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JOHN AND WILLIE LEONE FAMILY DEPARTMENT OF ENERGY AND MINERAL ENGINEERING

MARKET DESIGN APPROACHES TO REDUCING COSTS UNDER HIGH WIND ENERGY INTEGRATION

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ABSTRACT

As vertically integrated electric utilities were replaced in much of the United States with marketplace models, electricity markets operated by Regional Transmission Operators (RTOs) were established to facilitate reliable and low-cost service for consumers. These markets were designed to support existing power generation infrastructure and patterns of consumption. Increased penetration of variable renewable energy sources, such as wind energy, has led to more rapid fluctuations in electric supply. Increased electrification of the residential and transportation sectors has led to more rapid fluctuations in demand. These effects have combined to necessitate greater flexibility in conventional generation. Because conventional generators incur start-up and no-load costs, the demand for flexibility has resulted in greater unit operational cost to conventional generators. RTOs throughout the U.S. adhere to a revenue sufficiency guarantee requiring that costs incurred by generators in operation must be covered by the sale of electricity generated or otherwise compensated for by uplift payments. External uplift payments are expenses that are indirectly passed to consumers, resulting in higher rates. RTOs help to guarantee the safety, reliability, and low-cost operation of the grid in their jurisdiction. With increasing willpower for renewable generation at all levels of public, private, and governmental involvement, RTOs are faced with overseeing this transition while still maintaining their other goals. This paper will examine wind generation specifically. It will evaluate market changes to allow low-cost integration of wind energy domestically and internationally. It will model potential modifications to U.S. electricity market structures, and their impact on uplift costs.

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1 Introduction

The development of utility scale wind energy throughout the United States has been characterized by steady growth since the early 2000s. Total wind production capacity reached 121,985 MW in 2020 following a year of record installations.[1] Over the last decade, wind power comprised 29% of all U.S. capacity additions.[1] This has been driven in large part by extensions to the production tax credit and appetite for clean energy by corporate buyers through power purchase agreements. Regionally, U.S. wind development has followed the onshore resource availability with significant concentrations in the Midwest, Great Plains, and Texas. Development to a lesser extent has been focused in mountainous areas of the northeast and the plains of west coast states. System operators that cover these regions have been left to manage the integration of large amounts of wind energy into their systems. Wind generation expressed as a percentage of load has reached 31.3% in SPP, 22.7% in ERCOT, 11.0% in MISO, and <10% in all other Independent Service Operators (ISOs) and Regional Transmission Organizations (RTOs).[1]

Wind energy poses a unique integration challenge because of its scale and variability. Onshore wind farms in the United States range generally from 200 – 600 MW,[2] significantly larger than the average utility scale solar installation of 1 – 5 MW.[3] Both wind and solar energy sources are weather dependent, but whereas solar generation proceeds in a predictable daily manner determined by sunlight hours, wind generation displays more intra hour variability. Thus, not only is wind farm output more difficult to predict, but its variability requires larger intervention on the part of conventional generators. However, the variability due to wind energy integration is only part of the ramping strain placed on conventional generators. The increased electrification of automotive sectors, residential cooking and heating, and distributed storage will result in steeper and more variable net load curves. Historically, residential electricity demand has followed a predictable morning and evening peaking pattern. However, the incorporation of these additional electric devices will alter consumer behavior especially in response to price signals. Electricity demand has been largely inelastic because demand for electricity is tied to behaviors that are generally fixed in a consumer's schedule. Charging an electric vehicle or residential storage can be performed at times when utilities have established lower kWh prices through time-of-use plans. These technologies will increase elasticity in electricity demand and contribute to further demand volatility.[4] Net demand or net load is the difference between energy demanded and energy supplied by variable sources. The combined effects of increased demand volatility and variability in supply produce a net load with greater ramping needs than are present in conventional systems. Figure 1 shows the variability in net load resulting from variable demand and wind inputs.

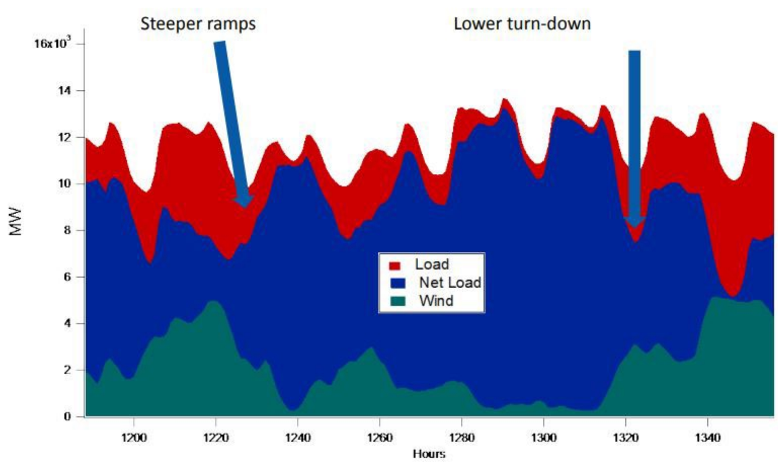


Figure 1 Net load displays steeper ramping than load due to wind contribution[5]

The resulting system has an increased need for flexibility. Both infrastructure and market mechanisms can support this need. Infrastructure mechanisms can include single cycle gas turbines, utility scale batteries, or running equipment with operating reserves such as combustion turbines or hydropower. Single cycle gas turbines are less fuel efficient than combined cycle gas turbines and are thus more expensive on a per kWh basis. However, the working fluid of a combined cycle gas turbine must be kept within a temperature range which limits its ability to ramp to meet demand. For other generation types which also utilize working fluid, coal and nuclear, the ramping ability is similarly limited. For these generators, RTOs require that operating reserves are held to adjust upward or downward pending unexpected changes in net load.[6] The effect of several generators in a service area adjusting their production by a small percentage can sum to a similar ramping ability as one single cycle gas turbine. While these mechanisms are essential to meeting the flexibility needs of evolving electricity infrastructure, the focus of this paper will remain on market mechanisms. Among these are increasing electricity interconnections, demand response, flexibility products, multi-period real-time dispatch models and intraday markets. Increasing the areas over which balancing authorities operate increases the number of assets from which ramping capacity can be drawn.[7] Demand response provides the opportunity for increased flexibility in demand. Agents with the ability to curtail large amounts of their own consumption at will and may sell rights to control their consumption to RTOs. Industrial clients and aggregate groups of consumer loads have been effective examples of this. While still in development, participation of electric vehicle charging as demand response could turn EV usage in systems with high wind penetration from a burden to a useful tool in balancing load.[8] Flexibility products, multi-period real-time dispatch models and intraday markets are discussed in the next Section.

The rest of the paper will proceed as follows. Chapter 2 will describe the current structure of U.S. and European energy markets, analyzing specific market modifications to account for higher shares of wind penetration and considering new ones. Chapter 3 will describe the analysis of introducing additional trading periods through a model with wind forecasts and realized generation. It will describe data inputs and the structure of the model, which was developed by Hohl and al. (2022). Chapter 4 will present the results and Chapter 5 will aim to make a concluding market policy recommendation based on these results.

2 Review of Current Market Structures

Broadly, electricity markets operate in three timeframes: long-term, short-term, and real-time, to facilitate pricing and procurement. The long-term markets include those aimed at guaranteeing adequate MW capacity. In a system with high wind penetration, the need for ramping ability provided by fast start gas turbines may not be met because their sporadic use will not make them profitable when compensated for MWh alone. Thus, capacity markets are introduced to remunerate the owner for MW capacity added rather than MWh energy produced.

The short-term markets are forward markets that include day-ahead trading periods and intraday trading periods depending on the market operator. Day-ahead markets are the foundation of liberalized U.S. and European electricity markets. Based on predicted levels of electricity demand and renewable energy generation, agents bid on forward positions that determine a preliminary schedule to buy or sell electricity the following day. Day-ahead market clearing prices are established at the intersection of offers to sell and bids to buy. Absent losses or congestion, all participating buyers and sellers carry out the transaction at this 'System Marginal Price' (SMP) in the day-ahead market regardless of their individual offers and bids. In the United States, the additional costs associated with losses and congestion are included in the 'Locational Marginal Price' (LMP). The transmission system is divided into nodes so that varying costs of losses and congestion can be accounted for on a discrete level. As with the European SMP, the energy component of LMP is consistent across nodes within the network, but loss and congestion components will vary depending on location.[9] In addition to the day-ahead market, European service operators have adopted intraday trading periods. Because system conditions may change over the day prior to dispatch, intraday settlements allow agents to trade again based on improved information such as evolving demand predictions or unplanned generator outages. Intraday settlements are thus important for allowing the program to be modified according to evolving information and more closely reflect the realized generation.[10]

The real-time markets calculate prices according to incremental supply offers and actual electricity demand as it is realized. In the U.S. and Europe, the real time markets are carried out centrally by the system operators.[9] If this price in consistent with the price in the day ahead market or the final intraday market, as in Europe, then no additional payments are made from buyer to seller. If net demand is greater than predicted in the previous settlement, whether due to greater electricity demand or lesser renewable generation, units with greater offers are instructed by the operator to produce and the offer price of the new marginal unit becomes the SMP. All units are paid the same price per MWh, but only the marginal unit for the previous settlement and any additional units engaged change quantity delivered. If net demand is less than predicted in the previous settlement, whether due to lesser electricity demand or greater renewable generation, conventional generators will buy back power sold in the previous settlement at the real-time price. The real-time price will be less than the price in the previous settlement; thus, the generators will buy back because repurchasing power sold in the previous settlement at a reduced price will be more profitable than producing at the previous price.

Structural differences between European and American electricity markets stem primarily from different levels of integration between market operations and system operations. In the US, ISOs and RTOs control both market and system operations. In Europe, market operations and system operations are handled separately. Day-ahead and intraday markets are facilitated by power exchanges, after which a physical program is established by Transmission System Operators (TSOs) incorporating physical and reliability constraints[11]. European generators place simple bids in both day-ahead and intraday markets that consist only of price per MWh served. Intraday markets in Europe serve to help capture the start-up and no-load costs that are omitted by simple bids. This is distinct from the U.S. framework in which RTOs centrally perform market clearing with physical constraints and additional operating costs already integrated. Generators in the U.S. provide not only an offer of price per MWh served, but no-load and start-up offers. They also provide the RTO with technical constraints that inform feasibility in how it dispatches units.[9] RTOs will respond to changing information on an intraday level, modifying generator programs via intraday commitment processes, but these processes do not produce settlement prices for energy. The rest of this Section proceeds as follows: Section 2.1 addresses market structure in the U.S., Section 2.2 addresses market structure in Europe, and Section 2.3 addresses uplift in U.S. RTOs/ISOs.

2.1 United States

In the United States, seven RTOs and ISOs manage markets and transmission planning across most of the country except the Southeast and parts of the West, where utilities remain largely vertically integrated.[12] ISOs were formed in response to FERC Orders 888 and 889 in the initial restructuring phase of electricity markets. RTOs were later formed in response to FERC Order 2000, which aimed to increase coordination between regions, thus RTOs are often larger than

ISOs.[13] Both types of organizations perform generally the same functions, but RTOs must meet stricter qualifications regarding required characteristics. In all RTOs and ISOs except ISO-NE, the day-ahead market includes procurement of both energy and operating reserves.[14] Simultaneous procurement of energy and operating reserves allows energy prices to better reflect the opportunity cost of providing operating reserves. Operating reserves are complemented through other mechanisms that enhance flexibility such as sub-hourly dispatch, flexible ramping products, and intraday markets.

By implementing shorter intervals in economic dispatch, RTOs can create more effective price signals that reflect immediate needs for ramping, making units with the ability to meet this need more profitable.[15] CAISO and MISO have also introduced dedicated flexible ramp products (FRPs) into ancillary services markets. In these markets, generators can offer flexible ramp up (FRU) and flexible ramp down (FRD) products. Offers are then scheduled by the RTO as they become necessary in real-time economic dispatch. FRU and FRD products are currently offered by conventional generators in these RTOs, but studies are ongoing to understand the capability of energy storage, demand response, and wind in offering these.[16]

Midcontinent ISO (MISO) has developed a unique approach to managing ramping capability. MISO created a new Dispatchable Intermittent Resource category which includes resources that have "forecast dependent fuel availability".[17] This measure helps MISO manage the significant wind contribution within the service area. Previously, wind generators were categorized as intermittent resources. These lacked the ability to participate in real-time markets and could not be curtailed except by manual intervention on the part of the ISO. Under this new classification, wind generators in MISO now are subject to the same market rules as standard generating resources, and can contribute dispatchable downward ramping ability if needed to alleviate transmission congestion or excess supply. Downward ramping ability is paid to wind generators at the local marginal price of electricity for the amount curtailed.[17] Generating resources and dispatchable intermittent resources are scheduled in the day-ahead market and are modified according to changing conditions in the real-time market. To ensure load balancing, both resources are subject to the same penalties for excessive or deficient deviations from agreed upon production values. Treating wind generators in a similar manner to other generating resources helps reduce the need for extra-market management by ISOs, while also reducing the ramping burden placed on the rest of the system.

Intraday markets have not been implemented in any United States ISOs or RTOs except CAISO, which implements a three-settlement energy market including a day-ahead market, a fifteen-minute market (FMM) and a five-minute real-time dispatch market. Under this system, owners of variable energy resources may submit updated production forecasts which are used to establish updated prices. Market participants may buy or sell deviations from the day-ahead market at the updated price. Incorporating updated forecasts into a trading period shortly before dispatch reduces the discrepancy between the final market price and the real-time price. In addition, while in most ISOs/RTOs real-time market clearing is based on single-interval dispatch models that minimize production costs in the current period, some organizations have moved to multi-interval dispatch models for real-time market clearing. Rather than identifying the cheapest dispatch configuration in each period as it approaches, as in single-dispatch, the schedule is optimized across multiple periods using forecast load subject to generator capacities and ramping limits.[18] CAISO's three-settlement market and multi-period dispatch models aim to allow evolving forecast information to refine the dispatch program. Whereas no market mechanism is introduced by multi-period dispatch, the FMM creates an intraday price signal for generators.

However, unlike in the European intraday markets, which run hours before actual electricity generation to reschedule slow-start and fast-start units, the FMM is a real-time market process, which is run every fifteen minutes to make commitment decisions for fast-start units.

2.2 Europe

In Europe, system operations are managed by 39 Transmission System Operators (TSOs) covering 35 member countries. These TSOs partner to form the European Network of Transmission System Operators for Electricity (ENTSO-E).[19] These systems are analogous to the U.S. ISOs/RTOs, but operate in most cases at a national rather than regional level. In Europe, each of the three market timeframes are utilized. Long-term capacity markets have been introduced by power exchanges in several member nations: Belgium, France, Great Britain, Ireland, Spain, and Sweden among others.[10] The implementation of these markets began in the late 2000s and has continued in concert with renewable development in these countries. [9] Power exchanges operate a day-ahead market, real-time market, and in most cases intraday markets (whose structure varies by region).[20] European day-ahead markets procure only energy, with operating reserves organized by TSOs after the fact. This approach reduces the complexity of the day-ahead markets compared to U.S. markets in often which these are co-optimized, but leads to less efficient market outcomes as producers withhold capacity from the energy market to provide reserves.

As noted above, intraday markets are run by power exchanges. These markets exist both in continuous and discrete forms. In a continuous market design, trading can take place between agents in an ongoing manner until the market gate closure before power dispatch. In a discrete market structure, trading takes place at established intervals prior to dispatch. The advantage of the continuous market is that agents can make bid decisions as forecasting information evolves, theoretically leading to greater consistency with real-time prices. However, without established bid times, there may not be sufficient liquidity for transactions to be made at any given moment. In effect, discrete bidding periods can lead to more efficient price outcomes because there is greater liquidity in each intraday auction.[10] One example of a member operator with a continuous intraday market is the Belgian Power Exchange, Elia. The Belpex Continuous Intraday Market (CIM) allows agents to trade bilaterally.[20] After the intraday trading period closes, portfolios of injection and offtake may be imbalanced; any imbalances in a portfolio are dealt with by the power exchange in the real-time balancing market. As the difference between supply and demand is realized, Elia will activate reserves to alter what it terms the "net regulation volume" upward or downward depending on the system need.[20]

In Belgium, wind supplies 14% of total electricity consumption.[21] In Belgium and several other European countries with significant energy contributions from wind, electricity prices have been at times negative in day-ahead and real-time markets. In 2022, negative prices been observed in western Denmark and the Central Western Europe power exchange including Germany, the Netherlands, and Belgium. On days with high wind contribution and weak demand, conventional units have offered negative prices to avoid the cost incurred by cycling the unit off and on. Belgium has recorded a 9% year-over-year increase in negative prices in Q2 of 2022 which corresponds with an 11% regional increase in offshore wind generation and 10% increase in onshore wind generation over the same period.[22] In regions with less wind penetration, such as Central Eastern Europe and South Eastern Europe, energy prices have remained positive. Even in the Great Britain and Ireland region, which has seen wind output grow 45% over Q2 2021 to Q2 2022, the total renewable share remains low enough at 33% that negative electricity prices have not yet been an issue.[22]

2.3 Uplift

Most U.S. ISOs/RTOs have a “revenue sufficiency guarantee”[8] that any accepted offer resulting from the initial day-ahead auction be compensated through additional “uplift” payments, if the auction revenue is insufficient to cover costs incurred by meeting the agreed upon production, such as start-up costs. [9] These uplift payments represent a costly component of generation compensation which has been debated by power producers. Uplift payments have been controversial because they can incentivize producers who participate in the day-ahead market to under-schedule reserves, knowing that the start-up costs associated with a fast start gas turbine will be repaid and allowing them to operate their inflexible units more cheaply.[9] In systems with a large share of renewable generation, it important that conventional generators remain financially solvent. However, uplift payments may disincentivize investment in more flexible generator types because they sustain generators that do not complement well a system with high renewable penetration. Uplift is an important metric in this context because it reveals how efficiently existing generation assets are being used to meet net demand. These costs, on the order of $10 - 100 M are ultimately passed along to consumers. Figure 2, displays the magnitude of these payments across the U.S.[14]

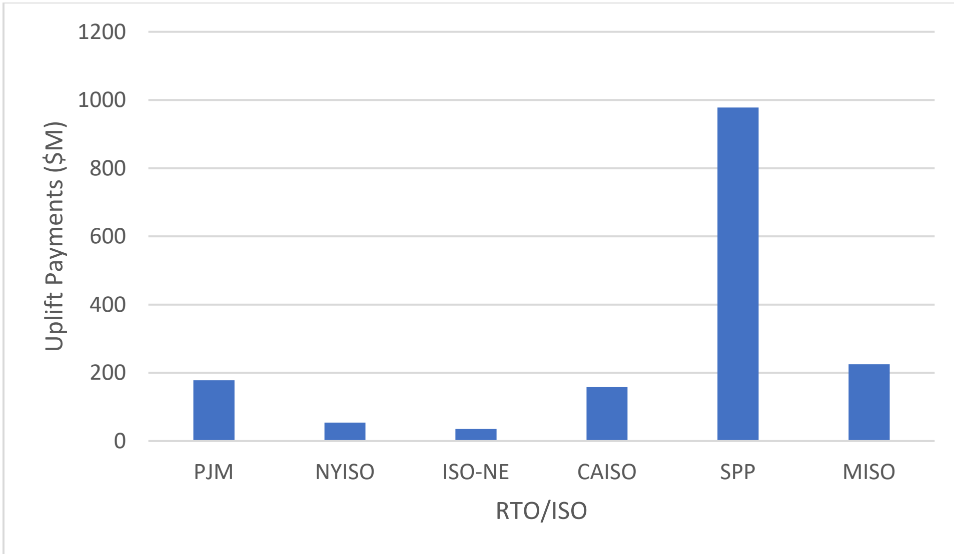


Figure 2: Uplift payments across U.S. electricity markets in 2021[23–28]

SPP and MISO have among the highest uplift costs because of a weather event in February that struck both regions and led to high fuel prices and increased operating costs. In the previous year, SPP had uplift more congruent with other ISOs of $53 million.[25,27] ISOs have considered different strategies to attempt to reduce uplift. PJM, the U.S. ISO making the greatest uplift payments, has undertaken an initiative to reduce these. Among the proposed market changes is permitting resources operating at minimum generation to set the price. PJM has proposed eliminating start-up cost payments to units that start-up prior to the time established in the day ahead market. Also proposed is the elimination of day-ahead operating reserves allowing real-time reserve prices to be set by actual costs.[14] This would be similar to the European energy-only day ahead market approach. In 2015, MISO implemented a model of Extended Locational Marginal Price which amortizes the costs of no-load, start-up, and the minimum generation limit into the LMP calculation.[14] This has helped raise prices in the real time market and alleviated the need for uplift for the more expensive units participating. In 2013, CAISO implemented a tiered cost recovery plan for its day ahead market. The first tier allocates uplift only according to deviations from the day ahead forecast demand. The second tier allocates uplift to loads and exports. Making these discrete encourages liquidity in the real time market which should lead to price outcomes that are more consistent with generator costs, reducing the need for total uplift. CAISO has also considered implementing an amortized LMP similar to the MISO approach.[14] While other system attributes may contribute to this outcome, it is worth noting that the costs of uplift are proportionally lower in MISO and CAISO (1.08 and 0.78 % of total market volume respectively) than in PJM, NYISO, and ISO-NE where uplift reducing measures have not yet been implemented.[14] In Europe, uplift payments are not present because power exchanges do not provide a revenue sufficiency guarantee to generators. This has put financial strain on generators, but has promoted investment in flexible generation infrastructure.

3 Model Structure and Data Inputs

The model implemented is a 3-node electric power system which corresponds in makeup to the Northeastern U.S., the region for which wind data have been collected. Physical constraints of modelled components are compiled. For transmission lines between nodes, capacity is set such that the 3-node system resembles the existing system. Similarly, generators are chosen such that the overall generation mix is consistent with the existing system. Parameters for each of the generators are included such as startup costs, no load costs, heat rate, fuel price, ramp rate, minimum and maximum output, and required notification times. Not all parameters apply consistently to all generator types. For instance, hydro plants have no minimum output. For wind and hydro plants, fuel costs are assumed to be zero and heat rate does not apply. For nuclear plants, it is assumed that they are ‘must-run’ and thus startup and shutdown costs are omitted.

To test the system, load profiles were gathered from representative days in PJM, NYISO, and ISO-NE in summer 2007. These were combined to create hourly load profiles at each node which serve to determine demand in the day ahead, intraday, and real time markets. These load profiles are fixed in each representative day, so that variation in net demand comes exclusively from evolving wind predictions. In each hour, reserve requirements are held constant at 10% of total system load. Historical wind data were provided by ISO-NE at six different look-ahead periods ranging in 3 hour increments from 24 hours – 3 hours and finally 30 minutes. 419 days in the dataset provide the ability to sample, simulate, and generalize back out to behavior over the course of the data collected. Different levels of wind penetration in the market are simulated to see how uplift outcomes under different market structures vary with wind penetration.

The model is structured such that both two-settlement and multi-settlement systems are simulated. Under both market designs, the objective function is set that the system operator minimizes cost across the 3 nodes over the 24 hour period. The optimization is subject to physical constraints of the representative system. In the two-settlement system, the real-time and day-ahead markets are cleared as described in Chapter 2. In the multi-settlement system, two intraday markets are introduced in between the day-ahead and real-time markets. These behave similarly to the real-time market, where any deviations from the previous forward schedule are settled according to the clearing price in the current period. Unit commitment constraints such as notification time limit the feasibility of certain modifications to the program during the intraday periods.

The demand profile, wind resource, and wind penetration form a representative day. With this simulated day, generator and network constraints, and market clearing conditions, the optimization problem solved in GAMS will determine the outcome under the two market designs. After prices and dispatch instructions have been established, the model will solve for the revenue of each generator. Based on cost parameters (i.e. startup, no-load, fuel costs, etc.), the model will also solve for total eligible operating cost of generators over the representative day. The cost minus revenue is used to determine the shortfall of each generator in each period. Shortfall is used to determine eligibility for uplift payments. Units must have a positive shortfall to be eligible for uplift. For example, generators that buy back energy or reserves in the real-time stage are not eligible for uplift as their shortfall would be zero. Uplift payments are distributed to each generator on this basis, and thus the total system uplift under each set of conditions is calculated.

3.1 Model Methodology

The uplift cost outcomes of two-settlement (2S) and multi-settlement (MS) market structures are simulated under three representative wind forecast cases to understand how these structures react to different forecast trends. The first wind forecast case includes an underestimate day-ahead forecast with linearly improving intra-day forecasts. The second includes an overestimate day-ahead forecast with linearly improving intra-day forecasts. The third includes an overestimate day-ahead forecast with erroneous underestimate intra-day forecasts. Real time wind energy production from a sample day was used as the realized production in each case. Holding ultimate wind energy production constant across cases ensures that differences in total uplift costs are the result of market structure interactions with forecast trends. Hohl et al. found a 15% mean absolute error in the day-ahead forecast relative to real-time production.[29] Thus, each wind case involved a 15% overestimate or underestimate by the day-ahead forecast, followed by subsequent improvement or error.

2S and MS market structures were first simulated under wind case 1 in the *Wind Case 1* folder. Forecasts at day-ahead, intraday 1, and intraday 2 stages as well as real-time wind energy production over a 24-hour period were pasted from sheet one of *Wind Forecasts by Case.xlsx* into the 'Wind Data' sheet of *Data_to_Import.xlsx* files in 2S and MS subfolders. Matlab files *Export_Data_to_GDX_2S.m* and *Export_Data_to_GDX_MS.m* were run in 2S and MS subfolders respectively. The Matlab scripts executed GAMS models and exported generator behavior and uplift cost data to *Results_2S_1.xlsx* and *Results_MS_1.xlsx*. Data from these two files were compiled into the same *Results_MS_1.xlsx* file by executing a macros script *…Run_Macros.xlsm*. Compiled uplift outcomes for wind case 1 were automatically loaded to *Checkpoint 1 Results.xlsx* where they were plotted on day-ahead (DA), adjustment from day-ahead, and total uplift cost bases. Of these plots, the most important for comparing market structures is the 'Adjustment from DA Uplift' because the day-ahead uplift costs are the same for both 2S and MS. Market structures were subsequently simulated under remaining wind cases in corresponding folders. For wind cases 2 and 3, the 24-hour forecast and production values were pasted from sheets two and three of *Wind Forecasts by Case.xlsx* into the 'Wind Data' sheets of *Data_to_Import.xlsx* files in *Wind Case 2* and *Wind Case 3* folders respectively. Simulations were carried out according to the above process in each folder. Results for wind cases 2 and 3 were also automatically loaded to *Checkpoint 1 Results.xlsx*.

Modifications to the multi-settlement model were made to test the impact of two sensitivities: Intra-day period 1 timing and permitting decommitment. Changing the dispatch time of intra-day period 1 (ID1) will alter the number of hours for which a three-hour forecast is available. Making the ID1 earlier should allow the multi-settlement market structure to make greater use of available forecasts, which will exacerbate the effects of those forecasts whether accurate or inaccurate. Similarly, permitting decommitment allows already committed units to turn off if forecasts indicate that there will be an excess of committed units in real time. This should make the multi-settlement structure more responsive to forecasts. If these forecasts are accurate, the cost should be reduced by permitting decommitment because it will decrease no-load costs borne by the generators.

To compare how well the three idealized wind cases represent real wind forecast behavior, real predictions and generation outcomes for 10 days were analyzed in the baseline two-settlement and multi-settlement models. The days were selected from throughout the year to capture the behavior of wind production across seasons.

4 Results and Discussion

The results begin with the baseline evaluation of the three wind cases described above and their uplift costs. They follow with the analysis of modified ID1 timing under the multi-settlement structure. The results of the model permitting decommitment are then presented. Finally, the 10 sample days of wind predictions and realized production are presented to evaluate the applicability of the three wind cases.

Figure 4 depicts the sensitivity analysis performed. It shows each of the unique combinations of wind cases and model formulation, which are described in further detail in their respective sections.

Model Variations

Wind Cases	**Baseline**	**Modified MS ID1 Timing**	**Permitting Decommitment**
Wind Case 1	x	x	x
Wind Case 2	x	x	x
Wind Case 3	x	x	x

Figure 3: Sensitivity Analysis Matrix

4.1 Baseline Model

The baseline model for the multi-settlement structure observes the following schedule depicted in figure 4. It includes a day-ahead market (DA), intra-day market 1 (ID1), intra-day market 2 (ID2), and a real-time market (RT).

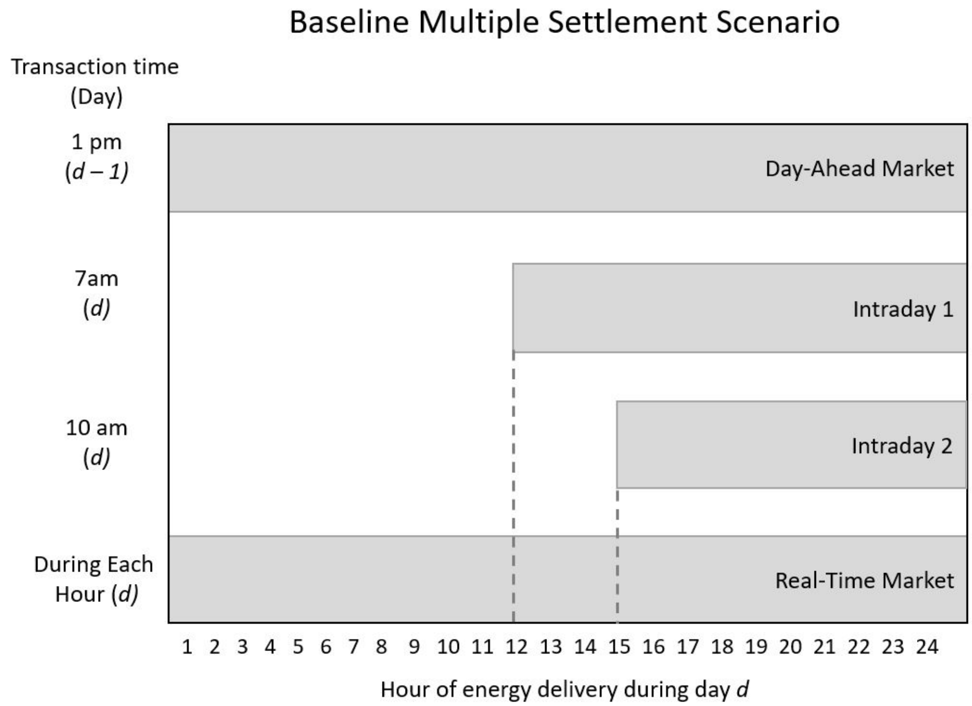


Figure 4: Baseline multi-settlement schedule

The two-settlement market structure is consistent across each model variation and observes the schedule depicted in figure 5.

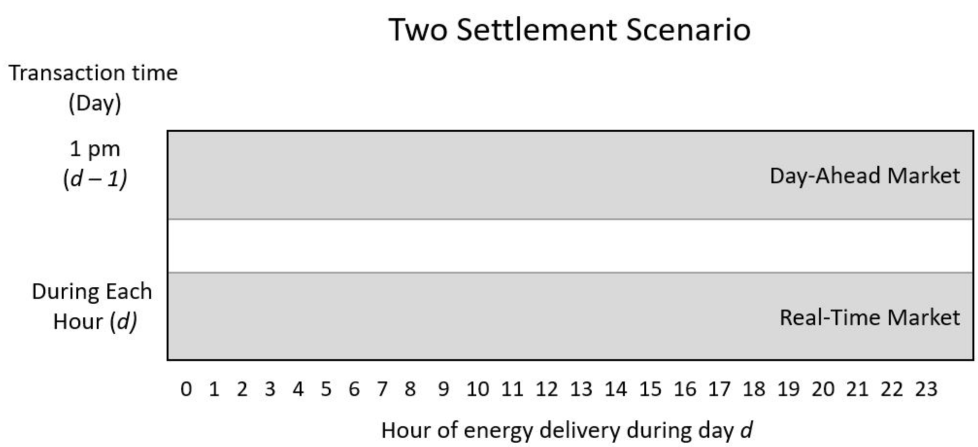


Figure 5: Universal two-settlement schedule

The wind cases 1-3 are shown alongside their respective uplift cost outcomes in the following figures. These demonstrate how costs compare between 2S and MS market structures under different patterns of predicted and real wind production behavior. Because the uplift costs at the DA stage are the same for both 2S and MS structures, the adjustment from the DA uplift is the relevant metric for comparison between market structures.

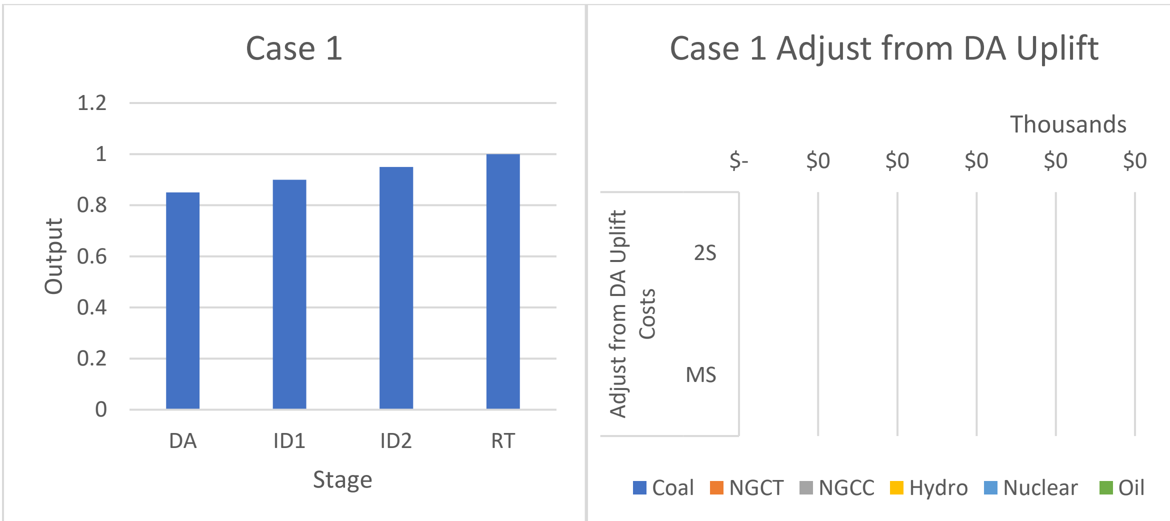


Figure 6: Case 1 Wind and Uplift Data

In case 1, the steadily rising prediction of wind production until the RT period does not result in any adjustment from the day ahead uplift. This is because under the baseline model, generators are not permitted to decommit. The increased wind contribution would lower the net load on the system, but generators have already been committed in the day-ahead period. They must remain on resulting in wind curtailment and no cost savings in the MS structure versus the 2S structure.

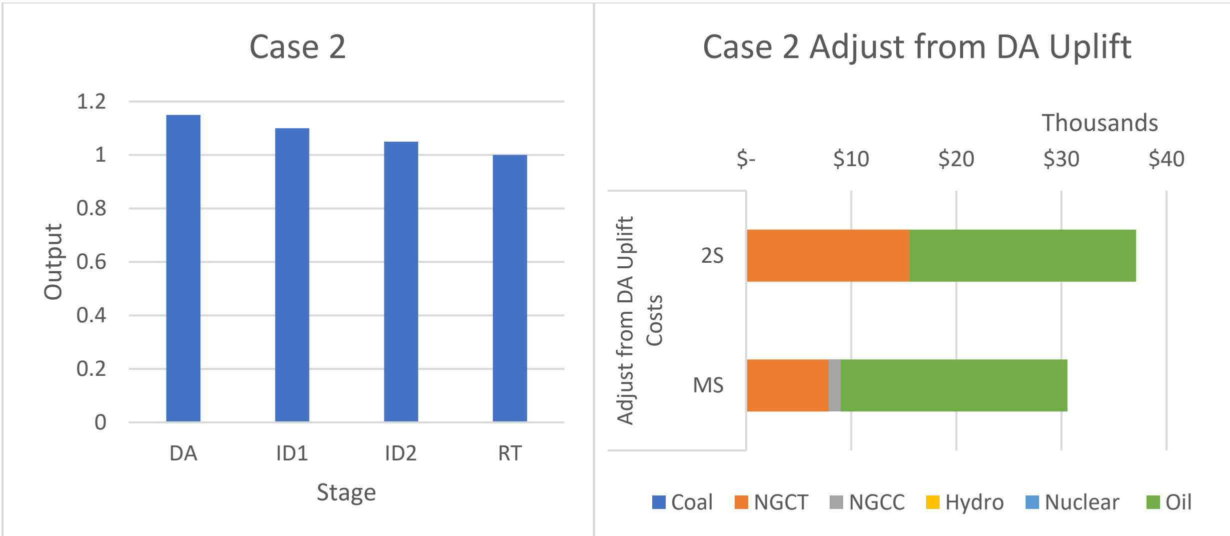


Figure 7: Case 2 Wind and Uplift Data

In case 2, the steadily decreasing prediction of wind production until the RT period results in adjustment from the DA period uplift for both two-settlement and multi-settlement market structures. However, the additional uplift cost is less under the MS structure than the 2S. This is because with a steadily decreasing wind production forecast, including the intra-day stages allows lower cost units, which require greater notification time, the ability to turn on. This results in a lower cost borne by the generators corresponding lower uplift costs.

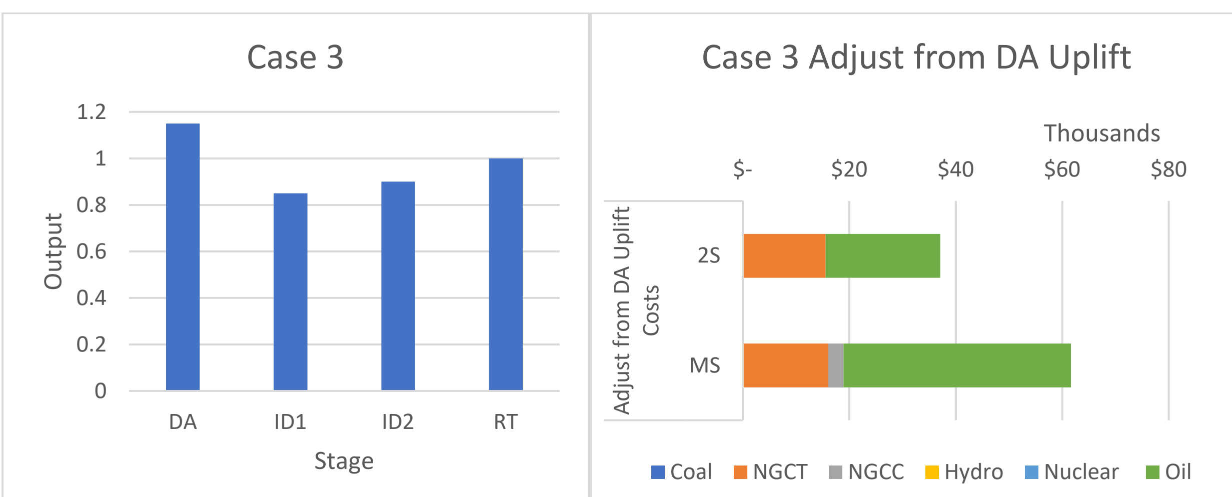


Figure 8: Case 3 Wind and Uplift Data

In case 3, the initial overestimate prediction followed by the erroneous underestimate predictions results in adjustment from the DA period uplift for 2S and MS structures. In this case, the additional uplift cost is greater for the MS structure than for the 2S. This is because the MS market structure allowed for an erroneous forecast to cause more generators to be turned on than necessary. This results in increased start-up and no-load costs borne by the generators corresponding to higher uplift costs. The following sections display the same wind cases under a modified MS model.

4.2 Modified MS ID1 Timing

To test the effect of intra-day market timing on uplift cost, the ID1 stage was moved back 6 hours. This allows the 3-hour forecast to influence generator commitment behavior for longer period of the day. The modification to ID1 stage timing is shown in figure 9.

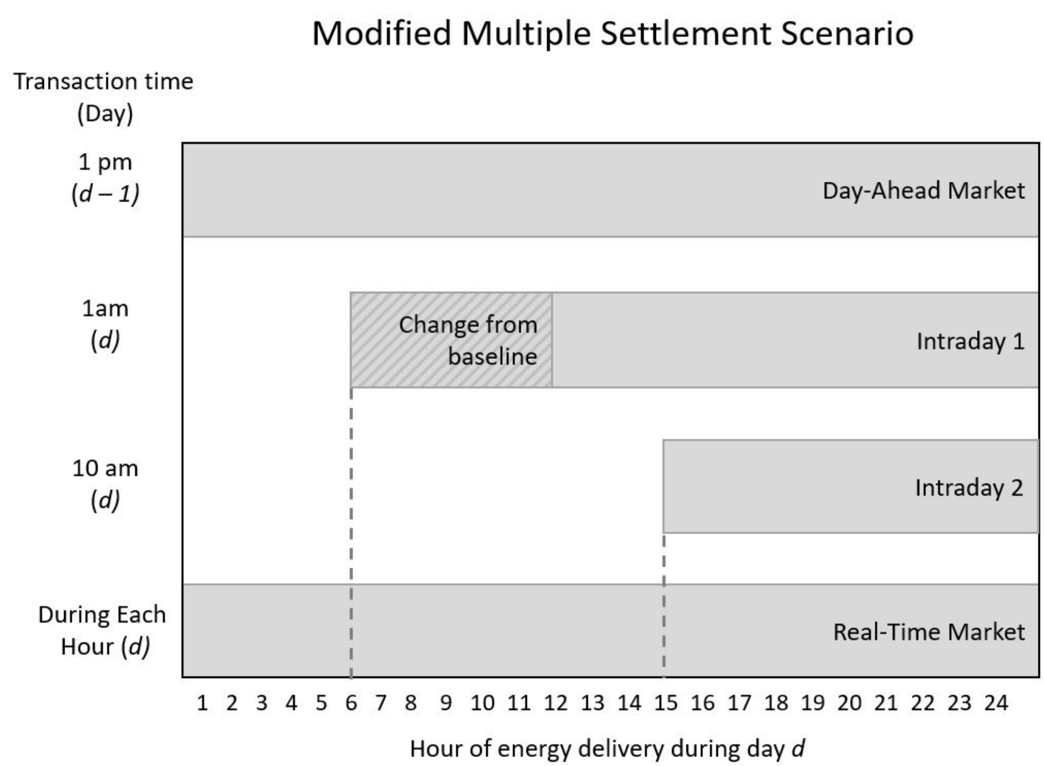


Figure 9: Modified ID1 multi-settlement schedule

Under wind case 1, the modified ID1 timing has no effect on uplift cost outcomes. This is because, provided units cannot decommit, there is no benefit realized by forecast data when the predicted wind output is steadily increasing. Units turned on in the DA period must remain on regardless of increased wind predictions. Under wind case 2, the modified ID1 timing again has no impact on the uplift cost outcomes. This is despite minor commitment differences between this case and the baseline MS structure. This is due to the fact committed units were already above the threshold of revenue sufficiency and did not require uplift payment initially under the baseline case. Under wind case 3, the modified ID1 timing further increases the uplift cost of generators on the network, but only for combined cycle units. This increase is less than 1%. The erroneous underestimate forecast is applied to a greater number of hours throughout the day, resulting in additional no-load costs.

4.3 Permitting Decommitment

To test the effect of decommitment on uplift cost, the model was modified to permit units to decommit in a later stage after committing in a prior stage. This modification was found to have little effect on uplift cost compared to the baseline. Under wind case 1, some units decommit but this has no appreciable effect on uplift cost. This is, again, likely due to the fact that the decommitment of these units results in only a slight decrease in no-load costs that were already above the threshold of revenue sufficiency and did not require uplift payment initially. Under wind case 2, more units decommit in the MS market. This results in a reduction in MS uplift cost versus 2S uplift cost as shown in figure 10.

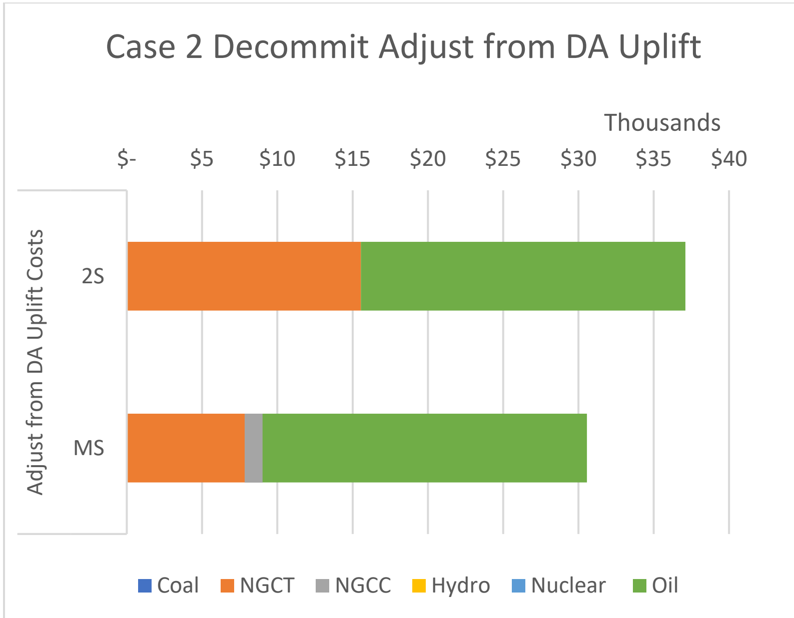


Figure 10: Wind Case 2 Decommit Uplift Data

Under wind case 3, more units decommit in the MS structure. However, these decommitments are the result of erroneous forecasts, meaning there are additional start-up costs incurred at the real-time dispatch. This results in an increase in MS uplift cost versus 2S uplift cost as shown in figure 11.

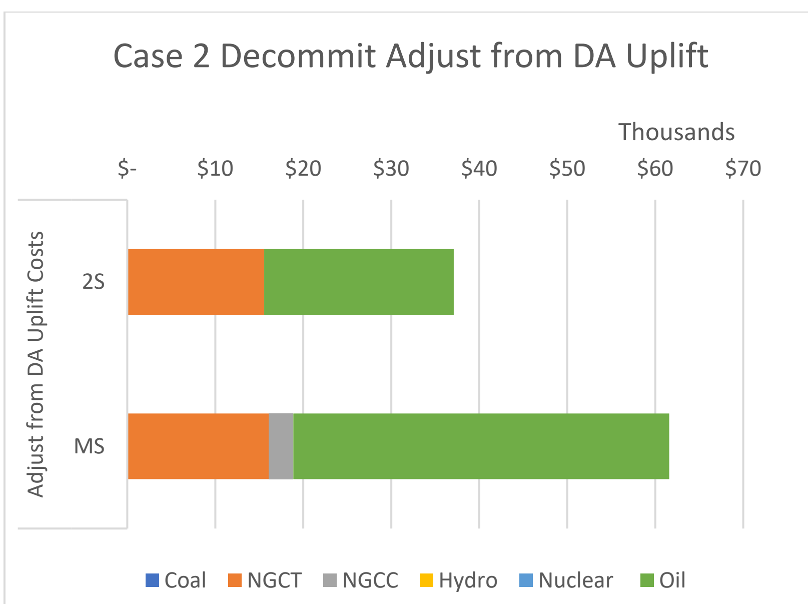
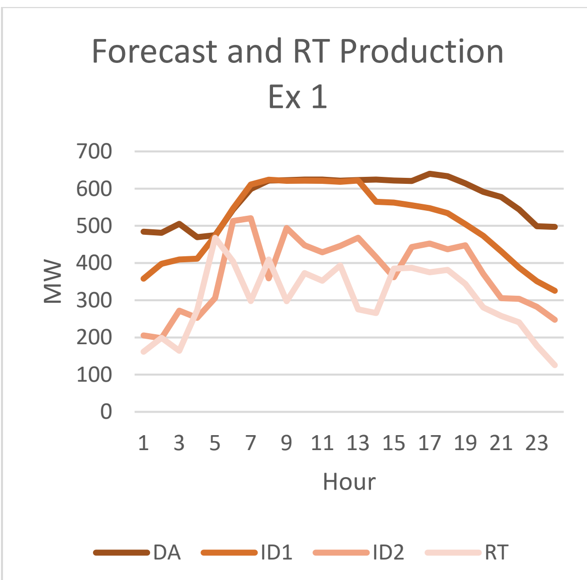
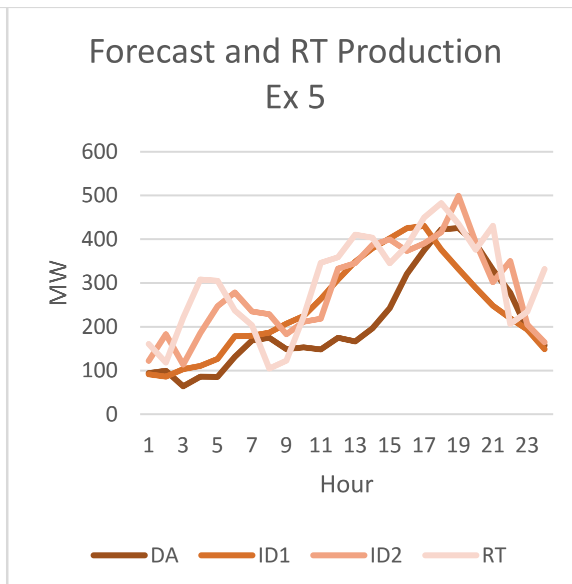


Figure 11: Wind Case 3 Decommit Uplift Data

4.4 Sample Days

The 10 sample days lend credibility to the outcomes associated with the three idealized cases by proving similar behavior. Figure 10 offers an overview of the sample days and the way predictions evolve over the 24-hour period. All 10 sample days are presented with uplift cost data in the Appendix.





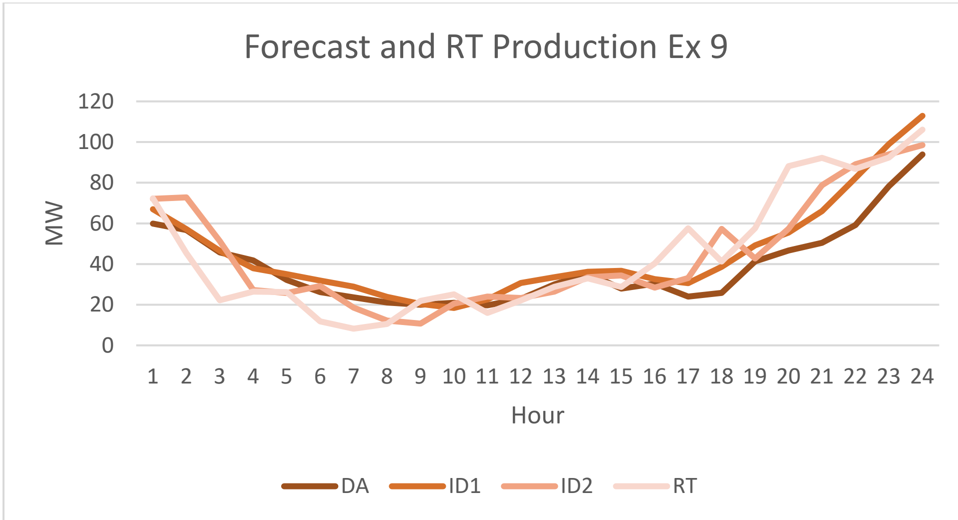


Figure 12: Sample days

Each of the above samples corresponds to one of three cost outcomes among the 10 sample days. In Ex 1, the multi-settlement structure resulted in lower uplift costs. This supports the conclusion found in wind case 2 because generally production forecasts are steadily decreasing from DA to RT periods. In Ex 5, the two-settlement structure resulted in lower uplift costs. This supports the conclusion found in wind case 3 because generally production forecasts are steadily increasing from DA to RT periods. In Ex 9, the two market structures resulted in the same uplift cost. This is likely because the forecasts offer no significant improvement, nor do they diverge from the initial forecast erroneously. While not considered by one of the above wind cases, uplift cost parity occurred between 2S and MS market structures in 7 of 10 sample days. In each of the 6 cases, relative stability occurred between forecasts. Conversely, only one sample day provided the forecast conditions necessary to produce conditions where MS structure yielded the lower uplift cost. The frequency of this outcome indicates that there may be little gained by implementing a multi-settlement market structure if the majority of days lead to only to cost parity and if there are erroneous or underestimate forecasts, the cost of MS will exceed that of 2S.

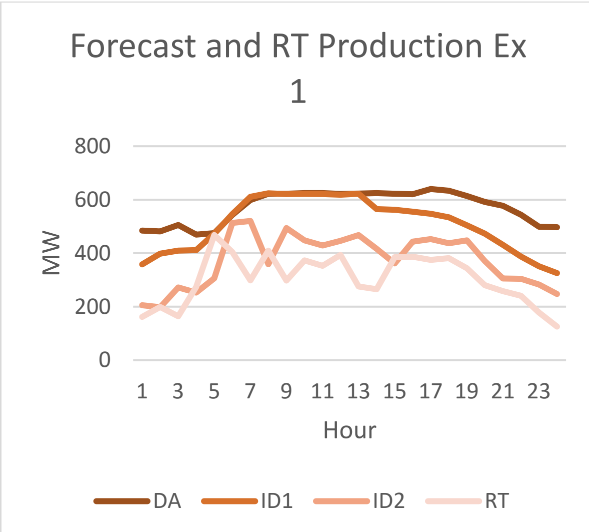
5 Conclusions

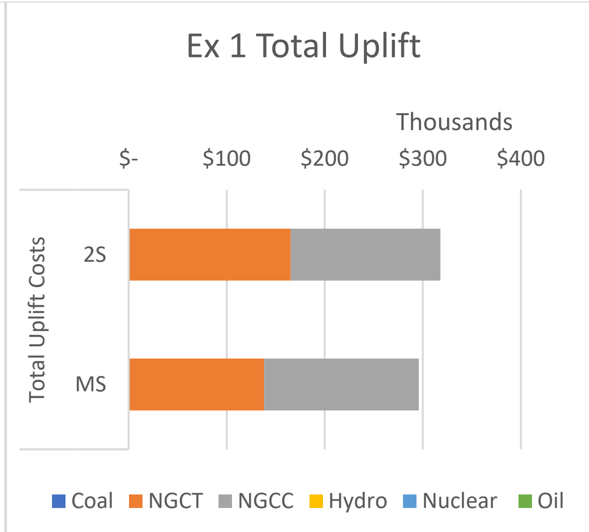
The increase in wind generation in the United States will be met with increasing need for flexibility in conventional generation infrastructure. Flexibility is not, however, a characteristic of the most efficient generation units. Due to the thermal cycle involved in heat recovery, the most efficient generation units require more notification time than the less efficient units. To reduce uplift costs the market should facilitate the dispatch of more efficient units. By including additional intraday market stages, dispatch can react to changes in forecasting. When forecasts are accurate and improving, the MS market structure achieves parity or improves on uplift costs of the 2S market structure. When forecasts are erroneous, the MS structure results in greater uplift costs than the 2S. Uplift costs were generally not reactive to sensitivities tested in the MS structure. Advancing the ID1 stage led to minor changes to dispatch. These changes exaggerated the discussed effects of the accurate or inaccurate forecasts on uplift cost, but did not result in significant change. Permitting decommitment displayed the same pattern. There was little change to uplift cost compared to the baseline.

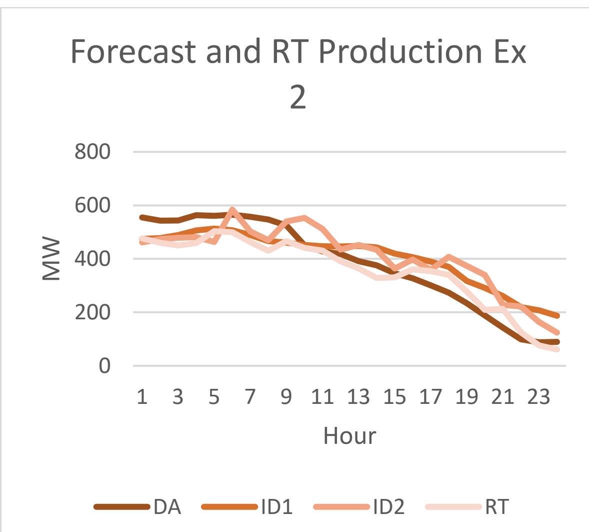
These results communicate that, regardless of more minor details of timing and permitted behavior, RTOs may benefit from the inclusion of intra-day market stages if there is sufficient evidence that their forecasting capability would lead to lower cost outcomes on average. The danger is that implementing a multi-settlement market structure could exacerbate the impacts of bad forecasting, resulting in increased costs passed along to consumers. Among the sample of days taken from ISO New England wind data, the majority did not result in a difference in uplift cost between the MS and 2S market structures. Two days resulted in greater uplift costs in the MS structure, and one day resulted in greater uplift costs in the 2S structure. This initially implies that the ISO New England would not benefit from implementing a multi-settlement market structure, and that it may increase uplift costs. However, a more wholistic analysis of ISO New England data could prove that implementing a multi-settlement market structure would improve cost outcomes.

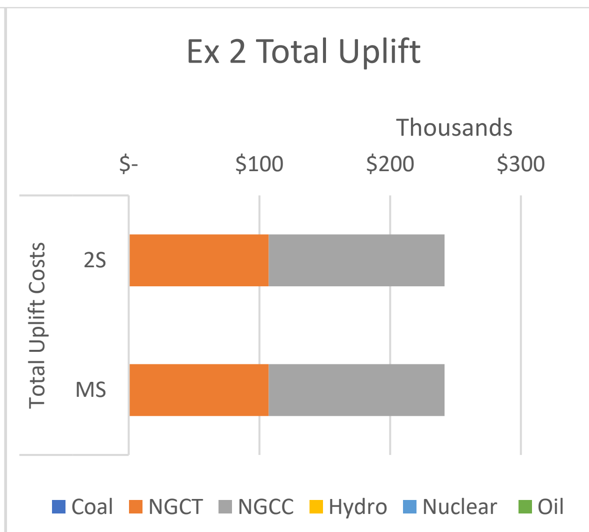
RTOs should carry out extensive modeling analysis based on their own wind production data to evaluate whether a multi-settlement market structure would facilitate lower uplift. If the results of such a study conclude that existing wind data do not support the MS structure, RTOs should consider investing resources to develop more accurate wind production forecasting. Wind cases 1 and 2 (figures 7, 8) suggest that accurate and improving forecasts result uplift cost outcomes in the MS structure that are less than or equal to those in the 2S structure. Regardless of RTO circumstances, systems with greater wind generation must be planned for. While this study did not determine that MS structures will result in lower uplift costs than 2S structures consistently, an individual RTO may find that the MS structure is beneficial in their systems or work to produce the forecasting capabilities which make this the case.

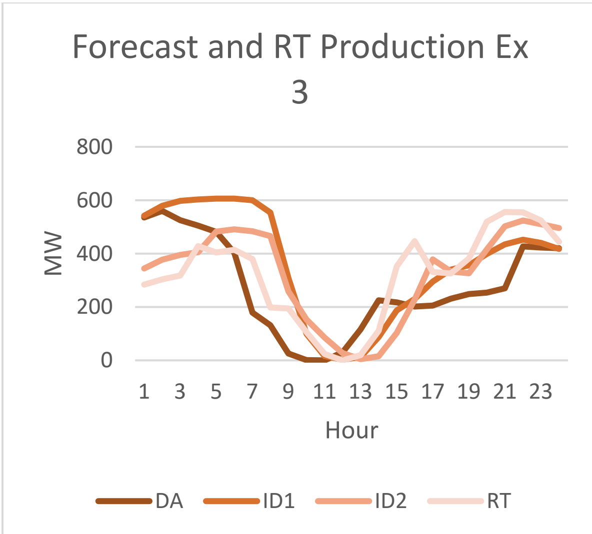
6 Appendix

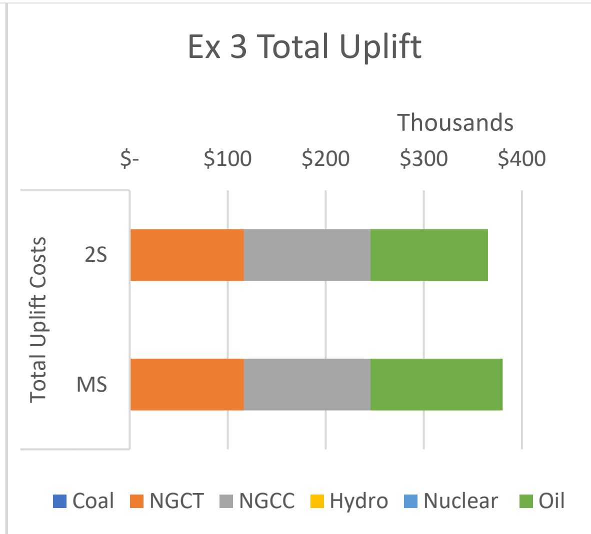

Forecast and RT Production Ex 1
800
600
400
200
0
MW
1 3 5 7 9 11 13 15 17 19 21 23
Hour
DA
ID1
ID2
RT

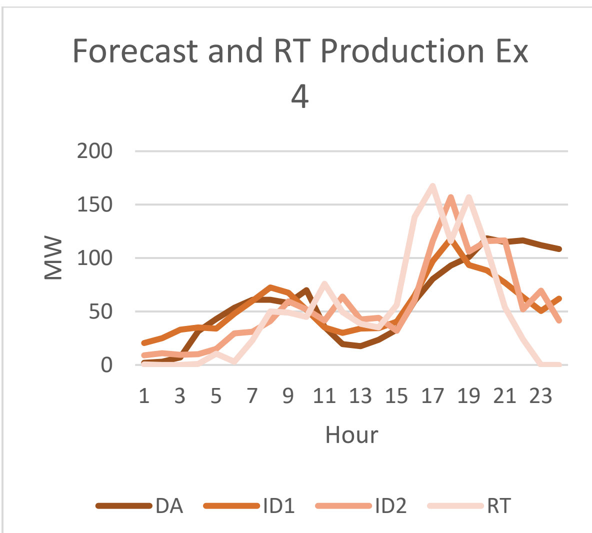

Ex 1 Total Uplift
Thousands
$- $100 $200 $300 $400
Total Uplift Costs
2S
MS
Coal
NGCT
NGCC
Hydro
Nuclear
Oil

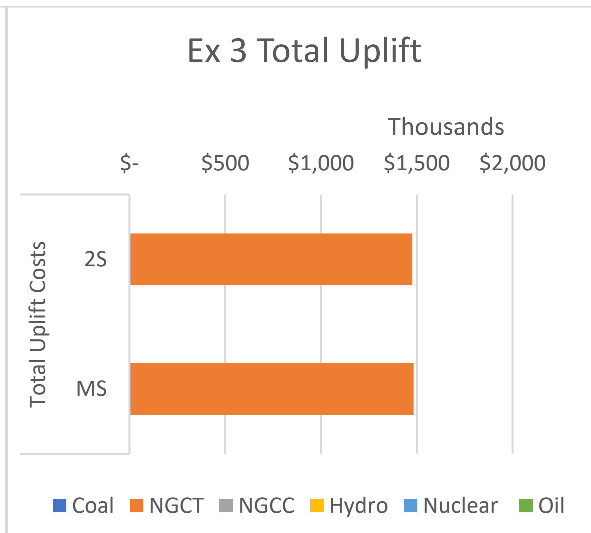

Forecast and RT Production Ex 2
800
600
400
200
0
MW
1 3 5 7 9 11 13 15 17 19 21 23
Hour
DA
ID1
ID2
RT

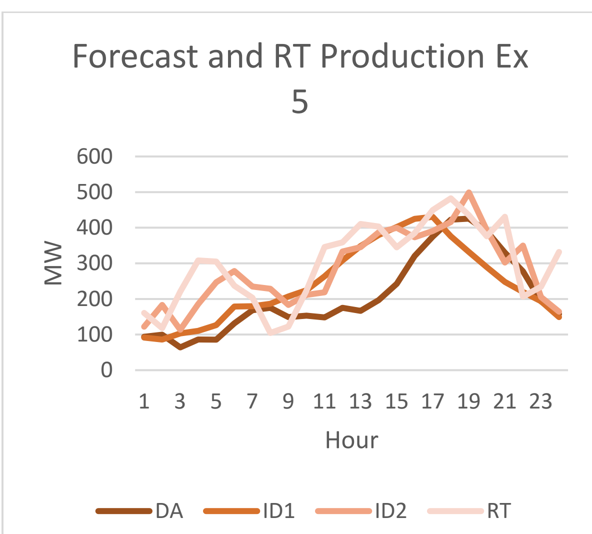

Ex 2 Total Uplift
Thousands
$- $100 $200 $300
Total Uplift Costs
2S
MS
Coal
NGCT
NGCC
Hydro
Nuclear
Oil

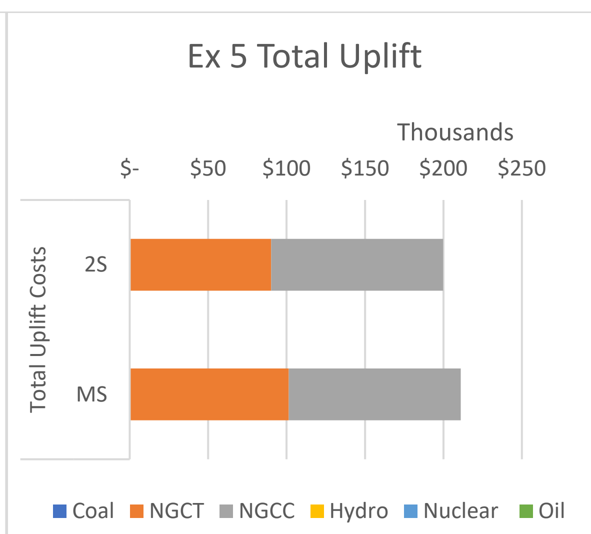

Forecast and RT Production Ex 3
800
600
400
200
0
MW
1 3 5 7 9 11 13 15 17 19 21 23
Hour
DA ID1 ID2 RT

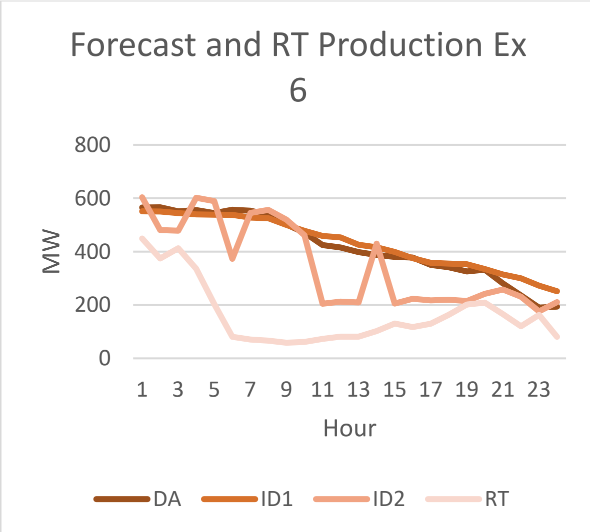

Ex 3 Total Uplift
Thousands
$- $100 $200 $300 $400
Total Uplift Costs
2S
MS
Coal NGCT NGCC Hydro Nuclear Oil

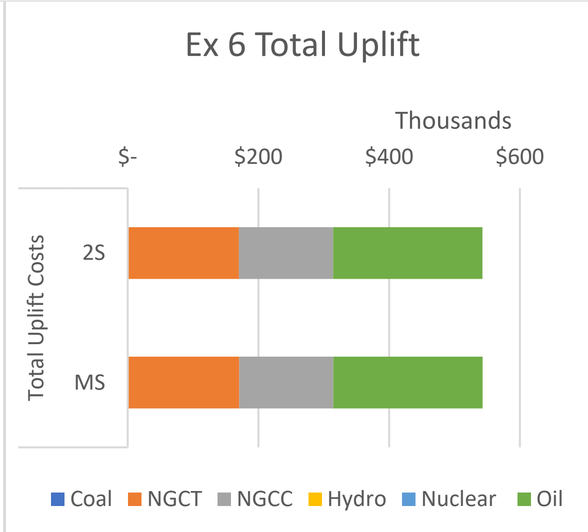

Forecast and RT Production Ex 4
200
150
100
50
0
MW
1 3 5 7 9 11 13 15 17 19 21 23
Hour
DA ID1 ID2 RT

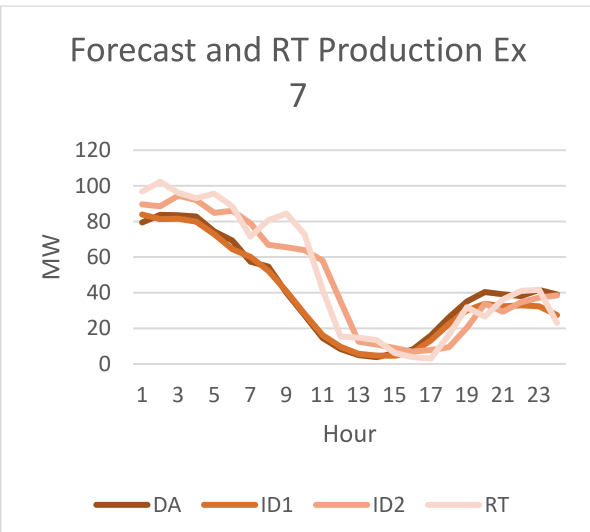

Ex 3 Total Uplift
Thousands
$- $500 $1,000 $1,500 $2,000
Total Uplift Costs
2S
MS
Coal NGCT NGCC Hydro Nuclear Oil

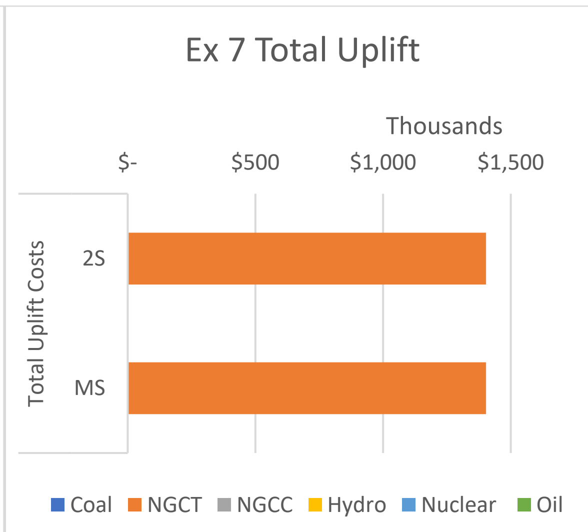

Forecast and RT Production Ex 5
600
500
400
300
200
100
0
MW
1 3 5 7 9 11 13 15 17 19 21 23
Hour
DA ID1 ID2 RT

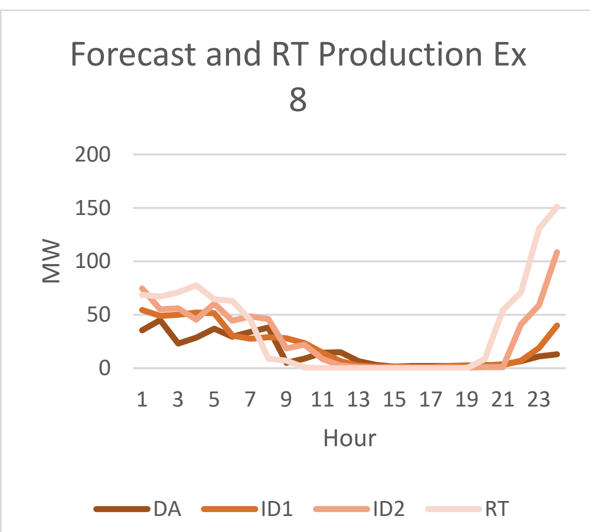

Ex 5 Total Uplift
Thousands
$- $50 $100 $150 $200 $250
Total Uplift Costs
2S
MS
Coal NGCT NGCC Hydro Nuclear Oil

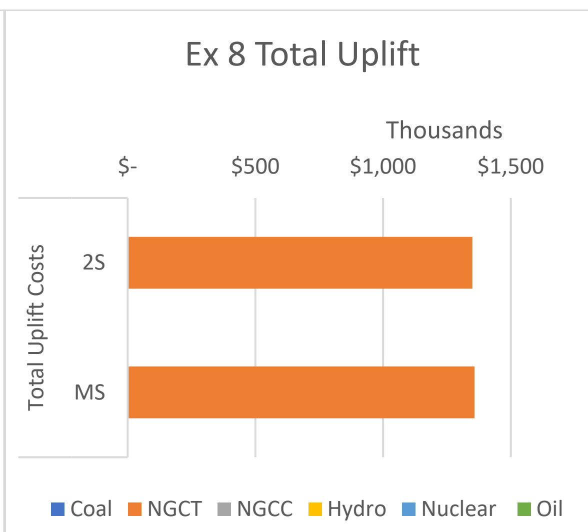

Forecast and RT Production Ex 6
MW
800
600
400
200
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour
DA ID1 ID2 RT

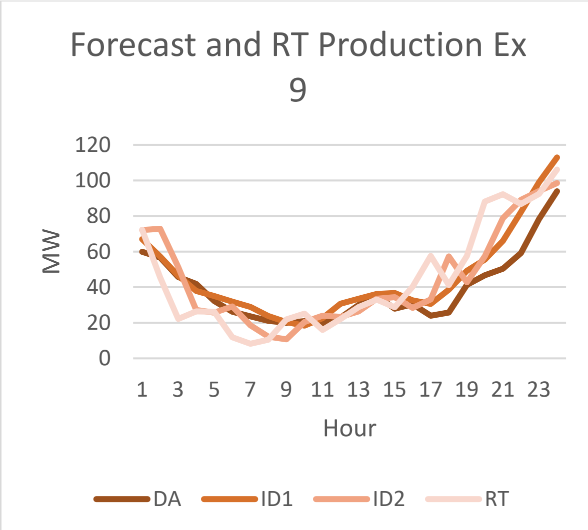

Ex 6 Total Uplift
Thousands
$- $200 $400 $600
Total Uplift Costs
2S
MS
Coal NGCT NGCC Hydro Nuclear Oil


Forecast and RT Production Ex 7
MW
120
100
80
60
40
20
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour
DA ID1 ID2 RT

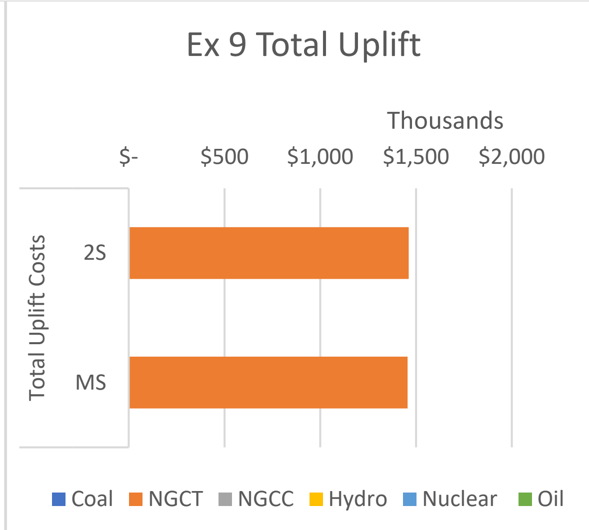

Ex 7 Total Uplift
Thousands
$- $500 $1,000 $1,500
Total Uplift Costs
2S
MS
Coal NGCT NGCC Hydro Nuclear Oil


Forecast and RT Production Ex 8
MW
200
150
100
50
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour
DA ID1 ID2 RT

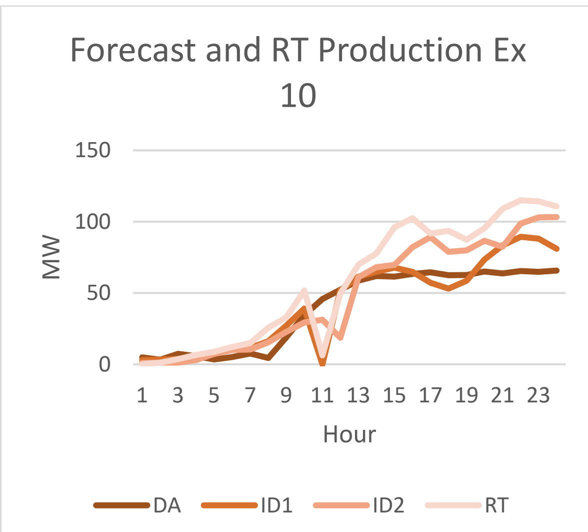

Ex 8 Total Uplift
Thousands
$- $500 $1,000 $1,500
Total Uplift Costs
2S
MS
Coal NGCT NGCC Hydro Nuclear Oil



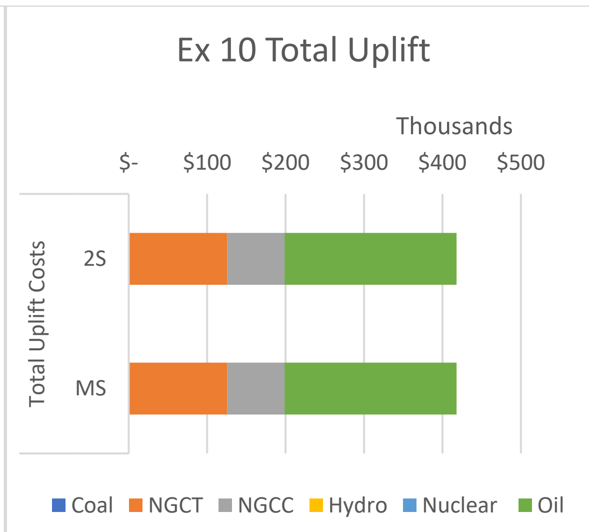
Forecast and RT Production Ex 9
MW
120
100
80
60
40
20
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour
DA
ID1
ID2
RT



Ex 9 Total Uplift
Thousands
$- $500 $1,000 $1,500 $2,000
Total Uplift Costs
2S
MS
Coal
NGCT
NGCC
Hydro
Nuclear
Oil



Forecast and RT Production Ex 10
MW
150
100
50
0
1 3 5 7 9 11 13 15 17 19 21 23
Hour
DA
ID1
ID2
RT



Ex 10 Total Uplift
Thousands
$- $100 $200 $300 $400 $500
Total Uplift Costs
2S
MS
Coal
NGCT
NGCC
Hydro
Nuclear
Oil

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ACADEMIC VITA

Spencer E. Hurst

EDUCATION

The Pennsylvania State University, University Park Graduation: August 2023

Schreyer Honors College

Major: BS, Energy Engineering, Minor: Economics

WORK EXPERIENCE

Field Engineering Intern, Mortenson Wind Group May – July 2022

- Coordinated engineering team response to daily component offload process
- Wrote work instructions for installation processes based on hands-on experience and manufacturer documentation

Project Manager, Siemens eMobility April 2021 – May 2022

- Independently managed Siemens' Meter Integrated Charger Pilot Program in partnership with ConEdison and the New York State Energy Research and Development Authority
- Developed process for customer acquisition and technical requirement vetting

Engineering Intern, Andris Consulting LLC May – Aug 2021

- Collated estimated project costs, infrastructure assessments, and annual budgets to develop project timeline for Wilmington Dept. of Public Works Master Plan
- Contributed to state of the industry report on renewable energy applications in water and wastewater treatment

LEADERSHIP AND EXTRACURRICULAR EXPERIENCE

President, Association of Energy Engineers Aug 2022 – May 2023

- Coordinated alumni and industry relationships for general body meetings
- Led the club in its first time attending the MIT Energy Conference

Member, Society of Energy, Business, and Finance Jan 2021 – May 2023

AWARDS AND SCHOLARSHIPS

College of Earth and Mineral Science, Energy and Mineral Engineering Department Student Merit Award Winner 2022

Recipient of Provost Award, Academic Excellence, George J Coleman, Mendonca Honors, Matthew J Wilson Honors, and Strickler Honors Scholarships 2019 – 2023