Flexible Storage Operation in a Market Environment

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***Abstract*—Future power systems with high penetrations of variable renewables will require increased levels of flexibility from generation and demand-side sources in order to maintain secure and stable operations. One potential source of increased flexibility is large-scale energy storage, which can provide a variety of ancillary services across multiple timescales. In order for adequate investment to take place, it is essential that the correct market signals are present which encourage suitable levels of flexibility, either from storage or alternative sources. This paper explores the changes required in operational practices for storage plant at different levels of installed wind capacity, and the challenges that private storage plant operators will face in generating appropriate bids in a market environment at high penetrations of variable renewables. The impacts on system generating costs are explored under different operating assumptions.**

I. Introduction

Grid-scale energy storage has been commonly used in power systems for decades, largely in the form of pumped hydro storage (PHS). Historically, energy storage has been primarily used for energy arbitrage, which was of significant value to systems where large price spreads existed between baseload and peaking plant. It has also been widely used by systems with large capacities of inflexible baseload plant, such as nuclear, filling the nighttime valley, allowing the units to remain online, while also providing valuable peaking capacity. With the decline of nuclear power plant installations, and reduced price spreads evident on many systems (a single fuel, natural gas, is often marginal in many systems, as opposed to, historically, coal and more expensive oil) the business case for energy storage has diminished, with a large decline in new grid-scale energy storage installations in recent decades.

The large-scale integration of variable renewable generation is having an impact on power system operations globally, with wind generation capacity reaching 318.5 GW by the end of 2013 [1], creating new challenges for many power systems. Renewed interest in grid-scale energy storage has been sparked by the growth of variable renewables, which can increase price volatility and network congestion, improving the business case for energy arbitrage. Energy storage can also reduce wind curtailment and provide many valuable ancillary services, the requirements for which are increasing. However, it is widely acknowledged that arbitrage alone is unlikely to justify the high capital costs and efficiency losses of energy storage. As such, the aggregation of multiple benefits are essential.

The valuation of energy storage in an evolving power system is an active area of research, with advancements in valuation methodologies still required in order to aggregate multiple value streams. Studies which estimate the value of energy storage can be broken into two main categories, either using engineering models or system models [2]. While engineering models typically assess the techno-economic performance of a specific storage technology using profit maximisation strategies (usually using a price taker approach), system models search for least cost solutions from a system point of view which would be representative of system operation under a virtually integrated monopoly. In theory , in a perfectly competitive market, operating decisions under profit maximisation and system cost minimisation should coincide and lead to the same result. However, a prerequisite of a perfectly competitive market is good information [3]. At high penetrations of variable renewables, price uncertainty increases, which creates particular challenges for generating efficient bidding strategies for a storage plant operator, who must purchase energy from the grid, as well as offering its generation capacity. While conventional generators have, if not static, certainly predictable marginal costs based on fuel and operation & maintenance costs, the marginal cost for a storage plant varies, depending on pumping costs and also, due to their energy limited nature, the opportunity cost, related to the foregone opportunity to use the stored energy at a later point in time. This is complicated further when reserves are provided along with energy arbitrage, with the cost of providing reserve dominated by the opportunity costs of withholding capacity from the energy market.

Many strategies have been developed in order to maximise the profits of a storage plant, but these strategies largely focus on systems with low penetrations of variable renewables, or concentrate on arbitrage profits alone. Typically a price taker approach is adopted, where it is assumed that prices are predictable and the storage plant operation does not impact on the price. The focus is usually on profit maximisation for the plant owner rather than the potential impact on the wider

This work was conducted in the Electricity Research Centre, University College Dublin, Ireland, which is supported by the Commission for Energy Regulation, Bord Gáis Energy, Bord na Móna Energy, Cylon Controls, EirGrid, Electric Ireland, Energia, EPRI, ESB International, ESB Networks, Gaelectric, Intel, SSE Renewables, and UTRC.

This publication has emanated from research conducted with the financial support of Science Foundation Ireland under Grant Number SFI/09/SRC/E1780.

system. At very high penetrations of variable renewables, developing effective strategies for storage plant operation will be crucial, both in terms of profit generation for the plant owner and in terms of system operating cost minimisation. With increased levels of price variability and uncertainty, storage plant operations are likely to become less efficient. Access to information will be crucial in allowing plant to be operated for maximum benefit. Privately owned storage plant would have inferior information (e.g. wind and load forecasts, status of generation fleet) compared to system operators [4]. However, in many regions, system operators are prohibited from owning and operating generating assets (including energy storage) to avoid potential conflicts of interest [5].

It has been proposed that system operators should be allowed to operate storage assets as part of an optimisation process [6]. An optimisation process with an increased horizon not only reduces operating costs, but also maximises profits for storage plant owners. In the U.S., PJM alone optimises pumped hydro storage in the day-ahead market. However, despite the potential benefits, no system operators fully optimise pumped hydro storage operations in the real-time market [7].

This paper explores the impact on system operations when a storage plant is dispatched in a system with increasing shares of wind generation capacity. As the operation of the storage plant is constrained, the impact on system operating costs is examined. Section II describes the methodology used to perform the assessment, along with details of the test system and wind profiles. Section III outlines the simulation results at the different levels of installed wind generation for the 3 different storage plant. Section IV discusses the results and outlines planned future work, while Section V concludes.

II. Methodology

Operating costs are estimated for an isolated test system with a 7 GW peak demand and with four levels of installed wind capacity. Energy storage is then added to the system and the resulting in cost savings are estimated. In this study, three different storage plant are added to the system (Table I). The storage plant consists of a 200 MW plant both in charging and discharging mode, with an energy capacity of 0.8 GWh. Previous analysis on similarly sized systems [8] indicates that additional energy capacities of this order are sufficient to capture the majority of the cost savings and curtailment reductions. Plant A & B are based on a variable speed pumped hydro plant. However, plant B is dispatched for energy only while plant A can provide both arbitrage and reserve. Plant C is based on a fixed speed pumped hydro plant. While plant C has a fixed charging rate, plant A & B have variable charging rates. For plant A & C the full charging rate can be offered as reserve, while when generating they can provide all available headroom above the operating point as tertiary operating reserve (TOR).

System operating costs are obtained by solving the unit commitment and economic dispatch (UCED) problem using PLEXOS for Power Systems® [9], a commercially available power system modelling tool. Total generation costs are calculated using mixed integer programming (MIP) and the

TABLE I
Storage plant characteristics, 200 MW, 0.8 GWh

Plant	η (%)	*Min. Gen. (MW)*	*Min. Charge (MW)*	*TOR (MW)*
A	80	50	120	150
B	80	50	120	0
C	80	100	200	100

Xpress MP solver, with energy and reserve co-optimised. All storage operating decisions are determined in order to minimise total operating costs. The on/off decisions for both charging and discharging are binary and are solved as part of the system unit commitment problem using MIP. Operating costs are estimated for a winter period with UCED at a 15 minute resolution. The commitment decisions for those plant with longer start up times (greater than 15 minutes) are made based on hourly data, which then feed into the 15 minute simulations where commitment decisions are made for the peaking plant, along with an ED of all units. As the sub-hourly modelling captures most of the balancing requirements, activation of the remaining reserve categories is driven by contingency events and should be infrequent.

The objective function recognises fuel, carbon and start-up costs. Start-up and shut-down profiles are included for all generators to ensure that realistic profiles are achieved during the transition phases of operation, which is particularly important when considering the energy balance at sub-hourly time-scales. Other generator constraints include maximum and minimum generation levels, minimum up and down times, ramp rates and reserve response levels. Thermal plant are modelled with incremental heat rates, ensuring that plant inefficiencies at partial output are captured.

The optimisation horizon in PLEXOS is set to 24 hours with a further 24 hour look ahead, which ensures that unit starts are scheduled appropriately for plant with high start-up costs. Such an approach also creates realistic dispatches for energy storage, as it ensures that energy remains in storage at the end of each day, where appropriate, depending on future system needs. Without the additional lookahead, the future value of the stored energy would not be considered and the energy storage contents would be drained at the end of each optimisation period.

A single category of operating reserve is modelled with its requirement based on 100% of the largest in-feed [10]. TOR must be delivered within 90 seconds and maintained until 300 seconds, with low overall energy requirements due to the short duration. An additional requirement accounts for load and wind power forecast errors, over the reserve activation period, in addition to forced outages [11] which increases with the installed wind generation capacity.

In order to maintain system stability and security, the instantaneous penetration from non-synchronous sources, i.e. wind power plant, is limited. A 75% system non-synchronous penetration limit is assumed which is in line with the 2020 target in Ireland.

1) Test System: The plant mix consists of 7412 MW of dispatchable plant, largely made up of gas plant, with

TABLE II
TEST SYSTEM PLANT PORTFOLIO

Plant type	*No. units*	*Capacity (MW)*
Peat	2	228
Coal	7	1901
Natural gas (base and midmerit)	14	4074
Natural gas (peaking)	4	388
Distillate (peaking)	11	606
Hydro (run of river)	15	216
Wind	$\sim$	0 - 7500
New storage	1	200

primarily combined cycle gas turbines (CCGT) providing midmerit and baseload, and open cycle gas turbines (OCGT) providing the peaking capacity - see Table II. There are also a number of baseload coal and peat plant - sufficient capacity to set the price at low demand levels, along with a number of peaking distillate plant at the top of the merit order. 216 MW of run of river hydro plant are also present on the base system. Three different levels of installed wind capacity are examined: 0 MW, 2500 MW, 5000 MW and 7500 MW which represent 0%, 15.7%, 30.3% and 40.6% of the annual energy demand respectively. The system peak demand is 7 GW with a total annual electricity requirement of 38 TWh.

The base fuel prices are taken from the central scenario in [12] for the year 2025. A carbon price of 10 euro per tonne is assumed.

The demand profiles are scaled up from 15 minute realised profiles for Ireland from 2009. Metered 15-minute Irish wind power plant generation data from 2009 is used to generate the wind profiles, which are scaled up on a regional basis, recognising regional growth patterns in wind farm installations. A percentage of the data has also been time-shifted to recognise further regional diversity.

2) Storage Operational Constraints: A number of operational constraints are added to the operation of the 3 modelled storage plant and the impact on the system operating costs are analysed. Each constraint is additive. In the base scenario simulations, which the constrained simulations are compared to, there are no constraints placed on the storage plant operation. It is free to cycle in order to minimise operational costs, with reservoir levels at the end of the day dependant on future system needs by using the look-ahead described previously.

An end of day target is imposed on the reservoir of the storage unit. Storage plant which are sized to provide daily load levelling in systems with low levels of variable renewable generation are typically operated in this way. Indeed, in the absence of a significant look ahead period end of day targets are typically required to obtain efficient dispatch strategies, although previous work has highlighted the importance of variable end of day targets [13], or indeed optimisation strategies over a longer duration [14]. The impact of a fixed end of day target is explored as the installed wind generation capacity increases.

At high penetrations of variable renewable generation, the net load variability increases significantly, which can place a significant cycling burden on conventional plant, with increased start / shutdown and ramping requirements in order to maintain the supply / demand balance. Energy storage has the potential to play a significant role in providing valuable flexibility at sub-hourly timescales, and it is important that it is incentivised to do so with compensation based on sub-hourly settlements [7]. A further constraint is placed on the storage plant whereby the pumping load and generation levels are fixed for the sub-hourly dispatches, based on the hourly results. Again, the impact on system operating costs is explored with increasing levels of installed wind generation capacity.

Finally, for each storage plant type, and for each modelled wind generation capacity, a fixed daily dispatch is generated depending on the day of the week. Again the impact of this strategy is examined for the different plant types at the different wind levels. While in reality dispatch strategies would be much more sophisticated, accounting for wind and more accurate load forecast levels, the increased price uncertainty at high levels of wind generatio capacity will undoubtedly lead to less efficient scheduling which will impact on the plant value. While storage plant may be able to revise their dispatch strategies as more up to date information becomes available, due to their energy limited nature, full advantage of price swings can only be taken when sufficient capacity is available. Reservoir levels must also be maintained in order to honour future commitments. Future work will examine the impact of this uncertainty in more detail.

III. RESULTS

Each of the 3 modelled storage plant from Table I have quite different average dispatch profiles (Fig. 1 - 3) which is worth noting before the operational constraints are applied. Plant A is extremely flexible and has quite a flat dispatch profile as it is an excellent provider of reserve. It is rarely dispatched at maximum capacity - rather it spends longer durations throughout the day generating close to its minimum generation level of 50 MW, while simultaneously providing large quantities of operating reserve. Plant output increases towards the evening peak, but typically maximum output is not reached. When the same plant is dispatched for arbitrage only (plant B), the generation capacity is saved to meet the largest peaks in demand, both at lunchtime, and particularly to meet the evening peak when it is typically dispatched close to its maximum output. Plant C can provide reserve, but is less flexible than plant A, so it is rarely dispatched at maximum output, but rather is held close to minimum generation levels (100 MW) so that its reserve capacity can be utilised. As wind generation is added to the system, all 3 plant types see a flattening of the profile, as increasingly both pumping and generation levels are required at other times of the day in order to meet the needs of the varying net load.

At high levels of wind generation the net load (and hence system prices) become less predictable - Fig.4. This results in a less predictable dispatch profile for the modelled plant. While Fig.s 1 - 3 show the flattening of the average dispatch profile as wind generation increase, Fig. 5 and Fig. 6 highlight the increased variability of the dispatch profiles.

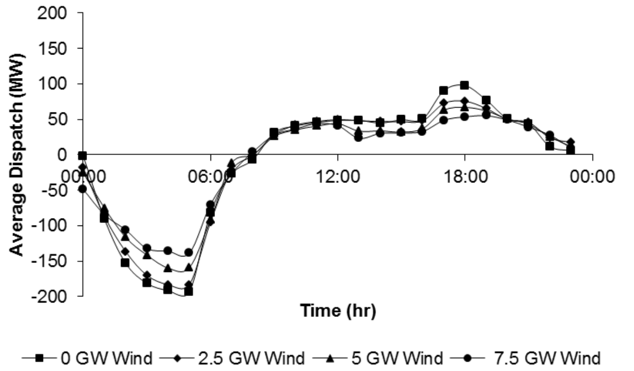

Fig. 1. Average daily dispatch (generation & pumping (-ve)) of plant A (Variable speed PHS with reserve provision)

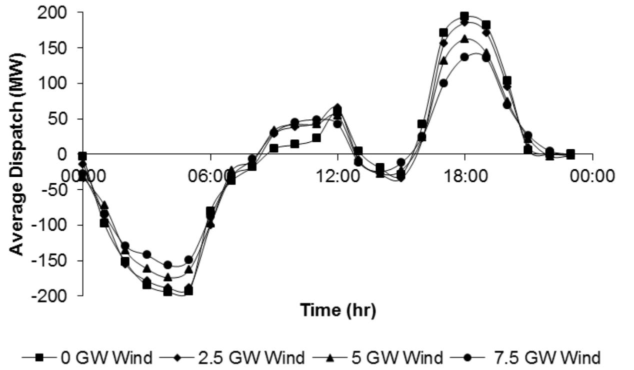

Fig. 2. Average daily dispatch (generation & pumping (-ve)) of plant B (Variable speed PHS - no reserve provision)

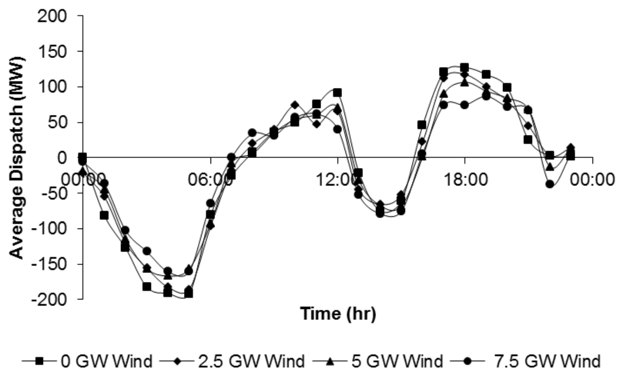

Fig. 3. Average daily dispatch (generation & pumping (-ve)) of plant C (Fixed speed PHS with reserve provision)

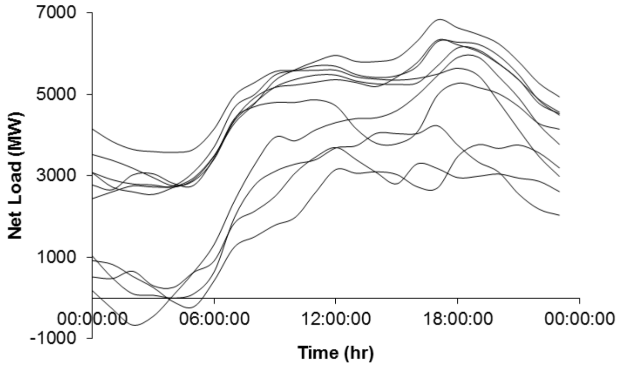

Fig. 4. Net load on 10 separate week days (7.5 GW wind generation)

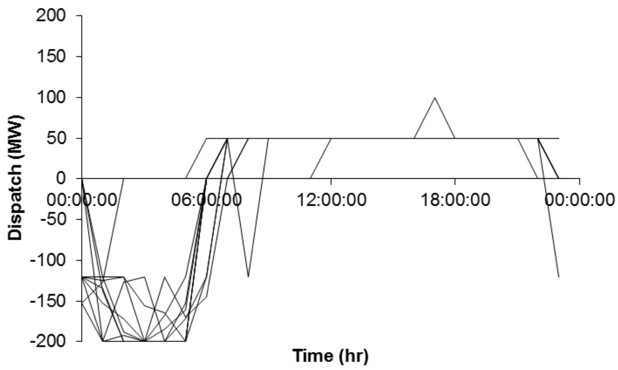

Fig. 5. Plant A dispatch on 10 separate week days (7.5 GW wind generation)

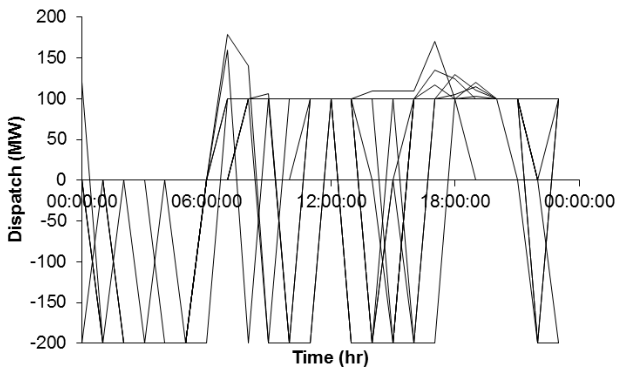

Fig. 6. Plant C dispatch on 10 separate week days (7.5 GW wind generation)

10 dispatches are shown for 10 different weekdays, corresponding to the net loads shown in Fig. 4. It is interesting to note that the variability in the dispatches of plant A is much smaller than that of plant C. It is this variability which makes operating decisions at high levels of wind generation challenging, both in terms of reduction operating costs and in terms of maximising profits for the plant owner.

The value of the plant to the system also changes as the installed wind generation capacity increases - Fig. 7. While plant B (arbitrage only) captures 73% of the cost savings of plant A with no wind generation, this falls to less than 60% for 7.5 GW of wind generation. Cost savings for plant A increase by 54% from the lowest to the highest wind scenario, with the less flexible plant C resulting in cost saving increases of 49%. Plant B sees a more modest increase in savings of 26%.

As each of the plant are constrained in their operation, there is a resulting reduction in realised cost savings. The reductions in cost savings are shown for the 3 modelled plant in Fig.s 8 - 10. Constraining the plant to a fixed end of day reservoir level has minimal impact at low wind levels, as the ideal plant operation has a strong diurnal pattern. However, this constraint becomes more significant as the wind level rises, and optimisation over longer horizons becomes more beneficial. The reductions in cost savings are

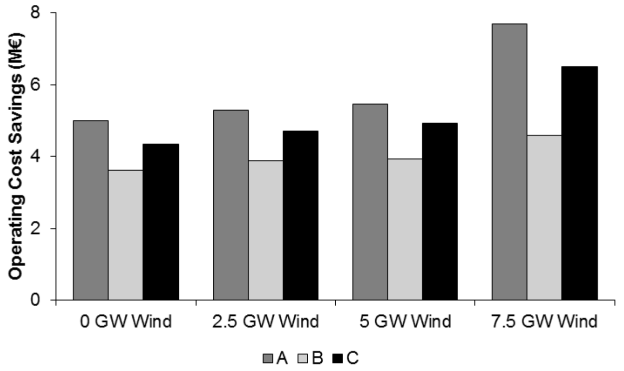

Fig. 7. Operating cost savings at 4 different wind levels

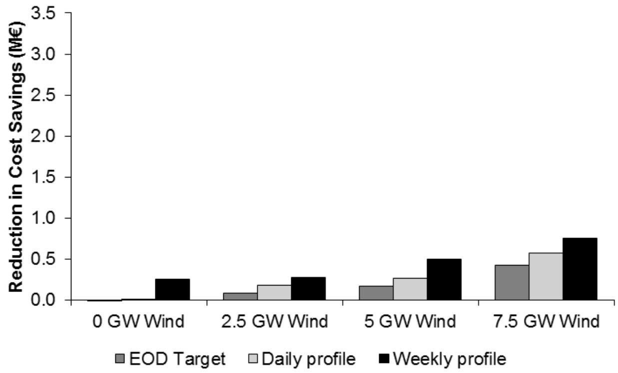

Fig. 8. Reduction in cost savings - Plant A

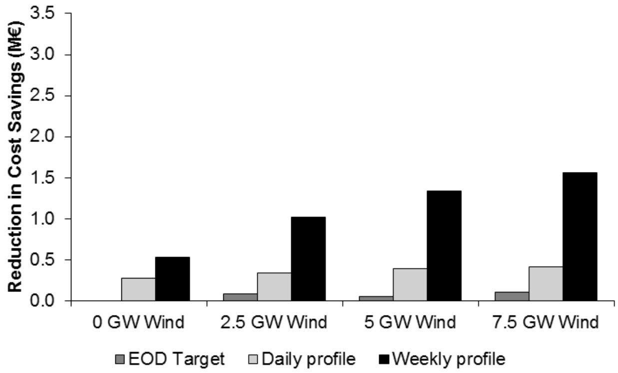

Fig. 9. Reduction in cost savings - Plant B

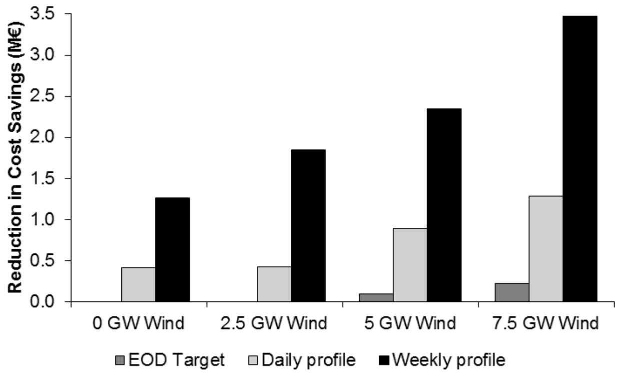

Fig. 10. Reduction in cost savings - Plant C

as high as 420,000 euro over the test period which occurs for plant A at 7.5 GW of wind - approximately 5% of the potential cost savings. These results highlight the importance of optimisation over longer periods and the potential cost of constraining a plants operation in this way.

By fixing the plant dispatch at an hourly resolution (daily profile), the potential for sub-hourly balancing is limited. Again, the importance of this constraint increases with increasing wind generation capacities as the sub-hourly net load variability also increases. For plant A at 7.5 GW of wind generation this amounts to a reduction of 577,000 euro or 7.5%. Interestingly, the impact of this constraint is proportionally much higher for plant B & C with reductions in cost savings of 9% and 19% respectively. The very large reserve capacity of plant A is typically exploited to the full when dispatched, even at a 15 minute resolution, minimising the impact of the daily profile constraint. In other words, the large reserve provision is of significant value in itself, even when generation and pumping levels are fixed at an hourly resolution. For the less flexible plant C, with both lower reserve levels and higher minimum pumping and generating levels, higher levels of plant cycling are required to provide maximum value to the system. At 7.5 GW of wind the plant is started an average of 3 times per day, compared to twice per day for plant A, and sees a 10% increase in required starts when moving from hourly to sub-hourly dispatches. Plant C is more likely to be dispatched further from its optimum point or even in the wrong state (pumping versus generating) which results in significant reductions in cost savings. These results highlight the importance of incentivising and rewarding sub-hourly plant flexibility, particularly for the less flexible plant.

The final constraint sees plant operations locked in to a weekly profile. This actually works reasonably well at 0 wind generation, with 95% of the cost savings still achieved by plant A. Even at 7.5 GW wind generation, plant A still manages to capture 90% of the cost savings with this very basic strategy. However, once again, the impact of this constraint is proportionally much higher on plant B & C, with reductions in cost saving of 34% and 53% respectively. Both plant generate for shorter durations, closer to their maximum output and are more likely to miss price spikes when their capacity is of most value. While large reductions in cost savings are not surprising, using such a crude dispatch strategy, it is of interest that the more flexible plant A is still able to realise the majority of the cost saving.

IV. Discussion & Future Work

Future power systems with high penetrations of variable renewables face significant challenges in maintaining system security and reliability. Energy storage is an excellent source of system flexibility which can rise to many of the future challenges at multiple timescales. Privately owned storage plant are dispatched in order to maximise profits. It is essential that market mechanisms are in place which allow the full value of the plant's flexibility to be accessed. Constraining the operations of a storage plant has a significant impact on its value to the system, particularly at high wind penetrations.

While the fixed weekly profile is unrealistically restrictive, high penetrations of variable renewables will lead to increases in price variability and uncertainty. Lack of information for plant operators will undoubtedly lead to less efficient plant operations. Future work will focus on capturing the cost of this uncertainty, both in terms of operating costs and also plant profitability.

The operating reserve modelled in this work is essentially contingency reserve and assumed to be dispatched infrequently, and for relatively short durations. It is assumed that the majority of the required load balancing is captured in the 15 minute simulations. Hence the impact on storage plant operations is not expected to be onerous. However, storage can also play a valuable role in hedging against wind uncertainty. Due to its energy limited nature, providing large volumes of reserve will have a large impact on plant operations and its ability to meet future obligations. While a system operator may be best positioned to make these decisions, regulations currently prohibit them from doing so. This will also be addressed in future work.

V. Conclusion

Storage plant flexibility is of significant value to future systems with high penetrations of variable renewables. It is essential that market mechanisms are in place which allow the full potential of the plant's flexibility to be accessed. Inefficient plant operation has a large impact on potential cost savings. Lack of good information and increased price uncertainty and variability are likely to lead to imperfect plant dispatch decisions, which becomes very costly at high wind penetrations, particularly for less flexible plant.

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