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ENERGY MODELLING EXPERTISE

WP3 - Assessment of FCS and Technical Rules

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Perth, 21st April

Scope

- Are the existing spinning reserve, load following, curtailment and demand response criteria in the SWIS adequate for the forecast levels of intermittent generation?
  - Identify scenarios and penetration levels at which additional services may be required
- Can intermittent generators provide the frequency control services required?
  - including load following for overnight load troughs
- What are the costs associated with the provision of frequency control services for the forecast penetration levels of intermittent generation?
  - How should these costs be allocated?

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Background

- Frequency Control Ancillary Services in the SWIS:
  - Load Following
    - Constant balancing of supply and demand
    - Real-time operation
  - Spinning Reserve
    - Responds if another unit experiences a forced outage
- Increased wind penetration
  - Intermittent generation is netted off demand
  - Increased variability of intermittent generation increases load following requirement

Scenarios

- Scenarios developed in WP1

Capacity of wind installed by scenario			
		Capacity of wind installed (MW)	
	Description	**By 2020-21**	**By 2029-30**
1	Strained network	1045	1460
2	Minimal change	488	820
3	Low emissions	744	1076
4	Coal development	620	835

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Metrics for assessing load following requirements

Rules:

3.10.1. The standard for Load Following Service is a level which is sufficient to:

- *provide Minimum Frequency Keeping Capacity, where the Minimum Frequency Keeping Capacity is the greater of:*
  - *30 MW; and*
  - *the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average.*

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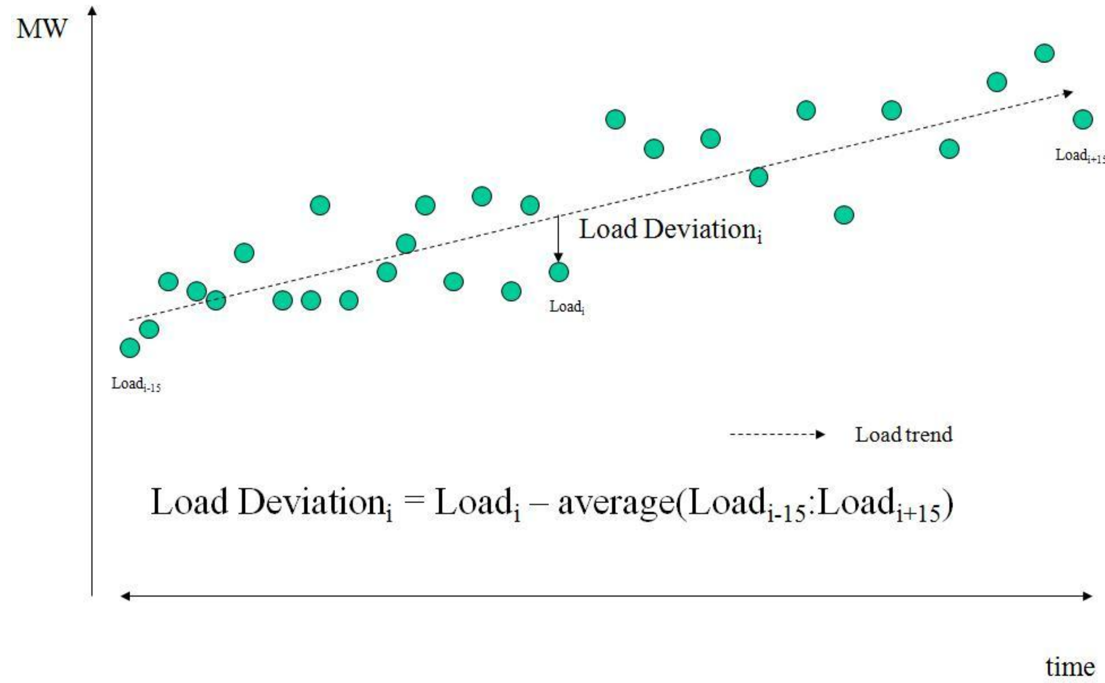
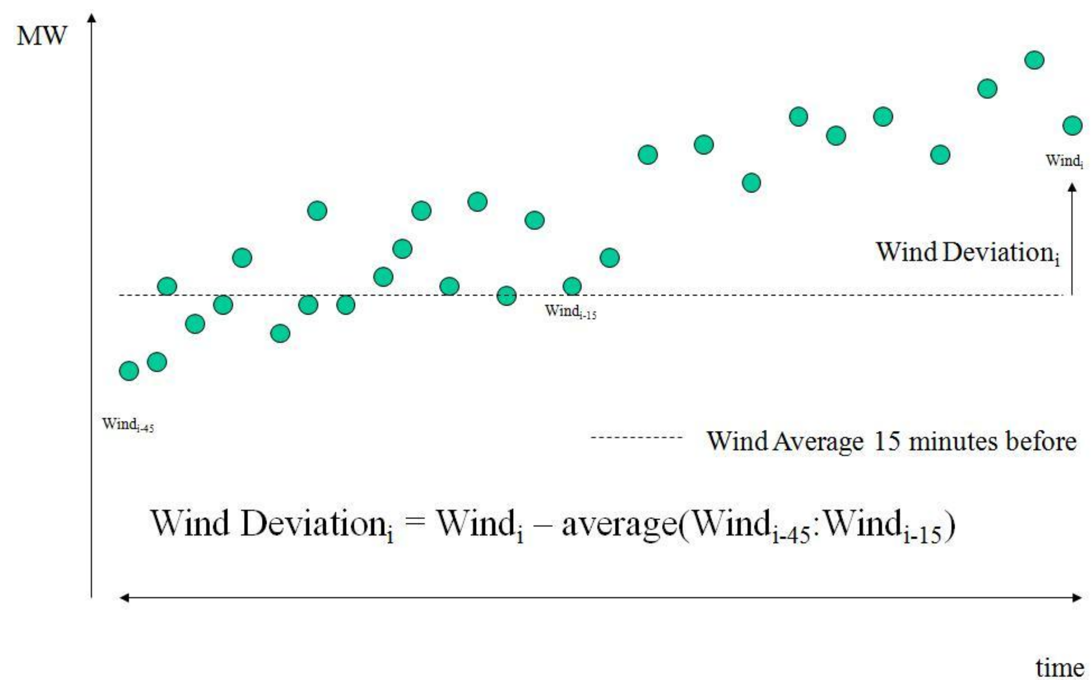
Load Following Requirement

- Calculate load deviation and wind deviation separately
  - Variability due to wind or demand alone
- Also calculate actual load following requirement with combination of the two
  - $\Delta S_i = \Delta L_i - \Delta W_i$
- Calculate 99.9th percentile
- Provides a measure of variability over 30min rolling average
  - Poor expectation of ability to predict wind based on past output
  - Does not account for shorter or longer deviations (perhaps important?)





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Proposed alternative metrics

Type	Relevant timeframe	How it is provided	How to calculate it
Slow Following (S)	5min - 60min	Continuous slow and coarse grained variation within an hour Could be provided through AGC (Automatic Generation Control) or through slower contact with System Management (eg. phone)	Maximum of the difference between the level at which most plant are dispatched each 60min, and the rolling 30min average. Determine 99.95th percentile of negative and positive deviations. $\Delta S_{i+} = max_{j=1:60}[(L_{E,i+j} - W_{E,i+j}) - (L_{E,i+30} - W_{E,i})]$ $\Delta S_{i-} = min_{j=1:60}[(L_{E,i+j} - W_{E,i+j}) - (L_{E,i+30} - W_{E,i})]$ $L_{E,i} = \langle L_{i-15}: L_{i+15} \rangle$ $W_{E,i} = \langle W_{i-30}: W_{i-1} \rangle$
Regulation (R)	1min - 5min	AGC response - pulsed signal from system management to increase or decrease output each minute. Provides minute to minute deviations from 5min dispatch.	Difference between actual load and wind and their rolling 30min average. Calculate positive and negative deviations, and determine 99.95th percentile of each. $\Delta R_i = [L_i - \langle L_{i-15}: L_{i+15} \rangle] - [W_i - \langle W_{i-30}: W_{i-1} \rangle]$
Fast response (F)	< 1min	Governor response, system inertia	Minute to minute variations in the load and wind. Calculate positive and negative deviations, and determine 99.5th percentile of each. $\Delta F_i = (L_i - W_i) - (L_{i-1} - W_{i-1})$

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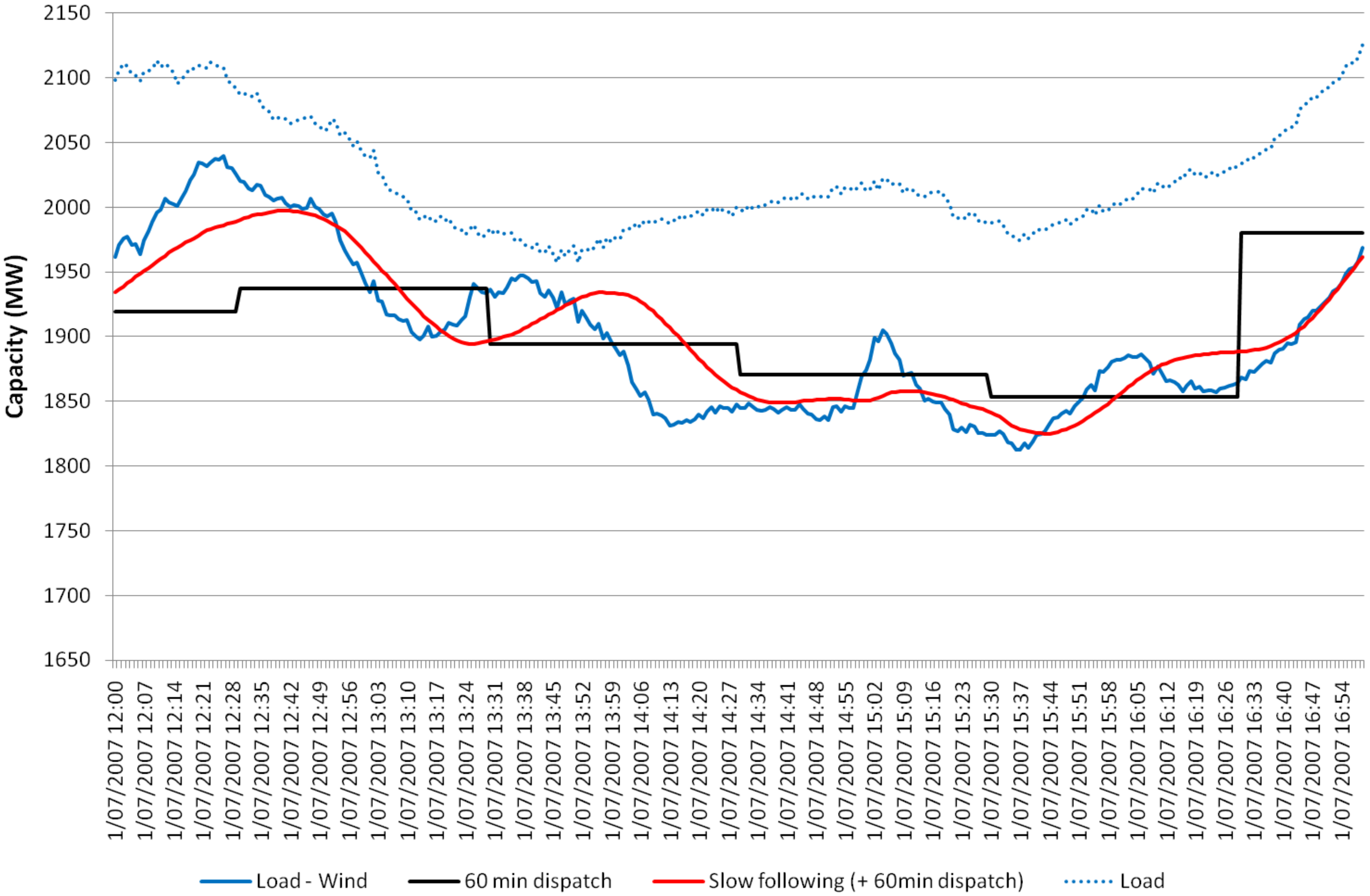
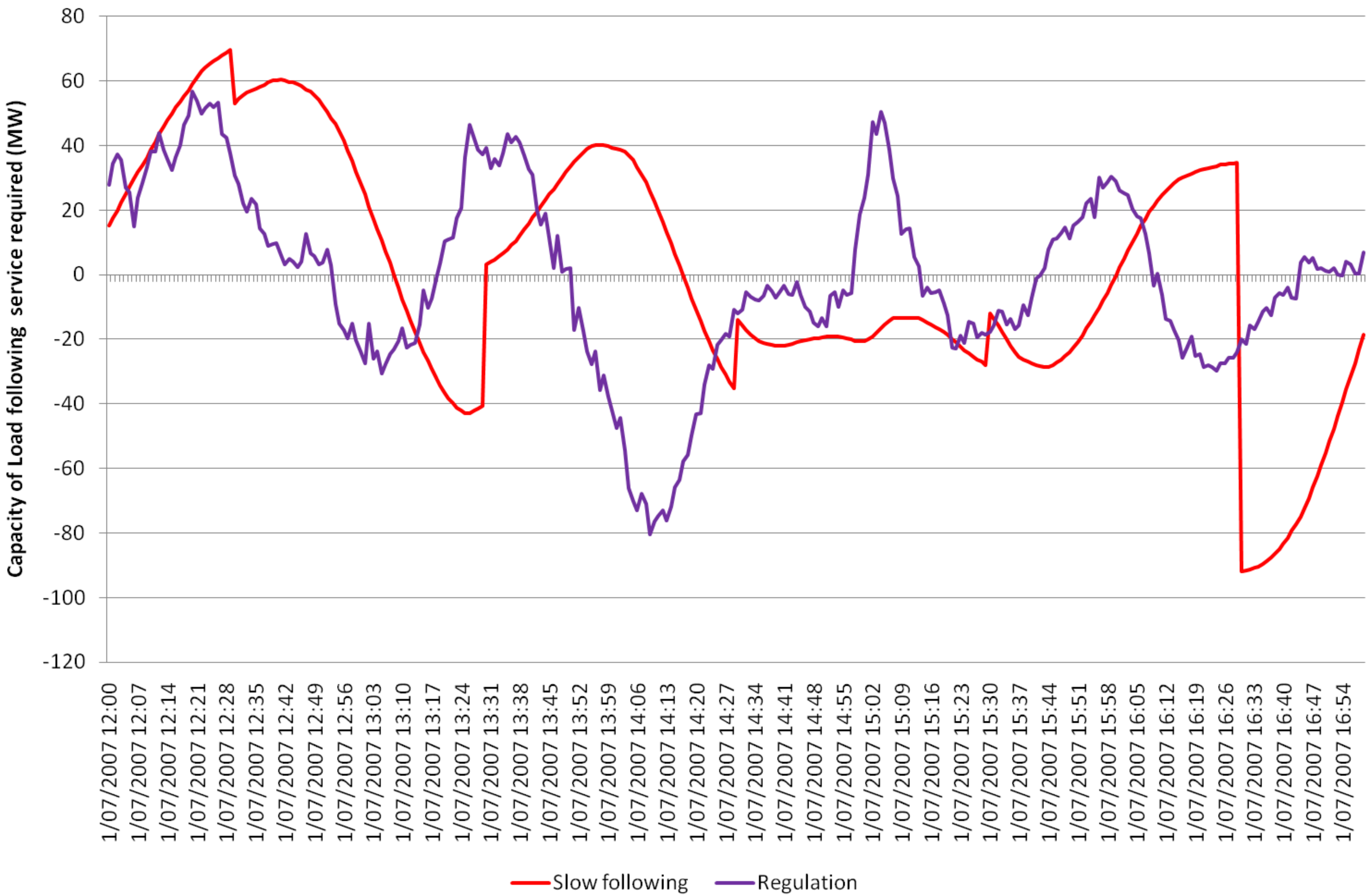
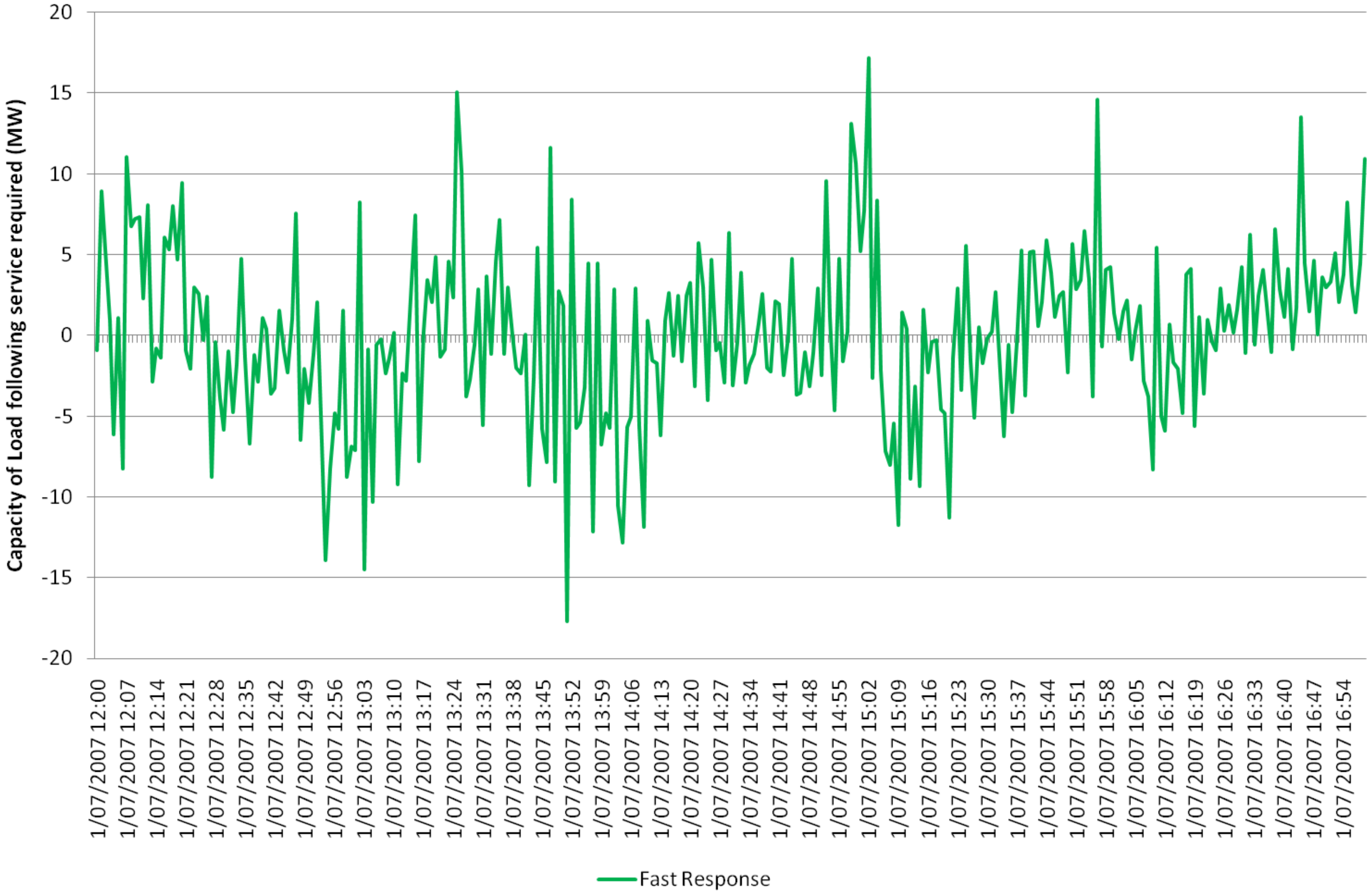
Slow following



Slow following and Regulation



Fast Response



Wind forecasting

- To understand impacts of wind on future grid, need to forecast 1min wind traces (forecast aggregate variability)
- Wind Energy Simulation Tool (WEST)
  - Inputs:
    - Historical wind data from Bureau of Meteorology (1min resolution, 2008-09)
    - Average wind speed at each location at turbine height (Renewable Energy Atlas)
    - Manufacturer turbine power curves (wind speed → MW output)
  - Calibration
    - Use comparison of Albany WF with Albany Airport BOM data and Walkaway WF with Geraldton BOM data
    - Calibrate time of day average
    - Calibrate smoothing (gusty wind → smoothed turbine output)
  - Output:
    - 1min wind traces for each individual wind farm, correctly correlated with each other, and with annual load
    - Sum to give aggregate trace

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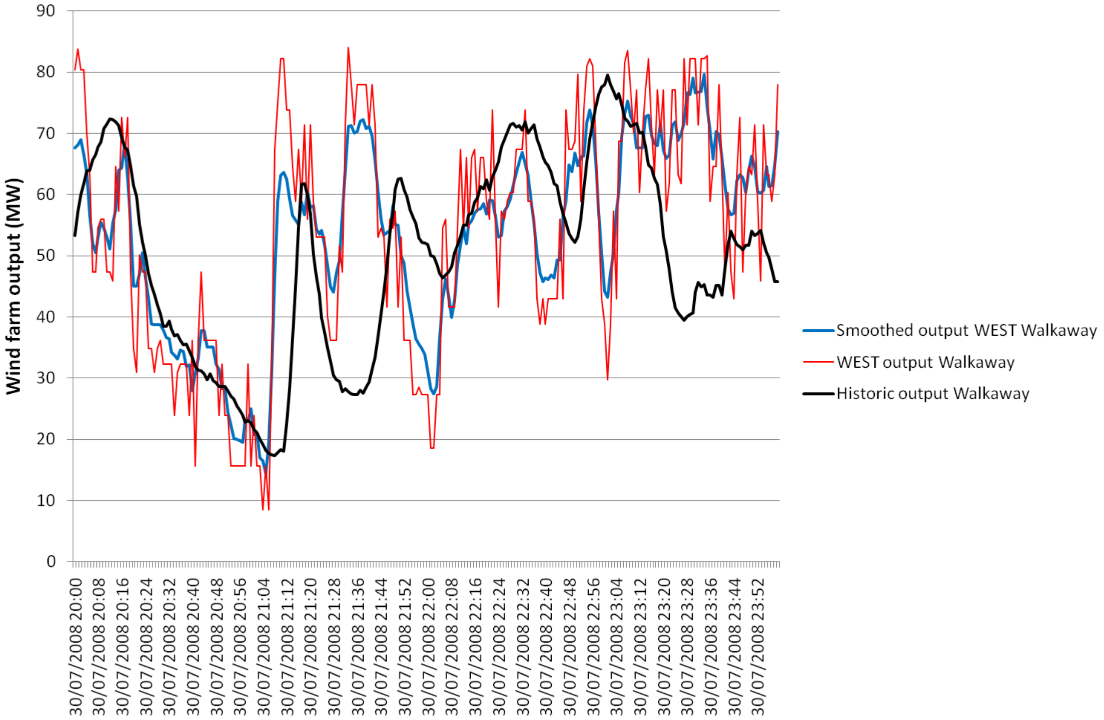
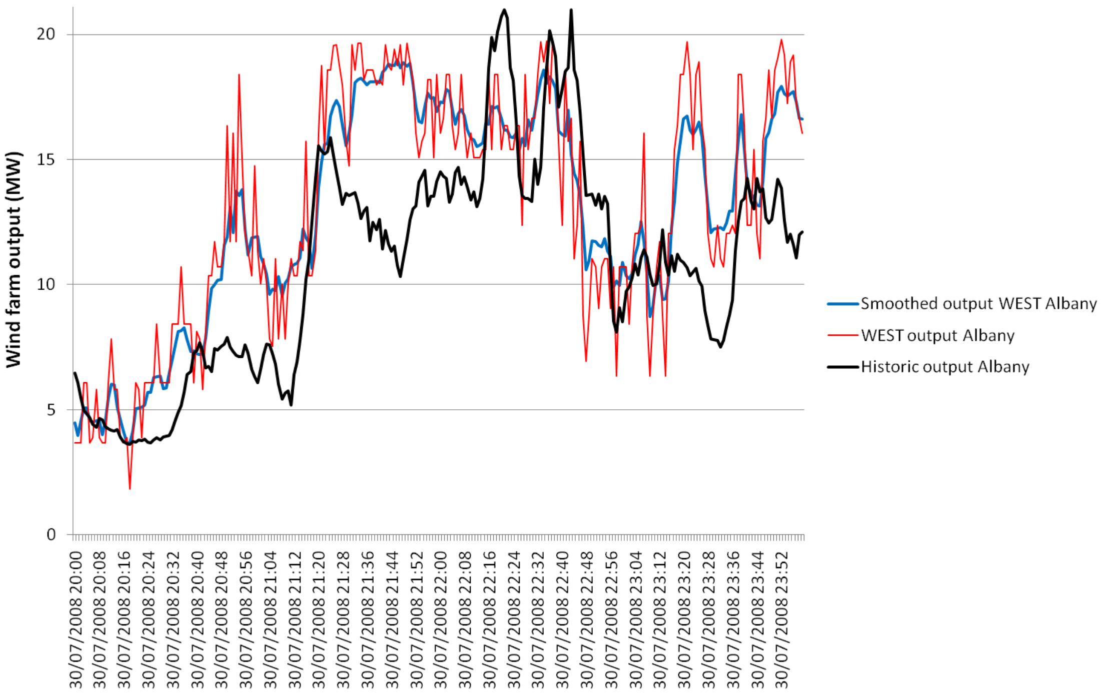
Calibration

- 1min wind forecast examples
  - Calibration against Albany and Walkaway WF





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Wind farm correlation

- Correlation of wind farms from site to site is very important
  - High correlation leads to larger aggregate variability (and load following requirement)
- WEST captures geographical correlation
  - Analysed sites with sufficient 1min data available
    - BOM is installing new automatic weather stations, will have data from many more locations in future
- Wind farms appear to be correlated in three distinct zones
  - **South area** - South coast of WA. Includes Albany wind farm.
  - **North area** - North west coast of WA. Includes Walkaway wind farm, and any wind farms in the area around Geraldton.
  - **Perth area** - Intermediate area in-between.

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Correlation factors of wind data (2008-09)

		Geraldton Airport BOM	Walkaway trace	Emu Downs trace	Pearce RAAF BOM	Perth Metro BOM	Perth Airport BOM	Bickley BOM	Mandura BOM	Dwellingup BOM	Albany Airport BOM	Albany trace	Esperance BOM
		NORTH	NORTH	NORTH / PERTH	PERTH	PERTH	PERTH	PERTH	PERTH	PERTH	SOUTH	SOUTH	SOUTH
Geraldton Airport BOM	NORTH	-	0.49	0.30	0.31	0.49	0.35	0.21	0.41	0.25	0.07	0.08	0.17
Walkaway trace	NORTH	0.49	-	0.56	0.28	0.30	0.31	0.21	0.18	0.21	-0.01	0.06	0.02
Emu Downs trace	NORTH / PERTH	0.30	0.56	-	0.44	0.32	0.43	0.38	0.15	0.31	0.03	0.05	0.01
Pearce RAAF BOM	PERTH	0.31	0.28	0.44	-	0.60	0.69	0.57	0.42	0.48	0.23	0.14	0.12
Perth Metro BOM	PERTH	0.49	0.30	0.32	0.60	-	0.67	0.45	0.60	0.41	0.21	0.15	0.23
Perth Airport BOM	PERTH	0.35	0.31	0.43	0.69	0.67	-	0.54	0.43	0.46	0.18	0.13	0.09
Bickley BOM	PERTH	0.21	0.21	0.38	0.57	0.45	0.54	-	0.34	0.60	0.22	0.07	0.10
Mandura BOM	PERTH	0.41	0.18	0.15	0.42	0.60	0.43	0.34	-	0.42	0.25	0.10	0.28
Dwellingup BOM	PERTH	0.25	0.21	0.31	0.48	0.41	0.46	0.60	0.42	-	0.22	0.06	0.15
Albany Airport BOM	SOUTH	0.07	-0.01	0.03	0.23	0.21	0.18	0.22	0.25	0.22	-	0.55	0.43
Albany trace	SOUTH	0.08	0.06	0.05	0.14	0.15	0.13	0.07	0.10	0.06	0.55	-	0.24
Esperance BOM	SOUTH	0.17	0.02	0.01	0.12	0.23	0.09	0.10	0.28	0.15	0.43	0.24	-

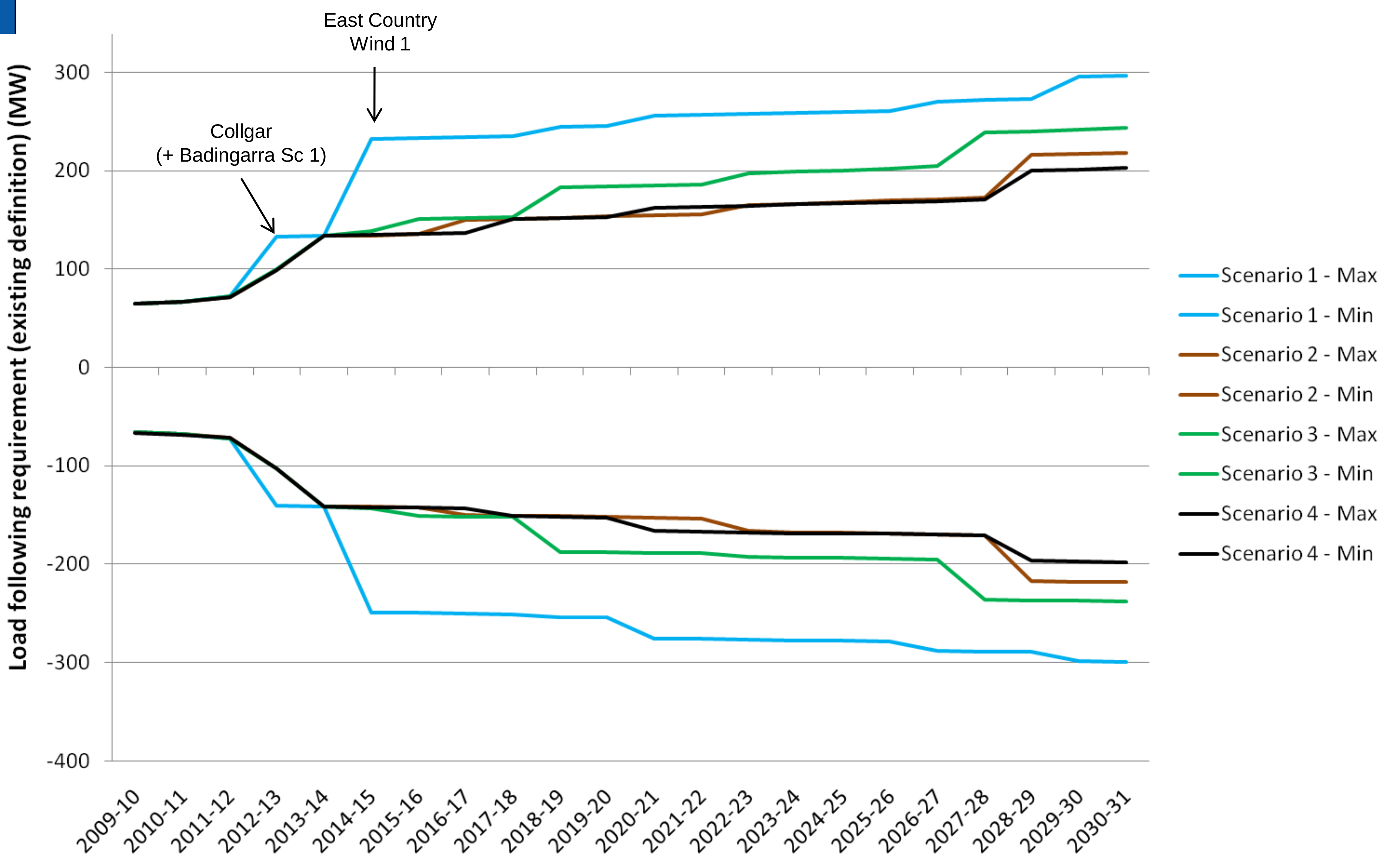
Load following requirements - Results

- Use metrics developed to analyse variability of aggregate wind in each year
  - Based upon installation schedule from WP1
- Analysed variability of load in each year
  - Based upon 1min load trace developed from 2008-09 1min load and peak demand forecasts

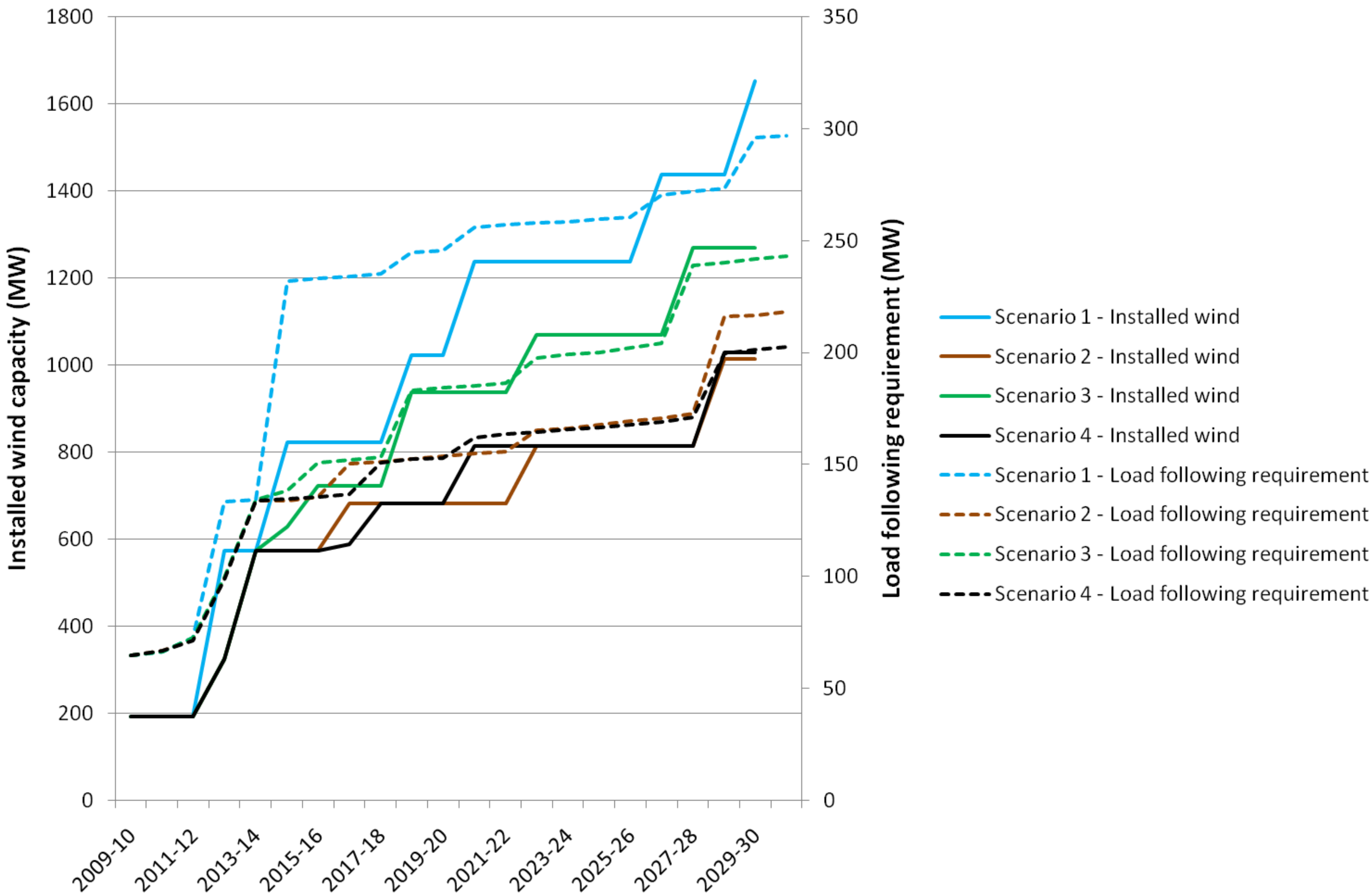
Forecast Load following requirement - Existing definition (MW)

	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Max	Min	Max	Min	Max	Min	Max	Min
2009-10	65	-66	65	-66	65	-66	65	-67
2010-11	66	-68	67	-68	66	-68	67	-69
2011-12	72	-72	72	-72	72	-72	71	-72
2012-13	133	-141	99	-102	99	-103	99	-103
2013-14	134	-141	134	-142	134	-141	134	-142
2014-15	232	-249	134	-142	138	-143	135	-142
2015-16	233	-250	135	-142	151	-151	135	-143
2016-17	234	-250	150	-150	152	-152	137	-144
2017-18	235	-251	151	-151	153	-152	151	-151
2018-19	245	-254	152	-151	183	-188	152	-152
2019-20	245	-255	154	-152	184	-188	153	-153
2020-21	256	-276	155	-153	185	-189	162	-166
2021-22	257	-276	156	-154	186	-189	164	-167
2022-23	258	-277	165	-166	198	-193	164	-168
2023-24	259	-277	166	-168	199	-194	166	-169
2024-25	260	-278	168	-168	200	-194	167	-169
2025-26	261	-278	169	-169	202	-195	168	-169
2026-27	270	-288	171	-170	204	-195	169	-170
2027-28	272	-289	173	-171	239	-236	171	-170
2028-29	273	-289	216	-217	240	-237	200	-196
2029-30	296	-299	217	-218	242	-237	201	-198
2030-31	297	-300	218	-218	243	-238	203	-199

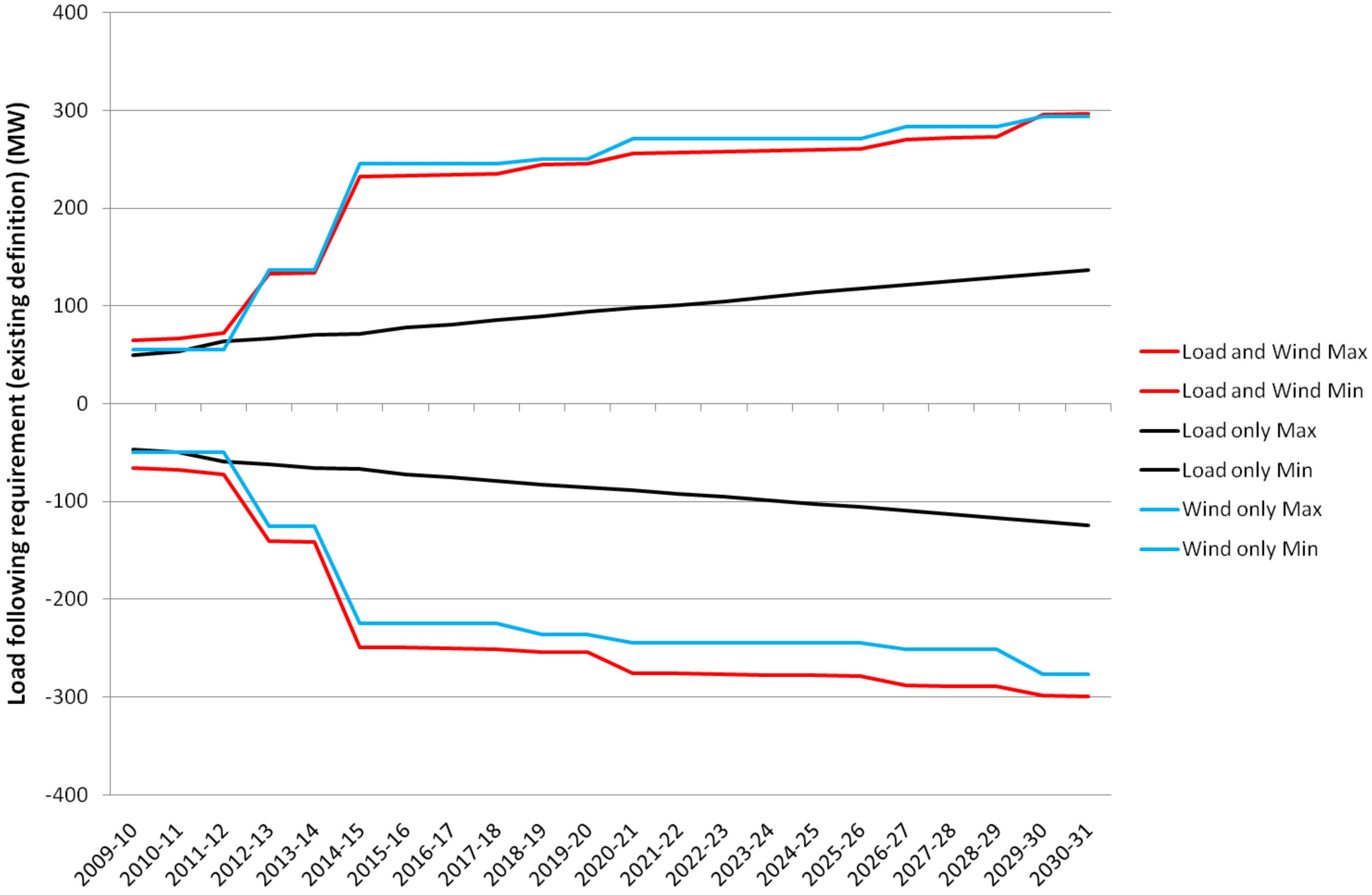
- Load following requirement increases substantially
- Increase depends heavily on relative locations of installed wind farms (geographical correlation)



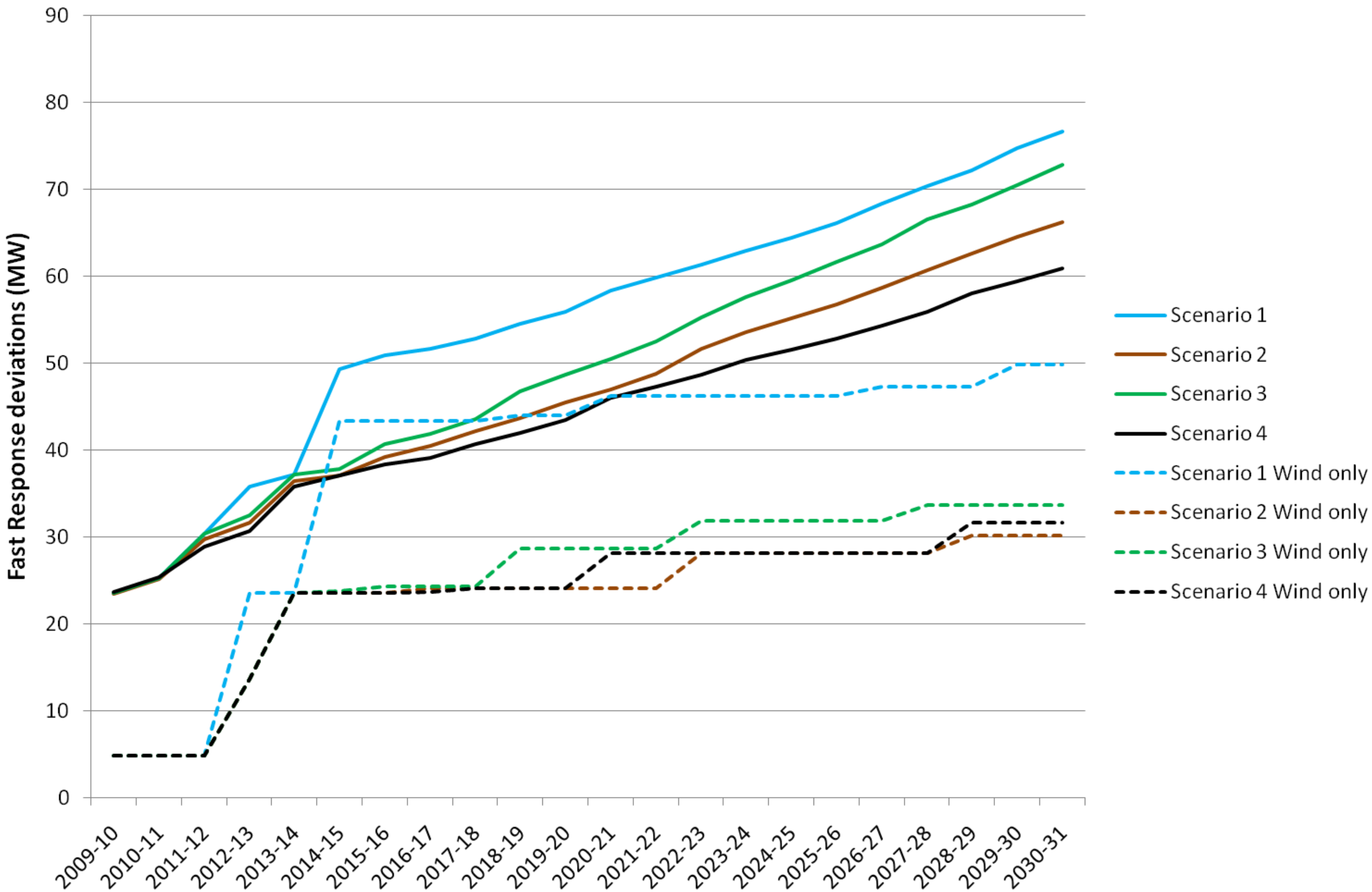
- Increase in load following requirement is 5-40% of wind farm capacity
  - Average 14% - typical for Collgar (35 MW increase in load following requirement)
- Depends heavily on relative locations of wind farms installed



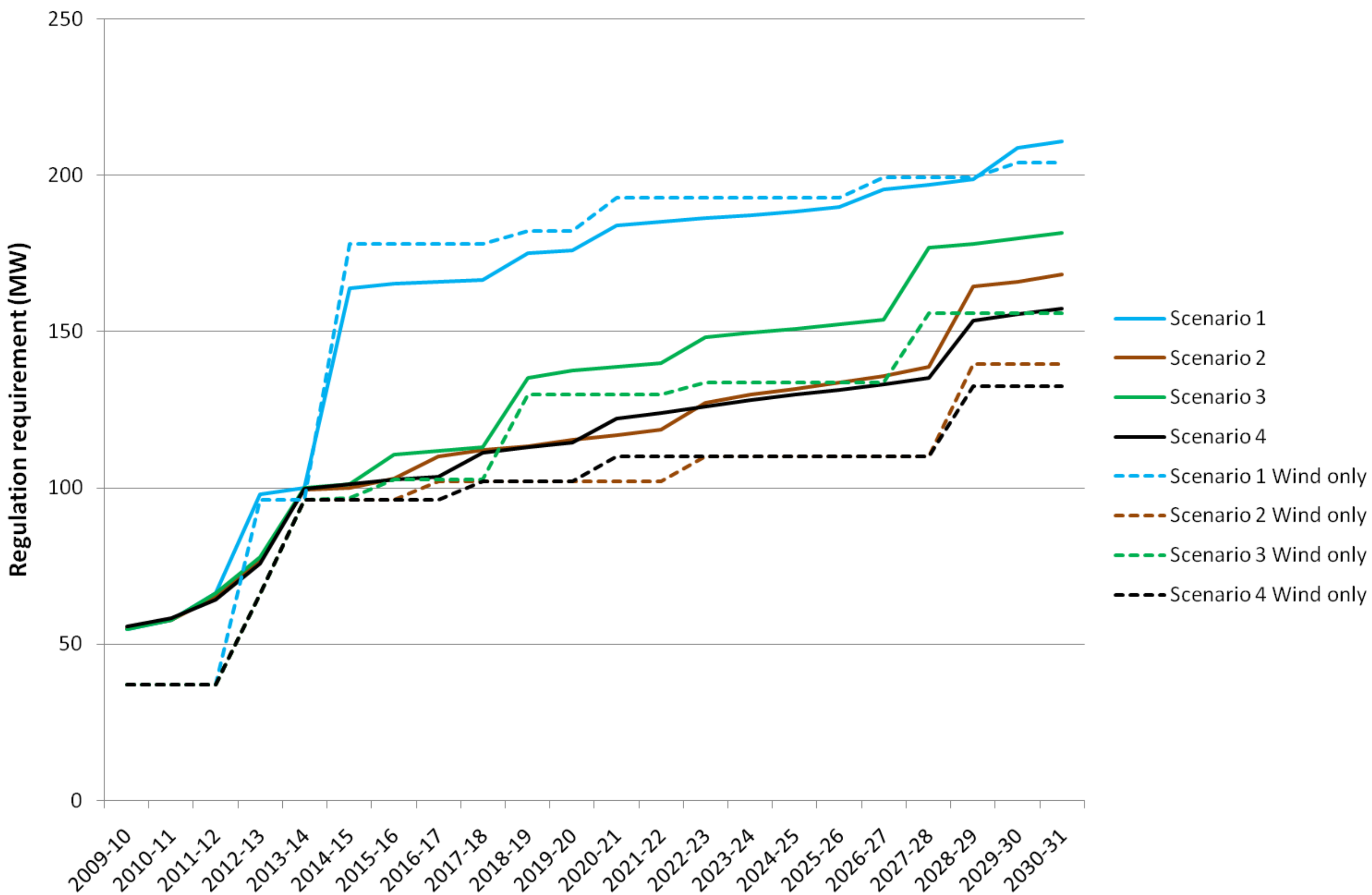
- Load following requirement (existing definition) is dominated by the wind variability



- Fast response (< 1min) is dominated by the load variability



- Improved knowledge about future wind improves load following requirement over 30 min rolling average
  - Regulation 30% lower than existing metric for load following
  - Importance of accurate wind forecasting



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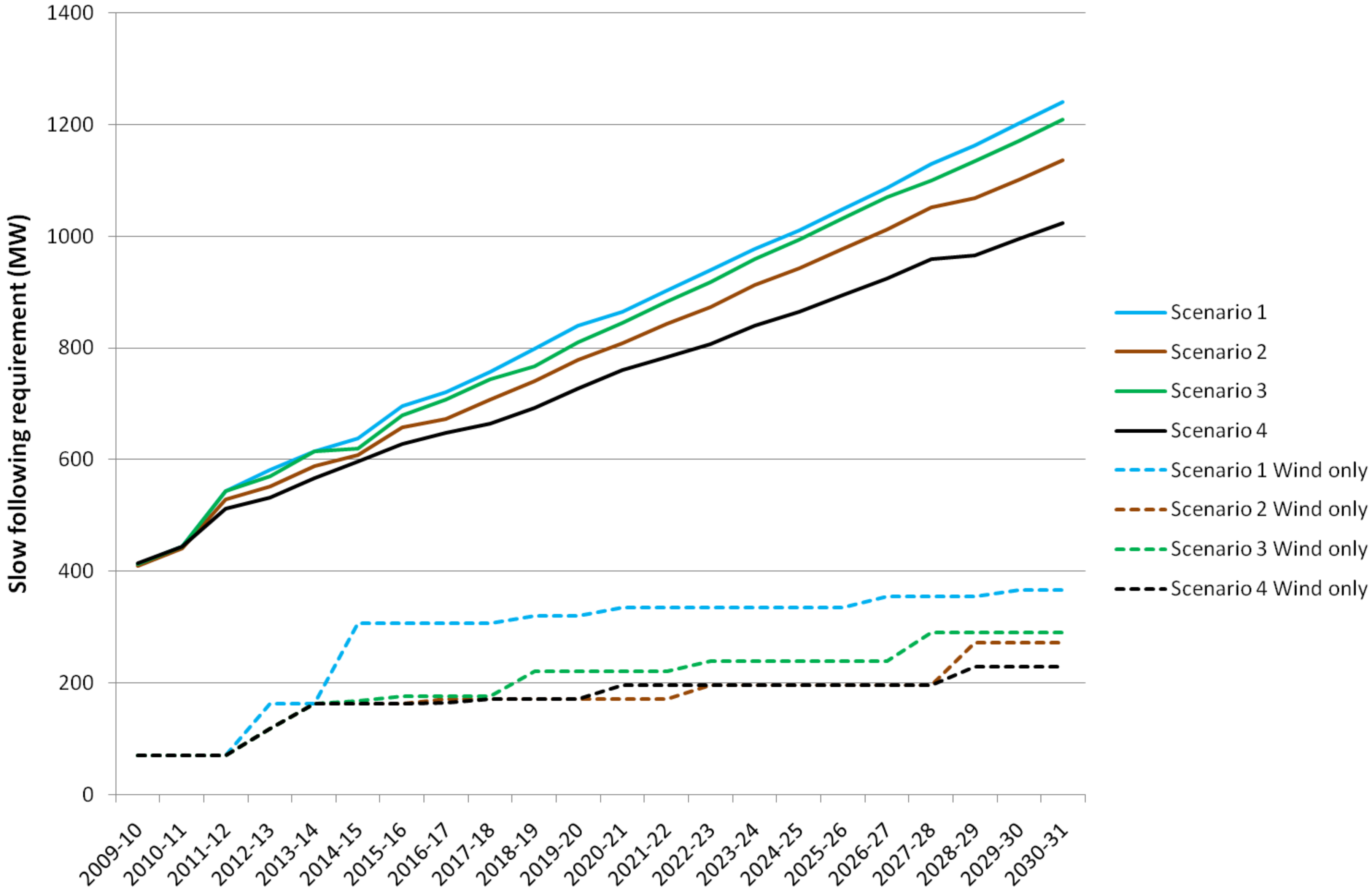
- Slow following requirement is dominated by load variability (daily ramp)



Technical feasibility?

- Verve has 323 MW of load following capability
  - Pinjar Frame 9's
  - Pinjar Frame 6's
  - Mungarra units
  - Two LMS100 units (commissioning 2011)
- Sufficient to provide load following required
  - Slow following can be provided with larger range of plant
- Will require continuous operation of almost 300 MW of load following capability
  - Dispatch of 548 MW of OCGT capacity on continuous basis, out of dispatch merit order
  - Very expensive, particularly during overnight periods

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Frequency modelling

- Developed a system frequency model to analyse system frequency response in the SWIS.
- Short term system frequency fluctuations depend on:
  - Magnitude of imbalance between supply and demand
  - System inertia
  - Amount of generation by governor responsive units
- Calibrated with generator inertia and governor/turbine data provided by Western Power
- Benchmarked against several contingency events
  - System frequency and dispatch data from past generator tripping events provided by Western Power

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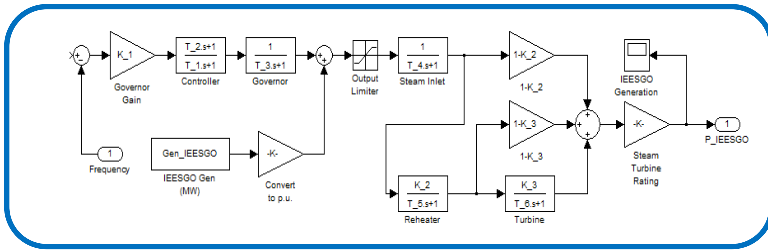
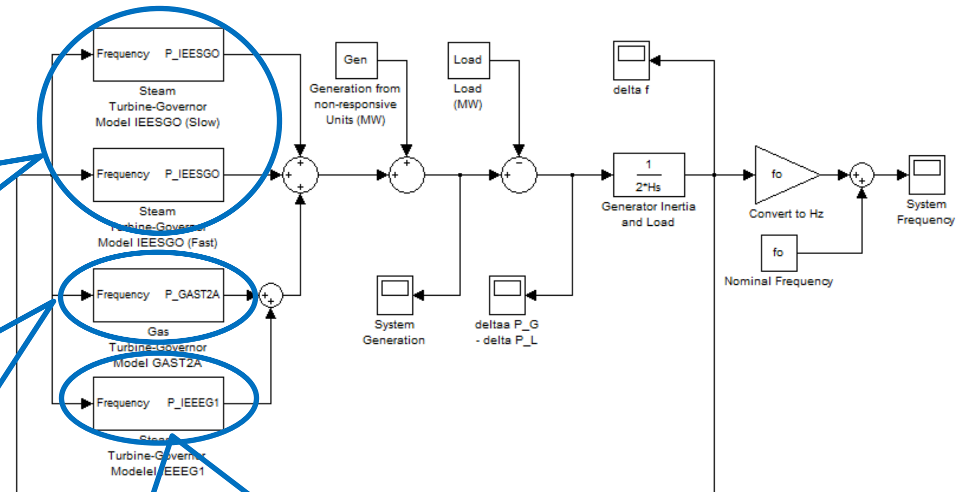
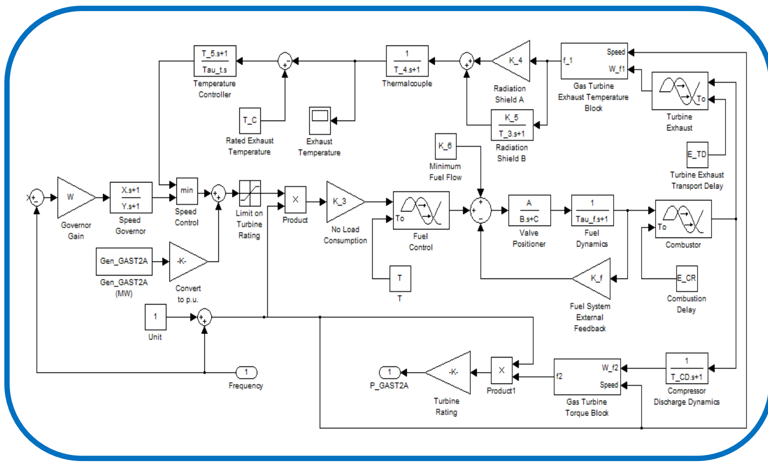
- Western Power provided governor-turbine models for each generator in SWIS
- Grouped into four types(similarities in parameters)

Steam turbines – two classes in data from Western Power (time constant for reheater) Eg. Kwinana, Bluewaters, Collie, Muja U5-8 (slow) & Muja U1-4 (fast)

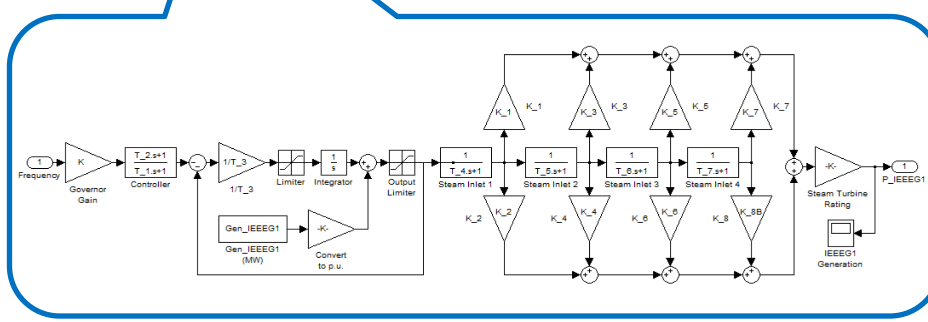






Gas turbines

Eg. Pinjar, Mungarra, Cockburn GT, Geraldton, West Kalgoorlie, Worsley



Alternative model for steam turbines (steam component of CCGTs). Fast response time. Eg. Cockburn SG

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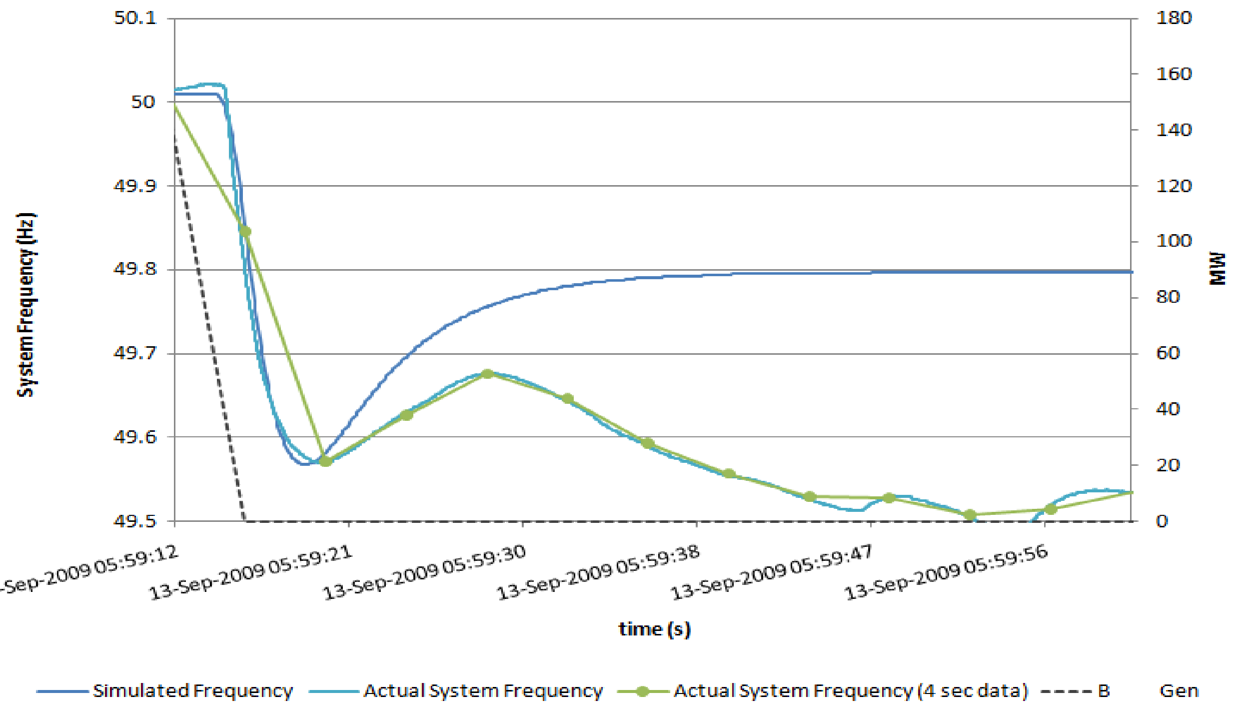
Benchmarking – Contingency events

- Trip of coal-fired unit
  - Loss of 150MW supply
- Historic data used for calibration:
  - System load = 1,720MW
  - System inertia immediately after around 12,529 MWs.
  - Most likely responsive generation mix (grouped by the governor-turbine type) to arrest the frequency decline
- Calibrate system parameters to match immediate frequency response
- Several similar events analysed



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Frequency modelling

System Loading Applied in the Frequency Modelling (MW)												
	Scenario 1			Scenario 2			Scenario 3			Scenario 4		
	Min.	Int.	Max.	Min.	Int.	Max.	Min.	Int.	Max.	Min.	Int.	Max.
2009-10	1,306	2,727	4,148	1,306	2,753	4,200	1,306	2,727	4,148	1,306	2,795	4,283
2014-15	1,804	3,593	5,381	1,804	3,661	5,518	1,804	3,593	5,381	1,804	3,761	5,718
2019-20	1,974	4,101	6,229	1,974	4,185	6,396	1,974	4,101	6,229	1,974	4,361	6,749
2024-25	2,153	4,561	6,969	2,153	4,684	7,216	2,153	4,561	6,969	2,153	4,943	7,734
2029-30	2,348	5,028	7,709	2,348	5,192	8,036	2,348	5,028	7,709	2,348	5,533	8,719

System Inertia Applied in the Frequency Modelling (MWs)												
	Scenario 1			Scenario 2			Scenario 3			Scenario 4		
	Min.	Int.	Max.	Min.	Int.	Max.	Min.	Int.	Max.	Min.	Int.	Max.
2009-10	7,004	12,392	16,647	7,004	12,392	17,725	7,004	12,392	16,647	7,004	12,392	17,725
2014-15	6,435	17,592	21,764	8,404	15,728	23,878	7,756	15,619	22,905	8,404	15,728	25,367
2019-20	5,968	20,588	25,922	8,404	17,080	28,811	6,444	18,505	25,015	7,784	17,881	31,202
2024-25	5,475	22,802	29,382	7,935	20,628	32,247	5,608	20,785	27,435	7,518	20,797	35,721
2029-30	5,929	26,080	30,385	7,731	24,499	35,356	4,955	24,262	28,567	7,057	23,078	39,800

Total Generator Dispatch and Capacity of Units Offering Governor Response (MW)												
	Scenario 1			Scenario 2			Scenario 3			Scenario 4		
	Min.	Dispatch	Capacity	Min.	Dispatch	Capacity	Min.	Dispatch	Capacity	Min.	Dispatch	Capacity
2009-10	70	155	239	70	155	239	70	155	239	70	155	239
2014-15	194	460	718	114	282	423	121	285	448	119	282	439
2019-20	202	477	747	130	307	483	164	386	608	119	282	439
2024-25	207	486	766	130	307	483	160	377	593	150	357	555
2029-30	247	580	913	190	446	703	187	440	693	160	381	593

- Input fast response requirements to the frequency model
  - System disturbance
- Vary system load
  - IMO forecasts
  - Min, Max and intermediate
- System inertia determined based upon system load, utilising dispatch model
- Governor response assumed to be provided by plants dispatched for load following only

Results

- Frequency maintained within required limits in almost all cases
  - 49.8Hz to 50.2Hz
- As deviations increase, quantity of load following plant providing governor response also increases
- Where insufficient, add 60 MW and 40 MW of governor response
  - Scen 2 and Scen 3
- Increasing inertia to provide similar response requires vast increase
  - 7,935 MWs to
  - 17,800 MWs
- Increasing governor response is more effective

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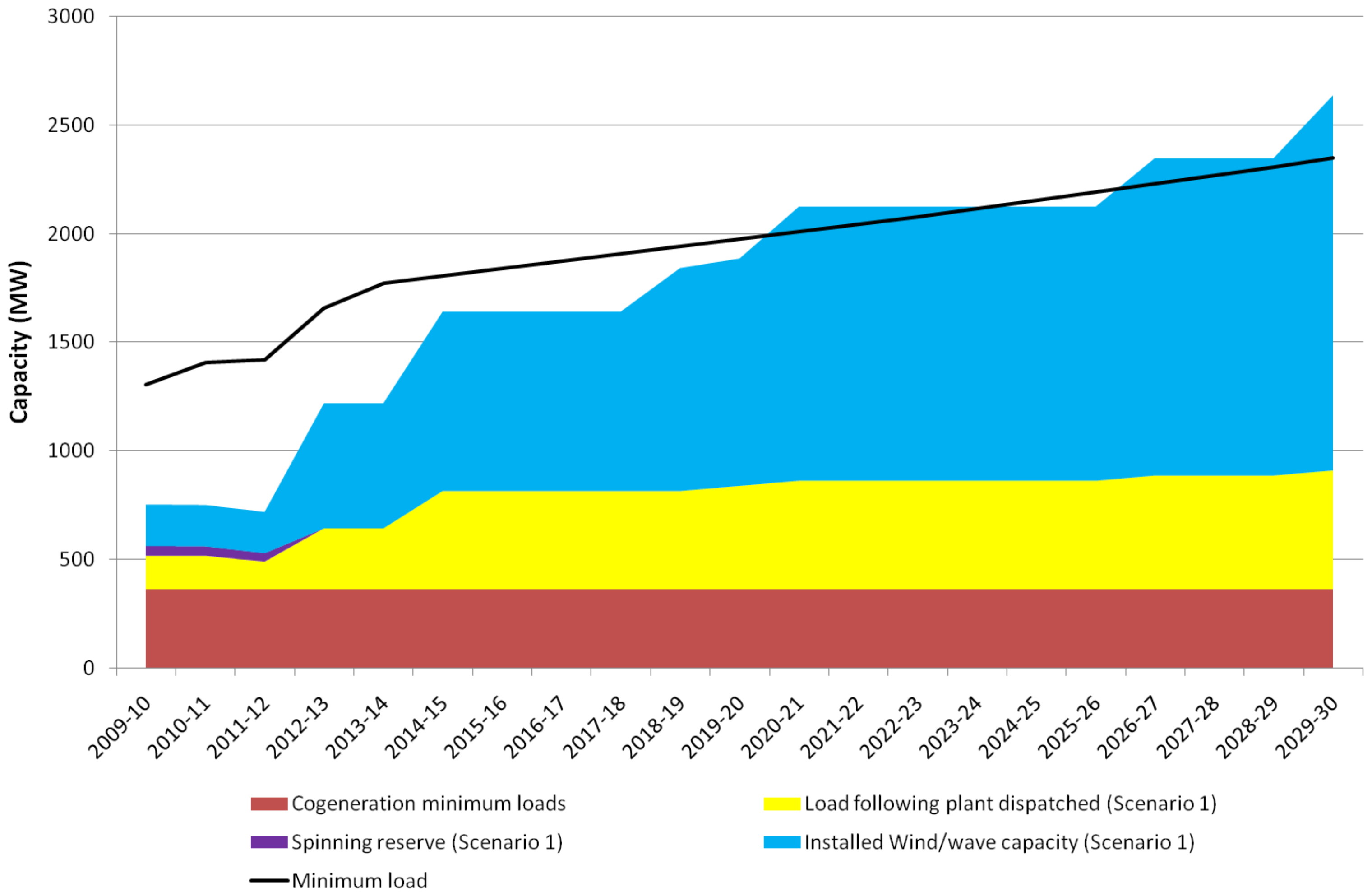
System Frequency Response

Scenario 1						
	Min. Load		Intermediate Load		Max. Load	
	Min.	Max.	Min.	Max.	Min.	Max.
2009-10	49.83	50.17	49.88	50.13	49.90	50.10
2014-15	49.85	50.15	49.87	50.13	49.89	50.11
2019-20	49.84	50.16	49.87	50.13	49.88	50.12
2024-25	49.82	50.18	49.85	50.15	49.88	50.13
2029-30	49.82	50.18	49.85	50.15	49.88	50.13
Scenario 2						
	Min. Load		Intermediate Load		Max. Load	
	Min.	Max.	Min.	Max.	Min.	Max.
2009-10	49.84	50.18	49.88	50.13	49.90	50.10
2014-15	49.83	50.17	49.82	50.14	49.89	50.11
2019-20	49.82	50.18	49.84	50.17	49.89	50.12
2024-25	49.79	50.22	49.84	50.17	49.87	50.13
2029-30	49.82	50.19	49.86	50.15	49.88	50.12
Scenario 3						
	Min. Load		Intermediate Load		Max. Load	
	Min.	Max.	Min.	Max.	Min.	Max.
2009-10	49.83	50.18	49.88	50.13	49.90	50.10
2014-15	49.84	50.16	49.87	50.13	49.89	50.11
2019-20	49.84	50.15	49.87	50.13	49.89	50.11
2024-25	49.80	50.20	49.84	50.16	49.87	50.13
2029-30	49.80	50.21	49.84	50.17	49.87	50.14
Scenario 4						
	Min. Load		Intermediate Load		Max. Load	
	Min.	Max.	Min.	Max.	Min.	Max.
2009-10	49.83	50.18	49.88	50.13	49.90	50.10
2014-15	49.84	50.16	49.87	50.13	49.90	50.11
2019-20	49.82	50.19	49.86	50.14	49.89	50.11
2024-25	49.82	50.18	49.86	50.14	49.88	50.12
2029-30	49.81	50.20	49.86	50.15	49.89	50.12

Possible Issues

- What issues may arise with this quantity of wind and load following plant?

- Wind curtailment required overnight by 2020 (if all wind operating simultaneously)
- Overnight cycling of all coal-fired generation will become a necessity
  - Technical feasibility? Long term system reliability?
  - Costs?



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Costs of load following service

- Two approaches to analysing cost
  1. Use method specified in WEM Rules
     - Estimate of costs faced by participants if Rules stay as they are
     - Gives most insight into inaccuracies and flaws in the existing rules
  2. Use first principles dispatch modelling
     - Gives better estimate of "actual" costs
     - Requires assumptions around how the system would be managed
       - Most efficient dispatch, or existing dispatch?
       - All load following plant by Verve, or other participants?
     - Does not give insight into inadequacies in the Rules
- ROAM has taken first approach
  - Determined that existing WEM Rules have some significant problems

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Costs in WEM Rules

$$\text{Total cost}_{\text{LF}} = \text{Capacity cost}_{\text{LF}} + \text{Availability cost}_{\text{LF}}$$

$$\text{Capacity cost}_{\text{LF}} = \text{Reserve Capacity Price} \times \text{LF requirement}$$

Set by Reserve Capacity Auction

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Capacity costs

- Reserve capacity prices published by IMO
- Project forward average of 2010-12
  - $138,020 /MW pa
  - Assumes technology costs remain reasonably consistent with current levels

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Capacity Costs (Load Following)

Year	Load following requirement (MW)	Projected Capacity Cost - Load Following ($pa)			
	Scenario 1	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2009-10	65	$7,002,844	$7,007,508	$7,002,844	$7,034,623
2010-11	66	$9,577,229	$9,598,865	$9,577,229	$9,654,684
2011-12	72	$9,548,846	$9,462,646	$9,548,846	$9,381,455
2012-13	133	$18,382,881	$13,685,095	$13,711,319	$13,635,408
2013-14	134	$18,519,521	$18,472,594	$18,519,521	$18,458,792
2014-15	232	$32,015,115	$18,490,537	$19,079,882	$18,574,729
2015-16	233	$32,175,218	$18,675,483	$20,812,033	$18,690,666
2016-17	234	$32,292,535	$20,741,643	$20,969,376	$18,893,555
2017-18	235	$32,448,497	$20,875,522	$21,144,661	$20,806,512
2018-19	245	$33,802,473	$21,009,401	$25,241,094	$21,012,162
2019-20	245	$33,868,723	$21,205,390	$25,416,379	$21,115,677
2020-21	256	$35,316,552	$21,394,477	$25,557,160	$22,371,659
2021-22	257	$35,494,598	$21,493,851	$25,710,362	$22,582,829
2022-23	258	$35,593,973	$22,800,901	$27,267,227	$22,682,204
2023-24	259	$35,690,587	$22,945,822	$27,488,059	$22,851,968
2024-25	260	$35,821,706	$23,143,190	$27,619,178	$22,999,649
2025-26	261	$35,974,908	$23,369,543	$27,877,276	$23,147,331
2026-27	270	$37,308,181	$23,577,953	$28,204,383	$23,325,377
2027-28	272	$37,535,914	$23,834,670	$32,950,890	$23,619,359
2028-29	273	$37,691,876	$29,810,935	$33,156,540	$27,561,210
2029-30	296	$40,837,352	$29,908,930	$33,369,091	$27,795,844
2030-31	297	$40,965,710	$30,125,621	$33,563,699	$27,949,046

Availability Costs

$$\text{Availability cost}_{\text{LF}} = \text{Total Availability cost} - \text{Availability cost}_{\text{SR}}$$

$$\text{Total Availability Cost} = 0.5 \times \left[\text{M}_p \times \sum_{t=p} \text{MCAP} \times \left(\text{SR Requirement}_p - \text{SR provided}_{\text{contracts}} \right) \right] + 0.5 \times \left[\text{M}_{op} \times \sum_{t=op} \text{MCAP} \times \left(\text{SR Requirement}_{op} - \text{SR provided}_{\text{contracts}} \right) \right] + \text{Contracts}_{SR} + \text{Contracts}_{LF}$$

Availability cost_{SR} =

$$0.5 \times \left[M_p \times \sum_{t=p} \text{MCAP} \times \left(\text{SR Requirement}_p - \text{SR provided}_{\text{contracts}} - 0.5 \times \text{LF Requirement} \right) \right] + 0.5 \times \left[M_{op} \times \sum_{t=op} \text{MCAP} \times \left(\text{SR Requirement}_{op} - \text{SR provided}_{\text{contracts}} - 0.5 \times \text{LF Requirement} \right) \right] + \text{Contracts}_{SR}$$

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Issues

- Equations do not take into account load following provided by contracted ancillary service providers (other than Verve)
  - Double counting this component
  - Hasn't yet occurred, but may in future
- Equations become invalid once the load following requirement exceeds the spinning reserve
  - This occurs in 2012-13 in Scenario 1, and in 2013-14 in other Scenarios!
- ROAM has provided alternative equations in the report which address these issues
  - Based on existing methodology
  - Still far from ideal
    - Existing methodology relies on constant recalibration of arbitrary factors
    - No longer accurate if:
      - Fuel prices change
      - Introduction of a carbon price
      - Introduction of intermittent generation
      - Any significant change to the system
- Ideally, implement an efficient market for ancillary services
  - Costs determined by the market

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Availability Costs

- Equations imply linear scaling with LF Requirement
  - Take into account SR Requirement (swap-over)
  - Increased Margin applied this year (peak)

Availability costs

Margin_{peak}	Year	Load following requirement (Scenario 1) (MW)	Spinning Reserve requirement (peak) (MW)	Availability cost ($ pa)		
				Total	Load Following	Spinning Reserve
15%	2008-09 (as published)	60	220	28,092,698	3,381,721	24,710,977
15%	2014-15 (projected)	232	220	29,619,920	17,220,276	12,399,643
	2020-21 (projected)	256	220	32,674,362	20,274,719	12,399,643
	2030-31 (projected)	297	220	37,900,881	25,501,238	12,399,643
30%	2014-15 (projected)	232	220	59,239,839	34,440,552	24,799,287
	2020-21 (projected)	256	220	65,348,724	40,549,437	24,799,287
	2030-31 (projected)	297	220	75,801,762	51,002,475	24,799,287

Total costs (Load Following)

- Costs increase substantially
  - Consider ways to reduce costs
  - Introduce a competitive market for ancillary services

Table 14.5 – Load Following Costs (Scenario 1)

Margin_{peak}	Year	Load following requirement (MW)	Capacity Cost of Load Following ($ pa)	Availability Cost of Load Following ($ pa)	Total Load Following Cost ($ pa)
15%	2008-09 (as published)	60	6,441,298	28,092,698	9,823,019
15%	2014-15 (projected)	232	32,015,115	29,619,920	49,235,391
	2020-21 (projected)	256	35,316,552	32,674,362	55,591,271
	2030-31 (projected)	297	40,965,710	37,900,881	66,466,948
30%	2014-15 (projected)	232	32,015,115	59,239,839	66,455,667
	2020-21 (projected)	256	35,316,552	65,348,724	75,865,990
	2030-31 (projected)	297	40,965,710	75,801,762	91,968,185

Allocation of costs

- Load following costs currently paid by loads and intermittent generators
  - Proportional to metered load/generation
- Important to consider best approach moving forward
- Intermittent generators proportionally contribute more variability
  - Majority of load following requirement due to intermittent generators (60-80%)
- But loads would have a windfall gain if intermittent generation paid for this full amount
- Load variability must be managed as an inherent part of the system, therefore wind should only pay for variability in excess of this amount
  - Intermittent generators pay for marginal load following requirement in excess of that required by the load variability

Load Following Costs (Scenario 1) - Allocation of Costs

Margin_{peak}	Year	Total Load Following Cost ($ pa)	Proportion of cost to Loads	Proportion of cost to Intermittent Generators	Cost to Loads ($ pa)	Cost to Intermittent Generators ($ pa)
15%	2014-15	49,235,391	31%	69%	15,119,782	34,115,609
	2020-21	55,591,271	38%	62%	21,167,830	34,423,441
	2030-31	66,466,948	46%	54%	30,657,071	35,809,877
30%	2014-15	66,455,667	31%	69%	20,407,986	46,047,681
	2020-21	75,865,990	38%	62%	28,887,959	46,978,031
	2030-31	91,968,185	46%	54%	42,419,206	49,548,979

- Costs sufficient to deter wind penetration in the SWIS?
  - Less than benefit from 40% capacity factor (vs 30%)
- Investigate ways to reduce load following costs
  - Competitive market for ancillary services

Load Following Costs (Scenario 1) - Costs to intermittent generators					
$Margin_{peak}$	Year	Cost to Intermittent Generators ($ pa)	Installed wind capacity (MW)	Cost to Intermittent Generators ($/MW pa)	Cost to Intermittent Generators ($/MWh)
15%	2014-15	34,115,609	826	41,317	$12
	2020-21	34,423,441	1,046	32,919	$9
	2030-31	35,809,877	1,776	20,167	$6
30%	2014-15	46,047,681	826	55,768	$16
	2020-21	46,978,031	1,046	44,925	$13
	2030-31	49,548,979	1,776	27,904	$8

Ramp-limit impacts

- Currently a 15% /min ramp limit on intermittent generation
  - Is this effective at reducing variability?
  - Is it a significant burden on wind farms?

Effect of limiting ramp rate (2030-31, Scenario 1) - existing metric					
	Ramp rate limitation (% of wind farm capacity per minute)	Load and Wind		Wind only	
		Min	Max	Min	Max
Existing load following definition	None	-300	297	-277	294
	15%	-300	297	-277	295
	5%	-298	295	-275	290
	1%	-229	276	-253	219
	0.2%	-147	222	-204	91

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- Significant energy loss if apply stringent enough ramp limit to reduce load following requirement

Effect of limiting ramp rate (2030-31, Scenario 1) - existing metric	
Ramp rate limitation (% wind farm capacity per minute)	Percentage of wind energy curtailed per annum (MWh)
15%	0.00%
5%	0.42%
1%	5.55%
0.2%	20.66%

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Intermittent generation to provide ancillary services?

- Two possible ways intermittent generation can contribute to frequency control
  - Provide an inertial response
  - Active frequency regulation via curtailment

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Inertial response

- Rotating turbine is a store of kinetic energy
  - If synchronised to the grid can provide an inertial response
- Fixed speed turbines
  - Eg. squirrel-cage induction generators (SCIG)
  - provide an inertial response
  - Older design, less efficient
- Variable speed turbines
  - More modern, more efficient designs
  - Do not provide an inertial response
  - Can be fitted with a control loop to mimic an inertial response (can be better than SCIG)
- This analysis suggests that system inertia is not a significant problem if plant required for load following is online
  - But could consider providing incentives for intermittent generators to provide an inertial response

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Curtailment to provide regulation

- To provide active frequency control intermittent generators need to be curtailed
  - For 1 MW of load following, curtail 1 MW.
- To provide load following must be able to:
  - Curtail output by a constantly adjustable amount
  - Know maximum available at any time
  - Able to accept and respond to minute to minute instructions via AGC
- Studies suggest technically feasible
- But is it cost effective?
  - Can purchase load following from Verve plant at $6-$16 /MWh
  - By curtailing have opportunity cost of ~$120 /MWh
    - Revenue from electricity sales and RECs sales should to sum to LRMC
    - Even if spot price is $0, still forgo RECs sales of ~$60 /MWh
  - Unlikely to be an attractive option unless already curtailed for another reason

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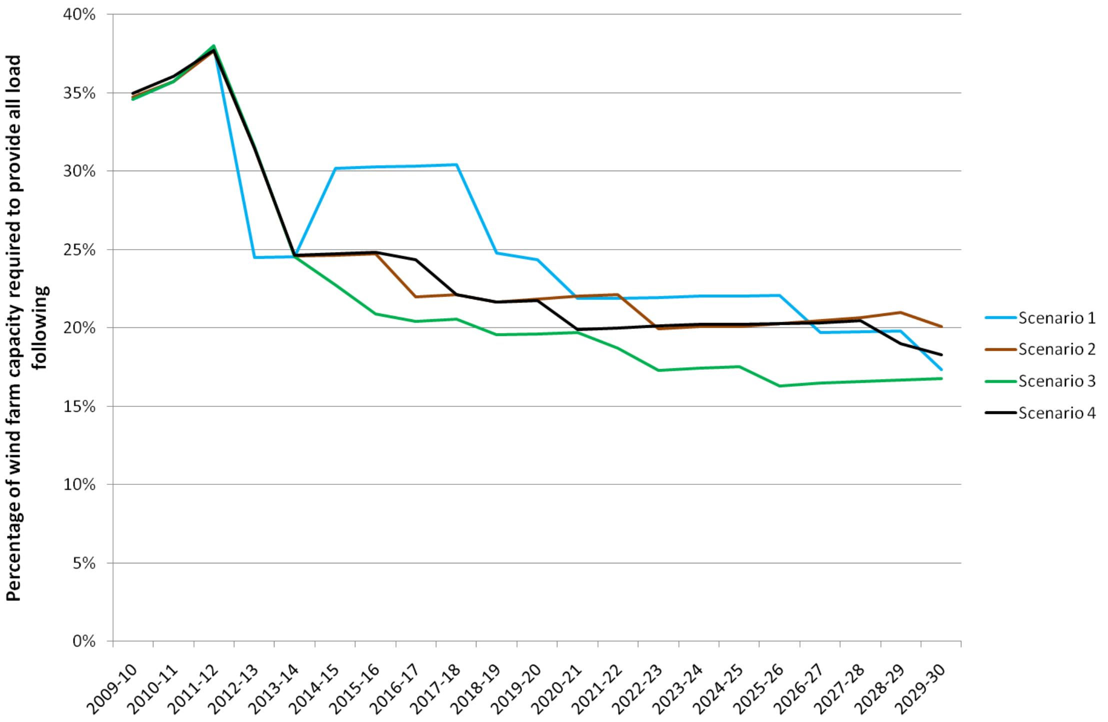
Load following if already curtailed

- If a wind farm is already curtailed (eg. overnight minimum load conditions) it becomes attractive to provide load following
  - No opportunity cost
  - Can achieve revenue from ancillary service
- If aggregate wind curtailment is greater than the whole load following requirement, wind farms can increase output (decrease curtailment) by offering load following service
  - Would need to be curtailed by 15-20%



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Recommendations

- Consider reviewing load following definition
  - Include fast and slow response components
- Consider commissioning a detailed wind correlation study
  - Incentives for wind to distribute geographically and minimise load following impact
- Load following requirement increases from 60 MW to 300 MW in 2030
- If the load following service is explicitly split into different components, different participants should be responsible for the costs of each
  - Fast and slow components dominated by load variability, regulation dominated by wind variability
- Arduous requirements for wind farms to provide system inertia should not be applied
  - Additional system inertia is not required
- Intermittent generators must have the facilities to curtail if necessary
  - Wind curtailment may occur at time of minimum load

- Consider implementing more transparent dispatch merit order priorities
  - Daily cycling of coal-fired generation is likely to become significant
- Methodology for calculating costs of load following in Rules should be reviewed as an immediate priority
- Establish an efficient market for frequency control ancillary services
  - Costs of load following increase significantly
- Intermittent generators should pay the marginal cost of load following
  - Above that required by load variability
- Ramp limits should not be applied to intermittent generators individually
  - Ineffective at reducing variability
- Intermittent generation is unlikely to be an attractive provider of load following service

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