# Impacts of Generation-Cycling Costs on Future Electricity Generation Portfolio Investment

P. Vithayasrichareon, *Member, IEEE,* and I. F. MacGill, *Member, IEEE*

***Abstract*—This paper assesses the impacts of incorporating short-term generation dispatch into long-term generation portfolio planning frameworks. A case study of a power system with coal, combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT) and wind generation options highlights that incorporating operational criteria into the long-term generation investment and planning analysis can have operating, economic and emissions implications for the different generation portfolios. The extent of the impacts depends on a number of factors including dispatch strategies, carbon price and the mix of technologies within the portfolio. As variable generation within power systems increases and carbon pricing begins to change the merit order, such short-term operational considerations will become more significant for generation investment and planning.**

***Index Terms*—Monte Carlo simulation, generation planning, portfolio analysis, generation dispatch, operational constraints**

## I. Introduction

DECISION making in generation investment and planning requires a long-term perspective amidst considerable uncertainties in expected future demand, fuel prices, plant construction costs and wider energy and climate policies such as carbon pricing. Given the long planning horizon, generation investment and planning frameworks often ignore the actual details of short-term electricity industry operation [1]. For example, many generation planning models are based on the use of a Load Duration Curve (LDC), where the chronology is removed, to determine a future optimal generation technology portfolio. In reality, however, generating plants have significant inter-temporal operating constraints such as minimum operating levels, ramp rates, and startup/shutdown times. There are also operating expenses associated with inter-temporal generation dispatch such as plant startup costs.

Generation portfolio analysis frameworks[1] have been increasingly employed for generation investment and planning to determine optimal generation portfolios with different cost-risk profiles [2, 3]. Optimal generation portfolios fall along the so called 'efficient frontier', representing cost-risk tradeoffs among possible generation portfolios. However, similar to most long-term generation planning models, operational issues including unit constraints and inter-temporal generation dispatch are not generally considered [4].

This work has been supported in part by Australian Renewable Energy Agency (ARENA).

The authors are with the Centre for Energy and Environmental Markets and School of Electrical Engineering and Telecommunications, University of New South Wales, Sydney, Australia (email: peerapat@unsw.edu.au).

Recent growth of variable renewable generation such as wind and solar has increased the complexity of electricity industry operation as well as posing operational challenges for conventional plants through increased cycling [5, 6]. There are also additional costs due to cycling operation including startup/shut down of generating units [7, 8]. Generation portfolios that appear attractive under standard long-term generation portfolio planning frameworks might have challenging operational requirements given expected demand patterns and the variability of high renewable penetrations. Furthermore, the additional costs associated with cycling operation could potentially alter the merit of different candidate generation portfolios.

In previous work, we have presented a probabilistic generation portfolio modeling tool for assessing future generation portfolios under high level of uncertainties [9, 10]. Despite the capability of the tool in addressing uncertainties and risks associated with long-term generation planning, there are still inherent limitations in the method it applies with regard to issues associated with short-term electricity industry operation. The work presented in this paper aims to address these limitations by implementing a post-processing extension to the tool which incorporates generating unit constraints and inter-temporal generation dispatch.

This paper intends to provide a high-level assessment of the potential impacts of short-term operational aspects on the technical viability, economics and emissions of generation portfolios that appear favorable from the initial investment and planning framework. The post-processing assessment includes indices of possible violations of operating constraints such as number of starts/stops, ramp rates, the economic and emissions implications of different dispatch strategies around minimum plant operating levels.

## II. Probabilistic Generation Portfolio Modeling Tool

The generation investment and planning tool implemented in our previous work assesses the costs of possible future electricity generation portfolios given uncertain future fuel prices, carbon prices, plant capital costs, and electricity demand. The tool extends conventional LDC methods by incorporating potentially correlated uncertainties for key cost assumptions and future demand using Monte Carlo Simulation (MCS). The expected costs, cost uncertainties and $CO_2$ emissions of a range of potential new-build generation portfolios in a given future year are directly obtained from several thousand repeated scenarios with probabilistic input parameters. The cost spread for a generation portfolio can, for some distributions, be represented by standard deviation (SD) and is referred to here as 'cost uncertainty', which carries a similar meaning to 'risk' in the economic and finance contexts. The tool applies financial portfolio analysis techniques to determine an efficient frontier containing optimal generation portfolios given tradeoffs between expected (average) cost and its associated cost uncertainty.

Results from a previous case study of an electricity industry with coal, CCGT, OCGT, and wind generation options are used to demonstrate use of the tool [10]. Simulated half-hourly wind generation estimates are subtracted from electricity demand to obtain a residual demand and then rearranged to get a residual LDC (RLDC) [2]. This RLDC is then served by thermal technologies in the portfolios.

The expected yearly generation cost and cost uncertainty of different thermal generation portfolios obtained from the previous case study are shown in Fig. 1. An 'efficient frontier' (EF)[2] containing the 'optimal' generation portfolios (labeled *A* - *E*) is represented by a solid line. This result is also the basis of the case study presented later in Section V.

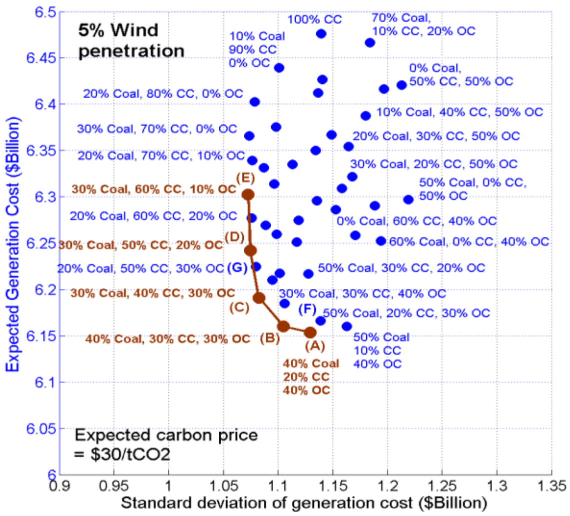


Fig. 1. Results from the tool showing the expected cost, associated cost uncertainty and $CO_2$ emissions of generation portfolios [10].

Despite its capability in addressing risk and uncertainty in generation planning, the operational aspect was not considered. Such limitation is addressed in this paper through a post-processing extension described in the next section.

## III. Post-Processing Extension to The Monte Carlo Based Decision Support Tool

In this extension approach, candidate generation portfolios are taken from the initial MCS analysis and then run each through a year of sequential half-hourly constrained economic dispatch to meet residual demand (demand net of renewable generation)[3]. A range of operating constraints for the different generation technologies is incorporated in this dispatch to assess their potential operating, economic and emissions implications for different generation portfolios. These operational constraints include minimum generation levels and potentially other criteria associated with the startup/shutdown of generating units during dispatch intervals.

Some key operating implications of constrained dispatch for different generation portfolios are assessed by counting the number of startups and ramp-rate violations of each generation technology within a portfolio over the year of simulated operation. The potential economic implications of additional startup costs and increased running costs are also assessed including their impact on overall industry costs and hence, potentially, the EF of optimal generation portfolios. Emissions implications are also assessed based on changes in the annual $CO_2$ emissions of the different candidate portfolios.

The post-processing analysis in this paper is not intended to solve detailed economic dispatch, unit commitment and production scheduling. Minimum startup/shutdown times and ramp rate constraints are not imposed. However, their implications can still be assessed, in part, based on how often these constraints are violated by the simulated dispatch.

### A. Central Economic Dispatch Objective and Constraints

The dispatch objective function is to minimize total operating costs in each dispatch period taking into account the chronology of generation dispatch subject to generator and demand balancing constraints as shown in (1) - (4).

$$Minimize \quad \sum_{i=1}^{I} VC_i.(P_{i,t}).v_{i,t} \tag{1}$$

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

where $VC_i$ is the variable operating cost of generating unit $i$ (\$/MWh), $P_{i,t}$ is the output of generating unit $i$ at period $t$ (MW), and $v_{i,t}$ is on-off decision variable indicating whether unit $i$ is online or offline in period $t$.

$$\sum_{i=1}^{I} v_{i,t} P_{i,t} = D_t \tag{3}$$

$$P_i^{min} \le P_{i,t} \le P_i^{max} \tag{4}$$

where $D_t$ is the demand in period $t$ (MW), $P_i^{min}$ and $P_i^{max}$ are the minimum and maximum output of generating unit $i$.

Analysis is undertaken for two dispatch models with different startup/shutdown criteria for generation: 1) *Min Start/Stop* - keeping all large thermal plant on-line if possible by sharing loading reductions; and 2) *Max Low-Cost Gen* - dispatching the lowest operating cost plants at highest possible outputs whilst shutting down the higher cost units where not required. Both dispatch models assume that every individual unit of the same technology has the same operating and cost characteristics. Therefore, generating units of the same technology are dispatched equally as well as sharing the startups/shutdowns. Dispatch criteria are shown in Table I.

TABLE I
THE TWO GENERATION DISPATCH MODELS CONSIDERED IN THE SIMULATION

| *Min Start/Stop* Dispatch | *Max Low-Cost Gen* Dispatch |
|---|---|
| Minimize the start/shutdown of generating units. | Maximize outputs of lowest cost units in each dispatch period |
| Dispatch low cost units at part-load to allow other units to remain online although they are less economical to run. | Dispatch lowest cost technology close to its maximum capacity. |
| Startups/shutdowns only occur when the online units cannot increase or reduce their outputs any further. | Shutdown occurs if outputs of the lowest cost units would have to be reduced. |

[2] Along the frontier, the expected cost cannot be reduced without increasing cost uncertainty and vice versa.
[3] All available renewable generation is assumed to be dispatched.

The main tradeoff between these two dispatch models is between startup costs and running costs. *Min Start/Stop* dispatch saves on startup costs by minimizing shutdowns but incurs higher running costs, while *Max Low-Cost Gen* incurs higher startup costs but saves on running costs since the lowest cost units are dispatched near their maximum capacity.[4] The two dispatch models provide a basis for comparing the extremes of these two general dispatch approaches. Actual dispatch and scheduling are, of course, far more complex in practice as there are numerous additional factors that need to be considered such as network constraints and plant maintenance schedules.

### *B. Operating Costs and $CO_2$ Emissions Calculations*

Total annual operating costs of each generation portfolio consist of running costs and start-up costs as expressed in (5).

$$TOC(\$)=TRC+TSC \tag{5}$$

where *TRC* and *TSC* are the total annual running cost ($) and total annual startup cost ($) of the generating portfolio.

The total running costs of each generation portfolio is determined based on (6).

$$TRC=\sum_{t=1}^{T}\sum_{i=1}^{I}VC_i.P_{i,t} \tag{6}$$

where $VC_i$ is the variable operating cost of generating unit $i$ ($/MWh), $P_{i,t}$ is the output of generating unit $i$ in the portfolio at period $t$ (MW), $I$ is the number of generating units in the portfolio and $T$ is the number of dispatch period in a year.

The variable costs consist of variable O&M, fuel, and any carbon costs. Total annual startup costs of each generation portfolio consist of the startup fuel cost and startup carbon cost of generating units in the portfolio, as expressed in (7).

$$TSC_{i,t}=\sum_{t=1}^{T}\sum_{i=1}^{I}(S_{i,t}^{fuel}+S_{i,t}^{carbon}+S_{i,t}^{others}) \tag{7}$$

where $S_{i,t}^{fuel}$, $S_{i,t}^{carbon}$, $S_{i,t}^{others}$ are the start-up fuel cost, startup carbon cost and other associated costs during startup of generating unit $i$ in the portfolio at period $t$ respectively. These other potential costs include increased O&M, increased forced outages, unit life shortening, increased unit heat rate, and startup manpower [11].

$CO_2$ emissions of each portfolio is determined from (8).

$$total\ CO_2=\sum_{t=1}^{T}\sum_{i=1}^{I}(CO_{2_{i,t}}^{running}+CO_{2_{i,t}}^{start}) \tag{8}$$

where $CO_{2_{i,t}}^{running}$ and $CO_{2_i}^{start}$ are the emissions ($tCO_2$) during the operation and startup of unit $i$ in period $t$ respectively.

## IV. Description of The Case Study

The case study for this work considers coal, CCGT, OCGT and wind generation options based on [10] and as shown in Section II. The data for this study are based primarily on actual demand and wind generation from South Eastern Australia, and a number of Australian specific consultancies studies on plant capital and fuel costs. A case study with 5% wind penetration and an expected carbon price of $30/$tCO_2$ was chosen to demonstrate the post-processing extension. The shares of coal, CCGT and OCGT are varied from 0% to 100% in 10% intervals resulting in 66 possible thermal generation portfolios. The EF for this case study is, as noted above, shown in Fig. 1

### *A. Demand profile and the installed generation capacity*

The actual 30-minute combined demand and wind generation for the states of South Australia (SA), Victoria (VIC), and Tasmania (TAS) in Australia was used for the simulation, and are shown in Fig. 2. The residual demand was obtained by subtracting wind generation from total demand.

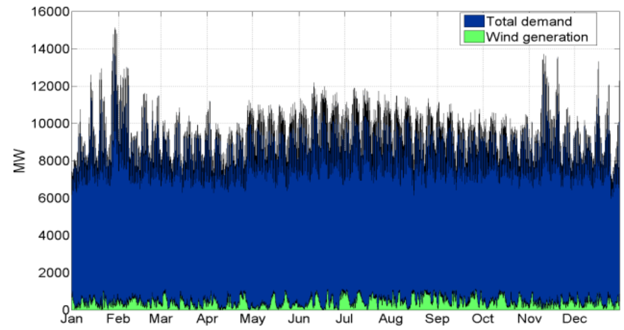


Fig. 2. 30-minute demand and wind generation in South Eastern Australia.

### *B. Operating Characteristics of Generating Units*

Operating and cost characteristics of each technology are shown in Table II [12, 13]. The amount of fuel used during a startup are estimated based on hot start conditions (offline 0-6 hours) [14]. Other potential costs associated with starting up generating units including increased O&M, forced outages, unit heat rate, and manpower [11]. These costs are estimated to be between 2-5 times the startup fuel costs [14, 15].

TABLE II
OPERATING CHARACTERISTICS OF EACH TECHNOLOGY

| Characteristics | Coal | CCGT | OCGT |
|---|---|---|---|
| Unit size (MW) | 600 | 500 | 150 |
| Minimum generation (MW) | 300 | 200 | 0 |
| Ramp rate (MW/hour) | 480 | 720 | 600 |
| Fuel used during startup (GJ) | 2,500 | 1,500 | 200 |
| Startup fuel cost ($/start) | 50,000 | 7,850 | 1,040 |
| Other startup costs ($/start) | 250,000 | 23,550 | 2,080 |
| $CO_2$ emissions during startup ($tCO_2$) | 187.5 | 90 | 12 |

. Prices and emission intensities for each fuel type are estimated based on [12, 16, 17] and are shown in Table III.

TABLE III
PRICE AND EMISSION INTENSITY OF EACH FUEL TYPE

| | Coal | Natural gas | Oil |
|---|---|---|---|
| Price ($/GJ) | 0.6 | 5.2 | 20 |
| Emission intensity ($tCO_2$/GJ) | 0.09 | 0.06 | 0.075 |

## V. Simulation Results And Analysis

Generator unit outputs at 30-minute intervals for each generation portfolio considered are simulated for both dispatch models over the year. The operating, economic and emissions implications of incorporating operational aspects into the dispatch are assessed for the candidate generation portfolios, which are those on or near the Efficient Frontier (EF).

[4] For both dispatch models, peaking OCGTs are only dispatched when coal and CCGT are already running at their capacity (assuming OCGT has the highest running costs, which is valid for the assumed fuel and carbon prices).

*A. Implications of incorporating operational constraints*

Fig. 3 illustrates an example of 30-minute constrained dispatch of a generation portfolio (40% coal, 20% CCGT, 40% OCGT) during a typical month. For the moderate carbon price of $30/tCO$_2$ assumed, coal plants still have the lowest operating costs, and therefore are dispatched as base-load generation while CCGTs are considered to be the intermediate load following plants. OCGTs are only dispatched during the high demand periods. Generally, outputs of the base-load units in *Min Start/Stop* dispatch are varied more frequently than *Max Low-Cost Gen* dispatch, in order to enable as many units as possible to remain online. These different generation patterns influence the cycling of generating units, operating costs, and emissions of the generation portfolios.

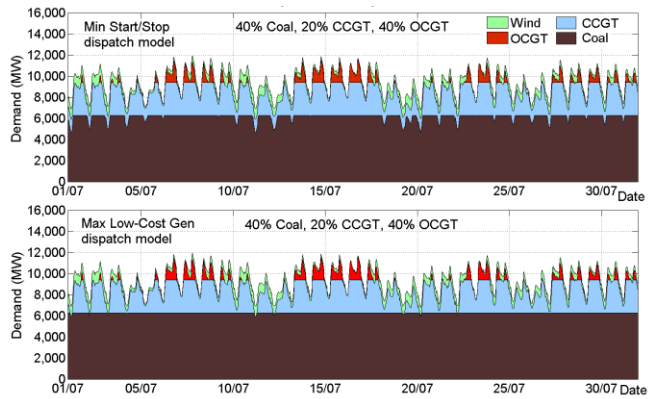


Fig. 3. Generation patterns of each technology for a typical month of a generation portfolio for both dispatch models.

*1) Operational Impacts*

The average numbers of unit startups for the candidate portfolios for both dispatch models are shown in Table IV.

TABLE IV
AVERAGE NO. OF STARTUPS/UNIT/YEAR FOR BOTH DISPATCH MODELS

| Portfolio | *Min Start/Stop* | | | *Max Low-Cost Gen* | | |
|---|---|---|---|---|---|---|
| | Coal | CCGT | OCGT | Coal | CCGT | OCGT |
| A) 40% coal, 20% CC, 40% OC | 0 | 0 | 57 | 0 | 227 | 57 |
| B) 40% coal, 30% CC, 30% OC | 0 | 0 | 14 | 0 | 204 | 14 |
| C) 30% coal, 40% CC, 30% OC | 0 | 0 | 14 | 0 | 45 | 14 |
| D) 30% coal, 50% CC, 20% OC | 0 | 0 | 4 | 0 | 42 | 4 |
| E) 30% coal, 60% CC, 10% OC | 0 | 1 | 2 | 0 | 36 | 2 |
| F) 50% coal, 20% CC, 30% OC | 0 | 0 | 14 | 0 | 270 | 14 |

Since CCGT units are the higher operating cost large thermal plant under assumed fuel and carbon prices, they incur more frequent startup/shutdown than the base-load coal units, particularly for *Max Low-Cost Gen* dispatch. Among the candidate portfolios, coal plants do not incur any startup/shutdowns in either dispatch models since all the coal units can maintain operation above their minimum operating level, even during low-demand periods. OCGT units are not often required to startup since they are rarely dispatched.

For *Min Start/Stop* dispatch, CCGT units in each portfolio are rarely shutdown (and hence startup) since all coal and CCGT units can operate above their minimum levels for all periods. However, for portfolios with high shares of coal, the base-load coal units may have to ramp up/down more often.

For *Max Low-Cost Gen* dispatch, CCGT units incur far more frequent startups since this dispatch model attempts to operate the base-load coal units near their maximum capacity by shutting down CCGT units where possible. Portfolio *F* (50% coal, 20% CCGT, 30% OCGT) has the highest number of average startups per unit for CCGT - around 270 starts/year. This number is largely in the typical range of designed starts for recently installed CCGT units of around 250 starts per year. This design criterion is widely expected to increase to over 350 starts in the future given technology advances [18].

All generation portfolios were able to meet the maximum 30-minute ramps since there are sufficient fast response gas plants. There appear to be no major concerns in the operational viability of any generation portfolios for either dispatch model. The results also highlight that, other than the dispatch model, the frequency of unit startups depends on the mix of technologies in the portfolios.

*2) Economic Impacts*

Fig. 4 compares the expected costs and cost uncertainty (SD of costs) of the candidate portfolios for the cases with and without operating constraints, for both dispatch models.[5] The original EF without the operating constraints is compared with the modified EFs for each dispatch model.

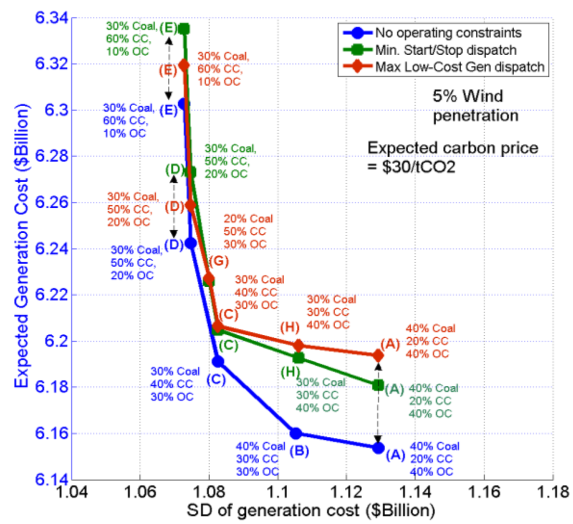


Fig. 4. Efficient frontiers (EFs) of optimal generation portfolios after incorporating the operating constraints.

Generally, incorporating short-term operational constraints increases the overall industry generation costs of portfolios for both dispatch models due to increased running costs and additional startup costs. However, the extent of these cycling cost impacts varies according to the mix of technologies in generation portfolios, which subsequently affects the relative cost-risk profiles of generation portfolios, and hence the EF. As shown in Fig. 4, portfolio *B* (40% Coal, 30% CCGT, 30% OCGT) is replaced by portfolio *H* (30% Coal, 30% CCGT, 40% OCGT) on the EF when operating constraints are incorporated for both dispatch strategies.

For this case study, the additional costs due to the operating constraints are generally small, representing less than 1% of total generation costs. Whilst the economic impacts of considering operating constraints are relatively limited for this

[5] The cost uncertainty of each portfolio is unchanged since this study does not consider uncertainties associated with short-term operation.

case study, they do have an impact on which portfolios lie on the EF. Neglecting these constraints in the long-term portfolio investment and planning framework, therefore, may impact selection of the most appropriate portfolio in some cases. Furthermore, these costs will become more significant if demand variability and renewable penetrations increase.

*3) Emission Impacts*

Incorporating operational constraints resulted in emissions reductions for *Min Start/Stop* dispatch, particularly for portfolios with large shares of coal (i.e. 50%). This is because high emitting coal plants are dispatched at lower load factors under this dispatch in order to permit low-emission CCGT units to remain on-line. For *Max Low-Cost Gen* dispatch, it appears that the $CO_2$ emissions of the portfolios are about the same with the unconstrained dispatch case given that the low-operating cost coal plants are dispatched near their maximum capacity, which is also the case in the unconstrained dispatch. The results suggest, therefore, that *Min Start/Stop* dispatch represents a more appropriate option for reducing overall emissions in this particular case study.

### B. Impacts of different carbon prices and wind penetrations

In this case study, the merit order of generation technology did not change until the carbon price reaches \$60/t$CO_2$ at which point CCGT replaces coal units as the lowest cost generation. As a result coal units incur frequent output changes including starts/stops. Coal units have high startup costs and are relatively inflexible due to their typically low ramp rates and high minimum operating levels. At a high carbon price, therefore, the operational and economic implications associated with the inclusion of the short-term operating constraints may be quite significant.

In such a scenario, *Min Start/Stop* dispatch still does not present major operational implications since coal units are kept online most of the time by reducing the output of base-load CCGT units. For *Max Low-Cost Gen* dispatch, however, the average startups for coal units are between 80-250 starts/unit/year. This is significantly higher than the typical 'design' number of starts of 20 per year without the need to replace major parts due to fatigue effects [19]. The inclusion of operational constraints also results in frequent ramp-rate violations of the coal units. Such operating patterns under *Max Low-Cost Gen* dispatch can lead to major economic impacts.

Higher wind penetrations can also be expected to have significant operating, economic and emissions impacts on generation portfolios. Beyond its high capital but low operating costs, the increased variability of wind generation at high penetrations poses additional challenges for conventional generators due to increased cycling operation.

## VI. Conclusions

This paper applies a post-processing extension to assess the operational, economic and emission impacts of incorporating short-term operational constraints into the results of a long-term generation portfolio investment and planning tool.

The case study results provide some insights into how different future generation portfolios might be impacted by different possible dispatch strategies. The results for this particular case study may seem to suggest that these operational constraints have moderate impacts on the most appropriate generation portfolios, and the overall industry costs obtained from the initial generation investment planning analysis. However, in future low-carbon electricity industries with high levels of variable renewable generation and high carbon prices, these impacts are likely to be more significant due to increased cycling of thermal generating units.

There are some limitations in the post-processing extension to the tool. The constrained dispatch did not consider shutdown and minimum synchronization time of generating units. Dispatch was only undertaken at 30-minute intervals. Network and security constraints were not considered. These limitations and the implications of higher wind penetrations and carbon prices will be further explored in future work.

## VII. References


[1] J. Reneses, E. Centeno, and J. Barquin, "Coordination between medium-term generation planning and short-term operation in electricity markets," *IEEE Trans. on Power Syst.*, vol. 21, 1, pp. 43-52, 2006.

[2] R. Doherty, H. Outhred, and M. O'Malley, "Establishing the Role That Wind Generation May Have in Future Generation Portfolios," *IEEE Trans. on Power Syst.*, vol. 21, 3, pp. 1415-1422, 2006.

[3] S. Awerbuch, "Portfolio-Based Electricity Generation Planning: Policy Implications For Renewables And Energy Security," *Mitigation and Adaptation Strategies for Global Change*, vol. 11, 3, pp. 693-710, 2006.

[4] E. Delarue, C. De Jonghe, R. Belmans, and W. D'Haeseleer, "Applying portfolio theory to the electricity sector: Energy versus power," *Energy Economics*, vol. 33, 1, pp. 12-23, 2011.

[5] N. Troy, E. Denny, and M. O'Malley, "Base-Load Cycling on a System With Significant Wind Penetration," *IEEE Trans. on Power Syst.*, vol. 25, 2, pp. 1088-1097, 2010.

[6] J. Kabouris and F. D. Kanellos, "Impacts of Large-Scale Wind Penetration on Designing and Operation of Electric Power Systems," *IEEE Trans. on Sust. Energy*, vol. 1, 2, pp. 107-114, 2010.

[7] A. Shortt, J. Kiviluoma, and M. O'Malley, "Accommodating Variability in Generation Planning," *IEEE Trans. on Power Syst.*, vol. 28, 1, pp. 158-169, 2013.

[8] C. Batlle and P. Rodilla, "An Enhanced Screening Curves Method for Considering Thermal Cycling Operation Costs in Generation Expansion Planning," *IEEE Trans. on Power Syst.*, vol. 28, 4, pp. 3683-3691, 2013.

[9] P. Vithayasrichareon and I. F. MacGill, "A Monte Carlo based decision-support tool for assessing generation portfolios in future carbon constrained electricity industries," *Energy Policy*, vol. 41, pp. 374-392, 2012.

[10] P. Vithayasrichareon and I. F. MacGill, "Assessing the value of wind generation in future carbon constrained electricity industries," *Energy Policy*, vol. 53, pp. 400-412, 2013.

[11] S. A. Lefton, P. M. Besuner, G. P. Grimsrud, and T. A. Kuntz, "Experience in Cost Analysis of Cycling Power Plants in North America and Europe," APTECH Engngineering Services Inc., 2001.

[12] ACIL Tasman, "Fuel resource, new entry and generation costs in the NEM," ACIL Tasman Melbourne, 2009.

[13] AEMO, "2011 National Transmission Network Development Plan," Australian Energy Market Operator, Melbourne, 2011.

[14] S. A. Lefton, P. M. Besuner, and D. D. Agan, "The Real Cost Implications of On/Off Cycling Combined Cycle Power Plants," APTECH Engineering Services, Inc., 2006.

[15] G. P. Grimsrud and S. A. Lefton, "Economics of Cycling 101: What Do You Need to Know About Cucling Costs and Why?," APTECH Engineering Services Inc., 1995.

[16] Australia Institute of Energy. *Energy Value and Greenhouse Emission Factor of Selected Fuels*. Available: http://www.aie.org.au

[17] WEC, "2010 Survey of Energy Resources," World Energy Council, London, 2010.

[18] D. Robb, "CCGT: Breaking the 60 per cent efficiency barrier," *Power engineering international*, vol. 18, 3, pp. 28-32, 2010.

[19] SKM, "Garnaut Climate Change Review Update: Advice on Change in Merit Order of Brown Coal Fired Stations," Sinclair Knight Merz, 2011