Impact of Operational Constraints on Generation Portfolio Planning with Renewables

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***Abstract*—Increasing variable renewable generation penetrations will cause increased cycling operation for conventional generating plants. Not all of these plants are necessarily well suited to such operation. Traditional long-term generation planning frameworks often neglect these operational characteristics and therefore do not reflect the operational constraints and costs associated with cycling of generating plants. Using a detailed generation dispatch model in PLEXOS, this study assesses the potential impact of short-term operational constraints and costs on future 'high renewable' generation portfolios obtained from a long-term portfolio planning framework. A case study of the Australian National Electricity Market (NEM) with different renewable penetrations, ranging from 15% to 85%, suggests that the technical and cost impacts associated with the operational constraints modelled are moderate even at high renewable penetrations. The extent of the impacts also depends particularly on the level of carbon price and the mix of generation technologies within the portfolios.**

***Index Terms*— Generation planning, operational constraints, cycling, flexibility, variability, renewable generation**

I. Introduction

VARIABLE renewable generation, particularly wind and solar photovoltaics (PV), are fast becoming major generation sources in a number of electricity industries. Given their variable, somewhat unpredictable and partly dispatchable nature, there are concerns over the potential operational and economic impacts of integrating such renewable sources into power systems. In particular, they will increase the variability of net demand to be met by conventional dispatchable generation necessitating more frequent cycling (ramp up/down, startup/shutdown) operation of these units [1]. Large thermal generation has particular technical limitations and costs associated with such operation.

As the shares of wind and solar generation are projected to substantially increase in the coming decade, it is important to ensure that this can be accommodated by future electricity systems [2] with large thermal plants. Hence, long-term generation planning and investment modeling needs to reasonably capture actual operational characteristics of generating plants and their ability to respond to rapid and frequent changes in net demand [3]. Key thermal plant operating characteristics include minimum generation levels, startup times and costs, ramp rate limits, and minimum up/down times. Given the associated complexities and the long time horizon involved, traditional long-term generation planning frameworks often ignore these operational constraints, and the costs associated with them. However, this may mean that generation portfolios calculated to be optimal under long-term planning frameworks may not be operationally viable or economically optimal in practice.

This paper aims to assess how the technical limitations and economic impacts of generator operational characteristics, especially at high renewable penetrations, might impact on the least cost generation portfolio outcomes obtained from long-term planning tools. In particular, it compares overall future industry costs obtained from a long-term generation portfolio planning and investment modelling tool, MC-ELECT [4], against these industry costs when operating costs are obtained by solving a detailed inter-temporal constrained dispatch in PLEXOS (a commercial power market modelling tool) [5].

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II. Generation Planning and Investment Models

A. Monte Carlo based Generation Portfolio Modelling Tool

A long-term generation portfolio planning tool, 'MC-ELECT', developed in previous work, extends load duration curve (LDC) optimal generation mix techniques by using Monte Carlo simulation to incorporate key uncertainties [4]. The expected costs, cost risks and CO_2 emissions of a range of generation portfolios in a given future year are obtained from several thousand repeated scenarios with probabilistic input parameters. The outputs can be described as an 'expected' (mean) future value of annual portfolio costs. The cost spread can be represented by standard deviation and is referred to as 'cost risk'. Financial portfolio techniques is then used to determine an Efficient Frontier that contains optimal portfolios in terms of expected costs and associated cost risk [6].

MC-ELECT was employed to analyze future generation portfolios with different renewable energy penetrations in the Australian National Electricity Market (NEM) for 2030 [7]. Fig. 1 illustrates the previously calculated optimal generation portfolios for different renewable penetration levels, ranging from 15% to 85%. This result forms the basis of the case study presented in this paper (Sections IV. V. , which explores the impact of short-term operational constraints on those portfolios determined to lie on the efficient frontier.

The main limitation of MC-ELECT is inherently linked to its use of LDC, which removes chronology and prevents the analysis of short term operational issues. This is common with other long term approaches overlooking unit commitment issues. A post processing extension to the modelling tool has been previously implemented to assess the impacts of short-term operational aspects, but the dispatch simulations were simplistic and can only handle low to moderate levels of renewable penetration [8]. The analysis in this paper therefore addresses the need for more detailed operational modelling.

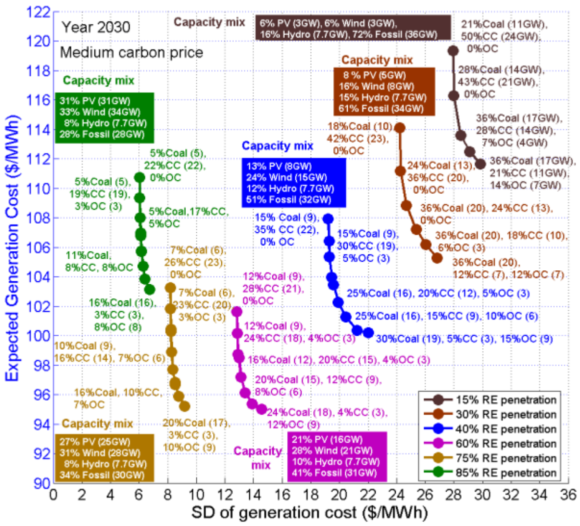

Fig. 1. Previous results from an Australian case study showing the optimal generation portfolios in terms of expected cost ($/MWh) and associated cost risks (standard deviation) for different renewable penetrations in 2030 [7].

B. *PLEXOS Integrated Energy Model*

PLEXOS is an energy market simulation package with particular capabilities in modelling operational aspects of power systems including solving optimal unit commitment and economic dispatch [5]. PLEXOS is widely used in by utilities, consultants and researchers [9-12]. Some of these studies also compared capacity expansion planning under LDC approach with chronological unit commitment [12].

In PLEXOS, simulations can be solved over different timeframes, ranging from long term generation capacity expansion to short term unit commitment. Capacity expansion problems are solved using a Long Term tool based upon the LDC (chronology removed). In contrast, chronological unit commitment problems are solved using a Short Term (ST) scheduling tool, taking into account inter-temporal constraints including minimum generation level, minimum up and down times, startup costs and ramp rates. The high level of detail means PLEXOS is capable of highly precise short-term modelling. For the purpose of this study, the ST Schedule tool in PLEXOS has been used to assess the impact of short-term operational constraints on the optimal generation portfolios obtained from MC-ELECT described previously.

III. Methodology

The optimal generation portfolios for each renewable energy penetration were taken from MC-ELECT, as shown in Fig. 1. PLEXOS and the Xpress-MP solver was then employed to solve a year of hourly constrained generation dispatch. Hourly PV and wind generation profiles are input into PLEXOS. Hydro generation was dispatched to minimize annual system cost subject to a hydro energy limit constraint. The constraints incorporated into the PLEXOS modelling were start-up costs, minimum operating levels, ramp rates and synchronous generation requirements. Technical and cost implications associated with these constraints were then analyzed. Minimum up/down times and spinning reserve were not considered in the analysis.

A minimum synchronous generation requirement is also imposed in all dispatch periods to provide adequate system inertia, fault feed-in levels and system stability [13]. This constraint is important for high renewable scenarios since some prevalent kinds of renewable generation (wind and PV) are non-synchronous and therefore do not generally provide inertia and fault feed-in current to the system [14]. For the purposes of this study, coal, gas and hydro plants are assumed to provide synchronous generation (some types of renewable generation such as solar thermal, geothermal and biomass are also synchronous, although these technology types have not been modelled in this study). The impact of requiring various synchronous generation levels via this constraint was examined, as outlined in Section IV.

Generators were dispatched based on their short run marginal cost (SRMC) with the objective of minimizing total system operating cost (including startup costs) of meeting demand in a year subject to generating unit and demand balancing constraints as shown in Eq. (1) – Eq. (6). SRMC is the sum of the fuel, variable operations and maintenance (O&M) and greenhouse emissions costs of each unit.

$$\min \sum_{t=1}^{T} \sum_{i=1}^{I} [VC_i . (P_{i,t}) + S_i(\nu_{i,t})] \tag{1}$$

$$\nu_{i,t} = \{0,1\} \tag{2}$$

Subject to:

- *System demand* $$\sum_{i=1}^{I} \nu_{i,t} P_{i,t} = D_t \tag{3}$$
- *Capacity* $$\nu_{i,t} . P_i^{\min} \le P_{i,t} \le \nu_{i,t} . P_i^{\max} \tag{4}$$
- *Ramp rates* $$(P_{i,t+1} - \Delta_i) \le P_{i,t} \le (P_{i,t+1} + \Delta_i) \tag{5}$$
- *Synchronous requirement* $$P_{conv,t} \ge (SC/100).D_t \tag{6}$$

where VC_i is the SRMC of generating unit i ($/MWh), $P_{i,t}$ is the output of generating unit i (MW) and $\nu_{i,t}$ is on-off decision variable indicating whether unit i is online or offline in period t. S_i is the startup costs which include fuel, maintenance and other costs as explained in Section IV. D_t is the demand in period t (MW), P_i^{min} and P_i^{max} are the minimum and maximum output of generating unit i. $P_{conv,t}$ is the output of conventional generating unit i at period t (MW). SC is the minimum synchronous requirement (%).

IV. The Australian National Electricity Market (NEM) Case Study

This study considers six different renewable energy penetration scenarios for the Australian NEM in 2030, which are 15%, 30%, 40%, 60%, 75% and 85% renewable.[1] Eight technologies were included: coal, combined cycle gas turbine

[1] The existing renewable energy penetration in the NEM is around 15%.

(CCGT), open cycle gas turbine (OCGT), co-generation, distillate, utility-scale PV (single axis tracking), wind (on shore) and hydro. It was assumed that new generation options only come from CCGT, OCGT, PV and wind. The optimal generation portfolios for 2030 under a medium carbon price obtained from MC-ELECT are the focus of this study. Three carbon price scenarios are considered: \$20, \$91 and \$115/tCO_2. These prices correspond to medium and high projections of carbon prices for Australia in 2030 as modelled by the Australian Treasury [15]. Although carbon pricing legislation has recently been repealed in Australia it is assumed that a comparable mechanism will be applied by 2030 to achieve the necessary emission reductions, as recommended by the Australian Government Climate Change Authority [16]. A number of minimum synchronous generation requirements (from 0% to 40%) are considered.

A. Hourly Demand, PV, Wind and Hydro Generation Data

An indicative hourly electricity demand profile for 2029 – 2030 was sourced from analysis by the Australian Energy Market Operator (AEMO) on a 100% renewables system under a moderate economic growth scenario. AEMO's demand projections were derived from the historical demand pattern in 2009 – 2010. Hourly wind and solar output profiles for 2030 were simulated from hourly traces of 1-MW on-shore wind and solar PV (single axis tracking) generation in different locations across the NEM provided by AEMO [13].

For hydro generation an annual hydro energy dispatch limit of 13 TWh was applied, based upon the long-term average hydro generation estimated by AEMO [13].

B. Operating Characteristics of Generating Units

Operating and cost characteristics assumed for each technology are shown in Table I and II. These data were estimated based upon a number of consultancy studies and reports both in Australia and internationally [11, 17-19].[2]

TABLE I
GENERATOR STARTUP CHARACTERISTICS OF EACH TECHNOLOGY

Characteristics		Coal	CCGT	OCGT
Unit size (MW)		600	500	150
Startup fuel cost (\$'000/start)	Hot	128	1.2	0.4
	Warm	216	1.3	0.4
	Cold	255	1.5	0.5
Non-fuel startup costs (capital & maintenance, emissions and other costs) (\$/MW)	Hot	65	38	25
	Warm	79	59	37
	Cold	124	85	42
CO_2 emissions intensity (tCO_2)		0.75[a]	0.6	0.6
Startup fuel price (\$/GJ)		20[a]	11.65	14

[a] Diesel is used for starting up coal generating units

The key components of start-up costs are: fuel costs, capital and maintenance costs, greenhouse emissions, and other costs. Fuel costs are dictated by the rate at which fuel is consumed during start-up and the fuel price. Maintenance and capital expenditures ('wear and tear costs') are attributed to thermal and pressure stress which occur during start-up and culminate in equipment degradation. The emissions cost is dependent on the carbon price and the thermal efficiency. Expenditure on unit starts towards auxiliary power, chemicals and labor are included under 'other' costs. These costs are influenced by the amount of time that has elapsed since the unit was last active. Three time periods (hot, warm and cold) were defined.

TABLE II
MINIMUM OPERATING LEVEL AND RAMP RATE CHARACTERISTICS

Operating parameters	Coal	CCGT	OCGT	Cogen	Distillate	Hydro
Min. Gen (% of capacity)	50	40	0	65	0	0
Ramp rate (MW/hour)	8	10	12	3	20	200

V. SIMULATION RESULTS AND ANALYSIS

Fig. 2 illustrates an example of hourly dispatch of a generation portfolio with a 40% renewable penetration during a typical week. At a low carbon price (\$20/tCO_2), the low SRMC of coal units by comparison with gas-fired CCGT and OCGT sees them providing base-load generation. The significant coal and renewable generation capacity of these portfolios means CCGT and OCGT are not heavily utilized. With higher renewable penetrations, thermal generation units are required to cycle more often.

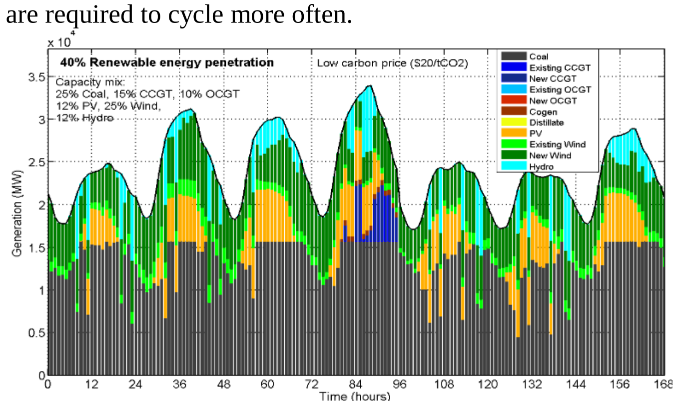

Fig. 2. Example of typical weekly generation patterns for portfolios with a 40% renewable penetration a low carbon price (\$20/tCO_2).

A. The Impact on Number of Startups/Shutdowns

The average number of startups of coal and gas units for selected portfolios with different renewable penetrations facing a medium carbon price are shown in TABLE III.

TABLE III
AVERAGE NUMBER OF STARTUPS/UNIT/YEAR FOR EACH TECHNOLOGY FOR SELECTED PORTFOLIOS FOR A MEDIUM CARBON PRICE (\$91/tCO_2).

RE pen (%)	Portfolio (% share of coal and gas in total capacity)	Average no. of startups/unit/year				
		Coal	New CCGT	New OCGT	Existing CCGT	Existing OCGT
30%	36% coal, 12% CC, 12% OC	16	68	0	11	1
	18% coal, 42% CC, 0% OC	0	23	0	0	0
40%	10% coal, 40% CC, 0% OC	0	21	0	0	0
	25% coal, 15% CC, 10% OC	16	51	0	3	0
60%	24% coal, 4% CC, 12% OC	29	233	70	117	1
	12% coal, 28% CC, 0% OC	25	50	0	0	0
85%	16% coal, 3% CC, 8% OC	102	0	204	201	21
	5% coal, 16% CC, 5% OC	14	128	0	30	0

The highest number of startups for CCGT is around 230 starts per year, which is within a typical design range of recently installed and future new build CCGT of around 250-350 starts per year [20]. The number of coal startups also appears to be operationally viable for most portfolios. Coal units are consistently dispatched given their relatively low SRMC compared to gas generation. For low to moderate

[2] Only coal, CCGT and OCGT start-up costs were considered in the modelling since the other thermal technologies modelled (cogeneration and distillate) represent less than 1% of generation capacity in the NEM in 2030.

renewable penetrations, at times of very low demand coal units are able lower their output rather than switch off completely. However, for very high renewable penetrations, coal units in portfolios with considerable share of coal capacity (e.g. 16% coal, 3% CCGT and 8% OCGT) can experience up to around 100 starts per year, which is arguably higher than the typical design range of coal units at present. However, coal plants may be able to increase their flexibility through modifications in hardware and operational practice and there are certainly some examples of flexible coal plants that withstand daily startup and shutdown [21].

Generally, the number of startups increases with higher renewable penetration. However, as shown in Fig. 3, this is not always the case as the number of startups also depends on the mix of conventional technologies within the portfolio.

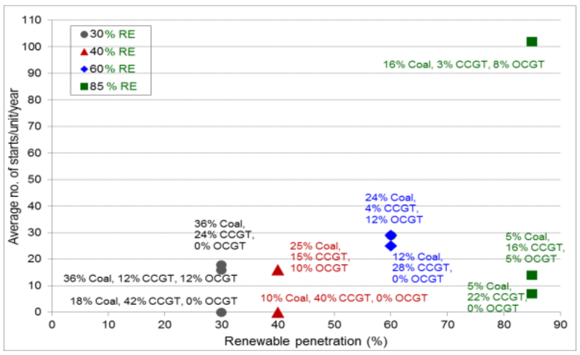

Fig. 3. Average number of coal starts per unit per year in a range of portfolios for different renewable penetrations. Percentages indicate the proportion of installed capacity that is coal, CCGT and OCGT.

For each generation portfolio, the number of unit startups is also influenced by the level of carbon price. Higher carbon prices result in reductions in the number of coal starts since coal units are less dispatched due to their now increased SRMC. The reduction in coal starts is offset somewhat by a smaller increase in the number of gas startups. The opposite is seen for lower carbon prices. If a small amount of conventional generation is required for only a short period of time, it is preferable to startup CCGT or OCGT and shut down again given their flexibility and relatively low startup costs.

B. The Impact of Minimum Generation Constraint

Minimum generation constraints impose additional costs to portfolios since individual coal and gas units must be dispatched at higher levels (compared to the case without the constraint). However, results show that the increase in costs associated with this constraint is very small. The largest cost increase observed in any portfolio was \$2/MWh (or a 2% increase), which occurs only in generation portfolios with 85% renewable penetration. At low to moderate renewable penetrations, minimum operating levels have a negligible effect since thermal generating units are already dispatched well above their minimum levels (less than a 1% increase in system costs for renewable penetration levels below 60%).

Generally, as the renewable penetration rises, the cost impacts due to minimum generation constraints were observed to increase since this constraint results in additional curtailment of PV and wind generation to accommodate increased coal and gas generation. The cost impacts due operational constraints for a number of portfolios with different renewable penetrations are shown in TABLE IV.

C. The Impact of Ramp Rate Limits

Of the operational constraints considered, ramp rate constraints have the smallest impact on both cost and dispatch. All generation portfolios were found to be able to meet the maximum hourly ramps required. Hence, the impact of ramp rate constraints on overall generation cost is almost negligible. However, the dispatch simulation was optimized on an hourly basis which does not capture the actual ramping requirements of the system over shorter timeframes. If the dispatch simulation was carried out with a finer granularity, ramp rate limits may be violated to a greater extent. As shown in TABLE IV, costs incurred due to ramp rate constraints increase very slightly as renewable penetration increases.

TABLE IV
COSTS OF SELECTED PORTFOLIOS SUBJECT TO DIFFERENT OPERATIONAL CONSTRAINTS FOR A MEDIUM CARBON PRICE (\$91T/CO2)

RE pen	Portfolio	Generation cost (\$/MWh)		
		Without constraint	With Min. gen	Min. gen & ramp rates
30%	36% coal, 12% CC, 12% OC	108.0	108.0	108.0
	18% coal, 42% CC, 0% OC	119.1	119.1	119.1
40%	10% coal, 40% CC, 0% OC	115.2	115.3	115.3
	25% coal, 15% CC, 10% OC	104.2	104.3	104.3
60%	24% coal, 4% CC, 12% OC	97.1	97.8	97.8
	12% coal, 28% CC, 0% OC	104.9	105.6	105.6
85%	16% coal, 3% CC, 8% OC	100.3	102.3	102.4
	5% coal, 16% CC, 5% OC	105.5	106.5	106.5

D. The Impact of Synchronous Generation Requirement

Different synchronous generation requirements between 0% and 40% were imposed. The synchronous requirements incur significant additional costs, particularly at high renewable penetrations and carbon prices, since in these scenarios low operating cost renewable generation must be curtailed to accommodate increased thermal generation. TABLE V illustrates the changes in system cost of generation portfolios with 40% and 60% renewable penetration for different carbon prices when various synchronous requirements (0% to 40%) are imposed.

TABLE V
TOTAL COST OF PORTFOLIOS WITH 40% AND 60% RENEWABLE PENETRATION FOR DIFFERENT SYNCHRONOUS REQUIREMENTS

RE pen	Carbon Price (\$)	Portfolio	Total generation cost (\$/MWh)				
			0%	10%	20%	30%	40%
40%	20	25% coal, 15% CC, 10%OC	65	No change			65.4
	91	25% coal, 15% CC, 10%OC	104	No change			104.2
	115	25% coal, 15% CC, 10%OC	117	No change			117.2
60%	20	24% coal, 4% CC, 12% OC	69.8	69.9	70.1	70.5	71.4
	91	24% coal, 4% CC, 12% OC	96	96.6	97	99	102
	115	24% coal, 4% CC, 12% OC	105	106	107	108	112

For portfolios with low to moderate renewable penetrations (i.e. 15% to 40% renewable), the cost impact of synchronous requirement is negligible since at least 40% of the demand in each period is already being served by conventional generators (the highest synchronous requirement modelled is 40%). For renewable penetrations greater than 40%, the introduction of a synchronous requirement begins to have significant cost impacts, particularly at high carbon prices. Even very low synchronous requirements add to system cost. At a 60% renewable penetration, imposing a 40% synchronous requirement increases the total system costs by around 7%.

For most portfolios, system cost increases with the level of synchronous generation requirement as illustrated in Fig. 4. The figure also illustrates the significant differences in the cost attributed to synchronous requirements as renewable penetration increases from 60% to 85%. For all of the portfolios modelled, costs associated with synchronous generation requirement increase with higher carbon prices.

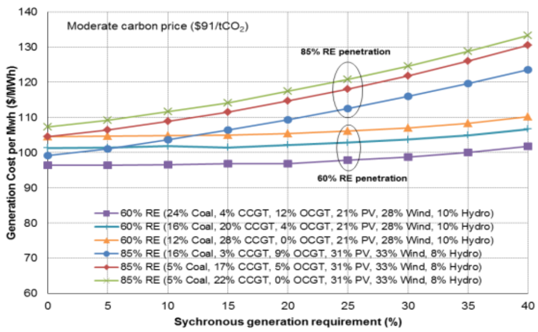

Fig. 4. Generation cost of different portfolios with 60% and 85% renewable penetration for different levels of synchronous generation requirements.

VI. Conclusions

This paper examines the impact of short-term operational characteristics on generation portfolios obtained under a long-term portfolio planning modelling. These include startup costs, minimum generation level, ramp rate limits and synchronous generation requirement.

Results from the Australian case study with different levels of renewable penetrations in 2030 suggest that the inclusion of startup costs, minimum generation and ramp rate constraints do not have a significant cost impact on generation portfolios obtained using a long-term portfolio planning framework that does not include these factors. While there are shifts in the amount of generation dispatched, ultimately the total annual cost does not change by more than 2%, even under very high (85%) renewable penetration. However, the synchronous generation requirements can result in significant increase in generation costs particularly at high renewable penetrations and carbon prices.

Generally, coal and gas plants can experience frequent cycling operation (ramp up/down and starts/stops) with higher renewable penetration. However, the number of unit startups appears fairly reasonable except for some portfolios with high renewables (high share of coal capacity) where coal units can face up to 100 starts per year. This, however, suggests that coal plants may need to increase their flexibility to withstand increased cycling in low-carbon and high renewable futures. The impacts of the operational constraints modelled depend particularly on the level of carbon price and the mix of generation technologies within the portfolio.

There are some limitations of this study. Some constraints including minimum up/down times of generating units were not modelled. Transmission network constraints were also ignored. The modelling in this paper does not investigate the effects that arise when start-up costs, minimum operating levels, ramp rates and synchronous generation requirements are all incorporated simultaneously. There is still much to be done in improving our understanding of the additional costs associated with more variable operation of thermal plants. It is of course likely that new thermal plant designs for electricity industries with high variable renewable generation will provide improved operational flexibility and reduced cycling costs. Furthermore, there are opportunities to address the low system inertia present at times of high non-synchronous renewable penetrations other than imposing a minimum synchronous generation limit. All of these limitations represent areas for future work.

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