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Impact of Pumped Storage on Power Systems with Increasing Wind Penetration

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Abstract—In this paper, the unit commitment and dispatch of a power system with and without a pumped storage unit is examined for increasing levels of installed wind power, from 17% of total energy to 80% of total energy generated by wind (3 GW to 15 GW of installed wind on the Irish system in 2020). At high levels of installed wind, it is shown that storage reduces curtailment and increases the use of the base loaded plant on the system. This reduces system costs. However, when the additional capital costs of storage are taken into account, it is shown that storage is not viable from a system perspective until extremely large levels of wind power are seen on the system. At these levels of installed wind, while the system can operate without storage, it is less costly to do so with storage. The capacity credit of the storage unit is also examined, using a simplified approach, and shown to decrease as larger amounts of intermittent wind power are added to the system.

Index Terms—Power System modelling, Wind Energy, Large Scale Energy Storage

I. INTRODUCTION

Over the past decade, due to concerns about rising fuel prices, energy security and climate change, there has been a large increase in the amount of renewable energy installed worldwide [1]. It is expected that in the next few decades, the amount installed will increase significantly. Many of these sources - wind, solar, tidal and hydro, are uncontrollable and variable in nature [2] and some, wind in particular, are relatively unpredictable [3]. This could lead to situations where a large amount of wind power could be available at times when it is not needed, or it might not be available when needed. It also dramatically changes the operation of the conventional units in the system, with the possibility of units designed to be base-loaded cycling from their maximum to minimum values frequently, as well as shutting down and starting up more often than they were designed for [4].

The increase in renewable energy has led many to believe that large-scale electricity storage could solve its associated problems [5]. These units would store energy when it is cheapest, i.e. when the wind is blowing during the night, and use this stored energy to generate during the day. This also

would have the effect of smoothing the load curve. With large amounts of variable generation, the load curve moves from a well known curve, to a net load curve which is highly irregular. This will make it harder to operate the system. Much of the work in the literature on storage has examined hydro-storage with high levels of wind power. These generally examine the effect of using storage with the wind power to provide a more predictable power source, i.e. a dedicated storage for wind power, rather than a storage which is used as part of a power system [6], [7], [8].

Other work has concentrated on the impact of storage on the system in general. Most of this type of work has focused on the likelihood of endogenous investment in storage compared to other types of plant, normally Combined Cycle Gas Turbines (CCGTs). Sullivan et al [9] examined the US system and found that storage can lead to more installed wind power, once there is enough wind power on the grid to make it sufficiently valuable. Swider [10] has examined the addition of Compressed Air Energy Storage (CAES) to the system using an endogenous investment model. This showed that, at certain levels of wind power and certain capital costs, CAES can be economic in Germany for large-scale wind power deployment, taking into account the intermittency of wind. This work differs from [10] and [9] in that it examines one year of wind on the system in a future date with and without storage. While this means that it does not use an investment model to examine when storage would be best built, the operation is examined using a full mixed integer unit commitment algorithm over a year, to give more accurate system operation on an hour-to-hour basis. This is similar to the approach taken in [11]. Here, it was found that, though storage became more viable for the system with increasing levels of wind power, it never proved to be the best option for the system. This work examines higher levels of wind penetration for a system with relatively little interconnection, to find a point at which storage becomes viable. It uses a mixed integer model to obtain more accurate results for the unit commitment and dispatch of the Irish system. Finally, this paper discusses the concept of the capacity credit [12] of storage, and why it is different from the capacity credit of conventional plant, especially with large levels of wind in the system.

While storage at lower levels of wind power may be seen to be uneconomical purely from a fuel cost basis [11], [13], it seems clear that, at some point, if a large enough amount of wind is installed, the amount of wind curtailed on the system means that it becomes sensible to have storage to reduce fuel costs, even when accounting for the round-trip efficiency

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of storage. However, as storage capital costs are generally expected to be greater (needing both a generator / pump and space to store energy as water or gas), the savings made would need to be enough to ensure the system was less expensive to build as well as operate. This paper examines the operation of a system with and without a storage unit for various levels of wind power and examines the cost savings associated as the wind installed on the system increases. Section II describes the methodology of the study; the scheduling model used and the way storage is modelled. Section III describes the test system, and the changes made to this to examine storage at various levels of installed wind power. Section IV examines the results obtained, in terms of both operation of storage and of the system, as well as costs. From these results, it aims to find the point at which it makes economic sense for storage to be installed on the system. In Section V, the idea of the capacity credit of storage, and how this will change as more variable, unpredictable power is put on the system is examined. This is an initial analysis, which makes certain assumptions about the size and operation of the storage, and the predictability of the wind power on the system. More sensitivities will need to be examined using the same methodology to gain a fuller understanding.

II. SCHEDULING MODEL

The model used to carry out this analysis is based on the scheduling model used in the Wilmar planning tool [14], [15]. This was developed to examine the integration of wind in the Nordic market, and further developed to examine the Irish system in 2020 as part of the All Island Grid Study [16], which examined the effect of increasing renewable penetration for various plant mixes on the Irish system in 2020. This is generally used as a stochastic optimization model, which aims to minimize costs over multiple possible scenarios of wind and load, to ensure a minimum expected cost. These scenarios of wind and load are obtained from the Scenario Tree Tool, another part of the Wilmar tool. In this analysis, deterministic values of wind and load are used with a deterministic version of the Wilmar scheduling model, where the wind forecasts used are assumed perfect. This means that the uncertainty of wind is not accounted for, however the variability is still seen. This was done as the stochastic case takes much longer to solve (days instead of hours for scheduling of one year), and an initial analysis was examined here. The results seen here would still be expected to be close to what would be seen when uncertainty is included, as storage is not affected as much as other units when the system is stochastically operated instead of deterministically operated, as seen in [17].

The unit commitment model is a mixed integer model which takes into account constraints on units, such as minimum and maximum generation, ramp up and ramp down rates, start up times and costs, and emissions. It is implemented in the GAMS modelling language, and solved using the CPLEX solver, with a duality gap of 0.01%. Each case took approximately 4 hours to solve on a computer with a 2.0GHz dual core processor. Rolling planning is used, where the system is replanned a number of times during the day (every three hours is used

here), taking into account the state of the units at the start of each planning loop. Reserve is carried to cover the loss of the largest unit. Spinning reserve is provided by online units, and is used to cover outages. Replacement reserve, which would act on a 5 minute time scale, is used to replace this spinning reserve. This can be carried by units off line if they have quick enough start-up times.

Storage is represented as a separate unit type in the model. The unit can either pump or generate, but not do both at the same time - this is done to represent a pumped storage unit with one turbine, used as either pump or generator. An inefficiency is assumed when pumping, e.g. if this is 75%, for every 100MWh of electricity pumped, only 75MWh is stored. The efficiency of the generator is assumed to be 100% - if 100MWh is generated, the amount of energy in the store reduces by 100MWh. Therefore, the total round trip efficiency would be 75%. This is consistent with approximate values expected from pumped storage. Further details on the Wilmar tool can be found in [17], [18] and [15]. The model used here is slightly updated from the model used in [16], with the main addition being a constraint to ensure a minimum number of large units are kept online to ensure enough inertia in the system. If this is not the case, the system will encounter difficulties maintaining frequency [19].

III. TEST SYSTEM

The test system examined here is based on one of the portfolios produced in the All Island Grid Study [20]. The base system, that is the one used for all cases, is described in section III-A. The changes made to this system as wind power installed is increased and storage added is described in III-B.

A. Base System

The base case for this system is based on portfolio five from the All Island Grid Study, with 3GW of wind installed. The base system consisted of the units shown in Table I. It should be noted that the existing storage unit in Ireland, Turlough Hill, was removed so the systems could be compared with and without storage. 1000MW of interconnection to Great Britain (GB) is assumed, the operation of which is planned day ahead, and cannot be changed during the day. The GB system consists of 36 units, which represent the different fuel types. This is a refinement on the method used in [16], where there was eight units, one for each fuel type. By splitting each fuel type into multiple units, a better representation of the GB system can be obtained. The net load that is seen on the Irish system for this study is 53.9TWh. The peak demand is approximately 9.6GW, with 3.5GW minimum demand.

B. Changes made for wind and storage

For this initial analysis, a pumped storage plant was added. This was a plant with a maximum generating and pumping capacity of 500MW, minimum generating and pumping capacity of 50MW, and round trip efficiency of 75%. The storage is assumed to be large enough to store enough energy to generate at maximum capacity for 10 hours, i.e. 5000MWh.

TABLE I
TYPES OF UNIT IN PLANT PORTFOLIO USED IN STUDY

Type of unit	No	Capacity (MW)	Fuel (€/GJ)
Combined Cycle Gas	15	4533	5.91
Open Cycle Gas	13	1356	6.23
Coal	5	1257	1.75
Gasoil	9	383	10.0
Peat	3	345	3.71
Base RE	1	306	2.78
Hydro	1	216	
Tidal	1	200	

To ensure that this additional capacity on the system does not make the system more reliable, and therefore make a comparison of cases with and without storage unfair, conventional capacity had to be taken off the system. In this study, it was initially assumed that 500MW capacity of storage, with 5000MWh energy storage, could replace 500MW conventional plant. One 400MW Combined Cycle Gas Turbine (CCGT) and one 103MW Open Cycle Gas Turbine (OCGT) were replaced by storage in every case. It should be noted here that the storage is not actually replacing a previously built plant, but instead replacing it in the plans for a future plant mix.

As wind was added to the system, conventional plant was removed. The amount removed depended on the capacity credit of wind. As the amount of wind installed on the system increases, it would be expected that the capacity credit of wind will decrease, as shown in [21]. Using the capacity credit of wind from this work, wind was added and conventional units removed. If it was found, after an initial simulation, that the amount of hours demand was not met is reasonable, i.e. less than approximately eight hours per year, then the amount of conventional capacity removed for wind was deemed adequate. Otherwise, less conventional capacity was removed, and the system re-simulated until a satisfactory reliability level was reached. Fig. 1 shows the capacity of conventional plant removed from the system versus the amount of wind installed.

Fig. 1. Amount of conventional capacity displaced as wind added to system

IV. RESULTS

The test system described in the previous section was used to examine the expected operation of a system with and without storage at various levels of installed wind power. Wind power was increased in steps of 3GW, from 3GW installed (17% of total energy demand) to 15GW installed (80% of total energy demand if no curtailment). Storage with a generating and pumping capacity of 500MW was added instead of a suitable amount of conventional plant, as described. This had a storage size enough for 10 hours of operation, i.e. 5000MWh.

A. System Operation

When the system was simulated, it was found that 500MW storage was not always adequate to replace 500MW conventional plant. At high levels of wind, there was an increase in amount of hours in which load and primary reserve could not be met - the model allows this to happen at a very high cost when there is not sufficient capacity to meet demand. Therefore, additional capacity had to be added to the storage in higher wind cases. This was found to be 20MW for both 12GW and 15GW of wind installed, meaning 520MW generating and pumping capacity needs to be added to replace 500MW of conventional capacity. This indicates that capacity credit of storage units begins to decrease as more wind is added to the system - it does not actually give the capacity credit of storage, as it does not show the available capacity at peak hours which would be needed for this. Capacity credit is discussed in more detail in Section V.

1) *Storage operation:* Fig. 2 shows the average pumping in each hour of the day, while Fig. 3 shows the average generation, as well as average load. These are shown for the lowest and highest amounts of wind power examined. The generating can be seen to be done at high load, with the pumping done at times of low load. It can be seen that the average pumping and generating profiles are more smoothed with higher wind, showing that they are less likely to follow load, as they are with lower wind. Examining the capacity factors, the capacity factor of the generator ranges from 16.5% to 20.5%, depending on wind installed, with an increase as more wind is installed. The average capacity factor in the pump is a few percent higher in each case.

2) *Wind Curtailment:* Figure 4 shows the curtailment of wind on the system for increasing amounts of installed wind with and without the storage. Here, wind will only be curtailed if there is too much of it being produced, bearing in mind that there is the option to export up to 1000MW every hour, but also that a minimum number of large units need to be online in every hour (here assumed to be 8 for the island of Ireland). As can be seen, very little wind is curtailed at 3GW and 6GW of wind installed. However, there is a sharp rise in curtailed wind at higher levels of installed wind. At 7GW of installed wind and above, a significant reduction in curtailment can be seen when storage is added. This analysis does not examine transmission issues, frequency and inertia issues, or voltage stability. If these were taken into account, the curtailment may change and storage may be more useful, but from an hour-to-hour scheduling point of view, there does

Fig. 2. Average pumping by hour of day of 500MW storage, for two levels of installed wind

Fig. 3. Average generation by hour of day of 500MW storage, for two levels of installed wind

not seem to be any major advantage of storage (as opposed to other flexible plant) until penetrations of greater than 40% (of energy from wind, i.e. approximately 7GW) are reached on the system examined. It should be noted that this is a relatively flexible system already, with a large amount of flexible plant [21], [20].

Figure 5 shows the change in the percentage of total energy provided by wind with and without storage. As the amount of wind installed increases above approximately 9GW, storage allows the wind installed to meet significantly more of the energy requirements. For example, to meet 60% of energy from wind, without any storage, 11,650MW of wind would need to be installed. By replacing conventional plant with 500MW of storage, only 11,250MW of wind needs to be installed.

3) *Operation of the remaining system:* The major change in the remainder of the system due to the addition of storage came in the operation of the interconnector. The net export from Ireland to GB is shown in Figure 6. Firstly, it can be seen, as expected, that Ireland goes from being a net importer to a net exporter as more wind is installed. By adding storage, the net export is reduced. The reduction in export due to

Fig. 4. Wind curtailment as a percentage of total energy produced from wind over different installed wind levels, with and without storage

Fig. 5. Energy provided by wind for increasing installed wind levels, with and without storage

storage is greater at lower levels of wind. Storage allows the system to take better advantage of the cheaper base loaded units and wind energy. Instead of exporting at times of high level, the system can continue importing the cheaper electricity from GB, and the energy can then be stored to displace more expensive mid merit and peaking units during the day. Ireland becomes a net exporter at approx 7GW of wind installed with no storage, whereas with storage, the system can take advantage of the cheaper GB base loaded units for longer to fill the store.

As regards the operation of the conventional units on the system, the capacity factors for units were examined. It could be seen that, at high wind levels, base loaded units were used more when storage was added (in the region of 0% - 3% change in capacity factor). This is because they could stay online at higher load levels during hours of low demand. Conversely, peaking units were used less (in the region of 0% - 1.5% change in capacity factor).

Another motivation for installing storage may be the possibility to reduce carbon dioxide emissions. It could be claimed that as storage allows more of the total demand to be met from wind at high penetrations, carbon emissions should reduce. Fig. 7 shows this not to be the case. It can be seen that, for all wind installed, carbon actually increases when storage is

Fig. 6. Net export from Ireland to GB for increasing installed wind levels, with and without storage

added. The carbon emissions in GB go up due to increased use of the interconnector to import to Ireland when storage is added. This causes an increase in the use of base loaded coal in GB - the emissions from this and the increase in base loaded coal in Ireland outweigh the savings from the fact that more energy is generated from wind. At 15GW, when the net exports from Ireland are almost the same with and without storage, the emissions become approximately equal whether or not storage is installed. This may indicate a reduction in emissions due to storage above 15GW. The emissions seen are obviously dependent on the system and the price of carbon - at a higher price or with cleaner base loaded units (nuclear is simulated in GB here, but is already at full load), the carbon might be reduced by adding storage. However, many power systems use coal for base loaded operation. It is also interesting to note that carbon actually reduces in Ireland as storage is added for all wind cases, but the increase in GB causes a net increase across both systems.

Fig. 7. Net change in carbon dioxide emissions (GB and Ireland) for increasing installed wind levels, with and without storage

B. Economic analysis

1) *System Costs:* The change in total system costs (fuel and carbon costs) is shown in Fig. 8. This is for the total system simulated, i.e. including Great Britain (GB), with carbon at €30/tonne. GB is included due to the fact that, as shown in Section IV-A.3, one of the main impacts of storage is a change in the operation of the interconnection from GB to Ireland. As this would cause a change in the operation of the GB system solely due to a change in the Irish system, the

changes in cost in GB need to be taken into account. From the graph, it can be seen that, at 3GW and 6GW, the system actually becomes more costly to operate with storage replacing conventional plant. This is due to the fact that storage has an inefficiency when pumping, and also the fact that storage will operate when there is a significant difference in marginal prices over the course of the day. This leads to a small increase in cost. This does not mean a storage unit would not make a profit based on marginal price, but it means the total system costs are increased. It is not until approximately 7GW that storage reduces the total system costs. This is the point when curtailment of wind starts to become significant on this system. Due to the fact that storage is now storing free energy, instead of curtailing it, the system costs are reduced.

Fig. 8. Change in total system costs when 500MW capacity storage with 5000MWh of energy storage is added - positive indicates system is less expensive to operate when storage added

The shape of Fig. 8 shows that there is an increase in the rate of change of the savings at or close to the point when wind curtailment becomes significant without storage, around 7GW. The rate of increase in the savings then slows down again as more wind is installed. This is most likely due to the fact that only 500MW of storage is added here, and much of the benefits of this are being seen in the range of 7GW to 10GW of wind installed - above this, larger storage would be needed. These results are for one type of storage (i.e. not CAES with its additional natural gas cost), and one size of storage - a larger capacity (in MWh) may change the point at which the costs change, as well as the rate of increase in savings as more wind is added. With more storage installed, it would be expected that the rate of increase in savings seen around 10GW here would not reduce until higher levels of installed wind.

2) *Examination of capital costs:* As stated earlier, the capital cost of storage is expected to be greater than conventional plant at a similar size. This is due to the fact that, as well as the equipment, a large reservoir is needed, and changes may need to be made to the equipment. The capacity credit of storage, discussed in the next section, may also be lower, especially at higher wind levels, meaning more storage must be built than the conventional capacity it replaces in the future

plant portfolio. In this section, the net present value is used to obtain results indicating at what level of wind a storage plant similar to the one modelled would be of economic benefit to the system. This does not take into account the other benefits that the system may receive.

The basic objective of this section is to find the additional capital cost due to storage that is acceptable at certain levels of wind power. This is shown in Fig. 9, which shows the net present value of the cost savings, taking into account various discount rates with a payback time of 20 years. It can be seen that, for example, at 9GW wind installed, a 500GW storage unit with a reservoir large enough for 10 hours would have to be priced at a maximum of €200 000/MW to €270 000/MW greater than 500MW of conventional capacity, depending on discount rate, to ensure it is less expensive for the system over 20 years. Obviously, when the running costs are more expensive (as they are up to 7GW wind installed), the storage would have to cost less than a conventional unit, which is unlikely. As an example, a pumped storage unit is currently close to double the cost of a CCGT [9], which costs somewhere in the region of € 700 000/MW [20] (an OCGT would be significantly less, in the region of €500 000/MW). Therefore, if the storage is assumed to be replacing units at this cost, it will not have a positive impact on this system if replacing CCGT generation, until penetration levels even higher than that examined here are seen - this is far higher than expected on the Irish system in 2020, where 7GW wind (40% of energy) is an ambitious target. Of course, this depends on the assumptions made about discount rate and lifetime etc, as well as cost of storage. A CAES unit would be expected to be less expensive. However, the extra cost due to the fuel used in CAES would mean the cost savings may be less. CAES will be modelled in future work and the same approach used.

Fig. 9. Additional capital expenditure justified over and above cost of conventional plant per MW of storage installed

While the above results indicate storage is not needed from a system economics point of view, that is not to say storage would not be profitable to build from the point of view of a developer. Here, the storage would need to make enough to cover its cost, regardless of its overall effect on system costs. This is not examined here, but may be covered in future work. It was shown in [13] that at lower levels of wind, storage would probably not compete economically, based on prices

on the Irish system expected in 2020.

C. Discussion and Further Work

The work here is an initial analysis of the impact of storage on the system at high levels of wind power. Further work will need to account for the uncertainty of wind by using stochastic optimization. This would be expected to reduce the amount of curtailment avoided as the future wind power production will not be known when scheduling the system. However, the need for flexible, but more expensive plant may also be reduced. Sensitivities on size and generating capacity of storage, carbon price, and modelling of CAES will also be performed to give a more thorough analysis. As storage size decreases, the curtailment, and therefore cost savings may decrease whereas a larger store could increase savings. CAES may improve the case for storage if its capital costs and operating efficiency are better. More work will also be done on the capital costs of different storage technologies, and how these affect the viability of storage for a power system.

V. CAPACITY CREDIT OF STORAGE - DISCUSSION AND INITIAL ANALYSIS

Methods for calculating the capacity credit of conventional units are well established [12], [22]. A common method to calculate the capacity credit is equivalent load carrying capability, or ELCC. For conventional units, the primary requirements for this are the rated capacity, forced outage rates and maintenance schedules. These are then measured against a perfectly reliable unit, or a benchmark unit. By modelling the system with and without the generator, the additional load that can be met by the system without changing reliability level can be calculated, giving the capacity credit of the unit. Much interest has recently been given to the capacity credit of wind, where the fact that wind is variable is taken into account [23], [24]. Therefore, a representation of the wind time series, matched with the load at the time they occur, is needed to calculate capacity credit, and calculate the additional peak load that can be met with wind.

There follows a description some of the main issues relating to capacity credit of storage, and also a short example of how the capacity credit of storage will change as wind increases. Firstly, it should be noted that storage can be treated, in relation to ability to meet peak, as a conventional unit with an energy limit. The storage unit itself, i.e. generator / pump would have the characteristics described above (forced outage rate etc). However, the energy limited nature of storage means the system will have to be simulated to obtain a time series of the energy in store, similar to the time series used for calculating wind power capacity credit. Storage may not be able to meet multiple consecutive hours at or near to peak demand, depending on the size of the store. When wind is low, if the store is big enough, then storage can be assumed to be able to contribute to system adequacy in much the same manner as a conventional unit. As storage will pump during hours of low demand, it will be expected to be full, or at least able to meet several hours of peak demand. However, at higher levels of wind, the variability and uncertainty of wind

means that there may not be enough energy in store at the time when it is needed, and therefore storage cannot add to system adequacy. The system therefore needs to be simulated to examine the level of energy in store at peak hours.

This study provides an initial approximation of a method to calculate the capacity credit of storage. In some studies on the capacity credit of wind, an approximation for ELCC is to calculate the ability to meet load at a certain amount of peak load hours [25]. While this is a simplistic approximation to make, it gives a good approximation for the capacity credit. As a first approach to the problem, it is proposed here to examine the energy in store in each of the 100 peak hours of the year simulated in the previous section. While it is realised that this is not a sophisticated method of determining capacity credit, it will give an indication of the effect of installed wind on storage. The amount of energy available to generate in each of the 100 peak hours is shown in Fig. 10 for the cases of 3GW and 15GW of wind installed. This shows that, as more wind is installed, the average energy in store is more likely to be below the maximum generating capacity of the unit at peak hours, due to the fact that the net load curve has become less predictable and regular. If there is less available than 500MWh, then the storage unit cannot generate at maximum capacity.

Fig. 10. Average energy in store for 100 peak hours for two different levels of wind installed

By taking an average of the energy in store over the 100 peak hours (setting an upper limit of 500MWh, equivalent to generating at maximum capacity for one hour), the ability of storage to meet demand at peak hours can be seen. This average will decrease as more wind is installed. It is suggested here that this could then be used to calculate ELCC, treating storage as a conventional unit, but with a lower capacity, depending on the average energy in store at peak hours. For example, if the average available generating capacity of 500MW of storage was 480MW, this would then be thought of as a 480MW conventional unit, and the usual ELCC methods would be applied based on forced outage rate and maintenance schedules to give the actual capacity credit. The equivalent approximate conventional capacity of storage with 10 hours storage capacity is shown in Fig. 11 for a storage unit which replaces 500MW of conventional capacity. This shows, as

expected, that storage can be treated much the same as a normal generator at levels of wind below 40% penetration, but will not contribute as much to system adequacy at high wind. It can also be seen that there is a step change at around 12GW wind. Here, the 520MW of storage that was added to replace 500MW conventional can only provide an average of 430MW at peak load hours.

Further work will use more robust methods to calculate ELCC of storage. This will involve using the time series of available energy in store over the year (or multiple years) to produce a more thorough analysis of ELCC. The approximation used here should only be used as an indication of the fact that ELCC of storage would decrease as more wind is carried on the system. The capacity credit of storage will also depend on the stochastic nature of wind, as well as the size of the store - these will all be examined in further work.

Fig. 11. Approximate conventional capacity equivalent to 500MW of storage for various wind levels installed, based on energy in store at 100 peak hours

VI. CONCLUSIONS

This paper examined the impact of large scale electricity storage at increasing levels of installed wind power. It was shown that storage reduces curtailment as wind power increases on the system, thereby reducing the operating costs. However, it was shown that this reduction in operating costs would not be enough to justify the additional cost of building pumped storage, when examining the system as a whole. Storage was shown, even at high wind levels, to be still operated based mainly on the load profile, however, the operation becomes more dependent on wind as installed wind increases. It was shown that storage displaces exports when the power system is weakly interconnected, as well as peaking and mid merit plant, while increasing the use of base loaded plant. This actually causes an increase in carbon dioxide emissions in the system examined. Finally, an initial analysis of the capacity credit of storage found that, at low levels, it contributes to system adequacy much the same as a conventional unit of similar size and forced outage characteristics. However, its contribution to meet hours with high load reduces as the level of wind installed increases, due to the variability in wind.

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