Evaluating which forms of flexibility most effectively reduce base-load cycling at large wind penetrations

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***Abstract*—Increasing penetration of wind power on power systems worldwide is resulting in the unconventional operation of base-load generating units. These units which were originally designed for operation at full output are more frequently required to balance the variability of the wind. This results in increased start-stop cycling and hours at low load which causes severe deterioration to the plants components. Interconnection, storage and demand side management increase the flexibility of a power system and can balance variations in the wind power output, thus reducing the onus on thermal plants. This study will attempt to quantify which of these forms of flexibility is most effective at reducing base-load cycling on a thermal test system with a large amount of wind.**

***Index Terms*—Wind Power, Base-load generators, Plant Cycling, Pumped Storage, Interconnection, Compressed Air Energy Storage, Demand Side Management, Power System Modelling,**

I. Introduction

As international energy policy drives greater penetrations of renewable generation, power systems worldwide are incorporating significant portions of wind power. In Europe, for example, 230 GW of installed wind is predicted for the year 2020 which would supply between 14% and 18% of the total electricity demand [1]. However this abundant resource is both variable and uncertain in nature introducing further complexity to the challenge of balancing generation and demand. Traditionally system demand has been largely predictable as demand profiles follow daily, weekly and seasonal patterns, allowing generation to be efficiently committed. However, in recent times, the net load (load minus wind) curve that conventional generation must follow has become increasingly variable as generation from wind increases [2]. This requires greater operational flexibility from thermal plant in order to maintain a stable system. Unexpected shortfalls in wind power output force conventional plant to ramp-up their output or come online at short notice in order to meet the demand, whilst the increased uncertainty on the system requires more spinning reserve to be available from online conventional units, resulting in increased part-load operation [3]. Periods of low demand coinciding with high wind power output can lead to conventional plant being shut down. This effect has been exacerbated of late due to a reduction in demand as a result of wide-spread economic recession [4]. In essence, the regular running regimes of conventional units are altered by the introduction of wind power and cycling operation (i.e. start-ups and shut-downs, part load operation and ramping) becomes more common [5].

Thermal plant can be broadly categorised as base-load, mid merit and peaking. Mid merit units follow the daily demand and shut down nightly whilst peaking units are used to meet the extreme peaks in demand. Base-load units, typically coal, combined cycle gas turbine (CCGT) or nuclear, are those units which traditionally run on a continuous basis to supply the base electricity demand and therefore have minimal operational flexibility. As such, cycling these units will cause extensive damage to the units' components, resulting in more frequent forced outages and a reduced plant lifetime. Varying output levels and repeated start-ups lead to thermal transients and fluctuating pressure levels, putting the plant's critical components under extreme stresses. Previous work by the authors identifies combined cycle gas turbines (CCGT's) as the base-load plant type most likely to experience increased cycling due to increasing levels of wind largely due to their high minimum stable output levels [6]. Cycling CCGTs can result in cracking of thick-walled components such as the boiler or superheater header, condensate build-up in the heat recovery steam generator (HRSG) pipe-work and waterside corrosion due to the presence of ionic species following interruptions to operation of the condenser, amongst a host of other problems [7]–[9]. Given the vast number of components affected, the costs associated with cycling base-load units are difficult to quantify and often the damage caused by such operation may not manifest itself for many years. Nonetheless some studies have estimated it can cost as much €500,000 for a start-stop cycle, depending on the type of unit, once all the wear-and-tear and plant deterioration is accounted for [10].

As wind levels continue to grow steadily, considerable interest surrounds the idea of incorporating sources of flexibility into power systems to aid the challenge of meeting demand with a large portion of intermittent generation and minimise the onus on conventional plant. Given the capital intensive nature of many of these forms of flexibility, particularly energy storage, they can often appear economically unfeasible.

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However, incorporating the added value provided to the system by reducing cycling of base-load units, could improve the merit of such options [11].

II. Flexibility Options for Power Systems

Power system flexibility is defined in [12] as the ability to respond rapidly to large fluctuations in supply or demand. A flexible power system therefore is inherently capable of supporting a larger penetration of variable renewables. Storage facilities, interconnection to neighbouring power systems and demand side management (DSM) are well cited sources of flexibility within a power system [12], [13]. Swider shows in [14] the increased flexibility and reserves required as a result of wind power generation favours investment in compressed air energy storage (CAES) schemes. Van der Linden in [15] notes the benefits of CAES include greater flexibility on the power system as well as allowing base-load plant to operate in their most efficient manner and avoid harmful cycling. Brown et al. find in [16] that pumped storage on isolated systems can allow a greater penetration of renewables and improve the dynamic security of the system, however Tuohy & O'Malley also show in [17] that although pumped storage can reduce wind curtailment, the increased use of base-load units can actually lead to increased emissions. Hamidi & Robinson find in [18] that responsive demand on a system with a high wind penetration makes greater use of the wind resource and reduces emissions, whilst Malik notes in [19] that the avoided cycling cost of thermal units is a major benefit of DSM. Denny & O'Malley find in [20] that the net benefits of wind can be increased significantly by increasing the level of interconnection on the power system. Work done by Goransson in [21] also shows that investment in transmission to a region sufficiently far away to make wind speeds uncorelated (supergrid) or to a region with excess flexible capacity can decrease the total system costs of a system with a high wind penetration. The flexibility of compressed air energy storage, pumped storage, demand side management and interconnection has been shown to benefit power systems with a high wind penetration. This paper examines how the nature of these various forms of flexibility alters the operation of base-load plant and investigates which is most beneficial to scheduling a system with a large supply of intermittent wind power to minimise cycling of these inflexible plants. This paper also examines which form of flexibility minimises wind curtailment and yields the greatest CO_2 reductions.

III. Methodology

The approach taken in this paper was to model how different sources of flexibility, when incorporated into an isolated thermal system with a high wind penetration, could reduce cycling of base-load plants. Various scenarios were developed in which equal capacities of interconnection, pumped storage, demand side management and compressed air energy storage were used. These were compared against a base case, in order to rank which flexibility option was most effective.

The modelling tool used was the Wilmar Planning tool which is described extensively in [22]. The Wilmar planning tool is a stochastic unit commitment and economic dispatch model that models the stochastic nature of wind and load through the generation of scenario trees. The model produces a year-long dispatch with hourly time resolution for each individual generating unit so that their specific operation can be examined. The scheduled demand for each hour must meet a tertiary spinning reserve (90 seconds to 5 minutes) target and minimum number of units online constraint. The model minimizes the cost function over all scenarios generated by the scenario tree, subject to the generating units' operational constraints, such as minimum down times (the minimum time a unit must remain offline following shutdown), synchronization times (time taken to come online), minimum operating times (minimum time a unit must spend online once synchronized) and ramp rates. The cost function contains fuel, carbon and start-up costs.

IV. Test System & Scenarios

The base case test system examined was primarily a thermal system with a large penetration of intermittent wind power. Wind alone comprises 40% of the installed capacity and delivers over 18 TWh of energy, supplying 34% of the total electricity demand. A large proportion of the thermal plant consists of base-load CCGT or coal plant as seen in Table I. As these units are the focus of the paper their characteristics are given in Table. II. The system peak demand is 9.6 GW and the minimum is 3.5 GW. The base case test system contains no forms of energy storage, responsive demand or interconnection so all variations in the net load are dealt with by the thermal units.

TABLE I
Installed Capacity by Generation Type for Base Case

Generation Type	MW	% of Total Capacity
Base-load Coal	1324	9
Base-load CCGTs	2901	19
Mid-Merit Gas	2165	14
Inflexible Mid-Merit (Peat)	343	2
Gasoil Peakers	383	3
OCGT Peakers	1243	8
Wind Power	6000	40
Other Renewables	776	5

Six scenarios were developed each incorporating 500 MW of a flexible resource into the base-case test system. These included 500 MW interconnection, traded day-ahead and intra-day, 500 MW pumped storage, modelled as 4 identical units and 1 single unit, 500 MW CAES and 500 MW DSM. These are summarised in Table III.

In scenarios 1 and 2, which included 500 MW interconnection, the neighbouring interconnected power system has base-load nuclear plants resulting in cheaper electricity prices compared to the test system over 50% of the time, thus making imports more prevalent. For scenario 3 which included 500 MW of pumped storage it was assumed that the maximum capacity of the energy store was 5000 MWh and the minimum

TABLE II
CHARACTERISTICS OF A TYPICAL CCGT AND COAL UNIT ON THE TEST SYSTEM

Characteristic	**CCGT**	**Coal**
Max Power (MW)	400	260
Min Power (MW)	217	103
Max Efficiency (%)	56	37
Hot Start-up Cost (€)	12,440	5,080
Full Load Cost (€/hour)	8,500	1,780
Min Load Heat Rate (GJ/hour)	1585	1140
Max Primary Reserve Contribution (% of Max Power)	9	13
Minimum Down Time (Hours)	2	5
Synchronization Time (Hours)	2	5

TABLE III
SCENARIOS EXAMINED

Scenario 1	500 MW Interconnection traded intra-day
Scenario 2	500 MW Interconnection traded day-ahead
Scenario 3	500 MW Pumped Storage 1 Unit
Scenario 4	500 MW Pumped Storage 4 Units
Scenario 5	500 MW DSM
Scenario 6	500 MW CAES

was 920 MWh. The unit had an efficiency of 78% and the maximum contribution to tertiary spinning reserve was 200 MW. It took 8.5 hours to fully fill the reservoir and running at it's minimum output the unit could generate for 102 hours. In scenario 4 the pumped storage unit was modelled as 4 identical 125 MW units which all filled and generated from the same reservoir and can cumulatively provided the same contribution to tertiary spinning reserve as the single unit in scenario 3. In scenario 5 which contained 500 MW DSM, the DSM was modelled as two 250 MW units, one a peak shifting unit and the other a peak clipping unit. The peak shifting unit corresponded to load which could be shifted in time during the day without reducing the energy demand. This was modelled as a storage unit with an efficiency of 100%. The peak clipping unit corresponded to peak load which could be reduced at times of high electricity prices. The clipped load does not increase demand at another time. The variable costs for the peak shifting and clipping units were €40/MWh and €100/MWh respectively. The DSM units do not contribute to spinning reserve. For scenario 6 which included 500 MW of CAES, the maximum capacity of the energy store was modelled as 2000 MWh and the compressor had a capacity of 330 MW. These values are based on characteristics given in [23], scaled accordingly for a 500 MW unit. The CAES unit had a maximum contribution to tertiary spinning reserve of 90 MW.

V. RESULTS

A. Impact of flexibility options on base-load units

Scenarios 1 to 6 were compared with the base-case test system to evaluate which forms of flexibility were most beneficial to the operation of the base-load units. The cycling activity of a typical CCGT and coal unit on the base case test system is outlined in Table. IV. In the base case CCGTs undergo a large number of annual start-ups as they are forced offline more often with high levels of wind. The coal units on the other hand avoid start-stop cycling due to their long start-up times but operate at part-load on an ongoing basis to provide spinning reserve to the system. This is indicated by the utilisation factor, which is the ratio of actual generation to maximum possible generation during hours of operation in a given period. They are also subject to severe ramping as at times of very high wind output they are some of the few thermal units online to provide power balancing. Severe ramping is defined in this paper as a change in output greater than half the difference between a unit's maximum and minimum output over one hour (excluding hours when the unit is starting up or shutting down).

TABLE IV
CYCLING ACTIVITY IN BASE CASE

Cycling Activity	CCGT	Coal
Start-ups	140	7
Utilization factor	0.90	0.78
Hours of severe ramping	84	283

Scenarios 1 & 2 - Interconnection

Fig. 1 shows the percentage change in start-ups from the base case for an average sized CCGT unit (400 MW). The addition of 500 MW of interconnection, scheduled intra-day or day-ahead, gave the largest reductions of CCGT start-ups of 12% and 13% over all the flexility options examined. CCGT units can stay online more often and avoid harmful shut-downs on the interconnected systems compared to the isolated base case system as excess wind can be exported instead of forcing units offline. The coal units in the base case were at their minimum number of annual start-ups so no reduction in start-ups was possible. As the CCGTs are online more on the interconnected system compared to the base case, the demand for spinning reserve can be spread over more units, relieving the onus on the coal units. Consequently, Fig. 2 shows a reduction in utilisation factor for a CCGT unit indicating the increase in spinning reserve they are providing the system, whilst Fig. 3 shows an increase in utilisation factor for a coal unit indicating a reduction in spinning reserve provision, thereby allowing more efficient operation.

On the system where the interconnector is scheduled day-ahead, the exchanges on the interconnector cannot be changed on the day of operation. Wind is more often over forecast on the test system at the time horizon at which the interconnector is scheduled, leading to under-commitment of thermal plant. CCGT units, having large minimum stable generation levels, may be offline to accommodate the expected levels of wind but cannot come online quickly enough to meet the shortfall and the interconnector cannot be rescheduled so online units are ramped-up or fast starting gas units are turned on instead. Thus the system where the interconnector is scheduled day-ahead has less CCGT start-ups than the system where the interconnector is scheduled intra-day, but this corresponds to less online hours for these units, which is not favourable. However, overall the difference in the operation of the base-load units on the systems where the interconnector is scheduled day-ahead and intra-day is not significant, showing the benefits of intra-day scheduling for base-load units are small when the system is scheduled stochastically. (The operation of other units, particularly peaking units show greater difference but they are not the focus of this study.)

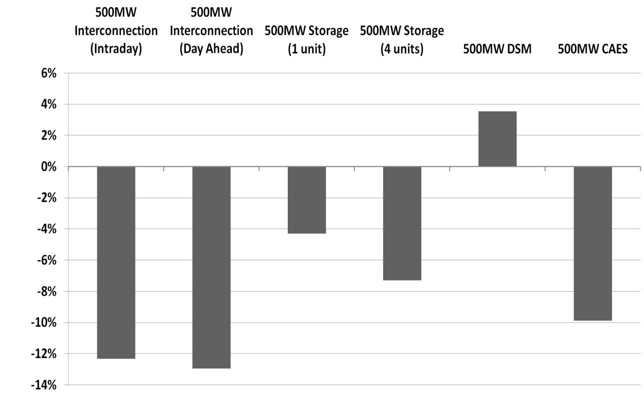

Fig. 1. % Change in start-ups for an average CCGT unit in each scenario relative to base case

Fig. 4 and Fig. 5 show the percentage change in the number of hours a typical CCGT and coal unit perform severe ramping relative to the base case. Interconnection was the only flexibility option which increased ramping of base-load units relative to the base case. Flows on the interconnector are governed by the price differences between the two systems and at times the test system imports power from the interconnected neighbouring system despite having a high wind output to deal with. This will lead to increased ramping relative to the base case. More coal ramping is seen when the interconnector is scheduled day-ahead compared to intra-day to compensate for under-commitment events as discussed.

Scenarios 3 & 4 - Pumped Storage

The addition of 500 MW of pumped storage reduced CCGT start-ups by 4.3% and 7.3% when modelled as one 500 MW unit or four 125 MW units respectively as seen in Fig. 1. Pumping at times of high wind raised the base load and allowed more base-load units to stay online. The pumped storage unit(s) could provide 200 MW of spinning reserve to the system, thereby reducing the demand for spinning reserve from thermal plant. As a result a large increase in the utilisation factor for a CCGT unit and a coal unit is seen when pumped storage is added to the system as in Fig. 2 and Fig. 3 thereby allowing the base-load units operate in a more efficient manner. The increase in utilization factor is larger for a coal unit as coal units are the main thermal providers of spinning reserve on the system and therefore are most impacted by the addition of a storage unit. Significant reductions in ramping were also achieved by the addition of a pumped storage unit showing its effectiveness at smoothening the net load curve.

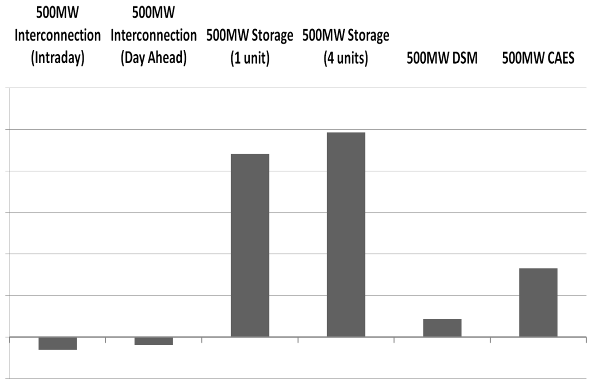

Fig. 2. % Change in utilization factor for an average CCGT unit in each scenario relative to base case

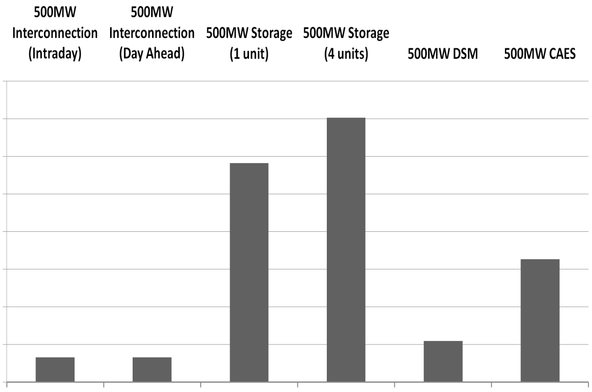

Fig. 3. % Change in utilization factor for an average coal unit in each scenario relative to base case

Splitting the pumped storage capacity over four turbines allowed greater operational flexibility. For example the single 500 MW turbine had a minimum generating level of 40 MW whereas the four 125 MW turbines could operate at a minimum of 10 MW each, thereby extending the maximum generation time that could be achieved from the same energy store. Modelling the storage as four identical units thus showed significant benefits over a single 500 MW storage unit. The system with four 125 MW pumped storage turbines has an extra 3% less CCGT start-ups than the system with one 500 MW unit as well as an extra 16% and 19% less hours ramping for a CCGT and coal unit as seen in Fig. 4 and Fig. 5.

Scenario 5 - Demand Side Management

The 250 MW DSM clipping unit reduces the peak demand and therefore does not impact the operation of base-load units. The DSM shifting unit reallocates demand in time in order to meet it at a lower cost. Its flexibility however, is more restricted compared to the pumped storage units because the DSM shifting unit has a variable cost (€40/MWh) associated with it. For example, on a windy night if the wind power output begins to decrease, online thermal units will have to ramp up their output in order to meet demand, or alternatively the DSM shifting unit could reduce the demand at this time to avoid ramping of thermal plant. However, it is uneconomical

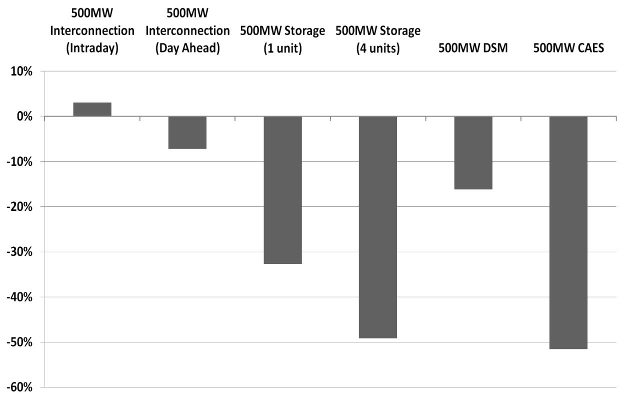

Fig. 4. % Change in ramping for an average CCGT unit in each scenario relative to base case

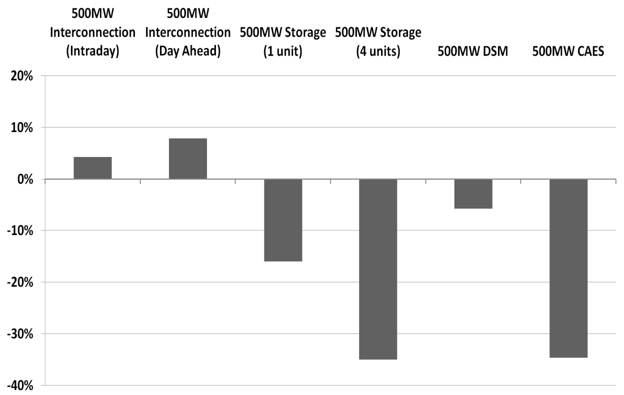

Fig. 5. % Change in ramping for an average coal unit in each scenario relative to base case

for the DSM shifting unit to reduce the demand (i.e. generate) when the electricity price is below €40/MWh, which often corresponds to these windy night-time periods. As a result the reduction in ramping of base-load units, 16% for a CCGT and 6% for a coal unit, is seen to be lower than the scenarios with storage (3, 4 & 6) as in Fig. 4 and Fig. 5.

The addition of 500 MW of DSM actually increased CCGT start-ups by over 3.5% relative to the base case as seen in Fig. 1. The DSM shifting unit, generally increases the demand at night (i.e. charges) but occasionally it may stop charging for an hour or two, only to resume charging an hour or two later, according to the spot price at the time. This can lead to increased CCGT start-ups as seen in Fig. 1, albeit this increase is small. The addition of DSM results in a small improvement in the utilization factor of both CCGT and coal units of 0.4% and 1% respectively as seen in Fig. 2 and Fig. 3, despite the fact the DSM shifting unit does not contribute to spinning reserve. Overall the results for scenario 5 were comparable with scenarios 1 and 2 which included interconnection, as both the flexibility of both were limited by the spot price of electricity and neither contributed to spinning reserve.

Scenario 6 - Compressed Air Energy Storage

The CAES unit reduced CCGT start-ups by almost 10% as seen in Fig. 1. Thus it was more effective at reducing base-load cycling than pumped storage. The total production over the year from the CAES unit was 1,461 GWh, double the production from the pumped storage in scenarios 3 and 4, indicating CAES is more favourable than pumped storage due to its high efficiency. The CAES unit modelled contributes 90 MW to spinning reserve compared to 200 MW from pumped storage so its impact on the utilization factor of CCGT and coal units is not as large as pumped storage as seen in Fig. 2 and Fig. 3. The reduction in base-load ramping achieved by CAES was similar to scenario 4 (four pumped storage units). CCGT ramping was reduced by 51% and coal by 35% as seen in Fig. 4 and Fig. 5.

B. *Impact of flexibility options on wind curtailment and CO_2 emissions*

The available wind power on the test system in the test year was 18.4 TWh. Table V shows the amount of available wind that was curtailed in each of the scenarios. It is clear that pumped energy storage was most effective at minimising wind curtailment events on the system. In Scenario 4, the 500 MW of pumped storage was split over four 125 MW units which gave greater operating flexibility and was most effective at minimising wind curtailment over all scenarios. Scenarios 1 and 2, which included interconnection gave the least reductions in wind curtailment relative to the base case, showing the flexibility of interconnection is limited when the flows between power systems are set according to the price difference. There was surprisingly little difference in wind curtailment between the systems with day-ahead scheduled interconnection and intra-day scheduled interconnection again illustrating the advantages of intra-day scheduling are minimal.

The CO_2 emissions for each scenario can be seen in Table VI. Each scenario is seen to increase CO_2 relative to the base case, with the largest increase in scenarios 3 and 4 which contained pumped storage. This is due to greater levels of production from base-load coal units.

TABLE V
CURTAILMENT OF WIND IN EACH SCENARIO

Scenario	Wind Curtailed (GWh)	% Change from Base Case
Base Case	484.1	
Scenario 1	338.8	-30.01
Scenario 2	338.9	-29.99
Scenario 3	90.7	-81.28
Scenario 4	69.6	-85.63
Scenario 5	184.6	-61.87
Scenario 6	241.2	-50.17

VI. CONCLUSIONS AND FUTURE WORK

Different forms of flexibility were incorporated into an isolated thermal test system with a high proportion of wind in order to evaluate which was most effective at reducing cycling of base-load units, induced by the intermittency of the wind on the system. Adding different types of flexibility

TABLE VI
CO_2 EMISSIONS IN EACH SCENARIO

Scenario	**CO_2 emissions (Mtons)**	**% Change from base case**
Base Case	15.95	
Scenario 1	16.41	2.90
Scenario 2	16.40	2.87
Scenario 3	16.76	5.12
Scenario 4	16.77	5.20
Scenario 5	16.71	4.81
Scenario 6	16.67	4.57

to the system resulted in reduced start-ups and ramping and increased utilization of base-load plant. It was found that interconnection was most effective at reducing CCGT start-ups as excess wind was exported instead of forcing units offline. Scheduling the interconnector intra-day showed no significant benefits to the operation of the base-load units over day-ahead scheduling. Adding storage to the system significantly improved the utilisation factor of the base-load units as the storage could provide a large portion of the spinning reserve allowing the base-load units operate closer to maximum capacity. It also substantially reduced ramping carried out by base-load units showing it was the most effective at smoothening variations in the net load curve. All scenarios examined increased CO_2 emissions relative to the base case as a result of greater production levels from the base-load coal units. This paper has not examined the cost at which the reduction in cycling was attained. The various flexibility options examined have very different capital costs associated with them. Future work will weigh the benefits of each of these options against the costs involved.

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