Centre for Energy and Environmental Markets

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Impacts of Operational Constraints on Generation Portfolio Planning with Variable Renewable Generation

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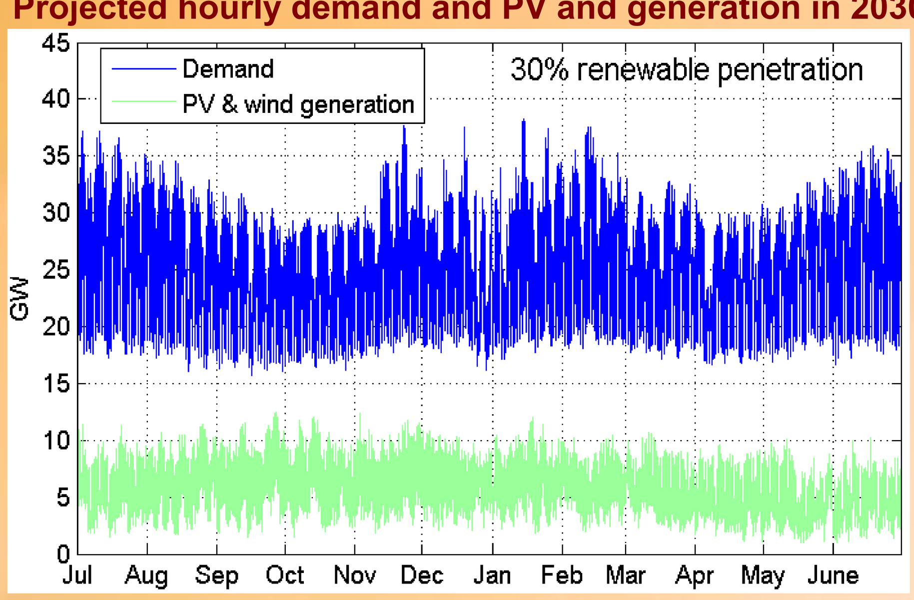
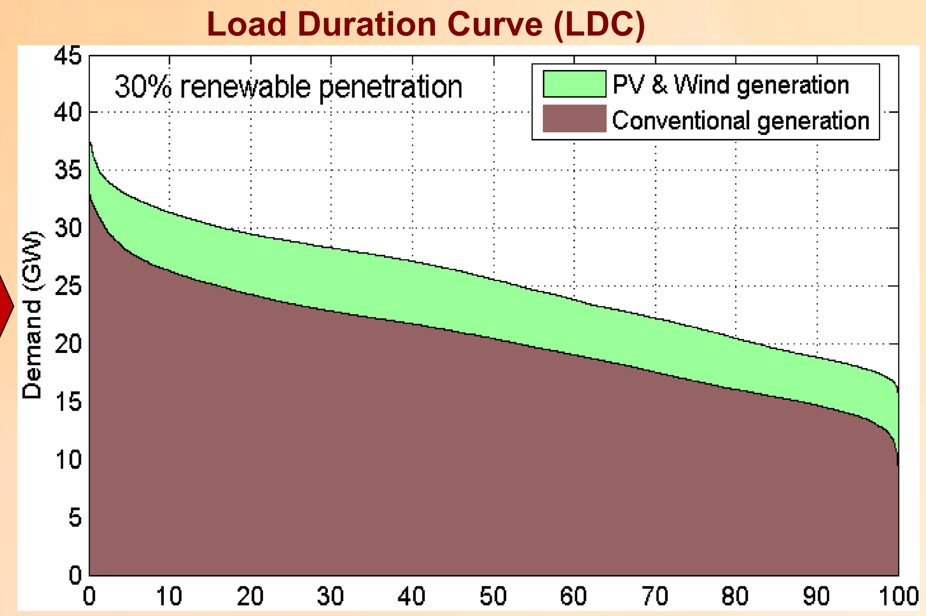
1. Context

- ♦ Wind and solar are now achieving high penetrations in power systems.
- ♦ Concerns over the operational and economic impacts of renewables on power systems due to their variability and partly dispatchable nature.
- ♦ Variable renewable generation poses operational challenges for conventional generating plants in terms of frequent cycling operation and may increase overall costs.
- ♦ *Load Duration Curve (LDC)* techniques often used in generation planning - *simple but ignore inter-temporal operational aspects.*
- ♦ Optimal generation portfolios obtained under long-term planning models may not be operationally viable or economically optimal in practice.
- ♦ Long-term generation planning models need to capture plant operational characteristics and their ability to respond to changes in demand to ensure that power systems can accommodate high renewables (*e.g. minimum operating levels, ramp rates, startup times & costs).*

Projected hourly demand and PV and generation in 2030



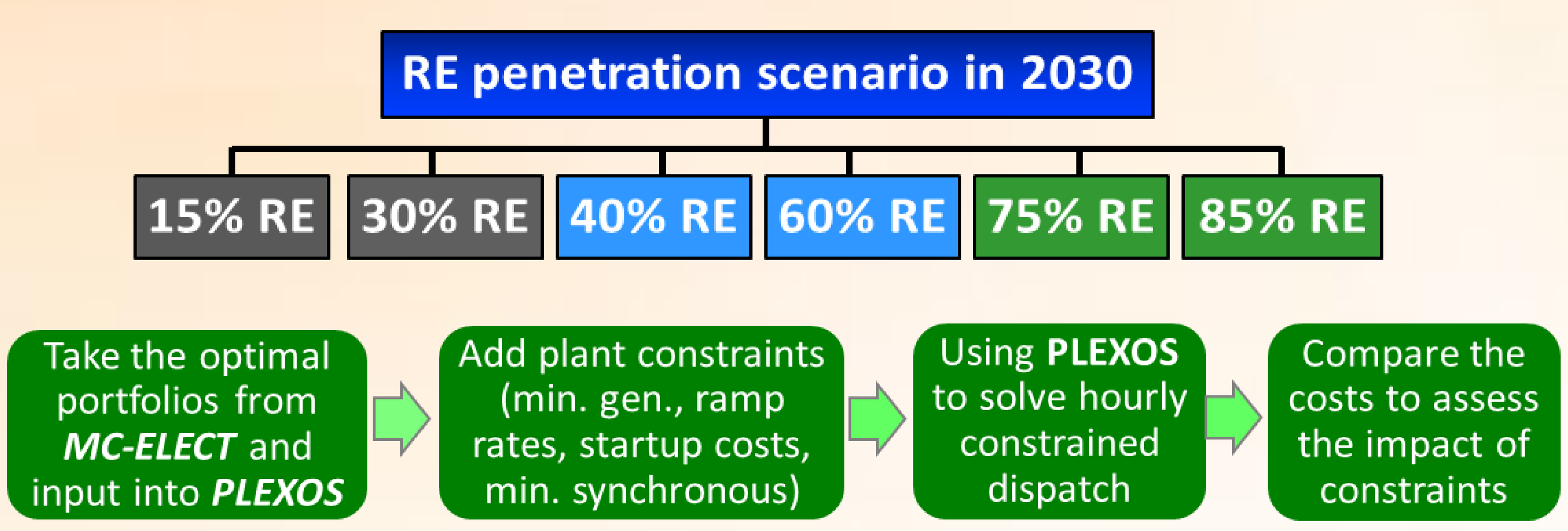
Load Duration Curve (LDC)



2. Objectives

- ♦ To assess how generator operational characteristics might impact future generation portfolios with high renewables obtained under long-term generation portfolio planning models.
  - ♠ Technical and cost impact of the operational constraints.
  - ♠ Compare the overall costs obtained from a long-term planning model with those from solving a detailed inter-temporal constrained dispatch.

3. Methodology



- ♦ Using a long-term portfolio planning tool, **MC-ELECT**, to obtain optimal portfolios for different renewable penetrations for 2030.
  - ♠ Detailed modelling of future uncertainties but uses LDC which ignores short term operation aspect and constraints.
- ♦ Using **PLEXOS** (a commercial power market modelling tool) to solve a detailed inter-temporal constrained dispatch based on SRMC.
  - ♠ The least cost portfolios from MC-ELECT are rerun through a year of hourly constrained dispatch in PLEXOS.
  - ♠ Constraints included are *minimum generation levels, ramp rates, synchronous generation requirements and startup costs.*
  - ♠ *Synchronous generation* is provided by conventional generators to provide adequate system inertia.
  - ♠ Costs can then be compared to assess the impact of constraints.

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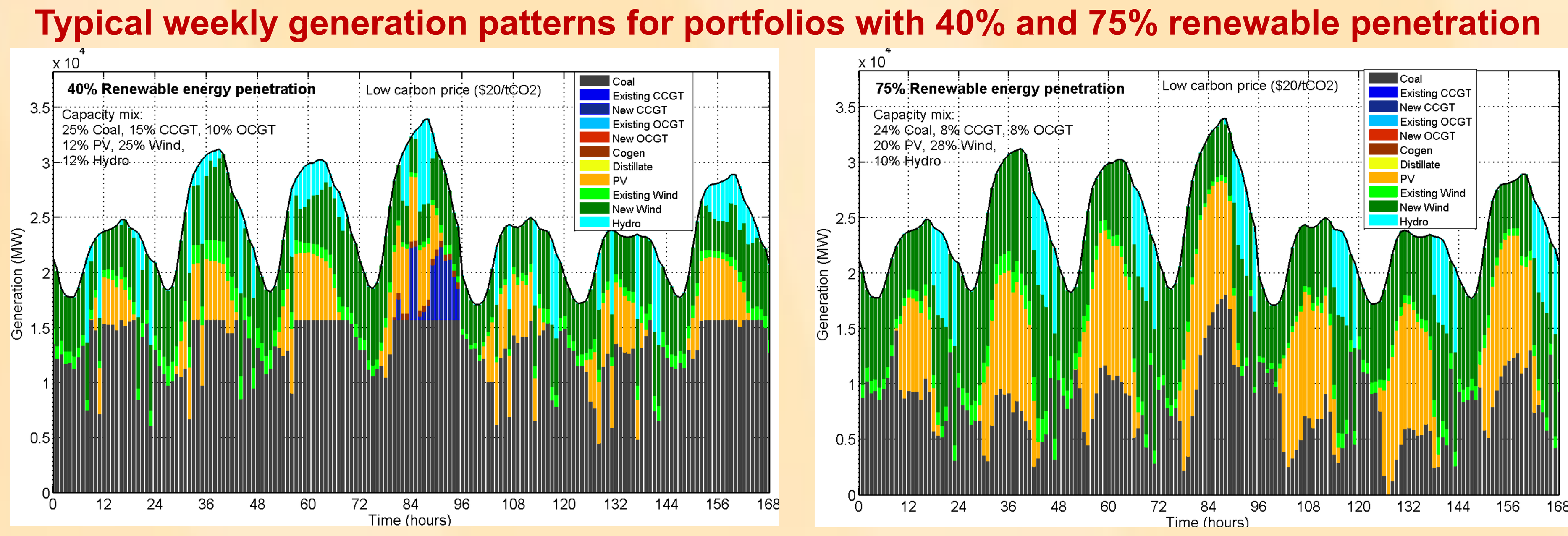
4. Australian NEM Case Study

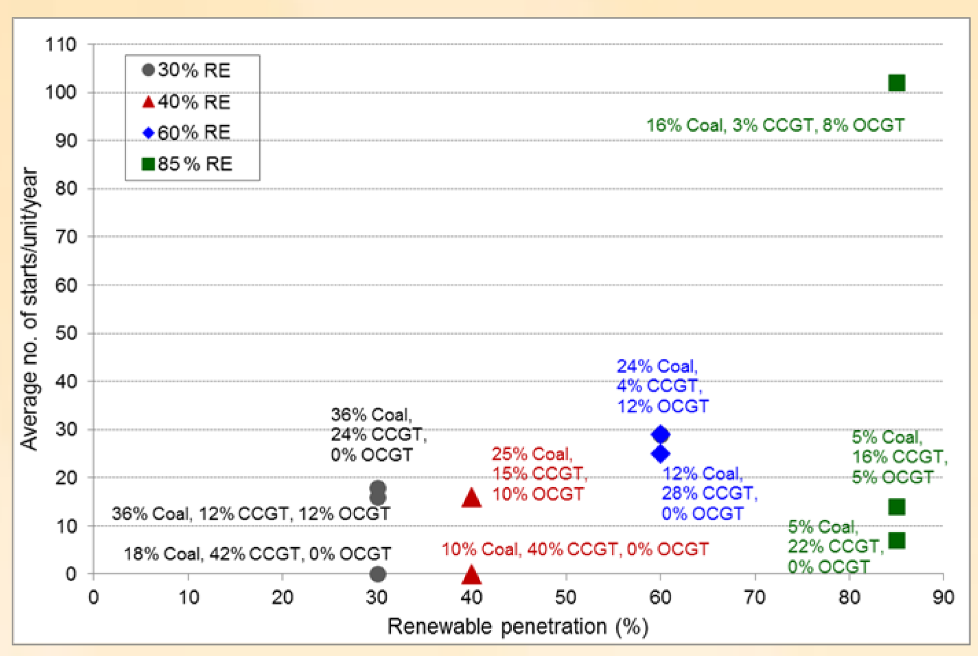
- ♦ Six different renewable penetration scenarios in 2030.
- ♦ Main generation technology options are coal, CCGT, OCGT, hydro, wind (on shore), utility scale PV (single axis tracking).
- ♦ Three carbon price scenarios: low, moderate and high.

Typical weekly generation patterns for portfolios with 40% and 75% renewable penetration



Thermal plants are required to cycle more often with higher RE penetrations

Detailed operational dispatch - Number of starts/stops



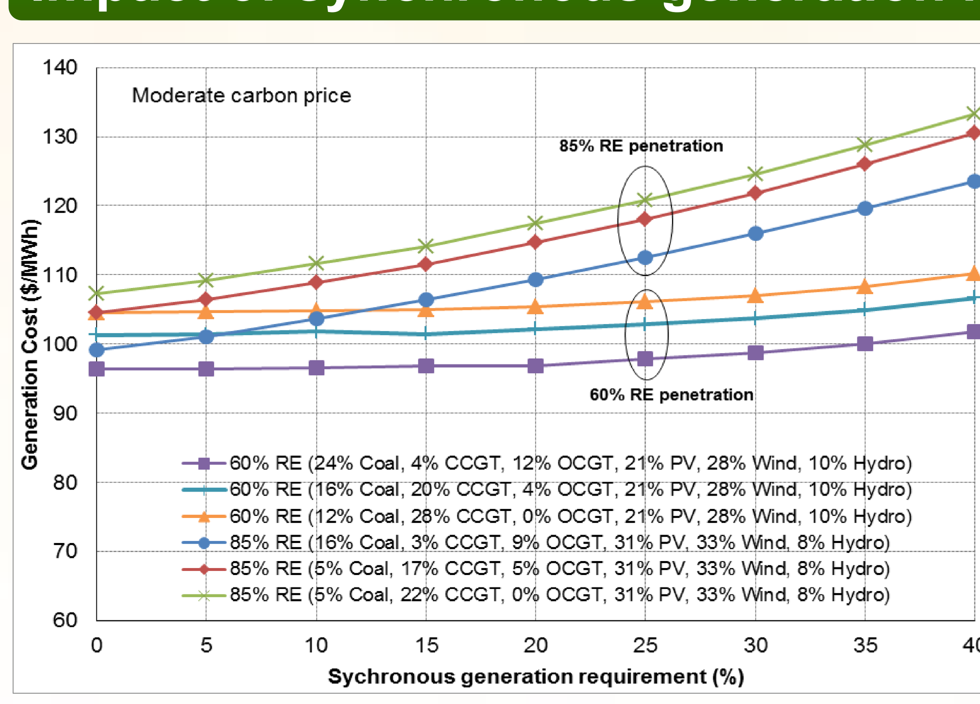
- Number of unit starts/stops depend on RE penetration levels and the technology share in the portfolio.
  - ∗ *The highest no. of starts for **CCGT** is 230/unit/year - within design range.*
  - ∗ *Number of **coal** starts seem technically viable for most portfolios. For high renewables, **coal** units might experience up to 100 starts/year.*
- Also depends on the carbon price.

Impact of minimum generation and ramp rate limits

- Min. generation and ramp rate constraints only slightly increase the overall costs of portfolios obtained under the long-term planning.
- All of the portfolios can meet the maximum ramps required even with high RE.

RE	Portfolios	Total generation cost ($/MWh)			% Cost increase	
		Without constraints	With Min. gen	Min. gen & ramp rates	With Min. gen	Min. gen & ramp rates
30%	36% coal, 12% CCGT, 12% OCGT	108.0	108.0	108.0	0	0
	18% coal, 42% CCGT, 0% OCGT	119.1	119.1	119.1	0	0
40%	10% coal, 40% CCGT, 0% OCGT	115.2	115.3	115.3	0.1%	0.1%
	10% coal, 40% CCGT, 0% OCGT	104.2	104.3	104.3	0.1%	0.1%
60%	24% coal, 4% CCGT, 12% OCGT	97.1	97.8	97.8	0.1%	0.1%
	12% coal, 28% CCGT, 0% OCGT	104.9	105.6	105.6	0.7%	0.7%
85%	16% coal, 3% CCGT, 8% OCGT	100.3	102.3	102.4	2%	2%
	5% coal, 16% CCGT, 5% OCGT	105.5	106.5	106.5	1%	1%

Impact of synchronous generation requirement



- Synchronous requirements impose significant additional costs at high RE penetrations (~7% cost increase)
  - ∗ *Low operating cost renewables are curtailed to accommodate thermal generation*
- Negligible impact at low penetrations
- Costs associated with synchronous requirement increase with higher carbon prices

5. Conclusions

- ♦ Technical and cost impacts due to the inclusion of minimum generation and ramp rate constraints seem moderate even at high RE penetrations.
- ♦ Frequent cycling operation for coal and CCGT units as RE penetration increases, but generally appears within technical limits.
- ♦ The synchronous requirements can have significant cost impact.
- ♦ The impacts also depend on carbon price and the generation mix.
- ♦ Future work will explore issues at finer dispatch time intervals.

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