- Market billing cycles
- Introduction to NEM prudentials
- Prudential assessment and management
- Forward plan for engagement
- Settlement systems and interfaces

KEY OUTCOMES AND ACTIONS

- Key actions:
  - AEMO committed to providing more information on the causer pays process
- Stakeholders requested more information in the following areas:
  - Causer pays
  - Ancillary services cost recovery
  - Market fees
- Stakeholders indicated a preference to delay further discussion on prudential arrangements
- Notes from the meeting are located at: http://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/WA-Forums/WAMRP-Settlements-Forum

CAUSER PAYS



SESSION OBJECTIVES

1. Overview
2. Contribution factors
3. Dispatch outcomes
4. Regulation recovery
5. Questions

OVERVIEW

WHO PAYS FOR REGULATION FCAS IN THE NEM?

- Since 2001, regulation FCAS in the NEM has been recovered on the principle of causer pays
- This involves two different methodologies:
  - For participants with appropriate metering (either generation or load), costs are apportioned based on the most recent contribution factor (MPF) – set out in NER 3.15.6A(i)(1)
  - The residual contribution (RMPF) is apportioned amongst market customers without appropriate metering based on energy – set out in NER 3.15.6A(i)(2)

CONTRIBUTION FACTORS (MPFS)

- Contribution factors (also known as MPFs or causer pays factors) are calculated according to the Causer Pays Procedure: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Ancillary-services-causer-pays-contribution-factors
- MPFs are calculated so as to represent the net frequency contribution of the market participant's "portfolio", which permits positive and negative performance to be offset geographically and over time within the same category

HOW IS REGULATION FCAS RECOVERY SETTLED?

- The calculation of regulation FCAS recovery is performed in the settlement component of AEMO's Electricity Market Management System (EMMS)
- The calculation is based on:
  - Dispatch outcomes, including FCAS prices and the constraint cost for each binding FCAS requirement (global or local)
  - Contribution factors applicable for that settlement period
  - Metering data used to determine customer energy
- A high level overview of the calculation is available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Ancillary-Services/Ancillary-Services-Payments-and-Recovery

CONTRIBUTION FACTORS

OVERVIEW

- Determined every 4 weeks based on historical frequency performance
- Calculation process involves:
  - Determining deviations using 4 second data
  - Calculating a performance factor based on the deviation and the regulation requirement (frequency indicator)
  - Aggregating factors over time
  - Aggregating factors over portfolio
  - Scaling factors according to overall system factors
- Calculation of the residual involves determining the un-metered proportion
- MPFs (metered and residual) are normalised such that AMPF = 100

DEVIATION CATEGORIES

Type	Includes	Treatment
1	Scheduled and semi-schedule (SCADA metered) generation	Deviation from target to target trajectory
2	SCADA metered non-scheduled generation/load	Deviation from initial value constant trajectory
3	Within 5 minute demand variation	Deviation of regional demand from best fit (least square error) trajectory
4	Load forecast error	Deviation of best fit from target-to-target trajectory

4 SECOND PERFORMANCE

- Performance factor is determined based on deviation multiplied by the total amount of regulation instructed (frequency indicator)
- Negative factor indicates contribution to need for regulation service
- Categorised by lower or raise (based on frequency indicator), and enabled or not enabled (based on whether generator was enabled for regulation FCAS)
  - i.e. REF, RNEF, LEF, LNEF
- Dispatch intervals subjected to large frequency deviations (i.e. contingency events) are excluded from the process

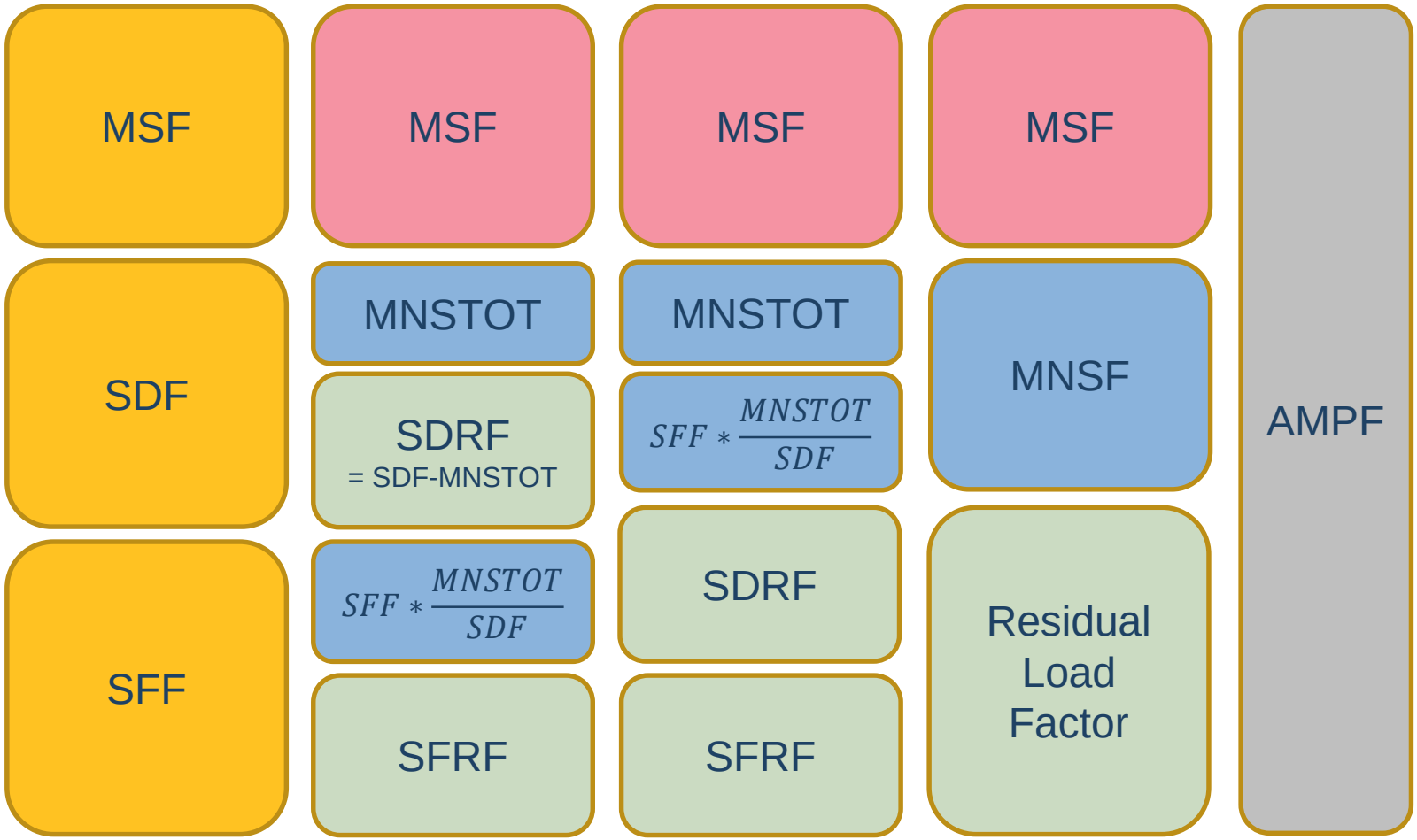
FACTOR AGGREGATION

- 4 second performance factors are aggregated (averaged) to determine 5 minute performance
- For each unit, 5 minute factors are aggregated (averaged) over the sample period (28 days)
- Within each portfolio, the individual categories (REF, RNEF, LEF, LNEF) are aggregated, however Type 1 and Type 2 are summed separately
- An aggregate factor for each portfolio is determined:
  - Ignores positive factors when regulation is enabled (i.e. REF or LEF > 0)
  - Overall positive factor assumed to be zero

CATEGORY TOTALS

- The sum of Type 1, 2, 3 and 4 are derived:
  - MSF = SUM(Type 1)
  - MNSTOT = SUM(Type 2)
  - SDF = SUM(Type 3)
  - SFF = SUM(Type 4)
- Total amount apportioned to metered non-scheduled and residual is determined (refer to diagram following)
- Factors are normalised so that AMPF = 100
  - Normalising involves scaling all factors by a consistent amount in order to achieve an aggregate factor of 100

DIAGRAM OF FACTOR REARRANGEMENT



DISPATCH OUTCOMES

LOCAL/GLOBAL REQUIREMENTS

- In the dispatch process, FCAS requirements can be associated with one or more regions:
  - Regions are included on the LHS of the constraint equation
  - This indicates that the constraint can be met by regulation services from generators in those regions only
- FCAS constraints which involve all regions are considered global requirements (e.g. F_I* sets)
- FCAS constraints which involve a subset of regions are considered local requirements (e.g. F_MAIN*, F_T*, F_S* sets)

REQUIREMENT COST

- The marginal price for the constraint is used to determine the requirement cost for each DI
- The requirement cost is adjusted to account for the co-optimisation of regulation and delayed contingency service:
  - Regulation service can be substituted as delayed contingency, and then part of the cost would be recovered as contingency
  - This process is detailed in the efficient dispatch business specification: https://www.aemo.com.au/Datasource/Archives/Archive1048
- AEMO publishes the requirement cost and the affected regions in the dispatch timeframe (every 5 minutes), along with information to assist participants to estimate their recovery amounts

REGULATION RECOVERY

OVERVIEW

- Regulation FCAS recovery is calculated using the following steps:
  - The cost of each requirement (FCAS constraint) is determined in each DI – it is adjusted based on the amount of regulation service dispatched for delayed contingency service
  - Relevant participants are determined for each requirement in each DI, based on the region(s) related to the requirement
    - The CMPF is the sum of MPFs for relevant participants
    - The CRMPF is the scaled global RMPF

RECOVERY AMOUNTS

- The recovery amount for each market participant is the sum of MPF-based and energy-based costs:
  - MPF-based costs are determined for relevant market participant's as: MPF / (CMPF + CRMPF) * Requirement Cost
  - Energy-based costs are determined for market participant's as: TCE / ATCE * CRMPF / (CMPF + CRMPF) * Requirement Cost
    - TCE and ATCE excludes connection points with a metered contribution factor

STEP 1 – RELEVANT PARTICIPANTS

- For each DI and each requirement, determine the relevant participants:
  - Participant has a MPF record (zero or non-zero) in any region related to the requirement, and also has meter data (zero or non-zero) for the associated connection point

STEP 2 – CMPF AND CRMPF

- For each DI and each requirement:
  - Determine the Constraint MPF (CMPF) but summing the MPFs of all relevant participants
  - Determine the Constraint Residual MPF (CRMPF) by scaling the NEM RMPF based on the proportion of customer energy in the regions related to the constraint
    - i.e. NEM RMPF x ATCE(constraint regions) / ATCE(NEM)

STEP 3 – MPF RECOVERY

- For each DI and each requirement, determine:
  - The CMPF recovery factor as Requirement Cost / (CMPF + CRMPF)
- For each DI and each requirement, determine for each participant:
  - The recovery amount is the participant's MPF x CMPF recovery factor
- The TI recovery amount for the participant is a sum over DIs and requirements

RESIDUAL RECOVERY

- For each DI and requirement, determine:
  - The CRMPF recovery factor as Requirement Cost x CRMPF / (CMPF + CRMPF) / ATCE (constraint region)
  - ATCE excludes connection points that have a zero or non-zero MPF
- For each DI and requirement, determine for each participant:
  - The recovery amount is the participant's TCE x CRMPF recovery factor
  - TCE excludes connection points that have a zero or non-zero MPF
- The TI recovery amount for the participant is a sum over DIs and requirements

EXAMPLE - CONTRIBUTION FACTORS

PARTICIPANTID	EFFECTIVEDATE	CONNECTIONPOINTID	MPF
CSENERGY	11/10/2015	QBOH	1.04191
CSENERGY	11/10/2015	QBOL	0.00000
CSENERGY	11/10/2015	QCAX	0.00000
CSENERGY	11/10/2015	QCAA2	0.00000
CSENERGY	11/10/2015	QCAA4	0.00000
CSENERGY	11/10/2015	QCAB1	3.55266
CSENERGY	11/10/2015	QCAB2	0.00000

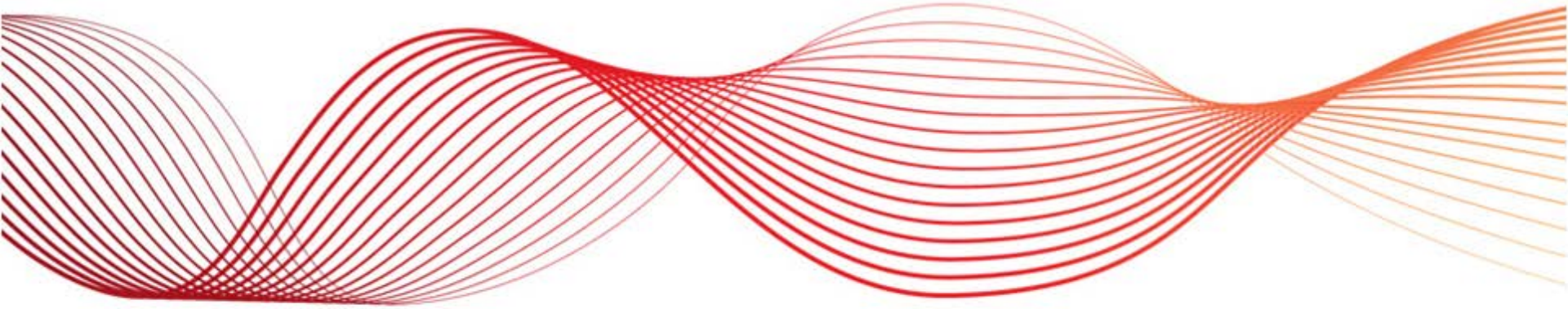
EXAMPLE - DISPATCH OUTCOMES

SETTLEMENTDATE	REGIONID	RAISEREGRRP	LOWERREGRRP
12/10/2015 00:00:00	SA1	$13,100	$13,100

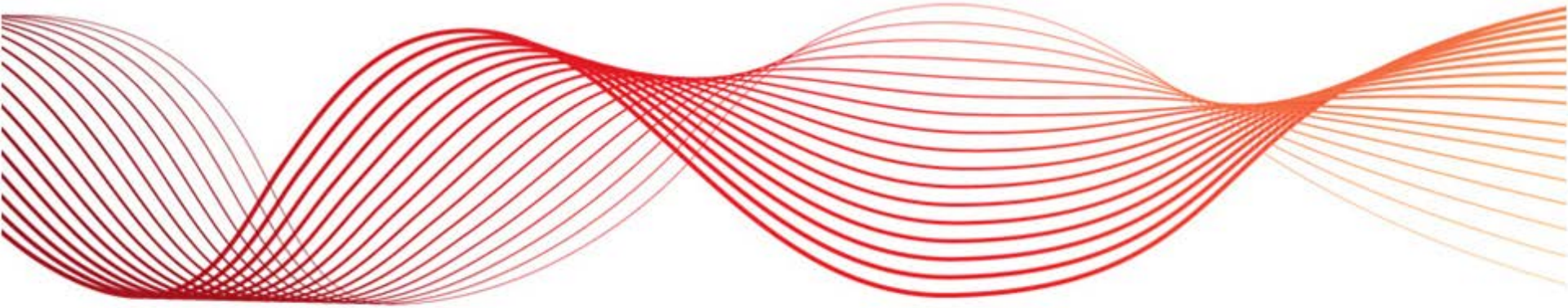
SETTLEMENTDATE	REGIONID	RAISEREGLOCAL DISPATCH	LOWERREGLOCAL DISPATCH
12/10/2015 00:00:00	SA1	35.0	35.0

INTERVAL_DATETIME	REGIONID	CONSTRAINTID	ADJUSTED_COST
12/10/2015 00:00:00	SA1	F_S+LREG_0035	$38,206.84

BREAK



FULL RUNWAY PRICING



FULL RUNWAY CALCULATION

$$CPB(m) = ((((G(m) - G(m+1)) / Max(G)) * RCS) / m)$$

$$FRC(m) = sum(CPB(m:M)) * -1$$

WHERE:

m	Represents the facility at position m, within a dispatch interval stack that has been sorted by actual generation output in descending order (largest to smallest). m=1 represents the facility at the top of the stack with the largest generation output.
M	Represents the facility at the bottom of the stack (i.e. the facility with the smallest actual generation output).
G	Represents the actual generation output of a facility.
RCS	Cost of Service to Recover. Represents the total payments made to facilities as compensation for a contingency raise event ($/interval).
CPB	Cost per Block. Represents the cost of contingency raise recovery for each facility that produced generation output in a dispatch interval.
FRC	Facility Recovery Charge. Represents the dollar amount to be recovered from each facility in order to cover the RCS.

WORKED EXAMPLE

Cost of service to be recovered (RCS) = $1,000

- STEP 1 – Create stack
  - All facilities are placed into a stack along with their actual generation output (MW) for the given dispatch interval, sorted by generation output in descending order (largest to smallest).

Step 1 – create stack

m	Facility Name	Output (G)
1	Generator4	250
2	Generator3	202
3	Generator5	202
4	Generator1	150
5	Generator6	70
6	Generator2	66

WORKED EXAMPLE CONTINUED

- STEP 2 – Step amount
  - Calculate the output step amount for each facility in the stack.
  - Find the difference between the output of a facility minus the output of the facility immediately below it in the stack.
  - The step amount for the last facility in the stack is defaulted to the actual output of that facility.

Step 1 – create stack			Step 2 – step amount
m	Facility Name	Output (G)	G(m) - G(m+1)
1	Generator4	250	48
2	Generator3	202	0
3	Generator5	202	52
4	Generator1	150	80
5	Generator6	70	4
6	Generator2	66	66

Step Amount = (G(m) – G(m+1))

WORKED EXAMPLE CONTINUED

- STEP 3 – Portion of generation
  - The portion of generation for each facility in the stack is calculated.
  - This is calculated as the output *Step Amount* (from previous step) divided by the largest output quantity in the stack.

Portion of Generation = Step Amount/Max(G)

Step 1 – create stack			Step 2 – step amount	Step 3 – portion of generation
m	Facility Name	Output (G)	G(m) - G(m+1)	(G(m) - G(m+1)) /Max(G)
1	Generator4	250	48	0.192
2	Generator3	202	0	0
3	Generator5	202	52	0.208
4	Generator1	150	80	0.32
5	Generator6	70	4	0.016
6	Generator2	66	66	0.264

WORKED EXAMPLE CONTINUED

- Step 4 - Total Cost of Step Quantity
  - Calculate the total cost of step quantity for each facility in the stack. This is calculated as the *Portion of Generation* (from previous step) multiplied by the cost of service to recover (RCS).

Total Cost of Step Quantity = Portion of Generation*RCS

Step 1 – create stack			Step 2 – step amount	Step 3 – portion of generation	Step 4 – total cost of step qty
m	Facility Name	Output (G)	G(m) - G(m+1)	(G(m) - G(m+1)) /Max(G)	((G(m) - G(m+1)) /Max(G)) *RCS
1	Generator4	250	48	0.192	192
2	Generator3	202	0	0	0
3	Generator5	202	52	0.208	208
4	Generator1	150	80	0.32	320
5	Generator6	70	4	0.016	16
6	Generator2	66	66	0.264	264

WORKED EXAMPLE CONTINUED

- Step 5 – Cost per block
  - Calculate the Cost per Block for each facility in the stack. This is calculated as the *Total Cost of Step Quantity* (from previous step) divided by the stack position of the facility, in order to determine the recovery amount per facility.

Cost per Block (per facility) = Total Cost of Step Quantity / m

Step 1 – create stack			Step 2 – step amount	Step 3 – portion of generation	Step 4 – total cost of step qty	Step 5 – CPB per facility
m	Facility Name	Output (G)	G(m) - G(m+1)	(G(m) - G(m+1)) /Max(G)	((G(m) - G(m+1)) /Max(G)) *RCS	(((G(m) - G(m+1)) /Max(G)) * RCS) /m
1	Generator4	250	48	0.192	192	192
2	Generator3	202	0	0	0	0
3	Generator5	202	52	0.208	208	69.33333333
4	Generator1	150	80	0.32	320	80
5	Generator6	70	4	0.016	16	3.2
6	Generator2	66	66	0.264	264	44

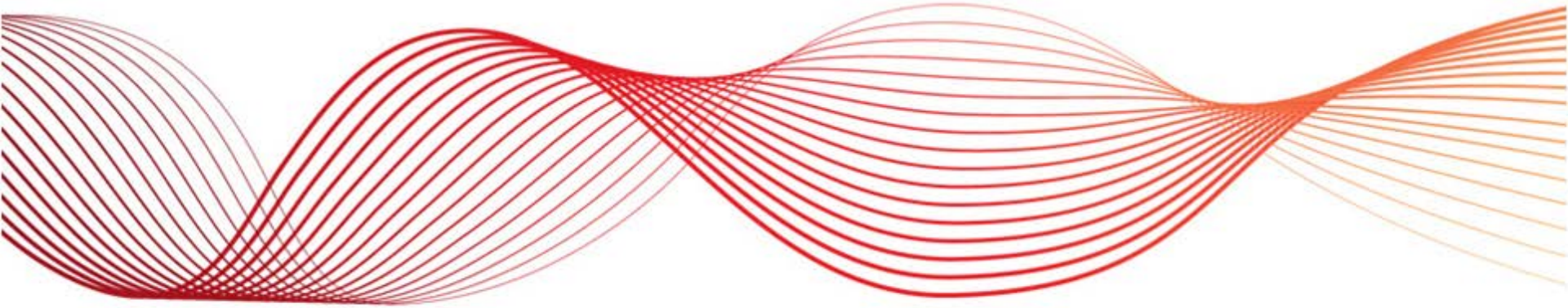
WORKED EXAMPLE CONTINUED

- STEP 6 – Facility recovery charge
  - FRC is calculated by adding the CPB values of all the facilities from the bottom of the stack, up to and including the CPB of the facility being calculated. The FRC for the facility on the bottom of the stack is defaulted to the CPB for that facility.

Facility Recovery Charge (per facility) = Sum(CPB(m:M))

Step 1 – create stack			Step 2 – step amount	Step 3 – portion of generation	Step 4 – total cost of step qty	Step 5 – CPB per facility	Step 6 – FRC per facility
m	Facility Name	Output (G)	G(m) - G(m+1)	(G(m) - G(m+1)) /Max(G)	((G(m) - G(m+1)) /Max(G)) *RCS	(((G(m) - G(m+1)) /Max(G)) * RCS) /m	Sum(CPB(m :M))
1	Generator4	250	48	0.192	192	192	$388.53
2	Generator3	202	0	0	0	0	$196.53
3	Generator5	202	52	0.208	208	69.33333333	$196.53
4	Generator1	150	80	0.32	320	80	$127.20
5	Generator6	70	4	0.016	16	3.2	$47.20
6	Generator2	66	66	0.264	264	44	$44.00

APPROACH TO REGISTRATION



TYPE OF PARTICIPANTS IN NEM

- Customer
- Generator
  - Ancillary service provider
  - Small generator aggregator
- Network Service Provider
- Trader (Settlement residue Auction) – N/A
- Reallocator
- Special Participant
- Intending participant

Information on Registration categories and documents:
https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/New-participants/Application-forms-and-supporting-documentation

TRANSITION PROCESS

- 4 phase process – currently in phase 1 (Gap Analysis)
  - Checking current data in Western Power, System Management and AEMO's systems

- Transition plan:
  - Transfer as much data as possible in to AEMO systems
  - Send out participant packages to confirm information
  - Gather additional information
  - Approvals and final adjustments made

NEM SETTLEMENT ONBOARDING TASKS

- RCTI Check
  - http://www.aemo.com.au/-/media/Files/Electricity/NEM/Settlements_and_Payments/Settlements/2016/RCTI-Agreement-June-2016.docx
- Default payment nomination
- Settlements direct
- Contact info
- Emission factor for CDEII
- Metering Check
- Fees and exclusions
- Settlements Revisions Liability Deed
  - http://www.aemo.com.au/-/media/Files/Doc/0536-0007-doc.doc

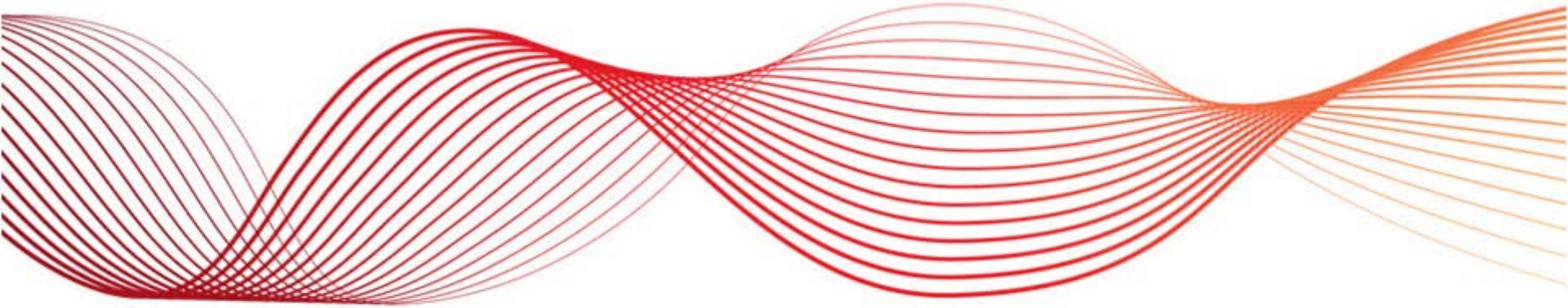
NEM PRUDENTIAL ONBOARDING TASKS

- Austraclear
- Credit support
- MCL
- Reallocation agreements
- Bank guarantees NEM and WEM

Further information on Prudential documents:

http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments/Prudentials-and-payments/Procedures-and-guides

MARKET FEES



MARKET FEE TYPE

Function	Budget 2016-17 $'000	Rate [1]	Paying Participants
NEM			
General Fees (unallocated)	20,981	$0.11663/ MW·h of customer load	Market Customers
Allocated Fees			
- Market Customers	26,436	$0.14695/ MW·h of customer load	Market Customers
- Generators[2] and Market Network Service Providers	22,520	Daily rate calculated on 2015 capacity/ energy basis	Generators and Market Network Service Providers
Participant Compensation Fund	Nil	Daily rate calculated on capacity/ energy basis	Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers
Registration fees	426	Refer to table 6	Intending Participants
Other	1,948		Dependent on service provided
TOTAL NEM	**72,311**		
FRC ELECTRICITY			
FRC Operations	10,047	$0.06100/ MW·h of customer load in jurisdictions with FRC	Market Customers with a Retail Licence
Other	50		Dependent on service provided
TOTAL FRC ELECTRICITY	**10,097**		
National Transmission Planner	2,889	$0.01606/ MW·h of customer load	Market Customers
Electricity Consumer Advocacy Panel	4,781	$0.00951/ connection point for small customers/ week	Market Customers
Additional Participant ID		$5,000 per additional participant ID	Existing Participants

[1] All fees and rates are exclusive of GST
[2] Excluding non market non scheduled generators

CUSTOMER FEE CALCULATION EXAMPLE

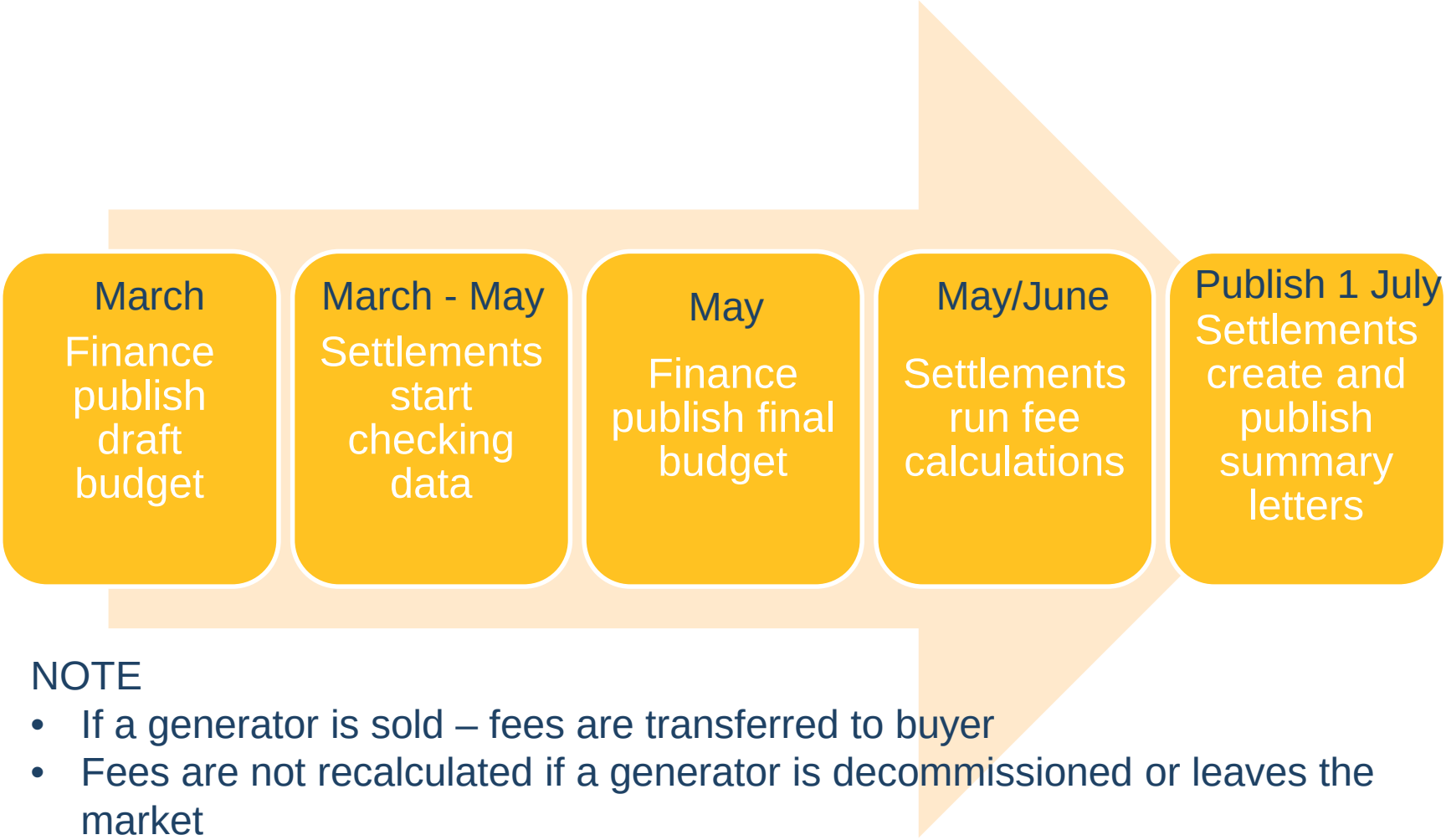
		Customer energy	X	Fee rate	=	Fee Charge
Participant id	**Interval No**	**Customer energy**	**Fee rate**		**Fee charge**	
Energy1	1	20	$	0.14695	$	2.94
Energy1	2	10	$	0.14695	$	1.47
Energy1	3	30	$	0.14695	$	4.41
Energy1	4	20	$	0.14695	$	2.94
Energy1	5	10	$	0.14695	$	1.47
			TOTAL		**$**	**13.23**

- Total Fee charge = Half hour MW energy values multiplied by fee rate
- Fee rates can be found: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Fees-and-charges
  - Appendix B of Electricity Budget and Fee Stakeholder Report.

GENERATOR FEES

- NEM Generator fees are charged to **registered** generator participants on the basis of a calculated daily rate
- Generators are not charged for fees in first calendar year or operation
- SGA's fees are based on generation quantity – treated as customer.

GENERATOR FEE PROCESS

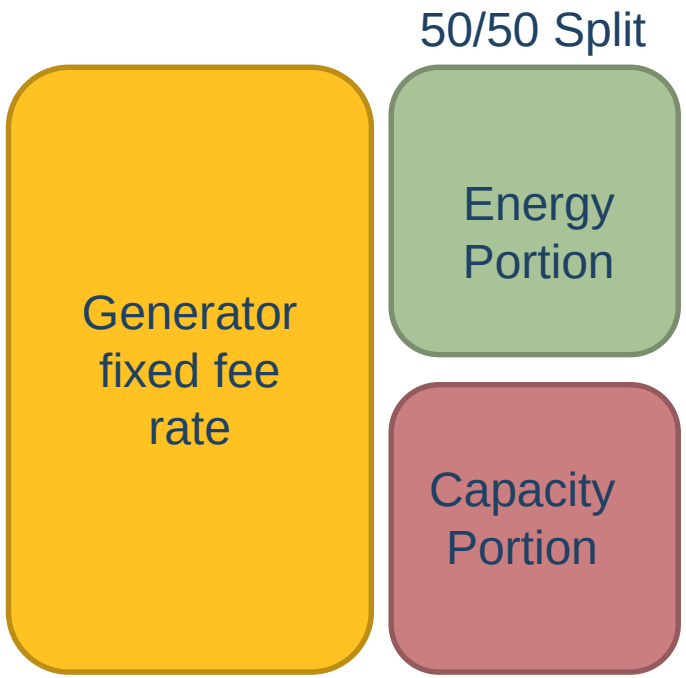


NOTE

- If a generator is sold – fees are transferred to buyer
- Fees are not recalculated if a generator is decommissioned or leaves the market

GENERATOR FEE CALCULATION

Generator fee are calculated based on two factors:



where:

- Energy = Aggregate of the MWh of energy scheduled (for a scheduled or semi-scheduled generating unit or a market network service) or energy metered (for a non-scheduled generating unit) in the previous calendar year (hence CalYr-1).
- Capacity = Highest capacity value within the previous calendar year of either the registered capacity or notified maximum capacity.

TYPES OF GENERATOR FEES

		Example Total fee to be recovered: $50000
Fee type	**Paying participants**	**Fee recovery amounts**
Generator Fee	MNSPs and all Generators (except non-market, non-scheduled)	$33333.33
Market Generator Fee	Market Generators, & MNSPs	$16666.67
Participant Compensation Fund	Scheduled generators (incl Semi-S) and NSPs	Not charged currently, fund is full

GENERATOR FEE CALCULATION EXAMPLE

	Input		Share			Daily Fee rate		
	Energy	Capacity	Energy share	Capacity share	Average share	PCF	Generator	Market
Generator 1	15000	60	0.625	0.4	0.5125	$ -	$ 46.80	$ 23.40
Generator 2	1000	40	0.041667	0.266667	0.154167	$ -	$ 14.08	$ 7.04
Generator 3	8000	50	0.333333	0.333333	0.333333	$ -	$ 30.44	$ 15.22
Total	24000	150	1	1	1			

Step 1: Calculate share of energy and capacity

- Energy output / Total market energy
- Capacity quantity / Total market capacity

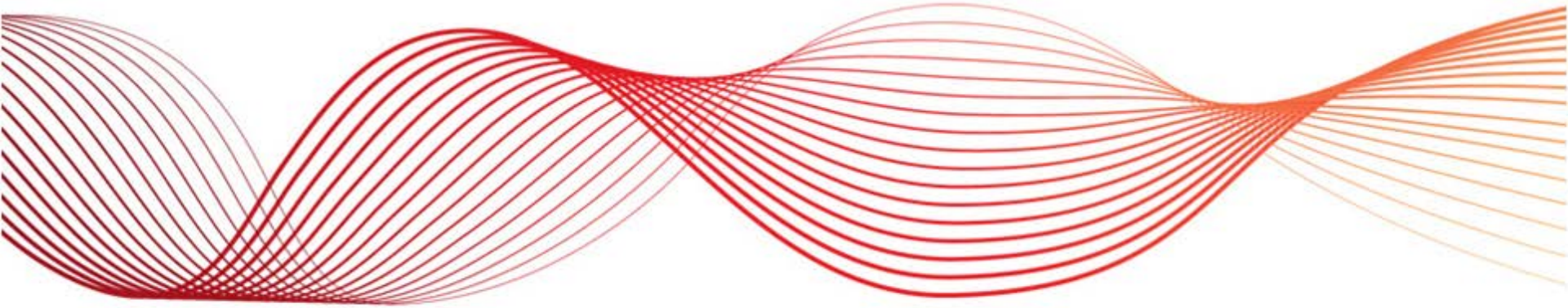
Step 2: Determine average share

- (Energy portion + Capacity portion) / 2

Step 3: Calculate fee rate per generator

- (Average share x market fee recovery amount type) / 365

NEXT MEETING AND CLOSING



NEXT STEPS

- Next meeting: 14 December 2016
  - Topic suggestions?
- Meeting schedule for 2017
- Any other suggestions or comments?

MORE INFORMATION

- Website: http://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/WA-Forums/WAMRP-Settlements-Forum
- Email: WAMRPWholesale@aemo.com.au
- Phone:
  - Chris Muffett (02) 8884 5317
  - Ruth Guest (02) 9239 9179
  - Dimi Botha (08) 9254 4345
  - Mike Hales (08) 9254 4312